Excerpts for Closing Submissions:

1. CAC/MH 1-145a-b, Coalition Exhibit 16.

2. Excerpts from Kinectrics PowerPoint, Coalition/MH II-53c-g, Attachment 2, pages 1, 7, 8, 10, 23, 24, 26, 28, 35, 37, 39, 40, 62, 63, 64.

3. Excerpts from Power Stream, Chapter 5, Coalition Exhibit 20, pages 1, 3, 4, 5, 6, 17-28, 33, 35-38.

4. Excerpts from Manitoba Hydro 2012 Asset Condition Assessment, Coalition/MH II-53c-g, Attachment 1, pages 1, 11, 33 and 86.

5. Coalition/MH II-52a-f.

6. Excerpt from PECO Energy Universal Services Program, Final Evaluation Report, Coalition Exhibit 24, cover and pages 14 and 15.

REFERENCE: Chapter 11: Financial Evaluation of Development Plans; Section: 11.3; Page No.: 16

QUESTION:

Has Manitoba Hydro reviewed the projected financial requirements and financial metrics of the various developments plans with its credit rating agencies? If yes, what has been their reaction as to whether the plans could impact the Corporation's or the Province's credit ratings?

RESPONSE:

Manitoba Hydro has reviewed the projected financial requirements and financial metrics of the Preferred Development Plan with the credit rating agencies as it was forecasted within IFF12.

There are a multitude of potential factors that may impact the credit ratings and the cost of debt to the Province of Manitoba within the financial markets. For example, the credit rating agencies identify numerous rating considerations and factors within their reports (for the credit rating reports for the Manitoba Hydro-Electric Board and the Province of Manitoba, please see the response to PUB/MH I-085(a)-(b)). The causal role, if any, associated with Manitoba Hydro's capital investment program upon the future credit ratings and the cost of debt is indeterminable.

REFERENCE: Chapter 11: Financial Evaluation of Development Plans; Section: 11.3; Page No.: 16

QUESTION:

Is it acceptable to the credit rating agencies, Manitoba Hydro's lenders and the provincial government for Manitoba Hydro to have a debt/equity ratio in excess of 85% for more than 10 consecutive years? Please provide any comments from credit rating agencies and lenders that support your contention.

RESPONSE:

For credit rating agency comments regarding Manitoba Hydro's debt/equity ratio, please see the response to PUB/MH I-0085(a)-(b) for the credit rating reports for the Manitoba Hydro-Electric Board and the Province of Manitoba. Notable excerpts from the Manitoba Hydro reports are as follows:

DBRS: "Continued significant capex levels are expected to lead to an increase in debt levels, which will likely cause credit metrics to decline moderately over the medium term." [DBRS report on the Manitoba Hydro-Electric Board dated September 16, 2013; page 1]

S&P: "We believe Manitoba Hydro's monopoly, gas and electric franchises, and related regulatory frameworks provide satisfactory cash flow stability. Furthermore, the utility's owner, Manitoba, strongly supports its creditworthiness. In our opinion, exposure to significant hydrology risk and its highly leveraged financial risk profile offset these strengths." [S&P report on the Manitoba Hydro-Electric Board dated September 11, 2013; page 2]

Moody's: "Given the uptick in capex and corresponding debt, financial metrics are predicted to fall below targets in the next three fiscal years. The equity ratio, in particular, will be challenged and not likely to return to target until FY2032. The weakening financial profile restricts financial flexibility and adds risk in case of unexpected events such as low water levels, cost overruns and construction delays, given the nature of a hydroelectric plant's long construction cycle before cash generating begins. However, we view Manitoba Hydro as being capable of prudently managing debt and mitigating such risks by seeking rate increases and curtailing capital spending to continue as a self-supporting corporation." [Moody's Investors Service report on the Manitoba Hydro-Electric Board dated September 23, 2013; page 2]

Manitoba Hydro
October 19, 2012

Transmission Asset Condition Assessment Project Findings

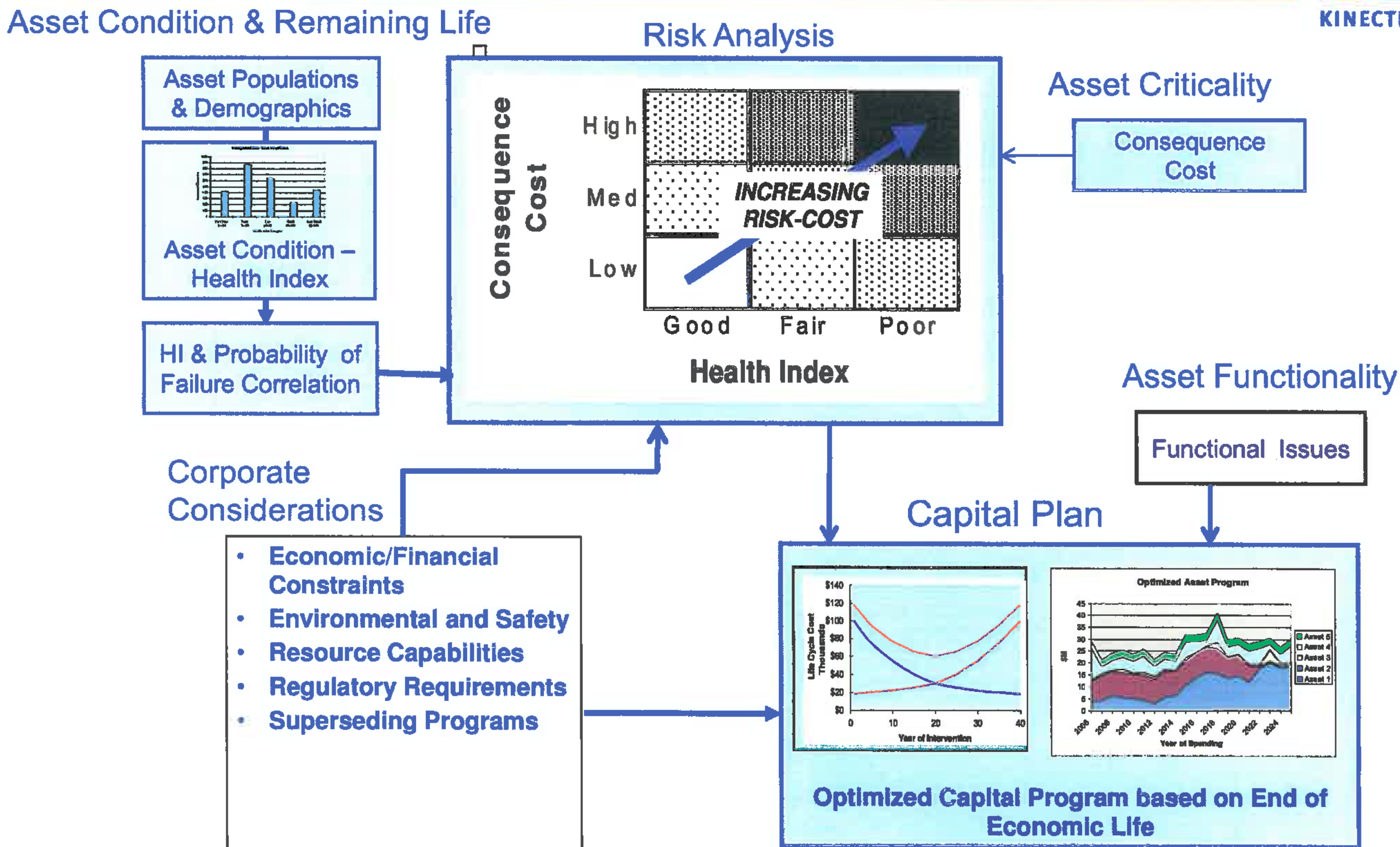
KINECTRICS

Experts in Asset Management

F

ACA & Risk Assessment Methodology Components

KINECTRICS

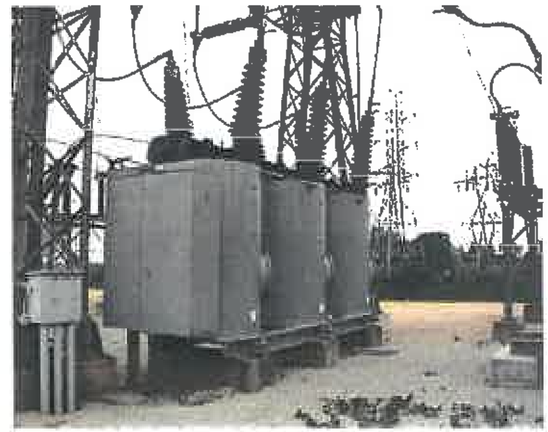


General Asset Condition Data

KINECTRICS

Asset Condition data can include:

- Age
- Historical and present utilization and stress
  - loading, tension
- Test Data
  - unique to each component –DGA, Furan, moisture content, partial discharge, Doble, IR thermography, torsional strength, etc
- Inspection Data
  - corrosion, leaks, cracks, etc
- Maintenance Program and Records
- Reliability Statistics, i.e. Failure and Outage Data
- Environmental Conditions
- Manufacture
  - original quality, product performance industry wide
- Information and opinions from client's staff

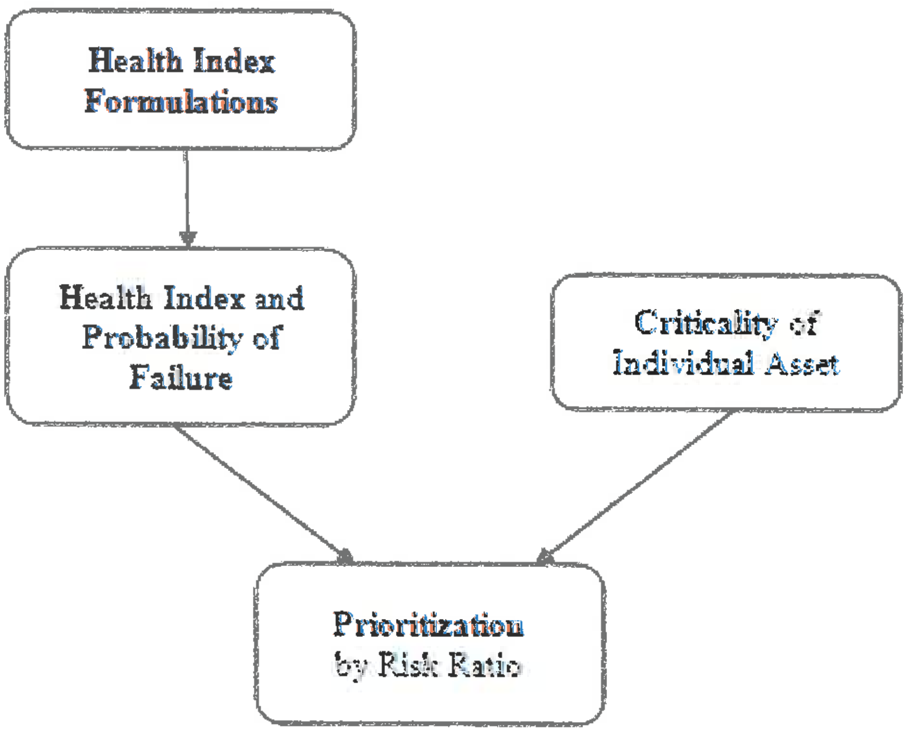


Age is one of the condition parameters used to calculate overall asset condition so that Asset Condition is not only a function of asset age.

Estimating Risk Cost

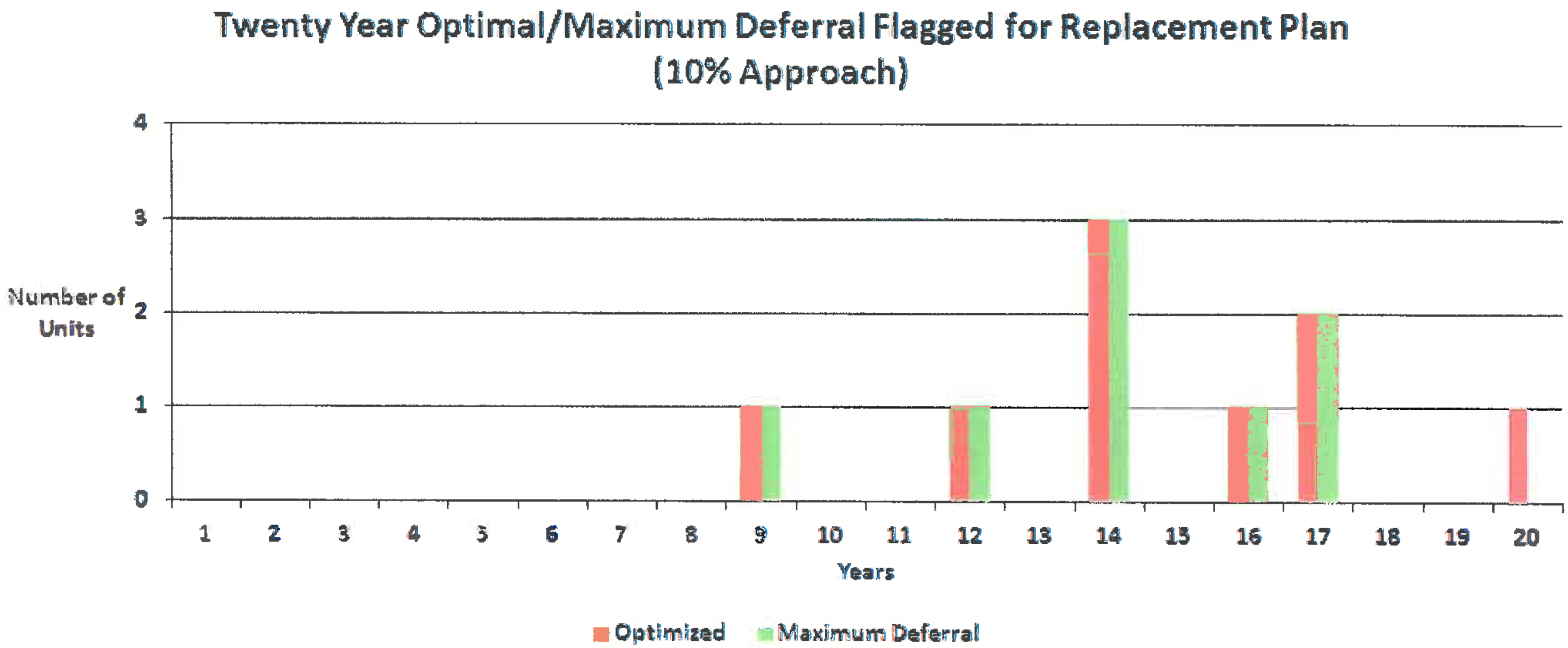
KINECTRICS

Risk Cost = P (failure) x Consequence Cost (Criticality)



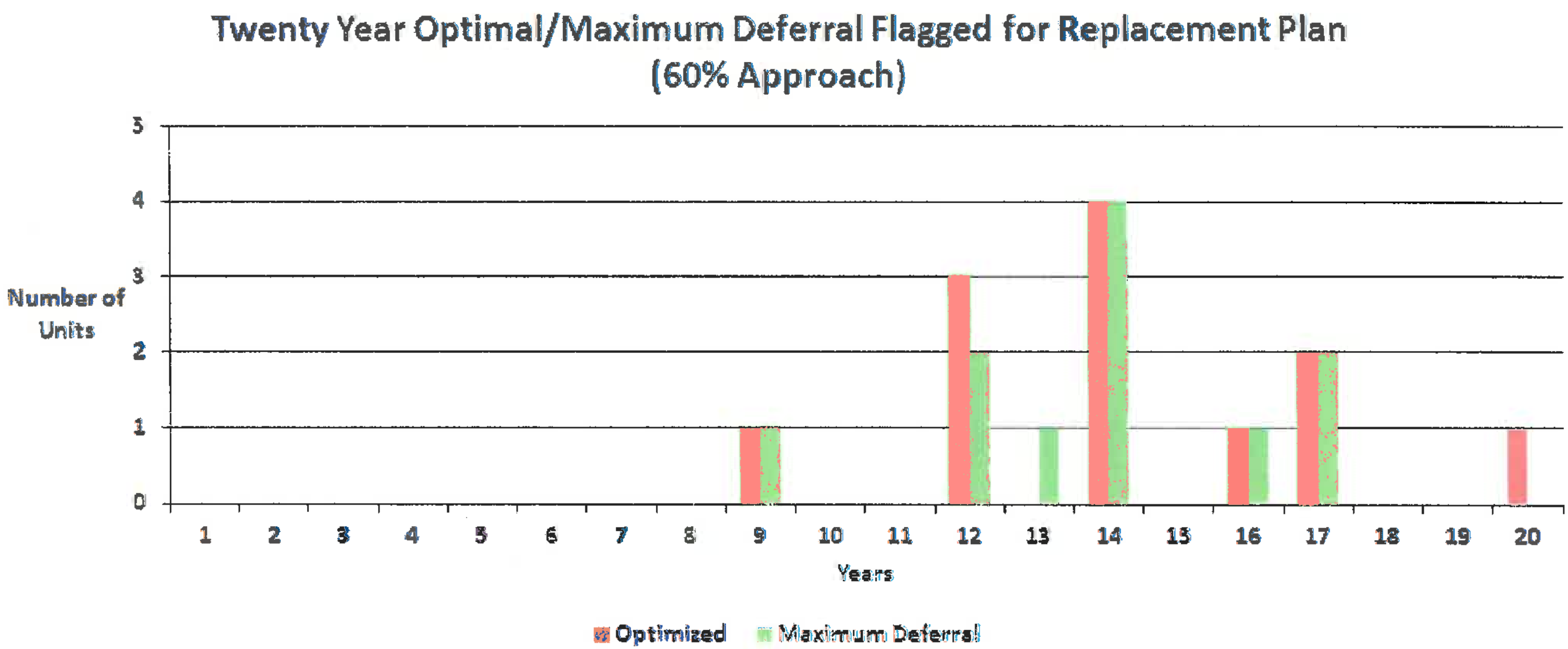
Transformers Flagged for Replacements - 1

KINECTRICS



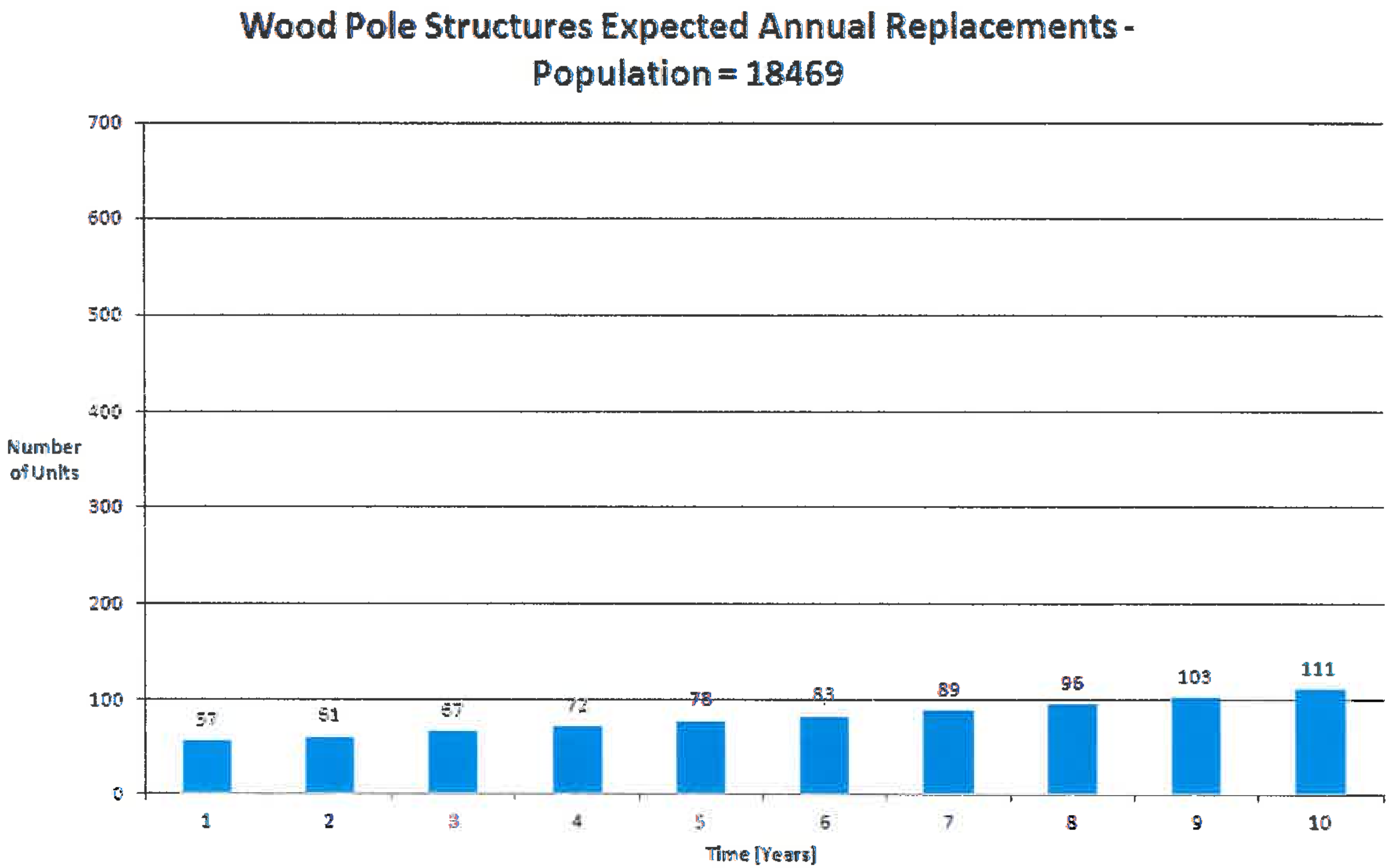
Transformers Flagged for Replacements - 2

KINECTRICS



Wood Poles Flagged for Replacements

KINECTRICS



Prioritized List of Transformers/LTCs – 10% Approach

KINECTRICS

Unique ID (NpHandle)	Location	Age	HI (Final)	Effective Age (HI Final)	POF at Effective Age	Criticality	Risk Factor (Criticality*POF) 10% Approach
[redacted]	[redacted]	8	47.84	59.3	0.38209	1.74	0.663
		35	51.96	56.6	0.27425	1.77	0.486
		40	53.75	55.1	0.22663	1.56	0.354
		10	53.51	55.1	0.22663	1.49	0.338
		45	54.65	54.4	0.19766	1.56	0.309
		36	57.34	51.9	0.14686	1.88	0.275
		38	56.41	52.8	0.15866	1.56	0.248
		12	57.40	51.9	0.14686	1.49	0.219
		40	61.60	48.4	0.08851	1.35	0.120
		49	63.63	46.5	0.06681	1.67	0.111
		36	65.74	44.4	0.04947	1.98	0.098
		38	64.09	45.5	0.05480	1.67	0.091
		27	64.18	45.5	0.05480	1.67	0.091
		18	64.44	45.5	0.05480	1.67	0.091
		11	63.94	46.5	0.06681	1.35	0.090
		44	64.13	45.5	0.05480	1.60	0.088
		34	66.08	43.4	0.04006	1.94	0.078
		13	66.15	43.4	0.04006	1.60	0.064
		21	66.15	43.4	0.04006	1.56	0.063
		44	66.35	43.4	0.04006	1.56	0.063

Recommended Condition Data Improvements - 2

KINECTRICS

- Start collecting information for creating a failure curve for SPAR arms. Age will then be used in conjunction with this failure curve to estimate number of units expected to be replaced annually.
- Start collecting condition data on steel structures by initiating a program of steel tower climbing inspections and footings assessments using ultra-sound methodology
- Use multi-purpose software to unable:

  a) storage of condition input data for multiple years,

  b) updating results based on the condition data changes

  c) analyzing options to deal with assets "flagged for action" and

  d) prioritizing the required investments portfolio

Results Interpretation – Transformers and Breakers - 1

KINECTRICS

- Condition results indicate that MH's transformers and breakers have considerably longer lives than in other jurisdictions. This is due to a combination of rigorous maintenance practices combined with colder than average ambient temperature and moderate loading.
- The "Effective age" of assets was in most cases less than the corresponding chronological age so much so that even using industry failure curves to relate condition with the corresponding probability of failure still resulted in relatively few future replacements.

Results Interpretation – Wood Poles and SPAR Arms

KINECTRICS

- Results using “effective age” MH-specific failure curve resulted in replacement rate very close to the actual one with the predicted steady increase in the number of replacements over the next 20 years.
- Using chronological age instead of “effective age” would have resulted in almost doubling the actual replacement rate for wood poles.
- For SPAR arms only chronological age information was available. Using this information and MH-specific pole failure curves resulted in the replacement rate very close to the actual one. Going forward, failure curves for SPAR arms should be developed as their failure rate may be difference than that of wood poles.

F

How the Results Should be Used

- The results presented support "condition based" long-term replacement strategy. It is important to note that:
  - ✓ The replacement strategy and prioritized list of units "flagged for action" should be used as a starting point. Actual decisions on overall long-term replacement plan and appropriate action for each unit (replace, refurbish, intensify maintenance, adjust spare units inventory, do nothing) should be made by Manitoba Hydro staff using Economic End-of-Life approach and investment prioritization techniques.
  - ✓ Factors other than condition should also be taken into account, such as obsolescence (included to some degree in developing Health Index), system growth requirements, impact on ageing from adjusting maintenance practices, regulatory requirements, etc.
  - ✓ The resultant long-term planning should include requirements for both capital expenditure and staffing as well as requirements for incremental operating costs associated with closing condition data gaps and potential increase in corrective maintenance

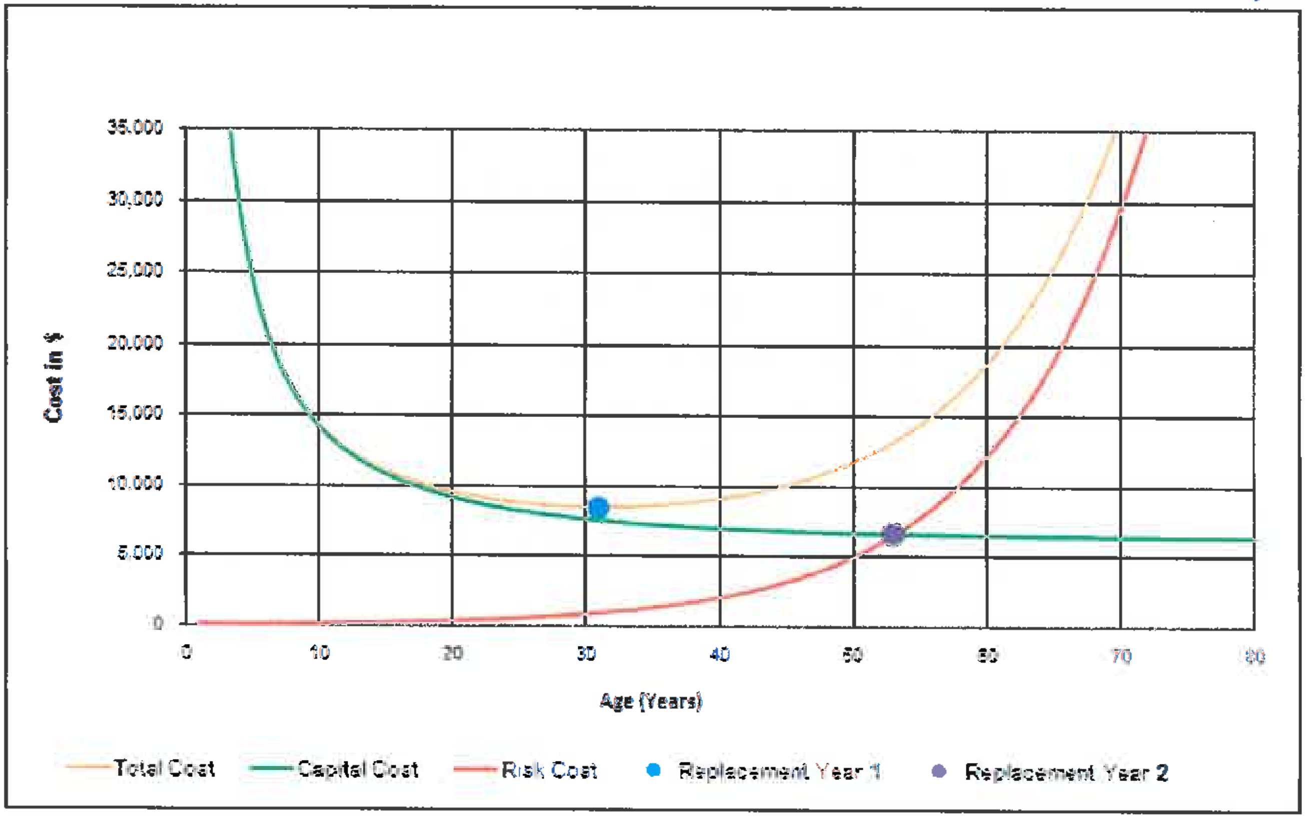
Economic End-of-Life

KINECTRICS

Economic End-of-Life at the point of least life cycle cost

Optimize replacement or rehabilitation timing

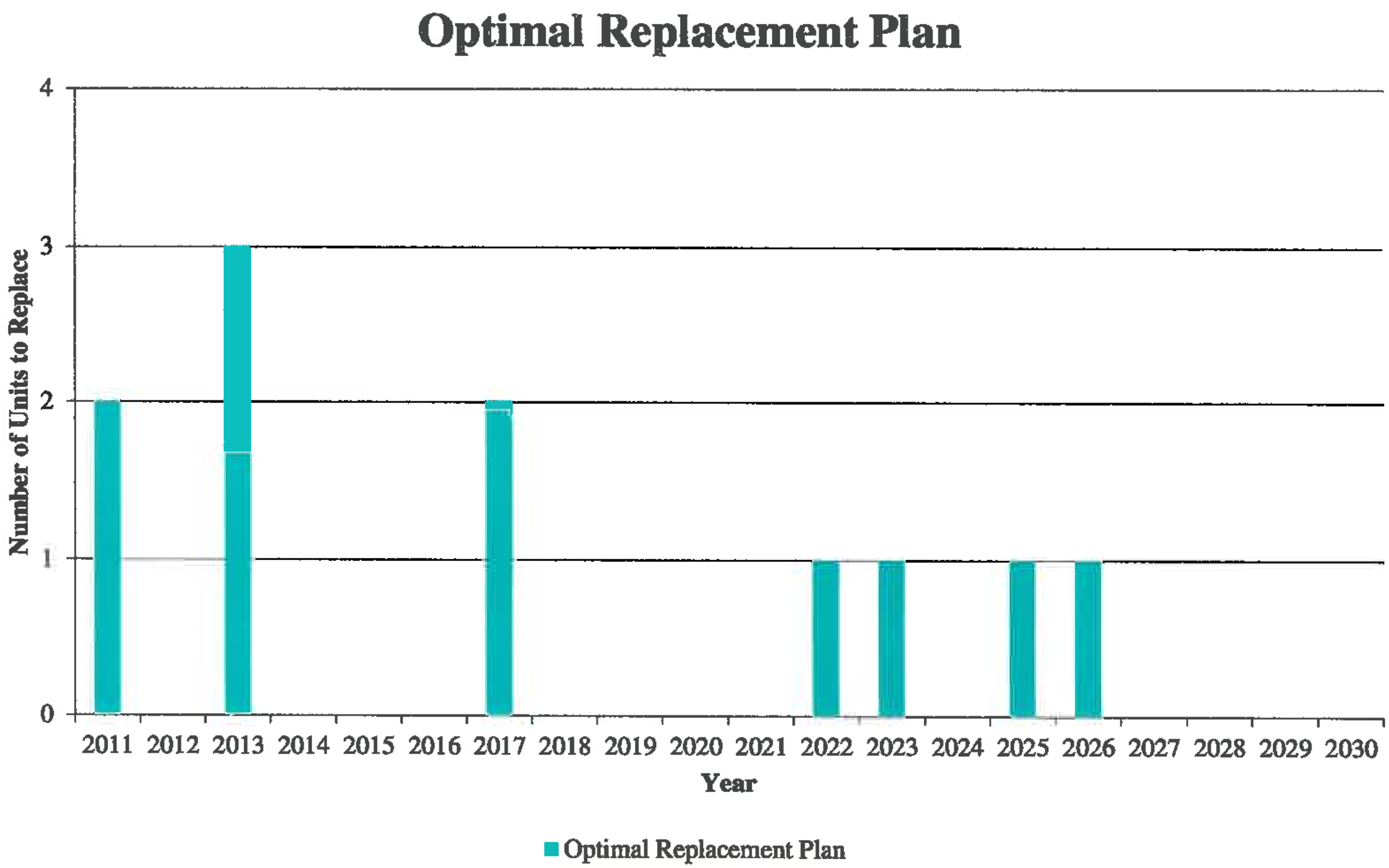
Compares Risk Cost to Capital Cost (includes benefit of delaying capital expenditures, and Maintenance Cost)



6

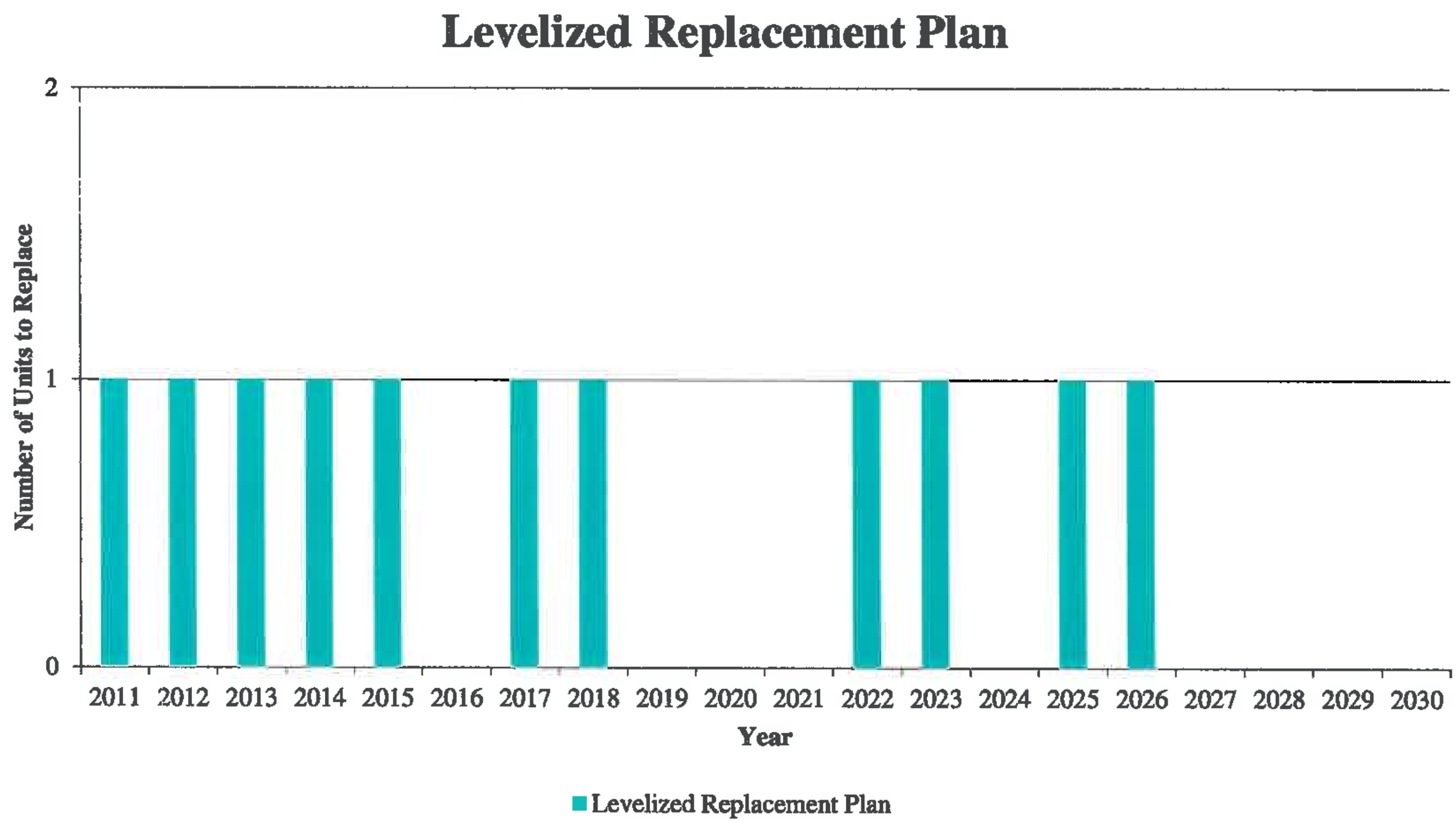
Optimized Capital Plan

KINECTRICS



Levelized Capital Plan

KINECTRICS



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Chapter 5

Consolidated

Distribution System Plan

Delivered: February 24, 2015

Program	Health Index (max score = 100)	Inspection Results (Code A, B, C)	Prioritization Score (max score = 100)
Pole Replacement	not applicable	Used field inspection results to select replacement candidates **Code A**= Very Bad, immediate replacement **Code B**= Fair, replacement candidate for next budget cycle **Code C**= Good condition, no replacement needed and maintain inspection	A higher point total yields greater replacement priority. (scored from % Remaining Strength, Condition, # of Transformers, # of Primary Conductors, # of Switches, Criticality of Pole and Age of Pole.) **NOTE**: Candidates will belong to one of the following groupings: - Remaining strength is less than 60 % - Remaining strength is greater than 60%, however other aspects of the pole are bad (i.e. butt rot, insect infestation, decay, splitting, bending, leaning)
Cable Remediation: Cable Replacement	not applicable	**TAN DELTA TEST RESULTS** **Code A** = Critically Aged. Intervention Required **Code B** = Aged. Further study required. (Repeat testing evey 2 years based on test reults) **Code C** = No Action Required/Repeat after 5 Years	A higher point total yields greater replacement priority. (scored from Age, Cable Condition, Service Quality and Financial Impact)
Cable Remediation: Cable Injection	not applicable	**TAN DELTA TEST RESULTS** **Code A** = Critically Aged. Intervention Required **Code B** = Aged. Further study required. (Repeat testing very 2 years based on test results) **Code C** = No Action Required/Repeat after 5 Years	A higher point total yields greater replacement priority. (scored from Age, Cable Condition, Service Quality and Financial Impact)
Switchgear Replacement	**Good Condition**= high Health Index, >70 **Fair Condition**= middle Health Index, 51-70 **Poor Condition**= low Health Index, <51	Used field inspection results to select replacement candidates. **Code A**= Very Bad, immediate replacement **Code B**= Fair, replacement candidate for next budget cycle **Code C**= Good condition, no replacement needed and maintain inspection	not applicable
Mini-Rupter Switch Replacement	**Good Condition**= high Health Index, >70 **Fair Condition**= middle Health Index, 51-70 **Poor Condition**= low Health Index, <51	Used field inspection results to select replacement candidates **Code A**= Very Bad, immediate replacement **Code B**= Fair, replacement candidate for next budget cycle **Code C**= Good condition, no replacement needed and maintain inspection	not applicable
Automated Switch Replacement	(**Good Condition**= high Health Index, >70 **Fair Condition**= middle Health Index, 51-70 **Poor Condition**= low Health Index, <51	Used field inspection results to select replacement candidates. **Code A**= Very Bad, immediate replacement **Code B**= Fair, replacement candidate for next budget cycle **Code C**= Good condition, no replacement needed and maintain inspection	not applicable
Submersible Transformer Replacement	**Good Condition**= high Health Index, >70 **Fair Condition**= middle Health Index, 51-70 **Poor Condition**= low Health Index, <51	Used field inspection results to select replacement candidates **Code A**= Very Bad, immediate replacement **Code B**= Fair, replacement candidate for next budget cycle **Code C**= Good condition, no replacement needed and maintain inspection	not applicable
Distribution Transformer Replacement	**Good Condition**= high Health Index, >70 **Fair Condition**= middle Health Index, 51-70 **Poor Condition**= low Health Index, <51	Used field inspection results to select replacement candidates. **Code A**= Very Bad, immediate replacement **Code B**= Fair, replacement candidate for next budget cycle **Code C**= Good condition, no replacement needed and maintain inspection	not applicable
Station Equipment Replacement	**Good Condition**= high Health Index, >70 **Fair Condition**= middle Health Index, 51-70 **Poor Condition**= low Health Index, <51	**NOTE**: Inspection & testing results are used to generate the health index and replacement candidates	not applicable

Figure 1: Summary of Health Index Results, Inspection and Testing

The remediation programs for maintaining the distribution system are:

- Pole Remediation (replacement or reinforcement);
- Cable Remediation (replacement and injection);
- Switchgear Replacement;
- Mini-Rupter Switch Replacement;
- Automated Switch Replacement;
- Submersible Transformer Replacement;
- Distribution Transformer Replacement;
- Station Equipment Replacement (Substations & Transformer Stations);
- 44kV Porcelain Insulator Replacement;
- Fault Indicator Replacement;
- Storm Hardening and Rear Lot Remediation;
- Information Systems;
- Facilities;
- Information systems;
- Facilities Remediation; and
- Fleet Replacement.

These are further described below.

<u>Pole Remediation</u>

Through an annual inspection and testing program, PowerStream monitors the condition of its poles to ensure that they meet minimum requirements for safety and reliability. Among other factors, PowerStream is guided in its pole assessment process by Clause 8.3.1.3 of CSA Standard C22.3 No. 1-10, which states that:

> *"when the strength of a structure has deteriorated to 60% of the required capacity, the structure shall be reinforced or replaced".*

In the quote from the CSA standard, the reference to capacity is interchangeable with pole strength for this program.

Other considerations include pole condition information such as rot, decay, splitting, insect infestation, bending, and leaning. PowerStream believes that the remediation of poles exhibiting poor (or worse) condition is non-discretionary. The remediation is required to maintain compliance with the CSA code, as well as considerations for safety of the public and for workers operating in, on, or around the poles and their associated equipment.

When an existing pole is replaced, PowerStream must install the new pole according to the current standards. In most cases the existing associated components attached to the existing pole are also at end-of-life and therefore must also be replaced. Examples of the associated components are brackets, cross arms, down guys, anchors, ground wires, insulators, arresters, and fasteners. If in any particular case, the pole has transformers, switches, or other equipment with significant remaining life, these are salvaged and re-used.

When a pole in reinforced, the base will be restored to full strength. See Figure 2.

Figure 2: Pole Reinforcement Installation

PowerStream annually inspects and tests a portion of pole population. The pole remediation candidates are selected based on the combination worst candidates of the following two groupings:

- Poles that have less than 60% remaining strength (CSA reference); or
- Poles that have more than 60% remaining strength but exhibit worsening conditions such as rot, decay, splitting, insect infestation, bending, and leaning.

Poles are prioritized based on their assessed health index, the worst being selected for replacement or reinforcement. See Figure 3 below.

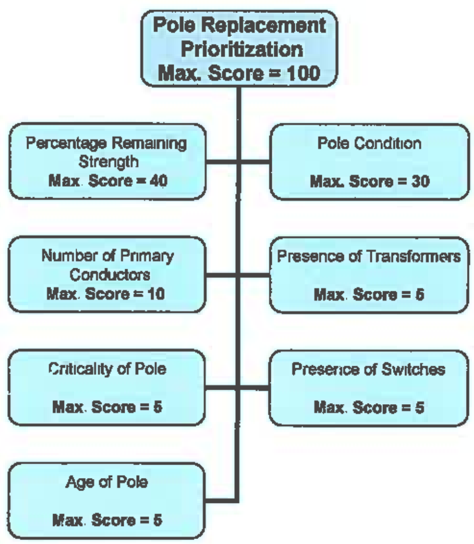

Figure 3: Pole Prioritization Matrix

Cable Remediation

PowerStream monitors the condition of its primary cables to ensure that they meet minimum requirements for safety and reliability. The asset demographics indicate that the oldest cables of the PowerStream cable population are at end-of-life, are deteriorating and are failing. To mitigate the effects of this, annual remediation efforts are required.

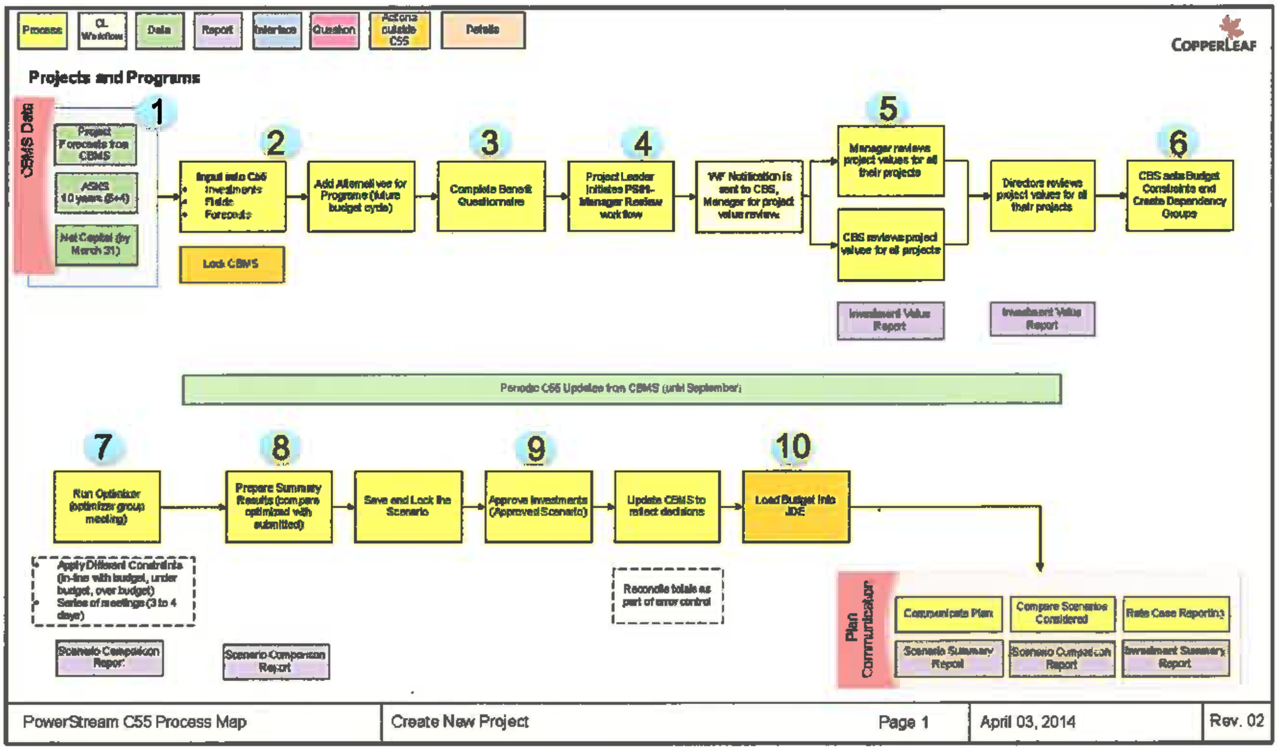

Figure 5: Capital Budget Cycle

Key Step One – Capital Budget Management System (CBMS) Entry

The Capital Budget Management System is one of the first tools applied in the budget cycle. PowerStream's Capital Investment Process incorporates a ten year forward looking plan. Business units that have major capital expenditures put together their own ten year departmental capital expenditure plans and five year budgets.

The business unit ten year capital expenditure plans are summarized into a Corporate Ten Year Capital Expenditure Plan. The information is combined from the following business units:

- Asset Investment Planning;
- Distribution Design;
- Operations;
- Lines;
- Supply Chain Services;

- Smart Grid & Metering; and
- Information Services.

Early in the calendar year a request is sent out by Asset Investment Planning to all business units in PowerStream to prepare ten year capital expenditure plans and five year budgets. These plans are developed over the January to March period. The information in the Corporate Ten Year Capital Expenditure Plan is used by the Finance Department in their financial models to consider affordability. In addition, information in the first five year plan is used in rate planning for the forward looking years.

In 2014, all project leads entered their project information (costs, year of expenditure, rationale etc.) into the Capital Budget Management System (CBMS) tool, which is then loaded into the Optimization tool for review and consolidation. In 2015, for efficiency gains, a project will be proposed to allow direct entry of the budget data into the optimization tool. Refer to Exhibit G, Tab 2, Section 5.2.3 page 7, for additional information.

These five year plans serve as the starting base for the development of the Corporate Capital Expenditure Plan.

The business unit capital plans serve three purposes:

i) assist business units in their future planning and enable the business units to provide solid five year budgets;
ii) forms the basis of the information provided in a rate application for the forward looking years; and
iii) provides the Finance team with information for financial planning.

Business units provide details in their five year budgets on forecast capital spending requirements and describe the process by which they have determined the capital spending requirements. Specific projects/programs and costs identified in the plans are generally preliminary and the projects/programs identified in the plans may or may not be approved for execution at this point.

Key Step Two – Input Data into Optimization Tool (Input into C55)

Data is entered into the Copperleaf C55 Optimization tool. Critical fields are entered including details on the proposed investment, forecasts of the expenditures over the five year budget horizon, answers to specific questions asked, based on the investment type, for both benefit and risk.

The value and risk questionnaire was created using vendor expertise, existing practices and the contribution of project leads as experts who request capital projects or programs.

Within Copperleaf's C55 program, all projects are valued (and optimized) based upon a Value Function. The Value Function is a weighting of a number of Value Measures. Value Measures can include risk mitigation, financial benefits, impacts on Key Performance Indicators (KPI), and cost. The Value Function was configured to reflect how projects contribute to PowerStream's strategic objectives as shown below. Questions were designed to provide value and scoring for these strategic elements, as noted in Exhibit G, Tab 2, Section 5.2.1, Figure 1.

21

Financial Benefits:

- Hard Financial Benefits
- Soft Financial Benefits

Productivity

4 Pillars	Corporate Strategic Objective
Financial	F2 (provide an optimized rate of return)
Processes	I1 (focus on continuous improvement)

KPI Impacts:

- Reliability
-
- Reliability for Spares
-
- Customer Communication
- Customer Service
-
- Rate Ready Organization
- Environmental Improvements
- Employee Wellness
- Technological Innovation

Customers	C1 (deliver professional services and exceptiopnal customer experience)
Customers	C1 (deliver professional services and exceptiopnal customer experience)
Customers	C3 (continue developing the PowerStream brand)
Customers	C1 (deliver professional services and exceptiopnal customer experience)
Processes	I4 (develop a rate submission ready organization)
Foundation	E2 (ensure a safe and healthy workplace)
Foundation	E1 (be a best in class employer)
Foundation	E4 (investigate and apply new and innovative technologies)

Risk Mitigation:

IT Capacity	Foundation	E3 (build integrated technoogy platforms)
Financial	Financial	F2 (provide an optimaized rate of return)
Environmental	Foundation	E1 (be a best in class employer)
Safety	Foundation	E2 (ensure a safe and healthy workplace)
Distribution	Customers	C2 (provide customer swith cost effective, competive distribution rates)
Compliance	Processes	I3 (Shape and Influence positive advocacy)

Cost:

Project Cost	Financials	F1 (increase shareholder value)

Key Step Three – Complete Benefit Questionnaire

Once project identification is complete, the business units, in conjunction with the Capital Budget Supervisor, answer a series of questions about each project/program. The questions posed are aligned with PowerStream's corporate goals and risk matrix.

The answers to the questions form the basis for scoring both the value of the project to the corporation and its customers if the project is undertaken and the risk to the corporation and its customers if the project is not completed in the planned year. The Capital Budget Supervisor coordinates the business units across the organization to ensure that timelines are met, and consistent interpretations of the answers are applied.

In addition to answering the benefit and risk questions required for scoring the projects/programs, for those projects/programs that exceed the materiality threshold, additional questions with respect to Chapter 5 of this rate filing are posed and business leads are required to provide the requisite information. Business cases, as appropriate, are also created. Once the questions on the projects are all answered, the data on the projects is ready for optimization. PowerStream utilizes Copperleaf's C55 product for optimizing multi-year portfolios.

The current configuration of PowerStream's Value Function and the Value Measures that comprise the Value Function is summarized below:

- Each of the Value Measures is calibrated to the same scale (1 value point approximately equal to $1000). Consequently, within the Value Function, each of the Value Measures (except Project Cost) is weighed with the same value of +1. As Project Cost is a negative contributor to Project Value it is weighted with a cost of -1.
- All Value Measures are computed on an annual basis (e.g. the financial benefits for 2017 can be specified as being different than 2018). The stream of benefits (or costs) is converted to a single value for the Value Measure, by taking the Present Value of the stream, back to the beginning of the current fiscal year. The PV calculation uses the system defined discount rate.

- The Value of Risk Mitigation in all risk categories is computed using the same methodology. The project owner specifies the Baseline Risk and the risk present if the project is not completed.
- Residual Risk: The risk present if the project is completed. The value of Risk Mitigated is computed as: Baseline Risk – Residual Risk.
- For each risk the project owner specifies both the consequence and the probability of Consequence
- Projects in the following categories have been identified as Mandatory or Must Do investments as PowerStream is mandated to complete these investments, specifically:
    - Emergency Restoration;
    - Subdivision Services;
    - Road Authority Projects;
    - Emerging Development Capital;
    - Customer RGEN;
    - ICI projects;
    - Subdivisions;
    - Layouts; and
    - Emerging customers.

These projects are flagged as "must do" and are considered as mandatory as part of the optimization process. These projects have mitigated risk value as they are mitigating a compliance risk. These projects are subtracted, by the system, from the constraint amount, effectively reducing the amount of money available for competing projects and programs.

The value function combines all the value measures to compute the overall value of an investment. The value of an investment reflects the total value that the project is bringing to PowerStream, taking into account all of its financial benefits, impact on KPIs, risk mitigation and costs.

Key Step Four – Initiate Manager Review

Once a project lead has completed a project/program entry into C55, and automatic workflow notification is produced to advise the Manager, Director or VP and the Capital Budget Supervisor that the item is ready for review.

Key Step Five – Manager Review Projects/Program Values

Once a project/program, or series of projects/programs have been entered by project leads, their respective managers, directors or vice-presidents can review, on an individual or comparative basis, projects under their purview. Once reviewed and any follow-up questions answered, the projects/programs are then ready for the optimization process.

Key Step Six – Set Budget Constraint

The Finance department sets several budget funding level constraints to allow for analysis and to establish financial criteria to permit the optimization results to be compared to the optimal funding amount. These levels are available for optimization runs to create varied constraint scenarios.

Key Step Seven – Run the Optimization

The C55 tool is capable of running multiple scenarios with the project/program list being optimized for the greatest annual value. All capital projects/programs in the corporation are run through the Optimizer tool with projects from IT, fleet, planning, station construction and lines construction competing on value through the same tool. The multiple scenarios permit the results to be compared under various constraints and risks. The software tool takes all the projects/programs within the capital portfolio, calculates a numeric dollar value based on the benefit and risk calculations and the initial capital cost, and uses that value in the optimization process.

The C55 optimizer selects the combination of start dates of projects that brings the highest total value to PowerStream while fitting within the specified financial constraints.

Until projects are compared with one or another and the financial constraints are specified it is not known whether a project will be funded or not – so a project lead cannot know for certain whether or not a project will be funded.

Key Step Eight – Prepare the Results of the Various Scenarios

With the constraints set and the "must do" projects/programs accounted for, the results of the various scenarios are presented and reviewed by a multi-departmental senior optimization team, who discuss which projects must be approved as part of the five year capital budget. Members of the senior optimizer team include key leaders from each of the business units who have major capital spend across the corporation, as well as Rates & Regulatory department and Organizational Effectiveness department representatives.

Projects that were scored negative, are generally deferred beyond the six year horizon but are also discussed to ensure that any intangible benefits are considered. Once reviews and dependencies are considered, optimization can be run several times to achieve that optimal balance between the computation (science) and human element (art).

A decision is made on the preferred constraint scenario, and any project/program adjustments and deliberations occur prior to finalizing the preferred listing.

Key Step Nine - Determining and Approving the Portfolio of Projects/Programs

The result from the senior optimization team is a proposed scenario of multi-year projects and programs that will be approved by the PowerStream's Executive Management Team (EMT) and the Audit and Finance Committee for approval prior to approval by the Board of Directors.

The proposed scenario is submitted for approval with the appropriate business case details. For projects less than $500,000 the information is in its "mini-business case" format for each project. For any specific project or program that is greater than $500,000 or for IT related projects greater than $100,000, a full business case is provided and submitted for approval.

In conjunction with this process, for a rate filing year, the DS Plan's Customer Engagement process, as detailed in Exhibit G, Tab 2, Section 5.4.2, considers the responses of PowerStream's customers and a detailed review is held to correlate the proposed plan to the engagement results.

Key Step Ten – Load the Approved Portfolio into JD Edwards

The approved first year portfolio of projects/programs is loaded into the JD Edwards financial system so that it is available for all departments use within the project execution process, enabling project/program implementation.

Maintenance Planning Criteria and Assumptions

PowerStream has two main capital activities related to maintenance, which are planned and unplanned maintenance.

Planned (Proactive) Inspection and Maintenance

Activities associated with PowerStream's annual distribution inspection and preventative maintenance program are detailed in Table 2. When an inspection is performed on a given set of assets, a rating code is assigned. If the rating code assigned warrants immediate replacement, the replacement cost will generally be capitalized, while repairs will generally be expensed.

	2015	2016	2017	2018	2019	2020
O & M COSTS	3,290,425	**3,824,791**	4,364,492	**4,909,270**	5,459,443	6,014,538
insulator washing	140,000	141,400	142,814	144,242	145,684	147,142
pole testing	185,000	186,850	188,719	190,606	192,512	194,437
underground cable testing	51,945	53,177	54,431	55,506	56,521	57,417
dry ice cleaning	353,295	356,829	360,397	363,999	367,640	371,317
infrared scanning	146,856	148,516	150,193	151,841	153,490	155,104
overhead switch maintenance	353,329	357,419	361,532	365,606	369,752	373,528
vegetation management	2,060,000	2,580,600	3,106,406	3,637,470	4,173,844	4,715,593

Table 2: Annual O & M Spending

A description of these is below.

Insulator Washing

Overhead line insulator washing is required annually to prevent failure in the distribution system. Insulators become contaminated by road salt or other airborne contaminants which can result in flashovers and interruption of power. Insulator washing is carried out without necessitating isolation of the overhead circuits and the resulting customer interruptions. It also includes visual inspection and identification of any damaged equipment in the main feeder infrastructure.

Pole Testing

As part of PowerStream's Asset Condition Assessment (ACA) Program, wood poles are inspected and tested. This work is performed by a contractor who submits electronic records of their inspections/tests to the Asset Investment Planning department. Results of the testing are used to determine candidates for pole remediation. Refer to Exhibit 2, Tab 4, Section 5.3.3 for information on the pole remediation program.

Underground Cable Testing

In 2012, PowerStream commenced a program to perform Very Low Frequency ("VLF") Tan Delta testing of its underground cable to determine if there has been any deterioration in the cable insulation. Targeted areas, based upon cable age and deteriorating performance, are identified and tested, and the results and taken into consideration for the selection of areas for cable remediation. Refer to Exhibit G, Tab 2, Section 5.3.3 for information on the cable remediation program.

Dry Ice Cleaning

The dry-ice cleaning program for air-insulated pad-mounted switchgear and vault room switchgear is a cleaning method that allows an efficient and cost effective maintenance of switchgear. Air-insulated switchgear become contaminated with dirt, dust and road salt that can lead to flashovers and equipment failure. The high pressure dry ice method of cleaning allows for air-insulated switchgear to be cleaned without the necessity of isolating the equipment and removing the unit from service. Switchgear is typically cleaned on a six year cycle unless a location is determined to require more frequent cleaning due to high levels of contamination.

Infrared Scanning

PowerStream's Lines Department also uses infrared scanning to identify overheating components on its overhead and underground distribution system. As a result of the infrared scanning, equipment showing signs of overheating is scheduled for repair or replacement on a priority level based on the severity of the overheating.

Overhead Switch Maintenance

Maintenance of three phase gang operated switches, both manually operated and remotely operated, is required to ensure the switches are free of contamination and operate smoothly and efficiently. PowerStream currently maintains the switches over a five year cycle. Maintenance of overhead switches requires isolation of the switches.

Vegetation Management

PowerStream's vegetation management program was historically based on a five-year tree trimming cycle, with adjustments for more densely treed, overhead areas. Targeted tree trimming that is not part of the regular five-year cycle was carried out directly as a result of outages caused by trees and as part of the worst performing feeder program. In assessing the effectiveness of the tree trimming program, it became evident that there was a trend toward increased "reactionary" tree trimming as a result of outages and to meet the needs of the worst performing feeder program. This was diverting resources away from the annual cycle trimming program and upon review it was determined that the five year trimming cycle was not adequate to keep up with tree growth across the service territory. As such the tree trimming cycle has been adjusted to a three year cycle across the territory.

Additionally, further vegetation management strategies were recommended by the System Hardening review as a result of the ice storm. PowerStream has changed its policy for rear yards and heavily treed front yards from a five year cycle to a two year cycle. Rural areas now have a 4 year tree trimming cycle where previously they were not part of the tree trimming cycle.

Unplanned (Reactive) Maintenance

Activities in this category are typically associated with equipment failures that are usually accompanied by outage trouble shooting and restoration. Power interruptions on the distribution system result from a variety of causes as indicated by the multitude of Canadian Electrical Association (CEA) cause codes. Responses to outages are performed by trouble crews.

Where the repairs made to the distribution system are minor, maintenance work orders are charged. This includes work such as splicing conductors, repairing guying and down grounds on poles, tightening loose attachments, painting rusted tanks, levelling uneven pad bases or repositioning shifted transformers and repairing secondary failures.

Impact of System Renewal on Routine O&M and Emergency/Reactive Repairs

Routine O&M

Although System Operations and Maintenance (O&M) and capital investments are interrelated, a significant portion of System O&M expenditures are directed to activities that are independent of specific capital expenditure, including:

- Testing of assets for health condition assessments necessary to provide the information that is used to plan the capital programs;

Items b), c) and i) - Non Recoverable replacement of Distribution Equipment due to accidents/vandalism: This subcategory is trending upwards by inflationary amounts from 2015 to 2107, and trends downwards from 2018-2020 on recoverable as a focus on recovering these costs will be implemented.

Items d) and k) - Storm Damage - Replacement of distribution equipment due to storms: This sub-category is expected to trend upwards from 2015-2018, and then is expected to trend downwards in 2019 and beyond as a result of storm hardening initiatives.

Item e) Switchgears - Unscheduled Replacement of Failed (end of useful Life) Distribution Equipment: This sub-category is expected to trend upwards from 2015-2018, and then is expected to trend downwards as a result of proactive replacement programs.

Items f), g) and k) - Unscheduled Replacement of Failed (end of useful Life) Poles, Conductors and Devices: This sub-category is expected to trend upwards from 2015-2018, and then is expected to commence trending downwards as a result of remediation programs.

Item h) Inspections, Patrol, Testing: This sub-category is expected to trend upwards by inflationary amounts.

Item l) Cable Faults – Primary: This sub-category is expected to trend upwards by inflationary amounts as the cable remediation program is expected to maintain the current levels.

Item m) Cable Faults – Secondary: This sub-category is expected to trend upwards as the secondary system ages and additional plant is installed. There is no proactive replacement program for this asset (run to failure).

Item n) Customer Premises: This sub-category is expected to trend upwards by inflationary amounts.

Item o) Switching for Control Room: This sub-category is expected to trend upwards by inflationary amounts.

Item p) Permanent Removals: This sub-category is expected to trend upwards by inflationary amounts.

Impact of System Renewal on Reliability

As seen in Figure 7, 2013 was a difficult year for PowerStream. Since reliability indices are lagging, the rolling three year average SAIDI will have increased. Even though PowerStream will be within its historical three year average, PowerStream will not be using this as its indication of reliability improvement. Instead, PowerStream will be striving for targets determined by its Reliability Model.

In 2014, PowerStream created its Reliability Model. This model was designed to calculate a five year forward looking reliability projection in terms of SAIDI performance based on the past five years of reliability history and future planned capital system renewal reliability related improvements.

Within the model, outage causes are associated with controllable and uncontrollable factors that are included in the Canadian Electrical Association outage cause codes. These are listed in Table 4.

(CEA Code #) Controllable factors	(CEA Code #) Uncontrollable factors
(5) Defective Equipment	(9) Foreign Interference (3rd party event)
(1) Scheduled Outage (by P/S to do work)	(2) Loss of Supply (Hydro One)
(3) Tree Contact	(7) Adverse Environment *(Weather Dependent) ie salt*
(8) Human Element	6) Adverse Weather *(Weather Dependent)*
	(4) Lightning *(Weather Dependent)*

Table 4: Controllable and Uncontrollable Outage Cause Codes

The model breaks down SAIDI into its controllable and uncontrollable factors and identifies contributions made by factors tied to weather, as weather has a significant impact on reliability and makes up most of the uncontrollable SAIDI. Refer to Figure 7.

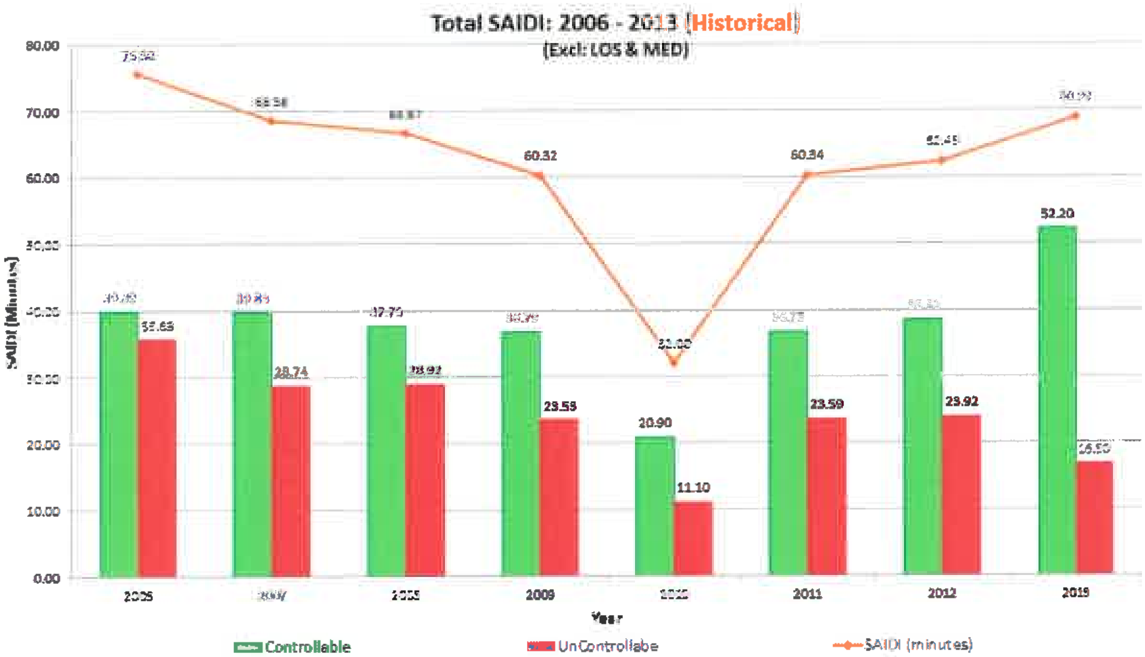

Figure 7: Historical Values for SAIDI to depict Weather Variability

The model, for each of the years between 2015 and 2020, makes future performance predictions based on the variables outlined in the following relationship:

Predicted SAIDI	=	Baseline SAIDI (Avg last 5 yr)	+	Weather Outages	+	Increase in Scheduled Outages	-	Reliability Improvements

These are defined below:

- 'Baseline SAIDI' or starting point CMI (Customer Minutes of Interruption) is calculated by averaging the past five years SAIDI performance due to non-weather related outages.
- 'Weather Outages' is calculated by averaging the SAIDI performance due to weather related outages over the past five years.
- 'Increase in Scheduled Outages' is calculated using the yearly increase in capital spend as a proportional guideline.
- 'Reliability Improvements' is calculated based on the CMI Savings achieved from each technical project or work program accounted for in the 5 Year Reliability Work Plan.

A list of the technical projects and work programs included in the 2015 to 2019 Reliability Work Plan that impact SAIDI are shown in Table 5. The distribution system programs are described starting on page 4 of this Section (5.3.3).

#	Description	Capital	O&M
1	Worst Performing Feeders (WPF)		X
2	Inspection and Maintenance		X
3	Pole Remediation	X	
4	Cable Remediation	X	
5	Switchgear Replacement	X	
6	Mini-Rupter Switch Replacement Program	X	
7	Automated Switch Replacement	X	
8	Submersible Transformer Replacement	X	
9	Distribution Transformer Replacement	X	
10	44kV Insulators Replacement Program	X	
11	Fault Indicator Program	X	
12	Storm Hardening & Rear Lot Remediation	X	
13	Distribution Automation	X	

Table 5: 2015 to 2019 Reliability Based Projects and Programs

Based on the Reliability Model calculations, the 5 year reliability forecast for 2015 to 2019 is depicted in Figure 8.

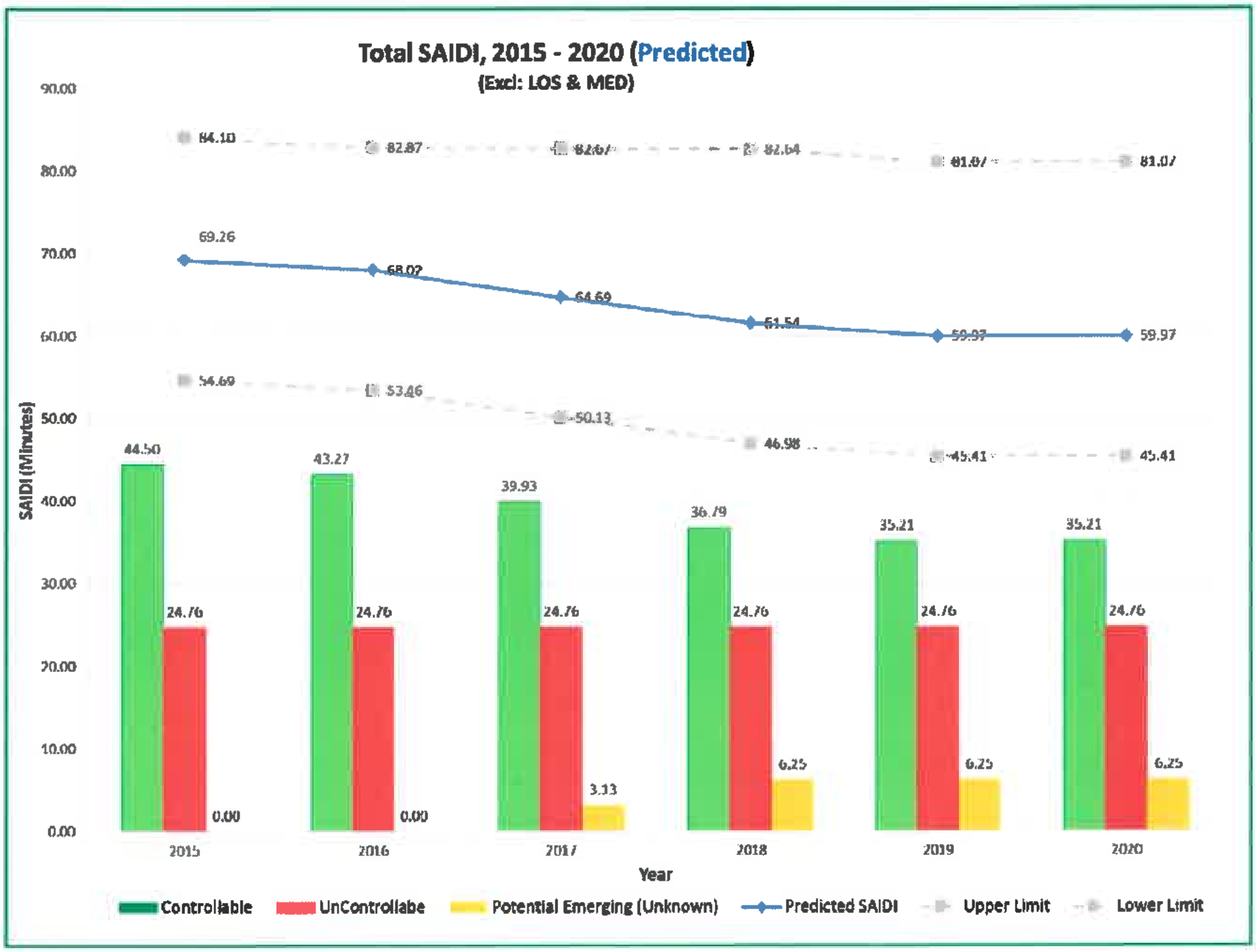

Figure 8: 2015 to 2019 Reliability Projection

Figure 8 breaks down the Future years' predicted SAIDI into its controllable and uncontrollable codes. The green bars indicate contributed SAIDI from controllable factors and red bars indicate contributed SAIDI from uncontrollable factors. The yellow bars are included to account for a certain level of uncertainty that arises in future years due to potential emerging reliability problems that are yet unknown. The blue line on the chart illustrates the total SAIDI prediction for each year.

Since weather has appeared to be relatively unpredictable based on the analysis of previous year's performance, an upper and lower limit are included to create boundaries for the SAIDI targets. These are represented using grey dotted lines.

The upper and lower bounds are there to account for the unpredictable nature of the weather and other emerging outages that could disrupt the targets. The upper limit is calculated using three Standard Deviations of the average performance. The lower limit is calculated based on the minimum SAIDI experienced in previous years, as it is expected that weather would not be milder than has been in the past.

In summary, there is an expectation that the projects and programs will lead to a modest improvement in reliability to customers as the controllable portion of the SAIDI will decrease as the capital projects/programs and the O& M projects are implemented.

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MANITOBA HYDRO
2012 ASSET CONDITION ASSESSMENT

December 17, 2012

Kinectrics Inc.
800 Kipling Avenue
Toronto, ON
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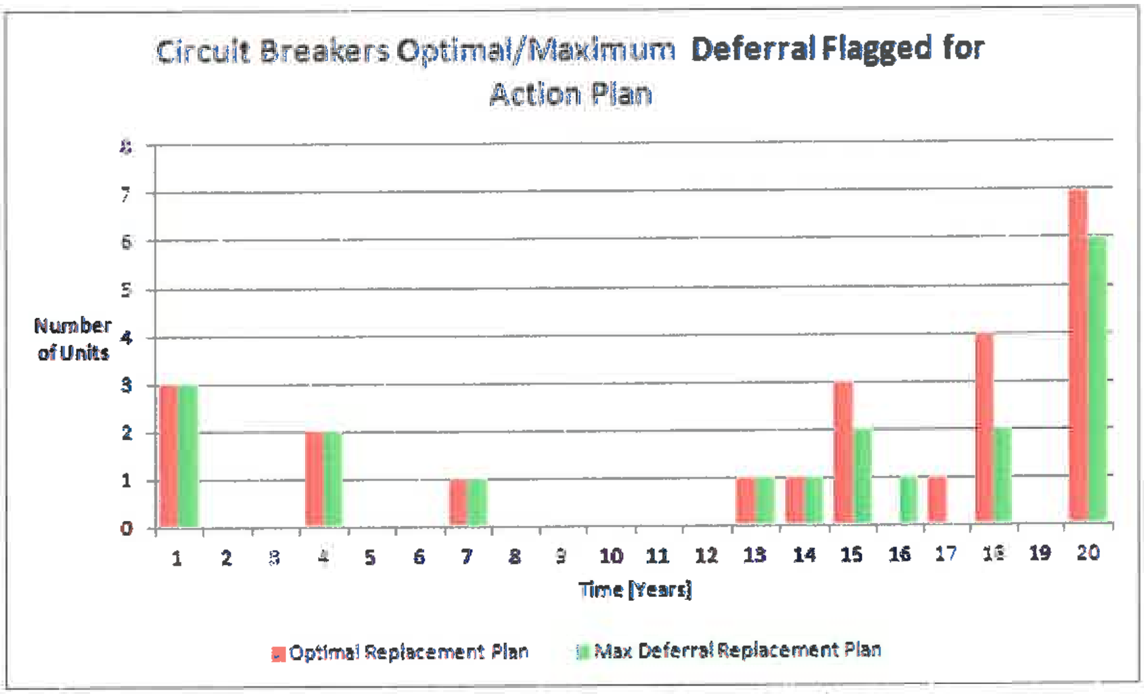

Figure 7 Circuit Breakers Flagged for Action Plan

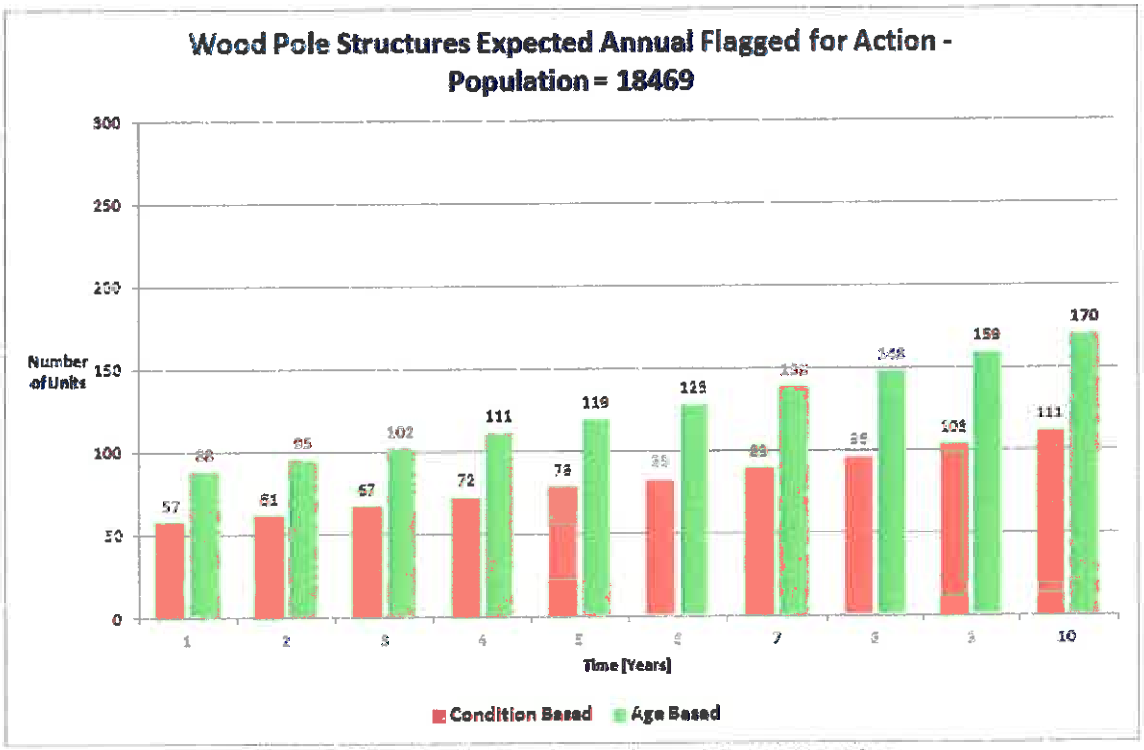

Figure 8 Wood Pole Structures Flagged for Action Plan

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Table 5 Age Criteria

Parameter Score	Condition Description
4	0-19
3	20-29
2	30-39
1	40-44
0	45+

Table 6 shows a sample Health Index evaluation for a particular oil breaker. The sub-condition parameter scores (CPFs) shown are assumed values between 0 through 4.

The Condition Parameter Score (CPS) is evaluated as per Equation 2. The Health Index (HI) is calculated as per Equation 1. As no de-rating factors are defined, there is no multiplier for the final Health Index.

Table 6 Sample Health Index Calculation

Condition Parameters	Operating Mechanism			Contact Performance			Arc Extinction			Insulation			Service Record		
Sub-Condition Parameters Scores (CPF) Weights (WCPF)	Sub-Condition Parameter	CPF	Weight (WCPF)	Sub-Condition Parameter	CPF	Weight (WCPF)	Sub-Condition Parameter	CPF	Weight (WCPF)	Sub-Condition Parameter	CPF	Weight (WCPF)	Sub-Condition Parameter	CPF	Weight (WCPF)
	Lubrication	4	9	Closing Time	2	1	Moisture	4	8	Insulation	4	1	Operating Counter	3	2
	Linkage	2	5	Trip Time	3	3	Leakage	5	1				Loading	4	2
	Cabinet	3	2	Contact Resistance	2	1	Tank	5	2				Age	3	1
				Arcing Contact	3	1	Oil Level	2	1						
							Oil Quality	3	8						
Condition Parameter Score (CPS)	Operating Mechanism CPS (4*9 + 2*5 + 3*2) / (9+5+2) = 3.25			Contact Performance CPS (2*1 + 3*3 + 2*1 + 3*1) / (1+3+1+1) = 2.67			Arc Extinction CPS (4*8 + 5*1 + 5*2 + 2*1 + 3*8) / (8+1+2+1+8) = 3.35			Insulation CPS (4*1) / (1) = 4			Service Record CPS (3*2 + 4*2 + 3*1) / (2+2+1) = 3.4		
Weights (WCP)	Weight = 14			Weight = 7			Weight = 9			Weight = 2			Weight = 5		
Health Index (HI)	$HI = \frac{(3.25*14 + 2.67*7 + 3.35*9 + 4*2 + 3.4*5)}{(14 + 7 + 9 + 2 + 5)*4} =$ 80.6%														

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1.6 Criticality and Condition-Based Flagged for Action Plans

As it is assumed that Substation Transformers/Load Tap Changers are proactively replaced, the risk assessment and replacement procedure described in Section II.2.3 was applied for this asset class.

The following table shows the detailed criticality matrix for transformers/LTCs. Such a matrix is used to calculate criticality of each unit.

Table 35 Criticality Factors for Transformers/LTCs

Criticality Factor (CF)	Description	Weight (WCF)	Score (CFS)	
Load Criticality	Outage to bank would not result in outage to restoration-time-sensitive customers (e.g. hospitals, government buildings, some industrial/commercial)	15	Low	0
	Outage to bank would result in outage to restoration-time-sensitive customers (e.g. hospitals, government buildings, some industrial/commercial)		High	1
Physical Protection	Transformer has oil containment AND deluge system, blast wall (or lots of physical space between transformers)	15	Low	0
	Transformer has oil containment but no blast wall or deluge system (transformers in close proximity)		Medium	0.5
	Transformer has no oil containment, blast wall or deluge system		High	1
Customer Impact	Outage impacts no customers	15	No	0
	Outage impacts less than 1,000 customer or outage less than 4 hours (any outage where ties can be used to restore service)		Low	0.5
	Outage impacts less than 10,000 customers or outage less than 24 hours (outage requiring spare or mobile to restore customers)		Medium	1
Location	Not located in populated area (residential) or close to environmentally sensitive area (e.g. river or lake)	15	No	0
	Located in populated area (residential) or close to environmentally sensitive area (e.g. river or lake)		Yes	1
System Impact	System has firm capacity, no overload on parallel transformers or need to curtail exports	20	No	0
	System does not have firm capacity, potential overloads on parallel transformers or need to curtail exports		Yes	1
Expected Outage Duration	Spare or mobile substation available for transformer, ability to transfer load	10	Low	0
	No spare or mobile substation available for transformer, insufficient ability to transfer load		High	1

Section:	Tab 4 Appendix 4.	Page No.:	p. 7
Topic:	Capital Expenditure Forecast		
Subtopic:	Objectives of the Electric Asset Health Index Summary Report		
Issue:	Describe Manitoba Hydro's risk management process		

PREAMBLE TO IR (IF ANY):

Please refer to response to Coalition/MH-I-93(c).

QUESTION:

a) Please describe how the weightings for each of several factors for each asset class are determined.

b) Provide copies of any analysis, if any, to support the specific quantification of the weighing factors uses for each criteria in the asset classes (distribution, transmission, generation).

c) Please provide the numerical value for the weightings of each AHI criteria for the transmission system circuit breakers on page 93 of Appendix 4.2 of the 2015/16 and 2016/17 GRA:

   i. Operating mechanism
   ii. Contact Performance
   iii. Arc Extinction
   iv. Insulation
   v. Service Record
   vi. Age (as a separate factor)

d) Please provide the numerical value for the weightings of each AHI criteria for the substation class transmission transformers noted on page 90 of Appendix 4.2 of the 2015/16 and 2016/17 GRA:

- Insulation
- Cooling

- Cooling system
- Sealing and connection
- Service record
- Age (as a separate factor)

e) For each of the 29 asset classes identified in the Electrical Infrastructure Condition Asset Summary, please identify the criteria and provide the value for the weighing assigned to each criteria in the AHI, and specifically provide the value for Age (where used) as a separate factor.

f) For each of the 29 asset classes identified in the Electrical Infrastructure Condition Asset Summary, please identify criteria and provide the value for the weighing assigned to each criteria for the consequence of failure of the asset.

RATIONALE FOR QUESTION:

To understand the risk management approach used by MH for capital assets.

RESPONSE:

a) Weighting for each factor used in deriving the AHI score is based on the relative importance of this factor in determining the overall condition of an asset, i.e. the more important a particular factor is in determining the asset's overall condition the higher its weighting and impact in the condition assessment formulation. The same weights were used in calculating AHI for all assets within the same asset class to ensure consistency.

Furthermore, the resultant AHI scores were validated by comparing calculated condition for some of the units with Manitoba Hydro's actual knowledge of and experience with these assets, i.e. was the unit found to be in "poor" condition using Health Indexing approach indeed known to be in "poor" condition by Manitoba Hydro technical and/or field staff.

b) Assigning weights is an exercise based on empirical results and experience of technical and field experts and is used as such by many utilities. Manitoba Hydro is not aware of any studies or analysis supporting specific weighting values. For some asset types, Manitoba Hydro has used weightings similar to other utilities.

c) – e) The weighting factors used in the condition assessment formulations are presented in the table below as either a percentage or as the weighting values used in the condition assessment formulations to achieve the appropriate level of impact for each factor.

Asset	Parameter/ Factor	Weight	Comments
Overhead Transformers	Age	100%	Visual and grounding inspections results were used to define age thresholds for assigning condition to individual transformers
Padmount Transformers	Age	100%	Visual and maintenance inspections results were used to define age thresholds for assigning condition to individual transformers
Overhead Primary Conductor	Age	100% for Aluminum Conductors	Copper conductor and steel conductor were assigned "very poor" and "poor" condition, respectively, regardless of age. Visual inspections were used as the basis for defining age thresholds for assigning condition to specific sections of aluminum conductor
Manholes	Visual inspections/expert opinion	100%	Results from the 2012 sample were extrapolated for the whole population.
Underground Cables	Age	100%	Cable type was used to define age thresholds for assigning condition to specific cable sections
Duct-lines	Visual inspections/expert opinion	100%	Results from the 2012 sample were extrapolated for the whole population
Street Lights	Age	100%	Visual inspections results and installation methods were used to define age thresholds for assigning condition to individual units

Asset	Parameter/ Factor	Weight	Comments
Wood Poles	Age	100%	Visual inspections and maintenance programs results were used to define age thresholds for assigning condition to individual poles
Transmission/ Distribution Breakers	Operating Mechanism	11 to 14	Depends on breaker type
	Contact Performance	7	
	Arc Extinction	5 to 9	Depends on breaker type
	Insulation	2	
	Service Record	5	Equal weighting is applied to Age and Operation Counter to determine Service Record score
Transmission/ Distribution Transformers	Insulation	6	
	Cooling	1	Cooling System is only parameter of Cooling
	Sealing & Connection	3	
	Service Record	3	Equal weighting is applied to Age and Loading to determine Service Record score
Transmission Battery Banks	Age	3 to 5	Varies with age to reflect increasing importance of age on battery condition.
	Functional Failure Count	5	
	Potential Failure Count	4	
Protection Relays	Age	2	
	Vendor Support	2	
	Spare Availability	4	
	Maintenance Performance	4	
Transmission Conductor	Age	1	Condition score based on age only
Transmission Steel Towers	Age	1	
	Inspection Records	4	

Asset	Parameter/ Factor	Weight	Comments
Transmission Wood Pole Structures	Pole Strength	5	
	Pole Physical Condition	4	
	Auxiliary Accessories	1	
	Service Record	3	A 2:1 weighting is applied to Age and Overall Condition Count to determine Service Record
HVDC Synchronous Condenser	Age	1	The weight for the excitation component of the synchronous condenser is 0.930
	Maintenance History	1	The weight for the excitation component is 0.710
	Operational Performance	1.5	The weight for the excitation components of the synchronous condenser for power circuitry, and control circuitry are 0.92 combined
	Physical Condition	1	The weight for the excitation component of the synchronous condenser for spare parts is 0.46
HVDC Valve Group	Age	1	
	Maintenance History	1	
	Operational Performance	1.5	
	Physical Condition	1	
HVDC Converter Transformer	Oil	1.135	
	Power Factor	0.666	
	Winding Resistance	0.666	
	O&M History	0.433	
	Age	0.433	
HVDC Transformer	Oil	1.135	
	Power Factor	0.666	
	Winding Resistance	0.666	
	O&M History	0.433	
	Age	0.433	
HVDC	Age	1	

Asset	Parameter/ Factor	Weight	Comments
Smoothing Reactors	Maintenance History	1	
	Operational Performance	1.5	
	Physical Condition	1	
HVDC Breakers	Dielectric	0.439	
	O&M History	1.316	
	Resistance	0.877	
	Number of Operations	0.702	
HVDC Shunt Reactors	Age	1	
	Maintenance History	1	
	Operational Performance	1.5	
	Physical Condition	1	
Generation, Transformers	Oil Analysis: a) Dissolved Gas Analysis-DGA b) Furan Levels	34%	
	Insulation tests: a) Capacitance b) Dissipation Factor c) Excitation current d) Insulation resistance	20%	Excitation current measurements are obtained during transformer turns ratio tests.
	DC winding resistance test	20%	
	Operations and Maintenance History	13%	for example historic failures, abnormal operating characteristics, issues with aux systems, failures or problems on equipment of similar design or manufacture, transformer turns ratio test
	Age	13%	As a function of in service date.

Asset	Parameter/ Factor	Weight	Comments
Governors	Age	0.17	
	Operations and Maintenance History	1.17	
	Spare parts	0.83	
	Performance	1.17	
Exciters	Age	1	Scoring varies between different models and manufacturers
	Operations and Maintenance History	1	Scoring varies between different models and manufacturers
	Spare parts	1	Scoring varies between different models and manufacturers
	Power Circuitry test	1	
	Control Circuitry test	1	
Generation, Breakers	Equipment performance	30%	
	Obsolescence Criteria: a) Equipment age b) Spare parts c) Technical support availability	70%	
Generators	Insulation Resistance and Polarization Index	0.1 - 0.25	Scoring depends on classification of the generator and there are currently 5 types – [11, 13.8kV] = 0.15 [6.6, 6.9, 7.2kV] = 0.25 [4.16kV – Jenpeg] = 0.25 [2.4kV] = 0.15 [thermal stations] = 0.1
	HVDC Ramp test	n/a – 0.75	Scoring depends on classification of the generator and there are currently 5 types – [11, 13.8kV] = 0.5 [6.6, 6.9, 7.2kV] = 0.75 [4.16kV – Jenpeg] = n/a [2.4kV] = 0.5 [thermal stations] = 0.45

Asset	Parameter/ Factor	Weight	Comments
	TVA probe	n/a – 0.35	Scoring depends on classification of the generator and there are currently 5 types – [11, 13.8kV] = 0.35 [6.6, 6.9, 7.2kV] = n/a [4.16kV – Jenpeg] = n/a [2.4kV] = n/a [thermal stations] = 0.2
	DF Tip-up (BDN, SLK)	n/a – 0.75	Scoring depends on classification of the generator and there are currently 5 types – [11, 13.8kV] = n/a [6.6, 6.9, 7.2kV] = n/a [4.16kV – Jenpeg] = 0.75 [2.4kV] = 0.35 [thermal stations] = 0.25
Turbines	The turbine is made up of many components, each of which the condition is assessed using the following parameters and methodology Some components, that have a significant impact on the operation of the unit, are considered "critical" The final Score is based on the lowest of any of the critical components, or the average of all components; whichever is lower.		
	Age	1	Scored first relative to a perfect score of 10 - for brand new with no recorded issues.
	Repaired to Original or Engineered Redesign implemented	1	Score impacted if applicable
	Operating restrictions in place due to component	1	Score further impacted if applicable
	Estimated longevity of repairs implemented	1	Score further impacted if applicable
	Asset maintainability	1	Score further impacted if applicable
	Severity of outstanding or non-repairable deficiencies	1	Score further impacted if applicable

f) None of the asset classes have criteria and weightings for the consequence of failure of the asset. Asset condition, consequence of failure and other factors such as deferring benefits are factored into the risk analysis for project justification and prioritization.

Coalition Exhibit 24

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Applied Public Policy Research
APPRISE
Institute for Study and Evaluation

PECO Energy
Universal Services Program
Final Evaluation Report

October 2012

Poverty Level (Cap Tier)	2009 CAP Participants	CAP Eligible PECO Residential Households	Participation Rates
51% -75% (D)	61,513	41,975	63%
76%-100% (D1)		55,390	
101%-125% (E)	38,957	58,118	34%
126% - 150% (E1)		56,274	
Total	**130,960**	**286,702**	**46%**

Participation rates for electric and gas customers were quite similar. Table II-14 shows that 22,000 of 45,000 eligible gas customers received CAP benefits and 131,000 of 286,000 eligible electric service customers participated in CAP.

Table II-14
Participation Rate
By Service Type

Service Type	2009 CAP Participants	CAP Eligible PECO Residential Households	Participation Rates
Electric	130,619	286,240	46%
Gas	22,195	45,471	49%

Table II-15 describes the participation rates for CAP eligible households that were identified as having energy burdens greater than targets set forth by the BCS. CAP program participation for targeted households was lowest amongst households with income below 25 percent of federal poverty guidelines. Twenty-five percent of eligible households with annual income below 25 percent of the federal poverty guidelines participated in the CAP, while 67 percent of targeted households between 25 percent and 50 percent of the federal poverty guidelines participated in the CAP.

Table II-15 also shows that more than 100 percent of targeted households between 100 percent and 150 percent of the federal poverty guidelines participated in the CAP. This may result from the structure of PECO's CAP program, which does not target customers by energy burden. Consequently, many CAP participants, especially those in higher poverty groups, may participate in CAP despite having energy burdens that fall below the PUC targets.

Table II-15
Participation Rate for Targeted Households
By Poverty Level

Poverty Level (Cap Tier)	2009 CAP Participants	CAP Eligible PECO Targeted Residential Households	Participation Rates
0% -25% (A,B)	11,475	45,423	25%

Poverty Level (Cap Tier)	2009 CAP Participants	CAP Eligible PECO Targeted Residential Households	Participation Rates
26% -50% (C)	19,015	28,195	67%
51% -75% (D)	61,513	31,740	93%
76%-100% (D1)		34,701	
101%-125% (E)	38,957	20,670	109%
126% - 150% (E1)		15,146	
Total	**130,960**	**175,875**	**74%**

Table II-16 displays participation rates for both electric and gas customers who had energy burdens that exceeded the BCS targets. The table shows that 74 percent of targeted electric customers and 85 percent of targeted gas customers participated.

Table II-16
Participation Rate for Targeted Households
By Service Type

Service Type	2009 CAP Participants	CAP Eligible PECO Targeted Residential Households	Participation Rates
Electric	130,619	175,741	74%
Gas	22,195	26,194	85%

Table II-17 shows that PECO has higher CAP participation than other electric utilities in Pennsylvania. Using ACS estimates on the number of households in Pennsylvania with income at or below 150 percent of the FPL and data reported to the PUC on the number of households served by electric utilities in December 2009, we estimated that 46 percent of PECO households who were income-eligible received CAP benefits, while only 25 percent of income-eligible households in other utilities' service territories participated in CAP.

Table II-17
Participation Rates for Pennsylvania Electric Utilities

Service Type	CAP Electric Service Households	CAP Income Eligible Households	Participation Rates
PECO	130,619	286,240	46%
Other Electric Utilities	150,066	589,883	25%
Total	**280,685**	**876,123**	**32%**

Table II-18 shows that CAP participation was also higher for households receiving gas service from PECO than for those served by other gas utilities in Pennsylvania. The PECO gas CAP participation rate was 49 percent, compared to 37 percent for other gas utilities.