2014

Integrated Pole Maintenance (IPM) Manual

Manitoba Hydro

5/12/2014

Available in accessible formats upon request

INTRODUCTION

Manitoba Hydro's Integrated Pole Maintenance is an ongoing, systematic program of pole inspection, mitigation of wood deterioration through the application of supplemental wood preservative and insecticide, and the rehabilitation or replacement of weak poles.

Integrated pole maintenance is administered by the Program Coordinator from Distribution Asset Maintenance Planning. The pole maintenance work is carried out by contractors for Manitoba Hydro and is inspected and reported on by Patrollers from Line Maintenance.

This manual provides guidelines for Integrated Pole Maintenance work and is a supplement to the Request for Quotation tender. This manual will take you through the technical, safety, and environmental aspects of pole maintenance and inspection work. Examples of the different treatment methods and how to record and report on this work will be given and explained as well.

BACKGROUND

Over time, natural depletion of the original preservative treatment in utility poles causes the concentration of the preservative to fall below the level toxic to decay fungi. This and the exposure of unprotected wood as the pole seasons put the pole at risk for decay infection. When this happens, decay begins and the pole deteriorates, usually in

the groundline area of the pole. The initial stages of decay provides attractive habitat for carpenter ants, which nest in the softened wood, tunneling out the interior of the pole. In either case, pole strength is eventually reduced below design requirements. This presents the opportunity for unexpected power interruption, with the possibility of a dangerous situation, should the pole fail.

Regular pole inspection and maintenance allows Manitoba Hydro to detect and rehabilitate or replace the weak poles before they fail, and to re-establish preservative levels and eradicate carpenter ant infestations in the good poles; interrupting the deterioration process and prolonging pole service life.

Manitoba Hydro implemented this program in 1989, inspecting and maintaining approximately 5,500 poles. This has grown to an annual program of approximately 70,000 poles across the Province.

Manitoba Hydro's Integrated Pole Maintenance program is carried out in accordance with all federal and provincial legislation and associated regulations. The program itself is permitted under the auspices of a Manitoba Conservation Environment Pesticide Use Permit issued annually.

In general, the work involves detailed pole inspection, pole strength evaluation, prescriptions for line maintenance, application of remedial treatments, recommendations for pole replacement or reinforcement, and the recording of all pole and treatment information.

The work proceeds as follows:

- excavation of the earth around the pole to a depth of 60 centimetres.
- thorough pole inspection inside and out.
- pole strength evaluation.
- prescription of remedial treatment or replacement.
- remedial treatment if appropriate.
- filling and tamping of the excavation.

All poles that are fifteen years of age or older and are considered serviceable for a further fifteen years receive remedial treatment. Poles that are deemed to require replacement are not remedially treated.

1. Safety and Environmental Concerns

The Manitoba Hydro onsite representatives (Inspectors) are responsible for the inspection of the work done by the contractors. They are responsible for stopping any work that they deem as unsafe or that does not follow safe work guidelines as laid out by Manitoba Hydro in Requirements or Conditions of the tender. The following sections outline requirements of the contractor that the Inspectors must enforce. If the

contractor does not follow any of these requirements then the Inspector must stop any work from occurring until the requirements are met.

1.1 Personal Protective Equipment

The contractor must ensure that all of their employees wear appropriate protective equipment when exposed to any hazards. Protective equipment includes: hard hats, eye protection, gloves, high visibility non-synthetic clothing, and CSA approved green triangle class 1 and CSA dielectric "OMEGA" rated protective footwear.

The person in the picture is wearing all appropriate safety equipment. His equipment includes a hard hat, protective safety glasses, high visibility coveralls, long sleeve shirt, and steel-toe boots with CSA approved green triangle class 1 and CSA dielectric "OMEGA" rated patches on them.

When applying chemicals the person applying also needs to wear goggles, an apron, chemical resistant gloves and boots.

These two CSA rating symbols should be present on all boots worn on the worksite at all times.

1.2 First Aid

The contractor must ensure that at all times clean water, soap, towels, eyewash stations, and first aid kits are available for all persons onsite.

1.3 Chemicals

The contractor must maintain a Workplace Hazardous Materials Information System (WHMIS) file for all hazardous materials used at each work site. Controlled substances brought to a worksite without Material Safety Data Sheets (MSDS) cannot be used for any work. MSDSs for all chemicals that may be used are to be supplied by contractor. Any other alternate chemicals must be approved by the Program Coordinator before being used at the worksite.

All chemicals should be labeled if they are not in their original containers with workplace labels similar to the ones shown in the pictures here. Please see the Pesticide Application Requirements for Manitoba Hydro Employees and Contractors publication number 0004/05 from the Employee Safety and Health Department of Manitoba Hydro for full regulatory and applicator licensing information, technical guidance, and safety requirements for pesticide applications, located in Tender Appendix.

1.3.1 General Chemical Storage Requirements

All chemicals used for Integrated Pole Maintenance are required to be stored according to the following minimum conditions:

- In a cool, dry, well ventilated area.
- Pesticides are not stored together with food, food products, drinking water and/or personal use equipment.
- On level, solid ground.
- Elevated off the ground.
- Protected from the elements.
- Away from heat, flame, or any source of ignition.
- In a restricted access, fenced area with gated, locked entrances.
- In their original, labeled containers.
- Spill containment within a reasonable distance.
- Area kept neat and tidy.
- Different pesticides are stored in separate areas to prevent cross contamination.
- Maintenance areas and equipment are segregated from the pesticides storage areas.
- No smoking signs posted.

In addition to these conditions, log books must be maintained up to date for all stored chemicals inventory. Log books must also be maintained on any vehicle carrying chemicals.

The chemical storage facility must have similar signage posted at all pedestrian entrances:

Copies of the above sign are available through Employee Health and Safety.

These requirements are only for general storage of chemicals. They do not include consideration of every possible chemical incompatibility and the resulting chemical reaction. Always refer to the product Material Safety Data Sheet to find all storage criteria.

For complete guidelines on chemical storage please see the Chemical Storage publication number 0018/06 from the Employee Safety and Health Department of Manitoba Hydro in Tender Appendix.

1.3.2 General Personal Protective Equipment for Safe Handling of Pesticides

When handling any chemicals the following personal protective equipment must be worn:

- Protective eyewear (i.e. goggles)
- Chemical resistant rubber gloves
- Long sleeves
- Protective clothing (i.e. an apron)
- Chemical resistant boots

Always refer to the Material Safety Data Sheets for each chemical's personal protective equipment for specifications when handling.

1.3.3 List of Approved Chemicals for I.P.M.

Internal Treatment
Guardsman Post and Pole Fumigant
Woodfume
FluRods
Cobra Rods

Internal Void Flooding
Mineral Spirits
Copper Naphthenate 2% and 8%

Groundline
CuRap 20
Cop-R-Plastic
Cobra Wrap
Cobra Wrap SD

Ants
Prelude 240
Dragnet FT

External Surface Treatment and Filling Inspection Holes
Copper Naphthenate 2% and 8%

1.3.4 Pesticide Container Disposal

All empty containers must be disposed of according to Manitoba Government Provincial Guidelines. All containers must be triple rinsed and made unusable before being disposed of at approved collection sites.

1.4 Spill Response

The contractor must ensure that spill response equipment and materials are onsite at all times with the exception of holding/storage containers which must be within a reasonable distance from the work site. A spill response kit should include an absorptive material such as kitty litter that can be used to absorb any spill. Any contaminated soil from the site should also be removed with a shovel and disposed of properly. In the event of a spill the contractor will complete a Hazardous Materials Incident Report with the help of the Inspector.

1.5 Transportation of Dangerous Goods

The contractor must ensure that anyone who is transporting dangerous goods has a Transportation of Dangerous Goods certification in accordance with the Transportation of Dangerous Goods Act.

For transport of dangerous goods by air or over water please consult the Manitoba Hydro Dangerous Goods Officer as these regulations are often updated.

Product Trade Name	Transportation of Dangerous Goods Description	TDG Label	TDG Placard	Limited Quantity Index	Reportable Quantity	Bill of Lading Required
Cobra Rods	Not Regulated	none	none		Internally	none
Copper Naphthenate - 2%	Regulated by Road and Rail if > 454 L PETROLEUM DISTILLATES, N.O.S. (Solvent naphtha), Class 3.3, UN1268, PG III (Always regulated for Air and Marine)	Class 3	Class 3 if over 500 kg	5 L (marine)	100 L	
Copper Naphthenate - 8%	Regulated by Road and Rail if > 454 L FLAMMABLE LIQUID, N.O.S., solution, (naphtha, petroleum), Class 3.3, UN1993, PG III (Always regulated for Air and Marine)	Class 3	Class 3 if over 500 kg	5 L (marine)	100 L	yes
Cop-R-Plastic	SODIUM FLUORIDE, mixture, Class 6.1, UN1690, PG III	Class 6.1	Class 6 if over 500 kg	5 kg	5 kg	yes
Cu-Rap 20	CORROSIVE SOLID, N.O.S. (ethanolamine), Class 8, UN1759, PG III	Class 8	Class 8 if over 500 kg	5 kg	5 kg	yes
FluRods	SODIUM FLUORIDE, Class 6.1, UN1690, PG III	Class 6.1	Class 6 if over 500 kg	5 L	5 kg	yes
Post and Pole Fume	CORROSIVE LIQUID, BASIC, INORGANIC, N.O.S. (metam sodium), Class 8, UN3266, PG III	Class 8	Class 8 if over 500 kg	5 L	5 L	yes
Woodfume	ENVIRONMENTALLY HAZARDOUS SUBSTANCE, LIQUID, N.O.S. (metam sodium), Class 9, UN3082, PG III	Class 9	Class 9 if over 500 kg	5 L	1 L	yes
Isopar M (Imperial Oil)	Not Regulated	none	none		100 L	none
Paraflex (Petro-Canada)	Not Regulated	none	none		100 L	none
Prelude 240	Not Regulated	none	none			none
Dragnet FT	FLAMMABLE LIQUID, N.O.S.(permethrin), Class 3, UN1993, PG III	Class 3	Class 3 if over 500 kg	5 L	100 L	yes

1.6 Licences, Permits and Insurances

The Manitoba Hydro onsite representative must ensure that all contractor employees applying preservatives have Manitoba Agriculture Core Pesticide Certification and those applying insecticides have a Manitoba Agriculture Structural Applicator Licence which is renewed annually for a fee, and re-certified every 5 years.

Permits are required to work in provincial and federal parks. These permits must be obtained at least one week prior to work beginning within the park.

The contractor must possess General Liability Insurance, Automobile Liability Insurance, and Environmental Liability Insurance as laid out in Section 24 of the General Requirements of the tender. Only insured vehicles are to be used for pole maintenance work and vehicles must be identified with the contractor's company name.

1.7 Cleanup

The Manitoba Hydro onsite representative must ensure that the contractor maintains the worksite in a clean and tidy manner. If the contractor fails to keep the worksite clean, the onsite representative will write a letter to the contractor to remedy this.

The onsite representative will ensure that internal pole treatment chemicals will not be spilled on pole surfaces and preservative paste will not be visible above the paper wrap on the pole surface. As well, all preservative wastes and empty containers must be disposed of in accordance with the Manitoba Provincial Government Guidelines.

1.8 Biosecurity (New for 2014)

P853
All Manitoba Hydro staff and contractors who carry out work on agricultural land will:

- refer to and be aware of the Standard Operating Procedure (SOP) and this Agricultural Biosecurity policy
- be able to provide a copy of SOP to landowner or producer leasing the land, if asked, whether:
    - there is only one MH employee/contractor — that individual should have a copy of SOP with them
    - there are 2 or more MH employees/contractors — one individual in the group should have a copy of SOP
- be able to inform a landowner or producer leasing the land about the SOP, if asked
- Comply with requirements of SOP and this policy.

With any construction project on agricultural land, there is a potential to introduce and/or spread disease, pests and invasive plant species through the movement of people and equipment. To help protect the health and sustainability of the agricultural sector, Manitoba Hydro has approved a new Agricultural Biosecurity Corporate Policy (Policy P853). The policy explains the requirements of Business Units, staff and contractors who carry out work on agricultural land in Manitoba.
Unrelated to any activities by Manitoba Hydro, The discovery in September of two canola plants infected with clubroot as a timely example of the need for vigilance. Clubroot is a serious disease affecting a number of crops grown in Manitoba, including canola. It has been present in neighbouring states and provinces for years, but this is the first time it has been confirmed on plants in Manitoba. The disease is spread through movement of soil. It can survive in the soil for up to twenty years.

Preventing the spread of clubroot between farms is one example of why it is important to have Biosecurity procedures in place. Not only does this give producers and landowners assurance that we take the issue seriously, but it also gives our staff and contractors consistent direction to make sure they are carrying out their work in a way that helps to protect Manitoba's agricultural sector." With a formal Biosecurity policy now in place, Hydro makes another progressive step in its extensive history of environmental responsibility.

Further to this policy, Business Units are also responsible for developing a Standard Operating Procedure (SOP) with specific operational requirements for their staff and contractors. At minimum, the SOP will include an assessment of the potential Biosecurity risk and suitable procedures to manage the risk.
The new policy required the input and collaboration of many different groups including Transmission, Customer Service & Distribution and Human Resources & Corporate Services.

1.8.1 Customer Service and Distribution Agricultural Biosecurity SOP

Customer Service and Distribution

Procedure
Agricultural Biosecurity

Document Owner: Char Gladue
Last Revised: April 29, 2014
Next Revision: April 29, 2017

Related Policies: P853 Agricultural Biosecurity
G125A Point of Delivery for Intensive Livestock Operations

1. PURPOSE OF THE PROCEDURE

This standard operating procedure (SOP) provides guidance for Customer Service & Distribution (CS&D) employees to assist in the prevention of spreading invasive organisms.

2. SCOPE

This procedure applies to the Customer Service & Distribution Business Unit, its employees and contractors. All invasive organisms (plants, pests, disease) that pose a risk to agricultural operations are included in this procedure.

The procedure is geographically specific to:

1. Land zoned for agricultural use by a provincial or municipal government, planning commission or planning district
2. Manitoba Hydro's service area (gas & electric)

3. APPLICABILITY

The SOP is applicable when there is a reasonable risk of moving invasive organisms in soil from one location to another while performing tasks in CS&D, or at the landowner's request. Frozen, dry, or uncultivated ground poses little risk. Where possible, try to avoid wet areas or traveling through areas that contain manure.

Conditions where the SOP does not apply include:

1. Where land use is not zoned agricultural
2. When equipment only comes in contact with gravel or pavement
3. Where the work is carried out on a public right of way
4. In emergency situations (*The Manitoba Hydro Act* will prevail in order to return services to normal operating condition)

4. GENERAL INFORMATION

Agricultural biosecurity is the protection of crops and livestock systems against the threats to production from invasive organisms (disease, pests and invasive species).

Human activity is one of the factors in the spread of invasive organisms. Responsibility for the management of agricultural biosecurity rests with all stakeholders.

5. RESPONSIBILITY

- All CS&D employees who carry out work on agricultural land must be aware of this Standard Operating Procedure
- Contractors (non-prime) who carry out work on agricultural land must be made aware of this Standard Operating Procedure prior to the commencement of work
- Employees from other Business Units carrying out work on behalf of CS&D will be required to follow this SOP during the course of their work
- Managers must monitor compliance with the procedure

6. PROCEDURAL INSTRUCTIONS

1. Continue with the well established practice of communicating with landowners or producers prior to beginning work on or adjacent to private property. This is the landowner or producer's opportunity to voice any concerns, including those related to biosecurity.

    - Respect the landowner or producer's written biosecurity protocol.

2. If a degree of elevated risk is identified (see list below) mechanical cleaning shall be performed which removes about 90% of the soil. Manitoba Hydro vehicles and equipment should enter and exit fields in a clean condition. Mechanically clean vehicles and equipment by removing visible dust, soil, and plant materials using brushes, brooms, and shovels from:
    - interior and exterior of vehicles and equipment
    - shovels, augers and vehicle tires
    - clothes, personal protective equipment, and boots

Elevated risk identifiers:

A. Confirmed presence of invasive species (e.g. clubroot)
B. Extremely wet conditions with disturbed soil (significant accumulation of soil on vehicles and equipment)
C. Work involves close contact with livestock
D. Where there is heightened sensitivity around a particular project and/or from a particular customer or group of customers.

3. RECORD the action completed related to cleaning on one of the three documents: the workorder, the job plan (tailboard), or environmental checklist.

7. DISTRIBUTION, COMMUNICATION & REVIEW

The SOP will be communicated to CS&D employees and contractors as required. It is available on Manitoba Hydro's intranet and to the public upon request.

For subject matter expert guidance or questions from the public, please contact Mr. Alec Stuart, Manager, Corporate Environmental Management at environment@hydro.mb.ca or 204-360-3015.

This procedure will be reviewed every three years by the Division Managers of CS&D.

8. PROCEDURE APPROVAL

Date: April 30, 2014

Signature:  April 30/14

G. B. Reed, Vice President, Customer Service & Distribution Business Unit

2. Treatments

2.1 Pole Inspection

The Manitoba Hydro onsite representative must ensure that the following inspection guidelines are carried out by the contractor:

a) All poles shall be:
   - Tagged with a pole identification barcode if not previously tagged.
   - Inspected visually above ground for obvious problems.
   - Sound and bore inspected, and classified according to continued serviceability.
   - Inspected below groundline externally and be classified according to continued serviceability if over 15 years in service.

b) Danger poles and all poles with split tops shall be reported to the onsite representative immediately who will decide on the appropriate course of action.

c) Dimensions of all hollows, voids, decay pockets, mechanical damage, external decay and remaining sound wood shall be measured and recorded as described in Appendix 7 of the tender.

d) All 3/8" drill holes shall be flooded with a 2% copper naphthenate solution and plugged with a 7/16" diameter preservative-treated wooden plug with a minimum length of 2", or with an appropriately sized plastic plug.

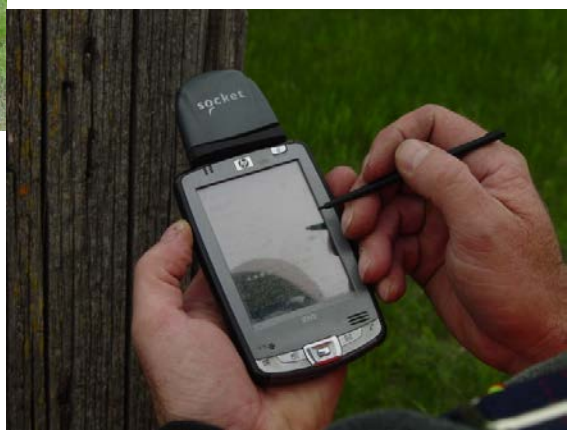
e) Poles supported with a wooden stub shall receive both stub and pole inspection to ensure the continued integrity of the structure.

The contractor inspector then completes a full above ground inspection noting any obvious problems such as split tops and floating wires.

First, the barcode of the pole is scanned so any data entered into the datalogger will correspond to the unique barcode number for that pole.

The circumference of the pole is taken to classify the pole as well as note any loss of circumference due to rotting.

All information obtained through the inspection is recorded on the data logger by the contractor inspector.



2.2 Pole Strength Evaluation

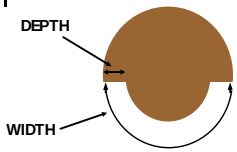
Poles shall be classified as SERVICEABLE (S), REJECT (X), REINFORCEABLE (XR), or DANGER (XD) based on an evaluation of the remaining pole strength using the strength assessment tables and charts found in tender or remaining strength booklet.

Remaining Strength Categories	
Remaining Strength	**Pole Classification**
< 50%	Danger Pole **XD**
50% to 70%	Reject/Reinforceable Pole **X / XR**
> 70%	Serviceable Pole **S**

POLE STRENGTH EVALUATION

Manitoba Hydro

SHELL ROT: 0.5" - 3" DEEP



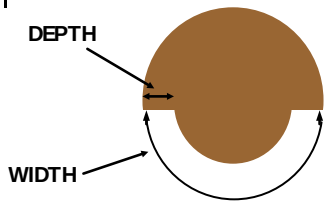
GROUNDLINE AREA

ORIGINAL CIRCUMFERENCE AT DAMAGE [in]	DEPTH OF ROT [in]											
	0.5		1		1.5		2		2.5		3	
	MAXIMUM WIDTH OF ROT [in]											
25	21.75	25	9.25	21.75	5.75	19	4	9.25	USE EXTERNAL POCKET CHART			
30	30	30	21.5	27.5	8	24.5	5.75	21	4.5	10.5		
35	35	35	27	33.5	11.25	30	8.5	27.25	6.25	15	5.25	12.25
40	40	40	40	40	25.25	35.5	10.75	32.75	8.5	29.75	6.75	16
45	45	45	45	45	32.25	41.25	13.75	38.25	11	35.5	8.5	31.5
50	50	50	50	50	37.75	50	18.5	43.75	13.5	41	11.75	38
55	55	55	55	55	43.25	55	36.5	49.25	16.5	46.25	13.75	43.75
60	60	60	60	60	48.75	60	43	55.25	20.25	51.75	16.25	49
65	65	65	65	65	54.5	65	48.5	61.25	37	57.5	19	54.5
70	70	70	70	70	60	70	54.25	70	47.5	63.25	22.75	60
COLOUR CODES	GREEN = SERVICEABLE [70%]						YELLOW = REINFORCE [50%]					
	NOTE: WIDTHS LARGER THAN "REINFORCE" ARE DANGER POLES											

OLE STRENGTH EVALUATION

Manitoba Hydro

SHELL ROT: 3.5" - 6" DEEP

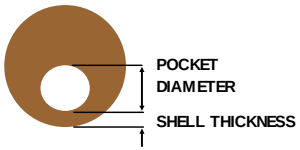


GROUNDLINE AREA

ORIGINAL CIRCUMFERENCE AT DAMAGE [in]	DEPTH OF ROT [in]											
	3.5		4		4.5		5		5.5		6	
	MAXIMUM WIDTH OF ROT [in]											
25	USE EXTERNAL POCKET CHART											
30												
35												
40												
45	7.25	17										
50	9	23	8	18.5								
55	11.5	25	9.5	23	8.75	20						
60	14.25	46.25	11.5	42	10	24	9.25	21.25				
65	16.5	51.75	14.75	48.75	12	41	10.75	25	10	23		
70	18.75	57.25	17	54.5	14.25	51	12.5	30.5	11.5	26.25		
COLOUR CODES	GREEN = SERVICEABLE [70%]						YELLOW = REINFORCE [50%]					
	NOTE: WIDTHS LARGER THAN "REINFORCE" ARE DANGER POLES											

POLE STRENGTH EVALUATION

Manitoba Hydro



ENCLOSED POCKET

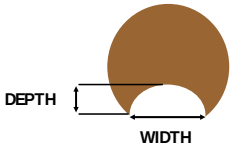
GROUNDLINE AREA

ORIGINAL CIRCUMFERENCE AT DAMAGE [in]	SHELL THICKNESS [in]													
	0.5		1		1.5		2		2.5		3		3.5	
	MAXIMUM POCKET DIAMETER [in]													
25	3.25	5.50	5.75	5.75										
30	3.75	6.00	5.25	7.50	6.50	6.50								
35	4.25	6.50	5.25	9.00	8.00	8.00								
40	4.75	7.25	5.75	10.50	8.50	9.50	8.50	8.50						
45	5.25	8.00	6.00	10.75	7.75	11.25	10.25	10.25						
50	5.75	8.50	6.50	11.00	8.00	12.75	11.50	11.75	10.75	10.75				
55	6.25	9.25	7.00	11.25	8.25	14.50	10.75	13.50	12.50	12.50				
60	6.75	10.00	7.50	12.00	8.50	16.00	10.50	15.00	14.00	14.00	13.00	13.00		
65	7.25	10.75	8.00	12.50	9.00	16.50	10.50	16.50	14.50	15.50	14.50	14.50		
70	7.75	11.50	8.50	13.25	9.25	16.25	10.75	18.25	13.50	17.25	16.25	16.25	15.25	15.25
COLOUR CODES	GREEN = SERVICEABLE [70%]							YELLOW = REINFORCE/REPLACE [50%]						
	NOTE: WIDTHS LARGER THAN "REPLACE" ARE DANGER POLES													

POLE STRENGTH EVALUATION

Manitoba Hydro

EXTERNAL POCKET: 0.5" - 3" DEEP

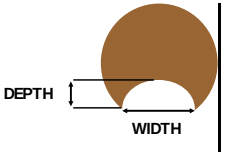


GROUNDLINE AREA

ORIGINAL CIRCUMFERENCE AT DAMAGE [in]	POCKET DEPTH [in]											
	0.5		1		1.5		2		2.5		3	
	MAXIMUM POCKET WIDTH [in]											
25	5.5	7	4.75	6.5	3.75	5.75	3	5	2.75	4.5	2.5	4.25
30	6.75	8.5	6.25	8	5	7.25	4.25	6.5	3.75	6	3.25	5.5
35	8.25	10	7.5	9.5	6.5	9	5.5	8.25	4.75	7.5	4.25	7
40	9.5	11.25	8.75	11	8	10.5	6.75	9.75	6	9	5.25	8.5
45	10.75	12.75	10	12.5	9.5	12	8.25	11.5	7.25	10.75	6.5	10
50	12	14.25	11.25	14	10.75	13.5	9.75	13	8.5	12.25	7.5	11.5
55	13.25	15.75	12.5	15.5	12	15	11	14.75	10	14	9	13.25
60	14.5	17.25	13.75	17	13.25	16.5	12.5	16.25	11.5	15.5	10.25	14.75
65	15.75	18.75	15	18.5	14.5	18	13.75	17.75	12.75	17.25	11.75	16.5
70	17	20.25	16.5	20	15.75	19.5	15	19.25	14.25	18.75	13	18
COLOUR CODES	GREEN = SERVICEABLE [70%]						YELLOW = REINFORCE/REPLACE [50%]					
	NOTE: WIDTHS LARGER THAN "REPLACE" ARE DANGER POLES											

POLE STRENGTH EVALUATION

Manitoba Hydro



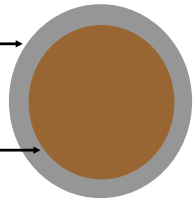
EXTERNAL POCKET: 3.5" - 6" DEEP

GROUNDLINE AREA

ORIGINAL CIRCUMFERENCE AT DAMAGE [in]	POCKET DEPTH [in]											
	3.5		4		4.5		5		5.5		6	
	MAXIMUM POCKET WIDTH [in]											
25	2.25	4	2.25	4	2.25	3.75	2.25	3.75	2	3.75	2	3.75
30	3	5.25	2.75	5	2.75	4.75	2.75	4.75	2.75	4.5	2.5	4.5
35	3.75	6.5	3.5	6.25	3.5	5.75	3.25	5.75	3.25	5.5	3	5.5
40	4.75	8	4.5	7.5	4	7	4	6.75	3.75	6.5	3.75	6.5
45	5.75	9.25	5.25	8.75	5	8.25	4.75	8	4.5	7.75	4.25	7.5
50	7	11	6.25	10.25	5.75	9.75	5.5	9.25	5.25	9	5	8.75
55	8	12.5	7.5	11.75	6.75	11.25	6.5	10.75	6	10.25	5.75	10
60	9.25	14	8.5	13.25	8	12.75	7.5	12.25	7	11.75	6.75	11.25
65	10.75	15.75	9.75	15	9	14.25	8.5	13.75	8	13	7.5	12.5
70	12	17.25	11	16.5	10.25	15.75	9.5	15.25	9	14.5	8.5	14
COLOUR CODES	GREEN = SERVICEABLE [70%]						YELLOW = REINFORCE/REPLACE [50%]					
	NOTE: WIDTHS LARGER THAN "REINFORCE/REPLACE" ARE DANGER POLES											

POLE STRENGTH EVALUATION

Manitoba Hydro



EXTERNAL BUTT ROT

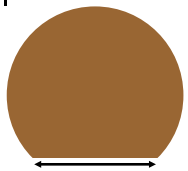
GROUNDLINE AREA

POLE STATUS		REMAINING STRENGTH	ORIGINAL POLE CIRCUMFERENCE AT DAMAGE [in]									
			25	30	35	40	45	50	55	60	65	70
			MINIMUM ALLOWABLE CURRENT CIRCUMFERENCE [in]									
SERVICEABLE		>70%	22.25	26.75	31.25	35.75	40.00	44.50	49.00	53.50	57.75	62.25
REJECT	REINFORCE/REPLACE	50% to 70%	20.00	24.00	28.00	31.75	35.75	39.75	43.75	47.75	51.75	55.75
	DANGER	<50%	<20	<24	<28	<31.75	<35.75	<39.75	<43.75	<47.75	<51.75	<55.75

POLE STRENGTH EVALUATION

Manitoba Hydro

MECHANICAL DAMAGE



GROUNDLINE AREA

POLE STATUS		REMAINING STRENGTH	ORIGINAL POLE CIRCUMFERENCE AT DAMAGE [in]									
			25	30	35	40	45	50	55	60	65	70
			MAXIMUM ALLOWABLE DAMAGE WIDTH [in]									
SERVICEABLE		>70%	6.25	7.5	8.75	10	11.25	12.5	14	15.25	16.5	17.75
REJECT	REINFORCE/REPLACE	50% to 70%	7.25	8.75	10.25	11.75	13.25	14.75	16.25	17.75	19.25	20.5
REJECT	DANGER	<50%	7.25+	8.75+	10.25+	11.75+	13.25+	14.75+	16.25+	17.75+	19.25+	20.5+

Reinforcement Specifications Table

54 Inches above ground line

Pole measurements based on **original pole** circumference or diameter

Org. Pole Diameter	Org. Pole Circumference	Minimum Shell Thickness at 54"
8" to 10.5"	25" to 33"	2.5"
10.5" to 13"	33" to 41"	3"
13" to 16"	41" to 50"	3.5"
Over 16"	Over 50"	4"

In addition to reinforceable criteria table at 54 inches above ground line the shell thickness at ground line and banding locations be the **minimum of 2 inches.**

Remaining Strength Evaluation Charts	**Code**	**Measurements Required**
Shell Rot	SR	SR(followed by Depth and Width of Rot)
Enclosed Decay Pocket	DP	DP(followed by Minimum shell thickness and Maximum pocket diameter)
External Butt Rot	BR	BR(followed by Current ground line circumference)
Mechanical Damage	MD	MD(followed by width of damage)
External Decay Pocket	EP	EP(followed by Depth and Width of decay pocket)

Additional Descriptions requiring Measurements		
Stubbing Measurement	SM	SM(followed by minimum shell thickness @ groundline plus 12" and 54" above grade)
Fire Damage (Mechanical Damage or External Pocket or Shell Rot Chart Used)		FD(followed by evaluation chart used (appendix 8) and corresponding measurements) eg. FD/EP/4/2
Heart Rot (Enclosed Pocket Chart Used)		HR(followed by Minimum shell thickness and Maximum pocket diameter) eg. HR/4/3
Internal Decay (no void) (Enclosed Pocket Chart Used)		ID(followed by Minimum shell thickness and Maximum pocket diameter) eg. ID/1/8

Additional Pole Condition Descriptions	Code
Carpenter Ant Galleries	CA
Compression Wood	CW
Decayed Top	DT
Excessive Checking	EC
Excessive Spur Cuts Checking	SC
Lightning Damage	LD
Split Top	ST
Wind Shake	WS
Woodpecker Holes	WPH

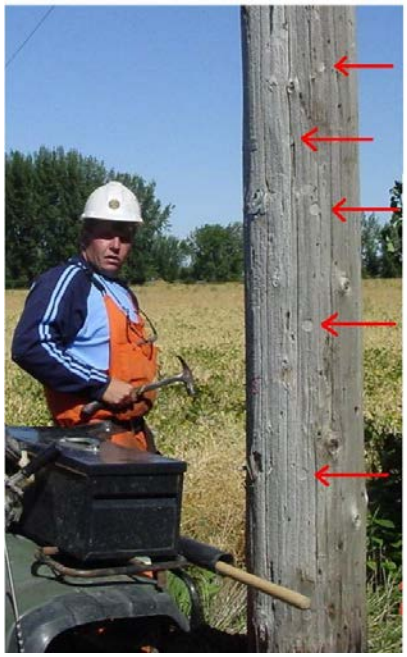
a) Serviceable poles (S) a pole with an average minimum of 5 cm (2 inches) of shell thickness and 70% or greater of their original strength as per remaining strength evaluation charts and tables.
b) Reject poles
    i) Reject Pole (X) A standing pole containing defects that will render it unserviceable within the next 15 years. A pole with between 50% and 70% of its original strength and does not qualify as Reinforceable.
    ii) Reinforceable Pole (XR) A pole retaining 50% to 70% of its original strength with a minimum of 5 cm (2 inches) of shell and qualifies under pole strength evaluation charts and tables as defined in Tender and remaining strength evaluation charts and tables and recommended thicknesses for steel truss manufacturer.
    iii) Danger Pole (XD) A pole with 2.5 cm (1 inch) or less of shell or one that has less than 50% of its original strength.

In these two pictures we see an external pocket. The picture on the left shows the external pocket being measured with a shell gauge for its depth while the picture on the right shows the pocket's width being measured. These measurements are then used with the circumference of the pole to determine the remaining strength in the pole and the pole classification.

In these two pictures we see an enclosed pocket being measured. The picture on the left shows the shell gauge measuring three inches of shell to the edge of the pocket. The picture on the right shows the shell gauge pushed into the pocket as far as it can go showing that the enclosed pocket is very deep.

2.3 Sounding

Sounding is striking the pole with a hammer to allow detection of unsound wood beneath the pole surface. Excavatable poles are sounded to a minimum 20 cm (8 inches) below groundline to 200 cm (6 feet) above groundline. Unexcavatable poles are sounded from the groundline to 200 cm (6 feet) above groundline. Where unsound wood is suspected, these areas are to be bored to assess the extent of the damage. Where hollows are found, a depth probe or shell thickness indicator shall be used to determine the size of the pocket and remaining shell thickness. A minimum of 3 borings are to be used.



When inspecting a pole that was sound tested, the pole should appear to have numerous hammer dents in the wood around the entire circumference from the groundline to at least 200 cm (6 feet). The red arrows in the pictures indicate hammer dents in the wood left from sounding the pole.

2.4 Boring

Boring inspection is done by drilling a minimum of three 3/8” holes into a pole at a 45° angle at or below the groundline to investigate the internal condition. The actual location of the inspection holes will vary with the surrounding soil texture with the lowest hole ranging from 10 cm (4 inches) below groundline in heavy clay soils to 25 cm (10 inches) below groundline in sandy soils. Where hollows are found, a depth probe or shell thickness indicator should be used to determine the size of the pocket and remaining shell thickness. A minimum of three borings extending below groundline to the centre of the pole constitutes one bore inspection. Bore inspections may also be conducted above the groundline of the pole if an enclosed pocket is suspected and being investigated.

When inspecting a pole that has been bored, there should be 3 plugged holes 120° apart from each other around the base of the pole at the groundline as well as above any possible hollows above groundline.

2.5 Fume

This treatment involves the drilling of a minimum of four 0.75 inch holes at 30° to the pole axis into the pole centre, beginning at the groundline and continuing in an upward spiral pattern. These holes are drilled into solid wood, avoiding rot pockets, checks and any other holes from which the fumigant can escape. Fumigant is then poured into the hole, and the hole is plugged. The volatile fungicide travels as a gas throughout the wood, sterilizing any decay fungi present, and preventing re-infection for many years.

Fumigant application must follow the following guidelines:

1. Measure the pole circumference at the groundline.
2. Determine the number, depth, and vertical separation of the holes to be used from the measured circumference and the following table:

RECOMMENDED FUME APPLICATION PATTERN
(3/4" drill bit)

Pole Circumference (inches)	Holes Number - Depth	Vertical Separation
0 to 34	4 - 15"	9"
35 to 42	6 - 15"	6"
43 to 49	8 - 15"	5"
50 to 54	8 - 18"	5"
55 to 60	10 - 18"	4"
60 plus	12 - 18"	3"

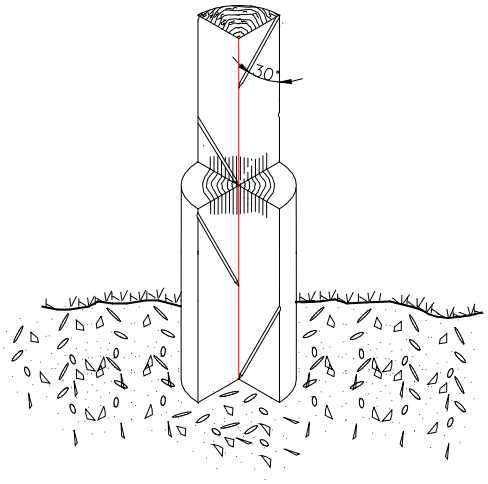
3. Using a 3/4” drill bit, drill the first hole at groundline with the drill bit set at an angle of at least 30 degrees from the pole axis, aimed at the pole centre (pith). Take care that the drill does not exit on the opposite side of the pole. The holes are then spaced horizontally around the pole in order for the upward spiral drill pattern to complete one full rotation, i.e. a 6 hole pattern would be spaced at 60 degree intervals around the pole, and an 8 hole pattern would be spaced at 45 degree intervals.

   Note: to treat a previously fumed pole, reuse the previous drill holes wherever possible. The old hole shall be cleaned by running the same size drill bit to the proper depth. The old wooden plug shall be removed by pushing the old plug into the hole to provide a guide for the drill bit to follow the old hole. The old plug is then drilled out, cleaning the old hole. Plastic plugs can often be removed using their built in slots and threads, but may be done the same as wooden plugs if desired.

4. Holes should be drilled into sound wood only - avoiding rot pockets, checks, ant gallery voids, and any other holes from which the fumigant could escape. If a void is encountered when drilling a hole, the hole should be plugged and another hole drilled further up, down or around the pole as appropriate.
5. Standing upwind, equally fill all holes to within 2” of the top. This will leave enough room to insert the plug without forcing out the fumigant. **Apply only up to the maximum volume per pole allowed by the product label. DO NOT OVERFILL HOLES OR ALLOW FUMIGANT TO LEAK DOWN THE SIDE OF THE POLE.**
6. Plug all holes with an appropriately sized plastic plug. Insert the plug carefully so that the fumigant doesn’t “squirt” out.

7. Tag the pole at eyelevel to indicate the treatment and date. Keep records of all poles including the date, location, and volume of fumigant used.

The diagram to the right shows the basic application pattern for drilling the fume holes into the pole.

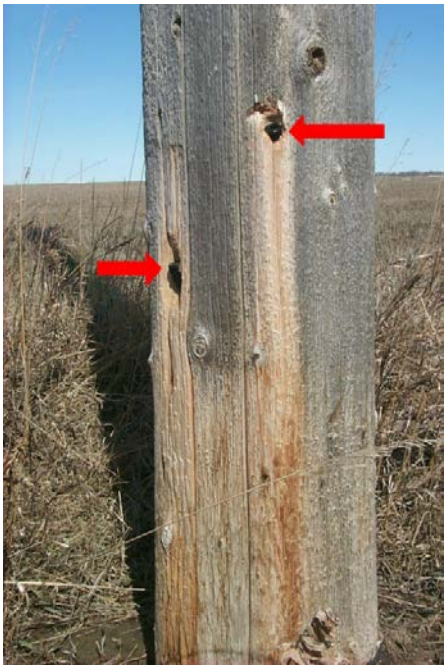


Basic Fumigant Application Pattern

The picture to the left shows two holes that are already drilled (red arrows) and a third hole being drilled above those two. The pattern follows a spiral up the pole.

The picture to the right shows a hammer and plug pounder being used to countersink an old fume plug so the hole can be reused for this retreatment.

The applicator in the picture is filling the previously drilled holes with wood fume. He is being sure not to overfill the holes. Also note that he is wearing long sleeves and chemical resistant gloves and boots to reduce his chance of exposure to the chemical.



Overfilling holes with fumigant should be completely avoided. Fumigant on the outside of wood poles attracts rodents due to the salt content of the chemical. Rodents then gnaw on the wood creating large holes making serviceable poles, reject poles.

The picture to the left shows a pole that was internally treated with fumigant. The red arrows indicate plugged holes from fumigation. The lighter, discoloured wood below the holes is the result of fumigant that was overfilled and has leaked down the pole.

When fumigant leaks down the pole, it attracts rodents which results in a serviceable pole being turned into a reject pole as seen in the picture to the right.

When inspecting a pole that has been fumed, there should be 4 - 12 plugged holes in an upward spiral pattern starting at the groundline depending on the size of the pole. There should be no evidence of the holes being overfilled and fumigant leaking down the outside of the pole.

2.6 Internal Void Flooding

Internal flooding of decay voids is done with 2% copper naphthenate in mineral spirits solution. An upward series of 10 mm holes is drilled to determine the size and location of the void and to evaluate pole strength. Preservative is pumped under pressure into the lowest hole until it runs out of the next highest hole. The hole that the preservative is running out of is plugged and additional preservative is pumped into the cavity until it runs out of the next highest hole. This procedure is continued until the cavity is filled or until a maximum of 4 litres of solution are applied. All holes shall be plugged with 7/16" diameter x 5 cm (2 inches) long treated wooden plugs, or appropriately sized plastic plugs. Fumigants alone are not sufficient to control decay around voids. Fumigant concentration drops as it reaches the surface of the internal decay pocket. The preservation level in this zone must therefore be boosted through flooding of the void with a liquid preservative.

In the picture to the left we see an inspector filling an internal void with copper Naphthenate using a pressurized tank and nozzle.

When inspecting a pole that has been treated for an internal void you should see a vertical series of plugged holes with no leaking of preservative down the side of the pole.

2.7 Groundline Treatment

External groundline preservative shall be a dual-biocide topical treatment applied as a "Bandage Treatment" as described on the following page. The barrier wrap shall be a minimum of 1-mil poly lined, 26-lb kraft paper, 60 cm (24 inches) in width. Before preservative is applied, all dirt and decayed wood is to be removed from the excavation

and disposed of as per Provincial and local preserved wood disposal guidelines. Pesticides shall not be applied when it is raining or to poles in standing or moving water. Poles with underground dip services shall not have a bandage treatment.

When inspecting a pole that has been groundline treated, the ground around the pole should be clean with no left over fill. The hole should be backfilled 5 cm (2 inches) above the normal groundline around the pole. The barrier wrap should be wrapped tightly around the pole and be secured. The barrier wrap should be exposed 5 cm (2 inches) above the backfill.

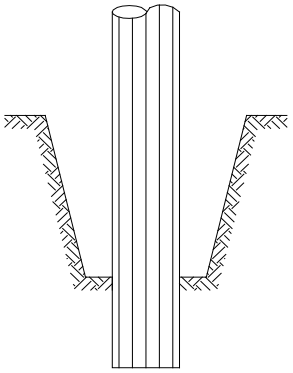
2.8 Backfilling

When backfilling the hole, all the original soil must be cleaned up from the ground around the pole and used to fill the hole. The hole should be backfilled in three stages, 1/3 of the depth at a time, followed by thorough tamping at each stage. If required extra fill may be brought on site to backfill with if there is insufficient material present. The backfilling should be 5 cm above the normal groundline around the pole and 5 cm of paper should be visible above the backfill. The site should be returned as closely as possible to the condition it was in before work was begun.

This picture shows a decent backfill. The backfill is above the normal groundline and slopes away from the pole. The backfill is also well tamped up against the pole, leaving no space between the soil and the pole. The ground around the pole is clean and appears undisturbed from its original condition. The paper is also exposed a little bit more above the backfill.

BANDAGE METHOD GROUND LINE TREATMENT

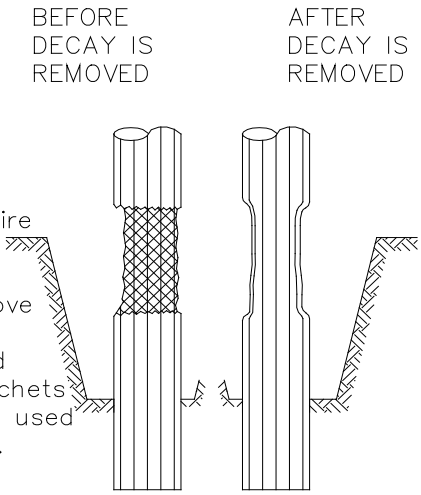
1) Remove earth from pole to allow at least 50 cm of preservatives below ground line



2)

Clean pole of all dirt and surface decay in the ground line area.

The pole will be wire brushed, scraped & chipped as necessary to remove all dirt, external decay pockets and shell rot. No hatchets or axes are to be used for this procedure.

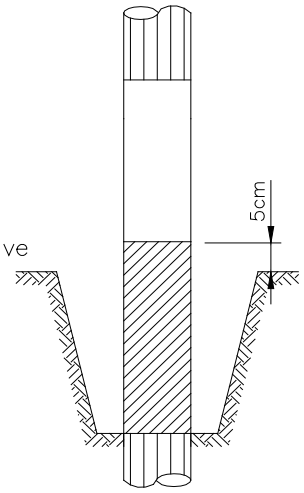


3)

Wrap paper around the pole with the bottom edge 5cm above the ground line.

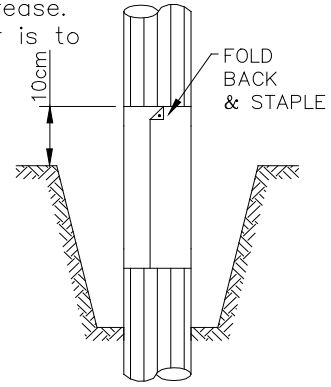
Apply at least 50cm of preservative below the paper.

Spread evenly at 0.3cm thick and work into checks.



4)

Wrap paper over the grease with 10cm above ground line & 5cm above grease. Overlap of paper is to be minimum of 10cm. Paper is to be stapled along overlap and in the top 5cm.

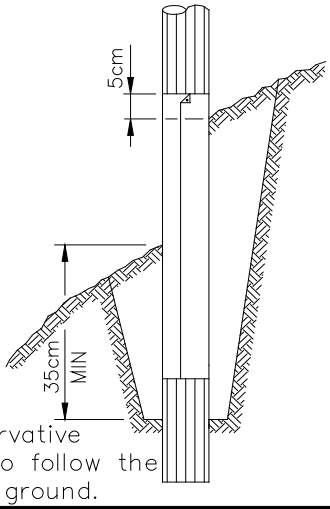


5)

If pole is set in sloping ground, apply additional length of preservative and paper.

The low side must have a 35cm min. excavation.

Paper and preservative may be sloped to follow the countour of the ground.

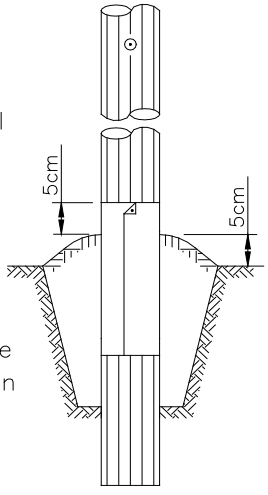


6)

Backfill and tamp earth around pole 5cm above normal ground line.

5cm of paper is to be exposed above the backfill.

Install maintenance tag at eye level on road side of pole.



2.9 Ants

All ant infested poles should be treated internally with Prelude™ insecticide as per label specifications. If ants are present in the stub or abandoned pole nearby, it must be treated as well. Carpenter ant galleries are treated with a synthetic pyrethroid insecticide to control the invading ant colony, preventing further mechanical damage. The poles are drilled several times to determine the extent of the gallery. The drill holes are flooded with a water/insecticide emulsion and then plugged. Care should be taken to ensure the entire ant gallery is flooded thoroughly.

When inspecting a pole that has been treated for ants you should see evidence of ant activity which includes sawdust around the pole or inside checks (cracks) as well as boring holes into the wood. Typically a large check (crack) is rounded out near the groundline and used as an entrance/exit hole.

2.10 Mechanical Damage

Mechanical damage up to 2 metres above ground that penetrates beyond the original preservative treatment (thus exposing unprotected wood) is shaved to remove loose and decayed wood and to eliminate areas that may trap water (see picture to the left). The area is then treated with a liquid 2% copper naphthenate solution. This re-establishes the preservative barrier between the wood pole and potential decay infection.

The pole strength evaluation chart should be consulted to ensure the pole is still serviceable.

When inspecting a pole that has mechanical damage, the damaged area should be clean of loose and/or decayed wood and all exposed wood should be externally treated with preservative so no untreated wood is visible.

The picture to the right shows a properly treated mechanical damage. The damaged area has been cleaned so there is no loose or decayed wood. The shaved area has been thoroughly covered with copper naphthenate so no untreated wood is exposed.

Here is the same mechanical damage treated pole but viewed from the side. Here you can see there is no area available for water to collect on; the surface is smooth.

The example of mechanical damage treatment on the right is a bad example as there is some untreated wood exposed that was not covered with copper naphthenate. There are also many splinters coming off this treatment showing that the area was not properly shaved. In the side view picture you can see that the damage was not shaved down properly so water may collect on the ledge that was left giving an entry for decay into the pole.

2.11 Internal Treatment of Poles in Standing Water

The wood is treated with solid boron or sodium fluoride rods. The rods dissolve in water and the preservative diffuses throughout the remaining wood, sterilizing existing internal decay infection.

When treating a pole with internal rods keep the bottom of the first set of three holes 1.5 to 2" above groundline 120° apart (this is especially critical in wet landscapes). Push three rods into each hole and plug the hole. Do not hammer the rods directly as they will break. Drill three more holes each 6" higher up the pole and centered between the original three holes at the bottom of the pole. Follow the diagram on the following page.

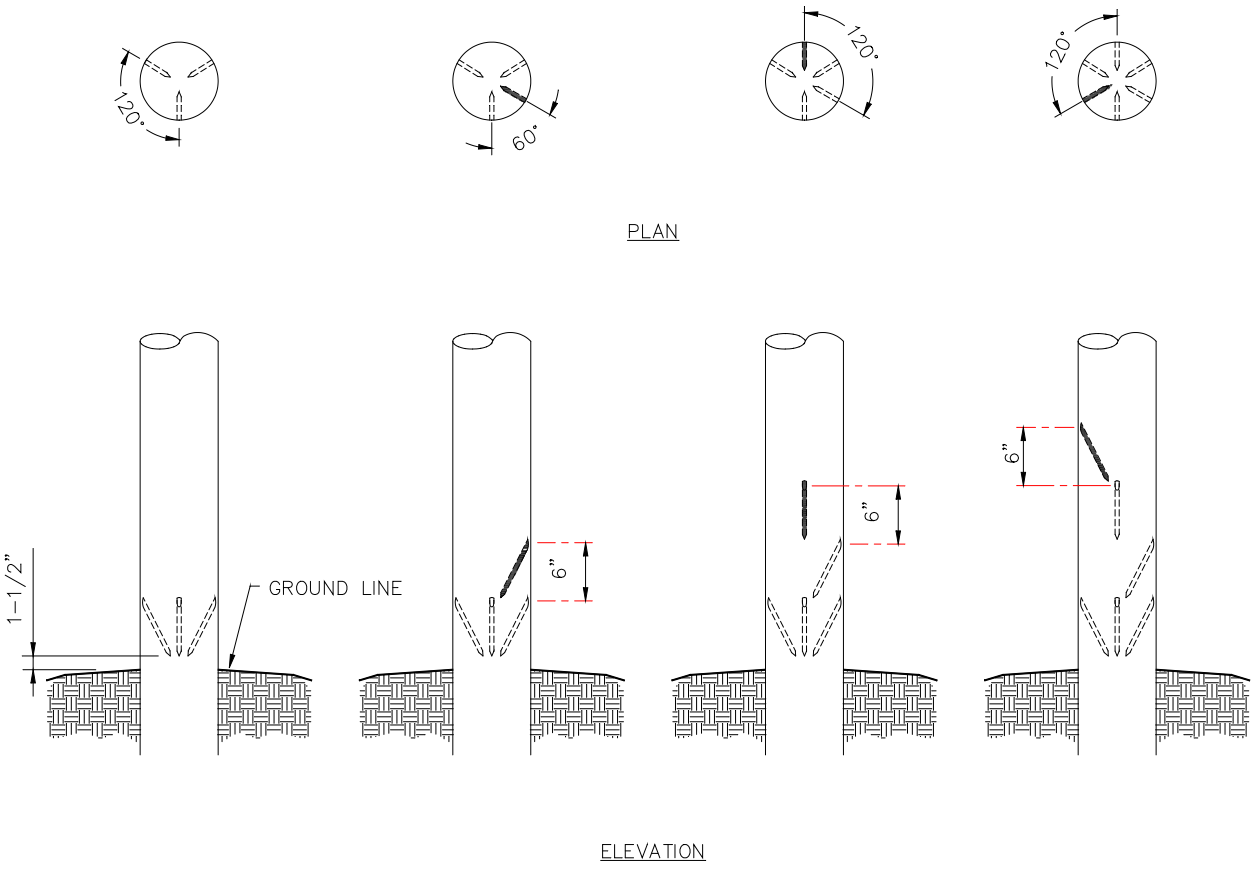
For an average 50" circumference pole (Line 12) insert 3 rods into each of the remaining 3 holes and plug.
For an average 45" circumference pole (Line 78) insert 2 rods into each of the remaining 3 holes and plug.

Drill hole

Drop in FLUROD

Plug hole

When handling any internal treatment rods be sure that chemical resistant gloves are worn.



2.12 Rock Plate Assemblies (New for 2014)

Where rock set poles are found the rock plate assemblies must be thoroughly inspected to ensure that the pole is safely anchored into the granite rock. Rusting and deterioration of these rods and plates due to corrosive soils has generated a need to closely assess and if need be replace the damaged installations.

Introduction This guide was created in order to assess and categorize the rock plates that are currently in service with Manitoba Hydro.
Over the years, the corporation has used various types and configurations of rock plate hardware to meet the needs of setting poles in stone. Rusting and deterioration of these rods and plates due to corrosive soils has generated a need to closely assess and if need be replace the damaged installations.
Information given in the following pages will enable workers to analyze the various types by using the length and size associated with installations over the years.
Any visible form of deterioration must be reported to the supervisor in charge of the area or group.

Points to consider in assessing rock set structures:
As some of these assemblies are getting quite old or may have been installed during undesirable circumstances, it is crucial to have a close look at them whenever they are unearthed or exposed.
Points to consider and make note of while doing the checks are:
1. Hardware Integrity – what has the assembly suffered over the years that would cause it to fail?
Questions to ask are:

i. Has the steel deteriorated due to corrosion?
(See example page 46 ii. Are there structural cracks in the metal or welds?
iii. Have the bolts loosened off due to pole shrinkage?

2. Rock Integrity – has the assembly been set in bedrock or a rock large enough to act as a proper anchoring point for the rock pins?
Questions to ask are:

i. Are there cracks that lead away from the drilled hole?
ii. Does the rock in the same vicinity look as if it is shale and not granite?
iii. Does the pole easily move when pushed upon?

What to look for...
3. Sulfur or Grout problems – are there problems with the way that the rock pins were fused?
Questions to ask are:

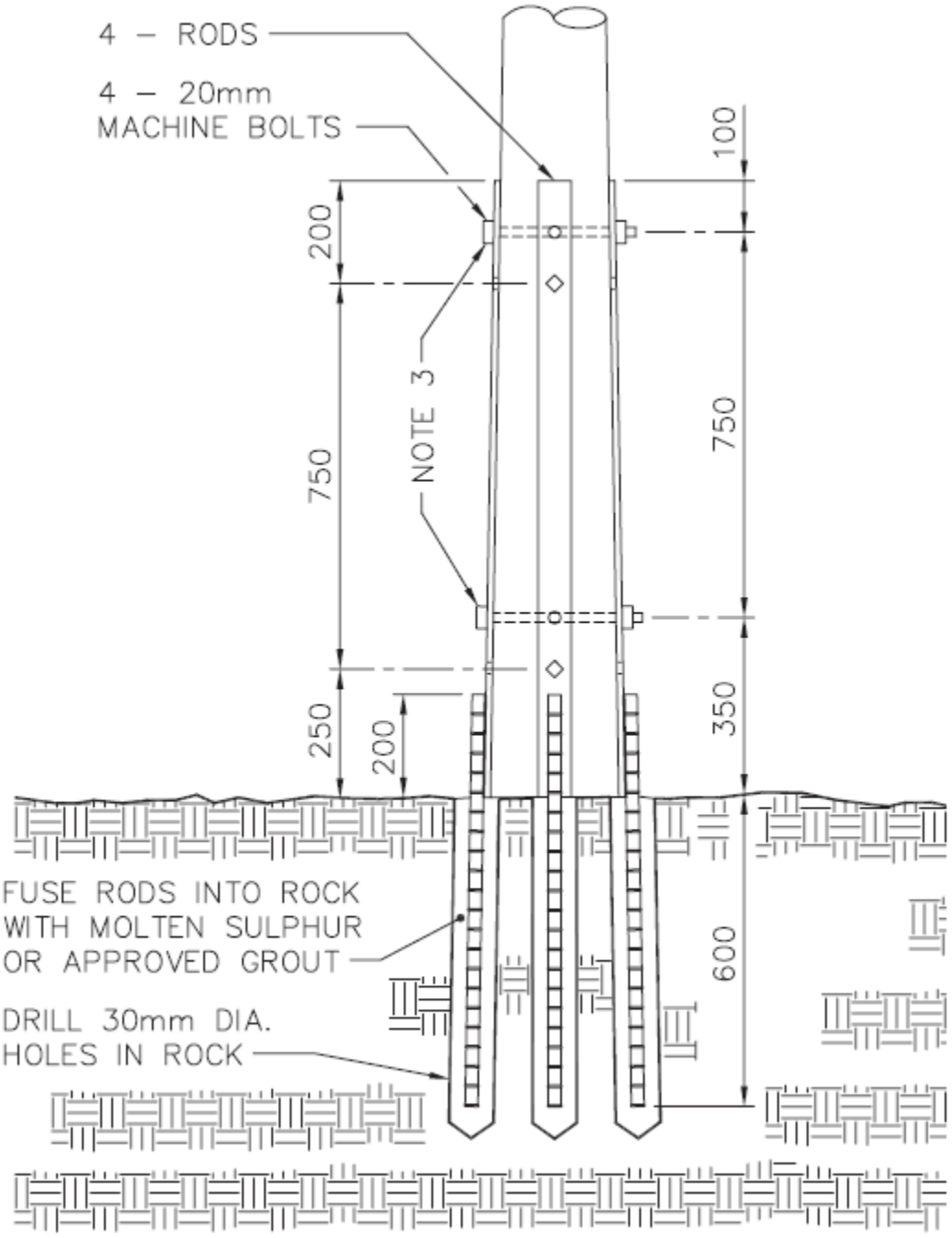
i. Was the hole properly filled to the top with either sulfur or grout during installation?
ii. Did the sulfur seep away due to cracks in rock during installation?

In most of the cases mentioned above a quick visual look is enough to check the integrity of the rock set installation.
Probing with a small rod in the fused hole would easily determine sulfuring problems.

ALL PROBLEMS MUST BE REPORTED TO SUPERVISOR

This is the current standard used in rock setting a pole.

All of the Characteristics of the Current Standard installations fall under the Type 1 and should be noted as such when doing the assessment and coding of any of these assemblies.



Current Standard for Rock Set Installations

Corroded Rock Plate Assembly

As the picture clearly shows, the deterioration of this rock plate assembly is quite advanced and shows need for replacement.
Until such time as we can determine the residual strength of these rusted pins, the need for replacement will be assessed on an individual basis.

Type 1

Characteristics:

- 4 – (2.5 in. X 48 in.) galvanized plate welded to 1 in. galvanized rod
- continuous 8 in. weld attaching rod to plate
- 4 – ¾ in. galvanized bolts set at a 29 in. spacing

Type 2

Characteristics:

- 4 – (2.25 in. X 48 in.) galvanized plate welded to 1 in. galvanized rod
- continuous 8 in. weld attaching rod to plate
- 4 – ¾ in. galvanized bolts set at a 29 in. spacing

Type 3

Characteristics:

- 4 – (2.25 in. X 48 in.) black steel plate welded to 1 in. black steel rod
- continuous 8 in. weld attaching rod to plate
- 4 – ¾ in. galvanized bolts set at a 29 in. spacing

Type 4

split weld (top and bottom) connecting plate to rod

Characteristics:

- 4 – (2.5 in. X 48 in.) black steel plate welded to 1 in. black steel rod
- 2 separate 4 in. weld areas that connect rod to plate
- 4 – ¾ in galvanized bolts set at a 29 in. spacing

Type 5

Characteristics:

- 4 – (2.25 in. X 36 in.) black steel plate welded to 1 in. black steel rod
- 2 – 4 in. welds attaching rod to plate
- 4 – ¾ in. galvanized bolts set at a 9 in. spacing

Type 6

Characteristics:

- 4 – (1.5 in. X 36 in.) black steel rod flattened to become bolting plate
- no welds as rod is 1 piece
- 6 – 5/8 in. galvanized bolts set at a 12 in. spacing

Type 7

Characteristics:

• 4 – 48 in. galvanized pipes with welded partial collars that bolt from one to the other (making a continuous collar)

• not commonly used to date (picture taken in Flin Flon April 2005)

3. Materials and Tools

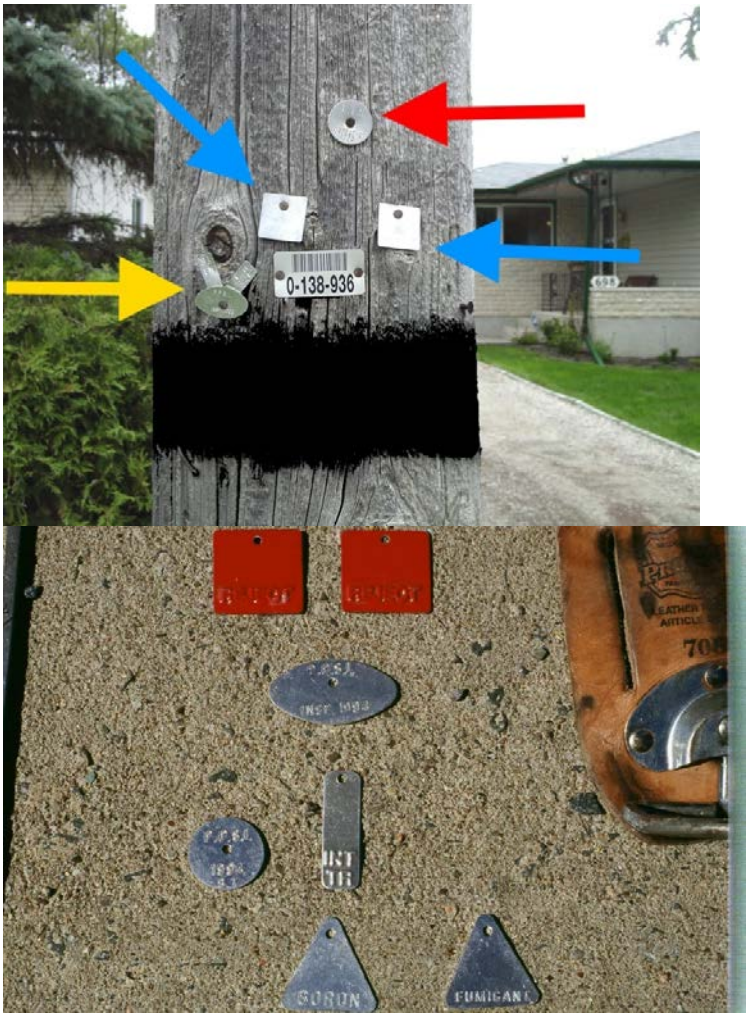
3.1 Tags

All poles that are inspected are required to have a pole identification tag with a bar code installed on the roadside at eyelevel regardless of their classification. Inspection and treatment tags should also be at eyelevel on the roadside of the pole and indicate remedial treatments received the year the work was preformed and the name of the contractor. All pole tagging and markings shall be in accordance with Manitoba Hydro standard procedures as stated in the tender in Section 6 of the Technical Requirements and Appendix 11 of the tender.

Poles to be reinforced must have a large “x” painted on them. Poles to be replaced must have a horizontal bar 5 cm (2 inches) wide painted on them. Reject poles have one blank, square aluminum tag while danger poles have two. Paint markings must be at eyelevel on the roadside of the pole below the aluminum tags. The paint must be weather resistant black.

This is an example of a normally treated pole. The circular tag at the top means that the pole was inspected as well as groundline treated. The triangular tag attached to the circular tag means that the pole was treated with fumigant. The bottom tag is the pole’s barcode tag.

The pole to the right has a large black X spray painted on it to indicate that it is a re-inforceable pole. Note that the X is very large and visible from the road.

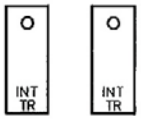
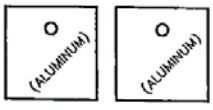


There are many tags attached to this example pole. The first marking that should be noted is the thick, black line painted below the barcode tag. This black line indicates that the pole is a reject pole. The two square, silver tags indicated by the blue arrows specify that this is a danger pole. The tag indicated by the yellow arrow is an inspection tag with a year of inspection of 2006. As the inspection tag is oval and not circular; there was no groundline treatment for this pole. The two rectangular tags sticking out of the inspection tag indicate that this pole was internally treated for carpenter ants. Finally the tag indicated by the red arrow is from a previous inspection. The tag shows that the pole was inspected and groundline treated in 1993.

All tags should follow the guidelines as laid out in the tender and on the following page. All tags must be made of aluminum, a minimum of 1/16 of an inch thick; round tags a minimum of one inch in diameter and square tags a minimum of 1.25 inches square. All lettering shall be a minimum of 1/8 of an inch in size.

All pole markings shall be made on the road side with weather resistant black paint and shall be a minimum of two inches in width.

INTEGRATED POLE MAINTENANCE PROGRAM
TAGGING AND POLE MARKING SYSTEM

TAGGING AND POLE MARKING SYSTEM		
TAGS *	POLE ** MARKINGS	DESCRIPTION
	NONE	– POLE WAS INSPECTED
	NONE	– POLE WAS INSPECTED – POLE WAS GROUNDLINE TREATED
	NONE	– ALWAYS IN COMBINATION WITH ONE OF THE INSPECTION TAGS ABOVE – INTERNAL VOIDS DUE TO ROT WERE PRESERVATIVE TREATED
	AS NECESSARY AS DETERMINED BY INSPECTION	– ALWAYS IN COMBINATION WITH ONE OF THE INSPECTION TAGS – INTERNAL VOIDS DUE TO ANTS WERE INSECTICIDE TREATED
	NONE	– ALWAYS IN COMBINATION WITH ONE OF THE INSPECTION TAGS ABOVE – HEARTWOOD WAS TREATED WITH A LIQUID FUMIGANT
	PAINTED ?X" ON ROAD SIDE OF POLE	– POLE WAS INSPECTED – POLE IS WEAKENED DUE TO ROT OR ANTS OR MECHANICAL DAMAGE – POLE MUST BE REINFORCED -- CLIMB ONLY IF SUPPORTED --
	HORIZONTAL BAR ON ROAD SIDE OF POLE	– POLE WAS INSPECTED – POLE WAS CLASSED AS A REJECT – POLE MUST BE REPLACED -- DO NOT CLIMB --
	HORIZONTAL BAR ON ROAD SIDE OF POLE	– POLE WAS INSPECTED – REPLACEMENT TO BE DONE IMMEDIATELY -- DO NOT CLIMB THIS POLE --

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3.2 Plugs

All wooden plugs must be a minimum of 7/16 in diameter and 5cm (2 inches) in body length. All wooden plugs must be treated with preservative. Plastic plugs are also acceptable as long as you ensure the appropriate size has been chosen.

3.3 Paper

The barrier wrap used to perform the BANDAGE METHOD GROUND LINE TREATMENT which is illustrated on page 19 should be as described. A minimum of 1-mil poly lined, 26-lb kraft paper, 60 cm (24 inches) in width.

3.4 Tools

Tools below are typical tools used for inspection and treatment of our wood poles. First is the digging bar, second is the gas drill with two bit sizes used for bore inspections and internal floods. The last picture is of a depth probe or shell thickness indicator, used to measure the size of a internal pocket as well as the remaining shell thickness.

4. Administration

4.1 Start-up Meetings

Prior to starting the season a start-up meeting will be held with the contractor, district staff, program coordinator and inspectors to review all technical and safety requirements.

4.2 Work Clearance Requests

Work clearance requests are to be filled out by the Manitoba Hydro onsite representative and submitted to the local district each time work starts in a new district.

4.3 Quality Assurance Audits

Quality assurance (QA) audits will be carried out by the Inspectors on the contractor's work. These will include:

a) inspection of all recorded data and reports against field conditions
b) re-excavating the pole
c) removal of the wrap and treatment
d) complete re-inspection of the pole condition
e) re-evaluation of the pole strength and serviceability, and
f) evaluation of all treatments applied to the pole.

4.4 Accident and Spill Reporting

All injuries and chemical spills must be reported to the program coordinator and Safety Officer. Major incidents must be reported immediately and minor incidents must be included in the weekly reports to the program coordinator. In the event of a hazardous material incident (injury, spill, etc.), a Hazardous Material Incident Report (located in Appendix 6) must be completed and submitted to the program coordinator, the Corporate Hazardous Materials Officer, the Area Spill Response Coordinator, and the Responsible Line Management.

4.5 Private Properties and Complaint Records

Before entering private property, the contractor needs to obtain permission from the property owner. If access is denied the Manitoba Hydro onsite representative will try to obtain permission from the property owner. If the property owner is unavailable the contractor may proceed with the work if the work is accessible. Locked property shall not be entered as per Tender.

All complaints from property owners or the public should first be directed to the contractor. If the contractor is unable to resolve the complaint the Manitoba Hydro onsite representative should step in. A record of every complaint must be kept on a Manitoba Hydro Complaint Record form found in Tender Appendix.

4.6 Contact Phone Numbers

Program Coordinator	Murray McDonnell	360-
Tech Support	Ivan Gibson	360-4606
	Bei Hu	360-6331

5. IPM Report Tool

To ensure that the customers receive uninterrupted service, existing poles need to be maintained and replaced. With the large amount of poles currently in use, it is impractical to keep individual paper records. Finding all the rotten poles after 1960 that were Danger or Stubbable would be impossible if someone had to search through boxes of pages. Making the data electronic allows Manitoba Hydro to easily organize data so that the relevant data is easily visible and accessible. The latest application version for IPM Report Tool is v1.6.

5.1 Starting IPM Report Tool

To start IPM Report Tool, double click on icon shown in **Figure 5.1.1**

Figure 5.1.1
IPM Report Tool icon

This is the main screen of the IPM Report Tool. From here you can create and edit Daily Reports, Enter inspector Hours, and Create Reports.

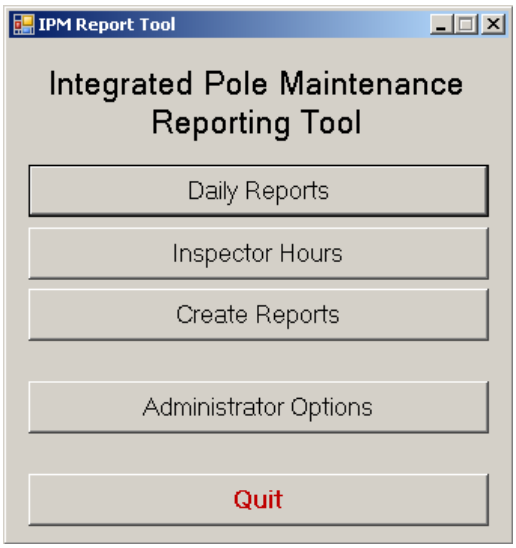


Figure 5.1.2
Main Screen

5.2 Entering Daily Reports

Daily reports are used to record information about pole maintenance. Inspectors first fill out the information on paper before they enter it onto their computers. This guide will show what parts of the Daily Report sheet get entered into the IPM Report Tool.

To start entering a Daily Report into the IPM Report Tool, click on “Daily Reports” located on the main screen (**Figure 5.1.2**). A new window should appear (**Figure 5.2.1**), this is the list of all the daily reports. From here you can create a new report, edit an existing report, or delete reports. Click on the “New” button in the lower left corner.

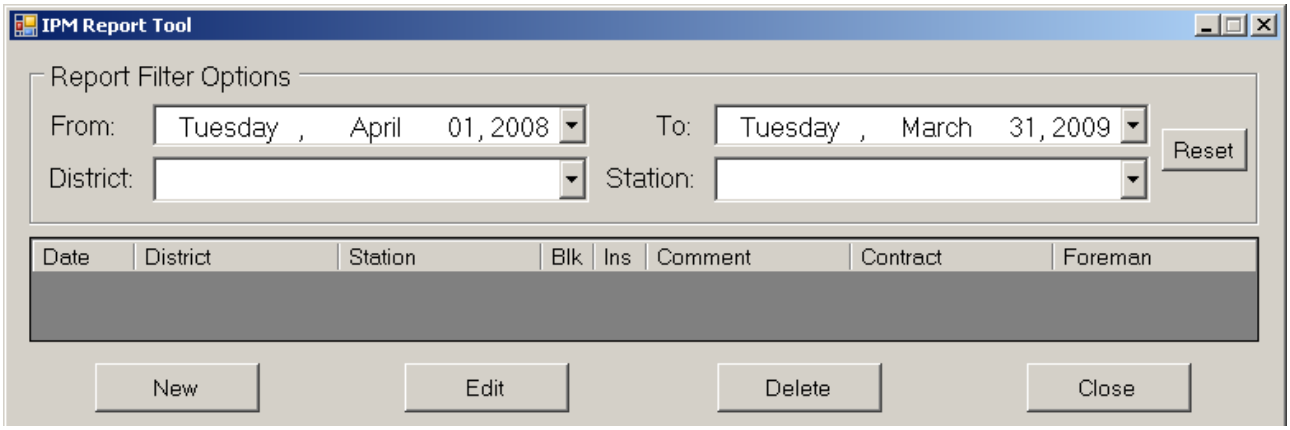


Figure 5.2.1
Daily Reports

The Daily Report window (**Figure 5.2.3**) will appear. Enter information from the daily report sheet (**Figure 5.2.2**).

Date:	April 29, 2011	District:	38324 Stonewall
Station Area:	2228 komarno	Line:	BLK 07
Contractor:	Interlake - PP	Crew Foreman:	Joe Public

Figure 5.2.2
Daily Report Sheet

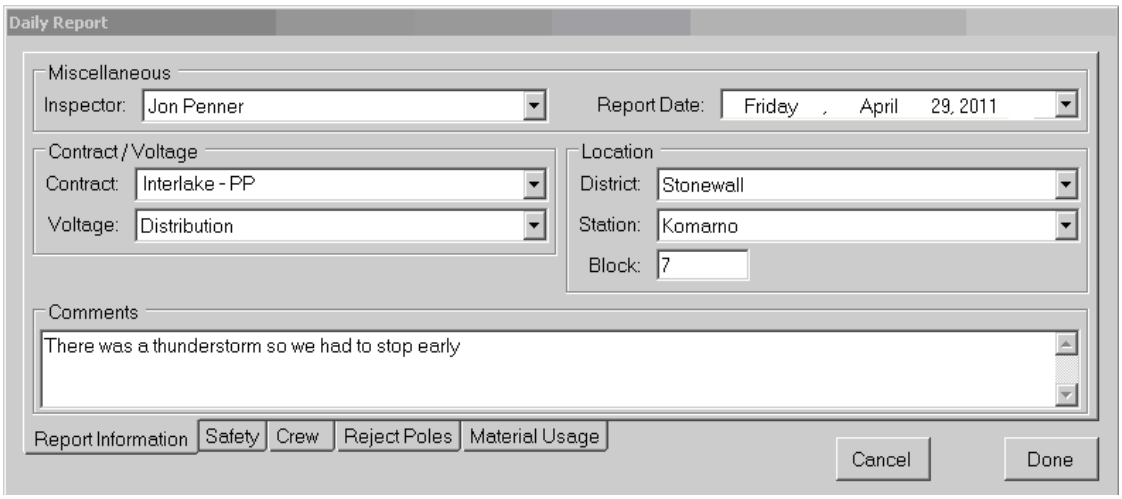


Figure 5.2.3
Report Information

When you are done entering the Report Information, click on the Safety tab at the bottom left corner. The below picture should appear. For both Accidents and Spills, click either Yes or No. If yes, fill out the Description and Persons box.

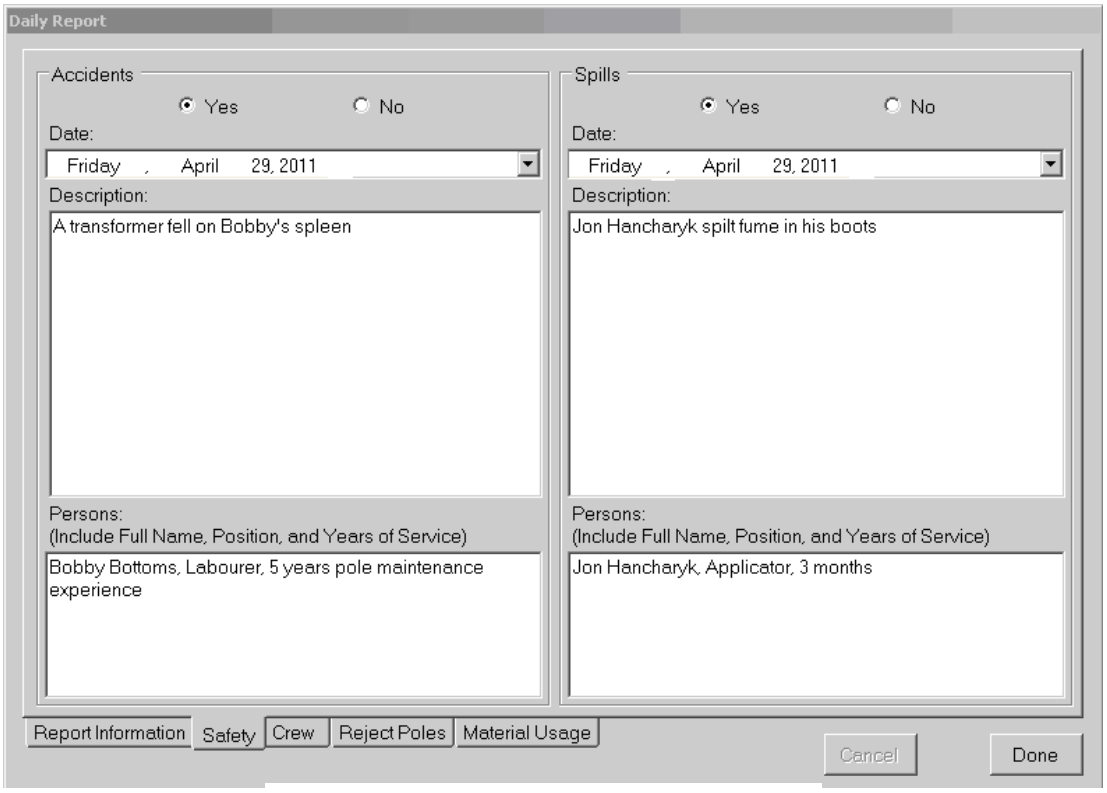


Figure 5.2.4
Safety Tab

When you are done entering safety information, click on the Crew tab at the bottom.

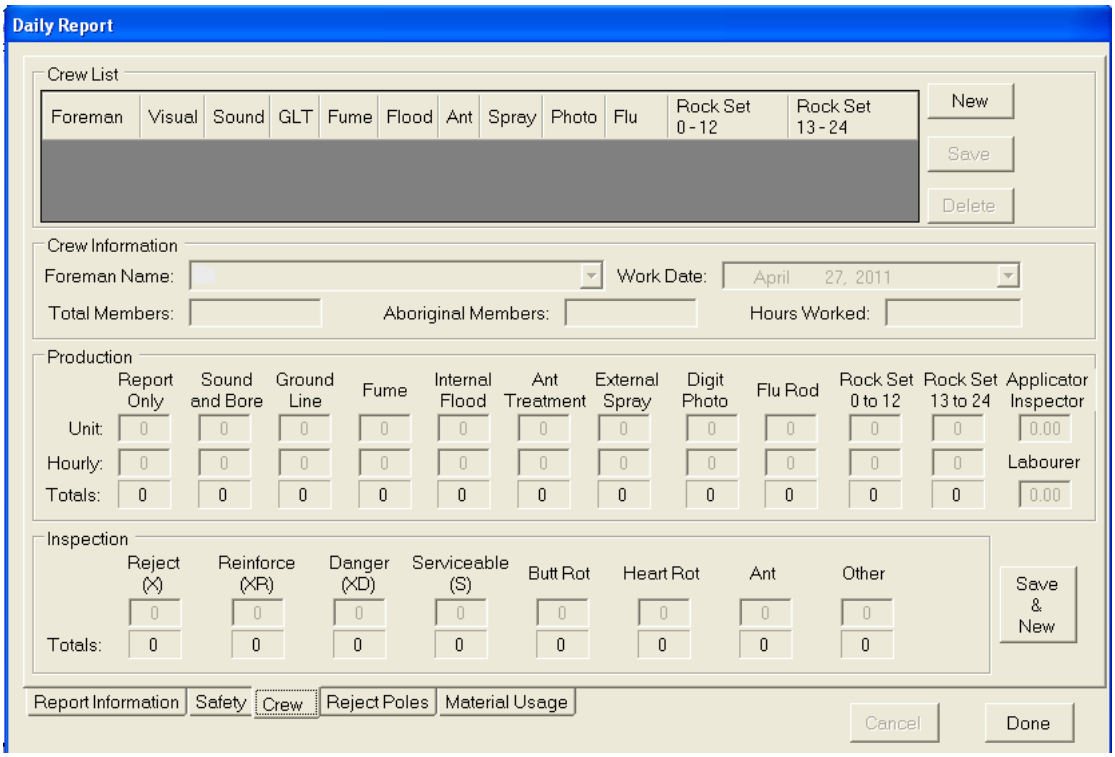


Figure 5.2.5
Crew Tab

Click on the "New" button on the top. You can now enter the Crew Information, Inspection and Production data. When you are done this, click on the Save button.

Contractor:	Interlake - PP	Crew Foreman:	Joe Public √

Crew Members (Checkmark those qualifying as aboriginal):

Grabe Chartrand	√		
Frank Watt			
Bill Fontaine	√		

Figure 5.2.6
Crew Members

Production (# of Poles):

Voltage	Total Poles	Report Only	Sound &Bore	GLT	Fume	Interal Flood	Ant Treat	Ext. Spray	Digital Photo	Flu Rod	Rock Set 0-12	Rock Set 13-24
Distribution	37	0	37	2	14	1	1	10	1	1	2	3

Figure 5.2.7
Production

Inspection Results (# of Poles):

Voltage	Regular Rejects (X)	Reinforce Rejects (XR)	Danger Rejects (XD)	Servicable (S)	Butt Rot	Heart Rot	Ants	Other Damage
Distribution	1	1	1	34	0	1	1	10

Figure 5.2.8
Inspection

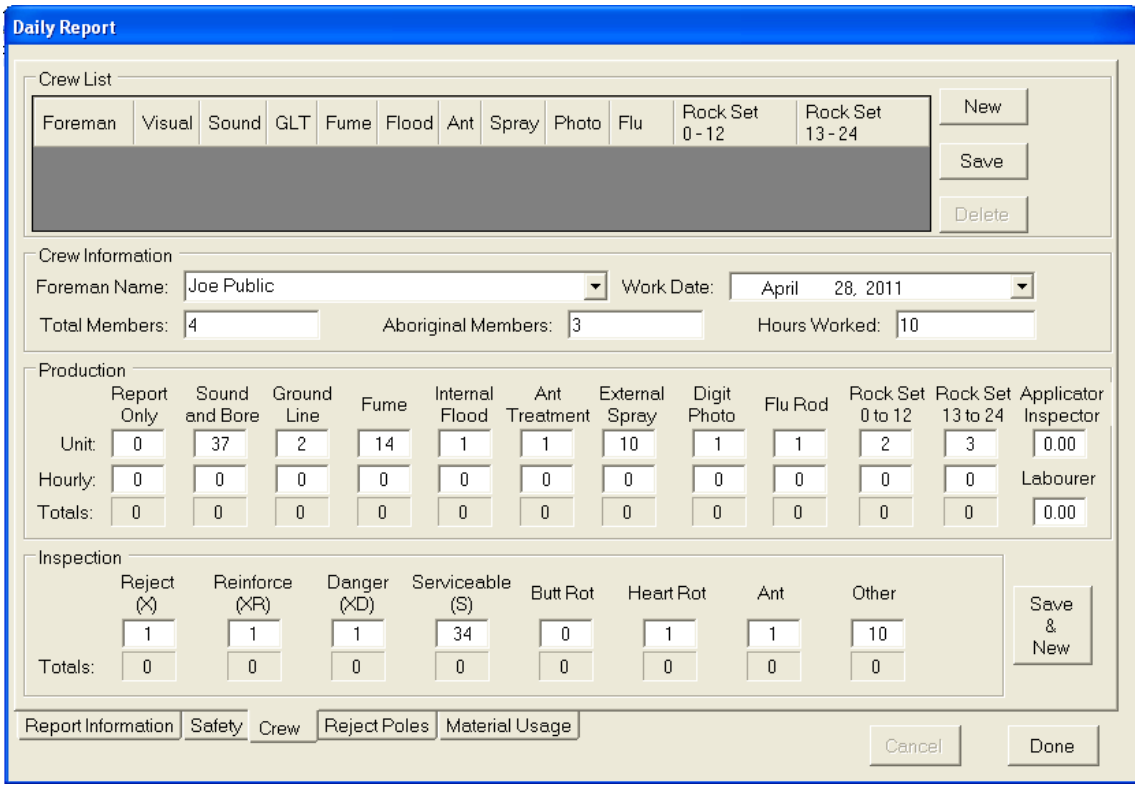


Figure 5.2.9
Crew tab

The Crew list will update when you click the save button. This list will show all the crew for the particular District / Station / Block. To edit a crew, click on the Forman name and all the fields will load.

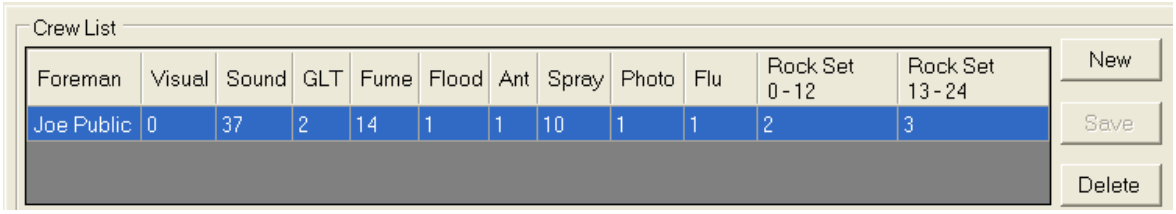


Figure 5.2.10
Crew list

When you are done editing a Crew, the below window will appear. Click Yes to save any changes, No to discard any changes, and Cancel if you accidentally clicked on something and this window appeared.

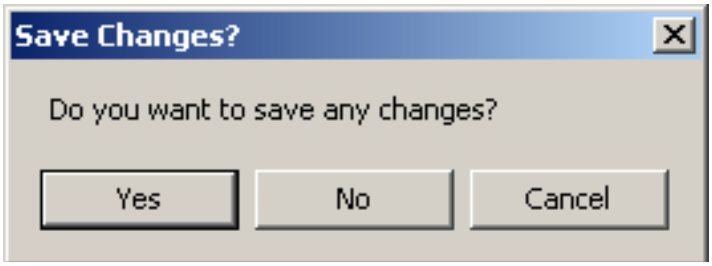


Figure 5.2.11
Do you want to save changes?

When you are done adding all the crews and they are saved, click on the Reject Poles tab. The top displays how many reject poles entries are needed.

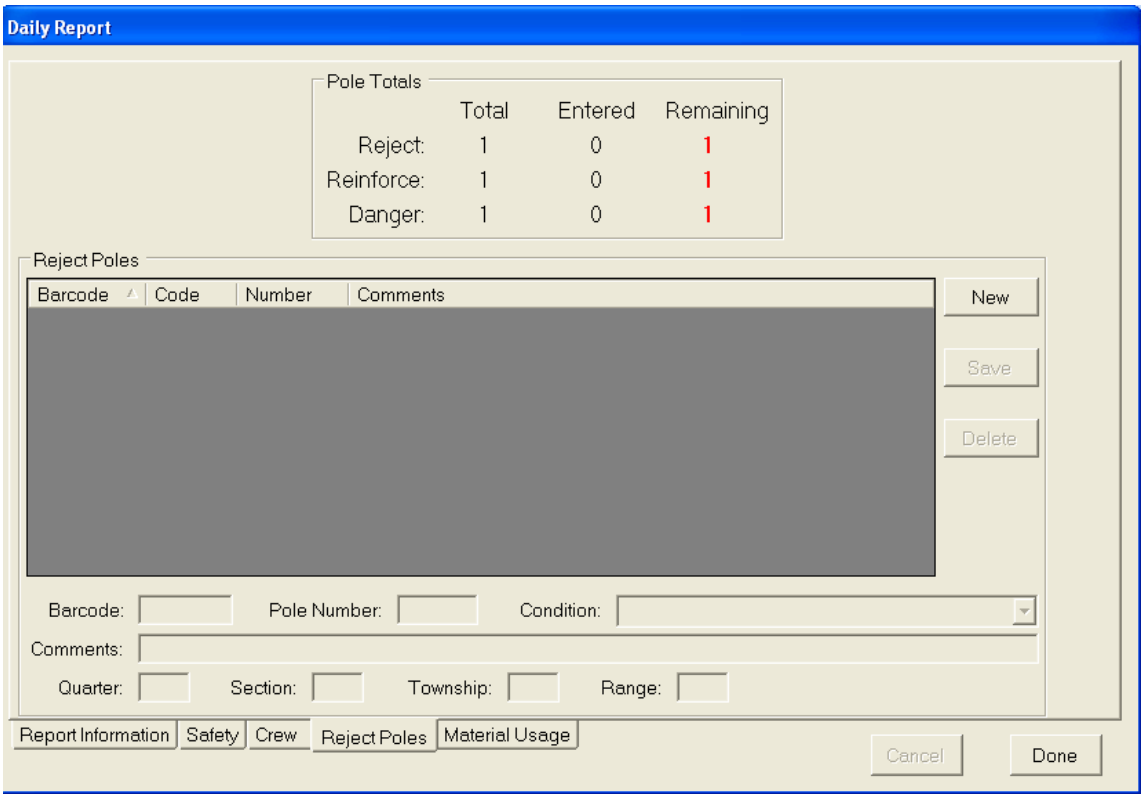


Figure 5.2.12
Reject Poles

Click on the New button to create a new Reject Pole. Fill in the fields and then click Save.

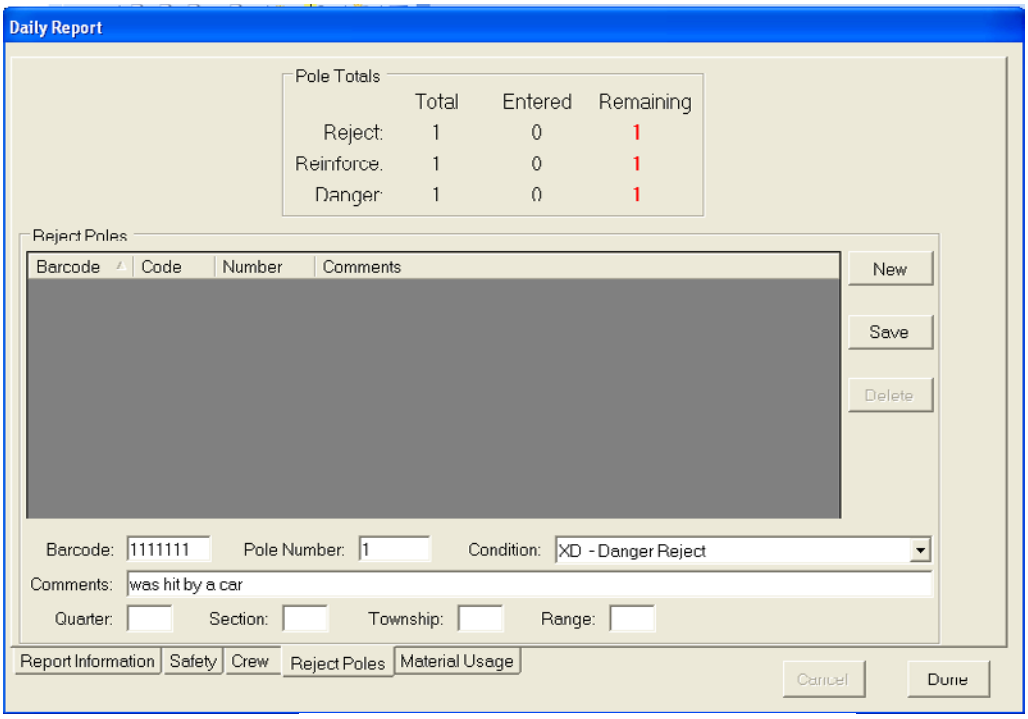


Figure 5.2.13
Entering a Reject Pole

The Pole Totals and the Reject Poles list will update. Enter the remaining Reject Poles and then select the Materials tab.

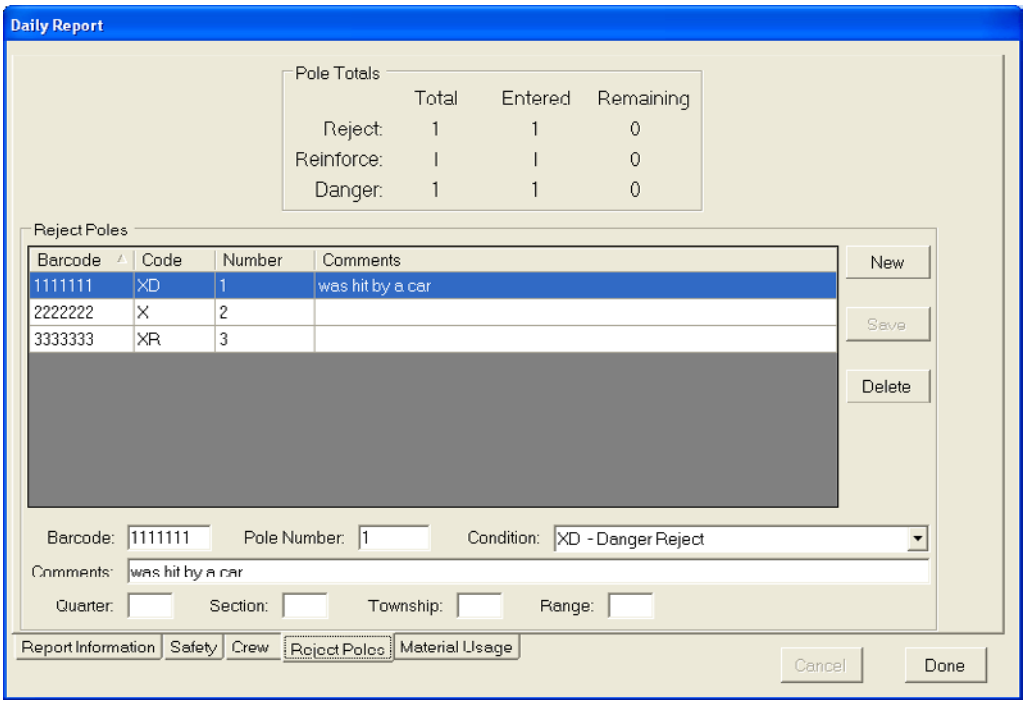


Figure 5.2.14
Finished entering a Reject Pole

When the material tab is loaded, it will appear blank like the below picture.

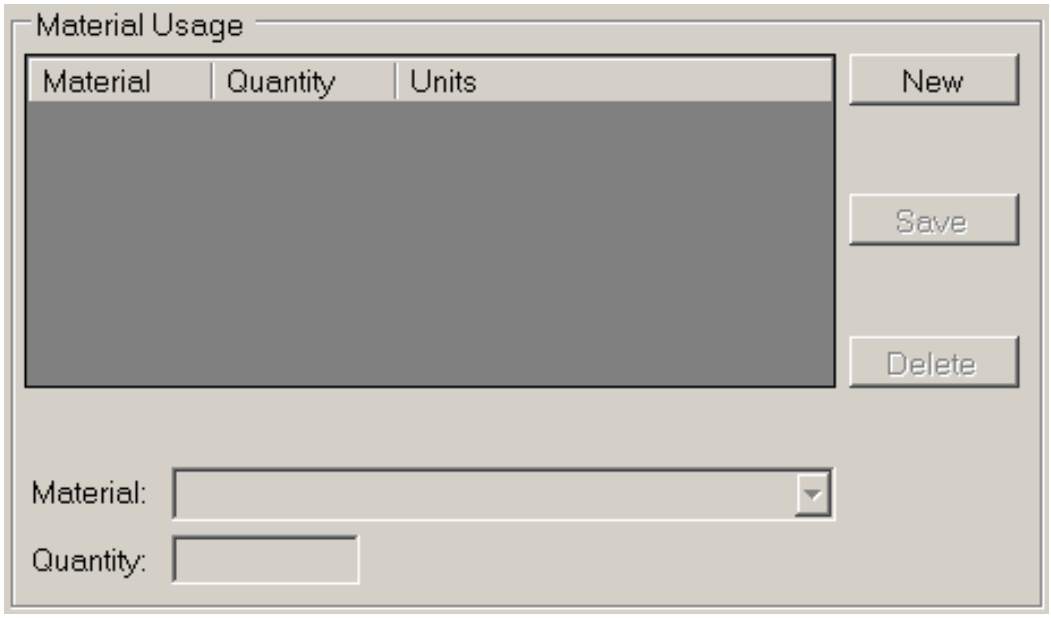


Figure 5.2.15
Material Usage

Click on the new button, select a material and enter the quantity of that material. Click on the Save button when you are done.

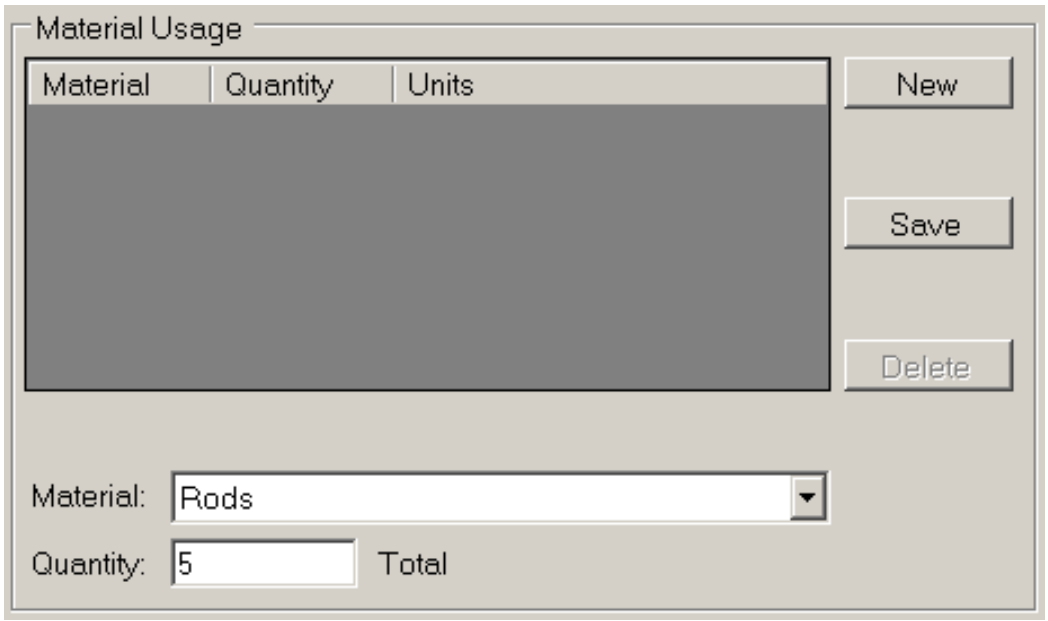


Figure 5.2.16
Entering a material

After saving, the Material Usage list will update.

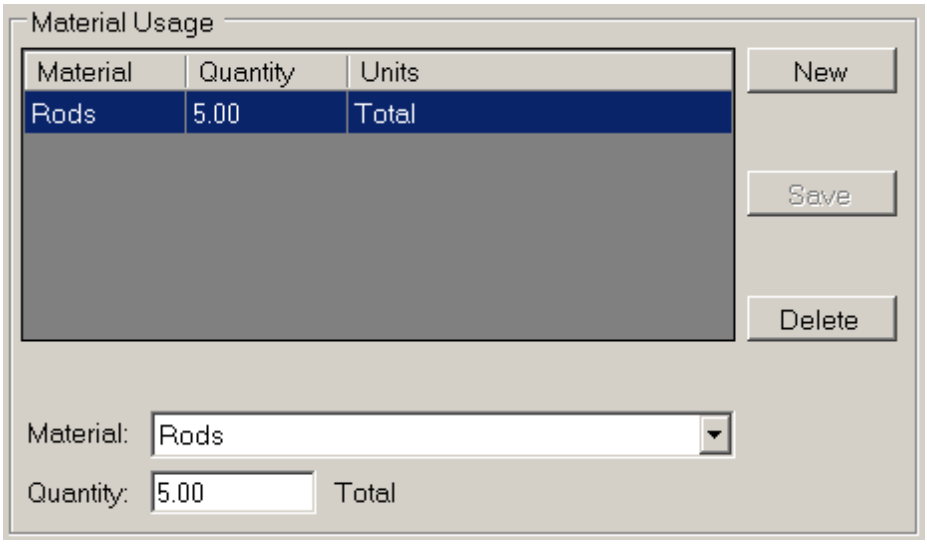


Figure 5.2.17
Finished entering a material

Enter the remaining materials and click the “Done” button in the lower right hand corner.

The Daily Report window will close. You can now see that the below list has been updated, showing two crews. To edit an existing Daily Report, click on a Crew and click the Edit button. To Delete a Daily Report, select a crew that belongs to the Daily Report and click Delete. Be careful when deleting, it will delete ALL Crews belonging to that Daily Report.

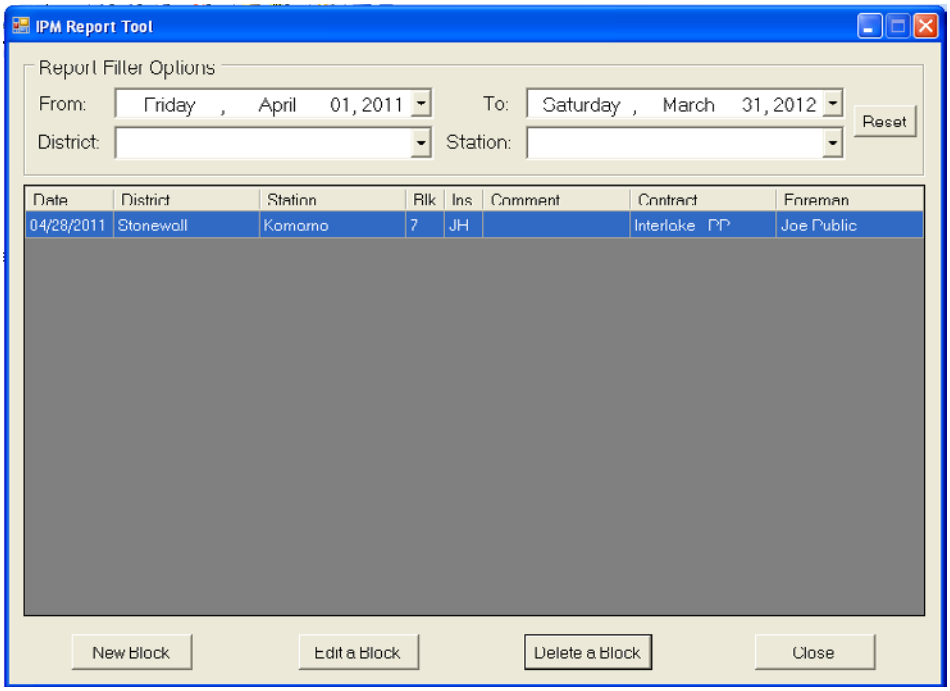


Figure 5.2.18
Updated Daily Report list

5.3 Inspector Hours

To keep track of your hours, click on the “Inspector Hours” button on the main screen. Select yourself from the drop-down box in the upper left corner. When you select yourself, the window should load up the first week of which hours have not been entered yet. Click on the Previous Week and Next Week buttons at the top to change weeks. When you are finished entering your hours, click on the “Done” button.

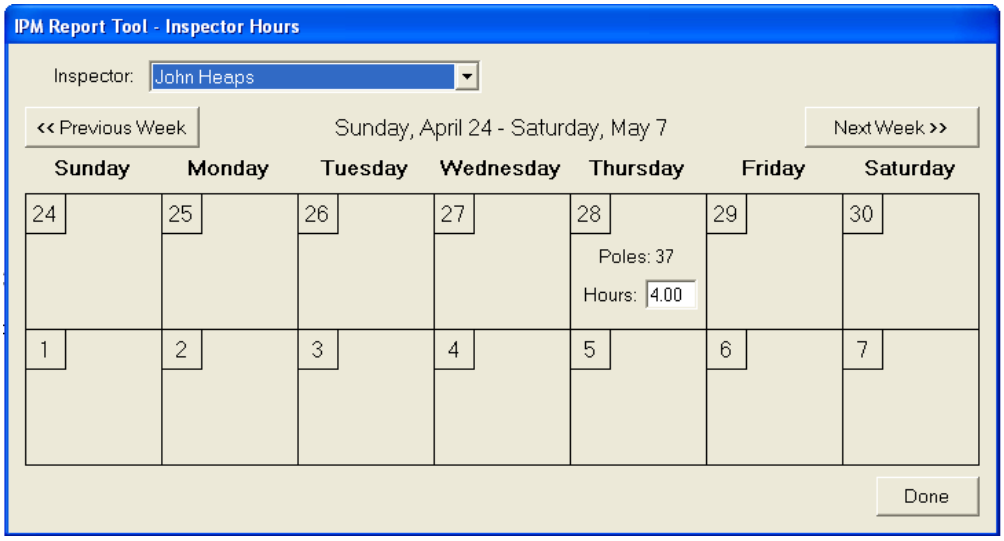


Figure 5.3.1
Inspector Hours

5.4 Create Reports

Reports are used to view information about Reject Poles, Production and Inspection totals, cost breakdowns, or Inspector Hours in a summarized form. These reports can be viewed on the computer, printed, or emailed.

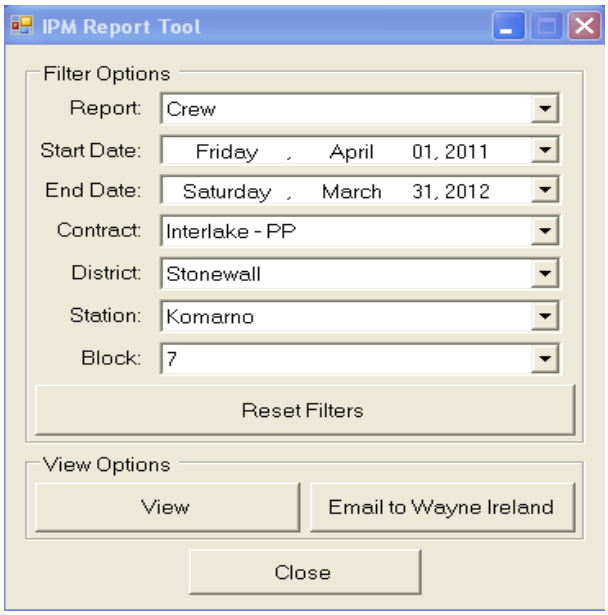


Figure 5.4.1
Create Report

To create a new report, click on the Create Reports button on the main screen. This will bring up the Create Reports window, where you can choose the report type and filter options. There are six types of reports that you can choose from.

Inspector Hours
Detailed information on Inspection Hours

Cost Summary
Production / Inspection totals and a cost breakdown

Reject Poles
Details location and condition information for individual reject poles

Safety
Information on Accidents and Spills

Danger Poles
Details location and condition information for individual danger reject poles

Crew
Details production and Inspection information for crew

There are several filter options you can choose when making a report.

Start date and End date change the date range of information used in creating the reports. Contract selects which Company to use. District / Station / Block lets you select which area to use information from.

To view the report, click on the View button. To email the report to the IPM Program Coordinator, click the Email to Wayne Ireland button.

5.5 Sample Reports

Inspector Hours

For Days 4/28/2011 through 4/28/2011

Month Day	Inspector	Poles	Hours
April 28	John Heaps	37	4.00

Integrated Pole Maintenance - Cost Summary

Contract Name: Interlake - PP

Voltage: Distribution — District: Stonewall

Network: 525040 — Station: Komarno

Reporting from: 4/1/2011 To 3/31/2012 — Block: 7

Production Totals:

	Total Poles	Report Only	S&B	GLT	Fume	Flood	Ant	Spray	Photo	Flu	Rock Set 0 to 12	Rock Set 13 to 24
Total:	37	0	37	2	14	1	1	10	1	1	2	3
% of Total:		0%	100 %	5%	38 %	3%	3%	27 %	3%	3%	5%	8%

Inspection Totals:

	Regular Reject	Reinforceable	Danger Reject	Serviceable	Butt Rot	Heart Rot	Ants	Other Damage
Total Reported:	1	1	1	34	0	1	1	10
% of Total Poles:	3%	3%	3%	92 %	0%	3%	3%	27 %

Reject Poles:

	Total	In Service	% of Total	Unused
Regular:	1	1	2.70 %	0
Reinforceable:	1	1	2.70 %	0
Danger:	1	1	2.70 %	0
Total Reject Poles:		**3**	**8.11 %**	

Manpower:

Total Manhours:	40
Total Aboriginal Manhours:	30

Cost Breakdown:

Visual Only:	0		
Sound and Bore:	37	$5.70	$210.90
Inspection:	37	$3.86	$142.82
Ground Line:	2	$32.42	$64.84
Fume:	14	$15.88	$222.32
Internal Flood:	1	$15.52	$15.52
Ant Treatment:	1	$16.54	$16.54
External Spray:	10	$10.83	$108.30
Digit Photo:	1	$2.95	$2.95
Flu Rod:	1	$17.88	$17.88
Rock Set 0 to 12:	2	$20.50	$41.00
Rock Set 13 to 24:	3	$41.00	$123.00
Applicator / Inspector:	0.00	$0.00	$0.00
Labourer:	0.00	$0.00	$0.00
		Total Cost:	**$966.07**

Integrated Pole Maintenance - Reject Pole Report

Contractor: Interlake - PP

Reporting from: 4/1/2011 to 3/31/2012

District: Stonewall | Station: Komarno | Block: 7

		Barcode	Pole #	Qtr / Sec / Twp / Rng	Comments
Total X :	1				
		2222222	2		
Total XR :	1				
		3333333	3		
Total XD :	1				
		1111111	1		was hit by a car

Integrated Pole Maintenance - Safety Report

Date: 4/29/2011 District: Stonewall Station: Komarno Block: 7

Accident Date: 4/29/2011

Description:

A transformer fell on Bobby's spleen

Persons Involved:

Bobby Bottoms, Labourer, 5 years pole maintenance experience

Spill Date: 4/29/2011

Description:

Jon Hancharyk spilt fume in his boots

Persons Involved:

Jon Hancharyk, Applicator, 3 months

Integrated Pole Maintenance - Danger Pole Report

Contractor: Interlake - PP

Reporting from: 4/1/2011 to 3/31/2012

District: Stonewall Station: Komarno Block: 7

Barcode	Pole #	Qtr / Sec / Twp / Rng	Comments
Total Danger Reject Poles: 1			
1111111	1		was hit by a car

Integrated Pole Maintenance - Crew Report

Contractor: Interlake - PP
Reporting from: 4/1/2011 to 3/31/2012

District: Stonewall
Station: Komarno
Block: 7

District: Stonewall | Station: Komarno | Block: 7

Foreman: Joe Public | Date: 4/28/2011 | Crew Members: 4

Inspection	Total Poles	Report Only	S&B	GLT	Fume	Flood	Ant	Spray	Photo	Flu	Rock Set 0 to 12	Rock Set 13 to 24
Unit	37	0	37	2	14	1	1	10	1	1	2	3
Hourly	0	0	0	0	0	0	0	0	0	0	0	0

Production	Regular Reject	Reinforceable	Danger Reject	Serviceable	Butt Rot	Heart Rot	Ants	Other Damage
	1	1	1	34	0	1	1	10

DISTRIBUTION ASSET MAINTENANCE

Asset Class Review Date: 5/17/2017 **Asset Strategy Review Date**: 5/17/2022

Asset Information

Asset class: Overhead Assets

Asset sub-class: Anchor

Asset: Power Screw

Primary function: Supporting structure

Limiting factors:
- Corrosion
- Mechanical damage
- Stress due to over tension

Procedure documents:
- No documentation current is in place for this asset.

Maintenance standards:
- Corporate Policy P340

Strategy Information

Maintenance strategy level: 0 - Corrective; reactive

Maintenance strategy drivers:

Primary (choose one)	Secondary (choose all that apply)
Safety	☐ Safety
	☒ Cost
	☒ Reliability
	☐ Environment
	☐ Corporate Citizenship
	☐ Legal requirements
	☐ Executive directive

Other maintenance requirements:

Approved by: PROVINCE OF MANITOBA J. D. SHABAGA Member 36036 REGISTERED PROFESSIONAL ENGINEER

Date:

Revisions: **Revision Date:** [Revision Date]

DISTRIBUTION ASSET MAINTENANCE

Asset Class Review Date: 5/17/2017 **Asset Strategy Review Date**: 5/17/2022

Asset Information

Asset class: Overhead Assets

Asset sub-class: Anchor

Asset: Rock Set

Primary function: Supporting structure

Limiting factors:
- Corrosion
- Mechanical damage

Procedure documents:
- IPM Manual (DAM Website)
- IPM Tender Agreements
- Rock set inspection procedure.

Maintenance standards:
- Rock set inspection procedure.

Strategy Information

Maintenance strategy level: 0 - Corrective; reactive

Maintenance strategy drivers:

Primary (choose one)	Secondary (choose all that apply)
Safety	☐ Safety
	☒ Cost
	☒ Reliability
	☐ Environment
	☐ Corporate Citizenship
	☐ Legal requirements
	☐ Executive directive

Other maintenance requirements:
- Rock set inspection procedure in the approval process within Distribution Standards.

Approved by: J.D. SHABAGA Member 30036 — PROVINCE OF MANITOBA — REGISTERED PROFESSIONAL ENGINEER

Date:

Revisions: **Revision Date:** [Revision Date]

DISTRIBUTION ASSET MAINTENANCE

Asset Class Review Date: 5/17/2017 **Asset Strategy Review Date**: 5/17/2022

Asset Information

Asset class: Overhead Assets

Asset sub-class: Conductor

Asset: Conductor

Primary function: Power delivery

Limiting factors:

- Corrosion
- Mechanical damage (tree contact or ice build-up)
- Loading
- Lightning/Over voltage
- Salt accumulation

Procedure documents:

- Detailed Overhead Feeder Inspection Manual (DAM Website)

Maintenance standards:

- Detailed Overhead Feeder Inspection Manual (DAM Website)

Strategy Information

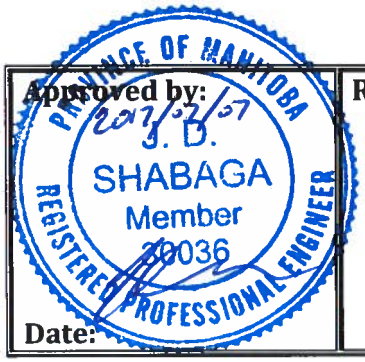
Maintenance strategy level: 0 - Corrective; reactive

Maintenance strategy drivers:

Primary (choose one)	Secondary (choose all that apply)
Reliability	☒ Safety
	☒ Cost
	☐ Reliability
	☐ Environment
	☐ Corporate Citizenship
	☐ Legal requirements
	☐ Executive directive

Other maintenance requirements:

- It is recommended that 3/13 Steel, #9 Alloy & 2/0 Hemp Core to be evaluated for replacement where found within the network.
- Due to the nature of overhead conductors, life cycles far exceed that of the poles supporting them. As a result, corrective strategies are sufficient for this asset.

Approved by:  **Date:**	**Revisions:** **Revision Date:** [Revision Date]

DISTRIBUTION ASSET MAINTENANCE

Asset Class Review Date: 5/17/2017 **Asset Strategy Review Date**: 5/17/2022

Asset Information

Asset class: Overhead Assets

Asset sub-class: Cross Arms

Asset: Fiberglass

Primary function: Supporting structure

Limiting factors:
- Cracking

Procedure documents:
- No documentation current is in place for this asset.

Maintenance standards:
- No documentation current is in place for this asset.

Strategy Information

Maintenance strategy level: 0 - Corrective; reactive

Maintenance strategy drivers:

Primary (choose one)	Secondary (choose all that apply)
Reliability	☒ Safety
	☒ Cost
	☐ Reliability
	☐ Environment
	☐ Corporate Citizenship
	☐ Legal requirements
	☐ Executive directive

Other maintenance requirements:

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DISTRIBUTION ASSET MAINTENANCE

Asset Class Review Date: 5/17/2017 **Asset Strategy Review Date:** 5/17/2022

Asset Information

Asset class: Overhead Assets

Asset sub-class: Cross Arms

Asset: Steel

Primary function: Supporting structure

Limiting factors:
- Pole fire due to tracking along crossarm
- Corrosion (limited)

Procedure documents:
- No documentation current is in place for this asset.

Maintenance standards:
- No documentation current is in place for this asset.

Strategy Information

Maintenance strategy level: 0 - Corrective; reactive

Maintenance strategy drivers:

Primary (choose one)	Secondary (choose all that apply)
Reliability	☒ Safety
	☒ Cost
	☐ Reliability
	☐ Environment
	☐ Corporate Citizenship
	☐ Legal requirements
	☐ Executive directive

Other maintenance requirements:

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DISTRIBUTION ASSET MAINTENANCE

Asset Class Review Date: 5/17/2017 **Asset Strategy Review Date**: 5/17/2022

Asset Information

Asset class: Overhead Assets

Asset sub-class: Cross Arms

Asset: Wood - Solid

Primary function: Supporting structure

Limiting factors: Wood degradation (rot, insect, fire)

Procedure documents:
- Detailed Overhead Feeder Inspection Manual (DAM Website)

Maintenance standards:
- Detailed Overhead Feeder Inspection Manual (DAM Website)
- Corporate Policy P340

Strategy Information

Maintenance strategy level: 2 - Condition-based

Maintenance strategy drivers:

Primary (choose one)	Secondary (choose all that apply)
Reliability	☒ Safety
	☒ Cost
	☐ Reliability
	☐ Environment
	☐ Corporate Citizenship
	☐ Legal requirements
	☐ Executive directive

Other maintenance requirements:

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Date:

Revisions: **Revision Date:** [Revision Date]

DISTRIBUTION ASSET MAINTENANCE

Asset Class Review Date: 5/1/2017 **Asset Strategy Review Date**: 5/2/2022

Asset Information

Asset class: Underground Assets

Asset sub-class: Padmounted Equipment

Asset: Distribution Centre - Automated

Primary function: Power delivery

Limiting factors:
- Corrosion
- Mechanical Failure

Procedure documents:
- Corporate Policy P343

Maintenance standards:
- No formal documentation current is in place for this asset.

Strategy Information

Maintenance strategy level: 2 - Condition-based

Maintenance strategy drivers:

Primary (choose one)	Secondary (choose all that apply)
Safety	☐ Safety
	☒ Cost
	☒ Reliability
	☐ Environment
	☐ Corporate Citizenship
	☐ Legal requirements
	☐ Executive directive

Other maintenance requirements:
- Distribution Centres are commonly referred to as DC.

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DISTRIBUTION ASSET MAINTENANCE

Asset Class Review Date: 5/1/2017 **Asset Strategy Review Date:** 5/2/2022

Asset Information

Asset class: Underground Assets

Asset sub-class: Padmounted Equipment

Asset: Distribution Centre - Manually Operate

Primary function: Power delivery

Limiting factors:
- Corrosion
- Mechanical failure

Procedure documents:
- Corporate Policy P343

Maintenance standards:
- No formal documentation current is in place for this asset.

Strategy Information

Maintenance strategy level: 2 - Condition-based

Maintenance strategy drivers:

Primary (choose one)	Secondary (choose all that apply)
Safety	☐ Safety
	☒ Cost
	☒ Reliability
	☐ Environment
	☐ Corporate Citizenship
	☐ Legal requirements
	☐ Executive directive

Other maintenance requirements:
- Distribution Centres are commonly referred to as DC.

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Date:

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DISTRIBUTION ASSET MAINTENANCE

Asset Class Review Date: 5/1/2017 **Asset Strategy Review Date**: 5/2/2022

Asset Information

Asset class: Underground Assets

Asset sub-class: Ductlines

Asset: Ductlines

Primary function: Supporting structure

Limiting factors:
- Structural degradation

Procedure documents:
- No formal documentation current is in place for this asset.

Maintenance standards:
- No formal documentation current is in place for this asset.

Strategy Information

Maintenance strategy level: 0 - Corrective; reactive

Maintenance strategy drivers:

Primary (choose one)	Secondary (choose all that apply)
Cost	☐ Safety
	☐ Cost
	☐ Reliability
	☐ Environment
	☐ Corporate Citizenship
	☐ Legal requirements
	☐ Executive directive

Other maintenance requirements:
- A review of current maintenance practices is underway.

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DISTRIBUTION ASSET MAINTENANCE

Asset Class Review Date: 5/17/2017 **Asset Strategy Review Date:** 5/17/2022

Asset Information

Asset class: Overhead Assets

Asset sub-class: Grounding

Asset: Rod Assembly

Primary function: Power delivery

Limiting factors:
- Corrosion
- Theft (of copper)

Procedure documents:
- Detailed Overhead Feeder Inspection Manual (DAM Website)
- Grounding inspection and remediation tender documents
- Grounding manual

Maintenance standards:
- Corporate Policy P340

Strategy Information

Maintenance strategy level: 0 - Corrective; reactive

Maintenance strategy drivers:

Primary (choose one)	Secondary (choose all that apply)	
Safety	☐	Safety
	☒	Cost
	☒	Reliability
	☐	Environment
	☐	Corporate Citizenship
	☐	Legal requirements
	☐	Executive directive

Other maintenance requirements:
- Assembly includes rod, wire and all associated hardware.

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DISTRIBUTION ASSET MAINTENANCE

Asset Class Review Date: 5/1/2017 **Asset Strategy Review Date**: 5/2/2022

Asset Information

Asset class: Underground Assets

Asset sub-class: Underground Cables

Asset: HPPT - 115kV & Below

Primary function: Power delivery

Limiting factors:

- Oil containment integrity
- Oil quality (dissolved gas content)
- Insulation degradation

Procedure documents:

- No formal documentation current is in place for this asset, with the exception of SB14.

Maintenance standards:

- No formal documentation current is in place for this asset.

Strategy Information

Maintenance strategy level: 0 - Corrective; reactive

Maintenance strategy drivers:

Primary (choose one)	Secondary (choose all that apply)
Reliability	☐ Safety
	☒ Cost
	☐ Reliability
	☐ Environment
	☐ Corporate Citizenship
	☐ Legal requirements
	☐ Executive directive

Other maintenance requirements:

- Emergency procedure to respond to LPOF alarm can be found at the High Voltage Oil Filled SharePoint Site.
- HPPT is an abbreviation for High Pressure Pipe Type

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DISTRIBUTION ASSET MAINTENANCE

Asset Class Review Date: 5/17/2017 **Asset Strategy Review Date:** 5/17/2022

Asset Information

Asset class: Overhead Assets

Asset sub-class: Insulators

Asset: Insulators

Primary function: Supporting structure

Limiting factors:

- Cracking (porcelain)
- Salt accumulation
- Tracking
- Lightning/over voltage
- Ice accumulation
- UV degradation (polymer)

Procedure documents:

- Detailed Overhead Feeder Inspection Manual (DAM Website)

Maintenance standards:

- Detailed Overhead Feeder Inspection Manual (DAM Website)

Strategy Information

Maintenance strategy level: 0 - Corrective; reactive

Maintenance strategy drivers:

Primary (choose one)	Secondary (choose all that apply)
Reliability	☒ Safety
	☒ Cost
	☐ Reliability
	☐ Environment
	☐ Corporate Citizenship
	☐ Legal requirements
	☐ Executive directive

Other maintenance requirements:

- Some insulator washing is done in an ad hoc fashion in various locations within the distribution network.
- Historically near heavily trafficked roads have been over insulated to mitigate electrical tracking due to salt spray.
- Historically, insulators have been replaced on worst performing feeders.

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DISTRIBUTION ASSET MAINTENANCE

Asset Class Review Date: 5/1/2017 **Asset Strategy Review Date**: 5/2/2022

Asset Information

Asset class: Underground Assets

Asset sub-class: Padmounted Equipment

Asset: Junction Points

Primary function: Power delivery

Limiting factors:
- Corrosion

Procedure documents:
- Corporate Policy P343

Maintenance standards:
- No formal documentation current is in place for this asset.

Strategy Information

Maintenance strategy level: 2 - Condition-based

Maintenance strategy drivers:

Primary (choose one)	Secondary (choose all that apply)
Safety	☐ Safety
	☒ Cost
	☒ Reliability
	☐ Environment
	☐ Corporate Citizenship
	☐ Legal requirements
	☐ Executive directive

Other maintenance requirements:
- During regular inspections, thermal graphic imaging is used to determine the connection of the cable terminations for heating.
- Junction Points are commonly referred to as JP.

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DISTRIBUTION ASSET MAINTENANCE

Asset Class Review Date: 5/1/2017 **Asset Strategy Review Date:** 5/2/2022

Asset Information

Asset class: Underground Assets

Asset sub-class: Underground Cables

Asset: Low Voltage Customer Underground Cable

Primary function: Power delivery

Limiting factors:
- Cable Insulation
- Mechanical damage

Procedure documents:
- No formal documentation current is in place for this asset.

Maintenance standards:
- No formal documentation current is in place for this asset.

Strategy Information

Maintenance strategy level: 0 - Corrective; reactive

Maintenance strategy drivers:

Primary (choose one)	Secondary (choose all that apply)
Reliability	☒ Safety
	☒ Cost
	☐ Reliability
	☐ Environment
	☐ Corporate Citizenship
	☐ Legal requirements
	☐ Executive directive

Other maintenance requirements:

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DISTRIBUTION ASSET MAINTENANCE

Asset Class Review Date: 5/1/2017 **Asset Strategy Review Date**: 5/2/2022

Asset Information

Asset class: Underground Assets

Asset sub-class: Underground Cables

Asset: LPOF 115kV & Below

Primary function: Power delivery

Limiting factors:
- Oil containment integrity
- Oil quality (dissolved gas content)
- Insulation degradation

Procedure documents:
- No formal documentation current is in place for this asset.

Maintenance standards:
- No formal documentation current is in place for this asset.

Strategy Information

Maintenance strategy level: 0 - Corrective; reactive

Maintenance strategy drivers:

Primary (choose one)	Secondary (choose all that apply)
Reliability	☐ Safety
	☒ Cost
	☐ Reliability
	☐ Environment
	☐ Corporate Citizenship
	☐ Legal requirements
	☐ Executive directive

Other maintenance requirements:
- Emergency procedure to respond to LPOF alarm can be found at the High Voltage Oil Filled SharePoint Site.
- LPOF is an abbreviation for Low Pressure Oil Filled

DISTRIBUTION ASSET MAINTENANCE

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DISTRIBUTION ASSET MAINTENANCE

Asset Class Review Date: 5/1/2017 **Asset Strategy Review Date**: 5/2/2022

Asset Information

Asset class: Underground Assets

Asset sub-class: Manholes

Asset: Manholes

Primary function: Supporting structure

Limiting factors:
- Structural (concrete or rebar) degradation

Procedure documents:
- Corporate Policy P343

Maintenance standards:
- No formal documentation current is in place for this asset.

Strategy Information

Maintenance strategy level: 2 - Condition-based

Maintenance strategy drivers:

Primary (choose one)	Secondary (choose all that apply)
Safety	☐ Safety
	☒ Cost
	☒ Reliability
	☐ Environment
	☐ Corporate Citizenship
	☐ Legal requirements
	☐ Executive directive

Other maintenance requirements:
- Current practice is to assess the structural integrity of the manhole using visual inspection methods. A new process is under development that digitally scans and quantifiably assesses the structure of the manhole using LiDAR.

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Last modified by: opreston **Print date**: 7/6/2017

DISTRIBUTION ASSET MAINTENANCE

Asset Class Review Date: 5/1/2017 **Asset Strategy Review Date**: 5/2/2022

Asset Information

Asset class: Underground Assets

Asset sub-class: Padmounted Equipment

Asset: Padmounted Transformer - Single Phase

Primary function: Power delivery

Limiting factors:
- Oil containment integrity
- Insulation degradation
- Corrosion

Procedure documents:
- Corporate Policy P343

Maintenance standards:
- No formal documentation current is in place for this asset.

Strategy Information

Maintenance strategy level: 2 - Condition-based

Maintenance strategy drivers:

Primary (choose one)	Secondary (choose all that apply)
Safety	☐ Safety
	☒ Cost
	☒ Reliability
	☐ Environment
	☐ Corporate Citizenship
	☐ Legal requirements
	☐ Executive directive

Other maintenance requirements:

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DISTRIBUTION ASSET MAINTENANCE

Asset Class Review Date: 5/1/2017 **Asset Strategy Review Date:** 5/2/2022

Asset Information

Asset class: Underground Assets

Asset sub-class: Padmounted Equipment

Asset: Padmounted Transformer - Three Phase

Primary function: Power delivery

Limiting factors:
- Oil containment integrity
- Insulation degradation
- Corrosion

Procedure documents:
- Corporate Policy P343

Maintenance standards:
- No formal documentation current is in place for this asset.

Strategy Information

Maintenance strategy level: 2 - Condition-based

Maintenance strategy drivers:

Primary (choose one)	Secondary (choose all that apply)
Safety	☐ Safety
	☒ Cost
	☒ Reliability
	☐ Environment
	☐ Corporate Citizenship
	☐ Legal requirements
	☐ Executive directive

Other maintenance requirements:

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Last modified by: opreston **Print date:** 7/6/2017

DISTRIBUTION ASSET MAINTENANCE

Asset Class Review Date: 5/1/2017

Asset Strategy Review Date: 5/2/2022

Asset Information

Asset class: Underground Assets

Asset sub-class: Underground Cables

Asset: PILC Cables

Primary function: Power delivery

Limiting factors:
- Cable insulation degradation

Procedure documents:
- No documentation current is in place for this asset.

Maintenance standards:
- No documentation current is in place for this asset.

Strategy Information

Maintenance strategy level: 0 - Corrective; reactive

Maintenance strategy drivers:

Primary (choose one)	Secondary (choose all that apply)
Reliability	☐ Safety
	☒ Cost
	☐ Reliability
	☐ Environment
	☐ Corporate Citizenship
	☐ Legal requirements
	☐ Executive directive

Other maintenance requirements:
- Upon failure of a PILC cable segment, replace with equal or greater capacity TRXLPE cable using current installation standards.
- Upon failure of a pothead, replace termination structure and associated PILC cable segment using equal or greater capacity TRXLPE cable and terminations using current installation standards.
- PILC is an abbreviation for Paper Insulated Lead Covered

Approved by: 2017/07/07 J. B. SHABAGA Member 30036 PROVINCE OF MANITOBA REGISTERED PROFESSIONAL ENGINEER **Date:**	**Revisions:** **Revision Date:** [Revision Date]

DISTRIBUTION ASSET MAINTENANCE

Asset Class Review Date: 5/17/2017 **Asset Strategy Review Date:** 5/17/2022

Asset Information

Asset class: Overhead Assets

Asset sub-class: Poles

Asset: Concrete

Primary function: Supporting structure

Limiting factors:
- Mechanical damage (vehicle, snow plow, etc.)
- Corrosion of rebar
- Concrete degradation

Procedure documents:
- No documentation current is in place for this asset.

Maintenance standards:
- No documentation current is in place for this asset.

Strategy Information

Maintenance strategy level: 0 - Corrective; reactive

Maintenance strategy drivers:

Primary (choose one)	Secondary (choose all that apply)
Safety	☐ Safety
	☒ Cost
	☒ Reliability
	☐ Environment
	☐ Corporate Citizenship
	☐ Legal requirements
	☐ Executive directive

Other maintenance requirements:
- It is recommend that maintenance of these assets follow the guild lines set for the maintenance of Street Light concrete bases.

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DISTRIBUTION ASSET MAINTENANCE

Asset Class Review Date: 5/17/2017 **Asset Strategy Review Date**: 5/17/2022

Asset Information

Asset class: Overhead Assets

Asset sub-class: Poles

Asset: Wood - Laminated

Primary function: Supporting structure

Limiting factors:
- Wood degradation (rot, insect, fire)
- Mechanical damage (vehicle, snow plow, etc.)

Procedure documents:
- IPM Manual (DAM Website)
- Detailed Overhead Feeder Inspection Manual (DAM Website)
- IPM Tender Agreements

Maintenance standards:
- IPM Tender Agreements
- Corporate Policy P340 & P350

Strategy Information

Maintenance strategy level: 2 - Condition-based

Maintenance strategy drivers:

Primary (choose one)	Secondary (choose all that apply)
Safety	☐ Safety
	☒ Cost
	☒ Reliability
	☐ Environment
	☐ Corporate Citizenship
	☐ Legal requirements
	☐ Executive directive

Other maintenance requirements:
- Pole Treatment Process flow chart and IPM Quality Assurance Process are currently under development.

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DISTRIBUTION ASSET MAINTENANCE

Asset Class Review Date: 5/17/2017 **Asset Strategy Review Date**: 5/17/2022

Asset Information

Asset class: Overhead Assets

Asset sub-class: Poles

Asset: Steel – Lattice Pole

Primary function: Supporting structure

Limiting factors:
- Mechanical damage (vehicle, snow plow, etc.)
- Corrosion

Procedure documents:
- No documentation current is in place for this asset.

Maintenance standards:
- No documentation current is in place for this asset.

Strategy Information

Maintenance strategy level: 0 - Corrective; reactive

Maintenance strategy drivers:

Primary (choose one)	Secondary (choose all that apply)
Safety	☐ Safety
	☒ Cost
	☒ Reliability
	☐ Environment
	☐ Corporate Citizenship
	☐ Legal requirements
	☐ Executive directive

Other maintenance requirements:

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DISTRIBUTION ASSET MAINTENANCE

Asset Class Review Date: 5/17/2017 **Asset Strategy Review Date**: 5/17/2022

Asset Information

Asset class: Overhead Assets

Asset sub-class: Poles

Asset: Steel – Trolley Pole

Primary function: Supporting structure

Limiting factors:
- Mechanical damage (vehicle, snow plow, etc.)
- Corrosion

Procedure documents:
- No documentation current is in place for this asset.

Maintenance standards:
- No documentation current is in place for this asset.

Strategy Information

Maintenance strategy level: 0 - Corrective; reactive

Maintenance strategy drivers:

Primary (choose one)	Secondary (choose all that apply)
Safety	☐ Safety
	☒ Cost
	☒ Reliability
	☐ Environment
	☐ Corporate Citizenship
	☐ Legal requirements
	☐ Executive directive

Other maintenance requirements:
- These assets are located exclusively in downtown Winnipeg as they were originally installed by Winnipeg Hydro.

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Date:

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Print date: 7/6/2017

DISTRIBUTION ASSET MAINTENANCE

Asset Class Review Date: 5/17/2017 **Asset Strategy Review Date**: 5/17/2022

Asset Information

Asset class: Overhead Assets

Asset sub-class: Poles

Asset: Wood - Solid

Primary function: Supporting structure

Limiting factors:
- Wood degradation (rot, insect, fire)
- Mechanical damage (vehicle, snow plow, etc.)

Procedure documents:
- IPM Manual (DAM Website)
- Detailed Overhead Feeder Inspection Manual (DAM Website)
- IPM Tender Agreements

Maintenance standards:
- IPM Tender Agreements
- Corporate Policy P340 & P350

Strategy Information

Maintenance strategy level: 2 - Condition-based

Maintenance strategy drivers:

Primary (choose one)	Secondary (choose all that apply)
Safety	☐ Safety
	☒ Cost
	☒ Reliability
	☐ Environment
	☐ Corporate Citizenship
	☐ Legal requirements
	☐ Executive directive

Other maintenance requirements:
- Pole Treatment Process flow chart and IPM Quality Assurance Process are currently under development.

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DISTRIBUTION ASSET MAINTENANCE

Asset Class Review Date: 5/17/2017 **Asset Strategy Review Date:** 5/17/2022

Asset Information

Asset class: Overhead Assets

Asset sub-class: Recloser

Asset: Electronic

Primary function: Power delivery

Limiting factors:
- Loading
- Frequency of operation & Magnitude of fault current (duty cycle)

Procedure documents:
- No documentation current is in place for this asset.

Maintenance standards:
- Corporate Policy P340

Strategy Information

Maintenance strategy level: 1 - Schedule-based

Maintenance strategy drivers:

Primary (choose one)	Secondary (choose all that apply)
Safety	☐ Safety
	☒ Cost
	☒ Reliability
	☐ Environment
	☐ Corporate Citizenship
	☐ Legal requirements
	☐ Executive directive

Other maintenance requirements:
- Historically, this asset has been maintained by Apparatus Maintenance Department (AMD)

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DISTRIBUTION ASSET MAINTENANCE

Asset Class Review Date: 5/17/2017 **Asset Strategy Review Date**: 5/17/2022

Asset Information

Asset class: Overhead Assets

Asset sub-class: Recloser

Asset: Hydraulic

Primary function: Power delivery

Limiting factors:
- Loading
- Frequency of operation & Magnitude of fault current (duty cycle)

Procedure documents:
- No documentation current is in place for this asset.

Maintenance standards:
- Corporate Policy P340

Strategy Information

Maintenance strategy level: 1 - Schedule-based

Maintenance strategy drivers:

Primary (choose one)	Secondary (choose all that apply)
Safety	☐ Safety
	☒ Cost
	☒ Reliability
	☐ Environment
	☐ Corporate Citizenship
	☐ Legal requirements
	☐ Executive directive

Other maintenance requirements:

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DISTRIBUTION ASSET MAINTENANCE

Asset Class Review Date: 5/1/2017 **Asset Strategy Review Date**: 5/2/2022

Asset Information

Asset class: Underground Assets

Asset sub-class: Underground Cables

Asset: RINJ Cable

Primary function: Power delivery

Limiting factors:
- Cable insulation degradation

Procedure documents:
- No documentation current is in place for this asset.

Maintenance standards:
- No documentation current is in place for this asset.

Strategy Information

Maintenance strategy level: 0 - Corrective; reactive

Maintenance strategy drivers:

Primary (choose one)	Secondary (choose all that apply)
Reliability	☐ Safety
	☒ Cost
	☐ Reliability
	☐ Environment
	☐ Corporate Citizenship
	☐ Legal requirements
	☐ Executive directive

Other maintenance requirements:
- Upon failure of a RINJ cable segment, replace with equal or greater capacity TRXLPE cable using current installation standards.
- RINJ is an abbreviation for Rubber Insulated Neoprene Jacketed

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Date:

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DISTRIBUTION ASSET MAINTENANCE

Asset Class Review Date: 5/1/2017 **Asset Strategy Review Date:** 5/2/2022

Asset Information

Asset class: Underground Assets

Asset sub-class: Underground Cables

Asset: Secondary Network Cable

Primary function: Power delivery

Limiting factors:
- Cable Insulation

Procedure documents:
- No formal documentation current is in place for this asset.

Maintenance standards:
- No formal documentation current is in place for this asset.

Strategy Information

Maintenance strategy level: 0 - Corrective; reactive

Maintenance strategy drivers:

Primary (choose one)	Secondary (choose all that apply)
Safety	☐ Safety
	☒ Cost
	☒ Reliability
	☐ Environment
	☐ Corporate Citizenship
	☐ Legal requirements
	☐ Executive directive

Other maintenance requirements:
- Failure of these cables represents a higher risk as they are contained within confined space locations.

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Revisions:

Revision Date: [Revision Date]

DISTRIBUTION ASSET MAINTENANCE

Asset Class Review Date: 5/1/2017 **Asset Strategy Review Date**: 5/2/2022

Asset Information

Asset class: Underground Assets

Asset sub-class: Padmounted Equipment

Asset: Secondary Network Transformers

Primary function: Power delivery

Limiting factors:
- Oil containment integrity
- Insulation degradation
- Oil quality (dissolved gas content)
- Corrosion

Procedure documents:
- Corporate Policy P343

Maintenance standards:
- No formal documentation current is in place for this asset.

Strategy Information

Maintenance strategy level: 2 - Condition-based

Maintenance strategy drivers:

Primary (choose one)	Secondary (choose all that apply)
Safety	☐ Safety
	☒ Cost
	☒ Reliability
	☐ Environment
	☐ Corporate Citizenship
	☐ Legal requirements
	☐ Executive directive

Other maintenance requirements:
- Dissolved gas sampling is performed annually with records archived LIMS.

Approved by: [Approved by] **Date:**	**Revisions:** **Revision Date:** [Revision Date]

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DISTRIBUTION ASSET MAINTENANCE

Asset Class Review Date: 5/1/2017 **Asset Strategy Review Date**: 5/2/2022

Asset Information

Asset class: Street Light Assests

Asset sub-class: Street Light Bases

Asset: Street Light Bases

Primary function: Supporting structure

Limiting factors:
- Structural degradation
- Corrosion

Procedure documents:
- Corporate Policy P348

Maintenance standards:
- No formal documentation current is in place for this asset.

Strategy Information

Maintenance strategy level: 2 - Condition-based

Maintenance strategy drivers:

Primary (choose one)	Secondary (choose all that apply)
Safety	☐ Safety
	☒ Cost
	☐ Reliability
	☐ Environment
	☐ Corporate Citizenship
	☐ Legal requirements
	☐ Executive directive

Other maintenance requirements:
- This asset includes both concrete pile bases and power screw bases.

Approved by: 2017/07/07 J. B. SHABAGA Member 30036 PROVINCE OF MANITOBA REGISTERED PROFESSIONAL ENGINEER

Date:

Revisions: **Revision Date:** [Revision Date]

DISTRIBUTION ASSET MAINTENANCE

Asset Class Review Date: 5/1/2017 **Asset Strategy Review Date**: 5/2/2022

Asset Information

Asset class: Street Light Assests

Asset sub-class: Street Light Cable

Asset: Street Light Cable

Primary function: Power delivery

Limiting factors:
- Cable Insulation

Procedure documents:
- No formal documentation current is in place for this asset.

Maintenance standards:
- No formal documentation current is in place for this asset.

Strategy Information

Maintenance strategy level: 0 - Corrective; reactive

Maintenance strategy drivers:

Primary (choose one)	Secondary (choose all that apply)
Corporate Citizenship	☒ Safety
	☒ Cost
	☒ Reliability
	☐ Environment
	☐ Corporate Citizenship
	☐ Legal requirements
	☐ Executive directive

Other maintenance requirements:

Approved by: PROVINCE OF MANITOBA 2017/07/27 J. D. SHABAGA Member 30036 REGISTERED PROFESSIONAL ENGINEER **Date:**	**Revisions:** **Revision Date:** [Revision Date]

DISTRIBUTION ASSET MAINTENANCE

Asset Class Review Date: 5/1/2017 **Asset Strategy Review Date:** 5/2/2022

Asset Information

Asset class: Street Light Assests

Asset sub-class: Street Light Standards

Asset: Street Light Standards

Primary function: Supporting structure

Limiting factors:
- Structural degradation
- Corrosion
- Mechanical damage

Procedure documents:
- Corporate Policy P348

Maintenance standards:
- No formal documentation current is in place for this asset.

Strategy Information

Maintenance strategy level: 2 - Condition-based

Maintenance strategy drivers:

Primary (choose one)	Secondary (choose all that apply)
Safety	☐ Safety
	☒ Cost
	☐ Reliability
	☐ Environment
	☐ Corporate Citizenship
	☐ Legal requirements
	☐ Executive directive

Other maintenance requirements:
- Some standards within this asset class are direct buried.

Approved by: 29/05/17

PROVINCE OF MANITOBA J. D. SHABAGA Member 39036 REGISTERED PROFESSIONAL ENGINEER

Date:

Revisions: **Revision Date:** [Revision Date]

DISTRIBUTION ASSET MAINTENANCE

Asset Class Review Date: 5/17/2017 **Asset Strategy Review Date**: 5/17/2022

Asset Information

Asset class: Overhead Assets

Asset sub-class: Switches

Asset: Air Break

Primary function: Power delivery

Limiting factors:
- Frequency of operation
- Load current

Procedure documents:
- Detailed Overhead Feeder Inspection Manual (DAM Website)

Maintenance standards:
- Corporate Policy P340

Strategy Information

Maintenance strategy level: 0 - Corrective; reactive

Maintenance strategy drivers:

Primary (choose one)	Secondary (choose all that apply)
Safety	☐ Safety
	☒ Cost
	☒ Reliability
	☐ Environment
	☐ Corporate Citizenship
	☐ Legal requirements
	☐ Executive directive

Other maintenance requirements:

Approved by: 2017/07/07 J. D. SHABAGA Member 39036

PROVINCE OF MANITOBA REGISTERED PROFESSIONAL ENGINEER

Date:

Revisions: **Revision Date:** [Revision Date]

DISTRIBUTION ASSET MAINTENANCE

Asset Class Review Date: 5/17/2017 **Asset Strategy Review Date**: 5/17/2022

Asset Information

Asset class: Overhead Assets

Asset sub-class: Switches

Asset: Vac Rupters

Primary function: Power delivery

Limiting factors:
- Frequency of operation
- Load current

Procedure documents:
- Detailed Overhead Feeder Inspection Manual (DAM Website)

Maintenance standards:
- Corporate Policy P340

Strategy Information

Maintenance strategy level: 0 - Corrective; reactive

Maintenance strategy drivers:

Primary (choose one)	Secondary (choose all that apply)
Safety	☐ Safety
	☒ Cost
	☒ Reliability
	☐ Environment
	☐ Corporate Citizenship
	☐ Legal requirements
	☐ Executive directive

Other maintenance requirements:
- Apperatus Maintenance Department (AMD) has similar devices within areas of responcibility.

Approved by: Ron/07/17 J. D. SHABAGA Member 30036 PROVINCE OF MANITOBA REGISTERED PROFESSIONAL ENGINEER

Date:

Revisions:

Revision Date: [Revision Date]

DISTRIBUTION ASSET MAINTENANCE

Asset Class Review Date: 5/17/2017 **Asset Strategy Review Date**: 5/17/2022

Asset Information

Asset class: Overhead Assets

Asset sub-class: Transformers

Asset: Transformers

Primary function: Power delivery

Limiting factors:

- Load current
- Corrosion
- Over voltages
- Oil Leaks
- External contacts (wild life)

Procedure documents:

- Detailed Overhead Feeder Inspection Manual (DAM Website)
- Overload transformer reports

Maintenance standards:

- Corporate Policy P340

Strategy Information

Maintenance strategy level: 0 - Corrective; reactive

Maintenance strategy drivers:

Primary (choose one)	Secondary (choose all that apply)
Reliability	☒ Safety
	☒ Cost
	☐ Reliability
	☐ Environment
	☐ Corporate Citizenship
	☐ Legal requirements
	☐ Executive directive

Other maintenance requirements:

- It is recommended that bird guards to be installed on the bushings of these units as a standard process in relation to transformer replacement.

DISTRIBUTION ASSET MAINTENANCE

Approved by: **Date:**	**Revisions:** **Revision Date:** [Revision Date]

DISTRIBUTION ASSET MAINTENANCE

Asset Class Review Date: 5/1/2017 **Asset Strategy Review Date:** 5/2/2022

Asset Information

Asset class: Underground Assets

Asset sub-class: Underground Cables

Asset: TRXLPE Cable

Primary function: Power delivery

Limiting factors:
- Cable insulation degradation

Procedure documents:
- No documentation current is in place for this asset.

Maintenance standards:
- No documentation current is in place for this asset.

Strategy Information

Maintenance strategy level: 0 - Corrective; reactive

Maintenance strategy drivers:

Primary (choose one)	Secondary (choose all that apply)
Reliability	☐ Safety
	☒ Cost
	☐ Reliability
	☐ Environment
	☐ Corporate Citizenship
	☐ Legal requirements
	☐ Executive directive

Other maintenance requirements:
- Upon failure of a TRXLPE cable segment, the cable segment can be splice up to two times (if possible) and put back into service prior to being replaced with equal or greater capacity TRXLPE cable using current installation standards.
- TRXLPE is an abbreviation for Tree Retardant Cross Link Poly Ethaline.

PROVINCE OF MANITOBA J. D. SHABAGA Member 30036 REGISTERED PROFESSIONAL ENGINEER

Approved by:

Date:

Revisions:

Revision Date: [Revision Date]

Last modified by: opreston

Print date: 7/6/2017

DISTRIBUTION ASSET MAINTENANCE

Asset Class Review Date: 5/1/2017 **Asset Strategy Review Date:** 5/2/2022

Asset Information

Asset class: Underground Assets

Asset sub-class: Padmounted Equipment

Asset: Vault Transformers

Primary function: Power delivery

Limiting factors:
- Oil containment integrity
- Insulation degradation
- Corrosion

Procedure documents:
- Corporate Policy P343

Maintenance standards:
- No formal documentation current is in place for this asset.

Strategy Information

Maintenance strategy level: 2 - Condition-based

Maintenance strategy drivers:

Primary (choose one)	Secondary (choose all that apply)
Reliability	☒ Safety
	☒ Cost
	☐ Reliability
	☐ Environment
	☐ Corporate Citizenship
	☐ Legal requirements
	☐ Executive directive

Other maintenance requirements:

Approved by:

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2017/07/07
J. D.
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Date:

Revisions:

Revision Date: [Revision Date]

Last modified by: opreston **Print date:** 7/6/2017

DISTRIBUTION ASSET MAINTENANCE

Asset Class Review Date: 5/1/2017 **Asset Strategy Review Date:** 5/2/2022

Asset Information

Asset class: Underground Assets

Asset sub-class: Underground Cables

Asset: 66kV XLPE Cable

Primary function: Power delivery

Limiting factors:
- Cable insulation degradation

Procedure documents:
- No formal documentation current is in place for this asset.

Maintenance standards:
- No formal documentation current is in place for this asset.

Strategy Information

Maintenance strategy level: 0 - Corrective; reactive

Maintenance strategy drivers:

Primary (choose one)	Secondary (choose all that apply)
Reliability	☐ Safety
	☒ Cost
	☐ Reliability
	☐ Environment
	☐ Corporate Citizenship
	☐ Legal requirements
	☐ Executive directive

Other maintenance requirements:
- This is a difficult cable type to test as the associated outages are very difficult to schedule and the procedure is very labour intensive and complicated. In addition to this, the risk of damage to the cable insulation as a result of this test is high and cable replacement costs are high with lengthy lead times for ordering. As a result of this, cable testing for this cable type is very impractical.
- XLPE is an abbreviation for Cross Link Poly Ethaline.

DISTRIBUTION ASSET MAINTENANCE

Approved by: PROVINCE OF MANITOBA J. D. SHABAGA Member 30036 REGISTERED PROFESSIONAL ENGINEER **Date:** 2017/12/07	**Revisions:** **Revision Date:** [Revision Date]

DISTRIBUTION ASSET MAINTENANCE

Asset Class Review Date: 5/1/2017 **Asset Strategy Review Date**: 5/2/2022

Asset Information

Asset class: Underground Assets

Asset sub-class: Underground Cables

Asset: XLPE Cable

Primary function: Power delivery

Limiting factors:
- Cable insulation degradation

Procedure documents:
- No formal documentation current is in place for this asset; however, reference information can be found in the following papers:
  - IEEE Guide for Field Testing of Shielded Power Cable Systems Using Very Low Frequency (VLF)
  - XLPE Cable Rehabilitation Program - A Summary of the Development and Implementation of Manitoba Hydro's Underground Cable Rehabilitation Program.

Maintenance standards:
- XLPE cable segments at tested to IEEE Standard 400-2 standards using VLF Dissipation Factor (Tan Delta) Measurement

Strategy Information

Maintenance strategy level: 2 - Condition-based

Maintenance strategy drivers:

Primary (choose one)	Secondary (choose all that apply)
Cost	☐ Safety
	☐ Cost
	☒ Reliability
	☐ Environment
	☐ Corporate Citizenship
	☐ Legal requirements
	☐ Executive directive

Other maintenance requirements:
- Upon failure of a XLPE cable segment, contact the DAM Underground Coordinator to assess cable condition. Cable may be silicone injected, splice and put back into service or replaced with equal or greater capacity TRXLPE cable using current installation standards.
- Further information regarding cable testing can be found in the review paper

"2016 – Energy Ottawa – Direct Current (DC) Polarization/Depolarization Current Measurement Method Evaluation"

- XLPE is an abbreviation for Cross Link Poly Ethaline

Approved by: PROVINCE OF MANITOBA 2017/03/17 J. B. SHABAGA Member 30036 REGISTERED PROFESSIONAL ENGINEER **Date:**	**Revisions:** **Revision Date:** [Revision Date]

A REPETITIVE MAINTENANCE TASKS

A1 Maintenance Task Template

Circuit Breakers - SF_6 Dead Tank (Spring Operator) ABB PM				
Tasks	Triggers			
	Not Critical	Low	Medium	High
Integrity Check	12 months	12 months	12 months	12 months
Functional Check	< 1 ops in 24 months	< 1 ops in 24 months	< 1 ops in 24 months	< 1 ops in 24 months
Density Monitor Check	60 months	60 months	60 months	60 months
Mechanism and Main Contact Check	2000 operations / 15 years/ FAO's	1750 operations / 15 years/ FAO's	1500 operations / 15 years/ FAO's	1250 operations / 15 years/ FAO's

No.	Date	Revision	AMR Specialist	Tech Supp Services	Insul. Eng.	AMR Eng.	
4	2010 12 22	Combined Mech and Main contact check into one task.	CM	DJD		GV	Original signed by G.A. Verch 2011 02 01
3	2004 04 19	Increased Integrity Check trigger interval.	CM	TR		DW	
2	2001 12 15	Changed the trigger of the Density Monitor Check from 24 to 60 months. Removed the SF6 gas quality check from the main contact check. Removed the Vibration Measurement test from the Mechanism Check. Removed the air gap clearance check from the mechanism check. Changed header.	GW	TR		DW	
1	2001 06 05	Combined lubrication & mechanism check. Added time trigger to mechanism check. Removed infrared scan. Changed diagnostic check to main contact check.	GW	TR		DW	
0	2000 11 06			TR		DW	

T&D Reliability Centered Maintenance Project Final Report

Prepared by: Don Webster

Checked by:

Approved by:

Date: 2001 05 14

Report No.: AMD 2001-06

File No.:

Executive Summary

Reliability Centered Maintenance (RCM) is a methodology that leads to the performance of the right maintenance task, at the right time and for the right reason. Reliability Centered Maintenance was pursued by T&D as a means of improving maintenance performance in terms of reliability and cost efficiency. This report reviews the progress of RCM within T&D to December 31, 2000, including the development, implementation, achievements and opportunities of the RCM Program.

An RCM Pilot Project was initiated in February of 1998 to evaluate the potential of RCM in T&D, and was completed in August, 1998. A business case based on the results of the Pilot Project projected an average annual maintenance cost benefit of $2,003,000, with break even on investment by 2006/2007. The full scale T&D RCM Project proceeded and the RCM order was finally closed out in August, 2000 at a total cost of $2,582,000. Implementation of RCM in T&D commenced in April, 2000. The projected average annual maintenance cost benefit is now $3, 308,145, with breakeven in 2002/2003.

Implementing RCM in T&D has enabled the movement from what was previously a time-based maintenance practice which over-maintained equipment and was often invasive in nature, to a maintenance practice which is condition-based and eliminates many of the invasive maintenance tasks. By emphasizing condition monitoring tasks that do not require equipment outages, RCM has reduced the number of equipment outages by approximately 70%.

The performance of the RCM Program will be measured with respect to reliability, availability and cost effectiveness. A total of 27 measurements have been identified consisting of nine external measurements (high level indicators which measure maintenance performance from the perspective of the customer), 6 internal measurements (leading indicators that measure maintenance performance from the perspective of the electrical equipment) and 12 maintenance process measurements, which monitor aspects of the maintenance process which can potentially effect the performance of the equipment.

The T&D RCM Engineering Committee has been established to provide direction for the continuing RCM program, and will encourage and support the continuing application of RCM methodology in T&D, to achieve and optimize the full benefits of RCM to the Corporation.

The Committee includes members from Apparatus Maintenance Division, Communications Department, System Support Department, Line Maintenance and Insulation Engineering/Testing.

Table of Contents

Objective

The objective of this report is to review the progress of RCM within T&D, including the development, implementation, achievements and opportunities of the RCM program. The benefits of the RCM program are addressed in terms of improved reliability, availability and financial benefits.

Conclusions

1. Reliability Centered Maintenance (RCM) is a process which is used to determine that a physical asset, system or process continues to do whatever is required of it. RCM is a methodology which leads to the performance of the right maintenance task, at the right time and for the right reason. Implementing RCM in T&D has enabled the movement from what was previously a time-based maintenance practice which over-maintained equipment and was often invasive in nature, to a maintenance practice which is condition-based and eliminates many of the invasive maintenance tasks.

2. The goal of RCM is to improve reliability by identifying the ways in which components of a system fail, and then selecting maintenance tasks which can prevent or predict these failures before a forced outage occurs. At this point, it is not known what the improvement in reliability will be, or even if there will be an improvement. Reliability theory suggests that the worst possible outcome regarding reliability would be that reliability would remain unchanged. Improvement in equipment reliability will be established through future measurements of the performance of the RCM Program via RMS/AMPS.

3. The previous maintenance practice required relatively frequent outages to take equipment out of service on a regular basis to perform invasive maintenance. In the RCM Program, most calendar time-based intrusive maintenance has been replaced with non-invasive condition monitoring tasks which do not require outages. The frequency of many maintenance tasks which do require outages were decreased to better reflect the inherent reliability of the equipment. It is estimated that scheduled equipment outages will be reduced by approximately 70% with RCM.

4. The total cost of the T&D RCM Project from the beginning of the RCM Pilot Project in February, 1998 to the close out of the RCM order at the end of August, 2000, was $2,582,020. This compares with an estimated cost of $3,073,157 which was estimated during the Pilot Project.

5. Most of the financial benefits derived from RCM will be a result of labour reductions associated with programmed maintenance. There is a projected labour reduction of 26 EFT's in T&D. It should be noted that this is a theoretical reduction due to RCM alone and does not consider other factors affecting manpower requirements. For manpower planning purposes, an EFT (filled and vacant positions) reduction of 15 is projected for T&D.

6. The projected annual benefit from RCM is $3,308,145. This compares with an annual projected benefit of $2,003,000 estimated during the pilot project. The economic analysis models the benefits as starting at 20% of the projected annual benefits in fiscal year 2000/2001, and escalating in equal 20% increments until the full projected annual benefits are attained in fiscal year 2004/2005.

7. The RCM program will break even on investment in fiscal year 2002/2003. The accumulated net present value of the benefits from the RCM program will be $23,400,000 after 20 years (from the start of the Pilot Project), providing an average annual rate of return on investment of 51.1% over the 20 year period. The Pilot Project had estimated break even in 2006/2007, an accumulated NPV after 20 years of $9,700,000 and an average annual rate of return of 23.5%.

8. With RCM, a maintenance program is now in place that is documented, justified and monitored for optimization.

9. Improvements have been made in AMPS and RMS to support RCM. These changes will provide improved reporting of failures and analysis of the root causes of failures.

10. The performance of the RCM program will be measured. A total of 27 measurements have been identified consisting of 9 external measurements, 6 internal measurements and 12 maintenance process measurements. The external measurements are high level indicators which measure maintenance performance from the perspective of the customer. The internal measurements are leading indicators for maintenance performance and measure maintenance performance with respect to the electrical apparatus. All of these indicators measure maintenance performance with respect to reliability, availability and cost effectiveness. The maintenance process measurements will monitor aspects of the maintenance process which can potentially affect the performance of the apparatus.

11. An RCM Training Module has been developed to provide RCM and reliability training to existing technicians and trainees.

12. The T&D RCM Engineering Committee was formed to provide the direction, framework and climate which will encourage and support the continuing application of the RCM methodology in T&D, to achieve and optimize the full benefits to the Corporation.

Recommendations

1. Further application of criticality (system) analysis, should be persued in T&D in order to direct maintenance resources at those system components which have significant failure consequences and probability.

2. Training concerns resulting from RCM should be pursued to resolution as per the recommendations of the Apparatus Maintenance Process Review Team.

3. The T&D Engineering Committee will pursue the issue of outage coordination between Maintenance Departments.

4. Communication between the T&D RCM Engineering Committee and the Generation and HVDC RCM Groups should be enhanced in order to share RCM experience, particularly where there is common equipment.

Introduction

Prior to fiscal year 2000/2001, maintenance within T&D had been basically time-based preventative maintenance. While some condition-based predictive maintenance had also been applied, it was often overridden by the time-based overhaul. In addition, many of the maintenance tasks were not optimized. The result of this practice was unnecessary maintenance which not only lead to maintenance costs which were higher than they needed to be, but also in some cases, resulted in reduced reliability rather than improved reliability.

Reliability Centered Maintenance (RCM) was pursued as a means of improving maintenance performance in terms of reliability and cost. RCM is a process used to determine what must be done to ensure that any physical asset, system or process continue to do whatever is required of it. An RCM Pilot Project which studied the supply to Rosser Station and St. Vital Station was initiated in February, 1998. After the Pilot Project was completed in August 1998, the full scale T&D RCM Project proceeded based on the economic analysis developed in the Pilot Project. Implementation of the RCM Program commenced in April, 2000 and the T&D RCM order was closed out in August, 2000.

A. Former Maintenance Practice in T&D

The former maintenance practice in T&D was mostly time-based preventative maintenance. This was the common maintenance practice of most electric utilities for the last forty years. Some predictive maintenance had been introduced in T&D over the years including various diagnostic tasks for transformers and timing and motion analysis for circuit breakers. A maintenance formula for scheduling high voltage circuit breaker maintenance was also being used. The previous maintenance practice had several shortcomings.

1. Most maintenance was time-based while the variable which actually caused deterioration of the equipment was often not time. For example, the complete inspection interval for circuit breakers was 10 years. This was not the appropriate trigger for maintenance, as the operating mechanism actually deteriorated with operations and the interrupters deteriorated with accumulated fault current.

2. Where the appropriate maintenance triggers were used, the trigger was often overridden by the existing time-based maintenance. For example, even though the circuit breaker maintenance formula would predict the maximum number of fault operations a circuit breaker could accumulate before the contacts required replacement, the contacts were still inspected every 10 years, even if the formula indicated that very little contact erosion would be expected.

3. Maintenance intervals were not optimized. Because of this, in many cases, maintenance inspections were performed too frequently. Some equipment would be opened up every maintenance cycle, only to find nothing wrong with it. What was desired was a maintenance practice that would lead to the performance of invasive maintenance work when it was actually necessary.

4. By performing invasive maintenance on equipment when it was really unnecessary to do so, in some cases, the equipment was inadvertently left in a more unreliable state. By disassembling equipment and rebuilding it, a stable system was disturbed and infant mortality failures were reintroduced.

5. Maintenance costs were higher than they needed to be. Every time a piece of equipment was disassembled, only to find nothing wrong with it, maintenance resources were being wasted.

6. Relatively frequent outages were required. Circuit breakers would be taken out of service every year or every two years to perform an inspection which was little more than a visual inspection.

B. Reliability Centered Maintenance

Reliability Centered Maintenance (RCM) is a process used to determine what must be done to ensure that any physical asset, system or process continues to do whatever is required of it. RCM is a methodology which leads to performance of the right maintenance task, at the right time, and for the right reason. RCM is not new. RCM was born in the airline industry in the late 1960's. RCM has now been adopted by a growing number of electrical utilities on a world wide basis. While it is not easy to describe the RCM process briefly, RCM has four defining features:

1. The primary objective of RCM is to preserve system function, not equipment function.

2. RCM identifies specific equipment failure modes that can defeat the function of the system. A failure mode is a description of how a piece of equipment fails.

3. RCM then determines the consequences and the probability of the various failure modes and prioritizes the importance of the various failure modes.

4. RCM then assigns task maintenance which can predict, prevent or mitigate each failure mode. The most cost effective tasks are chosen for each failure mode.

C. The RCM Pilot Project

RCM was pursued as a means of improving the existing maintenance practice in T&D in terms of reliability and cost. An RCM Steering Committee chaired by W. DeJaegher was established. An RCM Pilot Project which studied the supply to Rosser Station and St. Vital Station, was initiated in April 1998. An RCM Project Group lead by D. Hosea was formed and International Reliability Consultants (IRC) served as the consultant for the Pilot Project. The Pilot Project included the Apparatus Maintenance Division, Communications Department, System Support Department and Transmission Construction and Line Maintenance Division.

The Pilot Project performed criticality analysis (system analysis) of the supply to Rosser Station and St. Vital Station. Criticality analysis is the analysis process which determines the consequences and the probability of a particular failure mode for a piece of equipment, and assigns a criticality level of non-critical, low, medium or high to the apparatus. In RCM, the maintenance applied to the same make and model of equipment may be different for different criticality levels.

The criticality analysis also required analysis of Dorsey, Transcona, Ridgeway and Selkirk Generating Stations. The Project Group developed maintenance tasks for the station equipment by conducting Mode/Cause/Task Analysis with a number of field staff. Mode/Cause/Task Analysis lists the failure modes for the piece of equipment, identifies possible causes of each failure mode and then selects tasks which can prevent, predict or mitigate each failure mode.

The maintenance tasks selected during the Pilot Project differ from the existing maintenance tasks in that:

1. Time-based invasive maintenance was virtually eliminated for most apparatus.

2. Condition-directed tasks were now being used. Equipment was left in service if the condition of the equipment indicated it was suitable to leave it in service.

3. Tasks were now triggered by the parameters which actually caused the deterioration of the equipment.

4. The visual inspection requiring no equipment outage became a key condition-directed task.

5. Task frequencies were adjusted to better reflect the inherent reliability of the equipment.

6. In general, most of the tasks which were performed in the existing maintenance practice were still being performed in RCM. The tasks had different triggers and some tasks which previously required outages, were modified so that outages were not required, but generally the same tasks were still being performed.

A business case analysis was developed based on the results of the Pilot Project. The business case estimated an annual net maintenance cost benefit of $2,003,000 which would be achieved by fiscal year 2006/2007, with breakeven on investment being achieved in 8 years. The accumulative net present value of the benefits was estimated to be $9,700,000 by the end of 2016/2017 (20 years after the start of the pilot project). The average annual rate of return on investment was estimated to be 23.5% over 20 years.

The Pilot Project was completed in August, 1998.

D. Development/Implementation of RCM in T&D

Based on the economic analysis developed in the Pilot Project, the full scale T&D RCM Project proceeded. Initially the scope of the Project was limited to voltages of 33kV and higher. In January 1999, the project was expanded to include voltages below 33kV. This brought the lower voltage circuit breakers (including metalclad switchgear breakers) and reclosers into the Project. The scope of the project was again expanded to include auxiliary equipment in December 1999. This equipment consisted mostly of batteries and battery chargers.

D.1 The T&D RCM Engineering Committee

The T&D RCM Engineering Committee was formed in February 1999. The mission of the Committee was to "provide the direction, framework and climate which will encourage and support the continuing application of the Reliability Centered Maintenance methodology in T&D, to achieve and optimize the full potential benefits to the Corporation." The Committee reported to the RCM Steering Committee. The T&D RCM Engineering committee is chaired by D. Webster and consists of members from Apparatus Maintenance Division, Communications Department, System Support Department, Line Maintenance and Insulation Engineering/Testing. The Committee is responsible for directing the implementation of the T&D RCM Program.

D.2 RCM Documents

D.2.1 The RCM Task Template

The key RCM document is the RCM Task Template which is now simply referred to as the Maintenance Task Template. The Task Template lists the maintenance tasks and the maintenance intervals for these tasks. Refer to Task Template BKR020 on the following page. The variables which are used to schedule the maintenance tasks, such as time or operations, are referred to as task triggers. The values assigned to these trigger variables are referred to as criticality triggers. There are four levels of criticality; non-critical, low, medium and high. The criticality triggers may vary with the criticality level on the Task Template. The criticality level to be applied to a given piece of equipment is determined by criticality analysis (system analysis).

While the application of criticality is in general, a major component of RCM, only limited application of criticality has been applied within T&D. The only applications of criticality at this point are circuit breaker mechanisms and relays. The reason for the limited application of criticality has been the difficulty in differentiating tasks and triggers for different criticality levels. Further applications of criticality will be pursued as experience is gained with RCM.

In the Apparatus Maintenance Division, the RCM Project Group developed the Task Templates by conducting Mode/Cause/Task Analysis with field staff who had experience in maintaining the equipment. The task trigger variables and values were selected by the Technical Support Specialists. In the Protection Maintenance Section of System Support Department, Communications Department, and Line Maintenance, the Task Templates were developed by the Maintenance Engineering Staff.

The Technical Support Services (TSS) Section of the Apparatus Maintenance Division has developed 59 Task Templates to date and has posted them on the TSS Maintenance Manual Web Page. Protection Maintenance has developed a total of 22 Task Templates for relays, recorders and meters. Communications Maintenance has completed 28 Task Templates for tele-protection, power line carrier, telephones, microwave radios, firbre and metallic cables, and VHF radios.

Breaker - SF6 (Spring Operator)

ABB HPL

Task	Criticality Triggers			
	Not Critical	Low	Medium	High
Integrity check	6 months	6 months	6 months	6 months
Infrared Scan	24 months	24 months	24 months	24 months
Functional check	<1 operation in 24 months	<1 operation in 24 months	<1 operation in 24 months	<1 operation in 24 months
Density monitor check	24 months	24 months	24 months	24 months
Insulation check	120 months	120 months	120 months	120 months
Diagnostic check	FAO's / ASO's	FAO's / ASO's	FAO's / ASO's	FAO's / ASO's
Mechanism check (PLG 1002)	2000 operations	1500 operations	1250 operations	1000 operations
Mechanism check (PLG 1002A)	4000 operations	3750 operations	3250 operations	3000 operations

Integrity check	Visual inspection Record operations (faults/ others) - verify by SCADA Functional check of heaters/thermostat operation
Infrared Scan	Infrared scan of current carrying parts
Functional check	Functional operation (Open/Close) and observe
Density monitor check	Test of density monitor
Insulation check	Modal 100 bridge test of grading capacitors
Diagnostic check	Dynamic contact resistances SF6 gas quality (arc by-products - SO_2)
Mechanism check	Motion analyze dashpots Vibration measurements (includes timing/motion)

Track & Trend Information	Timing/motion	Compare to original traces
	Density monitor	Changes?? (+/-% of setting)
	Dynamic contact resistance	Compare to original traces
	Vibration measurements	Compare to original traces
	Number of operations - Faults/ others	Accumulate operations to contact rating
	SF6 gas quality (arc by-products)	PPM (SO_2)
	Insulation measurements	D.F./Capacitance

							Original Signed By D.K. Webster 00 06 01
1	00/05/23	Added ASO's	BC	WD		DW	
0	99/11/25		BC	DW	W.McD	DW	
No.	Date	Revision	RCM Analyst	Tech Supp Serv	Insul. Eng.	RCM Eng.	

Line Maintenance has developed templates for 23 components. A given tower structure will have a number of these components.

D.2.2 RCM Job Descriptions

The maintenance tasks on the Task Templates differ from the former maintenance tasks. They have different names than the former tasks, have different content and are performed at different intervals than the previous tasks. The Electrical Apparatus Maintenance (EAM) Manuals in current use in Apparatus Maintenance are written for the former maintenance tasks and are not compatible with the new RCM maintenance tasks. Many of the existing standards in the Manuals are also out of date and are written in several different formats. A new standard for writing maintenance standards for the EAM Manual has been drafted. The standard incorporates RCM requirements and all maintenance standards in the manual will be written to the new standard by the end of 2002.

In the interim, a document was necessary to link the new RCM tasks to the existing standards. This document is referred to as the "RCM Job Description". The Job Descriptions list the maintenance tasks on the Task Template and either briefly describes the task and/or identify the location in the existing standard (or other document) where the task is described. The new RCM tasks are also not compatible with the existing test sheets. New "check sheets" have been created for most of the Integrity Checks on the Task Templates. Check Sheets will now need to be created for the other tasks on the templates. The Job Descriptions and Check Sheets have been posted on the TSS Maintenance Manual Web Page.

D.2.3 Supporting Documentation for RCM Task Templates

There are a number of RCM documents which support the RCM Task Templates.

1. Maintenance Task Justifications

   This document gives the justification for the maintenance tasks and triggers. It documents the reason the tasks were chosen and the basis for the task triggers.

2. Component Task Comparisons.

   Lists three sets of maintenance tasks.

   - the manufacturer's maintenance recommendations.

   - the pre-RCM maintenance tasks identified in the Electrical Apparatus Maintenance Manuals.

   - the new RCM maintenance tasks. This document illustrates the fact that most of the pre-RCM maintenance tasks are still being performed in RCM. The name of the tasks may be different, and their triggers may be different, but they are still being performed. The document shows that maintenance tasks are generally not eliminated; they are simply being performed at more appropriate times.

3. Comments on Tasks

   For each maintenance task, this document briefly comments on why the task is being performed and how it should be performed.

4. Breakdown/Defective History

   Gives the failure history for the apparatus covered by the Task Template. This document gives the number of failures and problems experienced by the equipment and briefly describes the failure or problem. The data source for the failures and problems is RMS and/or AMPS. This document quantifies the level of inherent reliability of the equipment and also establishes what kind of problems have been experienced with the equipment. This information is used to select maintenance tasks and choose appropriate triggers for the tasks.

5. Mode/Cause/Task Analysis

   Documents the mode/cause/task analysis which was used to select the RCM maintenance tasks. The document lists the failure modes for the apparatus and then assigns possible causes for each failure mode. Tasks are then identified which can detect or prevent the failures. For each failure cause, there are generally a number of tasks listed which can detect or prevent the failure. From this list, the most cost effective task is chosen for each failure cause. It is this collection of cost effective tasks which appear on the Task Template.

D.2.4 The Protection Maintenance Ground Rules

Protection Maintenance has developed a document titled "RCM Ground Rules for Protection Schemes", that is used to determine the maintenance interval for relay schemes. There are three basic types of relay schemes.

1. A/B
2. Main/Backup
3. Main

Maintenance intervals are based on three factors; the consequence of failure, the probability of failure and environmental factors. The consequence of failure is determined by the scheme type and the technology of the major relays within the scheme. There are four relay technologies:

1. Electro Mechanical
2. Solid State
3. Digital - Not Monitored.
4. Digital - Monitored.

The probability of failure is established by the technology of the major relay within the scheme. There are two environmental classifications, good and bad, which are based on the cleanliness and vibration level of the relay location. The three factors are then multiplied together to yield a single maintenance factor. A graph is then used to convert the maintenance factor into a maintenance interval for the relay scheme.

E. RCM Training

During the Project, the Project Group gave a number of RCM presentations in the work centres when they were conducting interviews for mode/cause/task analysis and also provided RCM training for TSS staff. An RCM Training Module was prepared by Don Webster and was mailed out to all Apparatus Maintenance Staff in March, 2000. The initial target group for the Training Module was the existing Technicians. The long term intent is to have the Training Module included in the Training Program for Technicians. RCM presentations were made in the work centres over the Spring of 2000. The presentations were conducted by the RCM Project Group and members of TSS, Protection Maintenance and RMS. The presentations were generally well received. The major concerns expressed by staff were the concern for job loss, the reduced opportunity for "hands on" training under RCM and some concerns relating to the new RCM maintenance tasks and triggers. The questions and concerns expressed by staff and the responses of the presenters were recorded at the presentations and will be posted on the TSS Web Site. At this point in time, staff are familiar with the basic principles of RCM. Their major concerns are with the performance and the usefulness of some of the RCM tasks. The problems associated with the performance of some of the tasks are currently under investigation by TSS staff.

F. RMS/AMPS/TLMIS

There are three Computerized Maintenance Management Systems (CMMS) being used in T&D. RMS is the "in-house" system developed by the Apparatus Maintenance Division. RMS was originally an acronym for Regional Maintenance System but is now simply a name. AMPS is a commercial system used by Power Supply. The TLMIS (Transmission Line Maintenance Information System) is an in-house maintenance management system recently developed for Line Maintenance.

RMS was an existing system at the beginning of the RCM Project. RMS was in DOS format and was not capable of supporting RCM. RMS was converted from its existing DOS version to Windows in the Spring of 2000. RMS was also modified to support RCM. RCM now has failure reporting and root cause failure analysis. TSS staff are responsible for the root cause failure analysis and are required to "sign off" all root cause failure analysis in RMS. There are pick lists in RMS for the technician to choose from when selecting the failure mode and failure cause for the failure report. These pick lists will help to improve the quality and usefulness of the failure data in RMS. This was a previous shortcoming of RMS.

AMPS was also an existing system at the beginning of the RCM project. The system was purchased from TSW (The System Works) which is presently known as Indus International. A module from Indus will be added to AMPS to enable it to support RCM.

Line Maintenance will use the Transmission Line Maintenance Information System (TLMIS) as a line patrol/inspection software. This software is being developed in-house and will be capable of supporting their RCM activities.

G. RCM Task Implementation

In January, 2000, entry of the RCM Task Templates into RMS and AMPS was started. These Task Templates were then implemented for the maintenance year starting April, 2000. When Task Templates were not yet available, existing maintenance practices were followed.

The 59 Task Templates developed by TSS have now been installed in RMS. A number of task templates are currently under development and will be completed by the beginning of the 2001/2002 fiscal year. These include air systems, power supplies, converters, inverters, engines, fuses, generators and switchgear.

Protection Maintenance has developed 22 Task Templates for relays, recorders and meters. These task templates have been installed in AMPS. Task templates for RTUs, telemetry and EMS/SCADA will be developed and implemented in fiscal year 2001/2002.

Communications Maintenance has developed 28 task templates for teleprotection, power line carrier, telephones, microwave radios, firbre and metallic cable, and VHF radios. These task templates have been installed in AMPS. Four task templates remain to be developed and implementation will be completed by the beginning of the 2001/2002 fiscal year. Communications will perform maintenance with the lines in service where there is redundancy.

Line Maintenance has developed task templates for 23 components. The Line Maintenance Task Templates differ from the other groups in that they apply to components of the tower structures and not the entire structure. A given tower will have a number of these components and all the task templates associated with those components will apply to that specific tower. The task templates have not been entered into the TLMIS as the programming has not yet been completed. The anticipated completion date is December, 2002.

Most of the task templates which were developed in the Pilot Project have now gone through a number of revisions. Through continuous improvement, some tasks have been added, deleted or altered and some of the task triggers and trigger values have been changed.

H. RCM Project Completion

The T&D RCM order was closed out in August, 2000. A number of task templates remain to be completed and revisions to existing task templates continue to be revised on relatively infrequent basis. The continuing revisions are expected as there is very little chance that the templates would have been entirely correct on the first attempt. The templates will most likely be revised from time to time as new knowledge is applied from what is continually being learned. This is often referred to as the "RCM Living Program". This reflects the fact that RCM is a continuous improvement process. It is not just a one time effort.

The Apparatus Maintenance Process Improvement Team identified "a critical ongoing need to retain a skill set in RCM philosophy and practice within our TSS Group" and recommended that a permanent position be created in TSS to fulfil this requirement. A job description was written for an Apparatus Maintenance Reliability Specialist and the position was bid. This Specialist will perform RCM related analysis for TSS, Protection Maintenance, Communication Maintenance and Line Maintenance.

I. The Circuit Breaker Maintenance Formula

One major shortcoming of the existing maintenance program identified by the RCM Project Group was the circuit breaker maintenance formula. The existing formula was developed in 1985. The formula calculated the number of fault operations a circuit breaker could tolerate before the contacts were eroded to the extent that they needed to be replaced. The formula was based on the manufacturer's recommended number of fault operations and the ratio of the rated interrupting current to the fault current available at the circuit breaker bus. It had always been known that the formula was very conservative, as faults do not all occur at the breaker bus but actually occur some distance down the line being protected by the circuit breaker. The formula was not modified as the required adjustments were fairly complex and would have to be calculated on a breaker by breaker basis.

During the summer of 1999, calculations were performed for all T&D circuit breakers to provide new fault adjusted operations (FAOs) based on faults occurring uniformly along the length of the line(s). The new FAO values are significantly greater than the previous values. These new values will then be adjusted as required based on the measured amount of contact erosion when the contacts are inspected when the FAO trigger is reached. The new FAO values will greatly reduce the amount of invasive maintenance performed on circuit breakers, and the cost associated with invasive maintenance.

Historically, FAOs were applied to high voltage circuit breakers in T&D. FAOs have now been applied to metalclad switchgear breakers and three phase reclosers. The Power Supply Business Unit has also applied FAOs to some of their circuit breakers.

J. RCM Project Cost

The estimated and actual cost for the T&D RCM Project are given in Table 1. These costs include all costs from the beginning of the Pilot Project in February 1998 to the close out of the T&D RCM Project order at the end of August, 2000.

	Estimated	Actual
Pilot Project	$ 833 729.00	$ 818 442.00
Implementation Phase of Project	$2 239 428.00	$1 763 578.00
Total T&D Project Cost	$3 073 157.00	$2 582 020.00

Table 1 - RCM Project Cost

T&D and Power Supply's HVDC Division shared one order for the project. The costs identified here are T&D's share of the total project cost. A major component of the Pilot Project cost was the consultant fee. T&D's portion of this cost was $335,592.

The annual costs of the project are as follows:

	Total Annual Cost	Consultant Fee
1997/98	$ 142 995.00	$ 52 954.00
1998/99	$1 300 678.00	$282 638.00
1999/00	$ 810 096.00	
2000/01	$ 268 251.00	
TOTAL	**$2 582 020.00**	**$335 592.00**

K. RCM Benefits

The major potential benefits when making changes to improve and optimize a maintenance program are improved reliability, improved availability and reduced maintenance cost.

K.1 Reliability

On an equipment level, reliability is measured by the failure rate of that equipment. It is the goal of RCM to reduce forced outages of equipment to as close to zero as possible by detecting evolving failures before they cause forced outages. It is not known what this improvement in reliability will be, or even if there will be an improvement. Basic reliability theory suggests that the worst possible outcome regarding reliability would be that reliability would remain unchanged. Reliability would not be expected to deteriorate, at least not significantly. Improvements in equipment reliability will be established through future measurement of the performance of the RCM Program via RMS/AMPS.

K.2 Availability

Availability, on an equipment level, is the fraction of the time that the equipment is in service. Availability is reduced by in-service failures and by outages taken to perform maintenance on the equipment. RCM has replaced most calendar time-based invasive maintenance with non-invasive condition monitoring tasks which do not require outages. In addition, the frequencies of many maintenance tasks which do require outages were decreased to better reflect the inherent reliability of the equipment. It is estimated that scheduled equipment outages will be reduced by approximately 70% with RCM.

K.3 Financial Benefits

Most of the financial benefits derived from RCM will be the result of labour reduction associated with programmed maintenance. RCM has eliminated most calendar time-based intrusive maintenance tasks and relies more on non-intrusive monitoring tasks. The intrusive tasks required outages and were labour intensive. Most of the monitoring tasks require no outage and therefore have fewer hours associated with them than similar pre-RCM tasks. In addition, the RCM tasks which do require outages are generally performed at reduced frequencies compared to the pre-RCM tasks.

K.3.1 Maintenance Labour Reduction

Most of the labour reduction resulting from RCM is in the Apparatus Maintenance Division. Table 2 compares the RCM calculated man-hours with the actual pre-RCM man-hours. The annual man-hour reduction in Apparatus Maintenance is estimated to be 53,300 manhours or 27.33 EFT's.

The labour reductions were calculated by assigning hours to the tasks on the RCM Task Templates and applying these hours to the apparatus covered by the Task Templates. These hours were then totaled and compared to the hours for the pre-RCM tasks. The hours for the RCM tasks were estimated by the Maintenance Planners. The net result was a reduction in programmed maintenance of 53.73%. This reduction was then applied to the actual pre-RCM hours for programmed maintenance.

	Pre-RCM Mhrs.%	Pre-RCM Actual Mhrs. 1999/2000	Post-RCM Mhrs. %	Post-RCM Calculated Mhrs.	Mhr. Reduction	EFT Reduction
Programmed Maintenance	22.8	83 922	12.3	38 831	45 091	
Programmed Projects	4.6	16 927	5.4	16 927	0	
Capital Projects	14.1	51 986	16.5	51 986	0	
Non-Programmed Work	12.1	44 467	14.1	44 467	0	
Corrective Work (In-Service Failures)	4.6	16 868	5.4	16 868	0	
Corrective W ork (During Scheduled Maintenance)	3.8	13 800	4.4	13 800	0	
Contracting-In	0.3	1 024	0.3	1 024	0	
Recording	0.4	1 513	0.5	1 513	0	
Administration*	37.3	137 345	41.1	129 136	8 209	
	100.0	367 852	100.0	314 552	53 300	27.33
***NOTE:**	*Administration includes clerks, engineering, patrols, stores, supervisors, planners, meetings, vacation and sick time*					

Table 2 - Apparatus Maintenance ManHour and EFT Reduction

Notes:

1. RCM tasks which are triggered by non-time variables were modeled by assigning time triggers to the tasks. The non-time triggers generally apply to circuit breakers. It was assumed that the pre-RCM 10 year complete maintenance would now be performed every 20 years. This was based on the fact that circuit breakers were generally maintained at 10 years, as the maintenance formula would generally not trigger the complete prior to 10 years. The new FAOs are on average about twice the previous FAOs. Therefore, it is reasonable to assume that circuit breakers will not require contact replacement for 20 years. This is in fact a conservative assumption as most 115 kV and 230 kV circuit breakers will never require contact replacement due to the low rates of fault accumulation at these voltages.

   Tasks triggered by operations, such as the mechanism check, were assigned a 15 year interval. This value should be conservative as most operating mechanism will never reach their triggers, which may be thousands of operations. This would be especially true for the 115 kV and 230 kV circuit breakers. The 15 year task may be appropriate however, for some lubrication related problems.

2. Some assumptions were necessary regarding the distribution of the pre-RCM manhours. The pre-RCM correctives do not differentiate between correctives due to in-service failures and correctives that are performed as a result of scheduled maintenance detecting a problem. Both are simply listed as correctives in the report. In addition, some corrective work has historically not even been recorded as a corrective, but instead, has simply been included in the programmed maintenance which immediately preceded the corrective work. If this corrective work is not removed from the programmed maintenance, the reduction calculation could be unrealistically high as the reduction would also be applied to some of the corrective work.

The following assumptions were made. It was assumed that 55% of the corrective hours resulted from in-service failures and 45% of the corrective hours applied to correctives performed as a result of scheduled maintenance detecting a problem. This was based on the data within RMS. It was assumed that half of the corrective hours resulting from scheduled maintenance were incorrectly included in the programmed maintenance. Although these assumptions are reasonable, there could be an error of several EFTs in the total.

3. The administration manhours include clerical staff, engineering, patrols, supervisors, planners, meetings, vacation and sick time.

4. The calculated manhour and EFT reductions are the theoretical savings due solely to RCM. They should not be applied to manpower planning. The manhour reduction assumes that all RCM tasks are performed and all pre-RCM tasks were performed prior to RCM and are included in the actual hours. The reduction does not take into account the fact that approximately 20% of pre-RCM programmed maintenance was generally not completed. Because of this, the calculation method will under estimate the theoretical labour savings and will overstate the actual reduction of current staff that is possible. In terms of manpower planning, the actual current staff (filled and vacant positions) reduction possible would be approximately 6 EFTs less than the number given in Table 2. The calculated reduction also does not consider any other factors such as changes in capital projects, programmed projects and non-programmed work.

   It should also be noted that the entire RCM maintenance program is based on estimated hours. While these estimates are believed to be conservative, there may be a considerable difference between future actual hours and the estimated hours. Future experience with the RCM program will be required to establish manpower requirements.

Component Type	% of Total Reduction
Arresters	2.12
Batteries	6.83
Battery Chargers	1.31
Capacitor Banks	1.68
Circuit Breaker (All)	21.61
Circuit Switchers	0.33
Disconnects/Switches	9.95
Instruments	5.79
Metering	1.51
MOD's	5.31
Reactors	0.36
Reclosers	2.65
Recorders	5.97
Regulators	3.62
Relays	10.07
Tap Changers	2.98
Transducers	2.69
Transformers - CT	2.64
Transformers - PT	7.06
Transformers - Power	5.51
TOTAL	100.00

Table 3 - Apparatus Maintenance Labour Reduction Distribution

5. The percentage of the total labour reduction attributed to each generic component type is shown in Table 3. The largest contributors to the reduction, in order of magnitude, are circuit breakers, relays, and disconnects/switches.

In addition to the projected labour reduction of 27 EFTs identified for Apparatus Maintenance, 2 EFTs were estimated by Protection Maintenance and 3 EFTs by Communications Maintenance.

Similarly to Apparatus Maintenance, the EFT reductions in Protection Maintenance and Communications Maintenance are theoretical savings due to RCM alone. Because of current staffing requirements, the five EFTs identified here will not result in an actual reduction of five staff.

K.3.2 RCM Staff

Some additional staff will be required to carry on the RCM maintenance program. RCM requires some work to be performed which was not previously being performed. Much of this work is associated with data management and quality control. The following additional staff have been identified.

1. An Apparatus Maintenance Realibility Specialist position has been bid in Apparatus Maintenance. The Analyst will:

   - perform system analysis of transmission and distribution systems in order to determine the criticality of the failure modes.

   - provide guidance to technical support staff in the selection of preventative and predictive maintenance tasks based on RCM analysis.

   - conduct studies of the maintenance and failure data to determine equipment reliability and recommend changes in the maintenance standards to optimize reliability.

   - monitor the application of RCM and assist staff to ensure that RCM methodology is being applied in a consistent manner.

   The Specialist will perform these duties for all of T&D.

2. Additional manhours will be required in the field to:

   - input data for tracking and trending.
   - ensure the quality of data for tracking and trending.
   - ensure the quality of failure reports and root cause failure analysis.
   - monitor equipment performance and alert technicians to abnormal data trends.

   The equivalent of 5 EFTs have been included to do this work. This will ensure that TSS receives quality data for analysis. It is critical that TSS has clean data for analysis, so that appropriate maintenance recommendations can be made. Regardless of who performs this work and where they perform it, it is necessary to identify the work in the overall labour reduction as it represents additional work necessary for the continuance of the RCM Maintenance Program.

K.3.3 T&D Net Labour Reduction

The T&D net labour reduction is shown in Table 4.

Apparatus Maintenance EFT Reduction		
For Calculation of Labour Savings		**For ManPower Planning**
- Mhr. Reductions = 53 300/1 950 = 27.33 =	27	21
- Reliability Specialist	-1	-1
- Five (5) Field EFTs	-5	-5
AM Net EFT Reduction	**21***	**15**
T&D Net EFT Reduction		
- Apparatus Maintenance	21*	15
- Protection Maintenance	2*	0
- Communications Maintenance	3*	0
- Line Maintenance	0*	0
T&D Net EFT Reduction	**26***	**15**

Table 4

For the Annual Maintenance Net Cost Benefit derived from the indicated Net EFT Reduction, refer to Table 5

K.3.4 Projected Annual Maintenance Cost Benefit

Most of the savings derived from RCM are labour savings. There will also be some savings in parts and material. With intrusive maintenance being greatly reduced with RCM, the parts and material associated with this maintenance will also be reduced. The annual parts and material savings will be assigned a conservative value of $200 000 per year.

Table 5 shows the estimated annual maintenance net cost benefit derived from RCM.

Estimated Total Annual Maintenance Net Cost Benefit		
- Apparatus Maintenance	21 x 1950 x $62.75	$2 569 613.00
- Protection Maintenance	2 x 1950 x $52.00	$ 202 800.00
- Communications Maintenance	3 x 1950 x $57.39	$ 335 732.00
- Line Maintenance	0	$ 0.00
- Material Savings		$ 200 000.00
Total Net Annual Benefit	**26**	**$3 308 145.00**

Table 5

The annual maintenance cost benefits are calculated by multiplying the manhour reductions by the appropriate activity rates. The projected annual benefit derived from RCM is $3 308 145 per year. It is important to note that this cost benefit was determined by calculating the difference in man-hours required to complete the pre-RCM planned maintenance program to that required to accomplish the post-RCM program. For a number of years now, the planned programs have not been totally completed due to resource shortages; hence the actual "bottom line" cost reductions will be less than the Total Net Annual Savings indicated in Table 5. The historical resource shortage is approximately 6 EFTs in Apparatus Maintenance, 2 EFTs in Protection Maintenance and 3 EFTs in Communications Maintenance. This results in a "bottom line" cost reduction of $2 035 438. It is however, appropriate to use programmed costs rather than actual costs in order to make visible the true benefits attributable to the RCM application.

K.3.5 T&D RCM Economic Analysis

In developing the T&D RCM economic analysis, it is recognized that all of the projected annual benefits will not be realized in the first year of implementation. It will take a number of years before the full benefits are realized. RCM was implemented in T&D at the start of the 2000/2001 fiscal year. All of the Task Templates were not completed at that time. Where Task Templates were not available, the previous maintenance practice was retained. Therefore 2000/2001 is a mixture of RCM maintenance tasks and pre-RCM maintenance tasks. In addition some time is required for maintenance staff to become familiar with the new RCM tasks and triggers and develop efficiency in planning, scheduling and performing the tasks.

Table 6

T&D Reliability Centered Maintenance

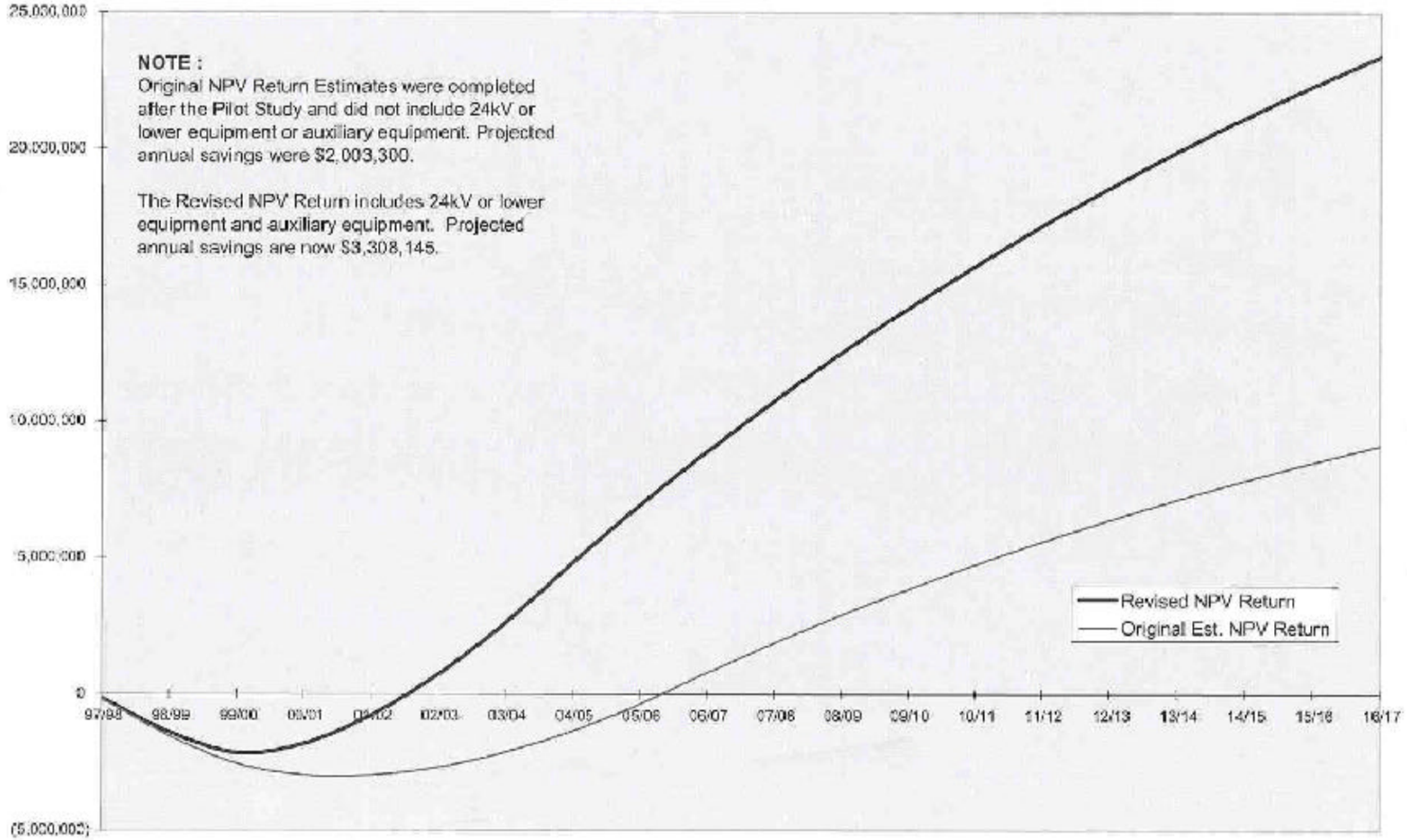
20 Year Benefit Projections

	Maintenance Labor Savings		Project Expenses				
Year	**Annual Revenue**	**PV of Revenue**	**Annual Expenses**	**PV of Expenses**	**Accum Benefit Total/Year**	**Annual NPV** (Rev-Exp)	**Accumulated NPV**
97/98	$0	$0	$142,995	$142,995	($142,995)	($142,995)	($142,995)
98/99	$0	$0	$1,300,678	$1,227,866	($1,443,673)	($1,227,866)	($1,370,861)
99/00	$0	$0	$870,096	$775,406	($2,313,769)	($775,406)	($2,146,267)
00/01	$661,629	$556,618	$268,251	$225,676	($1,920,391)	$330,943	($1,815,324)
01/02	$1,323,258	$1,050,918	$0	$0	($597,133)	$1,050,918	($764,406)
02/03	$1,984,887	$1,488,130	$0	$0	$1,387,754	$1,488,130	$723,724
03/04	$2,646,516	$1,873,099	$0	$0	$4,034,270	$1,873,099	$2,596,823
04/05	$3,308,145	$2,210,303	$0	$0	$7,342,415	$2,210,303	$4,807,125
05/06	$3,308,145	$2,086,569	$0	$0	$10,650,560	$2,086,569	$6,893,694
06/07	$3,308,145	$1,969,762	$0	$0	$13,958,705	$1,969,762	$8,863,457
07/08	$3,308,145	$1,859,494	$0	$0	$17,266,850	$1,859,494	$10,722,951
08/09	$3,308,145	$1,755,399	$0	$0	$20,574,995	$1,755,399	$12,478,350
09/10	$3,308,145	$1,657,131	$0	$0	$23,883,140	$1,657,131	$14,135,481
10/11	$3,308,145	$1,564,364	$0	$0	$27,191,285	$1,564,364	$15,699,845
11/12	$3,308,145	$1,476,791	$0	$0	$30,499,430	$1,476,791	$17,176,636
12/13	$3,308,145	$1,394,119	$0	$0	$33,807,575	$1,394,119	$18,570,755
13/14	$3,308,145	$1,316,076	$0	$0	$37,115,720	$1,316,076	$19,886,831
14/15	$3,308,145	$1,242,402	$0	$0	$40,423,865	$1,242,402	$21,129,233
15/16	$3,308,145	$1,172,852	$0	$0	$43,732,010	$1,172,852	$22,302,084
16/17	$3,308,145	$1,107,195	$0	$0	$47,040,155	$1,107,195	$23,409,279
TOTAL	$49,622,175	$25,781,221	$2,582,020	$2,371,942			

Discount Rate =	5.93%	
Present Value of Revenue (Using NPV formula)		$25,781,221.31
Present Value of Expenses (Using NPV formula)		$2,371,942.21
Net Present Value of Benefits		$23,409,279.10
Benefit/ Cost Ratio =	10.87	
IRR	51.07%	

T + D RCM Project

(Accumulated NPV - Breakeven Point)



In the economic analysis, the benefits were conservately modeled as starting at 20% of the projected annual benefit in fiscal year 2000/2001 and escalating in equal 20% increments until the full projected annual benefit is attained in fiscal year 2004/2005. The economic analysis is shown in Table 6. The accumulated net present values from Table 6 are plotted on the graph on the previous page, along with the accumulated net present values estimated in the pilot project. The accumulated NPV is much greater than estimated in the pilot project because:

1. Equipment rated 24 kV and below and auxiliary equipment were not included in the pilot project but have now been included in the project. Equipment rated 24 kV and below includes the lower voltage circuit breakers, metalclad circuit breakers and three phase reclosers. Auxiliary equipment consists mainly of batteries and battery chargers.

2. Better estimates of the maintenance task hours are now available.

3. A total EFT reduction of 5 has been assigned to Protection Maintenance and Communications Maintenance, while only 2 EFTs were estimated in the pilot project.

Table 7 gives a comparison of the financial benefits derived from RCM to the benefits calculated in the pilot project.

	Calculated by Pilot Project	**Current Projection**
Annual Maintenance Cost Benefit	$2 003 000.00	$ 3 308 145.00
Break Even	2006/2007	2002/2003
Accumulated NPV after 20 years	$9 700 000.00	$23 400 000.00
Average Annual ROI over 20 years	23.5%	51.1%
EFT Reduction due to RCM	17	26

Table 7

K.4 Additional RCM Benefits

Besides improved reliability and availability and the financial benefits derived from RCM, there are a number of less tangible benefits which are also very important.

1. A documented and justified maintenance program is now in place and monitored for optimization in what is commonly referred to as the "RCM Living Program". The term reflects the fact that RCM is not just a one time event. It is a continuous improvement process.

2. Maintenance resources are applied where they will provide the greatest benefit.

3. Maintenance tasks which do not predict or prevent failures or are not cost effective, have been eliminated.

4. By fast-tracking implementation of RCM, maintenance savings are being realized in fiscal year 2000/2001.

5. Improvements made to RMS and AMPS to support RCM, will provide improved reporting of failures and analysis of the root causes of failures.

6. There will be less "wear and tear" on equipment due to reduced testing.

7. There will be improved staff ownership of the maintenance program. Field staff are actively involved in the development of the program and have a continuing role in its future development.

L. Measurement of RCM Effectiveness

A number of measurements will be used to monitor the effectiveness of the RCM program. The measurements will fall into two general categories:

1. External measurements of maintenance performance.

   - These are high level measurements of the effectiveness of the maintenance program.

   - They are lagging indicators that reflect how well the maintenance program has performed.

   - They measure maintenance performance from the perspective of the customer.

2. Internal measurements of maintenance performance

- These are leading indicators for maintenance performance.
- They measure maintenance performance with respect to the electrical apparatus.

The External and Internal indicators were developed by the AM Maintenance Process Review Team.

L.1 External Measurements

The external measurements will consist of the following metrics.

1. STN-SAIFI: The average number of interruptions per year per customer served, caused by events within stations. This is a reliability indicator.
2. STN-SAIDI: The average cumulative interruption duration (in minutes) per year per customer served, caused by events within stations. This is an availability indicator.
3. STN-CAIDI: The average duration (in minutes) of each interruption caused by events within stations. This is an availability indicator which only includes customers who have actually experienced interruptions.
4. Key Customer Interruption Rate: The average number of interruptions per year per key customer, caused by events within stations.
5. Quality of Power Indicator: The number of functional failures per year with a failure mode of "fails to regulate" per installed unit. The indicator includes regulators, LTCs, autoboosters and switched capacitor banks.

Cost Effectiveness Indicators

6. CE:STN-SAIF = STN-SAIFI x Maintenance Cost per Customer.
7. CE:STN-SAIDI = STN-SAIDI x Maintenance Cost per Customer.
8. CE:STN-CAIDI = STN-CAIDI x Maintenance Cost per Customer.
9. Maintenance Cost per Customer

Notes:

1. Indicators 1, 2, 3 and 4 include all interruptions for all events within stations including events which are not preventable by maintenance including lighting, ice storms and wildlife.

2. An interruption must be at least one minute in duration to be included in any of the indicators.

3. All indicators are calculated on a fiscal year basis.

4. For indicators 1, 2 and 3, only two of the three will be independent as CAIDI = SAIDI/SAIFI.

5. Indicators 6, 7 and 8 require the first variable in the expression to be multiplied by the maintenance cost per customer rather than divided by it.

   The reason for this is that the first variable in the expression is an indicator which decreases as it improves. If it was divided by the maintenance cost per customer, then the cost effectiveness indicator would also decrease with an increase in the maintenance cost per customer, which is clearly not the desired result. When the two variables are multiplied, then the cost effectiveness indicator will decrease with an improvement of the first variable in the expression and will also decrease with a decrease in the maintenance cost per customer, thus producing the desired result.

6. The data for indicators 1, 2 and 3 is available from the System Interruption Report System of the Transformer Load Management System (TLMS). It is possible to generate a report which keys on interruptions where the cause was within a station. A trial report was run for Suburban East. The report was found to be only about 50% accurate. Of the known events, only half were included in the report. Almost all the events were actually in TLMS but were not included in the report because the fault location was not recorded as a station in the original Service Interruption Report. The Service Quality Department which is responsible for the TLMS, indicates that now this information will be used, they can implement procedures and educate staff to produce a report which will be close to 100% accurate. They are also reviewing the historical data and correcting these errors. Consideration has also been given to having the Electrical Maintenance staff report this information to help ensure accuracy.

L.2 Internal Measurements

The following internal measurements have been identified.

1. Reliability

Forced Outage Rate for:

- circuit breakers
- transformers
- three phase reclosers

$$= \frac{\text{annual number of forced outages}}{\text{number of apparatus}}$$

A forced outage is defined as the automatic or emergency removal of a piece of equipment directly caused by defective equipment, adverse weather, adverse environment, system condition, human element or foreign interference.

2. Maintainability

Mean Time to Repair/Replace for:

- current breakers
- transformers
- three phase reclosers

$$= \frac{\text{total annual hours of forced outage time}}{\text{total annual number of forced outages}}$$

3. Maintenance Cost Effectiveness

Average Maintenance Cost for:

- circuit breakers
- transformers
- three phase reclosers

$$= \frac{\text{annual maintenance cost}}{\text{number of apparatus}}$$

4. Maintenance Task Estimating Effectiveness

$$= \frac{\text{total annual estimated hours x 100\%}}{\text{total actual annual hours}}$$

This indicator measures the effectiveness of the estimator (the Planner) and not the technician performing the work.

5. Maintenance Training Expenditure

$$= \frac{\text{annual training expenditure X 100\%}}{\text{total operating cost}}$$

This indicator should be comparable to utilities following best practices.

6. Forces Outages/Alarm Response Time

Average Response Time For:

- circuit breakers
- transformers
- three phase reclosers

$$= \frac{\text{total annual response time}}{\text{total annual forced outages and alarms}}$$

The response time is the time for the technician to arrive on site after a forced outage or alarm, ready to start analyzing the problem. The time starts at the moment of failure or alarm.

Some of the metrics such as the Forced Outage Rate will be fairly easy to calculate and will only require a minor change to RMS to collect the required data. The impact on field staff will be minor and will consist of an additional check box for forced outages on the failure report screen. Other indicators such as the mean time to repair/replace and the forced outage/alarm response time will have a greater impact on field staff and RMS, as they would now have to track and record information which they did not previously record. Some of the internal indicators may be discarded, modified or replaced depending on the practicality of implementing these measurements. The indicators will be implemented at the beginning of the 2001/2002 fiscal year.

L.3 Maintenance Process Measurements

In addition to the internal and external measurements, the AM Process Review Team identified twelve maintenance process measurements. While these indicators do not measure the performance of the equipment, they monitor aspects of the maintenance process, which, if improved, will eventually improve the performance of the equipment. There is a cause and effect relationship between the maintenance process indicators and the apparatus performance indicators. The process indicators can be viewed as leading indicators for the internal indicators. As an example, one of the process indicators is the number of outstanding root cause failure analysis (RCFA). RCFA are performed to prevent failures from reoccurring. If there is a backlog of RCFA to be done, then reoccurrences of the failures may occur before the cause of the failure is determined. Thus, the maintenance process effects equipment performance.

Similarly to the other measurements, these indicators will be implemented at the start of the 2001/2002 fiscal year.

M. Opportunities and Issues

RCM is not a one time event. It is a continuous improvement process. Changes and improvements will be required as we move forward with RCM. A number of future opportunities and issues are evident.

1. Criticality

   The objective of RCM is to preserve system function, not equipment function. Criticality is a measure of the consequence and probability of failure of a system component. In RCM, most of the maintenance resources are directed at those system components which have significant failure consequence and probability. This practice is sometimes referred to a "system based RCM". RCM which ignores criticality on a system basis and only considers criticality on a component basis, is referred to as "component based RCM". At this point, it is essentially component based RCM that is being practiced in T&D. The only current applications of criticality are circuit breaker operating mechanisms and relays. As RCM continues to develop, an effort will be made to find additional applications of criticality in system based RCM.

   All of the necessary system analysis has been performed by the RCM Project Group. It is a matter of finding an application for the analysis.

2. The continuation of RCM principles is a major concern. Failures will occur with RCM as they will with any maintenance program. Over-reaction to these failures as an indication that the RCM way is the wrong way, must be resisted. The decision to change must be based on the analysis of these failures and a rational analysis of reliability over time, and not by knee-jerk reactions to individual failures.

3. Training has been identified as a major concern with RCM. Now that some equipment will no longer be taken out of service to perform invasive maintenance on a regular basis, there is a concern that technicians will no longer be able to maintain competency in invasive maintenance, and trainees will have difficulty in obtaining the necessary experience to complete their training. The training issues were considered by the AM Process Review Team. It was recommended that the Electrical Technician Training Committee (ETTC) address the first training concern. To address the second training concern, the Review Team recommended that the position of Field Training Coordinator be reaffirmed for each of the Departments, and provided with opportunities to enhance coordination of training on a Divisional basis.

4. Outage coordination will be an issue with RCM. There will need to be more communication among the Planners, so that the Maintenance Departments are aware of each other's outages, and can jointly plan their maintenance activities around these outages, which will be far fewer in number with RCM. The T&D RCM Engineering Committee will pursue this issue and ensure that a workable system is developed.

5. More communication between Generation North/South and HVDC RCM Groups and the T&D RCM Engineering Committee is required to share RCM experience, particularly where there is common equipment. These groups will be invited to meetings of the Committee and are now included on the e-mail list for the TSS Alerts regarding the Technical Support Services Web Site.

Overhead Distribution Line Refurbishment

Manitoba Hydro

Introduction

The replacement of aging assets approaching their "end of life" is anticipated to be substantial and will require significantly higher replacement rates to maintain the distribution system performance over the next 20 years. Distribution Asset Maintenance Department has been continuously improving the strategy to effectively manage these assets through a "Line Refurbishment Program".

The Line Refurbishment program is funded by Distribution Asset Maintenance with the primary customer being Customer Service Operations. Additional stakeholders within the Customer Service & Distribution business unit include "Distribution Engineering & Construction". Corporate Finance is largely involved from outside the business unit. Success of each project within the program is dependent upon a collaborative effort from all departments.

The intent of this manual is to communicate the development and current practices of the "Overhead Line Refurbishment Program".

Manitoba Hydro

Background

Manitoba Hydro has always completed maintenance or system improvements on the distribution system. Historically these improvements tended to be more reactive rather than a planned approach. The changing of business practices over the recent years demanding greater accountability and resource management has caused us to continuously look for ways to improve upon all aspects of our distribution maintenance. Essentially what is required is a "Refurbishment" of the plant that was originally installed between 1940 & 1960 under the "Rural Electrification" program. This Overhead Line Refurbishment program has to take into consideration factors such as reliability, risk and customers being served for each section of distribution being considered for the program.

Technological advancements and corporate alignment have better enabled us to share industry best practices both internally and worldwide. Customer Service Operations consisted of 72 Districts and following realignment in 2007 our Operations are coordinated through 20 Customer Service Centers. This realignment combined with the Distribution Maintenance Planning System (DMPS) and the Mobile Workforce Management (MWM) system has provided a more consistent application toward identifying, planning and scheduling of required maintenance on 66KV and below distribution.

Manitoba Hydro

Definition of Line Refurbishment (overhead)

Refurbishment of a section of distribution (66KV & below) in which the condition of the critical asset(s) have reached the end of life as identified by "CSO end of life criteria".

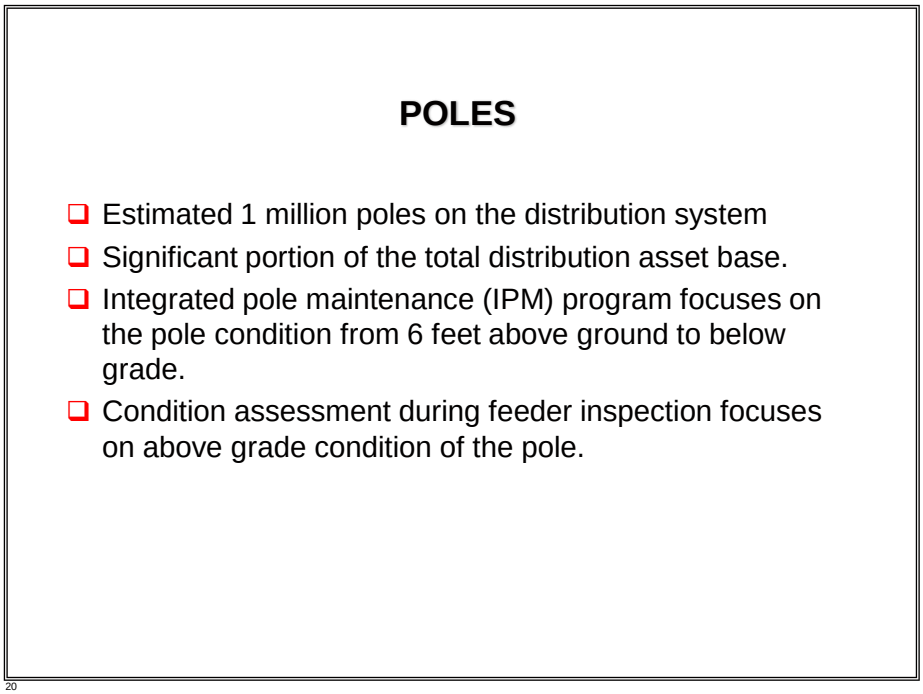
- ***Critical overhead distribution assets = poles, overhead conductors and overhead transformers*** [i]
- ***End of Life Criteria = evaluation of condition assessment via detailed feeder inspection & information gathered on e-form 2201***

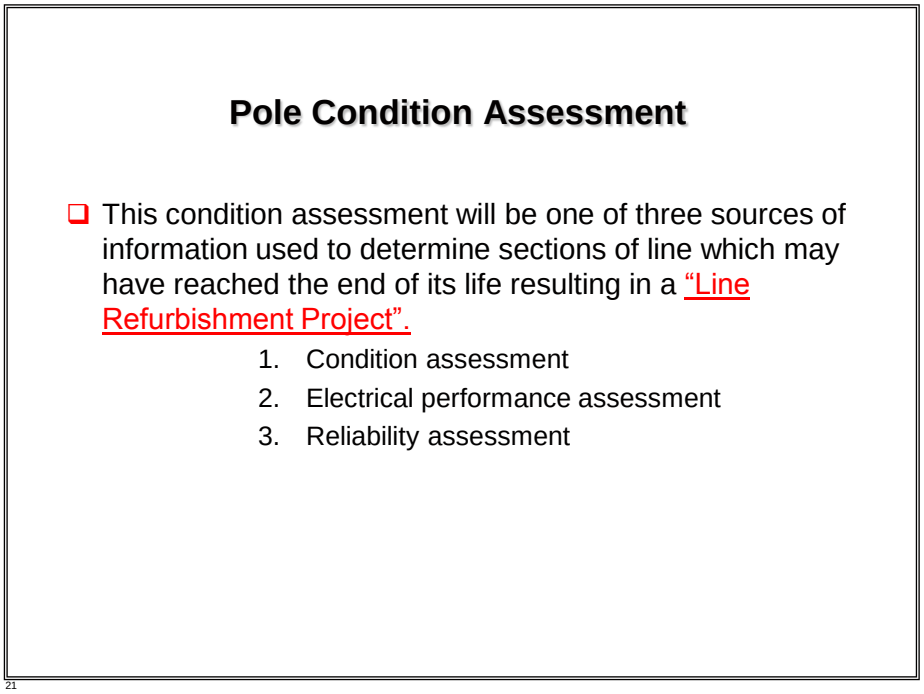
Index

1. Identifying Overhead Line Refurbishment Requirements

1.1. *Detailed Feeder Inspections* [ii]

- ***Planned condition assessments of the pole asset s are completed during these inspections.***
- ***Distribution identified as having "high priority pole condition" will be considered for line refurbishment***



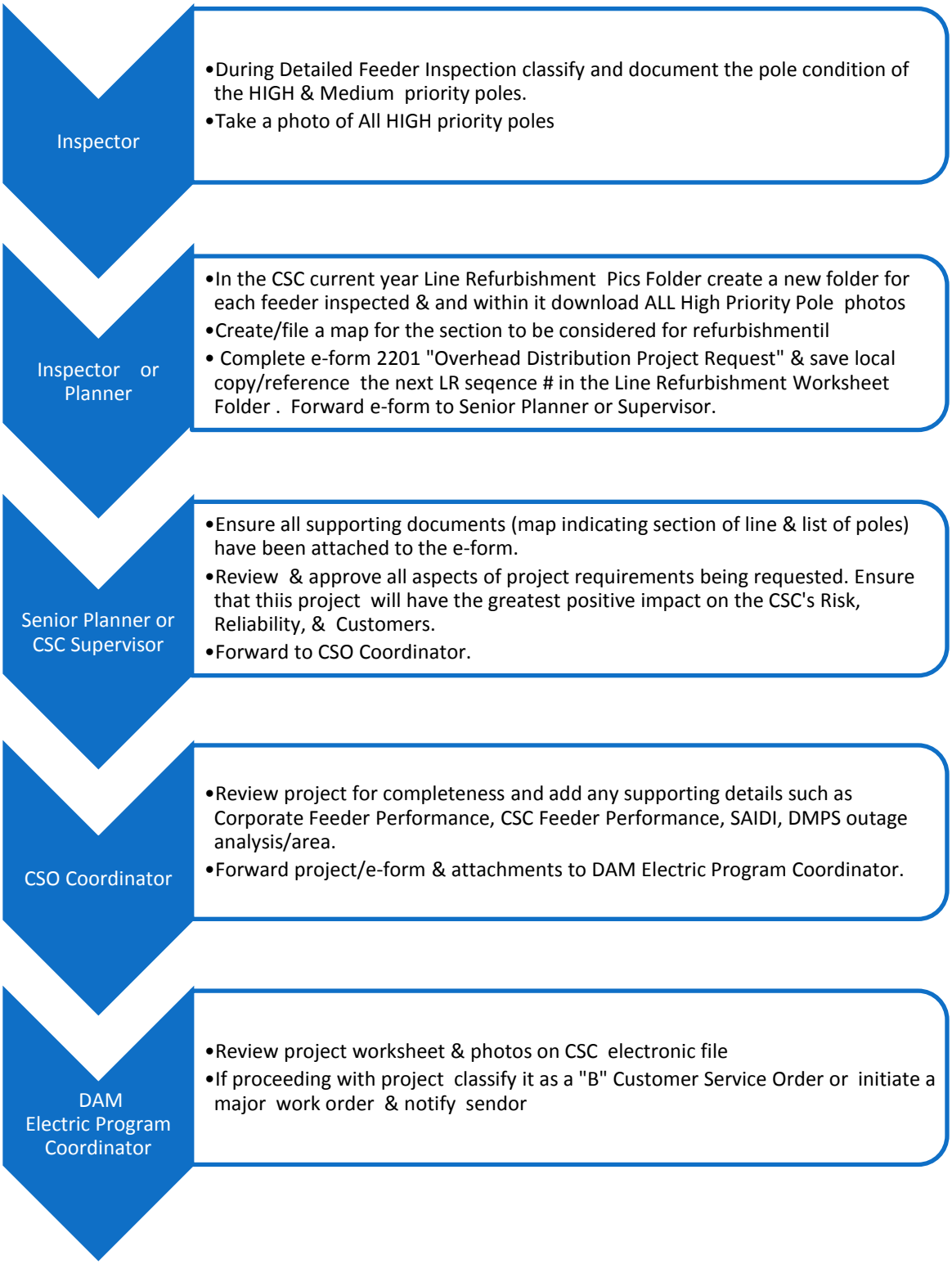


1.2. *Reliability /Reactive Based Projects*

- ***Unplanned assessment driven by customer reliability issues which identifies sections of distribution with "high priority pole condition"***
- ***Distribution identified as having met "end of life" will be considered for line refurbishment***

2. Planning The Project

2.1. Line Refurbishment Flowchart



2.2. *Determining Which Section of Line to Submit, Considering;*

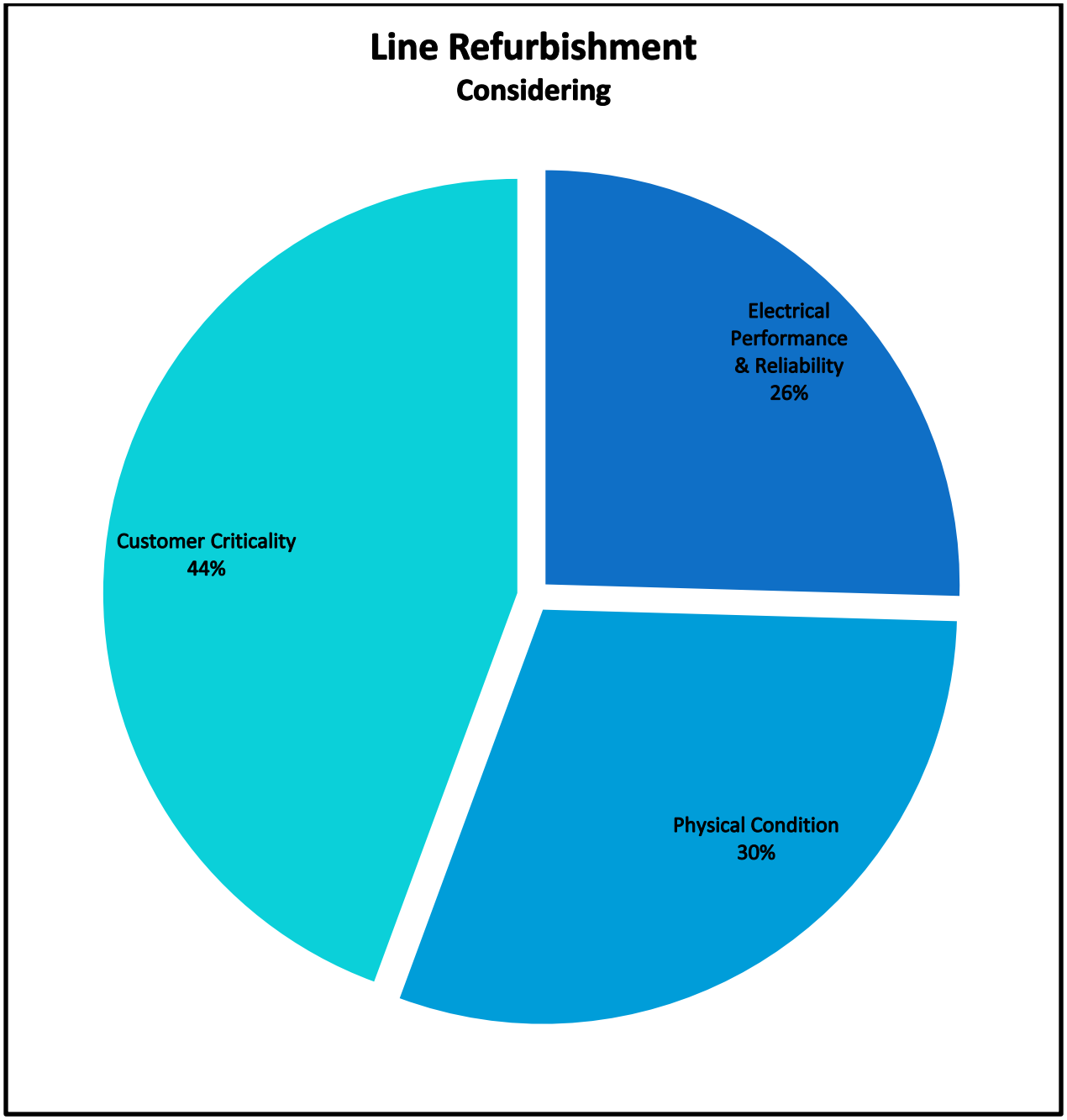
2.2.1. Asset Condition – As determined during "Detailed Feeder Inspection"

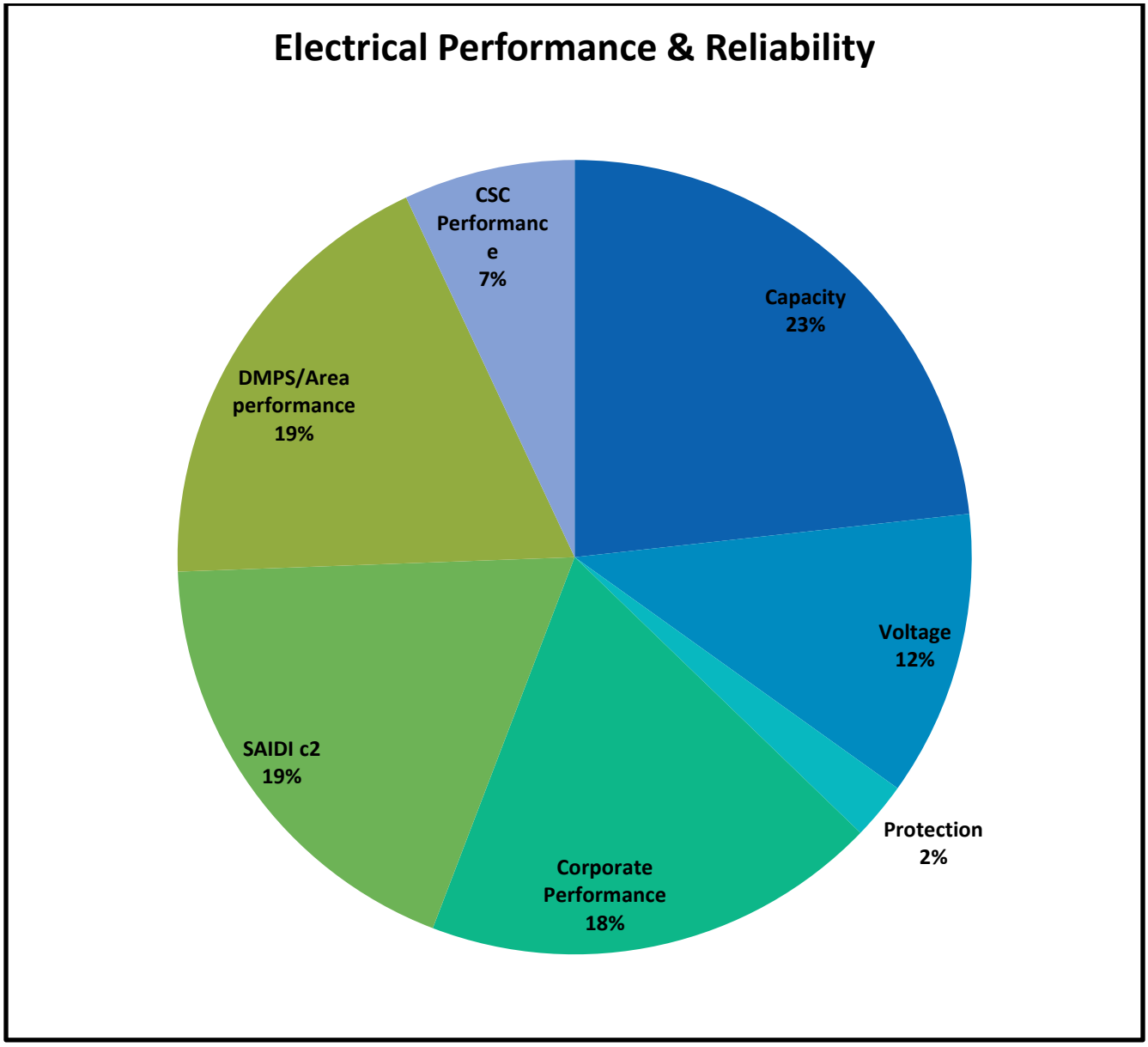
2.2.2. Customer Criticality

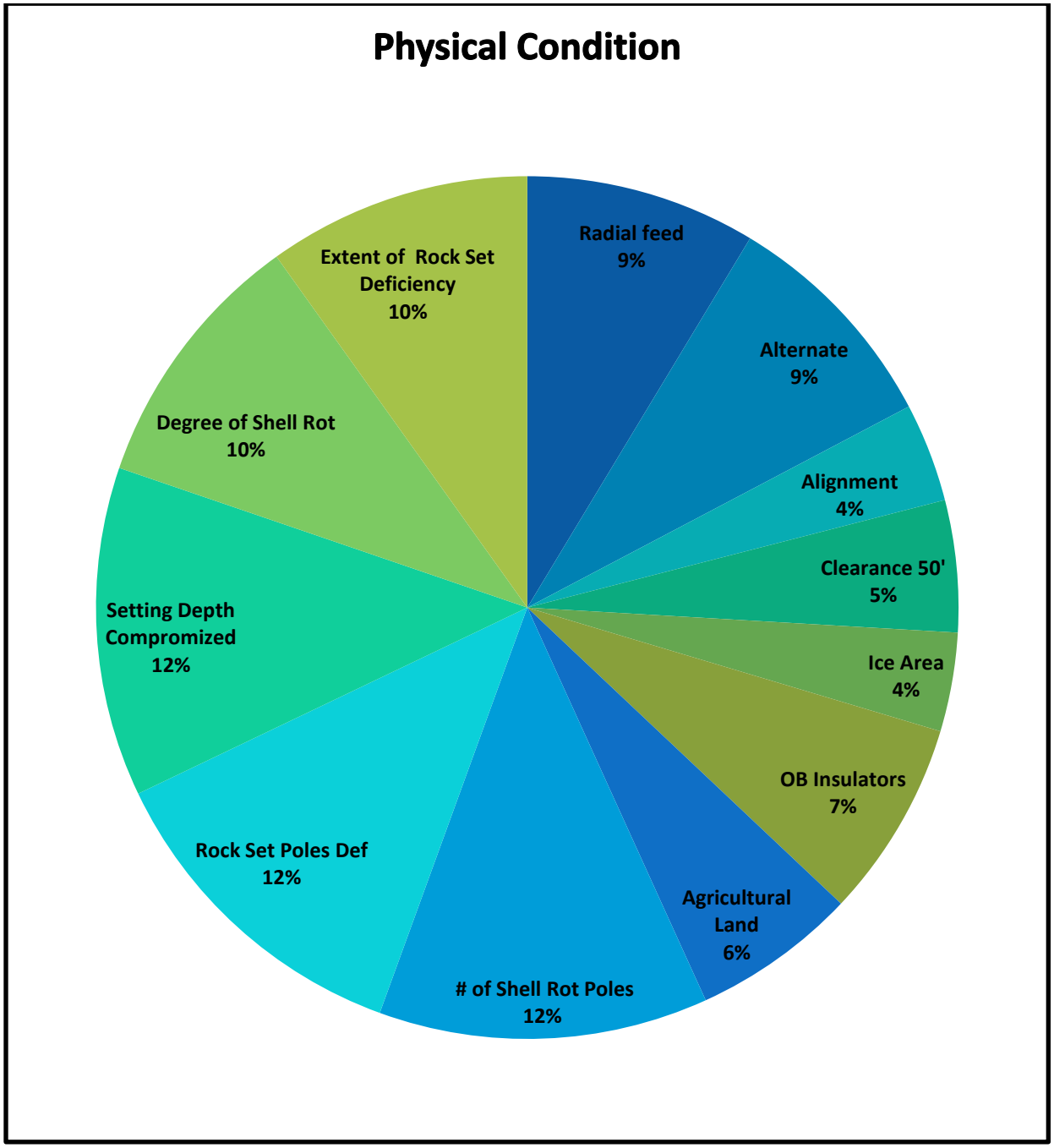
- *Banner is the resource to identify the following;*
  - *Critical Services*
  - *Major/Key Accounts*
  - *Major Residential & Small to Medium Businesses*
  - *Remaining Customers*

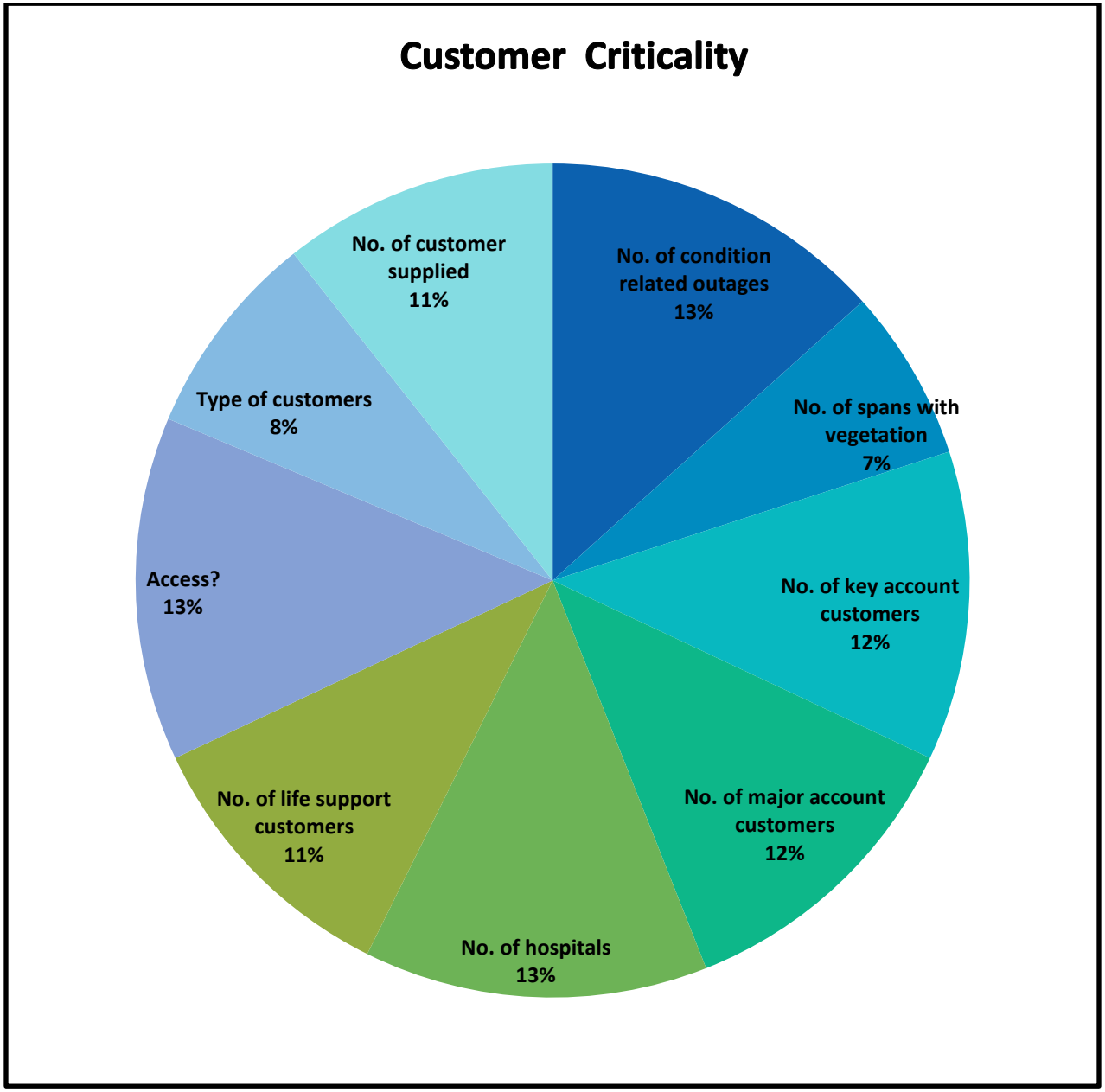
2.2.3. Electrical Performance ……

- *Distribution Maintenance Planning System (DMPS)*
- *Distribution Performance*
  - *Quarterly Reporting Corporately on Feeder Performance & System Average Interruption Duration Index (SAIDI c2)*
  - *Feeder Performance within the CSC (DOPRS)*

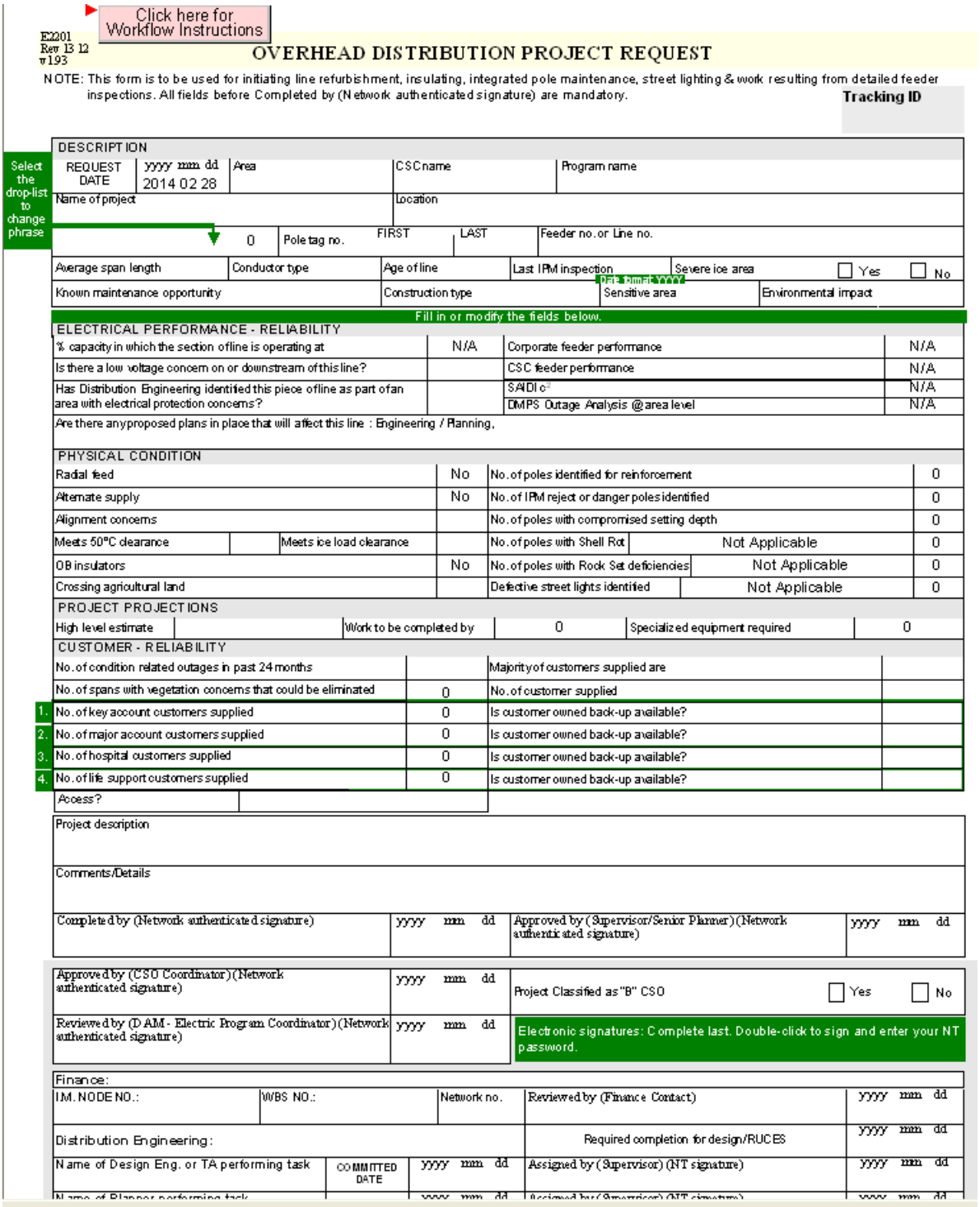

Line Refurbishment
Considering
Electrical Performance & Reliability 26%
Physical Condition 30%
Customer Criticality 44%


Electrical Performance & Reliability
CSC Performanc e 7%
Capacity 23%
DMPS/Area performance 19%
Voltage 12%
SAIDI c2 19%
Protection 2%
Corporate Performance 18%


Physical Condition
Radial feed 9%
Alternate 9%
Alignment 4%
Clearance 50' 5%
Ice Area 4%
OB Insulators 7%
Agricultural Land 6%
# of Shell Rot Poles 12%
Rock Set Poles Def 12%
Setting Depth Compromized 12%
Degree of Shell Rot 10%
Extent of Rock Set Deficiency 10%


Customer Criticality
No. of customer supplied 11%
No. of condition related outages 13%
No. of spans with vegetation 7%
No. of key account customers 12%
No. of major account customers 12%
No. of hospitals 13%
No. of life support customers 11%
Access? 13%
Type of customers 8%

2.3. e-form2201



Click here for Workflow Instructions

E2201
Rev 13 12
v193

OVERHEAD DISTRIBUTION PROJECT REQUEST

NOTE: This form is to be used for initiating line refurbishment, insulating, integrated pole maintenance, street lighting & work resulting from detailed feeder inspections. All fields before Completed by (Network authenticated signature) are mandatory.

Tracking ID

Select the drop-list to change phrase

DESCRIPTION

REQUEST DATE	yyyy mm dd 2014 02 28	Area	CSC name	Program name
Name of project			Location	
0	Pole tag no.	FIRST	LAST	Feeder no. or Line no.
Average span length	Conductor type	Age of line	Last IPM inspection	Severe ice area ☐ Yes ☐ No
Known maintenance opportunity		Construction type	Sensitive area	Environmental impact

Fill in or modify the fields below.

ELECTRICAL PERFORMANCE - RELIABILITY

% capacity in which the section of line is operating at	N/A	Corporate feeder performance	N/A
Is there a low voltage concern on or downstream of this line?		CSC feeder performance	N/A
Has Distribution Engineering identified this piece of line as part of an area with electrical protection concerns?		SAIDI c^2	N/A
		DMPS Outage Analysis @ area level	N/A

Are there any proposed plans in place that will affect this line : Engineering / Planning,

PHYSICAL CONDITION

Radial feed		No	No. of poles identified for reinforcement		0
Alternate supply		No	No. of IPM reject or danger poles identified		0
Alignment concerns			No. of poles with compromised setting depth		0
Meets 50°C clearance		Meets ice load clearance	No. of poles with Shell Rot	Not Applicable	0
OB insulators		No	No. of poles with Rock Set deficiencies	Not Applicable	0
Crossing agricultural land			Defective street lights identified	Not Applicable	0

PROJECT PROJECTIONS

High level estimate		Work to be completed by	0	Specialized equipment required	0

CUSTOMER - RELIABILITY

No. of condition related outages in past 24 months		Majority of customers supplied are	
No. of spans with vegetation concerns that could be eliminated	0	No. of customer supplied	
1. No. of key account customers supplied	0	Is customer owned back-up available?	
2. No. of major account customers supplied	0	Is customer owned back-up available?	
3. No. of hospital customers supplied	0	Is customer owned back-up available?	
4. No. of life support customers supplied	0	Is customer owned back-up available?	
Access?			

Project description			
Comments/Details			
Completed by (Network authenticated signature)	yyyy mm dd	Approved by (Supervisor/Senior Planner) (Network authenticated signature)	yyyy mm dd

Approved by (CSO Coordinator) (Network authenticated signature)	yyyy mm dd	Project Classified as "B" CSO	☐ Yes ☐ No
Reviewed by (D AM - Electric Program Coordinator) (Network authenticated signature)	yyyy mm dd	Electronic signatures: Complete last. Double-click to sign and enter your NT password.	

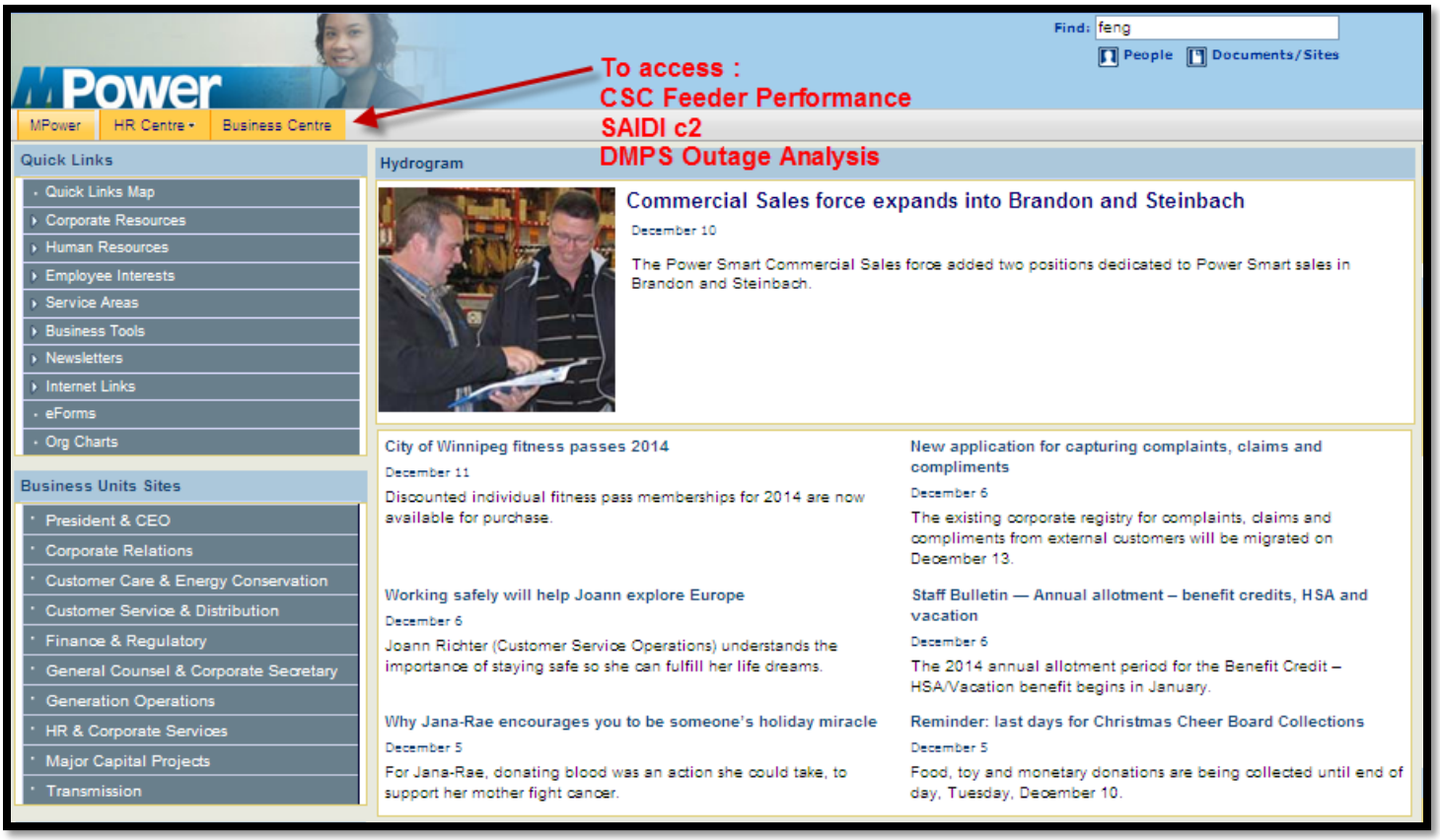
Finance:

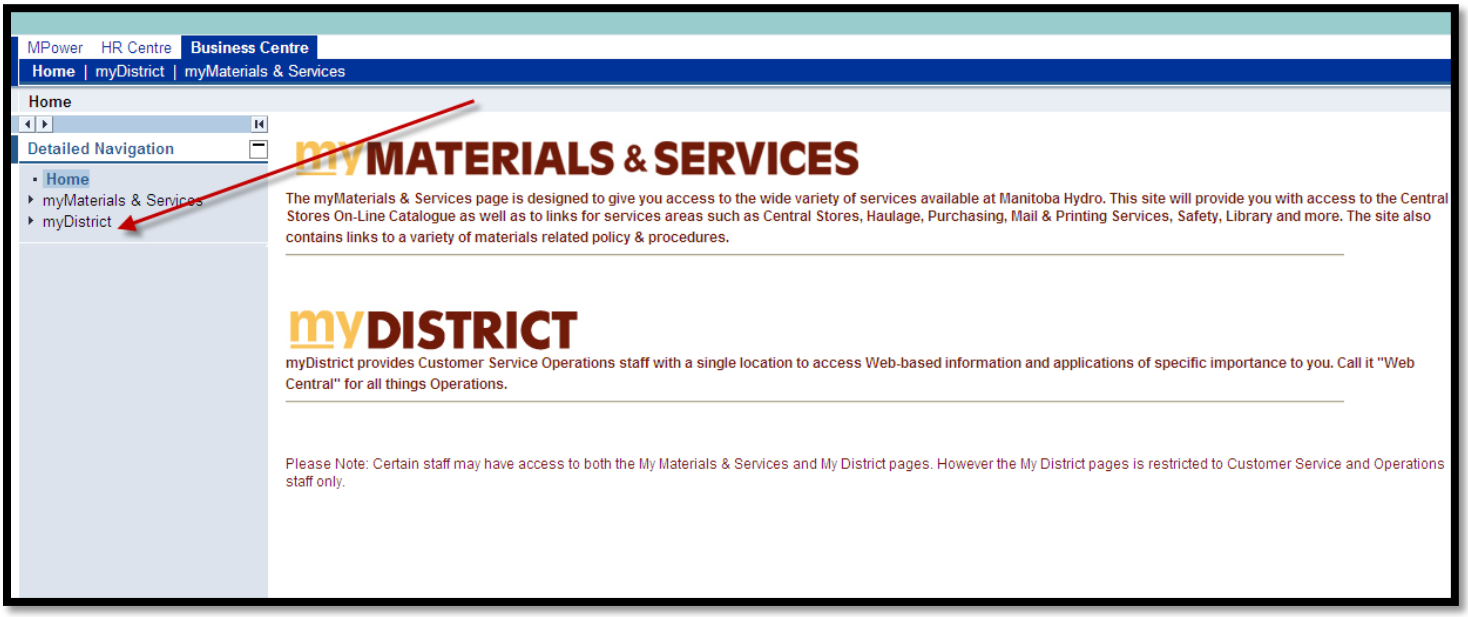
I.M. NODE NO.:	WBS NO.:	Network no.	Reviewed by (Finance Contact)	yyyy mm dd
Distribution Engineering:			Required completion for design/RUCES	yyyy mm dd
Name of Design Eng. or TA performing task	COMMITTED DATE yyyy mm dd		Assigned by (Supervisor) (NT signature)	yyyy mm dd
Name of Planner performing task	yyyy mm dd		Assigned by (Supervisor) (NT signature)	yyyy mm dd

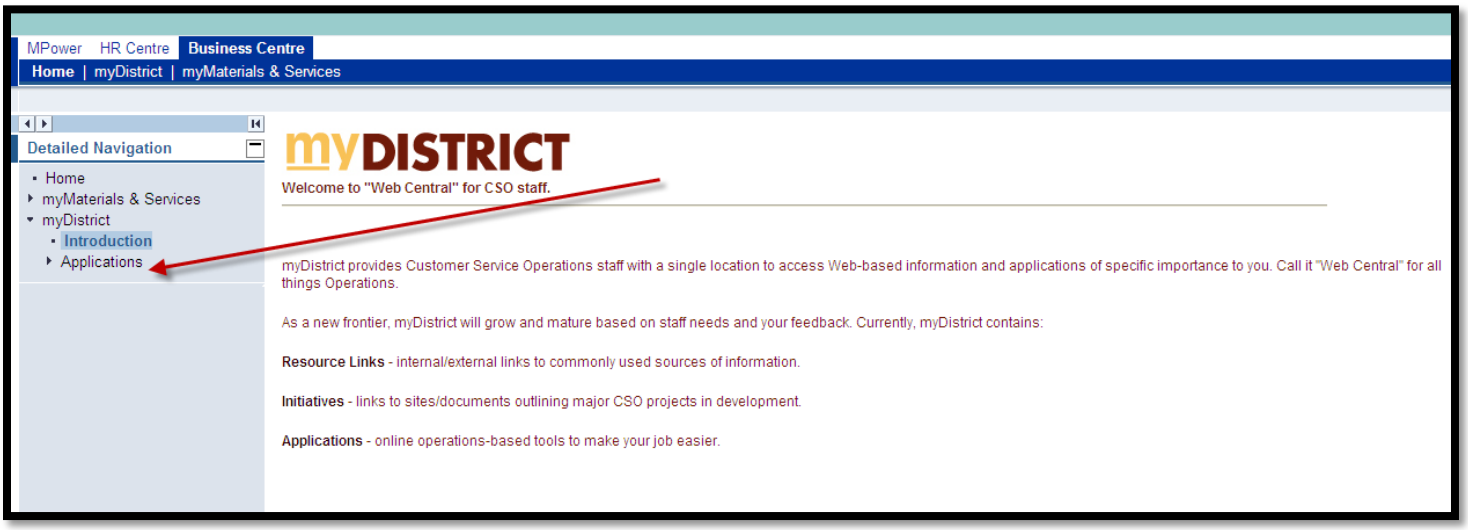
2.4. Accessing Distribution Outage Performance Reporting Systems

(DOPRS)

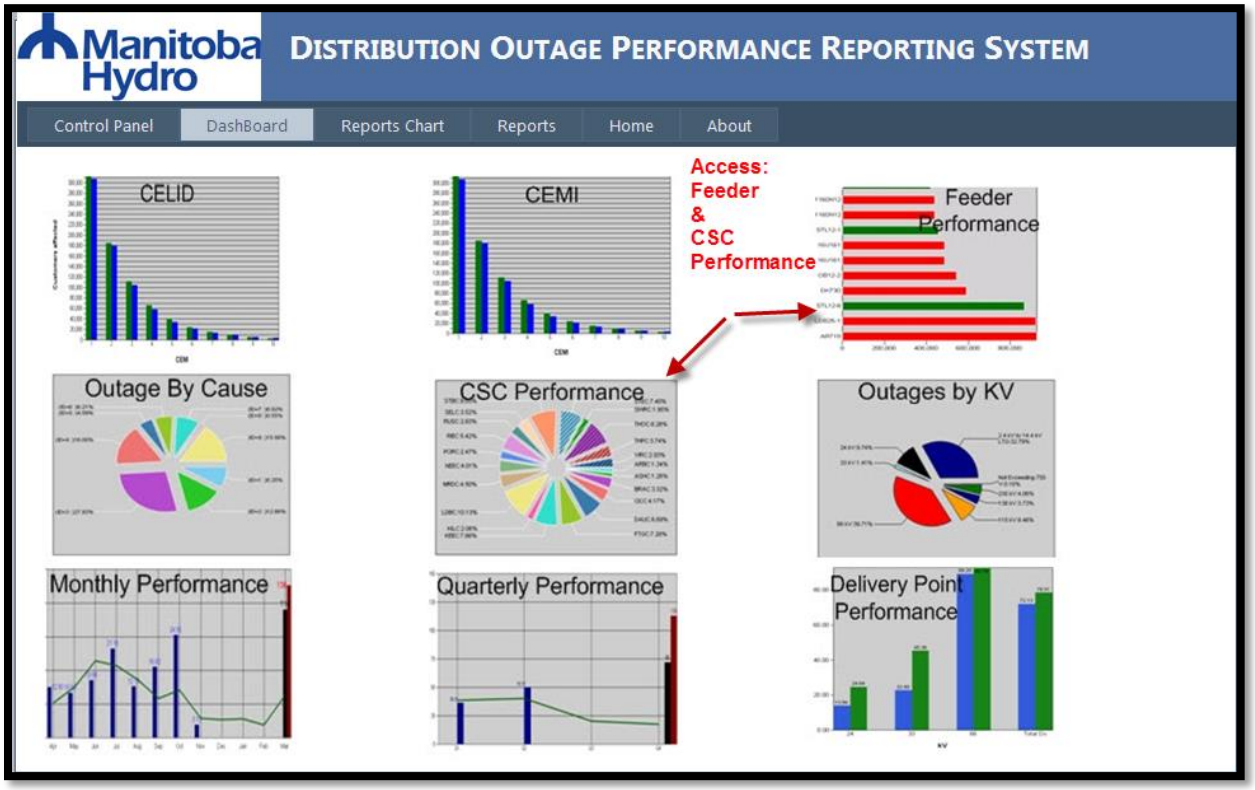
See also link to training video




MPower
HR Centre
Business Centre
Home | myDistrict | myMaterials & Services
Home
Detailed Navigation
Home
myMaterials & Services
myDistrict
myMATERIALS & SERVICES
The myMaterials & Services page is designed to give you access to the wide variety of services available at Manitoba Hydro. This site will provide you with access to the Central Stores On-Line Catalogue as well as to links for services areas such as Central Stores, Haulage, Purchasing, Mail & Printing Services, Safety, Library and more. The site also contains links to a variety of materials related policy & procedures.
myDISTRICT
myDistrict provides Customer Service Operations staff with a single location to access Web-based information and applications of specific importance to you. Call it "Web Central" for all things Operations.
Please Note: Certain staff may have access to both the My Materials & Services and My District pages. However the My District pages is restricted to Customer Service and Operations staff only.


MPower
HR Centre
Business Centre
Home | myDistrict | myMaterials & Services
Detailed Navigation
Home
myMaterials & Services
myDistrict
Introduction
Applications
myDISTRICT
Welcome to "Web Central" for CSO staff.
myDistrict provides Customer Service Operations staff with a single location to access Web-based information and applications of specific importance to you. Call it "Web Central" for all things Operations.
As a new frontier, myDistrict will grow and mature based on staff needs and your feedback. Currently, myDistrict contains:
Resource Links - internal/external links to commonly used sources of information.
Initiatives - links to sites/documents outlining major CSO projects in development.
Applications - online operations-based tools to make your job easier.


MPower
HR Centre
Business Centre
Home | myDistrict | myMaterials & Services
Detailed Navigation
Home
myMaterials & Services
myDistrict
Introduction
Applications
Overview
TCRS
CSI
SIR
SIAR
DOPRS
DMPS Reporting
myDISTRICT
Applications
On-line operations-based tools to make your job a lot easier.
Trouble Call Response System (TCRS)
Manage customer trouble calls related to electrical power outages.
CSI
Common Sales Interface (CSI)
Pricing for customer requested electrical services.
Service Interruption Entry Program (SIR)
Enter a new Service Interruption Record.
Service Interruption Analysis Reports (SIAR)
Generate Service Interruption Analysis Reports.
Distribution Outage Performance Reporting System (DOPRS)
Generate interactive reports on outages by CSC, Causes, Voltage or System.
DMPS
Distribution Maintenance Planning System (DMPS)
Distribution Maintenance Planning System Reporting.

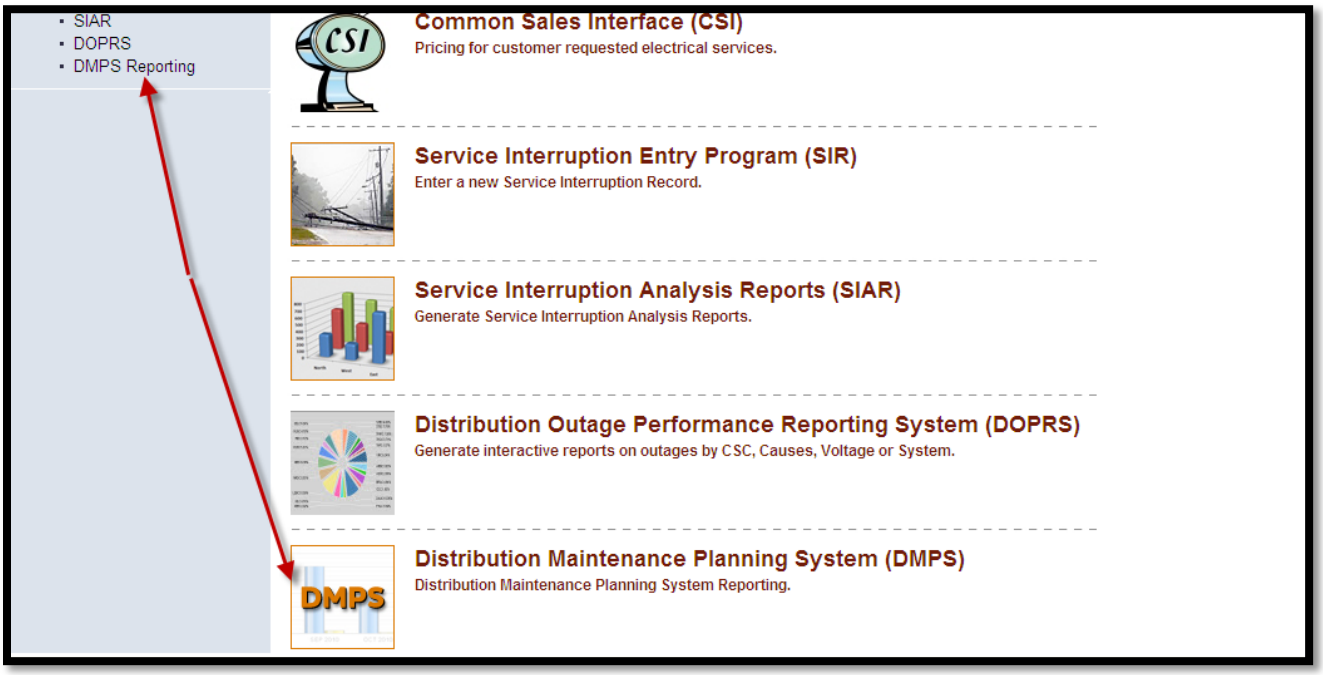


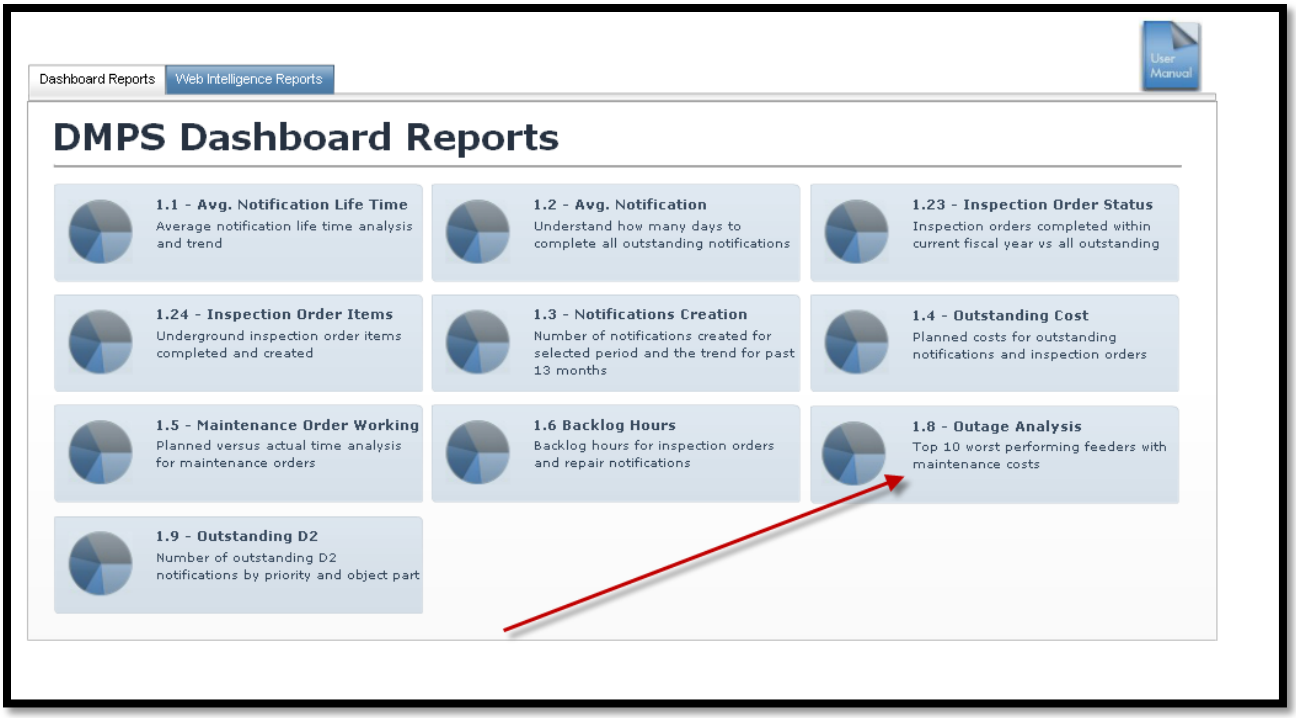
Feeder Performance for: WESTMAN By Customer Minutes from: 2012-01-01 to: 2012-12-31

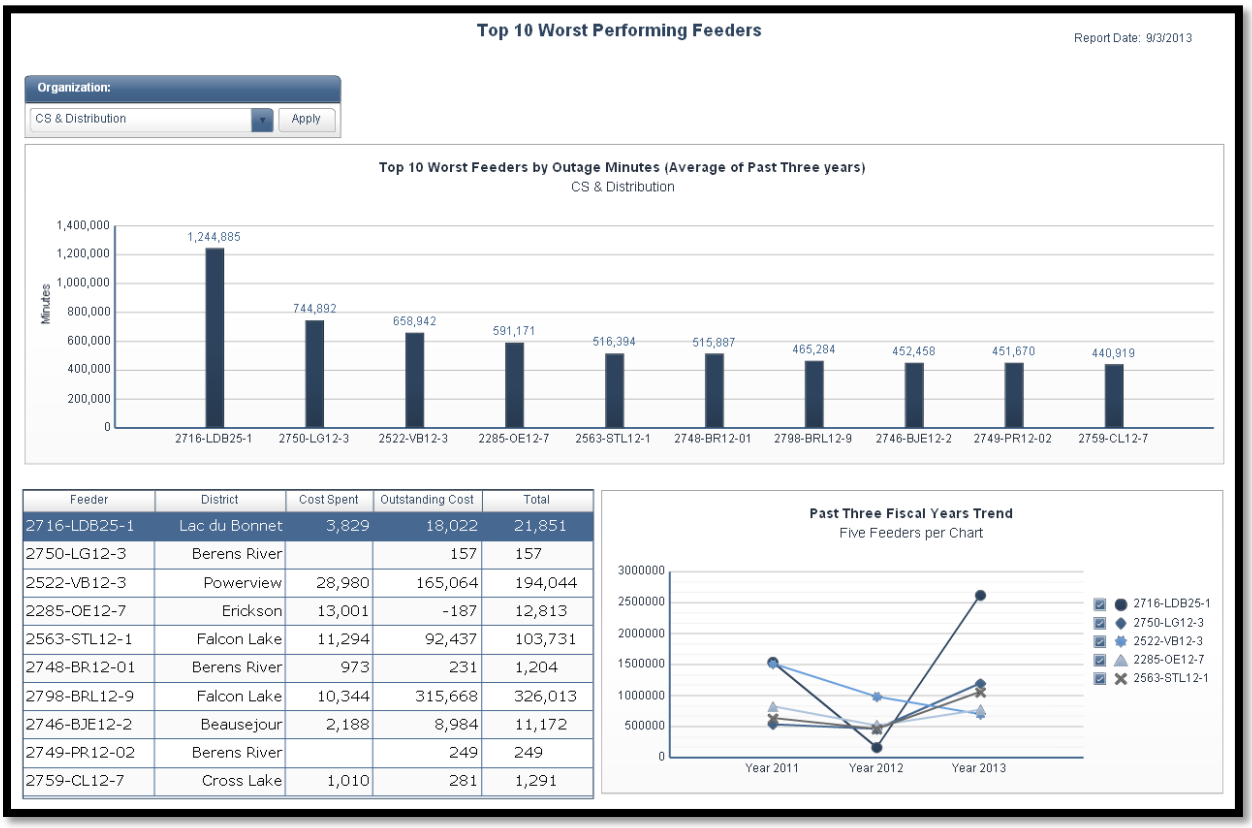
		From: 2012-01-01 to: 2012-12-31				5-Year Average values for supplied range			
District	Feeder	Number of Outages	Customer Interruptions	Customer Minutes	SAID^C2 (min)	Number of Outages	Customer Interruptions	Customer Minutes	SAID^C2 (min)
HAMIOTA	HA25-4	13	391	211,060	0.39	8.0	234.2	64,194	0.12
BRANDON	LN12-4	3	3,109	172,225	0.32	1.0	1,040.2	56,206	0.18
VIRDEN	SV25-3	8	857	142,870	0.26	7.8	420.2	79,138	0.15
BRANDON	CP12-16	1	828	124,200	0.23	0.4	171.6	25,860	0.12
VIRDEN	VW25-5	2	840	122,110	0.22	0.6	173.2	25,384	0.12
PILOT MOUND	CT12-04	6	486	117,381	0.22	8.8	269.2	49,828	0.09
BRANDON	SH04-1	1	331	89,039	0.16	0.2	66.2	17,808	0.16
RESTON	RE12-4	3	214	83,740	0.15	2.8	113.4	22,948	0.04
KILLARNEY	NL12-6	2	187	66,810	0.12	0.4	37.4	13,362	0.12
BRANDON	RS25-2	3	1,445	57,433	0.11	3.8	880.4	64,360	0.12
VIRDEN	CN25-04	4	546	56,543	0.10	0.8	109.2	11,309	0.10
SOURIS	HY25-2	1	190	56,050	0.10	1.8	114.2	23,750	0.07
MELITA	ML12-7	8	410	55,682	0.10	3.4	138.0	20,400	0.05
VIRDEN	OL25-3	4	165	53,460	0.10	2.6	88.2	22,836	0.04
VIRDEN	VS25-2	3	560	52,135	0.10	1.0	150.8	11,249	0.05
BRANDON	HP12-1	2	471	49,740	0.09	1.0	194.2	30,618	0.10
BRANDON	BK12-2	1	102	47,736	0.09	0.2	20.4	9,547	0.09

(based on outage & outstanding maintenance requirements)

2.5. Access to DMPS Worst performing Feeder

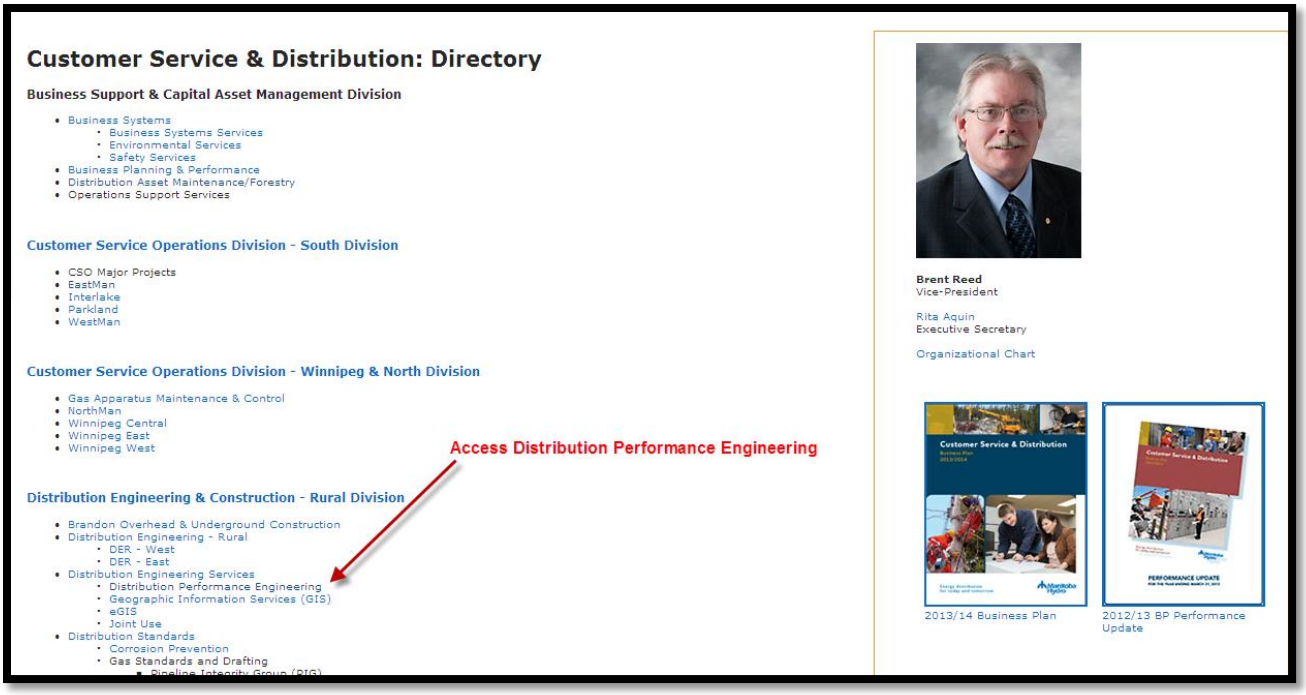


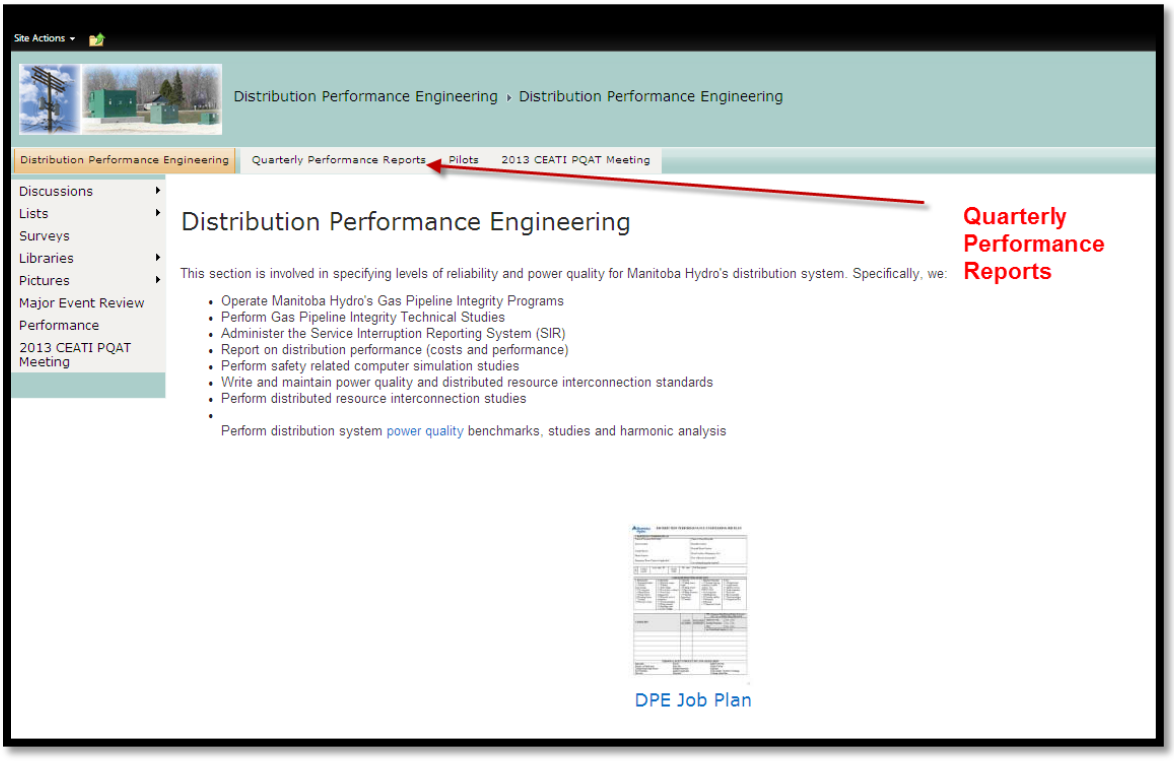




Feeder	District	Cost Spent	Outstanding Cost	Total
2716-LDB25-1	Lac du Bonnet	3,829	18,022	21,851
2750-LG12-3	Berens River		157	157
2522-VB12-3	Powerview	28,980	165,064	194,044
2285-OE12-7	Erickson	13,001	-187	12,813
2563-STL12-1	Falcon Lake	11,294	92,437	103,731
2748-BR12-01	Berens River	973	231	1,204
2798-BRL12-9	Falcon Lake	10,344	315,668	326,013
2746-BJE12-2	Beausejour	2,188	8,984	11,172
2749-PR12-02	Berens River		249	249
2759-CL12-7	Cross Lake	1,010	281	1,291

2.6. Accessing Corporate Feeder Performance





Overhead Line Refurbishment

Feeder Performance

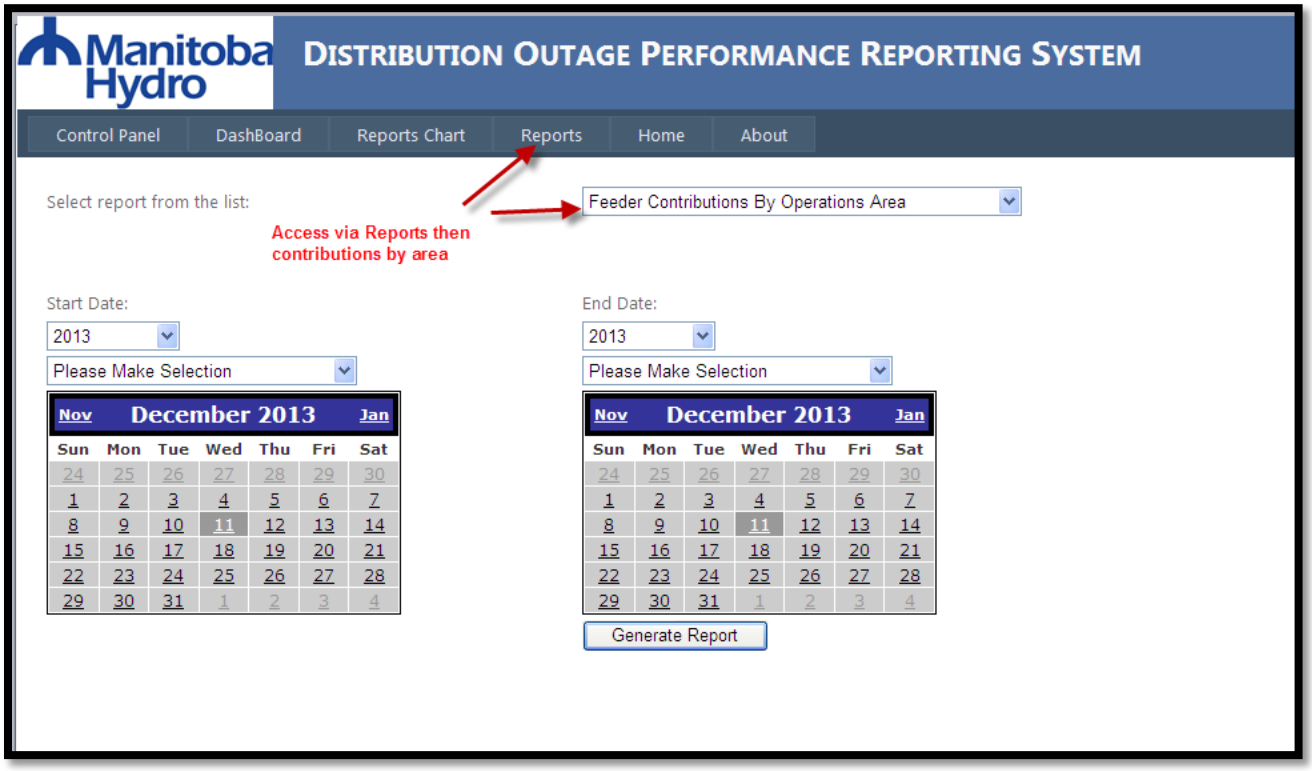
Circuits are present on this list if they meet at least two of the three following criteria:

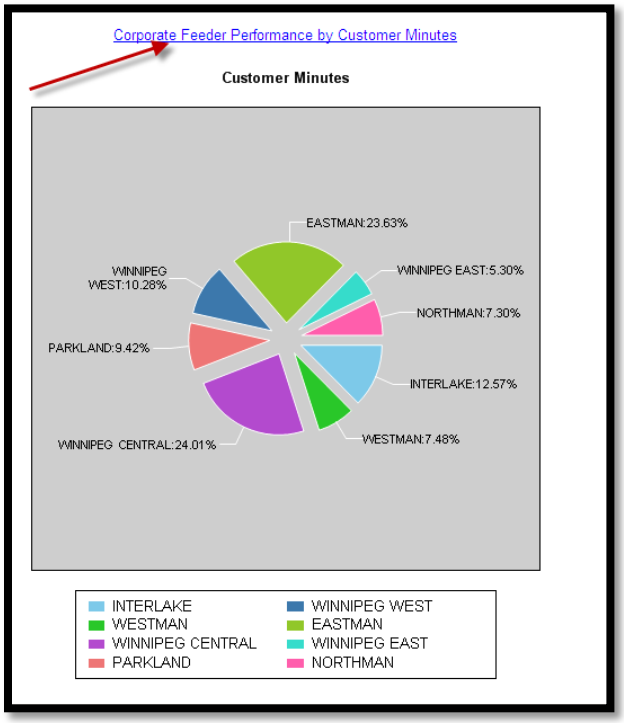
- 2013 Contribution to SAIDI (SAIDI ^C2) greater 0.5 minutes
- Projected 3 year future (2015) SAIDI ^C2 based on standard linear regression formulas greater than 0.5 minutes
- Total SAIDI^C2 in the last five years greater than 1.0 minutes

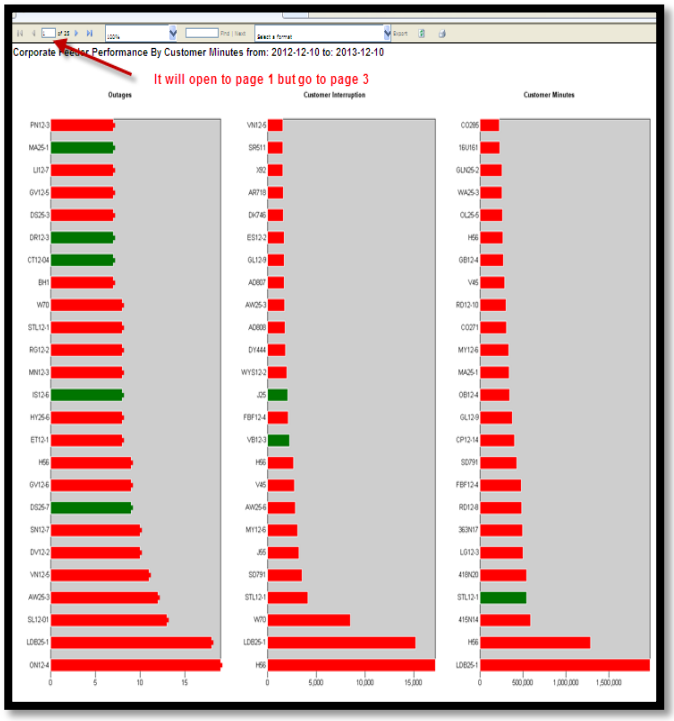
Single transformer outages are not included in this report. For more information on feeder performance go to Distribution Outage Performance Reporting System http://esdapps.hydro.mb.ca/distapps/doprs/Default.aspx

District	Feeder	Number of outages YTD	Customer Interruptions YTD	Customer Minutes YTD	YTD SAIDI^C2	SAIDI^C2 since 2009	5 year SAIDI
Keewatin	L17/18	2	13903	1952386	3.58	13.67	
Fort Garry	H56	9	17,187	1,284,800	2.34	4.58	
Lac du Bonnet	LDB25-1	11	5,396	468,385	0.85	6.64	
Gimli	FBF12-4	4	2,096	477,799	0.87	2.09	
Berens River	LG12-3	1	298	500,640	0.91	1.69	
St Boniface	V45	0	0	0	0	3.12	
River East	SD791	3	1,980	354,715	0.65	1.52	
Falcon Lake	STL12-2	3	520	118,349	0.22	2.55	
St Martin	MA25-1	6	768	281,835	0.51	1.94	
Keewatin	CO271	1	1,452	304,920	0.56	1.40	
City Centre	16U161	2	758	227,976	0.42	1.83	
Selkirk	MY12-6	4	3,082	331,921	0.6	1.12	
Powerview	GL12-9	6	1,681	376,024	0.68	1.18	
St Boniface	P78	2	5,660	280,138	0.51	1.33	
Powerview	GB12-4	2	1,525	267,890	0.49	1.33	
Keewatin	J54	6	879	159,060	0.29	1.18	
St Boniface	GP12-09	2	571	51,632	0.09	1.44	
Steinbach	LBE12-4	5	1,004	188,377	0.34	1.15	
Steinbach	RD12-10	0	0	0	0	1.33	

2.7. To Access SAIDI c2 Report use DOPRS







Overhead Line Refurbishment

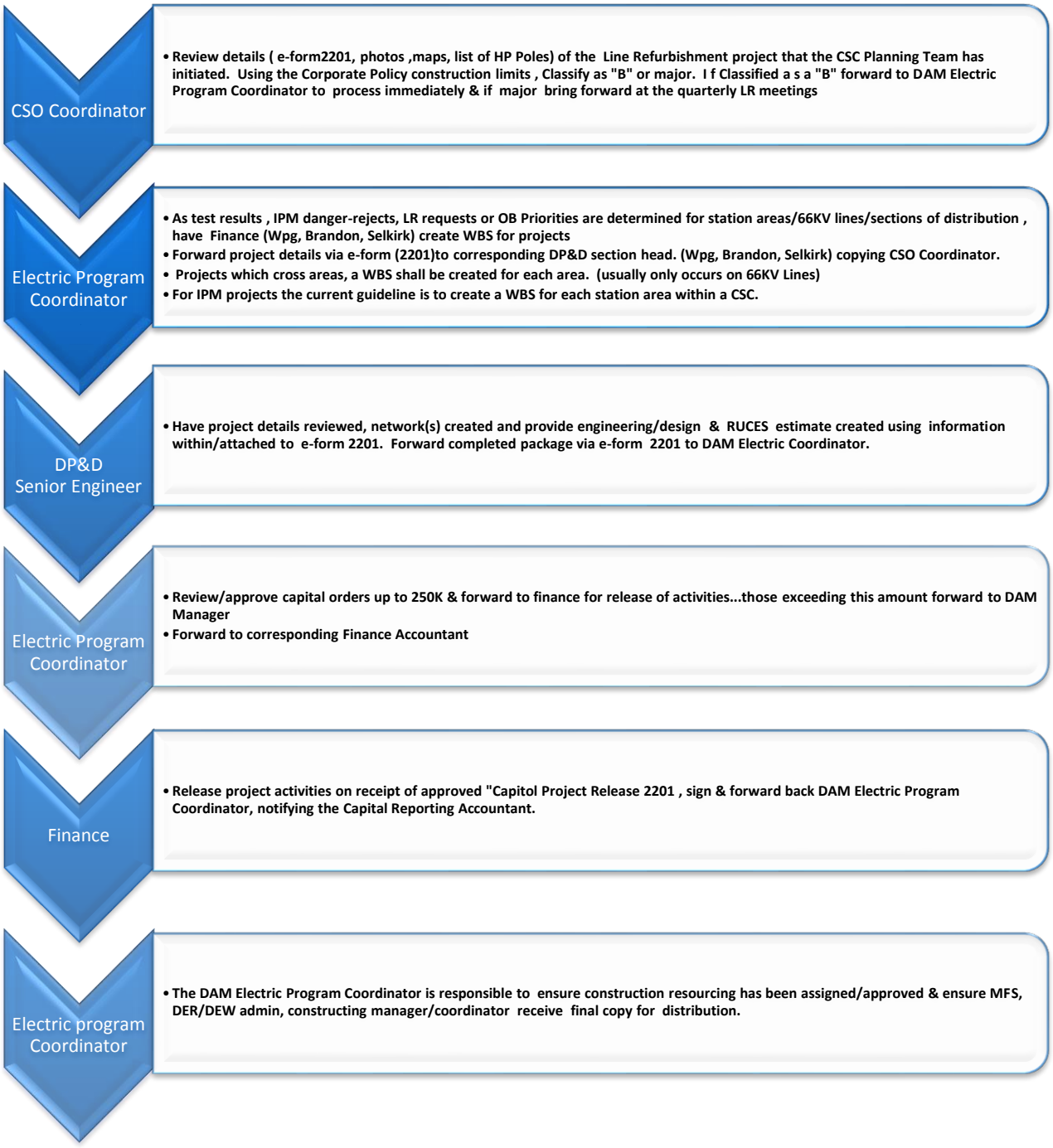
Corporate Feeder Performance By Customer Minutes from: 2012-12-10 to: 2013-12-10

Use this Column to score SAIDI c2 on report

		From: 2012-12-10 to: 2013-12-10				5-Year Average values for supplied range			
District	Feeder	Number of Outages	Customer Interruptions	Customer Minutes	SAID^C2 (min)	Number of Outages	Customer Interruptions	Customer Minutes	SAID^C2 (min)
LAC DU BONNET	LDB25-1	18	15,184	1,975,544	3.60	223.2	128,401.2	15,488,507	0.13
FORT GARRY	H56	9	17,187	1,284,800	2.34	18.0	35,697.6	2,593,539	0.26
CITY CENTRE	415N14	1	1,099	587,965	1.07	0.4	248.6	121,913	0.56
FALCON LAKE	STL12-1	8	4,107	540,616	0.99	57.6	21,908.8	5,560,429	0.18
CITY CENTRE	418N20	1	1,009	539,815	0.98	0.2	201.8	107,963	0.98
BERENS RIVER	LG12-3	1	298	500,640	0.91	0.6	171.8	184,510	0.57
KEEWATIN	383N17	1	1,146	492,780	0.90	0.2	229.2	98,556	0.90
STEINBACH	RD12-8	5	946	485,919	0.89	8.0	1,512.0	608,229	0.14
GIMLI	FBF12-4	4	2,096	477,799	0.87	7.2	2,840.8	612,804	0.16
RIVER EAST	SD791	5	3,511	427,132	0.78	17.0	9,017.0	825,909	0.09
BRANDON	CP12-14	1	1,284	398,040	0.73	0.6	629.0	131,727	0.41
POWERVIEW	GL12-9	6	1,681	376,024	0.69	15.6	3,488.4	822,268	0.10
ST BONIFACE	OB12-4	3	1,255	341,030	0.62	6.6	1,837.8	300,755	0.08
ST MARTIN	MA25-1	7	1,120	338,859	0.62	57.4	8,288.0	1,466,002	0.05
SELKIRK	MY12-6	4	3,082	331,921	0.60	12.0	5,511.2	490,023	0.08
KEEWATIN	CO271	1	1,452	304,920	0.56	0.8	754.0	151,614	0.35
STEINBACH	RD12-10	2	1,428	301,037	0.55	5.2	2,074.0	287,055	0.10
ST BONIFACE	V45	2	2,734	283,929	0.52	7.2	3,301.6	303,369	0.08
POWERVIEW	GB12-4	2	1,525	267,890	0.49	4.0	2,334.4	286,730	0.13
KEEWATIN	H56	1	2,653	265,572	0.48	0.2	530.6	53,114	0.48
VIRDEN	OL25-5	1	431	258,600	0.47	1.8	354.0	72,486	0.07
ISLAND LAKE	WA25-3	1	259	256,410	0.47	0.8	106.2	87,600	0.20
GODS LAKE NARROWS	GLN25-2	1	222	253,080	0.46	1.2	206.8	81,352	0.13
CITY CENTRE	16U161	2	758	227,976	0.42	4.4	2,559.6	320,920	0.14
KEEWATIN	CO285	3	1,413	223,245	0.41	10.2	4,774.2	596,582	0.11
FALCON LAKE	STL12-6	5	1,076	222,132	0.40	53.0	7,066.0	4,390,578	0.15
RIVER EAST	DY444	1	1,836	220,320	0.40	0.6	735.8	108,545	0.34
ARBORG	RN25-3	3	1,136	218,250	0.40	3.6	1,135.2	214,953	0.11
SELKIRK	PE12-4	2	1,058	217,440	0.40	4.8	2,058.4	241,816	0.09
ERICKSON	OE12-7	3	1,126	212,080	0.39	35.4	6,928.2	1,280,764	0.07
RIVER EAST	AD807	3	1,683	208,020	0.38	2.4	1,063.8	137,448	0.10
PORTAGE	PLR25-1	4	1,151	198,585	0.36	21.6	2,570.4	317,724	0.03

3. Processing the Order

3.1. Capital Order Flow

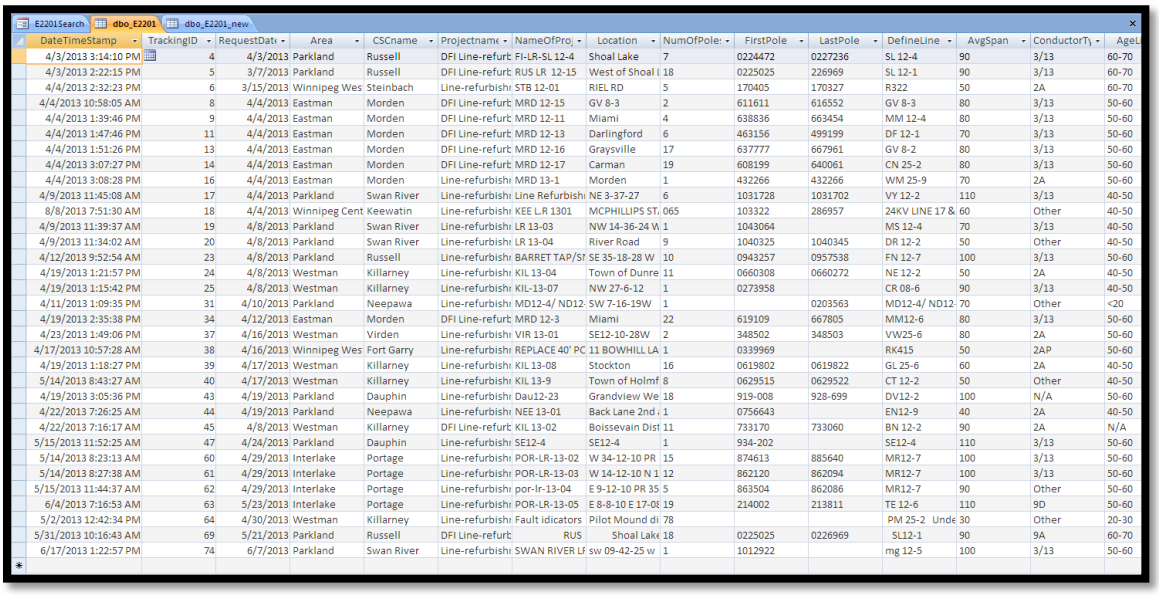


3.2. *Prioritize the Line Refurbishment Projects*

- ***The Distribution Asset Maintenance, Electric Program Coordinator will meet with the Customer Service Operations Coordinators to review projects for their areas on a quarterly basis to select the projects that shall be submitted to Distribution Engineering for design & RUCES estimates.***
- ***These projects will be selected using the weighted e-form giving consideration to all projects throughout the province to distribute the workload for all resources.***

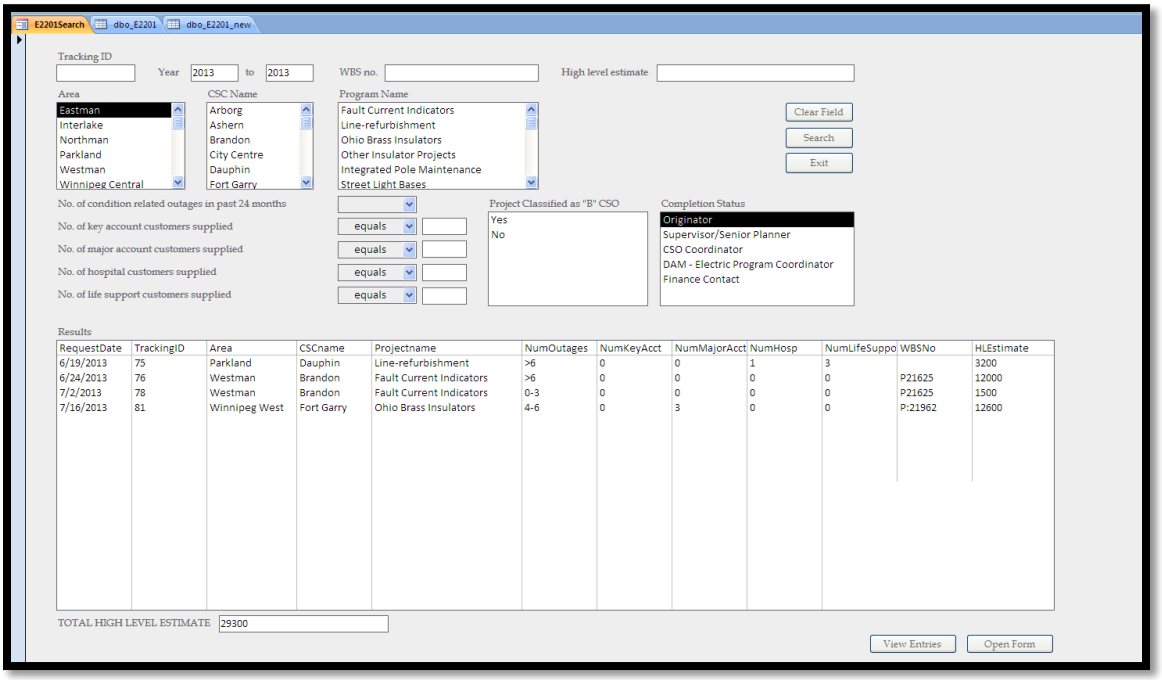
3.3. *Overhead Distribution Project Database*

There is an Access database built behind the e-form 2201 for tracking & reporting purposes.



E2201Search | dbo_E2201 | dbo_E2201_new

DateTimeStamp	TrackingID	RequestDat	Area	CSCname	Projectname	NameOfPro	Location	NumOfPole:	FirstPole	LastPole	DefineLine	AvgSpan	ConductorTy	AgeL
4/3/2013 3:14:10 PM	4	4/3/2013	Parkland	Russell	DFI Line-refurb	FI-LR-SL 12-4	Shoal Lake	7	0224472	0227236	SL 12-4	90	3/13	60-70
4/3/2013 2:22:15 PM	5	3/7/2013	Parkland	Russell	DFI Line-refurb	RUS LR 12-15	West of Shoal I	18	0225025	226969	SL 12-1	90	3/13	60-70
4/4/2013 2:32:23 PM	6	3/15/2013	Winnipeg Wes	Steinbach	Line-refurbishi	STB 12-01	RIEL RD	5	170405	170327	R322	50	2A	60-70
4/4/2013 10:58:05 AM	8	4/4/2013	Eastman	Morden	DFI Line-refurb	MRD 12-15	GV 8-3	2	611611	616552	GV 8-3	80	3/13	50-60
4/4/2013 1:39:46 PM	9	4/4/2013	Eastman	Morden	DFI Line-refurb	MRD 12-11	Miami	4	638836	663454	MM 12-4	80	3/13	50-60
4/4/2013 1:47:46 PM	11	4/4/2013	Eastman	Morden	DFI Line-refurb	MRD 12-13	Darlingford	6	463156	499199	DF 12-1	70	3/13	50-60
4/4/2013 1:51:26 PM	13	4/4/2013	Eastman	Morden	DFI Line-refurb	MRD 12-16	Graysville	17	637777	667961	GV 8-2	80	3/13	50-60
4/4/2013 3:07:27 PM	14	4/4/2013	Eastman	Morden	DFI Line-refurb	MRD 12-17	Carman	19	608199	640061	CN 25-2	80	3/13	50-60
4/4/2013 3:08:28 PM	16	4/4/2013	Eastman	Morden	Line-refurbishi	MRD 13-1	Morden	1	432266	432266	WM 25-9	70	2A	50-60
4/9/2013 11:45:08 AM	17	4/4/2013	Parkland	Swan River	Line-refurbishi	Line Refurbishi	NE 3-37-27	6	1031728	1031702	VY 12-2	110	3/13	40-50
8/8/2013 7:51:30 AM	18	4/4/2013	Winnipeg Cent	Keewatin	Line-refurbishi	KEE L.R 1301	MCPHILLIPS ST	065	103322	286957	24KV LINE 17 &	60	Other	40-50
4/9/2013 11:39:37 AM	19	4/8/2013	Parkland	Swan River	Line-refurbishi	LR 13-03	NW 14-36-24 W	1	1043064		MS 12-4	70	3/13	40-50
4/9/2013 11:34:02 AM	20	4/8/2013	Parkland	Swan River	Line-refurbishi	LR 13-04	River Road	9	1040325	1040345	DR 12-2	50	Other	40-50
4/12/2013 9:52:54 AM	23	4/8/2013	Parkland	Russell	Line-refurbishi	BARRET TAP/ST	SE 35-18-28 W	10	0943257	0957538	FN 12-7	100	3/13	50-60
4/19/2013 1:21:57 PM	24	4/8/2013	Westman	Killarney	Line-refurbishi	KIL 13-04	Town of Dunre	11	0660308	0660272	NE 12-2	50	2A	40-50
4/19/2013 1:15:42 PM	25	4/8/2013	Westman	Killarney	Line-refurbishi	KIL-13-07	NW 27-6-12	1	0273958		CR 08-6	90	3/13	40-50
4/11/2013 1:09:35 PM	31	4/10/2013	Parkland	Neepawa	Line-refurbishi	MD12-4/ ND12	SW 7-16-19W	1		0203563	MD12-4/ ND12	70	Other	<20
4/19/2013 2:35:38 PM	34	4/12/2013	Eastman	Morden	DFI Line-refurb	MRD 12-3	Miami	22	619109	667805	MM12-6	80	3/13	50-60
4/23/2013 1:49:06 PM	37	4/16/2013	Westman	Virden	Line-refurbishi	VIR 13-01	SE12-10-28W	2	348502	348503	VW25-6	80	2A	50-60
4/17/2013 10:57:28 AM	38	4/16/2013	Winnipeg Wes	Fort Garry	Line-refurbishi	REPLACE 40' PC	11 BOWHILL LA	1	0339969		RK415	50	2AP	50-60
4/19/2013 1:18:27 PM	39	4/17/2013	Westman	Killarney	Line-refurbishi	KIL 13-08	Stockton	16	0619802	0619822	GL 25-6	60	2A	40-50
5/14/2013 8:43:27 AM	40	4/17/2013	Westman	Killarney	Line-refurbishi	KIL 13-9	Town of Holmf	8	0629515	0629522	CT 12-2	50	Other	40-50
4/19/2013 3:05:36 PM	43	4/19/2013	Parkland	Dauphin	Line-refurbishi	Dau12-23	Grandview We	18	919-008	928-699	DV12-2	100	N/A	50-60
4/22/2013 7:26:25 AM	44	4/19/2013	Parkland	Neepawa	Line-refurbishi	NEE 13-01	Back Lane 2nd	1	0756643		EN12-9	40	2A	40-50
4/22/2013 7:16:17 AM	45	4/8/2013	Westman	Killarney	DFI Line-refurb	KIL 13-02	Boissevain Dist	11	733170	733060	BN 12-2	90	2A	N/A
5/15/2013 11:52:25 AM	47	4/24/2013	Parkland	Dauphin	Line-refurbishi	SE12-4	SE12-4	1	934-202		SE12-4	110	3/13	50-60
5/14/2013 8:23:13 AM	60	4/29/2013	Interlake	Portage	Line-refurbishi	POR-LR-13-02	W 34-12-10 PR	15	874613	885640	MR12-7	100	3/13	50-60
5/14/2013 8:27:38 AM	61	4/29/2013	Interlake	Portage	Line-refurbishi	POR-LR-13-03	W 14-12-10 N 1	12	862120	862094	MR12-7	100	3/13	50-60
5/15/2013 11:44:37 AM	62	4/29/2013	Interlake	Portage	Line-refurbishi	por-lr-13-04	E 9-12-10 PR 35	5	863504	862086	MR12-7	90	Other	50-60
6/4/2013 7:16:53 AM	63	5/23/2013	Interlake	Portage	Line-refurbishi	POR-LR-13-05	E 8-8-10 E 17-0	19	214002	213811	TE 12-6	110	9D	50-60
5/2/2013 12:42:34 PM	64	4/30/2013	Westman	Killarney	Line-refurbishi	Fault idicators	Pilot Mound di	78			PM 25-2 Unde	30	Other	20-30
5/31/2013 10:16:43 AM	69	5/21/2013	Parkland	Russell	DFI Line-refurb	RUS	Shoal Lake	18	0225025	0226969	SL12-1	90	9A	60-70
6/17/2013 1:22:57 PM	74	6/7/2013	Parkland	Swan River	Line-refurbishi	SWAN RIVER LF	sw 09-42-25 w	1	1012922		mg 12-5	100	3/13	50-60



- ***Currently (September 2013) an excel "Capital Program Tracking Report" is also maintained by DAM/Electric Program Coordinator.***

3.4. *Corporate Finance Role*

- ***In addition to working closely with the CS&D Business Unit allocating funds and reporting on the many programs, the corresponding finance representative plays a key role toward each individual project by;***
  - ***Creating & Closing the Work Breakout Structure (WBS#) which enables reporting functions via System Applications Program (SAP).***

3.5. *Distribution Engineering Role & Requirements*

3.5.1. All major customer service orders for Line Refurbishment are submitted to Distribution Engineering to ensure that the refurbished section of line will meet current design, standards, and loading requirements. The goal is to provide engineering with projects one year in advance to allow for work scheduling.

- ***The project (e-form 2201) & supporting documents are forwarded to corresponding Distribution Engineering Section Head for an Engineered Design & RUCES Estimate. This information is also tracked in the access database & Capital Program Tracking Report***
- ***Distribution Engineering creates the "network" within SAP and appropriate work "activities", while corporate finance releases the "activities' as requests/approvals are submitted.***

3.5.2. Completed Distribution Design & RUCES Estimates

- ***The completed design drawings, RUCES estimate and approvals are forwarded to the DAM- Electric Program Coordinator via the "Customer Service Operations Order Release" e-form 1914a***

4. Request for Construction

- ***Manitoba Hydro completes distribution construction using resources from Distribution Construction Department. Customer Service Operations Department or in some instances Contracted Services. The CSO coordinator had indicated on the original request who would be completing the work for each order. The DAM –Electric Program Coordinator ensures the work is forwarded and approved by the corresponding Department Manager***

5. Measurements & Tracking

- ***On behalf of Business Support & Capital Asset Management Division Distribution Asset Management Department" is responsible to regularly report on projects within the Line Refurbishment program therefore;***
  - ***Continuous cooperation, co-ordination and collaboration of stakeholders noted within this manual are essential.***
  - ***Ongoing measurements and reporting will be supplied to our stakeholders in order for us to continuously improve upon the "Overhead Line Refurbishment Process"***

[i] *Distribution Asset Condition*
ii Detailed Feeder Inspection Manual

A REPETITIVE MAINTENANCE TASKS

A1 Maintenance Task Template

Transformer - Power
Rated < 230 kV and < 50 MVA (max rating) plus all 3 phase regulators

Tasks	Triggers			
	Not Critical	Low	Medium	High
Integrity Check	12 months	12 months	12 months	12 months
DGA Oil Sample	36 months	36 months	36 months	36 months
Standard Oil Sample	60 months	60 months	60 months	60 months
Maintenance Inspection	120 months	120 months	120 months	120 months

10	2011 07 05	Removed tapchangers & grounding transformers from eq. family. Changed classification rating from 138 kV to 230 kV and 80 MVA to 50 MVA	CM	GCD		GV	Original signed by G. A. Verch 2011 07 13
9	2005 06 03	Change heading to read Rated ≤ 138 kV from Rated less than 230kV.	CM	JK		DW	
8	2005 03 22	Insulation check task merged into Maintenance Inspection.	CM	JK		DW	
7	2004 10 12	Bushing tasks returned to template.	CM	JK		DW	
6	2004 03 11	Added refer to bushing template detail for integrity check description.	CM	JK		DW	
No.	Date	Revision	AMR Specialist	Eq. Specialist	Insul. Eng.	AMR Eng.	

MAINTENANCE TASK TEMPLATE

Asset Identification Section

Protection and Control System – Battery Bank Station/Communication - Lead Acid, Vented(Flooded)

Maintenance Program Section

Procedure/Task Name	ADMS File Name	Applicable Division			Frequency / Trigger	Tolerance	Qualification	Total Task Hours
		Gen South	Gen North	HVDC			Certified Power Electrician	
Integrity Check – Battery Bank, Station/Communication – Lead Acid	150.ps_Integ_Batt_Lead_Acid_proc.pdf	X	X	X	3 Months	±2 week	X	2
Ohmic Check - Battery Bank, Station/Communication – Lead Acid	150.ps_Ohmic_Chk_Battery_Lead_Acid_proc.pdf	X	X	X	Installation	N/A	X	4
					After Installation test approx. every 2 weeks pending Engineering approval	N/A		
					1 Years	±3 Months		
Specific Gravity Readings – Battery Bank, Station/Communication – Lead Acid	150.ps_Spec_Grav_Rdgs_Batt_Lead_Acid_proc.pdf	X	X	X	1 Years	±3 Months	X	4

Procedure/Task Summary	
Integrity Check – Battery, Room, Heating & Ventilation – Lead Acid	The Integrity Check is needed to ensure the integrity of the components and basic functions of the battery bank. This check is mainly a visual inspection along with some functional checks of associated equipment. The batteries will remain in service during this check. *(NOTE: The interval between two sequential Integrity Check tasks shall not exceed 4 months.)*
Ohmic Check - Battery – Lead Acid	The Ohmic Check is performed to measure the state of health of the battery bank and to identify whether testing (capacity testing) might be appropriate. *(NOTE: The interval between two sequential Ohmic Check tasks shall not exceed 18 months.)*
Specific Gravity Readings – Battery – Lead Acid	The Specific Gravity Check is performed to measure the state of charge of the battery bank and to identify whether remedial action (equalize charge) might be appropriate. *(NOTE: The interval between two sequential Specific Gravity Readings shall not exceed 18 months.)*
	NOTE: In HVDC, the *Ohmic Check* task and the *Specific Gravity Readings* task are both performed under the "*Diagnostic Checks*" task.

Track & Trend Section

Component	Tracking	Database	Test Package or Setting Letter
Battery Cell	Water Consumption	AMPS Inspection Readings	150.ps_Integ_Batt_Lead_Acid_cksh.pdf
Battery Cell	Cell Voltage Resistance Readings and Specific Gravity Readings	Alber Resistance Tester File transferred to Amps as CDF file	Application Guide for Battery Ohmic Measurements Using the Alber CRT-400 Resistance Tester

Revision Section

No	Date (YYYY-MM-DD)	Revision Reason and Reference	RCM Section	Generation Maintenance Engineering	Generation NERC Project	HVDC NERC Compliance Engineer	Technical Services Electrical	Technical Services R&P Group	HVDC Mtce Performance Section
2	2015-08-12	A "NOTE" was added in the Task Summary section to specify that the Diagnostic Checks performed in HVDC include the Ohmic Check and the Specific Gravity Readings. This will allow demontration of compliance through ODBC reports.	Christian Gosselin						
1	2015-02-11	A "***NOTE"*** was added in the Task Summary of the Integrity Check, the Ohmic Check and the Specific Gravity Readings to indicate the maximum interval between tasks. This provides clarification to meet NERC Standard PRC 005-2.	Christian Gosselin		Yuguang Xiao				
0	2013-01-29	Changes to tasks and frequency due to review and development of standardized maintenance plan. This task template supersedes SRCM decisions.	Brian Trumbley (no signature due to retirement)	Kristy-Lee Tremblay	Yuguang Xiao	Sadhna Schipper	Alex Muzyczka	Wat Ngu	Kelvin Kent

Wendelin E. Schuhmann

Original signed by:

MAINTENANCE TASK TEMPLATE

Asset Identification Section

Protection and Control System – Battery Bank Station/Communication - Lead Acid, Valve Regulated

Maintenance Program Section

Procedure/Task Name	ADMS File Name	Applicable Division			Frequency / Trigger	Tolerance	Qualification	Total Task Hours
		Gen South	Gen North	HVDC			Certified Power Electrician	
Integrity Check – Battery Bank, Station/Communication – Lead Acid	150.ps_Integ_Batt_Lead_Acid_proc.pdf	X			3 Months	±2 week	X	2
Ohmic Check - Battery Bank, Station/Communication – Lead Acid	150.ps_Ohmic_Chk_Battery_Lead_Acid_proc.pdf	X			Installation	N/A	X	4
					After Installation test approx. every 2 weeks pending Engineering approval	N/A		
					1 Years	±3 Months		

Procedure/Task Summary	
Integrity Check – Battery, Room, Heating & Ventilation – Lead Acid	The Integrity Check is needed to ensure the integrity of the components and basic functions of the battery bank. This check is mainly a visual inspection along with some functional checks of associated equipment. The batteries will remain in service during this check. *(NOTE: The interval between two sequencial Integrity Check tasks shall not exceed 4 months.)*
Ohmic Check - Battery – Lead Acid	The Ohmic Check is performed to measure the state of health of the battery bank and to identify whether testing (capacity testing) might be appropriate. *(NOTE: The interval between two sequencial Ohmic Check tasks shall not exceed 18 months.)*

Track & Trend Section

Component	Tracking	Database	Test Package or Setting Letter
Battery Cell	Cell Voltage Resistance Readings	Alber Resistance Tester File transferred to Amps as CDF file	Application Guide for Battery Ohmic Measurements Using the Alber CRT-400 Resistance Tester

Revision Section

No	Date (YYYY-MM-DD)	Revision Reason and Reference	RCM Section	Generation Maintenance Engineering	Generation NERC Project	HVDC NERC Compliance Engineer	Technical Services Electrical	Technical Services R&P Group	HVDC Mtce Performance Section
1	2015-02-11	A **"*NOTE*"** was added in the Task Summary of the Integrity Check and the Ohmic Check to indicate the maximum interval between tasks. This provides clarification to meet NERC Standard PRC 005-2.	Christian Gosselin		Yuguang Xiao				
0	2013-01-29	Changes to tasks and frequency due to review and development of standardized maintenance plan. This task template supersedes SRCM decisions.	Brian Trumbley (no signature due to retirement)	Kristy-Lee Tremblay	Yuguang Xiao	Sadhna Schipper	Alex Muzyczka	Wat Ngu	Kelvin Kent

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