Consolidated

Distribution System Plan

Developed in accordance with

"Ontario Energy Board – Filing Requirements for Electricity Transmission and Distribution Applications"

Chapter 5

Consolidated System Plan Filing Requirements

March 28, 2013

Filed with Algoma Power's 2015 COS Application

File #EB-2014-0055

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Attachments

[1] Section numbers correspond to the sections in the Chapter 5 filing requirements

5.2 Distribution System Plan

5.2.1 Distribution System Plan Overview

a) Key Elements of the Plan

Algoma Power Inc.'s ("API's") Distribution System Plan ("DS Plan") consolidates API's Distribution Asset Management Program ("DAMP"), with a five-year Capital Expenditure Plan. API has prepared a plan that is based on sustaining asset replacement, reliability improvement and meeting the overall expectations of both new and existing customers. With the exception of a large TS improvement project in 2017, for which API is requesting Board review of cost responsibility, capital expenditures presented in the 2015-2019 plan are relatively consistent year over year, and represent an overall declining trend as compared to API's historical 2010-2014 capital expenditures. API's DS Plan has been developed in accordance with the OEB's Chapter 5 Consolidated System Plan Filing Requirements dated March 28, 2013 and initially capitalized terms referred to herein have the same meanings as those ascribed under such filing requirements.

Capital spending by category is designed to meet both customer-driven and asset-driven requirements. System Access spending is based on historical actual levels required to meet regulatory obligations for connections, upgrades and plant relocation driven by customers and third parties. System Renewal spending levels are driven by sustaining proactive asset replacement programs, mainly driven by pole replacement. Target replacement rates are based on consideration of the number, type, age and condition of in-service assets. System Service spending is focused on reliability-driven projects, which are prioritized based on outage analysis and consideration of the impact of contingency scenarios. Finally, spending in the General Plant category is focused on ensuring that adequate tools, equipment and systems are in place to support the day to day operations of API's business. The majority of this category comprises levelized annual spending on items such as tools, equipment, fleet, IT and land rights, as well as programs related to vegetation management.

Recent investments in various business systems (SAP, GIS/OMS, SCADA, Vegetation Management, etc.), and continued development and integration of these systems are expected to continuously improve API's asset management and capital planning processes. These systems are also expected to assist with reliability improvement initiatives and will improve API's ability to provide better information to its customers in terms of outage updates and detailed Time of Use consumption history.

API has undertaken significant stakeholder consultation for many years. Customer engagement activities have also been expanded and have become more formalized (e.g. annual customer satisfaction survey) in the previous five years since API became part of the FortisOntario group. API's DS Plan incorporates the customer feedback obtained through a large variety of customer and stakeholder consultation activities, as described more fully in Sections 5.2.2 and 5.2.3 below.

b) Expected Sources of Cost Savings

The sustaining asset replacement programs identified in the System Renewal category are expected to have a number of positive impacts on future O&M costs:

- Proactive pole replacement prior to failure of the in-service pole or associated components will reduce costs associated with outage response and reactive replacement. Given the extremely rural nature of much of API's service territory, the cost associated with single pole replacement on a reactive basis is significantly higher than for multi-pole replacement as part of a sustained program.
- The recloser replacement program allows for replacement of legacy units that can no longer be economically maintained. The type of replacement units now available results in a much less labour-intensive program of inspection and corrective maintenance as required, as opposed to the periodic preventive maintenance required for legacy assets.
- Any voltage conversion work that occurs in conjunction with line rebuilds on legacy lower voltage systems will have a positive impact on reduction of line losses.

Reliability-driven programs in the System Service category, as well as SCADA investment and the ROW Hardening program are expected to have positive impacts on overall system reliability, resulting in lower costs associated with outage response. Over time, the continued deployment of SCADA-capable devices and integration of these devices to a central control room is also expected to decrease costs associated with certain routine switching operations.

Additional asset and condition information and system operating data available from SAP, GIS, OMS and SCADA will allow for:

- Efficiencies in the conceptual and detailed design processes, in terms of reduced site visit requirements by engineering and operations staff;
- Increased accuracy of cost analysis for items such as line losses and avoided future costs during the project prioritization process; and
- Adjustments to inspection and maintenance programs for certain asset types (e.g. move from time-based to condition-based maintenance) due to the availability of more detailed asset condition information and operating records

c) Period Covered by the DS Plan

API's DS Plan includes 2010-2014 as the historical period and 2015-2019 as the forecast period (with a 2015 Test Year).

d) Vintage of Information on Investment Drivers

Although API has existing and reasonably effective processes for the maintenance of asset records, inaccuracies have been observed. A complete inventory of standard distribution (excluding sub-transmission express feeder) pole and line assets was conducted in the early 1980's using standard collection methods available at the time. Those methods included listing asset features, producing sketches on occasion and the measurement of spans by means of a hip chain. Since that time, documentation of changes to API's assets such as as-built drawings and written entries on work orders have been used to update the records. Due to limitations of the update process and shortcomings in the databases and software that previously stored these records, there have been errors and omissions populating that data.

API's asset records have been and continue to be valuable as aids in planning asset maintenance and rebuild requirements, but it is recognized that those efforts would be better served by a more reliable and accurate data set. API will endeavour over the next three to five years to audit and revise asset records and to collect more spatially accurate data using GPS and GIS technology. A parallel and continual effort to improve API's records maintenance processes will accompany the GPS data collection in order to ensure that asset data integrity will be protected.

In order to collect and update asset records in an efficient and cost-effective manner, API is investigating the feasibility of collecting the required information in conjunction with its regular pole testing program. Preliminary testing of specialized data collection equipment during the 2013 pole testing program has shown encouraging results with relatively minimal incremental costs. Also, engineering staff will begin collecting additional asset data as part of the design process for service connections and upgrades, and during the commissioning process for planned pole replacement projects. This will more efficiently utilize the significant time travelling to certain areas of the system during the course of regular day-to-day activities.

Independent of the efforts described above to improve the accuracy of API's asset record databases, API collects data on asset condition through a variety of regular inspection and maintenance programs. As shown in the flowchart in Section 5.3.1(b), this condition information feeds into the Asset Condition Assessment process, which ultimately drives project identification and prioritization. The vintage of information on asset condition ultimately depends on the frequency of the inspection and maintenance programs associated with that asset type. For most feeder-related assets (poles, hardware, conductor, transformers, switches, etc.), the asset condition information will range from one to six years old. Assets in substations and on express feeders are generally inspected and maintained more frequently. Condition information on substations is current to within less than one year. Express feeder information is generally current within one to three years.

e) Asset Management Plan Development

API has not previously submitted a formal DS Plan. Since API's previous Cost of Service application, API has developed a comprehensive DAMP, which is included as Appendix A to this DS Plan. The DAMP provides a high-level overview of API's distribution system and managed electrical assets, with detailed information on the inspection and maintenance programs by asset type, as well as the planning and condition assessment processes by which these assets are managed. The continuation of programs such as pole testing, infrared scanning and DGA analysis have improved API's ability to more accurately assess the condition of in-service assets. API expects that continued implementation and integration of business systems such as SAP, GIS, OMS, SCADA and Vegetation Management will provide improved analytic capabilities to assist with project prioritization within the programs identified in the current five-year DS Plan.

f) Contingencies

Contingencies Related to Transmission Supply Point Investments

API has included the Echo River TS upgrade project in 2017 as part of the current five-year plan, based on interpretation of the TSC that API is ultimately responsible for the upgrades that are required to improve reliability and contingency performance. API is working with GLPT to determine who bears cost responsibility for this project. Should API and GLPT not be able to resolve this issue, API may apply to the Board at a future date for a determination. Depending on the outcome, this project could be removed from API's plan.

API intends to address the adequacy of other supply point contingencies with GLPT, through the Regional Infrastructure Planning process. Given the current uncertainty over the ultimate cost responsibility (transmission vs. distribution) for resolving these concerns, and the uncertainty surrounding the timing of any potential projects, API has not included any related capital expenditure in this five-year DS Plan.

API has recently received confirmation to proceed with the required transmission and distribution impact assessment processes for a proposed large load addition on its No.4, 44 kV express feeder. This request, combined with a recently announced expansion at an existing mining customer site, and potential resumption of milling operations in Dubreuilville, would require a significant reconfiguration of the existing transmission supply to the area 44 kV system. API intends to further evaluate the potential load scenarios in the area with GLPT to determine the most appropriate solution to meet the long-term needs of API customers in the area. Given the preliminary nature of the impact assessment, and the range of possible options for system expansion, API has not included any related capital expenditure in this 5-year DS Plan.

More detailed descriptions of the above issues are included in Section 5.3.2(d) below. API expects that any additional investment required by API as a result of these contingency or load growth issues would be significant relative to its overall capital program. As a result of the potentially significant investment, and the uncertainty of future projects, API believes that any resulting projects would be addressed by one or more ICM applications, as required.

Contingencies Related to Asset Replacement

In the course of preparing the DS Plan, API has become aware of an increasing occurrence of failing porcelain cutouts, causing worker safety and reliability issues. Preliminary visual inspection of failed cutouts has revealed hairline cracks, with failure in approximately the same location on many of these devices. API is collecting a sample of failed cutouts to send to a third party for a more in-depth failure cause analysis. API is also reviewing the impacts to operating practices associated with these devices. Depending on the outcomes of these investigations, and determination of the number of in-service devices that are impacted by this issue, it may become necessary to implement a cutout replacement program within the five-year period covered by the DS Plan.

5.2.2 Coordinated Planning with Third Parties

a) Regional Planning

API falls into the East Lake Superior area, which is included in Group 2 of the Regional Infrastructure Planning ("RIP") process. GLPT has initiated the RIP process, and API has provided feedback on supply point contingency issues that are of greatest concern, from reliability and capacity perspectives. RIP process correspondence between API and GLPT is attached as Appendix B.

Customer Engagement

API actively communicates with its customers regarding ongoing business elements, accomplishments and changes in regulatory matters. Specific communication to API's customers regarding this 2015 COS rate application, has been through API's annual stakeholder sessions which began in February 2014. API promotes open dialogue and seeks customers' feedback and experiences to shape its business direction where practical and with regard to its long-term strategy of improving reliability, service quality and capacity.

The unique geography of API's 14,200 square kilometre service territory presents challenges in reaching all of the communities in which it serves. API has developed a multi-channeled communication model to reach out and engage its customers, stakeholders and third parties with whom they do business. Below, these channels are described in more detail.

Bill Inserts – API send bills inserts regularly to its customers with the monthly invoice. This includes a semi-annual newsletter “Making Connections” which provides information on specific customer initiatives, safety messages, community involvement, distribution and cost of power rate information and information regarding current CDM initiatives.

Annual Meetings with Large Customers – Annually, large general service customers are invited to meet with the Company to review opportunities and to explore conservation initiatives and opportunities as well learn more about changes in the industry and the Company’s efforts to address the changes. Customers are encouraged to ask questions and provide feedback in support of API distribution activities.

Corporate Website – The website provides a one stop location for API’s customers to gain access to important information on distribution services, rates, regulatory matters and decisions, customer initiatives, conservation and demand management programs. API’s website also provides customers a mechanism to correspond with API. In 2013 API began offering e-billing via the website and a web portal to allow customers access to time-of-use consumption information.

Annual Customer Survey - Annually, Algoma Power conducts a customer satisfaction survey. The telephone survey is conducted by a third party and is comprised of eight main questions. The chart below depicts overall customer satisfaction, reliability and safety and quality of service results since its inception, in 2010.

	2010	**2011**	**2012**	**2013**
Overall Satisfaction	69	73	74	72
Reliability and Safety	88	85	91	92
Quality of Service	77	83	85	83

Each category has seen increases since 2010. The customers continue to rate Algoma Power highest in providing safe and reliable delivery of electricity. The survey provides valuable feedback and identifies areas in need of improvement. In 2013, the customers identified a need for API to improve in providing timely and accurate information during power outages. As a result, API is focussed on implementing better ways to reach customers during power outages such as engaging in social media. The implementation of an OMS will also assist in providing more accurate outage and restoration information to customers.

Conservation and Demand Management ("CDM") Programs – API remains diligent in promoting and engaging customers through its CDM programs. A variety of outreach efforts have been deployed including the placement of ads in municipal publications, marketing material displays in keys areas of all municipalities and community outreach events and Home Shows. These events provide an opportunity to interact with customers at a grassroots level.

School awareness events have proven to be a very useful way to increase attention to the subject of Energy Conservation at the primary level. The Aboriginal community has been engaged through Lunch and Learn events held in the most Northern portion of the service territory.

In an effort to further educate and engage its business customers CDM efforts have involved providing over 30 (no charge) Spot the Opportunity energy efficiency assessments with Burman Energy and a Key Account Manager ("KAM") shared resource on three occasions. In addition, API has delivered a technologies symposium in cooperation with the Sault Ste. Marie PUC inclusive of a workshop, presentations and trade show component. A booth at agricultural events has been utilized to reach out to agribusiness communities. API also participated as a delegate at the Algoma District Municipal Association bi-annual meetings in which 30 municipal officials ranging from Mayors and Councillors to Clerks attended.

CDM activities are on-going and will remain a key channel to reach out and engage API's customers.

Algoma Power engages stakeholders and third parties within whom they do business with in a number of ways:

Annual Municipal Stakeholder Meetings - Annually, API sets an agenda of current customer service initiatives, public safety initiatives, conservation demand management updates, including incentives, and operations maintenance and capital projects. 17 municipal councils, planning boards and First Nation councils within its service territory are contacted to schedule attendance at one of their meetings. Each presentation provides the councils with updates and encourages dialogue between council and API on a number of levels. The operational topics discussed are tailored to each municipality. Councils have commented positively on the value these presentations provide.

Other Noteworthy Engagements - API hosts an Annual Contractor Safety Night with local contractors and invites the local office of the Electrical Safety Authority (ESA). The event provides discussions on Public Safety issues, Customer Service topics regarding interactions between API and the contractor community as well any changes to API's customer connection process.

Annual Road Superintendent Meeting - This spring event brings together API Operations staff with local Townships, Roads Boards agencies, and the Ministry of Transportation (MTO). API presents short term and longer term capital and maintenance outlooks for the next three years to the participants with broad descriptions of the scopes of work. The intent of the discussion is to share work program locations and timing, looking for either synergies in the work flow or ways to avoid conflicting work schedules and project timing.

Safety issues related to road maintenance are also discussed highlighting working clearances to energized conductors and ditching activities in very close proximity to API's circuits. The meeting also features an open general discussion to address specific operations issues of importance to attendees.

MTO Annual Utility Meeting - API attends this annual meeting where local Ministry of Transportation staff present short and long term capital and maintenance plans. MTO issues affecting the various utility companies are discussed and a forum is presented for API staff to raise any issues they have encountered in relation to MTO practices or along MTO rights-of-way since the previous year's meeting.

Bell Aliant Quarterly Joint Use Meetings - Beginning in June, 2014, API will meet quarterly with local representatives from Bell Aliant to discuss each company's upcoming and ongoing capital and maintenance projects. The purpose of these meetings is to ensure both companies can coordinate resources for demand work initiated by a joint use request as well as to monitor the progress of work related to these joint use requests.

MNR Species at Risk Review - Throughout the calendar year, the location of each capital project undertaken by API is sent to local Ministry of Natural Resources offices for a species at risk review. The MNR provides guidance to API regarding species at risk in the area, often proposing work windows to minimize impacts to species during critical breeding and/or nesting periods. For vegetation at risk, the MNR provides their location so that API can identify them in the field and ensure measures are taken to minimize impacts to these specimens.

API will continue its on-going efforts of engaging its customers through this multi-channeled model. By utilizing this model, customers can actively provide feedback and be aware of the Company's on-going activities while staying current with industry changes. In 2014, API will continue to expand this model with the introduction of social media as yet another channel to reach its customers. Overall, this approach presents many channels to customers to actively engage with API.

b) As the Regional Planning Process for the East Lake Superior area is current in preliminary stages of information exchange between LDC's and the lead transmitter, there are no deliverables available at this time.

c) The comment letter provided by the OPA in relation to REG investments is included as Appendix D.

5.2.3 Performance Measurement for Continuous Improvement

a) Methods of Measurement

Customer Oriented Performance

As mentioned in Section 5.2.2 above, API conducts annual customer surveys and engages in a large variety of consultation activities with customers and stakeholders. The feedback obtained through these activities provides API with a sense of customer preferences that can be considered in both short-term and long-term plans. Based on this feedback, API has transitioned to a long-term sustaining Pole Replacement program on completion of its High-Risk Conductor Replacement program. API believes that sustaining asset replacement is the best way to avoid the reliability and cost impacts that would be associated with reactive replacement of poles that have failed or are near failure.

API has also included a number of reliability-driven initiatives in both recent years and in the current plan to address concerns of overall reliability levels, outage response times and communication to customers during outage events. These initiatives include continued investment in business systems (GIS/OMS, SCADA), a ROW Hardening program, specific substation projects to address shortcomings in contingency plans, and general reliability improvement programs within the System Service category. Specific examples of how customer feedback has influenced the inclusion of specific projects and programs can be found in Section 5.2.3(c) below.

API also compiles and submits a variety of performance-based reports for internal analysis and/or submission to the Board on a regular basis. This includes items such as reliability statistics and ESQR reports to the Board. As these reports are compiled, they are reviewed to determine if any failure to meet target performance levels, or any trending in performance requires any corrective action, or any adjustments to future capital or maintenance programs.

Cost Efficiency and Effectiveness With Respect to Planning Quality and DS Plan Implementation

While API's capital programs for sustaining replacement are based on estimated unit costs (e.g. cost/pole), more specific project-level estimates are prepared during the detailed design stage. In advance of committing to a scope of work and budget for any individual project within a program, the detailed designs and estimates are issued to the operations group in charge of construction for review and commitment to the scope and budget. This process assists with ensuring that all project-level estimates are realistic and that ongoing actual vs plan cost analysis is meaningful. Project costs are also reviewed on completion to ensure that any significant variances from planned costs are justifiable (e.g. due to shallow rock not identified during the initial design, due to increased travel time caused by inclement weather, etc.). The analysis of these costs and variances also ensures that the unit cost estimates used for future program-level planning continue to be reasonable.

Members of the operations, forestry, engineering, finance and procurement departments also meet on a monthly basis to review progress (physical and financial) on the annual capital program. This process ensures that all departments are aware of any issues that may impact project timing or budgets and allows for rescheduling or reprioritization of various items within the annual plan to ensure efficient use of resources and completion of overall annual targets.

This process also helps to identify opportunities for improvement in execution of the capital plan. For example, monthly meetings in recent years have identified that issues with Species at Risk legislation have affected the timing of many projects in specific areas of API's system. As a result, API has worked with the MNR to proactively identify Species at Risk issues earlier in the design process, and has also advanced the design process in relation to the timing of construction to allow more opportunity to schedule activities around timing restrictions imposed by the MNR.

Asset and/or System Operations Performance

API's System Interruption Reports contain detailed information on outage location, cause, equipment involved and customers impacted. There is also a section where recommendations and comments can be made by the operational staff involved in outage response where they believe that follow-up by other departments is warranted. As the outage records are populated in API's outage database, copies are also circulated to any department flagged for follow up action. This ensures that specific issues of concern (e.g. repeated failure of a certain type of equipment, forestry concerns on a specific line section, etc.) are routed to the department that can most adequately resolve the issue.

b) Summary of Performance and Performance Trends

A key objective of API is to achieve and subsequently maintain a high level of distribution system reliability. Capital investments are aimed at improving or maintaining reliability by proactively upgrading deteriorating facilities. Where possible and practical, investments are also made to add system redundancy so that customers can be supplied from alternate paths in emergency or planned outage situations. Investments in systems such as SCADA and OMS will provide real-time system information that facilitates the rapid identification of system problems and remote switching to improve the efficiency of outage response.

Maintenance programs and operational practices are also designed with reliability in mind. For example, API maintains industry-standard systematic vegetation management programs to ensure that appropriate clearances are maintained between power lines and surrounding vegetation. In forced outage situations, outage response efforts focus on locating and repairing the faulted areas promptly so that affected customers can be restored. When system components must be taken out of service for planned maintenance, switching is carried out so as to minimize disruption to customers.

API currently maintains an Access database of all outages that occur on its distribution systems. This allows for the tracking and analysis of reliability performance. SAIDI and SAIFI indices are computed from the data. These indices are defined as follows:

- SAIDI, System Average Interruption Duration Index – reflects the total outage time to the average customer over a period of one year.
- SAIFI, *System Average Interruption Frequency Index* – reflects the number of interruptions to the average customer over a one-year period.

Indices are computed on a monthly and annual basis. Data is submitted to the Ontario Energy Board in accordance with regulatory requirements. In addition, data is also analysed internally by API to identify reliability trends and potential areas for reliability improvement.

Reliability Results

Interruptions to the distribution network are recorded and reported annually to the OEB as a condition of API's license. The tables below classify the outage contributions based upon the significant challenges that API faces with the structure of its distribution network. Express Feeder data includes Tree Contact, Planned Work, and Forced outage data specific to express feeders. Within the table categories, Tree Contact, Planned Work and Forced exclude outage data related to Express Feeders.

SAIDI					
Outage Type	**2009**	**2010**	**2011**	**2012**	**2013**
Loss of Supply	0.055	1.520	2.317	0.376	4.821
Express Feeder	1.880	3.397	2.646	3.128	0.220
Tree Contact	2.688	2.370	2.987	2.157	6.810
Planned Work	3.693	6.888	4.239	4.320	2.198
Forced (All other causes)	1.544	2.476	1.500	1.338	2.751
API - OEB Reporting	**9.86**	**16.65**	**13.69**	**11.32**	**16.80**

SAIFI					
Outage Type	**2009**	**2010**	**2011**	**2012**	**2013**
Loss of Supply	0.056	0.917	1.565	1.353	4.513
Express Feeder	0.902	0.848	2.036	4.869	0.802
Tree Contact	0.949	0.727	1.207	0.850	1.208
Planned Work	0.822	1.585	1.046	1.181	0.605
Forced (All other causes)	0.689	0.544	0.491	0.808	1.044
API - OEB Reporting	**3.42**	**4.62**	**6.35**	**9.06**	**8.17**

2013

Loss of Supply events provided a 4.821 SAIDI contribution. API has been actively working with the transmitter in reviewing root causes of each outage and exploring solutions to address potential reoccurrences.

Express Feeders contributed 0.220 to API's annual SAIDI. Significant contributors within the Express Feeder category were Equipment Failure (0.134), Lightning (0.027) and Wildlife (0.025) to the annual SAIDI. Within the Express Feeders category, Tree Contacts and Planned Work did not provide significant contributions.

Tree Contacts provided an annual SAIDI contribution of 6.81. An example of tree related outages occurred on June 2 2013, when a tree fell onto a feeder in the Goulais Mission area (approximately 47 kilometers northwest of Sault Ste. Marie) causing an interruption that impacted 82 customers for 2.8 hours. This interruption contributed 0.019 to API's annual SAIDI. The 98 minute response time was attributed to the location of the outage, road conditions, current weather conditions, and the location of the responding line crew.

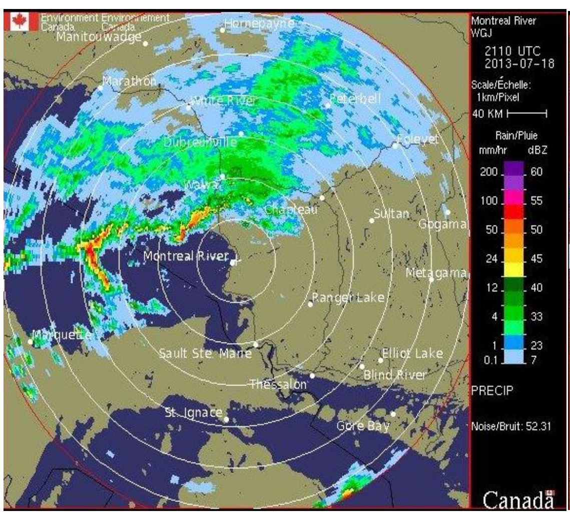
Planned work activities contributed 2.198 to API's annual SAIDI. Planned Work activities include conductor replacement projects, planned vegetation management work, and daily work such as single pole replacements and customer connections.

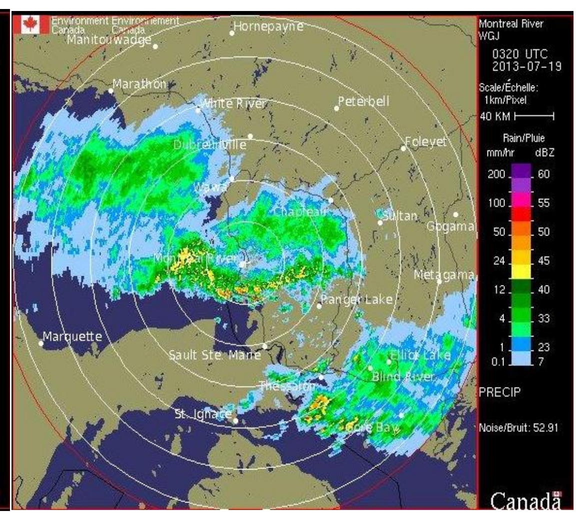
Forced outages from all other causes contributed 2.751 to API's annual SAIDI value. A significant contributor within this outage type was defective equipment, which resulted in a SAIDI contribution of 1.60 and a SAIFI contribution of 0.67. An example of a failed piece of equipment occurred February 14, 2013, when a fuse cutout body failed causing an interruption that impacted 366 customers for 4.75 hours in a rural seasonal area located approximately 15 kilometers north of the village of Desbarats. Based upon the location of the outage, road conditions, current weather conditions, and the location of the responding line crew, API response time for this outage was 75 minutes. Response time is defined as the amount of time elapsed between API becoming aware of the outage, and the arrival of the first crew on site.

<u>Notable Events in 2013</u>

<u>July 18 / 19 2013</u>

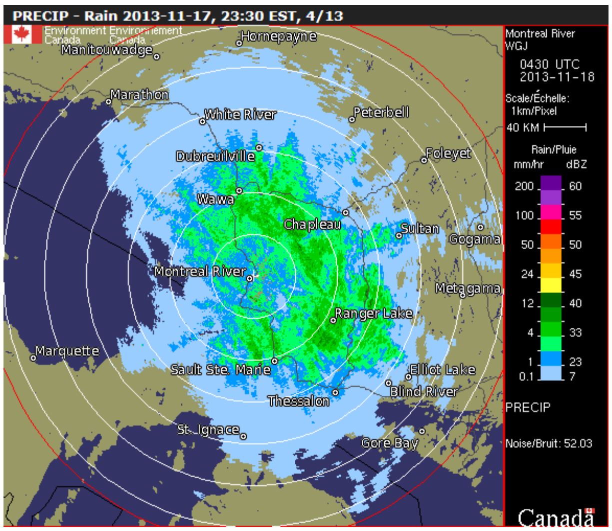
A major thunderstorm moved throughout API's service territory with high winds, heavy rain and significant lightning activity covering API's entire 14,200 sq. km service territory. Outages due to the weather were reported throughout API's distribution system from Wawa to St Joseph Island, with the storm primarily impacting API's Batchawana and Goulais distribution networks. 2251 customers were impacted (19.36% of the customer base) with outage durations ranging from 1 hour to 21.2 hours. Multiple tree contacts due to high winds with rain and lightning were the major causes of outages. Loss of Supply, Express Feeders and Planned Work did not contribute to this outage. July 18 contributed a combined SAIDI of 2.433 and SAIFI of 0.218 to the annual reliability statistics. Crews and staff from 2 service centres were deployed on a 24 hour round-the-clock basis in order to restore all customers.

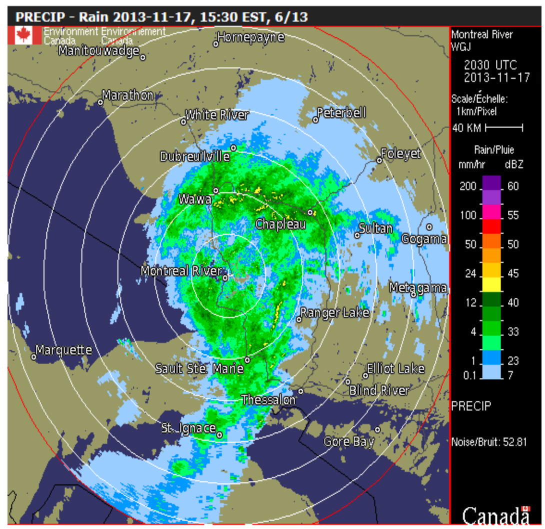




<u>November 17 and 18, 2013</u>

A major storm system moved throughout API's entire 14,200 sq km service territory with high winds, and heavy rain. Outages due to the multiple tree contacts with heavy wind were reported in the Goulais service area north of Sault Ste. Marie and the Bar River service area in a section of API's eastern distribution system. 2901 customers were impacted (24.8% of the customer base) with outage durations ranging from 1.5 hour to 27.3 hours. Multiple trees contacts due to high winds with rain were the major cause for the outages. November 17 and 18 contributed a combined SAIDI of 3.09 and SAIFI of 0.336 to the annual reliability statistics.





Crews and staff from all 3 service centres and multiple trades groups were deployed on a 24 hour round-the-clock basis in order to restore all customers.

In 2013 API's average response time was 92.4 minutes based upon the location of the outages, road conditions, current weather conditions and the location of the responding line crew.

2012

Loss of Supply events provided a 0.376 SAIDI contribution.

Express Feeders contributed 3.128 to API's annual SAIDI. Significant contributors within the Express Feeder category were Planned Work (1.942), Lightning (0.588) and Unknown Causes (0.136) to the annual SAIDI. Within the Express Feeders category, Tree Contacts and Equipment Failures did not provide significant contributions.

Tree Contacts provided a SAIDI contribution of 2.157. An example of tree related outages, on August 5 2012 a spruce tree fell onto a feeder in the Goulais area north of Sault Ste. Marie, causing an interruption that impacted 735 customers for 5 hours. This interruption contributed 0.314 to API's annual SAIDI.

Planned work activities contributed 4.32 to API's annual SAIDI. Planned work activities include conductor replacement projects, planned vegetation management work, and daily work such as single pole replacements and customer connections.

Forced outages from all other causes contributed 1.338 to the annual SAIDI value.

In 2012, API's average response time was 146.2 minutes based upon the location of the outages, road conditions, current weather conditions, and the location of the responding line crew.

<u>2011</u>

Loss of Supply events provided a 2.317 SAIDI contribution. Express Feeders contributed 2.646 to API's annual SAIDI. Significant contributors within the Express Feeder category were Tree Contacts (1.21), Failed Equipment (0.663) and Adverse Weather Snow (0.492).

Tree Contacts provided a SAIDI contribution of 2.987. An example of a tree related outage occurred on August 14 2011 after a tree fell onto an off road section of the power line in the Batchawana area. The outage lasted 4 hours and impacted 879 customers. Response time was 75 minutes travelling north along Highway 17 from Sault Ste. Marie, which contributed to the restoration time.

Planned work activities contributed 4.239 to API's annual SAIDI. Planned work activities include conductor replacement projects, planned vegetation management work, and daily work such as single pole replacements and customer connections.

Forced outages from all other causes contributed 1.50 to the annual SAIDI value.

In 2011 API's average response time was 106.1 minutes based upon the location of the outages, road conditions, current weather conditions, and the location of the responding line crew.

2010

Loss of Supply events provided a 1.52 SAIDI contribution.

Express Feeders contributed 3.397 to API's annual SAIDI. A significant contributor within the Express Feeder category was Planned Work (2.857). In 2010 significant projects on the express feeders east of Sault Ste. Marie were completed. A new transformer was installed at the Desbarats DS to supply St Joseph Island as well as the related voltage conversion work required at this substation to accommodate supplying St Joseph Island.

Tree Contacts provided a SAIDI contribution of 2.370. An example of a tree related outage occurred on June 27 2010, after a large maple tree fell on to a circuit breaking a pole and 2 phase primary conductors in the Batchawana area. The outage lasted 6.5 hours and impacted 737 customers. An outage response time of 90 minutes, travelling north along Highway 17 from Sault Ste. Marie. contributed to this outage.

Planned work activities contributed 6.888 to API's annual SAIDI. Planned work activities include conductor replacement projects, planned vegetation management work, planned major equipment replacements, and daily work such as single pole replacements and customer connections. An example of a planned outage occurred on June 22, 2010 for a construction project to replace poles in the Wawa area. The outage lasted 5.66 hours and impacted 106 customers.

Forced outages from all other causes contributed 2.476 to the annual SAIDI value. An example of a forced outage occurred on August 5 2010 in the Wawa area caused by lightning lasting 1.83 hours and impacting 59 customers. This outage had a SAIDI contribution of 0.009.

In 2010 API's average response time was 74.0 minutes based upon the location of the outages, road conditions, current weather conditions, and the location of the responding line crew.

2009

Loss of Supply events provided a 0.055 SAIDI contribution.

Express Feeders contributed 1.88 to API's annual SAIDI. Significant contributors within the Express Feeder category were Defective Equipment (1.238) and Adverse Weather - High Winds (0.598). On January 19 2009 a piece of equipment failed resulting in a 2.81 hour interruption impacting the eastern service area of API and 5144 customers.

Tree Contacts provided a SAIDI contribution of 2.668. An example of a tree related outage occurred on August 29, 2009 after a tree fell into a circuit on St Joseph Island, east of Sault Ste. Marie. The outage lasted 4 hours and impacted 1202 customers.

Planned work activities contributed 3.693 to API's annual SAIDI. Planned work activities include conductor replacement projects, planned vegetation management work, planned major equipment replacements, and daily work such as single pole replacements and customer connections. An example of a planned outage occurred on November 10, 2009 for the ROW Expansion program, in the Batchawana area. The outage lasted 6.08 hours and impacted 647 customers.

Forced outages from all other causes contributed 1.544 to the annual SAIDI value. An example of a forced outage occurred on December 26 2009 north of Desbarats caused when a snow plow hit a pole causing it to lean and the impact also dislodged the attached conductors. The outage lasted 4.0 hours and impacted 13 customers. This outage had a SAIDI contribution of 0.0044.

In 2009 API's average response time was 135.9 minutes based upon the location of the outages, road conditions, current weather conditions, and the location of the responding line crew.

Aside from its current operational and data management practices pertaining to reliability performance, API in the process of implementing a computerized Outage Management System to improve the effectiveness of its outage response in terms of problem identification, internal communications, and dissemination of information to customers, crew dispatching, and automated collation of outage data. API is participating and monitoring developments in OEB initiatives to introduce reliability performance into the regulatory regime, in preparation for the implementation of such requirements.

c) Effect on Distribution System Plan

Ongoing review of reliability statistics and the results of customer feedback show that customers desire both improved reliability and improved communication during outages with respect to status and estimated restoration times. As a result, certain information revealed through historical outage analysis has been a significant driver in the development of the DS Plan. Examples of both completed and planned activities that have been implemented to assist with meeting reliability improvement objectives are:

- As a result of the ongoing impact of tree-related outages, API engaged Ecological Solutions Inc., a third-party expert in utility vegetation management practices, to complete a comprehensive review of the current status of API's ROW's and vegetation management program, as well as to provide recommendations on a go-forward basis. The results and recommendations of this exercise have influenced both the capital and maintenance programs in this DS Plan.
- API has included sustaining Pole Replacement and Recloser Replacement programs in order to avoid the significant reliability impacts that would be associated with reactive replacement of these assets on failure.
- After increasing frequency of express feeder outages with no apparent cause, Operations crews were instructed to conduct more extensive patrols and to note additional detail on interruption reports for future events. Evaluation of comments and recommendations on the interruption report following a specific 2013 outage to the east of Sault Ste. Marie 34.5 kV system led API to discover a larger issue with the sensitivity of transmission protections at the source and the coordination of settings between the transmission source and API devices. API immediately worked with GLPT to change the protection schemes and settings on various API and GLPT-owned 34.5 kV and 44 kV devices and has plans to investigate whether changes to protection schemes may be warranted in other areas. API expects that these changes will result in significant future reduction in express feeder outages that were a significant contributor to both SAIDI and SAIFI in the past five years.
- API is in the process of implementing a SCADA system and integrating existing SCADA-capable field devices. Analysis of historical outages revealed that for many causes such

as insulator failure or conductor damage, a relatively small percentage of the total number of outages occurred on express feeders, but that these events had a disproportionate impact on reliability statistics due to the configuration of API's system. Prioritization of integrating express feeder SCADA devices to a control room is expected to reduce both the number of affected customers and the restoration times associated with these types of express feeder outages.

- API is in the process of implementing an Outage Management System that will build on the recently implemented GIS platform. This system will assist with identifying the extent of unplanned outages, pinpointing outage locations and providing customers with more detailed information updates on status and restoration times.
- Following completion of the Hawk Junction DS project in the 2015 System Service category, API has included annual System Service budgets in the range of $500k to support additional projects driven by reliability improvement.

5.3 Asset Management Process

API began development of its DAMP in 2013. API's DAMP provides details of API's Asset Management Process including inspection and maintenance programs by asset type, information on the assessment of asset condition, and details on both capital and O&M planning. API's DAMP is attached in Appendix A. For convenience, relevant sections of the DAMP are copied into sections below as appropriate.

5.3.1 Asset Management Process Overview

The fundamental objective of API's DAMP is to prudently and efficiently manage the planning and engineering, design, addition, inspection and maintenance, replacement, and retirement of all distribution assets in a sustainable manner that maximizes safety and customer reliability, while minimizing costs, in the short and long terms.

This objective is met through the application of thorough and sound planning, prudent and justified budgeting, and ongoing oversight, documentation, and review of all efforts and expenditures while implementing the documented capital and operating plans.

API will maintain a comprehensive DAMP which outlines the operating and capital processes, activities, and expenditures that are necessary to ensure that API continues to provide the safe, reliable, and efficient distribution of electricity to its customers.

There are three key principles that are integral to API's DAMP:

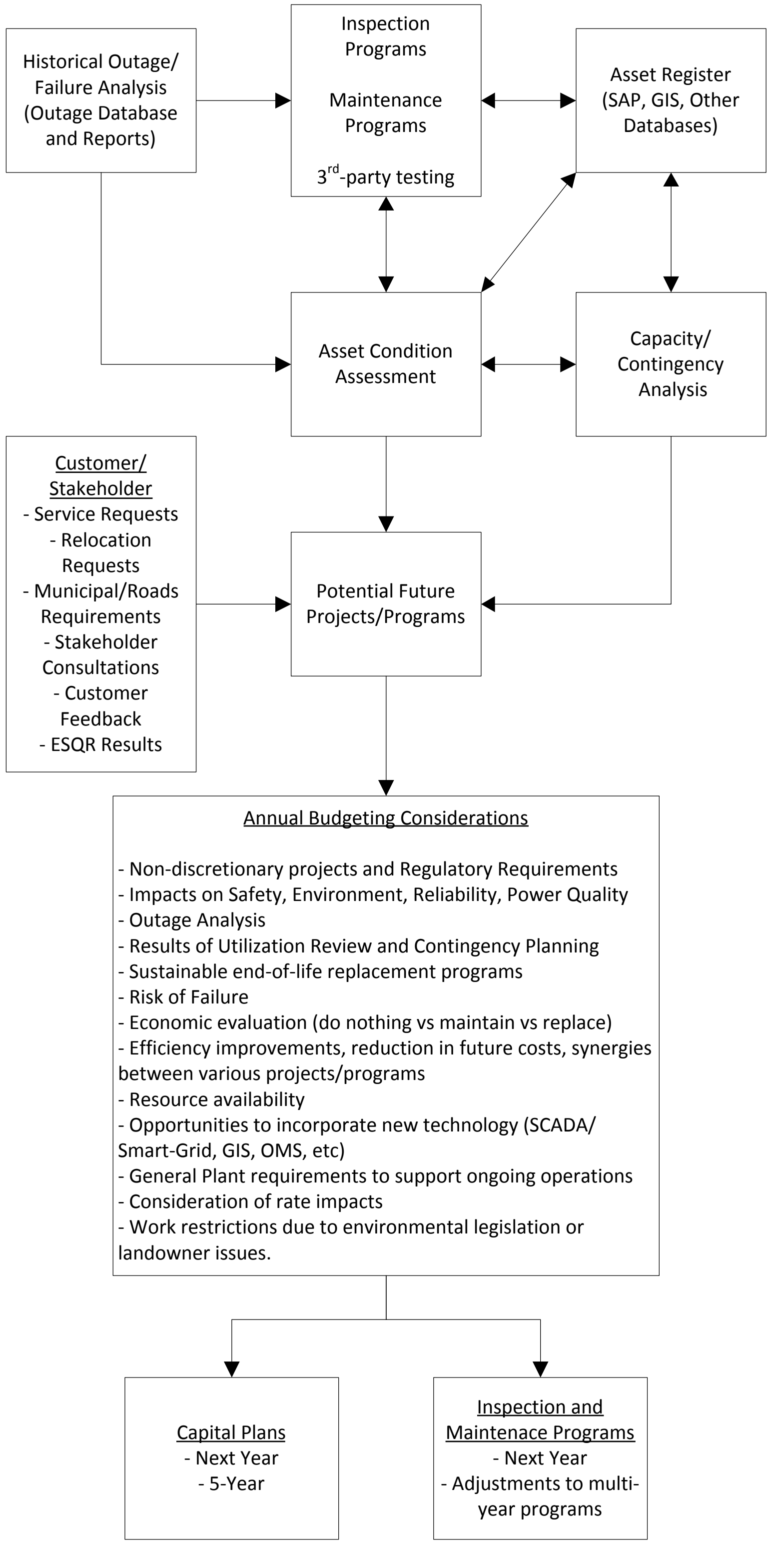
(1) Provide for the growth needs of the customers in the various service territories;
(2) Provide safe, reliable, and high-quality service to all of the customers of API; and
(3) Satisfy the first two principles in a sustainable manner which minimizes the long-term costs to be borne by the ratepayers of API.

These key principles are derived from safety considerations; acts, regulations, codes and guidelines; good utility practice; and customer expectations.

a) The table below illustrates how the asset management objectives and principles identified above, as well as API's core values, relate to each other and to the Renewed Regulatory Framework for Electricity ("RRFE") performance outcomes established by the Board.

RRFE Performance Outcome	**API Asset Management Objectives/Principles**	**API Core Values**
Customer Focus	- Provide for growth needs of customers - Provide safe, reliable, and high-quality service - Minimize long-term costs to be borne by ratepayers	- Customer Service - Respect for People - Community Involvement - Safety and the Environment
Operational Effectiveness	- *Prudently and efficiently* manage the planning and engineering, design, addition, inspection and maintenance, replacement, and retirement of all distribution assets in a sustainable manner	- Customer Service - Productivity
Public Policy Responsiveness	- Principles are derived from safety considerations; *acts, regulations, codes and guidelines*	- Safety and the Environment
Financial Performance	- Prudently and efficiently manage the planning and engineering, design, addition, inspection and maintenance, replacement, and retirement *of all distribution assets in a sustainable manner*	- Productivity - Financial Success

b) The following flowchart illustrates the inputs, outputs and overall flow of API's asset management process:



Sources of information providing input to the process described above include asset registers (primarily SAP and GIS, with some external databases), results of prior inspection, maintenance and 3rd-party testing activities (databases and paper-based reports), and historical outage information (database with raw data and spreadsheets with more detailed reporting/analysis).

The top half of the flowchart above illustrates multiple information flows between various data sources (asset register, outage database, test results, etc.) and API's inspection and maintenance programs. This information ultimately drives assets condition assessment and capacity/contingency analysis processes, which in turn inform the development of a list of potential future projects and programs. Potential future projects are also informed by customer/stakeholder input, such as requests for new services, requests for plant relocations, feedback from customers, and feedback from stakeholder consultations.

Results of the asset condition assessment and capacity/contingency analysis occasionally flow back to other data sources in the form of record updates or immediate adjustments to inspection or maintenance programs due to identification of high-priority repairs, or requirements for additional testing.

On an annual basis, API evaluates potential projects/programs, with consideration of the factors listed in the "Annual Budgeting Consideration" section of the above flowchart. This process is the primary driver of development of future capital and inspection/maintenance programs.

Given the historical processes used to collect much of the source information, and the ongoing migration of certain databases to newly implemented corporate systems (SAP, GIS, Engineering Analysis Software), some of the information flows and processes shown in the above chart are currently informal in nature.

Priority in project selection is given to non-discretionary projects that are required to meet regulatory obligations, for example, service connections, plant relocations and the unexpected replacement of failed in-service equipment. Programs to replace certain end-of-life assets in advance of failure are also given high priority to allow for a paced and sustainable replacement program that levelizes annual spending by asset type to the extent possible, and results in efficient use of internal resources. Consideration is then given to general plant items, to ensure that annual spending on critical items such as fleet, buildings, computer hardware/software, tools and test equipment, etc. is sufficient to support day-to-day business and operations activities. Any remaining projects that are more discretionary in nature are evaluated according to any applicable criteria listed in the "Annual Budgeting Consideration" section of the above flowchart. A final list of projects is selected, based on consideration of these criteria in relation to overall costs and benefits of particular projects or programs.

Non-discretionary activities such as customer demand work and relocations are generally budgeted based on a five-year rolling average of historical activity and costs. The same approach is taken for budgeting most general plant items, such as tools, test equipment and small capital items related to offices and work centres. The resulting budgets are reviewed for reasonability and adjustments are made for known future changes, or past irregularities. For example, costs associated with one-time connection of a large industrial customer would be excluded from historical averages in determining future customer demand budgets.

Sustainment programs such as the Pole Replacement programs are generally budgeted based on the target replacement rate, times an estimated replacement cost per unit, based on analysis of historical costs. System service programs are generally more discretionary in nature. Given the positive reliability impacts expected from programs in other categories (Pole Replacement, ROW Hardening, SCADA, etc.), API has included System Service amounts in some years that are relatively low in comparison to the overall budget. The System Service amounts included will allow for completion of projects to address API's most pressing reliability-driven needs.

<u>5.3.2 Overview of Assets Managed</u>

a) The Board has acknowledged API's unique, vast and challenging service area in its decision in EB-2007-0744. In that decision, the Board stated:

> *"In reviewing the record for this case and examining the history of this applicant before the Board it has become apparent that conventional ratemaking practice cannot address the issues presented by this applicant.*
>
> *Conventional ratemaking cannot result in a rate that will cover the Company's costs, provide for a reasonable return on investment, while being reasonable from a ratepayer's point of view.*
>
> *This circumstance arises directly out of the characteristics of the Applicant's service area. The Applicant's service area is more than twice the area of the greater Toronto area. It has less than 12,000 customers and has the lowest customer/kilometer ratio*

> *in Ontario with only 6.7 customers per kilometer on average. 99.9% of its service area is rugged and sparsely populated wilderness. Its service area is characterized by long runs of distribution wire between customers.*
>
> *This is a high cost, low revenue service area.*"[2]

API has prepared an extensive description of the unique features and challenges associated with its service area. This information is included in the Consolidated Distribution System Plan Overview (Exhibit 2, Tab 3, Schedule 1) in order to explain how this uniqueness and the associated challenges have influenced the development of the DS Plan.

b) As described in more detail in the Consolidated Distribution System Plan Overview referenced above, API's distribution is atypical to that of the general population of electricity distributors in Ontario. Much of the system has been designed and constructed to mimic an integrated transmission and distribution utility to serve a geographically dispersed customer base. The API distribution system is a network of "express feeders" (lines that serve a transmission-like function to interconnect localized distribution systems), long runs of distribution lines with sparsely connected customers and more localized distribution systems in locations where customers are more clustered. The following tables provide a summary of API feeders by voltage level and the capacity of distribution substations. TS supply point capacity and utilization is provided in part (d) below.

[2] EB-2007-0744, Decision and Order; p. 3.

Feeder Information

Feeder Information		**Circuit km**		
Source Voltage (kV)	**# of Feeders**	**Overhead**	**U/G, Submarine**	**Total**
44	1	86		86
34.5	5	129		129
24.9/14.4	3	368	5	373
12.5/7.2	15	1185	7	1192
12	1	8	1	9
8.3/4.8	9	56	1	57
2.4	1	2		2
Total	**35**	**1834**	**14**	**1848**

Notes:

1. Single-phase system voltages are included with the corresponding 3-phase (line-to-line) voltages (e.g. areas supplied entirely by a single-phase 4.8 kV feeder would be included in the 8.3/4.8 kV category).
2. Voltage levels and feeder counts are based on the voltage at the breaker/recloser position at the substation or delivery point.
3. Circuit km total for areas supplied by mid-feeder step-down transformers are included with the source feeder.

Distribution Substation Capacity

Substation	**HV kV**	**LV kV**	**Capacity (kVA)**
Garden River DS	34.5	12.5	2 x 3000
Bar River DS	34.5	12.5	10000
Desbarats DS (12 kV Desbarats Supply)	34.5	12.5	8333
Desbarats DS (St Joe's 25 kV Supply)	34.5	25	8333
Bruce Mines DS	34.5	12.5	5000; 10000
Wawa #1 DS	34.5	8.3	8333
Wawa #2 DS (8.3 kV Supply)	34.5	8.3	8333
Wawa #2 DS (12.5 kV Rural Supply)	34.5	12.5	2000
Hawk Junction DS	44	8.3	1000

Notes:

1. Stations showing two capacity values are dual-element configuration.

c) The following tables provide information on the age profiles (by decade of manufacture) of major in-service assets. Age information for poles should be considered current as of March 2014, with consideration that there may be some accuracy issues, as discussed in more detail in Section 5.2.1(d), above. The age information for all other assets listed below is current as of March 2014.

Distribution Poles (Mostly Wood)								
	2010's	2000's	1990's	1980's	1970's	Older	Unknown	Total
Distribution Line	1939	4365	3438	5414	6279	5697	270	27402
Express Feeder	29	143	380	531	302	824	76	2285
All Poles	1968	4508	3818	5945	6581	6521	346	29687

OH Transformers								
	2010's	2000's	1990's	1980's	1970's	Older	Unknown	Total
Number	412	1067	1322	989	631	295	57	4773

Padmount Transformers								
	2010's	2000's	1990's	1980's	1970's	Older	Unknown	Total
Number	15	66	0	0	0	0	0	81

Line Voltage Regulators					
	2010's	2000's	1990's	1980's	Total
Number	6	0	0	3	9

Substation Power Transformers & Station Voltage Regulators					
	2010's	2000's	1990's	1980's	1970's	Total
Number	2	3	3	2	2	12

d) As described in more detail in the “Introduction to API” section referenced above, API’s service area consists of a number of non-contiguous areas supplied by separate transmission delivery points, or by API-owned DS’s and step-down transformers connected to express feeders. As a result, the evaluation of system capacity requires analysis at various levels of the system, for both normal and contingency configurations. API’s asset management objectives include providing for the growth needs of customers, as well as providing safe, reliable and high-quality service to all customers. This section will summarize the adequacy of system capacity, both distribution and transmission, for current system loading, under normal system configuration. This summary is followed by a description of how certain contingency scenarios and the possibility of a significantly large customer addition are driving investment to upgrade the capacity and/or configuration of certain transmission delivery points.

Distribution Asset Capacity Utilization – Normal Configuration

An exact evaluation of the capacity utilization of distribution assets is complicated by the fact that API has little data available on the exact loading of individual distribution stations or feeders. Historically, API's station configuration consisted of simple layouts with no metering or SCADA-capable devices. There were few, if any, SCADA-capable devices on any distribution feeders. As a result, API's current process for capacity evaluation relies on load allocation algorithms in engineering analysis software. These algorithms allocate the known load at an upstream delivery point to various locations on API's system based on options such as the number of downstream customers, the total capacity of downstream pole-top transformers, etc. While the results are approximations of actual loading, the resulting utilization has been sufficiently low, such that API has a low level of concern with immediate or short-term overloading of any assets, other than specific cases during contingency scenarios (see Contingency Capacity sections below).

Transmission Delivery Points – Normal Configuration

In 2014, API conducted a review of peak load vs capacity on all transmission delivery points, based on 2012 and 2013 loads. The following table provides a summary of capacity utilization by delivery point.

Delivery Point	HV kV	LV kV	Capacity (kVA)	Winter Peak kVA	Summer Peak kVA	% Capacity Utilized	# Customers
Andrews TS	115	25	5,000	236	243	4.9%	63
Batchawana TS	115	7.2[2]	4,000	1,495	1,596	39.9%	883
D.A Watson TS (Wawa)[1]	115	34.5	75,000	8,066	5,034	10.8%	1702
Echo River TS	230	34.5	25,000	14,389	12,168	57.6%	5918
Goulais TS	115	12.5	15,000	9,271	7,916	61.8%	2870
Limer - No. 4 Circuit	44	44	25,000	11,152	9,894	44.6%	228
Mackay TS	115	2.4	500	41	52	10.4%	11
Northern Ave 34.5 kV	115	34.5	26,700	See Note 3			1
Northern Ave 12 kV	34.5	12	10,000	2,921	2,542	29.2%	5

Notes:

1. The large available capacity of Watson TS is a result of a large amount of generation connecting at 34.5 kV.
2. Batchawana TS supplies only 2 phases at 7.2 kV L-N. Transformers are rated 2500 and 1500 kVA.

3. The Northern Ave 34.5 kV feeder normally supplies <100 kVA to a single customer; however, it occasionally supplies the entire Echo River TS load.

Distribution Asset Capacity Utilization – Contingency Configurations

API has identified two feeders with capacity/performance issues during system contingencies.

No.4 44 kV Feeder – Recent load growth on API's 44 kV No.4 Circuit has resulted in a peak load of approximately 11 MVA, or approximately 150 Amps. While this is below the thermal ratings of conductor and equipment on this feeder, the vast majority of this load is located approximately 45 km or more from the transmission supply point. A 44 kV regulator is in place at the Hawk Junction DS to provide acceptable levels of voltage to all customers by compensating for changes in supply voltage and for voltage drop along API's 44 kV circuit.

The voltage regulator in service at Hawk Junction is a single-element installation, with no spare regulator available. This configuration results in substantial reliability risk, with an increasing level of risk as the in-service equipment ages or as feeder loads increase. API evaluated the impact on system voltage levels in the area for the condition where the voltage regulator had to be removed from service during winter months (either due to failure or need for priority repairs). With the regulator bypassed, API would be unable to maintain acceptable voltage levels for downstream customers in the area. This load makes up 20-25% or more of API's total system load, depending on the time of year. As a result, API has planned a project to purchase a spare 44 kV regulator and to rebuild the Hawk Junction DS to a dual-element configuration in 2014/1015. More detail on the justification for this project can be found in Section 5.4.5.2.

NA1 34.5 kV Feeder – As illustrated in the Transmission Delivery Point table above, this feeder normally supplies <100 kVA to a single 34.5 kV-connected industrial customer. This feeder is also the main contingency for supplying 34.5 kV to the Garden River DS, which steps down to 12.47 kV to supply customers throughout the Garden River First Nation. There are no issues with capacity or performance with either of these configurations.

Up to the 1980's however, the NA1 feeder was historically the only supply to the area east of Sault Ste. Marie. At the time of construction of the Echo River TS closer to load centres in this area, the NA1 feeder still provided an adequate contingency to supply the East of Sault system load. Echo River TS was therefore constructed with a single transformer to supply the 34.5 kV system in the area, with provision to accommodate the addition of a second transformer should the need arise. The NA1 feeder has been used for contingency supply to the East of Sault system since that time. The entire east of Sault Ste. Marie load has typically only been supplied from the NA1 feeder during periods of low to average loading (spring to fall months) to allow planned maintenance activities requiring outages to the Echo River TS.

API has recently observed recent winter peaks as high as 15.6 MVA on the east of Sault Ste. Marie system. API's analysis shows that supplying this level of load from the NA1 feeder would result in extreme low voltages for most customers in the area. Some areas would experience voltages in the range of 20% below nominal. A prolonged outage would require rotating blackouts to maintain adequate system voltages.

API has evaluated the possibility of resolving this issue through investment in upgrading the NA1 feeder to a higher capacity, or a dual-feeder configuration. The distribution solution was found to have significant drawbacks, including:

- Upgrading of the first 32 km of the feeder (from the source TS to the first relatively large load center at the Bar River DS) would be required to see significant voltage improvement. Much of the upgrade would require pole replacements to accommodate the larger conductor.
- Any future load growth would begin to offset the voltage improvements gained by the feeder upgrades.
- The additional capacity provided would be vastly underutilized during normal system configuration, while the existing capacity of the ER1 and ER2 feeders, from the Echo River TS to the Bar River DS, would remain unused during contingencies.
- The first 32 km of the 34.5 kV supply from the Northern Ave TS would be a single-circuit radial feed during contingencies. During a prolonged contingency where the load had to be supplied from the NA1 feeder (e.g. transformer failure at Echo River), a single fault in this 32 km stretch would result in an outage to approximately 5000 customers. With no alternate feeder, the outage to all 5000 customers would last as long as it took API to dispatch crews, clear the fault and restore power. The heavy load on a single feeder would require sectionalized restoration, resulting in even longer outages to the customers furthest from the source.
- With more than 75% of the customers/load located 50-70 km from the Northern Ave source, the line losses during any contingency situation (including regular planned maintenance at Echo River) would continue to be excessively high.

- Some of the above drawbacks could be reduced by rebuilding the NA1 feeder to dual-circuit construction; however this would come with significant additional costs and challenges. Also, many of the above-mentioned drawbacks would be only partially offset.
- A preliminary cost estimate of upgrading 32 km of 34.5 kV line is in the order of $4.8 million, slightly more than the cost of adding a second transformer at Echo River TS.

Due to the significant costs and drawbacks associated with a distribution solution to the contingency issue, API has included a project for upgrades to the Echo River TS in 2017.

<u>Transmission Delivery Points – Contingency Configurations and Load Growth</u>

API has identified three primary areas of concern with existing transmission delivery point configurations due to inadequate contingency capacity or anticipated load growth.

Echo River TS / Northern Ave TS – API's issue with the supply to this area is fully described in the section above, under "NA1 34.5 kV Feeder". Given the significant drawbacks associated with a distribution solution to provide an adequate contingency for outages at the Echo River TS, and the fact that the Echo River TS was originally designed to easily accommodate the addition of a second transformer, API's belief is that a transmission solution is more appropriate in the circumstance. API has included a 2017 project to cover the costs of purchasing and installing a second transformer at the Echo River TS. As previously mentioned however, API is working with GLPT to determine who bears cost responsibility for this project. Should API and GLPT not be able to resolve this issue, API may bring this issue to the Board at a future date for a determination.

Goulais TS / Batchawana TS – The Goulais TS contains three 115/7.2 kV, 5MVA transformers, connected in a bank to effectively form a single-element 115/12.47 kV supply with a capacity of 15 MVA. All contingency plans provided by GLPT would effectively limit the station capacity to approximately 5 MVA or less, resulting in an almost 60% overload under system peak conditions.

The Batchawana TS consists of two single-phase transformers (rated 1.5 and 2.5 MVA), connected to GLPT's 115 kV system in an open-delta configuration. These transformers effectively supply two API 7.2 kV phases, which are used to connect customers in the area.

While the capacity meets API's current needs and there is an available spare, the lack of 3-phase supply causes several issues:

- API is unable to supply more efficient 3-phase service to larger customers in the area;
- Line losses are higher than average, due to lack of ability to balance load between 3 phases and subsequently reduce neutral currents; and
- Protections cannot take advantage of ground fault relaying to sense certain phase-to-ground faults that are close to load currents on an individual phase basis, but produce significant phase unbalance on a 3-phase system.

There is currently a single-phase 7.2 kV interconnection between the Goulais and Batchawana systems, allowing for limited load transfer between the two. Other than this limited load transfer capability, planned maintenance activities at either TS require complete outages to API's distribution system in the area.

Given the configuration and contingency issues associated with these two supply points, API intends to use the Regional Infrastructure Planning process as an opportunity to discuss the possibility of various alternate configurations for supplying the area. Should the transformation assets in the existing TS's be reasonably close to end of life, or if the cost of improvements in these TS's would be excessive, then one obvious alternative would be construct single new dual-element TS to replace transformation assets in both TS's. In the long term, this would provide a more reliable, efficient and maintainable supply to API's distribution systems in the Goulais/Batchawana area. As this investigation is still in very preliminary stages, API has not included any investment in the current 5-year plan. API expects that any investment to be borne by API would be included in its next Cost of Service application, or through an ICM application if the investment was significant and became critically urgent.

Limer / No. 4 Circuit 44 kV Supply – This supply point has a capacity of approximately 28 MVA, with an existing peak load of approximately 11 MVA. This supply point is relatively unique in that it is supplied as a tap from a GLPT-owned 44 kV line that was deemed to be a transmission asset due to the unusual transmission system configuration in the area. The GLTP-owned 44 kV line also connects a wholesale transmission customer, meaning that any available capacity is shared among API and this customer, according to the provisions of the TSC.

In late 2013, API was informed that the other 44 kV transmission customer had applied to GLPT to significantly increase its load. As a result, GLPT determined that the remaining available capacity of the 44 kV system would drop to the point that GLPT had to initiate the Available Capacity Study process contained in its Customer Connections Process approved by the Board. GLPT subsequently requested a 5-year load forecast from API under this process.

Through preliminary meetings with GLPT, API has learned that the combined API load forecast and new transmission customer load would slightly exceed the available system capacity of 28 MVA. In addition, API had been in discussion with an existing mining customer with regards to a possible large distribution load addition (this had not been included in API's load forecast since it was not a firm commitment at the time). API subsequently received a deposit to proceed with CIA/SIA processes for a new 21 MW distribution load addition. Also, another API mining customer publicly announced plans for a mine expansion at the end of 2013. Follow-up discussion with this customer in 2014 confirmed the potential for a 4+MW load addition if the project proceeds as planned.

API met with GLPT to discuss the possibility that API load may increase to an amount well in excess of the available 44 kV system capacity. A technical discussion of potential upgrades to increase the 44 kV system capacity revealed that this would involve significant challenges due to the unusual 115/12/44 kV configuration of the nearby TS, with generation connected at 12 kV. The resulting wide range of possible operating currents on the 12 kV bus would exceed the 12kV bus rating, and could also create significant protection and operational issues, even with an upgrade to the 12 kV bus. There could also be difficulty in controlling and stabilizing system voltages in the area. This suggests that a new 115/44 kV TS supplying two API 44 kV feeders would likely be the preferred solution for the amount of load being considered.

Given the preliminary stages of this request and the fact that many different investment scenarios are options are possible, API has not included an amount in the current 5-year plan. Should this project proceed, API would be required to file an ICM application once exact investment requirements are known.

5.3.3 Asset Optimization Policies and Practices

a) Overview of Lifecycle Optimization

API's asset lifecycle optimization practices include consideration of overall inspection, maintenance, repair and replacement requirements for each type of asset over its expected life. The optimal balance of these activities will depend on factors such as:

- The number, type, condition, and criticality of assets in service;
- Minimum inspection and maintenance requirements according to DSC requirements, manufacturer's recommendations and Good Utility Practice;
- Health, safety and environmental requirements;
- Risk of Failure (safety, environmental, reliability, cost, etc.);
- Availability of spare equipment and evaluation of contingency plans;
- Analysis, by asset type, of available options to refurbish vs. replace existing assets; and
- Replacement prior to end of life due to factors beyond API's control (e.g. storm damage, vehicle accidents, vandalism, PCB regulations, smart meter regulations, unexpected customer demand work, road relocations, etc.)

Inspection, Maintenance and Replacement Programs

API's inspection programs are designed to satisfy the requirements in Appendix C of the DSC. Additional programs such as infrared scanning, pole testing and transformer dissolved gas analysis are used in order to more accurately identify the condition and the probability of failure for certain critical assets. Where the results of inspections identify issues requiring immediate attention, corrective maintenance and/or asset replacement is undertaken as required. Less immediate issues are addressed through future maintenance or capital programs.

API's preventive maintenance programs generally consist of regularly scheduled activities based on manufacturer's recommendations and Good Utility Practice. This includes activities such as removing equipment from service for replacement of consumable components, detailed electrical testing, cleaning, lubrication, etc. Details of API's major in-service distribution assets, as well as full details of the inspection and maintenance programs in place for each type of asset can be found in API's DAMP. Section 5 of API's

DAMP, as well as the information in 5.3.1(b) above, describe how the output of the inspection and maintenance programs supports the continuous reassessment of future Capital and Maintenance plans.

API's annual System Renewal budget includes the following programs:

- Line Rebuilds and Express Feeder Rebuilds (Pole Replacement) – Planned replacement of approximately 500 poles per year.
- Recloser, Voltage Regulator, etc. – Replacement of failed units, units where ratings have been exceeded, or replacement of units where maintenance/repair requirements are uneconomical.
- Small Capital (Lines and Substation) – Replacement of substation assets or line assets other than poles, where immediate issues are identified through inspection and maintenance program and where replacement is determined to be the optimal solution.
- Transformer Replacement – Replacement of failed transformers and transformers identified as high failure risk during inspections.
- Storm Damage – Replacement of assets that fail suddenly due to damage during severe storms (wind, lightning, etc.)

The Storm Damage replacement program is budgeted based on a rolling five-year average of historical actual costs. Given that API annually experiences some amount of asset failure during storms requiring immediate replacement, budgeting based on historical averages ensures that normal spending levels on these replacements will not adversely impact other planned capital projects. The Recloser, Voltage Regulator, etc. program and the Small Capital program are also budgeted based on historical actual costs. This ensures that capital budget is available where analysis of refurbish vs replacement considerations determines that replacement is the optimal solution. Finally, the Pole Replacement and Transformer Replacement programs are budgeted based on a target number of replacements, multiplied by a cost per pole or cost per transformer that is based on historical averages.

The target number of replacements is determined by considering the number, type, age and condition of assets in service, in comparison to the expected useful life of these assets, to determine a replacement rate that is sustainable in the long-term. The Pole

Replacement program is broken out into Line Rebuild and Express Feeder rebuilds in recognition that both the planning requirements and the cost per pole will be different between the two types of line. This breakdown will allow more efficient analysis of program spending for budgeting future costs, and will also prevent an inflated average cost per pole from being used in future Line Rebuild budgeting as the Express Feeder rebuilds taper off.

Priority in the System Renewal category is given to the Storm Damage replacement program as the amount of annual storm damage is beyond API's control, and repair of this damage is non-discretionary. The Recloser, Voltage Regulator, etc. program and the Small Capital programs are given the next level of priority as this allows for prudent decisions on refurbish vs replacement strategies that ultimately reduce future costs and/or introduce benefits in terms of reliability, maintainability and operability of the system.

Finally, the Pole and Transformer Replacement Programs are budgeted based on annual target replacement rates. Due to the large amount of in-service poles, and the target replacement rate of 500 poles per year, there is some flexibility in the annual replacement targets. For example, spending in the Pole Rebuild program for the last four years of the current plan (2016-2019) is budgeted at $4.4M, based on 100 Express Feeder poles at $10k per pole, and 400 Distribution poles at $8.5k per pole. In 2015 however, API reduced spending in this program by approximately $800k to ease pressure on the overall capital budget resulting from one-time investments in the Hawk Junction DS.

<u>Lifecycle Optimization by Asset Type</u>

As mentioned above, the optimal balance of inspection, maintenance, repair and planned replacement will vary by asset type. Critical assets such as substation transformers will be the subject of frequent inspection and preventive maintenance programs throughout their life. On the other extreme, assets such as insulators and most pole line hardware are visually inspected in accordance with the DSC mandated frequencies, but are not otherwise inspected or maintained. These assets are generally replaced on failure, or at the time of the planned replacement of the associated pole. The remainder of this section describes API's lifecycle optimization practices by asset type.

Poles

API conducts visual inspections of its distribution feeders on a minimum six-year cycle, in accordance with DSC requirements for rural systems. Inspections are carried out more frequently for certain express feeders, due to the criticality of these feeders, and the access issues associated with many sections that make response to forced outages extremely difficult and time-consuming. These visual feeder inspections are conducted by internal resources.

In addition to minimum inspection requirements in the DSC, API also retains a third-party contractor to perform more detailed pole testing. The target test rate is approximately 10% of the pole population per year. With completion of the High-Risk Conductor Replacement program and transition to Pole Replacement under the Line Rebuild and Express Feeder Rebuild programs in the current five-year plan, the results of this detailed pole testing program will assist API in the following activities:

- Identifying poles at high risk of failure for immediate replacement in the current year or for high-priority replacement in the early years of the program.
- Identifying groups of poles (e.g. by area, vintage, type or combination of these factors) that are showing common signs of premature decay or other issues that require prioritization within the program.
- Identifying whether certain less critical poles may have an estimated above-average useful life. This would allow for relatively newer, but more critical poles to be replaced in other areas, which would have greater benefits in terms of reliability and system efficiency. It would also allow voltage conversions of remaining lower voltage pockets to proceed in a more coordinated manner with pole replacements.

The regular inspection and testing programs described above are consistent with Good Utility Practice with respect to the lifecycle management of wood poles. The Western Red Cedar poles primarily used by API are naturally resistant to many types of decay, fungi and insects. As a result, the vast majority of poles do not experience significant loss of strength during their useful lives, and no additional maintenance is typically required. Due to the high number of in-service poles, and the consequence of failure, API employs a proactive replacement strategy. The target planned replacement rate of approximately 500 poles per year is intended to replace the vast majority of poles prior to in-service failure or prior to a reduction in strength to values below the limits specified in CSA standards. It also ensures that associated components such as insulators, hardware, crossarms, grounding components and guying components remain intact without major issues for the life of the pole. Extending the replacement cycle would result in a situation where poles and many of the associated components fail in service, resulting in potentially large outages and public safety issues.

Overhead Conductor

Conductors are inspected as part of the regular feeder inspections mandated in the DSC. Other than visual inspection, there are few options for additional in-service testing or maintenance of conductors. Conductors are generally repaired (spliced) as they fail, due to tree contact for example. In some cases, conductors are proactively replaced due to high risk of failure, or due to efficiencies of replacing in conjunction with pole replacement, as described below.

In recent years, API identified that much of the in-service #6 and #4 ACSR conductors presented a high risk of failure. Accordingly, the High-Risk Conductor Replacement program was initiated in 2003 to proactively replace this high-risk conductor. With the introduction of Ontario Regulation 22/04, there was a requirement to replace many of the poles in conjunction with this conductor replacement in order for the overall system to satisfy safety requirements mandated by the regulation.

With the transition from a major replacement program focused on conductor to a major replacement program focused on pole replacement, API's lifecycle management strategy for overhead conductors has changed. In-service failure of conductors larger than #4 ACSR is rare, outside of failure due to tree contacts. As a result, conductor will either be run to failure, or will be proactively replaced under certain conditions:

- During proactive pole replacement projects that involve a majority of poles on any given line section, factors such as age, condition, loading, and risk of failure would be evaluated to determine whether it would be economical to replace the conductor in conjunction with pole replacement.
- Where inspections or outage analysis identifies specific subsets of the conductor population with above-average risk of failure, this conductor will be considered for replacement. In most cases, API expects that the conductor replacement on any

given line section would require significant replacement of poles and associated hardware in order to meet safety standards under Ontario Regulation 22/04. Conductor replacement under these conditions would therefore be considered as a factor influencing the prioritization of certain line sections under the Line Rebuild program, rather than as a separate program for replacement of the conductor only.

Pole Line Hardware

This group of assets includes items such as crossarms, insulators, bolts, fused cutouts, anchoring and guying components, grounding components, etc. These assets are inspected (to the extent possible) during visual feeder patrols. These components are normally run to failure or replaced in conjunction with planned pole replacements. Often, these components will survive from the initial pole installation to the time of planned replacement, without issue. Occasionally, groups of components are identified that require proactive replacement. Examples include certain lots of insulators or switches where manufacturing defects or design issues are identified that pose higher risks of failure or pose safety issues to workers or the public. No programs of this type are included in the current five-year plan.

Distribution Transformers

Transformers are inspected visually during the six-year feeder patrols, as well as on an ad-hoc basis during other planned work such as service connections or disconnections.

Due to the large number of in-service transformers, it would be extremely impractical to closely monitor and maintain pole-top and pad-mount transformers in the same fashion as substation power transformers, and the expense of such a program would far exceed its utility.

The risk of failure of any individual pole-top or pad-mount transformer is relatively low. API also maintains an adequate inventory of spare transformers which allows for immediate replacement of failed units. As a result, transformers are mainly replaced on a run-to-failure strategy, which is consistent with practices at most utilities.

There are a few situations where API proactively replaces transformers that have not yet failed:

- Voltage conversion – transformers are replaced as required for voltage conversions. The units removed from service are tested and the majority are returned to stock for use elsewhere in API's system. Also, in cases where line rebuild projects occur in areas planned for voltage conversion in the near future, any existing single-voltage transformers are replaced with dual-voltage transformers during the line rebuilds. This allow for a more efficient future voltage conversion with reduced costs and outage durations.
- Overloading – transformers identified as being overloaded, or those that would have a high probability of future overloading due to the connection of new services or service upgrades are proactively exchanged for a larger size transformer.
- Near end-of-life or PCB contaminated – transformers at end of life, or those containing PCB's are removed from service during otherwise planned activities. This eliminates the higher future costs associated with a one-time trip for the sole purpose of exchanging a failed or PCB-contaminated transformer.

Transformers that are replaced for reasons unrelated to end of life (voltage conversion and potential for overloading) are inspected and tested and returned to spare inventory if deemed suitable for future use.

<u>Reclosers, Capacitors, Voltage Regulators, Gang-Operated Switches</u>

The assets in this category are relatively small in number, expensive and critical to the proper operation of the distribution system. In service failure could result in widespread outages, power quality issues, as well as potential safety or environmental issues. As a result, there are additional inspection and preventive maintenance programs associated with these assets.

The more critical assets in this category are subjected to annual infrared scanning, with corrective maintenance scheduled as required based on the outcome of the scans. Regular operational checks (i.e. manually verifying voltage regulator or capacitor operation) are also conducted on a semi-annual basis. In addition, many of these assets are removed from service for more detailed testing, repairs and overhauls as required. Specific details on the inspection and maintenance programs in place for each type of asset can be found in Section 4 of API's DAMP.

Due to the costs associated with both the initial purchase and ongoing maintenance of these assets, decisions to replace vs repair the assets are frequently required. For example, reclosers are removed from service for testing and overhaul on a six-year cycle. Often, regular testing, and minor repairs will allow the removed equipment to be returned to service. Should any time-consuming repairs or replacement components be required however, then it is often more economical to replace the unit. API has also found that the replacement units often provide improved functionality (more accurate timing, ability to change parameters to replace multiple variation of legacy equipment, SCADA-ready, etc.), and also require less future maintenance. As a result, API has budgets an annual capital amount for replacement of these assets where the replacement option is superior to the repair option.

<u>Substation Power Transformers and Station Voltage Regulators</u>

Substation power transformers and station voltage regulators are generally among the most expensive distribution assets. They also have a high consequence of failure in terms of potential safety and environmental impacts, outage impacts and replacement costs. A single transformer failure could result in a prolonged outage to thousands of customers, with extensive restoration time if the outage impacts an area with no interconnection to other systems. The combination of the high value, criticality, and small number of in-service assets justifies more intensive inspection and maintenance programs for this group of assets.

Power transformers and voltage regulators are inspected at least every 6 months as required by the DSC. Overall condition is observed, and readings of gauges are recorded. Annually, all substation assets are scanned using infrared cameras and have oil samples taken for dissolved gas analysis. Any issues identified during any of the inspection processes are noted and prioritized for corrective maintenance as required. Where these units can be removed from service without significant outage impact, they will be subjected to detailed inspections, adjustments and testing on a six-year cycle.

These assets are generally replaced proactively when results of inspection and maintenance activities suggest that there is an increasing probability of failure in the near future. None of the currently in-service transformers or regulators are forecasted to be replaced in the five-year plan.

Substation Switching and Protection Assets

API's substations are relatively simple configurations consisting of 1-2 incoming express feeders (34.5 or 44 kV), 1-2 power transformers or voltage regulators, and 1-3 outgoing feeders. Protective and switching devices include power fuses and the same types of reclosers and gang-operated switches as those used on overhead lines. These assets are inspected on 6-month cycles, in accordance with DSC requirements. Further inspection and maintenance programs for these devices will be similar to the programs in place for the overhead line switching assets, as described above. Full details of API's substation inspection and maintenance programs can be found in Section 4 of API's DAMP, attached as Appendix A. API's substations currently have no control buildings, DC systems, circuit breakers, or metal clad switchgear.

Other Substation Assets

This group of assets includes the general substation site, fencing, structures and foundations, buswork, insulators, hardware, etc. These items are inspected on a six-month cycle in accordance with the DSC. Annual infrared scanning is also conducted to identify issues such as loose connections or hot-spots on equipment. Any issues identified during routine inspections are noted and prioritized for corrective maintenance as required.

API also budgets an annual amount for small capital replacements in substations that are required to correct deficiencies or high-risk issues identified during inspection and maintenance activities.

Metering Assets – AMI

API recently deployed the Sensus FlexNet Advanced Metering Infrastructure ("AMI") system in order to meet the requirements of the provincial smart metering mandate. The AMI communications network currently consists of the following equipment:

- 8 Tower Gateway Base stations (TGB's)
- 23 Repeaters – with more being added as required to reach remote meters

TGB's are relatively expensive assets that comprise complex transceiver units housed in weatherproof enclosures, with integrated HVAC systems and battery backup. Each TGB typically reads thousands of meters, either directly or via repeaters. As part of the long-term AMI contract with Sensus, these units are remotely monitored on a 24/7 basis, and preventive maintenance activities are performed by Sensus on a 6-month basis. Maintenance includes changing air filters, verifying correct operation of all HVAC and power systems, and firmware upgrades as required. Sensus is responsible for any repairs to these units during the term of the AMI contract.

Repeaters are pole-mounted devices that are used to read meters beyond TGB coverage areas. One type of repeater is used to effectively extend the reach of a nearby TGB to read meters in “dead-zones”, or just beyond the reach of TGB’s. Another type of repeater is effectively a “mini-TGB”, with a direct backhaul link, and is used in place of TGB’s for extremely remote and low-density areas, where deployment of TGB’s would be impractical and uneconomical. These devices are monitored for communication uplink availability, with alarms sent to API in the event that communications are lost. Given the relatively low number of meters relying on each repeater, issues are corrected only as identified. In most cases, a simple reset of the communication link will restore connectivity. In other cases, a complete replacement of the repeater or associated antenna hardware is required. In this case, spare equipment is readily available, and replacement can generally occur prior to the loss of any TOU consumption data.

Meters and Instrument Transformers

Meters follow a certification maintenance program as they are subject to re-verification regulations made under the Electricity and Gas Inspection Act. API samples meters in accordance with regulatory requirements, and will keep meters in service as long as they continue to meet regulatory requirements. Other than periodic verification of large/poly-phase services, meters are not subject to any additional inspection or maintenance programs.

Instrument transformers that are associated with large poly-phase services are inspected and tested in conjunction with the associated meters during the periodic verifications of these services.

Wholesale metering installations are subject to the requirements of the IESO’s Market Rules. API’s Meter Service Provider (“MSP”) manages the periodic re-verification and replacement of meters as required to meet market rules. The MSP also reviews data from these meters and flags any potential data integrity issues for further investigation.

Underground and Submarine Assets

Less than 1% of API's system is underground and most underground assets are relatively new. These assets are inspected on the frequencies mandated by the DSC. Issues or deficiencies are noted and corrected as required. As the age of this asset group increases and issues are identified through regular inspections, API will review available options for life-extending maintenance and will make the appropriate decisions to maintain vs replace at that time.

Rights of Way ("ROW")

The objective of API Vegetation Management ("VM") plan is to manage vegetation in proximity to electrical equipment on a regular schedule to enhance and sustain reliability and worker accessibility to the system, while minimizing hazards created by vegetation in proximity to energized equipment.

Achieving this objective requires ongoing investment in maintenance programs that include brush removal, herbicide application, tree trimming and hazard tree removal. In 2013, API contracted Ecological Solutions Inc. to complete a comprehensive review of the current status of API's ROW's, as well as to quantify recommendations for future activities that would ultimately lead to a lowest cost sustainable VM plan. The report completed as result of this exercise is attached as Appendix E. The results of this exercise have been fundamental to the review of API's VM programs and the establishment of future maintenance budgets. Details of API's vegetation maintenance programs are attached as Appendix C.

API's overall vegetation management program also includes two capital programs. The first is the ROW Expansion program that was undertaken in recent years to establish widened ROW's to set the foundation for sustainable ROW maintenance programs that meet the overall VM objective described above. The second is the planned ROW Hardening program to remove a backlog of off-ROW hazard trees that were identified through the work of Ecological Solutions Inc. The justification for this program, provided in Section 5.4.5.2, describes why the removal of this backlog is necessary in order for API to successfully implement a vegetation maintenance programs that are sustainable in the long term.

Fleet

In order to support the day-to-day activities of the three work centres in its service territory, as well as to enable access to remote areas of its system across challenging terrain, API maintains a relatively large and diverse fleet, consisting of:

- 13 aerial devices (bucket trucks, radial boom derricks)
- 22 pickup trucks
- 8 snowmobiles
- 5 off-road vehicles
- 2 forestry chippers
- 1 forklift
- 20 trailers (open & enclosed) – for transporting poles, heavy materials, snowmobiles and off-road vehicles

API has developed and implemented a preventative fleet maintenance plan in its SAP work management system that complies with manufacturers recommendations and prescribed regulations.

Maintenance of booms for hoisting and man lifts (buckets) includes requirements for a variety of one month, 3 month, 6 month and annual inspections, including dielectric testing. Cab and Chassis have separate inspection requirements that are similar in frequency. Additionally, regulations prescribe annual CVOR (Commercial Vehicle Operator's Registration) inspections and emissions testing.

Maintenance of pick-up trucks generally includes 3 month service requirements and annual Safety Inspections. Heavier pickups (11) are subject to CVOR inspections and emissions testing.

Annual allowance is made for replacement of one aerial device, as well as approximately four pickup trucks and a variety of other items as required. This results in approximate replacement cycles of 13 years for aerial devices and 5 years for pickup trucks. Condition assessment and evaluation of future maintenance costs may extend the in-service life of some pickup trucks beyond 5 years. Replacement of lower-value items such as snowmobiles and off-road vehicles is based mainly on evaluation of the overall condition (age, hours/km of use, maintenance/repair requirements, etc.).

b) As described in Sections 5.3.1(b) above, the outputs of API's inspection and maintenance programs, as well as outage analysis and general asset information are used as inputs to the Asset Condition Assessment and Capacity/Contingency Analysis process. This ensures that all known asset-related risks are incorporated into the processes that ultimately result in the identification of future projects and programs to be considered. Further, during the annual budgeting process, several factors based on risk management affect the prioritization of both individual projects and of projects within the larger replacement programs. The complete list of factors is included in the flowchart in Section 5.3.1(b).

Section 5.3.3(a) above also details how the asset lifecycle optimization practices for each asset type are tailored to the risk associated with failure of various in-service assets. High-risk assets have more involved inspection and maintenance requirements and are more likely to be replaced on a proactive basis as opposed to a run-to-failure approach.

The following programs/activities that have made up a large percentage of API's capital program in recent years demonstrate how risk management has been fundamental to the prioritization of capital expenditures:

- High-Risk Conductor Replacement
- ROW Expansion Program
- Multiple Substation Rebuild/Retirement Projects (Wawa, Desbarats/St Joe's Island, Bar River)

As API's System Renewal spending has transitioned to a sustainment-based approach, the prioritization based on risk management is more applicable to project prioritization within programs. For example, an Express Feeder Rebuild program was established as a distinct subset of the more general sustaining Pole Replacement program to ensure that these more critical feeders received due attention and prioritization within the overall capital program, despite being of a slightly newer vintage than some of the oldest poles on other less critical feeders.

5.4 Capital Expenditure Plan (2015 – 2019)

5.4.1 Summary

a) Capability to connect new load or generation customers

Connection of New Load

Section 5.2.3(d) above provides a detailed assessment of the capacity utilization of existing system assets. API expects that its system will continue to be able to accommodate the vast majority of requests for new load connections and for service upgrades. Infrequent requests for connection in remote areas may trigger requirements for significant line extensions, however the process and cost responsibility for these request are adequately dealt with under the provisions of Section 3.2 and Appendix B of the DSC.

As mentioned in section 5.2.3(d) above, API has recently received a request for a significantly large new load on its No.4 44 kV feeder. This single customer request, combined with indications of expansions from another nearby customer, and a possible resumption of milling operations in Dubreuilville could result in loads of 30-40+ MW on this feeder. This is approximately 3-4 times the existing peak feeder load, and exceeds the available capacity at the transmission supply points. API expects to continue discussions with these customers and to complete a more thorough analysis of the available transmission supply options to this area, both internally and in conjunction with GLPT.

Connection of REG Projects

As described in detail in Section 5.4.3, API has not experienced any major issues with connection of existing microFIT or small FIT projects to its system, and does not expect any issues within the current five-year plan, based on the anticipated volume of new projects.

b) Total annual expenditures over the forecast period, by investment category:

CATEGORY	**Forecast Period** (planned)				
	2015	**2016**	**2017**	**2018**	**2019**
	$ '000				
System Access	1,020	1,020	1,020	1,020	1,020
System Renewal	4,044	4,834	4,834	4,834	4,834
System Service	1,232	538	5,088	538	538
General Plant	2,679	2,679	2,529	2,029	1,029
CIAC	- 100	- 100	- 100	- 100	- 100
TOTAL EXPENDITURE	8,875	8,971	13,371	8,321	7,321

c) System Access expenditures are primarily customer-driven and are relatively consistent year over year. As previously explained, this category is non-discretionary spending to meet regulatory obligations and API budgets future amounts based on a five-year rolling average of historical amounts. Adjustments are occasionally made for known future changes, such as above average relocations requests that API becomes aware of through the stakeholder consultation processes described in Section 5.2.2. Also past irregularities such as costs associated with one-time connection of a large industrial customer would be excluded from historical averages in determining future customer demand budgets. The five-year plan for System Access expenditures are consistent with historical spending in this category, and accounts for 11% of API's total five-year capital expenditures.

System Renewal expenditures are driven by sustaining proactive asset replacement programs, mainly driven by pole replacement. Target replacement rates are based on consideration of the number, type, age and condition of in-service assets. Annual budgets for smaller, non-discretionary items are based on historical actual amounts. This includes items such as amounts for urgent replacements due to storm damage, or priority replacement of one-off items as a result of high-risk issues identified during inspection and maintenance programs. In general, annual budgets for this category are the total of the sustainment program and the non-discretionary annual amounts that are budgeted as described above. There is however, some flexibility in the annual pole replacement targets due to the large amount of in-service poles, and the target replacement rate of 500 poles per year. For example, API reduced 2015 pole replacement targets to ease the overall budget impact of the Hawk Junction DS project in the System Service category. Over the next five years, System Renewal spending comprises 49% of API's total capital expenditures.

System Service spending is focused on reliability-driven projects, which are prioritized based on outage analysis and consideration of the impact of contingency scenarios. System service expenditures are generally more discretionary in nature than System Access and System Renewal expenditures. Given the positive reliability impacts expected from programs in other categories (Pole Replacement, ROW Hardening, SCADA, etc.), API has included System Service amounts in the years without substation projects that are relatively low in comparison to the overall budget. The System Service amounts included in the five-year DS Plan will allow for completion of projects to address API's most urgent reliability-driven needs. System Service spending makes up 17% of API's overall capital expenditures in the five-year plan.

Spending in the General Plant category is focused on ensuring that adequate tools, equipment and systems are in place to support the day to day operations of API's business. The majority of this category comprises levelized annual spending on items such as tools, equipment, fleet, IT and land rights, as well as programs related to vegetation management. For example, API replaces one aerial device, approximately four pickup trucks and miscellaneous small fleet items every year to maintain a consistent and sustainable fleet replacement rate. Recent investments in various business systems (SAP, GIS/OMS, SCADA, Vegetation Management, etc.), and continued development and integration of these systems are expected to continuously improve API's asset management and capital planning processes. These systems are also expected to assist with reliability improvement initiatives and will improve API's ability to provide better information to its customers in terms of outage updates and detailed Time of Use consumption history. General Plant items account for 23% of API's total five-year expenditures. As mentioned above, a number of the General Plant items in the current five-year plan are reliability driven. These items were included in General Plant as opposed to System Service as they relate to assets that are not directly part of the distribution system. The choice to allocate budget amounts to General Plant as opposed to System Service was directly influenced by customer feedback that showed a desire for both improved reliability and improved communication during outage events. API's analysis of historical outage data and its vegetation management review showed that General Plant investments in ROW Hardening, SCADA and OMS would be more effective in meeting these customer expectations than most System Service type investments.

d) Table of Capital Expenditures by Category

Investment Category	Category Five-Year Total 2015-2019	Project/Program Description	Forecast Expenditures ($'000) 2015	2016	2017	2018	2019
System Access		Customer Demand Work (New Connections and Service Upgrades)	$907	$907	$907	$907	$907
		Total of Items Less Than Materiality (New Transformers/Meters, Plant Relocations)	$113	$113	$113	$113	$113
	$5,100	**System Access Total**	**$1,020**	**$1,020**	**$1,020**	**$1,020**	**$1,020**
System Renewal		Replacements due to Storm Damage	$102	$102	$102	$102	$102
		Small Priority Replacements - Lines/Stations (One-off Priority Replacements)	$198	$198	$198	$198	$198
		Express Feeder Rebuilds (Part of Pole Replacement Program)	$977	$1,000	$1,000	$1,000	$1,000
		Line Rebuilds (Part of Pole Replacement Program)	$2,633	$3,400	$3,400	$3,400	$3,400
		Total of Items Less Than Materiality (EOL Transformers, Recloser Replacement)	$134	$134	$134	$134	$134
	$23,380	**System Renewal Total**	**$4,044**	**$4,834**	**$4,834**	**$4,834**	**$4,834**
System Service		Protection, Automation, Reliability (Substations, Express Feeders, Lines)	$197	$500	$500	$500	$500
		Hawk Junction DS Rebuild/Expansion	$997				
		Echo River TS - Add Second Transformer			$4,550		
		Total of Items Less Than Materiality (Transformers for Volt Conv & Capacity Issues)	$38	$38	$38	$38	$38
	$7,934	**System Service Total**	**$1,232**	**$538**	**$5,088**	**$538**	**$538**
General Plant		ROW Access Program	$90	$90	$90	$90	$90
		IT Hardware	$170	$170	$170	$170	$170
		Business Systems (SCADA, GIS, OMS, etc.)	$171	$171	$171	$171	$171
		Fleet (1 aerial device, 4 pickups, misc trailers, ORV's, snowmobiles)	$551	$551	$401	$401	$401
		ROW Hardening Program	$1,500	$1,500	$1,500	$1,000	
		Total of Items Less Than Materiality (Facilities, Tools, Software, Land Rights)	$197	$197	$197	$197	$197
	$10,945	**General Plant Total**	**$2,679**	**$2,679**	**$2,529**	**$2,029**	**$1,029**
Total	**$47,359**		**$8,975**	**$9,071**	**$13,471**	**$8,421**	**$7,421**

e) Given the preliminary nature of the Regional Planning Process in API's service area, no investments have been included in the current five-year plan as a direct result of this process.

f) API's customer engagement activities are described in detail in Section 5.2.2 above. Feedback on customer preferences is reflected in a number of reliability-driven projects and programs that have been included in both System Service and General Plant categories. Specific details of the impact on the five-year plan can be found in Sections 5.2.3 (a) and (c) above.

g) API is in the process of evaluating significant load additions to its No.4 44 kV Feeder, as described in more detail in Section 5.3.2(d) above. Should these loads proceed according to preliminary indications, the future 44 kV load in this area could be in the range of 3-4 times the existing load. This would require significant upgrades to the transmission and distribution systems in the area. Apart from these preliminary requests for large industrial load additions, API does not expect any significant change to its system in terms of load growth or connection of REG projects.

   API expects that the continuation of SCADA implementation and integration, along with other reliability-driven investments over the next five years will be a significant first step towards smart grid development.

h) Projects planned in response to:

   <u>Customer Preferences</u>

   Feedback has indicated that improved reliability and improved communication during outages are important from the perspective of API's customers. API has included a Protection, Automation, Reliability Program in its System Service category, with annual investment of $500,000 in most years. This is directly aimed at projects to address the most impactive reliability and contingency issues faced by API in response to customer desire for improved reliability and decreased response time. Substation projects at Hawk Junction DS and Echo River TS in 2015 and 2017 totaling approximately $5.5 million will also address existing contingency issues that could result in prolonged outages that are unacceptable to API customers. Many other projects and programs in the System Renewal and General Plant category are also expected to have positive impacts on system reliability.

<u>To Take Advantage of Technology-Based Opportunities to Improve Operational Efficiency, Asset Management and the Integration of Distributed Generation and Complex Loads</u>

The Protection, Automation, Reliability Program ($500,000 in most years), combined with ongoing SCADA implementation and integration and development of other business systems ($171,000 per year), is expected to result in the following:

- Efficiencies in the conceptual and detailed design processes, in terms of reduced site visit requirements by engineering and operations staff;
- Increased accuracy of cost analysis for items such as line losses and avoided future costs during the project prioritization process;
- Adjustments to inspection and maintenance programs for certain asset types (e.g. move from time-based to condition-based maintenance) due to the availability of more detailed asset condition information and operating records; and
- Improvements to the asset management process overall as more detailed information is available on asset condition, inspection and maintenance costs, overall expected life, the effect of operating conditions such as overloading or number of operations, and the effect of various maintenance strategies on overall asset performance.

<u>To Study or Demonstrate Innovative Processes, Services, Business Models, or Technologies</u>

API is investigating the possibility of leveraging its AMI infrastructure to provide SCADA backhaul communications in areas that are beyond the reach of many traditional communication options. API is currently in the process of working out the details of a low-cost pilot project with Sensus to demonstrate the feasibility of this approach. The possibility of using this solution is made possible by API's low customer density, which results in under-utilization of existing AMI towers.

API actively participates in the research project Corridors for Life ("CFL"). CFL focuses on assessing and developing improved management practices for maintaining utility corridors in Northern Ontario. The project incorporates Integrated Vegetation

Management ("IVM") principles, mitigation strategies for species at risk, and has partnership between industry, government, educational institutions, and First Nations. The CFL project is one of the mechanisms API demonstrates its innovation and commitment to continual improvement. IVM is a system of managing vegetation by which compatible and incompatible vegetation is identified, and control methods are evaluated, selected, and implemented to achieve specific objectives.

Compatible vegetation (e.g., low-growing shrubs) are not targeted for removal or control, as they are not capable of interfering with power lines, causing interruption to electrical service, providing public access to electrical facilities, or impeding the access of restoration and line maintenance crews. Inversely, incompatible vegetation (e.g., trees and tall shrubs) must be managed or controlled by utility companies. Defining compatible/incompatible vegetation depends on many factors, such as type of vegetation, location of vegetation within the ROW, height of the power line (when at maximum sag point), voltage, and power line design. Through CFL API has established demonstration plots and trial areas to evaluate different VM strategies on utility ROW's.

5.4.2 Capital Expenditure Planning Process Overview

a) The following descriptions relate API's capital expenditure planning objectives, by category, to API's asset management objectives as well as the Board's performance outcomes.

   i. System Access – Expenditure planning for this category is based on budgeting sufficient annual amounts to meet customer expectations, as well as regulatory requirements in relation to new connections, service upgrades and plant relocations. This relates to API's asset management objective of providing for the growth needs of its customers, as well as the Board's performance outcomes of customer focus and public policy responsiveness.

   ii. System Renewal – Expenditure planning for this category is based on budgeting sufficient amounts on a five-year basis to meet the long-term sustaining replacement requirements of major assets, as well as budgeting sufficient annual amounts to ensure efficient use of API internal resources in completion of capital replacement programs. This relates to API's asset management objectives of providing safe, reliable and high-quality service as well as prudently and efficiently managing the entire lifecycle activities of distribution assets in a sustainable manner. It also relates to the Board's performance outcomes of operational effectiveness, and financial performance.

iii. System Service – Expenditure planning for this category is based on prioritizing projects and programs associated with reliability improvement. Reliability impacts are informed by analysis of possible contingency scenarios and of historical outage data. This relates to API's asset management objective of providing safe, reliable and high-quality service, as well as the Board's performance outcomes of customer focus and operational effectiveness.

iv. General Plant – Expenditure planning for this category is based on providing the facilities, equipment, tools and business systems required to support day to day operations, and budgeting each of these items in a way that levelizes annual expenditures to the extent practical. Additional investment in business systems and in programs related to vegetation management are also budgeted based on opportunities to improve processes, realize efficiencies, and respond to customer desires for reliability improvement and improved communication. This relates to API's asset management objectives of providing safe, reliable and high-quality service as well as prudently and efficiently managing the entire lifecycle activities of distribution assets in a sustainable manner. It also relates to the Board's performance outcomes of customer focus, financial performance, and operational effectiveness.

b) API considers all viable alternatives for resolving system capacity issues or operational constraints. For all identified issues and constraints, a "do-nothing" alternative is considered in order to determine whether the risks associated with the issue/constraint merit any significant investment. Once a capacity issue or operational constraint has been identified for which "do-noting" is not an acceptable approach, API considers any reasonable alternatives to resolve the issue. The alternatives include, but are not limited to distribution system upgrades, transmission system upgrades, or new transmission supply points. As an example, API has included a 2017 project to add a second transformer at Echo River TS as the most practical long-term solution to addressing the operational constraints and reliability issues associated with contingencies on the East of Sault 34.5 kV system. API determined that something must be done to resolve the current issues and determined that any distribution solutions would be in the same range of costs as the transmission solution, but with many drawbacks. Further details of the constraints and planned solution are provided in Section 5.3.2(d). API has historically managed the evaluation of distribution vs transmission alternatives through regular meetings with GLPT as required. The Regional Planning Process is simply expected to result in a more formal approach for considering these issues.

c) The overall method used to identify, select and prioritize capital projects is fully illustrated and described in detail in Section 5.3.1(b), as this process is integrally linked to API's asset management process. The allocation of overall budget between categories and the budgeting projects and programs within each category are described in Section 5.4.1(c) above.
d) API's customer engagement activities are described in detail in Section 5.2.2 above. Details of how this feedback has impacted API's DS plan are included in Sections 5.2.3 (a) and (c), and Section 5.4.1(h).
e) API has not included any REG investments in the current DS Plan.

5.4.3 System Capability Assessment for Renewable Energy Generation

a) As of March 2014, API has connected a 30 kW FIT project, and is in the process of completing a CIA for a 250 kW FIT project. API has also connected approximately 113 microFIT projects, totaling 1,039 kW of capacity, and a small number of microFIT applications are pending.
b) API expects to continue to connect a few dozen microFIT projects annually, generally without issue. API does not expect many, if any, larger FIT projects due to transmission constraints in the Northeast area.
c) In the absence of the Northeast Zone transmission constraints, API expects that a maximum of approximately 22 MW could be connected throughout its service area (under ideal conditions of project location). In the absence of both Northeast Zone constraints and all local transmission line/station constraints, API expects that upwards of 150 MW could be connected (again under ideal conditions of project location on each distribution feeder).
d) As mentioned above, the Northeast Zone transmission constraints severely limit any large REG projects in API's service area. Local transmission line and station constraints are also limiting in some cases. Due to the overriding limitation of the Zone constraint, API has not provided a complete listing of local transmission constraints.
e) Constraints for Dubreuil Lumber Inc. (API's only embedded LDC) would also be limited by the Northeast Zone constraints.

5.4.4 Capital Expenditure Summary

CATEGORY	**Historical Period** (actual)					**Forecast Period** (planned)				
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
	$ '000									
System Access	1,824	1,050	1,122	5,441	1,033	1,020	1,020	1,020	1,020	1,020
System Renewal	5,132	3,828	4,871	2,772	4,171	4,044	4,834	4,834	4,834	4,834
System Service	973	802	591	241	1,325	1,232	538	5,088	538	538
General Plant	2,266	3,507	1,707	1,733	2,279	2,679	2,679	2,529	2,029	1,029
GEC	-	742	2,223	-	-	-	-	-	-	-
CIAC	- 91	- 35	- 98	- 247	- 91	- 100	- 100	- 100	- 100	- 100
Chage in WIP	356	- 109	- 373	1,350	- 834	-	-			
TOTAL EXPENDITURE	10,460	9,785	10,043	11,290	7,883	8,875	8,971	13,371	8,321	7,321

System Access

2010 includes costs of $862k related to connection of a new industrial customer. 2013 includes capitalization of costs of almost $4.5 million related to Smart Metering. With these one-time costs excluded, costs for the forecast period are in line with historical costs in this category.

System Renewal

Forecasted average system renewal costs are approximately 12% higher than historical average costs in this category. This is primarily due to a 2013 reduction in this category to ease the overall budget impact of other projects.

System Service

Forecasted average costs in this category are significantly higher than the historical average due to a potential 2017 project to add a second transformer at Echo River TS to resolve operational constraints. More detail on this project can be found in Section 5.3.2(d) above.

General Plant

Forecasted average costs in this category are approximately 5% lower than historical average costs.

5.4.5 Justifying Capital Expenditures

5.4.5.1 Overall Plan

A comparison of forecast vs. historical expenditures by category is provided in Section 5.4.4, above. Investment drivers vary by category, and are summarized in Sections

5.3.1(b) and 5.4.1(c), which detail API's asset management and capital planning processes, and how the output of these processes affect project prioritization and the allocation of capital expenditures among categories. Drivers associated with each category are also discussed in Section 5.4.1(c).

As described in Section 5.4.4, with the exclusion of Smart Meter costs and a one-time large customer addition, System Access, System Renewal and General Plant investments included in this plan are relatively in line with historical spending in these categories. These investment levels are required to meet regulatory requirements, sustainable replacement requirements for in-service assets, and the day-to-day business and operational activities at API.

System Service costs are higher than historical averages, primarily due to a large investment in a TS upgrade, as described in the contingency review in Section 5.3.2(b).

With all costs included, the overall forecast five-year plan represents a 5% decrease from the historical five year expenditures.

5.4.5.2 Material Investments

As detailed in the table of capital expenditures provided in Section 5.4.1(d), the majority of API's capital expenditures over the forecast period consist of programs or budget items with relatively consistent annual spending. As a result, rather than providing a repetitious breakdown of projects by year, API is providing detail for most items at the program level, with a table of annual forecasted spending for each item.

Also, for the convenience of the reader, API has combined the following items from the filing requirements under a single heading for each material program/project:

- Part A – General Information on the Project/Activity
- Part B – Evaluation Criteria and Information Requirements for Each Project/Activity
- Part C – Category-Specific Requirements for Each Project/Activity

Where specific projects within a program are currently identified for 2015, a summary of the preliminary scope and costs of these projects is also provided.

System Access

New Customer Additions and Service Upgrades

A. *General Information on the Project/Activity*

Forecast Expenditures ($'000)				
2015	2016	2017	2018	2019
$907	$907	$907	$907	$907

This capital expenditure is required to collect all costs for the installation and replacement of API plant that is driven by customer requests for new services or service upgrades. A unique feature of API's very rural service territory is that the vast majority of API's customer demand work is related to single-customer requests for connections to new residences, or for service upgrades to existing residences. Development of new subdivisions is relatively rare. As a result, most new services or service upgrades require a single new or modified connection to existing API plant. In many cases, this requires pole replacement, reframing or other upgrades in order to meet the requirements of Ontario Regulation 22/04.

B. *Evaluation Criteria and Information Requirements for Each Project/Activity*

1. Efficiency, Customer Value, Reliability

a) The primary driver of this activity is customer service requests. This program allows API to satisfy its asset management objective of providing for the growth needs of customers, as well as meeting regulatory obligations under the DSC. This program is justified on the basis of customer service requests that are relatively consistent year over year in terms of both the number of requests and the investments required to complete the connections.

b) This activity is considered non-discretionary, as there are regulatory obligations to process customer service requests in a timely manner. API budgets an annual amount for this activity that is based on a rolling five-year average of historical costs.

c) Given the regulatory requirements to process these requests, and the requirements of Ontario Regulation 22/04 in relation to the new or modified connections to API's system, few alternatives exist for this activity. For each individual connection however, API does consider whether the connection or upgrade can be accommodated with a minimal scope of work (e.g. connection to existing secondary bus without anchoring or pole changes), while meeting the applicable safety requirements. Where a more involved scope is required to complete the connection, API assesses the possibility of incorporating additional related work (e.g. adjacent pole changes) to take advantage of fixed costs related to mobilization and excavation equipment. The number of poles replaced annually under this activity is taken into consideration in setting the targets of the Pole Replacement program.

2. Safety

   The design and construction of new or modified service connections is completed in accordance with USF Standards to meet the requirements of Ontario Regulation 22/04 and to ensure that no undue safety hazards exist.

3. Cyber-Security, Privacy

   Customer connections requests are managed in accordance with relevant privacy legislation.

4. Co-ordination, Interoperability

   Once designs are complete, API involves various third parties as required in the review and approval process. This may include any combination of road authorities, First Nations, municipalities, planning boards and government ministries. This process ensures coordinated planning with third parties in relation to road activities, other utilities and regulatory concerns.

5. Economic Benefits

   All associated work will be completed using local employees and contractors within Ontario.

6. Environmental Benefits

   As described in 1(c) above, where the scope of the new or modified connection involves significant construction (pole changes, anchoring, etc.), API builds efficiencies into the process by incorporating additional related work to take advantage of the mobilization of heavy equipment to the area. Reduced mobilization and set-up of this equipment minimizes emissions and potential impact on species at risk.

C. Category-Specific Requirements for Each Project/Activity

The projects within this activity relate mostly to individual new or modified connections to residential and seasonal dwellings. Once requests are received and customers have met certain obligations, the timing of completing these connections is prescribed by the DSC and API has little control over the timing of specific activities.

API does however make efforts in several areas to control costs and to build efficiencies into the overall design and construction process:

- Online mapping tools, as well as databases of asset and property information are reviewed in the office in advance of site visits to determine reasonable connection options.
- Site visits with customers/contractors are grouped by area to minimize travel time and costs. Activities such as tagging, commissioning and data collection are also scheduled around these site visits to take advantage of mobilization to remote areas.
- For each service request, technicians identify whether any minimal scope connection options exist that will both meet the customer's requirements and the requirements of Ontario Regulation 22/04.
- For connections where minimal scope options are not available, opportunities to incorporate efficiencies are considered (e.g., changing additional poles to take advantage of line crew and equipment mobilization).

System Renewal

Storm Rebuilds

A. General Information on the Project/Activity

Forecast Expenditures ($'000)				
2015	**2016**	**2017**	**2018**	**2019**
$102	$102	$102	$102	$102

This capital expenditure is required to collect all costs related to the replacement of major assets (poles, reclosers, switches, etc.) as a result of failure or serious damage caused by storms (typically during significant rain, snow, wind or lightning events). Separately budgeting for this item minimizes the impact of inevitable storm damage on other planned projects and programs and also allows annual expenditures to be tracked for analysis and trending purposes.

B. <u>Evaluation Criteria and Information Requirements for Each Project/Activity</u>

1. Efficiency, Customer Value, Reliability
   a) The primary driver of this activity is asset failure or high risk of failure due to damage during storms. This relates to API's objective of supplying safe, reliable, and high-quality service to its customers.
   b) This activity is considered non-discretionary. Storms are unpredictable in nature and have the potential to cause severe damage to API's system. Assets that fail or are severely damaged during these events must be repaired or replaced in order to safely continue supplying power. Annual amounts are budgeted based on a 5-year average of historical costs.
   c) Assets that have failed due to storm damage must either be replaced or repaired. While repair options are considered and selected where prudent, for many types of assets that have failed structurally or electrical, the repair option is either not possible, or not practical. For assets that have sustained severe damage during storms, but have not yet failed, replacement is justified due to safety concerns and reliability and costs consequences associated with the increased risk of failure.
2. Safety

   Failed or severely damaged equipment must be replaced for safety reasons. The replacement is performed in accordance with USF Standards, meeting the requirements of Ontario Regulation 22/04 to ensure that no undue safety hazards remain.
3. Cyber-Security, Privacy

   Not applicable
4. Co-ordination, Interoperability

   Not applicable
5. Economic Benefits

   All associated work will be completed using local employees and contractors within Ontario.
6. Environmental Benefits

   Not applicable

C. Category-Specific Requirements for Each Project/Activity

API's objective is to provide safe, reliable, and high-quality service to its customers. Asset replacement under the Storm Rebuild program involves only those assets that have already failed, or are severely damaged and on the verge of failure due to storm damage. As a result, this spending is considered non-discretionary and these assets are replaced immediately.

The timing and priority of replacements under this program are beyond API's control due to the unpredictable nature of storm events and the resulting damage to API's system. Budgeting for these replacements based on a five-year historical average is considered prudent to minimize the impact of inevitable storm damage on other planned programs and projects.

Small Lines/Stations Capital

A. General Information on the Project/Activity

Forecast Expenditures ($'000)				
2015	**2016**	**2017**	**2018**	**2019**
$198	$198	$198	$198	$198

This capital expenditure is required to collect all costs for priority replacement of individual line or station components that are identified as defective or as having a high risk of failure during regular inspection and maintenance activities. Budgeting for these items allows for prudent decisions to be made on refurbishment vs replacement strategies, for assets that are not the focus of larger sustaining replacement programs.

Annual amounts are budgeted based on a 5-year average of historical costs. A risk of applying this budgeting approach to a future five-year plan is that identification of any systemic issue with these assets during the next five years (e.g. identification of a high-risk lot or vintage of switch) may require the establishment of a priority replacement program at the expense of other asset replacement programs.

B. Evaluation Criteria and Information Requirements for Each Project/Activity

1. Efficiency, Customer Value, Reliability

a) The primary driver for this activity is the replacement of end of life assets due to failure, or due to high failure/performance risk. This relates to API's asset management objective of providing safe, reliable, and high-quality service. Specific replacement requirements in any given year are based on review of asset condition information obtained through regular inspection and maintenance activities, or documented on interruption reports.

b) While not completely non-discretionary, this Small Capital budgets are given a relatively high priority due to the higher than average failure and/or performance risk of assets to be replaced.

c) Spending in this program is relatively low compared to the overall System Renewal category. Some of the assets replaced under this program have already failed or been identified as defective, and as a result the do-nothing approach is not an option. For assets identified as being at a high-risk of failure, the reactive replacement costs would often be higher than the proactive replacement costs and reactive replacement would involve additional reliability impacts.

2. Safety

   The planned and proactive replacement of assets with high failure and/or performance risk is inherently safer than reactive replacement as the working conditions can be controlled and the optimal replacement plans can be determined in advance. All design and construction work is completed in accordance with USF Standards meet the requirements of Ontario Regulation 22/04 and to ensure that no undue safety hazards exist.

3. Cyber-Security, Privacy

   Not applicable

4. Co-ordination, Interoperability

   Not applicable

5. Economic Benefits

   All associated work will be completed using local employees and contractors within Ontario.

6. Environmental Benefits

   Some replacements involve oil-filled equipment. Proactive replacement of oil-filled equipment prior to in-service failure minimizes the risk of oil leaks to the environment.

C. <u>Category-Specific Requirements for Each Project/Activity</u>

API's objective is to provide safe, reliable, and high-quality service to its customers. Asset replacement under the Small Capital program involves assets that have a high risk of failure and/or high performance risk. Asset condition information is gathered through regular inspection and maintenance programs and information on interruption reports. This condition information is considered in conjunction with the risks associated with failure or substandard performance, taking into account the function and criticality of the asset. Assets are proactively replaced where assessment of overall asset condition indicates that short-term failure is likely and the safety, environmental, reliability, and/or cost impacts of unplanned failure are considered unacceptable. As a result of the high risks associated with assets replaced under this program, these replacements are considered a priority, and the do-nothing option is not a reasonable alternative unless a major upcoming project would otherwise involve replacement of the asset in question.

Express Feeder Rebuilds

A. <u>General Information on the Project/Activity</u>

Forecast Expenditures ($'000)				
2015	**2016**	**2017**	**2018**	**2019**
$977	$1,000	$1,000	$1,000	$1,000

This program is a subset of API's overall sustaining Pole Replacement program. API has identified approximately 588 poles on sections of its 34.5 kV Wawa feeders and 44 kV No.4 Circuit feeder that were installed prior to the mid 1960's and are showing signs of rotting.

The remote locations and off-road nature of many of these sections makes access extremely difficult and costly during forced outage situations. During certain times of year, emergency access is only possible by snowmobile or helicopter.

As a result, API has identified these sections for priority replacement within the pole replacement program. An Express Feeder Rebuild program was established as a subset of the overall Pole Replacement program in recognition of the higher risks associated with these feeders, as well as significant differences in planning requirements and costs associated with the express feeder rebuilds. The separation of costs related to the express feeder rebuilds will allow more efficient analysis of program spending for budgeting future costs, and will also prevent an inflated average cost per pole from being used in future Line Rebuild budgeting as the express feeder rebuilds taper off.

Historical costs for this activity are $400k in 2013 and are forecasted to be $1.28 Million in 2014. 2013 costs are primarily related to LiDAR data acquisition, the design of the Wawa 34.5 kV circuits, and replacement of a small number of poles in the vicinity of the Wawa airport. 2014 costs are related to replacement of poles on both Wawa 34.5 kV feeders, starting at the D.A. Watson TS, with continuation of design activities on all three feeders. The program target for 2015-2019 is approximately 100 poles per year.

B. <u>Evaluation Criteria and Information Requirements for Each Project/Activity</u>

1. Efficiency, Customer Value, Reliability

a) The primary driver of this program is the planned and sustainable replacement of end of life poles. Secondary drivers are maintaining reliability and optimizing the overall lifecycle costs associated with poles. This program is based on the fundamental objective of API's DAMP, which is *"to prudently and efficiently manage the planning, engineering, design, addition, inspection and maintenance, replacement, and retirement of all distribution assets in a sustainable manner that maximizes safety and customer reliability, while minimizing costs, in the short and long terms."* API's asset register and the results of condition assessment and contingency analysis processes are sources of information driving this program.

b) Given the criticality of the feeders involved, along with the remote nature and access challenges associated with many of the sections being replaced, this program is considered a high priority within the System Renewal category. The relative priority ranking would be lower than the more non-discretionary Storm Rebuild and Small Capital programs, but higher than the Line Rebuild program. The pacing of this program is based on the overall number and condition of express feeder poles targeted for replacement over the next five years.

c) API expects that the cost and reliability impacts associated with reactively replacing failed poles on these sections of line would far exceed the impacts associated with planned replacement. As a result, a do-nothing approach was not considered. More information on alternative routing considered for the replacement of certain line sections is provided in Section C below.

2. Safety

   The planned and proactive replacement of assets with high failure and/or performance risk is inherently safer than reactive replacement as the working conditions can be controlled and the optimal replacement plans can be determined in advance. All design and construction work is completed in accordance with USF Standards meet the requirements of Ontario Regulation 22/04 and to ensure that no undue safety hazards exist. New access roads or trails created during the course of this program are expected to provide safer long-term access to certain line sections for future inspection and maintenance activities.
3. Cyber-Security, Privacy

   Not applicable
4. Co-ordination, Interoperability

   Express feeder rebuilds will be coordinated with several third parties. This includes outage coordination with GLPT, coordination of access and species at risk with the MNR, and coordination of potential line relocations with upcoming road realignments in the area.
5. Economic Benefits

   All associated work will be completed using local employees and contractors within Ontario.
6. Environmental Benefits

   API will involve the MNR in the planning stages of the projects within this program to minimize impacts on the natural environment and to species at risk, where applicable. It is expected that the information gained through this process will assist API in minimizing the environmental impact of establishing new access trails, as well as in considering the potential environmental impacts of future inspection and maintenance activities.

C. *Category-Specific Requirements for Each Project/Activity*

Due to the number, condition, criticality and location of the poles identified for replacement in this program, the reliability impacts of a “do-nothing” or run to failure would be significant. Combined, these three feeders supply 40% of API’s peak load, meaning that prolonged outages on failure could result in both substantial customer impact and loss of revenue. The costs associated with reactive replacement would also be quite high, and there could be significant safety risks associated with gaining access to certain line sections on an unplanned basis.

In addition to the do-nothing approach that API rejected, alternatives to rebuilding the lines in kind were evaluated. For the Wawa 34.5 kV feeders, API evaluated the option of relocating portions of the feeders to a slightly longer path along a nearby road. This option was rejected for several reasons, including cost, soil conditions, steep terrain profiles along sections of the road, heavy vegetation clearing requirements and interference with third-party infrastructure along certain sections. For most of the No. 4 Circuit included in the five-year plan, there simply are no nearby roads to consider relocating to. API has however identified one section of the No. 4 circuit where relocation may be an attractive option, especially in light of certain road realignments being considered by a mine in the area. API intends to further examine the potential for line relocation in this area near the end of the five-year plan.

The degree of deterioration observed during visual inspections indicates that these poles have reached the end of their useful lives, and that the risk of failure will increase over time. The vast majority of poles on the line sections targeted for rebuilds have been in service in excess of 50 years, which exceeds the typical useful life for these assets.

Priority for individual sections to be replaced on the three feeders in the five year plan will be based on a consideration of the following:

- Condition of existing poles.
- Criticality of line section (customers and load downstream of any given protective device)
- Existing access, and access restrictions based on time of year and/or species at risk
- Permitting requirements for any new access required for construction equipment
- Coordination of outage requirements with GLPT

Consideration of third-party projects in the area (this will be impactive to a particular section of the No.4 Circuit).

The higher risks and unique access challenges associated with these express feeder line sections has led API to prioritize these rebuilds as a distinct subset of the Pole Replacement program, with a higher priority than the remaining distribution line rebuilds.

Line Rebuilds

A. General Information on the Project/Activity

Forecast Expenditures ($'000)				
2015	**2016**	**2017**	**2018**	**2019**
$2,633	$3,400	$3,400	$3,400	$3,400

This program represents the most significant portion of API's sustaining asset replacement strategy. With completion of the High-Risk Conductor Replacement program, API has transitioned to a Pole Replacement program over 2013 and 2014.

The goal of the Pole Replacement program is to achieve a sustainable replacement rate that results in proactive replacement of the vast majority of poles near end of life, but prior to failure. The result is a balance between the cost of the replacement program and relatively larger costs, reliability impacts and safety concerns associated with reactive replacement of these assets. The resulting levelized annual replacement rates also allow for efficient use of internal resources.

The target replacement rate for the Line Rebuild program is approximately 400 poles per year, with a reduction in 2015 due to inclusion of the Hawk Junction DS project. The program's annual replacement target is based on the number, age and overall condition of in-service poles, with consideration that poles are also being replaced in the Express Feeder rebuild program over the next five years. Annual program costs are based on an estimated unit cost of $8,500 per pole. Forecast program costs are similar to historical spending on the Conductor Replacement program, which included replacement of the majority of associated poles.

API has consistently completed similar volumes of line rebuild work in recent years and does not anticipate significant risks in achieving the annual targets included in the five-year plan. As described in Section 5.2.3(a), API has implemented processes to review both the physical and financial progress of projects and programs on a monthly basis in order to proactively identify and resolve any issues during the early stages of any specific project.

The priority associated with any given pole or line section within this program will depend on a number of considerations, as described in detail in API's Asset Management process in Section 5.3.1(b). Considerations include, but are not limited to, the condition, age and criticality of in-service poles, as well as opportunities to create synergies between API's planned pole replacements and other planned API or third-party projects. The material projects identified below have tentatively been selected for inclusion in API's 2015 program. Cost estimates for these projects are based on preliminary unit costs, with committed scopes and costs expected later in 2014.

B. *Evaluation Criteria and Information Requirements for Each Project/Activity*

1. Efficiency, Customer Value, Reliability

a) The primary driver of this program is the planned and sustainable replacement of end of life poles. Secondary drivers are maintaining reliability, optimizing the overall lifecycle costs associated with poles, as well as improved system performance. This program is based on the fundamental objective of API's DAMP, which is *"to prudently and efficiently manage the planning, engineering, design, addition, inspection and maintenance, replacement, and retirement of all distribution assets in a sustainable manner that maximizes safety and customer reliability, while minimizing costs, in the short and long terms."* API's asset register and the results of third-party testing programs are the primary sources of information driving this program.

b) The condition and age profile of API's current pole population is currently at a point where the occurrence of pole failure (excluding causes such as tree contact, vandalism and motor vehicle accidents) is infrequent in relation to the overall number of forced outages. Current inspection and testing programs typically identify high-risk poles for replacement prior to failure. In order to maintain the current performance levels of this asset group, API has determined target annual replacement rates that will result in little change to the overall age profile of in-service poles on completion of the five-year plan. Details of the age breakdown by decade of in-service poles are provided in Section 5.3.2(c).

c) API has considered alternatives that involve increasing or decreasing the annual replacement target associated with this program. Based on the number of overall pole changes anticipated over the next five years through all capital projects and programs, API expects little change in the number of near end of life poles on completion of the five-year plan. Over time, increasing the annual pole replacement targets would effectively decrease the average in-service pole age and the average age of poles being replaced. API does not believe this to be warranted based on the historical performance and failure rates of these assets. Decreasing the annual pole replacement targets would result in an increasing liability associated with high-risk in-service poles. This could quickly lead to a cycle where the increasing reactive replacement costs due to more frequent unexpected pole failures and a greater number of deficiencies identified during patrols lead to less budget room available for the proactive replacement, which further decreases the annual number of poles replaced proactively. Adopting this approach over a five-year plan, could result in a bow-wave of future replacements, requiring both increased capital and O&M budgets at the time of API's next COS application.

2. Safety

   The planned and proactive replacement of assets with high failure and/or performance risk is inherently safer than reactive replacement as the working conditions can be controlled and the optimal replacement plans can be determined in advance. All design and construction work is completed in accordance with USF Standards meet the requirements of Ontario Regulation 22/04 and to ensure that no undue safety hazards exist.

   The replacement of end of life poles also results in improved working clearances in comparison to existing construction. Grounding and guying systems are also replaced and improved, and insulators and cut-outs are changed from porcelain to polymer reducing the likelihood of breakages. Certain lines are relocated from difficult off-road locations when possible. Smaller diameter Aluminum Conductor Steel Reinforced (ACSR) conductors subject to mechanical failure are also replaced with new wire as warranted during the rebuilds.

3. Cyber-Security, Privacy

   Not applicable.

4. Co-ordination, Interoperability

   A large number of third parties are typically included in the planning of any line rebuild project. This may include any combination of road authorities, First Nations, municipalities, planning boards and government ministries. This process ensures coordinated planning with third parties in relation to road activities, other utilities and regulatory concerns.

   Line rebuilds are also coordinated with other projects where possible. This includes activities such as voltage conversions that are expected to improve system performance, or reliability-driven projects.

5. Economic Benefits

   All associated work will be completed using local employees and contractors within Ontario.

6. Environmental Benefits

   API will involve the MNR in the planning stages of the projects within this program to minimize impacts on the natural environment and to species at risk, where applicable. It is expected that the information gained through this process will inform API's scheduling of construction activities, as well as future inspection and maintenance programs in any given area.

C. *Category-Specific Requirements for Each Project/Activity*

API considers the Line Rebuild program to be a critical part of an overall sustaining proactive replacement strategy that optimizes the overall lifecycle management of its assets. While there is some flexibility in the annual pole replacement targets, a minimum number of overall replacements are required over the course of the five-year plan to sustain asset performance at current levels.

Though age is not the only factor influencing the replacement priority, there is often a strong relationship between the age of a pole and the overall condition of the pole and associated line hardware. The majority of poles replaced by this program will have been in service in excess of 50 years, which exceeds the typical useful life for this asset. With the planned replacement targets, API expects little change in the overall age profile on completion of the five-year plan.

Given the expansive nature of API's service area, the planned and programmatic replacement of groups of poles by line section is much more cost-effective than sporadic replacement of individual high-priority poles or reactive replacement of failed poles. API's lifecycle management of pole assets is described in detail in Section 5.3.3. Regular inspections and testing programs are designed to identify high-risk poles for proactive replacement prior to failure. API expects that the target replacement rates will maintain the status quo where one-off reactive replacement requirements are relatively rare. Any reduction in the overall replacement targets associated with this program will result in increased one-off replacements, at a higher cost per pole.

As of March 2014, the following projects have been identified as priority projects for 2015.

- 24 Poles ($204,000) Richards Landing – St Joseph Island
- 30 Poles ($255,000) Bruce Mines – North of 5th Concession on Centre Line Rd
- 25 Poles ($212,500) Desbarats – Huron Lake Road
- 20 Poles ($170,000) Desbarats – Along HWY 17 East
- 100 Poles ($850,000) From Harmony to Batchawana along HWY 17 North
- 60 Poles ($510,000) Batchawana – Along HWY 17 North of Sand Point Road
- 60 Poles ($510,000) Agawa Bay – Along HWY 17 North of Frater Road to Provincial Park

System Services

Protection, Automation, Reliability

A. General Information on the Project/Activity

Forecast Expenditures ($'000)				
2015	**2016**	**2017**	**2018**	**2019**
$197	$500	$500	$500	$500

API's asset management process, described in Section 5.3.1(b) includes analysis of historical outage data as well as an analysis of system capacity and contingency plans. These analyses often identify projects that could improve reliability and/or contingency performance, but do not fit into other investment categories. The goal of budgeting an annual amount for the Protection, Automation, Reliability program is to allow for a variety of projects that will result in the greatest benefits to system reliability and contingency performance. Many of these projects also have positive impacts on power quality, system maintainability, accommodation of REG projects, future cost savings, and/or progression toward Smart Grid implementation.

Analysis of recent outage data and contingency plans suggests that the following types of projects will be priorities in the five-year plan:

- Installation of additional SCADA-capable devices, especially on systems with loop configurations (e.g. portions of the East of Sault 34.5 kV)
- Installation of new 3-phase platform transformers on the East of Sault 34.5 kV system to allow for improved contingency response to failure at single-element

stations, as well as for station off-loading for maintenance during light loading periods.

- Replacement of main-line fused disconnects with reclosers (prioritize heavily loaded devices).
- Installation of additional fault circuit indicators (FCI's)

B. <u>Evaluation Criteria and Information Requirements for Each Project/Activity</u>

1. Efficiency, Customer Value, Reliability

a) The primary driver for this program is reliability. Secondary drivers are operational efficiencies, improved system performance, maintainability and operability. This relates to API's asset management objective of providing safe, reliable, and high-quality service. The selection, prioritization, and justification of individual projects in any given year will be based on the analysis of historical outage data as well as an analysis of system capacity and contingency plans that form part of API's asset management process.

b) Investments in this program are relatively discretionary as compared to most other projects and programs, and as a result are given less priority. While justifications could be made for a large number of projects driven by reliability improvement and cost efficiencies, API is mindful of the associated rate impacts and resource requirements. Planned spending on this program is therefore relatively low in comparison to other programs and projects included in the five-year plan, representing less than 5% of the total five-year capital.

c) The projects selected for the current five-year plan will be those that result in the most obvious contingency improvements, reliability benefits and cost-saving opportunities. For example, the installation of new platform banks on the East of Sault 34.5 kV system will result in the following benefits:

    i. The ability to off-load distribution substations during periods of light loading will allow assets within that substation to be maintained in accordance with the optimized asset maintenance program outlined in API's DAMP, without associated outages to customers supplied from that station.

    ii. The new installation will effectively create an additional feeder, resulting in fewer customers per feeder, and therefore fewer customers affected by feeder faults that trip the main feeder recloser.

iii. The new supply point will result in creation of 3-phase feeder ties in some locations, which will enable future smart grid applications such as automated feeder reconfiguration to restore non-faulted line sections.

iv. In the event of severe failure of substation assets, the new supply points will supplement the existing limited load transfer capability to allow complete restoration of the affected load. In the case of a power transformer failure, this could reduce restoration time from a day or more to several hours or less.

2. Safety

   The improvements to reliability and contingency performance due to these investments are expected to reduce the safety risks that may be associated with outage restoration efforts in unfavourable conditions due to weather, time of day, or other factors.

3. Cyber-Security, Privacy

   To the extent that any new SCADA-capable devices are installed and integrated to API's SCADA system, the security of the communications link will be considered during the integration phase.

4. Co-ordination, Interoperability

   The reliability-driven investments associated with this program are expected to incorporate modern SCADA-capable equipment that will serve as a foundation for future Smart Grid projects.

5. Economic Benefits

   All associated work will be completed using local employees and contractors within Ontario.

6. Environmental Benefits

   Projects under this program will result in replacement of some oil-filled equipment with oil-free equipment, minimizing the potential environmental impacts of equipment failure. Also, reliability improvements resulting in a reduction of outage frequency would reduce the emissions associated with vehicles responding to after-hours outage events.

C. *Category-Specific Requirements for Each Project/Activity*

As discussed above, this program is relatively discretionary in comparison to other projects and programs within the current five-year plan. As a result, the consideration of a do-nothing approach for any specific project within this program would essentially maintain the status quo in terms of reliability, costs and contingency performance.

Given the significant benefits in terms of reliability, contingency response and operational efficiency associated with typical projects outlined in Section A above, API believes that the investment levels in the five-year plan strike a reasonable balance between an overall do-nothing approach, and investment driven by customer feedback and operational effectiveness in response to the Board’s RRFE performance outcomes. In addition, these projects are expected to incorporate advanced SCADA-capable equipment and technologies. These technologies will improve operational efficiencies and asset management practices, as well as provide the foundation for future Smart Grid projects.

As a specific example of the evaluation of project alternatives, the installation of new 3-phase step-down banks on the East of Sault 34.5 kV system provides all of the benefits listed in Section B.1.(c) above, at an estimated cost of approximately $400k per bank. For each future 8-hour customer outage avoided for station maintenance activities or forced outages scenarios, the SAIDI benefit would be in the range of 0.74 to 1.24, depending on the station.

A project to convert these DS’s to a dual-element to achieve similar contingency performance would cost at least twice this amount, with fewer reliability benefits during normal system operation and increased future O&M costs. Likewise, constructing 3-phase feeder ties between DS’s (where possible) to mimic the configuration of many urban LDC’s would cost 3-5 times as much as the new step-down banks and would result in system performance issues due to the distances involved. While the risk of substation transformer failure is relatively low, the multi-day outage resulting from such a failure is not likely to be acceptable to API’s customers. This is evidenced by customer reaction to multi-day outages in other parts of Ontario and Eastern Canada during ice storms in December 2013. As a result, API believes that this type of project strikes a reasonable cost/benefit balance between the do-nothing approach and more significant investments required to achieve the redundant configurations typical to more urban LDC's.

Hawk Junction DS Rebuild/Expansion (2015 Project - $997k)

A. General Information on the Project/Activity

This project involves expanding and reconfiguring the Hawk Junction DS to a dual-element configuration for both the 44 kV voltage regulator and the 44/8.3 kV local distribution. Given the condition of assets in the existing station, soil issues, clearance issues and lack of oil containment, all new bays will be constructed adjacent to the existing DS. The resulting design and construction plan will minimize the outages, planning requirements, and logistical challenges associated with attempting to incorporate the existing station footprint into the new design. Any suitable equipment of structural equipment from the existing station will be incorporated into the new station to the extent possible to reduce costs. Recent load growth on API's 44 kV No.4 Circuit has resulted in a peak load of approximately 11 MVA, or approximately 150 Amps. While this is below the thermal ratings of conductor and equipment on this feeder, the vast majority of this load is located approximately 45 km or more from the transmission supply point. A 44 kV regulator is in place at the Hawk Junction DS to provide acceptable levels of voltage to all customers by compensating for changes in supply voltage and for voltage drop along API's 44 kV circuit.

The voltage regulator in service at Hawk Junction is a single-element installation, with no spare regulator available. This configuration results in substantial reliability risk, with an increasing level of risk as the in-service equipment ages or as loads increase. API evaluated the impact on system voltage levels in the area for the condition where the voltage regulator had to be removed from service during winter months (either due to failure or need for priority repairs). With the regulator bypassed, API would be unable to maintain acceptable voltage levels for downstream customers in the area. This load makes up 20-25% or more of API's total system load, depending on the time of year. As a result, API has planned a project to purchase a spare 44 kV regulator and to rebuild the Hawk Junction DS to a dual-element configuration in 2014/1015.

B. *Evaluation Criteria and Information Requirements for Each Project/Activity*

1. Efficiency, Customer Value, Reliability

a) The primary driver for this program is reliability and contingency performance. Secondary drivers are improved system performance, maintainability and operability as well as reduction of environmental risks. This relates to API's asset management objective of providing safe, reliable, and high-quality service. The results of API's contingency analysis process are the primary source of justification for this project.

b) This project has become a high priority due to the continuing load growth described above. With the current configuration, API is unable to provide an adequate contingency for equipment failure. API also expects that annual maintenance windows for voltage regulator maintenance during periods of lighter loading will continue to decrease, further compounding the risk of failure as the 43 year old voltage regulator approaches the end of its useful life. As a result, API considers this project to be the highest capital priority, aside from non-discretionary spending related to regulatory obligations or the replacement of failed assets.

c) Given the current load, system configuration, asset age, criticality and condition, the risks associated with a do-nothing approach are not considered to be acceptable. Also, with the configuration of API's 44 kV system, and the location of major loads with respect to the area transmission supply, any possible transmission solutions to this issue would be prohibitively expensive and were not considered further.

2. Safety

The dual-element station layout will increase electrical clearances and isolation zones for future maintenance activities.

3. Cyber-Security, Privacy

To the extent that any new SCADA-capable devices are installed and integrated to API's SCADA system, the security of the communications link will be considered during the integration phase.

4. Co-ordination, Interoperability

The configuration of the new station will allow future flexibility for incorporation of a second 44 kV feeder and further station changes should a new 21 MW mining load proceed as indicated on the No. 4 Circuit.

5. Economic Benefits

   All associated work will be completed using local employees and contractors within Ontario.

6. Environmental Benefits

   The station expansion and rebuild will resolve the risks associated with a lack of secondary oil containment in the existing station.

C. *Category-Specific Requirements for Each Project/Activity*

In addition to satisfying API's objective of providing safe, reliable, and high-quality service, this project will provide direct benefit at large industrial customers that comprise a significant portion of API's load. Prolonged outages to these resource-based customers (even on a planned basis), results in economic hardship due to lost production and possible damage to equipment or facilities. The timing and priority of this project has been directly affected by load growth on the associated feeder and the overall age and condition of the in-service voltage regulator, which is nearing the end of its typical useful life.

Given the current load, system configuration, asset age, criticality and condition, a do-nothing approach was not considered acceptable as the prolonged outages and/or power quality issues for the length of time required for API to source and install a replacement voltage regulator would not be acceptable to customers. Alternatives to the project are limited by the overall 44 kV system configuration, the locations of the transmission source with respect to large loads, and the relative accessibility of various portions of API's 44 kV system. As a result, API has planned the expansion and rebuild of the existing station to a dual-element configuration as the most practical approach to resolve the contingency issue.

Echo River TS – Add Second Transformer (2017 Project - $4,550k)

A. General Information on the Project/Activity

This project involves the addition of a second transformer at the Echo River TS as the preferred solution to resolve limitations to the contingency supply to API's East of Sault 34.5 kV system due to limitations on API's NA1 feeder. This represents a situation where a transmission investment was determined to be an overall superior and more cost-effective solution to resolving a capacity issue. As mentioned above, API is working with GLPT to determine cost responsibility and, if necessary, may seek a determination from the Board on this matter at a future date.

Up to the 1980's, API's NA1 feeder was historically the only supply to the area East of Sault Ste. Marie. At the time of construction of the Echo River TS closer to load centres in this area, the NA1 feeder still provided an adequate contingency to supply the East of Sault system load. Echo River TS was therefore constructed with a single transformer to supply the 34.5 kV system in the area, with provision to accommodate a second transformer should the need arise. The NA1 feeder has been used for contingency supply to the area since that time. The entire East of Sault load has typically only been supplied from the NA1 feeder during periods of low to average loading (spring to fall months) to allow planned maintenance activities requiring outages to the Echo River TS.

API has recently observed recent winter peaks of 15.6 MVA on the East of Sault Ste. Marie system. API's analysis shows that supplying this level of load from the NA1 feeder would result in extreme low voltages for most customers in the area. Some areas would experience voltages in the range of 20% below nominal. A prolonged outage would require rotating blackouts to maintain adequate system voltages.

B. Evaluation Criteria and Information Requirements for Each Project/Activity

1. Efficiency, Customer Value, Reliability

   a) The primary driver for this program is reliability and contingency performance. Secondary drivers are improved system performance, maintainability and operability. This relates to API's asset management objective of providing safe, reliable, and high-quality service. The results of API's contingency analysis process are the primary source of justification for this project

   b) This project is the second highest priority in the System Service category (behind the Hawk Junction project). The limitations to the existing contingency and the associated risk levels will continue to increase with any amount of load growth on the East of Sault Ste. Marie 34.5 kV system. Also, the probability of transformer failure at Echo River TS would naturally increase as the asset ages.

   c) An evaluation of the distribution vs. transmission alternatives to resolving the contingency issue is provided in Part C of the project justification below. This includes the relative costs of both options.

2. Safety

   API is not aware of any material safety benefits associated with this project.

3. Cyber-Security, Privacy

   Not applicable

4. Co-ordination, Interoperability

   This project is included in API's DS Plan as a result of coordinated efforts between API and GLPT to examine all reasonable solutions to the issue identified. In addition to resolving API's contingency issue, this project would be expected to provide operability and maintainability benefits to both API and GLPT.

5. Economic Benefits

   All associated work will be completed using local employees and contractors within Ontario.

6. Environmental Benefits

   API is not aware of any material environmental benefits associated with this project.

C. <u>*Category-Specific Requirements for Each Project/Activity*</u>

API has evaluated the possibility of resolving this issue through investment in upgrading the NA1 feeder to a higher capacity, or a dual-feeder configuration. The distribution solution was found to have significant drawbacks, including:

- Upgrading of the first 32 km of the feeder (from the source TS to the first relatively large load center at the Bar River DS) would be required to see any significant voltage improvement. Much of the upgrade would require pole replacements to accommodate the larger conductor.
- Any future load growth would begin to offset the voltage improvements gained by the feeder upgrades.
- The additional capacity provided would be vastly underutilized during normal system configuration, while the existing capacity of the ER1 and ER2 feeders from the Echo River TS to the Bar River DS would remain unused during contingencies.
- The first 32 km of the 34.5 kV supply from the Northern Ave TS would be a single-circuit radial feed during contingencies. During a prolonged contingency where the load had to be supplied from the NA1 feeder (e.g. transformer failure at Echo River), a single fault in this 32 km stretch would result in an outage to approximately 5000 customers. With no alternate feeder, the outage to all 5000 customers would last as long as it took API to dispatch crews, clear the fault and restore power. The

heavy load on a single feeder would require sectionalized restoration, resulting in even longer outages to the customers furthest from the source.

- With more than 75% of the customers/load located 50-70 km from the Northern Ave source, the line losses during any contingency situation (including regular planned maintenance at Echo River) would continue to be excessively high.
- Some of the above drawbacks could be reduced by rebuilding the NA1 feeder to dual-circuit construction; however this would come with significant additional costs and challenges. Also, many of the above-mentioned drawbacks would be only partially offset.
- A preliminary cost estimate of upgrading 32 km of 34.5 kV line is in the order of $4.8 million, slightly more than the estimated cost of adding a second transformer at Echo River TS.

Given the significant drawbacks associated with a distribution solution to provide an adequate contingency for outages at the Echo River TS, and the fact that the Echo River TS was originally designed to easily accommodate the addition of a second transformer, API considers the transmission solution to be more appropriate in the circumstance. Given the risks associated with contingency scenarios with the current system and supply point configuration, API does not believe that a do-nothing approach is reasonable in the long-term. As a result, API has included a 2017 project to cover the costs of purchasing and installing a second transformer at the Echo River TS.

<u>General Plant</u>

ROW Access Program

A. <u>General Information on the Project/Activity</u>

	Forecast Expenditures ($'000)				
Project/Program Description	**2015**	**2016**	**2017**	**2018**	**2019**
ROW Access Program	$90	$90	$90	$90	$90

This Capital Expenditure is to collect all costs of the design, engineering, legal agreements, materials, equipment, internal labour and contracts related to the creation of access to API's existing power line locations.

2015 work will focus on an islanded 2.9 km portion of API's 12.5kv line feeding Michipicoten Harbour and Michipicoten First Nation. Recent weather events in the area have destroyed traditional access routes resulting in helicopter transportation being the only available means of getting workers equipment and material on site.

The topography of the area is typical rugged Canadian Shield with steep rock outcroppings and streams with a covering of dense forest. Two 10,000 square foot landing sites each with 256 square foot landing pads near the ROW will be required to accommodate the safe delivery of personnel, equipment and materials to complete repairs in case of a failure.

B. *Evaluation Criteria and Information Requirements for Each Project/Activity*

1. Efficiency, Customer Value, Reliability

a) The primary driver of this program is the support of system capital and maintenance investments. This relates to API's asset management objective of providing safe, reliable, and high-quality service. API's evaluation of outage response scenarios revealed that lack of access to certain line sections could severely hamper restoration efforts and result in prolonged restoration times for certain outage situations.

b) Program spending is relatively modest in the five-year plan, and is actually below API's materiality threshold on an annual basis. Overall, this program accounts for less than 1% of the total five-year capital spending. A project justification is provided however since annual amounts are close to the materiality threshold the overall program would otherwise comprise a large portion of the total of less than materiality projects included in the General Plant category.

2. Safety

This program is expected to improve worker safety by reducing the risks associated with the current methods of accessing certain line sections (helicopter, snowmachine, walking long distances). Planned locations of access allow workers to be better prepared for hazards they may encounter by limiting the number of unknown obstacles they will meet.

3. Cyber-Security, Privacy

   Not applicable

4. Co-ordination, Interoperability

   Where possible and appropriate, API will consider investigating the access requirements of third parties to certain areas. For example where a new trail may create access to API's ROW's that is suitable for snowmobile and off-road vehicles, API may involve local snowmobile clubs to partner in creating this access and/or in the ongoing maintenance of these trails. API will also involve the MNR as required for the creation of any new access roads or trails.

5. Economic Benefits

   All associated work will be completed using local employees and contractors within Ontario. To the extent that API is able to partner with third parties in the establishment or maintenance of certain access, there may be economic benefits to all parties involved.

6. Environmental Benefits

   API will involve the MNR in the review of any proposed new access to ensure that the environmental impacts are minimized. In some cases, API expects that creating alternatives to existing access locations and/or access methods will reduce the future environmental impacts of capital projects, inspection and maintenance programs and outage response. Alternatively, unplanned access during emergencies may lead to unintended environmental impacts.

C. *Category-Specific Requirements for Each Project/Activity*

As discussed in more detail in Exhibit 2, Tab 3, Schedule 1, access to certain portions of API's lines has eroded over time with reduction in resource-sector activity and inability to access line sections by rail. As a result of these access restrictions, API has included a program to address the most critical access issues in the current five-year plan.

Given the potential worker safety and environmental benefits mentioned above, and the potential reduction is restoration times for outages occurring on the most inaccessible portions of API's lines, API considers the program investment levels over the next five years to be a reasonable alternative to the do-nothing approach.

IT Hardware

A. *General Information on the Project/Activity*

Project/Program Description	Forecast Expenditures ($'000)				
	2015	2016	2017	2018	2019
IT Hardware	$170	$170	$170	$170	$170

This budget item includes the annual replacement of workstations, servers and network equipment and miscellaneous hardware on regular cycles, with relatively consistent year over year replacements.

B. *Evaluation Criteria and Information Requirements for Each Project/Activity*

1. Efficiency, Customer Value, Reliability

a) The main driver of this investment is to provide IT equipment required to support API's day to day business requirements.

b) This investment is a high priority within the General Plant category as API's IT infrastructure supports critical functions of API's business

c) Sustained replacement of assets on predictable cycles with consistent year over year spending will result in the most efficient use of internal resources and the lowest program costs in the long term.

2. Safety

   Not applicable.

3. Cyber-Security, Privacy

   Privacy and security practices will meet all regulatory requirements and will be consistent with good utility practice.

4. Co-ordination, Interoperability

   API's IT investments and activities are coordinated with those of other FortisOntario subsidiaries and affiliates in order to share certain costs and use internal resources in an efficient manner.

5. Economic Benefits

   Installation, configuration and integration of new hardware will be completed using local employees and contractors within Ontario.

6. Environmental Benefits

   Not applicable.

C. *Category-Specific Requirements for Each Project/Activity*

This investment covers the consistent annual replacement of IT hardware on predictable cycles that generally coincide with warranty coverage and useful lives. Deviation from this approach could result in failures outside of warranty periods, increase risk of system failures and unpredictable annual costs.

Business Systems (SCADA, GIS, OMS, etc)

A. General Information on the Project/Activity

	Forecast Expenditures ($'000)				
Project/Program Description	**2015**	**2016**	**2017**	**2018**	**2019**
Business Systems (SCADA, GIS, OMS, etc.)	$171	$171	$171	$171	$171

This program captures the capital costs associated with the ongoing development, implementation and integration of various business systems with the overall goal of creating operational efficiencies and improving system reliability. Spending in early years of the plan will focus on completion of the initial implementations of various systems and the customization and/or configuration of these systems to support API's specific requirements and processes. Spending in later years will focus on continued integration between systems to improve operational and administrative efficiencies.

B. Evaluation Criteria and Information Requirements for Each Project/Activity

1. Efficiency, Customer Value, Reliability

a) The primary driver of this program is the improvement of operational efficiencies. Secondary drivers include reliability improvement, improved customer communication and the incorporation of advanced technologies. In addition to improving operational efficiencies, API expects that continued development and integration of these systems will improve various components of the asset management process described in Section 5.3.1.

b) This program is a medium priority within the overall capital plan. Investments in these systems will result in operational efficiencies and process improvements. These investments are also partially driven by customer feedback indicating a desire for improved reliability and improved communication during outages.

c) Most of the systems being implemented have been selected with consideration of the systems currently in place at other FortisOntario subsidiaries. Selecting different software or systems specific to API would increase costs related to licensing, implementation, system integration, technical support and process development.

2. Safety

   Overall reliability improvements and the ability to remotely control certain assets is expected to lead to decrease frequency of outage response as well as more efficient response (less travel between switches). A reduction in these activities would reduce the overall exposure to the associated hazards.

3. Cyber-Security, Privacy

   Consideration will be given to the security of any communication methods or networks associated with system implementation and integration. Also, the privacy implications of system integration will be evaluated to ensure that sensitive or confidential information is not inadvertently exchanged between systems.

4. Co-ordination, Interoperability

   The development and integration of these systems is coordinated with other FortisOntario subsidiaries in order to minimize both the initial implementation and long-term management costs.

5. Economic Benefits

   Where possible, system implementation and integration efforts will be completed using local employees and contractors within Ontario.

6. Environmental Benefits

   The GIS and Vegetation Management systems will allow more integrated management of API's environmental aspects on a geographical basis, allowing environmental concerns to be efficiently considered during the planning stages of capital projects and maintenance programs.

C. *Category-Specific Requirements for Each Project/Activity*

API is proposing continued investment in the implementation and integration of various business systems in place at other FortisOntario subsidiaries.

A passive approach would maintain the status quo of managing a large variety of paper based process, Access databases and spreadsheets to manage the various data sources and processes associated with API's asset management process. This results in administrative inefficiencies and potential sources of error where information required by multiple systems must be manually populated in more than one location. It also results in further inefficiencies where information and reports need to be extracted from multiple systems and combined manually in spreadsheets in order to support project and program planning, tracking and analysis requirements.

Transportation & Work Equipment

A. General Information on the Project/Activity

Forecast Expenditures ($'000)				
2015	**2016**	**2017**	**2018**	**2019**
$551	$551	$401	$401	$401

This Capital Expenditure is to collect all costs related to the annual purchase of one Line/Forestry truck ($275-400k) and a further $150k annually to cover replacement of pickup trucks, snow-machines, ORV's etc. Many lines are not road accessible, particularly some critical express feeders. A variety of equipment is required to allow for inspections, patrols and emergency response through various seasons and ground conditions.

B. Evaluation Criteria and Information Requirements for Each Project/Activity

1. Efficiency, Customer Value, Reliability

a) The primary driver for this program is the replacement of end of life fleet assets at a rate that is sustainable with relatively consistent annual spending. An adequate fleet is required to support API's capital and O&M programs, as well as for outage response. The overall type, age and condition of fleet assets is the primary source of information used to justify this program.

b) The overall requirement to maintain an adequate fleet compliment to meet API's day to day business requirements is considered a non-discretionary item and is among the highest priority programs within the General Plant category. Replacements are based on the expected economically useful life of each type of equipment and are staggered to maintain a relatively constant age profile for in-service fleet assets.

c) Sustained replacement of fleet assets on predictable cycles with consistent year over year spending will result in the most efficient use of internal resources and the lowest program costs in the long term.

2. Safety

   API's overall lifecycle management of fleet assets results in the availability of safe, reliable vehicles to support operational activities.

3. Cyber-Security, Privacy

   Not applicable.

4. Co-ordination, Interoperability

   Not applicable.

5. Economic Benefits

   API sources new vehicle purchases through Ontario dealers.

6. Environmental Benefits

   Newer fleet assets are generally more fuel efficient than the units being replaced. As a result, API's fleet is expected to become more fuel efficient over time.

C. *Category-Specific Requirements for Each Project/Activity*

Investment in fleet replacements is planned at a sustaining pace based on an optimized lifecycle management approach each fleet item. The details of API's fleet assets and the lifecycle optimization practices that drive the replacement rates described above are provided in Section 5.3.3(a). This approach results in a sustainable fleet program that provides operational staff with a reliable compliment of vehicles, with a consistent age profile over time. The resulting annual capital and maintenance costs are predictable and the impact on other projects or programs due to urgent unexpected replacement or repairs is minimized.

ROW Hardening

A. *General Information on the Project/Activity*

Forecast Expenditures ($'000)				
2015	**2016**	**2017**	**2018**	**2019**
$1,500	$1,500	$1,500	$1,000	

The ROW Hardening program is a continuation of API's ongoing efforts to reduce the reliability and cost impacts associated with tree-caused outages. Following completion of the ROW Expansion program presented in previous cost of service applications, API continued to observe frequent outages due to falling trees. In recent years, these fall-in outages have increasingly been caused by trees located beyond the edge of the ROW.

In 2013, API contracted Ecological Solutions Inc. to complete a comprehensive review of the current status of API's ROW's, as well as to quantify recommendations for future activities that would ultimately lead to a lowest cost sustainable Vegetation Management ("VM") plan. The report completed as result of this exercise is attached as Appendix E.

The results of this review indicated that over 825,000 "danger trees" located outside of the ROW''s have the potential to contact line conductors on failure. Based on a 2% annual mortality rate, approximately 16,500 trees will need to be assessed annually for the risk posed to nearby power lines. The expectation is that approximately 3000 of these danger trees will be designated as "hazard trees" and identified for proactive removal based on a high risk of impacting API's lines. As a result, API has included for the annual removal of approximately 1000 off- ROW trees in its sustainable VM maintenance program.

The comprehensive review of the current status of API's ROW's also found a backlog of approximately 15,000 hazard trees with above average risk of falling into API's lines due to factors such as species, state of decay, height and location. API is proposing a ROW Hardening program over the next four years (2015-2018) to proactively remove these trees. This program will have positive impacts on system reliability and worker safety, and will reduce the impacts to other projects and programs that would be associated to reactive response to tree-caused outages.

API has consistently completed larger volumes of tree removal work in recent years and does not anticipate significant risks in achieving the annual targets included in the five-year plan. As described in Section 5.2.3(a), API has implemented processes to review both the physical and financial progress of projects and programs on a monthly basis in order to proactively identify and resolve any issues during the early stages of any specific project.

B. *<u>Evaluation Criteria and Information Requirements for Each Project/Activity</u>*

1. Efficiency, Customer Value, Reliability

a) The primary driver of this program is to achieve a ROW standard that optimizes the long-term balance between reliability performance and overall system O&M costs. This program is based on the fundamental objective of API's DAMP, which is *"to prudently* *and efficiently manage the planning, engineering, design, addition, inspection and maintenance, replacement, and retirement of all distribution assets in a sustainable manner that maximizes safety and customer reliability, while minimizing costs, in the short and long terms."* Secondary drivers include reliability and operational effectiveness.

b) API has placed a high priority on this program as the results of a third-party evaluation clearly demonstrate that prioritizing the proactive removal of the backlog of hazard trees will result in lower long-term costs in comparison to a reactive approach.

c) The alternatives to proceeding with the program at the planned pace of investment are summarized in Part C of the project justification below.

2. Safety

   This program is expected to improve worker safety by allowing proactive removals to take place under planned conditions during times of optimal access and weather conditions.

   This program is also expected to improve public safety in terms of reducing the frequency of tree contact along sections of API's ROW that are frequently accessed by recreational users. Also the risk of fires cause by tree contact and arcing will be reduced.

3. Cyber-Security, Privacy

   Not applicable

4. Co-ordination, Interoperability

   API will coordinate activities under this program with the MNR, road authorities, First Nations, municipalities and private landowners as required.

5. Economic Benefits

   All associated work will be completed using local employees and contractors within Ontario.

6. Environmental Benefits

   API will involve the MNR in the planning stages of activities to be completed within this program to minimize impacts on the natural environment and to species at risk, where applicable. It is expected that the information gained through this process will assist API in minimizing the environmental impact associated with this program, as well as in considering the potential environmental impacts of future vegetation management activities in these areas. This program will also reduce the risk of forest fires caused when decayed trees fall into the power line.

C. *Category-Specific Requirements for Each Project/Activity*

The results of the quantitative analysis conducted in support of this program are included in the report attached as Appendix E. By not completing the program to remove the backlog of hazard trees, API would be in a position of reactively responding to damage caused by these trees. The higher cost per tree removal for a reactive approach would lead to far fewer removals, foregoing opportunities to improve reliability by removing more trees proactively. Due to the unpredictable nature of tree failures with regards to location and timing, a reactive response approach also takes lines and forestry resources away from other planned projects and programs. This leads to delays and/or rescheduling of planned activities, which results in increased costs and potential impact to customers.

The findings and recommendations included in the expert review attached as Appendix E, specifically the assessment of the cumulative liability associated with the backlog of decaying off-right-of-way trees, present a compelling business case that the prioritized removal of this backlog will result in the lowest-cost sustainable vegetation management program. In reviewing these recommendations, API has planned a four-year removal program that will allow for efficient identification and planning of specific work activities, as well as notification requirements and requirements to coordinate with third-party stakeholders.

Distribution Asset Management Program

Prepared By:	API Engineering Dept.

Revision:	R1
Release Date:	February 6, 2014
Print Date:	May 8, 2014

Distribution Asset Management Program

Table of Contents:

1 Introduction

1.1 Non-Disclosure

There are specific sensitive details of information, such as private customer information and confidential future business development plans that are protected by the *Ontario Freedom of Information and Protection of Privacy Act.* Therefore certain specific details will not be described in this document.

1.2 Objective

The fundamental objective of the API Distribution Asset Management Program (DAMP) is to prudently and efficiently manage the planning and engineering, design, addition, inspection and maintenance, replacement, and retirement of all distribution assets in a sustainable manner that maximizes safety and customer reliability, while minimizing costs, in the short and long terms.

This objective is met through the application of thorough and sound planning, prudent and justified budgeting, and ongoing oversight, documentation, and review of all efforts and expenditures while implementing the documented capital and operating plans.

API will maintain a comprehensive Distribution Asset Management Plan which outlines operating and capital processes, activities, and expenditures to ensure that API continues to provide the safe, reliable, and efficient distribution of electricity to its customers.

There are three key principles that are integral to the API Distribution Asset Management Plan:

(1) Provide for the growth needs of the customers in the various service territories

(2) Provide safe, reliable, and high-quality service to all of the customers of API

(3) Satisfy the first two principles in a sustainable manner which minimizes the long-term costs to be borne by the ratepayers of API.

These key principles are derived from safety considerations; acts, regulations, codes and guidelines; good utility practice; and customer expectations.

1.3 Scope

The scope of the API Distribution Asset Management Program (DAMP) includes the long-term management of distribution assets owned by API.

This document is intended to provide a synopsis of the Asset Management Program at API. For reasons of brevity and confidentiality, this document does not attempt to encompass all of the information and activities that fully define the DAMP, as described later. The purpose of this document is to provide an 'objective summary' with sufficient detail to supply an overall understanding of API's Asset Management efforts.

1.4 Acts, Regulations, Codes and Guides

The following is a partial listing of the acts, regulation, codes and guidelines that direct API's operations:

(1) The principal regulator guiding API's practices is the OEB. Under the guiding principles set out in the *Electricity Act, 1998* (the "Electricity Act"), the OEB has established a Distribution System Code ("DSC") that defines how and under what conditions, a utility is to provide service and interact with its customers. It is prescriptive in nature and deals with virtually every aspect of utility operations including such things as: connections and expansions, standards of business practice and conduct, quality of supply (reliability), infrastructure inspections, metering and conditions of service. The licensed distributor's conditions of service are set out by the distributor in a document that is filed with the OEB and posted on the distributor's web site.

(2) A second entity is the Electrical Safety Authority ("ESA"). The ESA derives its authority from the Electricity Act. The ESA is responsible for ensuring the safety of all electrical installations in the province of Ontario for systems operating at a voltage less than 50kV under Ontario Regulation 22/04. Under the regulations, every electrical installation and associated equipment must be installed in accordance with a design or standard approved by a professional engineer. Every year there is a compliance audit conducted by an outside agency and the utility is required to sign a regulatory declaration stipulating that it has complied with the regulations.

(3) The Occupational Health and Safety Act ("OHSA") governs how work is performed and is enforced by the Ministry of Labour. The act is comprehensive and forms part of every job. At API the health and safety of employees and customers is given top priority and there is an active joint health and safety committee that oversees operational activities. There is also a Central Environmental and Safety Committee (CESC) to centrally coordinate safety and reporting activities. Extensive training programs ensure that staff is competent to perform their duties. Every effort is made to make sure that employees have the right tools and protective equipment to do their job safely.

(4) The Ministry of Environment ("MOE") is responsible for regulating how hazardous waste is handled. API has registered hazardous waste storage sites in its service territories and deals with a variety of substances in the course of building, operating and maintaining the electric distribution system.

(5) Measurement Canada ("MC") regulates API's revenue metering activities.

(6) The Ministry of Transportation ("MTO") is the governing body with respect to activities associated with the fleet. It also mandates the requirements for traffic control at worksites that are near or on roadways.

(7) API is an engineering focused company and as such is governed in its activities by the *Professional Engineers Ontario Act* ("PEO"). The PEO regulates codes of practice and ethics within the engineering staff at the utility.

(8) API owns distribution system assets in a number of municipalities located in Northern Ontario. The needs, rules and by-laws of these municipalities must be respected.

(9) There are a host of other entities that mandate rules, programs and work practices. These include, but are not limited to: the Electrical Utility Safety Association ("E&USA"); the Independent Electric System Operator ("IESO"); the Canadian Coast Guard; the Ministry of Natural Resources, the Department of Fisheries and Oceans,

Measurement Canada, CN and CP Rails; various Conservation Authorities; and the Canadian Standards Association ("CSA").

All of the above impact planning, and ensure that API follows "Good Utility Practice" in providing exceptional customer service.

1.5 Documents that Support the Asset Management Plan

API has completed various internal infrastructure studies and refers to other relevant sources of information in order to develop and sustain the Asset Management Plan. Internal studies may contain proprietary information, and are therefore not included in the Asset Management Plan for general distribution. The following are examples of reports and studies supporting the Asset Management Plan with a short description of each:

1.5.1 System Planning

System planning is broken into two segments; long term (fifteen year outlook) and medium term (five year plan).

Annually a fifteen year forecast is performed identifying significant capital and maintenance programs and anticipated durations. Each type of program is identified with a broad scope description with cost projections. A program is intended to identify a component of the distribution network that will have a significant impact on O&M or capital investments. Regional planning with the transmitter is also intended to be included as an integral part of the long term planning process.

Medium term planning occurs subsequent to each annual long term planning review. It is at this point that the capital and maintenance programs and projects are identified and included as part of API's Distribution System Plan (DSP). Section 5 of this document provides more detail on the medium and long-term planning processes.

1.5.2 The API Construction Verification Program (CVP)

As required by Ontario Regulation 22/04, API performs all material procurement, project design, construction, and follow-up inspections in accordance with ESA-approved CVP, utilizing only professionally approved construction standards. This process is reviewed and updated on an ongoing basis.

1.5.3 Municipal Presentations

API meets with each municipality that is serves, through an annual presentation to their council. The presentation covers API capital and maintenance plan for the current year as well as serves as the municipality's opportunity to respond to the presented plan. It also provides municipalities an opportunity to inform API of any municipal plans (new development, streetlight projects, etc.) that may impact API's system.

API hosts an annual Roads Supervisor meeting where members of each municipal roads department meet with API staff to discuss current and future work projects. Timelines and project scopes are discussed with efforts to both streamline each project and minimize impacts to the area residents.

1.5.4 Distribution System and Substation Assessments

A comprehensive review of system and substation equipment and performance indicators is used to optimize preventative maintenance programs and to drive future capital plans. Key indicators such reliability, failure history, failure impacts, test results, safety factors and age are considered in the prioritization of capital and maintenance activities.

1.5.5 Predictive Maintenance Reports

Results from predictive maintenance techniques such as infrared scanning, oil testing, conductor testing, pole testing, and insulation testing are used to assess the condition of individual system components. The overall assessment forms the basis for the development of maintenance, refurbishment, intervention, and equipment retirement strategies.

1.5.6 Technical Studies

Various technical reports are prepared on an as-needed basis, the results of which are incorporated into the DAMP as required. An example would be a Connection Impact Assessment (CIA) prepared for a distributed generation applicant under Ontario's Feed-In-Tariff (FIT) program.

1.5.7 Distribution System Information

API maintains its system asset inventory through diverse data records (and reports) such as relational databases, CAD drawings, GPS records, and electronic spreadsheets. In addition, API manages a variety of paper-based maintenance and inspection records.

API has been transitioning to the FortisOntario SAP enterprise resource planning software, as well as implementing a GIS system. It is expected that many of API's asset records, reports and assessments will be migrated to these systems in the coming years. These systems are expected to assist in providing more in-depth reporting and analysis of asset records and asset performance.

2 Overview

2.1 General Overview of API System

API owns and operates the electricity distribution system in portions of the district of Algoma, serving approximately 11,650 customers located in a number of townships and First Nations territories. The service territory includes an area of approximately 14,200 square kilometers, and 1848 km of distribution circuits, over 99% of which are overhead lines. The API system meets a winter peak demand of approximately 40 MW.

API is comprised of several distribution regions operating independent of each other in the following areas interconnected either by API's own 34.5 kV and 44 kV systems or independently supplied through various connection points by a licensed transmitter's substations. The list and service area maps below provide a summary of these operating regions:

(1) Sault Ste. Marie to Thessalon (2 Transmission supply points & API 34.5 kV supply)

(2) Goulais / Searchmont (Transmission supply point)

(3) Batchawana (Transmission supply point)

(4) Montreal River (Transmission supply point)

(5) McKay (Transmission supply point)

(6) Wawa and surrounding area (2 Transmission supply points & 34.5 kV supply)

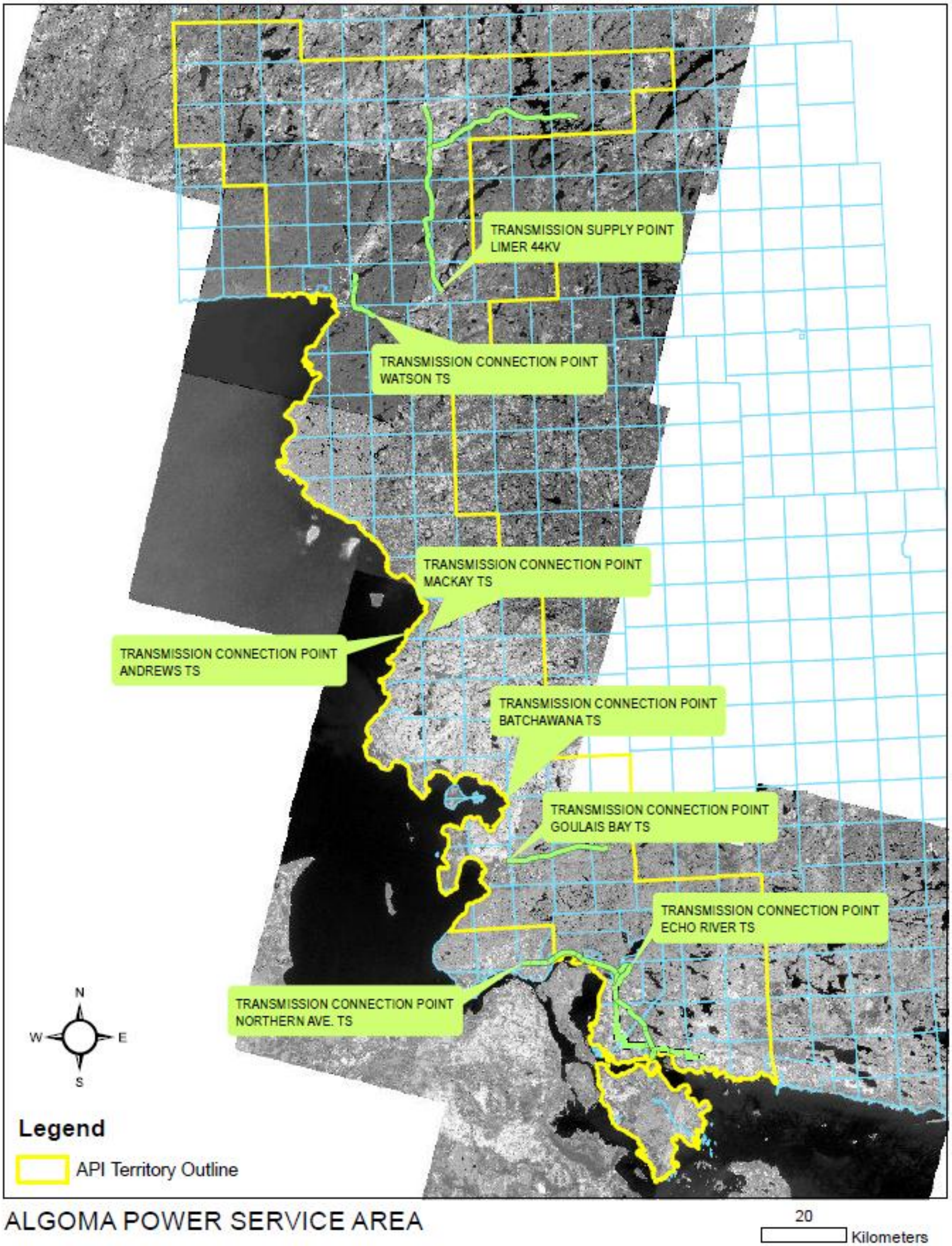
(7) Highway 101 to Whitefish Lake (3 API 44 kV supply points)

(8) Hawk Junction (API 44 kV supply)

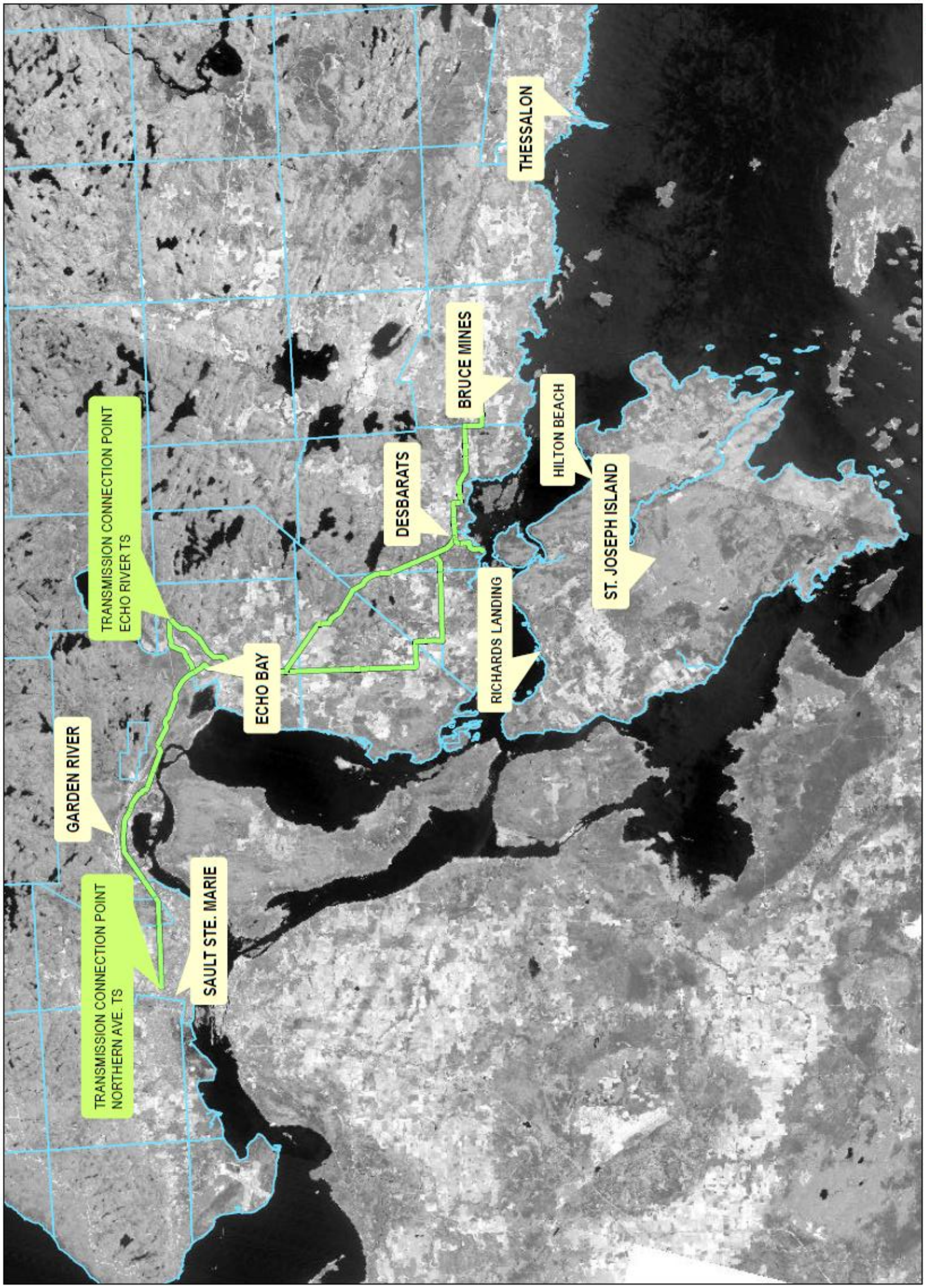
(9) Goudreau (API 44 kV supply)

(10) Lochalsh (API 44 kV supply)

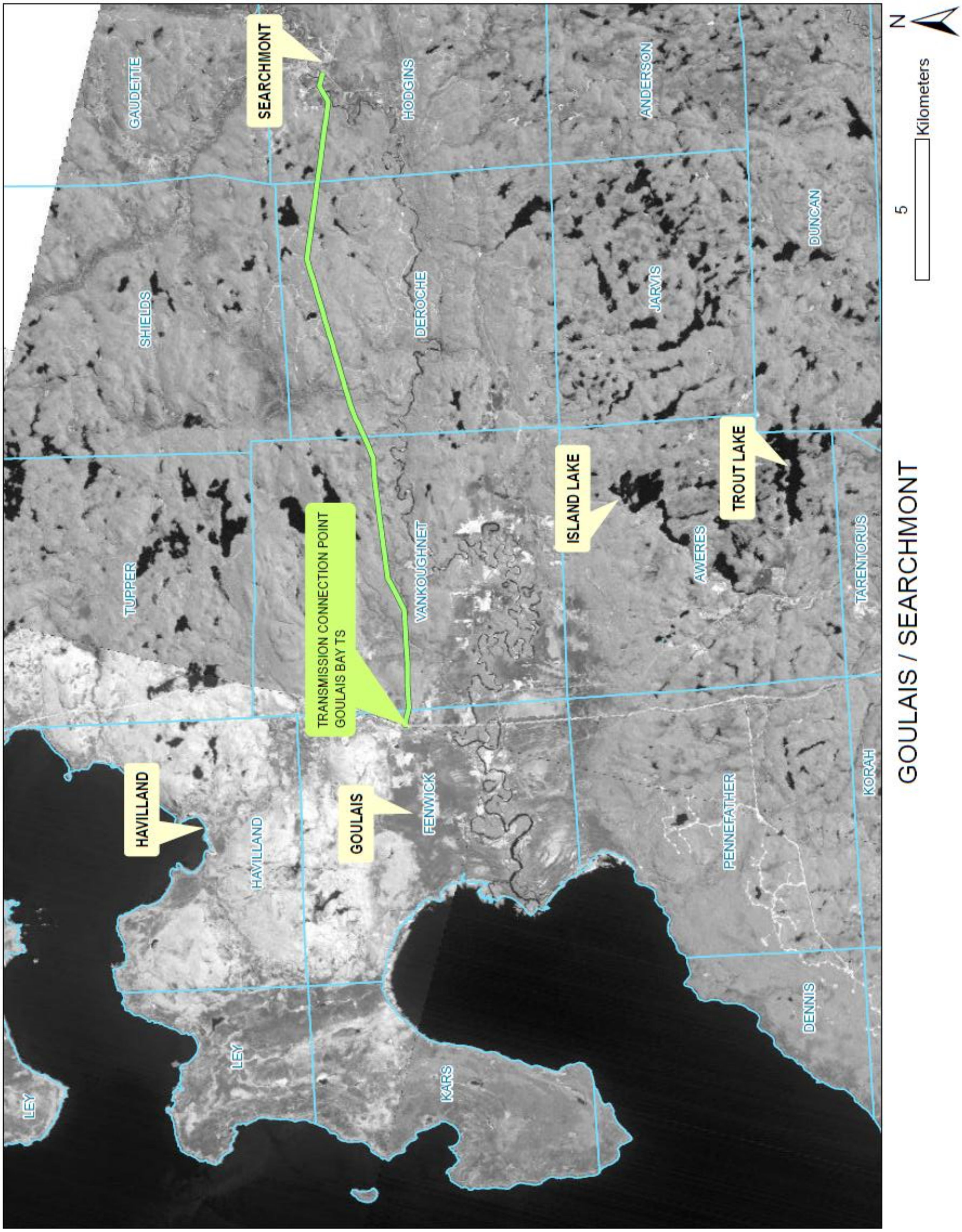
(11) Missanabie (API 44 kV supply)



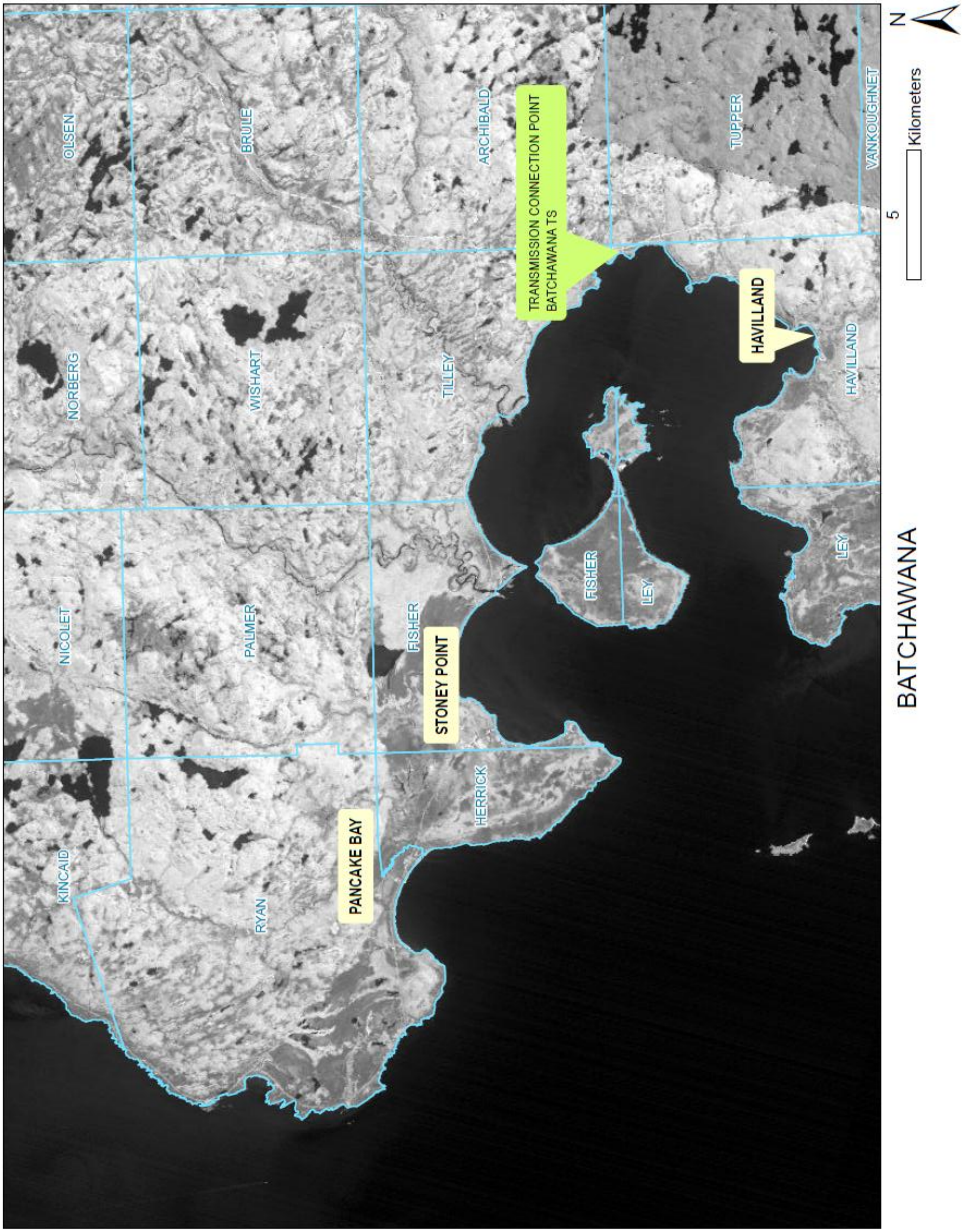
ALGOMA POWER SERVICE AREA



SAULT STE. MARIE TO THESSALON



GOULAIS / SEARCHMONT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BRULE
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NORBERG
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HAVILLAND
NICOLET
PALMER
FISHER
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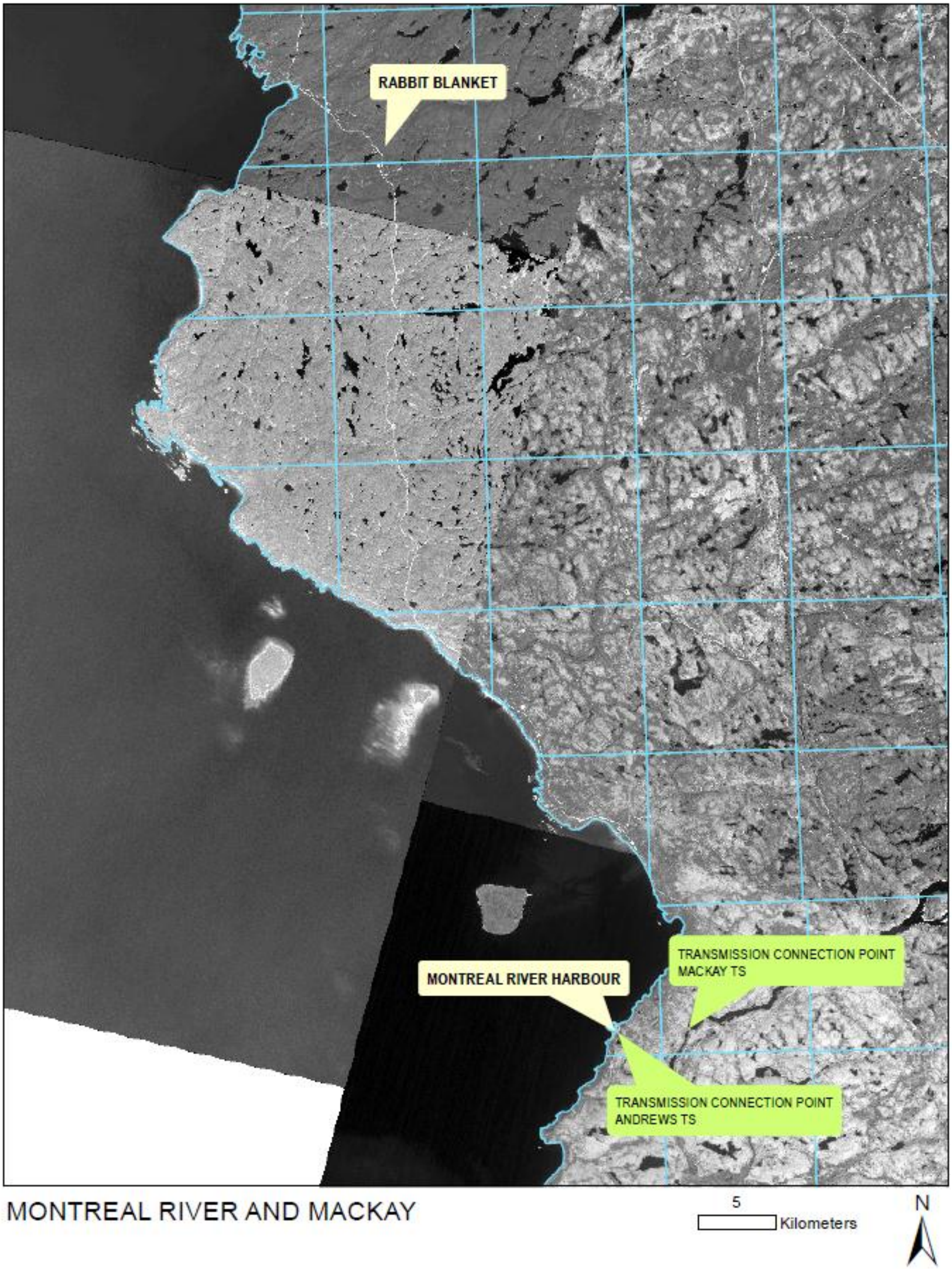
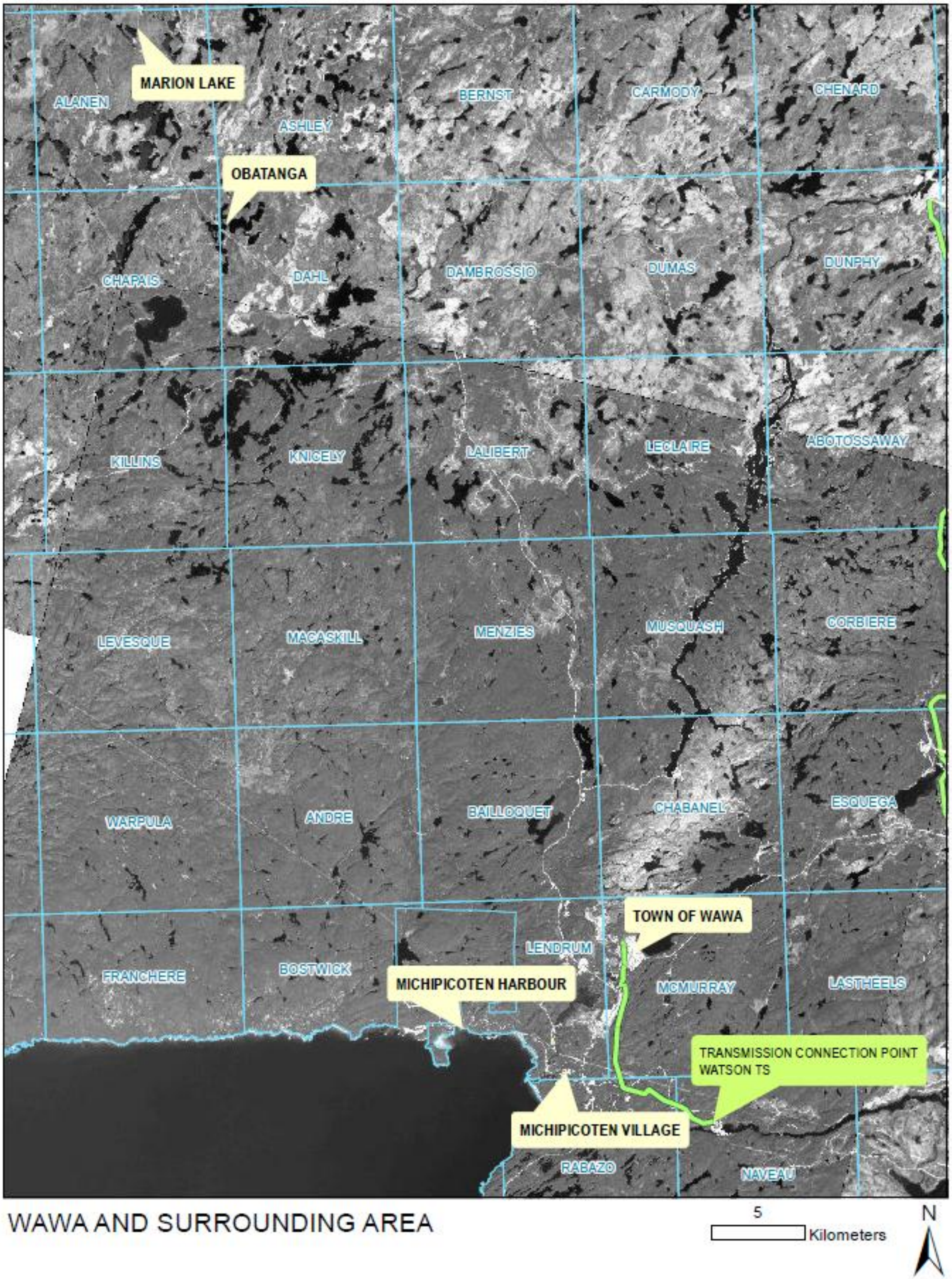
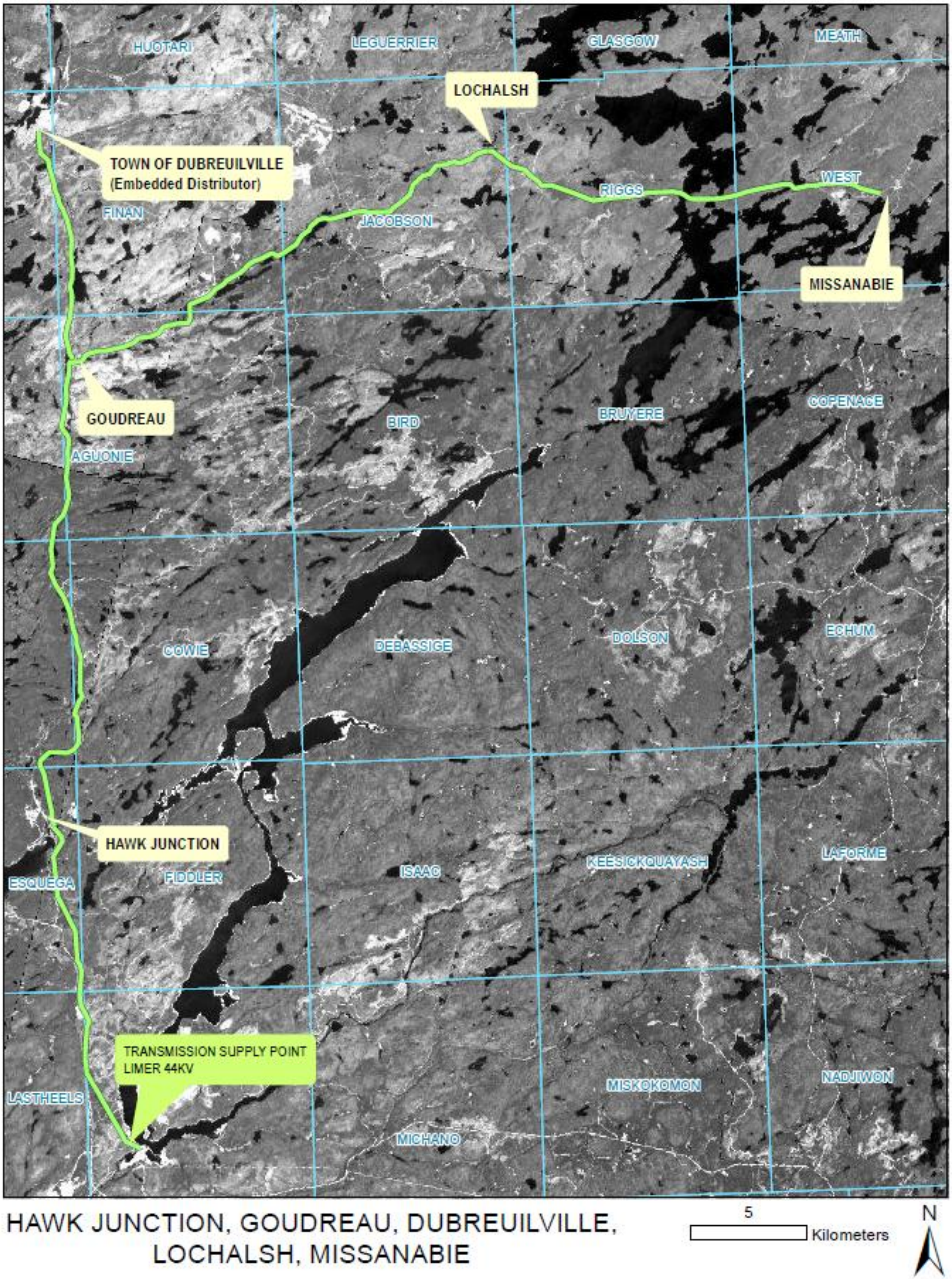


MONTREAL RIVER AND MACKAY



WAWA AND SURROUNDING AREA



HAWK JUNCTION, GOUDREAU, DUBREUILVILLE, LOCHALSH, MISSANABIE

2.2 Supply Points from the IESO-Controlled Grid

The API distribution system is supplied from the Great Lakes Power Transmission ("GLPT")-owned transmission system through eight delivery points located at seven different transmission substations and on a GLPT-owned 44 kV transmission circuit. Three of the GLPT-owned transmission stations and the 44 kV transmission circuit supply 34.5 kV and 44 kV API-owned express feeders supply seven distribution substations, a number of pole-mounted step-down transformers and an embedded distributor. The other GLPT-owned transmission substations supply distribution feeders directly at lower distribution-level voltages.

2.3 Distribution Lines by Voltage Class

There are a wide variety of voltages presently in use on API's distribution system, including: 44 kV, 34.5 kV, 24.9Y/14.4 kV, 12.5Y/7.2 kV, 8.3Y/4.8 kV, 4.16Y/2.4 kV, 12 kV, 4.8 kV and 2.4 kV.

44 kV – A single 44 kV radial feeder is supplied as a tap from a 44 kV transmission circuit in rural areas east of Wawa. The feeder supplies an embedded distributor, a distribution substation, six pole-mounted step-down transformers, and a number of customer-owned substations connected directly at 44 kV.

34.5 kV – API operates two 34.5 kV systems in its service territory, one in the Wawa area and the other in the area east of Sault Ste. Marie. The Wawa system consists of two 34.5 kV feeders running in parallel from the D.A Watson transmission substation to the town of Wawa, where they join at the Wawa No.2 substation to supply a 34.5 kV bus in a main-alternate configuration. These feeders supply the two distribution substations in the town of Wawa as well as a single-phase step-down transformer supplying a small load in a rural area outside the town. The system east of Sault Ste. Marie consists of three 34.5 kV feeders supplied from two separate transmission substations. These feeders supply four API distribution substations, and three customer-owned substations connected directly at 34.5 kV. The feeders are normally operated radially; however, the system contains many normally open feeder interties, allowing load transfers between feeders and providing alternate supplies to many of the distribution substations. In general, many of API's larger load centres are located at long distances from its transmission supply points and use of the 34.5 kV systems allows these areas to be supplied with acceptable voltage levels and lower overall system losses than would be possible with direct supply at lower distribution-level voltages.

24.9Y/14.4 kV – This voltage level is used in areas where use of API's predominant voltage of 12.5Y/7.2 kV would result in unacceptable voltage levels or excessive line losses on the distribution system. The largest system in this voltage class is located on St. Joseph Island, which serves almost 1800 customers spread over an area of 365 square kilometres. This voltage level is also used on three other feeders, either as a direct supply from a transmission station at this voltage level, or through the use of step-up transformers from a 12.5Y/7.2 kV feeder.

12.5Y/7.2 kV – This voltage level serves slightly more than half of API's customer. In most areas, this voltage level can provide acceptable voltage profiles while reducing losses as compared to lower voltages previously used. As this is a common voltage level, equipment is readily available at reasonable costs and with minimal lead-time. Most of the distribution feeders east of Sault Ste. Marie (with the exception of St Joseph Island) are supplied at this voltage level via 34.5 kV to 12.5Y/7.2 kV substations. This voltage level is also supplied directly from two transmission supply points North of Sault Ste. Marie, and on a feeder from one of the distribution substations in Wawa that supplies the rural load outside of the town.

12 kV – This voltage is used only on a feeder supplying customers within the city of Sault Ste. Marie. This feeder supplies the six locations within Sault Ste. Marie.

8.3Y/4.8 kV and 4.8 kV Delta – Most areas using 8.3Y/4.8 kV in the area east of Sault Ste. Marie have been converted to 12.5Y/7.2 kV, or 24.9Y/14.4 kV in the case of St. Joseph Island. Some small pockets of single-phase 4.8 kV remain supplied by single-phase step-down transformers from the other voltages. These areas will continue to be converted to higher voltages in conjunction with conductor replacement, pole replacement or other capital programs in these areas in order to improve voltages and reduce losses.

The entire 4.8 kV Delta system in the Town of Wawa was converted to 8.3Y/4.8 kV in 2009. Use of the 8.3Y/4.8 kV voltage level in this case was considered the most economical and practical choice for converting the 4.8 kV delta system. This allowed the entire conversion to take place over a period of months rather than years, with minimal service interruptions. It also allowed most of the existing distribution transformers as well as a large substation transformer to be re-used and will allow 4.8 kV transformers removed from other areas to be transferred to Wawa for future use. As there are 12.5Y/7.2 kV feeders in rural areas surrounding the town, use of the 8.3Y/4.8 kV feeders will be limited to the town site itself.

There are also a number of lightly loaded feeders being supplied at 8.3Y/4.8 kV or at 4.8 kV single-phase in remote areas near Wawa supplied from API's 44kV subtransmission circuit. Given the extremely small load levels in these areas, and the fact that the Wawa work centre will be required to maintain an inventory of 4.8 kV class equipment for use on feeders within the town, no voltage conversion is planned for these areas in the short-term planning horizon.

4.16Y/2.4 kV – This voltage class is currently in use in the Town of Bruce Mines, east of Sault Ste. Marie. The town is currently supplied from a 3-phase 12.47-4.16 step-down bank. The Bruce Mines 4.16 kV system will be gradually converted to 12.47 kV in conjunction with the planned pole replacements.

1.38/2.4 kV – This voltage is used to supply a small feeder directly from a transmission substation in a remote area. As there are approximately only twelve customers on this feeder and much of the load is seasonal, there are no short-term plans to convert this feeder to another voltage class.

2.4 Distribution Substations

API presently operates seven distribution stations ("DS"). Photos and further details of each station are illustrated in Appendix A - "Substations":

API's DS's are generally split between newer and older vintage, with four substations (Wawa#1, Garden River, Bar River, and Desbarats) having been built or upgraded in the last 10 years and the other substations being in the 30-50+ year old range.

2.4.1 List of Distribution Substations by Area

<u>Wawa and Surrounding Area</u>

Wawa #1 Substation

Wawa #2 Substation

Hawk Junction Substation (Includes 44 kV Voltage Regulator Installation)

<u>Sault Ste. Marie and Surrounding Area</u>

Garden River Substation

Bar River Substation

<u>Desbarats and Surrounding Area</u>

Desbarats Substation

Bruce Mines Substation

2.5 Summary of Major Distribution Assets

The following table summarizes in-service assets as of December 31, 2013:

Distribution Line Assets	
Poles	29,687
Distribution Transformers	4854
Capacitor Banks	4
Voltage Regulators	9
Reclosers	153
Circuit Breakers	1
Express Feeder Load-Break Switches	7
Total Overhead Line (km)	1834
Total Underground Line (km)	14
Distribution Substation Assets	
Substations	7
Power Transformers (Banks)	11
Voltage Regulators	1
Reclosers	14
3-Phase Switches	25
Power Fuses (Sets)	10
Metering Assets	
Tower Gateway BaseStations (TGB's)	8
FlexNet Remote Portal (FRP)	8
FlexNet Network Portal (FNP)	15
AMI Meters	11,784
Interval Meters	12
Wholesale Meters	22

3 Distribution Assets

3.1 Categories of Assets

The distribution assets of API can be broken down into various categories and definitions:

(1) **Financial (Fixed) Asset**: This is the 'traditional' accounting/finance view of assets, included in various accounts and focusing on financial information such as original cost, current book value, and depreciation amounts.

(2) **Physical Assets (Components):** This is the 'traditional' operations view of assets, which are actual material parts such as a 45 foot class 4 wood pole, a cross-arm, or a section of 28kV underground primary cable.

(3) **Managed Asset (MA)**: For purposes of the API DAMP, a *Managed Asset* (MA) is an assembly of one or more components tracked and managed as a single entity. For example a single 'Pole' MA might consist of the pole itself in addition to any supporting components such as guy wires and anchors. A framing MA may contain a cross-arm, three 28kV insulators, plus the sundry other approved hardware required. API's various rights of way and land corridors also are identified as managed assets.

API's DAMP will focus almost entirely on *Managed Assets* as the effective meaning of 'assets' in the context of this document.

3.2 Overhead and Underground Distribution Managed Assets

3.2.1 Poles

Poles constructed of wood and occasionally resin composites, these form the 'backbone' of the overhead distribution system. Wooden poles are used in over 98 percent of all cases.

The poles used in API's distribution systems range in height from 25' (7.6m) to 85' (25.9m). A typical height for a single-circuit three-phase pole is 45' (13.7m).

Poles come in several standard 'strengths' known as classes, as defined by CSA specifications.

API's pole age profile can be found in Appendix B.

3.2.2 Framing Assemblies

This MA is the assorted hardware components installed on a pole or structure that provide mechanical support and clearances, and electrical isolation / insulation for the various conductors and equipment required on an overhead distribution line.

It can include cross arms, insulators, brackets, bolts, washers, nuts, and sundry other hardware.

It should be noted that the specific choice of some of these components, such as insulators, will vary depending on the required voltage of the system.

3.2.3 Transformers and Voltage Regulators

Distribution transformers are used to transform electricity from one voltage to another, for example, from 14.4 kV to 120/240 Volts. Overhead (Pole Top) transformer capacity in use at API ranges from 3 to 167 kVA. Padmount transformers range from 15 kVA to 750 kVA

Most distribution transformers change primary voltage (2400V or greater) to one of API's three standard secondary voltages:

(1) 120/240V single phase

(2) 120/208V three phase

(3) 347/600V three phase

Some specialized units, known as step-downs or step-ups, transform one primary voltage to another. These units are generally used to supply portions of API's system that require a legacy voltage, or to supply small remote loads centres from API's 34.5 kV or 44kV express feeders.

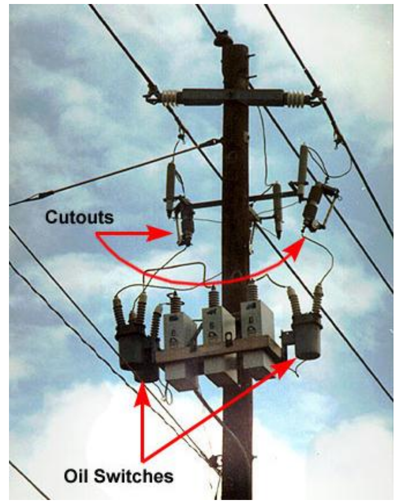
Voltage regulators are a form of transformer that automatically maintains line voltages within a narrow specified range and allows API to maintain voltages within CSA standard guidelines on long rural feeders.

An age profile for overhead transformers is included in Appendix B.

3.2.4 Overhead Switches

This type of MA allows for opening and closing, or isolating, of current-carrying components, which either prevents or allows the flow of electricity. Switches can have different characteristics:

(1) Gang-operated or single-phase operated: A gang-operated switch, generally a three-phase device, allows all three phases of the switch to be opened or closed at once, often from the ground. Single-phase switches are typically operated using insulated sticks, and are operated one phase at a time.



(2) Load-break or Non-load-break: A Load-break switch allows for the interruption of power flow even when a significant amount of current is flowing. Non-load-break switches cannot interrupt large current flows and are more often used in combination with nearby protective devices for providing visual confirmation of isolation.

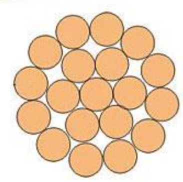
(3) Remote-controlled or locally operated.

3.2.5 Overhead Conductor

Conductors, also called wires, or cables run from pole to pole, or pole to building, and carry the current from the source to the customers. Overhead conductor has several different characteristics:

(1) Metal or alloy: older conductors were mostly copper, but most modern applications use aluminum, or aluminum alloys to save weight and cost

(2) Size / Gauge: the size of the wire is matched to the expected maximum current required. Larger conductors cost more, weigh more, and can take longer to install, but carry more current ('higher ampacity') and can have longer useful lives



(3) Insulation: some conductors have one or more layers of insulation on them, if they are bundled together or are installed in a location where they can be expected to be contacted by vegetation or the public. The bundled cable shown at right has two insulated and one bare conductor, and is used for supplying a typical 'house service'. Most primary / high voltage conductors are bare, as this saves costs and weight.

(4) Single or Bundled: At lower voltages, to save space and add strength, more than one conductor may be twisted or lashed into a 'bundle'. This is most common for secondary or service wires.

3.2.6 Underground and Submarine Cable

Underground and submarine cables serve a similar function as overhead conductor. In addition to the characteristics discussed for overhead conductors above, the following characteristic are important to the selection and installation of underground or submarine cables:

(1) Insulation Type and Voltage Rating: most cables in service and all new cables installed are cross-linked polyethylene (XLPE) type insulation, with ratings of 46, 35, or 28 kV.

(2) Insulation Class: cables on 4-wire grounded systems (e.g. 28 kV or less) are typically specified as 100% insulation class. Cables on 3-wire systems (34.5 or 44 kV) require 133% insulation class as ground faults causing temporary over-voltages may take longer to clear.

(3) Terminations: "Elbows" or terminations must be installed to transition from underground or submarine cable to equipment or overhead conductors. These terminations are frequently points of failure and must be selected and installed carefully in order to avoid becoming a weak link.

(4) Mechanical Protection:

- (i) Underground cables may be direct buried, installed in duct, or installed in concrete encased duct depending on location.
- (ii) Submarine cables typically include an outer layer with a steel armour for protection against rocks, ice, boat anchors, etc.
- (iii) All submarine and underground cables require additional mechanical protection, in the form of rigid ducts and/or metal guards at shorelines and riser poles for public safety.

3.2.7 Protective and System Devices

Aggregated into this MA group are:

(1) reclosers (a type of aerial circuit breaker),

(2) capacitors, of two types:

- (i) Fixed (always 'on')
- (ii) Switches (only 'on' under specific conditions)

(3) current sensors

(4) voltage sensors

(5) primary (pole-mounted) instrument transformers

3.3 Distribution Substation (DS) Managed Assets

3.3.1 Power Transformers

Power transformers in API's DS's are used to transform electricity from one of API's express feeder voltages (34.5 kV or 44 kV) to another primary voltage (8 kV to 25 kV) to supply distribution feeders.

Power transformers are typically 3-phase, with capacities ranging from 1000 to 10,000 kVA. Older installations use three single-phase transformers connected in a bank to function as a 3-phase transformer.

Power transformers are much larger than pole top transformers. These units typically weigh several thousand kilograms and contain thousands of litres of oil. As a result, they must be placed on engineered concrete foundations.

3.3.2 Protective Devices

Substation protective devices in service at API include reclosers and power fuses.

Substation reclosers virtually identical to 3-phase overhead line reclosers, with modifications to the mounting arrangements.

Power fuses provide protection on the primary side of most in-service power transformers.

Protective relays that monitor and control substation reclosers are currently managed as part of the recloser asset. As other SCADA assets such as data concentrators and communications equipment are installed, it is expected that relays, SCADA equipment and communications equipment will be grouped as MA's separate from the protective devices.

3.3.3 Voltage Regulators

Substation voltage regulators generally provide 3-phase voltage regulation. This regulation can be provided either on the feeders supplied by the substation, or on the express feeder serving the substation.

There is currently only one substation-class regulator in service at API. This is a 3-phase, 44 kV regulator, with a through capacity of 60 MVA. It is located at Hawk Junction DS and provides voltage regulation for loads located downstream on the No.4 Circuit 44 kV express feeder.

3.3.4 Switches

This type of MA allows for opening and closing, or isolating of current-carrying components, which either prevents or allows the flow of electricity. Switches can have different characteristics:

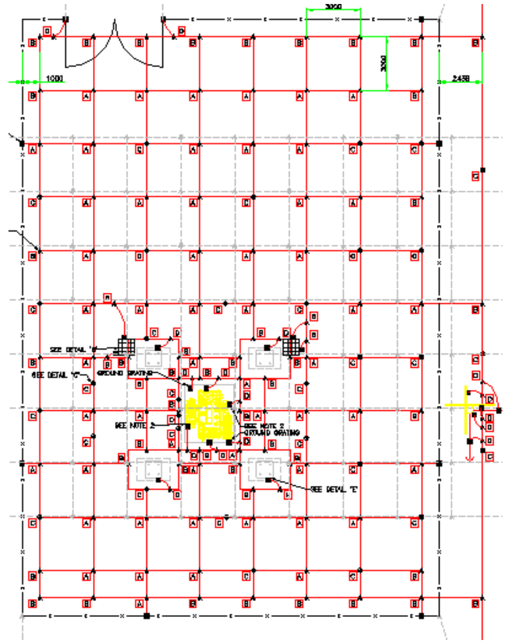
(1) Gang-operated or single-phase operated: A gang-operated switch, generally a three-phase device, allows all three phases of the switch to be opened or closed at once, often from the ground. Single-phase switches are typically operated using insulated sticks, and are operated one phase at a time.

(2) Load-break or Non-load-break: A Load-break switch allows for the interruption of power flow even when a significant amount of current is flowing. Non-load-break switches cannot interrupt large current flows and are more often used in combination with nearby protective devices for providing visual confirmation of isolation.

(3) Remote-controlled or locally operated.

3.3.5 Grounding System and Lightning Protection

Substation grounding systems consist of a network of buried electrodes interconnected by buried conductors forming a "grounding grid". Conductive structures and equipment throughout the substation are connected directly to this buried grid.



Lightning masts and/or shield wires are installed to provide protection against direct lightning strikes. Also, lightning arresters are typically installed adjacent to power transformers and other critical equipment.

The main functions of the grounding and lightning protection system are:

(1) To protect equipment by providing a means of carrying electric currents into the earth under normal and fault conditions.

(2) To limit overvoltages at equipment terminals during lightning discharges.

(3) To protect personnel in the vicinity of grounded equipment from critical shocks by limiting step and touch potentials to acceptable values.

3.3.6 Substation Civil/Structural Assets

Aggregated into this MA group are:

(1) Steel Structures

(2) Concrete Foundations

(3) Fencing

(4) Yard Surfacing

(5) Cable Trays/Ducts

3.4 Metering Managed Assets

This item includes

(1) revenue meters that measure, store and report electricity usage

(2) instrument transformers

(iii) current transformers (CTs)

(iv) potential or voltage transformers (PTs)

(3) any communications or data aggregation equipment owned by API used to facilitate the revenue metering process (collectors, antennae, etc)

4 Inspection and Maintenance Programs

4.1 Inspection and Maintenance (General)

Inspection and maintenance programs are integral aspects of any Asset Management program and good utility practice. Effectively maintaining existing line and substation equipment is necessary to keep equipment in good working condition, maximize equipment lifespan, and improve reliability by reducing the probability of failure. Maintenance programs optimize the value of capital investments. Maintaining equipment in proper working condition reduces the probability of equipment failure, enhances safety and increases reliability of supply to customers.

Maintenance activities at API are performed with a combination of internal personnel and qualified outside contractors and consultants.

API establishes its various maintenance cycles to achieve a number of objectives:

(1) Maintenance cycles for inspections will satisfy the minimum regulatory requirements.

(2) Critical assets may be inspected more frequently and may make use of more sophisticated inspection methods (e.g. thermographic scans at substations).

(3) Preventive maintenance activities are scheduled on cycles that attempt to optimize the life-cycle costs of equipment considering manufacturer's recommendations, good utility practice as well as API past experience.

(4) Preventive maintenance activities that are scheduled cycles greater than one year will be scheduled with a goal of levelling expenditures from year-to-year, as well as levelling activities between service centres on an annual basis. This ensures adequate resource availability to complete the planned program and minimizes travel costs associated with crews traveling between service centers.

Maintenance activities can be subdivided into four basic categories:

4.1.1 Predictive Maintenance:

This is the identification of equipment deficiencies that may lead to failure. Examples of predictive maintenance activities are visual inspections, equipment testing, and substation transformer dissolved gas analysis. Thorough inspections are the chief mechanism used at API for predictive maintenance, although other methodologies are used, such as pole condition testing and conductor testing.

4.1.2 Corrective Maintenance:

This is the repair equipment as a result of deficiencies identified through visual inspections or testing.

4.1.3 Preventive Maintenance:

The routine servicing or repair of equipment on a regular schedule to ensure that equipment remains in good working condition. Maintenance is undertaken at specific time intervals and is applied regardless of equipment condition. Examples of preventive maintenance activities are load-break switch maintenance, protective device maintenance, and substation equipment maintenance.

For many of API's MA's, there has been a gradual progression from preventative maintenance to predictive maintenance activities in the recent past. This trend is a result of both technological improvements and cost reductions in predictive maintenance technologies such as infrared scanning. Also, technological advances in new equipment are reducing the need for regular preventive maintenance. An example would be vacuum interrupting reclosers that no longer require periodic oil and contact replacement that was essential for the proper operation of traditional oil-filled reclosers.

4.1.4 Certification Maintenance

Certain assets require periodic certification or re-certification. This generally involves testing, calibration, and documentation (such as a 'seal' or 'sticker') by a third-party accredited or industry-accepted expert group. Examples of managed assets requiring certification:

(1) Revenue meters and instrument transformers (residential, commercial / industrial, and bulk)

(2) Insulated booms on Bucket Trucks

(3) Working grounds used by power line workers

4.2 Line Maintenance Activities

4.2.1 Predictive Maintenance

4.2.1.1 Visual Inspections

Predictive maintenance on overhead and underground distribution systems in the API service area generally takes the form of visual inspections. Details of inspection cycles are provided in Section 4.4 below.

All overhead lines scheduled to be inspected during that year are patrolled by walking, driving, snowmobiling or flying as required, and detailed inspections are carried out on most equipment. This includes poles, cross-arms, guy wires, transformers (overhead and pad-mounted), conductors and cables, insulators, arrestors, bushings, terminations, switching devices (fused cut-outs, load-break and disconnect switches, live-line openers, etc). Civil facilities, such as transformer pads and cable chambers, are also inspected. Underground facilities are inspected only where visible (risers, terminations, etc.)

The results of these inspections and any identified deficiencies are documented for follow-up and are archived. Deficiencies are assessed on the basis of the potential for failure and consequential impact on safety or reliability. They are then prioritized for corrective action as follows:

(1) Major deficiencies, where repair or replacement is required to address a pending failure or safety hazard. Examples of major deficiencies would be broken poles and cross-arms.

(2) Minor deficiencies, where the deficiency is of a nature where action can be deferred for a time. An example would be a blown lightning arrestor. Repairs to less critical deficiencies are typically planned so that a group of deficiencies within a given area can be addressed by a single crew in a short timeframe.

4.2.1.2 Inspections using Specialized Equipment

In addition to the cycle inspections described above, various line components are inspected using specialized equipment, with any deficiencies being noted and prioritized for correction. Thermographic scans of critical distribution line components (e.g. load-break switches and reclosers on express feeders) are conducted annually.

Beginning in 2009, API retained an external contractor to perform detailed pole testing on a small sample of its poles. This testing provides valuable details on the condition of the poles, the remaining pole strength and expected remaining life, as well as observations of any conditions that could potentially have an impact on remaining life of the poles. This information is provided in a searchable database that could be used for long-term planning of line rebuilds and pole replacements. The results of the testing have already proven valuable in that a small number of poles on a critical circuit were identified as requiring short-term replacement due to condition, while the remainder of poles had more life than expected and replacement could be delayed.

API will continue pole testing at a rate of approximately 10% of the pole population each year.

4.2.2 Corrective Maintenance

Any deficiencies identified during or outside of scheduled inspections are recorded and prioritized as described above. Repairs or replacements are carried out accordingly and completion is tracked through the corporate work management systems.

Often, corrective maintenance is performed on an ad-hoc basic, as problems are identified by employees or members of the public on an ongoing basis. Some of these problems result in an unplanned (forced) outage /service interruption.

4.2.3 Preventive Maintenance

Two major preventive maintenance activities are conducted on distribution lines and equipment:

4.2.3.1 Switch Maintenance

API will maintain load-break switches located on its express feeders on a six-year cycle, to the extent practical. This minimizes the likelihood of widespread outages due to switch failure and ensures that switches will operate reliably in the event of planned or forced outages elsewhere on the system. This maintenance activity has historically been limited due to system configuration and the outages that would be required to complete this activity. Recent system configuration changes, equipment upgrades, and changes to work practices are expected to allow maintenance of most switches starting in 2014. Switch maintenance will include the following main activities:

(1) Visual inspection of switch components, such as contacts, insulators and arc horns, to identify any broken or deteriorated parts and evidence of surface tracking or corrosion.

(2) Opening and closing switches to verify proper and efficient operation of blades and gang-operating mechanisms, where applicable.

(3) Cleaning and lubrication of electrical connections and moving parts.

(4) Replacement of worn components, or the entire switch if necessary.

4.2.3.2 Protective Device and Voltage Regulator Maintenance

API performs routine maintenance of its Reclosers and Voltage Regulators. For traditional oil-filled equipment, preventive maintenance activities are typically performed on a six-year cycle, and include the following main activities:

(1) Determination of number of operations since date of last maintenance to verify that existing maintenance intervals are adequate.

(2) Visual inspection of tanks, bushings, contacts, operating mechanisms, control boxes, etc. to identify any broken or deteriorated parts and evidence of surface tracking or corrosion.

(3) Testing of operations, both manually and using electrical test equipment to ensure proper operation.

(4) Electrical testing (ratio, resistance, etc.) to verify electrical integrity of device and all components.

The results of any tests performed are documented on equipment test forms and kept on file for trending and comparison purposes.

For newer equipment, API is transitioning to a more predictive/corrective based maintenance approach. The design of newer reclosers and voltage regulators allows for a combination of simple visual inspection, infrared scanning and analysis of operational history to determine whether or not any corrective maintenance is required. For example, the latest generation of recloser and regulator controls will estimate the percentage of remaining life on contacts or interrupters based on the history of load/fault current present during each previous operation. In many cases, this will significantly extend the time interval between overhauls or replacement.

4.3 Distribution Substation Maintenance Activities (General)

4.3.1 Predictive Maintenance

Predictive substation maintenance is integral to maintaining reliability and detecting potential equipment failure. Since substation equipment typically requires large investments for installation and since failure of substation components can affect large numbers of customers, therefore detecting potential failures before they occur is very important. There are presently three key predictive maintenance activities conducted in API substations:

4.3.1.1 Visual Inspections

Visual Inspections are essential for assessing the condition of substation components and identifying deterioration or areas where attention is required. The OEB Distribution System Code provides for different inspection intervals for substations based on various criteria and location. API's seven substations fall into the "Rural – Outdoor Open" category, and therefore performs detailed inspections at least once every six months.

Substation civil/ structural (fencing, structures, etc.) and electrical components (bus-work, switches, insulators, transformers, ground conductors, etc.) are inspected and any deficiencies recorded. In addition, data such as power transformer gauge readings are recorded. The condition of ancillary equipment such as lighting, eyewash stations, first-aid kits, and oil spill kits is also inspected.

API also performs monthly inspections of its oil containment facilities and quarterly sampling of effluent from the oil containment in accordance with Ministry of Environment requirements. During these monthly inspections of oil containment, the remainder of the substation is visually inspected at a high level and deficiencies requiring immediate correction are identified.

Any deficiencies noted during inspections are recorded, reported, and are then prioritized for corrective action.

4.3.1.2 Transformer Dissolved Gas Analysis

Dissolved gas analysis ("DGA") is an effective tool for assessing the condition of power transformers and identifying deterioration in transformer oil or insulation. DGA can also identify whether arcing or acid build up is occurring inside the transformer. DGA tests for the presence of dissolved gas and water in transformer insulating oil, and based on the level of gases or moisture present, assess the condition of the transformer. An important aspect of DGA is the trend analysis, which reviews the history of dissolved gas levels in the transformer.

DGA is scheduled annually on all power transformers and in API substations, whether in-service or spare. API uses a qualified contractor to perform the analysis, provide reports on transformer condition, and recommend any required actions if gassing is above normal levels or if acids are detected. Corrective action to deal with abnormalities is essential to prevent failure and extend the life of the transformer.

4.3.1.3 Thermographic Scanning

Thermographic (infra-red) scanning is scheduled annually for all distribution substations. Thermography captures the temperature of components compared to surrounding equipment and ambient temperature, and high relative temperatures can be indicative of overloaded or deteriorated components.

4.3.2 Corrective Maintenance

Corrective maintenance is a reactive activity that takes place when deficiencies in substation components are identified. Defective components are prioritized for repair or replacement on the basis of the severity of the condition, the criticality of the equipment, and the potential impact of failure on safety or service reliability.

4.3.3 Preventive Maintenance

Preventive maintenance on substation components is conducted on a regularly scheduled basis and is integral to keeping equipment in good working condition. Substation components typically undergo preventive maintenance on a six-year cycle, including inspecting, cleaning, lubricating, and testing, to the extent practical.

It is worth noting that the list of maintenance activities below are an ideal set of complete maintenance activities that would be performed if all components could be isolated and de-energized without customer outages. This historically has not been the case with API's system configuration. As a result, in many cases, API has been performing visual inspections and operation of these devices only, and performing the remaining activities on a corrective basis as issues have been identified.

Many of the substation upgrades and reconfigurations completed in the recent past are expected to allow the additional activities listed below to be performed at certain stations starting in 2014. In prioritizing and selecting reliability-based projects, one of the factors considered is the impact on future maintainability of the system. Its expected that projects in future years will have a positive benefit in terms of allowing more substation maintenance activities to occur with less customer impact.

The following major activities are included in this program:

(1) Transformers (distribution and instrument) – inspection and cleaning, On-line Tap-Changer maintenance, including oil refurbishment and contact inspection and replacement as required, inspection and cleaning of gauges, access ways, bushings, and connections.

(2) Breaker / Recloser / Circuit Switcher maintenance – inspection, cleaning of bushings, connections, contacts and moving parts, contact resistance and insulation testing.

(3) Switch maintenance – inspection and cleaning of bushings, connections, contacts, arc horns, and operating mechanisms, insulation testing.

(4) Oil renewal – replacing insulating oil in power transformers and oil-insulated circuit breakers and potential transformers as needed ensuring insulating oil is clear of contaminants.

(5) Accessories – other equipment such as motor operators and heating elements are inspected, cleaned, and maintained.

4.4 Substation Equipment Maintenance Methodologies (Type-Specific)

4.4.1 Predictive Maintenance (Typically on a Six-Month Cycle):

4.4.1.1 Power Transformers

(1) Inspect transformer tanks and fittings for signs of oil leaking/weeping.

(2) Inspect all gauges and record readings.

(3) Inspect bushings for cracks and contamination.

(4) Record on-load tap changer counts and ranges, and reset sweep arms (if applicable).

(5) Record any new and/or unusual noise.

(6) Verify manual operation of cooling fans (if applicable).

4.4.1.2 Overhead Switches

(1) Inspect the insulators for breaks, cracks, burns, or cement deterioration. If necessary clean the insulators particularly where abnormal conditions such as salt deposits, cement dust, or acid fumes exist. This is important to minimize the possibility of flashover as a result of the accumulation of foreign substances on the insulator surfaces.

(2) Inspect all live parts for scarring, gouging, or sharp points that could contribute to excessive radio noise and corona.

(3) Check for damaged fuses and replace if necessary

(4) Scan the switch with an infrared scanner to check for further defects

4.4.1.3 Underground Switches and Junction Units

(1) Scan the switch with an infrared scanner to check for defects

4.4.1.4 Surge Arrestors

(1) Check for cracked, contaminated, or broken porcelain; loose connections to line or ground terminals; and corrosion on the cap or base.

(2) Check for pitted or blackened exhaust parts or other evidence of pressure relief.

4.4.1.5 Buses and Shield Wire

(1) Inspect bus supports for damaged porcelain and loose bolts, clamps, or connections.

(2) Observe the condition of flexible buses and shield wires.

(3) Inspect suspension insulators for damaged porcelain (include line entrances).

4.4.1.6 Structures

(1) Inspect all structures for loose or missing bolts and nuts.

(2) Observe any damaged paint or galvanizing for signs of corrosion.

(3) Inspect for deterioration, buckling, and cracking.

4.4.1.7 Grounding System

(1) Check all above-grade ground connections at equipment, structures, fences, etc.

(2) Observe the condition of any flexible braid type connections.

4.4.1.8 Control and Metering Equipment

(1) Check current and potential transformers for damage to cases, bushings, terminals, and fuses.

(2) Verify the integrity of the connections, both primary and secondary.

(3) Observe the condition of control, transfer, and other switch contacts; indicating lamps; test blocks; and other devices located in or on control cabinets, panels, switchgear, etc. Look for signs of condensation in these locations.

(4) Examine meters and instruments externally to check for loose connections and damage to cases and covers. Note whether the instruments are reading or registering.

(5) Check the status of relay targets (where applicable).

(6) Make an external examination of relays, looking for damaged cases and covers or loose connections.

(7) Observe the ground detector lamps for an indication of an undesirable ground on the dc system.

(8) Check the annunciator panel lights.

4.4.1.9 Cables

(1) Inspect exposed sections of cable for physical damage.

(2) Inspect the insulation or jacket for signs of deterioration.

(3) Check for cable displacement or movement.

(4) Check for loose connections.

(5) Inspect shield grounding (where applicable), cable support, and termination.

4.4.1.10 Foundations

(1) Inspect for signs of settlement, cracks, spalling, honeycombing, exposed reinforcing steel, and anchor bolt corrosion.

4.4.1.11 Substation Area-General

(1) Verify the existence of appropriate danger and informational warning signs.

(2) Check indoor and outdoor lighting systems for burned-out lamps or other component failures.

(3) Verify that there is an adequate supply of spare parts and fuses.

(4) Inspect oil containment systems in accordance with relevant Operational Control Procedure.

(5) Check for bird nests or other foreign materials in the vicinity of energized equipment, buses, or fans.

(6) Observe the general condition of the substation yard, noting the overall cleanliness and the existence of low spots that may have developed.

(7) Observe the position of all circuit breakers in the auxiliary power system and verify the correctness of this position.

(8) Inspect the area for weed growth, trash, and unauthorized equipment storage.

4.4.1.12 Substation Fence

(1) Check for minimal gap under the fence or under the gate. Ensure that all gaps are less than 50mm at any point under the fence and less than 100mm at any point under the gate.

(2) Ensure the fence fabric is intact and document any areas with significant rust or corrosion.

(3) Ensure fence fabric, gates, tension wires, barb wire, and posts are adequately bonded and effectively ground.

(4) Check that the barbed wire is taut.

(5) Ensure the gate latches are operable.

(6) Ensure flexible braid-type connections are intact.

(7) Ensure fence is clear of obstructions such as vegetation grow-ins or imbedded objects (wind-blown trash)

(8) Verify that no wire fences are tied directly to the substation fence.

4.4.2 Preventive Maintenance Methodologies (Typically On a Six-Year Cycle)

4.4.2.1 Gang-Operated Switches

(1) The switch should be disconnected from all electric power sources before servicing.

(2) Ground leads or their equivalent should be attached to both sides of the switch, Local and applicable OHSA regulations should be followed.

(3) Inspect the insulators for breaks, cracks, burns, or cement deterioration. Clean the insulators particularly where abnormal conditions such as salt deposits, cement dust, or acid fumes exist. This is important to minimize the possibility of flashover as a result of the accumulation of foreign substances on the insulator surfaces.

(4) Check the switch for alignment, contact pressure, eroded contacts, corrosion, and mechanical malfunction. Replace damaged or badly eroded components. If contact pitting is of a minor nature, smooth the surface with clean, fine sandpaper (not emery) or as the manufacturer recommends. If recommended by the manufacturer, lubricate the contacts.

(5) Inspect arcing horns for signs of excessive arc damage and replace if necessary.

(6) For all S&C Alduti-Rupter switches, perform the outlined continuity check and additional maintenance as out lined in the Alduti-Rupter Switch and General-Maintenance Outline.

(7) Check the blade lock or latch for adjustment.

(8) Inspect all live parts for scarring, gouging, or sharp points that could contribute to excessive radio noise and corona.

(9) Inspect inter phase linkages, operating rods, levers, bearings, etc., to assure that adjustments are correct, all joints are tight, and pipes are not bent. Clean and lubricate the switch parts only when recommended by the manufacturer. Check for simultaneous closing of all blades and for proper seating in the closed position. Check gear boxes for moisture that could cause damage due to corrosion or ice formation. Inspect the flexible braids or slip-ring contacts used for grounding the operating handle. Replace braids showing signs of corrosion, wear, or having broken strands.

(10) Power-operating mechanisms for switches are usually of the motor-driven, spring, hydraulic, or pneumatic type. The particular manufacturer's instructions for each mechanism should be followed. Check the limit switch adjustment and associated relay equipment for poor contacts, burned out coils, adequacy of supply voltage, and any other conditions that might prevent the proper functioning of the complete switch assembly.

(11) Inspect overall switch and working condition of operating mechanism. Check that the bolts, nuts, washers, cotter pins, and terminal connectors are in place and in good condition. Replace items showing excessive wear or corrosion. Inspect all bus cable connections for signs of overheating or looseness.

(12) Inspect and check all safety interlocks while testing for proper operation.

4.4.2.2 Power Transformers

(1) Inspect the control cabinet, control relays, contactors, indicators, and the operating mechanism.

(2) Look for loose, contaminated, or damaged bushings; loose terminals; and oil leaks.

(3) Check oil levels in main tanks, tap changer compartment, and bushings.

(4) Inspect the inert gas system (when applicable) for leakage, proper pressure, etc.

(5) Read and record the operations counter indicator reading associated with the load tap changer.

(6) Observe oil temperature which should not exceed the sum of the maximum winding temperature as stated on the nameplate plus the ambient temperature (not to exceed 40C) plus 10C. Generally, oil temperature does not exceed 95 and 105C for 55 and 65C winding temperature rise units, respectively; since the ambient temperature rarely exceeds 30C for periods long enough to cause an oil temperature rise above these points.

(7) Perform the power factor test

(8) Perform the turns ratio test

(9) Perform the winding resistance test

(10) Perform the excitation current test

(11) Perform the insulation resistance test

4.5 Revenue Metering and Instrument Transformer Maintenance

This type of Managed Assets requires additional Certification Maintenance in addition to the typical ‘physical’ maintenance (predictive, corrective, and preventative) required by most other types of Managed Assets.

Typically, each class of revenue meter and instrument transformer (current transformers and potential / voltage transformers) must be re-certified by an accredited testing organization on a recurring basis.

The frequency and nature of these recertification are dictated by regulations enforced by Measurement Canada (Industry Canada), a Federal regulator.

5 Distribution Planning

Prudent and timely planning lies at the core of any sustainable asset management program. At API, planning is a continuous and evolving process designed to meet the present and changing needs of a variety of stakeholders.

Planning is divided into three general categories, with ongoing interaction between all three:

5.1 Long-Term Planning (15-Year Planning Horizon)

5.1.1 System Capacity/Performance Planning:

Historically, the planning, design and construction of distribution feeders at API has been driven by the need to serve both existing and new load customers with acceptable voltage levels and reasonable levels of line loss. Due to the rural, low-density nature of API's service territory, this has resulted in long, mostly radial feeders that are loaded below conductor and equipment capacity ratings, even during system peak loading.

Likewise, API's distribution stations are also loaded below transformer and other equipment ratings. This is a result of four stations having been rebuilt in the last 10 years, and the fact that the remaining stations were constructed during a period of higher loading and higher annual load growth in the areas that they supply.

As a result of the current state of feeder and substation load to capacity ratios, and the minimal long-term load growth currently expected in API's service territory, long-term planning is focused on the following activities:

(1) A high-level review of recent load levels to determine whether any feeder/equipment capacity ratings are being approached that would require more detailed system planning studies.

(2) A review of operational data (voltage complaints, voltage data from end of feeder smart meters, outage reports, etc.) to determine if any performance issues exist at current load levels. Given the minimal future load growth expectations, review of actual operational data is considered to be more accurate and cost-effective than review of a system model in a formal system planning study.

5.1.2 End-of-Life Asset Replacement Planning:

As described in Section 5.1.1 above, there is little driver for asset replacement purely from capacity or growth perspectives. As a result, API regularly updates and reviews the following types of information (where available) on various classes of assets such as poles, transformers and protective devices:

(1) Age profile

(2) Information from Condition Assessments, Inspections and Testing Programs

(3) Failure rates

This review is used to determine appropriate levels of sustainment capital spending (i.e. "System Renewal category) in the 5-year capital plan. The goal is to replace these assets on an end-of-life basis with annual expenditures for each asset group levelized to the extent possible.

5.2 Medium-Term Planning (Five Year Planning Horizon)

API uses results from its long-term planning efforts and other reports, such as asset condition reports, to perform 'tactical' planning which covers a five-year period. Changes to the regulatory environment must be taken into account as well.

The medium-term plan is updated annually to incorporate new information that may arise, such as new regulations, longer-term individual customer needs, or updated information arising from the activities described in the long-term planning process. Typical inputs to medium-term planning include:

(1) Customer-driven needs

(2) Municipal-driven needs

(3) First Nation driven needs

(4) Health, Safety and Environmental issues

(5) Regulatory requirements

(6) Reliability analysis

(7) Asset replacement requirements (based on the outcome of long-term planning)

(8) Expansion requirements (if any are identified through long-term planning)

(9) Extraordinary initiatives, such as FIT, Smart-Grid and Smart Meters

The results of the medium-term planning process are used to select and prioritize projects for inclusion in the 5-year capital plan. Results of medium-term planning are also used to review the effectiveness of maintenance programs and to make adjustments as required.

5.3 Short-Term Planning (One Year Planning Horizon)

Short- term planning involves developing specific plans to implement the projects defined in the current year budget as well as to operate and maintain the distribution system(s) in a safe and reliable manner.

It also addresses short-term needs, such as connection of a customer that was not identified previously during medium term planning, or reaction to external events such as a severe ice storm.

(1) Current Budget Year Project Design

(2) Customer-Driven Asset Development

(3) Municipal and Developer-Driven Asset Development

(4) Other Short-term Projects

6 Assessment of Asset Condition

6.1 Distribution Substations

The relatively low quantity of each type of DS asset ensures that each item can receive regular inspection, maintenance, and qualitative assessment.

Quantitative assessments such as dissolved gas analysis, operation counts, gauge readings, and detailed electrical testing are also performed on critical assets such as power transformers and protective devices.

The results of various substation inspection and maintenance activities are used as inputs to the long-term asset replacement planning process described in Section 5.1.2.

6.2 Poles

6.2.1 Defining Asset Condition

A wooden utility pole generally remains useful until:

(1) It fails (breaks or collapses) due to severe weather, vehicles, or loss of strength associated with advanced aging.

(2) New requirements necessitate a pole change-out. These needs might be for a taller or stronger pole to support more equipment.

(3) The pole is no longer required at its legacy location.

(4) Though a gradual process of loss of wood fibre and loss of fibre strength, the strength of the pole decreases until it reaches the point where it no longer satisfies required safety factors under worst-case conditions. At this point, inspections and/or testing will identify the need.

API has approximately 30,000 poles in service. Individually, the replacement value of these assets ranges from $2,000 to over $15,000. Because of the high expected useful life and large installed base of poles, it would be extremely impractical to closely monitor and maintain each pole in the same fashion as a Substation steel structure, and the expense of such a program would far exceed its utility.

API manages its pole assets through a combination of:

(1) Industry-standard purchasing specifications

(2) Inspection of new distribution poles as they are installed

(3) Visual circuit inspections. These inspections are performed on a six year cycle as part of API's Inspection Program.

(4) Annual pole testing by a third party of in-situ poles within a defined section of the distribution network.

(5) Inspections of poles whenever they are installed and/or visited during fieldwork.

(6) Review of the in-service pole age profile, failure rates, as well as the results of all pole inspection and testing programs for use as inputs to the long-term asset replacement planning process described in Section 5.1.2.

6.2.2 Measuring Asset Condition

Monitoring the condition of API's individual poles has been an ongoing process for many years. Annual feeder inspections are performed by API line crews where the visual inspection of each pole identifies observed impacts such as wood pecker damage. Paper based reporting provides identification of observed damage or concern for each impacted pole. The reporting does not include poles observed to be in acceptable condition.

API has an annual pole testing program utilizing a third party to perform the testing and subsequent report on the condition of the poles tested. Testing in recent years has focused on specific areas of concern in the network. In 2013 the testing began in a regional section of the network and will continue in subsequent years to follow a regional cycle of testing and reporting.

6.3 Distribution Transformers

API has over 4,800 in-service transformers throughout its distribution network. Individually, the replacement value of these assets ranges from $2,000 to over $40,000.

Testing of pole-top transformers to quantitatively evaluate condition would require regular DGA and electrical testing, with trending for each unit. Because of a relatively low cost, and large installed base of distribution transformers, it would be extremely impractical to closely monitor and maintain each transformer in the same fashion as a substation power transformer, and the expense of such a program would far exceed its utility.

API manages its distribution transformer assets through a combination of

(1) Industry-standard purchasing specifications

(2) Examination of the manufacturer's technical drawings and test results for each distribution transformer order placed

(3) Periodic inspection and testing of distribution transformers while they are retained in stores as spares

(4) Inspections and testing of transformers whenever they are installed and/or visited during fieldwork or feeder inspections.

(5) Intake inspection whenever a previously-used distribution transformer is returned to storage from the field. This is particularly important if the distribution transformer was removed from service because it is suspected to be not in good working order.

(6) Review of the in-service transformer age profile, failure rates, as well as the results of inspection programs for use as inputs to the long-term asset replacement planning process described in Section 5.1.2

6.4 Reclosers, Voltage Regulators and Express Feeder Load-Break Switches

These devices are installed in relatively small numbers (less than 200 devices total). Proper operation of these devices however is critical to the safe and reliable operation of API's system and failure of any individual device can have significant impacts on reliability.

API manages this group of assets through a combination of

(1) Industry-standard purchasing specifications

(2) Examination of the manufacturer's technical drawings and test results (where applicable) for each order placed

(3) Inspection and testing on delivery

(4) Periodic inspection and testing of equipment retained in stores as spares

(5) Testing of equipment whenever it is installed

(6) Periodic inspection and maintenance activities as describes in Sections 4.2.1-4.2.3

(7) Analysis of loading on transformers with suspected overloading

(8) Intake inspection whenever previously-used equipment is returned to storage from the field

(9) Review of failure rates as well as the results and costs of inspection and maintenance programs for use as inputs to the long-term asset replacement planning process described in Section 5.1.2

6.5 Other Distribution Assets

Annual capital spending for asset replacement ("System Renewal" category), is focused on the substation, pole, transformer and recloser/regulator/switch assets identified in the sections above. Annual spending is levelized to the extent practical in an effort to replace these assets on a sustainable long-term basis, according to their expected useful lives.

There are a large number of other relatively low-value assets in service on API's distribution lines. This includes items such as conductor, fused cutouts, insulators, arresters, single-phase switches, etc. Run-to-failure is typically the most economic approach for replacement of these assets, however they may occasionally be replaced proactively under the following circumstances:

(1) Periodic visual or thermographic inspections happen to identify pending failure

(2) Evaluation of outage reports identifies a specific asset type/make/model/vintage that is more prone to failure (e.g. certain runs of insulators and cutouts have been known to experience premature failure and would be replaced proactively)

(3) Assets of an older vintage, an obsolete type, or observed to be in poor condition are replaced in conjunction with other asset replacements (e.g. aging conductor and insulators are replaced in conjunction with pole replacements; porcelain cutout/arrester combinations are replaced in conjunction with transformer replacements)

7 Appendices

Appendix A – Substations

Appendix B – Pole and Overhead Transformer Age Profiles

API Distribution Asset Management Program

Appendix A – Substations

Wawa #1 Substation

Transformer Number	8600
Manufacturer	Pioneer Transformers
Number of Phases	3
Manufacturer Date	2008
Capacity MVA	6.25/7.92/9.32
Primary kV	34.5 kV
Secondary kV	8320
Taps	± 2.5%
Total Oil (Litres)	4710
Total Weight (kg)	15520

Wawa #2 Substation

Transformer Number	4039
Manufacturer	Federal Pioneer
Number of Phases	3
Manufacturer Date	1979
Capacity MVA	5.0
Primary kV	33 kV
Secondary kV	8000 Y/ 4619 Δ
Taps	± 10%
Total Oil (Litres)	5561
Total Weight (lbs)	36500

Hawk Junction Substation

Transformer Number	4633
Manufacturer	Ferranti Packard
Number of Phases	3
Manufacturer Date	1985
Capacity MVA	1.0
Primary kV	44 kV
Secondary kV	8320 Y/ 4619 Y
Taps	± 2.5%
Total Oil (Litres)	1905
Total Weight (kg)	5800

Garden River DS

Transformer Number	6095	8224
Manufacturer	Carte	Northern
Number of Phases	3	3
Manufacturer Date	1992	2007
Capacity KVA	3000	3000
Primary kV	34.5 kV	34.5 kV
Secondary kV	12.5	12.5
Taps	± 2.5%	± 2.5%
Total Oil (Litres)	3496	2511
Total Weight (kg)	11045	9254

Bar River DS

Transformer Number	7549
Manufacturer	Northern
Number of Phases	3
Manufacturer Date	2001
Capacity MVA	6/8/10
Primary kV	34.5 kV
Secondary kV	12.5 kV
Taps	± 2.5%
Total Oil (Litres)	4359
Total Weight (kg)	16239

Desbarats DS

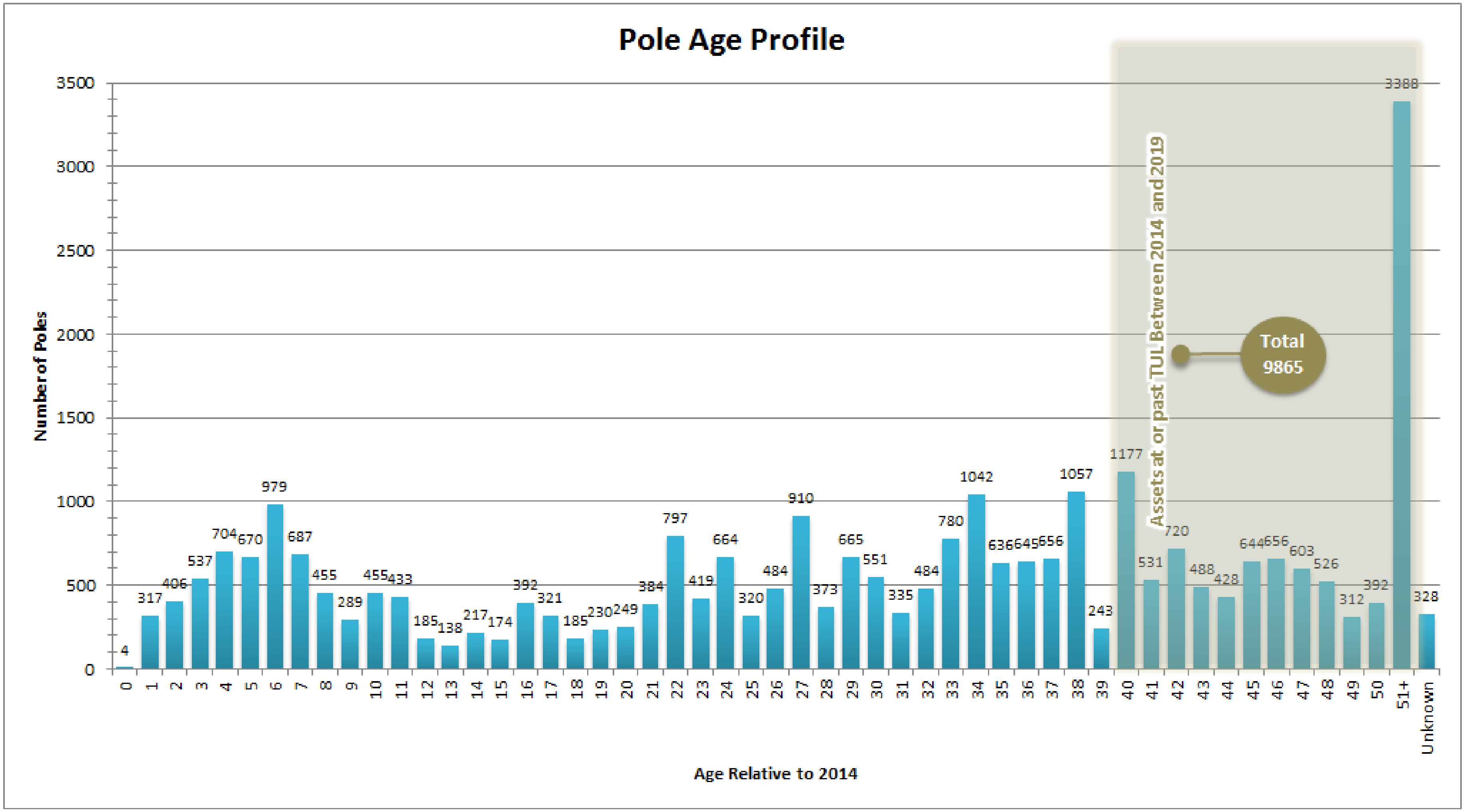
Transformer Number	7402	8971
Manufacturer	Northern	Virginia
Number of Phases	3	3
Manufacturer Date	1999	2010
Capacity MVA	5/6.67/8.33	5/6.67/8.33
Primary kV	34.5 kV	34.5 kV
Secondary kV	12.5 kV	25 kV
Taps	±2.5%	± 2.5%
Total Oil (Litres)	3851	3760
Total Weight (kg)	14627	15921

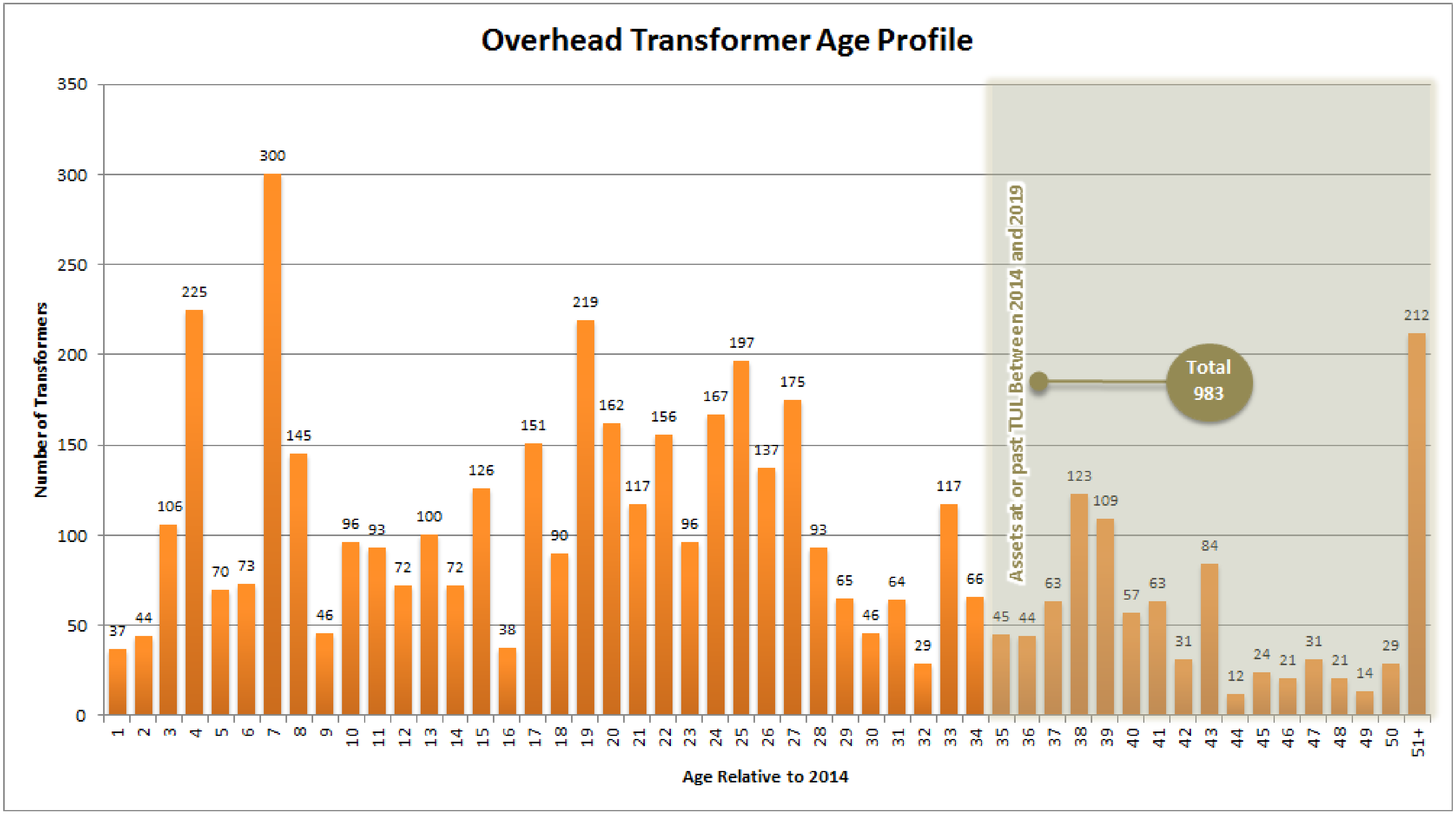
Bruce Mines DS

Transformer Number	5108	9318
Manufacturer	Carte	Northern
Number of Phases	3	3
Manufacturer Date	1993	2013
Capacity MVA	5	6/8/10
Primary kV	34.5 kV	34.5 kV
Secondary kV	12.5	25/12.5
Taps	±5%	±5%
Total Oil (Litres)	4359	4450
Total Weight (kg)	11454	16961

API Distribution Asset Management Program

Appendix B – Pole and Overhead Transformer Age Profiles


Pole Age Profile
Number of Poles
Age Relative to 2014
Assets at or past TUL Between 2014 and 2019
Total 9865
Unknown


Overhead Transformer Age Profile
Number of Transformers
Age Relative to 2014
Assets at or past TUL Between 2014 and 2019
Total
983

Great Lakes Power
Transmission

Great Lakes Power
Transmission LP
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November 29, 2013

Algoma Power Inc.
2 Sackville Road, Suite A
Sault Ste. Marie, Ontario, P6B 6J6
Phone (705) 256-3850 Fax (705) 253-6476

Dear Mr. Dan Richards

This letter formally launches the Regional Infrastructure Planning (RIP) process in accordance with the Ontario Energy Boards' (OEB) "Amendments to the Transmission System Code and Distribution System Code", dated August 26, 2013. The OEB TSC and DSC amendments are intended to support the Regional Infrastructure Planning process described in the Planning Process Working Group (PPWG) Report. As indicated in the OEB Notice, It is the Boards' expectation that transmitters and LDCs will follow the process set out in the PPWG report. The documents noted below can be accessed from the OEB Website

Notice of Amendments to TSC/DSC

http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2011-0043/Notice_Amend_TSC_DSC_EB-2011-0043.pdf

PPWG Report

http://www.ontarioenergyboard.ca/OEB/Industry/Regulatory%20Proceedings/Policy%20Initiatives%20and%20Consultations/Regional%20Planning/Regional%20Infrastructure%20Planning%20-%20Working%20Groups#20130517

As identified in the PPWG Report, 21 Regions have been established on a preliminary basis for undertaking Regional Planning. The 21 Regions have been placed into three prioritization groups based on need and planning activities already identified or under consideration. GLPT is the lead transmitter for the East Lake Superior Region which is prioritized in Group 2 and is scheduled to start the Regional Planning Process in 2014 – 2015. The map in the PPWG Report Appendix 3 shows East Lake Superior Region but the table list of distributors in Appendix 4 does not include East Lake Superior Region. For the East Lake Superior Region there are two distributors – Algoma Power Inc. and PUC Distribution Inc.

As set out in the TSC and DSC amendments noted above, we also request information regarding whether you foresee a potential need for additional transmission connection capacity to support the needs of your distribution system and if applicable the distribution system of any embedded license distributor in your system over the next five years.

From the DSC amendments:

8.5.1 A transmission-connected distributor shall, within 45 days of receipt of a request from a lead transmitter, provide the transmitter with a letter identifying whether the distributor foresees a potential need for additional transmission connection capacity to support the needs of the distributor's distribution system over the next five years. Where the distributor is a host distributor, the letter shall reflect any information provided to it by any of its embedded distributors under section 8.5.3.

We will appreciate your response as soon as possible and no later than 45 days (January 13, 2014). Please forward your information via email to the following email address – JTait@glp.ca. After receiving input from both distributors, GLPT will be participating in the RIP process associated with the East Lake Superior Region.

Great Lakes Power Transmission looks forward to working with you in executing the Regional Infrastructure Planning Process.

Sincerely,

Jim Tait
Technical Supervisor, Engineering
Great Lakes Power Transmission LP

Phone: (705) 941-5652
Email: JTait@glp.ca

Cc: Greg Beharriell, P.Eng. - API

Algoma Power Inc.
A FORTIS ONTARIO Company

January 17, 2014

Great Lakes Power Transmission LP
2 Sackville Rd. Suite B
Sault Ste. Marie, Ontario
P6B 6J6

Attention: **Jim Tait**
Technical Supervisor Engineering

RE: Regional Infrastructure Planning (RIP) Process

In response to your letter of November 29, 2013, API has reviewed the existing system load with respect to the connection capacity currently available at each of its delivery points. API's comments are divided into two sections:

1) Identification of areas where API foresees a potential need for additional transmission connection capacity to support the needs of API's distribution system over the next five years. This section is in direct response to the information requested in the abovementioned letter.
2) Identification of reliability concerns. In reviewing the PPWG Report, API believes that the RIP process is expected to address issues of both supply capacity and reliability. Given the proximity of much of API's load to that of PUC Distribution Inc., API believes that the potential exists for some overlap in relation to reliability concerns. API also believes that some combination of both transmission and distribution investment will likely lead to the most desirable and economical resolution to these concerns.

Connection Capacity

In response to GLPT's initiation of an Available Capacity Study on the 44 kV transmission system supplying API's Limer - No. 4 Circuit delivery point, API has developed a five-year load forecast for this delivery point, which was provided to GLPT in a response from API dated January 7, 2014. API also expects to submit a formal connection application with respect to a load addition of approximately 27 MW, which would certainly result in the available capacity being exceeded within the next five years. API expects that these details will be considered within the context of the Available Capacity Study and the CIA/SIA processes that would result from the connection application, rather than through this RIP process.

For all other delivery points, API has determined that peak load is currently at or below approximately 60% of the relevant delivery point equipment ratings. Given that there are no large load additions anticipated in any of these areas, and that modest overall load growth is expected, API does not foresee the need for additional capacity in these areas during normal system operating conditions.

Reliability Concerns

API has reviewed the potential response times and the subsequent available capacity for contingency scenarios (e.g. failure of supply transformer) at each of its supply points. API believes that improvements are required in the following areas in order to allow load to be restored within a reasonable time frame, and at full capacity, following a contingency.

- East of Sault Ste. Marie 34.5 kV System – This system serves approximately 5900 customers (50% of API's total customer base). The contingency for a failure of T1 at the Echo River TS supply point involves a complete load transfer to the Northern Ave TS 34.5 kV supply point. While there is no concern with equipment ratings at Northern Ave TS, API is unable to supply customers with adequate voltage levels during peak load conditions due to the distance of the load from the alternate supply point and the fact that there is a single 34.5 kV feeder available at Northern Ave TS. After reviewing the costs of distribution-only solutions to address this issue, API believes that transmission upgrades, or a combination of transmission and distribution upgrades may produce superior results at a comparable cost.
- Sault Ste. Marie 12 kV System – This system serves a feeder with approximately 2 MW of industrial load, located in an urban area. As the 34.5-12 kV transformer is a single-element configuration with no available spare, the restoration time is completely dependent on the ability to source, acquire and install a spare transformer. In our experience, this could involve an outage in the order of days to weeks. API believes that there may be merit in further exploring options involving a combination of distribution and transmission solutions, potentially including PUC Distribution Inc.
- Goulais/Batchawana 12.5 kV System – This system serves approximately 3750 customers (32% of API's total customer base). The contingency plan for transformer failure at Goulais TS involves replacement with a reduced capacity transformer that could result continued overloading until repairs are completed or a replacement unit becomes available. API also faces a number of challenges related to power quality, system losses and the coordination of protective devices in this area. API believes that both the contingency capacity issues and the long-term configuration of the supply points in this area should be considered together as part of an overall plan that includes both transmission and distribution upgrades.

API looks forward to working with you in the RIP process. In light of the concerns above, API requests that a priority during the initial stage of this process will be the development of firm standards/expectations for restoration of full capacity following contingency events. This would include timelines for restoration that are acceptable to both parties, as well as discussion of cost responsibility to achieve this level of service at the delivery points mentioned above. If GLPT believes that any of the abovementioned concerns are better addressed through alternate processes, please do not hesitate to contact me to discuss alternatives.

Regards,

Tim Lavoie
Regional Manager & Director of Northern Development
Algoma Power Inc. (a FortisOntario company)
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March 28, 2014

Algoma Power Inc.
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East Lake Superior Region
Regional Panning Initiating Letter

Dear Mr. Tim Lavoie:

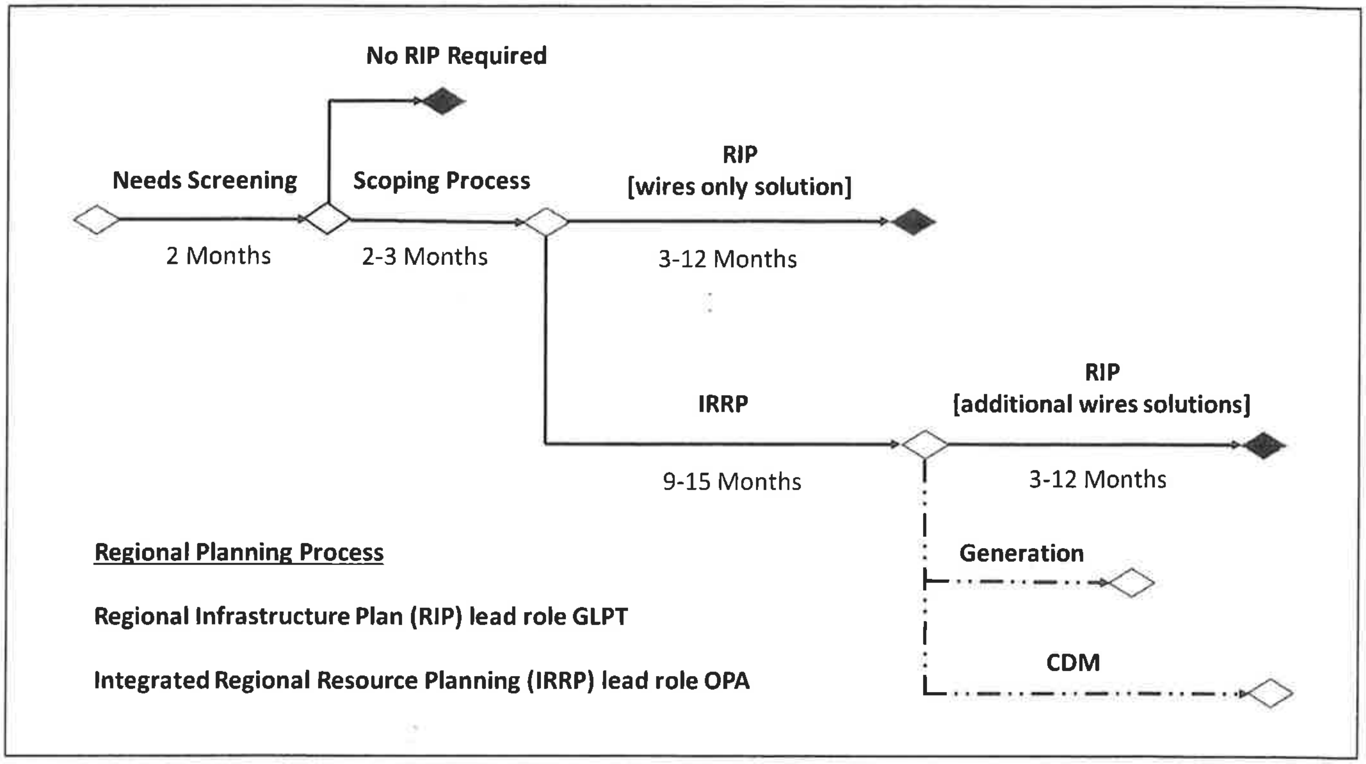
This letter is to initiate the Regional Planning Process in accordance with the Ontario Energy Boards' (OEB) "Amendments to the Transmission System Code and Distribution System Code", dated August 26, 2013. Great Lakes Power Transmission LP (GLPT) is the lead transmitter for the East Lake Superior Region which is prioritized in Group 2 and is scheduled to start the Regional Planning Process in 2014 – 2015.

This letter is also a follow up letter to the letter dated November 29, 2013 where GLPT asked the two Distributors in the East Lake Superior Region to provide GLPT with an initial five year forecast of their loads as well as whether the Distributor foresees a potential need for additional transmission connection capacity to support the needs of its distribution system over the next five years. The information provided by each Distributor will be used in the Regional Planning process.

The OPA and IESO are presently working with the designated transmitter on Group 1 Regions and this process is continuing into 2014. Since this Regional Planning Process is a new process the parties are learning about the process as they complete the Group 1 Regions.

Therefore, as the lead transmitter for the East Lake Superior Region, GLPT will initiate the Regional Planning process for this region on July 23, 2014. The first step in this process will be to have a kick-off meeting (conference call) which will include all the participating Distributors, the IESO, OPA and GLPT. GLPT will set up this meeting (conference call) in advance of this date.

The following time lines will be followed starting with the July 23, 2014 date. These time lines are part of Appendix 1 Description of RIP Process described in the Planning Process Working Group (PPWG) Report.



This letter is being sent to the two Distributors in the East Lake Superior Region as well as the OPA and IESO. Great Lakes Power Transmission looks forward to working with you in executing the Regional Planning Process and taking the lead for the Regional Infrastructure Planning Process.

Please contact me directly if you have any questions about the Regional Planning Process, initial date or timetable.

Sincerely,

Jim Tait
Technical Supervisor, Engineering
Great Lakes Power Transmission LP

Phone: (705) 941-5652
Email: JTait@glp.ca

cc: Greg Beharriell API
Dan Richards API

VEGETATION MANAGEMENT PLAN OVERVIEW

Vegetation can interfere with the safe and reliable operation of API's electrical system. Trees and brush growing in the vicinity of electrical wires increase the risk of injury to the public and API's employees and vegetation contacting or arcing with power lines can start forest fires (see Figure 1). Vegetation can cause electrical service interruptions when branches contact or come in close proximity to power lines. Some examples of contact are as vegetation grows naturally towards the conductor, as well as, during wind storms or with ice or snow build-up which causes movement or failure (breakage) of the vegetation and power lines to sag and/or swing. Trees or branches falling on power lines are also a major cause of power interruption whether through natural tree health decline and/or loading forces on trees, such as wind, snow, and ice (see Figure 2). Vegetation can also impede the efforts of staff to locate, inspect, maintain, and repair disruptions to electrical service.

Figure 1: Distribution Feeder Highway #17 North (Batchawana Bay) - Fire in tree caused by contact with live electrical wires.

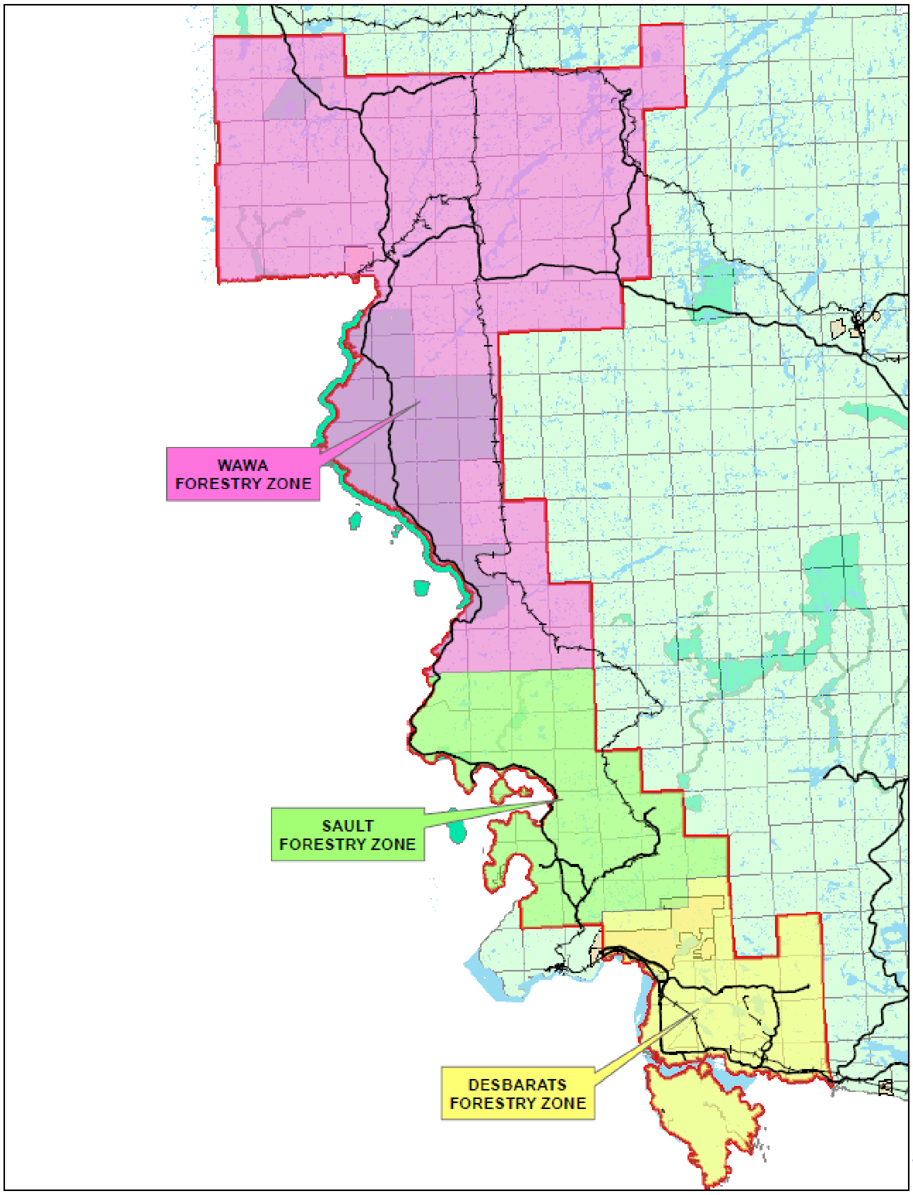
The Vegetation Management ("VM") Plan's overall objective is to manage vegetation in proximity to electrical equipment on a regular schedule to:

- enhance public safety near electrical equipment;
- avoid vegetation caused outages thereby sustaining and improving reliability;
- allow worker accessibility to the system; and
- manage and plan vegetation work activities in a least cost sustainable manner.

Figure 2: Express Feeder ROW - Trees Under Snow Load

API manages Right-of-Ways ("ROWs" or "ROW") to support its 1,848 kilometers of distribution line. Approximately 85% of API's power lines have treed edges averaging 490 trees per km with an average height 20.7m (68ft). Greater than 23% of API system has forested edges on both sides of the ROW (i.e. cross country and double-sided ROW). For more details on the extent of API's service territory see the overview section at Exhibit 2, Schedule 3, Tab 1.

The service territory is divided into three geographical zones: Wawa, Sault and Desbarats, which are shown on the map in Figure 3. The current VM plan is administered using these three zones, as well as system criticalities, and ROW characteristics (i.e. on-road, off-road, double sided) to manage smaller parts and different work activities within the entire system.



Algoma Power Inc. Forestry Zones

Figure 3: Map of API Service Territory and Forestry Geographical Zones

To meet its ROW VM challenges with greater effectiveness, API has steadily improved its VM programs and work practices. In 2011 API completed the majority of its ROW expansion program which decreased the number of trees that could contact a conductor. API's clearance standards are typical of industry standards and wider after the completion of the ROW Expansion program (see Diagram A). Based on the changed ROW conditions of a larger area to be maintained and newly established treed edge, API decided to conduct a 3rd party assessment in 2013 to ensure resources are directed to the most efficient and cost effective VM practices. The 3rd party assessment through Ecological Solutions Inc. included:

- Quantifying the volume of VM work specific to API service territory.
- Maintenance cycles based on the vegetation growth rates and volume of VM work.
- Recommendation for the least cost sustainable VM Plan.

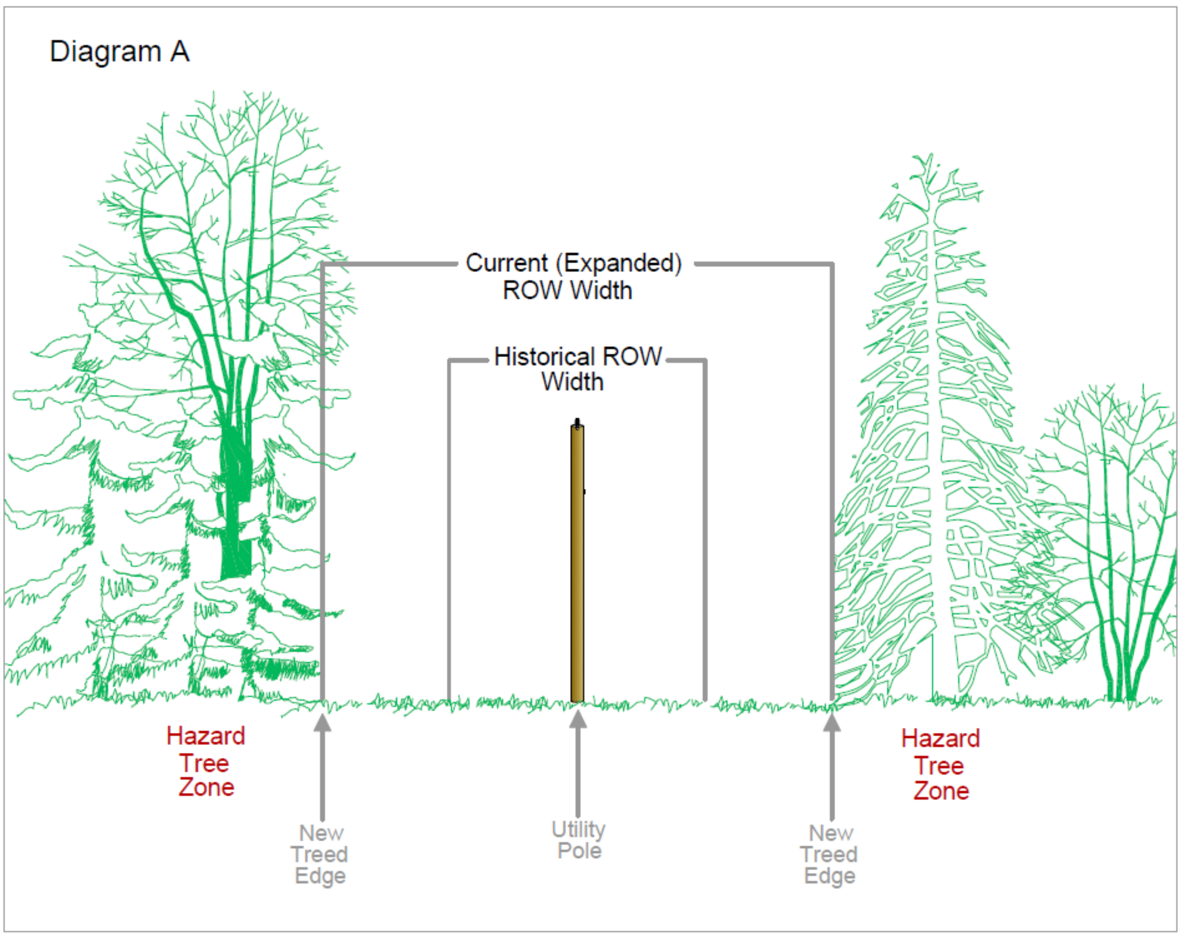


Diagram A: Cross Section of a ROW showing Historical Width and Current VM Width

VM work activities within the VM Plan include:

- Line Clearing Program to manage tree growth and hazard trees thereby controlling vegetation encroaching and/or falling into the lines. Work activities would typically include manual and mechanical tree removal, tree trimming and clean-up of cut material.
- Brush Control Program to maintain the active ROW widths and manage “grow-ins” by removing tall growing vegetation and promoting low growing “compatible” vegetation. Defining compatible/incompatible vegetation depends on many factors, such as type of vegetation, location of vegetation within the ROW, height of the power line (when at maximum sag point), voltage, and power line design. Work activities would typically include brush cutting both manual and mechanical, clean-up of cut material and herbicide treatments where acceptable.
- Demand Work to address imminent threats (vegetation concerns that cannot remain until schedule maintenance work occurs) identified by customer concerns, hazardous reports, and other unplanned maintenance.
- Condition Assessments to evaluate the effectiveness of the work program, document vegetation clearances and tree conditions, inspected and report any immediate hazards.
- Project Planning and Reporting to analyze, prioritize, coordinate, and evaluate both API’s long term cycle program and short term annual work programs while meeting the objectives of API’s VM plan. Work activities include working with government agencies, First Nations and municipalities ensuring regulatory requirements are met; setting targets, scope of work, budgets and forecasting for successful work completion and monitoring, recording data and reporting on annual work programs that ultimately drive the success of API’s long term VM plan.
- Customer/landowner notifications to inform landowners and/or customers of API’s annual VM work activities including permissions for herbicide use. Work activities include confirming land ownership and completing VM work notifications, creating work packages entailing scope of VM activities for field crews and managing public relations including community information sessions.

Reliability Results – Tree Caused Outages

Trees that interrupt electric service have been categorized as grow-in trees (trees that have the potential to grow into the conductor) and fall-in trees (trees that on failure/breakage will fall into and strike a conductor). From the outage statistics we learned that API is definitely moving in the right direction with the VM plan as grow-in outages have been minimal since 2010. However, trees are a primary cause of unplanned outages for API and are higher than industry norms and those outages are resulting from the failure of trees outside the ROW (see Figure 4). API's tree caused outages are primarily from fall-in trees.

Figure 4: Tree Caused Outage Due to "Fall-in" Tree - Tree from Outside the ROW

It is not practical or economically feasible to eliminate tree exposure to electrical equipment which cause power interruptions because trees continue to grow, decline, fail and fall. The VM workload volume is not static because trees continue to grow and decline. If left unmanaged, vegetation hazards in proximity to electrical equipment and tree caused electrical interruptions will increase. The tree caused outages however, can be reduced and held at a constant point by addressing the volume of VM work that emerges. To achieve a cost sustainable VM program, the annual work programs (line clearing and brush control described above) must remove and manage the minimum required volume of emerging problematic vegetation (i.e. grow-in and fall-in trees) to sustain clearances and reliability. This VM work volume has been quantified based on local annual growth rates and tree mortality rates and is referred to as Annual Volume Workload Increment ("AVI").

Quantification of APIs VM Workload (AVI)

To determine the AVI the total amount of work is determined for each work category (tree trimming, hazard tree removal, brush cutting and herbicide application). The maintenance cycles for each work category, with the exception of hazard trees, are derived from growth rates. The brush control area is defined by the width of ROW and the length of ROWs that are located adjacent to natural tree stands. Hazard trees are defined as trees that both could contact electric facilities on failure (breakage or tipping over) and have a visually assessable fault or indicator of failure (dead, diseased, damaged). The AVI for hazard trees is based on the tree inventory and mortality rates.

VM Program Cycles

With the recent work completed to quantify API's VM workload (AVI), the foundation for a least cost sustainable VM program has been provided. The associated maintenance cycles, based on API's AVI are described below.

<u>Brush Removal</u> is brush needing to be cut, whether by manual or mechanical means, and has a maintenance cycle of 9 years. Through growth rates studies, it is found that at 9 years minimal brush is encroaching on conductors and impeding on public safety and reliability.

Herbicide Application is brush that will be treated with herbicide and has a maintenance cycle of 3 years. Brush suitable for herbicide applications represents the lowest level of public and reliability risk and the least cost treatment for a utility. Herbicide applications require a 3-year cycle to ensure brush does not become too tall to treat with optimal herbicide applications.

Tree trimming is trees requiring clearance through trimming work and has a 6-year maintenance cycle. This cycle will serve to reduce and minimize the number of encroachments and grow-in related outages.

Hazard Tree Removal is trees needing to be removed and has a 3-year maintenance cycle. The AVI includes funding for the removal of newly emergent hazard trees. A 3-year established maintenance cycle will prevent the major build up in hazard trees between maintenance events.

API ROW Clearance Standard

Line Type	*Width (m)
Express Feeder (44kV)	16.5
Express Feeder (12.5-34.5kv)	10.5
New Primary (2.4-25 kV)	6
Existing Primary (2.4-25 kV)	4.5
Secondary (<750V) – System	1.5
Secondary (<750V) - Taps	1
Underground – Various Voltage Classes	3

*Widths are measured from either side of the outside conductor.

VM Cycles and Annual Workload				
Work Category	Brush Removal	Herbicide Application	Tree Trimming	Hazard Tree Removal
Cycles (Year)	9	3	6	3
Annual Workload	113.4 ha	101.6 ha	6.2 ha	1025 trees

VM Improvements and Efficiency

VM budget is now based on actual field conditions including the system's tree exposure, tree growth and mortality rates specific to API's service territory. Improvement and efficiencies achieved through this VM Plan are:

- Establishment of maintenance cycles required to deliver a sustainable, least cost VM program.
- Outage reporting improvements to allow for more analysis and informed decision making.
- Higher priority and focus for VM work on line segments between the station and the first protective device.
- Minimize branches hanging over conductors.
- Extending the use and/or introducing new work practices such as more mechanized equipment and different herbicide applications.

Risks of Underfunding/Deferring VM Work

Without the annual removal of the VM volume of work (AVI) and not committing to the level of funding required, reliability will begin to deteriorate and ROWs will begin to diminish. If VM work is deferred due to underfunding the following improvements and efficiencies will be lost:

- Reduction of hazard tree exposure due to widened ROWs
- Reliability improvements and worker accessibility
- Efficiencies with current VM work practices
- Potential gains in cost effectiveness through recommended VM work practices

Examples of how potential gains in cost effectiveness through VM work practices would not be achieved include:

- <u>The window for effectively treating brush</u> on the ROW with herbicides is limited. Brush suitable for herbicide applications represents the lowest level of public and reliability risk and the least cost treatment for a utility. If work is deferred due to reduced funding, the brush will continue to grow and become too tall to treat with herbicides. The brush will then need to be cut by mowing or hand cutting, escalating costs by as much as 20 times.

- Recommended optimal maintenance cycles are designed to prevent trees and vegetation from breaching the limits of approach. Without the funding necessary to attain these maintenance cycles, vegetation will increasingly grow into the limits of approach, necessitating a greater skill set of the worker and more expensive practices to complete this work. Grow-in outages will likely make a strong reappearance and the efforts to avoid them will increase inefficiency and increasingly draw resources away from other essential VM activities.

- Removal of hazard trees is to both sustain and improve reliability (see Diagram B). As noted in API's Reliability Results, Exhibit 2, Tab 8, Schedule 1, tree caused outages are occurring primarily from fall-in trees. The high incidence of hazard trees, if not addressed (funded), will continue to increase. They will reach a peak over the next 3 to 5 years and it should be expected that tree-related outages will increase 40-60%. Additionally, resources will be drawn away from other work necessary in the AVI, simply because it will not be possible and would be irresponsible to walk by obvious hazard trees that are imminent threats to safety and reliability. Consequently, funding intended to remove the brush and maintain clearances will be diverted making it impossible to achieve the objective of removing the required VM volume of work (AVI).

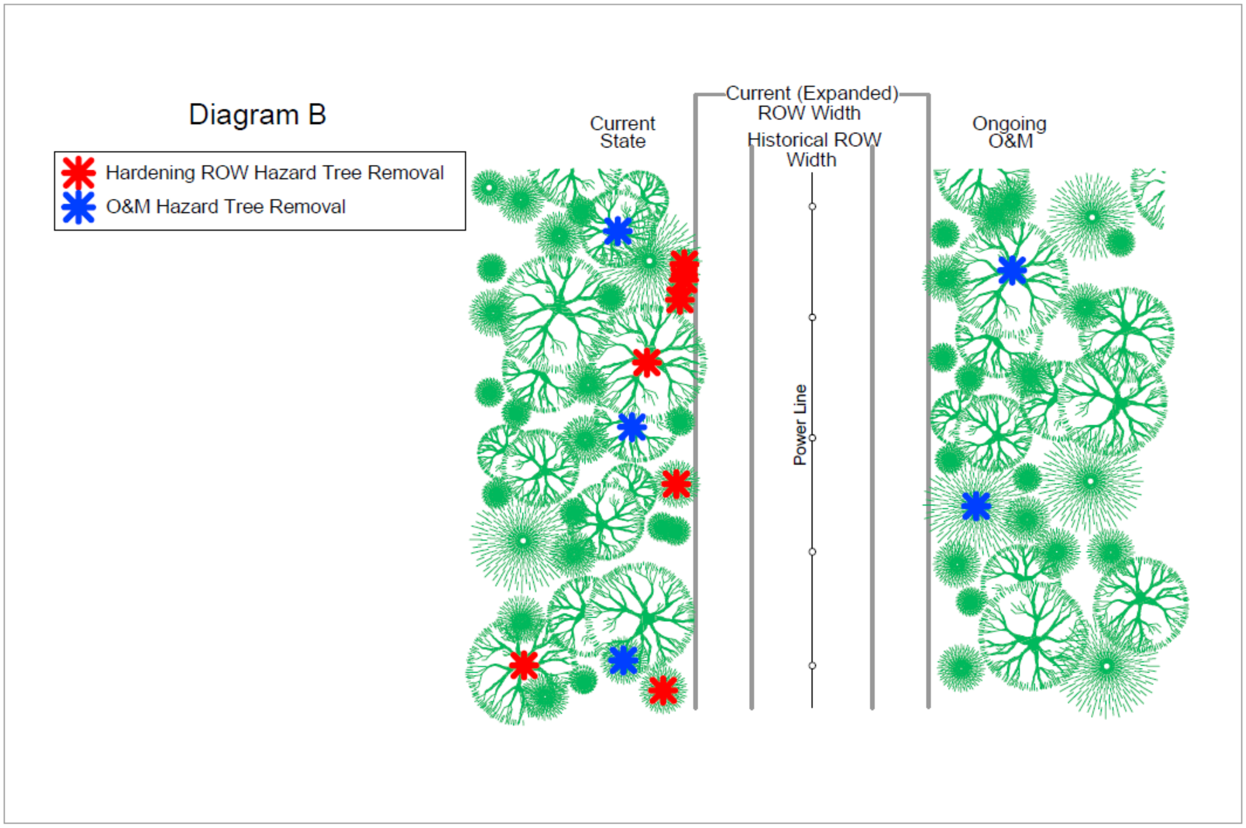


Diagram B: Showing difference between Hardening ROW program and on-going hazard tree removals through O&M.

VM Budget Requirements

Annually removing AVI provides simultaneously the least cost program and the lowest incidence of tree-related outages for the established clearance standards, work practices and cycles. A successful VM program can only be delivered if funding is adequate to remove and manage the AVI and the high incident of hazard trees. The O&M funding for API is based on AVI specific to its service territory set out in Exhibit 4, Tab 1, Schedule 1.

OPA Letter of Comment

Algoma Power Inc.

Renewable Energy Generation Investments Plan

March 27, 2014

ONTARIO POWER AUTHORITY

Introduction

On March 28, 2013, the Ontario Energy Board ("the OEB" or "Board") issued its Filing Requirements for Electricity Transmission and Distribution Applications; Chapter 5 – Consolidated Distribution System Plan Filing Requirements (EB-2010-0377). Chapter 5 implements the Board's policy direction on 'an integrated approach to distribution network planning', outlined in the Board's October 18, 2012 Report of the Board - A Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach.

As outlined in the Chapter 5 filing requirements, the Board expects that the Ontario Power Authority ("OPA") comment letter will include:

- the applications it has received from renewable generators through the FIT program for connection in the distributor's service area;
- whether the distributor has consulted with the OPA, or participated in planning meetings with the OPA;
- the potential need for co-ordination with other distributors and/or transmitters or others on implementing elements of the REG investments; and
- whether the REG investments proposed in the DS Plan are consistent with any Regional Infrastructure Plan.

Algoma Power Inc. – Distribution System Plan

The OPA received information on the renewable energy generation investments ("REG Investments") of Algoma Power Inc. ("API") by letter dated March 7, 2014, that the OPA understands will be included as part of API's Distribution System Plan. The OPA has reviewed the letter and has provided its comments below.

OPA FIT/microFIT Applications Received

Algoma Power Inc.'s letter indicates that it has successfully connected 113 microFIT projects, totalling 1,039 kW of capacity, and 1 FIT project, connected at a reduced capacity of 30 kW from 48 kW. With respect to anticipated connections, API is aware of a small number of active microFIT applications that have been offered contracts by the OPA, as well as 1 FIT project of 250 kW in capacity for which it sees no connection barriers.

According to OPA's information as of March, 2014, the OPA has offered contracts to 111 microFIT projects, totalling approximately 1,025 kW of capacity in API's territory. Additionally, the OPA has offered contracts to 2 FIT projects totalling approximately 298 kW of capacity. All 111 microFIT and 2 FIT projects remain active to date.

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The OPA finds that API's information is reasonably consistent with the OPA's information regarding renewable energy generation applications to date. The small disparity of 2 microFIT applications may be due to the date on which data was collected.

Consultation / Participation in Planning Meetings; Coordination with Distributors / Transmitters / Others; Consistency with Regional Plans

The OPA notes that Algoma Power Inc. is part of the "Group 2" – East Lake Superior region for regional planning purposes. At this time, the OPA anticipates that Great Lakes Power Transmission, the lead transmitter for this region, will be kicking-off the Needs Screening process later this year. With respect to planned REG investments, API's letter indicates that because of its success in connecting FIT and microFIT applications, and that there is only a small amount of anticipated future applications, it is not proposing any specific REG investments at this time.

Since neither a Regional Infrastructure Plan, nor an Integrated Regional Resource Plan has commenced for API's service territory, the OPA has no comment on the following three items outlined in the Chapter 5 filing requirements, specifically:

- whether the distributor has consulted with the OPA, or participated in planning meetings with the OPA;
- the potential need for co-ordination with other distributors and/or transmitters or others on implementing elements of the REG investments; and
- whether the REG investments proposed in the DS Plan are consistent with any Regional Infrastructure Plan.

The OPA looks forward to working with Algoma Power Inc. on regional planning once that process is triggered for API's area, and appreciates the opportunity to comment on the information provided as part of its Distribution System Plan at this time.

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Performance Management Review and Quantification of Vegetation Management Work, Risks & Resource Requirements

Prepared for

FortisOntario Inc.

Regarding Algoma Power Inc.

By

Siegfried Guggenmoos, B.Sc.(Agr.), P.Ag.
Ecological Solutions Inc.

March 2014

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Performance Management Review and Quantification of Vegetation Management Work, Risks & Resource Requirements

1. Executive Summary

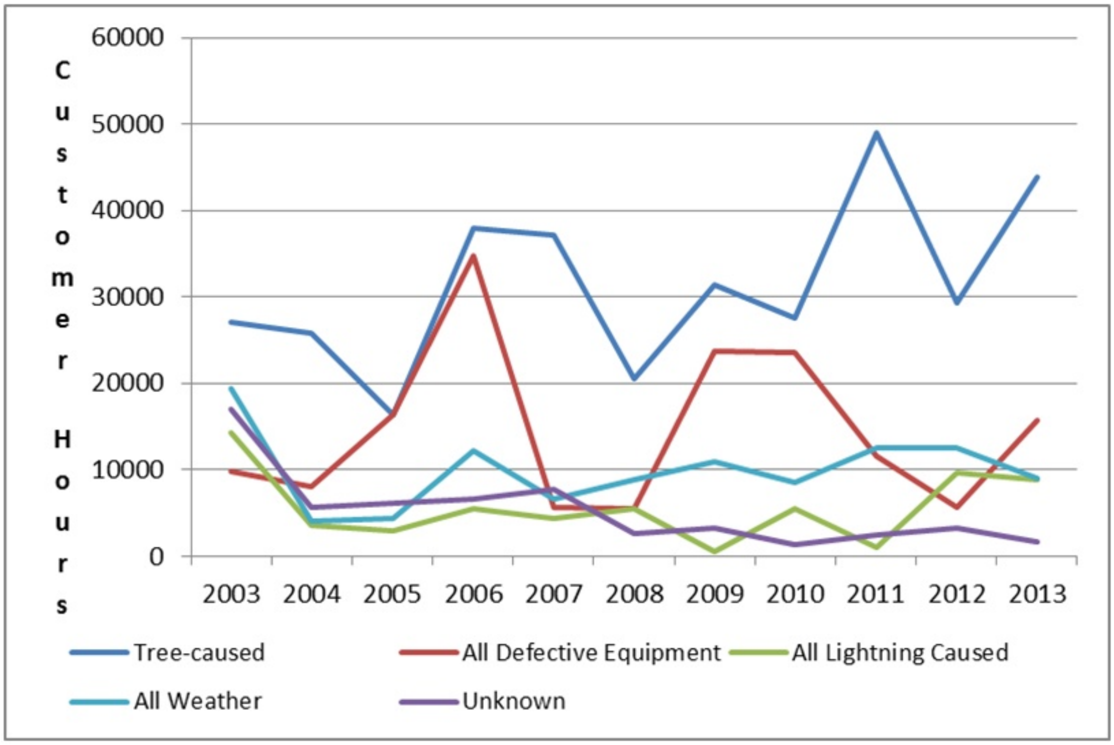
Algoma Power Inc. (API), began a program of widening right of ways in 2002. API has completed the majority of its right of way expansion program and is transitioning to maintenance program. Given this transition, API has undertaken an assessment, through Ecological Solutions Inc. (ESI), to determine the volumes of emerging maintenance work. Maintenance work volumes have been impacted by the capital work and will continue to change as the new edges transition to stable edges. The change in focus from major capital work back to maintenance also provides an opportunity to examine vegetation management (VM) practices to ensure funds are directed to the most efficient and cost effective practices.

This project explores the effectiveness of the API vegetation management (VM) program, identifying shortcomings and opportunities for improvement (Performance Management Review), including variances from standard utility practice, maintenance cycles based on biological fact, quantification of the annual workload volume increment[1], the least cost sustainable VM program, the resources required to achieve it and the term. These outcomes are driven by new, independent data acquired to determine the extent of tree exposure, trees requiring pruning, inventory of trees requiring assessments for hazards, regrowth rates, the area requiring active management broken down into quantity by work types (most cost effective treatment/work practice for conditions).

Trees are the primary cause of unplanned outages for API (*Exhibit 1-1*). This is common for electric distribution services. Indeed, for the majority of North American electric distribution companies tree-caused outages are the leading cause of service interruptions. Consequently, VM, which seeks to limit this cause of interruptions, is the single greatest operating and maintenance expense.

API's VM program falls short of a best in class program. The specifics are provided in 22 detailed findings. The opportunities for improvement are provided in 11 recommendations. In summary the current VM budget is not connected and based on actual field conditions of tree exposure, tree growth and mortality rates. Outage reporting cause codes could be improved to provide more guidance to the VM program and engineering options to improve reliability. A VM reporting system that links with other corporate databases and provides more detail on the work completed and the costs is required. There are operational practices that should be extended or introduced to reduce costs. These include the extension of foliar herbicide use, the introduction of brush mowers and telescoping saws.

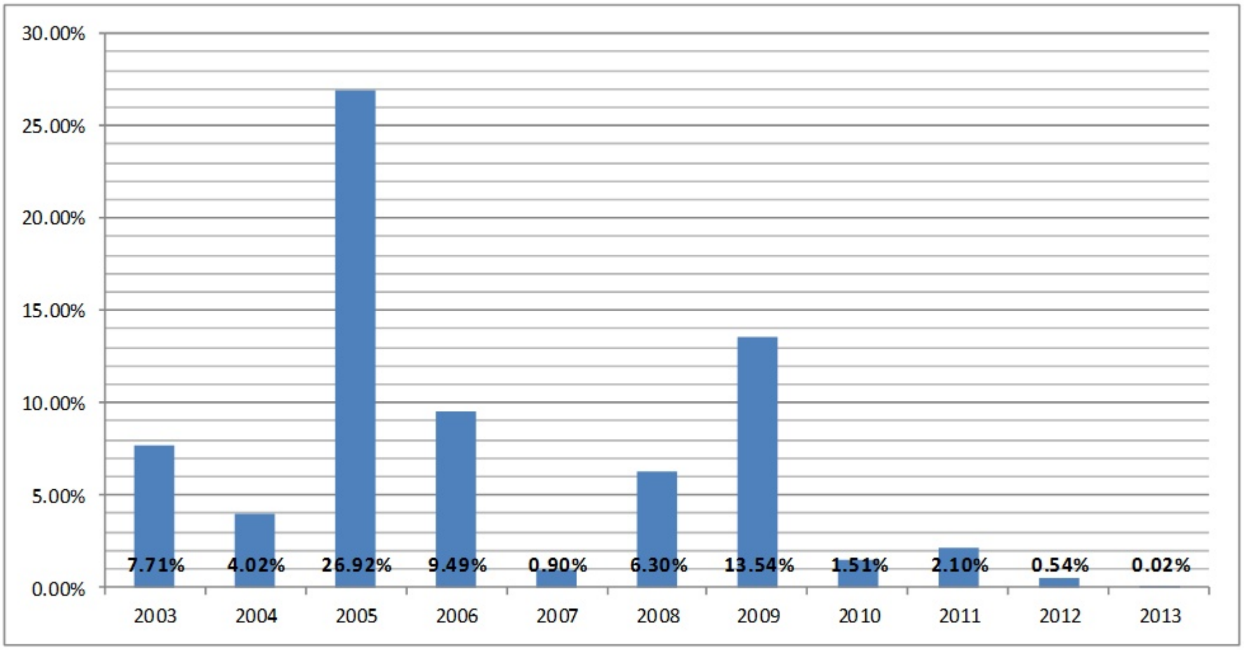
Exhibit 1-1
2003 – 2013 API Outage History By Cause



Trees being the primary cause of service interruptions, it is both necessary and justified that API thoroughly examines its VM program. From the outage statistics we learn that API is definitely moving in the right direction in its VM program as grow-in outages have been minimal since 2010 (*Exhibit 1-2*). From this it can be concluded that while the ratio of tree-related outages remains high, those outages are arising from the failure of trees outside the right of way. It is typical of good VM programs that less than 5% of tree-related outages are due to grow-ins.

The management of trees beyond the right of way is difficult. First, these trees are located off easement, generally, on private property. Secondly, hazard trees (trees that both could contact electric facilities on failure and have a visually assessable fault or indicator of a proclivity for failure) are difficult and costly to identify and remove. Third, it has been shown that the major factor in a utility's tree-related outage experience is the extent of the electric system's tree exposure.[2 3]

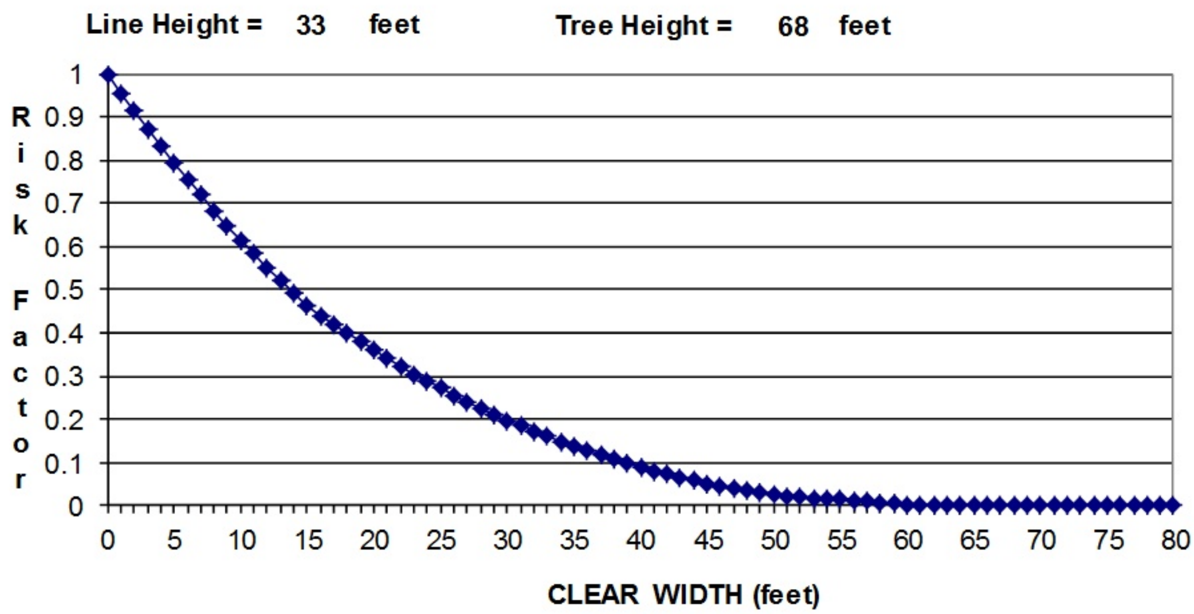
Exhibit 1-2
Ratio of Grow-in Outages to All Tree-caused



This project sought to rigorously quantify API's VM workload and the extent of tree exposure, which it did through data collection at 150 random sample points of 1 km each. It was found that about 85% of API lines have an adjacent treed edge. Forestry timber cruising methodology was applied to derive a measure of tree density outside the right of way. From this it is determined that API has 1032 ± 47 trees per hectare and 825,543 ± 37,705 danger trees (trees which on failure could contact conductors) at the 95% confidence level. Prior to the capital widening which has occurred that figure was considerably higher.

The capital widening was prudent. It decreased the both the number of danger trees (trees that could contact a conductor on failure) and the arc of line exposure for the remaining trees. The benefit in risk reduction is shown in *Exhibit 1-3* by comparing the Risk Factor (RF) at the average 8 feet clear width before widening with the RF at the established 15 feet clear width. The widening will ultimately provide a 32% reduction in tree-caused outages. API has not yet experienced this improvement because widening exposes trees which have grown inside the forest to sudden increases in wind loading, resulting in higher failure rates. Over time the new edges will harden and the reliability gain will be achieved, reflecting the decreased probability of a line contact on failure.

Exhibit 1-3
Line Strike Risk



The forest samples established the percent of decadent trees to be 11.2% of the population. While all of these trees will eventually fail, they may not all become hazard trees. Whether these decadent trees are deemed hazard trees will depend on tree species mode of failure, lean, their position relative to the power line and other trees blocking the fall path to the power line. However, this high percentage is indicative that API's VM is behind on the removal of hazard trees. The work inventory collected from 150 sample sites, which also accumulated hazard tree data, found only 2% hazard trees along the edges. This differential in hazard trees dependent upon distance from the line has two explanations. The capital widening created instability in edge trees. The edge trees that became hazard trees would be apparent if not generally, certainly to any experienced VM and utility passerby who would initiate remedial action. Secondly, both because of budget limitations and the instability created in new treed edges, API has restricted the search for hazard trees to the first metre along the edge. Considering the time since the capital widening was initiated many miles of edge should already have become stable. Yet the system level outage statistics do not show the expected steady reductions in tree-related outages. As API did not indicate that tree-related outages were arising almost exclusively on recently widened line segments, we conclude the expected reduction is not occurring due to an increasing number of hazard trees situated 6 to 15 m from the conductor.

Exhibit 1-4
Tree Species Risk Rating

Species	Records	% of Population	% Decadent	Risk per 1000 trees
Birch, white	679	10.94%	22.24%	24.3352
Fir, balsam	868	13.99%	16.59%	23.2071
Aspen, trembling	625	10.07%	16.32%	16.4384
Maple, sugar	957	15.42%	5.02%	7.7357
Spruce, white	496	7.99%	7.46%	5.9629
Maple, red	634	10.22%	5.68%	5.8018
Birch, yellow	208	3.35%	13.94%	4.6737
Pine, Jack	185	2.98%	14.59%	4.3513
Poplar, balsam	95	1.53%	22.11%	3.3844
Cedar white	306	4.93%	6.86%	3.3844
Pine, white	165	2.66%	12.73%	3.3844
Ash, white	116	1.87%	12.07%	2.2562
Tamarack	39	0.63%	28.21%	1.7728
Aspen, largetooth	48	0.77%	18.75%	1.4504
Spruce, black	237	3.82%	2.53%	0.9670
Oak, red	133	2.14%	3.76%	0.8058
Ash, black	16			
Hemlock, eastern	79	1.27%	3.80%	0.4835
Cherry, pin	14			
Other	2			
Ash, mountain	9			
Elm, American	21			
Pine, red	252	4.06%	0.40%	0.1612
Basswood	2			
Beech, American	1			
Ironwood	18			
Totals	**6205**		**11.20%**	**4.3079**

To improve on reliability API will need to address the backlog of hazard trees and establish a maintenance cycle that prevents the major build up in hazard trees between maintenance events. A 3-year hazard tree cycle is recommended. By weighting species frequency of occurrence with percent decadence provides guidance to the hazard tree program by highlighting which tree species pose the greatest risk to continuity of service (*Exhibit 1-4*).

The Performance Management Review found while API's current VM program has many positive aspects. However, if API is to transition to a sustainable maintenance program, there are some impediments that need to be removed. Doing so will result in improved reliability. There are also some opportunities for improvement and efficiency gains.

Clearance standards are (now) typical of industry standards. The standards are met in the field and good arboricultural practices are applied. Communication between the Forestry group and other API departments is exceptional. The leadership in the Forestry group is knowledgeable and committed to continuous improvement in the VM program.

The major obstacle to achieving a sustainable VM program is that the funding has not been based on an inventory and tree growth and mortality rates that would establish how that inventory changes. Because the VM workload is not static and expands by a logistic function, there is a specific amount of VM (the annual volume increment or AVI) that must be conducted within the year to hold the system in equilibrium. The acceptance of this approach of annually removing the AVI is recommended as it provides simultaneously the least cost program and the lowest incidence of tree-related outages for the established clearance standards and practices. A successful VM program can only be delivered if funding is adequate to remove the AVI. In API's case, there is also a backlog of work in addition to the AVI that needs to be addressed to be able to achieve equilibrium. The backlog occurs in hazard tree removals and pruning work. The pruning backlog will be addressed over the recommended term of the pruning cycle. The backlog of hazard tree work will require additional funding.

API has had recommendations for maintenance cycles in the past but these cycles were never attained. A key distinction in this review is that the various parts of the VM program are assigned separate and distinct maintenance cycles based on growth rates and clearance standards. Maintenance cycles and specific funding requirements will be discussed further.

One of the primary sources of tree-caused outages is the failure of branches overhanging conductors. API has a considerable amount overhangs. This is typical of distribution utilities with adjacent hardwood tree species. Due to the exposure to sugar maples, it is not feasible to remove all overhangs without antipathy from landowners. None the less, adopting a policy of removing overhangs wherever possible would contribute to improving reliability. The greatest effort should be focussed on line segments between the substation and the first protective device: line segments that have the greatest customer impact when lost.

In seeking cost effectiveness it is necessary to consider the maintenance free period provided. With respect to herbicide applications, foliar herbicide applications cost less, are more efficacious and generally provide a greater maintenance free period than stump treating and basal applications. API's foliar herbicide program is currently focussed predominantly on off-road line segments. Expanding foliar applications to all areas of brush regrowth, even while recognizing the constraints of environmental conditions and landowner concerns, offers the potential to substantially reduce the average per hectare cost of brush control.

The introduction of brush mowers, specifically the Hydro Ax, and the telescoping insulated boom saw offer opportunities for cost reductions. Brush mowing is considerably less costly than hand cutting of brush. However, due to much rocky terrain, the area suitable for mowing is restricted. None the less, the cost differential warrants a sound investigation of how much of the right of way can be treated with a mower. The application for the telescoping saw is the removal of overhangs. The telescoping saw is far more productive than pruning from an aerial bucket. However, the greatest cost savings will be found in areas that are not accessible to a bucket truck and would need to be climbed. Use of the telescoping saw will be limited by the need to restrict its use to areas where less than perfect pruning cuts can be tolerated.

To determine the AVI the total amount of work is determined by work category. The maintenance cycles, with the exception of hazard trees, are derived from the growth rates. The right of way area that is subject to invasion by brush because it runs adjacent to natural tree stands is presented in *Exhibit 1-5*.

Exhibit 1-5
Area Requiring VM

Voltage (kV)	Kms	Wire Zone (ft)	Edge type	Mean Clear Width (ft)	ROW Width (ft)	Miles	Acres	% Treed Edge	Potential Treed ROW Acres
44	85.9	7	ROW	54	115	53	744	95.55%	711
25/34.5	174.0	7	ROW	34	75	108	983	89.69%	882
25/34.5		7	Roadside	47		108		89.69%	
7.2/14.4	1425.7	1	ROW	18	37	886	3,973	83.21%	3,306
7.2/14.4		1	Roadside	89		886		83.21%	
Totals	**1686**					**1155**	**5700**	**85.76%**	**4898**

Wire Zone – distance between outer phases
Clear Width – distance between outer conductor and tree boles on edge

The total exposure to outside right of way trees, which have the potential on failure to contact conductors, is presented in *Exhibit 1-6*. Also provided is the annual number of decadent trees, that is, trees that have begun the process of mortality.

The API system is exposed to 825,543 trees that on failure could contact conductors. These trees are called danger trees. Based on a 2% annual mortality rate, 16,511 trees will need to be assessed annually for the risk they pose to power lines. Some portion of these trees will be designated hazard trees. Based on the mean field found tree heights, line heights and tree density we have calculated the arc of line exposure at 8.5 m (28 ft) from the conductor to estimate the probability of a line contact on failure. There are two estimates for the number of hazard trees. The first is based on an annual tree mortality rate of 2% and the second is derived from the percent of decadent trees found in the forest samples, which was 11.2% (*Exhibit 1-7*).

Exhibit 1-6
Tree Exposure

Voltage (kV)	Mean Tree Height (ft)	Mean Line Height (ft)	Trees Per Acre	Ft. To Tree Free @	Danger Trees	Decadent Trees	Mean Danger Tree Depth (ft)
44	63	33	416	54	0	0	0
25/34.5	62	41		47	63,566	1,271	13
25/34.5				47	0	0	0
7.2/14.4	68	33		59	761,977	15,240	41
7.2/14.4				59	0	0	0
Totals					825,543	16,511	

Exhibit 1-7
Hazard Trees

Voltage (kV)	Decadent Trees Calculated From Annual Mortality	Decadent Trees Based on Found Incidence
44	0	0
25/34.5	1,271	7,120
25/34.5	0	0
7.2/14.4	15,240	85,346
7.2/14.4	0	0
Totals	**16,511**	**92,466**
Hazard Trees	**2,683**	**15,026**

Growth rates were obtained by measuring internode lengths for the last five years of growth, measuring at least 30 stems at each of 15 of the 150 sample locations (462 brush samples). Line heights encountered in the sampling were from 7.8 m upwards. Growth beyond the five years sampled was extended by the average and placed in a frequency distribution to determine in what year trees would begin to intrude on conductors. From this it is deduced that brush control requires a 9-year maintenance cycle (*Exhibit 1-8*). Foliar herbicide applications require a 3-year cycle so as to manage the brownout which is generally negatively viewed and raises resistance to herbicide applications.

Pruning regrowth is derived from 307 stems on which the last five internode lengths were recorded. Using a similar process to extend growth over many years based on the 5-year average it is possible to determine when the established clearance is eroded. *Exhibit 1-9* shows the percent of the stems that would intrude on the limit of approach by years. From this the recommended 6-year maintenance cycle for pruning work is derived.

Exhibit 1-8
Brush Growth Based on Observed Growth 2009-2013

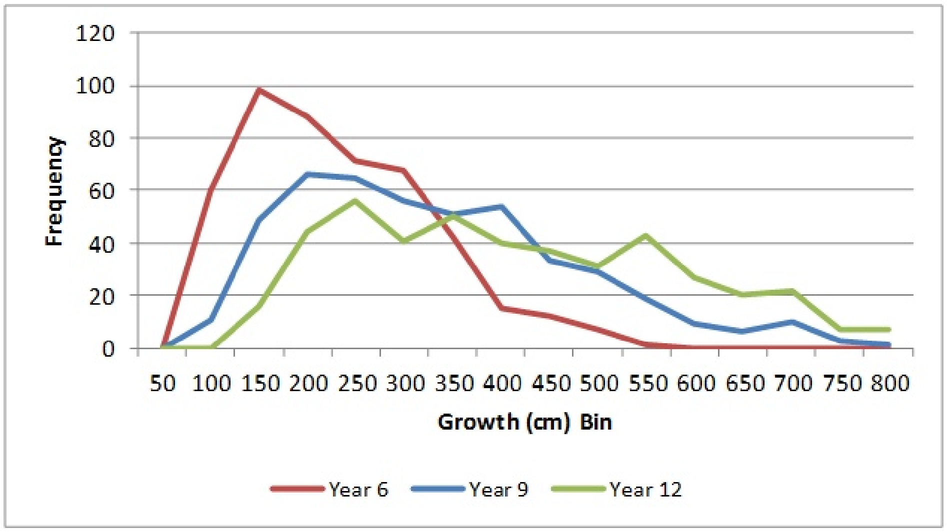
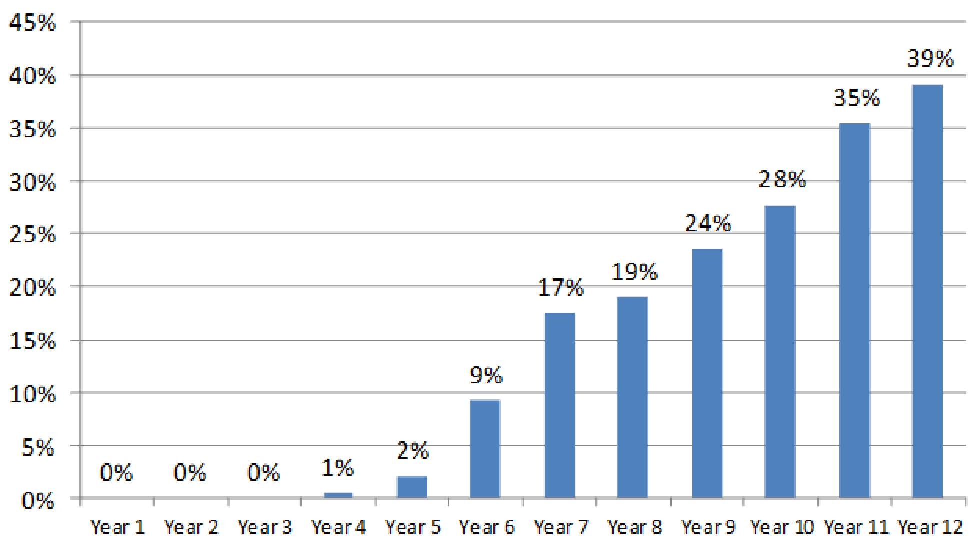


Exhibit 1-9
Pruning Breaching Limit of Approach



Having developed the maintenance cycles for the various work methods, the AVI is developed dividing the total volume for each work type by the maintenance cycle (*Exhibit 1-10*).

Exhibit 1-10
Annual Workload Volume Increment

	Brush (m^2)	Herbicide (m^2)	Pruning Top (m^2)	Pruning Side (m^2)	Hazard Trees
	10,206,864	3,048,804	187,354	185,008	3,069[1]
Cycle (years)	9	3	6	6	3
Annually	1,134,096	1,016,268	31,226	30,835	1,023

[1] 386 hazard trees have been added to account for secondary circuit kms

Unit costs are then applied to the work volumes to derive the value of the AVI. This provides the expenditures required to achieve a sustainable VM program (*Exhibit 1-11*). However, any backlog of work must also be addressed (*Exhibit 1-11*) and, therefore, it must be added if the VM is to be returned to a sustainable level.

Exhibit 1-11
Annual Workload Values

	Brush	**Herbicide**	**Pruning Top**	**Pruning Side**	**Hazard Trees**	**AVI**	**HT Backlog**	**Total**
	$22,965,444	$548,785	$515,223	$1,928,242	$507,738		$2,684,764	
Cycle (years)	9	3	6	6	3		3	
Annually	$2,551,716	$182,928	$85,871	$321,374	$169,246	$3,311,134	$680,681	$3,991,816

For a comprehensive accounting of how the backlog of work or cumulative liability is paid off, it is necessary to determine the rate of change of deferred work. This is accomplished by fitting a logistic function to the known data (*Exhibit 1-14*) and then using that function to calculate the effect of funding on the cumulative liability. In this way a schedule of funding, which ultimately brings the cumulative liability to zero was developed. The intent in this funding model (*Exhibit 1-12*) is to arrive at and maintain the cumulative liability as close to zero as possible. It has been assumed in the development of *Exhibit 1-12* that the new funding schedule would not be initiated until 2015. Between capital and maintenance funding for VM in 2014 the value falls over $400,000 short of the AVI. When the backlog is included, the proposed funding will fall over $1 million short.

Exhibit 1-12
Proposed VM Maintenance Budget[1]

	Minimum Required Budget	Proposed Funding	PV of $1	PV of Budget Provided	Unfunded	Liability	Cumulative Liability
Proposed Funding					('000)	('000)	('000)
Start 2014	('000,000)	('000,000)		('000,000)		$680.68	$2,042.04
End 2014	$3.99	$2.88	1.0000	$2.88	$1,109.73	$769.20	$2,811.25
End 2015	$3.99	$4.70	0.9524	$4.48	-$708.18	$0.00	$2,200.89
End 2016	$3.99	$4.70	0.9070	$4.26	-$708.18	$0.00	$1,594.56
End 2017	$3.99	$4.70	0.8638	$4.06	-$708.18	$0.00	$965.98
End 2018	$3.31	$4.30	0.8227	$3.54	-$988.87	$0.00	-$25.68
End 2019	$3.31	$3.31	0.7835	$2.59	$1.13	$1.13	-$24.54
End 2020	$3.31	$3.31	0.7462	$2.47	$1.13	$1.31	-$23.23
End 2021	$3.31	$3.31	0.7107	$2.35	$1.13	$1.51	-$21.72
End 2022	$3.31	$3.31	0.6768	$2.24	$1.13	$1.75	-$19.97
End 2023	$3.31	$3.31	0.6446	$2.13	$1.13	$2.02	-$17.95
Total	$35.83	$37.83		$31.01			-$17.95

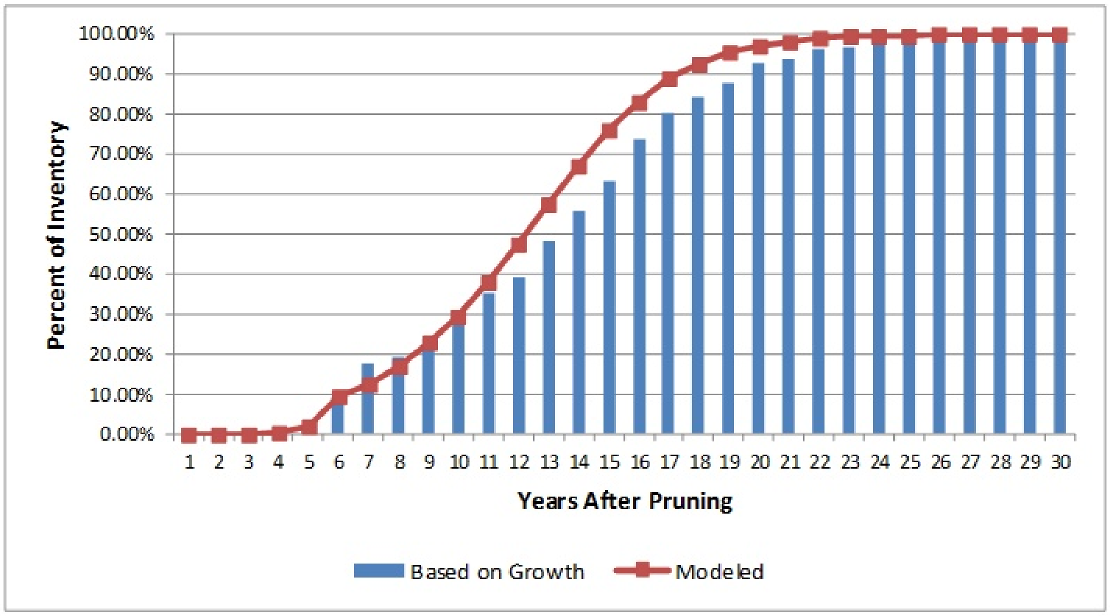
[1] In 2013 dollars

The schedule of VM funding set out in *Exhibit 1-12* should make it apparent that there is only one path to a sustainable VM program. If there is a current cumulative liability then funding must exceed the AVI value to be progressing towards a sustainable program. If there is no current cumulative liability then funding must match the AVI value. The logistic function that fits API's found field conditions informs us that every dollar of work deferred will need to be replaced with $1.155 in the next year. While not correct over the long term, as a logistic function curve has an asymptote, in the short term (i.e. 5 years) deferred work compounds at 15.5% per annum.

Without a commitment to the funding set out in *Exhibit 1-12* there is not much possibility that tree-caused outages will improve in the future. In fact, there are indications that reliability will deteriorate. If the high incidence of decadent trees is not addressed, their ratio of all trees will continue to increase. They will reach a peak over the next 3 to 5 years and it should be expected that tree-related outages will increase 40-60%.

There is a high incidence of hot spots (sites where contact with the conductor will occur within the next year). *Exhibit 1-13* shows the rate of development of hot spots. The field inventory work indicated that 38% of the pruning sites were hot spots. The corresponding number is at year 12 in *Exhibit 1-13*.

Exhibit 1-13
Modeling Hot Spot Development

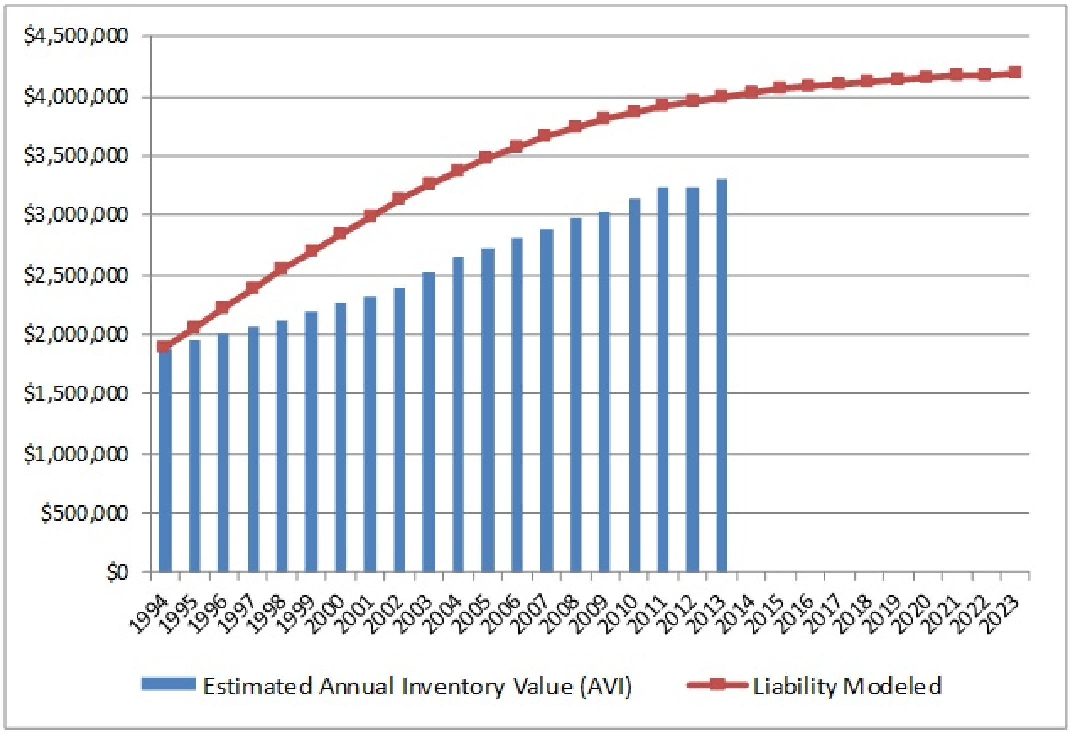


Very few sites were seen where tree-conductor contact was apparent. The fact is corroborated by outage statistics that show virtually no grow-in outages since 2010. This suggests that API has done an excellent job of hot spotting. Hot spotting is, however, inefficient, costing considerably more than routine maintenance work. The implications of not putting the pruning on an appropriate maintenance cycle, such as the recommended 6-year cycle, can clearly be seen in *Exhibit 1-13* looking to the right of year 12, which is the current level. With the number of hot spots expanding rapidly, doubling in fact over the next five years, how realistic is it to think API will be able to continue to avoid grow-in outages?

There is also a financial risk or penalty associated with funding below the AVI value. *Exhibit 1-14* projects forward the current maintenance underfunding which is not far removed from the AVI value but does not address the current backlog or cumulative liability. Deferring work, deferring a commitment to funding that reduces the cumulative liability will incur greater costs when the decision is subsequently made to provide a more reliable service to customers.

After the right of way reclamation work that has occurred, there now exists the possibility that the average cost per hectare for brush, which is the largest cost component, may be substantially reduced through the extension of foliar herbicide use and the introduction of brush mowers. However, reducing the VM funding from the recommended levels on speculation of the area that might be treated with foliar herbicide or mowing need be recognized for the gamble that it is and that the risk side of the equation shows any error that results in deferred work will be compounding at about 15% per annum.

Exhibit 1-14
Modeling the Workload Liability



2013 AVI is derived from field inventory, growth and mortality rates

API's VM program is currently on the cusp. There are many positive aspects. The capital expenditures have served to reduce the current liability. At this point API can move forward to a best in class VM program and a least cost sustainable program. However, the program is not many years removed from a program that is beyond control of deteriorating reliability and increasing public safety and wildfire risk. The positive path forward has been revealed in the recommendations provided.

2. Background

Algoma Power Inc. (API), as an investor owned electric distribution utility, is regulated by the Ontario Energy Board (OEB), to whom it must apply for the rates it can charge its customers.

API has completed the majority of its right of way expansion program and is transitioning to a maintenance program. Given this transition, API has undertaken an assessment to determine the volumes of emerging maintenance work. Future maintenance work volumes have been impacted by the capital work and will continue to change as the new edges transition to stable edges. The change in focus from major capital work back to strictly maintenance also provides an opportunity to examine vegetation management (VM) practices to ensure funds are directed to the most efficient and cost effective practices.

This project explores the effectiveness of the API VM program, identifying practices to be continued or extended, shortcomings and opportunities for improvement (Performance Management Review), including variances from standard utility practice, maintenance cycles based on biological fact, quantification of the annual workload volume increment[4], the least cost sustainable VM program, the resources required to achieve it and the term. These outcomes are driven by new, independent data acquired to determine the extent of tree exposure, trees requiring pruning, inventory of trees requiring assessments for hazards, regrowth rates, the area requiring active management broken down into quantity by work types (most cost effective treatment/work practice for conditions).

Trees are the primary cause of unplanned outages for API. This is common for electric distribution services. Indeed, for the majority of North American electric distribution companies tree-caused outages are the leading cause of service interruptions. Consequently, VM, which seeks to limit this cause of interruptions, is the single greatest operating and maintenance expense.

The setting of electricity rates in North America follows a quasi-judicial process. The regulator must provide public notice of a rate application, providing affected parties an opportunity to participate or intervene in the process. The intent of the process is to surface to the regulator all the facts and factors requiring consideration, such that the regulator has before it the best information upon which to base a decision. This report seeks to address that need.

This report describes:

- The investigation process
- Data collection and analysis
- Resulting conclusions, and
- Recommendations

The work is detailed under the following project elements:

- Performance Management Review
- Outage Statistics
- Quantification of the Utility Forest
- Within & Adjacent to ROW
- Outside ROW Tree Exposure
- Tree Growth Study
- Statistical Analysis
- Workload Inventory, Maintenance Cycles & Annual Workload Volume Increment
- Workload Valuation & Funding Requirements
- Risk Indicators & Model Progression
- Recommendations

Background to Utility Vegetation Management

As already stated, on many distribution systems, trees are the primary cause of unplanned service interruptions.[5 6] Even though greater conductor-to-tree clearances are maintained on transmission systems, these systems are not immune to tree-caused outage events. Within less than ten years, there were three major tree-caused cascading-outage events in the U.S. and one in Italy:

- July 2, 1996 on U.S. western grid; 2.2 million customers affected[7]
- August 10, 1996 on U.S. western grid; 7.5 million customers affected[8]
- August 14, 2003 on U.S. northeast grid; 50 million customers affected[9]
- September 28, 2003 intertie-line between Switzerland and Italy; 60 million customers affected[10]

This history suggests that how vegetation management is related to outage events is inadequately understood. A literature review will reveal few articles on establishing a mathematical link between vegetation management expenditures or maintenance cycles with the frequency of tree-caused outage events. Among the scant few that do exist, a number are flawed through the exclusion of critical variables. In the absence of appropriate, statistically derived regression algorithms linking the timing and scope of past maintenance activities with tree-caused outage events, a conceptual approach serves as a starting point and provides guidance.

The following section is included to provide the non-vegetation manager a context for understanding some of the key issues in vegetation management. Vegetation management concepts and principles are presented to make explicit key aspects of the relationship between vegetation management and tree-caused outage events. This information is general to utility vegetation management. None of the data used in the Vegetation Management Concepts and Principles section is derived from API. This introduction seeks to make distinctions between work types, their origins and provide mathematical representations for the change in vegetation management workload over time. More importantly, it should facilitate an understanding that tree-caused outages, while lagging work in the field, are a suitable proxy for assessing the adequacy or effectiveness of a vegetation management program. The vegetation management concepts and principles provide a conceptual template that will subsequently be used to make assessments regarding the adequacy of funding of API's vegetation management program.

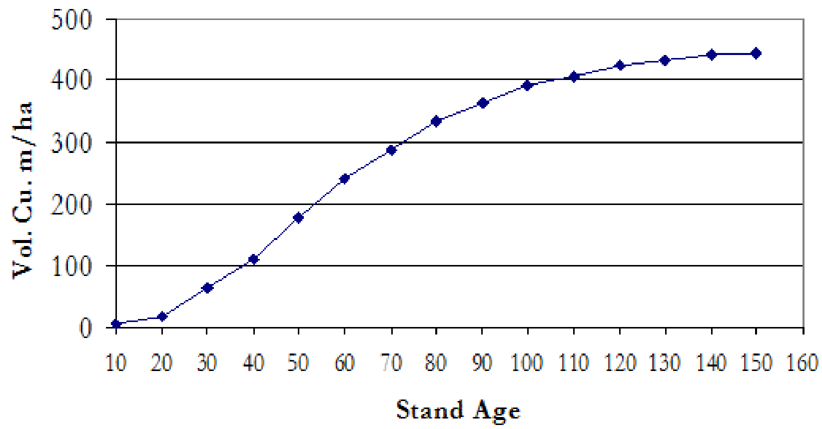
3. Vegetation Management Concepts and Principles

Trees that interrupt electric service can be categorized as in-growth trees and in-fall trees. The inventory of all trees that have the potential to either grow into a power line or, on failure (breakage), fall into and strike a conductor will be referred to as the utility forest. While we commonly think of forests in terms of more or less rectangular blocks, the utility forest amounts to ribbons or transects of the service area. Generally, the centerline of these transects is the power line. The utility forest has the same characteristics as any forest. In most cases the tree species composition is what is native to the area. The same patterns of biomass addition (tree growth) and tree mortality apply. Both of these patterns are significant factors in power line security and both can be mathematically represented by logistic functions, as illustrated in *Exhibit 3-15* and *Exhibit 3-16*. Biomass additions result in trees that encroach on conductors, thereby necessitating tree pruning and either mechanical or chemical (herbicide) brush clearing. Failure to mitigate this encroachment leads to deteriorating safety and reliability. *Exhibit 3-15* shows an asymptotic curve that is typical of biological populations. Tree mortality produces decadent trees that are subject to breakage or tipping over (*Exhibit 3-16*). Tree mortality is not an event that occurs at a specific point in time. Rather, tree mortality occurs over a period of months and years.

Natural tree mortality is a process of losing vigor either due to the stress of competition for light, water and nutrients or an inability to sustain the attained mass. In the early stages of senescence or decline there may be no visible defect. However, as the tree becomes increasingly decadent and subject to failure under increasingly less stress loading, symptoms of the decline become apparent. Such senescent trees must be identified as faulty and prone to failure under weather stress and must be removed prior to the occurrence of stress. *Exhibit 3-16* shows both the forest stand density over time and the population of trees of concern to utility facilities, the Decadent Trees. While the South Carolina forest data (*Exhibit 3-16*) is restricted to sixty-two years, the line for Decadent Trees is seen to be approaching an asymptote. Further, because the capacity of the land-base to produce biomass is limited, the line for the evolution of decadent trees must be asymptotic. The nature of the expansion of the two sources of tree-caused interruptions, biomass addition (in-growth) and tree mortality (in-fall), is additive or constructive. This in conjunction with the process of tree mortality leads to insight into the consequences of failure to manage trees in proximity to power lines.

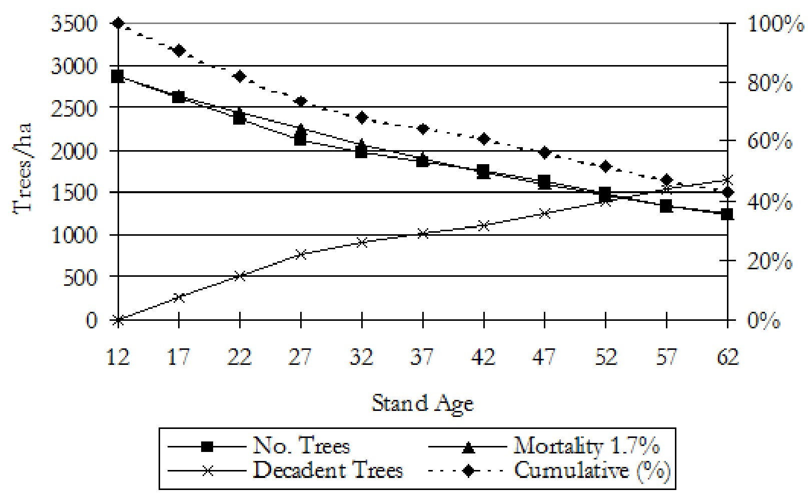
From a utility perspective, trees represent a liability in both the legal and financial sense. The fact that the utility forest changes by a logistic function is significant. It means that the tree liability, if not managed, will grow exponentially.

Exhibit 3-15
Vegetation Management Concepts and Principles
Forest Biomass Addition
Timber Production
Spruce on Good Site



Source: Freedman, Bill and Todd Keith, 1995. Planting Trees for Carbon Credits. Tree Canada Foundation.

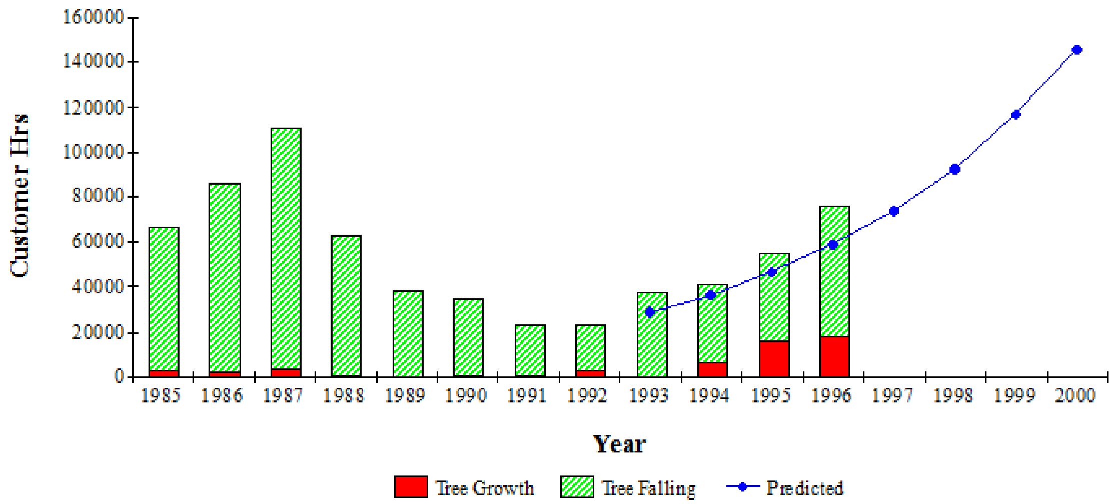
Exhibit 3-16
Vegetation Management Concepts and Principles
Stand Density
South Carolina
State Forest



Source: Crookston, Nicholas L. 1997. Suppose: An Interface to the Forest Vegetation Simulator.
Note: The graph shows the remaining live, viable trees. Of interest to utilities is the 60% of trees in the stand that die over 50 years because they hold the potential to disrupt electrical service.

Trees cause service interruptions by growing into energized conductors and establishing either a phase-to-phase or phase-to-ground fault. Trees also disrupt service when they or their branches fail, striking the line and causing phase-to-phase faults or phase-to-ground faults or breaking the continuity of the circuit. Because the two factors that are responsible for service interruptions, tree growth (biomass addition *Exhibit 3-15*) and tree mortality (*Exhibit 3-16*), change by logistic functions, the progression of tree-related outages is, necessarily, also exponential (*Exhibit 3-17*) up to the approach of the asymptote. Failure to manage the tree liability leads to both exponentially expanding future costs and tree-related outages. Conversely, it is possible to simultaneously minimize vegetation management costs and tree-related outages (*Exhibit 3-18*).

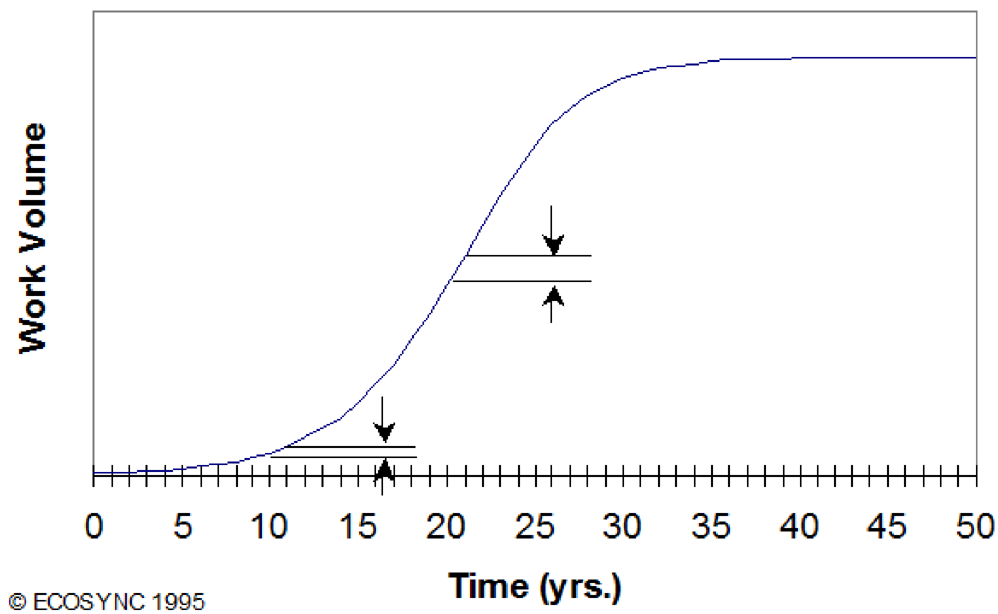
Exhibit 3-17
Vegetation Management Concepts and Principles
Tree-caused Distribution Outage Statistics



Source: Western Canadian utility
Note: This work and prediction for future tree-caused outages was performed in early 1997 to show the expected trend to 2000 based on funding below that required to remove the annual workload volume increment.

It is not possible to totally eliminate the tree liability because the ecological process of succession is a constant force for the re-establishment of trees from whence they were removed. The tree liability then is like a debt that can never be completely repaid. Under such circumstances, the best economy is found in maintaining the debt at the minimum level, thereby minimizing the annual accrued interest. However, irrespective of cost, minimizing the size of the tree liability or utility forest is rarely an option for utilities because there are multiple stakeholders with an interest in the trees. What can be achieved, however, is equilibrium. The tree liability can be held at a constant point by annually addressing the workload increment. To continue the debt analogy, a debt is stabilized when the annual payments equal the interest that accrues throughout the year. The interest equivalent in the utility forest is comprised of annual tree growth and mortality. Actions that parallel the reduction in the debt principal are actions that actually decrease the number of trees in the utility forest. Such actions include removal of trees and brush by cutting or through herbicide use.

Exhibit 3-18
Vegetation Management Concepts and Principles
Stabilizing Tree Workload
(Illustrative Model)



The graph shows the work volume that must be completed in a year to hold tree work inventory, costs and reliability steady. Performing less than the annual workload-volume increment shifts the total tree work inventory to the right, thus necessitating greater annual vegetation management expenditures to arrest the expansion of tree-related service interruptions.

When the pruning cycle removes the annual growth increment and the hazard tree program removes trees as they become decadent (*Exhibit 3-18*), tree-related outages are stabilized. The residual level of tree-related outages reflects the interaction of several characteristics, including the size of the utility forest, chosen maintenance standards (such as clear width), tree-conductor clearance, and tree-species characteristics (such as mode of failure and decay). An expression of a managed tree liability, one in which the annual workload volume increment is removed, is stable tree-related outages. Reducing tree-related outages below an achieved equilibrium necessitates actions that decrease the size of the utility forest. Actions are not limited to vegetation management. For example, increasing conductor height reduces the size of the utility forest as it reduces the number of trees that are capable of striking the line.

Funding

There are three possible outcomes determined by the level of investment made in vegetation management.

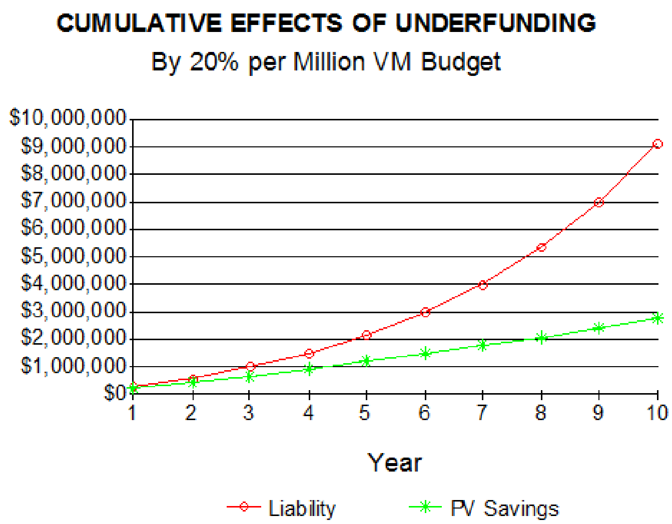
1. The annual workload volume increment is removed, thus keeping the size of the tree liability and next year's workload increment constant.
2. More than the annual workload volume increment is removed, thus decreasing the size of the tree liability and the subsequent year's workload increment.
3. Less than the annual workload volume increment is removed, thus increasing the size of the tree liability. That is because the work not done expands exponentially, thus increasing the workload increment for the following year.

Tree-related outages are an expression of the tree liability. Hence, changes in the tree liability result in proportional changes in tree-related outages (*Exhibit 3-17, Exhibit 3-19*). Actual outage experience may deviate from the trend based on variance from mean weather conditions.

When less than the annual workload volume increment is removed, the fact that tree liability increases by a logistic function has two major implications for future costs and reliability. First, the impact of doing less vegetation management work than the annual workload volume increment, as expressed through tree-related outages, may be relatively imperceptible for a few years. Second, the point at which the impact of under-funding is readily observed in deteriorating reliability is where the effect of annual compounding in the workload, and thereby costs, is large (*Exhibit 3-19*). The lack of a significant negative reliability response to reduced vegetation management investment (see 1992 to 1995 *Exhibit 3-17*) may provoke further funding reductions, thereby exacerbating the size of the future re-investment required to contain tree-related outages.

Recognition that the tree workload expands by a logistic function serves to explain some common utility experience. For many utilities, graphing customer hours lost on tree-caused interruptions over the last ten to twenty years reveals cyclical up and down trends (*Exhibit 3-17*). There are periods when trees are perceived as a problem and funding is increased. Increased funding permits a buying down of the tree liability, reducing tree risks and tree-related outages. Faced with these positive results, spending on vegetation management is reduced. While this tendency is perfectly logical, without the conceptual framework outlined, it is inevitable that funding will be reduced to the point where there is an observable response in tree-related outages. Unfortunately, by the time that tree-related outages are definitively observed to be on an increasing trend, for some years, vegetation management investment has been less than what is required to remove the annual workload volume increment. At this point, the power of compounding is well under way and only a very aggressive increase in funding will arrest the trend. The rate of change in the workload liability in *Exhibit 3-19* is approximately equal to a compounding rate of 27% per year. Warmer and wetter climates with a longer growing season support higher rates of change. In other words, for distribution systems, the rate of change in the tree workload is substantially higher than the discount rate (currently 3-11%) one would conceivably use to derive the present value benefit of deferred maintenance spending. Taking a short-term financial perspective, any deferred or diverted vegetation management funding that inhibits removal of the annual workload volume increment is poorly allocated unless it provides a better rate of return. The example provided in *Exhibit 3-19* shows that returning the work volume and reliability to the original levels after 10 years of under-funding by 20%, increases costs by 80% over maintenance, which annually removes the workload volume increment.

Exhibit 3-19
Vegetation Management Concepts and Principles
Impact of Under-Funding Vegetation Management Revealed Over Time



Notes: Rate of change in liability based on western Canadian utility with a 4-month growing season.
Interest/Discount rate = 6%

It has been shown, through *Exhibit 3-17* and *Exhibit 3-19*, that under-funding VM has a substantial impact on future reliability and costs to return to the level of reliability enjoyed before under-funding. The increase in workload due to deferred maintenance is not linear. Hence, the impacts of a dollar deferred this year cannot be erased with an investment of a dollar next year. Further, this section has provided the conceptual context that utilities have lacked, which lack has allowed the inefficient, repetitive cycles of under-funding followed by reactive catch-up periods.

Exhibit 3-19 illustrates that failing to make the necessary investment in vegetation management will, in most circumstances, prove imprudent. While utilities are expected to justify their intended vegetation management expenditures, regulators play a role in the effectiveness of the program. Failure to understand the nature of vegetation management workload expansion or skepticism that leads to decisions limiting the ability to remove the annual workload volume increment, will impose the inefficiencies illustrated in *Exhibit 3-19*. By focusing on cost containment, the regulatory process risks supporting such inefficiency. Utilities that are pressured to minimize costs must prove the harm that will result as a consequence of failure to fund and perform proposed work. This burden of proof proves very challenging for maintenance work, where it becomes necessary to prove that an event that did not occur would have occurred but for specific actions and expenditures. By insisting on demonstrable harm, the regulatory structure supports a reactive approach to maintenance with the attendant cyclical inefficiencies.

Managing the Tree Liability for Positive Returns

Trees need to be recognized as a liability in a utility context. While this puts utilities in conflict with community perceptions of trees as assets, the conflict does not change the fact that trees hold only the capacity to impair the safe, reliable operation of the electric system, not to augment it in any way. The recognition and quantification of the utility forest as a liability provides a measure of the potential for, or risk of, tree-conductor conflicts. Furthermore, it connects and clarifies the influence of design and operating decisions on maintenance costs and reliability risks.

Managing the tree liability necessitates an understanding of how and where tree risks arise, a quantification of the extent of tree exposure, the rate of change in the tree liability, and a commitment to funding that permits, at a minimum, the removal of the annual workload volume increment.

Appropriate investment in vegetation management is one of the best investments a utility can make. It serves to minimize tree-caused interruptions for the chosen clearance standard, thereby avoiding customer complaints, the need for regulator intervention, and in some cases performance penalties. It avoids the inefficiencies that are inherent in the cycle of allowing trees to become a major problem, getting trees under control by buying down the tree liability, and then losing the investment by failing to contain the tree liability. Investment based on the removal of the annual tree workload increment provides the conceptual approach that is needed to deliver a sustainable, least-cost vegetation management program. Simultaneously, such a program provides the lowest incidence of tree-caused service interruptions (*Exhibit 3-18*) for community-accepted clearance standards, thereby benefiting ratepayers and shareholders alike.

4. Benchmarking

Electric utilities do not operate in markets where they are free to set the price at which they sell their product and service. Co-ops must justify rates to their members. Municipal utilities receive oversight from elected civic officials and investor owned utilities must justify rates through a state or provincial regulatory process.

The commonality between these oversight bodies is that they serve to represent the interest of the ratepayer, to ensure utilities provide a reasonable level of reliability in service at a reasonable price. Determining what constitutes a reasonable service and price is particularly challenging for VM programs.

It is not uncommon for utility regulators to request performance comparisons to other utilities. It is assumed such comparisons will serve to monitor progress in efficiency or provide meaningful information to regulators, ratepayers and shareholders. However, in the field of VM, the information gathered generally fails to illuminate or inform decision-making. All too often the benchmarking studies are designed without any VM expertise. Consequently, such studies do not provide guidance on what the most efficient and effective utilities are doing rather they serve to provide a template to becoming, at best average. Why is that so? Is it possible to compare VM program results between utilities and what would constitute a sound basis for such comparisons?

Answering these questions requires an understanding of what makes up the VM workload; the drivers of this workload; how and what trees cause tree-related outages and under what circumstances. This information is presented in detail in the previous section, Vegetation Management Concepts and Principles and Managing Tree-Caused Electric Service Interruptions[11] and will be used here without further qualification or detailed reiteration.

There are several general practices in utility benchmarking that make the data provided unreliable. Typically, utilities are sent a survey to complete. Completing the survey is a cost to the participating utility. The benefit derived is that the firm undertaking the survey or benchmarking usually commits to providing all the respondents the results and thus the utility will have comparisons to its peers. This process is rife with barriers to obtaining meaningful data, including:

- The level of commitment to providing accurate, detailed data will vary with the utility, the cost of providing the data, etc.
- There is no control on who answers on behalf of the utility. Varying levels of commitment, urgency and competency produce variability in the veracity of the data.
- No audits are performed to verify the data. This allows utilities to state maintenance cycles that are theoretical, an operational fantasy, instead of the operational duration in fact. It also allows for estimates or outright guesses to be supplied. There is no way for the reader of the study to distinguish such a response from an accurate fact-based response.

- In the field of VM there are very few industry defined terms. A key missing is an industry-wide definition for a maintenance cycle. Consequently, two utilities reporting a three-year and a six-year pruning cycle may in fact be doing the same thing – pruning every tree on a circuit every six years and re-doing 35% of them three years later. One utility might call this a 3-year cycle while the other considers it a 6-year cycle with a mid-cycle cycle buster or hot spotting program.
- Questions seeking to establish efficiency or productivity are denominated in dollars, yet there are no questions that serve to make explicit differences in local labour rates.

These general deficiencies in benchmarking VM are adequate reason to reject inter-utility comparisons as a means of improving rate case decision-making. If, however, one wishes to explore whether or not VM benchmarking has any merit whatsoever there is a need to look in more detail, first at what does not work so that that which might, may emerge.

First, let's examine what is generally used for a basis of inter-utility comparisons. In the field of VM the commonly used measures are dollars per mile and dollars per customer. Measures of dollars spent on VM per mile of line or per customer may have meaning within the context of a specific utility over time but are meaningless as a basis of comparison between utilities. It should be obvious that gauging performance or efficiency on dollars per mile results in utilities that grossly under-fund VM emerging as very efficient and thereby, utilities to be emulated. This metric provides no insight to distinguish between efficiency and under-funding. It does not capture the public, nor regulator perception about the adequacy of the level of service provided. That is, there is no connection to the resulting reliability. A top-down driven approach to achieve the lowest dollar per customer or $/mi of line results in a disconnect from the biologically driven need and facts. It leads to under-funding VM, based on a refusal to accept tree growth and mortality rates as independent variables outside the control of the utility. Under-funding VM, as was shown in Vegetation Management Concepts and Principles, is financially imprudent.

The survey may ask whether VM work is contracted out or performed by in-house labour. It may ask whether the utility uses time and materials, cost plus, unit price or lump sum contracts. Generally, there is nothing to help the reader of the benchmarking study determine the merits of these practices beyond their prevalence amongst utilities. There should be no comfort in using the most prevalent practices as that fact alone is no assurance that these practices are the most cost effective or that they provide superior reliability or customer satisfaction.

Benchmarking participants may be asked to provide unit prices. First, without defining the unit there is no assurance that the price is based on a common denominator. Secondly, is it known whether the unit prices are standardized to include all loading such as time for travel, safety tailboards, disposing of wood wastes, etc.? Thirdly, what are the differences in local labour rates between participating utilities and what is their impact on the unit price?

Another common metric upon which utilities are compared is the length of the pruning cycle. Without a common definition of a maintenance cycle such comparisons are meaningless. Further, outside of the utility arborist profession, there is a commonly held belief that shorter maintenance cycles will have a substantial effect on the extent of major storm damage. Managing Tree-Caused Electric Service Interruptions[12] presents the facts to dispel this erroneous belief.

For the purpose of comparisons, utilities need to be matched on customer density per mile of line and in examining VM, on tree density or trees per mile of line. This includes both trees within the right of way and trees outside the right of way that are capable of interfering with electrical service on failure (danger trees or in the new ANSI terminology, risk trees). As trees outside the right of way account for 85% or more of tree-related outages, clearly this measure of exposure is required. Yet, at this writing very few utilities have quantified this exposure.

It is inappropriate to compare a utility with 12,000 miles of line and 20 million customers to a utility with 50,000 miles of line and 5 million customers. It should be a foregone conclusion that the second utility, if in similar environmental conditions, will spend far more maintenance dollars per customer. Nor is it appropriate to compare a utility averaging 1600 trees per mile with one that averages 800. While not inconceivable it is, however, unlikely that one could compare the efficiency of the VM programs. It might be assumed that the first utility having twice the tree exposure will have twice the VM program costs and twice the number of tree-related interruptions. This assumption would, however, be wrong. The relationship between tree exposure and outage incidents is a logistic function. It is not linear[13 14 15]. As detailed in section Vegetation Management Concepts and Principles, VM workload can also be described by a logistic function or curve. Given this, it would require advanced statistical analysis to make the two utilities comparable.

Reliability is measured in outage incidents, outage duration and customers affected. These records plotted by year provide an excellent relative measure of the success of the VM program. Historically, this data did not represent a sound foundation for comparing the effectiveness relative to outside VM programs. The variability in outage reporting had always been a concern even within a utility. Hence, these measures could be used on a relative or historical basis providing there was no reason to think that outage reporting had changed for better or worse. Technological advancements have provided systems that automate the capture of outage data. While these systems have made outage data far more accurate and reliable, they do not facilitate inter-utility comparisons because the statistics in themselves do not provide the context. Utilities that have higher tree exposure (trees/mile) will have both a higher absolute number of outages and a higher ratio of tree-caused outages relative to all unplanned outages. Can you determine whether a New England utility where tree-related outages are 26% of all unplanned outages has a less effective VM program than an Arizona utility with 8% tree-related outages? For the basis of comparison it is necessary to have an inventory of trees capable of growing into or falling onto the lines. Comparing utilities on the number of tree incidents per 1000 trees of exposure would constitute a rational, meaningful approach. However, even this metric would need to be carefully weighed to reflect differences in tree species, environmental conditions experienced and the occurrence of pest infestations.

While some variables or means for making comparisons between utility VM programs have been provided they are more data intensive and require a higher level of statistical analysis. The criticisms of VM benchmarking cannot be easily overcome. If utility VM programs are to be compared the following factors are required or must be accounted for.

- Very similar tree exposure
- Similar clearance standards
- Similar urban-rural mix
- Similar customer density
- Known and similar growth rates
- Similar geographic area and environmental conditions
- Defined and thereby, standardized and comparable terms i.e. hazard tree, danger tree, risk tree, maintenance cycle
- Uniform measures of productivity i.e. man-hours per unit, which removes the influence of labour rates
- Similar units of measure for VM practices i.e. acre, hectare, m^2, tree pruned, tree removals by similar size categories
- Similar political and regulatory environment i.e. no rules eliminating or severely limiting any integrated VM practice such as herbicide applications

Benchmarking that does not address these considerations cannot inform the decision-making process, regarding the appropriate size, scale and cost of a VM program. While making use of such benchmarking data, in the absence of anything else, may have enormous appeal to regulators as an avenue of demonstrating due diligence, its worth must be recognized.

When the nature of the source and expansion in the vegetation management workload is understood, then a new approach for ensuring the effective use of ratepayer dollars appears for the regulator. There is a specific amount of VM work that needs to be completed every year to achieve a least cost sustainable VM program. Failure to remove the annual workload volume increment results in exponentially expanding costs. The questions of relevance to both utility management and the regulator become:

- How do we determine if the current utility VM program is a sustainable program?
- How do we determine if the current utility VM program is the least-cost sustainable program?
- How does one determine the annual workload volume increment?
- How does one assess utility VM productivity?
- What are unit costs?
- Are there historical tracking metrics that will ensure the least-cost sustainable program and provide a snapshot of program status?

Contrary to inter-utility benchmarking, answering these questions will simultaneously provide a clear path to both an effective VM program and effective regulatory oversight of the utility VM program.

While this section has focussed on discouraging the use of benchmarking to inform regulatory decision making that is not to say that benchmarking has no merit whatsoever. The use of benchmarking by utilities to identify industry trends, practices and common or emerging issues for the purposes of continuous improvement is a valid application. When the benchmarking study has been designed by UVM professionals and the results are evaluated in the context of the potential pitfalls that have been outlined, it provides utility management carefully considered guidance for VM program improvement.

5. Performance Management Review

This section addresses API's vegetation management organization, processes and outcomes. Information on API's vegetation management program was garnered through data requests, interviews, and field tours.

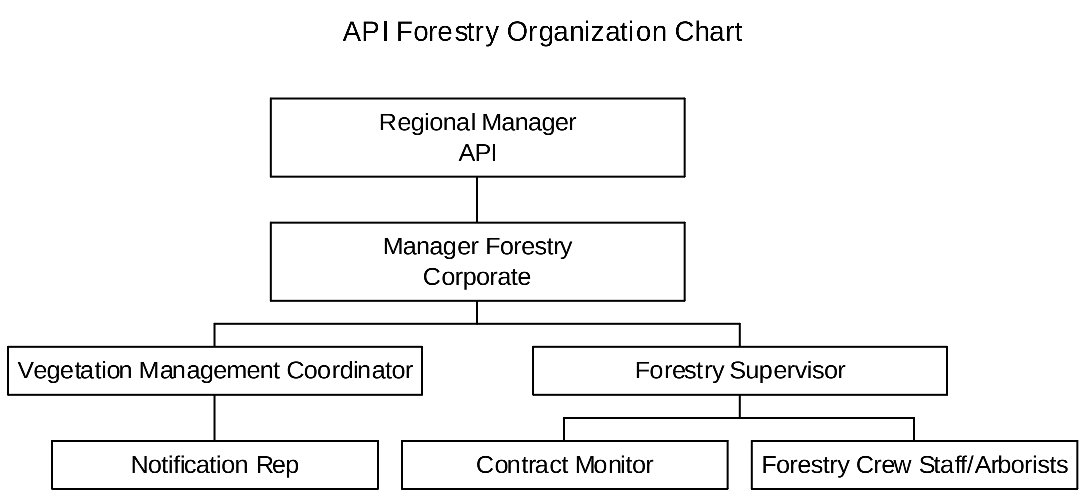
Vegetation management is critical in providing reliable service to the customer. Tree-conductor contacts are the single largest cause of unplanned service interruptions on the API system. Based on a visual qualitative assessment, API's exposure to trees is very high. (Quantitative assessments of tree exposure will be subsequently presented) It is only in the most developed urban areas that tree exposure is low and typical of conditions found at other utilities.

Organization [16]

The Manager Forestry Corporate holds the responsibility for API's vegetation management program and reports to the CEO of FortisOntario. Working under the direction of the Manager Forestry are the Vegetation Management Coordinator and the Forestry Supervisor. The Vegetation Management Coordinator holds the responsibility for planning, work and budget tracking and administration of the VM program. The Forestry Supervisor holds more of the field responsibility overseeing API's in-house VM crews and the Contract Monitors.

The organization chart [17] is presented in *Exhibit 5-20*.

Exhibit 5-20
API Forestry Organization Chart



Staffing [18]

API's staffing is as follows:

- Manager Forestry
- VM Coordinator
- Forestry Supervisor
- Contract Monitors – 3
- Notification Representative – 1 contracted position
- API Forestry Crew – 7

Facilities [19]

Vegetation management is performed on:

- 209 km sub-transmission – 44 kV, 34.5 kV
- 1556 km distribution – 2.4 kV, 4.6 kV, 7.2 kV, 12.5 kV, 25 kV
- 171 km secondaries
- substations

Easements & Rights [20]

All the sub-transmission lines have easements. Not all distribution lines have easements, though for any new lines an easement of 6 m (20 feet) each side of centre is obtained. Old easements are variable ranging from 30 feet to 100 feet. Registered easements have clear rights and those rights are exercised.

Where there are no easements API uses the authority of the Electricity Act.

Besides easements there are other types of negotiated rights. Along highways there are encroachment rights. There are permits with First Nations communities and agreements with the Ministry of Natural Resources and some forest management companies.

Clearance Standards & Pruning Maintenance Cycles

Work on First Nations lands is done on a 5-year cycle. There is no clear maintenance cycle for other work. API has been trying to achieve a 6 to 8-year maintenance cycle but funding limitations make it uncertain that this objective can be achieved. In the past maintenance cycles have extended to over 10 years.

The current distribution standard is to clear to 4.5 m each side of the lines. The target for pruning is also 4.5 m. For high priority secondaries API applies a 1.5 m ground to sky clearance. For lower priority secondaries API clears 1 m around the line.

Where sub-transmission is located alongside a roadway the clear width sought is 4.5 m. However, much of the sub-transmission is off-road. The off-road rights of way are variable in clear widths maintained ranging from 10 to 17 m from the line.

Tree Workload & Budgeting [21]

API does not currently have a tree workload inventory. Nor does API have growth and tree mortality studies to be able to forecast workload and resource requirements.

API indicated an effort was made in 2009 to determine an annual budget based on maintenance cycles. It was estimated at $3.2 million.

In 2010 set the annual budget at $2.7 million and there it has remained through 2013.

Work Planning [22]

Work planning is conceptually organized into cycle work, off-cycle work and demand work. Cycle work is broken down into approximately 50 km blocks. Off-cycle work looks at line segments while demand work is for an individual property.

In creating the work plan the first point of reference is past work. Cycle work planned and scheduled may be modified and re-prioritized based on field observations including patrols, the number of requests received from the public and interruption data. Once the program plan is assembled the landowner notification process begins. The main notification process is a mail-out.[23] With notifications complete, a work package [24] is issued. The Contract Monitor monitors the progress of the work. When the work is completed the work package is returned by the Forestry Supervisor and the VM Coordinator and Notification Representative update the records.

Modifications to the work plan are rare and when they do occur are usually budget driven. The monthly meetings may lead to a re-prioritization but that would really just shuffle components within the annual plan. If there is emergent work it is typically entered into the following year's plan.

Storm work does not affect the work plan. It is not charged to the preventative budget. There have not been issues with being unable to catch up on planned maintenance work after crews being diverted to storm work.

The VM Coordinator attends weekly engineering meetings. There is a formal process for planning capital projects which tracks who has responsibility, accountability and who needs to be consulted and or who needs to be informed.[25] Through these measures Forestry is both apprised of all capital projects and provides input to clearance standards, line location discussions and site preparation costs.

Maintenance Cycles [26]

For right of way brush control on First Nation lands API has been using a 5-year cycle.

API currently is targeting a 6 to 8-year maintenance cycle for brush control but is uncertain whether that is achievable due to budget limitations and whether that is the optimal maintenance cycle.

Pruning work is also thought to require a 6 to 8-year maintenance cycle but API indicated that there are areas that have not been re-pruned for over 10 years.

API expenditures have been $2.7 million annually since 2010. API believes there is a backlog of work.

API is looking for guidance on maintenance cycles and that is one of the reasons for undertaking this project.

Hot Spotting [27]

API estimates 5% of the VM budget is spent on hot spotting.

API is cognizant of areas with “cycle busters” and these are put into the plan under off-cycle work. Demand requests are prioritized and put into the program accordingly.

API has sought to limit demand work, off-cycle and hazard tree work as hot spotting being more expensive puts a further strain on an already limiting budget.

Tree Removals [28]

API is transitioning from a capital widening program to maintenance. The only tree removals sought from outside the right of way are for trees that have been designated hazard trees. As the general standard is to remove all tall growing brush from within the right of way, the only trees that exist on the right of way are ornamental or landscape trees which the landowner wishes to retain.

Hazard tree identification is a joint responsibility between the contractor and the Contract Monitor. However, due to budget constraints API has had to limit hazard tree identification and removal work. Consequently, operationally it is the Contract Monitors who identify hazard trees for removal. To work within the constrained budget API has been trying a new approach, limiting the search for hazard trees to the first metre beyond the right of way edge excepting trees from further back that constitute a clear, imminent threat.

For distribution lines there are no hazard tree specific patrols. The only vegetation patrols conducted are condition patrols which are used for work prioritization and planning. Line patrols are required every six years and these may serve to identify imminent tree threats.

On sub-transmission API did undertake a hazard tree project that went full depth in an effort to gain a clearer understanding of the extent of the work involved. API had not yet tabulated results. On sub-transmission a VM working patrol is conducted every three years. These patrols are supplemented by annual line patrols which may pick up imminent tree threats.

A request for the number of trees removed annually over the last five years could not be fulfilled.

Herbicides [29]

API is using herbicides where possible. For distribution lines because the right of way has been heavily populated by tall brush necessitating clearing, herbicide use has been restricted to stump treatments. Thought is now being given to maintaining the cleared areas with foliar and basal herbicide applications.

API has conducted foliar herbicide applications on sub-transmission lines and a little on distribution lines.

Forestry plans and conducts the substation weed control program but this work falls under the station budget.

Alternatives to Pruning [30]

API uses a whole range of alternatives to repetitive pruning. From a construction perspective API has used undergrounding, line moves, tree framing and line height increases. These are done on an individual business case basis.

The forestry group has used some tree height agreements, which they consider of questionable effectiveness. They do have a formal tree replacement process but have not actively pursued tree replacements as with a severely limiting budget it is believed that expenditures on other actions will provide a greater customer service, reliability and financial return.

Reliability [31]

API reported that there have been inconsistencies in data capture and reporting of outages. In general, API is working at educating staff regarding reporting and this effort will intensify as there are changes planned for cause codes and the reporting forms.

Regarding tree-related outages API reported that they were 28-33% of all unplanned outages. Tree-related outages are captured under inadequate clearance or falling trees. The location of the offending tree is not captured. There are a number of weather codes, such as winds greater than 80 km/hr, snow, icing, that may be obfuscating tree-related outages as it is not clear whether tree-related outages occurring as a consequence of one of these weather conditions would be recorded under the weather condition code or the falling trees code. While recognizing these limitations to optimal utility, the available data is used to prioritize the work and interruption reports are regularly circulated within API groups including Forestry.

API believes the capital right of way widening program has served to increase tree-related outages.

Reliability data from 2003 through Oct 15, 2013 was examined. [32] The data shows trees are the primary cause of unplanned interruptions on the API system (*Exhibit 5-21*). Equipment failure emerges as the second most important cause. It will be noticed that we have chosen to compare cause codes on the basis of customer hours interrupted. We prefer this approach as it provides the complete picture, subsequently using System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI) to gain a better understanding of the status of the VM program.

It is typical that when right of way widening has occurred that there follows a period of increased tree-related SAIFI. Decreasing tree-related SAIFI and increasing SAIDI values is actually an indicator of a VM program that is not only headed in the right direction but is starting to show the results. Excellent VM programs have a very low percentage of grow-in outages. Further, while they have good hazard tree identification and removal programs, because no hazard tree program can be 100% successful and the fact that healthy, structurally sound trees fail provided enough stress loading, the majority of tree-related outages arise from tree failures that break electric system hardware driving up restoration times or SAIDI.

When we use customer hours interrupted tree-related outages appear to be even a bigger factor than what was stated by API staff (*Exhibit 5-22*). Over the period of 2003 to 2013, tree-related outages have accounted for 33% to 59% of all unplanned customer interruption hours. However, the influence of trees and the VM program on reliability may be even greater. There are a number of weather related causes such as snow, icing and winds exceeding 80 km/hr, which may be capturing tree-related outages, thereby obfuscating the role of the VM in system reliability.

Exhibit 5-21
2003 – 2013 API Outage History By Cause

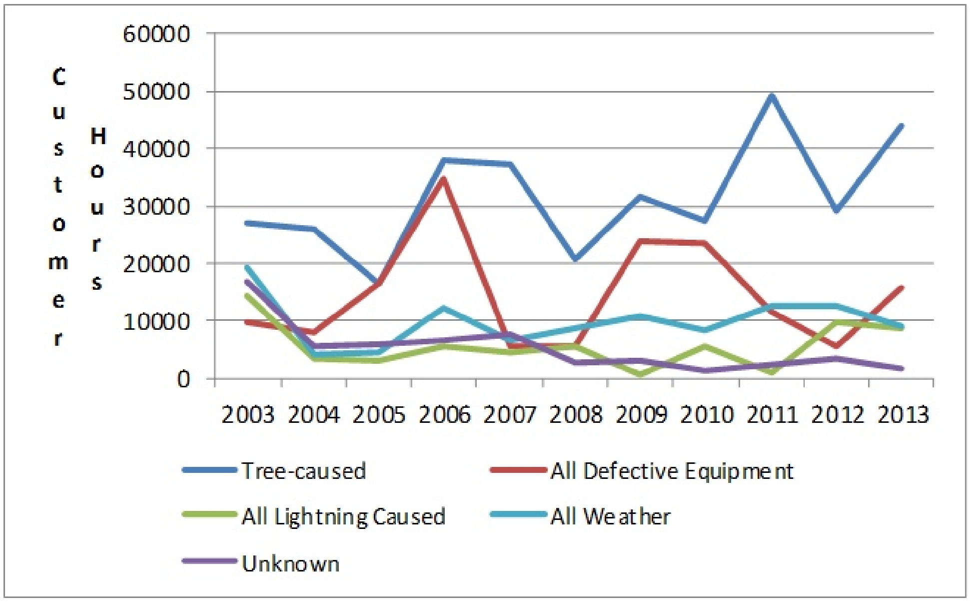
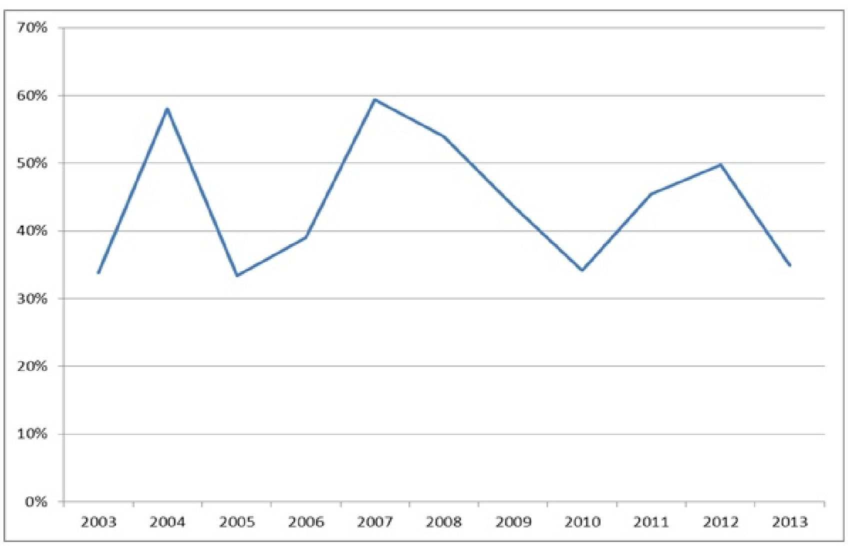


Exhibit 5-22
Percent Tree-related Outages



Both SAIFI (*Exhibit 5-23*) and SAIDI (*Exhibit 5-24*) show a slightly increasing trend.

Exhibit 5-23
API SAIFI 2003 - 2013

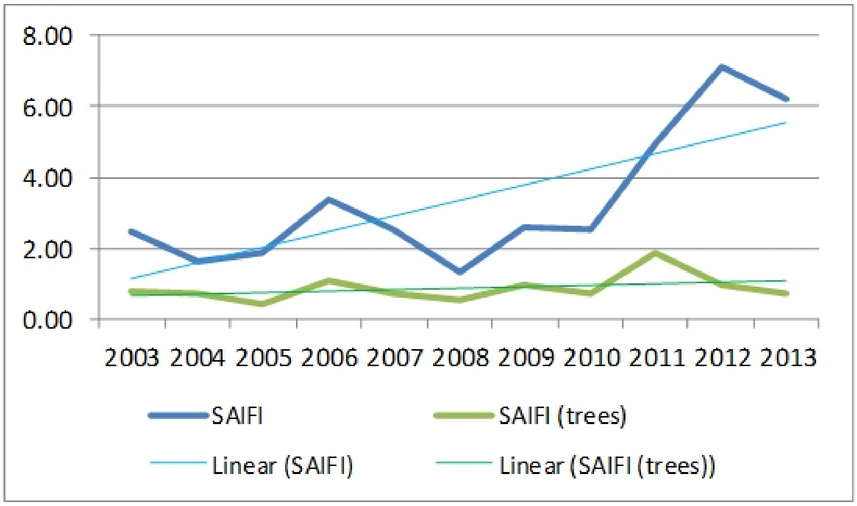
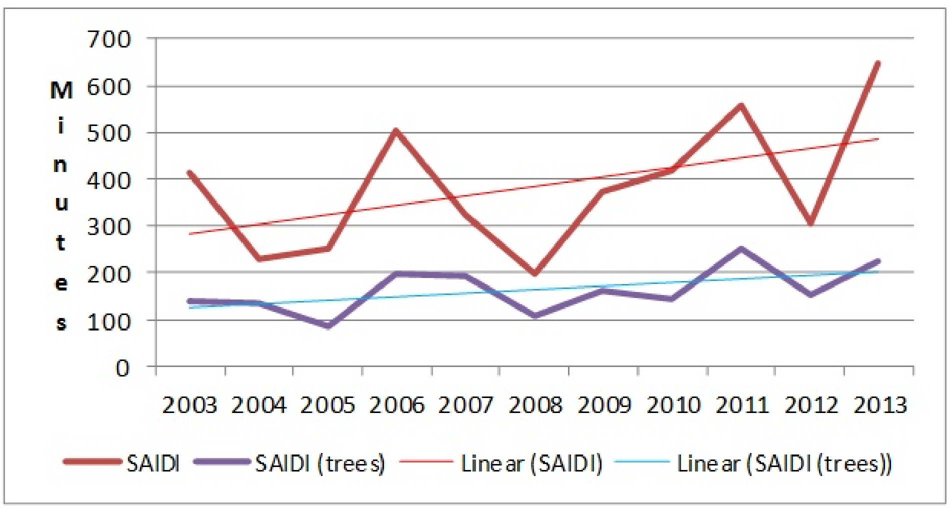
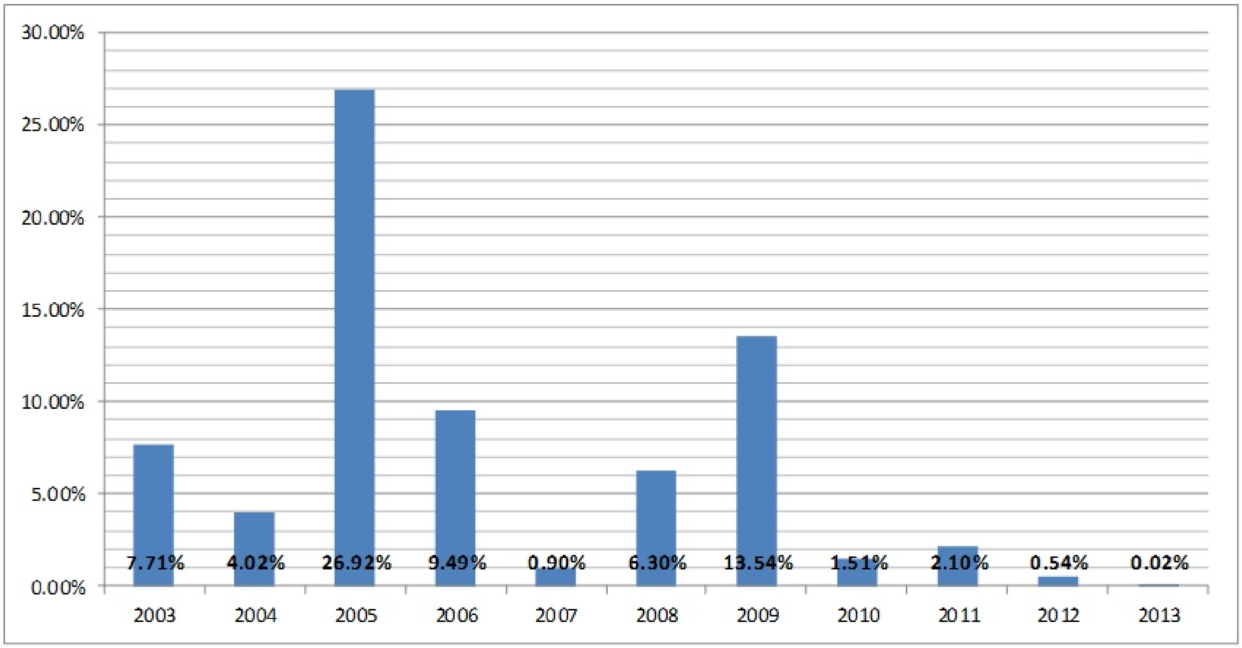


Exhibit 5-24
API SAIDI 2003 - 2013



Tree fault causes are divided into poor clearance and falling trees. We reclassify these causes into Grow-in and Fall-in outages. *Exhibit 5-25* shows the ratio of grow-in outages relative to all tree-caused outages. From 2010 through present the ratio of grow-in outages has been only a few percent of all tree-caused outages.

Exhibit 5-25
Ratio of Grow-in Outages to All Tree-caused



Field Work/Contracting [33]

API performs its VM field work through a mix of contract and in-house crews. There is one in-house crew. It is used in the performance of special jobs, demand work and projects such as the recent hazard tree work.

Contract crews are supplied through two contracting firms.

Work is generally contracted on the basis of $/km with a $/tree size category for the removal of hazard trees. While the work is not actually bid, API does request quotes for some work each year to maintain competition between contractors.

Productivity [34]

Work progress is tracked on spreadsheets. API monitors work completion on a timely basis but does not measure crew productivity. Incentive contracts have not been used.

Quality Assurance [35]

The Contract Monitors are in the field with the crews and consequently audits are performed as the work progresses. The Contract Monitors verify the right of way width, conductor clearances, the right of way floor, stump heights, stumps treated and dispersal of wood chips. The audit results are reported on the ROW Commissioning Report form.[36] The Forestry Supervisor performs this function for the in-house crew. On small projects a full audit is undertaken while large projects are spot checked.

Information & Data Systems [37]

API has a variety of systems for housing records. For the most part these systems are not integrated, that is they do not communicate with each other. There is an Access database for customer information that is used for customer notification purposes. Work tracking or progress is maintained by entries to Excel spreadsheets.[38] VM patrol data is submitted via paper forms.[39] Interruption reports from the field are filed on paper forms.[40] Accounting is housed in a SAPI database.[41]

Decision Support [42]

While no specific process was reported to be in place for the evaluation of alternatives, API did indicate that undergrounding of line segments, line moves, etc. are done following the preparation of a business case.

Field Conditions and Observations

1. **Lakeshore Drive C3K3420C [43] Desbarats Part 2**
    - ROW 15 ft. each side of centre established in 2010 during line upgrade
    - 75 spans
    - L/C & B/C 2008
    - 3 hazard trees
    - 2 white pine overhangs
    - Most brush regrowth about 2 m in height
    - Some spans with 3-4 m aspen regrowth
    - Along houses ROW floor clear; trim clearance 4-8 ft.
2. **McClennan Rd D4M3510D8 [44] Desbarats Part 1**
    - 18 spans
    - 15 ft. ROW each side established 2010 during line upgrade

- Cut and treat B/C & L/C 2008
- Brush regrowth 3 m
- 2 overhangs
- Some trim clearances 1.5 m

3. **Hardwood – Old Port Rd. C4K3430C [45] Desbarats Part 2**
   - 5 spans
   - B/C & L/C 2009
   - 1 overhang
   - Brush regrowth 3 m

4. **10th Side Rd B2L3610D [46] Part 2**
   - 73 spans
   - Various portions:
     - Maintenance 2004, L/C, B/C, 2006 B/C
     - Line Upgrade 2011 L/C
   - Pruning clearance 1.5-3 m
   - Brush regrowth 2-3 m
   - 1 hazard tree

5. **10th Side Rd B2L3610C [47] St. Joes Part 1**
   - 82 spans
   - Trimmed 2001-2002
   - Trim clearance 0.3 m
   - Brush cut & treat (B/C) 2006
   - ROW 4- 15 ft. with most ~ 8 ft.
   - A lot of trimming required where ROW clearance is 10 ft. or less
   - 15 hot spots
   - 8 spans with overhanging maple
   - Most of the overhead clearance > 10 ft.

6. **P-Line B1M3611C [48] St. Joes Part 1**
   - 63 spans
   - Reclaimed/expansion 2002-2003

- B/C 2006
- 5 hot spots
- ROW brush regrowth variable 1-4.5 m with most ~ 1.3 m

7. **Hwy 548 A2M3612C [49] St. Joe's Part 1**
   - 21 spans
   - Reclaimed/expansion 2003-2004
   - Last cleared 2006 B/C
   - ROW clearance 6-10 ft.
   - Brush regrowth 4-6 m
   - 4 hot spots
   - 8 spans of overhangs
8. **Hwy 548 \U-Line A1M3613C7 [50] St. Joes Part 1**
   - 49 spans
   - Reclaimed/expansion 2003-2004
   - B/C 2006
   - ROW Clear width 4-10 ft. with most at 8 ft.
   - Brush regrowth 1-3 m
   - 3 hot spots
   - 9 spans of overhang
9. **Hwy 548 \ U-Line A2N3634 [51] St. Joes Part 4**
   - 78 spans
   - New construction on primary 2007
   - 10 spans with a 22 ft. clear width
   - Remainder of ROW with 8 ft. clear width
   - Reclaimed/expansion 2000-2003
   - B/C 2006
   - Brush regrowth 2-4 m
   - This line scheduled for maintenance this year
   - 18 hot spots
   - 14 spans of overhang

- 3 hazard trees

10. Hwy 548 B1N3633 [52] St. Joes Part 4

- 58 spans
- Reclaimed/expansion 2002-2003
- B/C 2006
- ROW Clear width 3-8 ft.
- Brush 1-3 m
- 8 hot spots
- 3 spans overhang

11. Hwy 548 B3M3622 [53] St. Joe's Part 4

- 62 spans
- Reclaimed/expansion 2002-2003
- B/C 2006
- B/C & L/C 2013
- 1 overhang
- No brush
- ROW clear width 15-20 ft.

12. Trap Rock – Caribou Rd [54]

- 34.5 kV
- Used mulching and followed up with foliar herbicide
- ROW clear width > 20 ft.
- ROW currently populated with compatible species

13. Centreline Rd C1N3831 [55] Bruce Mines Part 2

- New line section 2013
- 195 spans
- B/C 2011
- ROW clear width 4-10 ft.
- Very little brush; mostly compatible
- 7 spans overhang
- 15 hot spots to prune

14. Hwy 101 [56]

- 296 spans
- Done with mulcher 2013
- Only brush is in stream buffers and steep slopes

15. **Jack Pine Tower Rd. LSU419710B1 HWY 101 Part 1**

- Narrow with spindly tree boles on edge
- L/C 2013
- Brush 1-3 m
- 1 hazard tree

16. Costello's Line .95 km T2G9710 [57] **HWY 101 Part 1**

- ROW clear width 18 ft.
- Mulched 2013

17. Whitefish Lake Rd U1G9711D [58] **HWY 101 Part 1**

- Cleared in 2012 L/C & B/C
- Brush regrowth 1-1.5 m but very little

18. Wawa 1 & 2 [59]

- Done in 2007 and 2012
- No brush
- Clear width 32.5 ft.; 35 from centre
- 1 hot spot

19. Wawa 3-phase Steep Hill Line [60]

- Cleared in 2008
- Clear width 10-20 ft.
- Brush 1-3 m
- Switches to underbuilt and back

6. Audit Findings & Conclusions

Finding 6-1 The API organization supports a responsive VM program.

To an extent API benefits from the small size of the organization. All in the Forestry department are very well informed on all aspects of the VM program. There is an evident commitment to continuous improvement and an enthusiastic openness to ideas, methods, technology, etc. that will facilitate improving service.

In large utilities there is often a disconnect between various departments that results in situations where departments in accruing benefits and efficiencies to their own group unwittingly create liabilities for other groups and the company as a whole. It is all too common that capital projects create future maintenance liabilities. This does not occur at API. There is excellent communication between various groups and processes have been put in place to ensure sustaining such communication.

Finding 6-2 The annual VM budget has not been based on biological fact.

Past studies have indicated that the API distribution VM program needed considerable work to improve service reliability.[61] While appropriate maintenance cycles were recommended, these recommendations appeared to be based on researcher experience, without the support of actual growth studies. To date API has not succeeded in establishing those maintenance cycles or cycles based on the biological facts of tree growth and mortality rates. While the current right of way conditions reveal considerable progress towards a sustainable program has been made, it cannot be fully realized unless funding is founded on the current inventory of work, tree growth and mortality rates.

While not impossible it is implausible that a problem that has not or cannot be measured will be successfully managed. In our over 35 years in the utility VM business we know of no utility that is successfully managing its vegetation that has not quantified the workload. There are various means of quantifying VM workload but the quickest is to establish an inventory of work supplemented by tree growth and mortality rates. As illustrated in section 3, Vegetation Management Concepts and Principles, there is a specific amount of annual funding required to achieve a sustainable VM program.

Finding 6-3 API does not have established maintenance cycles.

API is seeking to establish a 6 to 8 year cycle. Yet areas were seen that had not been maintenance pruned in over 10 years. It's not known if the targeted cycle, which represents a slippage from past recommendations is due to a lack of confidence in the recommendation or a concession to the fact that an 8 year cycle may be the very best or most optimistic cycle that's possible under the current funding allocation.

Finding 6-4 Branches overhanging distribution conductors are common.

Branches overhanging conductors have a large impact on reliability. Some of the overhangs are sugar maples that have commercial value and consequently, landowners will naturally seek to limit the amount of pruning. Some of the overhangs are from specimen trees such as white pines in landscaped settings. However, the majority of overhangs are from volunteer native, natural tree stands of little commercial value. Given restricted funding, addressing these overhangs may have been viewed as a lower priority than other work and unaffordable.

API does not have an outage code specific to branch failures. As a consequence, the impact on customer service of allowing the overhangs to exist is not known.

Finding 6-5 The VM work delivered in the field is consistent with the expressed standards and specifications.

The field tour revealed that current work is meeting the clearance standards and specifications. While sections of right of way were seen that do not have the desired 4.5 m clear width from centre-line, the edges were well established. Such sites either were not targeted in the capital widening or perhaps there were landowner objections that were not overcome.

In most cases where brush has been removed, cut stumps have been treated with herbicide. This was evident from the sporadic occurrence of spans with brush regrowth of substantially greater stem densities and height than the norm for the line section. Such areas being sporadic and limited suggest a landowner refusal to herbicide application.

Pruning work is consistent with good arboricultural practice. Such practice serves both to maintain the health of the trees and also to maximize the length of the maintenance cycle.

Finding 6-6 API VM program is well organized but the potential for greater cost effectiveness exists.

The work being done is consistent with industry best practices. However, the use of herbicides has been largely restricted to stump treatments as the right of ways required reclamation or clearing. Foliar herbicide applications have been restricted predominantly to sub-transmission lines. Foliar herbicide applications are not only more effective then stump treatments but also are less costly.

Most of the brush is hand cut. While the frequent occurrence of rock outcroppings limits areas that could be mowed by Hydro Ax, there are many kilometres, particularly south of the Montreal River, that are suitable.

On the areas re-growing after reclamation API has introduced some of the more cost effective practices such as foliar herbicide applications and mowing/mulching but the opportunity exists for a wide scale adoption of these practices.

Finding 6-7 API has been doing a good job of managing hot spots.

The field tour sought to obtain an understanding of right of way conditions where work had been recently completed, in areas that had not had work done for a number of years and may be considered mid-cycle, areas that were currently being worked and areas that were scheduled for work next year.

First, API's conceptual organization of the work into on-cycle, off-cycle and demand work is a useful construct. It forces recognition of what is being managed, what is behind and where there are "cycle busters" that warrant consideration for other approaches.

While the field tour revealed a considerable number of hot spots (locations where trees can be expected to make contact with conductors during the next growing season), they were predominantly in areas scheduled for work either currently or within the next year. Such a finding is expected and is indicative of effective management as in concentrating the work to scheduled areas the cost inefficiencies associated with hot spotting can be avoided.[62]

Finding 6-8 VM work on secondaries has added to the funding needs.

As reliability issues have emerged on secondaries, API has changed their standards to include work on secondaries as a part of routine maintenance. Due to a fixed budget funding this work requires sacrificing or delaying work on primary circuits.

Finding 6-9 API's approach to contracting VM work is judicious.

Given the scale of API's VM program the approach to contracting is good. Formal bidding of work would add administrative costs for little or no benefit. The time that would be spent in preparing and evaluating bids is better spent in communicating needs to the two contractors and maintaining the good working relationship.

In asking for quotes for a number of projects each year API is adequately reminding the contractors that it is a competitive environment while at the same time affording themselves the opportunity to compare current costs to historical costs.

Finding 6-10 Information and data systems require improvement.

API requires a data system designed around VM processes capable of linking with and communicating with other company databases. Providing data in response to the information requests was at times laborious. In one case the data could not be provided. This has implications for internal processes as questions may not be considered or answered due either to inability to provide meaningful data or due to the time and expense involved in obtaining data.

Further, were the field information collected more detailed it would provide insights useful in forecasting workload and costs.

7. Review of Outage Data

Finding 7-11 Tree-related outages are the primary cause of customer interruptions.

Trees are the number one cause of unplanned service interruptions followed by equipment failures (*Exhibit 5-21*). This is actually typical of distribution systems in general.

While it would be expected that unplanned outages as a whole are correlated to tree-related outages, in API's case the Pearson Product Moment Correlation Coefficient (r) is 0.69 with the probability of error 0.0031, a highly significant result. The high r-value highlights the fact that trees are the primary driver of the outage statistics.

Finding 7-12 API's tree-related outage experience is higher than industry norms.

Over the period of 2003 to 2013, tree-related outages have accounted for 33% to 59% of all unplanned customer interruption hours. The average is over 40% whereas industry averages are in the 20-25% range measured in customer outage hours.[63] [64] Due to location and the resultant amount of tree exposure of API's electric system, reliability statistics will always likely be on the higher end of industry norms. As tree exposure has been shown to be not only the primary driver in tree-caused outage incidents[65] [66] but also perhaps the only statistically significant indicator, there is limit to the amount of reliability improvement possible.

Finding 7-13 API's capital widening of distribution right of way has not yet improved reliability.

The outage data shows the impact of trees on reliability (*Exhibit 5-21*) and consequently, the importance of the VM program. That SAIFI and SAIDI show a slightly increasing trend (*Exhibit 5-23*, *Exhibit 5-24*) should not be a surprise following the recent capital widening of rights of way which has occurred. This widening served to expose trees which had grown inside tree stands to greater wind loading. Such trees have not deposited the tension and compression wood that results from frequent load exposure. Over the first few years of increased wind loading a considerable number of these trees fail. However, after three years the ratio of failures begins to decrease. While we have no quantitative study to reference showing when the newly established edge becomes as firm as the former edge, previous experience suggests this will occur five to eight years after widening.

Ultimately, the benefit of the capital widening will become apparent. It decreased the both the number of danger trees and the arc of line exposure for the remaining trees. Consequently, the capital widening was prudent.

It should be noted that the reliability data contains the effects of major storms. Major storms can obfuscate what changes are occurring in reliability during normal operating conditions. Additionally, we examined outage data for the system as a whole. As such, any demonstrable reliability improvement for specific capital widened line segments will not have been noted.

In examining the field conditions it was found that clear widths of line segments that have not undergone capital widening were generally 8 feet from centre line. Applying the average variables found for line height, tree height and tree density to the proprietary Optimal Clear Width Calculator (OCWC), it can be demonstrated that the widening that has occurred will ultimately pay reliability dividends. The Line Strike Risk chart (*Exhibit 7-26*) shows a substantial reduction in risk between an 8 foot clear width and a 15 foot clear width. That change in tree risk is further clarified in *Exhibit 7-27,* which shows an expected reduction in tree-caused interruption of 32%. It is also clear from the Line Strike Risk chart, *Exhibit 7-26*, that there is a diminishing return in line security with increasing clear width and that a clear width of 15 feet (4.5 m) is the starting point of that diminishing return.

Exhibit 7-26
Line Strike Risk

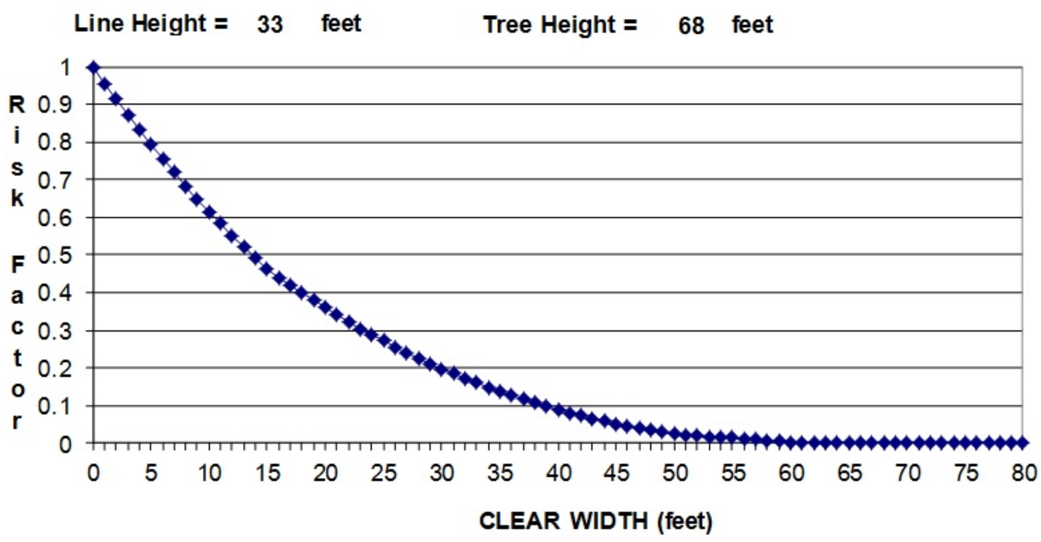


Exhibit 7-27
Expected Reliability Benefit of Widening

Cost: Benefit Analysis

Line Segment Specific:		Ac/mi	Trees/mi	Cost/mi	Line Security Improvement
Line Height	33				
Tree Height	68				
Trees/Ac	416				
Current Clear Width	8.00				
Current Risk Factor	0.683				
Increase Width	7	0.85	353		
New Risk Factor	0.465				32%

Finding 7-14 API's current outage cause codes fail to deliver insight into what VM actions will deliver significant reliability improvements.

API currently has two tree cause codes and they could be said to capture grow-in outages and fall-in outages. There is no distinction being made regarding the type of tree failure, nor is there detail on the location of the offending tree.

Finding 7-15 The level of tree grow-in outages is indicative of a well-managed VM program.

For reasons of reliability and public safety, electric utilities have a clear responsibility to maintain a separation between trees and energized conductors. Because of this responsibility and the attendant liability, the primary focus of VM programs is on work within the right of way. All well managed VM programs have a very low incidence of grow-in outages. VM programs with grow-in outages comprising less than 2% of tree-related outages are common for properly funded and well guided VM programs.[67] [68] [69]

Based on our observations and experience, we consider programs where grow-in outages represent 5-15% of all tree-related outages as falling off best in class and completely lost and in need of very substantial remedial re-investment when grow-in outages exceed 15%.

Thus, the history of grow-in outages, *Exhibit 5-25,* informs us that API's VM program has been shifted from one in serious trouble to one that is currently on the cusp of either becoming a best in class program or reverting to being very far behind. Since 2010, grow-in outages have been below 2%, which is consistent with best in class programs. No doubt a considerable amount of this grow-in outage experience reduction is attributable to the reclamation work which has eliminated the risk of vertical grow-ins from within the right of way in all but landscaped settings. The question for the future is whether the investment in reclamation will be protected or lost.

Finding 7-16 API's tree-related outages are due to the failure of trees from outside the right of way.

As API's standard is to clear all trees, except specimen or landscape trees, out to the right of way edge the possibility of tree from inside the maintained right of way failing and causing an interruption is extremely limited. That suggests that since 2010 over 98% of tree-related outages are due to the failure of trees located beyond the maintained right of way (*Exhibit 5-25*).

8. The Utility Forest

Work was undertaken to quantify the utility forest. The utility forest is comprised of all trees that could now or in the future interfere with the reliable delivery of electricity. The utility forest is not static but tends to increase over time as trees adjacent to power lines continue to increase in height thereby adding to the number of trees capable of interfering with electric service. As such, the utility forest comprises both trees and brush within the right of way and trees outside the right of way capable of contacting power lines on failure.

Utility VM is focussed first and foremost on the right of way. However, it is well established that for most utility VM programs the majority of tree-related outages arise from outside the right of way.[70] [71] Typically, tree failures from outside the right of way account for 85-98% of tree-related outages. Consequently, failing to include the utility forest outside the right of way in determining the VM workload would constitute a major oversight.

Finding 8-17 About 85% of API power lines have a treed edge.

The approach to quantifying the utility forest was a combination of digital and field data collection. API provided an overlay of their lines on Google Earth. A random sample of 150 points were marked in Google Earth and GPS coordinates were documented (*Exhibit 8-28*, *Exhibit 8-29*). Each of these 150 points was assessed for the amount of treed on both sides of the right of way. The amount of treed edge is 84.72% ± 2.74% (95% confidence level). The voltage class was determined for every sample point. The data in Google Earth is both somewhat aged and the time the data was collected can be variable. To determine if current conditions varied significantly from those in Google Earth a subset consisting of 36 of sample points was field verified for treed edge. A Student T test pairing the digital assessments derived from Google Earth with the field assessments found no significant difference between the two.

For each of the 150 random sample points a field inspection determined the quantity of work categorized as brush, crown prune, lateral prune, hazard trees and the spans having branch overhangs. At 10% of these sample points growth data was collected providing 461 brush growth records and 307 pruning regrowth records. At 73 of the sample locations data was collected from the adjacent forest to determine tree species, tree height and tree density. This resulted in 6,205 tree records. These records provide a clear picture of the species composition of the utility forest and the health of the outside right of way forest. Based on the sampling, 23% of API VM work is off-road or cross-country.

Exhibit 8-28
North Sample Points

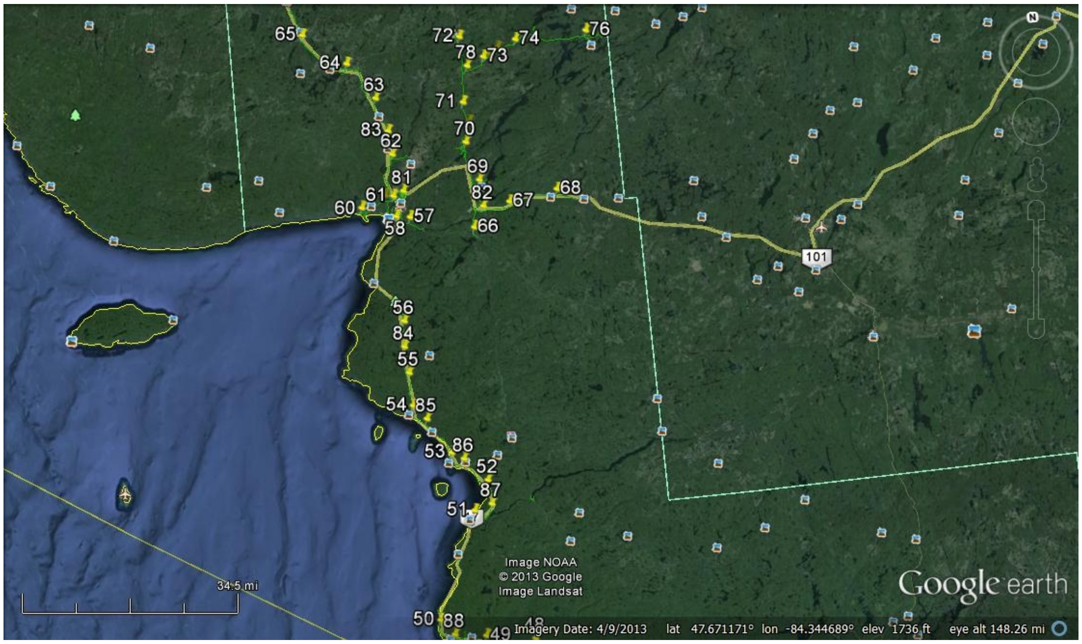
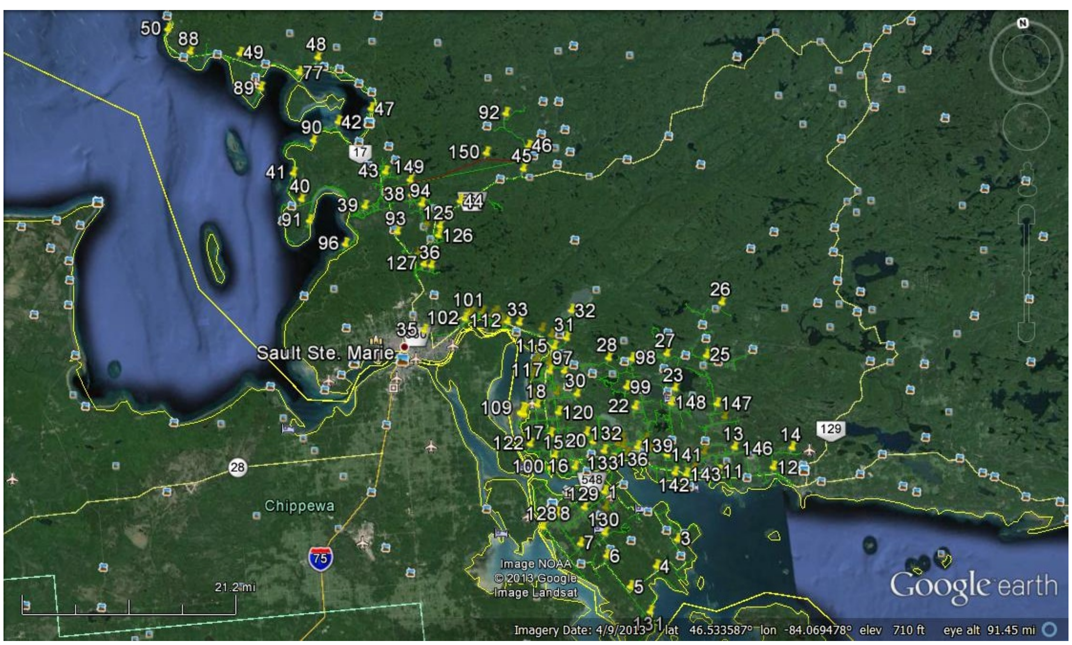


Exhibit 8-29
South Sample Points



Within Right of Way

It can be expected that brush will develop where there are adjacent trees supplying seed or through vegetative reproduction (root suckers). This will provide an upper limit to the brush work of 2031 ha or 5037 acres (*Exhibit 8-30*).

Exhibit 8-30
Maximum Area For Brush Control

Voltage (kV)	Kms	Actual edges sampled	Wire Zone (ft)	Edge type	Mean Clear Width (ft)	ROW Width (ft)	Miles	Acres	% Treed Edge	Potential Treed ROW Acres
44	85.9	10	7	ROW	54	115	53	744	95.55%	711
25/34.5	174.0	20	7	ROW	34	75	108	983	89.69%	882
25/34.5			7	Roadside	47		108		89.69%	
7.2/14.4	1425.7	116	1	ROW	18	37	886	3,973	83.21%	3,306
7.2/14.4			1	Roadside	89		886		83.21%	
Total	**1686**	**146**					**1155**	**5700**	**85.76%**	**4898**

[1] Weighted average
Wire Zone – the distance between the outside conductors

Generally, utilities strive to convert right of way plant species to power line compatible species that will resist the establishment of incompatible species. This process is greatly aided by the use of herbicides. Without herbicides seeding of compatible species can be used, however, the duration of the compatible species is limited as nature strives to re-establish species endemic to the area. The extent of brush control necessary will vary from the upper limit based on the extent and success of herbicide programs or the length of time since seeding. Based on the field inventory conducted rather than 85.76% (*Exhibit 8-30*) of the right of way area containing brush, we estimated 65% of the area currently requires active management.

Finding 8-18 65% of API's right of way currently requires active VM.

Sampling of 1 km sections at the 150 random sites found the inventory of work set out in *Exhibit 8-31*. While the amount of treed edge indicated 85% of the right of way is subject to being populated by incompatible species the field sampling reveals a lesser amount of 65% of the right of way currently requires active ongoing management. The difference is likely due to the benefits of herbicide applications which by eliminating incompatible species allow compatible species to flourish. This vegetative cover then resists, to some degree, the invasion of incompatibles. It is not say that the condition is permanent. At some point this 20% of the right of way area will require mediation. If it can be done with herbicides minimal inputs will sustain the early succession meadow community. However, if it is necessary to use cutting methods, these will rather than eliminating the incompatible species, expand their composition of the plant community. It need be recognized that there exists a risk of adding back the 20% of the brush workload either through choosing cutting methods or excessively long maintenance cycles that preclude the use of herbicides and therefore, limit the choice solely to cutting methods.

As we will be discussing work volumes in another section, we wish, at this point only, to highlight certain generalities that come to light in this inventory. First, the number of hot spots averages 4 per kilometre. This is a very high ratio. While ESI's own brief field tour revealed that hot spots tended to be concentrated in areas scheduled for work, the high average frequency suggests a program while well managed, is also close to the breaking point. Secondly, the data collected on overhangs suggest about 14% of the system has overhangs. The hazard trees noted in *Exhibit 8-31* capture only trees that are apparent from within the right of way or more commonly from the adjacent roadway. These hazard trees comprise 2% of the tree exposure along the edge (first 2.5 m).

Exhibit 8-31
Inventory Based on Sampling

Voltage (kV)	ROW Width (m)	Brush (m^2)	Brush Height (m)	Crown Trim (m^2)	Lateral Trim (m^2)	Hot Spots	Spans Overhang	Hazard Trees
44	29.5	209,008	1.18	14	0	1	0	17
25/34.5	21.94	187,324	1.57	457	456	5	2	37
7.2/14.4	11.52	724,504	1.65	14,042	13,872	594	226	644
Summary	**13.83**	**1,120,836**	**1.61**	**14,513**	**14,328**	**600**	**228**	**698**

Finding 8-19 Over 14% of API spans have branch overhangs.

The spans of overhang were documented during the inventory data collection. It was found that 14.3% of the spans have branch overhangs.

Outside Right of Way

To determine the outside right of way tree exposure data was collected at 73 of the 150 sample points. At each of these sites the following data was recorded:

- Line height

- Clear width on each side (distance from adjacent tree boles to nearest conductor)
- Wire zone
- Tree height on each side for the dominant (emergent) and co-dominant canopy
- 3 replicates each side of Basal Area Factor 10 samples recording tree circumference at breast height, tree species and decadence

Based on this data of over 6200 tree records, it was determined that API's tree density is 416 ± 19 trees per acre (1032 ± 47 trees/ha) at the 95% confidence level. Using tree height, line height and clear width and applying the Pythagorean Theorem the depth of the utility forest beyond the right of way edge was calculated. With the area determined and having calculated the mean tree density, the extent of the outside right of way tree exposure can be computed (*Exhibit 8-32*).

Exhibit 8-32
Tree Exposure

Voltage (kV)	Kms	Wire Zone (ft)	Mean Clear Width (ft)	Miles	% Treed Edge	Mean Tree Height (ft)	Mean Line Height (ft)	Trees Per Acre	To Tree Free @ (ft)	Danger Trees
44	85.9	7	54	53	95.55%	63	33	416	54	0
25/34.5	174.0	7	34	108	89.69%	62	41		47	63,566
25/34.5		7	47[1]	108	89.69%				47	0
7.2/14.4	1425.7	1	18	886	83.21%	68	33		59	761,977
7.2/14.4		1	89[1]	886	83.21%				59	0
Total	**1686**			**1155**	**85.76%**					**825,543**

[1] Roadside – distance from line, across road, to trees on edge

Finding 8-20 API's system is exposed to 825,543 trees which could interrupt service.

Danger trees are trees which on failure could contact conductors. The relevance of the number of danger trees is two-fold. First, it has been shown that tree exposure is very strongly correlated to tree-related outages.[72] [73] This is of utmost importance during storms that place stress loading on trees. Secondly, due to natural tree mortality, a certain percentage of the tree exposure will suffer decadence and ultimately death. There are two annual mortality rates applicable for API's service territory. For the boreal forest the rate is 3% per annum and for the Great Lakes St. Lawrence ecozone the rate is approximately 1%. We have used an average of 2% annual mortality. On that basis, it should be expected that each year 16,511 trees will become decadent and require evaluation for their potential to interfere with lines should they fail. Factors such as the arc of line exposed, the likelihood of a failed tree being blocked by other trees, whether the decadent tree is emergent to the co-dominant canopy, typical mode of failure, lean, etc. will serve in making a determination whether a tree is a hazard tree requiring mitigation or not.

While much of API's system has a forested edge, the actual exposure to danger trees of 490 trees per km is not a high ratio for a distribution system.[74] As even healthy trees fail and cause interruptions provided the stress loading from wind, ice or snow, this has a positive implication for reliability. The number of tree-caused outages arising from healthy, structurally sound trees has been shown to fall in the 45 to 70% range.[75] These are trees that are not targeted by the VM program. Consequently, the lower the system's exposure to trees, the better the reliability prospects.[76]

From the forest samples the composition of the utility forest is derived (*Exhibit 8-33*). One of the variables captured in assessing the forest plots was whether the tree was healthy or decadent. The average level of decadence inside the forest stand is 11.2% (*Exhibit 8-35*). Further species details are provided in *Exhibit 8-34*.

Finding 8-21 API's system is threatened by a high ratio of hazard trees.

The fact that the ratio of hazard trees is 2% along the edge but over 11% inside the forest edge shows API has been doing a good job of identifying and removing hazard trees from the forest edge. However, trees more than 2.5 m from the edge have not received adequate attention. While it is possible to accept a larger percentage of decadent trees inside the forest because of the reduced arc of line exposure and the consequent probability that a failure will not result in a line contact the found ratio of over 11% is about two times greater than the upper limit of expectations. Typical maintenance cycles would see the percentage of decadent trees top out at 5-6% just before retreatment. The observed level of decadent trees are sure to be contributing substantially to API's outage experience.

Working with the species composition and the found incidence of decadence it is possible to determine which tree species represent the highest levels of risk to the system. The data is presented in *Exhibit 8-35*. White birch is known to have a process of degeneration through branch failures. Both balsam fir and trembling aspen are susceptible to trunk failures. The top three at risk species are prevalent in the boreal ecozone.

Exhibit 8-33
Utility Forest Species Composition Trees Species (%)

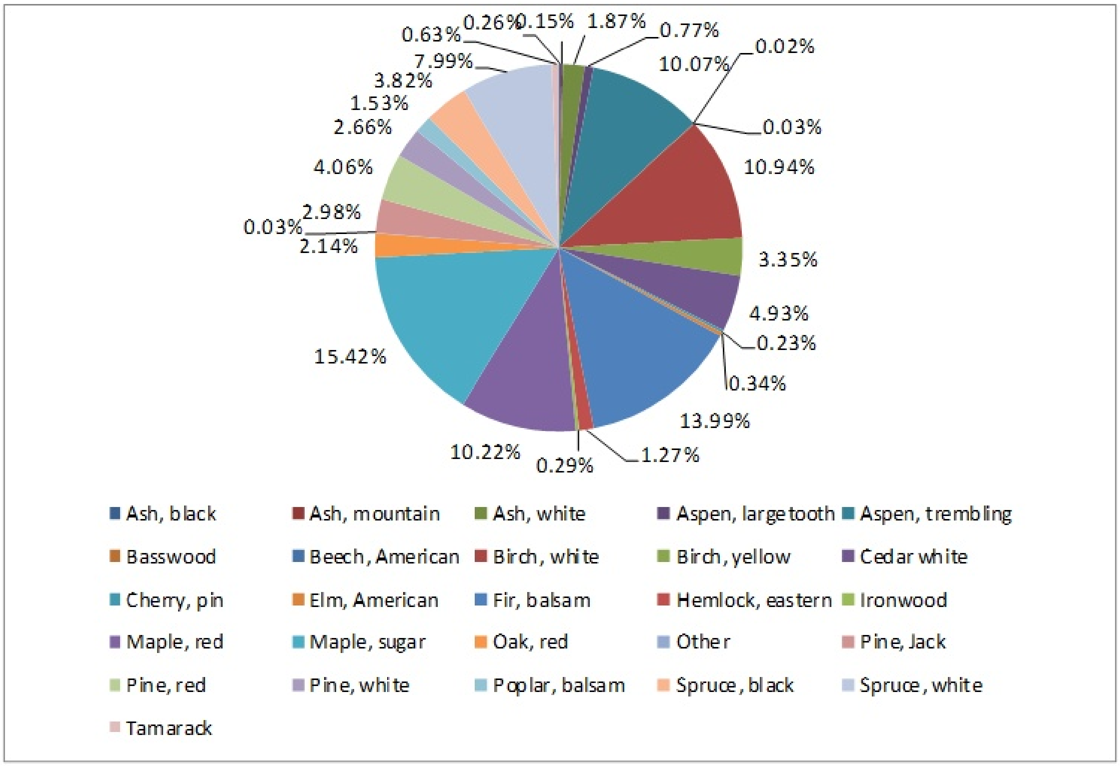


Exhibit 8-34
Utility Forest Health

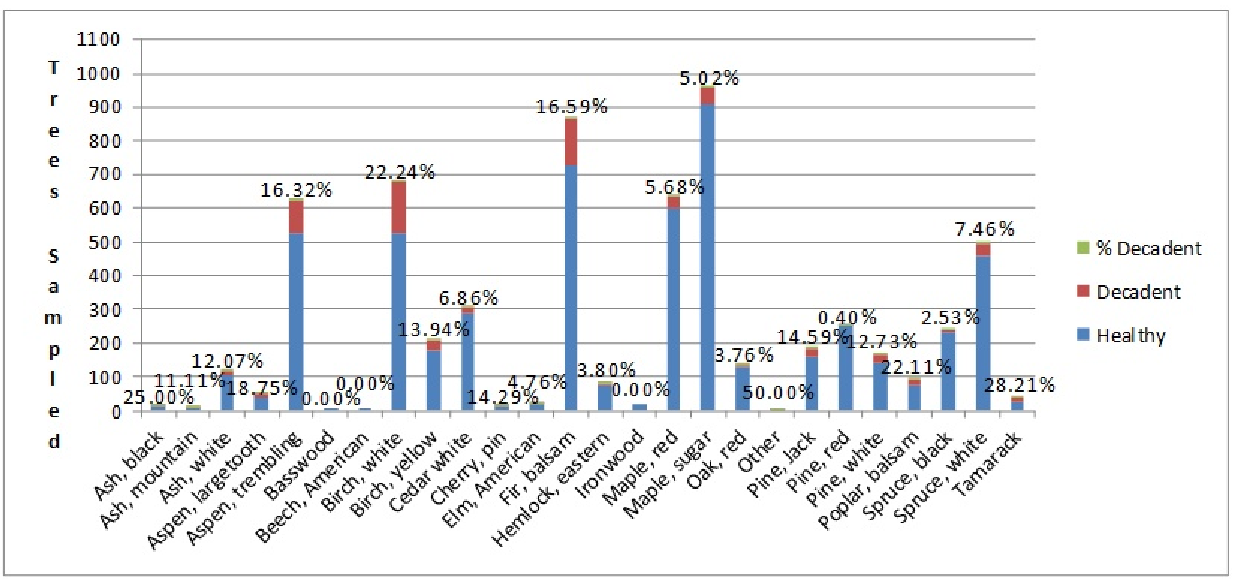


Exhibit 8-35
Tree Species Risk Rating

Species	Records	% of Population	% Decadent	Risk per 1000 trees
Birch, white	679	10.94%	22.24%	24.3352
Fir, balsam	868	13.99%	16.59%	23.2071
Aspen, trembling	625	10.07%	16.32%	16.4384
Maple, sugar	957	15.42%	5.02%	7.7357
Spruce, white	496	7.99%	7.46%	5.9629
Maple, red	634	10.22%	5.68%	5.8018
Birch, yellow	208	3.35%	13.94%	4.6737
Pine, Jack	185	2.98%	14.59%	4.3513
Poplar, balsam	95	1.53%	22.11%	3.3844
Cedar white	306	4.93%	6.86%	3.3844
Pine, white	165	2.66%	12.73%	3.3844
Ash, white	116	1.87%	12.07%	2.2562
Tamarack	39	0.63%	28.21%	1.7728
Aspen, largetooth	48	0.77%	18.75%	1.4504
Spruce, black	237	3.82%	2.53%	0.9670
Oak, red	133	2.14%	3.76%	0.8058
Ash, black	16			
Hemlock, eastern	79	1.27%	3.80%	0.4835
Cherry, pin	14			
Other	2			
Ash, mountain	9			
Elm, American	21			
Pine, red	252	4.06%	0.40%	0.1612
Basswood	2			
Beech, American	1			
Ironwood	18			
Totals	**6205**		**11.20%**	**4.3079**

Growth Rates and Maintenance Cycles

Growth rates were determined by measuring internode lengths of the five most recent years of growth. Growth rates were determined for brush regrowth for deciduous and conifer species and for pruning work divided into deciduous, conifer, crown growth and lateral growth. The growth rates are used to guide the selection of the maintenance cycle. Doing so, however, is a complex issue. If average growth rates are used, then by definition one half of the locations would have trees already exceeding the limit of approach. On the other hand if the highest found growth rate is used then much of the work would be performed before it is necessary.

Exhibit 8-36
Average Annual Brush Regrowth Rates

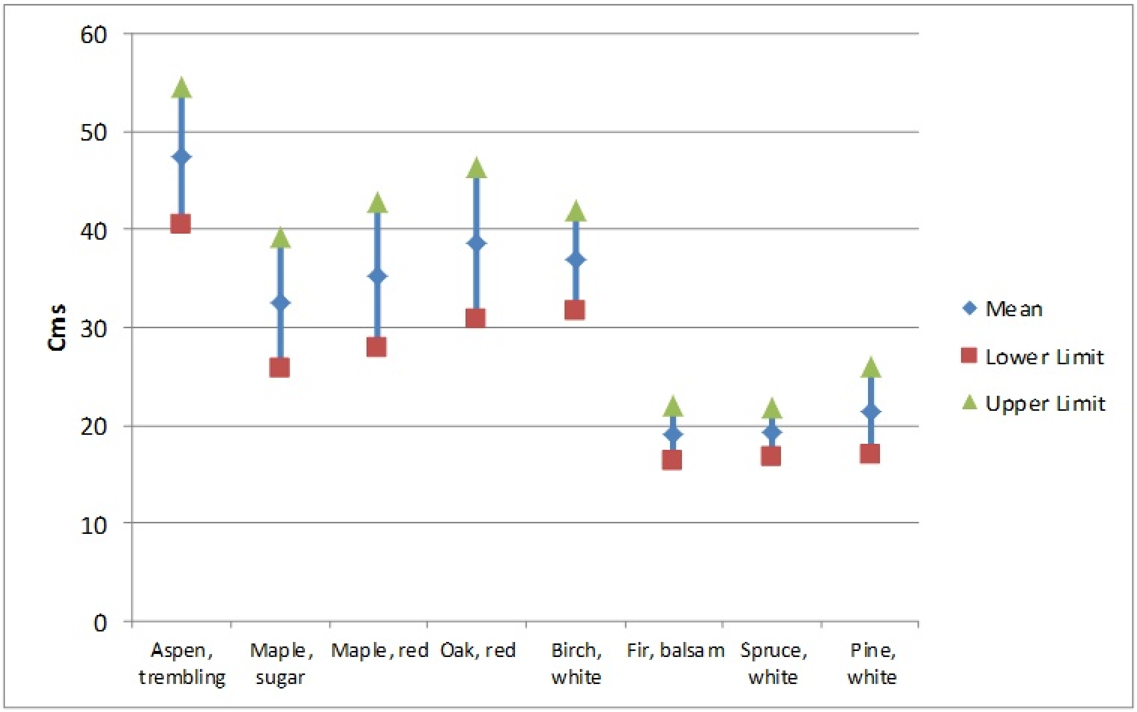


Exhibit 8-36 shows the regrowth rates for the major tree species along with the confidence interval at the 95% level.

Exhibit 8-37 provides the average brush growth rates across all species encountered. *Exhibit 8-38* shows the maximum brush growth rates on a cumulative basis. If the maximum growth rates are sustained over 6 years some of the brush will exceed the minimum encountered line height of 7.8 m. As the tree species exhibiting the higher growth rates are also the same species that are most prevalent, white birch, trembling aspen, sugar maple and red maple, a maintenance cycle that is skewed towards the maximum growth rate is necessary to avoid direct contact between trees and conductors. The field data collected does not support the assumption that maximum growth rates will be sustained over multiple years.

Exhibit 8-37
Average Brush Regrowth Rates

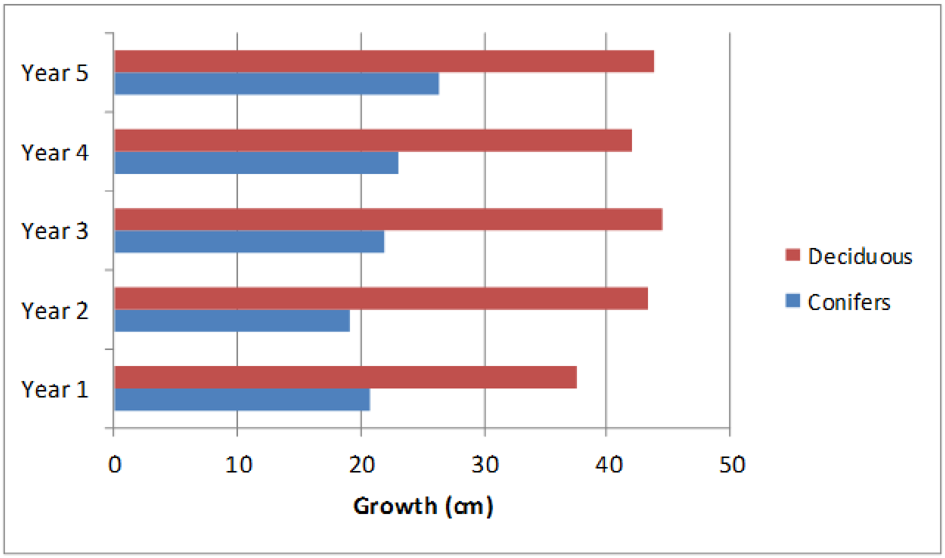
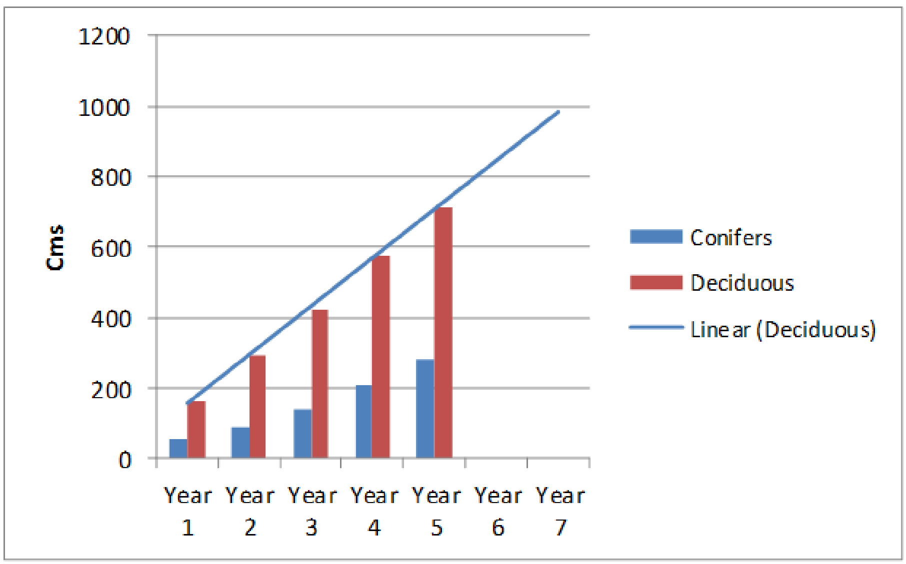


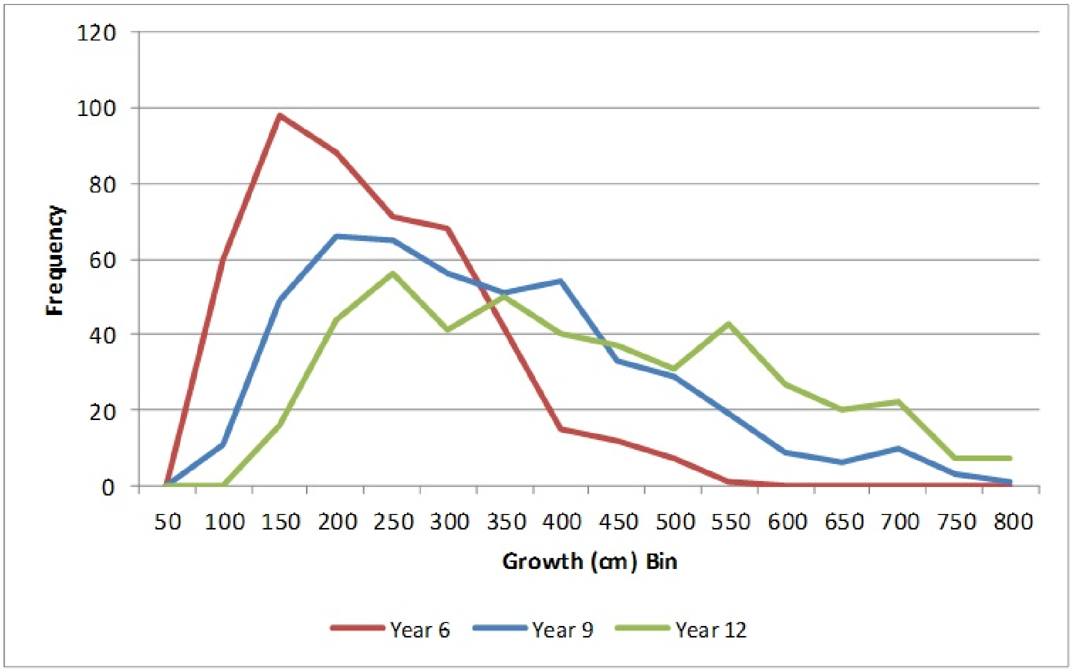
Exhibit 8-38
Maximum Cumulative Brush Growth



By dividing observed growth rates into 50 cm bins a frequency distribution can be developed (*Exhibit 8-39*). The average growth over the first 5 years was used to estimate growth beyond 5 years.

Examining *Exhibit 8-39* it is found that at 9 years there are a small number of trees intruding upon conductors, whereas a 12 year cycle does not meet public safety and reliability objectives. A 9-year maintenance cycle for brush may be considered a just in time cycle.

Exhibit 8-39
Brush Growth Based on Observed Growth 2009-2013



Accordingly, a 9-year maintenance cycle is recommended for right of way brush cutting. The appropriateness of this cycle cannot be confirmed or denied without funding support for a 9-year cycle.

The observed growth being applied to determine the maintenance cycle assumes that the growth observed for 2009-2013 is typical. If it is found that on a 9-year cycle too much of the brush is encroaching on primary conductors, from a public safety and fire prevention perspective this maintenance cycle would then need to be rejected and shortened.

Pruning regrowth is examined similarly. *Exhibit 8-40* shows the average regrowth for trees requiring pruning. *Exhibit 8-41* provides the maximum cumulative pruning regrowth over the last five years. Once again the most prevalent species appear heavily in the list though a number of conifer species are included as well as minor species such as pin cherry, ironwood and willows.

Exhibit 8-40
Average Pruning Regrowth Rates

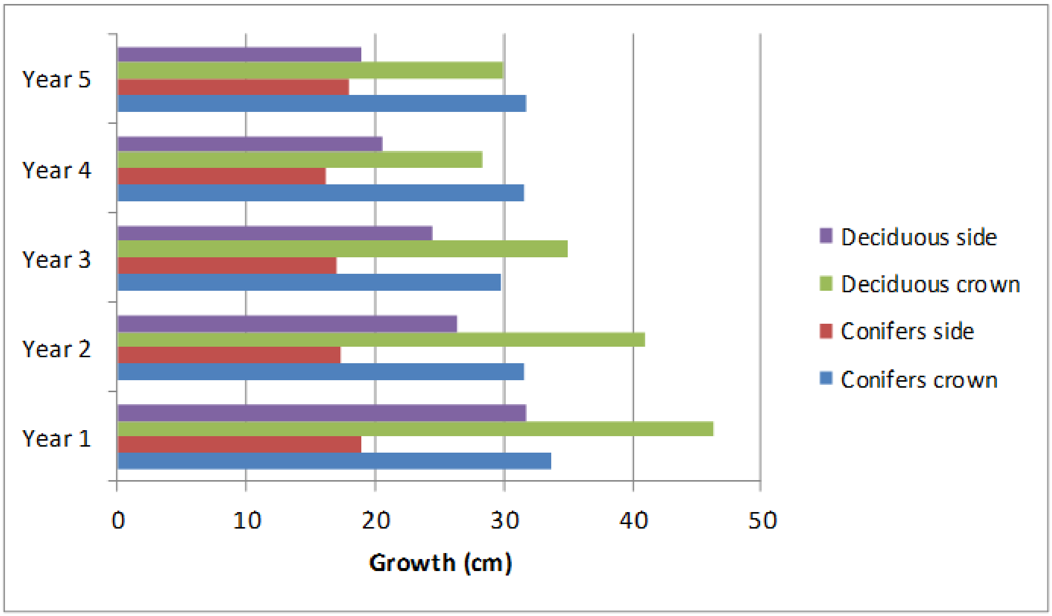
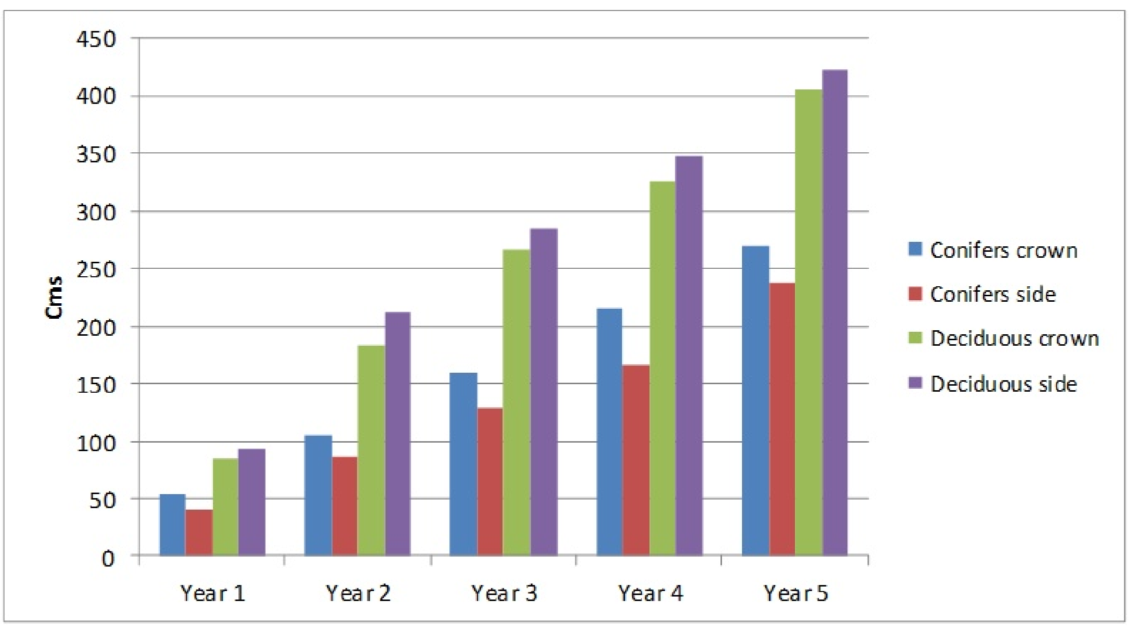


Exhibit 8-41
Maximum Cumulative Pruning Regrowth

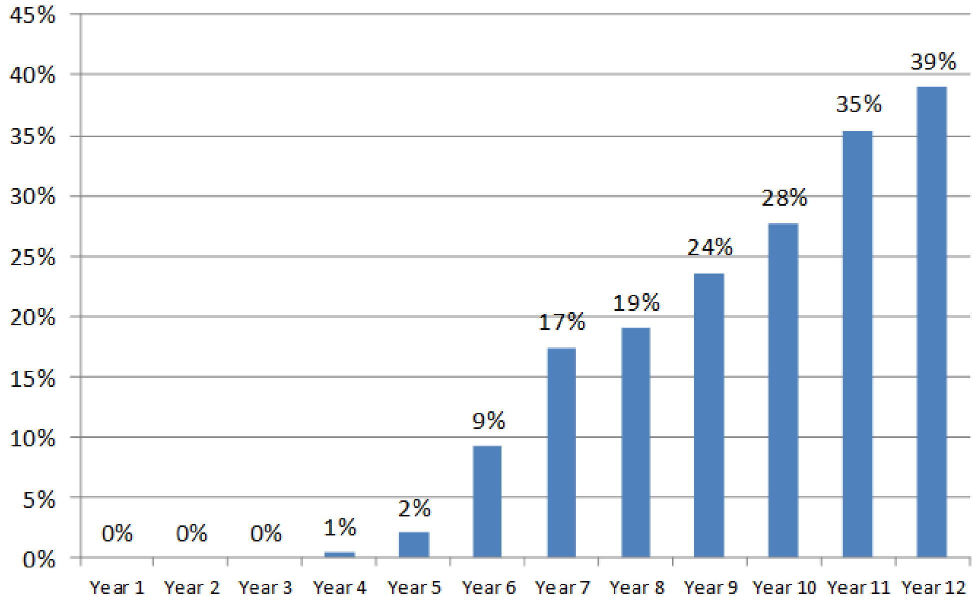


On collecting the data for areas requiring pruning, the data was segregated based on whether regrowth would be crown growth or lateral growth. It is seen in *Exhibit 8-40* and *Exhibit 8-41* that there is a difference between crown and lateral regrowth. A Paired Student T test was applied and for both coniferous and deciduous species to the first two years of regrowth. The results indicated a significant difference in growth rates.

Clearance sought on pruning is 4.5 m. However, customers can influence the clearance obtained and from what was observed in the field, API, similar to many other utilities, achieves an average clearance that would be closer to 3 m.[77] From *Exhibit 8-41* and *Exhibit 8-42* it can be seen that if the last five growing season have been representative then a 3-year pruning cycle would avoid all encroachment. However, at the current time there are areas that have not been pruned in 10 years. To go to a 3-year cycle represents a substantial increase in costs. For the near term a 6-year pruning cycle is recommended. During that 6-year period all trees should be pruned to 4.5 m or the maximum allowed by the landowner.

After the initial 6 years switching to a 4-year cycle may be preferable. With funding in place to achieve a specific cycle, only trees that would impinge on the primary conductor prior to the arrival of the next maintenance event should be pruned. From *Exhibit 8-42* it can be deduced that at 4 years only about 20% (Year 7) of the trees will require pruning. On a 4-year cycle some percentage of the trees will only require pruning of lateral growth every 4th or 5th cycle (*Exhibit 8-40, Exhibit 8-42* and *Exhibit 11-54*). As only 1% of the trees would breach the limit of approach grow-in outages would be essentially zero. Using this selective approach to pruning much less woody material is removed per pruning event reducing site cleanup and wood chip disposal time.

Exhibit 8-42
Pruning Breaching Limit of Approach



9. Quantification of Work Volume

In Vegetation Management Concept and Principles, borrowing from forestry terms, the concept of an annual workload volume increment was introduced. It is comprised of biomass additions and tree mortality. If the annual workload volume increment or AVI is removed, the system remains in equilibrium. It is the path to a sustainable VM program. We need, therefore, to quantify the AVI.

Work volume is derived from a combination of aerial photography and actual field measurements. Some of the field measurements are used in a conceptual approach and this can then be compared to the actual field inventory garnered. It's already been stated that aerial images were obtained using Google Earth. For each of the 150 images a 1 km section was evaluated for the amount of treed edge on each side. The incompatible species invasion pressure is on right of ways with adjacent tree stands. Assuming the establishment of incompatible species is significant only in right of way with adjacent trees then we can apply the percent of treed edge to the total system length to determine the linear length of right of way that will require management. Right of way widths were obtained in the field sampling. These widths will permit an area calculation of what may be said to be the maximum area requiring management (*Exhibit 9-43*).

The biggest risk to the transmission of electricity arises from trees located outside the right of way. The length of exposure was already determined in *Exhibit 9-43*. As part of the field data collection process the height of the conductor and the height of the trees was obtained. Timber cruising techniques were used to determine the number of trees per acre. Consequently, the mean total tree exposure (danger trees) can be calculated.

API's primary system is exposed to 825,543 ± 37,705 trees which on failure could interrupt service (*Exhibit 9-44*). Decadent tree development has been calculated using a 2% annual mortality. This is the number of trees becoming decadent annually and is used as the base when calculating the AVI. However, there are further considerations. First, the forest data indicated that 11.2% of trees were decadent, indicating API has a backlog of hazard trees. The second point applies to both the AVI trees and the backlog: not all the decadent trees will be considered a hazard to service. Some of the trees will be blocked from striking the line on failure by other trees. Some trees decay by shedding branches and trunk sections (i.e. white birch) and without a whole trunk failure would not intercept a conductor. Some trees will develop a lean that makes line contact on failure highly unlikely. Based on the average line height and tree height, the risk factor (RF) at a clear width of 28 feet from the nearest conductor was calculated using the OCWC. It is a RF of 0.225. Because judgements regarding whether a tree will contact the line on failure need to be made we have added 0.1 to the RF to provide a margin of safety. As a clear width of 0 provides a RF of 1, RF/2 provides a reasonable measure of the probability of interruption. Thus applying a factor of 0.1625 to the decadent trees, an estimate of hazard trees is derived (*Exhibit 9-45*).

Exhibit 9-43
Area Requiring VM

Voltage (kV)	Kms	Wire Zone (ft)	Edge type	Mean Clear Width (ft)	ROW Width (ft)	Miles	Acres	% Treed Edge	Potential Treed ROW Acres
44	85.9	7	ROW	54	115	53	744	95.55%	711
25/34.5	174.0	7	ROW	34	75	108	983	89.69%	882
25/34.5		7	Roadside	47		108		89.69%	
7.2/14.4	1425.7	1	ROW	18	37	886	3,973	83.21%	3,306
7.2/14.4		1	Roadside	89		886		83.21%	
Totals	**1686**					**1155**	**5700**	**85.76%**	**4898**

Exhibit 9-44
Tree Exposure

Voltage (kV)	Mean Tree Height (ft)	Mean Line Height (ft)	Trees Per Acre	Ft. To Tree Free @	Danger Trees	Decadent Trees	Mean Danger Tree Depth (ft)
44	63	33	416	54	0	0	0
25/34.5	62	41		47	63,566	1,271	13
25/34.5				47	0	0	0
7.2/14.4	68	33		59	761,977	15,240	41
7.2/14.4				59	0	0	0
Totals					**825,543**	**16,511**	

Exhibit 9-45
Hazard Trees

Voltage (kV)	Decadent Trees Calculated From Annual Mortality	Decadent Trees Based on Found Incidence
44	0	0
25/34.5	1,271	7,120
25/34.5	0	0
7.2/14.4	15,240	85,346
7.2/14.4	0	0
Totals	**16,511**	**92,466**
Hazard Trees	**2,683**	**15,026**

An inventory of workload was also derived from the sampling of 1 km section at 150 sites. *Exhibit 9-46* shows the work found within the 150 samples. The variability in workload from one kilometre to the next can be high. This creates challenges for a system as small as API's. Even having sampled every 12th km, the confidence level needed to be adjusted to ± 10% at the 90% confidence level. The data in *Exhibit 9-46* was used to calculate per kilometre workload and then this was extended by the system kilometres as shown in *Exhibit 9-47*.

Exhibit 9-46
Found Inventory of Work

Voltage (kV)	Length (m)	ROW Width (m)	Brush Length (m)	Brush (m^2)	Crown Trim (m^2)	Lateral Trim (m^2)	Hot Spots	Spans Overhang	Hazard Trees
44	10000	29.5	7085	209,008	14	0	1	0	17
25/34.5	16000	21.94	8538	187,324	457	456	5	2	37
7.2/14.4	124000	11.52	62891	724,504	14042	13872	594	226	644
All	**150000**	**13.83**	**78514**	**1,120,836**[1]	**14,513**	**14,328**	**600**	**228**	**698**

[1] ± 10% at 90% confidence level

Exhibit 9-47
Extension of Work to System

Voltage (kV)	Brush (m^2)	Crown Trim (m^2)	Lateral Trim (m^2)	Hot Spots	Spans Overhang	Hazard Trees
44	1,794,329	135	0	9	0	146
25/34.5	2,037,140	5,591	5,579	54	22	402
7.2/14.4	8,329,930	181,628	179,429	6,829	2,598	7,404
Secondaries	434,151					386
Totals	**12,595,550**	**187,354**	**185,008**	**6,892**	**2,620**	**8,339**

While the workload data in *Exhibit 9-47* is close, it is not the full picture as future work arising in areas recently completed and meeting the clearance requirements have not been captured.

Establishing Annual Workload (Volume Increment)

To capture the full extent of the work, some further adjustments are necessary as the inventory would not capture work that is not needed or apparent at this time. This would include areas that were pruned this year and consequently meet the clearance standard. The crown and lateral trimming quantities as well as brush will be affected. As API's most optimistic estimate is that it may be on an 8-year pruning cycle under the current funding, the trim area will be multiplied by 1.125 to account for areas that were pruned in the last year.

Brush workload is similarly affected as areas recently cleared would not show regrowth, neither would areas cleared in the last year which were stump treated with herbicide. The total potential area for brush control was previously determined to be 4898 acres (*Exhibit 9-43*) which is 19,750,000 m^2. However, API has used some herbicides and one of the intents of this is to shift the right of way to a power line compatible species composition resistant to invasion by incompatible species. It is consequently, necessary to determine to what extent the right of way has been converted to this condition and what portion of the right of way requires ongoing active management. Based on the inventory adjusted for areas recently done or that were cleared in the last year and stump treated we estimate the area requiring active brush management to be 65%.

Finding 9-22 23% of API's ROW kilometres have no adjacent roadway.

API is currently using foliar herbicides on off-road sub-transmission. We have assumed that all off-road brush areas could be treated with foliar herbicides. API's off-road area is 23% of the total kilometres.

Making these adjustments provides the total workload less any backlog. Dividing these totals by the maintenance cycle yields the annual workload volume increment (AVI). The AVI (*Exhibit 9-48*) is the work that must be done every year. Any work deferred expands according to a logistic function (see curve *Exhibit 3-18*).

Exhibit 9-48
Annual Workload Volume Increment

	Brush (m^2)	Herbicide (m^2)	Pruning Top (m^2)	Pruning Side (m^2)	Hazard Trees
	10,206,864	3,048,804	187,354	185,008	3,069[1]
Cycle (years)	9	3	6	6	3
Annually	1,134,096	1,016,268	31,226	30,835	1,023

[1] 386 hazard trees have been added to account for secondary circuit kms

Backlog of Work (Cumulative Liability)

It has been shown that there are two approaches to arriving at the area containing brush. We have a conceptual approach using the extent of tree exposure that was digitally derived. The second approach was the direct approach, collecting data on brush found in the field. The field data was then used to refine the conceptual approach as there is no way to determine from available photography the extent of the right of way conversion to compatible species. Applying the length of tree exposure and the field determined mean tree height, line height and tree density the total tree exposure was calculated. The inventory of decadent trees found in the field informs us both that using average tree mortality rates will lead to under-estimating the number of hazard trees and that there is a backlog of hazard trees requiring attention. There is a difference of over 75,000 decadent trees between field observed numbers and what would be expected based on average mortality. It amounts to a backlog of just over 12,000 hazard trees (*Exhibit 9-45*).

The amount of pruning required can only be derived from a field inventory. The field derived amount is what is used in arriving at the AVI. If there is a backlog in pruning work it is captured somewhat in the area which stems from a measure of length times depth. The rather high incidence of hot spots averaging 4 per km indicates the pruning is behind. However, the number of locations with evidence of trees already contacting conductors was small. Essentially, we have taken a measure of the area subject to grow in and needing pruning at some point. The length of pruning exposure is relatively static. The main variable is the depth or rate at which the clearance zone is penetrated and occupied. This rate has been addressed through the growth studies.

10. Workload Inventory Valuation

It is necessary to place a value on both the AVI and any backlog of work (Cumulative Liability). The unit costs used are found in *Exhibit 10-49*.

Exhibit 10-49
Unit Costs

Operation	Cost
Brush Removal	$2.25/m²
Crown Trim	$2.75/m²
Lateral Trim	$10.42/m²
Tree Removal	165.44/tree
Mowing	$0.60/m²
Foliar Herbicide	$0.18/m²

Tree removal was broken into three dbh size categories: 4-12 in; 12-24 in; > 24 in. The unit cost is the weighted average based on the size distribution found in the forest sampling. The distribution by size category is 71%; 28% and 1%, respectively. A cost has been shown for mowing though no area has been ascribed. While this cost has been entered to encourage thinking of the possible economy of using this practice, one must be cautious about varying cycle lengths between methods. This can be addressed by calculating and comparing long term maintenance costs on a present value basis (see *Exhibit 12-57*).

Exhibit 10-50
Annual Workload Values

	Brush	Herbicide	Pruning Top	Pruning Side	Hazard Trees	AVI	HT Backlog	Total
	$22,965,444	$548,785	$515,223	$1,928,242	$507,738		$2,684,764	
Cycle (years)	9	3	6	6	3		3	
Annually	$2,551,716	$182,928	$85,871	$321,374	$169,246	$3,311,134	$680,681	$3,991,816

Exhibit 10-50 shows the AVI to be $3,311,134. This is the amount that needs to be spent annually, based on current methods, if a sustainable program is to be delivered. The AVI can change for a number of reasons. If more widening occurs, reducing the system's tree exposure, then the number of hazard trees that will develop annually is also reduced. If mowing were introduced and it were found that 25% of the brush currently hand cut could be mowed then that too would change the AVI. A guiding principle for a

sustainable program is that the AVI must not be changed for reasons other than escalation unless the change is both quantified and is itself sustainable.

Exhibit 10-50 also shows that over the first three years of this program, the backlog of hazard trees is to be removed and this will require total annual VM funding of $3,991,816. As it is unlikely that the VM program will be funded at this level in 2014, projections will need to be made for 2015 forward. This being the case, the backlog or VM liability will expand necessitating a greater investment in the future.

Confidence in the Workload, AVI and its Valuation

While some of data collected is so extensive as to permit statements of a mean ± 5% at a 95% confidence level, some is not that rigorous. The area of brush falls easily within ± 10% at a 90% confidence level. The brush being the largest component of the AVI and the lowest confidence level, then this is what we must ascribe to the overall AVI. It need be interpreted as the mean amounts and value, ± 10% at a 90% confidence level.

The pruning area, the number of hazard trees/km and the spans of overhang/km do not meet ± 10% at a 90% confidence level standard. The hazard trees/km and the spans of overhang/km were only used to gain insight to the program and to provide direction to possible means of improving reliability. The actual data used for hazard trees is derived from the forest data of over 6000 records and it meets the highest or 95% confidence level.

The annual value of the pruning is only about 12% of the total AVI and thereby, we can state that the failure to achieve a narrow confidence interval does not substantially affect the overall AVI value or confidence in it.

As previously stated we have used two approaches to arriving at the AVI with points of intersection between the two. Not detailed here is the application of unit prices to the field inventory collected over the 150 km segments. Comparing the value thus derived to the calculated AVI the result is 101.9% This high level of agreement corroborates both the validity of the approach and the AVI value. The difference stems from the AVI being adjusted to include work done in the last year which would not appear in the field inventory.

Funding Required

There is a specific amount of work that needs to be done annually (AVI). This amount has been determined to cost $3,311,134 employing the current practices. There is also a backlog of hazard tree work, which if not addressed will continue to very adversely affect reliability. When this backlog is included the funding required is $3,991,816 for the first three years. That is, the total current Cumulative

Liability must be addressed. Having removed the backlog, the funding requirement will then drop back to AVI value of $3,311,134 (in 2013 dollars).

The AVI includes funding for some hazard tree work. However, it is only for what would be newly emergent hazard trees. If the backlog of hazard tree work is not funded, resources will inevitably be drawn away from other work considered necessary in the AVI simply because it will not be possible and would be irresponsible to walk by obvious hazard trees that are imminent threats to safety and reliability. Consequently, funding intended to remove the AVI will be diverted making it impossible to achive the objective of removing the AVI.

It is recommended in this report that VM be put on a rational basis. This cannot be accomplished without addressing both the AVI and the current backlog of work (Cumulative Liability). Further, as current funding is inadequate to meet the requirements of the AVI and the backlog, all deferred work will be compounding at over 15% (*Exhibit 11-55*). The same applies to currently outstanding work that is scheduled for future years. The only way to avoid this compounding is to complete the entire backlog in the current year. That is not feasible as a sudden large increase in work would necessitate hiring more contract crews and staff to administer and monitor the work, thereby introducing inefficiencies that quite possibly exceed the rate of workload expansion.[78] The proposed funding buys down the workload liability over a period of years.

Exhibit 10-51
Proposed VM Maintenance Budget[1]

	Minimum Required Budget	Proposed Funding	PV of $1	PV of Budget Provided	Unfunded	Liability	Cumulative Liability
		Proposed Funding				('000)	('000)
Start 2014	('000,000)	('000,000)		('000,000)		$680.68	$2,042.04
End 2014	$3.99	$2.88	1.0000	$2.88	$1,109.73	$769.20	$2,811.25
End 2015	$3.99	$4.70	0.9524	$4.48	-$708.18	$0.00	$2,200.89
End 2016	$3.99	$4.70	0.9070	$4.26	-$708.18	$0.00	$1,594.56
End 2017	$3.99	$4.70	0.8638	$4.06	-$708.18	$0.00	$965.98
End 2018	$3.31	$4.30	0.8227	$3.54	-$988.87	$0.00	-$25.68
End 2019	$3.31	$3.31	0.7835	$2.59	$1.13	$1.13	-$24.54
End 2020	$3.31	$3.31	0.7462	$2.47	$1.13	$1.31	-$23.23
End 2021	$3.31	$3.31	0.7107	$2.35	$1.13	$1.51	-$21.72
End 2022	$3.31	$3.31	0.6768	$2.24	$1.13	$1.75	-$19.97
End 2023	$3.31	$3.31	0.6446	$2.13	$1.13	$2.02	-$17.95
Total	$35.83	$37.83		$31.01			-$17.95

[1] In 2013 dollars

Exhibit 10-51 lays out a schedule for VM funding (Provided Budget column) stated in 2013 dollars. It addresses the required funding (AVI), expands all unfunded work by the found rate of workload change, determines the present value of the total VM liability assuming a 5% interest rate and sets out the VM investment schedule which eliminates the VM liability. In doing so, it has been assumed that funding for 2014 will be as currently planned and that the new funding level will begin in 2015.

11. Risk

To electric utilities trees are a liability. They have no capacity to improve electric service. Trees in proximity to power lines present a public safety hazard and thereby, constitute a legal liability. However, the major impact of trees is seen in reliability. Consequently, trees are a liability in terms of quality customer service. As was shown in Vegetation Management Concepts and Principles, VM as a whole represents a financial liability. All of these risks need to mitigated and managed.

As vegetation is not static, neither are the risks associated with trees in proximity to power lines. A number of areas of risk are examined.

Reliability

In some cases it is possible to show a direct link between funding and the deterioration of reliability or conversely, the improvement in reliability in response to an increased spend. This is somewhat obfuscated in API's case due to widening which increased the instability of edge trees. None the less, it is seen in *Exhibit 11-52* that every substantial increase in VM spending drove tree-related outages down. It should be anticipated, however, that at some point the susceptibility to increased failure along the new edge would become evident. It need be noted that the data does not separate out the influence of major storms. Thus, some of the peaks may be skewing the data as one or two major storms can easily increase annual outage statistics by 20-30%.

When tree-related outages as a percent of total unplanned outages are charted with the annual VM spend (*Exhibit 11-53*), the benefit of increased VM is evident in decreasing customer interruptions. As the major capital widening was completed in 2011, a trend of a decreasing percentage of tree-caused outages is expected to emerge through 2018 as the edges become more stable. However, if the annual spend does not equal or exceed the AVI value the gain may be offset by an increase in outages from other sources, such as hazard trees beyond the edge. We estimate that if the current hazard tree program persists, the percent of decadent trees will continue to increase to an asymptote where additions are balanced by annual failures, and as a consequence, that tree-caused outages will increase by 40-60% over the next five years.

Exhibit 11-52
VM Spend vs Tree-related Outages

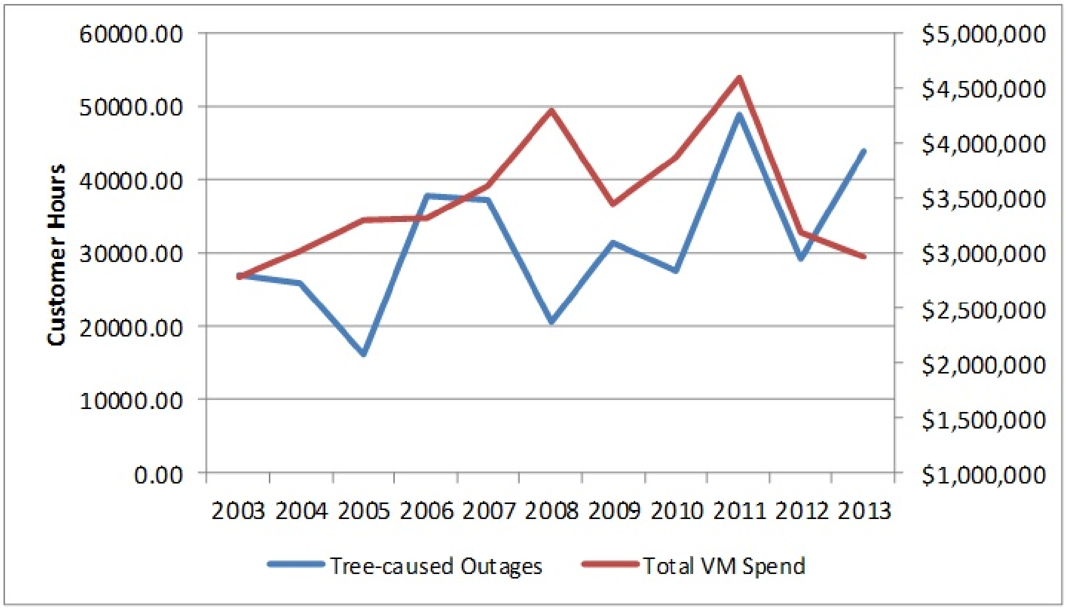
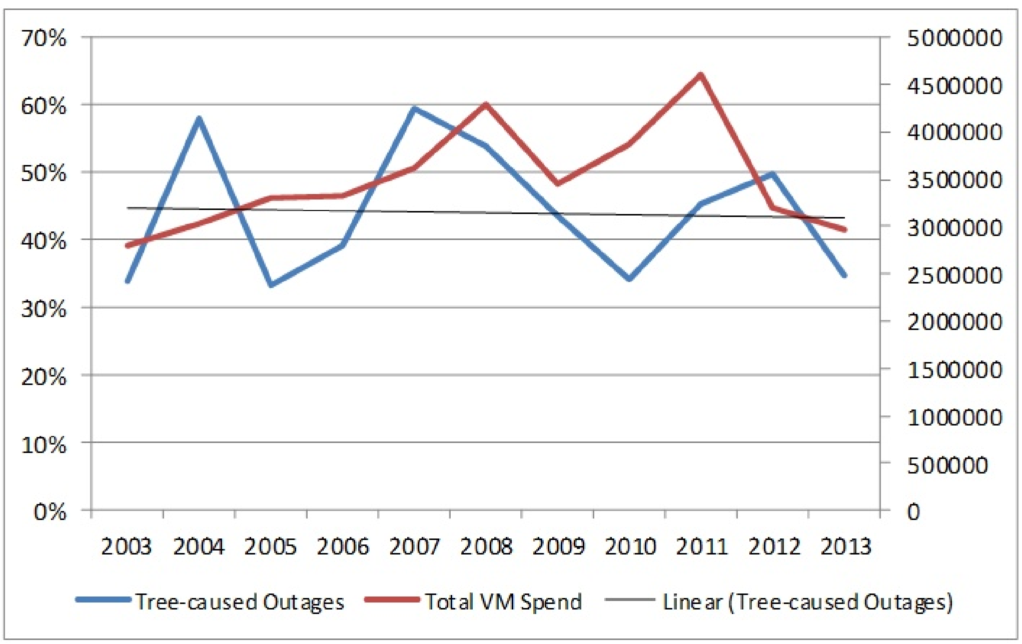


Exhibit 11-53
VM Spend vs % Tree-related Outages



Hot Spots

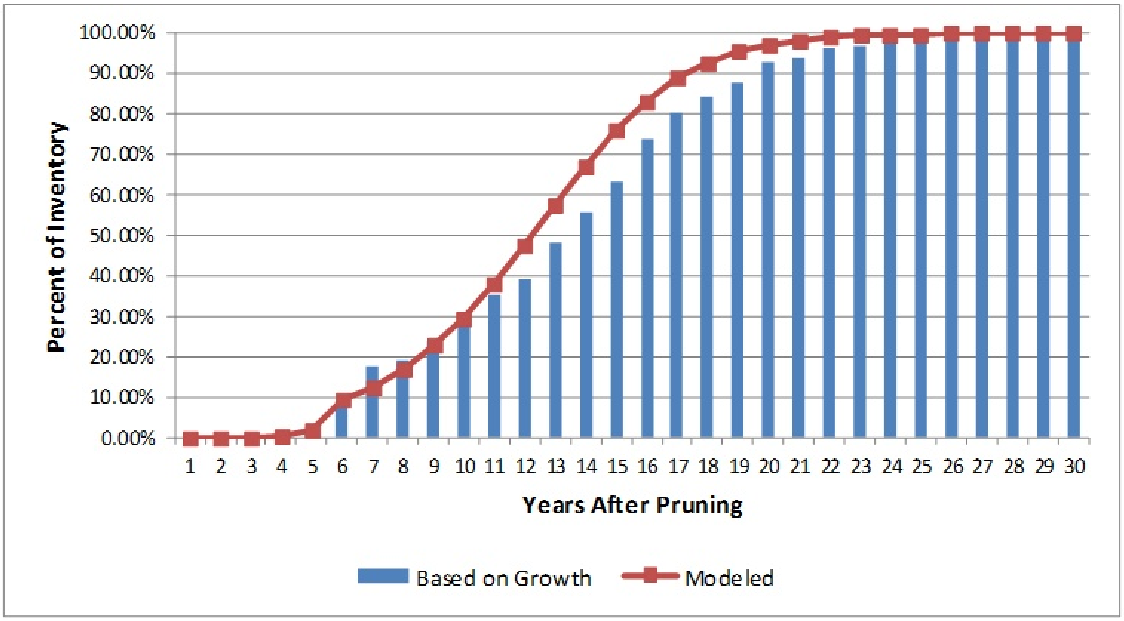
The incidence of hot spots was high, at about 4 per kilometre. Virtually none of the hot spots seen were actually in the conductor. While the incidence of hot spots is greatest in areas that have not received attention for quite some time, the inventory showed the incidence to be widespread. Hot spots within areas scheduled for work will be resolved, however hot spots occurring in areas not scheduled need to be managed on a demand basis. One study showed the management of hot spots to cost 30% more than maintenance pruning.[79] Hot spots jeopardize reliability and public safety and increase maintenance costs. Consequently, hot spot work needs to be minimized and carefully managed.

Chasing hot spots can sink a VM program to a state of total ineffectiveness. Not only does the windshield time involved erode cost effectiveness but also, there comes a breaking point where the hot spots are emerging faster than the capacity to address them. At that stage grow-in outages increase. An increasing rate of grow-in outages should be seen as an alarm for public safety. Grow-in outages do not occur at distribution voltages until branches are bridging phases. Such overgrown conditions create the potential for children to come into contact with conductors when climbing trees. For these reasons it would be useful to further examine the status of hot spots.

We have extended the 5 years of growth data collected out to 30 years. The data records were then put into a frequency distribution, the bins consisting of 50 cm increments. *Exhibit 11-54* shows the percent of trees that will breach the limit of approach within the year. The limit of approach was taken as 3 m. While one could argue this limit of approach given API targets a 4.5 m clearance, what cannot be argued is the pattern of hot spot development. In other words, the pattern seen in *Exhibit 11-54* remains the same regardless of the limit of approach chosen. Changing the limit of approach serves only to move the curve left or right by a few years.

The current level of hot spots is 38%. The closest match in *Exhibit 11-54* is year 12. This provides insight into the current status of the VM and also into what might be expected in the future if the pruning program is not put on maintenance cycle based on growth rates. The number of hot spots is in an exponential expansion phase. The future will prove very challenging as the number of hot spots doubles in the next five years. Grow-in outages will likely make a strong reappearance and the efforts to avoid them, by increasing hot spotting activities, will increase inefficiency and increasingly draw resources away from other also essential VM activities, such as hazard tree removals and maintenance pruning.

Exhibit 11-54
Modeling Hot Spot Development



Hazard Trees

There is a current backlog of hazard tree work valued at $2,042,044. It is recommended that this backlog be addressed over the first 3 years of the new program.

Failing to do so will increase tree-related outages. However, considering that at present 11.2% of the danger trees beyond the edge are decadent API is not far from the limit of maximum hazard tree-caused outages. BC Hydro found that mountain pine beetle invested trees all failed within 8 years. Applying the same assumption to API's service territory, the highest level of decadent trees is 16% of the danger tree population. However, hardwoods such as maples and oaks may take longer to fail. We have assumed 18% standing decadent trees to be the upper limit. Such an increase in standing decadent trees would result in a proportionate increase in tree-related outages of 40-60%.

If the AVI funding is provided but there is a failure to fund the removal of the backlog of hazard trees reliability will deteriorate for two reasons. Assuming one could remove only the hazard trees which have developed over the last three years, the then residual and current backlog would become increasingly decadent to the ultimate point of failure. This may be expected to occur over the next 5 to 6 years. However, a failure to fund the removal of the backlog has even more serious implications. It would necessitate a prioritization where only about one of every five hazard trees are removed. That raises a legal risk. Practically, however, it would likely be decided, the risk being recognized, that more than 20%

of the hazard trees will be removed. Such action and expenditure would preclude attaining the 3-year cycle for hazard trees and as the effects of this decision become apparent in the areas not yet done, invite the transfer of funds from other program aspects precluding their attainment of the maintenance cycle and lead to a reactive program.

Funding

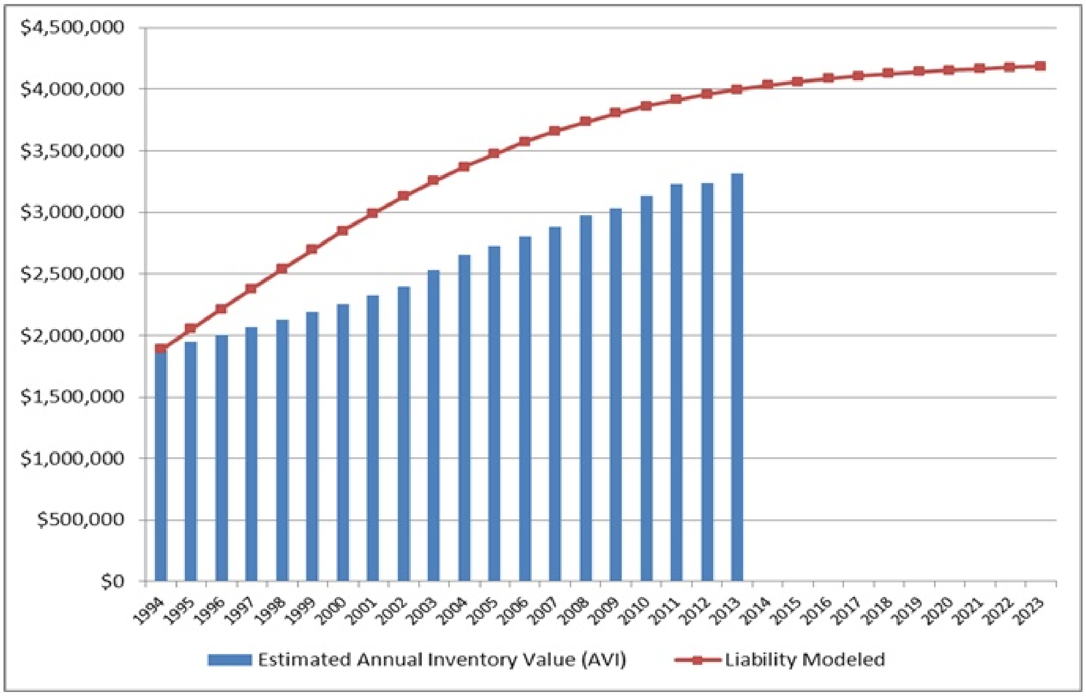
The AVI is valued at $3,311,134. While we have indicated that the funding requirement is higher than the AVI for the first 3 years of the proposed VM budget and program to address the backlog of hazard trees the critical value is the AVI. If funding does not meet or exceed the AVI value, the work not done does not remain static but expands according to a logistic function.

Knowing the current AVI value, the AVI was backward calculated to 1994, discounting by a 3% per annum cost of living increase and adjusting for the effects of the capital widening program on increasing brush area and decreasing total tree exposure and consequently hazard tree needs. A 30 year logistic model was then created so that it closely relates to the estimated starting point in 1994 and the total 2013 workload liability value. In fitting this model, the rate of expansion of API's VM work was determined (*Exhibit 11-55*). It is a factor of 1.155. For the sake of simplicity, it could be stated that $1 of deferred work this year will cost $1.155 next year.

Having determined the rate of change in the workload it is possible to quantify the net effects of underfunding, that is funding below the AVI value. To illustrate it has been assumed that the VM budget going forward will be $2,700,000. That leaves a shortfall of $629,048 from the AVI value. *Exhibit 11-56* shows the impact of 10 years of underfunding. The liability line shows what it would cost to get the program back to the least cost sustainable level. It should be noted that *Exhibit 11-56* is illustrative and does not include the value of the current backlog of work of $2,042,044. Rather, the data it presents assumes a program that has been fully funded in the past and becoming underfunded going forward.

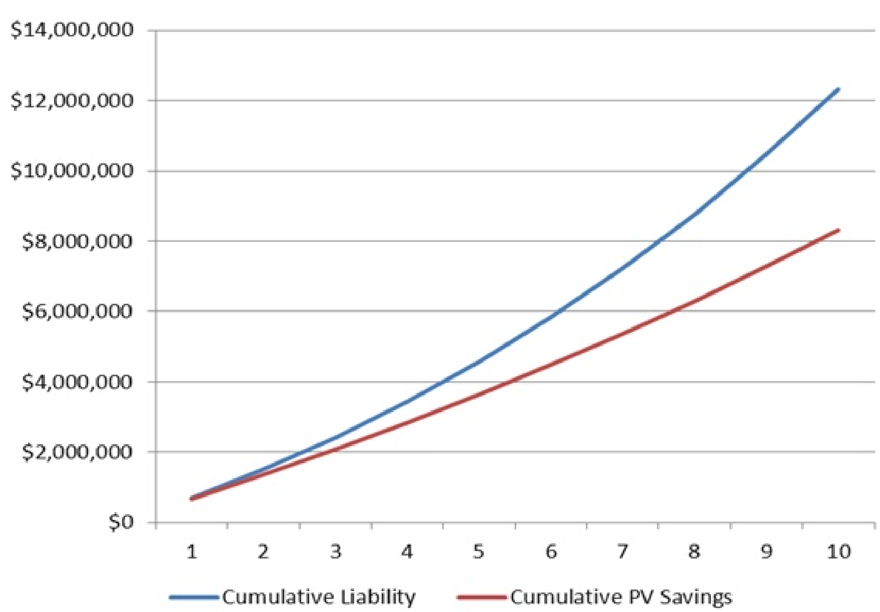
Exhibit 11-56 shows underfunding or deferring VM work is financially imprudent. This will inevitably be case as long as the rate of change in the workload substantially exceeds the discount rate used in determining the present value. In this illustration the workload rate of change is 15.5% versus a discount rate of 5%.

Exhibit 11-55
Modeling the Workload Liability



2013 AVI is derived from field inventory, growth and mortality rates

Exhibit 11-56
Present Value Impact of Current VM Underfunding



However, the failure to fund VM as set out in Exhibit 10-51 will have greater cost implications for the future. First, the potential gains in cost effectiveness through the recommended practices would be precluded. The window for treating brush with herbicides is limited. Brush suitable for herbicide applications represents the lowest level of public and reliability risk for a utility. Consequently, it is the first work deferred under constrained funding. Deferred work becomes brush that needs to be cut by mowing or hand cutting, escalating costs by as much as 20 times (Exhibit 12-57). Secondly, the recommended cycles are to prevent trees breaching the limits of approach. Without the funding necessary to attain these maintenance cycles trees will increasingly breach the limits of approach, necessitating a greater skill set, more expensive practices and workers to complete the work.

12. Conclusions and Recommendations

Recommendation 12-1 **Fund the VM program based on the inventory and tree growth and mortality (Refer to *Finding 6-2, Finding 6-1, Finding 8-17, Finding 8-18*).**

It is completely unreasonable to expect a VM program that is not funded on the biological facts of an inventory, tree exposure and tree growth and mortality to deliver a least cost sustainable program. To do otherwise is as imprudent as basing decisions on the assumption of winning the lottery, which while not impossible is highly improbable.

Vegetation Management Concepts and Principles provides how and why only an approach that annually addresses the annual workload volume increment will provide a least cost sustainable program while simultaneously minimizing tree-related service interruptions.

With the recently completed work performed to quantify API's work inventory, tree exposure and tree growth and mortality rates, the foundation for a least cost sustainable VM has been provided. While this new data provides direction on potential cost savings it also shows that there is a risk of the workload expanding from 65% of the right of way area to 85% of it if funding is inadequate to establish the recommended maintenance cycles. As areas treated with herbicide are not affecting reliability, worker and public safety, when funding is inadequate this is the work that is deferred. Once this deferred area is over-height for herbicide applications it is necessary to apply cutting methods which are not only more expensive but also tend to increase the stem density of incompatible species. The relative stability of the early succession plant population is disrupted and the area then requires regular maintenance (based on the recommended cycles).

The funding requirements to address the current Cumulative Liability have been provided in Exhibit 10-51.

Recommendation 12-2 **Establish the maintenance cycles required to deliver a sustainable, least cost VM program (Refer to *Finding 6-3*, *Finding 6-2, Finding 6-5, Finding 6-7*).**

The recently completed field work also provides data for the derivation of maintenance cycles. It need be noted there is not one maintenance cycle but several depending on the treatment to be applied.

Brush that is to be cut, whether by hand or machine, has a maintenance cycle of 9 years.

Brush that will be treated with foliar herbicide has a maintenance cycle of 3 years. Due to the short duration, annual variability in growth rates can have a substantial impact. Consequently, while funding should be based on the assumption of a 3-year cycle, field conditions must be checked to determine whether the treatment needs to be moved forward in time or delayed. This will necessitate either patrols of the all the areas for which herbicide applications are planned within the next two years or a considerable familiarity with the actual field conditions. In this way line segments may be moved forward into the current schedule or deferred to the following year.

Pruning work has a 6-year maintenance cycle. This will serve to both reduce the number of hot spots and to geographically concentrate the hot spots, which serves to reduce the extent of the cost inefficiencies inherent to handling hot spots. To further improve on reliability it is recommended after the first six year cycle is complete, to shift to a selective 4-year pruning cycle. In this case, each tree needs to be assessed and pruned only if it would intrude into conductors before the next pruning event four years hence.

Hazard trees are to be maintained on a 3-year cycle. The rate of hazard tree development is such that if hazard trees were only addressed on the 9-year brush maintenance cycle, the currently high level of decadent trees would be a constant condition with negative implications for service reliability. A 3-year maintenance cycle for hazard trees is expected to reduce the amount of decadent trees to about half the current level in areas just before retreatment. That is the worst case is the $1/3^{rd}$ of the service territory due for work would have about ½ of the current level of decadent trees while the other $2/3^{rds}$ of the service territory will have 0-4% decadent trees.

This hazard tree maintenance cycle along with the gradual firming of edges is expected to substantially decrease tree-related outages. Until such time as the edges are firm, there should be an annual hazard tree patrol for edges beginning with the most recently widened areas. Once stability of the edge is established the area can be rolled into the general hazard tree program.

It will be beneficial to monitor outages in the boreal forest ecozone versus the Great Lakes St. Lawrence ecozone. It is in the boreal forest ecozone where the tree species with the highest mortality rate and risk of failure occur. It may be found that the area warrants a more aggressive hazard tree program. Conversely, it may be found that in the Great Lakes St. Lawrence ecozone a longer cycle can tolerated.

Recommendation 12-3 Seek to eliminate branch overhangs (Refer to *Finding 6-4, Finding 8-19*).

It is recommended that API eliminate branch overhangs wherever possible. There may be substantial landowner resistance to removing overhangs on sugar maples as doing so may impact syrup production. However, this condition is restricted to the southern part of the service territory and predominantly St. Joseph Island. It was also noted that occasionally landscape white pines with substantial branch overhangs are encountered. As conifers tend to shed older branches, the risk of branch failure on such pines can be minimized by monitoring the lower branches for health and vitality, removing any decadent branches back to tree trunk.

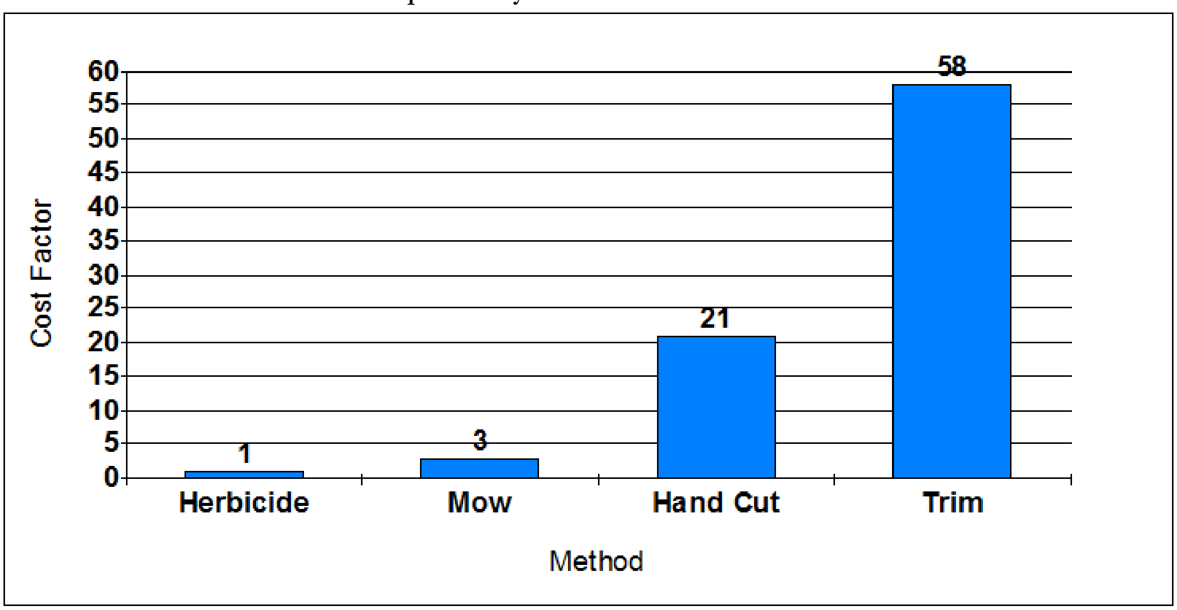
For trees that are not in landscaped settings and do not have commercial value beyond the wood itself, a ground to sky clear width of 4.5 m is recommended. As outage data does not detail outages arising from tree branch failures it is not possible to predict the reliability gain available.

Recommendation 12-4 Extend the use of herbicides and the introduction of alternative cutting equipment and procedures (Refer to *Finding 6-6*).

It is recommended that API extend its foliar herbicide program to include areas that are along roadways. Foliar herbicide results are superior to other methods (stump treating, basal) because the plants are intact, growing actively and thereby capable of translocating herbicide to the roots. Herbicide use being controversial with the public it is important that API continue its landowner permission based approach and also use rigorous brush height restrictions so as to manage the visual impact based on public traffic along and visibility of the site.

At this time only areas recently cleared could be considered for foliar herbicide applications. The plan going forward, however, would include the intention to follow up with herbicides 1 to 3 years after areas have been cleared. It's not known how much of the area housing brush could gain public acceptance for foliar herbicide application. Consequently, while a measure of the cost savings possible is presented in *Exhibit 12-57*, the AVI must not be adjusted to reflect these savings until such time as brush area to be transferred is known.

Exhibit 12-57
PV Cost Comparison by Method Over 20 Yrs. Maintenance



Source: TransAlta Utilities 1993.

Exhibit 12-57 also highlights another recommended practice which is brush mowing. The cost factor comparison to hand cutting provides a compelling reason to introduce the practice. It would be applied where brush exceeds the height limitations for herbicide applications and on an ongoing basis, in areas that cannot be treated with herbicides. Due to rocky terrain the area suitable for mowing is restricted. None the less, the potential savings warrants a determination of the area that could be mowed. API has used mulchers that have same restrictions in needing to avoid rocks. Mulchers have a higher unit cost than mowers but they do lead to a longer maintenance free period. Once again, the AVI value must not be adjusted until such time as there is an actual measure of the area that can be mowed.

The right of way reclamation work that has been done provides the opportunity to employ earlier intervention and less costly methods. API's current average per hectare cost for brush control, which reflects the reclamation, is $12,717. This is, relative to the industry high. Extending the use of foliar herbicide to as much as possible of the recently cleared area and introducing mowing hold the potential to substantially lower the average $/ha. If we assume 30% of the brush currently hand cut could be mowed the average $/ha would fall to $10,331. If foliar herbicides could be used to maintain 50% of the area supporting brush the average price per hectare would become $6,975. Were it possible to meet both the mowing and foliar herbicide hypotheticals the costs would drop to $5,731/ha. Clearly these practices hold the potential for significant savings in maintenance costs. The adoption of this recommendation will impact the AVI in two ways. First, once the area that can be transferred from hand cutting brush to foliar herbicide and mowing treatments is firm and known, a new lower AVI value can be calculated. However, as there are brush size limits for these operations, any deferred work may become unsuitable for the method and therefore will need to completed in the future through a more expensive method. Accounting for this escalation in costs requires a higher rate of change for any deferred work.

It has been recommended that overhangs be removed where possible. There are numerous kilometres of overhang that are not sugar maples but comprised of species that tend to shed branches. Typically, the extent of the overhang is not large. For that reason we recommend the use of a telescoping saw trimmer such as the Jarraff. This equipment does not provide fine pruning but a skilled operator can reduce stubs to 5-10 cm. Such equipment provides an economical means of attaining a ground to sky clearance.

Recommendation 12-5 **Work on secondaries requires separate funding so that this work does not occur at the expense of work on primary lines (Refer to *Finding 6-8*).**

API has been experiencing tree-related outages on secondaries. In response, API has begun clearing secondaries. At the present time, however, funds expended on clearing secondaries decreases the funding available for the maintenance of primary lines.

The workload, funding and AVI presented here have been adjusted to reflect this initiative.

Recommendation 12-6 **For capital projects a clear width of 6 m is recommended. (Refer to *Finding 7-13*, *Finding 7-12*, *Finding 7-11*).**

API's relatively low exposure to trees provides some guidance to tree-related outage mitigation. The risk of an interruption on tree failure is high where the right of way has not been widened, such that clear widths are only 8 feet (*Exhibit 7-26*). Much of this issue has already been addressed but there remain areas where widening would be beneficial.

Clear width is the distance from the outside conductor to the tree line or tree boles. It is shown in *Exhibit 7-27* that increasing the clear width to 4.5 m (15 feet) is expected to reduce tree-related outages 32%. However, a clear width of 6 m (20 feet) will result in a 48% reduction. API is currently establishing a right of way of 6 m each side of centreline. This recommendation slightly extends this practice to ensure a 6 m clearance between the conductor and tree boles should the line be on horizontal cross-arms.

Recommendation 12-7 **Place particular focus on line segments between the substation and the first protective device. (Refer to *Finding 7-11, Finding 8-19*, *Finding 8-21*).**

The greatest reliability improvement will be attained if the most rigorous standards are applied to the portion of line between the substation and the first protective device. For these line segments overhangs should not be tolerated. They should receive the greatest attention in patrolling for hazard trees. It is also on these line segments where a greater clear width would provide the greatest overall reliability improvement.

Recommendation 12-8 **Obtain a VM reporting system that links to other company databases (Refer to *Finding 6-10*).**

Part of the audit process involved the request for information. Some of the requested data was not easily attained.

For most distribution utilities VM is if not the primary, certainly one of top three O & M expenses. As such it warrants support through the provision of IT, accounting and other financial management services. Given VM's role in O & M expenses and reliability there is need for a good information management system. This system should collect data on VM work done, costing for the same and to be able to forecast future needs. Further, the system should link with customer, accounting and mapping databases.

Recommendation 12-9 Collect field data in more detail (Refer to *Finding 6-10*).

API currently tracks cost per kilometre. This is inadequate,[80] particularly, in light of the recommendations made which have established the need for various maintenance cycles based on the treatment. It is recommended that API track work performed as follows:

- Brush (<4 in dbh) removal – m^2
- Herbicide - m^2
- Pruning – m^2 or trees (>4 in dbh) and trim brush (<4 in dbh) in m^2
- Tree removals – trees by size category
  - 4-12 in dbh
  - 13-24 in dbh
  - > 24 in dbh
- Clearance on work completion for pruning and clear width for brush

API's VM program has been in a state of flux. Should the recommendations regarding different treatment methods, maintenance cycles and the funding to support them be accepted, then there will be a transition period for which there is no precedence at API and consequently, the currently known costs per kilometre will not apply and serve.

The greater detail provided by following this recommendation will provide greater insight into the VM program in general and provide a basis for comparing different methods. The data presented in *Exhibit 12-57* is a good example of the type of insight afforded by the more detailed VM reporting recommended and it need be recognized that this insight is not at all available if costs are tracked by kilometre.

Recommendation 12-10 Create more detailed tree outage cause codes (Refer to *Finding 7-14*).

It is recommended that cause codes make distinction between grow-in outages and fall-in outages and whether the offending tree is within or outside the maintained right of way. Fall-in outages should be further detailed as uprooted, trunk failure or branch failure. These distinctions will provide direction to the VM program but may also suggest engineering options to address tree-caused outages.[81] [82]

It is suggested that an arborist follow up on some portion of tree-caused outages to establish the tree species and the distance of the tree from the nearest conductor. This information will provide guidance on species vulnerabilities and how they might be addressed. The distance factor will provide guidance for the hazard tree program. As the availability of human resources may prevent inspection on each tree-caused outage a prioritization such as inspecting tree-caused outages on sub-transmission and/or all whole circuit outages may provide a reasonable starting point.

Recommendation 12-11 Substantially increase the intensity of the hazard tree program (Refer to *Finding 7-16, Finding 7-15, Finding 8-20, Finding 8-21*).

API's relatively low incidence of interruptions arising from tree in-growth indicates that API's tree-related outages are arising from hazard trees and overhangs. There are several aspects that need to be separated for API to successfully manage hazard trees.

The ratio of decadent trees more than 2 m beyond the forest edge is very high and this condition is likely contributing substantially to the outage experience. It is recommended that hazard trees beyond the edge (first 2 m) be treated on a 3-year cycle. While growth rates indicate a 9-year maintenance cycle will be adequate for the right of way, a tree mortality rate averaging 2% suggests hazard trees will continue to be a problem if this maintenance cycle is applied outside the right of way.

In the context of the capital widening which has occurred, the instability created by this action needs to be addressed. It is recommended that API patrol for edge hazard trees on an annual basis all areas that were widened. As the edge will become firm over time the patrols should be prioritized based on the most recently newly established edges. If good records are kept on the number of hazard trees identified and removed, the time it takes to establish a firm edge will be revealed. With this data it will be possible to determine whether ongoing annual hazard tree patrols are warranted and where the inspection cycle can be extended.

Once the newly established edges are firm, it is suggested API use the generally recommended 3-year hazard tree inspection cycle and removal cycle.

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[30] / Interview 1
[31] / Interview 1
[32] / IR 12
[33] / Interview 1
[34] / Interview 1
[35] / Interview 1
[36] / IR 13
[37] / Interview 1
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[39] / IR 3
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