Manitoba Hydro

TRANSMISSION AND DISTRIBUTION
POWER SUPPLY

REPORT ON

Impact of Generating Station Staffing on Asset and Operational Risks

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1. Executive Summary

Over the years, Manitoba Hydro has adopted various staffing strategies at our generating stations; leaving some plants that are staffed at all times while others that are not. With the advancement of the corporate risk management framework, it is now prudent to review our existing staffing practices, and to also develop a common process that can be used to assess staffing practice for future generating stations as well. With this in mind, a formal risk assessment was completed for each of our hydraulic generating stations to assess the impact of different staffing strategies on asset risks and operational risks. Potential financial and staff wellness opportunities that can result from a reduction in shift work were also identified and assessed in an attempt to harmonize corporate staffing approaches. Thermal generating stations and HVDC Converter stations were not included within the scope of this study.

Historically, an earlier task force was initiated in 2000 to review options for staffing Manitoba Hydro's Hydraulic and HVDC Stations, particularly the stations that are staffed on a 24 x 7 basis. Although the team could not reach a consensus at that time, the information that was gathered formed a starting point for the current risk assessment.

This report assesses the impact of on-site staff in mitigating asset risks such as fire, dam breach, security, plant flooding, water regulation, and other potentials for surprise. This report also assesses the impact of on-site staff in mitigating operational risks such as system restoration and plant operations. The risk assessment was a joint exercise with representation from Transmission System Operations, Generation North, Generation South and Engineering Services.

HVDC was invited to participate in the exercise, but declined because the HVDC converter stations at Radisson, Henday and Dorsey are considered critical elements in the Manitoba Hydro power system. Therefore, in order to properly identify and provide a prompt and intelligent response to any outage or emergency situation at these stations, it is essential that, for the foreseeable future, they be staffed on a 24 hour basis with qualified operators and technicians.

The risk assessment in this report represents the majority consensus of the stakeholders. Generation North Division and Generation South Division are responsible and accountable for managing the asset risks. Transmission System Operations Division is responsible and accountable for managing the operational risks.

1.1. Generation North Plants

Currently Kettle, Long Spruce, and Limestone are manned at all times (24 hours a day x 7 days a week). Kelsey is manned 10.24 hours a day x 7 days a week.

There are potential financial benefits, staff attraction/retention improvement benefits, training improvement benefits and staff wellness benefits to reducing shift work requirements at Kettle, Long Spruce, and Limestone. The financial benefits, although considered secondary to the security of our system and the ability for our operations to be sustainable is estimated to range from $400K to $660K per year.

In general, the asset risk of fire at one of our plants is considered one of the highest impact events, and the probability of a high impact fire occurring ranges from a "possible" event (1 in 10 years) to an "unlikely" event (1 in 30 years). On-site staff

complements our existing fire protection systems to lower the risk to a low impact event, with no change in probability.

The operational risk of restoring our system following a blackout is considered the highest impact event, and the probability of the need to have northern collector system on-site staff aid in system restoration is rare (1 in 100 years). Kelsey, on the other hand, is a black start plant that plays a time-critical role in our current restoration procedures. As such, it must be certified by Transmission System Operations Division as a black start facility and at all times (24 hours x 7 days per week) either: (i) have trained operating staff available within 20 minutes; or (ii) have remote Black Start Service capability installed. Kelsey is Generation North's only black start plant. Present staffing (8 hours X 7 days per week with Power Supply Workers housed at the onsite staff house) meets the condition to have trained operating staff available within 20 minutes.

To further explore the potential benefits and costs of reducing staffing levels at our northern collector system plants, a detailed engineering analysis should be done to identify any modifications required to allow the plants to be operated at reduced staffing levels. Provided the engineering analysis does not identify any significant barriers to operating Kettle at reduced staffing levels, it is recommended to proceed with a 2-year trial of reducing operating staffing at Kettle to assess whether the expected benefits are realized, and to see if unforeseen risks and costs are identified. While the plant is unmanned, the risk of fire will be mitigated through the existing fire protection systems as well as with an on-site security guard. The operational risk for Kettle is low, given that staff can be dispatched from Gillam within 20-30 minutes, and the risk of a blackout initiated from the northern collector system is "rare". A process will also be developed to staff the plant under higher risk conditions such as forecasted extreme weather events.

1.2. Generation South Plants

Currently Great Falls, Grand Rapids and Pointe du Bois are manned at all times (24 hours a day x 7 days a week). Great Falls provides a central annunciation point for alarms from Pine Falls and McArthur, which are both unmanned. Seven Sisters is manned 8.86 hours a day x 4 days a week.

As with the northern plants, there may be potential financial benefits and staff wellness benefits to reducing staffing levels at Great Falls. This option can be further assessed once the 2-year trial at Kettle is completed.

Grand Rapids and Seven Sisters are both black start plants that play a time-critical role in Manitoba Hydro's current restoration procedures, as such they must be certified by the Transmission System Operations Division as a black start facility and at all times (24 hours x 7 days per week) either: (i) have trained operating staff available within 20 minutes; or (ii) have remote Black Start Service capability installed.

2. Key Findings

The following are the major findings of this study:

- Generation North Division and Generation South Divisions are responsible and accountable for asset risks.
- Transmission System Operations Division is responsible and accountable for system operational risks.
- MISO is developing an ancillary services market planned for 2008 which will compensate generator owners for providing black start services.
- As outlined in the Wuskwatim Interconnection Operating Agreement, Wuskwatim shall at all times (24 hours x 7 days per week) either: (i) have trained operating staff available on site; or (ii) have remote Black Start Service capability installed.
- Plant staffing has a positive impact on the risk of fire at all plants.
- The risk of a fire at Point Du Bois in an unstaffed scenario was deemed unacceptable as the plant has the high exposure risk due to the lack of both active and passive fire measures.
- Jenpeg has the lowest exposure risk to a fire due to the design and layout of the station.
- Kettle has a higher exposure risk to fire than either Long Spruce or Limestone due to the stations layout and the material used in the original construction of the station. However, Kettle is relatively close to the town of Gillam where staff can be dispatched.
- Grand Rapids and Jenpeg have a higher exposure to the risk of local unrest in an unmanned scenario.
- The exposure risk to a Dam Breach scenario was deemed staff neutral at all of the plants. (High Impact with a Very Rare Probability)
- The exposure risk to Terrorism was deemed staff neutral at all of the plants (High Impact with a Rare Probability)
- All of the plants were deemed to have a higher exposure to the risk of vandalism in an unmanned scenario.
- Delays in restoration are most affected by battery back up. Battery failures at several critical AC terminal stations interrupt the restoration procedure. We are one year into a ten year battery replacement program.
- Staffing at Grand Rapids is critical for restoration: Grand Rapids is the black start unit for the Grand Rapids Islanding Scheme, which provides the primary

energization path to Dorsey. Delays at Grand Rapids during restoration impact the overall restoration plan for Manitoba. Grand Rapids can be put into a state of readiness from the SCC; however, a Power Supply Worker (PSW) is required to start the unit. Furthermore, Grand Rapids provides frequency control during load pick up (Grand Rapids' large units make it the best plant for this function). Automatic controls to put Grand Rapids units to 0% droop to automatically adjust for frequency deviation are available for purchase, but have never been justified at Grand Rapids. A PSW is therefore required to manually adjust for frequency deviations, since it would take an unacceptable amount of time for a mechanic to switch a unit to 0% droop.

- Staffing at Seven Sisters is critical for restoration since Seven Sisters is the black start unit for the Winnipeg River Islanding Scheme and is the alternate path for energizing Dorsey, should the Grand Rapids path fail. Seven Sisters can be put into a state of readiness from SCC but requires a PSW to start the black start unit. Remote controls exist, but they are not considered reliable for remote black start. Also, the Seven Sisters house unit breaker cannot be closed onto a dead bus; a PSW would have to do it manually. To provide an operable remote black start function, the start chain has to be modified to reset the start chain on closing of the generator breaker and the incomplete sequence timers have to be replaced.

3. Recommendations

1. On a 2-year trial basis, staff Kettle only during regular hours (8 hours a day x 5 days per week) provided that:
    a. An engineering analysis is undertaken to assess whether any modifications are required to existing equipment.
    b. A work process review is undertaken to identify which work processes may need to be changed (for example, emergency response instructions, system operating instructions)
    c. Measures are put in place to confirm if the proposed opportunities for Kettle's PSWs (both financial and human resource) are realized at the end of the trial period. Additional stresses on SCC workers must also be measured and weighed against the opportunities gained from reduced staffing at Kettle.
    d. Any unforeseen risks that are identified during the trial are mitigated immediately.
2. Manitoba Hydro's black start plants that are integral to system operations (Grand Rapids, Seven Sisters, Kelsey) must meet the following requirements:
    a. The supplemental generator controls, and communications have backup power supplies so full communications and functionality is maintained in the event that grid power is lost.
    b. At all times (24 hours x 7 days per week) the plant has to either: (i) have trained operating staff available within 20 minutes; or (ii) have remote Black Start Service capability installed.
    c. Transmission System Operations Division must certify the Black Start Service facilities, as outlined in Appendix 1.
3. After the two year trial at Kettle, reduced staffing at other plants should be evaluated based on the Kettle experience.
4. Over the next two years, Great Falls will document any situations where it is felt that the operators have a positive impact in managing an asset risk, such as emergency situations, outage prevention, or other similar events.
5. Destaffing at Grand Rapids is not advised for two reasons:
    a. Past experience with plant malfunctions, local unrest and vandalism indicates that this plant is at a higher asset risk than other plants; this risk is effectively mitigated with 24/7 staffing.
    b. Grand Rapids has a critical role in restoration; this risk is effectively mitigated with 24/7 staffing.

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4. Introduction

Staffing plants on a 24/7 basis is used at some of our plants as a risk mitigating strategy. Stakeholders representing Transmission Systems Operation, Generation North, Generation South and Engineering Services met to determine the asset risk exposure. Asset risks and the impact of plant destaffing are explored in the case of fire, dam breach, security, flooding, and water regulation. Risk mitigating strategies which supplement and/or replace existing strategies including staffing are investigated. Asset considered were limited to generating stations.

A study of staffing requirements to operate the HVDC and Hydraulic stations was conducted by HVDC, Generation North and System Control and completed in 2002. The findings were captured in a report entitled Hydraulic and HVDC Station Operator Staffing Review. The findings were inconclusive and further evaluation and quantification is required to work toward a common understanding.

Current staffing strategies utilized at generating stations and control structures:

Strategy	Station	Division
Manned		
Manned 24x7	Kettle	Generation North
	Long Spruce	Generation North
	Limestone	Generation North
	Grand Rapids	Generation South
	Great Falls	Generation South
	Pointe du Bois	Generation South
Unmanned		
Operated under Great Falls	Pine Falls	Generation South
	McArthur Falls	Generation South
Operated under Pointe du Bois	Slave Falls	Generation South
Manned daily (4 days/week)	Seven Sisters	Generation South
8/6 - manned daily	Kelsey	Generation North
	Laurie River	Generation North
	Jenpeg	Generation South
Unmanned	Missi	Generation North
	Notigi	Generation North

Operation staffing for the Generation South Hydraulic Stations is as follows:

- Great Falls has a minimum of 2 qualified PSW / Operators on a 24/7 basis. (1 will normally be at Pine Falls or McArthur Falls depending on work load)
- Pine Falls is handled by the PSW / Operators from Great Falls (typical day would have a PSW / Operator in the plant for about 4 hours during the day and 1 to 2 hours each night for a walk around check)
- McArthur Falls is handled by the PSW / Operators from Great Falls (typical day would have a PSW / Operator in the plant for about 4 hours during the day and 1 to 2 hours each night for a walk around check)

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- Seven Sisters is staffed with 1 or 2 PSWs assigned to operating duties / training 4 days per week with 2 more qualified PSWs scheduled for maintenance duties. A daily check of the plant is performed by 1 PSW on the remaining 3 days (1 to 2 hrs)
- Grand Rapids is staffed on a 24 / 7 with minimum 1 qualified PSW / Operator and at least 1 more person that may be qualified however most likely is a trainee. When there is switching required for outages on units or lines a second qualified person is required as per SCD's request.
- Jenpeg is staffed with 1 qualified PSW / Operator and normally a second person training in operating 11 hours per day 7 days a week. A qualified PSW / Operator is on standby during nonworking hours.
- Pointe du Bois is staffed on a 24 / 7 basis with a minimum of 2 qualified Station Operators and a minimum of a third person training in operating.
- Slave Falls is staffed with 1 qualified Station Operator 4 days per week with the staff from Pointe du Bois looking after it during non working hours. Slave Falls is checked at least once during non working days by the staff from Pointe du Bois.

5. Opportunity for Evaluating Staffing Options

A risk based evaluation of the Power Supply generating stations has been completed to determine the feasibility and opportunity for improving the current staffing strategies and to evaluate the necessity of a 24/7 operation.

The need to review our staffing strategy is driven by our changing work environment (Power Supply Worker, training, staff turnover), technology advancements, workforce demographics, and worker expectations. Improved reliability and sustainability of operations are the desired outcomes.

5.1. Benefits

5.1.1. Financial

A reduction in shift work requirements has the potential to reduce the operational costs required to operate and maintain the plants. For Kettle, Long Spruce and Limestone, the PSW staffing requirements to run a sustainable 24/7 operation was determined to be 16 positions at each plant[1]. With a reduction in shift work requirements, it is estimated that there is the potential to reduce this number to somewhere between 10 and 12 positions. The potential to reduce the combined operational costs for Kettle, Long Spruce and Limestone is estimated to be between $440K and $660K per year (Based on $110,000 per PSW EFT per year).

It should be noted that the need to perform maintenance at the most economical time, often outside of daily work hours will continue to drive and influence the maintenance outage schedule.

The original PSW Report indicated that PSW staff would perform 30% operational work and 70% maintenance work resulting in a potential technical trade staff reduction of 30%. With a 24/7 operation it is proving difficult to attract, train and retain the qualified staff that are needed to realize the potential cost saving benefits of the original PSW report.

The financial consideration is secondary to the need to have a reliable and sustainable operation.

5.1.2. Human Resources

A reduction in shift work requirements provides the potential opportunity to improve the attraction and retention of qualified staff, provide more meaningful work to employees and to improve the overall health and wellness of employees.

There is variation in the acceptance of shift work both in Generation North and South as quantified by demographic group, work location, and trade. Employees on shift tend to have less favourable sleeping and eating patterns which can lead to increased health problems over time due to the disruption of ones normal circadian rhythm sleeping patterns. As we age the quality of sleep declines and this can be further aggravated by shift work.

[1] Power Supply Worker Review Report prepared by W. Wittmeier, C. Boyer & R. McKinnon (2004)

With a reduction in shift work there is general agreement that the lifestyles of our employees would be improved. This improvement is directly related to individuals having time off that is in synch with their families and other people in the community. Gillam compared to other communities has more limitations on what a person does with their time off, so it is preferable to have time off with friends, and not when the rest of the community is working. With shift work, those affected often miss out on community and social events. In urban centers, this is not so much of a factor, as there are more things going on whether it' s during the week, weekend, days or evening. In a community like Gillam, a core of volunteers is required to run community organizations and activities. The amount of shift work has a direct impact on the commitment individuals can offer.

While the implementation of the Power Supply Worker program resulted in an improved retention of those former employees in the Station Operator trade, it also brought with it shift worker issues that have negatively impacted the attractiveness of the former maintenance trade technicians positions. The spouses and children are most often those affected when day workers become shift workers.

A reduction in the requirements for shift work has the potential to increase our ability to train staff, making our operations more sustainable. Training in a group /shop environment is better than the training one would typically receive on a shift basis, due multiple resources being available. With increased training, there is the potential opportunity for increased reliability.

Many of those individuals attracted to the organization via the Aboriginal Pre-placement Program find that working in a new culture when combined with shift work is quite difficult to adapt to.

5.2. Costs

5.2.1. Risk Mitigation Strategies

To mitigate risks posed by plant destaffing, costs in the form of automatic/remote controls, protection schemes, monitoring, standby requirements and others may be incurred. The effectiveness of these alternatives and the costs associated to reach the desired level of effectiveness when compared to staffing and human intervention has been questioned. Implementation of any additional risk mitigation strategies will have to be estimated.

5.3. Plant Differences

There are plants in Manitoba Hydro that are not currently staffed on a 24/7 basis; from this it can be concluded that it is technically possible to destaff, but whether it is the right thing to do should be influenced by completing a full risk analysis.

The location of the station (north, south, remote), level of automation, capacity of the station, and local staffing issues are a few of the differences that must be considered in the decision to change the staffing strategy at each individual station.

Generation North is experiencing difficulty with both attracting and retaining skilled employees. This is partly due to being in the North and partly because of shift work.

Staffing using an 8/6 strategy has successfully resolved staffing issues in some areas.

5.4. Solutions/Alternatives to Destaffing

A reduction in shift work requirements is a solution to the lack of trained employees for northern plants.

Other options:

- Increasing the number of PSW resources at each plant to 16 as per the recommendations in the PSW Report. (Current staffing levels are 12 to 13 staff status positions at Kettle, Long Spruce & Limestone excluding vacancies)
- Implement an 8- 6 operation in Gillam (Same as Jenpeg, Kelsey and Grand Rapids) - Bringing this into Gillam would destroy the community although it is a huge success in Quebec for their northern plants.
- Implement single person shifts at plants currently staffed 24/7 with a minimum of two people.
- Money (Bonuses)

6. Criteria

The Australian Risk Standard likelihood criteria were used to evaluate the likelihood of risks investigated. The Corporate Risk consequence matrix was used to evaluate the impact of the risks investigated. For the risk of delay to restoration, NERC criteria was used, which is detailed in Appendix 2.

Likelihood	Qualifier	Quantifier
Almost Certain	The event will occur on an annual basis	Once a year or more frequently
Likely	The event has occurred several times or more in a decade	Once every 3 years
Possible	The event might occur once in a decade	Once every 10 years
Unlikely	The event does occur somewhere from time to time.	Once every 30 years
Rare	Have heard of something like this occurring elsewhere.	Once every 100 years
Very Rare	Have never heard of this happening	Once every 1000 years

Consequence	Measure	Rating
Financial -	Net Income / capital investment:	Low - $0-$50 Million
		Medium - $51-$150 Million
		High - >$150 Million
System Reliability -	Domestic Customers:	Low - Outage affecting 50 customers for 4 hours. Not life threatening
		Medium - Outage affecting 500 customers for up to 24 hours. Have ability to serve critical loads. Not life threatening (critical loads served).
		High - Do not have capacity to serve Manitoba load for extended period of time. Life threatening. Loss of public confidence.
	MW Generation or Interconnection capacity:	Low - NERC level 1, in compliance with industry reliability standards
		Medium - Loss of 2000 MW. NERC level 2 - load management procedures in effect. In compliance with industry reliability standards
		High - Loss of >2000 MW. NERC level 3 - firm load interruption imminent or in progress; and/or non compliance with industry reliability standards.

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Consequence	Measure	Rating
Safety- Employee and Public -	High risk accidents, severity rate, frequency rate and public contacts:	Low - Minor injuries, in compliance with laws and standards.
		Medium - disabling injuries, in compliance with laws and industry standards.
		High - severe injuries and fatalities and/or non compliance with legislation and industry standards resulting in imprisonment for Manitoba Hydro management, significant fines and loss of public trust.
Environment -	Environmental Impact - air emissions, water management, spills, land and habitat disturbances, etc:	Low - Minor impact to environment in compliance with stakeholder expectations and laws and regulations. Ability to obtain/renew environmental licensing and operating approvals.
		Medium - Local and contained damage to environment. In compliance with stakeholder expectations and laws and regulations. Ability to obtain/renew environmental licensing operating approvals.
		High - Severe widespread and uncontained damage to environment and/or non-compliance with stakeholder expectations, laws and regulations resulting in imprisonment for Manitoba Hydro management, significant fines, loss of public trust and long term operating restrictions
Customer Value -	Customer perception of service with regard to retail electricity rates:	Low - no rate increase
		Medium - annual increase of <10%
		High - Annual increase >10%
	Customer perception of service with regard to reliability and quality service:	Low - Restoration service within 4 hours, no threat to public safety, <1.3 outages/customer/year, provision of energy related services
		Medium - Restoration service within 24 hours with no threat to public safety. 2 outages/customer/year.
		High - Outage for extended period of time. Life threatening. Loss of public confidence.
	Customer perception of service with regard to reputation:	Low - Local media coverage with negligible impact on stakeholders
		Medium - A highly visible event attracting national media coverage or environmental concern; and/or a moderate negative impact on stakeholders.
		High - A highly visible event attracting international media coverage or environmental concern; and/or a significant negative impact on stakeholders such as breach of privacy, contractual obligation or environmental stewardship

7. Risks Maps For Generation North

7.1. Kettle Risk Map

IMPACT							
	High	2 **6B**	3.1 4.1 **6A**	**8B**	**8A**	**9B**	**9A**
	Medium	**3B**	7.1 **3A**	7.2 1 **5B**	6 **5A**	**7B**	**7A**
	Low	**1B**	**1A**	7.2 1 8 3.3 **2B**	4.2 3.2 **2A**	**4B**	8 5.1 3.2 **4A**
		Very Rare	Rare	Unlikely	Possible	Likely	Almost Certain
		1 in 1000 years	1 in 100 years	1 in 30 years	1 in 10 years	1 in three years	Every Year or more Frequent
		PROBABILITY					

Asset Risk	Staffed	Unstaffed	Staff Neutral
1. Fire	2B	5B	
2. Dam Breach			6B
3. Security			
3.1 Terrorism			6A
3.2 Vandalism	2A	4A	
3.3 Local Unrest			2B
4. Station Internal Flood			
4.1 Catastrophic Failure			6A
4.2 Noncatastrophic Failure			2A
5. Water Regulation			
5.1 Exceeding License			4A
6. Potential For Surprise			5A
Operation Risk			
7. Delay in System Restoration			
7.1 Province Wide Blackout			3A
7.2 Southern System Blackout	2B	5B	
8. Operational Issues	2B	4A	

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7.2. Long Spruce Risk Map

IMPACT							
	High	2 **6B**	3.1 4.1 **6A**	**8B**	**8A**	**9B**	**9A**
	Medium	**3B**	7.1 **3A**	7.2 1 **5B**	6 **5A**	**7B**	**7A**
	Low	**1B**	**1A**	7.2 1 8 3.3 **2B**	4.2 3.2 **2A**	**4B**	8 5.1 3.2 **4A**
		Very Rare	Rare	Unlikely	Possible	Likely	Almost Certain
		1 in 1000 years	1 in 100 years	1 in 30 years	1 in 10 years	1 in three years	Every Year or more Frequent
		PROBABILITY					

Asset Risk	**Staffed**	**Unstaffed**	**Staff Neutral**
1. Fire	2B	5B	
2. Dam Breach			6B
3. Security			
3.1 Terrorism			6A
3.2 Vandalism	2A	4A	
3.3 Local Unrest			2B
4. Station Internal Flood			
4.1 Catastrophic Failure			6A
4.2 Noncatastrophic Failure			2A
5. Water Regulation			
5.1 Exceeding License			4A
6. Potential For Surprise			5A
Operation Risk			
7. Delay in System Restoration			
7.1 Province Wide Blackout			3A
7.2 Southern System Blackout	2B	5B	
8. Operational Issues	2B	4A	

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7.3. Limestone Risk Map

IMPACT							
	High	2 **6B**	3.1 7.1 4.1 **6A**	**8B**	**8A**	**9B**	**9A**
	Medium	**3B**	7.1 **3A**	7.2 1 **5B**	6 **5A**	**7B**	**7A**
	Low	**1B**	**1A**	7.2 1 8 3.3 **2B**	4.2 3.2 **2A**	**4B**	8 5.1 3.2 **4A**
		Very Rare	Rare	Unlikely	Possible	Likely	Almost Certain
		1 in 1000 years	1 in 100 years	1 in 30 years	1 in 10 years	1 in three years	Every Year or more Frequent
		PROBABILITY					

Asset Risk	**Staffed**	**Unstaffed**	**Staff Neutral**
1. Fire	2B	5B	
2. Dam Breach			6B
3. Security			
3.1 Terrorism			6A
3.2 Vandalism	2A	4A	
3.3 Local Unrest			2B
4. Station Internal Flood			
4.1 Catastrophic Failure			6A
4.2 Noncatastrophic Failure			2A
5. Water Regulation			
5.1 Exceeding License			4A
6. Potential For Surprise			5A
Operation Risk			
7. Delay in System Restoration			
7.1 Province Wide Blackout	3A	6A	
7.2 Southern System Blackout	2B	5B	
8. Operational Issues	2B	4A	

7.4. Kelsey Risk Map

IMPACT							
	High	2 **6B**	3.1 4.1 **6A**	**8B**	**8A**	**9B**	**9A**
	Medium	**3B**	**3A**	1 7 **5B**	6 **5A**	**7B**	**7A**
	Low	**1B**	**1A**	8 1 3.3 **2B**	4.2 3.2 **2A**	**4B**	5.1 3.2 **4A**
		Very Rare	Rare	Unlikely	Possible	Likely	Almost Certain
		1 in 1000 years	1 in 100 years	1 in 30 years	1 in 10 years	1 in three years	Every Year or more Frequent
		PROBABILITY					

Asset Risk	**Staffed**	**Unstaffed**	**Staff Neutral**
1. Fire	2B	5B	
2. Dam Breach			6B
3. Security			
3.1 Terrorism			6A
3.2 Vandalism	2A	4A	
3.3 Local Unrest			2B
4. Station Internal Flood			
4.1 Catastrophic Failure			6A
4.2 Noncatastrophic Failure			2A
5. Water Regulation			
5.1 Exceeding License			4A
6. Potential For Surprise			5A
Operation Risk			
7. Delay in System Restoration			5B
8. Operational Issues			2B

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7.5. Laurie River Risk Map

IMPACT							
	High	2 **6B**	3.1 4.1 **6A**	**8B**	**8A**	**9B**	**9A**
	Medium	**3B**	**3A**	1 **5B**	6 **5A**	**7B**	**7A**
	Low	**1B**	**1A**	7 3.2 8 1 3.3 **2B**	3.2 4.2 **2A**	**4B**	5.1 **4A**
		Very Rare	Rare	Unlikely	Possible	Likely	Almost Certain
		1 in 1000 years	1 in 100 years	1 in 30 years	1 in 10 years	1 in three years	Every Year or more Frequent
		PROBABILITY					

Asset Risk	**Staffed**	**Unstaffed**	**Staff Neutral**
1. Fire	2B	5B	
2. Dam Breach			6B
3. Security			
3.1 Terrorism			6A
3.2 Vandalism	2B	2A	
3.3 Local Unrest			2B
4. Station Internal Flood			
4.1 Catastrophic Failure			6A
4.2 Noncatastrophic Failure			2A
5. Water Regulation			
5.1 Exceeding License			4A
6. Potential For Surprise			5A
Operation Risk			
7. Delay in System Restoration			2B
8. Operational Issues			2B

8. Risk Maps for Generation South

8.1. Grand Rapids Risk Map

IMPACT							
	High	2 **6B**	3.1, 4.1 **6A**	7 **8B**	**8A**	**9B**	**9A**
	Medium	**3B**	**3A**	1, 7 **5B**	6 **5A**	**7B**	**7A**
	Low	**1B**	**1A**	8, 1 **2B**	4.2, 3.3 **2A**	3.3 **4B**	8, 5.1, 3.2 **4A**
		Very Rare	Rare	Unlikely	Possible	Likely	Almost Certain
		1 in 1000 years	1 in 100 years	1 in 30 years	1 in 10 years	1 in three years	Every Year or more Frequent
		PROBABILITY					

Asset Risk	**Staffed**	**Unstaffed**	**Staff Neutral**
1. Fire	2B	5B	
2. Dam Breach			6B
3. Security			
3.1 Terrorism			6A
3.2 Vandalism			4A
3.3 Local Unrest	2A	4B	
4. Station Internal Flood			
4.1 Catastrophic Failure			6A
4.2 Noncatastrophic Failure			2A
5. Water Regulation			
5.1 Exceeding License			4A
6. Potential For Surprise			5A
Operation Risk			
7. Delay in System Restoration	5B	8B	
8. Operational Issues	2B	4A	

Impact of Generating Station Staffing on Asset and Operational Risks

8.2. Great Falls Risk Map

IMPACT							
	High	2 6B	3.1 4.1 6A	8B	8A	9B	9A
	Medium	3B	3A	7 1 5B	6 5A	7B	7A
	Low	1B	1A	7 1 8 3.3 2B	4.2 2A	4B	8 5.1 3.2 4A
		Very Rare	Rare	Unlikely	Possible	Likely	Almost Certain
		1 in 1000 years	1 in 100 years	1 in 30 years	1 in 10 years	1 in three years	Every Year or more Frequent
		PROBABILITY					

Asset Risk	Staffed	Unstaffed	Staff Neutral
1. Fire	2B	5B	
2. Dam Breach			6B
3. Security			
3.1 Terrorism			6A
3.2 Vandalism			4A
3.3 Local Unrest			2B
4. Station Internal Flood			
4.1 Catastrophic Failure			6A
4.2 Noncatastrophic Failure			2A
5. Water Regulation			
5.1 Exceeding License			4A
6. Potential For Surprise			5A
Operation Risk			
7. Delay in System Restoration	2B	5B	
8. Operational Issues	2B	4A	

Impact of Generating Station Staffing on Asset and Operational Risks

8.3. Point du Bois Risk Map

IMPACT							
	High	2 **6B**	3.1 4.1 **6A**	1 **8B**	**8A**	**9B**	**9A**
	Medium	**3B**	**3A**	1 **5B**	6 **5A**	**7B**	**7A**
	Low	**1B**	**1A**	8 7 3.3 **2B**	4.2 **2A**	**4B**	8 5.1 3.2 **4A**
		Very Rare	Rare	Unlikely	Possible	Likely	Almost Certain
		1 in 1000 years	1 in 100 years	1 in 30 years	1 in 10 years	1 in three years	Every Year or more Frequent
		PROBABILITY					

Asset Risk	**Staffed**	**Unstaffed**	**Staff Neutral**
1. Fire	5B	8B	
2. Dam Breach			6B
3. Security			
3.1 Terrorism			6A
3.2 Vandalism			4A
3.3 Local Unrest			2B
4. Station Internal Flood			
4.1 Catastrophic Failure			6A
4.2 Noncatastrophic Failure			2A
5. Water Regulation			
5.1 Exceeding License			4A
6. Potential For Surprise			5A
Operation Risk			
7. Delay in System Restoration			2B
8. Operational Issues	2B	4A	

Impact of Generating Station Staffing on Asset and Operational Risks

8.4. Pine Falls / McArthur Falls Risk Map

IMPACT							
	High	2 **6B**	3.1 4.1 **6A**	**8B**	**8A**	**9B**	**9A**
	Medium	**3B**	**3A**	1 7 **5B**	6 **5A**	**7B**	**7A**
	Low	**1B**	**1A**	7 1 3.3 8 **2B**	4.2 **2A**	**4B**	8 5.1 3.2 **4A**
		Very Rare	Rare	Unlikely	Possible	Likely	Almost Certain
		1 in 1000 years	1 in 100 years	1 in 30 years	1 in 10 years	1 in three years	Every Year or more Frequent
		PROBABILITY					

Asset Risk	**Staffed**	**Unstaffed**	**Staff Neutral**
1. Fire	2B	5B	
2. Dam Breach			6B
3. Security			
3.1 Terrorism			6A
3.2 Vandalism			4A
3.3 Local Unrest			2B
4. Station Internal Flood			
4.1 Catastrophic Failure			6A
4.2 Noncatastrophic Failure			2A
5. Water Regulation			
5.1 Exceeding License			4A
6. Potential For Surprise			5A
Operation Risk			
7. Delay in System Restoration	2B	5B	
8. Operational Issues	2B	4A	

Impact of Generating Station Staffing on Asset and Operational Risks

8.5. Slave Falls Risk Map

IMPACT							
	High	2 **6B**	3.1 4.1 **6A**	**8B**	**8A**	**9B**	**9A**
	Medium	**3B**	**3A**	1 **5B**	6 **5A**	**7B**	**7A**
	Low	**1B**	**1A**	7 1 3.3 8 **2B**	4.2 3.2 **2A**	**4B**	8 5.1 **4A**
		Very Rare	Rare	Unlikely	Possible	Likely	Almost Certain
		1 in 1000 years	1 in 100 years	1 in 30 years	1 in 10 years	1 in three years	Every Year or more Frequent
		PROBABILITY					

Asset Risk	**Staffed**	**Unstaffed**	**Staff Neutral**
1. Fire	2B	5B	
2. Dam Breach			6B
3. Security			
3.1 Terrorism			6A
3.2 Vandalism			2A
3.3 Local Unrest			2B
4. Station Internal Flood			
4.1 Catastrophic Failure			6A
4.2 Noncatastrophic Failure			2A
5. Water Regulation			
5.1 Exceeding License			4A
6. Potential For Surprise			5A
Operation Risk			
7. Delay in System Restoration			2B
8. Operational Issues	2B	4A	

Impact of Generating Station Staffing on Asset and Operational Risks

8.6. Seven Sisters Risk Map

IMPACT							
	High	2 **6B**	3.1 4.1 **6A**	7 **8B**	**8A**	**9B**	**9A**
	Medium	**3B**	**3A**	7 1 **5B**	6 **5A**	**7B**	**7A**
	Low	**1B**	**1A**	3.3 1 8 **2B**	4.2 **2A**	**4B**	8 5.1 3.2 **4A**
		Very Rare	Rare	Unlikely	Possible	Likely	Almost Certain
		1 in 1000 years	1 in 100 years	1 in 30 years	1 in 10 years	1 in three years	Every Year or more Frequent
		PROBABILITY					

Asset Risk	**Staffed**	**Unstaffed**	**Staff Neutral**
1. Fire	2B	5B	
2. Dam Breach			6B
3. Security			
3.1 Terrorism			6A
3.2 Vandalism			4A
3.3 Local Unrest			2B
4. Station Internal Flood			
4.1 Catastrophic Failure			6A
4.2 Noncatastrophic Failure			2A
5. Water Regulation			
5.1 Exceeding License			4A
6. Potential For Surprise			5A
Operation Risk			
7. Delay in System Restoration	5B	8B	
8. Operational Issues	2B	4A	

Impact of Generating Station Staffing on Asset and Operational Risks

8.7. Jenpeg Risk Map

IMPACT							
	High	2 **6B**	3.1 4.1 **6A**	**8B**	**8A**	**9B**	**9A**
	Medium	**3B**	1 **3A**	**5B**	6 **5A**	**7B**	**7A**
	Low	**1B**	1 **1A**	7 8 **2B**	4.2 3.2 3.3 **2A**	3.3 **4B**	3.2 5.1 **4A**
		Very Rare	Rare	Unlikely	Possible	Likely	Almost Certain
		1 in 1000 years	1 in 100 years	1 in 30 years	1 in 10 years	1 in three years	Every Year or more Frequent
		PROBABILITY					

Asset Risk	**Staffed**	**Unstaffed**	**Staff Neutral**
1. Fire	1A	3A	
2. Dam Breach			6B
3. Security			
3.1 Terrorism			6A
3.2 Vandalism	2A	4A	
3.3 Local Unrest	2A	4B	
4. Station Internal Flood			
4.1 Catastrophic Failure			6A
4.2 Noncatastrophic Failure			2A
5. Water Regulation			
5.1 Exceeding License			4A
6. Potential For Surprise			5A
Operation Risk			
7. Delay in System Restoration			2B
8. Operational Issues			2B

9. Risk

9.1. Fire

Manitoba Hydro currently experiences up to 100 fires a year, mostly managed by staffed operations. Thermal plants are 2% of fire incidences.

MAJOR CORPORATE FIRES (DAMAGE ≥ $1.0 MILLION)

NO.	YEAR	DESCRIPTION	EST. LOSS
1	1973	250 man construction camp (Kiskitu) destroyed by fire in 25 minutes	$1.5M
2	1977	Kettle Generating Station Powerhouse superstructure equipment on fire due to SS2 switchboard	$3.5M
3	1981	Radisson HVDC Station valve damping resistor fire	$1.5M
4	1982	Pine Falls Generating Station generator cubicle auxiliaries and disconnects on fire	$3.0M
5	1987	Dorsey Converter Station valve group 32, 500 kV busing failure	$1.0M
6	1988	Kelsey 230kV bank #10 transformer tap changer and bushing fire	$2.0M
7	1992	Dorsey Converter Station Bipole I Valve Groups Replacement Project - a major fire occurred in the valve hall	Loss absorbed by supplier $2.0M
8	1995	Kettle Generating Station T9 generator step-up transformer and tailrace deck fire	$2.5M
		TOTAL	$17M

Note: Costs for loss of generation and transmission are not included.

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Fire stats of human caused vs. non human caused:

Typically fires which result from a human action involve activities such as smoking, cutting & welding, cooking, improper placed heaters, roof repairs, improper electrical equipment switching, and poor house keeping (in particular immediately following maintenance).

The non human element cause of fire is generally due to a failure of a particular piece of electrical/mechanical equipment.

The following list of fires in hydroelectric stations described below provides an appreciation of consequence of fire at attended stations.

Major Fire Records

Hydraulic Generating Stations (Gen South & Gen North)

	Event	Date	Fire (Record) Reported	Operator Attended
1	Kettle SS2 Switchboard Fire	1977	Yes	Yes
2	Kettle Units #5&7 Generator Circuit Ring Bus Fires	1981	Yes	Yes
3	Pine Falls – Generator Disconnect	1982	Yes	Yes
4	Long Spruce Generator Windings Blister Pack Failures/Fires (Three Units)	1983	Yes	Yes
5	Kelsey 230KV Bank #10 Transformer Top Changer & Bushing Fire	1988	Yes	Yes
6	Kelsey Unit #5 Exciter & Disconnect Fire	1991	Yes	Yes
7	Limestone Excitation Transformer Failure	1994	Yes	Yes
8	Kettle Junction Box – Cable Trays (Elv.382')	1995	No	Yes
9	Kettle T9 Generator Step-up Transformer & Tailrace Deck	1995	Yes	Yes
10	Great Falls Control Room – Relays Cubicles	1996	No	Yes
11	Selkirk Conveyor System Fire	1998	Yes	Yes

Pine Falls (1982) and Kettle (1977) had a fire due to improper switching, had there not been people there we could have lost the whole station. The fire protection activated as designed.

Preliminary Risk Assessment

Financial

In the event of a fire, assuming a quick and timely fire crew or operating staff response, the anticipated range of loss is:

Minimum Expected Loss (MEL)	$2K
Maximum Foreseeable Loss (MFL)	$100 K.

Lack of timely fire response can cause a major fire loss with anticipated range of loss of:

Minimum Expected Loss (MEL)	>$200K
Maximum Foreseeable Loss (MFL)	>$150 M.

Assumptions:

Maintained and functional fire protection system.

Loss does not include lost revenue due to unit outage.

Loss is representative of the expected worst case.

The Minimum Expected Loss estimates were used for this Risk Assessment since the Maximum Foreseeable Loss is based on the worse case scenario where all of the installed active fire systems fail to operate.

Manitoba Hydro is self-insured for the first $5 M but carries no “Boiler & Machinery” Insurance.

All of our plants would cost >$150 M to rebuild, but if our insurance covers us, this becomes a low impact ($5 M), provided Manitoba Hydro decides to purchase the “Boiler & Machinery” Insurance.

Boiler and machinery insurance is a financial risk control action which limits the corporations liability associated with the insured risk. Insurance does not prevent the loss, but it does control the financial risk exposure. Risk control can be achieved through improved maintenance practices, improved fire prevention and protection systems, and with the ability to respond to an event at either the incipient or beginning stages.

The expected premium to upgrade our current insurance to 5 million deductible with boiler and machinery coverage is expected to be in the range of 1million dollars for Power Supply.

System Reliability

Loss of a generating station due to fire is at maximum 1330 MW (at Limestone). Impact using reliability measures rates as low to medium.

Safety - Employee and Public

There is a risk to fire fighters responding to the fire; and a potential risk to the public should a fire break out and is not contained to the generating station.

Environment

Some generating stations contain asbestos and PCBs in the cable trays; a fire could release these contaminants and affect surrounding public. Water used to fight a fire will carry away contaminants which may find their way into the river.

Customer Value

Range depending on the severity of event, but certainly, if we loose a large plant then we see a medium risk with potential for national media attention.

Risk Identification

The identified risk of concern is the loss of an entire plant due to fire.

Ontario Hydro has de-staffed stations on the English River that are quite remote. These stations are remotely controlled from Thunder Bay. Since de-staffing, there was a fire at the Ear Falls G.S. (four units producing 17MW), which resulted in the complete loss of plant. The station was rebuilt following the fire and remains unmanned.

Three levels of response:

-Automatic

-Operating Staff

-Volunteer Fire Crew

If weather conditions are poor, a 5 minute response time can change into a 1 hour response time. Winnipeg River may have a faster response because there are fire stations near by, where as Grand Rapids, Jenpeg and Kelsey might have a slower response time.

After a fire extinguishes there is often smoldering happening which can lead to re-ignition within 10 minutes.

We are still exposed to these risks should the plant be staffed.

Is it tolerable to loose a plant such as Seven Sisters, seeing as it is valued at only 150 MW? Is it a different story if it's 1300 MW? Or is it more related to asset value?

Limestone and Long Spruce are unlikely to lose the entire plant due to fire because of the active and passive fire protection systems that are installed. Wuskwatim is being built as an unstaffed plant so it is being designed with both active and passive fire protection systems.

At Grand Rapids, Selkirk and a few other communities the Hydro fire crew dispatches their resources to fight a local community fire. It would be difficult and political to discontinue this service.

Impact of Generating Station Staffing on Asset and Operational Risks

Potential Impact and Probability

Impact:

Complete loss of a plant

High - financial (lost revenue, insurance not covered)

High - customer value

Probability:

All fires start as small. If attended, they don't end up being wide spread, and impact is minimized. Statistics provided by the fire protection engineer show that Manitoba Hydro has historically experienced a major fire every 4-5 years. Improvements in fire protection systems is expected to improve this record, this assumption is consistent with the fact that there has not been a major fire in the last 10 years.

Manning of the generating stations does not reduce the probability of a fire, but will reduce the probability of a major fire.

Low impact fires happen every year or more.

Impact and probability changes from plant to plant, and is greatly impacted by staffing. The location of each station, the age, the type of design and the physical layout has a direct impact on the probability of a major fire. Designs that include compartmentalization (separation) along with both active and passive fire protection systems have the lowest probability for a major fire.

In a scenario where staff is not available on site there is a greater likelihood that a fire will manifest into a catastrophic fire destroying the plant, making it a high impact risk. In a staffed scenario, operators can take action quickly to minimize damage caused by a fire, making it a low impact risk.

Generation North Plants

For Kelsey, Kettle, Long Spruce, Limestone and Laurie River the impact of a Fire with the plants staffed 24/7 has been classified as “Low” ($0 - $50 Million) while the probability of such an event occurring has been determined to be “Unlikely” (1 in 30 years).

For the same plants with the facilities at times unmanned the impact of a Fire has been classified as “Medium” ($51 - $150 Million) with the probability of such an event occurring remaining the same at “Unlikely” (1 in 30 years).

The risk of a major fire at Kettle has been deemed greater than the risk at the other Lower Nelson River plants due to the age and design of the plant (No fire separation & more flammable materials used during construction of the plant such as the generator asphalt mica windings)

Impact of Generating Station Staffing on Asset and Operational Risks

Plant	Impact		Likelihood		Risk Level	
Generation North	Staffed	Destaffed	Staffed	Destaffed	Staffed	Destaffed
Kettle	Low	Medium	Unlikely	Unlikely	2B	5B
Long Spruce	Low	Medium	Unlikely	Unlikely	2B	5B
Limestone	Low	Medium	Unlikely	Unlikely	2B	5B
Kelsey	Low	Medium	Unlikely	Unlikely	2B	5B
Laurie River	Low	Medium	Unlikely	Unlikely	2B	5B

Generation South Plants

For Grand Rapids, Great Falls, Seven Sister, Pine Falls, McArthur Falls and Slave Falls River the impact of a Fire with the plants staffed 24/7 has been classified as “Low” ($0 - $50 Million) while the probability of such an event occurring has been determined to be “Unlikely” (1 in 30 years).

For the same plants with the facilities at times unmanned the impact of a Fire has been classified as “Medium” ($51 - $150 Million) with the probability of such an event occurring remaining the same at “Unlikely” (1 in 30 years).

For Jenpeg the impact of a Fire with the plant staffed 24/7 or available on short notice has been classified as “Low” while the probability of such an event occurring has been determined to be “Rare” (1 in 100 years). For Jenpeg with the plant unmanned at times with staff not available on site the impact of a Fire has been classified as “Medium” with the probability of such an event occurring remaining the same at “Rare” (1 in 100 years).due to the layout and design of the plant (Water cooled stators, compartmentalization & below grade construction)

For Point Du Bois the impact of a Fire with the plant staffed 24/7 has been classified as “Medium” while the probability of such an event occurring has been determined to be “Unlikely” (1 in 30 years).

For Point Du Bois with the facility at times unmanned the impact of a Fire has been classified as “High” (>$150 Million) with the probability of such an event occurring remaining the same at “Unlikely (1 in 30 years). This analysis is due to the open design of the plant and the lack of modern fire protection measures (Active and Passive). Due to the age of Point Du Bois the plant was designed with no compartmentalization; there is a lack of flame resistant construction materials (Thermosetting material) and the plant has no sprinklers making it vulnerable for a major fire regardless of the plants staffing strategy.

Generation South	Staffed	Destaffed	Staffed	Destaffed	Staffed	Destaffed
Grand Rapids	Low	Medium	Unlikely	Unlikely	2A	5B
Great Falls	Low	Medium	Unlikely	Unlikely	2A	5B
Pointe du Bois	Medium	High	Unlikely	Unlikely	5B	8B

Pine Falls	Low	Medium	Unlikely	Unlikely	2A	5B
McArthur Falls	Low	High	Unlikely	Unlikely	2A	5B
Slave Falls	Low	Medium	Unlikely	Unlikely	2A	5B
Seven Sisters	Low	Medium	Unlikely	Unlikely	2A	5B
Jenpeg	Low	Medium	Rare	Rare	1A	3A

Risk Treatment

Existing Measures for Managing Risk Area:

Insurance - $5 M deductible. Tino Bambilla to inquire with our insurance company what is the impact of plant destaffing on insurance rates – do not expect a big impact. Our current insurance does not cover boiler and machinery loss or lost revenue.

Currently, fire protection is designed for staffed plants. Initially, fire protection was designed for asset protection, and now we're integrating some people safety, and it rates ahead of asset. Fire protection meets Industry Standards such as Corporate Fire Manual, National Fire Code, Manitoba Fire Code, and National Fire Protection Association (NFPA) 850 & 851 Codes and Standards.

Fire response is not a remote operation. It has to be confirmed by a person to enact a response.

Active:

Active fire protection includes automatic fire suppression systems such as:

Water Sprinklers

Gaseous Systems such as Halon, FM-200, Inergen, Argon, and CO2

If a fire protection is deemed to be a high cost maintenance system, replacement may be considered. Kettle has an old system (although it's had many improvements recently); most plants are in good shape.

Passive:

Passive fire protection includes:

Fire walls, fire separations, fire stopping and fire retardant coatings

Manual hose stations

Portable fire extinguishers

Firespread curbing, oil spill retention curbs, and oil containment system

Smoke and heat exhaust systems

Various assets have different levels of active/passive protection measures based on their respective station layouts. The layout has a definite impact on controlling fire spread Active and passive fire protection measures vary among generating stations due to the FP&P practices during the different construction periods and whether rehabilitation work has been completed. In the future, additional compartmentalizing can be introduced to further minimize the impact of a fire spread.

Impact of Generating Station Staffing on Asset and Operational Risks

Three generating stations on Nelson River (Gillam area) will require at least the following FP&P improvements:

Kettle G.S.: (35 years old)

- Upgrades of the existing "Conventional" Cerberus/Pyrotronics fire alarm and detection system with an "Addressable" system
- Upgrades of generator fire protection sprinkler system controls (Pyrotronics deluge panels)
- Review of fire separations and fire stops between units and determine the need for fire enclosures or compartmentalizing
- Sprinkler systems piping integrity tests to determine the extent of corrosion internal to the existing sprinkler system piping
- Halon 1301 Automatic System replacement (program in progress)

Long Spruce G.S. (29 years old)

- Upgrades of the existing "Conventional" Notifier fire alarm and detection system with an "Addressable" system
- Review of generator fire protection sprinkler system controls
- Review of fire separations and fire stops between units
- Sprinkler systems piping integrity tests to determine the extent of corrosion internal to the existing sprinkler system piping
- Halon 1301 Automatic System replacement (program in progress)

Limestone G.S. (16 years old):

- Review and possible upgrade of the existing "Honeywell Addressable" fire alarm and detection
- Review of generator fire protection sprinkler system
- Review of fire separations and fire stops between units and to determine the need for fire enclosures or compartmentalizing
- Sprinkler systems piping integrity tests to determine the extent of corrosion internal to the existing sprinkler system piping
- Halon 1301 Automatic System replacement (program in progress)

Halon replacement is costly, so limited in terms of which fire protection systems can be put into place.

Fire protection systems are tested annually, according to the fire code.

Proposed alternative/alternative measures for Managing Risk Area:

A night watchman (may be supported after security discussion).

We could install cameras that can provide visual cues to remote staff.

We could staff for a period after a maintenance event (high likelihood).

Residual Risk Assessment

Risk that remains after risk treatment:

For plants that get inspected a couple of times a day, the residual risk is that someone isn't there in time to detect and contain the fire at its incipient or earliest state.

Newer, bigger stations are more complex, making detection and troubleshooting more difficult.

Volunteer Fire Crew size can at times be based on how many volunteers you have rather than how many volunteers are needed. The overall skill level of the crew may vary and can be negatively impacted by high staff turnover. To offset these potential shortcomings there is a system of mutual aid response system where by stations will respond to and supplement the fire crew of the individual station faced with a fire event.

No utility in Canada or the USA, has their own paid fire brigade. Fire crew members are generally from a utility who dedicate their time on a voluntary basis. These volunteers may get paid some nominal amount for each fire call-out or response. Fire fighting training and fire fighting equipment is generally provided by some of the utilities while the others may rely on the local municipal or city fire crews (similar to Manitoba Hydro 1840 Cheverier Blvd. – WSC who depends on the City of Winnipeg Fire Department).

New risk introduced with risk treatment:

A night watchman needs to be trained in order to respond correctly to a crisis. The position will require a lower level of skill than an operator and so the expectation and system to ensure an adequacy of skill and understanding would have to be developed. The night watchman could become overwhelmed if there is a series of cascading events requiring response.

Reliance on cameras to monitor for emerging fire situations could be limited due to the field of view, ability of monitoring person to interpret the situation being viewed, and is susceptible to camera failure.

There is the potential for staff to become desensitized to a fire alarm. The effort associated with responding to a fire alarm increases in a destaffed station as each alarm requires a call out. There may be a temptation to ignore an alarm as a known nuisance alarm resulting in an under reaction to an actual fire event.

Reporting and Monitoring

Local Volunteer Staff

Fires are reported to Risk Management although not 100% of fires are reported.

Fire protection is checked yearly and documented through the existing maintenance management system.

Impact of Generating Station Staffing on Asset and Operational Risks

Emergency Response is ongoing - level 1 standard that they're training towards, and required to maintain qualifications.

If fire protection needs to be disabled for maintenance, proper reporting is in place.

9.2. Dam Breach

Preliminary Risk Assessment

Financial

In the event of a dam breach, Manitoba Hydro's insurers would cover what the company is legally obligated to pay as damages up to a maximum of $100 M (the limit of our insurance coverage) subject to terms and conditions of the policies.

Impact could vary from relatively minor (~$1M) to catastrophic (>> $150 M) depending on circumstances.

Manitoba Hydro's insurers have reviewed the Dam Safety program and annual reports.

The complete loss of Kettle (i.e. concrete structures, main dam north or south or Saddle Dam) would lead to the cascading failure of Long Spruce and Limestone.

System Reliability

A major dam breach at Kettle or Long Spruce could cause a disturbance and impact system reliability, depending on what the system power requirements are at the time.

Safety - Employee and Public

A dam failure has a high likelihood for the potential of multiple loss of life at Grand Rapids and Seven Sisters depending on the effectiveness of the advance warning.

Safety impact: High - Severe injuries and fatalities and/or non compliance with legislation and industry standards resulting in significant fines, loss of public trust, and possible imprisonment for Manitoba Hydro management.

Environment

There is a high impact (uncontained flooding) for the area surrounding the plant following a dam breach.

Environmental impact: High - Severe widespread and uncontained damage to environment, loss of public trust, long term operating restrictions, and rehabilitation or restoration costs.

Customer Value

A dam breach would attract International media attention.

Customer perception with regard to reputation: High - A highly visible event attracting international media coverage or environmental concern; and/or a significant negative impact on stakeholders such contractual obligation or environmental stewardship

Risk Identification

The specific risk of concern is dam breach (Any structure that loses control of flow) caused by:

Piping (internal failure)	Erosion from wave attack
Overtopping	Mass slope movement

How are these risks impacted by staffing?

Dam breach early warning systems and systems for detecting wind and wave conditions that could lead to erosion and a dam breach are installed and require human verification if they alarm. A prototype anti-vandalism security system is also in place at Seven Sisters that requires confirmation if it alarms. There is no replacement for the human eye to assess and initiate the required action in the event of an emerging dam breach situation. These systems are only at a couple of stations and represent an intermediate effort to mitigate the risk.

If something happens at Kettle, and if somebody is at Limestone and Long Spruce, they may be able to react in time and save the two other plants (unless it is a catastrophic failure at Kettle.) For a breach of the main or saddle dam at Kettle, response at Limestone and Long Spruce would only help to lengthen the time for evacuation and to assist in bringing down the system in a controlled manor. There is no remote spillway operation of the northern collector plants.

Some Dams in the US are hiring armed guards to patrol their forebays.

Potential Impact and Probability

Impact:

High (Financial, Safety, Environment and Customer Value indices)

Probability:

We've had some notable events with dam safety implications at several sites. Examples: sink hole at Kiskitto inlet control structure, near overtopping at Kiskitto outlet structure, wind damage to dykes at Great Falls, McArthur and Seven Sisters, and Limestone construction icing.

A breach is unlikely given the level of due diligence practiced at Manitoba Hydro and the standard to which we maintain our dams. Our dam safety program brings the probability of a dam breach event down to a very unlikely. For most of the dams the consequence category is generally high or very high and requires the dam to be able to withstand extreme loads (floods, earthquakes, wind events) that are equal to or less frequent than the 1 in 1000 year event.

Generation North Plants

For Kelsey, Kettle, Long Spruce, Limestone and Laurie River the impact of a Dam Breach has been classified as “High” while the probability of such an event occurring has been determined to be “Very Rare” (1 in 1000 years).

Generation South Plants

For Jenpeg, Grand Rapids, Great Falls, Seven Sister, Pine Falls, McArthur Falls, Pointe du Bois and Slave Falls River the impact of a Dam Breach has also been classified as “High” while the probability of such an event occurring has been determined to be “Very Rare” (1 in 1000 years).

Plant	Impact	Likelihood	Risk Level

Impact of Generating Station Staffing on Asset and Operational Risks

Generation North	Staffed	Destaffed	Staffed	Destaffed	Staffed	Destaffed
Kettle	High	High	Very Rare	Very Rare	6B	6B
Long Spruce	High	High	Very Rare	Very Rare	6B	6B
Limestone	High	High	Very Rare	Very Rare	6B	6B
Kelsey	High	High	Very Rare	Very Rare	6B	6B
Laurie River	High	High	Very Rare	Very Rare	6B	6B
Generation South	Staffed	Destaffed	Staffed	Destaffed	Staffed	Destaffed
Grand Rapids	High	High	Very Rare	Very Rare	6B	6B
Great Falls	High	High	Very Rare	Very Rare	6B	6B
Pointe du Bois	High	High	Very Rare	Very Rare	6B	6B
Pine Falls	High	High	Very Rare	Very Rare	6B	6B
McArthur Falls	High	High	Very Rare	Very Rare	6B	6B
Slave Falls	High	High	Very Rare	Very Rare	6B	6B
Seven Sisters	High	High	Very Rare	Very Rare	6B	6B
Jenpeg	High	High	Very Rare	Very Rare	6B	6B

Risk Treatment

Existing Measures for Managing Risk Area:

Butneau Early Warning and wind monitoring system.

Wind monitoring for overtopping for Generation South Plants.

Wave buoy at Grand Rapids and run up gauges on the dykes (for research), but they are not alarmed.

Fiber-optic cables have been installed at Seven Sisters (test installation) to detect earth movement or tampering on the dyke. The fiber-optic cable provides early warning by detecting a break in the cable due to mass movement or dam breach, possibly as a result of vandalism.

Under heightened risk, the number of inspections is increased (reactive), but we don't do anything proactively as a result of weather forecast. However, we are installing wind monitoring stations at most Generation South stations because the weather forecast isn't always reliable. We have worked with on call staff in the past. Grand Rapids will increase monitoring of the dyke during high wind events, and increase to twice a shift during storms.

At Pine Falls, a cable tray was ripped off due to wind, and an employee living in Pine Falls went to check, despite not being on call.

According to determination of risk for individual plants, dykes are inspected at different frequencies. The Annual Dam Safety reports for each station provide inspection guidelines.

Ongoing:

We hire consultants to complete periodic comprehensive dam safety reviews.

Proposed Measures for Managing Risk Area

Further consideration can be given to remote operation of spill way gates to enable timely response in the event of the occurrence of a low probability event. It is possible to raise all the gates at the same time, but the controls don't lend to that.

Residual Risk Assessment

Risk that remains after risk treatment:

Despite best efforts, there are no guarantees; initial design, systems and procedures can reduce the risk but it can never be made equal to zero.

Trucks speeding, trucks allowed onto a facility, large fuel tankers slow down. Jenpeg is speaking to the province to reduce speed over the bridge. Formalize what most people with common sense are already doing.

New risk introduced with risk treatment:

Remote operation of flood gates creates a public safety issue (need someone to monitor the channel).

For Generation North - The Northern Civil Section staff currently at Long Spruce would be considered the first defense in case of a problem with the earth structures. The current staff succession plan for this area is to hire Civil Engineering Technologists to fill positions as retirements occur. We also plan to move the supervisor position from Winnipeg back to Gillam. Based on this arrangement the training of the local plant staff to address earth structure problems would not be beneficial. We currently ensure that one of three staff is usually available in the Gillam area 100% of the time.

Reporting and Monitoring

There is an annual report for each plant that summarizes dam safety work. All surveillance reporting is captured here. If anything is flagged during an inspection a phone call is made and there is immediate response from Civil Engineering.

There is a capital item to deal with repairs required to mitigate problems identified in the process ($6 M for Gen South in 2006/07).

Routine Surveillance - daily/weekly/monthly inspections.

More rigorous inspection is done at minimum once a year, more often if a problem is flagged.

Instrumentation is manual, locally recorded and remotely recorded throughout the province. Civil Engineering feels that data analysis could be improved. For Generation North, this data is collected by the Northern Civil Section's Long Spruce staff and

forwarded to other Civil Engineering Department sections. There are plans for automating the collection of some of the data currently collected.

9.3. Security

Preliminary Risk Assessment

Terrorism: A method of opposing a government through the use of violence against civilians, taking of hostages, or destruction of critical infrastructure to gain specific demands; an organized purposeful activity.

Local unrest: The seizure of ownership or control of an asset for the purpose of achieving a politically motivated agenda.

Vandalism: Willful destruction or defacement of property, a non organized activity usually to no specific purpose.

Financial

A terrorist attack could easily have an impact of more than $150 M.

System Reliability

Terrorism can have an impact on system reliability, local unrest and vandalism to a much lesser extent.

Safety - Employee and Public

Vandalism could hurt the vandals, creating a legal liability. Loss of life is possible depending on the hazard awareness of the vandals.

Medium - disabling injuries, in compliance with laws and industry standards. Medium - disabling injuries, in compliance with laws and industry standards.

High - severe injuries and fatalities and/or non compliance with legislation and industry standards resulting in imprisonment for Manitoba Hydro management, significant fines and loss of public trust.

Environment

Customer Value

Blockades and local unrest that result from unsuccessful negotiations can have national if not international media coverage, and certainly impact Manitoba Hydro's reputation.

Medium - A highly visible event attracting national media coverage or environmental concern; and/or a moderate negative impact on stakeholders.

Risk Identification

The highest risk of vandalism and local unrest exists at Grand Rapids and Jenpeg. Every fall we experience vandalism on the dykes, where locals shoot locks off gates to get access to hunting grounds. Grand Rapids and Jenpeg have been blockaded. Any destaffing could bring that vandalism right to the power house.

Seven sisters station is a high consequence dyke with easy access, which is why they have piloted a program to detect earth movement on the dyke. If this system proves successful, there is interest in putting these systems on other critical dykes.

Dams are considered critical infrastructure in the US, as such, security issues will become greater. The US is moving road around Hoover Dam, patrolling forebays with armed guards. There is a definite movement towards greater security in the industry.

Staffing the stations won't keep those who are really committed to terrorism away.

Looking at the vulnerabilities of the system, transmission is more vulnerable than a generating station, as a tower is easier to take out, and can still cause shortage of power.

Kettle and Grand Rapids have been considered as “A” facilities for critical infrastructure. There is a recommendation to increase security at these stations.

There is also a risk of local unrest for a desired settlement.

Potential Impact and Probability

Impact:

Vandalism: If a station is unstaffed the frequency of vandalism could increase due to the perception of being able to get away with it. The financial and safety impact of vandalism is considered low.

Civil Disobedience: It would be an undesirable situation if a station blockade was set up while unmanned, the need to get staff into the station could be complicated. This would be further exacerbated if the blockade led to a local unrest of the station.

Terrorism: Impact could be easily in excess of $150 M.

Local unrest: If we lost control of the station, would we be willing to go into the plant? Until current negotiations are resolved, this could be considered to be a higher risk with a medium impact.

Probability:

Vandalism: Almost certain, happens every year. This would be expected to increase if station was unstaffed.

Terrorism: Unlikely, Manitoba is not a glamorous target.

Local unrest: Right now at Grand Rapids with negotiations going on, there may be a higher likelihood of an event happening (Possible). Currently negotiations are proceeding well, so we don't expect an event. Once resolved, likelihood should reduce.

Generation North Plants

For Kelsey, Kettle, Long Spruce, Limestone and Laurie River the impact of Terrorism has been classified as “High” while the probability of such an event occurring has been determined to be “Rare” (1 in 100 years).

For Kelsey, Kettle, Long Spruce and Limestone the impact of Vandalism has been classified as “Low” with the plants manned while the probability has been classified as “Possible” (1 in 10 years). With the plants not staffed 24 hours a day the probability increases to “Likely” (1 in three years). For Laurie River due to the plants remote location the impact of Vandalism has been also classified as “Low” but the probability

has been reduced to “Unlikely” (1 in 30 years) with the staff on site and to “Possible” (1 in 10 years) if the plants were run with no staff on site.

For Kelsey, Kettle, Long Spruce, Limestone and Laurie River the impact of a Local unrest has been classified as “Low” while the probability has been classified as “Unlikely” (1 in 10 years). This risk was determined to be staff Neutral.

Generation South Plants

For Jenpeg, Grand Rapids, Great Falls, Seven Sister, Pine Falls, McArthur Falls, Pointe du Bois and Slave Falls the impact of Terrorism been classified as “High” while the probability of such an event occurring has been determined to be “Rare” (1 in 100 years).

For Grand Rapids, Great Falls, Seven Sister, Pine Falls and Pointe du Bois the impact of Vandalism has been classified as “Low” while the probability has been classified as “Almost Certain” (Every Year or more frequent). The risk remains the same regardless of the staffing strategy in place (Staffed or Un-staffed). For McArthur Falls and Slave Falls the impact of Vandalism has also been classified as “Low” while the probability due to the sites locations has been classified as “Possible” (1 in 10 years) regardless of the staffing strategy in place. For Jenpeg the impact of Vandalism has been classified as “Low while the probability is show to increase from “Possible” (1 in 10 years) to “Almost Certain” (Every Year or more frequent” if the site was un-staffed.

For Great Falls, Seven Sister, Pine Falls, McArthur Falls, Pointe du Bois and Slave Falls the impact of a Local unrest has been classified as “Low” while the probability has been classified as “Unlikely” (1 in 10 years). This risk was determined to be staff Neutral. For Grand Rapids and Jenpeg the impact of a Local unrest has been classified as “Low” while the probability is show to increase from “Possible” (1 in 10 years) to “Likely” (1 in three years) if the site was un-staffed.

Terrorism						
Plant	**Impact**		**Likelihood**		**Risk Level**	
Generation North	Staffed	Destaffed	Staffed	Destaffed	Staffed	Destaffed
Kettle	High	High	Rare	Rare	6A	6A
Long Spruce	High	High	Rare	Rare	6A	6A
Limestone	High	High	Rare	Rare	6A	6A
Kelsey	High	High	Rare	Rare	6A	6A
Laurie River	High	High	Rare	Rare	6A	6A
Generation South	Staffed	Destaffed	Staffed	Destaffed	Staffed	Destaffed
Grand Rapids	High	High	Rare	Rare	6A	6A
Great Falls	High	High	Rare	Rare	6A	6A
Pointe du Bois	High	High	Rare	Rare	6A	6A

Impact of Generating Station Staffing on Asset and Operational Risks

Pine Falls	High	High	Rare	Rare	6A	6A
McArthur Falls	High	High	Rare	Rare	6A	6A
Slave Falls	High	High	Rare	Rare	6A	6A
Seven Sisters	High	High	Rare	Rare	6A	6A
Jenpeg	High	High	Rare	Rare	6A	6A

Vandalism						
Plant	**Impact**		**Likelihood**		**Risk Level**	
Generation North	Staffed	Destaffed	Staffed	Destaffed	Staffed	Destaffed
Kettle	Low	Low	Possible	Likely	2A	4A
Long Spruce	Low	Low	Possible	Likely	2A	4A
Limestone	Low	Low	Possible	Likely	2A	4A
Kelsey	Low	Low	Possible	Likely	2A	4A
Laurie River	Low	Low	Unlikely	Possible	2B	2A
Generation South	Staffed	Destaffed	Staffed	Destaffed	Staffed	Destaffed
Grand Rapids	Low	Low	Almost Certain	Almost Certain	4A	4A
Great Falls	Low	Low	Almost Certain	Almost Certain	4A	4A
Pointe du Bois	Low	Low	Almost Certain	Almost Certain	4A	4A
Pine Falls	Low	Low	None	Same	4A	4A
McArthur Falls	Low	Low	Possible	Possible	2A	2A
Slave Falls	Low	Low	Possible	Possible	2A	2A
Seven Sisters	Low	Low	Almost Certain	Almost Certain	4A	4A
Jenpeg	Low	Low	Possible	Almost Certain	2A	4A

Local unrest						
Plant	**Impact**		**Likelihood**		**Risk Level**	
Generation North	Staffed	Destaffed	Staffed	Destaffed	Staffed	Destaffed

Impact of Generating Station Staffing on Asset and Operational Risks

Kettle	Low	Low	Unlikely	Unlikely	2B	2B
Long Spruce	Low	Low	Unlikely	Unlikely	2B	2B
Limestone	Low	Low	Unlikely	Unlikely	2B	2B
Kelsey	Low	Low	Unlikely	Unlikely	2B	2B
Laurie River	Low	Low	Unlikely	Unlikely	2B	2B
Generation South	Staffed	Destaffed	Staffed	Destaffed	Staffed	Destaffed
Grand Rapids	Low	Low	Possible	Likely	2A	4B
Great Falls	Low	Low	Unlikely	Unlikely	2B	2B
Pointe du Bois	Low	Low	Unlikely	Unlikely	2B	2B
Pine Falls	Low	Low	Unlikely	Unlikely	2B	2B
McArthur Falls	Low	Low	Unlikely	Unlikely	2B	2B
Slave Falls	Low	Low	Unlikely	Unlikely	2B	2B
Seven Sisters	Low	Low	Unlikely	Unlikely	2B	2B
Jenpeg	Low	Low	Possible	Likely	2A	4B

Risk Treatment

Existing Measures for Managing Risk Area

Restricted access, improvements to fences and gates, and cameras in strategic locations are installed or being installed to enhance physical security. Further strategies are being developed to maintain a level of physical security that is consistent with NERC standards and best practice.

We have a system of alert levels which is utilized to guide each station in vigilance and to implement the required level of awareness.

Motion detectors are installed in some facilities.

The Corporate Emergency Response Manual gives direction in case of threats.

We installed earth movement detection technology to alarm of vandalism to earth dykes at Seven Sisters.

Proposed Measures for Managing Risk Area:

Report that will go to EC that recommends increased security or operators trained as security personnel at critical plants like Grand Rapids.

Background checks on employees for NERC cyber security standards.

Implementation of security awareness training for all employees.

Residual Risk Assessment

Risk that remains after risk treatment:

Security at many of our stations is lax.

New risk introduced with risk treatment:

Introducing security at Grand Rapids could further inflame the situation. Already requiring visitors to sign in has created some animosity in the plant.

Reporting and Monitoring

Corporate Security monitors alert levels.

After an event, there are procedures for reporting a crisis.

9.4. Station Internal Flood

Station internal flood is broken up into two subcategories:

Catastrophic: A sudden large failure resulting in immediate station flood and significant damage. The water flow into the powerhouse would overwhelm the drainage pumps. The head cover failure similar to Grand Rapids Unit 1 is an example.

Noncatastrophic: A failure which develops over time and results in station flooding, damage is usually contained to one unit. Examples include shaft seal failure resulting in flooding in the turbine pit and fracture of the service water intake piping. The failure results in a great deal of inconvenience but water flows into the powerhouse can generally be handled by station drainage pumps.

Risk increases in locations that have no headgates and rely on stoplogs for closure, or have poor quality intake gates which may not function in an emergency.

The following stations do not have headgates:

Pointe du Bois	Slave Falls
McArthur Falls	Jenpeg
Laurie River 1	

The following stations headgate operation is questionable under emergency conditions:

Seven Sisters	Kelsey house units
Laurie River 1	Laurie River 2

Preliminary Risk Assessment

Financial

The financial losses could vary considerably depending upon which station the event occurs and whether the failure is catastrophic or noncatastrophic. The ability to manually or automatically close the head gates in the event of a catastrophic failure will influence the impact of a catastrophic failure.

In the event that a catastrophic failure should occur at a station such as Kettle, Long Spruce or Limestone it is very likely that the total damages and revenue loss would be in excess of $150 million.

For a noncatastrophic failure the costs would probably not exceed $1 million.

The damage costs and the lost revenue costs resulting from the Grand Rapids failure were $16 million and $16 million respectively ($1992.) Again assuming a station such as Kettle the damage costs would probably range somewhere in the neighborhood of $30 million but the revenue losses could easily be well in excess of $100 million.

System Reliability

Safety - Employee and Public

The consequences is High for a catastrophic failure - Manitoba Hydro was extremely fortunate that when the head cover failure occurred at Grand Rapids that the event

happened at the precise time it did, if it had happened two hours earlier or later, fatalities would have resulted.

The likelihood of such an event occurring is rare to very rare.

For the noncatastrophic loss, the consequences should be rated as low and the likelihood of the event occurring rated as possible.

Environment

Catastrophic station flood would result in the release of oil and debris to the river. A noncatastrophic flood should have no significant environmental impact as it would be contained within the station.

Ron Brittner, Civil Structural Engineer, advises that studies of both Grand Rapids and Great Falls indicate that the structural integrity of the dam remains uncertain in the event of prolonged headcover failure flooding.

Customer Value

Customer value could be impacted in confidence in Manitoba Hydro to operate and provide a reliable, dependable supply of power.

High - Outage for extended period of time.

Risk Identification

We are concerned with flooding of the station due to failures of equipment. Examples include head cover failure and shaft seal failures at Grand Rapids that could have resulted in further damage had the station not been staffed.

Station flood is just an alarm, does not initiate automatic action.

Potential Impact and Probability

Impact:

Catastrophic failure: High

Non catastrophic failure: Low

Probability:

Catastrophic failure: Rare

Non catastrophic failure: Possible

Generation North Plants

For Kelsey, Kettle, Long Spruce, Limestone and Laurie River Plant #2 the impact of a catastrophic failure has been classified as “High” while the probability of such an event occurring has been determined to be “Rare” (1 in 100 years). All of the plants have operational Headgates that are maintained and tested as part of the Work Management System with the exception of Laurie River Plant #1. For this plant the station was designed without Headgates so stop logs must be manually installed by site staff.

For the same plants the impact of a Non catastrophic failure has been classified as "Low" while the probability has been classified as "Possible" (1 in 10 years)

Generation South Plants

For Jenpeg, Grand Rapids, Great Falls, Seven Sister, Pine Falls, McArthur Falls, Pointe du Bois and Slave Falls the impact of a catastrophic failure has been classified as "High" while the probability of such an event occurring has been determined to be "Rare" (1 in 100 years). All of the plants have operational Headgates that are maintained and tested as part of the Work Management System with the exception of McArthur Falls, Pointe du Bois and Slave Falls. For these plants the stations were designed without Headgates so stop logs must be manually installed by site staff. A typical response time to an incident at Point du Bois would be around 15 minutes while a response to an incident at McArthur Falls would be around 5 minutes.

For the same plants the impact of a Non catastrophic failure has been classified as "Low" while the probability has been classified as "Possible" (1 in 10 years)

Catastrophic Failure						
Plant	**Impact**		**Likelihood**		**Risk Level**	
Generation North	Staffed	Destaffed	Staffed	Destaffed	Staffed	Destaffed
Kettle	High	High	Rare	Rare	6A	6A
Long Spruce	High	High	Rare	Rare	6A	6A
Limestone	High	High	Rare	Rare	6A	6A
Kelsey	High	High	Rare	Rare	6A	6A
Laurie River	High	High	Rare	Rare	6A	6A
Generation South	Staffed	Destaffed	Staffed	Destaffed	Staffed	Destaffed
Grand Rapids	High	High	Rare	Rare	6A	6A
Great Falls	High	High	Rare	Rare	6A	6A
Pointe du Bois	High	High	Rare	Rare	6A	6A
Pine Falls	High	High	Rare	Rare	6A	6A
McArthur Falls	High	High	Rare	Rare	6A	6A
Slave Falls	High	High	Rare	Rare	6A	6A
Seven Sisters	High	High	Rare	Rare	6A	6A
Jenpeg	High	High	Rare	Rare	6A	6A

Non Catastrophic Failure

Impact of Generating Station Staffing on Asset and Operational Risks

Plant	Impact		Likelihood		Risk Level	
Generation North	Staffed	Destaffed	Staffed	Destaffed	Staffed	Destaffed
Kettle	Low	Low	Possible	Possible	2A	2A
Long Spruce	Low	Low	Possible	Possible	2A	2A
Limestone	Low	Low	Possible	Possible	2A	2A
Kelsey	Low	Low	Possible	Possible	2A	2A
Laurie River	Low	Low	Possible	Possible	2A	2A
Generation South	Staffed	Destaffed	Staffed	Destaffed	Staffed	Destaffed
Grand Rapids	Low	Low	Possible	Possible	2A	2A
Great Falls	Low	Low	Possible	Possible	2A	2A
Pointe du Bois	Low	Low	Possible	Possible	2A	2A
Pine Falls	Low	Low	Possible	Possible	2A	2A
McArthur Falls	Low	Low	Possible	Possible	2A	2A
Slave Falls	Low	Low	Possible	Possible	2A	2A
Seven Sisters	Low	Low	Possible	Possible	2A	2A
Jenpeg	Low	Low	Possible	Possible	2A	2A

Risk Treatment

Existing Measures for Managing Risk Area

An Inspection program for head cover bolts was completed at Grand Rapids and spot testing and analysis of Headcover bolts was completed at all other stations. There is also a penstock inspection program in place for Grand Rapids.

All plants have flood alarms that rely on operators for manual intervention. At some of the plants Operations staff is paged and there is a horn that sounds to advise that an alarm notification has been received in the Control Room.

Having staff onsite for our past emergencies has reduced the impact of the events.

Proposed Measures for Managing Risk Area

Kelsey is looking at systems to automate head gate closure. This is an inexpensive, $5K per unit, solution to mitigate the impact of catastrophic failure with automation of Headgate closure in the event of station flood. In consultation with design groups, and Grand Rapids experience, we've changed the standard design. Technology is more reliable now.

Residual Risk Assessment

Risk that remains after risk treatment:

Despite best efforts, station internal flood may still occur.

New risk introduced with risk treatment:

There is a risk of miss operation of the automatic closure of the head gates.

Reporting and Monitoring

Inspection programs are reported in the asset maintenance programs.

Operating rounds on a daily basis would report problems to Generation Maintenance.

9.5. Water Regulation

The function of the generating station is to both generate power and regulate the flow of water. Water regulation is accomplished by passing flow through the generating units and/or the spillway. Each generating station is responsible for maintaining the forebay level to within license limits. In the event of a disruption to the flow through the generating units, a station operator may be required to balance river flows by passing more water though the spillway.

Failure to properly regulate the water flow can result initially in license limit exceedence and could eventually lead to overtopping resulting in dam breach. Response times vary from station to station and are a function of river flow, operating mode (i.e. cycling) and forebay capacity. This section will deal with water regulation as it applies to license exceedence, overtopping is handled in the dam breach section of the report.

Pointe du Bois is a critical station where a loss of ability to pass flow through the units causes an immediate flow concern as initiating spill at Point du Bois is labour intensive.

The ability to operate the station spillways is critical for water regulation.

There can be situations where electrical or mechanical equipment failure requires the use of the Spillway Standby Diesel or gas engines to cut in spill.

Examples of water regulation incidents:

Pointe du Bois - Hot water tank that leaked, someone left the window open and the pipe froze, lost all the power to the spillway. The following day, we lost the station. We are putting diesel back up. Again, damage was minimized because the station was staffed.

Slave Falls - We exceeded the limit on the station. On October 17, 2004 a station outage resulted in loss of station service and water overtopping the spillway. Station service problems were caused by a poor cabling which resulted in DC ground faults causing loss of station auxiliaries and control.

Preliminary Risk Assessment

Financial

There are currently no financial penalties associated with exceeding our Water Power Act license limits. We do however have agreements with affected communities that define water regime using forebay levels and contain compensation provisions tied to the water regime. The upper limit of the water regime and the compensation zones are based on the license maximum. Compensation has only been paid or defined for water levels below the license maximum. Frequent or extensive excursions above the license maximum could trigger additional related project impact discussions with local communities.

System Reliability

Safety - Employee and Public

Environment

Our hydraulic generating stations are licensed under the provincial Water Power Act. They do not have nor is there the current requirement to have operating licenses under

the provincial Environment Act. The potential environmental impact from water levels rising above license maximums would be a function of the amount of rise and duration above the license limit and the time of year. In general, since the license maximum forebay levels are not linked directly to environmental parameters, minor variations above license maximum forebay levels would likely result in unmeasureable impacts.

Local stakeholder concerns could arise if a forebay level rises above the license maximum for an extended period and the forebay level is linked to a compensation provision in a community agreement. Currently this applies to Kelsey, Kettle, Long Spruce, Limestone, and Grand Rapids.

In the event of a Water Power Act license exceedance, determination of compliance depends on the root cause and the demonstrable level of due diligence exercised in response to the event.

Exceeding our license limits from a regulatory perspective currently has a low to medium impact depending on the amount, frequency and duration of exceedence. This risk is being managed through heightened monitoring and reporting. There are ongoing discussions with Manitoba Water Stewardship to clarify compliance with existing Water Power Act license conditions.

Exceeding our licenses from a stakeholder perspective currently has a low impact depending on the amount, frequency and duration of the exceedance and the level of demonstrable impact. Existing agreements have provisions to facilitate ongoing dialogue related to project impacts. However there is the potential for a third party to draw attention to and express outrage with even minor exceedances.

Customer Value

Risk Identification

We're concerned with license exceedence due to sudden changes in station operating status causing changes in flow capabilities.

Extreme weather conditions that increase water for example, extreme rainfall at Pointe du Bois requiring staff to be on hand to manage the flow on the Winnipeg River.

There is time to react in many instances. Many of the flow regulation conditions develop over time. There is the option to man the plant during high risk situations.

If we look at events caused by mechanical failure, the time to react may be seriously impacted. Likelihood of these events is low.

The Pine falls spillway can been controlled remotely from Great Falls but the gates can only be raised if a minimum spill of 4 feet is already in effect. If spill is less than four feet spill must be initiated at Great Falls. This feature ensures that the public is not put at risk. The remote lowering of the gates can be done at any spill level.

Ice can reduce the number of gates you have available.

Potential Impact and Probability

Impact:

Exceeding license limits – we need to document and report on events. Currently there are no penalties. At this time, it is a low to medium risk,. There are ongoing discussions with Manitoba Water Stewardship to clarify compliance with existing Water Power Act license conditions.

Exceeding license limits that are tied to community agreements-this could trigger related project impact discussions. This is currently a low risk.

Probability:

Almost certain-exceeding our license, as it happens pretty regularly.

Generation North Plants

For Kelsey, Kettle, Long Spruce, Limestone and Laurie River the impact of failure to properly regulate water flow has been classified as “Low” while the probability of such an event occurring has been determined to be “Almost Certain” (Every Year or more frequent)

Generation South Plants

For Jenpeg, Grand Rapids, Great Falls, Seven Sister, Pine Falls, McArthur Falls, Pointe du Bois and Slave Falls River the impact of failure to properly regulate water flow has been classified as “Low” while the probability of such an event occurring has been determined to be “Almost Certain” (Every Year or more frequent)

Plant	**Impact**		**Likelihood**		**Risk Level**	
Generation North	Staffed	Destaffed	Staffed	Destaffed	Staffed	Destaffed
Kettle	Low	Low	Almost Certain	Almost Certain	4A	4A
Long Spruce	Low	Low	Almost Certain	Almost Certain	4A	4A
Limestone	Low	Low	Almost Certain	Almost Certain	4A	4A
Kelsey	Low	Low	Almost Certain	Almost Certain	4A	4A
Laurie River	Low	Low	Almost Certain	Almost Certain	4A	4A
Generation South	Staffed	Destaffed	Staffed	Destaffed	Staffed	Destaffed
Grand Rapids	Low	Low	Almost Certain	Almost Certain	4A	4A
Great Falls	Low	Low	Almost Certain	Almost Certain	4A	4A
Pointe du Bois	Low	Low	Almost	Almost	4A	4A

Impact of Generating Station Staffing on Asset and Operational Risks

			Certain	Certain		
Pine Falls	Low	Low	Almost Certain	Almost Certain	4A	4A
McArthur Falls	Low	Low	Almost Certain	Almost Certain	4A	4A
Slave Falls	Low	Low	Almost Certain	Almost Certain	4A	4A
Seven Sisters	Low	Low	Almost Certain	Almost Certain	4A	4A
Jenpeg	Low	Low	Almost Certain	Almost Certain	4A	4A

Risk Treatment

Existing Measures for Managing Risk Area

There are diesel generators or gas engines as back up for water regulation for those plants with electrically operated gates hoists. (Redundant power supplies and dual electrical feeds to most of the newer installations)

There are alarm systems for forebay levels.

Upgrades to hoists, ongoing maintenance to mitigate concerns, strategic upgrading of dykes (Pointe du Bois in particular).

Some utilities regulate water on a localized manner, but we are managing water regulation on corporate wide level.

Dam safety inspection covers civil aspects of spill ways. Gen. North and Gen South cover electrical/mechanical issues on a year to year basis. There are periodic inspection program for civil structures as part of the Dam Safety program.

In addition, Manitoba Hydro employs external consultants for dam safety review which offers an external opinion on civil, mechanical and electrical conditions.

Cycle the spillway gates to manage icing concerns at Pine Falls. Skin heat is done at most plants. Operate ice booms to manage frazzle ice. Radiant heaters used at Pointe. Steam systems used at Pointe, Slave and Seven Sisters. There are portable units to cut the ice on the Winnipeg River (permanent units at Pointe and Slave).

Residual Risk Assessment

Risk that remains after risk treatment:

Risk treatment reduces likelihood.

New risk introduced with risk treatment:

Reporting and Monitoring

There is continuous monitoring of water levels

Impact of Generating Station Staffing on Asset and Operational Risks

There is immediate follow up and documentation on license exceedences.

We have dam safety reporting.

We have monitoring on EMS, SCADA, and operators plan to operate within the operation that MOST recommends.

9.6. Potential for Surprise

What haven't we though of? Uncommon acts of Nature can be considered in this section; these acts include Earthquakes, Tsunamis, Geomagnetically Induced Currents and others. What is the risk of events we cannot predict? Do we have a plan?

We can take for granted of having our redundant systems in place. If for example we had an electromagnetic pulse that rendered electronics useless. Other surprise elements:

- Tornado and lightning strikes.
- Ice storms.
- A weather condition that made staff unable to reach plants.
- Strange wind events.
- Forest Fires.
- Ferroresonance incident at Dorsey.
- Cyber breach.
- Accidental plane crash taking out a critical facility.
- Pandemic

Response times are calculated on ideal situations. If you combine that with an event, response may be slow.

The Corporation's Emergency Response plan has taken a generic hazards approach.

Preliminary Risk Assessment

Financial

System Reliability

Safety - Employee and Public

Environment

Customer Value

Risk Identification

Having critical infrastructure staffed allows for quick detection and determination of the problem and initiation of appropriate response.

Potential Impact and Probability

Impact:

Potential for surprise is generally rated at a medium impact. Given the above scenarios, impact could be greater, but also could be less

Probability:

Potential for surprise is generally rated as a possible event.

Evaluation for individual plants has not been conducted.

Risk Level: 5A

Risk Treatment

Existing and Proposed Measures for Managing Risk Area

Residual Risk Assessment

Risk that remains after risk treatment:

New risk introduced with risk treatment:

Reporting and Monitoring

9.7. Delay in Restoration

Although the risk of a blackout is not impacted by plant staffing levels, the immediate restoration efforts could be delayed if staff is not present when required. The risk of a blackout is a high impact event, as defined by reliability criteria, because it would affect more than 2000 MW of load. The risk of a blackout is an unlikely event, as it does happen from time to time in the industry. After the system goes black, system restoration begins. This section of the report analyzes the risk of system restoration delays, and the impact of plant staffing levels on restoration delays.

Preliminary Risk Assessment

Financial

If we consider societal costs, a delay from an 8 hour outage to a 24 hour outage would be $103M[2]. If the system is not restored in a timely manner, back up batteries will likely begin to fail, which would require recharging from portable generators. In this scenario significant delays to restoration are unavoidable. Battery back up should be rated for 8 hours, but we know many, if not most, of our battery back up is expected to last less than 8 hours[3]. Therefore, if the system cannot be restored in 8 hours, it is not unreasonable to expect restoration to take as long as 24 hours.

Loss of Export Market revenues are $0.96 M for an 8 hour outage to $2.88M for a 24 hour outage.

Manitoba Hydro's financial liability for a delay in system restoration is not fully quantifiable at this time, because liability for a blackout is linked to proof of negligence. For a blackout event in Manitoba, plant staffing levels is not expected to be considered negligent.

System Reliability

A delay in system restoration would be the prolonged wide spread blackout, could mean that some Manitoba customers would experience outages that would range from 8 hours to 24 hours. NERC criteria will be used to identify the reliability risk of delay to restoration caused by staffing options.

Safety - Employee and Public

Public safety is at a medium risk (traffic lights will be out, frozen pipes, people panic, etc) after a blackout. Prolonging the blackout simply prolongs the medium risk.

Environment

Impact to the environment is minimal, compared to financial, reliability and customer value impacts.

Customer Value

[2] Managing the Risk of a Complete System Shutdown Following the Loss of the HVDC System.

[3] See Appendix 4 for a detailed description of battery life for each station.

A blackout would likely attract international media attention. A delay in restoration, if leaked to the media, would likely attract the same level of media attention.

Risk Identification

Although NERC requires a control area to have a restoration plan for a complete black start condition, it is considered unlikely that an ac initiated disturbance that blacks out the province will in fact black out the northern collector system. The northern collector system is designed to withstand a full load rejection and idle at speed-no-load until the dc load is picked up. We consider the likelihood of southern system blackout, with the Northern Collector system idling, to be a 1 in 30 year event, as it does happen from time to time in the industry. There is, however, a chance that a northern collector system event could potentially black out the collector system, thereby causing the dc to go down and causing a blackout in Manitoba. We would consider the likelihood of a blackout caused by a Northern Collector fault to be a very rare event. For this very rare event, time to restore the system following a system shut down is dependant on having power supply workers (PSWs) at the plants to begin restoration procedures. Plant actions, like opening the spill ways at Limestone, Long Spruce and Kettle, regaining control of unit governor systems and transferring to the alternate station service supply, must be done before PSWs can put their stations in to a state of readiness.

Currently, because we're in the Day 2 market, we are pushing our system harder than we have before because of the financial opportunities that exist. This operation may expose us to additional risk. It is expected that the Northern Collector System will remain intact in this type of blackout. With load growth, should the DC fail, we will blackout part of the province; we do not have enough southern generation, or an alternate path for northern generation, to sustain southern load. NERC Planning standards classify a double Bipole outage as a Category D disturbance. NERC requires a study of Category D disturbances to determine the risks and consequences of the disturbance. The NERC planning standards state that these disturbances “may involve substantial loss of customer demand and generation in a widespread area”. There is no NERC or Midwest Reliability Organization (MRO) requirement to mitigate the impacts of this disturbance with a guideline.

The following table ranks the units into three levels of criticality and priority to system restoration. Within each category, units are listed merely in the order they are analyzed in this section.

Critical Priority 1 (Black Start Units)	Critical Priority 2 (Can impede Restoration)	Critical Priority 3 (Do not impede restoration)
Kelsey Grand Rapids Seven Sisters	Kettle Limestone Long Spruce Great Falls Pine Falls McArthur Falls	Laurie River Pointe du Bois Slave Falls Jenpeg

Black Start Units

The system is restored in islands built around units that have black start capability. These are the critical plants that allow for system restoration to begin. There are three black start plants that we depend on to restore our system, namely Kelsey, Grand Rapids and Seven Sisters.

Kelsey:

Kelsey can be put into the state of readiness from the control center. However, a PSW is required to start the unit. The amount of time that it takes a PSW to get to Kelsey from the staff house delays restoration of the Northern Collector island by that amount of time, although this amount of time is considered to be negligible; PSWs at Kelsey are either working at the plant or at the staff house and able to get to the plant quickly.

Black start capability is planned for Wuskwatim. This capability will supplement Kelsey's black start capability and provide an alternate cranking path for Kelsey and Grand Rapids. Kelsey will remain as the primary cranking path for the northern collector unit.

Grand Rapids:

Grand Rapids can be put into the state of readiness from the control center. However, a PSW is required to start the unit. The amount of time that it takes a PSW to get to Grand Rapids from either the staff house, or from a leisure activity in and around the area, delays restoration of the Grand Rapids island by that amount of time. In a staffed condition, the PSW should already be on site, so this time is negligible. In a destaffed scenario, this time could be anywhere from 15 minutes to an hour and a half, depending on where the PSW is when he/she is called out.

Grand Rapids units are used to control the frequency deviations that occur when load is picked up. If a unit is on 0% droop, this unit can automatically adjust to compensate for frequency deviations. However, it takes a mechanic 7 hours to put the unit on 0% droop. During restoration, a PSW is required to make the adjustments manually, since much load will be picked up by the time a mechanic can make the adjustments to a machine so that it does this automatically. Having a PSW make the adjustments for frequency deviations reduces the risk of shutting down the island. Controls exist that can set Grand Rapids Units to 0% droop remotely, but they are not considered to be cost effective at this time.

Security, especially at Grand Rapids could have a huge impact on restoration. All units with black start capability are considered "Class A" and must meet higher security standards. Security has been addressed in the asset risk section of this report.

Seven Sisters:

Seven Sisters can be put into a state of readiness from the SCC; Seven Sisters requires a PSW to start the black start unit at Seven Sisters. Remote controls exist, but they are not considered reliable for remote black start. Appendix 5 contains the most recent attempt at commissioning remote black start at Seven Sisters. It was also discovered during this test that the Seven Sisters house unit breaker cannot be closed onto a dead

bus. A PSW would have to do it manually. To provide an operable remote black start function, the start chain has to be modified to reset the start chain on closing of the generator breaker and the incomplete sequence timers have to be replaced. Engineering drawings were issued and materials were purchased for the work to be done by Winnipeg River staff (for all the units). So far, timers have been replaced for units 1 and 4 only with no start chain modifications done (Units 2 and 3 are the black start units). The remaining work is in the backlog, awaiting planning and outages.

The ancillary services market will put additional pressure on improving black start reliability at Seven Sisters. The ancillary services market is in the development stage. There are requirements regarding response time and remote start that will have to be addressed for Seven Sisters to qualify as a "self supplied black start unit"[4] in this market.

Northern Collector Island

The Northern Collector Island relies on the Kelsey black start capability if it has gone black. During restoration, water management must be coordinated with the three plants, which requires staff at all plants.[5] It is estimated that following a call out, and putting the stations into a state of readiness from the SCC, Kettle units can be operational in 30 minutes, Long Spruce in 1 hour and Limestone in 1.5 hours. But because of river flow, all three stations can only start units once Limestone is ready, and therefore starting units at these three plants have a 1.5 hour delay. . (It is assumed that it takes 1 hour for a PSW to come from Gillam to Limestone, and that half an hour is required to assess the plant, get control of the governors and transfer to the alternate station service supply.) A delay in the Northern Collector Island results in a delayed HVdc energization, which ultimately delays load being restored to southern Manitoba.

Grand Rapids Island

The Grand Rapids island has two main functions in restoration, outside of restoring the western part of the province. First, it provides the primary cranking path to energize Dorsey. Secondly, this island compensates for frequency deviations caused by load pick up (Grand Rapids' large units make them best suited to provide this compensation). Timely restoration of the Grand Rapids island requires staffing at Grand Rapids.

Winnipeg River Island:

Great Falls and Pine Falls

These plants can be put into a state of readiness from either Great Falls or SCC. This island serves as an alternate path to energizing Dorsey, should the Grand Rapids path

[4] Manitoba Hydro is looking to self supply black start requirements. If black start units do not meet a certain criteria, Manitoba Hydro will be forced to purchase additional ancillary services from the market to participate in the MISO market. Wording for this criterion is still under development.

[5] Long Spruce has the capability of remote spill way control from SCC, but these controls have not been tested or utilized since commissioned.

fail. This island is designed to serve critical loads (such as hospitals, fire pumping stations, police and more) in the Winnipeg area.

McArthur Falls

There is no supervisory control from either Great Falls or SCC; Great Falls can only control units at McArthur Falls. McArthur Falls cannot be put into a state of readiness remotely. McArthur falls is part of the island designed to serve critical loads (such as hospitals, fire pumping stations, police and more) in the Winnipeg area.

Pointe du Bois and Slave Falls

Both Pointe du Bois and Slave falls have the potential to be black start plants; however this functionality has not been tested and is not depended upon for our restoration plan. In our restoration plan, a black start of these units would be attempted. If successful, restoration of the central Winnipeg district could begin. If unsuccessful, restoration of central Winnipeg would be delayed, being energized only after the Grand Rapids island and Winnipeg River island are synchronized. An engineering review should be conducted to determine if Black Start capability is desirable at Pointe du Bois and Slave.

Potential Impact and Probability

There are two scenarios we will consider for restoration of the three Northern Collector plants:

- Scenario 1: Province is completely black, and restoration is required using all three black start facilities. This scenario's likelihood is rare. NERC requires us to have a restoration plan for the worst case scenario, which is this scenario. Appendix 3 contains a Gantt chart detailing the order in which the system is restored and demonstrating impact of staffing delays on restoration. In this scenario, the three black start units initiate restoration, and the Winnipeg River Island, Grand Rapids Island and Northern Collector Island are built around the black start units.
- Scenario 2: AC initiated disturbance either inside or outside Manitoba that causes the AC networked part of the province to go black, leaving the northern collector system to idle. The Northern Collector system is isolated from the rest of the province through Radisson MOD's K1-1 and K1-2. This scenario's likelihood is unlikely (1 in 30 year event) as it does happen from time to time in the industry. In this scenario, the Grand Rapids island still provides the main path to energize Dorsey, with Seven Sisters providing a back up path, should restoration of the Grand Rapids path fail. Restoration time is expected to be improved by a couple of hours in this scenario. (Load can be picked up quicker in this situation).

The remaining plants risk assessment is the same, regardless of how the fault started; there will be no scenario distinction for them.

Reliability Impact

If the plant is not staffed, the impact to restoration is delay in system restoration. Battery back up is rated for 8 hours (and that might be optimistic – many batteries are deficient and unlikely to supply the 8 hours of backup). If restoration takes longer, and batteries fail, time to restore increases significantly. Portable generators to charge

batteries would be required to be brought on site. Battery back up facilitates the opening and closing of breakers required for both putting the system into the state of readiness and restoration. Some breakers can be opened manually.

Our corporate criteria for rating this risk does not provide us the guidance in how to rate this risk. The North American Electric Reliability Council (NERC) has defined high, medium and low impacts for this kind of scenario. The Standard Authorization Request[6] Form from which the following NERC criteria were extracted is provided in appendix 2.

> High - A requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.
>
> Medium - A requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
>
> Low - A requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

Financial Impact

From the HVdc Risk Management Report we saw that societal costs for a four hour black out with four hour restoration would be $124 M in summer, and $184 M in winter. If the blackout lasted eight hours blackout with a sixteen hour restoration, societal costs would be $287 M in winter. The societal cost for a delay from an 8 hour outage to a 24 hour outage in winter is therefore $105 M. These costs do not directly affect Manitoba Hydro.

Manitoba Hydro costs from lost revenue from loss of 1200 MW of export revenue:

8 hour outage x 1200 MW x $100/MWh = $0.96 M

24 hour outage x 1200 MW x $100/MWh = $2.88 M

Prolonging of a blackout is a low to medium event using financial criteria.

[6] This Standard has not yet been approved.

Generation North

Kettle

Scenario 1: impact is medium in a staffed and destaffed scenario, using NERC's definition described above; in a planning horizon (decision to staff), restoration to a normal condition being hindered by this plant is unlikely. Kettle is only a 15 minutes from Gillam. The delays would likely be caused travel time to Limestone. Probability ranking remains rare, as the risk of being in a black out situation that blacks out the northern collector system is rare.

Scenario 2: impact is low in a staffed scenario. In a destaffed scenario, impact would be medium using NERC's definition described above; in a planning horizon (decision to staff), restoration to a normal condition being hindered by this plant is unlikely. The plant should be idling at speed no load, and controllable from SCC. Probability ranking remains unlikely, as the risk of being in a black out situation where the northern collector system idles is unlikely.

Long Spruce

Scenario 1: impact is medium in a staffed and destaffed scenario, using NERC's definition described above; in a planning horizon (decision to staff), restoration to a normal condition being hindered by this plant is unlikely. Long Spruce is only a half hour from Gillam. The delays would likely be caused travel time to Limestone. Probability ranking remains rare, as the risk of being in a black out situation that blacks out the northern collector system is rare.

Scenario 2: impact is low in a staffed scenario. In a destaffed scenario, impact would be medium using NERC's definition described above; in a planning horizon (decision to staff), restoration to a normal condition being hindered by this plant is unlikely. The plant should be idling at speed no load, and controllable from SCC. Probability ranking remains unlikely, as the risk of being in a black out situation where the northern collector system idles is unlikely.

Limestone

Scenario 1: impact is medium in a staffed scenario, using NERC's definition described above; in a planning horizon (decision to staff), restoration to a normal condition being hindered by this plant is unlikely. In a destaffed scenario, the impact is high; restoration to a normal condition will be hindered by travel time to Limestone, since neither Kettle nor Long Spruce units can be started until Limestone is ready to go. Furthermore, the Long Spruce bridge, between Limestone and Long Spruce is prone to snow drifts. In poor winter weather conditions, travel to Limestone could be impacted, and significantly delayed by this bridge. This risk can be mitigated by the "staff during adverse weather conditions" risk treatment. Probability ranking remains rare, as the risk of being in a black out situation that blacks out the northern collector system is rare.

Scenario 2: impact is low in a staffed scenario. In a destaffed scenario, impact would be medium using NERC's definition described above; in a planning horizon (decision to staff), restoration to a normal condition being hindered by this plant is unlikely. The plant should be idling at speed no load, and controllable from SCC. Probability ranking remains unlikely, as the risk of being in a black out situation where the northern collector system idles is unlikely.

Kelsey

Under a staffed and destaffed scenario, impact is medium, using NERC's definition described above; in a planning horizon (decision to staff), restoration to a normal condition being hindered by this plant is unlikely. Despite Kelsey being a black start unit, and the first step in the restoration procedure, on call PSWs are at the staff house; delay due to PSW response time for restoration is unlikely. Probability ranking remains unlikely, as the risk of being in this black out situation is unlikely.

Laurie River

Under a staffed and destaffed scenario, impact is low, using NERC's definition described above; in a planning horizon (decision to staff), staffing at this plant is not expected to affect the ability to restore the system. Laurie River is not critical to the restoration plan. Probability ranking remains unlikely, as the risk of being in this black out situation is unlikely.

Generation South

Grand Rapids

Under a staffed scenario, impact is medium, using NERC's definition described above; in a planning horizon (decision to staff), restoration to a normal condition being hindered by this plant is unlikely. Under a destaffed condition, impact is high; restoration to a normal condition will be hindered, as Grand Rapids is a black start unit, and is the first step in the restoration procedure. Probability ranking remains unlikely, as the risk of being in this black out situation is unlikely.

Great Falls

Under a staffed scenario, impact is low, using NERC's definition described above; in a planning horizon (decision to staff), staffing at this plant is not expected to affect the ability to restore the system. Under a destaffed scenario, impact is medium; in a planning horizon, restoration to a normal condition being hindered by this plant is unlikely. Seven Sisters is the first plant that requires staffing in this island. Seven Sisters is currently not staffed. It is expected that by the time Great Falls is required for restoration, it will already be staffed (as staffing Great Falls in a destaffed scenario should take the same amount of time or less than Seven Sisters). Probability ranking remains unlikely, as the risk of being in this black out situation is unlikely.

Pointe du Bois

Because Pointe du Bois is not relied upon for system restoration, impact is low under a staffed or destaffed scenario; in a planning horizon, staffing at this plant is not expected to affect the ability to restore the system. Probability ranking remains unlikely, as the risk of being in this black out situation is unlikely.

Pine Falls

Under a staffed scenario, impact is low, using NERC's definition described above; in a planning horizon (decision to staff), staffing at this plant is not expected to affect the ability to restore the system. Under a destaffed scenario, impact is medium; in a planning horizon, restoration to a normal condition being hindered by this plant is unlikely. Seven Sisters is the first plant that requires staffing in this island. Seven Sisters is currently not staffed. It is expected that by the time Pine Falls is required for

restoration, it will already be staffed (as staffing Pine Falls in a destaffed scenario should take the same amount of time or less than Seven Sisters). Probability ranking remains unlikely, as the risk of being in this black out situation is unlikely.

McArthur Falls

Under a staffed scenario, impact is low, using NERC's definition described above; in a planning horizon (decision to staff), staffing at this plant is not expected to affect the ability to restore the system. Under a destaffed scenario, impact is medium; in a planning horizon, restoration to a normal condition being hindered by this plant is unlikely. Seven Sisters is the first plant that requires staffing in this island. Seven Sisters is currently not staffed. It is expected that by the time McArthur Falls is required for restoration, it will already be staffed (as staffing McArthur Falls in a destaffed scenario should take the same amount of time or less than Seven Sisters). Probability ranking remains unlikely, as the risk of being in this black out situation is unlikely.

Slave Falls

Because Slave Falls is not relied upon for system restoration, impact is low under a staffed or destaffed scenario; in a planning horizon, staffing at this plant is not expected to affect the ability to restore the system. Probability ranking remains unlikely, as the risk of being in this black out situation is unlikely.

Seven Sisters

Under a staffed scenario, impact is medium, using NERC's definition described above; in a planning horizon (decision to staff) restoration to a normal condition being hindered by this plant is unlikely. Under a destaffed condition, impact is high; restoration to a normal condition will be hindered, as Seven Sisters is a black start unit, and is the first step in the restoration procedure. When remote black start capability is operational at Seven Sisters, impact in an unstaffed scenario will be medium. Probability ranking remains unlikely, as the risk of being in this black out situation is unlikely.

Jenpeg

Because Jenpeg is not relied upon for system restoration, impact is low under a staffed or destaffed scenario; in a planning horizon, staffing at this plant is not expected to affect the ability to restore the system. Probability ranking remains unlikely, as the risk of being in this black out situation is unlikely.

Plant	**Impact**		**Likelihood**		**Risk Level**	
Generation North	Staffed	Destaffed	Staffed	Destaffed	Staffed	Destaffed
Kettle – Scenario 1	Medium	Medium	Rare	Rare	3A	3A
Kettle – Scenario 2	Low	Medium	Unlikely	Unlikely	2B	5B
Long Spruce - Scenario 1	Medium	Medium	Rare	Rare	3A	3A
Long Spruce - Scenario 2	Low	Medium	Unlikely	Unlikely	2B	5B

Impact of Generating Station Staffing on Asset and Operational Risks

Limestone - Scenario 1	Medium	High	Rare	Very Rare	3A	6A
Limestone - Scenario 2	Low	Medium	Unlikely	Unlikely	2B	5B
Kelsey	Medium	Medium	Unlikely	Unlikely	5B	5B
Laurie River	Low	Low	Unlikely	Unlikely	2B	2B
Generation South	Staffed	Destaffed	Staffed	Destaffed	Staffed	Destaffed
Grand Rapids	Medium	High	Unlikely	Unlikely	5B	8B
Great Falls	Low	Medium	Unlikely	Unlikely	2B	5B
Pointe du Bois	Low	Low	Unlikely	Unlikely	2B	2B
Pine Falls	Low	Medium	Unlikely	Unlikely	2B	5B
McArthur Falls	Low	Medium	Unlikely	Unlikely	2B	5B
Slave Falls	Low	Low	Unlikely	Unlikely	2B	2B
Seven Sisters	Medium	High	Unlikely	Unlikely	5B	8B
Jenpeg	Low	Low	Unlikely	Unlikely	2B	2B

Risk Treatment

Existing Measures for Managing Risk Area:

Studies are underway to confirm current restoration procedures using computer simulation software. NERC Reliability standard EOP-005-0 requires us to verify restoration procedure using simulation.

There is a 10 year battery replacement program in place, designed to replace batteries at critical stations first. Once the program is complete, batteries at all AC terminal stations should be dependable for 12 hours of charge. This program is one year into its course, and is already one year behind schedule.

Proposed Measures for Managing Risk Area

This fall/winter, TSO staff hopes to visit the plants to confirm execution of the restoration plan to bring together plant operation plans with the system restoration plans.

Based on potential weather, Power Supply could staff the plants for high risk situations. A definition is required to determine a high risk weather condition, single contingency operating conditions, (high) river flows, and forest fires that put Manitoba Hydro in a high risk situation.

Experience from other blackouts indicates that cell phone communications quickly “jam” after the event, making call outs difficult, if not impossible. To mitigate this risk, on-call PSWs should be equipped with a VHF pager, providing dedicated communication in case of emergency. Furthermore, should the on-call PSW not be reachable, a back up plan should be in place to facilitate SCC’s role in getting a station manned.

Brandon is the weakest part of the province from a restoration standpoint, and so is the last part to be restored. The Brandon CTs are modular, and the option for black start was not purchased; black start capability could be purchased at a later date to mitigate this risk.

If plants become destaffed at night, estimated call out times would have to be confirmed and compared against the system restoration timing diagram to ensure timely restoration.

Residual Risk Assessment

Risk that remains after risk treatment:

Once the risk at Seven Sisters is mitigated by making remote black start feasible at Seven Sisters, proving that on-call staff can get to Seven Sisters within 20 minutes or staffing the plant, this risk will be mitigated to a 5B. 24/7 staffing mitigates the risk at Grand Rapids from an 8B to a 5B. All other risk mitigation reduces the impact of delays to system restoration. The probability of the blackout doesn't change.

Reporting and Monitoring

Ongoing program to keep plant staff involved in restoration plan development. Part of the ongoing program would include staffing drills.

Impact of Generating Station Staffing on Asset and Operational Risks

9.8. Plant Operational Issues

Preliminary Risk Assessment

Financial

Low

System Reliability

Low

Safety - Employee and Public

N/A

Environment

N/A

Customer Value

N/A

Risk Identification

Financial Risk in Operations

There is an economic risk to Power Supply if the promised energy from the day-ahead market cannot be delivered due to staff not being present at generating stations to perform required actions to facilitate the sale; generation must be made up elsewhere, which exposes us to real time market prices. Furthermore, there are penalties in the form of reserve sufficiency guarantees, should Manitoba Hydro not be able to deliver the energy promised in the day-ahead market.

Reliability Risk in Operations

From a reliability standpoint, a unit may trip off, and without an operator on site, getting the unit operational may not occur in a timely fashion; SCC would have to wait until the operator arrived for the call out to determine the problem and return the unit to operation.

As a balancing authority for NERC, there are performance targets we need to meet. Part of this is strict generation control. From a reliability performance standpoint, strict generation control is required as well. If we fail DCS (disturbance control standard) performance, we are penalized in the form of having to carry higher spinning reserves.

Right now, not many alarms come into SCC, because the onsite PSWs can deal with the alarms before they reach the SCC. We may require re-assessing local, secondary and primary alarming at the plant. In a destaffed scenario, how many alarms would be filtered through? And how many of those alarms are nuisance alarms (secondary alarms that don't require immediate action)? These questions need to be answered to identify the risk of overloading our SCC operators. This risk can be mitigated by hiring more SCC staff.

Potential Impact and Probability

Impact:

The impact of operational issues is limited from a financial sense by the fact that a PSW could be called out to perform the corrective action, should immediate problem correction be deemed a requirement. Reserve sufficiency guarantees could be pricey, but unlikely to reach the $50 M mark. Therefore financial impact is low. However, we should consider the amount of money we save from destaffing versus the money we may have to pay for call outs and sophisticated controls that allow a reliable destaffed scenario, to determine the business case analysis.

The reliability impact is also deemed to be low from an operational perspective; if something were to threaten reliability, on call operators would be called out to rectify the situation. Otherwise, the problem would likely wait until the PSW reported to work. So there is little to no impact to reliability.

Probability:

In the current staffed scenario, the likelihood of not being able to respond to a situation in a timely manner is unlikely. The probability of untimely response following an operational issue during a destaffed condition would be almost certain on yearly and perhaps monthly basis.

Northern Collector plants:

Kettle, Limestone, and Long Spruce are referred to the Northern Collector plants. Operational issues have a higher impact for these plants, because of the size of the units and the plants. Reserves are generally carried on theses plants, and are therefore the plants most critical to EM calls and reserve sufficiency guarantees. Despite the magnitude of the operational issues at these plants, impact would still be low using corporate criteria. In the current staffed scenario, the likelihood of not being able to respond to a situation in a timely manner is unlikely. In a destaffed condition, on call operators would have to come from Gillam. The probability of untimely response following an operational issue during a destaffed condition would be almost certain on yearly and perhaps monthly basis.

Grand Rapids:

Grand Rapids is likely the plant most affected by operational issues. It has been plagued by unique operation and maintenance problems since it was built. Furthermore, this plant is used to manage Area Control Error (ACE), Automatic Generation Control (AGC) and frequency control. (SCC has the ability to perform these functions remotely. Northern collector plants can also be used for AGC.) Despite being the plant that has the most affect on operational issues, the impact is still ranked low using the corporate criteria. It is currently staffed 24x7. In the staffed scenario, PSW have demonstrated how their quick actions can manage the issues that arise at the plant; likelihood of an untimely response is unlikely. In a destaffed scenario, staff may be difficult to locate due to the leisure activities they may be involved in while on call. The Grand Rapids staff house is close to the power plant; however the town of Grand Rapids provides many distractions. The probability of untimely response following an operational issue at Grand Rapids would be almost certain on yearly and perhaps monthly basis.

Winnipeg River plants:

All Winnipeg River plants are old, and so are more prone to having things go wrong. Operators are called out daily, at various points during the day and night, to solve problems. Likelihood of something going wrong at these plants is higher than the newer stations. However, units on these plants are small, so impact of operational issues is low, and much lower than impact for Northern Collector plants.

Currently, both Pointe du Bois and Great Falls are staffed 24/7. In the current staffed scenario, the likelihood of not being able to respond to a situation in a timely manner is unlikely. The probability of untimely response following an operational issue during a destaffed condition would be almost certain on yearly and perhaps monthly basis. Because of the age of the plants, likelihood of operational issues occurring at Winnipeg River plants is higher than at Northern Collector plants, despite registering the same likelihood on our scale.

Slave Falls, Pine Falls and McArthur falls are operated under Pointe du Bois and Great Falls. An operational issue at these plants has a PSW close by to address it in a staffed scenario (at Pointe du Bois and Great Falls). Analysis of a destaffed scenario (at Pointe du Bois and Great Falls) for these three plants is the same as the Point du Bois and Great Falls analysis.

Seven Sisters is manned daily, 4 days a week. There is an operator on call should there be any operational issue after hours. Destaffing beyond this point is not being considered. Impact is low at this plant for reasons already stated above. Likelihood untimely response following an operational issue occurs several times a year, without impacting the system much. If it were staffed, the likelihood of an untimely event would be unlikely.

Kelsey, Laurie River, Jenpeg

These plants already destaffed at night. We are not considering destaffing any further. Impact of operational issues is low at this plant for reasons already stated above. PSWs are called out once a day at Kelsey and Jenpeg; PSWs are called out once a week at Laurie River (Laurie River is a much smaller plant with only three units producing a combined output of 10 MW; Jenpeg has six units producing 168 MW and Kelsey has 6 units producing 224 MW). All three plants have staff houses on-site; thus response is timely. Likelihood of an untimely response following an operational issue is unlikely.

Plant	**Impact**		**Likelihood**		**Risk Level**	
Generation North	Staffed	Destaffed	Staffed	Destaffed	Staffed	Destaffed
Kettle	Low	Low	Unlikely	Almost Certain	2B	4A
Long Spruce	Low	Low	Unlikely	Almost Certain	2B	4A
Limestone	Low	Low	Unlikely	Almost	2B	4A

				Certain		
Kelsey	N/A	Low	Unlikely	Unlikely	2B	2B
Laurie River	N/A	Low	Unlikely	Unlikely	2B	2B
Generation South	Staffed	Destaffed	Staffed	Destaffed	Staffed	Destaffed
Grand Rapids	Low	Low	Unlikely	Almost Certain	2B	4A
Great Falls	Low	Low	Unlikely	Almost Certain	2B	4A
Pointe du Bois	Low	Low	Unlikely	Almost Certain	2B	4A
Pine Falls	Low	Low	Unlikely	Almost Certain	2B	4A
McArthur Falls	Low	Low	Unlikely	Almost Certain	2B	4A
Slave Falls	Low	Low	Unlikely	Almost Certain	2B	4A
Seven Sisters	N/A	Low	Unlikely	Almost Certain	2B	4A
Jenpeg	N/A	Low	Unlikely	Unlikely	2B	2B

Risk Treatment

Existing Measures for Managing Risk Area:

Currently there is staff on site to manage the operational issues. Many controls exist to perform operations from SCC.

Proposed Measures for Managing Risk Area:

Should plants become destaffed, alarming and automation of certain actions would have to be brought into the control center. How much would these controls cost, would more staff be required at SCC to handle more control actions and how effectively can they perform the required actions?

In a destaffed situation, shifts could be staggered to start and stop to coincide with starting and stopping times of the units; for example, have the plant partially staffed for load pick up at 6 am. (With the market evolving, the timing of these load pick ups is becoming more volatile). This risk mitigation treatment could be considered for one plant to test the functionality of a destaffed scenario at night, and alternate staffing times for day time operations.

Residual Risk Assessment

Risk that remains after risk treatment:

It is difficult to assess the risk that remains after staggering the shifts and leaving stations destaffed overnight, due to limited destaffed experience with large scale plants. Based on our experience with Winnipeg River plants, operators are called out daily to solve problems. This experience cannot be directly translated to Northern Collector plants or Grand Rapids, as the Winnipeg River does not supply AGC nor EM calls. We could begin tracking required operator actions during the proposed destaffed times to get a better idea of number of callouts for these stations.

New risk introduced with risk treatment:

SCC staffing requirements may have to be increased to cover destaffing in the plants, increased alarming from plants and increased operations from SCC. The pilot option (removing the night shift at one plant) would identify SCC needs better.

Reporting and Monitoring

Cost of outages, maintenance outages and forced outage rates would be used to monitor and quantify the cost effectiveness of this solution.

10. Appendix 1: Black Start Certification Requirements

Source: Wuskwatim Interconnection Agreement

3.11.2 Certification

In order for Generator to receive compensation for Black Start Service, Transmission Owner must certify the Generator's Black Start Service facilities. Four certification tests are required to be conducted jointly by Transmission Owner and Generator as follows:

a) Black Start Service facilities shall be tested annually. Service facility test shall be comprised of the following sequence:

- (i) verification of communications between Transmission Owner and Generator;
- (ii) startup of the supplemental generator;
- (iii) startup of the Black Start Unit.

b) Line energizing test shall be performed once every 3 years for a minimum 30 minute period or otherwise tested by steady state and dynamic computer simulation.

c) Load carrying test determines the ability of the Black Start Service facilities to remain stable and to control voltage and frequency while supplying restoration power to the generator or load that the restoration plan calls for. This is to be conducted at least every 5 years for a minimum 30 minute period, but if this is impractical, test may be conducted by steady state and dynamic computer simulation.

d) Any supplemental generators (diesel generators, batteries, etc.) and auxiliary equipment that may be required for support of the Black Start Service process shall be tested at least monthly.

3.11.3 Scope of Certification Testing

Black Start Service testing performed pursuant to Section 3.10.2 shall include the following components:

a) Black Start Service facilities;

b) Back up power supplies;

c) Any facilities used to control and / or protect main or supplemental generating units such as computers, programmable logic controllers or protective relaying;

d) Local service facilities to ensure critical plant loads (lighting, heating, air conditioning) are available during black start conditions;

e) Communication systems.

For the purposes of this Section 3.11.3, "critical plant loads" shall mean the plant infrastructure necessary for a plant operator to perform Black Start Service obligations.

3.11.4 Verification of Tests

Black Start Service tests shall be verified by the Transmission Owner's System Performance **Department** through steady state and dynamic computer simulations. Simulations to verify load carrying ability shall be conducted at least every five years.

3.11.5 Test Duration

Any supplemental generating unit shall be started, synchronized and carry load for at least 15 minutes per month. The Black Start Service facilities shall demonstrate the ability to deliver acceptable voltages and frequency values for a minimum of thirty minutes at both no load and during load pickup. The reactive supply and voltage control shall maintain system voltage within emergency voltage limits over a range from no external load to full external load.

3.11.6 Performance Requirements

a) Black Start Service facilities shall demonstrate the capability to start the generating units while isolated from all power sources and auxiliaries not expected to be available under actual black start conditions.

b) To meet certification requirements, the generating unit(s) must be started and synchronized to the system within a time specified by the

Transmission Owner. This includes being isolated from any other unrelated unit support except that of a supplemental generator designated specifically for Black Start Service.

c) All key operating aids and auxiliary systems used in the Black Start Service tests such as voice communications and control systems shall be verified to operate adequately without dependency on the interconnected power system or other unrelated generation support. The test shall include starting the generating unit(s) from a shutdown state with the head gates closed and the governor system depressurized to the alarm state.

d) Generator's Black Start Unit shall be capable of energizing an initially dead station and auxiliary bus condition and shall be able to safely withstand the sudden and unplanned loss of synchronization with the Transmission System and maintain generating capacity for a specified period of time. All auxiliary loads shall be isolated from the power system. Black Start Units shall be capable of re-energizing the plant auxiliaries to start one or more additional units. Black Start Units shall be capable of picking up external load.

e) The Transmission Owner shall conduct testing or simulation or both to verify the Black Start Service facilities are operable in accordance with the Transmission Owner's system restoration plan. These tests and/or simulations shall ensure the Black Start Service facilities and Transmission System are configured such that the Black Start Service facilities resources are able to energize the appropriate portions of the Transmission System and supply restoration power to the generating unit or loads as required by the restoration plan. If it is not feasible to isolate the transmission and loads in the black start path then computer simulations will be carried out at least every five years to ensure the Black Start Service facilities are able to perform as intended in the black start plans. The Black Start Service facilities must provide frequency and voltage within prescribed limits during line energization and remote load pickup. The Transmission Owner shall verify the actual performance of the Black Start Service facilities. The MW capability of the Black Start Service facilities must be accredited by the Transmission Owner.

11. Appendix 2: NERC SAR for Violation Risk Factors

Source: http://www.nerc.com/~filez/standards/Violation-Risk-Factors.html

E-mail completed form to: mark.ladrow@nerc.net

Standard Authorization Request Form

Title of Proposed Standard	Violation Risk Factors
Request Date	January 5, 2006

SAR Requestor Information	**SAR Type** (Put an 'x' in front of one of these selections)	
Name Stan Kopman, chair	☐	New Standard
Primary Contact: Stan Kopman	☒	Revision to existing Standard
Telephone (212) 840-1070 Fax (212) 302-2782	☐	Withdrawal of existing Standard
E-mail skopman@npcc.org	☐	Urgent Action

Purpose/Industry Need (Provide one or two sentences)

This SAR proposes a matrix that assigns a risk of high, medium, or lower for all of the requirements contained in the reliability standards. This assignment provides a baseline understanding of the risk that a violation of a requirement poses to the bulk power system. This factor will be used when determining a penalty or sanction for a violation of that requirement.

Reliability Functions

The Standard will Apply to the Following Functions *(Check box for each one that applies by double clicking the grey boxes.)*		
☒	Reliability Authority	Ensures the reliability of the bulk transmission system within its Reliability Authority area. This is the highest reliability authority.
☒	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within its metered boundary and supports system frequency in real time
☒	Interchange Authority	Authorizes valid and balanced Interchange Schedules
☒	Planning Authority	Plans the bulk electric system
☒	Resource Planner	Develops a long-term (>1year) plan for the resource adequacy of specific loads within a Planning Authority area.
☒	Transmission Planner	Develops a long-term (>1 year) plan for the reliability of transmission systems within its portion of the Planning Authority area.
☒	Transmission Service Provider	Provides transmission services to qualified market participants under applicable transmission service agreements
☒	Transmission Owner	Owns transmission facilities
☒	Transmission Operator	Operates and maintains the transmission facilities, and executes switching orders
☒	Distribution Provider	Provides and operates the "wires" between the transmission system and the customer
☒	Generator Owner	Owns and maintains generation unit(s)
☒	Generator Operator	Operates generation unit(s) and performs the functions of supplying energy and Interconnected Operations Services
☒	Purchasing-Selling Entity	The function of purchasing or selling energy, capacity and all necessary Interconnected Operations Services as required
☒	Market Operator	Integrates energy, capacity, balancing, and transmission resources to achieve an economic, reliability-constrained dispatch.
☒	Load-Serving Entity	Secures energy and transmission (and related generation services) to serve the end user

Reliability and Market Interface Principles

Applicable Reliability Principles *(Check boxes for all that apply by double clicking the grey boxes.)*	
☒	1. Interconnected bulk electric systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☒	2. The frequency and voltage of interconnected bulk electric systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk electric systems shall be made available to those entities responsible for planning and operating the systems reliably.
☒	4. Plans for emergency operation and system restoration of interconnected bulk electric systems shall be developed, coordinated, maintained and implemented.
☒	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk electric systems.
☒	6. Personnel responsible for planning and operating interconnected bulk electric systems shall be trained, qualified and have the responsibility and authority to implement actions.
☒	7. The security of the interconnected bulk electric systems shall be assessed, monitored and maintained on a wide area basis.
Does the proposed Standard comply with all of the following Market Interface Principles? *(Select 'yes' or 'no' from the drop-down box by double clicking the grey area.)*	
1. The planning and operation of bulk electric systems shall recognize that reliability is an essential requirement of a robust North American economy. Yes	
2. An Organization Standard shall not give any market participant an unfair competitive advantage. Yes	
3. An Organization Standard shall neither mandate nor prohibit any specific market structure. Yes	
4. An Organization Standard shall not preclude market solutions to achieving compliance with that Standard. Yes	
5. An Organization Standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes	

Detailed Description (Provide enough detail so that an independent entity familiar with the industry could draft, modify, or withdraw a Standard based on this description.)

The requirements associated with each NERC reliability standard have been assigned a level of risk; high, medium, or lower, based on the detrimental effect a violation of the requirement could have on the reliability of the bulk power system. These levels of risk are in a matrix that, if approved, will become an addendum to the existing reliability standards and included in the body of the newly developed standards.

These proposed initial risk factors were assigned by the SAR drafting team. Risk factors for new standards and requirements are proposed to be created by the standard drafting teams using criteria that will be included in the Reliability Standards Process Manual. The risk factors from this matrix will be inserted into the proper standard as each reliability standard comes up for its five-year review. At that time, the requirement and risk factor will be retired from the addendum.

All proposed risk factors will be posted for stakeholder comment prior to being balloted. For violation risk factors being developed for already approved standards, a matrix of risk factors will be balloted. In the future, risk factors will be added to each requirement by the associated standard drafting team. The risk factors will become a part of the standard and will be subject to stakeholder comment and balloting.

The Need for Violation Risk Factors

Since their inception, the NERC Reliability Standards have not included approved indicators of the relative risk of non-compliance. Without these indicators, it is difficult for the industry, regulators, and public to understand the risk that violations can have on the bulk electric system. From standard to standard, the current noncompliance levels do not provide a consistent indication of relative risk to the bulk electric system.

The proposed violation risk factors are designed to indicate the potential reliability impact of violating a standard requirement. Assigning a risk factor to each requirement is fundamental to implementing the ERO Sanction Guidelines if NERC becomes the ERO. The existing levels of noncompliance for each standard, when used with the existing penalty matrix, are based on a limited amount of information that makes it difficult to develop a fair or meaningful penalty or sanction for a violation. A new and more consistent method that relies on the violation risk factor to create the base penalty in the ERO Sanction Guidelines has been developed. The ERO Sanction Guidelines document is part of the NERC's ERO Application and will be used to determine penalties and sanctions when a requirement is violated.

Development of the Violation Risk Factors

The SAR drafting team developed the initial violation risk factors, using the definitions contained in the list and assigned a violation risk factor of high, medium, or lower to each currently approved standard requirement.

Definition of Risk Factors

The requirements associated with each of NERC reliability standards have been assigned a level of risk; high, medium, and lower, based on the detrimental effect a violation of the requirement could have on the reliability of the bulk power system. The following definitions were applied to determine the assignment of risk for each requirement:

High Risk Requirement
a. A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or

b. A requirement in a planning time frame that, if violated, could, under emergency, abnormal or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement
a. A requirement that, if violated, could directly and adversely affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or
b. A requirement in a planning time frame that, if violated, could, under emergency, abnormal or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement
a. A requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. A requirement that is administrative in nature; or
b. A requirement in a planning time frame that, if violated, would not, under the emergency, abnormal or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

Other Relevant Standards Activities

The violation risk factors are part of a larger plan to improve the standards process and the standards themselves. Also attached is the White Paper on Guidelines for Compliance Information in Support of Reliability Standards that was approved by both the Standards Authorization Committee and the Compliance and Certification Committee (CCC). The paper outlines the proposed changes to the Reliability Standards Process Manual that includes restructuring the compliance elements in the standards. Some of the compliance elements currently contained in the standards will be moved to a manual administered by the CCC. An open process to develop, revise, and approve compliance elements for a new or revised standard will parallel the development of that particular standard. Violation risk factors, however, would be included as part of each standard requirement. They would be developed by the subject matter experts on the standard drafting teams and reviewed and approved by the industry in accordance with the standards ballot process.

Related Standards

Standard No.	Explanation
All	All standards that are in effect as of 1/1/2006 have violation risk factors developed. Those approved after that date but before the final risk violation factors standard is balloted will have factors developed so no requirements are left without factors.

Related SARs

SAR ID	Explanation
Reliability Standards Process Manual	The Reliability Standards Process Manual is undergoing proposed changes; additional changes would be required.
Provide Missing Measures and Compliance Elements in Existing Standards	This is a parallel effort to clarify compliance enforcement elements in the standards for consistency.

Regional Differences

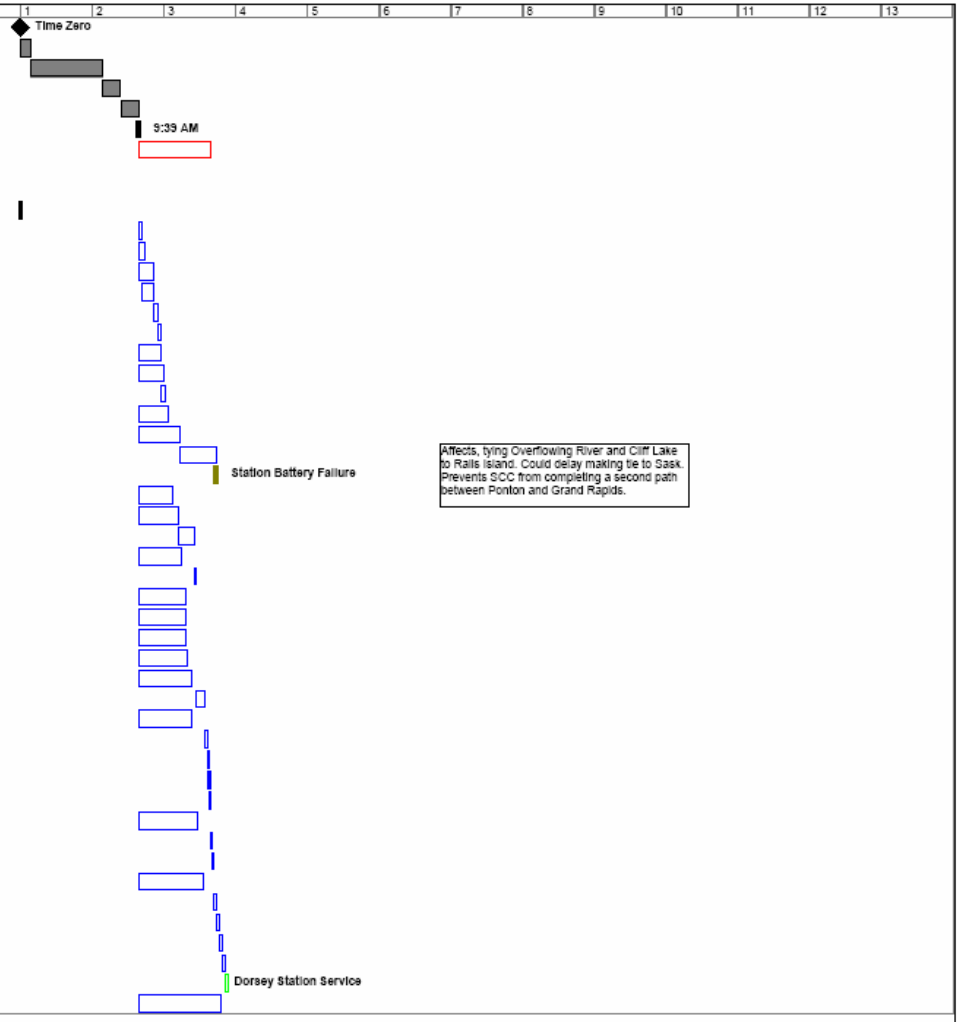
Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
RFC	
SERC	
SPP	
WECC	

12. Appendix 3: Gantt chart detailing the timing of the current System Restoration Plan following a complete blackout of the province

Source: Doug Rempel – Staff Officer, Emergency Operations, System Control Department, TSO

Impact of Generating Station Staffing on Asset and Operational Risks – Appendices

ID	Task Name	Station	Duration	Predecessors
1	**Time Zero - System Blackout**		0 hrs	
2	Panic factor	Delays	0.15 hrs	1
3	System Assessment	SCC	1 hr	2
4	Notifications, discussion	MISO, neighbours	0.25 hrs	3
5	Call outs, delays due to phone calls	SCD & Plant staff	0.25 hrs	4
6	Station Staffing plan	Initiation	0 hrs	5
7	Station Staffing plan	Complete	1 hr	6
8				
9	**Grand Rapids Island**		0 hrs	
10	Station Service Restored (HU)	Grand Rapids (BS)	0 hrs	
11	S.O.R.	Grand Rapids	0.05 hrs	5
12	S.O.R.	GR 25 kV stn	0.08 hrs	5
13	S.O.R.	Vermillion	0.2 hrs	5
14	Grand Rapids	Units online	0.16 hrs	11
15	Grand Rapids	G31V	0.07 hrs	13,14
16	Grand Rapids	GR 25 kV stn	0.03 hrs	15
17	S.O.R.	Ashern	0.31 hrs	5
18	S.O.R.	Minitonas	0.36 hrs	5
19	Grand Rapids	G2A	0.07 hrs	16
20	S.O.R.	Dorsey 1	0.41 hrs	5
21	Rail's Island	Staffed	0.58 hrs	6
22	S.O.R.	Rail's Island	0.5 hrs	21
23	Station Batteries - Semi-critical	Rails Island 91%	0 hrs	22
24	S.O.R.	Silver	0.48 hrs	5
25	S.O.R.	Ponton	0.56 hrs	5
26	Grand Rapids	G8P	0.22 hrs	19,25
27	S.O.R.	Dorsey 2	0.6 hrs	5
28	Vermillion	BK2, SS	0.03 hrs	26
29	S.O.R.	Rosser	0.65 hrs	5
30	S.O.R.	Dorsey 5	0.66 hrs	5
31	S.O.R.	Jenpeg	0.66 hrs	5
32	S.O.R.	Roblin South	0.68 hrs	5
33	S.O.R.	Raven Lake	0.73 hrs	5
34	Vermillion	BK1, V38R	0.12 hrs	28,33
35	S.O.R.	St. Leon	0.75 hrs	5
36	Vermillion	66kV L56	0.03 hrs	34
37	Raven Lake	BK3, Reactor	0.02 hrs	36
38	Vermillion	M39V, Reactor	0 hrs	37,18
39	Minitonas	BK3/4, SS	0.02 hrs	38
40	S.O.R.	Glenboro South	0.83 hrs	5
41	Vermillion	A6V	0.02 hrs	39,17
42	Ashern	BK1, 2, 5, SS	0.02 hrs	41
43	S.O.R.	Birtle South	0.91 hrs	5
44	Ashern	G2A to A6V	0.05 hrs	42
45	Ashern	A3R, reactor	0.03 hrs	44
46	Rosser	BK3, reactor	0.05 hrs	45
47	Rosser	D5R	0.03 hrs	46
48	Dorsey	**D13R, SS**	0.04 hrs	47
49	S.O.R.	Virden West	1.15 hrs	5



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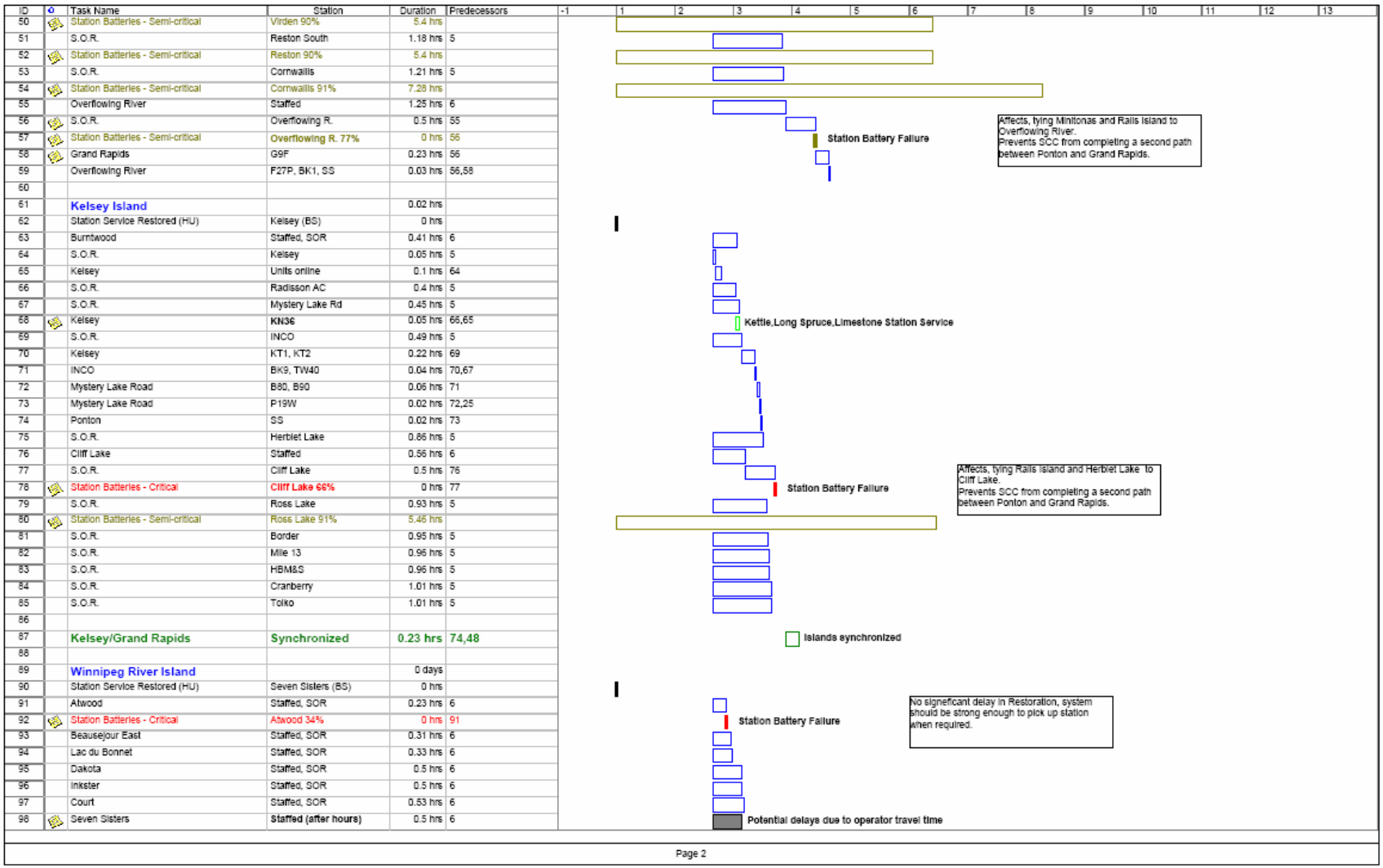
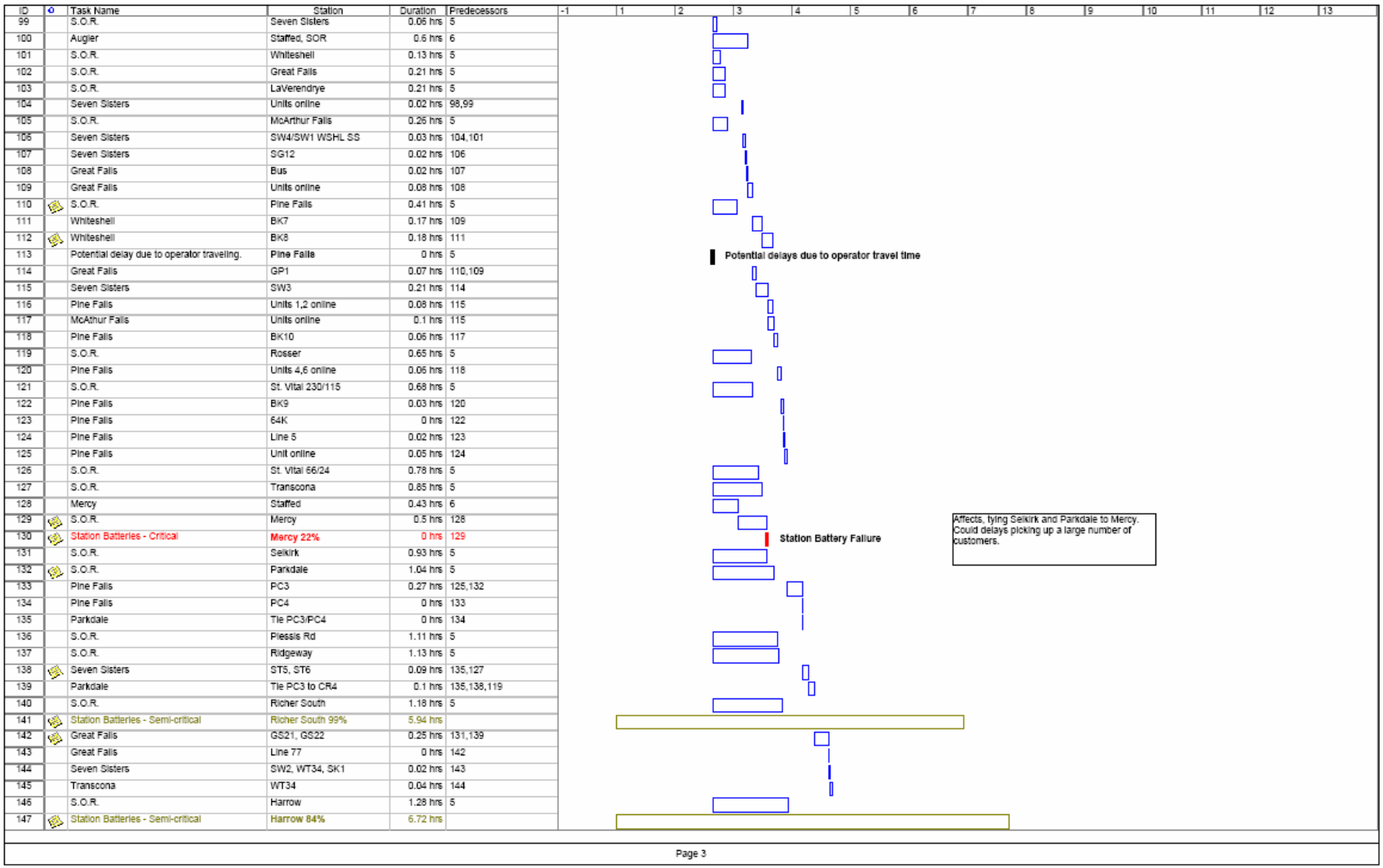
Impact of Generating Station Staffing on Asset and Operational Risks – Appendices



ID	Task Name	Station	Duration	Predecessors
50	Station Batteries - Semi-critical	Virden 90%	5.4 hrs	
51	S.O.R.	Reston South	1.18 hrs	5
52	Station Batteries - Semi-critical	Reston 90%	5.4 hrs	
53	S.O.R.	Cornwallis	1.21 hrs	5
54	Station Batteries - Semi-critical	Cornwallis 91%	7.28 hrs	
55	Overflowing River	Staffed	1.25 hrs	6
56	S.O.R.	Overflowing R.	0.5 hrs	55
57	Station Batteries - Semi-critical	Overflowing R. 77%	0 hrs	56
58	Grand Rapids	G9F	0.23 hrs	56
59	Overflowing River	F27P, BK1, SS	0.03 hrs	56,58
60				
61	**Kelsey Island**		0.02 hrs	
62	Station Service Restored (HU)	Kelsey (BS)	0 hrs	
63	Burntwood	Staffed, SOR	0.41 hrs	6
64	S.O.R.	Kelsey	0.05 hrs	5
65	Kelsey	Units online	0.1 hrs	64
66	S.O.R.	Radisson AC	0.4 hrs	5
67	S.O.R.	Mystery Lake Rd	0.45 hrs	5
68	Kelsey	KN36	0.05 hrs	66,65
69	S.O.R.	INCO	0.49 hrs	5
70	Kelsey	KT1, KT2	0.22 hrs	69
71	INCO	BK9, TW40	0.04 hrs	70,67
72	Mystery Lake Road	B80, B90	0.06 hrs	71
73	Mystery Lake Road	P19W	0.02 hrs	72,25
74	Ponton	SS	0.02 hrs	73
75	S.O.R.	Herblet Lake	0.66 hrs	5
76	Cliff Lake	Staffed	0.56 hrs	6
77	S.O.R.	Cliff Lake	0.5 hrs	76
78	Station Batteries - Critical	Cliff Lake 66%	0 hrs	77
79	S.O.R.	Ross Lake	0.93 hrs	5
80	Station Batteries - Semi-critical	Ross Lake 91%	5.46 hrs	
81	S.O.R.	Border	0.95 hrs	5
82	S.O.R.	Mile 13	0.96 hrs	5
83	S.O.R.	HBM&S	0.96 hrs	5
84	S.O.R.	Cranberry	1.01 hrs	5
85	S.O.R.	Tolko	1.01 hrs	5
86				
87	**Kelsey/Grand Rapids**	**Synchronized**	**0.23 hrs**	**74,48**
88				
89	**Winnipeg River Island**		0 days	
90	Station Service Restored (HU)	Seven Sisters (BS)	0 hrs	
91	Atwood	Staffed, SOR	0.23 hrs	6
92	Station Batteries - Critical	Atwood 34%	0 hrs	91
93	Beausejour East	Staffed, SOR	0.31 hrs	6
94	Lac du Bonnet	Staffed, SOR	0.33 hrs	6
95	Dakota	Staffed, SOR	0.5 hrs	6
96	Inkster	Staffed, SOR	0.5 hrs	6
97	Court	Staffed, SOR	0.53 hrs	6
98	Seven Sisters	Staffed (after hours)	0.5 hrs	6

Impact of Generating Station Staffing on Asset and Operational Risks – Appendices



ID	Task Name	Station	Duration	Predecessors
99	S.O.R.	Seven Sisters	0.06 hrs	5
100	Augier	Staffed, SOR	0.6 hrs	6
101	S.O.R.	Whiteshell	0.13 hrs	5
102	S.O.R.	Great Falls	0.21 hrs	5
103	S.O.R.	LaVerendrye	0.21 hrs	5
104	Seven Sisters	Units online	0.02 hrs	98,99
105	S.O.R.	McArthur Falls	0.26 hrs	5
106	Seven Sisters	SW4/SW1 WSHL SS	0.03 hrs	104,101
107	Seven Sisters	SG12	0.02 hrs	106
108	Great Falls	Bus	0.02 hrs	107
109	Great Falls	Units online	0.08 hrs	108
110	S.O.R.	Pine Falls	0.41 hrs	5
111	Whiteshell	BK7	0.17 hrs	109
112	Whiteshell	BK8	0.18 hrs	111
113	Potential delay due to operator traveling.	Pine Falls	0 hrs	5
114	Great Falls	GP1	0.07 hrs	110,109
115	Seven Sisters	SW3	0.21 hrs	114
116	Pine Falls	Units 1,2 online	0.08 hrs	115
117	McArthur Falls	Units online	0.1 hrs	115
118	Pine Falls	BK10	0.06 hrs	117
119	S.O.R.	Rosser	0.65 hrs	5
120	Pine Falls	Units 4,6 online	0.06 hrs	118
121	S.O.R.	St. Vital 230/115	0.68 hrs	5
122	Pine Falls	BK9	0.03 hrs	120
123	Pine Falls	64K	0 hrs	122
124	Pine Falls	Line 5	0.02 hrs	123
125	Pine Falls	Unit online	0.05 hrs	124
126	S.O.R.	St. Vital 66/24	0.78 hrs	5
127	S.O.R.	Transcona	0.85 hrs	5
128	Mercy	Staffed	0.43 hrs	6
129	S.O.R.	Mercy	0.5 hrs	128
130	Station Batteries - Critical	Mercy 22%	0 hrs	129
131	S.O.R.	Selkirk	0.93 hrs	5
132	S.O.R.	Parkdale	1.04 hrs	5
133	Pine Falls	PC3	0.27 hrs	125,132
134	Pine Falls	PC4	0 hrs	133
135	Parkdale	Tie PC3/PC4	0 hrs	134
136	S.O.R.	Plessis Rd	1.11 hrs	5
137	S.O.R.	Ridgeway	1.13 hrs	5
138	Seven Sisters	ST5, ST6	0.09 hrs	135,127
139	Parkdale	Tie PC3 to CR4	0.1 hrs	135,138,119
140	S.O.R.	Richer South	1.18 hrs	5
141	Station Batteries - Semi-critical	Richer South 99%	5.94 hrs	
142	Great Falls	GS21, GS22	0.25 hrs	131,139
143	Great Falls	Line 77	0 hrs	142
144	Seven Sisters	SW2, WT34, SK1	0.02 hrs	143
145	Transcona	WT34	0.04 hrs	144
146	S.O.R.	Harrow	1.28 hrs	5
147	Station Batteries - Semi-critical	Harrow 84%	6.72 hrs	

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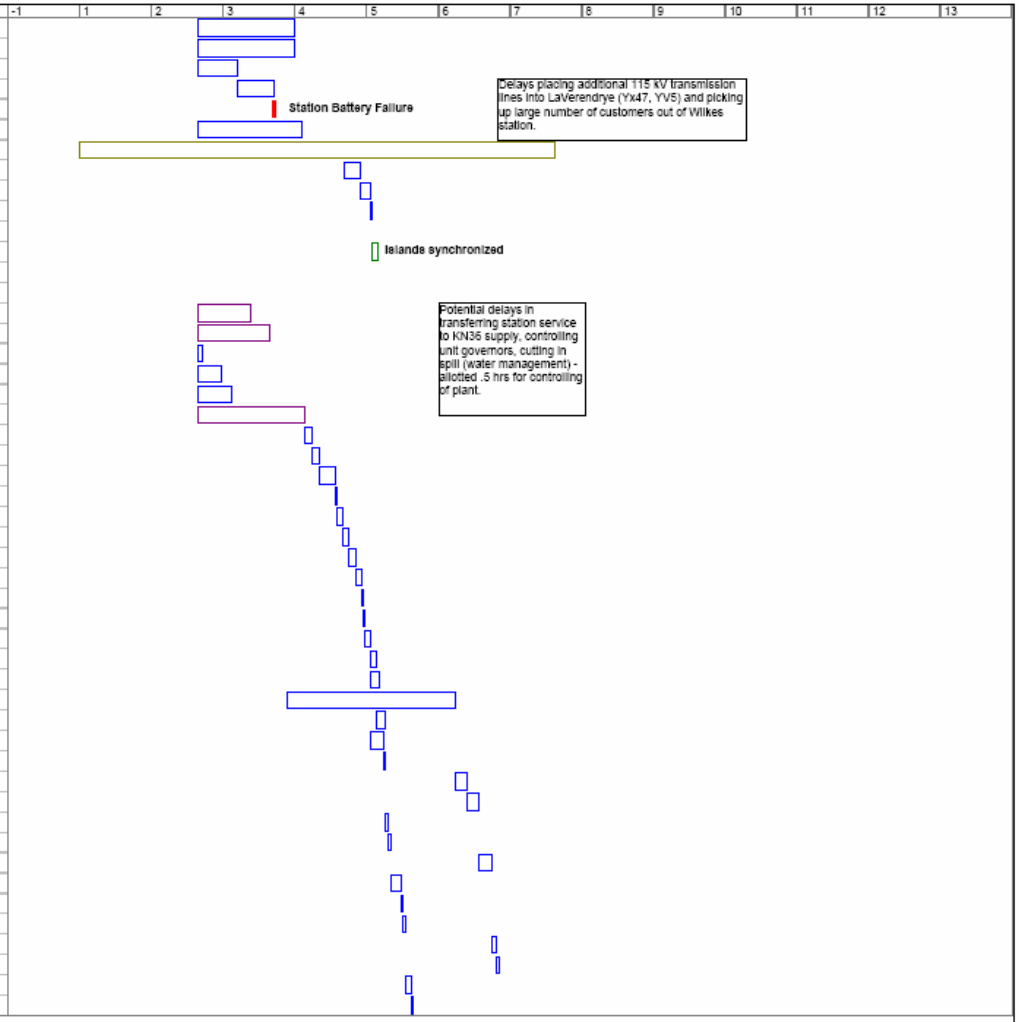
Impact of Generating Station Staffing on Asset and Operational Risks – Appendices

ID	Task Name	Station	Duration	Predecessors
148	S.O.R.	Mohawk	1.35 hrs	5
149	S.O.R.	Kirkfield	1.36 hrs	5
150	Wilkes	Staffed	0.56 hrs	6
151	S.O.R.	Wilkes	0.5 hrs	150
152	Station Batteries - Critical	Wilkes 54%	0 hrs	151
153	S.O.R.	St. James	1.46 hrs	5
154	Station Batteries - Semi-critical	St. James 83%	6.64 hrs	
155	Transcona	TV1, TV2	0.22 hrs	146,103,121,126,145
156	LaVerendrye	YH33	0.16 hrs	155
157	Rosser	RK6, RY7	0.02 hrs	156
158				
159	Grand Rapids/Winnipeg River	Synchronized	0.08 hrs	157,48
160				
161	HVDC		0 hrs	
162	Staff arrives and plant assessment	Kettle	0.75 hrs	6
163	Staff arrives and plant assessment	Long Spruce	1 hr	6
164	S.O.R.	Radisson DC	0.06 hrs	5
165	S.O.R.	Long Spruce	0.33 hrs	5
166	S.O.R.	Henday	0.48 hrs	5
167	Staff arrives and plant assessment	Limestone	1.5 hrs	6
168	Kettle	Unit 3, K3 line	0.1 hrs	167,66,164
169	Kettle	Unit 4	0.1 hrs	168
170	Radisson	K7	0.22 hrs	169
171	Radisson	A bus, SST1	0.02 hrs	170
172	Kettle	Units 9, 10 online	0.08 hrs	171
173	Kettle	Units 11, 12 online	0.08 hrs	172
174	Radisson	BK41, L41R	0.11 hrs	173,165
175	Long Spruce	L1	0.08 hrs	174
176	Long Spruce	B Bus	0.02 hrs	175
177	Long Spruce	A Bus	0.02 hrs	176
178	Long Spruce	L48H	0.08 hrs	177,166
179	Long Spruce	L2	0.08 hrs	178
180	Henday	T32	0.13 hrs	178
181	Dorsey	T11, SC11Y	2.35 hrs	48
182	Long Spruce	units online	0.12 hrs	179
183	Limestone	Units online	0.18 hrs	178
184	Long Spruce	L46H, L47H	0.03 hrs	183
185	Dorsey	T12, SC12Y	0.16 hrs	181
186	Dorsey	T21, SC21Y	0.16 hrs	185
187	Long Spruce / Radisson	L43R	0.04 hrs	184
188	Long Spruce / Radisson	L42R	0.04 hrs	187
189	Dorsey	SC7, SC8	0.2 hrs	186
190	Radisson	K5, K4, K2	0.14 hrs	188
191	Radisson	K1	0.02 hrs	190
192	Long Spruce	L4, L5, L3	0.05 hrs	191
193	Dorsey	F1, F2	0.05 hrs	189
194	Dorsey	F3	0.05 hrs	193
195	Henday	H3, SST1	0.07 hrs	192
196	Henday	H5, SST2	0.03 hrs	195



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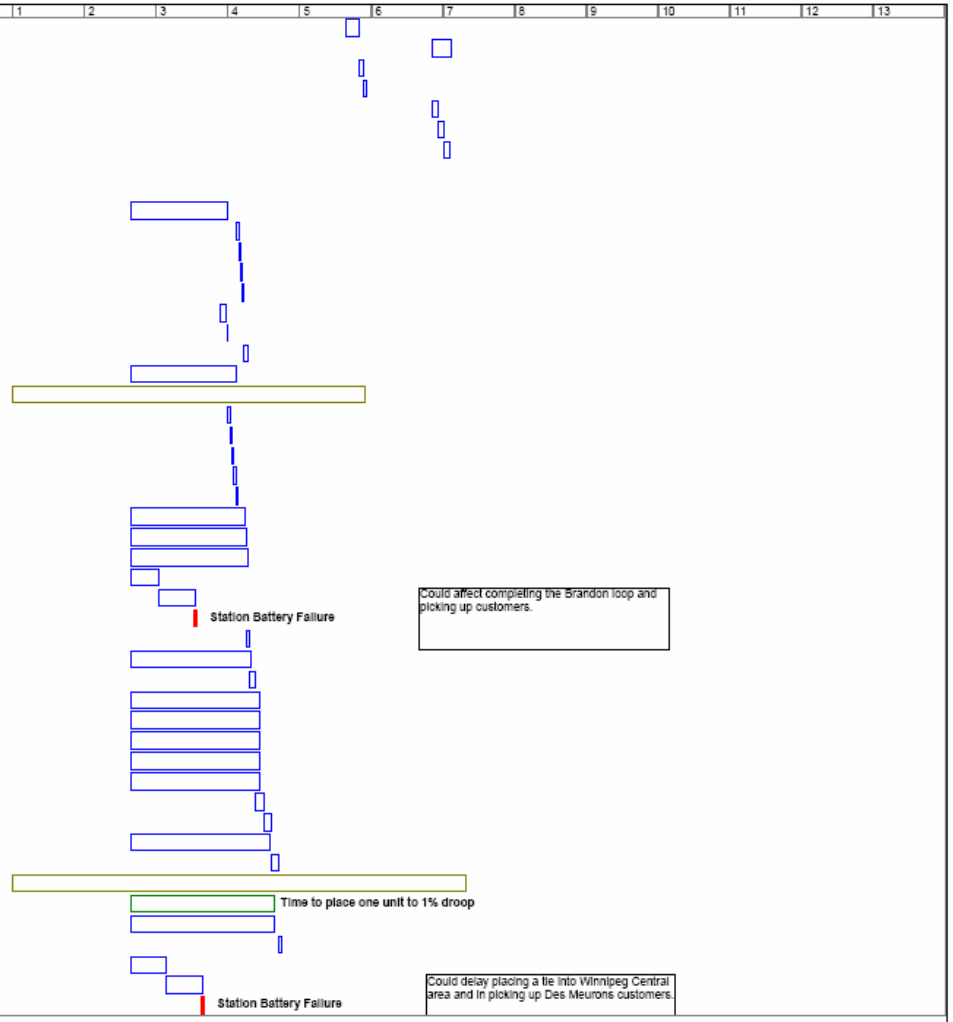
ID	Task Name	Station	Duration	Predecessors
197	Radisson	T11	0.17 hrs	196
198	Dorsey	SC9	0.25 hrs	194
199	Radisson	F1, F3	0.06 hrs	197
200	Radisson	T12	0.05 hrs	199
201	Dorsey/Radisson	VG11 Deblocked	0.08 hrs	194,197,199
202	Radisson	T21	0.08 hrs	201
203	Dorsey/Radisson	VG21 Deblocked	0.08 hrs	202,186
204				
205	**MH Island**		0 hrs	
206	S.O.R.	Neepawa South	1.36 hrs	5
207	Ponton	J30P	0.05 hrs	67
208	Jenpeg	J1, SS	0.02 hrs	207
209	Jenpeg	BK1, BK2	0.02 hrs	208
210	Jenpeg	J2, SS	0.02 hrs	209
211	Raven Lake	B69R	0.1 hrs	48
212	Raven Lake	BK1/2, SS	0.02 hrs	211
213	Jenpeg	Units online	0.05 hrs	210
214	S.O.R.	Bdn Victoria	1.48 hrs	5
215	Station Batteries - Semi-critical	Victoria 82%	4.92 hrs	
216	Birtle South	BK3/4, SS	0.03 hrs	212
217	Birtle South	Line 95	0.02 hrs	216
218	Birtle South	B70H	0.02 hrs	217,49
219	Virden West	BK1/2	0.05 hrs	218
220	Virden West	R29H	0.02 hrs	219,51
221	S.O.R.	Brandon GS	1.6 hrs	5
222	Grand Rapids	Units online	1.61 hrs	5
223	S.O.R.	Fortier	1.63 hrs	5
224	Highland Park	Staffed	0.4 hrs	6
225	S.O.R.	Highland Park	0.5 hrs	224
226	Station Batteries - Critical	Highland Park 58%	0 hrs	225
227	Reston	BK1/2	0.05 hrs	222
228	S.O.R.	Souris Enbridge East	1.68 hrs	5
229	Reston	C28R	0.07 hrs	227,53
230	S.O.R.	Boissevain	1.8 hrs	5
231	S.O.R.	Carberry North	1.8 hrs	5
232	S.O.R.	Crocus Plains	1.8 hrs	5
233	S.O.R.	Minnedosa	1.8 hrs	5
234	S.O.R.	Simplot	1.81 hrs	5
235	Dorsey	D16R, Rosser BK1	0.13 hrs	229
236	Rosser	R23R	0.1 hrs	235
237	S.O.R.	McPhillips	1.95 hrs	5
238	Rosser	RL1, 2, 3, 4	0.1 hrs	236,237
239	Station Batteries - Semi-critical	McPhillips 79%	6.32 hrs	
240	Seven Sisters	1% Droop	2 hrs	5
241	S.O.R.	Dawson Rd.	2.01 hrs	5
242	LaVerendrye	BK3/4	0.05 hrs	238
243	Des Meurons	Staffed	0.5 hrs	6
244	S.O.R.	Des Meurons	0.5 hrs	243
245	Station Batteries - Critical	Des Meurons 45%	0 hrs	244



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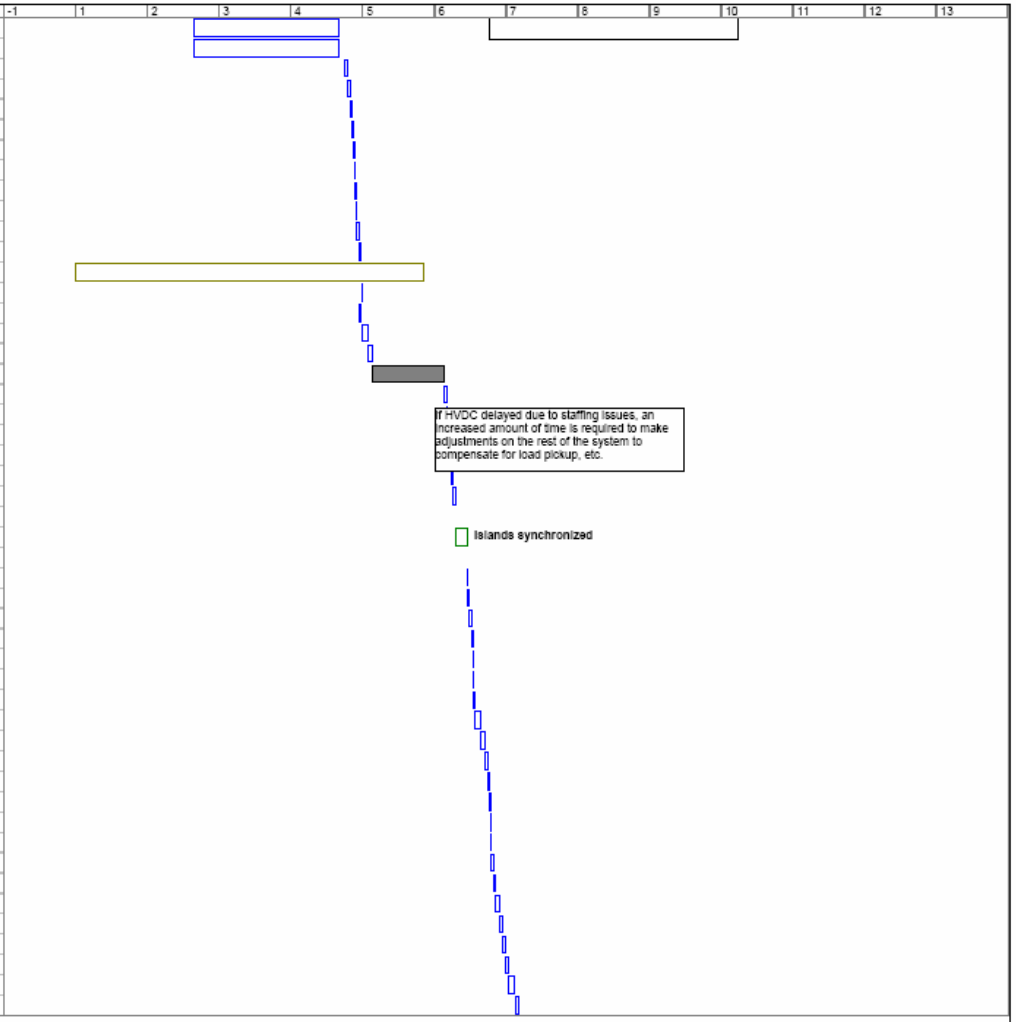
Impact of Generating Station Staffing on Asset and Operational Risks – Appendices

ID	Task Name	Station	Duration	Predecessors
246	S.O.R.	Springfield Rd	2.03 hrs	5
247	S.O.R.	Stonewall	2.03 hrs	5
248	LaVerendrye	B20, B30	0.04 hrs	242
249	LaVerendrye	D15Y, D55Y	0.04 hrs	248
250	Selkirk	SM26	0.02 hrs	249,129
251	Selkirk	SV24, SC25	0.02 hrs	250
252	Dorsey	D14S	0.02 hrs	251,35
253	Selkirk	TS44	0 hrs	252
254	Dorsey	D15Y	0.02 hrs	253
255	St. Vital	VP35, SV24	0 hrs	254
256	St. Vital	BK2/3	0.03 hrs	255
257	Parkdale	BK1/2	0.04 hrs	256
258	Station Batteries - Semi-critical	Parkdale 81%	4.86 hrs	
259	Parkdale	BK3/4	0.02 hrs	257
260	St. Vital/LaVerendrye	YV5	0.04 hrs	151,256
261	LaVerendrye	YX47, YX48	0.1 hrs	260
262	St. Vital	XV39	0.06 hrs	261
263	Increased time to make System adjustments	No HVDC	1 hr	262
264	Cornwallis	G37C	0.04 hrs	263
265	Dorsey/Cornwallis	D54C	0 hrs	264
266	Cornwallis	BK1, CB1	0.03 hrs	265
267	Brandon GS	East Bus	0.02 hrs	266
268	Brandon GS	BE2, BE3	0.03 hrs	267
269	Mohawk	XS49	0.04 hrs	268
270				
271	**MH island/Winnipeg Central**	**Synchronized**	**0.16 hrs**	**269**
272				
273	St. Leon	S53G	0 hrs	271
274	Dorsey/Ashern	A4D	0.02 hrs	273
275	Glenboro	BK3	0.03 hrs	274
276	Glenboro	Tie S53G to G37C	0.02 hrs	275
277	Letellier	S60L	0 hrs	276
278	St. Leon	BK3	0 hrs	277
279	St. Leon	Tie S60L to S53G	0.02 hrs	278
280	Dorsey	D36R	0.1 hrs	279
281	Dorsey	D72V	0.05 hrs	280
282	Ridgeway	R32V, R33V	0.05 hrs	281
283	Grand Rapids	G1A	0.02 hrs	282
284	Brandon GS	BE1	0.02 hrs	283
285	Brandon GS	Request C.T.	0 hrs	284
286	Rosser	RS51	0 hrs	285
287	St. James	BK3/4	0.04 hrs	286
288	Overflowing River	F10M	0.02 hrs	287
289	Kelsey	KK35, BK10	0.05 hrs	288
290	Kelsey	R26K	0.05 hrs	289
291	Kelsey	K24W	0.04 hrs	290
292	Kelsey	KH38	0.04 hrs	291
293	Kelsey	KS37	0.09 hrs	292
294	Parkdale	CP17	0.05 hrs	293



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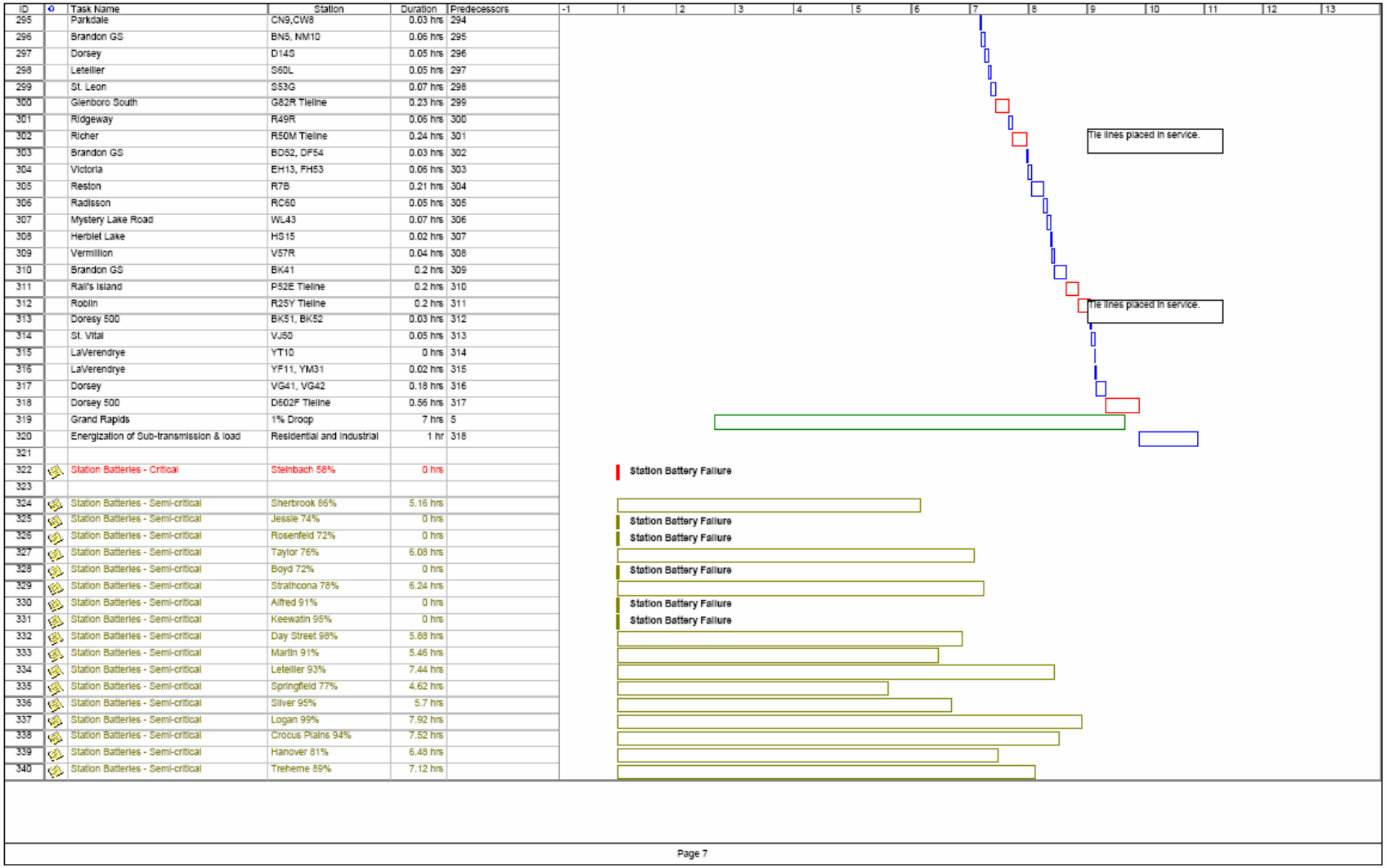
Impact of Generating Station Staffing on Asset and Operational Risks – Appendices



ID	Task Name	Station	Duration	Predecessors
295	Parkdale	CN9,CW8	0.03 hrs	294
296	Brandon GS	BN5, NM10	0.06 hrs	295
297	Dorsey	D14S	0.05 hrs	296
298	Letellier	S60L	0.05 hrs	297
299	St. Leon	S53G	0.07 hrs	298
300	Glenboro South	G82R Tieline	0.23 hrs	299
301	Ridgeway	R49R	0.06 hrs	300
302	Richer	R50M Tieline	0.24 hrs	301
303	Brandon GS	BD52, DF54	0.03 hrs	302
304	Victoria	EH13, FH53	0.06 hrs	303
305	Reston	R7B	0.21 hrs	304
306	Radisson	RC60	0.05 hrs	305
307	Mystery Lake Road	WL43	0.07 hrs	306
308	Herblet Lake	HS15	0.02 hrs	307
309	Vermillion	V57R	0.04 hrs	308
310	Brandon GS	BK41	0.2 hrs	309
311	Rail's Island	P52E Tieline	0.2 hrs	310
312	Roblin	R25Y Tieline	0.2 hrs	311
313	Dorsey 500	BK51, BK52	0.03 hrs	312
314	St. Vital	VJ50	0.05 hrs	313
315	LaVerendrye	YT10	0 hrs	314
316	LaVerendrye	YF11, YM31	0.02 hrs	315
317	Dorsey	VG41, VG42	0.18 hrs	316
318	Dorsey 500	D602F Tieline	0.56 hrs	317
319	Grand Rapids	1% Droop	7 hrs	5
320	Energization of Sub-transmission & load	Residential and Industrial	1 hr	318
321				
322	Station Batteries - Critical	Steinbach 58%	0 hrs	
323				
324	Station Batteries - Semi-critical	Sherbrook 86%	5.16 hrs	
325	Station Batteries - Semi-critical	Jessie 74%	0 hrs	
326	Station Batteries - Semi-critical	Rosenfeld 72%	0 hrs	
327	Station Batteries - Semi-critical	Taylor 76%	6.08 hrs	
328	Station Batteries - Semi-critical	Boyd 72%	0 hrs	
329	Station Batteries - Semi-critical	Strathcona 78%	6.24 hrs	
330	Station Batteries - Semi-critical	Alfred 91%	0 hrs	
331	Station Batteries - Semi-critical	Keewatin 95%	0 hrs	
332	Station Batteries - Semi-critical	Day Street 98%	5.88 hrs	
333	Station Batteries - Semi-critical	Martin 91%	5.46 hrs	
334	Station Batteries - Semi-critical	Letellier 93%	7.44 hrs	
335	Station Batteries - Semi-critical	Springfield 77%	4.62 hrs	
336	Station Batteries - Semi-critical	Silver 95%	5.7 hrs	
337	Station Batteries - Semi-critical	Logan 99%	7.92 hrs	
338	Station Batteries - Semi-critical	Crocus Plains 94%	7.52 hrs	
339	Station Batteries - Semi-critical	Hanover 81%	6.48 hrs	
340	Station Batteries - Semi-critical	Treherne 89%	7.12 hrs	

13. Appendix 4: Battery Replacement Project Schedule

Source: Doug Rempel – Staff Officer, Emergency Operations, System Control Department, TSO

Impact of Generating Station Staffing on Asset and Operational Risks – Appendices

Battery Replacement Schedule

The first two years of the schedule are batteries that are at end of life and require replacement in order to avoid failure.
The remaining batteries are part of the ten year replacement schedule.

Replacement dates are tentative and could change depending on the replacement of end of life batteries.

Fiscal year to be replaced : 2004/2005			
Station	Age in 2004	Ah Actual	Year Built
Chesterfield	15	38	1989
Control Center	9	295	1995
Whiteshell Stn. 33KV	14	256	1990
#5 Sub, 910 Scotland St.	23	240	1981
Pilot Mound	20	180	1984
Roblin South	20	180	1984
Ashern	11	174	1993
University	21	180	1983
Burntwood	16	156	1988
Inco	20	180	1984

Fiscal year to be replaced : 2005/2006			
Station	Age in 2005	Ah Actual	Year Built
St. Leon	20	300	1985
Stonewall	21	100	1984
#7 Sub, 407 Lindsay St.	24	120	1981
#1 Sub, 48 King St.	22	210	1983
Dawson Road	21	180	1984
Neepawa	21	180	1984
Sturgeon	21	180	1984
Rose Stn.	21	180	1984
Minitonas	20	180	1985
#15 Sub, 731 Cambridge St.	20	180	1985
Goulet	20	180	1985
Semple	20	180	1985
Brandon Lorne Ave.	19	180	1986
Brandon Mctavish	18	180	1987
Boissevain	18	180	1987
Crestview	16	208	1989
Transcona Terminal	15	256	1990
St. Matthews	9	295	1998

Stations with restoration plans | Work completed | Active

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Impact of Generating Station Staffing on Asset and Operational Risks – Appendices

Battery Replacement Schedule

Fiscal year to be replaced : 2006/2007					
Station	Age in 2006	% Capacity	Ah Actual	Ah Required	Year Built
Des Meurons	19	45%	174	386	1987
Cliff Lake	24	66%	180	271	1982
Overflow	23	77%	180	234	1983
Rails Island	23	91%	270	298	1983
Alfred	21	91%	120	132	1985
French	20	496%	173.6	35	1986
Augler	20	114%	182	160	1986
Keewatin	20	95%	180	189	1986
Laverendrye	20	139%	270	194	1986
Day	19	98%	180	183	1987
Debourmont	19	335%	104	31	1987
SK-1	19	164%	64	39	1987
Mercy	16	22%	48.4	216	1990

Fiscal year to be replaced : 2007/2008					
Station	Age in 2007	% Capacity	Ah Actual	Ah Required	Year Built
Atwood	15	34%	36.3	107	1992
Highland Park	14	58%	99	172	1993
Wilkes	14	54%	124	228	1993
Richer South	20	99%	174	175	1987
Ponton	20	164%	180	110	1987
Steinbach First	13	58%	128.5	222	1995
Dunraven	19	129%	180	139	1988
Ross Lake	19	91%	174	191	1988
Enbridge/Souris IPL	19	103%	129.6	126	1988
Kirkfield	19	190%	240	126	1988
Martin	19	91%	150	165	1988
Letellier	9	93%	388	417	1998

Fiscal year to be replaced : 2008/2009					
Station	Age in 2008	% Capacity	Ah Actual	Ah Required	Year Built
Morden	20	126%	198.4	157	1988
Parkdale	20	81%	240	298	1988
Souris	20	147%	48.4	33	1988
Mile 13	20	171%	210	123	1988
Stanley	20	133%	173.8	131	1988
Whiteshell	20	195%	240	123	1988
Shaftsbury	19	142%	64	45	1989
Inkster	19	180%	124	69	1989
Reston	19	90%	150	167	1989
Springfield	19	77%	198.4	259	1989
Sherbrook	18	86%	240	279	1990
Silver	18	95%	174	184	1990
McPhillips	11	79%	201	255	2002

Stations with restoration plans

Capacity : ≥100% / 70-99% / <70%

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Impact of Generating Station Staffing on Asset and Operational Risks – Appendices

Battery Replacement Schedule

Fiscal year to be replaced : 2009/2010					
Station	Age in 2009	% Capacity	Ah Actual	Ah Required	Year Built
Ness	19	168%	156	93	1990
Carberry North	19	173%	72.6	42	1990
Church	19	167%	240	144	1990
Dakota	19	101%	99.2	98	1990
Edmonton	19	102%	240	235	1990
Minnedosa South	19	413%	196.4	48	1990
Portier	19	102%	240	235	1990
Dunlop	19	116%	156	134	1990
Laxdal	19	168%	156	93	1990
Jessie	18	74%	210	284	1991
Rosenfeld	18	72%	198	276	1991
Victoria	18	82%	536	657	1991
Virden	18	90%	174	194	1991

Fiscal year to be replaced : 2010/2011					
Station	Age in 2010	% Capacity	Ah Actual	Ah Required	Year Built
Watt	19	168%	156	93	1991
Cranberry Portage	19	121%	99.2	82	1991
Sask Ave	19	163%	410	252	1991
St. Vital 66kV	19	117%	240	205	1991
Beausejour East	19	154%	76.8	50	1991
Markham	19	142%	64	45	1991
Berry	20	102%	156	153	1990
Kingsbury	18	89%	60.5	68	1992
Sutton	18	81%	104	128	1992
Logan	18	99%	320	324	1992
Crocus Plains	17	94%	124	132	1993
Hanover	17	81%	360	446	1993
St. James	17	83%	410	495	1993

Fiscal year to be replaced : 2011/2012					
Station	Age in 2011	% Capacity	Ah Actual	Ah Required	Year Built
Dau Vermillion	19	108%	536	496	1992
York	19	320%	240	75	1992
SWR Valley Road	18	124%	154	124	1993
Court	18	129%	99.2	77	1993
Beaverhill	18	189%	51	27	1993
Southwood	18	155%	128.5	83	1993
Poplarfield	17	171%	174	102	1994
Treherne	16	89%	200	224	1995
Taylor	15	76%	218	286	1996
Harrow	12	84%	160	191	1999
Boyd	11	72%	218	302	2000
Cornwallis	11	91%	388	427	2000
Strathcona	11	78%	218	278	2000

Stations with restoration plans

Capacity : ≥100%
70-99%
<70%

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Battery Replacement Schedule

Fiscal year to be replaced : 2012/2013					
Station	Age in 2012	% Capacity	Ah Actual	Ah Required	Year Built
Fernor	18	154%	200	130	1994
Storie Rd.	18	138%	51	37	1994
William River	18	147%	76.6	52	1994
Raven Lake	16	100%	240	240	1996
Roblin Greenway	16	164%	100	61	1996
Garden Hill	15	356%	648	182	1997
Gods Narrows	15	356%	648	182	1997
Oxford House	15	463%	648	140	1997
Herblet Lake	15	215%	648	301	1996
Chevrier	14	309%	108	35	1998
Churchill South	14	127%	167	131	1998
King Edward	14	160%	148.8	93	1998

Fiscal year to be replaced : 2013/2014					
Station	Age in 2013	% Capacity	Ah Actual	Ah Required	Year Built
Cromer North	14	179%	59.2	33	1999
Amy	13	148%	268	181	2000
Border	13	134%	201	150	2000
Charles	13	120%	218	182	2000
Piessis	13	109%	176	162	2000
Birtle South	12	113%	267	236	2001
Elviss	11	216%	201	93	2002
Notre Dame	11	216%	201	93	2002
Olive	11	175%	201	115	2002
Mohawk	11	112%	168	150	2002
Mystery Lake	10	195%	648	333	2003
Rosser	12	100%	478	476	2001

Fiscal year to be replaced : 2014/2015					
Station	Age in 2014	% Capacity	Ah Actual	Ah Required	Year Built
Atomic Energy	11	138%	160	116	2003
Bloodvein VCD	11	490%	152	31	2003
Windsor Park	11	714%	250	35	2003
Arlington	10	168%	246	146	2004
Empress	9	152%	251	165	2005
Cavalier	11	116%	180	153	2003
Grand Rapids 25kV	9	212%	195	92	2005
Baylor	9	186%	251	135	2005
Berens River	9	160%	251	157	2005
Bloodvein	9	149%	251	169	2005
Manigotogan	9	167%	251	150	2005

Stations with restoration plans

Capacity : ≥100% / 70-99% / <70%

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14. Appendix 5: Seven Sisters Remote Black Start Commissioning Report

Source: Gerald Koroscil, PEng., RCM Engineer, Reliability & Performance Dept.

Neufeld, Maria

To: Koroscil, Gerald
Subject: RE: Remote Black Start at Seven Sisters

From: Koroscil, Gerald
Sent: Thursday, August 24, 2006 2:59 PM
To: Neufeld, Maria
Subject: RE: Remote Black Start at Seven Sisters

Hi Maria
I'm attaching a copy of the commissioning report for the last attempt. Units 2 and 3 are the black start units. No house unit work was involved with this project.

The commissioning plan involved starting unit 2 to speed-no-load and synchronizing to a dead bus. Then, unit 3 would be started to speed-no-load, synchronized to unit 2, and switched to condense mode to provide a load for unit 2. The procedure would then be repeated but reversing the roles of units 2 and 3.

Two problems prevented satisfactory completion of commissioning. The start chain was designed to be reset when the gate position reached the normal speed-no-load setting regardless the generator breaker status. When synchronizing to a dead bus, the gates didn't reach the normal speed-no-load position and start chain didn't reset. After a 5 minute time delay, the incomplete sequence relay operated and tripped the unit. In order to start and load the units, the incomplete sequence function had to be disabled and the start chain reset manually. Also, the delay timeout of the incomplete sequence timer relays was inconsistent.

To provide an operable remote black start function, the start chain had to be modified to reset the start chain on closing of the generator breaker and the incomplete sequence timers had to replaced. Engineering drawings were issued and materials were purchased for the work to be done by Winnipeg River staff (for all the units). So far, timers have been replaced for units 1 and 4 only with no start chain modifications done. The remaining work is in the backlog awaiting planning and outages.

If you need more information, please call me.

<< File: SS remote black start commissioning.pdf >>

Gerald Koroscil, PEng.
RCM Engineer
Reliability & Performance Dept.
Manitoba Hydro
1-204-474-3539

Manitoba Hydro

COMMISSIONING SECTION

TRANSMISSION CONSTRUCTION & LINE MAINTENANCE

COMMISSIONING PROCEDURE

PROJECT NAME: SEVEN SISTERS UNITS 2 & 3 BLACK START TESTING

OPERATIONAL PROCEDURE NO.: 2004-004

PROJECT DETAILS:

Network No.: 224467 **Projected I.S.D.:** 2004 02 05 **Certificate No.:**
Station Name: Seven Sisters Generating Station **Station No.:**00.05
Project Coordinator: D. Shiels Transmission Services Dept.
Construction Authority:
Commissioning Coordinator: A. Miller Commissioning
Commissioning Field Supervisor: A. Miller Commissioning

Prepared By: A. Miller

Approved By: _____ D. Ruchotzke (Commissioning Superintendent)

Date: _____

NOTES

- Any changes made to the original intended design during construction or commissioning must have prior approval from the responsible engineering design section and must be included in the appropriate section of the final commissioning records.
- All matters relating to and affecting procedures, testing and commissioning must be reported to A. Miller, Commissioning Coordinator, Office Ph.: 474-3825, or Cell Ph.: 794-8162.
- The Commissioning Field Supervisor is to ensure that a Commissioning Notification is requested where/where applicable well in advance of energization dates as per safety rules.
- A Commissioning meeting must be held prior to energization to review job plan.
- Commissioning Certificate to be completed when installation is placed in service.

DISTRIBUTION *Identifies recipients of entire document, others receive cover pages only.

	D. Shiels	Transmission Services Dept.	453 Dovercourt
*	D. Ruchotzke	Commissioning	1140 Waverley
*	R. Sysak	Transmission Services Dept.	453 Dovercourt
*	A. Miller	Commissioning	1140 Waverley
	G. Korosril	Generation Engineering	1100 Waverley
*	R. Duke (2)	Generation South Winnipeg River	Great Falls Mb.

No units were started from SCC during this test.
⇒ Started locally only.
→ due to inc. seq. relay problems

SEVEN SISTERS GENERATING STATION
UNITS 2 & 3 BLACK START TESTING

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SEVEN SISTERS GENERATING STATION
UNITS 2 & 3 BLACK START TESTING

SECTION 1 SEVEN SISTERS BLACK UNIT STARTING TEST PROCEDURE

Prior Conditions:

a. 115kV line SW2 cleared as per O. O. #04-3891. _____
b. 115kV line SW3/SR3 cleared as per O.O. #04-3891 _____
c. 115kV bus cleared at 115kV tie Breaker 134 & Disconnect 37. _____
d. 115kV N. O. Disconnect 32 is closed. _____
e. Station service unit is functioning _____
f. Generating Units 2 and 3 cleared as per O. O. #04-3891. _____
g. Test and operate cards are required on the following devices. _____
   i. Unit 3 Start/Stop control _____

ii. Unit 2 Start/Stop control _____
iii. 115kV Breaker 68 _____
iv. 115kV Breaker 88 _____
v. Unit 2 Condense mode control switch _____
vi. Unit 3 Condense mode control switch _____

Test Procedure:

1.1 UNIT 2 UNDER TEST

Make note of the positions of the following switches. _____

a. 25SP (Potential Selection Switch). North/Off/South _____
b. 43SP (Sync Potential Switch). North/Norm/South _____
c. Scope changeover switch. North/Off/South _____
d. 43TRS (Station Synchronizing Switch). Auto/Man _____

2. Place the following switches to the indicated positions. _____

a. Ensure 25SP (Potential Selection Switch) set to 'South'. _____

b. 43SP (Sync Potential Switch) set to 'North'. _____

c. Ensure 43TRS (Station Synchronizing Switch) set to 'Auto'. _____

d. Scope changeover switch set to 'North' scope panel. _____

3. Initiate a unit 2 start command. _____

a. unit comes up to speed no load and connects to isolated 115kV bus. _____

4. Initiate a unit 3 start command. _____

5. Synchronize unit 3 to 115kV isolated bus (Unit 2). _____

6. Proceed with load readings on unit #2, at speed no load. (See Section 2) _____

7. Initiate command to allow unit 3 to operate in the "Condense Mode". _____

8. Place the following switches to the indicated positions. _____

   a. 43SP (Sync Potential Switch), set to 'South'. _____
   b. Ensure 43TRS (Station Synchronizing Switch), set to 'Auto'. _____
   c. Scope changeover switch, set to 'South' scope panel. _____

9. After thirty minutes take load readings and make note of any irregularities. _____

10. Initiate a stop to unit 3. _____

11. Place the following switches to the indicated positions. _____

   a. 43SP (Sync Potential Switch), set to 'North'. _____
   b. Ensure 43TRS (Station Synchronizing Switch), set to 'Auto'. _____
   c. Scope changeover switch, set to 'North' scope panel. _____

1.2 UNIT 3 UNDER TEST

12. When unit 3 has stopped, initiate a start and synchronize to isolated 115kV bus. _____

13. Proceed with load readings on unit #3, at speed no load. (See Section 3) _____

14. Initiate commands to allow unit 2 to operate in the "Condense Mode". _____

15. After thirty minutes take load readings and make note of any irregularities. _____

16. Initiate a stop to unit 2. _____

17. Initiate a stop to unit 3. _____

18. Place the following switches to the original positions as noted in step #1. _____

a. 25SP (Potential Selection Switch),	North/Off/South	_____
b. 43SP (Sync Potential Switch),	North/Norm/South	_____
c. Scope changeover switch.	North/Off/South	_____
d. 43TRS (Station Synchronizing Switch),	Auto/Man	_____

Tested By: _____ Date: _____

SECTION 2 UNIT 2 BLACK START TESTING

System Control Department
System Restoration Instructions

PROCEDURE NUMBER: REF. B3A	**REVISION NO.:**
SUBJECT: BLACK START TESTING REQUIREMENTS	**EFFECTIVE:** 2001-11-01
	REVIEW:
	EXPIRY:

Manitoba Hydro Black Start Unit Testing Record

Plant: Seven Sisters G.S. Black Start Unit Tested: Unit 2

Date of Test: _____

Unit Capability: 3[illegible] MW

Type of Unit: General Electric; kVA 43,000 Volts 1[illegible],000 Amp Arm. 2257 S/N: 132577

Period of Test: 30 minutes.

Time required to start the unit being black started: approx. 1 minutes.

Was the Unit Voltage acceptable: At no Load: Yes Under Load: Yes
(+/- 5% P.U.)

Was the Unit Frequency acceptable: At no Load: Yes Under Load: Yes
(+/- 0.036 HZ)

Did the unit meet expectations: Yes

Did the auxiliaries meet expectations: See attached notes

Remarks: test load was unit 3 running as a condenser.

Unit Voltage = +/- 5% p. u. = 11,500 kV (1 p. u. = 11,000kV)

= 10,450 kV

Unit Frequency = +/- 0.036 Hz = 60.036 Hz.

= 59.964 Hz.

Note: The above Black Start test includes that of the station service unit and the generating Unit that is being Black Started.

Plant Operating Authority: _____ Dated: _____

Prepared By: RWG SCD APPROVAL: GTA Issued Date: 2001 10 30

SECTION 3 UNIT 3 BLACK START TESTING

System Control Department
System Restoration Instructions

PROCEDURE NUMBER: REF. B3A
SUBJECT: BLACK START TESTING REQUIREMENTS

REVISION NO.:
EFFECTIVE: 2001-11-01
REVIEW:
EXPIRY:

Manitoba Hydro Black Start Unit Testing Record

Plant: Seven Sisters G.S. Black Start Unit Tested: Unit 3

Date of Test: _____

Unit Capability: 31 MW

Type of Unit: General Electric; kVA 43,000 Volts 11,000 Amp Arm. 2257 S/N: 132576

Period of Test: 30 minutes.

Time required to start the unit being black started: _____ minutes.

Was the Unit Voltage acceptable: At no Load: Yes Under Load: Yes
(+/- 5% P.U.)

Was the Unit Frequency acceptable: At no Load: Yes Under Load: Yes
(+/- 0.036 HZ)

Did the unit meet expectations: Yes

Did the auxiliaries meet expectations: See attached notes.

Remarks: test load was unit 2 running as a condenser.

Unit Voltage = +/- 5% = 11,500 kV (1 p. u. = 11.000kV)

= 10,450 kV

Unit Frequency = +/- 0.036 Hz = 60.036 Hz.

= 59.964 Hz.

Note: The above Black Start test includes that of the station service unit and the generating Unit that is being Black Started.

Plant Operating Authority: _____ Dated: _____

Prepared By RWG SCD APPROVAL: GTA Issued Date: 2001 10 30

SECTION 4 LOAD READINGS - REMOTE BLACK START TESTING

4.1 UNIT 2 - GENERATION MODE AND UNIT 3 - CONDENSE MODE

prior conditions

a. Bus work between Units 2 and 3 isolated from Main bus at Seven Sisters.
b. Unit 2 running as a generator
c. Unit 3 running as a condenser

4.1.2 UNIT 2 VOLTAGE , CURRENT & PHASE ANGLE READINGS

1. Use red phaser or BMI and zero reference voltage on Aø to grd. Record voltage and phase angle at the following location: Relay Panel #6

   Aø __106.5_V_ 0.0 ° Bø __106.4_V_-120__° Cø __108.9_V_120__°

2. Read currents at the following locations.

   a. Location
   Aø __0.160_A_58__° Bø __0.160_A_-47__° Cø __0.160_A_177__°

4.1.3 UNIT 2 LOAD CALCULATIONS

1. Use voltage and current values from Section 1.2 paragraph 1 & 2a..

Test Location:

INPUT DATA		Volts	θ°		Current	θ°		
	a	106.50	0.00	a	0.16	58.00	CTR:	480
	b	106.40	-120.00	b	0.16	-47.00	PTR:	100
	c	108.90	120.00	c	0.16	177.00	MULT.:	48000

CALC SEC		VA	Watts		Vars		Calc θ°
	a	17.04	9.03		-14.45		-58.00
	b	17.02	4.98		-16.28		-73.00
	c	17.42	9.49		-14.61		-57.00
	TOT	**51.49**	**23.50**	OUT	**-45.34**	IN	

CALC PRI		MVA	MWatt		MVar		Current
	A	0.82	0.43		0.69		76.80
	B	0.82	0.24		-0.78		76.80
	C	0.84	0.46		-0.70		76.80
	TOT	**2.47**	**1.13**	OUT	**-2.18**	IN	

Remarks:_____

_____

_____

Tested by:_____ Date:_____

4.2 UNIT 2 - GENERATION MODE AND UNIT 3 - CONDENSE MODE

PRIOR CONDITIONS

a. Bus work between Units 2 and 3 isolated from Main bus at Seven Sisters.
b. Unit 2 running as a generator
c. Unit 3 running as a condenser

4.2.2 UNIT 3 VOLTAGE , CURRENT & PHASE ANGLE READINGS

1. Use red phaser or BMI and zero reference voltage on Aø to grd. Record voltage and phase angle at the following location: Relay Panel #7

   Aø 106.7_V_0.0__° Bø __106.5_V_-120__° Cø __109.1_V_120__°

2. Read currents at the following locations.

   a. Location
   Aø 0.180_A_-133__° Bø __0.180_A_-133__° Cø __0.180_A_-133__°

4.2.3 UNIT 3 LOAD CALCULATIONS

1. Use voltage and current values from Section 1.2 paragraph 1 & 2a.

Test Location:

INPUT DATA		Volts	θ°		Current	θ°		
	a	106.70	0.00	a	0.18	-133.00	CTR:	480
	b	106.50	-120.00	b	0.18	106.00	PTR:	100
	c	109.10	120.00	c	0.18	-14.00	MULT.:	48000

CALC SEC		VA	Watts		Vars		Calc θ°
	a	19.21	-13.10		14.05		133.00
	b	19.17	-13.32		13.79		-226.00
	c	19.64	-13.64		14.13		134.00
	TOT	58.01	-40.06	IN	41.98	OUT	

CALC PRI		MVA	MWatt		MVar		Current
	A	0.92	-0.63		0.67		86.40
	B	0.92	-0.64		0.66		86.40
	C	0.94	-0.65		0.68		86.40
	TOT	2.78	-1.92	IN	2.01	OUT	

Remarks:_____

Tested by:_____ Date:_____

4.3 UNIT 3 - GENERATION MODE AND UNIT 2 - CONDENSE MODE

PRIOR CONDITIONS

a. Bus work between Units 2 and 3 isolated from Main bus at Seven Sisters
b. Unit 3 running as a generator
c. Unit 2 running as a condenser

4.3.2 UNIT 2 VOLTAGE , CURRENT & PHASE ANGLE READINGS

1. Use red phaser or BMI and zero reference voltage on Aø to grd. Record voltage and phase angle at the following location: Relay Panel #6

   Aø __106.5_V_0.0__° Bø 106.5_V_-120__° Cø 108.9_V_120__°

2. Read currents at the following locations.

   a. Location
   Aø 0.230_A_103 ° Bø __0.220_A_-17 ° Cø __0.220_A_-137__°

4.3.3 UNIT 2 LOAD CALCULATIONS

1. Use voltage and current values from Section 1.2 paragraph 1 & 2a..

PUT	PTA	b	106.50	-120.00	b	0.22	-17.00	PTR:	100
		c	108.90	120.00	c	0.22	-138.00	MULT.:	4800C

			VA		Watts		Vars		Calc θ°
CALC	SEC	a	24.50		-5.51		-23.87		-103.00
		b	23.43		-5.27		-22.83		-103.00
		c	23.98		-4.98		-23.43		258.00
		TOT	71.88		-15.76	IN	-70.13	IN	

			MVA		MWatt		MVar		Current
CALC	PRI	A	1.18		-0.26		-1.15		110.40
		B	1.12		-0.25		-1.10		105.60
		C	1.15		-0.24		-1.12		105.60
		TOT	3.45		-0.76	IN	-3.37	IN	

Remarks: _____

_____

_____

Tested by: _____ Date: _____

4.4 UNIT 3 - GENERATION MODE AND UNIT 2 - CONDENSE MODE

PRIOR CONDITIONS

a. Bus work between Units 2 and 3 isolated from Main bus at Seven Sisters.
b. Unit 3 running as a generator
c. Unit 2 running as a condenser

4.4.2 UNIT 3 VOLTAGE , CURRENT & PHASE ANGLE READINGS

1. Use red phaser or BMI and zero reference voltage on Aø to gnd. Record voltage and phase angle at the following location: Relay Panel #7

   Aø __107.1_V_ 0.0__° Bø __106.8_V_-120__° Cø __109.4_V_120__°

2. Read currents at the following locations.

   a. Location
   Aø __0.210 A -89__° Bø __0.210 A_151__° Cø 0.210 A 31__°

4.4.3 UNIT 3 LOAD CALCULATIONS

1. Use voltage and current values from Section 1.2 paragraph 1 & 2a..

Test Location:

INPUT DATA		Volts	θ°		Current	θ°		
	a	107.10	0.00	a	0.21	-89.00	CTR:	480
	b	106.80	-120.00	b	0.21	151.00	PTR:	100
	c	109.40	120.00	c	0.21	31.00	MULT.:	48000

CALC SEC		VA		Watts		Vars		Calc θ°
	a	22.49		0.38		22.49		89.00
	b	22.43		0.38		22.42		-271.00
	c	22.97		0.40		22.97		89.00
	TOT	**67.89**		**1.18**	OUT	**67.88**	OUT	

CALC PRI		MVA		MWatt		MVar		Current
	A	1.08		0.02		1.08		100.80
	B	1.08		0.02		1.08		100.80
	C	1.10		0.02		1.10		100.80
	TOT	**3.26**		**0.06**	OUT	**3.26**	OUT	

Remarks: _____

_____

_____

Tested By: _____ Date: _____

SECTION 5 SEVEN SISTER'S G.S. BLACK START TEST: UNITS 2 AND 3 RECORDER CALIBRATION LEVELS

Signal Units 2 & 3	Location	Primary Quantities	Transducer Output	GE FANUC Load	Recorder Range (in Vdc)
Field Amps	Aux. Gen.[2] Pnl.	0 – 800 amps	4 – 20 mA.	100 ohms	0.4 – 2.0 Vdc
Field Volts	Aux. Gen.[2] Pnl.	0 – 300 Vdc	4 – 20 mA	100 ohms	0.4 – 2.0 Vdc
Unit Mvars	Relay Pnl.	+/- 50Mvars	4 – 20 mA	100 ohms	0.4 – 2.0 Vdc
Unit Mwatts	Relay Pnl.	+/- 50 Mwatts	4 – 20 mA	100/150 ohms	0.4 – 2.0 Vdc
Unit Frequency (Unit Speed) [1]	Relay Pnl.	55 – 65 Hz	4 – 20 mA	100 ohms	0.4 – 2.0 Vdc
Unit Start Relays 4G2 & 4G3		0 or 250vdc	N/A	N/A	0-250 Vdc
Unit Terminal Voltage	Relay Pnl.	PT 202/PT302 2 x 11 000 – 110/110	N/A	N/A	0-110 Vac

Reference Drawings:
1-00105-GE-64000-0005 sht. 0003 Rev. 03
1-00105-GE-64000-0005 sht. 0004 Rev. 01
1-00105-GD-51000-0001 sht. 0002 Rev. 21 – AC SCHEMATIC DIAGRAM UNIT 2
1-00105-GD-51000-0001 sht. 0003 Rev. 21 – AC SCHEMATIC DIAGRAM UNIT 3

Notes:

1. The output of the Frequency Transducer is also used in the calculation of the speed of the generator.

   Speed = Frequency x 2.308 (See Drawing 1-00105-GE-64000-0005 sht. 0004 Rev. 01)

2. The Aux. Generator panel is located beside the generator on the floor. We would require monitoring of these points for both units 2 and 3.

Signal	Location	Primary Quantities	Transducer Output	GE FANUC Load	Voltage Range
Field Amps	Aux. Gen Panel	0-800 amps	4 - 20 ma	100 Ω	0.4 - 2.0 Vdc
Field Volts	Aux. Gen Panel	0-300 Vdc	4 - 20 ma	100 Ω	0.4 - 2.0 Vdc
Unit Mvars	Relay Panel	+/- 50 Mvars	4 - 20 ma	100 Ω	0.4 - 2.0 Vdc
Unit Mwatts	Relay Panel	+/- 50 Mwatts	4 - 20 ma	100 Ω/=150 Ω	0.4 - 2.0 Vdc
Unit Frequency	Relay Panel	55 - 65 Hz	4 - 20 ma	100 Ω	0.4 - 2.0 Vdc
Unit Terminal Voltage	Unit Control Panel	0 -110 Vac	0 - 1 ma	N/A	0.0 - 7.54 Vdc
Frequency Transducer			**Field Amps Transducer**		
4 ma	55.0 Hz	0.4 Vdc	4 ma	0.00 amps	0.4 Vdc
8 ma	57.5 Hz	0.8 Vdc	8 ma	200.0 amps	0.8 Vdc
12 ma	60.0 Hz	1.2 Vdc	12 ma	400.0 amps	1.2 Vdc
16 ma	62.5 Hz	1.6 Vdc	16 ma	600.0 amps	1.6 Vdc
20 ma	65.0 Hz	2.0 Vdc	20 ma	800.0 amps	2.0 Vdc
MWatts Transducer			**Field Volts Transducer**		
4 ma	-50.0 Mwatt	0.4 Vdc	4 ma	0.000 Vdc	0.4 Vdc
8 ma	25.0 Mwatt	0.8 Vdc	8 ma	75.0 Vdc	0.8 Vdc
12 ma	0.00 Mwatt	1.2 Vdc	12 ma	150.0 Vdc	1.2 Vdc
16 ma	+25.0 Mwatt	1.6 Vdc	16 ma	225.0 Vdc	1.6 Vdc
20 ma	+50.0 Mwatt	2.0 Vdc	20 ma	300.0 Vdc	2.0 Vdc
MVARs Transducer			**Terminal Voltage**	Transducer Calibration:	110kVac = 7.54 vdc
4 ma	-50.0 Mvar	0.4 Vdc	0 vdc	0kV	
8 ma	-25.0 Mvar	0.8 Vdc	3.77 vdc	55kV	
12 ma	0.00 Mvar	1.2 Vdc	6.17 vdc	90kV	
16 ma	+25.0 Mvar	1.6 Vdc	6.85 vdc	100kV	
20 ma	+50.0 Mvar	2.0 Vdc	7.54 vdc	110kV	

Note: Unit 3 Mwatt/Mvar Transducer has an extra cable in the output circuit. This has induced an extra 50Ω into the current loop.

Remarks: April 29, 2004 - Seven Sisters Remote Black Start Tests

Test #1 - Unit 2 synchronized to a dead bus with Unit 3 operating in the condense mode. Initially there were problems with unit 2 tripping by "INCOMPLETE SEQUENCE". The START RELAY 4G2 would not reset. Upon receiving a start command the 4G2 relay seals itself in and will only reset when the 'SPEED NO LOAD' contact opens. This contact will only open when Gate Position exceeds 45%.

Unit 2 had tripped by INC. SEQ. twice. The incomplete Sequence timing relay 48ST operated erratically. The time delay for this relay is set to 5 Minutes, but operated in 7 minutes and 19 minutes for each of the operations.

The third time that unit 2 was synchronized to the dead bus the gate position indicating meter showed that there was a spike and the gate position meter indicated a momentary position of =50%, which was above the 45% required to reset the 4G2 start relay. Unit 3 was then synchronized to unit 2 and switched to the condense mode. It was noticed that the 4G3 start relay for Unit 3 had not reset. Since the gate position was well below 45% it was decided to reset the 4G3 relay manually. Before the relay could be reset the 48ST INC. SEQ. relay for unit 3 (operating time was 3 minutes) had operated. Unit 3 did not trip. According to drawings, when the 48ST relay operates it should operate the 5G3 relay and trip unit 3 breaker.

Test #2 - When the units were reversed, Unit 3 in generate mode and Unit 2 in condense mode, the same problem arose. The 4G3 relay would not reset because of 'SPEED NO LOAD' contact. The 4G3 relay was manually reset before the 'INCOMPLETE SEQUENCE' relay had a chance to operate.

E1876(A)-Proposed 99 05

CAPITAL PROJECT JUSTIFICATION
FOR

Remote Control, Monitoring and Automation of Kettle, Long Spruce & Limestone

ORIGINATING DIVISION: Generation North

B.R.N.:

MAJOR ITEM X **DOMESTIC ITEM**

PREPARED BY: A. G. Monkman

DATE PREPARED: February 26, 2001

REPORT NO.:

REVIEWED BY:
(Originating Department Manager)

NOTED BY: (if applicable)

Designing Division:

Constructing Division:

Financial Department:
(for capital item over $1 million)

RECOMMENDED FOR IMPLEMENTATION:

Originating Division Manager: 01 03

Business Unit Vice-President:

DATE	REVISIONS	REVISED BY	ORIGINATING DIVISION MANAGER

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION

Project Description

De-staffing the Control Room of the (3) Hydraulic Stations, Kettle, Long Spruce and Limestone.

Recommendation

Assuming the 24x7 study, presently being done, confirms that the station control room can be de-staffed; plan, design and install equipment to reduce any risks associated with this initiative.

Project Scope

Once Station Control Room staffing requirements are confirmed; plan, design and install any required automation, remote control, and protective devices to provide for the continued safe and efficient operation of the station without staff in the Control Room.

Background

Power Supply presently operates 5 of 11 Hydraulic Generating Stations and all 3 HVDC Converter Stations on a 24 hr x 7 day basis. Three of the staffed stations are in Generation North.

Our present Reliability rate is averaging about 99.5%/year.
Our present Forced Outage rate is averaging about .5%/year.

Manitoba Hydro is facing a period of change that demands our attention as industry moves to a more competitive market. To participate and survive in a market where the price of the product or service is determined by the market, Manitoba Hydro will have to change. Adjusting our costs will help us compete in this market.

Manitoba Hydro has completed a Shift Worker study by Circadian Technologies, Inc., which indicates problems with working shift work and the effects on workers and their families. If shift work is not required in the station the concerns will be removed.

JUSTIFICATION—BUSINESS CASE ANALYSIS (SUMMARY):

Justification and Link to Corporate/Business Unit Goals

Health and safety in the work environment and corporate financial strength will be improved by reducing or eliminating the need for shift work and the numbers of workers required to operate the station.

state goal

ANALYSIS OF ALTERNATIVES:

Economic Analysis

Discount Rate	5.93%

Recommended Option	**NPV**
Reduce the required number of Shift Worker by 70% (this is about 21 positions). ($112,000/person in G N) and Install more automation, remote control and protection (these are one time costs)	$20,177,000

Other Alternatives Considered	**NPV**
Do nothing, maintain present Operating staff levels.	$0
Use the Multi Skilled Worker to perform the operating functions as required. (This may mean shift work depending on System requirements.)	

Risk Analysis

There may be some added risk in de-staffing the station(s) and the Forced Outage rate may rise slightly until the bugs are worked out. (Details will be obtained by the 24 x 7 Plant Staffing Team study)

RESOURCE REQUIREMENTS AND CAPITAL BUDGET ESTIMATE:

Resource Requirements

The 24 x 7 Plant Staffing Team, their expenses related to the survey being conducted and any field trips required to verify and clarify their findings.
Engineering support to determine the required automation, remote control and protection require to maintain or improve our present reliability.
Engineering and Construction support to design and install require equipment.

Total Budget

$3,000,000 ($1,000,000 per station (3))

Proposed Schedule

Capital additions well into 2002/2003 to 2004/2005.

Related Projects

Plant Optimization, Multi Skilled Worker, similar work may be required in HVDC and Generation South.

Reference Documents

Team sponsored by Power Supply Division Managers to review the need for staffing Hydraulic and HVDC station(s) 24 hour per day, 7 days per week.
2000 08 27 Kick-off meeting held with team members, Spence Lytwyn, Wally Koschik and Bud Monkman.
Plant Staffing survey results from working team.

01876(A)

Attachment #2
Approved July 29/03
EC 990.03

CAPITAL PROJECT JUSTIFICATION ADDENDUM
FOR

Remote Control, Monitoring and Automation of
Kettle, Long Spruce & Limestone
Addendum #1

REVIEWED BY:
(Owning Dept Manager) A Clark

NOTED BY:
(if applicable)

Designing Division:

Constructing Division:

Financial Department:
(if over $1 million)

RECOMMENDED FOR IMPLEMENTATION:

Owning Div. Manager: 03-06-16

Business Unit V.P.: 03 06 25

PREV. APPROVED BUDGET $: (Use $ value from approved CPJ or last approved CPJ Addendum)	$3,000,000
REVISED BUDGET $: (Total Net Cost)	$3,065,000
START DATE: (1st Cost Flow)	2002 04
PREV. APPROVED ISD: (Use In-service Date from approved CPJ or last approved CPJ Addendum)	2005 03
REVISED ISD: (Last Major In-service Date)	2007 03
RISK MATRIX/ BUSINESS CASE TIER:	
INVESTMENT REASON:	

OWNING DIVISION: Generation North

I.M. NODE NUMBER: 1.1.1.3. 19.1

W.B.S. NUMBER: P:04495

MAJOR ITEM X **DOMESTIC ITEM** ☐

PREPARED BY: V. Laing

DATE PREPARED: 2003 06 13

REPORT NUMBER:

FILE NUMBER (Optional):

1	2003/06/13	ISD deferred two years to allow for additional study.	V. Laing	A.A. Clark
ADDENDUM NUMBER	**DATE** (yyyy mm dd)	**REVISION**	**REVISED BY**	**APPROVED BY**

CER(1) Rev. 97 12

CAPITAL EXPENDITURE REVISION

(IN THOUSANDS OF DOLLARS)

Title	Investment Management Node:
REMOTE CONTROL & MONITORING - GEN NORTH	1.1.1.3.19.1
Owning Division	**Coordinating Division**	**ProjectNumber:**
GENERATION NORTH	GENERATION NORTH	P:04495

DESCRIPTION:
INSTALL EQUIPMENT TO REDUCE ANY RISKS ASSOCIATED WITH THE DESTAFFING OF THE HYDRAULIC STATION CONTROL ROOMS.

JUSTIFICATION:
HEALTH AND SAFETY IN THE WORK ENVIRONMENT AND CORPORATE FINANCIAL STRENGTH WILL BE IMPROVED BY REDUCING OR ELIMINATING THE NEED FOR SHIFT WORK AND THE NUMBERS OF WORKERS REQUIRED TO OPERATE THE STATION.

REVISION:
CASH FLOW REVISED TO ACCOMMODATE THE 24x7 STAFFING REVIEW STUDY CURRENTLY BEING PREPARED.

IN SERVICE DATES				Base estimate 2003/04/01 CLASS 2
2007/03/31	3065			Work start date 2002/04/01

PREV.AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Actual cost to date:	78		1			79
(Over)under expend:	400	3	18			421
2003/04	1134	28	88			1250
2004/05	1015	46	190			1251
V-A02 TOTAL	2627	77	297			3001
REV. AMOUNTS:						
Actual cost to date:	78		1			79
(Over)under expend:						
Auth 2003/04	100	1	11			112
Req: 2004/05	100	3	20			123
2005/06	1200	60	74			1334
2006/07	1149	82	186			1417
V-SEL TOTAL	2627	146	292			3065

Prepared by	yy mm dd	Approved by	yy mm dd	Approved by	yy mm dd	Approved by	yy mm dd
MD	03 06 13	OWNING DIVISION	03 06 16	COORDINATING DIVISION		VICE PRESIDENT	03 06 27

2003/06/13 3:44PM

D1876(A)

Attachment #2 Approved EC 1039.04 Aug 3/04

CAPITAL PROJECT JUSTIFICATION ADDENDUM
FOR

Remote Control, Monitoring and Automation of
Kettle, Long Spruce & Limestone
Addendum #2

REVIEWED BY:
(Owning Dept Manager)

NOTED BY:
(if applicable)

Designing Division:

Constructing Division:

Financial Department:
(if over $1 million) 04/06/25

RECOMMENDED FOR IMPLEMENTATION:

Owning Div. Manager: 04,06,25

Business Unit V.P.: 040630

PREV. APPROVED BUDGET $: (Use $ value from approved CPJ or last approved CPJ Addendum)	$3,065,000
REVISED BUDGET $: (Total Net Cost)	$3,068,000
START DATE: (1st Cost Flow)	2002 04
PREV. APPROVED ISD: (Use In-service Date from approved CPJ or last approved CPJ Addendum)	2007 03
REVISED ISD: (Last Major In-service Date)	2008 03
RISK MATRIX/ BUSINESS CASE TIER:	
INVESTMENT REASON:	C2.14 Efficiencies – Capacity Supply

OWNING DIVISION: Generation North

I.M. NODE NUMBER: 1.1.1.3.[illegible].1

W.B.S. NUMBER: P:04495

MAJOR ITEM X **DOMESTIC ITEM** ☐

PREPARED BY: V. Laing

DATE PREPARED: 2004 06 18

REPORT NUMBER:

FILE NUMBER (Optional):

1	2003/06/13	**ISD deferred two years to allow for additional study.**	V. Laing	E.C.#990.03
ADDENDUM NUMBER	**DATE** (yyyy mm dd)	**REVISION**	**REVISED BY**	**APPROVED BY**

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION ADDENDUM

Project Name (This section is required for all Addendums).

Remote Control, Monitoring and Automation of Kettle, Long Spruce & Limestone

Recommendation (This section is required for all Addendums).

Further study is required. ISD deferred an additional year.

Project Scope (This section is be filled out only if there is a change to the scope).

No change to scope.

Background (This section is be filled out only if there is information relevant to the recommendation).

No Change

JUSTIFICATION—BUSINESS CASE ANALYSIS (SUMMARY):

Justification and Link to Corporate/Business Unit Goals (This section is be filled out only if there is a change to the recommended alternative).

No Change

ANALYSIS OF ALTERNATIVES: (This section is be filled out only if there is a change to which alternative is being recommended).

Economic Analysis

Discount Rate	**For current corporate rates see G911** **%**	**For clarification on hurdle rates, contact Economic Analysis Department**
Recommended Option		**NPV** **(= PV of BENEFITS - PV of COSTS)**
Other Alternatives Considered		**NPV** **(= PV of BENEFITS - PV of COSTS)**

Risk Analysis - (This section is be filled out only if there is a change to the project risk).

RESOURCE REQUIREMENTS AND CAPITAL BUDGET ESTIMATE:

Resource Requirements (This section is be filled out only if there is a change to the resource requirements).

Total Budget - (This section is required for all Addendums).

The impact on annual budget requirements is as follows (in thousands of dollars):

Fiscal Year	Approved CPJ Budget	Current CEF Budget	Revised CPJ Budget	CPJ Increase (Decrease)	CEF / Revised CPJ Increase (Decrease)
Prev. Actuals	$ 127	$ 127	$ 127	$ 0	$ 0
2004/05	$ 187	$ 187	$ 61	$ (126)	$ (126)
2005/06	$ 1 334	$ 1 334	$ 68	$(1 266)	$(1 266)
2006/07	$ 1 417	$ 1 417	$ 1 357	$ (60)	$ (60)
2007/08			$ 1 455	$ 1 455	$ 1 455
Total	$ 3,065	$ 3,065	$ 3,068	$ 3	$ 3

Related Projects (This section is be filled out only if changed).

Reference Documents (This section is be filled out only if changed).

CER(1) Rev. 97 12

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

Title		Investment Management Node:
REMOTE CONTROL & MONITORING - GEN NORTH		1.1.1.3.19.1
Owning Division	Coordinating Division	ProjectNumber:
GENERATION NORTH	GENERATION NORTH	P:04495

DESCRIPTION:
INSTALL EQUIPMENT TO REDUCE ANY RISKS ASSOCIATED WITH THE DESTAFFING OF THE HYDRAULIC STATION CONTROL ROOMS.

JUSTIFICATION:
HEALTH AND SAFETY IN THE WORK ENVIRONMENT AND CORPORATE FINANCIAL STRENGTH WILL BE IMPROVED BY REDUCING OR ELIMINATING THE NEED FOR SHIFT WORK AND THE NUMBERS OF WORKERS REQUIRED TO OPERATE THE STATION.

REVISION:
DEFER IN-SERVICE DATE BY ONE YEAR.

IN SERVICE DATES			Base estimate 2004/04/01 CLASS 2
2008/03/31	3068		Work start date 2002/04/01

PREV.AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Actual cost to date:	117		10			127
(Over)under expend:	61	1	2			64
2004/05	100	3	20			123
2005/06	1200	60	74			1334
2006/07	1149	82	186			1417
V-A03 TOTAL	2627	146	292			3065
REV. AMOUNTS:						
Actual cost to date:	117		10			127
(Over)under expend:						
Auth 2004/05	50		11			61
Req: 2005/06	50	1	17			68
2006/07	1240	50	67			1357
2007/08	1210	72	173			1455
V-H10 TOTAL	2667	123	278			3068

Prepared by	yy mm dd	Approved by	yy mm dd	Approved by	yy mm dd	Approved by	yy mm dd
NK	04 06 24	OWNING DIVISION	04 06 25	COORDINATING DIVISION		VICE-PRESIDENT	04 06 30

2004/06/24 1:25PM

C2R(1) Rev. 97 12

CAPITAL EXPENDITURE REVISION

FORECAST HISTORY (in thousands of dollars)

ProjectNumber P:04495

Approved yy mm	TOTAL AMOUNT	COMMENTS
2004 1	3068.00	DEFER ISD BY 1 YEAR
2003 1	3065.00	DEFER ISD BY 2 YEARS
2002 1	3001.00	CASH FLOW REVISED TO ACCOMMODATE THE 24x7 STAFFING REVIEW STUDY CURRENTLY BEING PREPARED.
2001 1	3000.00	NEW ITEM.

ASSOCIATED PROJECTS

Project number	Description

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
2004/05 Apr	4		1			5	5
May	4		1			5	10
Jun	4		1			5	15
Jul	4		1			5	20
Aug	4		1			5	25
Sep	4		1			5	30
Oct	4		1			5	35
Nov	4		1			5	40
Dec	4		1			5	45
Jan	4		1			5	50
Feb	4		1			5	55
Mar	6					6	61
TOTAL	50		11			61	61
2005/06 Apr	4		1			5	5
May	4		1			5	10
Jun	4		1			5	15
Jul	4		1			5	20
Aug	5		1			6	26
Sep	4		1			5	31
Oct	4		1			5	36
Nov	4		1			5	41
Dec	4		1			5	46
Jan	4		2			6	52
Feb	4		2			6	58
Mar	5	1	4			10	68
TOTAL	50	1	17			68	68

2004/06/24 1:25PM

D1876(A)

Attachment #2

Approved
EC 1125.04
May 30/06

CAPITAL PROJECT JUSTIFICATION ADDENDUM FOR

Remote Control, Monitoring and Automation of Kettle, Long Spruce & Limestone Addendum #3

REVIEWED BY:
(Owning Dept Manager) A Clark 06/05/05

NOTED BY:
(if applicable)

Designing Division:

Constructing Division:

Financial Department:
(if over $1 million)

RECOMMENDED FOR IMPLEMENTATION:

Owning Div. Manager: 06,05,05

Business Unit V.P.: 06 05 17

PREV. APPROVED BUDGET $: (Use $ value from approved CPJ or last approved CPJ Addendum)	$3,060,000
REVISED BUDGET $: (Total Net Cost)	$3,219,000
START DATE: (1st Cost Flow)	2002 04
PREV. APPROVED ISD: (Use In-service Date from approved CPJ or last approved CPJ Addendum)	2008 03
REVISED ISD: (Last Major In-service Date)	2010 03
RISK MATRIX/ BUSINESS CASE TIER:	
INVESTMENT REASON:	C2.14 Efficiencies – Capacity Supply

OWNING DIVISION:	Generation North
I.M. NODE NUMBER:	1.1.1.3.18.1
W.B.S. NUMBER:	P:04495
MAJOR ITEM X	**DOMESTIC ITEM** ☐
PREPARED BY:	V. Laing
DATE PREPARED:	2006 05 02
REPORT NUMBER:	
FILE NUMBER (Optional):	

3	2006/05/02	ISD deferred two years to allow for additional study.	V. Laing	
ADDENDUM NUMBER	**DATE** (yyyy mm dd)	**REVISION**	**REVISED BY**	**APPROVED BY**

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION ADDENDUM

Project Name (This section is required for all Addendums).

Remote Control, Monitoring and Automation of Kettle, Long Spruce & Limestone.

Recommendation (This section is required for all Addendums).

Further study is required. ISD deferred an additional two years.

Project Scope (This section is be filled out only if there is a change to the scope).

No change to scope.

Background (This section is be filled out only if there is information relevant to the recommendation).

No Change.

JUSTIFICATION—BUSINESS CASE ANALYSIS (SUMMARY):

Justification and Link to Corporate/Business Unit Goals (This section is be filled out only if there is a change to some aspect of the recommended alternative).

No Change.

ANALYSIS OF ALTERNATIVES: (This section is be filled out only if there is a change to which alternative is being recommended).

Economic Analysis

Discount Rate	**For current corporate rates see G911** **%**	**For clarification on hurdle rates, contact Economic Analysis Department**
Recommended Option		**NPV** **(= PV of BENEFITS - PV of COSTS)**
Other Alternatives Considered		**NPV** **(= PV of BENEFITS - PV of COSTS)**

Risk Analysis - (This section is be filled out only if there is a change to the project risk).

RESOURCE REQUIREMENTS AND CAPITAL BUDGET ESTIMATE:

Resource Requirements (This section is be filled out only if there is a change to the resource requirements).

Total Budget - (This section is required for all Addendums).

The impact on annual budget requirements is as follows (in thousands of dollars):

Fiscal Year	Prev. Approved CPJ/Addendum	Proposed CPJ Addendum	Increase (Decrease)
Prev. Actuals	$ 147	$ 147	$ -
2006/07	$ 1,459	$ 10	$ (1,449)
2007/08	$ 1,454	$ 122	$ (1,332)
2008/09	$ -	$ 1,419	$ 1,419
2009/10	$ -	$ 1,521	$ 1,521
Total	$ 3,060	$ 3,219	$ 159

Proposed Schedule (This section is be filled out only if there is a change to the project schedule).

ISD deferred an additional two years to 2010/03/31.

Related Projects (This section is be filled out only if changed).

Reference Documents (This section is be filled out only if changed).

CER(1) Rev 97 12

CAPITAL EXPENDITURE REVISION

SIMULATED ROLLOVER

FORECAST HISTORY (in thousands of dollars)

ProjectNumber P:04495

Approved yy mm	TOTAL AMOUNT	COMMENTS
2005 1	3060.00	UPDATED INTEREST AND ESCALATION RATES.
2004 1	3068.00	DEFER ISD BY 1 YEAR
2003 1	3065.00	DEFER ISD BY 2 YEARS
2002 1	3001.00	CASH FLOW REVISED TO ACCOMMODATE THE 24x7 STAFFING REVIEW STUDY CURRENTLY BEING PREPARED.
2001 1	3000.00	NEW ITEM.

ASSOCIATED PROJECTS

Project number	Description

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
2006/07 Apr			1			1	1
May			1			1	2
Jun			1			1	3
Jul			1			1	4
Aug			1			1	5
Sep			1			1	6
Oct			1			1	7
Nov			1			1	8
Dec			1			1	9
Jan			1			1	10
Feb			1			1	11
Mar			-1			-1	10
TOTAL			10			10	10
2007/08 Apr	8		1			9	9
May	9	1	1			11	20
Jun	8	1	1			10	30
Jul	9	1	1			11	41
Aug	9	1	1			11	52
Sep	8	1	1			10	62
Oct	9	1	1			11	73
Nov	9	1	1			11	84
Dec	7	1	1			9	93
Jan	9	1	1			11	104
Feb	8	1	1			10	114
Mar	7	-3	4			8	122
TOTAL	100	7	15			122	122

CER(1) Rev. 97 12

CAPITAL EXPENDITURE REVISION

(IN THOUSANDS OF DOLLARS)

SIMULATED ROLLOVER

Title		Investment Management Node:
REMOTE CONTROL & MONITORING - GEN NORTH		1.1.1.3.19.1
Owning Division: GENERATION NORTH	Coordinating Division: GENERATION NORTH	ProjectNumber: P:04495

DESCRIPTION:

INSTALL EQUIPMENT TO REDUCE ANY RISKS ASSOCIATED WITH THE DESTAFFING OF THE HYDRAULIC STATION CONTROL ROOMS.

JUSTIFICATION:

HEALTH AND SAFETY IN THE WORK ENVIRONMENT AND CORPORATE FINANCIAL STRENGTH WILL BE IMPROVED BY REDUCING OR ELIMINATING THE NEED FOR SHIFT WORK AND THE NUMBERS OF WORKERS REQUIRED TO OPERATE THE STATION.

REVISION:

DEFER IN-SERVICE DATE BY TWO YEARS.

IN SERVICE DATES				Base estimate 2004/04/01 CLASS 2
2010/03/31	3219			Work start date 2002/04/01

PREV AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Actual cost to date:	117		30			147
(Over)under expend:	100	2				102
2006/07	1240	62	55			1357
2007/08	1210	86	158			1454
V-A05 TOTAL	2667	150	243			3060
REV AMOUNTS:						
Actual cost to date:	117		30			147
(Over)under expend:						
Auth 2006/07			10			10
Req 2007/08	100	7	15			122
2008/09	1240	114	65			1419
2009/10	1210	138	173			1521
V-HLD TOTAL	2667	259	293			3219

Prepared by	yy mm dd	Approved by	yy mm dd	Approved by	yy mm dd	Approved by	yy mm dd
	06 05 05	OWNING DIVISION	06 05 05	COORDINATING DIVISION		VICE-PRESIDENT	06 05 17

D1876(A)

REVIEWED BY EXECUTIVE COMMITTEE
MINUTE # 1316.04

DATE: 2010 07 20
Corporate Budget Services

CAPITAL PROJECT JUSTIFICAT FOR

Remote Control, Monitoring and Automation of Kettle, Long Spruce & Limestone Addendum Number #4

REVIEWED BY:
(Owning Dept Manager) Gary Siebert 2010/06/16

NOTED BY:
(if applicable)

Coordinating Division:

Constructing Division:

Financial Department:
(if over $1 million)

RECOMMENDED FOR IMPLEMENTATION:

Owning Div. Manager: 2010/06/22

Business Unit V.P.: 10 06 25

PREV. APPROVED BUDGET $: (Use $ value from approved CPJ or last approved CPJ Addendum)	$3,219,000
REVISED BUDGET $: (Total Net Cost)	$5,078,000
START DATE: (1st Cost Flow)	2002 04
PREV. APPROVED ISD: (Use In-service Date from approved CPJ or last approved CPJ Addendum)	2010 03
REVISED ISD: (Last Major In-service Date)	2011 03
RISK MATRIX/ BUSINESS CASE TIER:	
INVESTMENT REASON:	C2.14 Efficiencies - Capacity Supply
OWNING DIVISION:	Generation North
I.M. NODE NUMBER:	1.1.1.3.19.3
W.B.S. NUMBERs:	P:04495
MAJOR ITEM ☒	**DOMESTIC ITEM** ☐
PREPARED BY:	S.J. Boychuk, P.Eng
DATE PREPARED:	2010 06 01
REPORT NUMBER:	CPJGN018
FILE NUMBER (Optional):	

ADDENDUM NUMBER	DATE (yyyy mm dd)	REVISION	REVISED BY	APPROVED BY
1	2003 06	ISD deferred two years to allow for additional study.	V. Laing	EC #990.03
2	2004 06	ISD deferred one year to allow for additional study.	V. Laing	EC #1039.04
3	2006 05	ISD deferred two years to allow for additional study.	V. Laing	EC #1125.04

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION ADDENDUM

Project Name

Remote Control, Monitoring and Automation of Kettle, Long Spruce & Limestone

Recommendation

Increase funding to meet the project goal of operating the Kettle generating station with a 5 day per week day shift only staffing schedule for a 2 year trial period starting January 2011.

Project Scope

Project scope and funding only includes operating Kettle with a 5 day per week day shift schedule at this time. The long term vision for operating Long Spruce and Limestone with a day shift only schedule will be evaluated during the Kettle trial period, considering major construction plans in the north involving Conawapa and Keeyask.

Background

The 2006 report, "Impact on Generating Station Staffing on Asset and Operational Risks" investigated the impacts of de-staffing the control rooms at generating stations throughout Manitoba Hydro. This report recommended that Kettle G.S. control room be operated with 5 day per week day shift only schedule for a 2 year trial period.

The 2008 report, "Kettle Generating Station Operational Equipment Review" recommended equipment modifications to ready Kettle G.S. to operate with a 5 day per week day shift schedule. Since that date Generation North has been implementing those recommendations to ready Kettle G.S. Generation North decided to proceed with the project using the allocated funds.

JUSTIFICATION—BUSINESS CASE ANALYSIS (SUMMARY):

Justification and Link to Corporate/Business Unit Goals

To meet the 2 year trial start date of January 2011, the additional money is needed fiscal year 2010/11. Delaying the ISD will delay the 2 year trial period. This is not acceptable as momentum and staff support to this change will be lost.

A major portion of this project is the upgrade to the fire detection system. The cost of the new fire detection system is 300% the original estimate and used all allocated funds.

Other significant projects related to alarm annunciation, spillway control and station flood protection must be completed prior to starting the trial period. This requires additional money.

Continuing with the project is linked to the Power Supply Goal #1 to continuously improve safety, health and wellness in the work environment by reducing or eliminating the amount of shift work required at Kettle G.S. This will allow employees to achieve and maintain a healthy work / life balance.

This also supports Power Supply Goal #6 to have highly skilled, effective, innovative employees by

JUSTIFICATION—BUSINESS CASE ANALYSIS (SUMMARY):

Justification and Link to Corporate/Business Unit Goals

allowing employees to grow and develop through additional training, experience and challenges.

Power Supply Goal #7 to continue to make Power Supply a great place to work is supported by offering employees a choice to either continually work shifts or minimal shift work.

ANALYSIS OF ALTERNATIVES:

Economic Analysis

Discount Rate % For current corporate rates see G911
For clarification on hurdle rates, contact Economic Analysis Department

Recommended Option **NPV Benefits/(Costs)**

No change to recommended alternative.

Other Alternatives Considered **NPV Benefits (Costs)**

Risk Analysis

At this time there are no high risks with proceeding as recommended.

Design and construction risks associated with the annunciation, spillway control and flood protection are medium due to design time, material procurement and construction of the new systems. These risks are related to manpower issues and equipment availability.

Approval to proceed will need to be received by the end of June 2010 to continue with the project and take advantage of available Electrical Construction resources during the summer and fall.

RESOURCE REQUIREMENTS AND CAPITAL BUDGET ESTIMATE:

Resource Requirements

The impact on resource requirements is as follows:

Department/ Section	Cost Centre	Prev. Approved CPJ/Addendum	Proposed CPJ Addendum	Increase (Decrease)
Electrical Engineering	51040	0	3,624	3,624
Electrical Construction	52560	0	6,996	6,996
Technical Services	51280	0	865	865
Kettle Site	51340	0	4,700	4,700
Mechanical Engineering	51050	0	605	605
Power Projects Dept.	51460	0	2,135	2,135
		0	0	0
		0	0	0
Other	various	0		0
Total Resource Requirements		**0**	**18,925**	**18,925**

Previous estimates did not include detail with respect to internal resource requirements.

Total Budget

The impact on annual budget requirements is as follows (in thousands of dollars):

Fiscal Year	Previous CPJ / CPJ Addendum	This CPJ Addendum	Increase (Decrease)
Prev. Actuals	$ 147	$ 147	$ -
2006/07	$ 10	$ 10	$ -
2007/08	$ 122	$ 58	$ (64)
2008/09	$ 1,419	$ 327	$ (1,092)
2009/10	$ 1,521	$ 1,475	$ (46)
2010/11	$ -	$ 3,061	$ 3,061
2011/12	$ -	$ -	$ -
Total	$ 3,219	$ 5,078	$ 1,859

Proposed Schedule

ISD deferred one year to 2011/03/31.

Related Projects

Power Supply Physical Security Upgrade
NERC Cyber Security Project

Reference Documents
"Impact of Generating Station Staffing on Asset and Operational Risks", L.E. Midford, P.Eng, 2006 11 13
GN08-01, "Kettle Generating Station Operational Equipment Review", S.J. Boychuk, P.Eng, 2008 08 18

CER(1) Rev. 97 12

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

SIMULATED ROLLOVER

Title		Investment Management Node:
REMOTE CONTROL & MONITORING - GEN NORTH		1.1.1.3.19.3
Owning Division: GENERATION NORTH	Coordinating Division: GENERATION NORTH	ProjectNumber: P:04495

DESCRIPTION:
INSTALL EQUIPMENT TO REDUCE ANY RISKS ASSOCIATED WITH THE DESTAFFING OF THE HYDRAULIC STATION CONTROL ROOMS.

JUSTIFICATION:
HEALTH AND SAFETY IN THE WORK ENVIRONMENT AND CORPORATE FINANCIAL STRENGTH WILL BE IMPROVED BY REDUCING OR ELIMINATING THE NEED FOR SHIFT WORK AND THE NUMBERS OF WORKERS REQUIRED TO OPERATE THE STATION.

REFERENCE:
CPJGN018 ENTITLED "REMOTE CONTROL, MONITORING AND AUTOMATION OF KETTLE, LONG SPRUCE & LIMESTONE ADDENDUM #4" DATED JUNE 1, 2006.

REVISION:
INCREASE FUNDING TO MEET THE PROJECT GOAL OF OPERATING THE KETTLE GENERATING STATION WITH A 5 DAY PER WEEK DAY SHIFT ONLY STAFFING SCHEDULE FOR A 2 YEAR TRIAL PERIOD STARTING JANUARY 2011.

IN SERVICE DATES				Base estimate 2010/04/01 CLASS 3
2010/02/28	878	2011/02/28	91	
2010/08/31	2563	2011/03/31	1223	Work start date 2002/04/01
2010/10/31	44			
2010/12/31	279			

PREV.AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Actual cost to date:	1888		129			2017
(Over)under expend:	288	1				289
2010/11	1100	12	66			1178
V-HAP TOTAL	3276	13	195			3484
REV. AMOUNTS:						
Actual cost to date:	1888		129			2017
(Over)under expend:						
Auth 2010/11 Req.:	2953	7	101			3061
V-HLD TOTAL	4841	7	230			5078

Prepared by	yy mm dd	Approved by	yy mm dd	Approved by	yy mm dd	Approved by	yy mm dd
	10 06 06	OWNING DIVISION	2006 06 22	COORDINATING DIVISION		VICE PRESIDENT	10 06 25

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CAPITAL EXPENDITURE REVISION

SIMULATED ROLLOVER

FORECAST HISTORY (in thousands of dollars)

ProjectNumber P:04495

Approved yy mm	TOTAL AMOUNT	COMMENTS
2009 06	3485.00	DEFERRED IN-SERVICE DATE BY ONE YEAR AND RE-CASHFLOWED THE PROJECT.
2008 06	3218.00	UPDATED INTEREST AND ESCALATION RATES.
2007 10	3221.00	UDATED INTEREST AND ESCALATION RATES.
2006 10	3219.00	DEFERRED IN-SERVICE DATE BY TWO YEARS.
2005 10	3060.00	UPDATED INTEREST AND ESCALATION RATES.
2004 10	3068.00	DEFER ISD BY 1 YEAR
2003 10	3065.00	DEFER ISD BY 2 YEARS
2002 10	3001.00	CASH FLOW REVISED TO ACCOMMODATE THE 24x7 STAFFING REVIEW STUDY CURRENTLY BEING PREPARED.
2001 10	3000.00	NEW ITEM.

Forecasted Mthly Exp.		GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
2010/11	Apr	471		6			477	477
	May	403		9			412	889
	Jun	537	1	11			549	1438
	Jul	484	2	14			500	1938
	Aug	462	2	17			481	2419
	Sep	107		5			112	2531
	Oct	102		6			108	2639
	Nov	95		6			101	2740
	Dec	94		7			101	2841
	Jan	63		6			69	2910
	Feb	62		6			68	2978
	Mar	73	2	8			83	3061
TOTAL		2953	7	101			3061	3061
2011/12	Apr							
	May							
	Jun							
	Jul							
	Aug							
	Sep							
	Oct							
	Nov							
	Dec							
	Jan							
	Feb							
	Mar							
TOTAL								

APPROVED BY EXECUTIVE COMMITTEE
MINUTE # 1382.03
DATE: 2012 01 18
Financial Planning

CAPITAL PROJECT JUSTIFICA
FOR

Remote Control, Monitoring and Automation of Kettle, Long Spruce & Limestone Addendum Number #5

REVIEWED BY: G. Gusberti
(Owning Dept Manager)

NOTED BY:
(if applicable)

Coordinating Division:

Constructing Division:

Financial Department:
(if over $1 million) 11/07/12

RECOMMENDED FOR IMPLEMENTATION:

Owning Div. Manager:

Business Unit V.P.: June 18, 2011
11 09 19

PREV. APPROVED BUDGET $: (Use $ value from approved CPJ or last approved CPJ Addendum)	$5,078,000
REVISED BUDGET $: (Total Net Cost)	$12,566,000
START DATE: (1st Cost Flow)	2002 04
PREV. APPROVED ISD: (Use In-service Date from approved CPJ or last approved CPJ Addendum)	2011 03
REVISED ISD: (Last Major In-service Date)	2016 03
RISK MATRIX/ BUSINESS CASE TIER:	
INVESTMENT REASON:	C2.14 Efficiencies – Capacity Supply
OWNING DIVISION:	Generation North
I.M. NODE NUMBER:	1.1.1.3.19.3
W.B.S. NUMBERs:	P:04495
MAJOR ITEM X	**DOMESTIC ITEM** ☐
PREPARED BY:	Brad Minary
DATE PREPARED:	2011 05 27
REPORT NUMBER:	
FILE NUMBER (Optional):	

ADDENDUM NUMBER	DATE (yyyy mm dd)	REVISION	REVISED BY	APPROVED BY
1	2003 06	ISD deferred two years to allow for additional study.	V. Laing	EC #990.03
2	2004 06	ISD deferred one year to allow for additional study.	V. Laing	EC #1039.04
3	2006 05	ISD deferred two years to allow for additional study.	V. Laing	EC #1125.04
4	2010 06	Increase funding to meet the project goal of operating the Kettle generating station with a 5 day per week day shift only staffing schedule for a 2 year trial period starting January 2011.	S.J.Boychuk	EC #1316.04

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION ADDENDUM

Project Name
Remote Control, Monitoring and Automation of Kettle, Long Spruce & Limestone

Recommendation
Increase project scope to include the required equipment modifications to enable a day shift only staffing schedule at Long Spruce and Limestone.

Project Scope
The following equipment modifications at Long Spruce and Limestone are required to mitigate the risks of moving to a day shift only schedule: • Fire system • Flood control • Security upgrades • Reliability improvements

Background
The equipment modifications have been implemented at Kettle and unmanned operation began on January 14, 2011 for a two year trial period. Performance measures have been established to evaluate the success of this project. During the two year trial period, engineering and design assessments of Long Spruce and Limestone will be conducted to ensure implementation is not delayed.

JUSTIFICATION—BUSINESS CASE ANALYSIS (SUMMARY):

Justification and Link to Corporate/Business Unit Goals
Implementing the equipment modifications at Long Spruce and Limestone supports the following goals: • Power Supply Goal #1 to continuously improve the safety, health and wellness in the work environment by reducing or eliminating the amount of shift work in Generation North. • Power Supply Goal #6 to have highly skilled, effective and motivated employees by allowing employees to grow and develop through additional training, experience and challenges. • Power Supply Goal #7 to continue to make Power Supply a great place to work by providing a better work / life balance for station staff.

ANALYSIS OF ALTERNATIVES:

Economic Analysis		
Discount Rate	6.1%	For current corporate rates see G911 For clarification on hurdle rates, contact Economic Analysis Department

Recommended Option	NPV Benefits/(Costs)
Increase project scope to include the required equipment modifications to enable a day shift only staffing schedule at Long Spruce and Limestone.	($5,929,628)

Other Alternatives Considered	NPV Benefits (Costs)
Do nothing.	N/A

Risk Analysis

At this time there are no high risks associated with proceeding as recommended. The two year trial period will be complete and assessed prior to the implementation of equipment changes at Long Spruce and Limestone; however the engineering and design work will continue.

The successful implementation of this project is dependant on the completion of the following projects:

- Gillam Redevelopment and Expansion Program - Construction of central control building in Gillam.
- Limestone GSCADA Replacement
- Long Spruce UCMS

Delays in any of these will affect the schedule.

FERC and NERC changes and rulings may affect the physical and cyber requirements as legislation is developed and implemented.

Approval to proceed will need to be received in a timely manner to continue with the project and take advantage of available internal resources.

Capital Budget Estimate

The impact on annual budget requirements is as follows (in thousands of dollars):

Fiscal Year	Previous CPJ / CPJ Addendum	This CPJ Addendum	Increase (Decrease)
Prev. Actuals	$ 5,078	$ 4,849	$ (229)
2011/12		$ 470	
2012/13	$ -	$ 311	$ 311
2013/14	$ -	$ 3,320	$ 3,320
2014/15		$ 2,384	$ 2,384
2015/16		$ 1,232	$ 1,232
Total	$ 5,078	$ 12,566	$ 7,488

Proposed Schedule

Schedule for Long Spruce and Limestone is as follows:

-2011/2012 Conduct equipment assessments at Long Spruce and Limestone.
-2012/2013 Engineering and design
-2013/2016 Implement equipment modifications

Related Projects

- Gillam Redevelopment and Expansion Project
- Limestone GSCADA Replacement
- Long Spruce UCMS

Reference Documents

"Impact of Generating Station Staffing on Asset and Operational Risks", L.E. Midford, P.Eng, 2006 11 13

GN08-01, "Kettle Generating Station Operational Equipment Review", S.J. Boychuk, P.Eng, 2008 08 18

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CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

SIMULATED ROLLOVER

Title	Investment Management Node:
REMOTE CONTROL & MONITORING - GEN NORTH	1.1.1.3.19.3
Owning Division: GENERATION NORTH	Coordinating Division: GENERATION NORTH / ProjectNumber: P:04495

DESCRIPTION:
INSTALL EQUIPMENT TO REDUCE ANY RISKS ASSOCIATED WITH THE DESTAFFING OF THE HYDRAULIC STATION CONTROL ROOMS.

JUSTIFICATION:
HEALTH AND SAFETY IN THE WORK ENVIRONMENT AND CORPORATE FINANCIAL STRENGTH WILL BE IMPROVED BY REDUCING OR ELIMINATING THE NEED FOR SHIFT WORK AND THE NUMBERS OF WORKERS REQUIRED TO OPERATE THE STATION.

REFERENCE:
CPJ ENTITLED "REMOTE CONTROL, MONITORING AND AUTOMATION OF KETTLE, LONG SPRUCE & LIMESTONE ADDENDUM #5" DATED May 27, 2011

REVISION:
INCREASE PROJECT SCOPE TO INCLUDE THE REQUIRED EQUIPMENT MODIFICATIONS TO ENABLE A DAY SHIFT ONLY STAFFING SCHEDULE AT IONG SPRUCE AND LIMESTONE.

IN SERVICE DATES

2010/02/28	885	2011/05/31	728	2013/03/31	157
2010/09/30	2626	2011/07/31	17	2014/03/31	3320
2010/10/31	146	2012/03/31	154	2015/03/31	2384
2011/02/28	20	2012/08/31	895	2016/03/31	1232

Base estimate 2011/04/01 CLASS 3
Work start date 2002/04/01

PREV.AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Actual cost to date:	4616		233			4849
(Over)under expend:	225	7	-3			229
V-CPJ TOTAL	4841	7	230			5078
REV. AMOUNTS:						
Actual cost to date:	4616		233			4849
(Over)under expend:						
Auth 2011/12	419		51			470
Req: 2012/13	281	3	27			311
2013/14	3072	144	104			3320
2014/15	2160	150	74			2384
2015/16	1099	95	38			1232
V-HLD TOTAL	11647	392	527			12566

Prepared by	yy mm dd	Approved by	yy mm dd	Approved by	yy mm dd	Approved by	yy mm dd
	11 07 13	OWNING DIVISION	11 07 18	COORDINATING DIVISION		VICE-PRESIDENT	11 07 19

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CAPITAL EXPENDITURE REVISION

SIMULATED ROLLOVER

FORECAST HISTORY (in thousands of dollars)

ProjectNumber P:04495

Approved yy mm	TOTAL AMOUNT	COMMENTS
2010 07	5078.00	Increase funding to meet the project goal of operating the Kettle Generating Station with a 5 day per week day shift only staffing schedule for a 2 year trial period starting January 2011.
2009 06	3485.00	DEFERRED IN-SERVICE DATE BY ONE YEAR AND RE-CASHFLOWED THE PROJECT.
2008 06	3218.00	UPDATED INTEREST AND ESCALATION RATES.
2007 10	3221.00	UDATED INTEREST AND ESCALATION RATES.
2006 10	3219.00	DEFERRED IN-SERVICE DATE BY TWO YEARS.
2005 10	3060.00	UPDATED INTEREST AND ESCALATION RATES.
2004 10	3068.00	DEFER ISD BY 1 YEAR
2003 10	3065.00	DEFER ISD BY 2 YEARS
2002 10	3001.00	CASH FLOW REVISED TO ACCOMMODATE THE 24x7 STAFFING REVIEW STUDY CURRENTLY BEING PREPARED.
2001 10	3000.00	NEW ITEM.

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
2011/12 Apr	16		6			22	22
May	16		7			23	45
Jun	17		3			20	65
Jul	43		3			46	111
Aug	46		3			49	160
Sep	41		3			44	204
Oct	38		4			42	246
Nov	41		4			45	291
Dec	37		4			41	332
Jan	40		4			44	376
Feb	39		4			43	419
Mar	45		6			51	470
TOTAL	419		51			470	470
2012/13 Apr	21		4			25	25
May	25		4			29	54
Jun	24		4			28	82
Jul	23		5			28	110
Aug	25		5			30	140
Sep	22					22	162
Oct	25					25	187
Nov	25		1			26	213
Dec	21		1			22	235
Jan	25		1			26	261
Feb	22		1			23	284
Mar	23	3	1			27	311
TOTAL	281	3	27			311	311

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CAPITAL PROJECT JUSTIFICATION ADDENDUM FOR

REMOTE CONTROL & MONITORING GEN NORTH
Addendum Number 6

REVIEWED BY:
(Requesting Dept Manager)

NOTED BY:
(if applicable)

Responsible Division: GS L 2016 11 10

Constructing Division:

Financial Department: (if over $1 million) YBatalini 2016 11 16

RECOMMENDED FOR IMPLEMENTATION:

Requesting Div. Manager: John Kvern P.Eng 2016 11 03

Business Unit V.P.: Lon M. Bell 2016 11 17

PRIMARY JUSTIFICATION:
Indicate key project driver(s):

☒	Safety	☐	Customer Service
☐	System Supply	☐	Efficiency
☒	System Reliability	☐	Environmental

NERC COMPLIANCE*: ☒ YES ☐ NO

*Determine if the project requires compliance with North American Electric Reliability Corporation (NERC) CIP Cyber Security Standards.

PREV. APPROVED BUDGET $: (Use $ value from approved CPJ or last approved CPJ Addendum)	$12,566,000
REVISED BUDGET $: (Total Net Cost)	$12,814,000
START DATE: (1st Cost Flow)	2002 04
PREV. APPROVED ISD: (Use In-service Date from approved CPJ or last approved CPJ Addendum)	2016 03
REVISED ISD: (Last Major In-service Date)	2017 01
RISK MATRIX/ BUSINESS CASE TIER: (Optional)	
INVESTMENT REASONS: (Optional)	Sustainment, System Efficiency, Generation > 70 MW per Unit
REQUESTING DIVISION:	Generation North
I.M. NODE NUMBER:	1.1.1.3.19.3
W.B.S. NUMBERs:	P:04495
MAJOR ITEM ☒	**DOMESTIC ITEM** ☐
PREPARED BY: TP	Tony Pavlicic
DATE PREPARED:	2016 10 16
REPORT NUMBER:	2916
FILE NUMBER (Optional):	

ADDENDUM NUMBER	DATE (yyyy mm dd)	BUDGET AMOUNT (000) thousands	REVISION	REVISED BY	APPROVED BY
5	Jan 2012	$12,566	Increase project scope to include the required equipment modifications to enable a day shift only staffing schedule at Long Spruce and Limestone.	Brad Minary	EC #1382.03
4	July 2010	$5,078	Increase funding to meet the project goal of operating Kettle GS with a day shift only staffing schedule for a 2 year trial period starting January 2011.	S.J.Boychuk	EC #1316.04
3	May 2006	$3,219	In service date deferred two years to allow for additional study.	V. Laing	EC #1125.04
2	June 2004	$3,068	In service date deferred one year to allow for additional study.	V. Laing	EC #1039.04
1	June 2003	$3,065	In service date deferred two years to allow for additional study.	V. Laing	EC #990.03
CPJ	June 2001	$3,000	Install equipment to reduce any risks associated with the de-staffing of hydraulic station control rooms.	A.G. Monkman	EC #

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION ADDENDUM

Project Name

Remote Control & Monitoring – Gen North

Recommendation

Increase the budget by $0.2M to $12.8M from $12.6M to revise scope to reflect current requirements to support transition to day time only operations at Kettle, Long Spruce and Limestone.

Added:

- Kettle - Unit Control & Monitoring Upgrades and Forebay Monitoring
- Long Spruce - Spillway Remote Control, Powerhouse Downstream Wall Deluge Valves Replacement and Smoke Management System Upgrade
- Limestone - Powerhouse Downstream Wall Deluge Valves Replacement

Removed:

- Long Spruce Fire Detection System (to stand alone project)
- Limestone Fire Detection "Phase 2" Upgrade to current code (to stand alone project)

Project Scope

A detailed assessment of each station was performed to identify risks associated with operating the stations unmanned for periods of time. The following items were identified to reduce risk and or increase reliability of the following systems: Fire Monitoring, Flood Control and Station Alarming.

Project Scope

Cost Category	Previous Add #5	Current CPJ Add #6	Increase (Decrease)	% Change	Actual to Aug 2016	Comments
KETTLE						
Fire Detection Systems	$2,571	$2,641	$70	3%	$2,641	Project completed
Headcover Sump Level Controls	$848	$848	$0	0%	$848	Project completed
Trashrack Diff Pres Monitor/Trip	$333	$393	$60	18%	$393	Project completed
Accumulator Tank Switch	$128	$128	$0	0%	$128	Project completed
Spillway Control External To Long	$237	$239	$2	1%	$239	Project completed
UCMS Viewer External To Long Sp	$145	$145	$0	0%	$145	Project completed
Spillway Alarm Separation / Horn	$107	$731	$624	583%	$719	The Horn is a new Scope Item
Chlorine Monitoring & Intake Ga	$36	$30	-$6	-17%	$30	Project completed
Remote Control Centre	$354	$177	-$177	-50%	$177	Project completed
Compressor/Pump Rms Alarm Se	$120	$391	$271	226%	$391	Increase caused to redesign
Kettle Forebay Monitoring	$0	$78	$78		$78	New Scope Item
Unit Control & Monitoring Comm	$0	$88	$88		$83	Project completed
Kettle Total	*$4,879*	*$5,889*	*$1,010*	21%	*$5,872*	
LONG SPRUCE						
Fire Detection System	$1,971	$0	-$1,971	-100%	$0	New CPJ
Spillway Remote Control	$0	$97	$97		$76	Previous scope but no estimate
PH D/S Wall Deluge Valves Repla	$0	$369	$369		$189	New Scope Item
Smoke Management System Upg	$0	$2,321	$2,321		$53	New Scope Item
Long Spruce Total	*$1,971*	*$2,787*	*$816*	*41%*	*$318*	
LIMESTONE						
Fire Detection System	$1,975	$1,617	-$358	-18%	$1,591	Contractor pricing was less than estimated
Spillway Remote Control	$371	$419	$48	13%	$405	Parallel gate operation added to scope
Turbine Pit Flood Alarm	$728	$199	-$529	-73%	$190	Electrical Construction estimate was reduced after scope of work was finalized
Remote Control Centre	$185	$140	-$45	-24%	$0	
PH D/S Wall Deluge Valves Repla	$0	$437	$437		$437	New Scope Item
Limestone Total	*$3,259*	*$2,812*	*-$447*	*-14%*	*$2,623*	
Common						
Prj Mgmnt, Assessment & Alarmi	$1,538	$873	-$665	-43%	$828	Moved out identified scope items on their own and reduced engineering based on actuals
Interest	$526	$526	$0	0%	$489	
Escalation	$393	$38	-$355	-90%		
IFRS O/H Revision		-$111	-$111		-$111	
Common Total	*$2,457*	*$1,326*	*-$1,131*	*-46%*	*$1,206*	
Grand Total	**$12,566**	**$12,814**	**$248**	**$0**	**$10,019**	

Background

An Executive Recommendation "Gen North Remote Control and Monitoring" was approved January 10, 2016 to modify the project scope and to allow the work to continue while this CPJ addendum was being prepared.

The Recommendation estimated the project cost would decrease by $367k and contained the following details: addition of automated deluge valves at Limestone and Long Spruce, reduction of cost for the Fire Detection System Replacement at Limestone, reduction of cost for the Remote Spill and Turbine Pit Flood Alarm at Limestone, addition of a cost estimate for Remote Spill at Long Spruce (note: this work was indentified in the previous CPJ, however no estimate was provided) and increase in Other Miscellaneous project costs.

Other changes recommended in this CPJa include:

- Scope modification of Limestone Fire Detection Replacement- the RC&M project will be responsible for replacement of the Powerhouse and Unit Fire Detection systems to reduce the number of nuisance alarms to allow destaffing to occur and to define the remaining fire code deficiencies. A future project will address the fire code deficiencies. This plan has been approved by the Manitoba Hydro Fire Engineer and the Office of the Fire Commissioner.
- Removal of Long Spruce Fire Detection - The primary driver for the replacement of this system was equipment obsolescence and not destaffing. Therefore, a new project was created.
- Rehabilitation of the Long Spruce Smoke Management System - The automated functionality of the system needs to be restored to enable destaffing, in accordance with SNCs' recommendations and concurrence of the Manitoba Hydro Fire Engineer. This is presently a safety issue due to the fact that staff have to manually operate the ventilation system while potentially being in a burning building in the event of a fire.

The equipment modifications have been implemented at Kettle and destaffing operation began on January 14, 2011. Limestone equipment modifications have also been implemented and destaffing operation began on July 21, 2016. The target for Long Spruce is to complete the remaining scope of work and implement destaffing by January 2017.

Justification

Health and Safety in the work environment and corporate financial strength will be improved by reducing or eliminating the need for shift work and the number of workers required to operate the stations which aligns with the following Generation Operation goals:

- Employees - Generation Operations attracts, develops and retains a highly skilled and motivated workforce that should reflect the demographics of Manitoba.

- Financial Strength - heighten our efforts to provide innovative approaches to lower our costs to deliver competitively priced electricity, and at the same time look at opportunities to increase revenue sources.

Corporate Value Framework
N/A

ANALYSIS OF ALTERNATIVES: (This section is be filled out only if there is a change to which alternative is being recommended).

Economic Analysis		
Discount Rate	4.40% For current corporate rates see G911	For clarification on hurdle rates, contact Economic Analysis Department

Recommended Option	NPV Benefits/(Costs)

Other Alternatives Considered	NPV Benefits/(Costs)

Risk Analysis
Cost and Schedule - The contract for the Long Spruce Smoke Management Control System rehabilitation has not been finalized. Construction costs and schedule will be driven by market conditions. Cost and Schedule – A condition assessment of the dampers in the Smoke Management System is currently underway by a Contractor. Based on maintenance history and the fact that the dampers are at the end of their service life, it is suspected that many of the dampers will need to be refurbished to ensure reliable operation of the Automatic Smoke Management System, which may affect the cost and schedule of the project. Note that the dampers in the Smoke Management System were not part of the contract mentioned in the previous paragraph, which deals with rehabilitating the control system only. Cost and Schedule - Investigation into existing alarms at Long Spruce that might cause excessive callouts is in scope of the project. Maintenance issues causing alarms have been identified and notifications were entered in the EAM to troubleshoot and resolve the issues, which is largely now dependent on availability of outages and staff to successfully execute the work. Scope Creep- The scope of the previous work done at Kettle might be reviewed due to lessons learned from installation of similar systems at Long Spruce and Limestone. Schedule and Scope - The Service Agreement detailing alarm management responsibilities between Generation North and SCC not formalized by the destaffing schedule.

Total Budget

The impact on annual budget requirements is as follows (in thousands of dollars):

Fiscal Year	Prev. Approved Addendum #5	Proposed Addendum #6	Increase (Decrease)
Prev. Actuals	$ 4,849	$ 4,849	$ -
2011/12	$ 469	$ 346	$ (123)
2012/13	$ 310	$ 375	$ 65
2013/14	$ 3,321	$ 656	$ (2,665)
2014/15	$ 2,385	$ 729	$ (1,656)
2015/16	$ 1,232	$ 2,289	$ 1,057
2016/17	$ -	$ 3,570	$ 3,570
2017/18	$ -	$ -	$ -
Total	$ 12,566	$ 12,814	$ 248

Proposed Schedule

Kettle Operation Start – January 2011
Limestone Operation Start – July 2016
Long Spruce Operation Start – January 2017

Related Projects

P:24750 Long Spruce Fire Detection System Replacement
P:18475 Limestone Unit Control & Monitoring "GSCADA" Replacement

Reference Documents

Executive Recomendation – Gen North Remote Control and Monitoring by Hal Turner approved January 10, 2016
Impact of Generating Station Staffing on Asset and Operational Risks by L.E. Midford, P.Eng 2006 11 13
GN08-01 Kettle Generating Station Operational Equipment Review by S.J. Boychuk, P.Eng 2008 08 18

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CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

SIMULATED ROLLOVER

Title	Investment Management Node:
REMOTE CONTROL & MONITORING - GEN NORTH	1.1.1.3.19.3
Responsible Division: Engineering Services	Requesting Division: Generation North
	ProjectNumber: P:04495

DESCRIPTION:
Install equipment to reduce any risks associated with the destaffing of the hydraulic station control rooms.

JUSTIFICATION:
Health and safety in the work environment and corporate financial strength will be improved by reducing or eliminating the need for shift work and the number of workers required to operate the station.

REFERENCE:
Addendum #6 "Remote Control & Monitoring Generation North" dated 2016 10 16

REVISION:
Increase the budget by $0.2M to $12.8M from $12.6M to revise scope to reflect current requirements to support transition to day time only operations at Kettle, Long Spruce and Limestone.

Added:
Kettle - Unit Control & Monitoring Upgrades and Forebay Monitoring
Long Spruce - Spillway Remote Control estimate, Powerhouse Downstream Wall Deluge Valves Replacement and Smoke Management System Upgrade
Limestone - Powerhouse Downstream Wall Deluge Valves Replacement
Removed:
Long Spruce Fire Detection System (to stand alone project)
Limestone Fire Detection "Phase 2" (Upgrade to current code)

Contingency - $302

IN SERVICE DATES						Base estimate 2016/04/01 CLASS 3
2010/02/28	885	2011/05/31	790	2014/06/30	177	
2010/09/30	2696	2011/08/31	11	2014/12/31	422	
2010/10/31	146	2012/01/31	673	2016/05/31	2476	Work start date 2002/04/01
2011/02/28	20	2014/02/28	79	And on	4443	

PREV.AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Actual cost to date:	8806		438			9244
(Over)under expend:	2841	392	89			3322
V-CPJ TOTAL	11647	392	527			12566
REV. AMOUNTS:						
Actual cost to date:	8806		438			9244
(Over)under expend:						
Auth 2016/17	3446	38	88			3572
Req: 2017/18						
V-HLD TOTAL	12252	38	526			12816

Prepared by	yy mm dd	Approved by	yy mm dd	Approved by	yy mm dd	Approved by	yy mm dd
		RESPONSIBLE DIVISION	16 11 10	REQUESTING DIVISION	16 11 03	VICE-PRESIDENT	16 11 17

CER(1) Rev. 97 12

CAPITAL EXPENDITURE REVISION

SIMULATED ROLLOVER

FORECAST HISTORY (in thousands of dollars)

ProjectNumber P:04495

Approved yy mm	TOTAL AMOUNT	COMMENTS
2015 06	12,508.00	Removed Long Spruce Fire Detection System Replacement to allow Scope, Schedule and Budget to be managed separately and prioritized relative to the overall capital portfolio. Increased estimate for Limestone Fire Detection System Replacement to be more in line with Long Spruce estimate under P:24750. Once Long Spruce experience is gained Limestone Fire Detection will also be separated into its own project. Added Limestone Spillway Remote Control and continue to further assess Limestone requirements. Contingency - $117
2014 06	12,901.00	INCREASE DUE TO ADDITIONAL LABOR REQUIREMENTS AND ADDITION OF KETTLE SPILLWAY HORN TO MEET DAM SAFETY REQUIREMENTS. IFRS ADJUSTED APPROVAL: $12,455
2013 08	12,474.00	RE-CASHFLOWED DUE TO SCHEDULE CHANGES. IFRS ADJUSTED APPROVAL: $12,455
2012 06	12,063.00	RE-CASHFLOWED DUE TO SCHEDULE CHANGES. ESTIMATE ALSO REFLECTS CURRENT INTEREST AND ESCALATION AND ACTIVITY RATES. (IFRS)
2012 01	12,566.00	INCREASE PROJECT SCOPE TO INCLUDE THE REQUIRED EQUIPMENT MODIFICATIONS TO ENABLE A DAY SHIFT ONLY STAFFING SCHEDULE AT IONG SPRUCE AND LIMESTONE.
2010 07	5078.00	Increase funding to meet the project goal of operating the Kettle Generating Station with a 5 day per week day shift only staffing schedule for a 2 year trial period starting January 2011.
2009 06	3485.00	DEFERRED IN-SERVICE DATE BY ONE YEAR AND RE-CASHFLOWED THE PROJECT.
2008 06	3218.00	UPDATED INTEREST AND ESCALATION RATES.
2007 10	3221.00	UDATED INTEREST AND ESCALATION RATES.
2006 10	3219.00	DEFERRED IN-SERVICE DATE BY TWO YEARS.
2005 10	3060.00	UPDATED INTEREST AND ESCALATION RATES.
2004 10	3068.00	DEFER ISD BY 1 YEAR
2003 10	3065.00	DEFER ISD BY 2 YEARS
2002 10	3001.00	CASH FLOW REVISED TO ACCOMMODATE THE 24x7 STAFFING REVIEW STUDY CURRENTLY BEING PREPARED.
2001 10	3000.00	NEW ITEM.

Forecasted Mthly Exp.		GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
2016/17	Apr	262		15			277	277
	May	224		17			241	518
	Jun	28		6			34	552
	Jul	40		7			47	599
	Aug	202	1	7			210	809
	Sep	209	1	5			215	1024
	Oct	264	2	6			272	1296
	Nov	211	2	5			218	1514
	Dec	307	4	2			313	1827
	Jan	571	8	4			583	2410
	Feb	675	11	6			692	3102
	Mar	453	9	8			470	3572
TOTAL		3446	38	88			3572	3572
2017/18	Apr							
	May							
	Jun							
	Jul							
	Aug							
	Sep							
	Oct							
	Nov							
	Dec							
	Jan							
	Feb							
	Mar							
TOTAL								

CONCEPT DESIGN-REPORT FOR

Missi/Notigi/Laurie River Annunciation/Telemetry Upgrades

PREPARED BY: J. Smith, C.E.T.

CHECKED BY:

APPROVED BY: M. Aikens, P. Eng.

NOTED BY:

DATE: 2009-05-21

REPORT NO: ESD 09-17

FILE NO: 111-64010

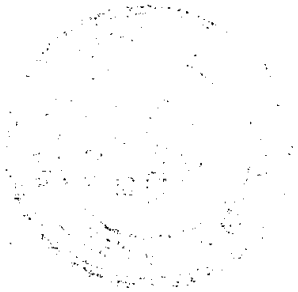
AUTHORIZED FOR IMPLEMENTATION

BY:

DATE:

DISTRIBUTION:

- G. Gusberti
- G. Ratushniak
- C. Boyer
- S. Simons
- B. Malowanchuk
- D. Kakoske
- S. Boychuk
- D. Beaudry



Executive Summary

Electrical Engineering recommends the installation of two small unit monitoring systems (UMS) at Missi Falls and Notigi Fall control structures at a cost of $910,000 and a unit control and monitoring system (UCMS) between the two Laurie River plants at a cost of $1,064,000.

The Missi and Notigi telemetry require replacement and need to be redirected from Kettle G.S. to Kelsey G.S. The new UMS will integrate the telemetry and alarms into the Kelsey G.S. UCMS. The Missi/Notigi communication upgrade project will support the new UMS communication to Kelsey G.S.

The Laurie River supervisory control between the two plants is out of service and the annunciation is failing. The new UCMS will replace these two systems. The Laurie River communication upgrade project will support the UCMS communication between the two plants and allow the alarms and telemetry to be integrated into the Kelsey G.S. UCMS.

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Recommendation

Electrical Engineering recommends the installation of a small scale UMS at Missi Falls and another at Notigi Control Structure to replace the existing telemetry and alarms which currently go to Kettle G.S. These two systems will integrate into the existing Kelsey UCMS. The Kelsey UCMS will interface with the RTU.

Electrical Engineering also recommends the installation of a small UCMS system between both Laurie River Plants to provide a common control and alarm interface for both plants. This UCMS will also integrate into the existing Kelsey UCMS.

Background

Currently, the alarms and telemetry from Missi Falls and Notigi are sent over unmaintained leased communication circuits to Kettle generating station. The Laurie River, Missi Falls and Notigi Falls Communications upgrades project will provide the opportunity to install an updated alarm and telemetry system.

The unmanning of Kettle G.S. in January 2011 requires the alarms for Missi Falls and Notigi to be re-routed to Kelsey G.S., which is responsible for the operation of the Churchill River Diversion stations.

The new monitoring systems will replace the antiquated telemetry system and, using the communications upgrades, integrate into the existing Kelsey UCMS.

Laurie River has been operating with the supervisory control system between plants out of service. This has required the operator to travel between plants to balance the units. Also, the existing annunciation systems for both stations at Laurie River are failing and no longer reliable.

The communications upgrades project will include installing fibre optic communications between the two Laurie River plants. The communication upgrades will provide communications for a new control and monitoring system between the two plants and allow the alarms and telemetry to be extended to Kelsey G.S.

Analysis of Alternatives

Description of Alternatives

The use of a remote terminal unit was considered for Missi Falls, Notigi Falls and Laurie River, but dismissed due to Technical Services' request to provide a system with future functionality for PLC controls at each station.

The standard UCMS design fits well with the project requirements and maintains consistency with the UCMS installations at other stations. No other alternatives were considered.

Cost estimate

Missi/Notigi Project Cost Summary		
Description	**Hours**	**Cost**
Engineering		335,000
Consultants		0
Site Labour		0
Owner Labour		0
Material		240,000
Installation		335,000
Project Management		
Contingency		
Total	**0**	**$910000.00**

Laurie River Project Cost Summary		
Description	**Hours**	**Cost**
Engineering		402,000
Consultants		0
Site Labour		0
Owner Labour		0
Material		260,000
Installation		402,000
Project Management		
Contingency		
Total	**0**	**$1064000.00**

Estimate Class

Check One (X)	INDICATE ESTIMATE CLASS	
	Level 1	PURPOSE: • to place *BLANKET PROJECTS* and/or *PROJECTS* whose *START DATES* are more than 24 months in the future, onto the system with minimal effort • would not typically be used for *PROJECTS* that are in response to emergencies or customer service requests ESTIMATE ACCURACY: +/- 50% COSTS: entered as an overall amount CASH FLOWS: entered as annual amounts DATES TO BE PROVIDED: Start and *ISD*
X	**Level 2**	PURPOSE: • to provide for a planning-level split between primary and secondary costs for *PROJECTS* whose *START DATES* fall between 12 and 24 months in the future, in order to identify internal labour and material requirements and allow for the appropriate estimation of overhead assessments • minimum *CLASS* required for submitting *projects* for *PROJECT BUDGET APPROVAL* (and is recommended but is not mandatory for *blanket projects*) • would not typically be used for *PROJECTS* that are in response to emergencies or customer service requests ESTIMATE ACCURACY: +/- 30% COSTS: include planning level cost elements for both primary and secondary costs CASH FLOWS: entered as annual amounts DATES TO BE PROVIDED: Start and *ISD*
	Level 3	PURPOSE: • Minimum *CLASS* required for *projects* whose *start dates* are less than 12 months away, or for projects that have already begun (other than *blanket projects*) ESTIMATE ACCURACY: +/- 30% COSTS: specific requirements both primary and secondary costs CASH FLOWS: entered as monthly amounts DATES TO BE PROVIDED: full schedule of activities
	Level 4	PURPOSE: • to reflect an increase in estimate accuracy as the *project* is carried out, usually resulting from having placed all of the contracts for externally procured material and services ESTIMATE ACCURACY: +/- 20% COSTS: entered as specific requirements for internal labour, Stores material, externally purchased material (with purchase orders placed), contracted services (with purchase orders placed), salvage credit and contributions CASH FLOWS: entered as monthly amounts DATES TO BE PROVIDED: full schedule of activities

Scope of Work

Missi Falls Scope of Work:

This project will replace the existing annunciation and telemetry with a Missi Falls Control Structure Unit Monitoring System (MFCS UMS).

The MFCS UMS will be a single GE Fanuc RX3i PLC based system using Genius Blocks for discrete I/O and card based analog I/O. The existing kW-hr meter and accumulator circuit will be replaced with a GE EPM6000 power meter and the power meter will provide the PLC kW-hr readings via modbus to the PLC. The other analog inputs will remain as they are now and, apart from the available power meter quantities, no other analog signals will be added or transducers changed. The analog signals to the PLC will be:

- Forebay Level
- Tailrace Level
- Spillway Gate 3 Position
- Spillway Gate 4 Position
- House Unit electrical quantities including kW-Hr readings

The discrete alarm inputs will remain as they are now, except end-of-line resistors will be added to ensure the integrity of the alarm cabling. No additional alarms will be added, apart from the necessary system monitoring alarms (PLC faults, I/O faults, etc).

The PLC and server cubicles will be assembled in Winnipeg and installed at site near the existing telemetry. Once the PLC is running and connected with Kelsey, the circuits will be transferred from the existing telemetry to the new UMS. We are assuming space is available to add the new cubicles to facilitate the cutover.

We are assuming the local power sources will be easily accessible and adequate to provide redundant power to the PLC and Genius Blocks. We are also assuming the server can be powered from the 48V battery bank and peripherals will be powered from the station AC supply and an inverter is not required. If the 48V battery bank cannot be used the station AC supply will also power the server.

The server will provide the PLC programming ability with Proficy Machine Edition software and the HMI programming with Cimplicity Plant Edition. The server will use SQL express for logging of alarms and trending locally at site. Proficy Historian will not be installed.

The server will also be used as a local viewer. No other viewers will be installed at Missi Falls. Screens will be created to provide the alarms and status based on the inputs from the existing annunciator/telemetry and new power meter. At

Missi Falls the alarms will have the ability to be blocked locally or blocked to Kelsey. The alarms will function independently of the Kelsey UCMS. Therefore, any alarms that occur will remain on the HMI until they are acknowledged locally. The alarms will use the existing horn for audible indication of alarms with an enable/disable option from the HMI.

The alarms and telemetry will be extended to Kelsey, which will connect to the Kelsey UCMS. The data will be passed from the Missi Falls PLC to the Kelsey UCMS firewall PLC using Ethernet Global Data (EGD). The EGD data will send the data via the Industrial Data Network (IDN) with a connectionless data transfer. A counter system similar to what is currently used for the Kelsey UCMS inter-PLC communication will alarm if the data transfer times out. The data will not be time-tagged at the source, but time-tagged as it is received at the Kelsey HMI.

The Missi Falls screens will be integrated into the Kelsey HMI. As mentioned, the alarms will operate independently from the Missi Falls HMI. A Missi Falls alarm acknowledged at Kelsey will not be acknowledged at Missi Falls or vice versa. At Kelsey the alarms will have the ability to be blocked or unblocked at Missi Falls (same as local at Missi Falls), locally at Kelsey (same at blocked to Kelsey) and to SCC. The alarm blocking will be common to both Missi Falls and Kelsey.

The MFCS UMS will not include any control points.

The alarms and telemetry will be logged on the Kelsey UCMS SQL software. Proficy Historian will not be added.

The Kelsey UCMS will provide the interface to the RTU, following similar alarm handling as the local UCMS alarms. We are assuming the Kelsey Firewall PLC will already be installed and provide all needed interfacing for data to be passed to both the RTU and the Kelsey UCMS. This estimate does not include any work by station design or system support to add the signals to SCC/SCADA or any work for adding telemetry of the Missi Falls signals to Winnipeg.

The removal of the existing telemetry equipment at Kettle and the clean-up of the RTU at Kettle are not included in this scope of work.

Notigi Falls Control Structure Scope of Work:

This project will replace the existing annunciation and telemetry with a Notigi Control Structure Unit Monitoring System (NCS UMS).

The NCS UMS will be a single GE Fanuc RX3i PLC based system using Genius Blocks for discrete I/O and card based analog I/O, similar in design to the MFCS

UMS. All analog inputs will remain as they are now and no other analog signals will be added or transducers changed. The analog signals to the PLC will be:

- Forebay Level
- Tailrace Level
- Spillway Gate 1 Position
- Spillway Gate 2 Position
- Spillway Gate 3 Position

The discrete alarm inputs will remain as they are now, except end-of-line resistors will be added to ensure the integrity of the alarm cabling. No additional alarms will be added, apart from the necessary system monitoring alarms (PLC faults, I/O faults, etc).

Like the Missi Falls UMS, the PLC and server cubicles will be assembled in Winnipeg and installed at site near the existing telemetry. Once the PLC is running and connected with Kelsey, the circuits will be transferred from the existing telemetry to the new UMS. Again, we are assuming space is available to add the new cubicles to facilitate the cutover.

We are assuming the local power sources will be easily accessible and adequate to provide redundant power to the PLC and Genius Blocks. We are also assuming the server can be powered from the 48V battery bank and peripherals will be powered from the station AC supply and an inverter is not required. If the 48V battery bank cannot be used the station AC supply will also power the server.

The NCS UMS will have the same single server/viewer HMI architecture as MFCS UMS and will handle alarms and telemetry to Kelsey in the same manner.

The NCS UMS will not include any control points.

The alarms and telemetry from NCS UMS will be logged on the Kelsey UCMS SQL software.

The Kelsey UCMS will provide the interface to the RTU for the NCS UMS in the same fashion as the MFCS UMS.

Laurie River 1 & 2 Generating Stations Scope of Work:

This project will replace the existing annunciation with a Laurie River Generating Station Unit Control and Monitoring System (LRGS UCMS) and extend the UCMS alarms and analog trending to Kelsey GS.

The LRGS UCMS will be GE Fanuc RX3i PLC based system with one PLC installed at each generating station with a single HMI server and two HMI

viewers. One viewer will be at Laurie 1 station and the other at Laurie 2. The UCMS will provide the existing alarms at both stations along with the electrical quantities for each unit. A GE EPM6000 power meter will be installed at each unit to read electrical quantities. If easily available, the LRGS UCMS will monitor temperature RTDs. Apart from the power meters, new transducers will not be installed. Wicket gate position will not be included. Forebay and tailrace level transducers will not be changed.

The analog monitored quantities will be:

- Forebay level
- Tailrace level

Each unit will have the following monitored:

- Power
- Vars
- Terminal Voltage (Vab, Vbc, Vca)
- Stator currents (Iab, Ibc, Ica)
- Frequency
- Stator and bearing temperatures (if available)

The HMI will provide control of the following quantities for each unit:

- Unit Start/Stop
- Voltage Raise/Lower
- Power Raise/Lower

The PLC will also provide per-unit VAR balancing and per-unit Load balancing between the units.

The discrete alarm inputs will remain as they are now, except end-of-line resistors will be added to ensure the integrity of the alarm cabling. No additional alarm will be added, apart from the necessary system monitoring alarms (PLC faults, I/O faults, etc).

We are assuming the local power sources will be easily accessible and adequate to provide redundant power to the PLC and Genius Blocks. The server will be powered from the station AC supply with a UPS; an inverter is not required.

The LRGS UCMS will handle alarms and telemetry to Kelsey in the same manner and the alarms and telemetry will be logged on the Kelsey UCMS SQL software.

Connecting the LRGS UCMS points to the Kelsey RTU will not be included in this scope of work.

Safety Impact

All changes will be evaluated to ensure that safety is impacted in a positive way.

Environmental Analysis

All facility changes will be evaluated to ensure that the environment is protected through responsible engineering practices. The enhanced station monitoring will provide added protection for the environment.

Proposed Schedule

Design of the Missi and Notigi UCMS will begin January 2010. Material purchases begin in March 2010. Off site cubicle assembly will start April 2010. Site work will begin at Notigi in June 2010 and at Missi in August 2010. Circuit cutover to the new UCMS and commissioning to Kelsey will begin October 2010 and both stations will be in service by December 2010.

The Laurie River UCMS will begin in 2012 and completed by 2013.

References

1. Laurie River / Churchill River Diversion (CRD) Communications Improvements, prepared by Dave Ramsay, 2009/03/16
2. Laurie River, Missi Falls and Notigi Communcations Upgrades Scope of Work & Cost Estimates, prepared by B. Malowanchuk/V. Smith 2009/05/13

D1876(A)

REVIEWED BY EXECUTIVE COMMITTEE
MINUTE # 1273.08

DATE: 2009 07 28
Corporate Budget Services

CAPITAL PROJECT JUSTIFICATION FOR

LAURIE RIVER / CHURCHILL RIVER DIVERSION (CRD) COMMUNICATIONS AND ANNUNCIATION UPGRADES

REVIEWED BY:
(Owning Dept Manager)

2009/06/01

NOTED BY:
(if applicable)

Coordinating Division:

Constructing Division:

Financial Department:
(if over $1 million)

RECOMMENDED FOR IMPLEMENTATION:

Owning Div. Manager: 2009,06,03

Business Unit V.P.:

09 06 03

BUDGET $: (Total Net Cost)	$4,772,000
START DATE: (1st Cost Flow)	2009 08
IN-SERVICE DATE: (Last Major In-service Date)	2012 08
RISK MATRIX/ BUSINESS CASE TIER:	**Unacceptable**
INVESTMENT REASON:	C3.17: Infrastructure-Communications
OWNING DIVISION:	Generation North
I.M. NODE NUMBER:	1.1.1.3.38.1
W.B.S. NUMBERs:	P: 15698
MAJOR ITEM X	**DOMESTIC ITEM** ☐
PREPARED BY:	Dave Ramsay
DATE PREPARED:	2009-05-25
REPORT NUMBER:	
FILE NUMBER (Optional):	

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION

Project Name

Laurie River / Churchill River Diversion (CRD) Communications and Annunciation Upgrades.

Recommendation

Upgrade the communications infrastructure and replace the annunciation systems with PLC based Unit Control Monitoring System (UCMS) at Laurie River, Missi Falls and Notigi.

Project Scope

The project scope is to upgrade the communication and annunciation equipment at Laurie River, Missi Falls and Notigi.

The following changes are required at each location:

Laurie River Generating Station

- Install microwave tower in Laurie River town site.
- Install microwave system between Laurie River and Leaf Rapids.
- Install fibre optic cable between the Plant 1, Plant 2 and the Communication Building.
- Replace annunciation system with a Programmable Logic Controller (PLC).

Missi Falls Control Structure

- Replace microwave system between Missi Falls and South Indian Lake.
- Install fibre optic between the control structure and the Communication Building.
- Replace annunciation system with a Programmable Logic Controller (PLC).

Notigi Control Structure

- Install microwave system between Notigi Control Structure and Notigi (MTS) tower.
- Replace annunciation system with a Programmable Logic Controller (PLC).

Background

The driver of this project is the outdated annunciation equipment at Laurie River, Missi Falls and Notigi. The equipment at these locations has reached its end of life, has no reliable spare parts and is partially out of service. The annunciation systems at Missi Falls and Notigi are integrated and currently send alarms to the Kettle Generating Station. To successfully un-man Kettle as per project *P:04495 - Remote Control and Monitoring - Gen North,* the annuciator system at Notigi and Missi needs to re-route alarms to Kelsey Generating Station.

When the annunciation equipment is upgraded it will not be effective unless the communications infrastructure is upgraded. The existing microwave link from Missi Falls to South Indian Lake is no longer supported by MTS and is well beyond its expected service life. At Laurie River the communications between the stations has been out of service for over 10 years and the telephone circuit is over a VHF radio

Background
link to Leaf Rapids. The only data capability for these sites is an Internet based satellite link that is insufficient, unreliable and not suitable for our requirements. The existing systems have failed many times in the past decade, with most of the infrastructure close to permanent failure. The costs to maintain these old systems has been increasing in direct relation to the age of the systems There has been many temporary fixes over the years that will no longer suffice given the age and condition of the systems.

JUSTIFICATION—BUSINESS CASE ANALYSIS (SUMMARY):

Justification and Link to Corporate/Business Unit Goals
The project supports the following Power Supply Business Unit goals: **"Optimize operations, maintenance and development to minimize net cost to Manitoba customers."** **"Continuously improve safety, health and wellness in the work environment."** Updated communications infrastructure and annunciation systems will provide more accurate water level information from the Churchill River Diversion allowing Manitoba Hydro to optimize water flows through the Lower Nelson River Generating Stations. The costs of maintaining the systems will be reduced significantly by implementing the recommended option. Lack of dependable communications infrastructure and annunciation equipment affects the phones, network access, and alarm annunciation. Adding reliable communications infrastructure and dependable annunciation equipment will increase the safety of all individuals working at these remote locations.

ANALYSIS OF ALTERNATIVES:

Economic Analysis		
Discount Rate	For current corporate rates see G911 5.75%	For clarification on hurdle rates, contact the Economic Analysis Department

Recommended Option	NPV (= PV of BENEFITS - PV of COSTS)
Upgrade the communications and replace the annunciation system with PLC based Unit Control Monitoring System (UCMS) at Laurie River, Missi Falls and Notigi.	($4,243,195)

Other Alternatives Considered	NPV (= PV of BENEFITS - PV of COSTS)
Install an RTU instead of a PLC. This option is cost prohibitive and will not meet our requirements.	($6,201,274)

Other Alternatives Considered	NPV (= PV of BENEFITS - PV of COSTS)
Do Nothing. Risk to corporation in terms of future hydraulic reliability and public safety is unacceptable.	Unacceptable

Risk Analysis

The risks associated with proceeding with the recommended changes are:

- Transportation - Moving large items like Microwave dishes and feed lines into Missi Falls is done by barge. If the barge cannot be utilized, the equipment will need to be slung in by helicopter. A helicopter large enough to sling in this equipment will cost $6000/Hr.
- Weather - The Fall has unpredictable weather with fog and freezing rain. Flights are often cancelled during this season and it would postpone any outdoor tower work.
- Other projects - If the pole replacement at Missi Falls or the Line replacement at Laurie River does not happen, we will need to install a microwave radio link instead of using Fibre optic cable as preferred.

RESOURCE REQUIREMENTS AND CAPITAL BUDGET ESTIMATE:

Resource Requirements

The estimated resource requirements are as follows:

Department/ Section	Cost Centre	Hours
Communication Eng & design	52110	427
Electrical Engineering design	51040	700
Telenorth - Rural - Communications	52133	739
Kelsey Site Labor	51360	124
Gen. North Technical Services	51280	60
Field Electrical Construction	52560	244
Total Resource Requirements		**2,294**

Total Budget

The annual net budget requirements are as follows (in thousands of dollars):

Fiscal Year		Proposed Budget
Prev. Actuals	$	-
2009/10	$	185
2010/11	$	3,491
2011/12	$	40
2012/13	$	1,056
Total	$	4,772

Proposed Schedule

- Communication Design completed winter 2009/10.
- Electrical Engineering Design for Missi/Notigi completed spring 2009/10.
- Communication work completed for Missi/Notigi summer 2010.
- Annunciation for Missi/Notigi completed fall 2010.
- Communication work completed for Laurie River winter 2010.
- Electrical Engineering Design for Laurie River completed spring 2012.
- Annunciation for Laurie River completed fall 2012.

Related Projects

-Missi Falls pole replacement. The fibre installation would be done in conjunction with this work to reduce costs.
-Laurie River line replacement between Laurie 1 and Laurie 2. The fibre installation would be done in conjunction with this work to reduce costs.
-P:04495 - Remote Control and Monitoring - Gen North

Reference Documents

Preliminary Scope Document - "Laurie River / Churchill River Diversion (CRD) Communication Improvements"
Dated 2009/03/10 by: Dave Ramsay

Scope of Work & Cost Estimates - "Laurie River, Missi Falls and Notigi Communications Upgrades"
Dated 2009/05/13 by: B. Malowanchuk/V. Smith

Recommended Communication Option - "Engineering Report for Missi Falls Communications Upgrade"
Dated 2009/02/25 by: B. Malowanchuk

Missi, Laurie, Notigi Communications Upgrade
Concept Design Report - "Missi/Notigi/Laurie River Annunciation/Telemetry Upgrade"
ESD 09-17 dated 2009/05/21 by: J. Smith

CER(1) Rev. 09 05

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

Title	Investment Management Node:
LAURIE RIVER/CRD COMMUNICATIONS AND ANNU	1.1.1.3.38.1
Owning Division: GENERATION NORTH	Coordinating Division: GENERATION NORTH — ProjectNumber: P:15698

DESCRIPTION:
Upgrade the communications infrastructure and replace the annunciation systems with PLC based Unit Control Monitoring System (UCMS) at Laurie River, Missi Falls and Notigi.

JUSTIFICATION:
Updated communications infrastructure and annunciation systems will provide more accurate water level information from the Churchill River Diversion allowing Manitoba Hydro to optimize water flows through the Lower Nelson River Generating Stations. The costs of maintaining the systems will be reduced significantly by implementing the recommended option.

Lack of dependable communications infrastructure and annunciation equipment affects the phones, network access, and alarm annunciation. Adding reliable communications infrastructure and dependable annunciation equipment will increase the safety of all individuals working at these remote locations.

This project support the Power Supply Business Unit goals to:

"Optimize operations, maintenance and development to minimize net cost to Manitoba customers."

"Continuosly improve safety, health and wellness in the work environment."

REFERENCE:
CPJ entitled "Laurie River/Churchill River Diversion(CRD) Communications and Annunciation Upgrades," dated 2009 05 25.
Recommended Communication Option - "Engineering Report for Missi Falls Communications Upgrade," dated 2009 02 25.
Concept Design Report - "Missi/Notigi/Laurie River Annuciation/Telemetry Upgrade," dated 2009 05 21.
CAMELOT ID# 2044

REVISION:
New Item.

IN SERVICE DATES				Base estimate 2009/04/01 CLASS 3
2010/07/31	765	2012/08/31	1097	
2010/08/31	972			Work start date 2009/08/01
2010/10/31	434			
2011/01/31	1505			

PREV.AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Actual cost to date:						
(Over)under expend:						
V-HAP TOTAL						
REV. AMOUNTS:						
Actual cost to date:						
(Over)under expend:						
Auth 2009/10	180		5			185
Req: 2010/11	3422	35	34			3491
2011/12	39	1				40
2012/13	1000	43	13			1056
V-HLD TOTAL	4641	79	52			4772

Prepared by	yy mm dd	Approved by	yy mm dd	Approved by	yy mm dd	Approved by	yy mm dd
	091061 02	OWNING DIVISION	09 06 03	COORDINATING DIVISION		VICE-PRESIDENT	09 06 03

CER(1) Rev. 09 05

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

FORECAST HISTORY			ProjectNumber P:15698
Approved yy mm	TOTAL AMOUNT	COMMENTS	

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
2009/10 Apr							
May							
Jun							
Jul							
Aug	52					52	52
Sep	63					63	115
Oct	5		1			6	121
Nov	4		1			5	126
Dec	4		1			5	131
Jan	16		1			17	148
Feb	16		1			17	165
Mar	20					20	185
TOTAL	180		5			185	185
2010/11 Apr	310	1	1			312	312
May	294	2	3			299	611
Jun	343	2	4			349	960
Jul	326	3	7			336	1296
Aug	319	3	4			326	1622
Sep	147	2	1			150	1772
Oct	507	6	2			515	2287
Nov	399	5	2			406	2693
Dec	399	6	4			409	3102
Jan	378	5	6			389	3491
Feb							3491
Mar							3491
TOTAL	3422	35	34			3491	3491

D1876(A)

APPROVED BY EXECUTIVE COMMITTEE
MINUTE # 1389.03
DATE: 2012 03 06
Financial Planning

CAPITAL PROJECT JUSTIFICA FOR

LAURIE RIVER / CHURCHILL RIVER DIVERSION (CRD) COMMUNICATIONS AND ANNUNCIATION UPGRADES
Addendum #1

REVIEWED BY: G. Gushorta
(Owning Dept Manager)

NOTED BY:
(if applicable)

Coordinating Division:

Constructing Division:

Financial Department:
(if over $1 million)

RECOMMENDED FOR IMPLEMENTATION:

Owning Div. Manager: July 18, 2011

Business Unit V.P.: 11 07 19

PREV. APPROVED BUDGET $: (Use $ value from approved CPJ or last approved CPJ Addendum)	$4,772,000
REVISED BUDGET $: (Total Net Cost)	$6,748,000
START DATE: (1st Cost Flow)	2009 09
PREV. APPROVED ISD: (Use In-service Date from approved CPJ or last approved CPJ Addendum)	2012 08
REVISED ISD: (Last Major In-service Date)	2014 03
RISK MATRIX/ BUSINESS CASE TIER:	Unacceptable
INVESTMENT REASON:	C3.17: Infrastructure-Communications
OWNING DIVISION:	Generation North
I.M. NODE NUMBER:	1.1.1.3.38.1
W.B.S. NUMBERs:	P:15698
MAJOR ITEM ☒	**DOMESTIC ITEM** ☐
PREPARED BY:	Rob Jensen P.Eng.
DATE PREPARED:	2011 05 31
REPORT NUMBER:	
FILE NUMBER (Optional):	

ADDENDUM NUMBER	DATE (yyyy mm dd)	REVISION	REVISED BY	APPROVED BY

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION ADDENDUM

Project Name
Laurie River / Churchill River Diversion (CRD) Communications and Annunciation Upgrades.

Recommendation
To increase the budget from $4.8M to $6.7M to reflect an increase in scope and cost increases for additional requirements.

Project Scope
Project Scope Increase: - Replacement of power distribution line from Missi Falls control structure to the radio building ($350K). Additional Requirements: - Satellite system upgrades at Missi/Notigi/LR ($240K) - Larger communication tower at Laurie River ($700K) - Laurie River radio building replacement ($300K)

Background
The budget change is a result of more detailed design specifications which identified additional requirements such as a larger communications tower and the replacement of the radio building at Laurie River. The Missi Falls distribution line replacement was added to the scope of this project because of the efficiencies that can be achieved by doing this work at the same time as the fibre optic installation required for the communications upgrade. Power Supply has agreed to fund the distribution line replacement because it does not currently place high on Distribution's priority list.

JUSTIFICATION—BUSINESS CASE ANALYSIS (SUMMARY):

Justification and Link to Corporate/Business Unit Goals
The project supports the following Power Supply Business Unit goals: **"Optimize operations, maintenance and development to minimize net cost to Manitoba customers."** **"Continuously improve safety, health and wellness in the work environment."** Updated communications infrastructure and annunciation systems will provide more accurate water level information from the Churchill River Diversion allowing Manitoba Hydro to optimize water flows through the Lower Nelson River Generating Stations. The costs of maintaining the systems will be reduced significantly by implementing the recommended option.

JUSTIFICATION—BUSINESS CASE ANALYSIS (SUMMARY):

Justification and Link to Corporate/Business Unit Goals
Lack of dependable communications infrastructure and annunciation equipment affects the phones, network access, and alarm annunciation. Adding reliable communications infrastructure and dependable annunciation equipment will increase the safety of all individuals working at these remote locations.

ANALYSIS OF ALTERNATIVES:

Economic Analysis		
Discount Rate	6.1	For current corporate rates see G911 For clarification on hurdle rates, contact Economic Analysis Department

Recommended Option	NPV Benefits/(Costs)
No change to recommended alternative.	N/A

Risk Analysis
No significant change in the risk associated with this project.

Capital Budget Estimate

The impact on annual budget requirements is as follows (in thousands of dollars):

Fiscal Year	Previous CPJ / CPJ Addendum	This CPJ Addendum	Increase (Decrease)
Prev. Actuals	$ 3,676	$ 783	$ (2,893)
2011/12	$ 40	$ 2,058	$ 2,018
2012/13	$ 1,056	$ 2,781	$ 1,725
2013/14+	$ -	$ 1,126	$ 1,126
Total	$ 4,772	$ 6,748	$ 1,976

Proposed Schedule
ISD 07/2011 Notigi Annunciation (in progress) 09/2011 Distribution line and Fibre at Missi (to start July 1st) 10/2011 Fibre optic link between LR1 and LR2 (to start end of July) 10/2011 Upgraded Satellite system Missi / Notigi / LR 12/2011 Missi Annunciation (in progress) 08/2012 Missi Microwave Upgrade 10/2012 Laurie River Microwave Tower 10/2013 Laurie River Annunciation

Related Projects
No change.

Reference Documents
None

CER(1) Rev. 97 12

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

SIMULATED ROLLOVER

Title		Investment Management Node:
LAURIE RIVER/CRD COMMUNICATIONS AND ANNU		1.1.1.3.38.1
Owning Division: GENERATION NORTH	Coordinating Division: GENERATION NORTH	ProjectNumber: P:15698

DESCRIPTION:
Upgrade the communications infrastructure and replace the annunciation systems with PLC based Unit Control Monitoring System (UCMS) at Laurie River, Missi Falls and Notigi.

JUSTIFICATION:
Updated communications infrastructure and annunciation systems will provide more accurate water level information from the Churchill River Diversion allowing Manitoba Hydro to optimize water flows through the Lower Nelson River Generating Stations. The costs of maintaining the systems will be reduced significantly by implementing the recommended option.

Lack of dependable communications infrastructure and annunciation equipment affects the phones, network access, and alarm annunciation. Adding reliable communications infrastructure and dependable annunciation equipment will increase the safety of all individuals working at these remote locations.

This project support the Power Supply Business Unit goals to:

"Optimize operations, maintenance and development to minimize net cost to Manitoba customers."

"Continuosly improve safety, health and wellness in the work environment."

REFERENCE:
CPJ entitled "Laurie River/Churchill River Diversion(CRD) Communications and Annunciation Upgrades," dated 2009 05 25.
Recommended Communication Option - "Engineering Report for Missi Falls Communications Upgrade," dated 2009 02 25.
Concept Design Report - "Missi/Notigi/Laurie River Annuciation/Telemetry Upgrade," dated 2009 05 21.
CAMELOT ID# 2044

REVISION:
To increase the budget from $4.8M to $6.7M to reflect an increase in scope and cost increases for additional requirements.

IN SERVICE DATES		Base estimate 2011/04/01 CLASS 3
2011/07/31	359	
2012/03/31	1277	
2013/03/31	3984	Work start date 2009/08/01
2014/03/31	1126	

PREV.AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Actual cost to date:	751		32			783
(Over)under expend:	2851	35	7			2893
2011/12	39	1				40
2012/13	1000	43	13			1056
V-CPJ TOTAL	4641	79	52			4772
REV. AMOUNTS:						
Actual cost to date:	751		32			783
(Over)under expend:						
Auth 2011/12	1947	10	103	-2		2058
Req: 2012/13	2537	76	168			2781
2013/14	1036	55	35			1126
V-HLD TOTAL	6271	141	338	-2		6748

Prepared by	yy mm dd	Approved by	yy mm dd	Approved by	yy mm dd	Approved by	yy mm dd
	11 07 12	OWNING DIVISION	11 07 18	COORDINATING DIVISION		VICE-PRESIDENT	11 07 19

CER(1) Rev. 97 12

CAPITAL EXPENDITURE REVISION

SIMULATED ROLLOVER

FORECAST HISTORY (in thousands of dollars)

ProjectNumber P:15698

Approved yy mm	TOTAL AMOUNT	COMMENTS
2010 06	$5,163	Revised base estimate and updated in-service dates.
2009 05	$4,772	New item

Forecasted Mthly Exp.		GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
2011/12	Apr	200		4		-2	202	202
	May	209		5			214	416
	Jun	229		6			235	651
	Jul	205	1	8			214	865
	Aug	146	1	7			154	1019
	Sep	146	1	8			155	1174
	Oct	131	1	9			141	1315
	Nov	145	1	9			155	1470
	Dec	130	1	10			141	1611
	Jan	138	1	11			150	1761
	Feb	138	1	11			150	1911
	Mar	130	2	15			147	2058
TOTAL		1947	10	103		-2	2058	2058
2012/13	Apr	191	4	7			202	202
	May	236	5	8			249	451
	Jun	225	5	9			239	690
	Jul	214	5	11			230	920
	Aug	236	6	12			254	1174
	Sep	203	6	13			222	1396
	Oct	225	7	15			247	1643
	Nov	236	8	16			260	1903
	Dec	191	7	18			216	2119
	Jan	225	8	19			252	2371
	Feb	202	8	19			229	2600
	Mar	153	7	21			181	2781
TOTAL		2537	76	168			2781	2781

ROUTING SLIP FOR APPROVAL OF A

CPJ or CPJ ADDENDUM for a MAJOR item

FINANCE CONTACT: **Lindsey Bortoluzzi (360-4728)**

DATE: July 7/15

PROJECT/COMPLEX NAME:

GREAT FALLS STATOR SPARE PURCHASE

PROJEC/COMPLEX - I.M. NODE NUMBER:	*WBS NUMBER(S):*
1.1.1.3.28.3	**P:24797**

OWNING DIVISION FOR PROJECT/COMPLEX:

Generation South Division

COORDINATING DIVISION FOR PROJECT/COMPLEX:

Engineering Services Division

INSTRUCTIONS:

1) Review attached CPJ and associated CER(s) belonging to this project and/or complex and follow the ADDITIONAL INSTRUCTIONS, if applicable.

If you wish to request changes:

2a) Circle YES under the CHANGES REQUIRED column next to your name and enter a description of the change(s) in the space provided below.

2b) Return the document/package immediately to the person listed next to the red "Return document/package to:" below.

If you wish to indicate your approval of the Project/Complex:

2a) Circle NO under the CHANGES REQUIRED column and follow the ADDITIONAL INSTRUCTIONS, if applicable.

2) ***Forward the document/package to the next person on the list.***

	CHANGES REQUIRED?	SIGNATURE	ADDITIONAL INSTRUCTIONS	
Reviewed by Project Manager **Jordan Austman**	YES / (NO)		***CPJ:*** INITIAL the title page, 'Prepared By:'	***CER(s):*** not applicable
Reviewed by Coordinating Section Head **Jules Gareau**	YES / (NO)		***CPJ:*** INITIAL the title page: Coordinating Division	***CER(s):*** not applicable
Reviewed by Coordinating Manager: **Hal Turner** Jules Gareau for Hal	YES / (NO)		***CPJ:*** INITIAL the title page: Coordinating Division	***CER(s):*** not applicable
Approved by Owning Division Manager: **Bob Dandenault**	YES / (NO)		***CPJ:*** SIGN and DATE the title page, Owning Division Manager	***CER(s):*** Sign and Date the Owning Division box
Approved by Coordinating Division Manager: **Joel Wortley**	YES / (NO)		***CPJ:*** SIGN and DATE the title page, Coordinating Division Manager	***CER(s):*** SIGN and DATE the Coordinating Division box
Finance: **Lindsey Bortoluzzi**	YES / (NO)		***CPJ:*** SIGN and DATE the title page, Financial Department	***CER(s):*** INITIAL 'Prepared by'

Return document/package to: **Lindsey Bortoluzzi (360-4728)**

COMMENTS:

NOTE: This project was approved on May 7th (approved CPJ is also attached). The updated CPJ is to reflect the IFRS adjustment that occurred after this date. No other changes have been made.

continue on reverse if necessary

These documents are time-sensitive. Your soonest attention would be appreciated.

D1876

CAPITAL PROJECT JUSTIFICATION FOR

GREAT FALLS STATOR SPARE PURCHASE

REVIEWED BY:
(Owning Dept Manager)

NOTED BY:
(if applicable)

Coordinating Division: J.G. 2015 07 22

Constructing Division:

Financial Department:
(if over $1 million)

RECOMMENDED FOR IMPLEMENTATION:

Owning Div. Manager: 2015 07 22

Business Unit V.P.: 2015-07-28

PRIMARY JUSTIFICATION:
Indicate key project driver(s):

☐	Safety	☐	Customer Service
☐	System Supply	☐	Efficiency
☒	System Reliability	☐	Environmental

NERC COMPLIANCE*: ☐ YES ☒ NO

*Determine if the project requires compliance with North American Electric Reliability Corporation (NERC) CIP Cyber Security Standards.

BUDGET $: (Total Net Cost)	$5,750,000
START DATE: (1st Cost Flow)	2015 05
IN-SERVICE DATE: (Last Major In-service Date)	2017 05
RISK MATRIX/ BUSINESS CASE TIER: (Optional)	
INVESTMENT REASONS: (Optional)	

OWNING DIVISION:	Generation South
I.M. NODE NUMBER:	1.1.1.3.28.3
W.B.S. NUMBERs:	P:24797
MAJOR ITEM ☒	**DOMESTIC ITEM** ☐
PREPARED BY:	J. Austman JTA
DATE PREPARED:	2015 04 21
REPORT NUMBER:	10147
FILE NUMBER (Optional):	

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION

Project Name

Great Falls Stator Spare Purchase

Recommendation

Approve a budget of $5.8M to procure and construct one 30 MVA spare Generator Stator to protect against an in-service failure of Units 1, 3, 5 and 6.

Project Scope

Included in the scope is the design, supply and construction of a spare stator (frame, core, coils) and all labour associated with supporting this contract and storing the stator for future use. Also included with the project is labour associated with a study to determine if more than one spare stator should be purchased. If it is determined that more than one spare stator is desirable a CPJ addendum will be prepared. The contract will be written to provide Purchaser's options for additional spare stators.

Installation will occur at some unknown time in the future. Therefore, this project does not include the installation of the stator or refurbishment of any of the other generator components (e.g. poles). In addition, items such as the sole plate machining / doweling, trenching, final electrical connections, and disassembly and assembly of a unit are excluded from the scope of this project.

Background

In April 2011, new stators were purchased for Unit 2 and Unit 4 following a risk based calculation.

In November 2011, a routine inspection of Great Falls Unit 2 identified that a keybar failure had occurred which resulted in movement of the stator core away from the frame and into the air gap towards the rotor. As a result, an emergency project was initiated to replace the stator and refurbish portions of the generator.

Subsequent to the Unit 2 failure, Mechanical Engineering conducted a study to analyze the viability of repairs to the keybars and concluded that it is not recommended to proceed in such a fashion.

The Great Falls Units 1, 3, 5 and 6 generators are of 1920's vintage. Unit 2 was replaced in 2012 and Unit 4 is being replaced in 2015.

An unplanned failure represents a long lead time replacement and extended outage. By procuring and constructing a stator in advance, the potential outage time can be reduced by a minimum of 1.5 years compared to reacting to an emergency situation.

Great Falls Units 2 and 4 have a Purchase Order date of April 27, 2011 (not including the tendering process). The first stator was ready for installation October 2012.

JUSTIFICATION—BUSINESS CASE ANALYSIS (SUMMARY):

Justification and Link to Corporate/Business Unit Goals

This project is recommended in order to protect against the risk of failure of 4 stators at Great Falls which aligns with the Business Unit goal for Asset Management – "Generation Operations is committed to acquiring, operating, maintaining and replacing its portfolio of assets to optimize availability by managing

JUSTIFICATION—BUSINESS CASE ANALYSIS (SUMMARY):

Justification and Link to Corporate/Business Unit Goals

risks and life cycle costs of the entire fleet".

ANALYSIS OF ALTERNATIVES:

Economic Analysis

Discount Rate	For current corporate rates see G911 6.95%	For clarification on hurdle rates, contact the Economic Analysis Department

Recommended Option	NPV Benefits (Costs)
Purchase spare Stator	($5.441M)

Other Alternatives Considered	NPV Benefits/(Costs)

Risk Analysis

Scope:
There is a risk that the stator may be damaged after it is built since it will be sitting between two running units for an unknown length of time. This risk is considered minimal since Unit 4 stator was built in 2012 and was tested in 2015 to verify that there are no ill effects from the method of storage.

Budget:
The estimate was developed based on the previously awarded contract for 2 stators in 2012 (plus escalation) and also an RFI for budgetary pricing in March 2014. In addition, $540K has been allocated to cover the risk of higher pricing being received.

Capital Budget Estimate

The annual net budget requirements are as follows (in thousands of dollars):

Fiscal Year	Proposed Budget
2015/16	$ 963
2016/17	$ 3,396
2017/18	$ 1,391
2018/19	$ -
2019/20	$ -
Total	$ 5,750

Proposed Schedule

Proposed Schedule

Technical Specifications - May / June 2015
RFP Preparation - July / August 2015
Proposal period, Evaluate, Negotiate, Award PO - August thru December 2015
Estimated delivery date of components - December 2016
Stator Construction - January thru May 2017

Related Projects

None.

Reference Documents

Finite Element Analysis of the Great Falls GS OEM Stators (Bunkowsky, 2015/03/11, ESD Report # ESD-2015-023)

CER(1) Rev. 97 12

CAPITAL EXPENDITURE REVISION

(IN THOUSANDS OF DOLLARS)

SIMULATED ROLLOVER

Title		Investment Management Node:
GREAT FALLS STATOR SPARE		1.1.1.3.28.3
Owning Division: Generation South	Coordinating Division: Engineering Services	ProjectNumber: P:24797

DESCRIPTION:

Procure and construct one 30 MVA spare Generator Stator to protect against an in-service failure of Units 1, 3, 5 and 6.

JUSTIFICATION:

An unplanned failure represents a long lead time replacement and extended outage. By procuring and constructing a stator in advance, the potential outage time can be reduced by a minimum of 1.5 years compared to reacting to an emergency situation. A spare will allow quick replacement as the lead time to purchase is about 18 months

REFERENCE:

CPJ titled "GREAT FALLS STATOR SPARE PURCHASE" dated 2015 04 21.
Copperleaf Number 10147

REVISION:

New Project.

This project was approved on May 7th. The updated CPJ is to reflect the IFRS adjustment that occurred after this date. No other changes have been made.

Contingency: $540

IN SERVICE DATES				Base estimate 2015/04/01 CLASS 2
2017/05/31	5750			Work start date 2015/05/01

PREV.AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Actual cost to date:						
(Over)under expend:						
2015/16	940	16	9			965
2016/17	3175	102	125			3402
2017/18	1295	56	42			1393
V-CPJ TOTAL	5410	174	176			5760
REV. AMOUNTS:						
Actual cost to date:						
(Over)under expend:						
Auth. 2015/16	940	15	9			964
Req: 2016/17	3175	96	125			3396
2017/18	1295	54	42			1391
V-HLD TOTAL	5410	165	176			5751

Prepared by	yy mm dd	Approved by	yy mm dd	Approved by	yy mm dd	Approved by	yy mm dd
VB	15 07 24	OWNING DIVISION	15 07 22	COORDINATING DIVISION	15 07 22	VICE-PRESIDENT	15 07 28.

CER(1) Rev. 97 12

CAPITAL EXPENDITURE REVISION

SIMULATED ROLLOVER

FORECAST HISTORY (in thousands of dollars)

ProjectNumber P:24797

Approved yy mm	TOTAL AMOUNT	COMMENTS

Forecasted Mthly Exp.		GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
2015/16	Apr							
	May	16					16	16
	Jun	19					19	35
	Jul	3					3	38
	Aug	6					6	44
	Sep	6					6	50
	Oct	7					7	57
	Nov	12					12	69
	Dec	212	3				215	284
	Jan	220	3	1			224	508
	Feb	208	4	2			214	722
	Mar	231	5	6			242	964
TOTAL		940	15	9			964	964
2016/17	Apr	220	5	4			229	229
	May	231	5	5			241	470
	Jun	231	6	6			243	713
	Jul	220	6	8			234	947
	Aug	243	7	9			259	1206
	Sep	220	6	10			236	1442
	Oct	231	7	11			249	1691
	Nov	243	8	12			263	1954
	Dec	193	6	13			212	2166
	Jan	385	13	14			412	2578
	Feb	350	13	15			378	2956
	Mar	408	14	18			440	3396
TOTAL		3175	96	125			3396	3396

Project Value Summary Report	Project Code	Report Start Year	Number of Years	Currency Scale
	10147	**2018**	**20**	**Thousands**
	Project Name			Scenario
	GREAT FALLS STATOR SPARE PURCHASE			**Outlook**

Project Category	Project	Preparer	KJARTANSON, DERRICK (dkjartanson)
Station	HGFL / Great Falls G.S.	Planning Portfolio	GW BU Projects
Responsible Division	G12700 / Engineering Services	Dependency Type	
Project Stage	Executing	Dependency Group Name	
Parent Project			

Project Overview

01. Finance Section	WBS	P:24797
	Network Number	VARIOUS
	I.M. Node	2.1.20.15.02.26
	I.M. Node Name	Great Falls Stator Frame Spare
02. CIC and CIJ/Addendum Section	Recommendation	Approve a budget of $5.8M to procure and construct one 30 MVA spare Generator Stator to protect against an in service failure of Units 1, 3, 5 and 6.
	Project Scope/Description	Purchase a spare Stator for Great Falls GS
	Background	In April 2011, new stators were purchased for Unit 2 and Unit 4 following a risk based calculation. In November 2011, a routine inspection of Great Falls Unit 2 identified that a keybar failure had occurred which resulted in movement of the stator core away from the frame and into the air gap towards the rotor. As a result, an emergency project was initiated to replace the stator and refurbish portions of the generator. Subsequent to the Unit 2 failure, Mechanical Engineering conducted a study to analyze the viability of repairs to the keybars and concluded that it is not recommended to proceed in such a fashion. The Great Falls Units 1, 3, 5 and 6 generators are of 1920's vintage. Unit 2 was replaced in 2012 and Unit 4 is being replaced in 2015. An unplanned failure represents a long lead time replacement and extended outage. By procuring and constructing a stator in advance, the potential outage time can be reduced by a minimum of 1.5 years compared to reacting to an emergency situation. Great Falls Units 2 and 4 have a Purchase Order date of April 27, 2011 (not including the tendering process). The first stator was ready for installation October 2012.
	Justification	This project is recommended in order to protect against the risk of failure of 4 stators at Great Falls which aligns with the Business Unit goal for Asset Management – "Generation Operations is committed to acquiring, operating, maintaining and replacing its portfolio of assets to optimize availability by managing risks and life cycle costs of the entire fleet". There is a high probability within the next 5 years a stator will fail in service. A spare will allow quick replacement as the lead time to purchase is about 18 months
	Risk of Proceeding with Recommended Project	There is a risk that the stator may be damaged after it is built since it will be sitting between two running units for an unknown length of time. This risk is considered minimal since Unit 4 stator was built in 2012 and was tested in 2015 to verify that there are no ill effects from the method of storage.
	Other Alternatives Considered	Alternatives considered: - Purchase a spare stator - Purchase and install a stator
	Proposed Schedule	Year 1 - Design Year 2 - Delivery of the stator
	Related Projects	N/A
	Investment Category Level 1	C3 / Sustainment
	Investment Category Level 2	CM / System Renewal
	Investment Category Level 3	C0040 / Generation = 15 - 69 MW per unit
	Rationale for OM&A Cost Changes	N/A

Manitoba Hydro

Project Value Summary Report

Project Code	Report Start Year	Number of Years	Currency Scale
10147	**2018**	**20**	**Thousands**

Project Name	Scenario
GREAT FALLS STATOR SPARE PURCHASE	**Outlook**

03. Responsibility Section	Requestor	Kevin Penner
	Request ID	
	Project Manager	AUSTMAN, JORDAN (jaustman)
	Requesting Business Unit	GBA_20 / Generation & Wholesale
	Requesting Division	G12500 / Generation South
	Requesting Cost Center	51520 / Great Falls Operations - Wpg River
	Responsible Cost Center	51460 / Power Projects
	Construction Department	
	Plant Manager	
	Site Contact	
04. Other - General	Vetted Need	Yes
	Approval State	CIJ - Approved
	EC/MHEB Approval Required	No
	Last Approved Addendum Number	0
	Engineering Report Required	No
	Estimate Accuracy	Estimate Class 2
	Reference No.	
	Environmental Impact Statement Required	No
	CBSLD (Capital Budget Single Line Diagram)	
	NERC Compliance	No
05. Other - Marketing & Customer Service	Technical Documentation	
06. Other - Gas Distribution	Gas Regulatory Classification	
	Mains Extension Over 500 Meters	No
	Plant Account Code	
	Reimbursement by Third Party	No
07. Other - Generation & Wholesale	Section (G&W)	PPD-1
	JobTrac No.	
08. Other - IT	Architecture Compliance (ARC)	
09. Other - Transmission	Region (Transmission)	
10. Asset Retirement	Asset Retirement	No
	Asset Retirement Description	Spare Stator
	SAP Project Type	24 - BOC-VP & Management
	Project Sub-Category	Default

Alternative Spend Profile

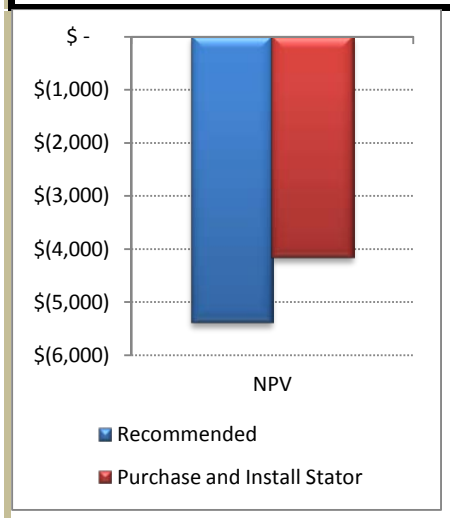
Name	Status	NPV	B/C Ratio	IRR %	Payback months	Total Spend	Alternative Start Date
Recommended	Recommende	$ (5,380)	0.00	0.00%	0	$ 5,771	7/1/2016
Purchase and Install Stator	Candidate	$ (4,166)	0.00	0.00%	0	$ 6,153	7/1/2016

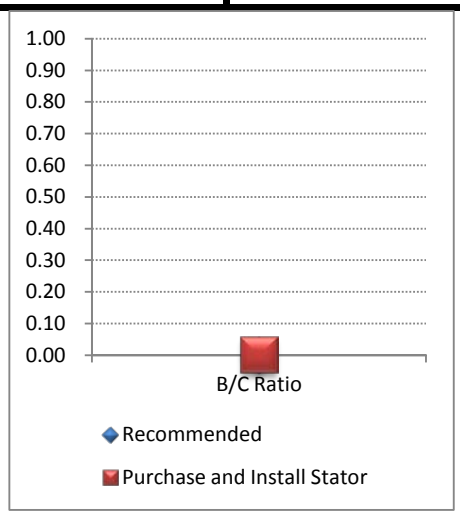
Manitoba Hydro

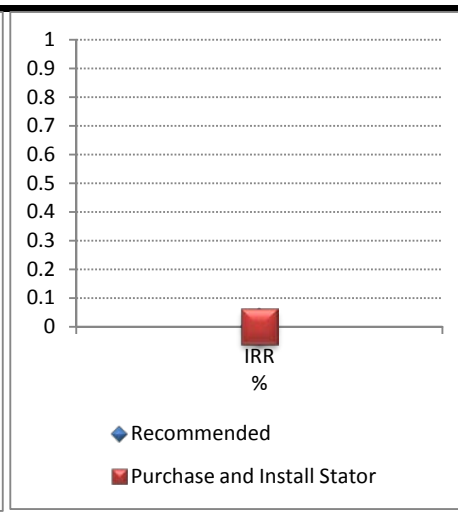
Project Value Summary Report

Project Code	Report Start Year	Number of Years	Currency Scale
10147	**2018**	**20**	**Thousands**

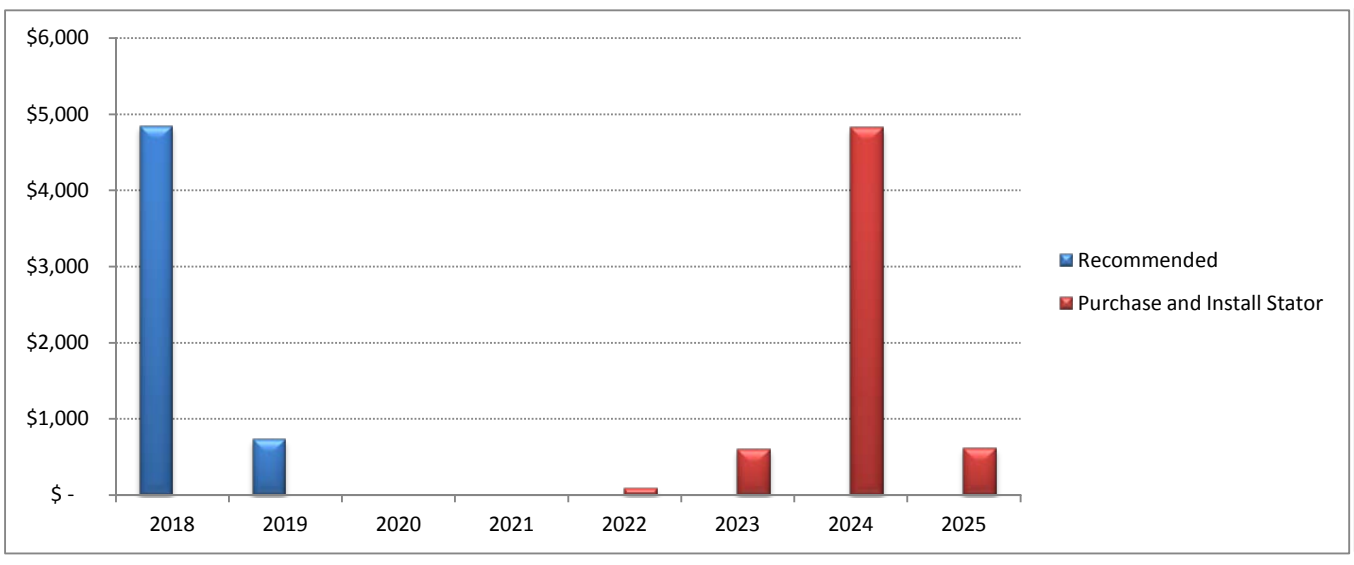
Project Name	Scenario
GREAT FALLS STATOR SPARE PURCHASE	**Outlook**







Name	Status	2018	2019	2020	2021	2022	2023	2024	2025
Recommended	Recommended	$ 4,836	$ 729	$ -	$ -	$ -	$ -	$ -	$ -
Purchase and Install Stator	Candidate	$ -	$ -	$ -	$ -	$ 83	$ 602	$ 4,819	$ 616



Actuals

Account Type	2018	2019	2020	2021	2022	2023	2024	2025
Capital	$ 24	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Internal Labor	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Operating	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Proposed

Account Type	2018	2019	2020	2021	2022	2023	2024	2025
Capital	$ 4,836	$ 729	$ -	$ -	$ -	$ -	$ -	$ -
Internal Labor	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Operating	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Approved

Account Type	2018	2019	2020	2021	2022	2023	2024	2025
Capital	$ 2,274	$ 740	$ 573	$ -	$ -	$ -	$ -	$ -
Internal Labor	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Operating	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Committed

Project Value Summary Report

Project Code	Report Start Year	Number of Years	Currency Scale
10147	**2018**	**20**	**Thousands**

Project Name	Scenario
GREAT FALLS STATOR SPARE PURCHASE	**Outlook**

Account Type	2018	2019	2020	2021	2022	2023	2024	2025
Capital	$ 4,465	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Internal Labor	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Operating	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Alternative Value

Name	Status	Total Value	Cost Present Value	Value / $K
Recommended	Recommended	20,138	$ 5,380	3.7432
Purchase and Install Stator	Candidate	-4,166	$ 4,166	-1.0000

Project Value Summary Report	Project Code	Report Start Year	Number of Years	Currency Scale
	10147	**2018**	**20**	**Thousands**
	Project Name			Scenario
	GREAT FALLS STATOR SPARE PURCHASE			**Outlook**

Project Comments

Date	User	Type	Comment

Project Attachments

Date	Attachment Name	User	Description
10/16/2015	http://fr.hydro.mb.ca/fp/CPJ%20Library/1.1.1.3.28.3/1.1.1.3.28.3%20Great%20Falls%20Stator%20Spare%20Purchase%20IFRS%20Adjusted%20.pdf	PRUDEN, DIANA (dipruden)	VP Approval - IFRS Adjusted July 28 2015

D1876(A)

APPROVED BY EXECUTIVE COMMITTEE
MINUTE # 1427.04

DATE: 2013 01 22
Financial Planning

CAPITAL PROJECT JUSTIFICATION FOR

FLEET SERVICES RELOCATION
700 HARROW SHOP TO ROSSER STATION

REVIEWED BY:
Brent Hopkins

NOTED BY:
(if applicable)

Coordinating Division: Corporate Services

Constructing Division: Corporate Services

Financial Department:
(if over $1 million)

RECOMMENDED FOR IMPLEMENTATION:

Owning Div. Manager: B.D. Ketcheson

Business Unit V.P.: V.A. Warden

V.A. WARDEN
2012 12 28

BUDGET $: (Total Net Cost)	**$12,895,000**
START DATE: (1st Cost Flow)	2012 12
IN-SERVICE DATE: (Last Major In-service Date)	2014 07
RISK MATRIX/ BUSINESS CASE TIER:	
INVESTMENT REASON:	

OWNING DIVISION: Corporate Services

I.M. NODE NUMBER: 1.1.4.2.3.1

W.B.S. NUMBERs: P: 21038

MAJOR ITEM ☒ **DOMESTIC ITEM** ☐

PREPARED BY: B. Hopkins/D. Little

DATE PREPARED: 2012 12 18

REPORT NUMBER:

FILE NUMBER (Optional):

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION

Project Name
Fleet Services Relocation

Recommendation
To construct a vehicle and equipment maintenance facility on Manitoba Hydro land adjacent to Rosser Station, and relocate 700 Harrow Fleet Services functions to the new location by July 2014, at a cost of $12.9 million.

Project Scope
The scope of work includes: 1. Road upgrade for access to the new site on Pipeline Road immediately north of Rosser terminal. 2. Development of a concrete and gravel yard and associated land drainage. 3. Upgrade of existing water and sewer services at the site. 4. Construction of a facility suitable for aerial device, derrick digger, crane, off road equipment, heavy duty truck and trailer maintenance.

Background
The need to relocate the Fleet Services' central garage has existed for many years, as the number and size of fleet vehicles has grown to a point that the existing site is obsolete. The 700 Harrow garage was commissioned in 1957 to service a fleet of less than 1,000 vehicles with virtually no aerial devices. Today, Manitoba Hydro's fleet is made up of 2,300 self propelled and 3600 total units. The 700 Harrow garage is responsible for the maintenance of 2,220 fleet units, with an annual operating budget of $6.6 million. In-house maintenance activities for this shop are focused on medium duty vehicles, off road equipment and medium duty trailers. The work ranges from; preventative maintenance on aerial devices, diggers and cranes to repairs and major overhauls of longer life cycle off road equipment. Interior and exterior space at 700 Harrow Street does not allow for effective servicing of larger modern utility equipment. Large all terrain equipment is being serviced in areas meant for light, on-road vehicles, while the congested yard site does not lend itself to the movement of large equipment. Crowded conditions and close proximity to energized electrical plant create hazardous situations for staff and require several 'work arounds' from a safety perspective. Many of the units have become so large that the current roadway system to the garage cannot accommodate their size, necessitating servicing to be undertaken on the outskirts of the city. In some other cases, the only way to move the equipment to Harrow is at night with a police escort. The result is the most valuable and critical equipment in the fleet is being serviced in outdoor field situations with spotted results. Sparling Avenue provides the only access route to the garage. Historically it has been used almost exclusively by Fleet Services and its customers, for parking and loading of equipment. The urban neighbourhood has grown around the site and created traffic safety concerns for staff and the public, as well as straining relationships with nearby businesses and residents. In the near future, Sparling Avenue will be the primary access to major retail development on Taylor Avenue, exacerbating the already unacceptable traffic hazards in the area. Power train maintenance, repairs on medium duty on-road equipment and light duty repairs have been out sourced as the 700 Harrow Street space has been outgrown. Contracting out has proven to be very

Background
expensive, while losing flexibility and quality of servicing. Options to outsource more specialized utility work that occurs at 700 Harrow is currently maximized. In the previous year, 630 work orders were outsourced as result of lack of shop capacity, at a cost of $546 000. Opportunities to utilize mobile repair trucks and conduct repairs in other MH spaces (eg Stonewall Training Centre), is currently maximized. The inefficiencies resulting from the use of the obsolete Harrow site have increased steadily over the past 20 years. The inefficiencies have resulted in 1400 incomplete maintenance and repair work orders representing a significant risk to the reliability and life cycle of the units affected.

JUSTIFICATION—BUSINESS CASE ANALYSIS (SUMMARY):

Justification and Link to Corporate/Business Unit Goals
Remaining at the current 700 Harrow location is not an option, as a large portion of the fleet cannot be serviced at the site and there is an unacceptable level of safety risk for personnel. Safety risks include operating equipment under energized transmission lines and on the increasingly busy Sparling Avenue. Shop congestion contributes to an exceptionally high department accident frequency rate. The issues with space at 700 Harrow contribute to significant labour inefficiencies. The circumstances mean maintenance on a piece of equipment requires double and in some cases triple the time and manpower to perform. Additionally, access to 700 Harrow with the larger equipment can only be moved at night with police escort through the residential neighbourhoods and soon to be commercial development. These issues not only add cost but also raise significant safety concerns. Approximately $1M would need to be spent immediately to reroute access to the service bays through the Hydro Museum parking lot and move the salvage yard to the 820 Taylor parking lot, due to upcoming major retail development in the area. The most efficient, cost effective solution is to relocate the Fleet Services facility to a location more conducive to commercial vehicle traffic. Six sites were evaluated and the team recommends relocating the operation to a seventeen acre parcel owned by the Corporation inside PTH 101 next to Rosser Terminal on Pipeline road. The site provides easy access to Corporate Service Centers, terminals, convertor stations and major transmission right of ways. Fleet Services suppliers and support vendors are located close to this site. The size of the site will allow for safe storage of critical large mobile equipment close to technicians and an equipped shop. The location also allows for efficient and safe loading and unloading of equipment and controlled access to PTH 101 that will reduce dispatch time for this equipment in system emergency situations. The property lies within the R.M. of West St. Paul, but the services (sewer and water) would be provided by the City of Winnipeg. It is anticipated that a mutually beneficial development agreement can be negotiated to cover the estimated $2.3M servicing cost. The Corporation owns 160 acres around this site which affords the opportunity for future expansion. Groups including Distribution Construction, Transmission Line Maintenance, Haulage Services and Materials Management have expressed interest in co-locating at the site given its ideal location and opportunities for synergies. While these options will be evaluated in independent business cases/CPJs, potential future services at Rosser site include emergency fuel storage, critical emergency response equipment storage, as well as an alternative energy depot. This project may have further positive impacts when considering the context of the overall Winnipeg space management master plan. Opportunities for Manitoba Hydro to use the re-purposed Harrow building include the consolidation of the Power Supply Chemical Labs, staging area during 820 Taylor heating/cooling replacement, storage space to replace leased 555 Hervo, 1840 Chevrier, or Hydro X space. In summary, relocation of Fleet Services into a purpose built structure will: 1. **Maintain Financial Strength** – Improved operating efficiencies, will result in an increase in

JUSTIFICATION—BUSINESS CASE ANALYSIS (SUMMARY):

Justification and Link to Corporate/Business Unit Goals

departmental productivity, reducing the need to outsource some of the repair work. This equates to approximately $600 000 in cost savings per year. The NPV of this project is quite favourable, indicating the project is cost effective.

2. **Improve Safety in the workplace** – Relieve congestion in the shop to enhance ergonomics and workflow. Eliminate the need for staff to work in traffic loading and unloading equipment and accessing garage bays. Eliminate the need to violate absolute limits of approach to high voltage equipment during the normal course of work. Keep large MH service vehicles off Sparling Avenue, which is to become a main thoroughfare for a major retail development.

3. **Provide Exceptional Customer Value** – Reduce equipment downtime as well as increase the volume of units which can be serviced on site, while increasing the quality control and decreasing costs. Reduce/eliminate the need for permitting to move large equipment. Reduce work order backlog and increase life span and availability of units. Eliminate heavy vehicle traffic from the Taylor site to enhance relationships with neighbouring businesses and residents.

4. **Attract, develop and retain a highly skilled and motivated workforce** – Providing up to date work space which reflects the latest healthy, safe, building environments will improve our ability to retain existing highly skilled technicians and attract highly skilled replacements.

5. **Promote cost effective energy conservation and innovation** – The new shop will be designed on an industry best practice footprint. Technology which supports vehicle emission reduction will be integrated into the design. Innovations developed in previous corporate building projects, in particular the principles learned in the design of Manitoba Hydro Place, will be integrated into the design to maximize value and demonstrate prudent environmental management practices while providing an improved quality of space for the workers.

Status Quo is not an option as outlined above.

Option 3: Increasing staff and space at the current location. The option would involve building an additional garage after relocating electrical infrastructure in the Harrow terminal yard, converting the parking area and front of the electrical museum into an access route and loading/unloading area for access to the garage as well as fencing a large portion of the parking space at 820 Taylor and using the space for the storage of salvaged vehicles and equipment awaiting liquidation or re-deployment. The cost of relocating Harrow terminal electrical infrastructure is prohibitive while the congestion around the electrical museum and the 820 Taylor parking lot will further congest an already crowded area.

Option 4: Contract Out. The costing of this option was based on current rates of vendors in the province today and extrapolated to the entire fleet maintenance and repair operation. The option was not recommended due to the unfavourable NPV and the fact that capacity to do this work does not exist outside of the Corporation in the province today.

ANALYSIS OF ALTERNATIVES:

Economic Analysis		
Discount Rate	For current corporate rates see G911 5.05%	For clarification on hurdle rates, contact the Economic Analysis Department

Recommended Option	NPV Benefits (Costs)
To construct a vehicle and equipment maintenance facility on Manitoba Hydro land adjacent to Rosser Station	$4,065,202

Other Alternatives Considered	NPV (= PV of BENEFITS - PV of COSTS)
Increasing staff and space at 700 Harrow	($9,011,917)
Contract out	($50,893,034)

Risk Analysis

Relocating the operation to the new site represents a low risk investment. The land is owned by the Corporation and is currently underused in a marginal secondary land use agreement. It is anticipated a mutually beneficial development agreement can be negotiated to cover the estimated $2.3M servicing costs.

The structure to be constructed is a modern heavy duty shop layout with limited specialized equipment attached to the structure. If for some unforeseen reason the site must be liquidated in the future, the asset will not be stranded, as it will be readily marketable as commercial real estate.

Total Budget

The annual net budget requirements are as follows:

Fiscal Year		Proposed Budget
Prev. Actuals	$	-
2012/13	$	500,000
2013/14	$	9,300,000
2014/15	$	3,095,000
Total	$	12,895,000

Proposed Schedule

Milestones	
- Building/Yard design	Mar 2013
- Issue Tender Documents	Apr 2013
- Yard Construction complete	Oct 2013
- Construction Start - Building	Jun 2013
- Construction Complete	May 2014

Proposed Schedule	
- Occupancy	Jul 2014

Related Projects

1. Emergency Response Fuel Storage at new Rosser site. 820 Taylor retrofit.

Reference Documents

1. Unit Breakdown for 700 Harrow Service Area
2. 700 Harrow Work Order Listing
3. 700 Harrow Floor Plan
4. Vendor Work Order Summary
5. Pipeline Road Floor Plan
6. Work Order Breakdown by Unit Class
7. Alternative Site Comparisons
8. Costing Analysis
9. Unapproved Safe Work Procedure for actuating booms under energized lines at 700 Harrow-Aug 2012
10. Fleet Services Relocation Discussion Paper #1
11. Fleet Services Relocation Discussion Paper #2

CER(1) Rev. 97 12

CAPITAL EXPENDITURE REVISION

(IN THOUSANDS OF DOLLARS)

Title		Investment Management Node:
Fleet Services Relocation To Rosser Stn.		1.1.4.2.3.1
Owning Division: Corporate Services	Coordinating Division: Corporate Services	ProjectNumber: P:21038

DESCRIPTION:

Fleet Services Relocation To Rosser Stn.

To construct a vehicle and maintenance facility on Manitoba Hydro land adjacent to Rosser Station, and relocate 700 Harrow Fleet Services functions to the new location by July 2014 at a cost of $12.9 million.

The scope of work includes:
1. Road upgrade for access to the new site on Pipeline Road immediately north of Rosser Terminal.
2. Development of a Concrete and gravel yard and associated land drainage.
3. Upgrade of existing water and sewer services at the site.
4. Construction of a facility suitable for aerial devices, derrick diggers, cranes, off road equipment, heavy duty trucks, and trailer maintenance.

REVISION:

Contingency: $0

IN SERVICE DATES		Base estimate 2012/04/01 CLASS 0
2015/03/31	12895	Work start date 2013/02/01

PREV.AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Actual cost to date:						
(Over)under expend:						
2012/13	492	7	1			500
2013/14	8774	234	292			9300
2014/15	2293	106	696			3095
V-0 TOTAL	11559	347	989			12895
REV. AMOUNTS:						
Actual cost to date:						
(Over)under expend:						
Auth 2012/13	492	7	1			500
Req: 2013/14	8774	234	292			9300
2014/15	2293	106	696			3095
V-HLD TOTAL	11559	347	989			12895

Prepared by	yy mm dd	Approved by OWNING DIVISION	yy mm dd	Approved by COORDINATING DIVISION	yy mm dd	Approved by VICE-PRESIDENT	yy mm dd
	13 02 27		13 01 15		13 02 27		13 01 25

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CER(1) Rev. 97 12

CAPITAL EXPENDITURE REVISION

FORECAST HISTORY (in thousands of dollars)

ProjectNumber P:21038

Approved yy mm	TOTAL AMOUNT	COMMENTS

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
2012/13 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb	246	3				249	249
Mar	246	4	1			251	500
TOTAL	492	7	1			500	500
2013/14 Apr	719	13	3			735	735
May	794	16	6			816	1551
Jun	719	15	10			744	2295
Jul	756	17	15			788	3083
Aug	756	18	19			793	3876
Sep	681	18	22			721	4597
Oct	794	22	27			843	5440
Nov	719	21	30			770	6210
Dec	681	21	35			737	6947
Jan	794	26	39			859	7806
Feb	681	23	39			743	8549
Mar	680	24	47			751	9300
TOTAL	8774	234	292			9300	9300

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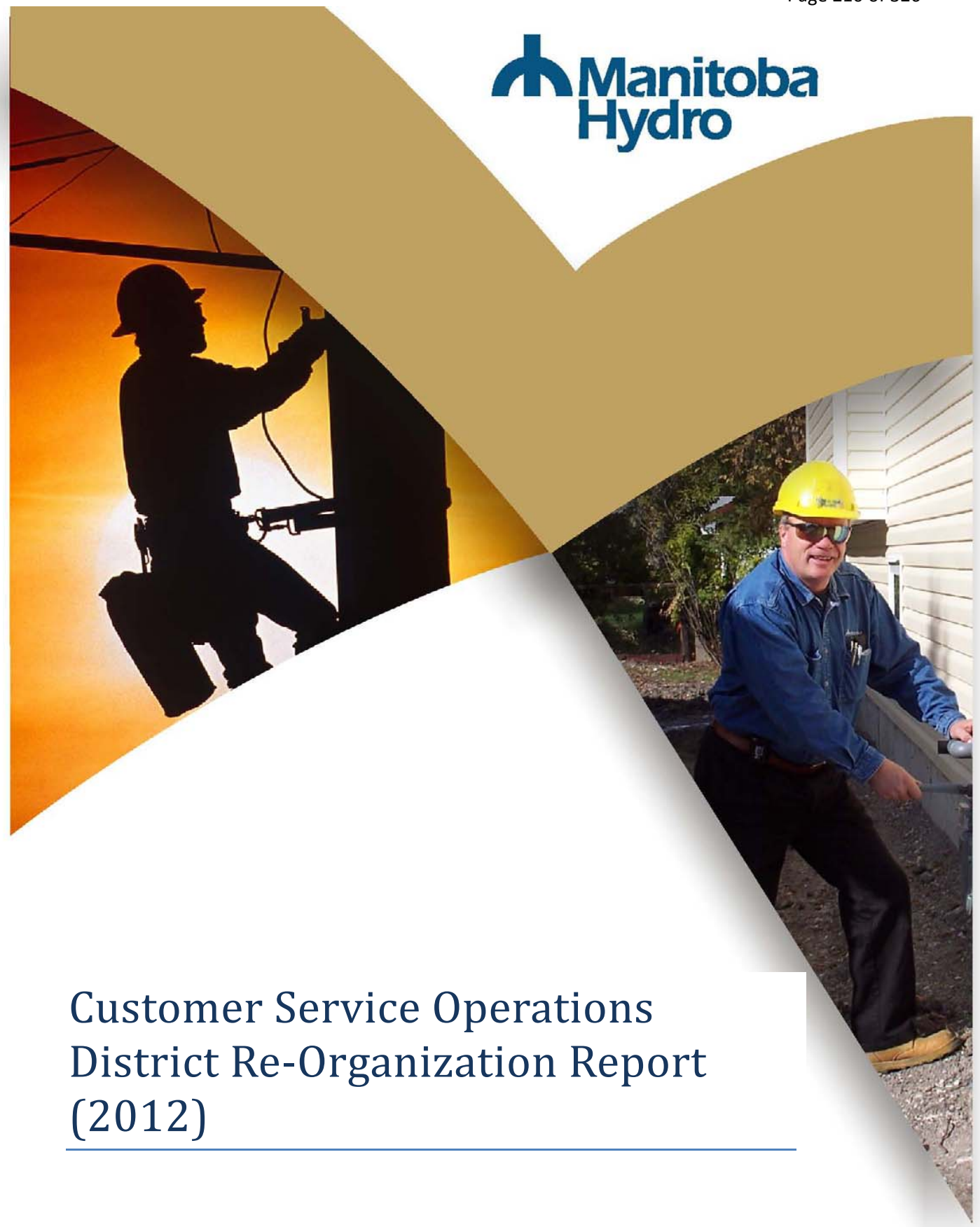

Customer Service Operations District Re-Organization Report (2012)

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CUSTOMER SERVICE OPERATIONS

REPORT ON

DISTRICT RE-ORGANIZATION REPORT (2012)

District Organizational Assessment Team	
Joe Thievin (Leader)	CSO - Major Projects
Brian Rychlicki (Facilitator)	Business Planning and Performance
Audrey Schmidt	Business Systems Department
Carolyn Nelson	Management Financial Services

PREPARED BY: **District Organizational Assessment Team**

DATE PREPARED: **2013 02 14**

REVIEWED BY:

RECOMMENDED FOR IMPLEMENTATION

DEPARTMENT:

DIVISION:

DATE:

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Executive Summary

Customer Service Operations has continued to evaluate its business processes with the vision of delivering exceptional customer service in an environment of complex financial constraints. At the same time, the divisions have adapted and changed in innovative way to meet employee and customer needs.

With the implementation of Mobile Workforce Management and changing business environment, there was a need to evaluate the rural organizational structure. The need gave rise to the *Customer Service Operations Re-Organization Plan (2007).* The re-organization plan was initiated to review existing rural district organizational structures and evaluate existing business operations as it relates to the utilization of staff, equipment, facilities and financial resources. The plan recommended four phases of change:

- phase I: Establish a new supervisory structure and project manager
- phase II: Introduce coordination and planning levels
- phase III: Front office closures and district boundary re-alignment
- phase IV: Closure of facilities

Phases I and II were approved and implemented in 2008 with phases III and IV to be evaluated and implemented in the future. The implementation of phases I and II created the foundation for future benefits.

Building on the momentum of past accomplishments, Customer Service Operations has re-evaluated the implementation of phases III and IV of the *Customer Service Operations Re-Organization Plan (2007).*

The purpose of the *Customer Service Operations District Re-organization Report (2012)* is to:

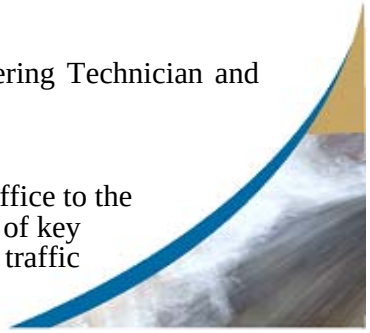
- provide a status update on the implementation of phases I and II and
- update the recommendations and implementation plan for phases III and IV (including the benefits of eliminating cash handling).

Phase I is completed with the establishment of a new supervisory structure and the elimination of the District Operator position. This included the centralization of key resources (Assistant District Supervisor, Estimator Planner and supporting staff) to the CSC. The savings associated with the completion of phase I was $1.4 million using a 30-year net present value (NPV).

Phase II is partially completed with the following outstanding:

- Relocation of all support staff – Energy Services Advisor, Engineering Technician and Electrical Inspector to the CSC
- Facility review to accommodate CSC staffing requirements

Since 2007, there has been a shift in customer traffic from the local district office to the CSC. The shift is a result of online service availability and the centralization of key resource staff to the CSC. Overall, there has been a 13% decline in customer traffic across the province. Many of the smaller district offices see less than two customers per day.



Given customer trends to access services online, centralized work planning, centralized collections, the value of the local district office is becoming obsolete. To address this eventuality, the implementation of the final phases of the *Customer Service Operations District Re-organization Report (2012)* should begin immediately. Inherent with the closure of the local district offices will be the elimination of cash handling. Cash payments will continue to be handled in the CSC and satellite offices.

Although the majority of local district offices will close, 12 satellite district offices will remain open. A satellite district office is best defined as an office in a location where the response time to customer outages cannot be effectively met or there is a need for a strong community presence due to workload or remoteness. With the exception of Flin Flon, Melita and Snow Lake, all satellite district offices are located in remote areas and play a vital role in the collection of arrears and customer communication. The Melita and Snow Lake district offices will remain open to customers due to the oilfield and mining activities.

The closure process will begin with closing the front office services followed by the closure of the entire facility. The complete facility closure will be contingent upon space availability within the CSC building to accommodate any relocated staff.

The closure of local facilities could have significant impacts on the employees who reside in these communities, particularly the administrative staff who are less mobile. As a result, a transition plan for each CSC will be developed to identify employee needs and the impact. The transition plan will identify a number of options to minimize the impact of the facility closures.

The implementation of this report and closure of 36 local district offices will affect approximately 160 employees and reduce the current staff compliment within Customer Service Operations by 23 positions (EFT). The financial benefits associated with this project are very significant.

Financial Impact of District Re-Organization

	NPV (in millions)			
Financial Benefits - District Re-Organization	**5-Year**	**10-Year**	**20-Year**	**30-Year**
Administrative staff salary reduction	$1.90	$5.94	$13.09	$17.46
Productivity improvements	$2.15	$6.74	$14.81	$19.75
Senior staff salary reduction (2007 report benefit)	$0.26	$0.61	$1.10	$1.40
Facility operational cost reduction	$0.83	$1.95	$3.51	$4.46
Stores material reduction (one-time benefit)	$2.41	$2.41	$2.41	$2.41
Elimination of cash handling	$0.40	$1.25	$2.75	$3.67
Total financial benefits	$7.95	$18.90	$37.67	$49.15
Significant Costs - District Re-Organization				
Employee relocation (one-time cost)	$0.70	$0.70	$0.70	$0.70
Facility renovations (one-time cost)	$4.51	$4.51	$4.51	$4.51
Total costs	$5.21	$5.21	$5.21	$5.21
Net Benefits of District Re-Organization	**$2.74**	**$13.69**	**$32.46**	**$43.94**

Note: Financial impacts do not include the sale of corporate facilities.

The internal rate of return for this project is 143% with a cost benefit ratio of 28.66.

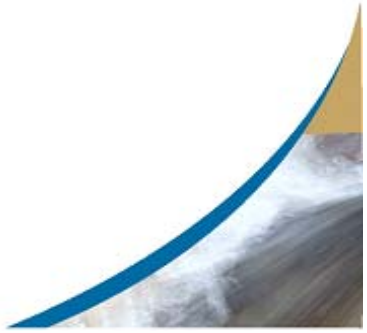
Centralization of the workforce will create a flexible workforce able to respond to customer demands effectively. In addition, maintenance crews will be created to address ongoing plant maintenance. The combined benefit will be improved service reliability and timely response to customer needs.

Access to amenities in larger communities and increased leisure time through reduced call rotations are among the key benefits to employees and their families.

The project team evaluated Customer Service Operations continuing down a path of status quo. The corporation will risk the loss of significant financial benefits and resource optimization if a status quo approach is taken. The shift in customer need for a local district office will continue to decline. Mobile Workforce Management, centralized collections, elimination of cash handling and the effects of customer self service are going to erode administrative functions in the districts to a point where the corporation will not be able to provide value added work to the administrative employee group.

The change management strategy will be viewed by communities and employees as a significant loss. A focused effort will be required to ensure the need for change is fully understood by communities and the employees who reside there.

The momentum created with phases I and II of this initiative will be difficult to change.
The requirement for a dynamic workforce is going to grow as we add customers and our plant continues to age. The closure of facilities is not a loss in service, but a new era of customer service.



Introduction

Over the past decade, Customer Service Operations has embarked on many initiatives to continually improve customer service and reduce costs through process improvement.

Recognizing the potential benefits of computer aided dispatch on the gas side of the business, a project team was formulated to implement a single solution to manage the workload in the Customer Service Centres (CSC). In 2005, Mobile Workforce Management was approved to replace the existing computer aided dispatch used by the natural gas group and plans were initiated for implementation on the electric side of the business. The estimated productivity improvements were in the range of 20% with a projected 30-year NPV of $41.8 million.

In 2007 a plan was developed and approved to optimize the rural district organization structure within the Customer Service Operations (CSO) Division to improve business and financial operations, while enhancing customer service and work life balance of employees. The implementation of a new district re-organization consisted of four phases as follows:

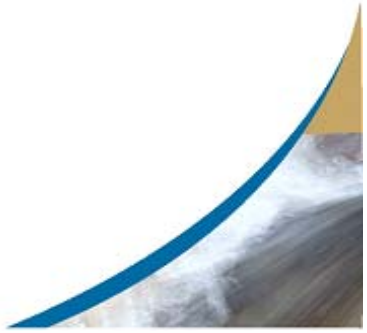
- Phase I: Establish new supervisory structure and placement of analyst/project manager
- Phase II: Introduce coordination and planning levels
- Phase III: Front office closures and district boundary re-alignment
- Phase IV: Closure of facilities

Phases I and II of the district re-organization were approved and the implementation process began. The initial phases of district re-organization form the foundation for future change.

Following closely behind the rural district re-organization, the *Winnipeg Area Facilities Report 2008* was approved. The report was to review the use and need for facilities based on a framework of integrated, cost effective and efficient customer services, by focusing on prompt emergency response times, reduced travel costs, optimal use of labor and sharing vehicles. The recommendations identified a reduction of two districts and three office buildings. The 30-year NPV associated with this report is $4.2 million.

With the corporation in a situation to rationalize costs and streamline its levels of service, the full implementation of Phase III and IV now appears timely as the completion of these phases in the original analysis are projected to yield financial benefits of $44.0 million over 30 years. Recognizing the evolution that has occurred in CSO business operations over the past five years, it is necessary to update pertinent information in the original report to validate its merit.

The team focused on details provided within the 2007 re-organization plan report, specific to rural Manitoba only.



The review considered the following:

- Establish new baseline of current staffing at each district
- Identification of EFT savings
- Identification of inventory savings
- Identification of fleet savings
- Categorization and staging of office closures
- Estimate of CSC facility upgrades/enhancements
- Listing and staging of activities to be undertaken as part of an office closure
- Impact to employees
- Update on impact to specific communities
- Communication plan
- Risk assessment

Over the past decade, Customer Service Operations has continued to deliver exceptional customer service in an environment of complex financial constraints. The initiatives implemented have resulted in financial benefits of $89.91 million.

Financial Impact of District Re-Organization and Other CSO Projects

	NPV (in millions)			
Financial Benefits - District Re-Organization	**5-Year**	**10-Year**	**20-Year**	**30-Year**
Administrative staff salary reduction	$1.90	$5.94	$13.09	$17.46
Productivity improvements	$2.15	$6.74	$14.81	$19.75
Senior staff salary reduction (2007 report benefit)	$0.26	$0.61	$1.10	$1.40
Facility operational cost reduction	$0.83	$1.95	$3.51	$4.46
Stores material reduction (one-time benefit)	$2.41	$2.41	$2.41	$2.41
Elimination of cash handling	$0.40	$1.25	$2.75	$3.67
Total financial benefits	$7.95	$18.90	$37.67	$49.15
Significant Costs - District Re-Organization				
Employee relocation (one-time cost)	$0.70	$0.70	$0.70	$0.70
Facility renovations (one-time cost)	$4.51	$4.51	$4.51	$4.51
Total costs	$5.21	$5.21	$5.21	$5.21
Net Benefits of District Re-Organization	**$2.74**	**$13.69**	**$32.46**	**$43.94**
Financial Benefits Other CSO Projects	**5-Year**	**10-Year**	**20-Year**	**30-Year**
Staff Reductions - MWM	$1.20	$3.76	$8.27	$11.02
Productivity Improvements MWM	$3.36	$10.50	$23.08	$30.77
Winnipeg Area Facilities Review	$1.20	$2.19	$3.48	$4.18
Total other financial benefits - other projects	**$5.76**	**$16.45**	**$34.83**	**$45.97**
Net Benefits of Combined CSO Initiatives	**$8.50**	**$30.14**	**$67.29**	**$89.91**

Note: Financial impacts do not include the sale of corporate facilities.

Phase I Implementation Update

New Supervisory Structure and Placement of Project Manager

A Project Manager was appointed in April 2008 to manage the implementation of the project. Shortly after, eight new CSC Supervisors were hired to support the new supervisory structure. This was completed by July 2008. The financial benefit using a 30-year NPV was $1.4 million.

Phase II Implementation Update

Introduction of Coordination and Planning Levels

A pilot study was conducted in the Lac du Bonnet CSC from 2007 to 2008 that incorporated the new planning and scheduling processes. The learnings would serve as the business model for the other CSC's throughout the province (rural and urban). These processes were formally documented and used to train staff moving into the newly created positions. It should be noted that no new staff were added during this process. Existing positions were eliminated and converted into the new positions using the newly developed model.

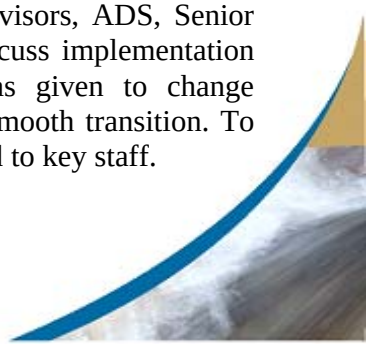
In July 2008, the selection process for the senior CSC planning and scheduling positions began. Each CSC created the following new positions:

- Assistant District Supervisor (ADS)
- Senior Planner
- Estimator Planner
- Senior Administrative and Office Supervisor

An expression of interest process was communicated to all staff within the CSO Divisions for a one year temporary assignment. This enabled employees to familiarize themselves with the new processes and position responsibilities. In the fall of 2009, the positions were formally bid and filled permanently. Senior Administrative Representatives, another key position and part of the CSC leadership team, were in place shortly after. The District Lead position was also created to replace the District Operator positions and filled permanently in the outlying districts to act as a liaison between the local district and the CSC.

The resource scheduler and district work order registry for planning and scheduling was developed as a prelude to Mobile Workforce Management. New role and responsibility training along with on-site mentoring was provided to all CSC's prior to the "go live" date in October 2008. Planning meetings were held with senior management, CSC Supervisors, ADS, Senior Planners, District Leads and Senior Administrative Representatives to discuss implementation and post implementation issues and opportunities. Close attention was given to change management, working with staff and bargaining unit leaders to ensure a smooth transition. To address training gaps, formal training modules were developed and delivered to key staff.

Natural gas processes, organization structure and boundaries did not change.



Independent accounting and reporting systems were implemented for each CSC when the new Supervisor positions were announced in the summer of 2008.

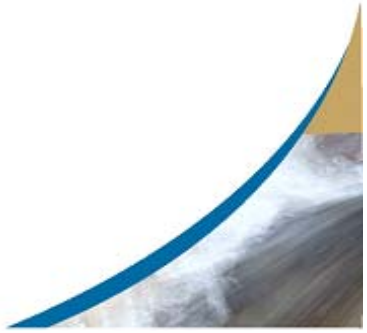
CSC boundary changes for electric customers were implemented in the summer of 2008. These changes were in essence the amalgamation of each district into a CSC utilizing the existing boundaries. Station areas have not moved and remain a component still to be implemented from the original vision.

New stand-by schedules were implemented and a new performance standard of *"80% of customers responded to within one hour"* was established and met.

The re-alignment and relocation of support services (Engineering Technician, Energy Services Advisor and Electrical Inspector) has been limited due to space availability within the CSC offices and low attrition rates.

Facility requirements in each of the CSCs were addressed on an immediate, mid and long term basis to house the new staff moving into each CSC. The immediate needs have been completed, however some mid and most long term requirements remain outstanding.

The intent of Phase I and II of the plan was to create a foundation for the future and was not anticipated to provide significant financial benefits. With the foundation in place, the implementation of Phase III and IV will enable the corporation to achieve additional financial benefits set out in the plan.



Phase III and Phase IV – Concept Validation

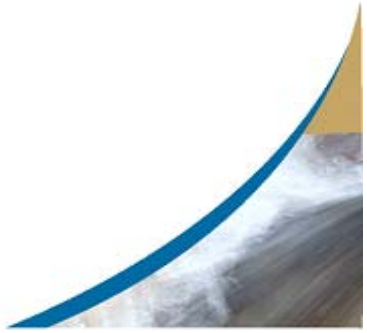
Phase III – Front Office Closures and District Boundary Re-alignment

The focus of Phase III will be the closure of front office services in all rural district offices with the exception of the CSC and satellite offices. CSC and Satellite offices will remain open to customer consultation and continue to accept customer payments.

Cash Handling

With the increase of online and alternative payment bill payment options, there has been a steady decline in the number of customers using in person bill payment methods. In the past nine years, customer traffic in the local district offices had dropped by 13%. On average, less than 8% of the customers in the areas where local district offices are scheduled to close access in person services.

The process of closing front offices should begin immediately with the administrative staff being relocated to the CSC where space is available. The balance of administrative staff could remain in the districts until renovations have been completed in the CSC. The transition of administrative staff to the CSC will have significant impacts and a transition plan will be developed.



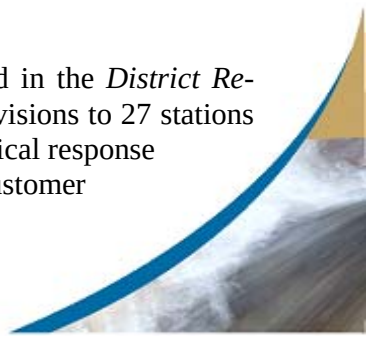
Local District Office Customer Traffic -2012				
District Office	**Percent of Customers making Local Office Bill Payments***		**District Office**	**Percent of Customers making Local Office Bill Payments***
Leaf Rapids District	0.0%		Shoal Lake District	7.6%
Piney District	1.2%		Birtle District	7.6%
Falcon Lake District	1.4%		Minnedosa District	8.0%
St. Martin District	2.9%		Beausejour District	8.1%
St. Pierre District	3.3%		Boissevain District	8.2%
Gimli District	3.6%		Carman District	8.6%
Somerset District	3.7%		Grandview District	9.0%
Treherne District	4.9%		Altona District	9.0%
Powerview District	5.4%		Hamiota District	9.3%
Erickson District	5.6%		Carberry District	9.4%
Morris District	5.7%		Souris District	10.0%
McCreary District	5.7%		Niverville District	10.3%
Elie District	6.1%		Winnipegosis District	12.6%
Glenboro District	6.5%		Gladstone District	13.5%
Lundar District	6.6%		Roblin District	14.5%
Stonewall District	6.6%		Ste. Rose District	16.0%
Pilot Mound District	7.4%		Fisher Branch District	16.1%
Macgregor District	7.5%		Reston District	22.6%
* Includes drop box payments			**Average**	**7.9%**

The higher volumes of customer traffic are a function of credit and collection activities. An increase in credit and collection activities results in greater numbers of customers paying bills in person and making credit arrangements.

To address concerns regarding the loss of the local district office, drop boxes will be set up for a period of six months to ease customers in the transition to alternate bill payment options.

CSC Boundary Revisions

District boundaries will be eliminated and station areas moved as outlined in the *District Re-Organizational Plan (2007)* and detailed in this document. There will be revisions to 27 stations in 13 of the 16 CSCs across the province. During the revision process, electrical response time will be enhanced, station splits between CSCs will be eliminated and customer preferences to access CSC services will be recognized.



Phase IV – Closure of Facilities

The implementation of phase IV will include the closure of the facility and relocation of the remaining staff to the CSC. Again, the completion of this phase is contingent upon the necessary renovations being completed and the infrastructure in place to accept the staff.

Facilities that are suitable for disposal should be sold immediately to recognize the financial benefits.

The timing of complete closures is contingent upon space availability. The implementation plan identifies the facilities that should be closed immediately.

The building closure process mirrors the satellite district concept of 1972 where the number of rural offices was reduced from 115 to 72.

Staffing

The centralization of credit and collections, elimination of cash handling combined with the closure of 36 district offices will reduce the need for 23 administrative positions. The balance of administrative staff positions are adequate to meet today's customer and administrative demands. All new opportunities to reduce further will be considered.

The combined benefits of Mobile Workforce Management and centralization of staff will enable current field staffing levels to meet increased operational requirements

Customer Impact

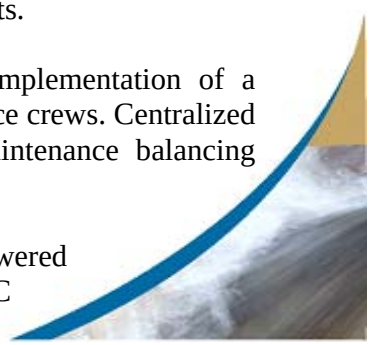
The most noticeable impact to customers will be the closure of the office and access to in person bill payment and account inquiry services. Customers in all communities will have access to alternative bill payment options including:

- On-line or telephone payments
- ePost
- Financial Institutions
- Manitoba Hydro Agents

Electrical outage responses times will be maintained or enhanced through centralized planning of resources and equipment. Since the implementation of Phase I and Phase II in 2008, outage response times have been enhanced and consistently below established targets.

Customers will continue to receive high quality service through the implementation of a comprehensive preventative maintenance program and dedicated maintenance crews. Centralized planning enables staff to manage both new construction and plant maintenance balancing customer needs with reliability.

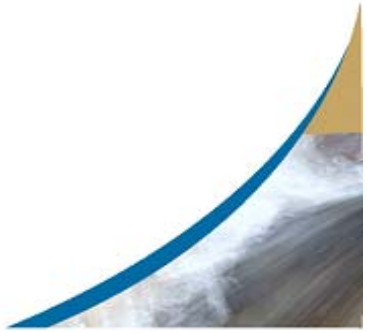
Customer telephone inquiries will be directed to the CSC for service. Unanswered calls will be routed to the Contact Centre and followed-up via email to a CSC delegate. The process ensures the highest level of service is delivered.



The following services have been provided on the Manitoba Hydro website to assist customers with access to services:

- New service applications
- Electrical Permit application
- Move in move out application
- Energy consumption history and rate information
- Meter read entry
- Sign up for equal payment plans or pre-authorized, on line payments
- Power Smart program information
- Street light outage reporting
- Structure move application
- Home and farm safety information

Customers will continue to have access to resident expert services in the CSC and on-site through managed appointments.



Financial Benefits – Customer Service Operations (10-year summary)

Financial Benefits of CSO Initiatives				
	NPV (in millions)			
	5-Year	10-Year	20-Year	30-Year
District Re-Organization	$2.74	$13.69	$32.46	$43.94
Mobile Workforce Management	$4.56	$14.26	$31.35	$41.79
Winnipeg Area Facilities Review	$1.20	$2.19	$3.48	$4.18
Net Benefits of Combined CSO Initiatives	**$8.50**	**$30.14**	**$67.29**	**$89.91**

Financial Impact - Customer Service Operations District Re-Organization Report (2007 and 2012)

Benefits:
Direct financial benefits from all phases of the Customer Service Operations District Re-Organization Reports (2007 and 2012) are estimated to be $43.94 million using a 30-year NPV. (Appendix A)

Financial benefits to be realized through the reduction of senior staff and employee salaries are $18.86 million. The reductions are a result of reducing the number of senior staff positions in phase I and the reduction of administrative positions in phase IV (19 positions).

The closure of facilities will eliminate the need for approximately 28,000 square feet of facility space reducing facility operating costs by $4.46 million. (Appendix A).

The elimination of the cash handling function in the local district offices will reduce costs by $3.67 million and four (4) administrative positions.

The benefit of reducing and eliminating stores material in the 36 local district offices scheduled for closure is $2.4 million. (Appendix F) – one-time financial benefit

Costs:
Providing workspace to accommodate staff moving from the local district offices to the CSC will be $4.51 million (Appendix G). The cost will be spread over a five year period.

The cost to relocate staff above the normal staff movement due to this initiative will be $700,000. (Appendix D)

A comparison of changes in the benefits set out in 2007 and the 2012 report can be found in Appendix C.

Note: The financial calculations are based on a ***30-year NPV*** with the exception of facility renovation and relocation relocation costs which are spread over a five year period.

Other Benefits

The disposal of closed facilities will provide additional financial benefit and reduced operating expenses to the corporation; however without a detailed appraisal and environmental assessment, the value cannot be estimated. The net effect of all of these was considered to have a minimal net benefit to the project.

Customer Service Operations continues to incur costs of $0.7 million annually in support of the Employee Relocation Program. Conservatively, this value could be reduced by 25% or $0.15 million following the implementation of phase IV. (Appendix D)

Financial Benefit Comparison between the 2007 and 2012 Reports

Financial Benefit Comparison

	2012	2007	Comments
District Re-Organization EFT Reduction - includes productivity	44.5	58.2	Difference is attributed to not being able to capture identified productivity savings in Distribution Construction. Customer growth and increased activity do not align with these goals
Financial Benefits - District Re-Organization (includes productivity)	$40.3 million	$37.8 million	Differences in discount rate
Senior Staff Salary Reduction	$1.4 million	$1.25 million	Differences in discount rate
Facility Operating Cost Reductions	$4.46 million	$3.34 million	Differences in discount rate
Fleet Reductions	0	$4.77 million	Fleet structure optimized.
Employee Relocation Cost	($.7 million)	($1.21 million)	Differences in discount rate
Stores Inventory Reduction	$2.41 million	$1.88 million	Differences in discount rate
MWM Financial Benefit from EFT Reduction	$41.8 million	$29.6 million	Differences in discount rate
Elimination of Cash Handling Benefit	$3.7 million	$15.6 million	Only four positions related to cash handling in 2012 due to reduced customer traffic as opposed to 23 in
Total Net Benefit	**$89.9million**	**$93 million**	$3.1 million difference

Note: All financial calculations use a 30-year NPV

See appendix B for additional information.

The financial benefit comparison above highlights changes in positions reduced and the financial impact of change in the discount rates.

Work Process Improvements

The CSC service delivery process will be enhanced with the key customer service resources and supports (Engineering Technician, Energy Services Coordinator and Electrical Inspector) in a single location.

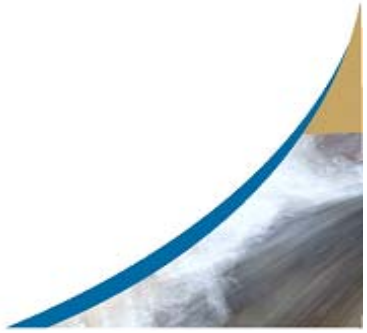
Productivity will increase with greater access to resources. Resource requirements will be matched to job requirements, creating greater efficiencies.

A larger pool of centralized resources will enable the CSC leaders to dedicate maintenance crews to plant maintenance.

The combined benefits of Mobile Workforce Management and centralization of resources will create a flexible workforce able to respond to the highest priorities.

Centralization of the administrative staff to the CSC will increase productivity and balance work volumes.

Administrative staff will be afforded job enrichment and the opportunity to become more proficient in their roles as centralization enables specialization.



Employee Benefit

Employees will continue to be provided a safe work environment with some enhancements. The larger pool of staff will reduce working alone situations. At the same time, there will be greater access to equipment (aerial devices and diggers) enhancing the restoration of electric service.

Having staff in one location creates an environment that facilitates quality communication and more employee/supervisor interaction. Junior staff will have the ability to be mentored by highly skilled senior staff.

Employees will have increased job opportunities due to the establishment of diverse job functions.

Staff will have the opportunities to reside in larger communities with a greater number of amenities, opportunities for spousal employment and quality education.

Reduced call rotations will provide staff with greater leisure time.

With the larger pool of administrative staff, job enrichment will be provided through rotational training opportunities

Overall Risk Assessment

Status Quo

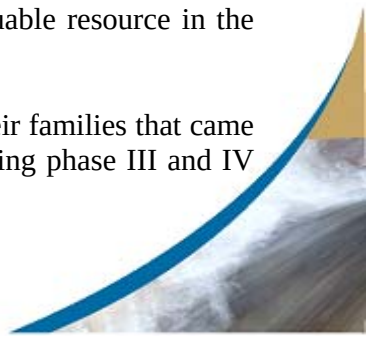
A status quo approach has the greatest risk. The impacts of Mobile Workforce Management, centralized collections, customer preferences and the movement toward centralization are going to have a significant effect on our business. In the absence of a vision for the future, Customer Service Operations will not achieve its goals.

A fully centralized workforce provides the flexibility to match work demands with resources generating operational efficiencies. The inefficiencies of a de-centralized workforce holds true for both administrative and field functions within a CSC.

The full benefit of Mobile Workforce Management is contingent upon a fully centralized workforce. Moving away from centralization erodes the benefits significantly.

With the implementation of Mobile Workforce Management, centralized collections and the elimination of cash handling, administrative work volumes will continue to decline and the corporation will be unable to provide value-added work – stranding a valuable resource in the districts.

The implementation of phases I and II offered benefits to employees and their families that came with residing and working in the larger centres. The risk of not implementing phase III and IV will hinder further advancement.

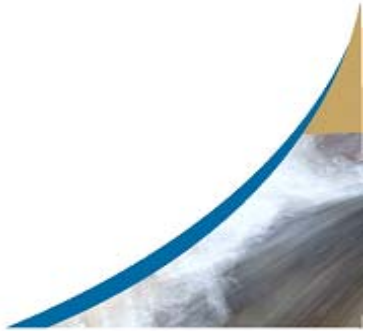


Full Implementation

With full implementation of phase III and IV, the corporation could lose experienced and trained staff who are unable or unwilling to relocate to the CSC.

Community and customer concerns will be significant. To a lesser extent, the closure of a facility will be seen as a loss of services for the community and customers. Of greater significance to the community will be the loss of employees from their communities. Manitoba Hydro employees are recognized as key members of a community.

The implementation of phase III and IV provides significant benefits and risks that can be managed throughout the process.



Implementation Plan

The schedule below outlines facilities that will be fully closed and staff relocated to the CSC immediately. District offices identified as Immediate Closure will only have the front offices closed while renovations are being completed in the CSC. Front office services (including cash payments) would only be maintained in the CSC and Satellite offices.

Facility Closures

Immediate Closure – Full	Immediate Closure – Front Office
Reston	St. Pierre
Leaf Rapids	Gimli
Somerset	Fisher Branch
Carman	Lundar
Morris	Treherne
Niverville	Stonewall
Piney	Grandview
Falcon Lake	Ste. Rose
St Martin	Gladstone
Elie	Altona
Macgregor	Birtle
McCreary	Roblin
Winnipegosis	Shoal Lake
Erickson	Souris
Carberry	Boissevain
	Glenboro
	Pilot Mound
	Hamiota
	Minnedosa
	Beausejour
	Powerview

Satellite Offices

Berens River	**Grand Rapids**	**Gillam**
Island Lake	**Churchill**	**Gods Lake Narrows**
Norway House	**Lynn Lake**	**Flin Flon**
Snow Lake	**Melita**	**Cross Lake**

The closure of all districts identified will occur over a period of three years.

Station Area Re-assignment

The re-assignment of station areas will require a significant amount of pre-work and preparation. The movement of customers and plant from one CSC to another impacts many computer databases (Banner, GIS systems, SAP and Mobile Workforce Management).

Final customer counts and the amount of plant movement will shift workload and require a post transition analysis to ensure equity in staffing levels.

CSC Transitional Plan

Managing the final phases of this project will have far reaching impacts on corporate databases, facilities, employees, communities and communities. To effectively manage all aspects of this project, each CSC will have a transitional plan outlining all aspects of implementation, issues and concerns along with actions to ensure the transition to the CSC is managed in a consistent and effective manner.

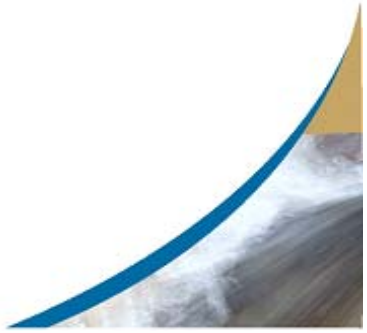
Barriers to Implementation

Employee Impact

The immediate closure of rural district offices and the expectation of commuting or relocation to a new work location will have a significant impact on the employees who are employed there. The administrative employee group will be most affected by office closures. The administrative employees are typically second income family members who are less mobile and unable to relocate or commute to a new work location. There are approximately 41 district administrative staff who may be expected to travel on average 46 additional kilometres daily to their new work locations.

The impact on field employees will be lessened due to the mobility of this work group and the use of mobile computers. Field staff are typically assigned or have access to a corporate vehicle to commute to alternate work locations.

The loss of employee status within the community and peers will be a barrier to employee buy-in and support for the implementation of Phase III and IV. During the implementation of Phase I and II, employees who moved into District Lead roles from District Operators felt a loss of status and identity during the transition. As the District Lead position is phased out and transitioned into another lead role, again there will another loss of identity and status.



CSC Renovations
The ability for the CSCs to accept additional staff from the districts is very limited. As a result, many of the CSCs will need to be renovated or have additional facilities constructed to accommodate the staff and vehicles. (Appendix C)

CSC renovations will cost the corporation $4.51 million spread over a five year period. Financial benefits of this initiative will cover renovation costs and have been factored into the NPV calculations. (Appendix G)

Community Concerns
Manitoba Hydro has always maintained a strong presence in rural Manitoba. This is attributed to the quality of employees and the corporation's commitment to community support. As a result, the loss or closure of a facility will be seen as a major loss to any community.

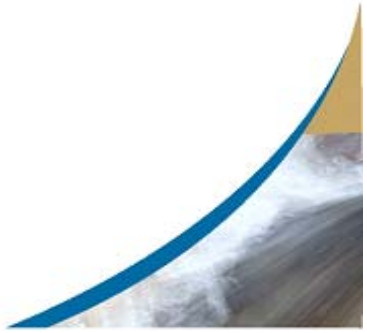
A strong communication plan will be required to gain any level of acceptance prior to the closure. A structured approach to closure will be required to ensure community and political concerns do not interfere with the process.

Pre-closure Activities

Front Office Services
The process to close front office services should begin three months prior to actual closure date. The communication process will include both internal and external stakeholders with a focus on employee and municipal government officials. (Appendix E)

In anticipation of office closures, the process of transitioning customers to alternative payment methods should begin immediately. Communication to customers will include information on alternate payment options and online services available.

Customers who have made three or more payments at the local district office in the past 18 months will receive a letter advising of the impending closure date. Contractors who obtained an electrical permit at the district office in the past 18 months will receive a letter advising that the office will be closed and the alternatives available.



CSC renovations to accept additional staff
The greatest barrier to full facility closure will be the CSCs ability to accommodate the additional staff. Eleven of the sixteen CSCs will require some renovation and the addition of supporting infrastructure to accept any staff. Approval of the final two phases must be followed by an analysis of the facility upgrades and timing. The process to renovate the facilities should be completed within a three year period. Appendix G outlines facility renovation costs.

The priority will be to relocate support staff and administrative staff to the CSC followed by the field staff.

An interim step to moving staff to the CSC would be to relocate staff to an alternate district office within the CSC while renovations and facility upgrades are being completed.

Staffing Considerations
Throughout the facility closure process, consideration should be given to the residency needs and the travel distances associated with relocation. The administrative staff group will be most sensitive to the relocation process and will require ongoing consultation to ease the transition.

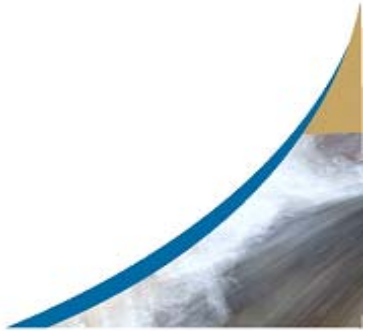
Materials
During the closure process, the storekeeping staff will be required to develop min/max levels for materials. Using the stock turnover reports, optimum stock levels will be identified and transferred to the CSC with the balances returned to central stores.

When the facility is closed, there should be no material stored at the local districts.

Communication Notifications
Communication notifications will include bill inserts, letters, office posters and presentations to key stakeholders.

A detailed communication plan has been developed and proven effective with past closures.

The communication process will begin three months prior to the facility closure.



Communication Plan

Internal Communication

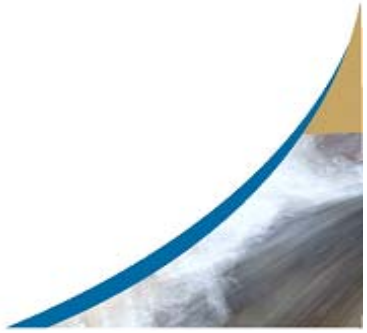
- A communication from the Vice-President to the staff
- Bargaining Units
- Staff communication at the CSC level
    - MPower
    - Presentation
- Other internal stakeholders

External Communication

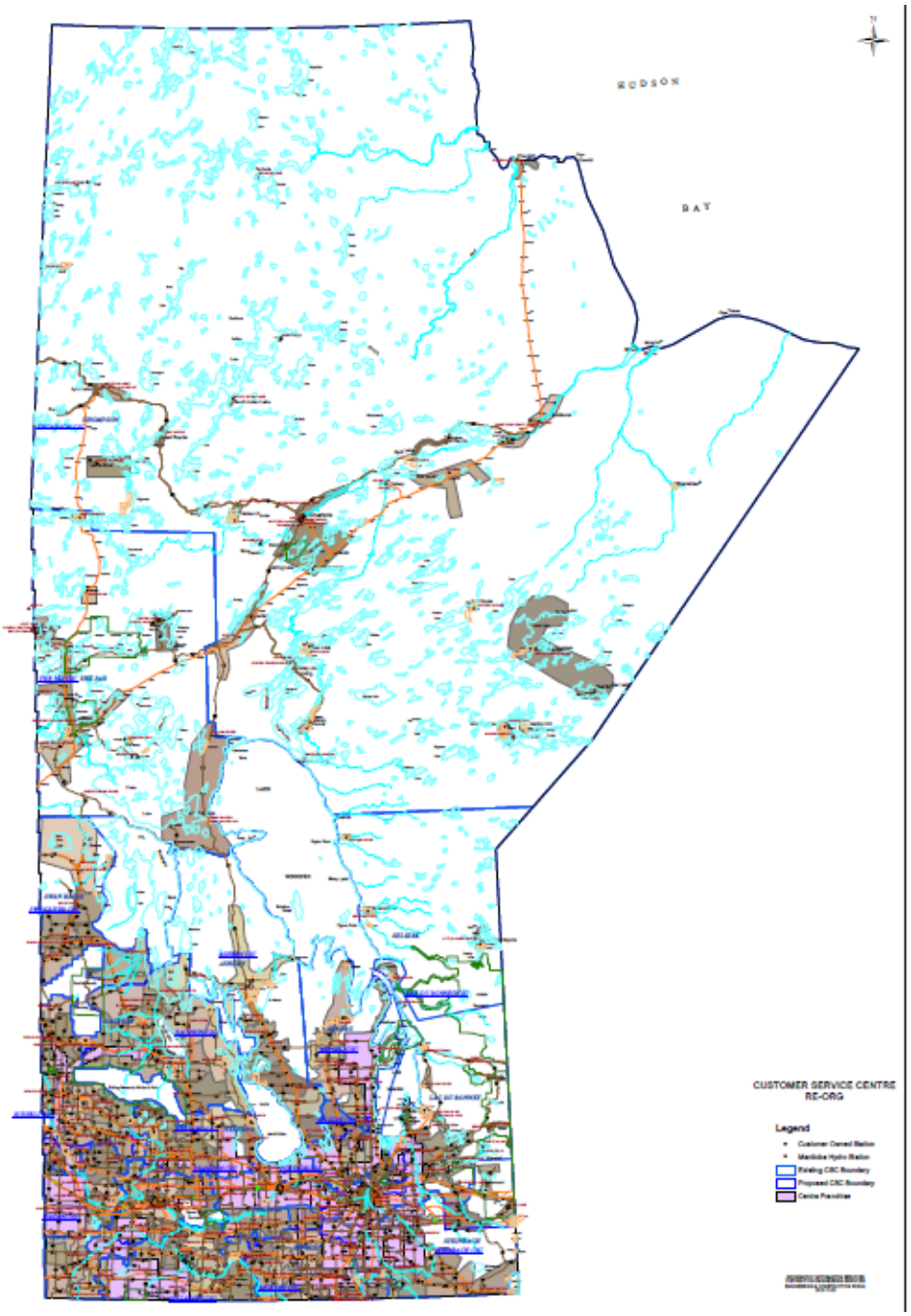
- Presentations to Municipal Officials (Association of Manitoba Municipalities)
- Letters to customers and contractors
- Media as required
- Other Utilities
- Other Government agencies
- Emergency Measures Organization
- Payment alternative promotions
- On-site posters
- Energy Matters
- Press Release

District Office Closure Checklist

See Appendix E



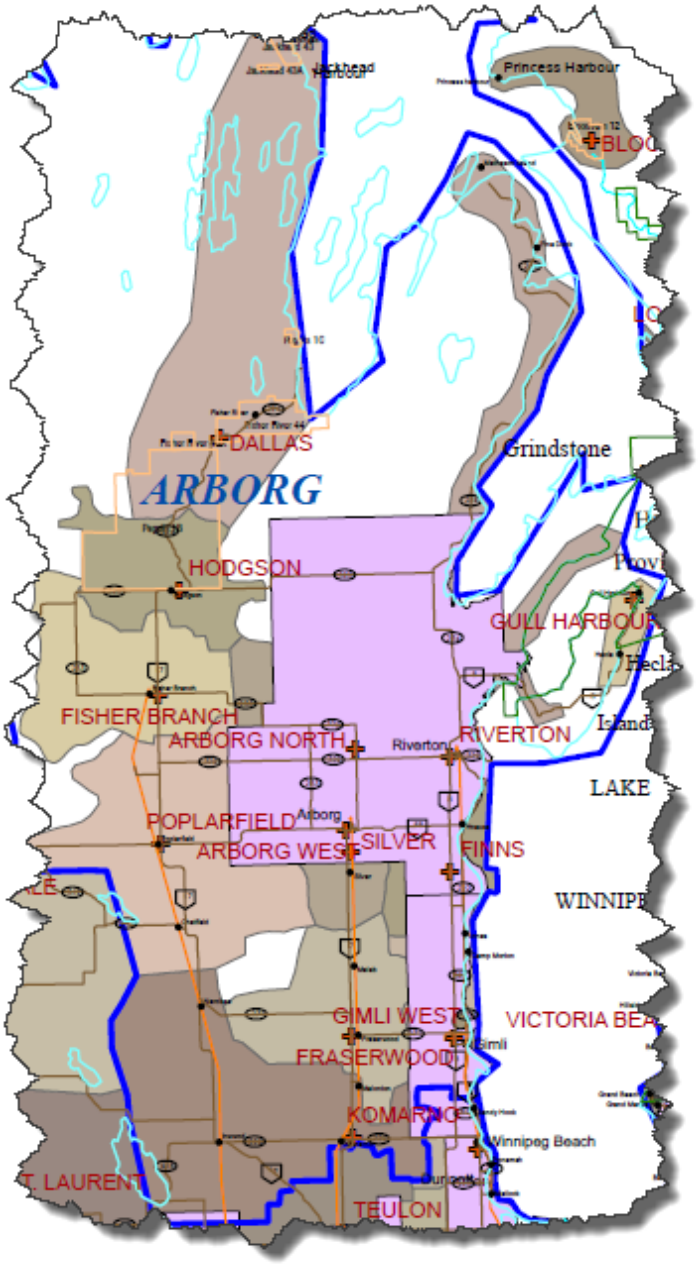
Provincial Customer Service Centre Overview



CSC Profiles

Arborg CSC

The Arborg CSC consists of the former Arborg, Fisher Branch and Gimli districts. The CSC has a customer base of 19,635 customers and 2,916 km of electrical distribution.



Profile Revisions

Winnipeg Beach Station Area

The Winnipeg Beach station area will be moved to the Selkirk CSC. The move will enable faster electrical outage response times and recognize customer preferences to access services of the Selkirk CSC. The impact of this revision is the transfer of 3,927 customers and 189 km of electrical distribution to the Selkirk CSC.

Komarno Station Area

A portion of the Komarno station area currently resides within the Arborg CSC with the balance in the Selkirk CSC. The entire station area will be moved to Arborg to improve response times. The impact of this move is the transfer of approximately 406 customers and 325 km of electrical distribution to the Arborg CSC from the Selkirk CSC.

Bloodvein Station Area

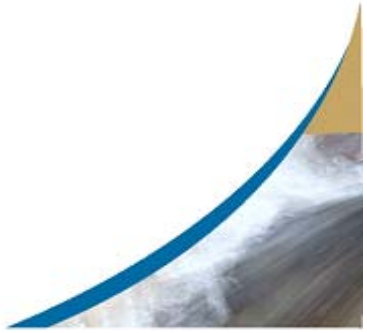
The Bloodvein station area is serviced by the Arborg CSC staff as a fly-in operation from St Andrews or Winnipeg airports in the summer months. During winter, the ice road from Pine Dock can be used to access Bloodvein. The customers and distribution will be transferred to the Lac du Bonnet CSC. The move of this station will align the station source (66 kV) with the CSC. Operational agreements between the Lac du Bonnet CSC and the Arborg CSC for outage response will be developed to ensure current levels of customer service are maintained. The impact of this revision is the movement of 197 customers and 46 km of distribution line to the Lac du Bonnet CSC.

Revised Profile

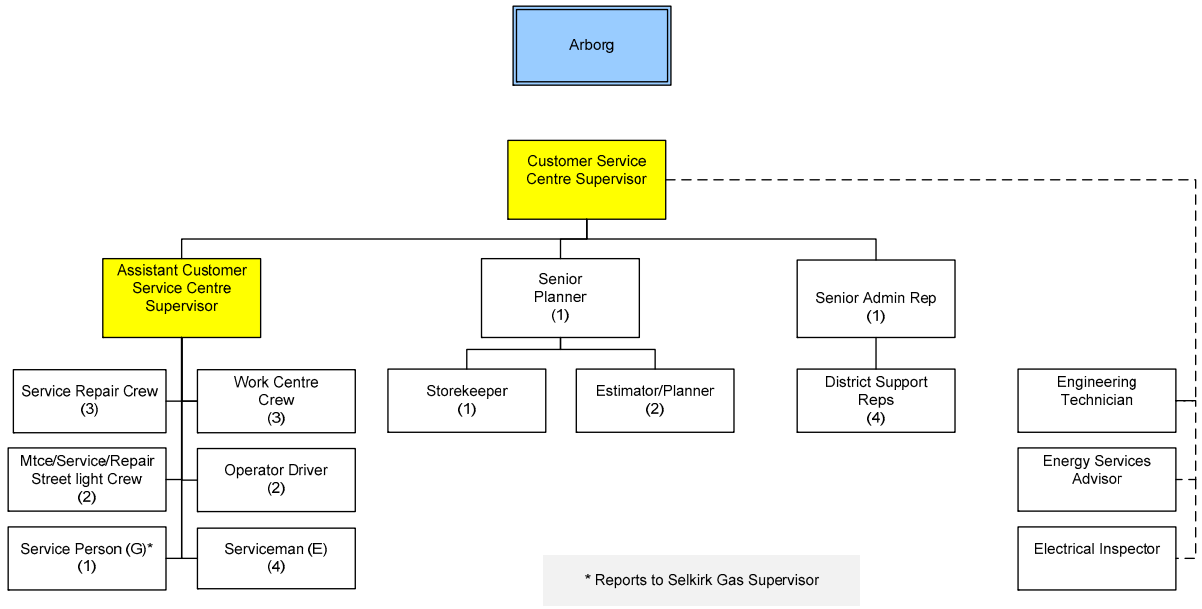
The revised profile has a customer base of 13,917 customers (reduction of 3,718) and electrical distribution of 3,006 km (reduction of 90 km).

Employees

Staffing levels will be the combined resources of Arborg, Gimli and Fisher Branch. Support positions (Energy Services Coordinator, Engineering Tech and Electrical Inspector) will be required to relocate to Arborg, however due to space constraints; the relocations have not taken place.



Organizational Structure



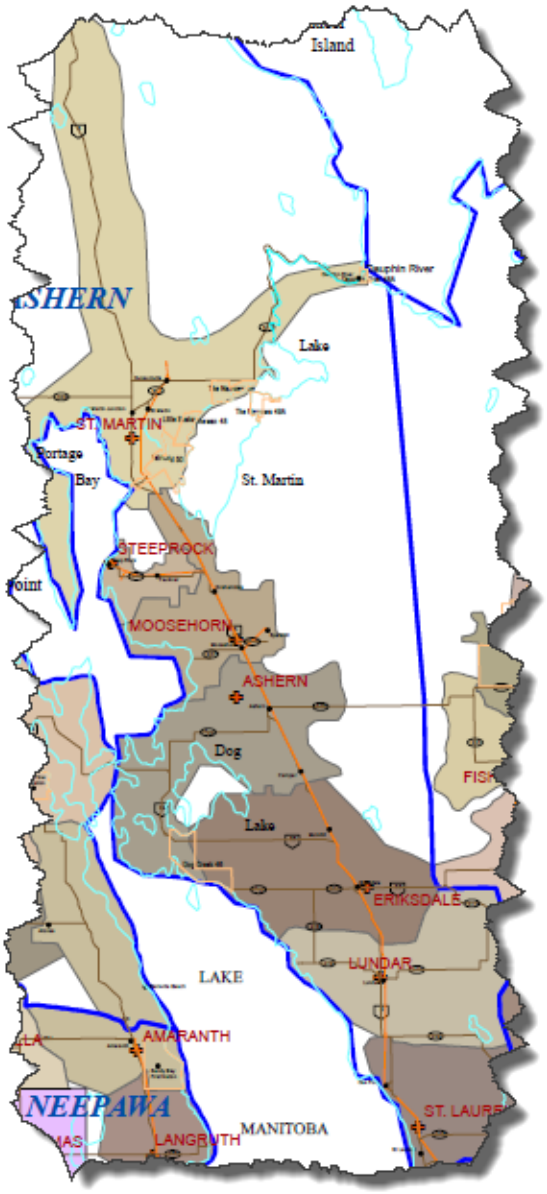
Facilities

The Arborg CSC building will require major renovations to accommodate the 16 additional positions being relocation from Gimli and Fisher Branch. The positions include:

- Field staff– 8
- Administrative staff – 4
- Energy Services Advisor – 1
- Electrical Inspector – 1
- Engineering Technician – 1
- Gas Service Person - 1

Ashern CSC

The Ashern CSC consists of the former Ashern, Lundar and St. Martin districts. The Ashern CSC has a customer base of 5,813 customers and 2,399 km of electrical distribution.



Profile Revisions

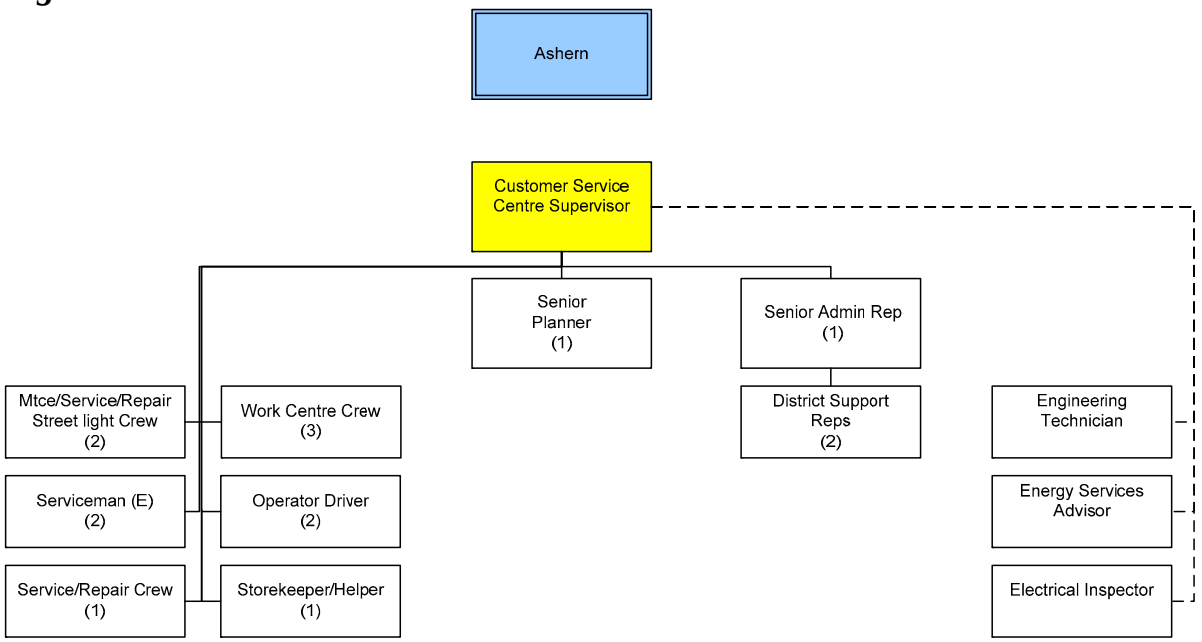
There are no revisions to the stations in the Ashern CSC.

Employees

Staffing levels will be the combined resources of Ashern, Lundar and St. Martin. Ashern CSC has a modified structure due to the smaller customer base. The assistant district supervisor (ADS) duties and storekeeping duties are shared with other staff duties. Support staff (Energy Services Coordinator, Engineering Technician and Electrical Inspector) from the Arborg CSC will support the Ashern CSC.

The relocation of the Digger crew to Ashern from Lundar will be required.

Organizational Structure



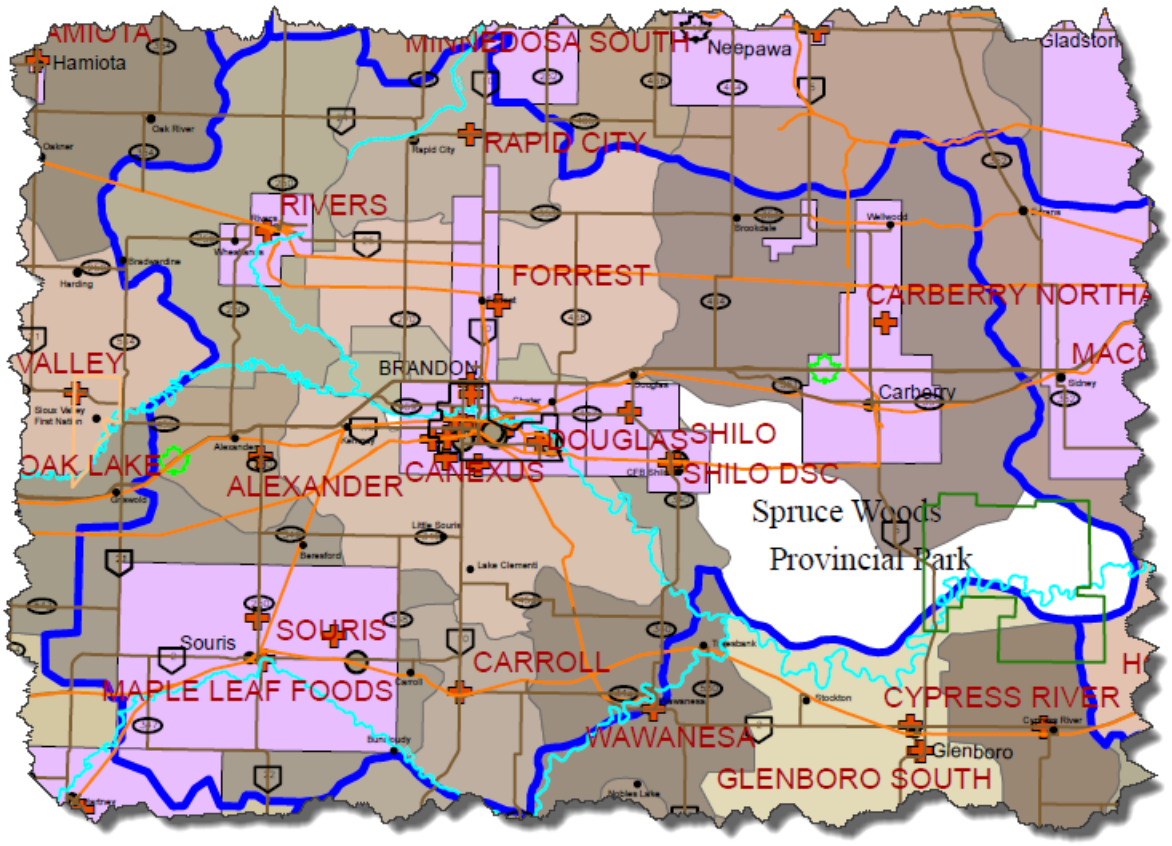
Facilities

The Ashern CSC building is inadequate to accommodate additional staff and is scheduled to be replaced in the fall of 2013. The positions include:

- Field staff– 7
- Administrative staff – 2
- Energy Services Advisor (workstation only) – 1
- Electrical Inspector (workstation only) – 1
- Engineering Technician (workstation only) – 1

Brandon CSC

The Brandon CSC consists of the Brandon, Souris and Carberry districts. The CSC has a customer base of 44,279 natural gas and electric customers and 2,719 km of electrical distribution.



Profile Revisions

Rapid City Station Area

The Rapid City station area will be re-assigned to the Brandon CSC from the Neepawa CSC. The move will enable faster electrical outage response times and recognize customer preferences to use the services of the Brandon CSC. The impact of this revision is the addition of 449 customers and 90 km of electrical distribution to the Brandon CSC.

Hartney Station Area

The Hartney station area currently resides within the Bandon CSC and will be re-assigned to the Virden CSC. The impact of this move is the transfer of approximately 657 customers and 454 km of electrical distribution to the Virden CSC.

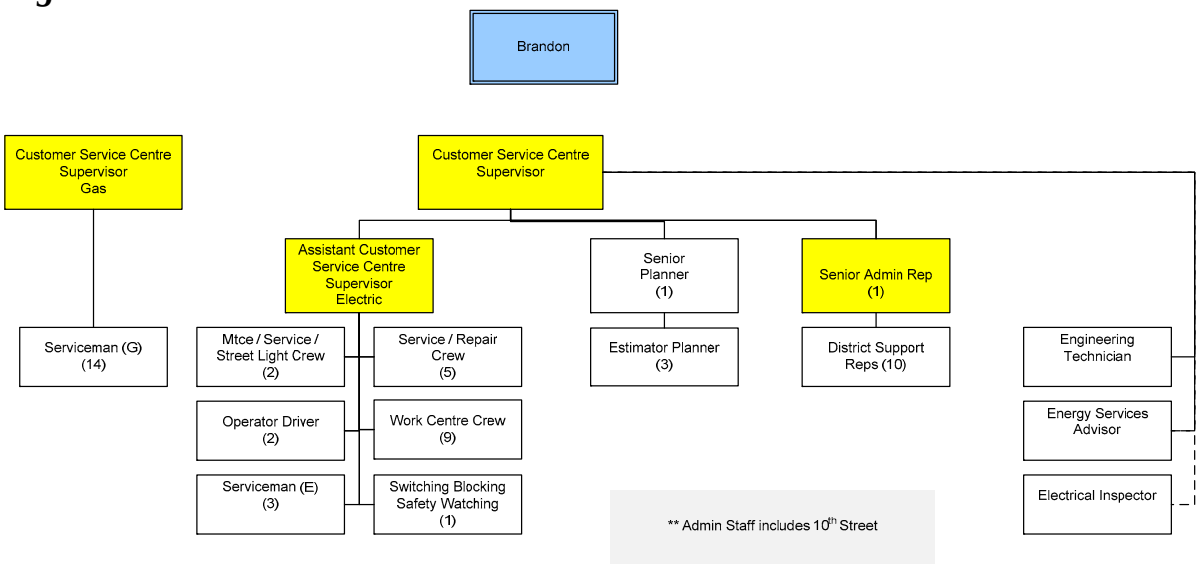
Revised Profile

The revised profile has a customer base of 44,071 customers (reduction of 208) and electrical distribution of 2,719 km (reduction of 364 km).

Employees

Staffing levels will be the combined resources of the Brandon, Souris and Carberry. The Brandon CSC has the core positions established and in place. Material Management functions are the responsibility of Satellite Stores, eliminating the need for a storekeeper.

Organization Structure



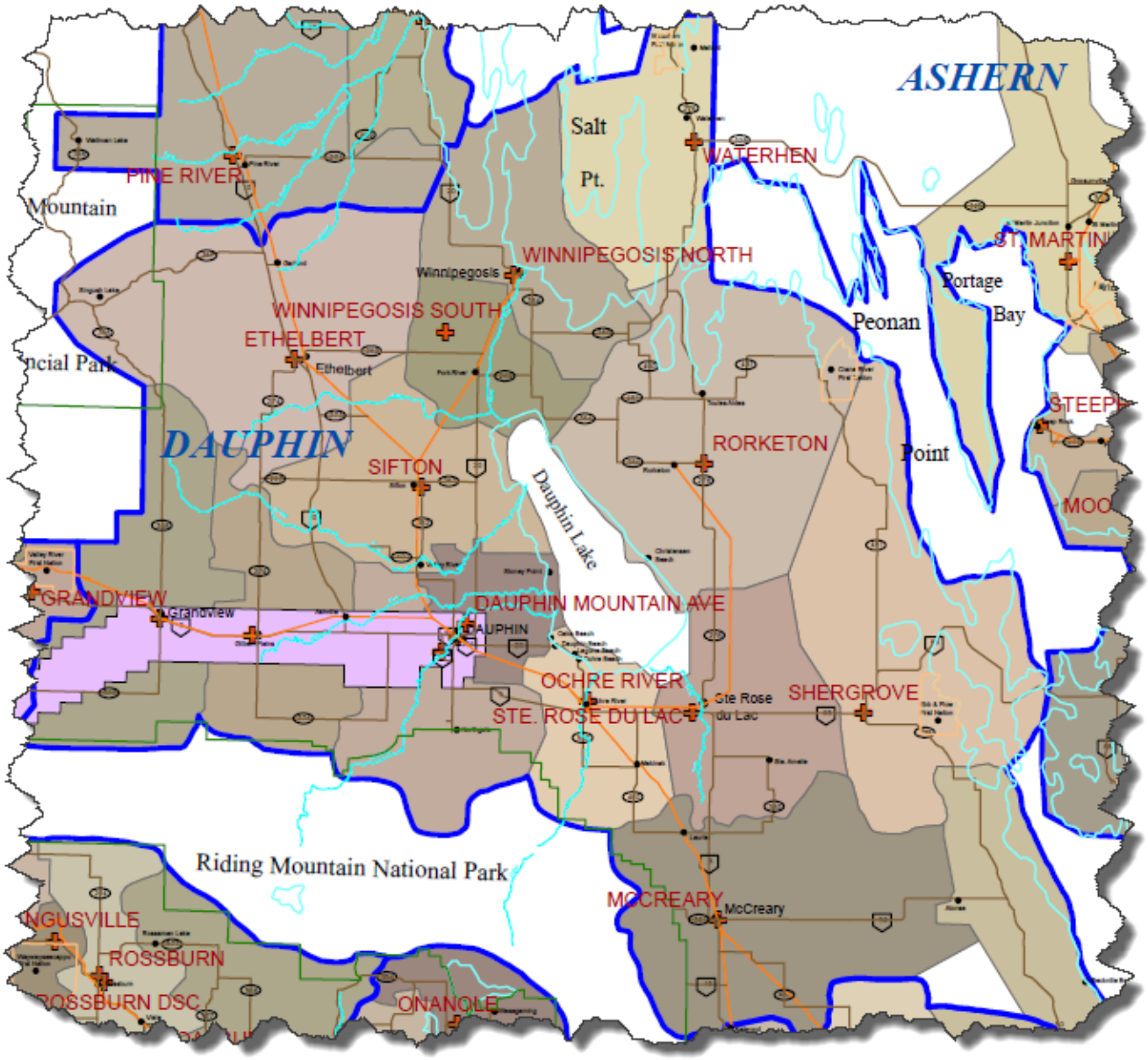
Facilities

The Brandon CSC building will require significant renovations to accommodate the nine additional positions being relocation from Brandon 10th Street, Souris and Carberry. The positions include:

- Field staff– 2
- Administrative staff – 7

Dauphin CSC

The Dauphin CSC consists of Dauphin, Ste. Rose, McCreary, Grandview and Winnipegosis districts. The Dauphin CSC has a customer base of 17,511 customers and 4,173 km of electrical distribution.



Profile Revisions

Camperville and Pine River Station Areas

The Camperville station area will be re-assigned to the Swan River CSC to optimize electrical outage response and customer service. The impact of the re-assignments will be the loss of 1,067 customers and 442 km of electrical distribution.

Shortdale Station Area

The Shortdale station area will be re-assigned to the Russell CSC. The impact of this re-assignment will be a loss of 209 customers and 118 km of electrical distribution.

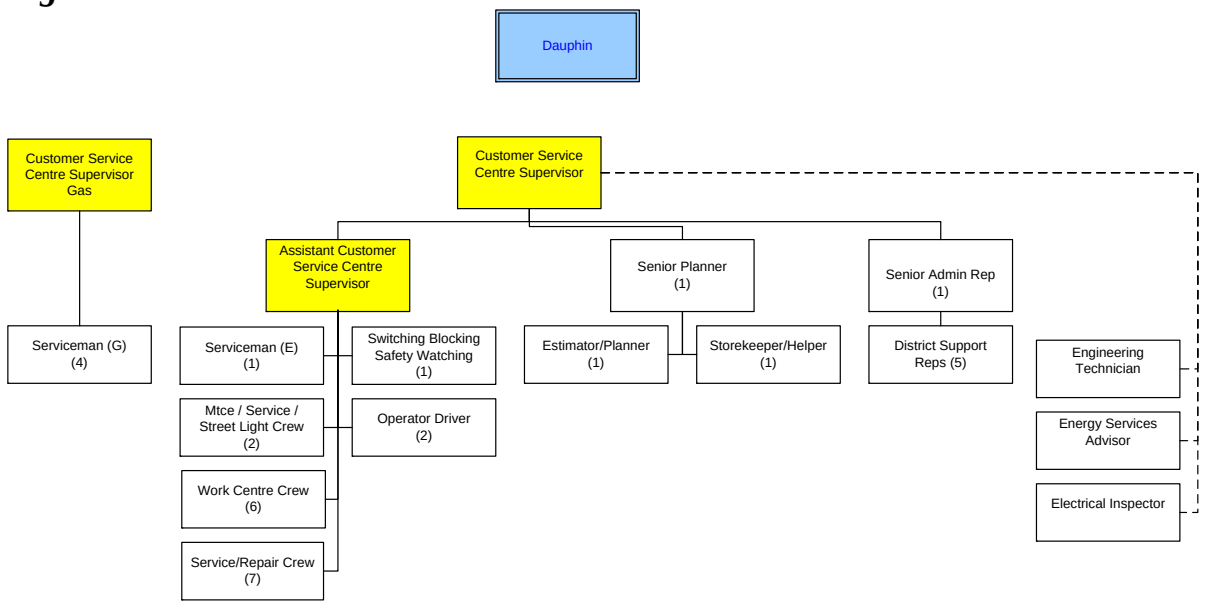
Revised Profile

The net result of the station re-assignments is a net loss of 1,276 customers and 560 km of electrical distribution. The revised profile for the Dauphin CSC is 16,235 customers and 3,613 km of electrical distribution.

Employees

Staffing levels will be the combined resources of the five districts. The Dauphin CSC has the core positions established and in place.

Organization Structure



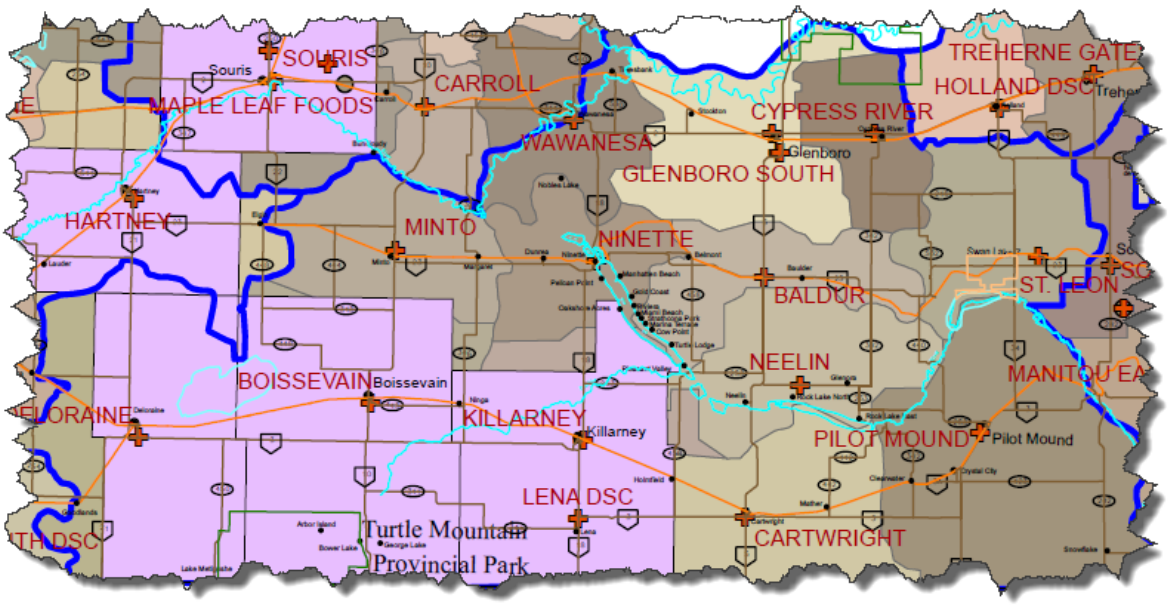
Facilities

The Dauphin CSC building will require major renovations to accommodate the 14 additional positions being relocation. The positions include:

- Field staff– 10
- Administrative staff – 4

Killarney CSC

The Killarney CSC combines the Killarney, Glenboro, Pilot Mound and Boissevain districts. The CSC has 10,506 customers and 4,135 km of distribution line.



Profile Revisions

Swan Lake Station Area

To improve customer service and electrical outage response, the Swan Lake station will be re-assigned to the Killarney CSC from the Morden CSC. The net impact of re-assigning this station is the addition of 704 customers and 341 km of distribution line.

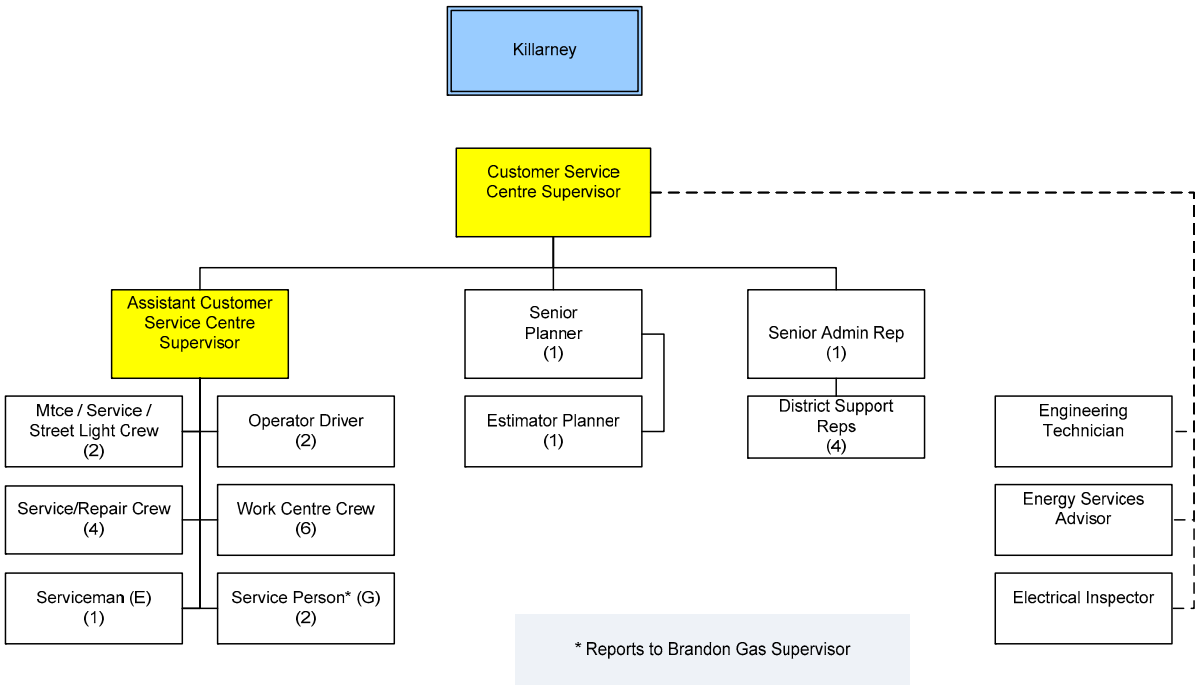
Revised Profile

The revised Killarney CSC profile is a customer base of 11,210 customers (increase of 704) and 4,476 km of electrical distribution (increase of 341).

Employees

The Killarney CSC staff compliment combines the employees of the four districts.

Organization Structure

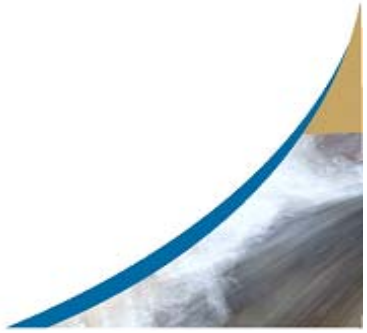


Facilities

The Killarney CSC building will require major renovations to accommodate the 11 additional positions being relocation. The positions include:

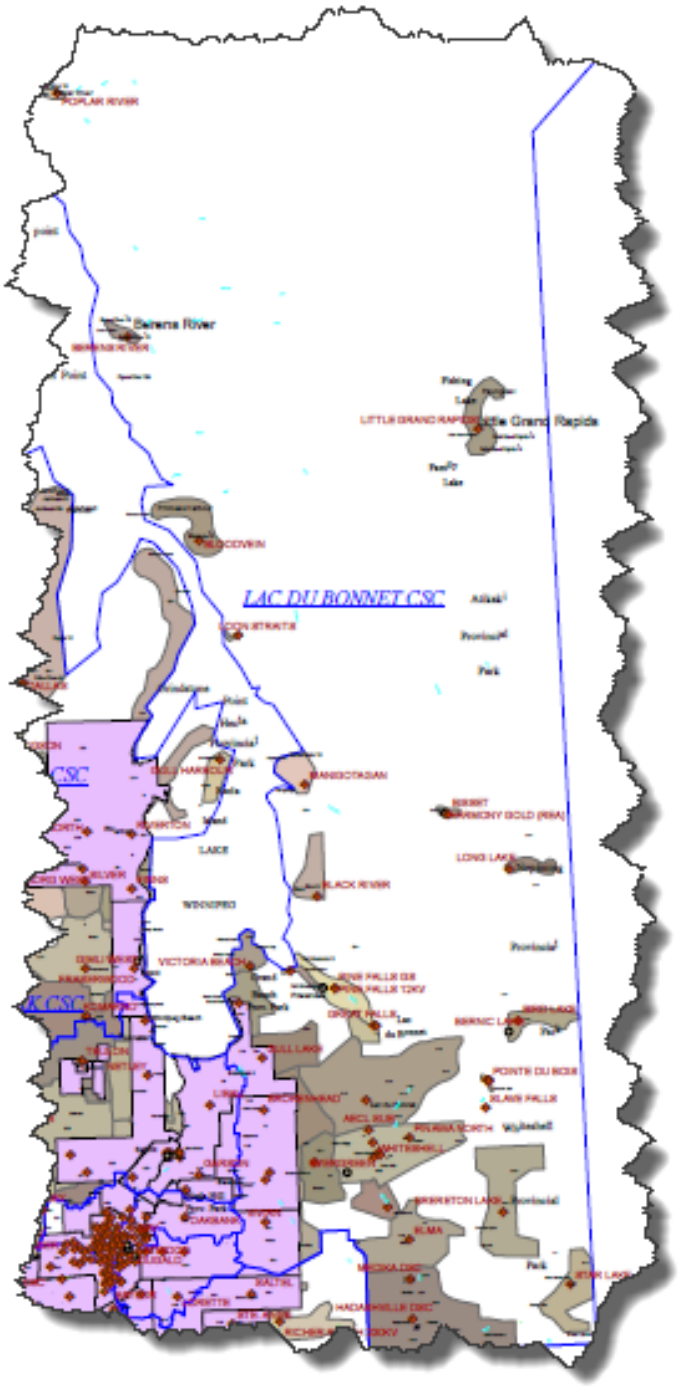
- Field staff– 8
- Administrative staff – 3

Staff movement to the Killarney CSC office cannot occur until renovations are completed to accommodate the staff.



Lac du Bonnet CSC

The Lac du Bonnet CSC combines the Lac du Bonnet, Powerview, Grand Beach and Beausejour. The CSC has a customer base of 25,383 and 2,629 km of electric distribution.



Profile Revisions

Garson and Libau Station Areas

The Garston and Libau station areas will be re-assigned from the Lac du Bonnet CSC to the Selkirk CSC. The movement of this station area results in a loss of 1,874 customers and 467 km of electrical distribution.

Bloodvein Station Area

The Bloodvein station area is serviced by the Arborg CSC staff as a fly-in operation from St Andrews or Winnipeg airports in the summer months. During winter, the ice road from Pine Dock can be used to access Bloodvein. The customers and distribution will be transferred to the Lac du Bonnet CSC. The move of this station will align the station source (66 kV) with the CSC. Operational agreements between the Lac du Bonnet CSC and the Arborg CSC for outage response will be developed to ensure current levels of customer service are maintained. The impact of this revision is the movement of 197 customers and 46 km of distribution line to the Lac du Bonnet CSC.

Berens River Satellite District

The entire Berens River Satellite District will be re-assigned to the Lac du Bonnet CSC. This includes the Berens River, Little Grand Rapids and Poplar River station areas. The result is the addition of 952 customers and 105 km of electric distribution.

Moving the station areas on the east side of Lake Winnipeg aligns the customers with the 66kV source out of the Lac du Bonnet CSC. The station re-assignment also eliminates the coordination between three CSC's when an electrical outage occurs.

While the majority of the travel in the Berens River areas is via aircraft, construction of an all-weather road is being completed that will link the communities in years to come. The nearest access to the all-weather road is from the Lac du Bonnet CSC.

Falcon Lake District

To optimize customer service and electrical outage response time, Falcon Lake District in its entirety will be re-assigned to the Lac du Bonnet CSC. Included in this re-assignment is the Hadashville/Medika DSC, Star Lake station and Brereton Lake station areas. Increases of 3,505 customers and 464 km of electric distribution will be added to the Lac du Bonnet CSC.

Revised Profile

The net impact of the station relocations is an increase of the Lac du Bonnet's customer base by 2,974 customers and 194 km of electric distribution. The revised profile is 28,357 customers and 2,823 km of electric distribution.

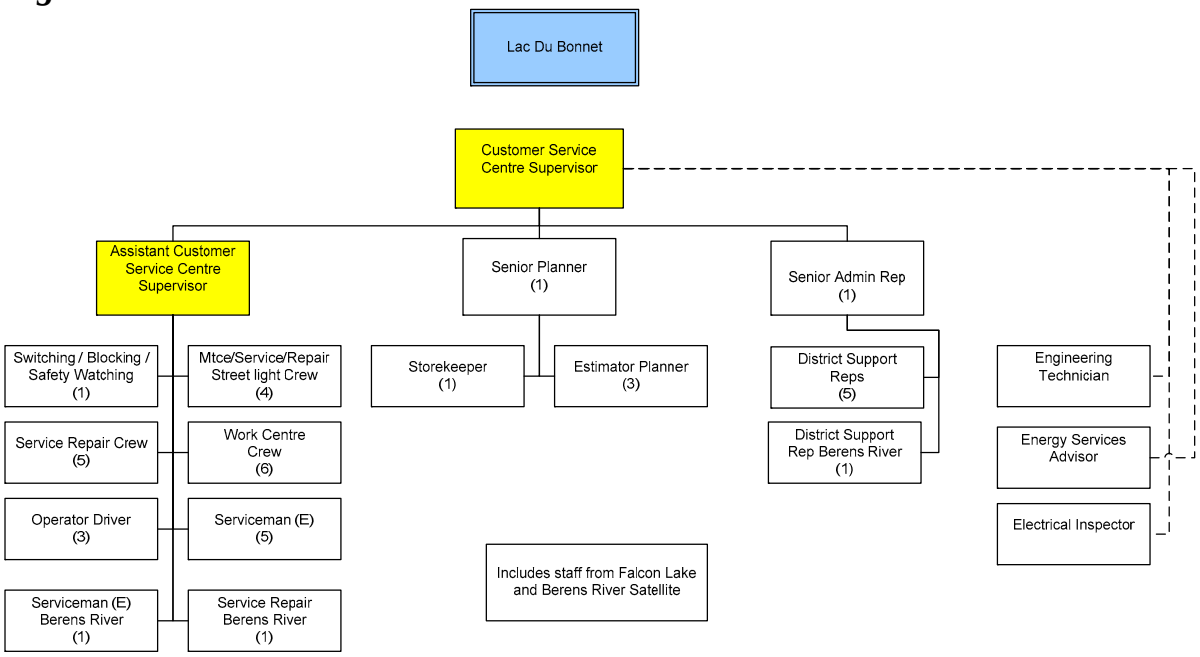
Employees

The Lac du Bonnet CSC has the combined resources of the four districts and the staff from Berens River and Falcon Lake districts. There will be a requirement to relocate support positions (Electrical Inspector and Energy Services Advisor) from Beausejour to the Lac du Bonnet CSC.

Berens River will continue to accept cash payments due to the remote nature of the area.

The station re-assignment process will not require the need to relocate any positions.

Organization Structure



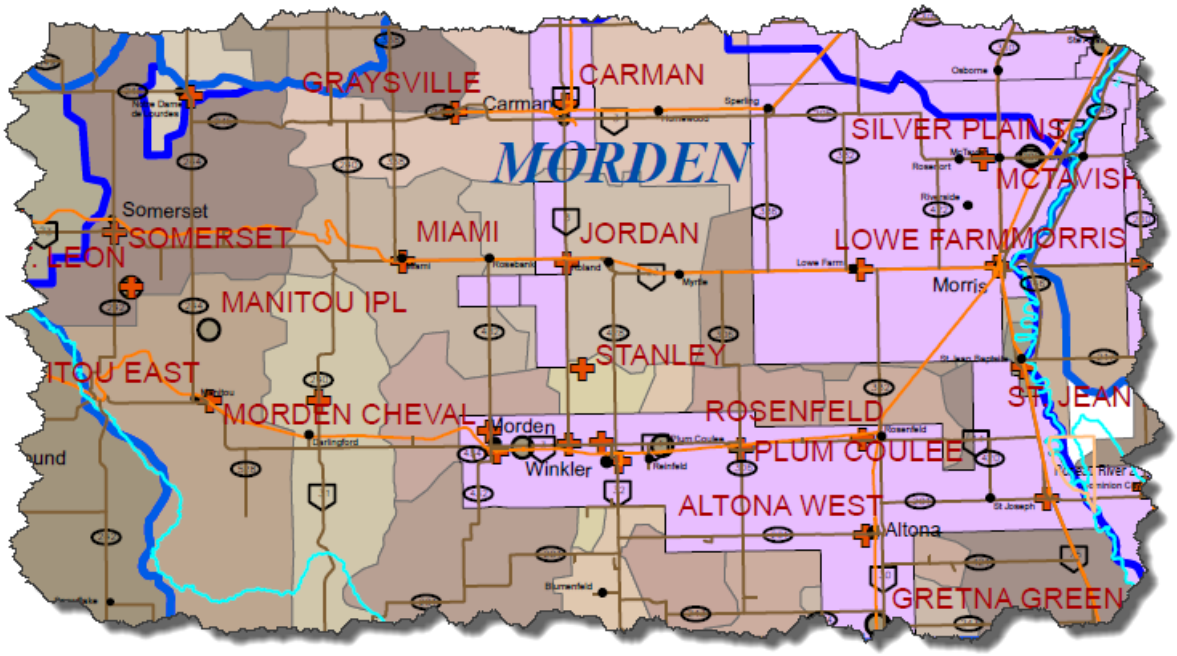
Facilities

The Lac du Bonnet will require major renovations to accommodate the additional staff from the closed districts and Falcon Lake. The positions include:

- Field staff – 11
- Administrative staff – 5
- Electrical Inspector – 1
- Energy Services Advisor – 1

Morden CSC

The Morden CSC combines Morden, Winkler, Carman, Somerset, Altona and Morris districts. There are 34,195 customers and 4,431 km of electric distribution in the CSC.



Profile Revisions

Elm Creek and Notre Dame de Lourdes Station Areas

The 1,005 customers and 526 km from the two station areas will be re-assigned to the Portage la Prairie CSC from the Morden CSC. The move will closer align the natural gas boundaries and improve electrical outage response.

Swan Lake Station Area

The Swan Lake station area will be re-assigned to the Killarney CSC to improve electrical response time and customer service. There are 704 customers and 341 km of electric distribution.

Dominion City Station Area

To improve accessibility, electrical outage response and customer service, the Dominion City station area will be re-assigned to the Steinbach CSC. The station re-assignment will move 620 customers and 288 km of electric distribution line.

Ste. Agathe and Sanford Station Areas

The Ste. Agathe and Sanford station areas will be re-assigned to the Fort Garry CSC from the Morden CSC. The net impact is the movement of 1,161 customers and 502 km of electric distribution.

Revised Profile

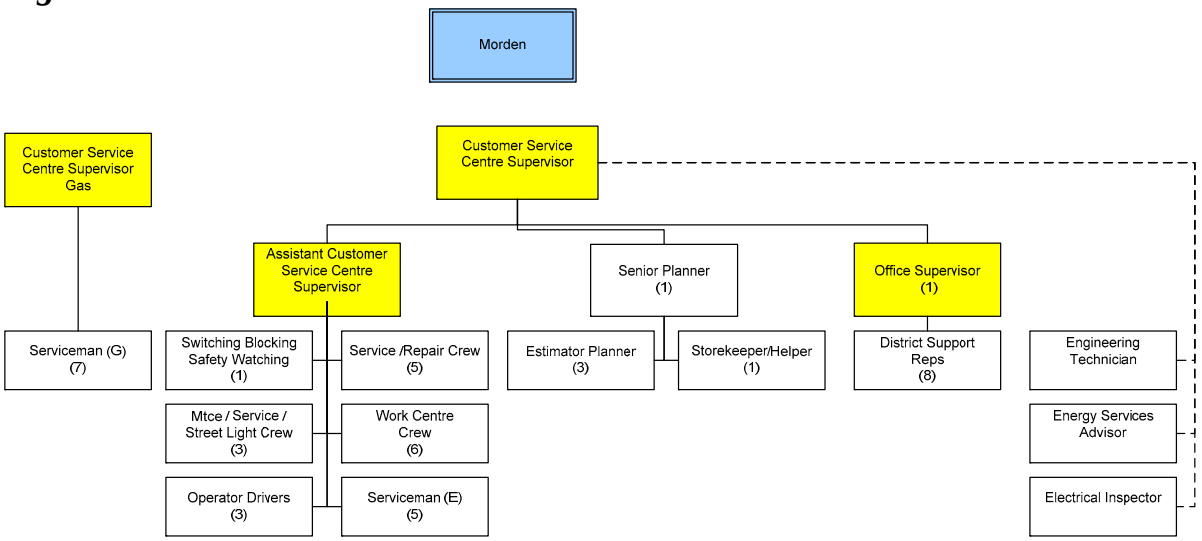
The net impact of re-assigning the six station areas is a net loss of 3,490 customers and 1,657 km of electric distribution from the Morden CSC. The revised profile for the Morden CSC has 30,705 customers and 2,774 km of electric distribution.

Employees

The Morden CSC will be the combined staff of the former districts of Morris, Winkler, Carman, Altona, Somerset and Morden.

Given the movement of customers and plant to the Steinbach CSC and Winnipeg West CSC, two positions will be relocated – one to the Fort Garry CSC and a second to the Steinbach CSC.

Organization Structure



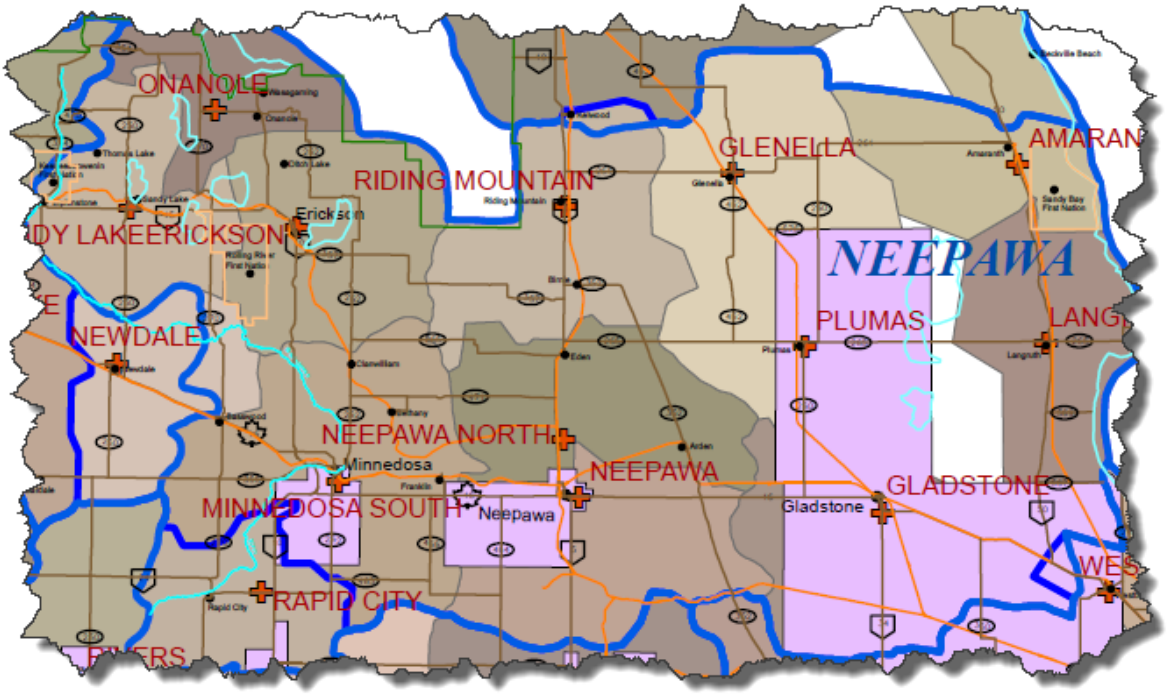
Facilities

The Morden CSC will require renovations to accommodate the additional staff. The positions include:

- Field staff – 12
- Administrative staff – 6

Neepawa CSC

The Neepawa CSC combines Neepawa, Erickson, Minnedosa and Gladstone districts. There are 14,430 customers and 2,593 km of electric distribution.



Profile Revisions

Rapid City Station Area

The Rapid City station area will be re-assigned to the Brandon CSC to improve electrical response time and customer service. There are 449 customers and 90 km of electric distribution.

Newdale Station Area

The Newdale station area will be added to the Neepawa CSC from the Russell CSC to improve electrical response time and customer service. There are 227 customers and 77 km of electric distribution in this area.

Revised Profile

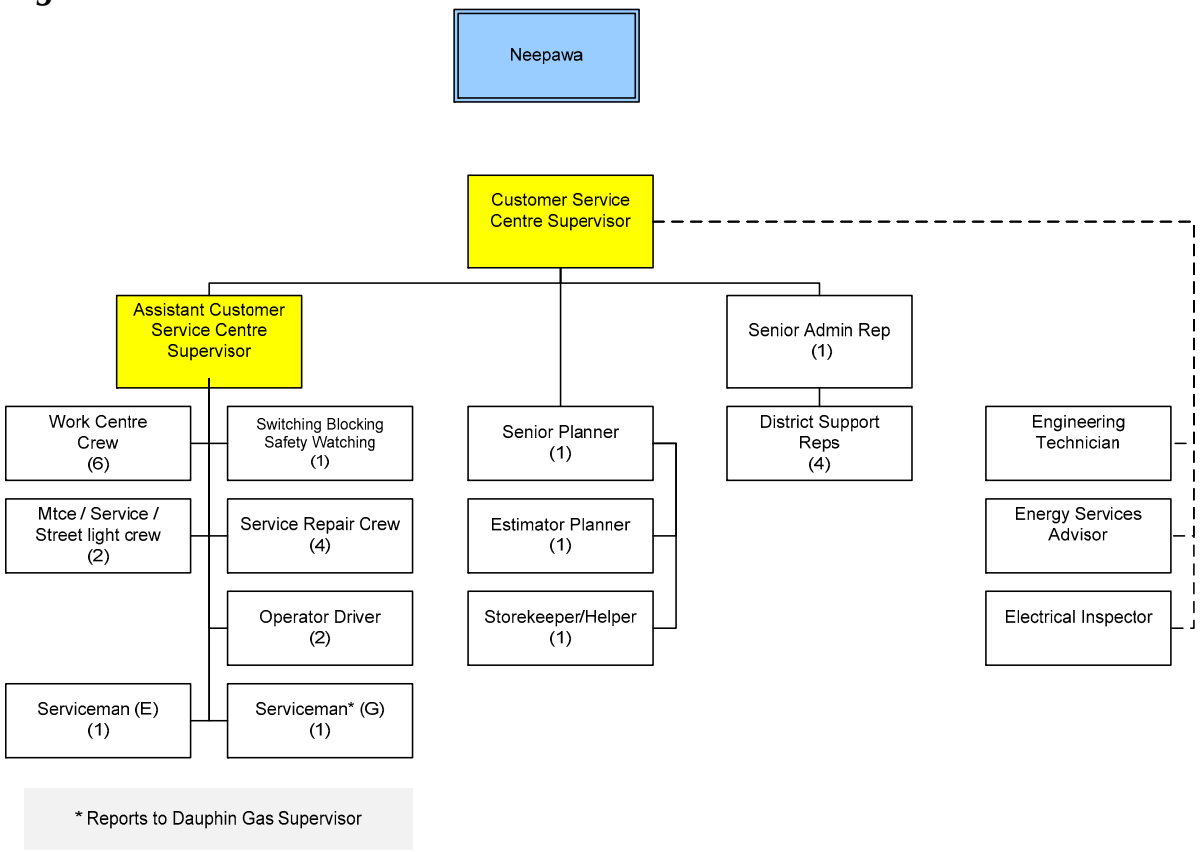
The net impact of re-assigning the two station areas to the Neepawa CSC is the loss of 222 customers and 13 km of electric distribution. The revised Neepawa CSC profile has 14,208 customers and 2,580 km of electric distribution.

Employees

The Neepawa CSC will combine the staff from the Neepawa, Gladstone, Erickson and Minnedosa districts.

To standardize the CSC organization structure, a storekeeper will be added. The addition of a storekeeper will enable field resources to focus on field activities.

Organization Structure



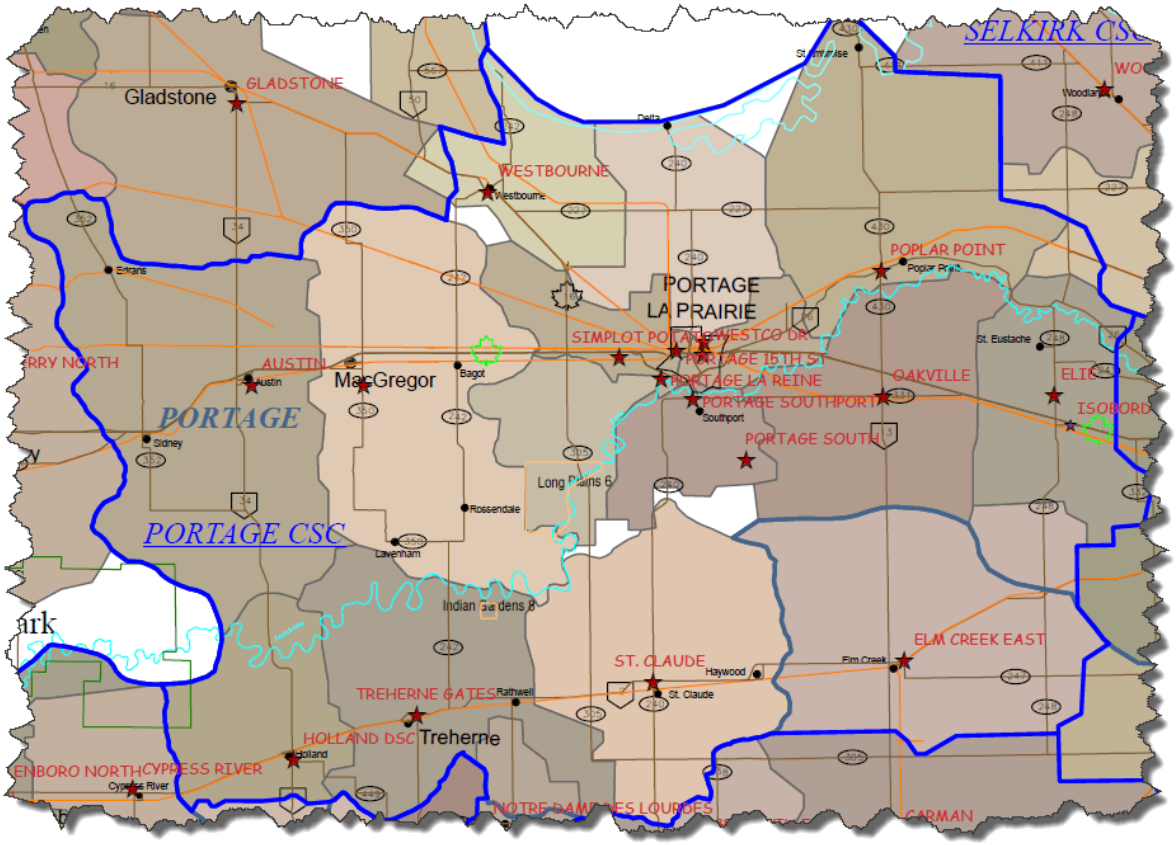
Facilities

The current facility is inadequate and is scheduled to be replaced in the near future to accommodate the additional staff and vehicles. The positions include:

- Field staff – 12
- Administrative staff – 2

Portage la Prairie CSC

The Portage la Prairie CSC combines Portage la Prairie, MacGregor, Treherne and Elie districts. There are 21,231 customers and 3,966 km of electric distribution.



Profile Revisions

Elm Creek and Notre Dame de Lourdes Station Areas

The Elm Creek and Notre Dame de Lourdes station areas will be re-assigned to the Portage la Prairie CSC to align the natural gas boundary, improve electrical outage response time and customer service. There are 1,005 customers and 526 km of electric distribution.

Cabot Station Area

The Cabot station area will be re-assigned to the Fort Garry CSC to improve electrical response time and customer service. The re-assignment will result in a loss of 954 customers and 217 km of electric distribution.

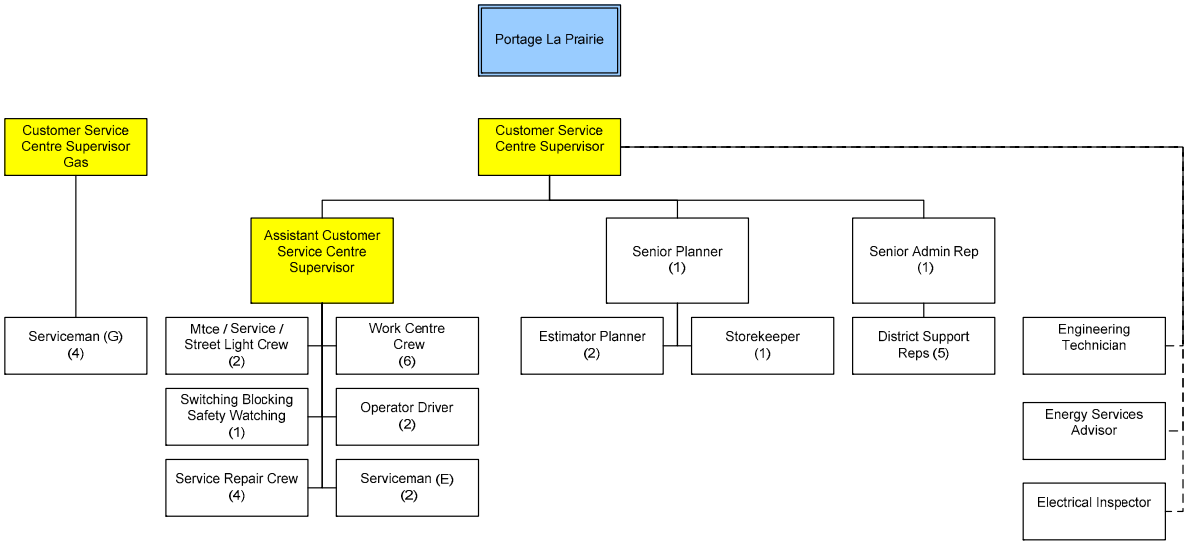
Revised Profile

The net impact of re-assigning the station areas is the net gain of 51 customers and 309 km of electric distribution. The revised Portage la Prairie profile has 21,282 customers and 4,275 km of electric distribution.

Employees

The Portage la Prairie CSC will combine the staff from the Treherne, MacGregor, Elie and Portage la Prairie districts.

Organization Structure



Facilities

The current facility is can accommodate the additional staff with minor renovations. The positions include:

- Field staff – 5
- Administrative staff – 3

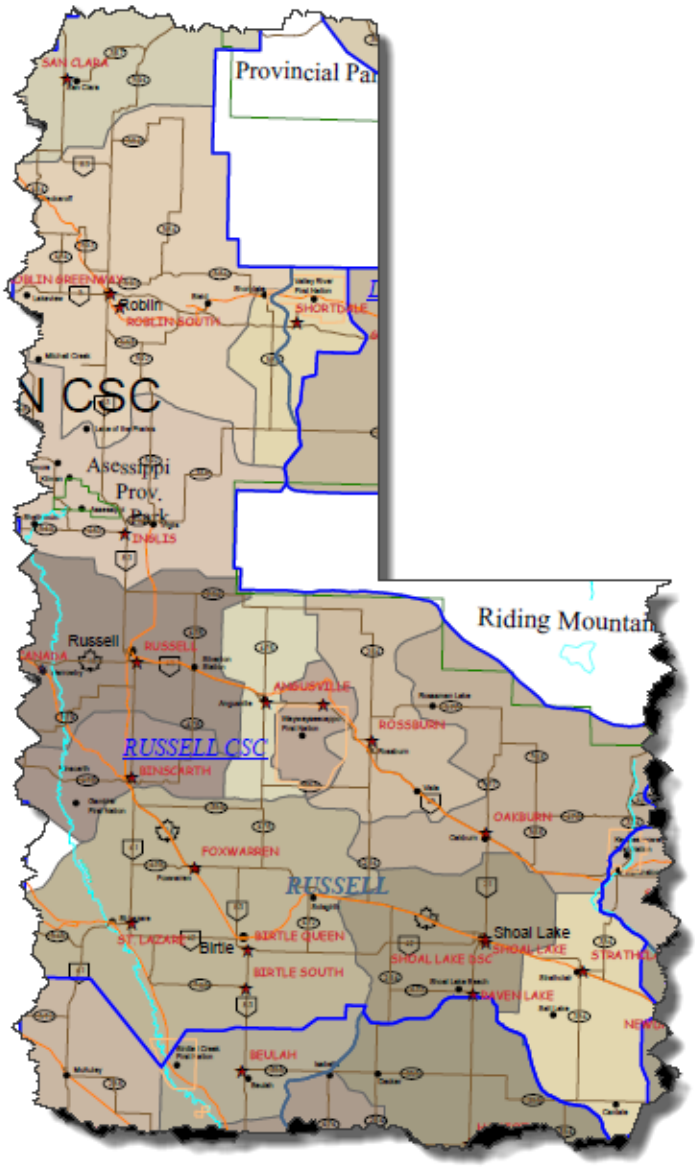
Russell CSC

The Russell CSC combines Russell, Shoal Lake, Birtle and Roblin districts. There are 11,260 customers and 3,854 km of electric distribution.

Profile Revisions

Shortdale Station Area

The Elm Creek station area will be re-assigned from the Dauphin CSC to the Russell CSC, eliminating the station split between the two CSC's. There are 209 customers and 118 km of electric distribution in this area.



Newdale Station Area

The Newdale station area will be re-assigned to the Neepawa CSC from the Russell CSC to improve electrical response time and customer service. There are 227 customers and 77 km of electric distribution.

Beulah, Manson and Miniota Station Areas

The Beulah, Manson and Miniota station area will be re-assigned to the Virden CSC to improve electrical response time and customer service. The re-assignment will result in a loss of 905 customers and 690 km of electric distribution in this area.

Revised Profile

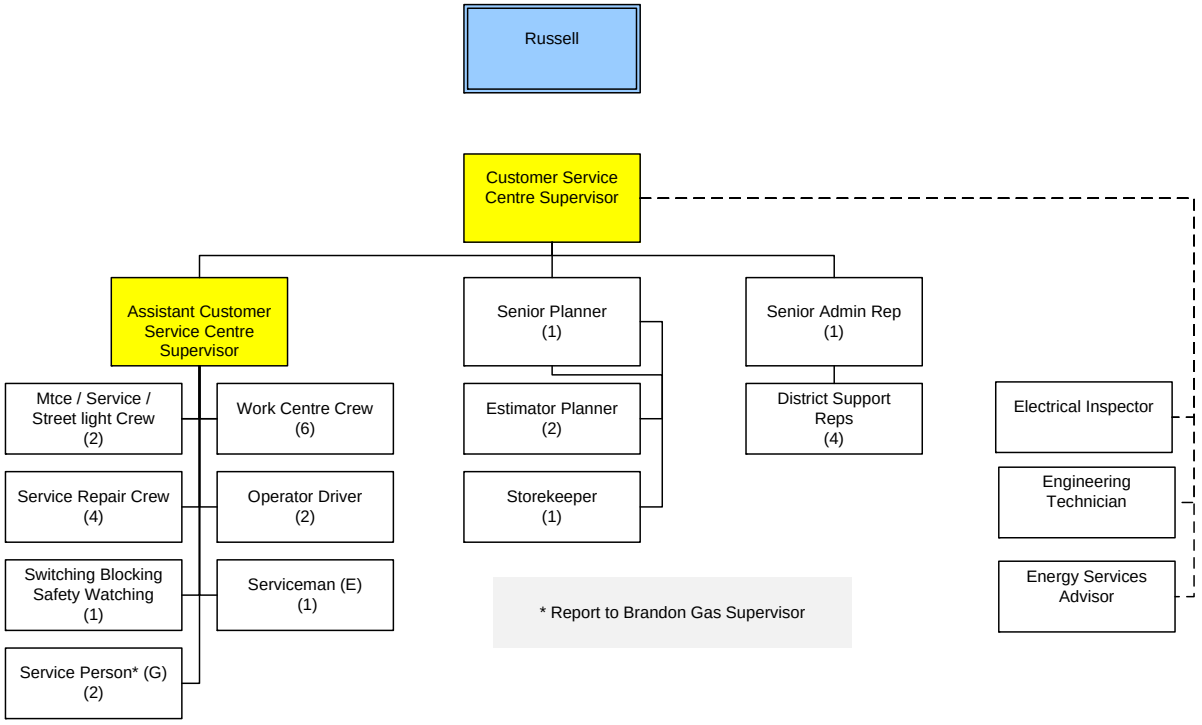
The net impact of the station relocations is a loss of 923 customers and 649 km of electric distribution. The revised profile is 10,377 customers and 3,205 km of electric distribution

Employees

The Russell CSC will combine the staff from the Russell, Shoal Lake, Birtle and Roblin districts.

To standardize the CSC organization structure, a storekeeper will be added to the staff compliment.

Organization Structure



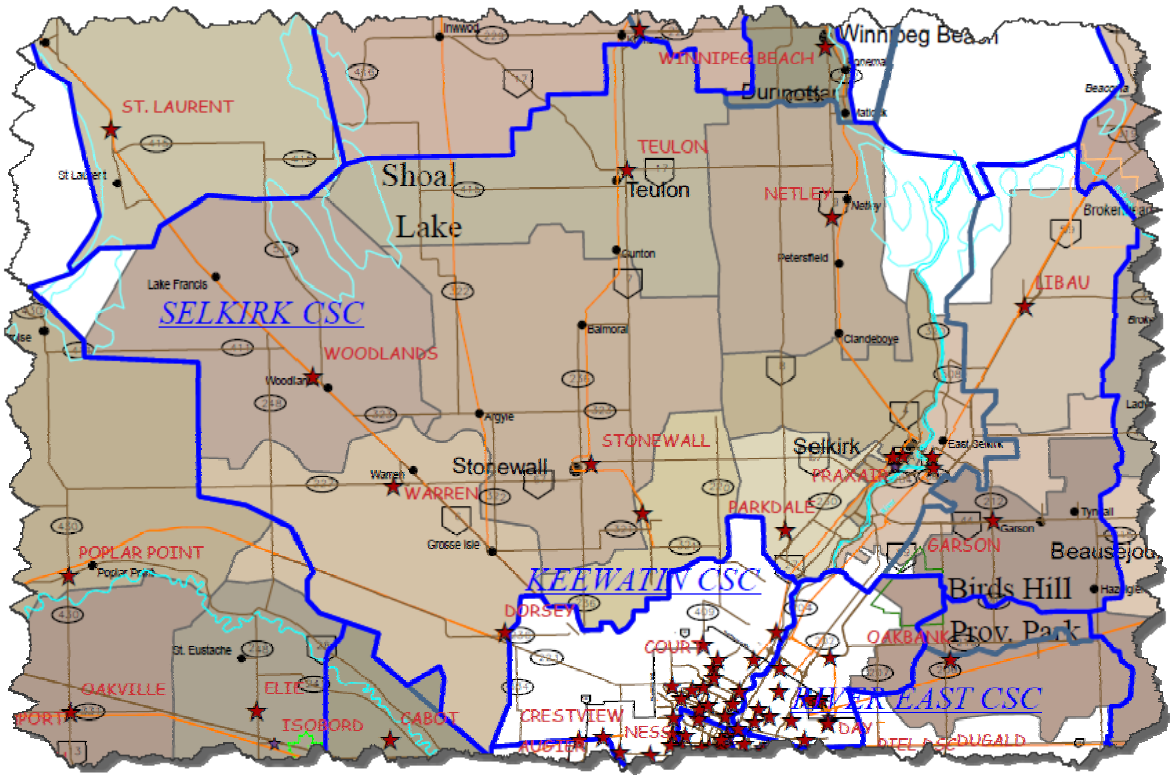
Facilities

The current facility is can accommodate the additional staff with minor renovations. The positions include:

- Field staff – 10
- Administrative staff – 4

Selkirk CSC

The current Selkirk CSC combines the Selkirk, Berens River and Stonewall districts. There are 28,323 customers and 2,903 km of electric distribution.



Profile Revisions

Komarno Station Area

The Komarno station area will be re-assigned to the Arborg CSC to improve electrical outage response time and customer service. There are 406 customers and 325 km of electric distribution.

Garson and Libau Station Areas

The Garson and Libau station areas will be added to the Selkirk CSC from the Lac du Bonnet CSC to improve electrical outage response time and customer service. There are 1,877 customers and 467 km of electric distribution.

Winnipeg Beach Station Area

The Winnipeg Beach station area will be moved to the Selkirk CSC from the Arborg CSC to improve electrical outage response time and customer service. There are 3,927 customers and 189 km of electric distribution.

Berens River Satellite Office (Berens River, Little Grand Rapids and Poplar River Station Areas)

The Berens River Satellite office will be re-assigned to the Lac du Bonnet CSC recognizing the 66kV station source in the Lac du Bonnet CSC. Station areas on the south east side of Lake Winnipeg are fed by a single distribution line from Manigotagan. The re-assignment of this station will assign responsibility of electrical outages to one CSC. There are 952 customers and 105 km of electric distribution in this area.

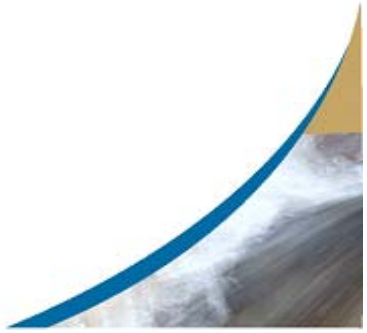
Revised Profile

The net impact of the station relocations is an increase of 4,446 customers and 226 km of electric distribution. The revised profile is 32,769 customers and 3,129 km of electric distribution

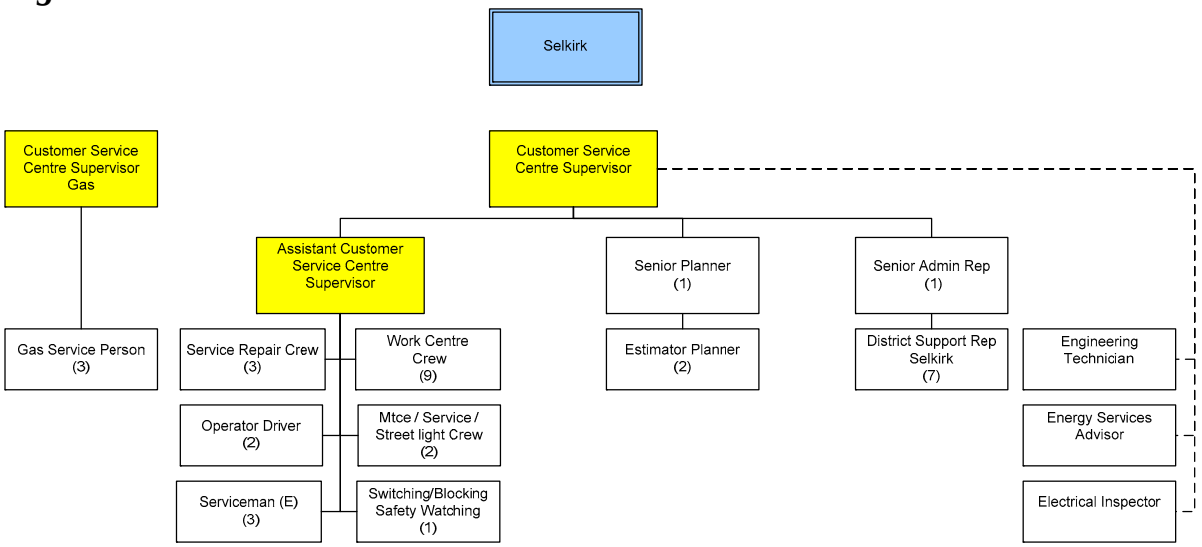
Employees

The Selkirk CSC will combine the staff from the Stonewall and Selkirk districts. All staff from the Berens River Satellite office will report to the Lac du Bonnet CSC.

To manage the workload associated with the addition of customers and distribution line, a single field position should be relocated from Arborg CSC to the Selkirk CSC.



Organization Structure



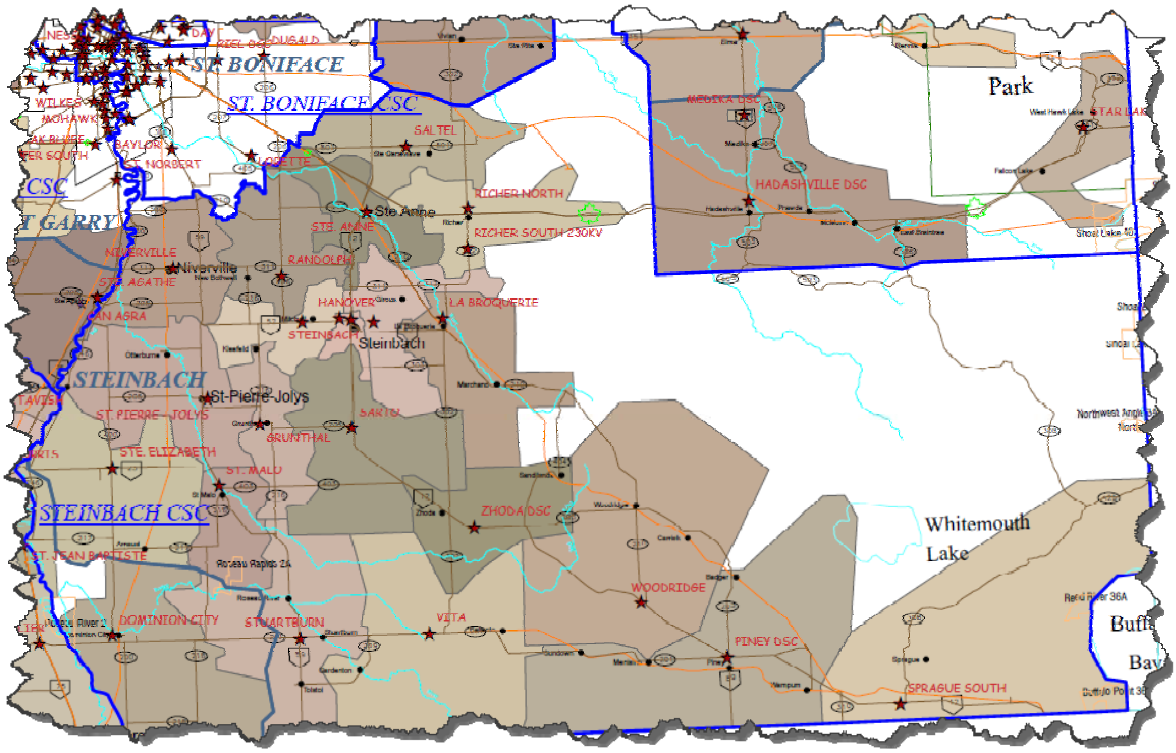
Facilities

The current facility is not adequate to accommodate the additional staff without major renovations. Positions to be relocated to the CSC include:

- Field staff – 7
- Administrative staff – 3

Steinbach CSC

The current Steinbach CSC combines the former Steinbach, Niverville, Falcon Lake, St Pierre and Piney districts. There are presently 38,032 customers and 4,953 km of electric distribution.



Profile Revisions

Dominion City Station Area

The Dominion City station area will be added to the Steinbach CSC to improve electrical outage response time and customer service. There are 620 customers and 288 km of electric distribution.

Falcon Lake District (Hadashville/Medika DSC, Star Lake and Brereton Lake Station Areas)

The Falcon Lake District including all of the station areas will be re-assigned to the Lac du Bonnet CSC. The re-assignment will reduce Steinbach customer base by 3,505 customers and 464 km of distribution line.

Moving Falcon Lake district to Lac du Bonnet aligns the seasonal customer expertise of the Lac du Bonnet staff in addition to improving customer service and electrical outage response.

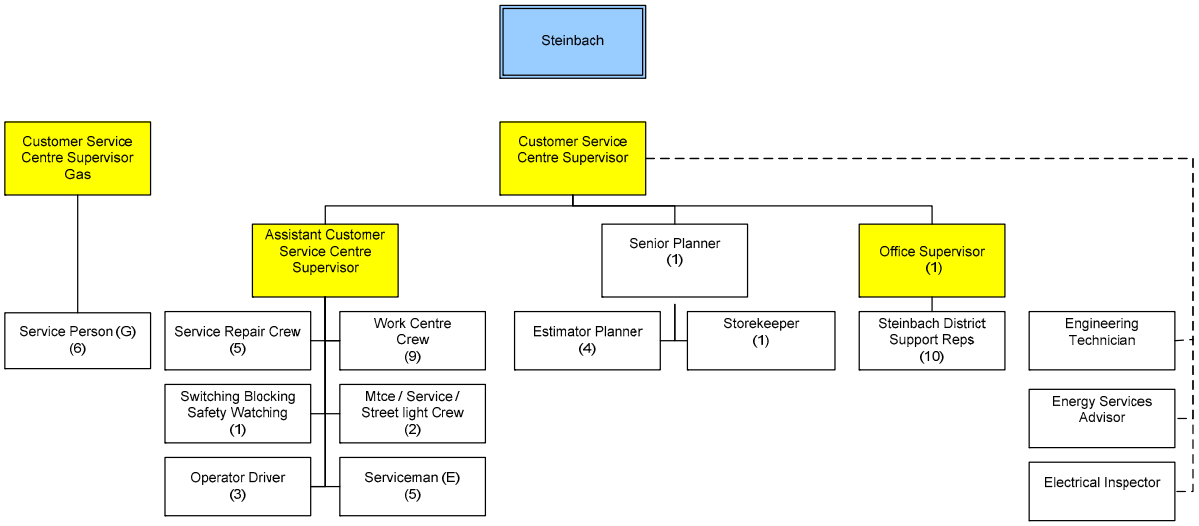
Revised Profile

The net impact of the station relocations is a decrease of 2,885 customers and 176 km of electric distribution. The revised profile is 35,147 customers and 4,777 km of electric distribution.

Employees

The Steinbach CSC will combine the staff from the Steinbach, Niverville, Piney and St Pierre districts. Staff from the Falcon Lake district will report to the Lac du Bonnet CSC.

Organization Structure



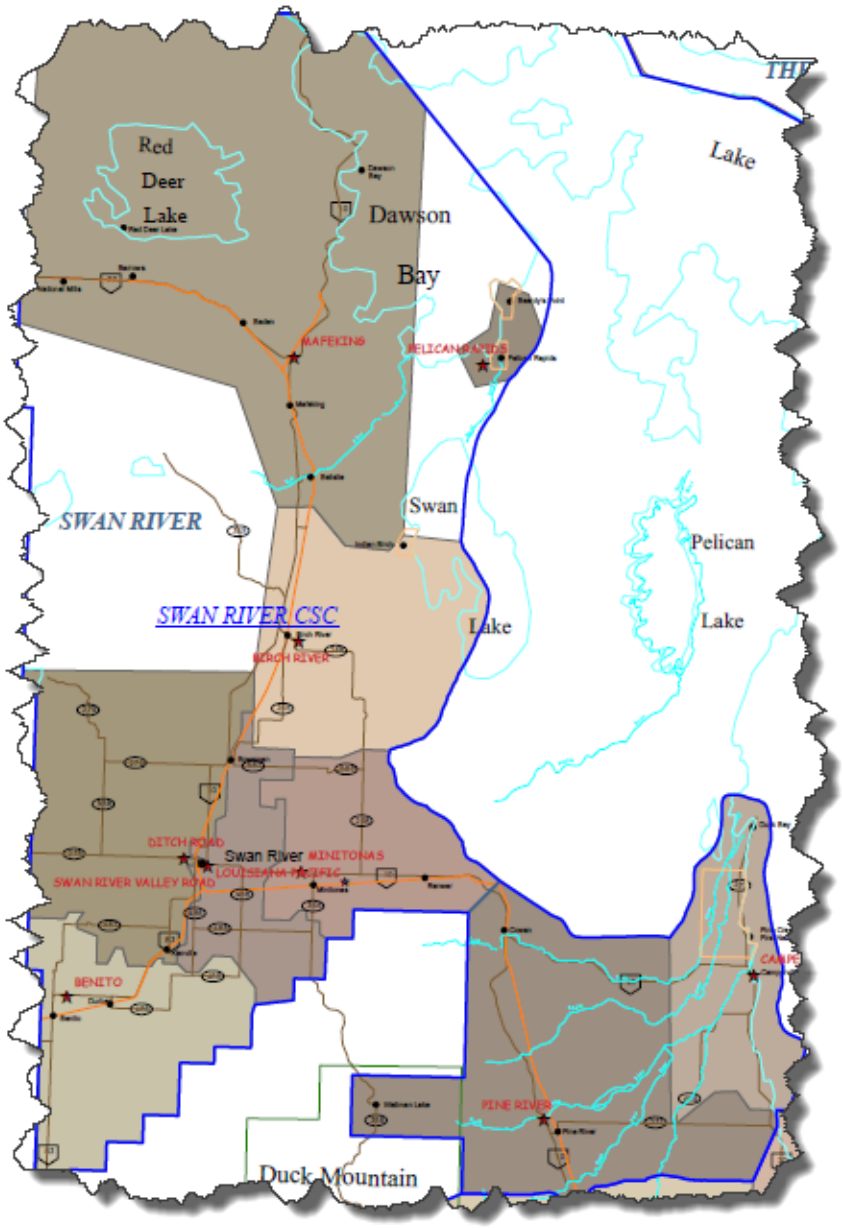
Facilities

The current facility is not adequate to accommodate the additional staff without significant renovations. Positions to be relocated to the CSC include:

- Field staff – 7
- Administrative staff – 4

Swan River CSC

The current Swan River CSC has 5,725 customers and 2,040 km of electric distribution.



Profile Revisions

Camperville and Pine River Station Areas

The Camperville and Pine River station areas will be added to the Swan River CSC from the Dauphin CSC to improve electrical outage response time and customer service. There are 1,067 customers and 442 km of electric distribution.

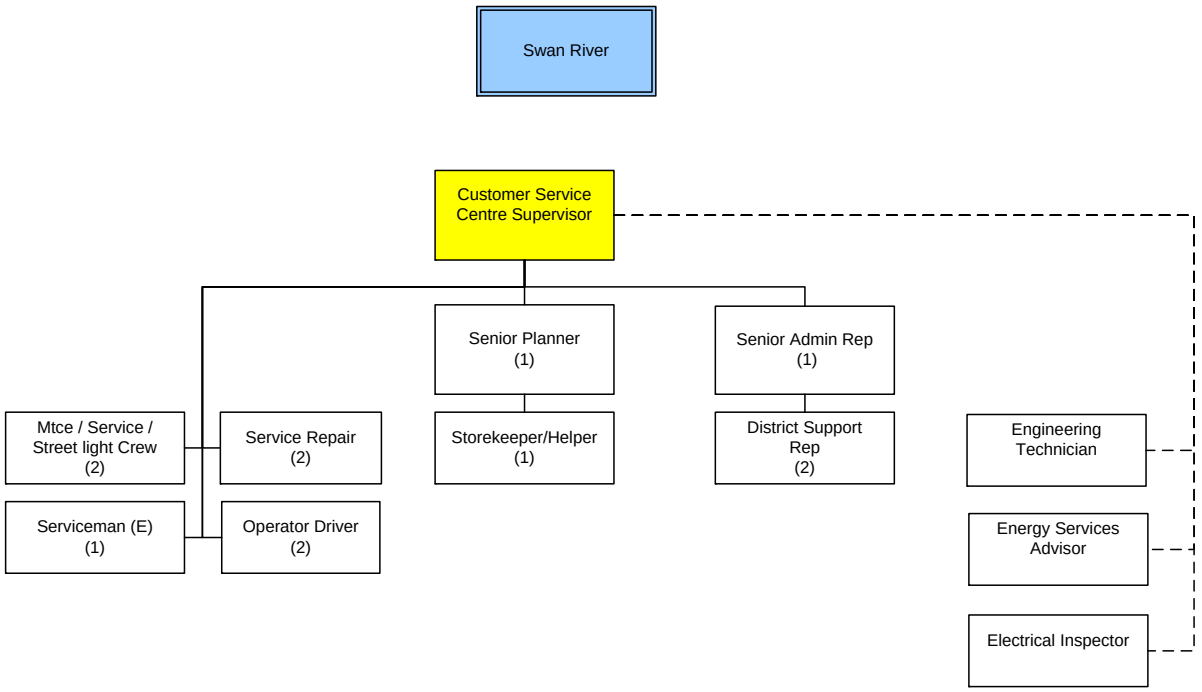
Revised Profile

The net impact of the station relocations is an increase of 1,067 customers and 442 km of electric distribution. The revised profile is 6,792 customers and 2,482 km of electric distribution

Employees

To standardize the organization structure, a storekeeper will be added to the organizational structure.

Organization Structure

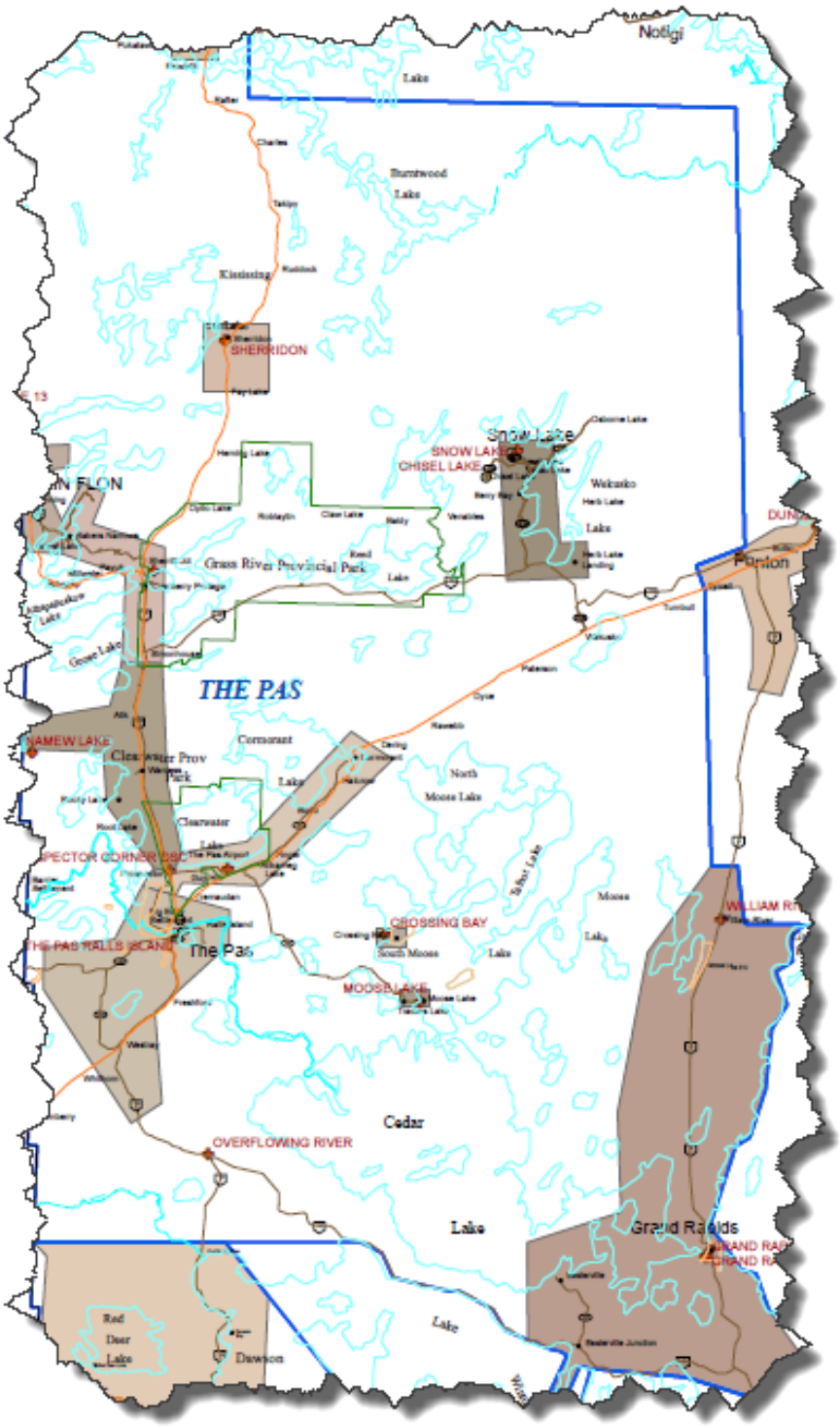


Facilities

Given that there are no revisions to the staffing levels, no facility enhancements are required.

The Pas CSC

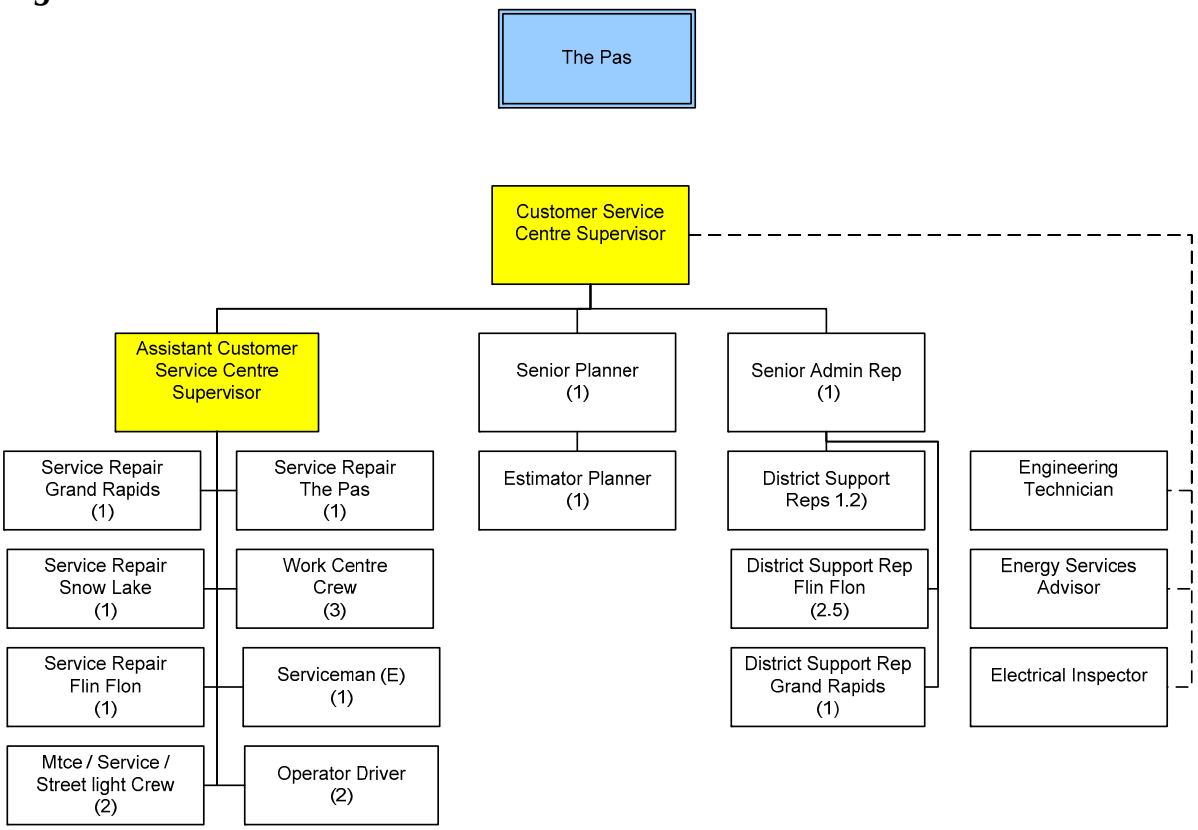
The current profile for The Pas CSC is 11,044 customers and 1,138 km of electric distribution. The Pas CSC combines The Pas district along with the Flin Flon, Grand Rapids and Snow Lake Satellite Offices.



Profile Revisions

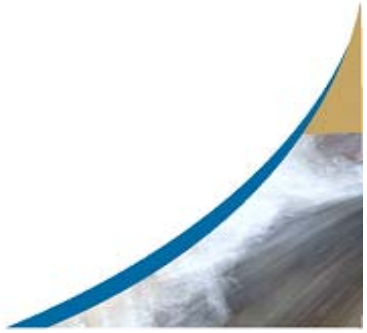
There are no revisions to The Pas profile.

Organization Structure



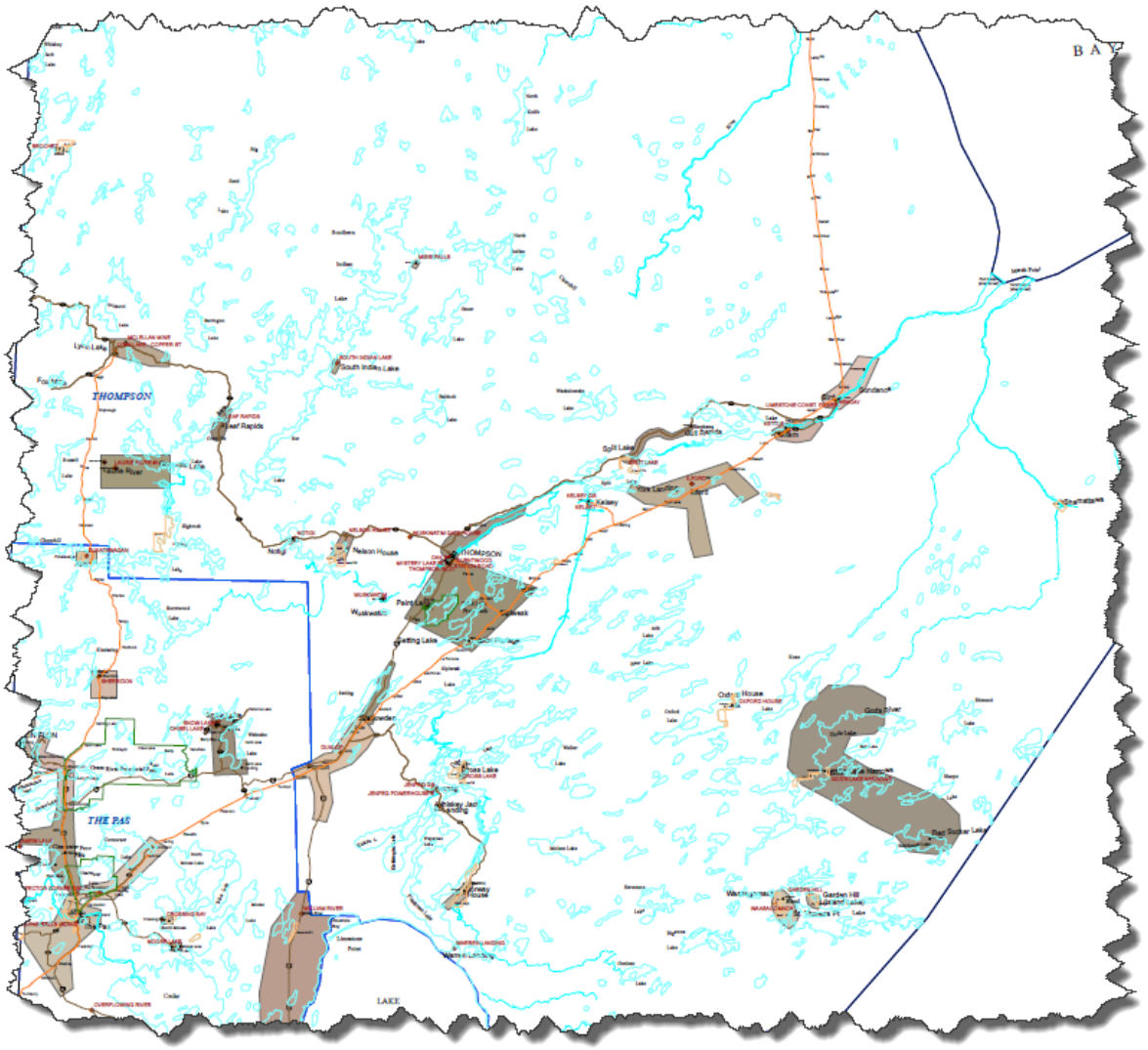
Facilities

Facility upgrades are not required.



Thompson CSC

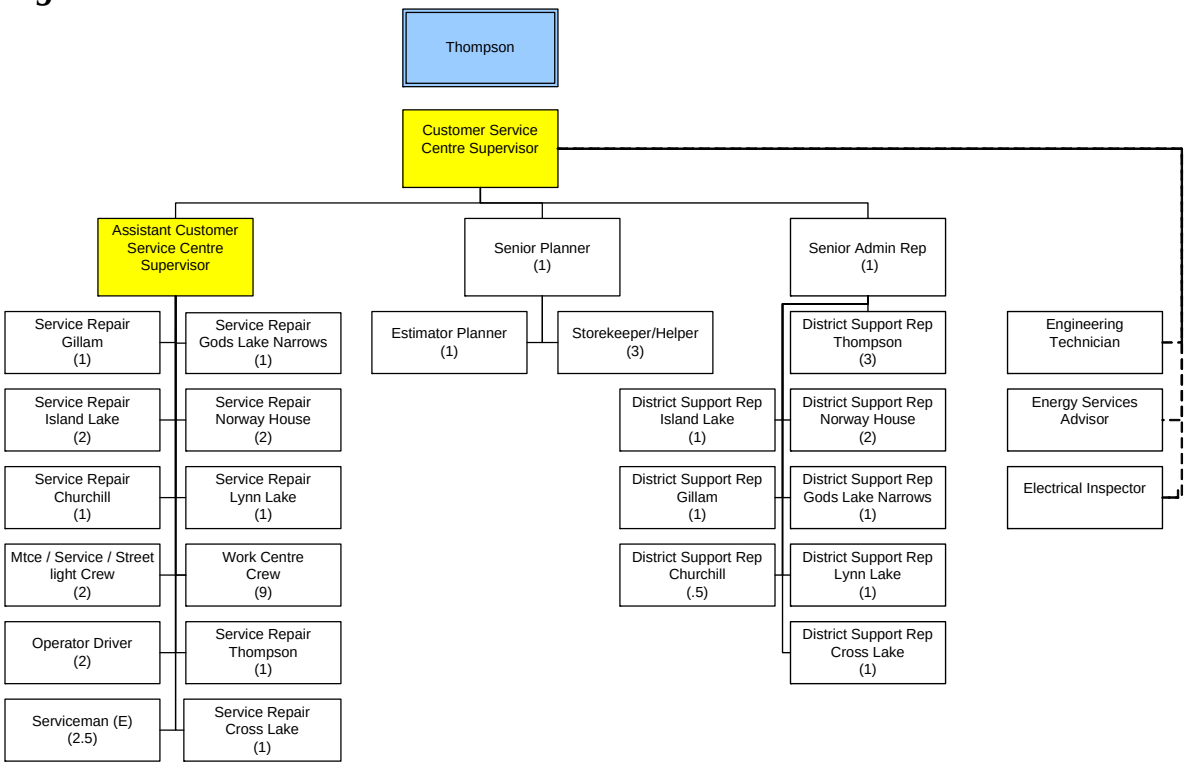
The Thompson CSC combines the Thompson district, and Gillam, Gods Lake Narrows, Island Lake, Cross Lake, Norway House, Lynn Lake and Churchill satellite offices. The combined customer base in this centre is 15,999 with 1,170 km of distribution.



Profile Revisions

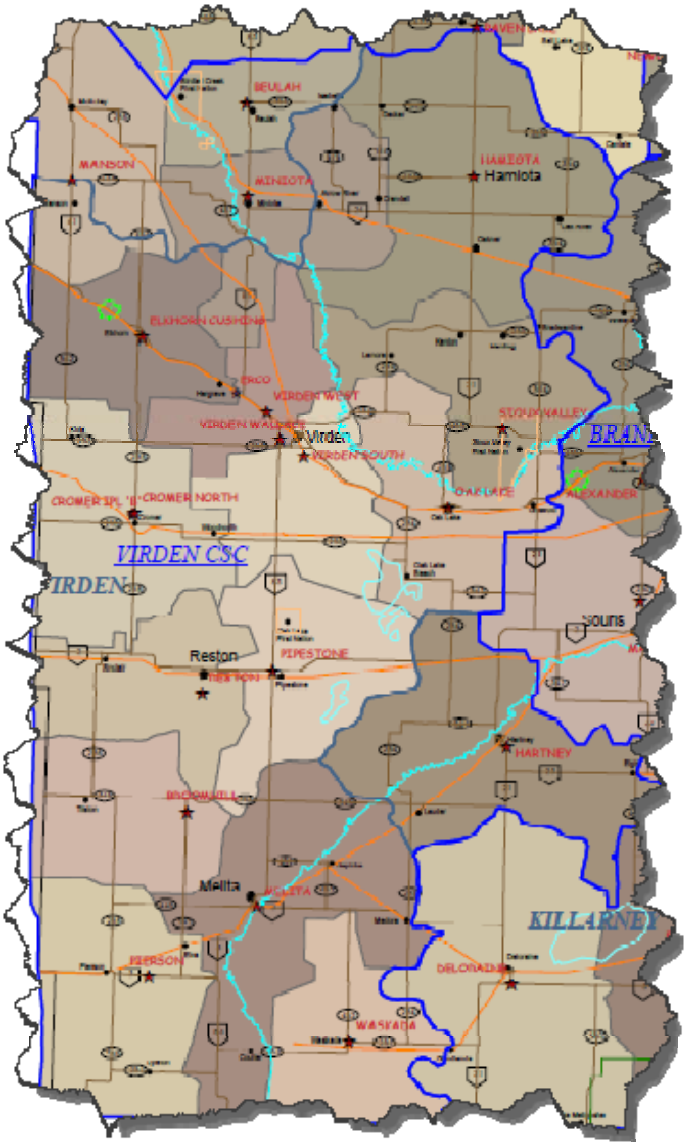
There are no revisions to the Thompson CSC profile.

Organization Structure



Virden CSC

The Virden CSC combines the Virden, Melita, Hamiota and Reston districts. Virden CSC has 18,349 customers and 4,593 km of distribution line.



Profile Revisions

Beulah, Manson and Miniota Station Areas

The Beulah, Manson and Miniota station area will be re-assigned to the Virden CSC to improve electrical response time and customer service. The re-assignment will result in an increase of 905 customers and 690 km of electric distribution in this area.

Hartney Station Area

The Hartney station area currently resides within the Bandon CSC and will be transferred to the Virden CSC. The impact of this move is the transfer of 657 customers and 454 km of electrical distribution to the Virden CSC from the Brandon CSC.

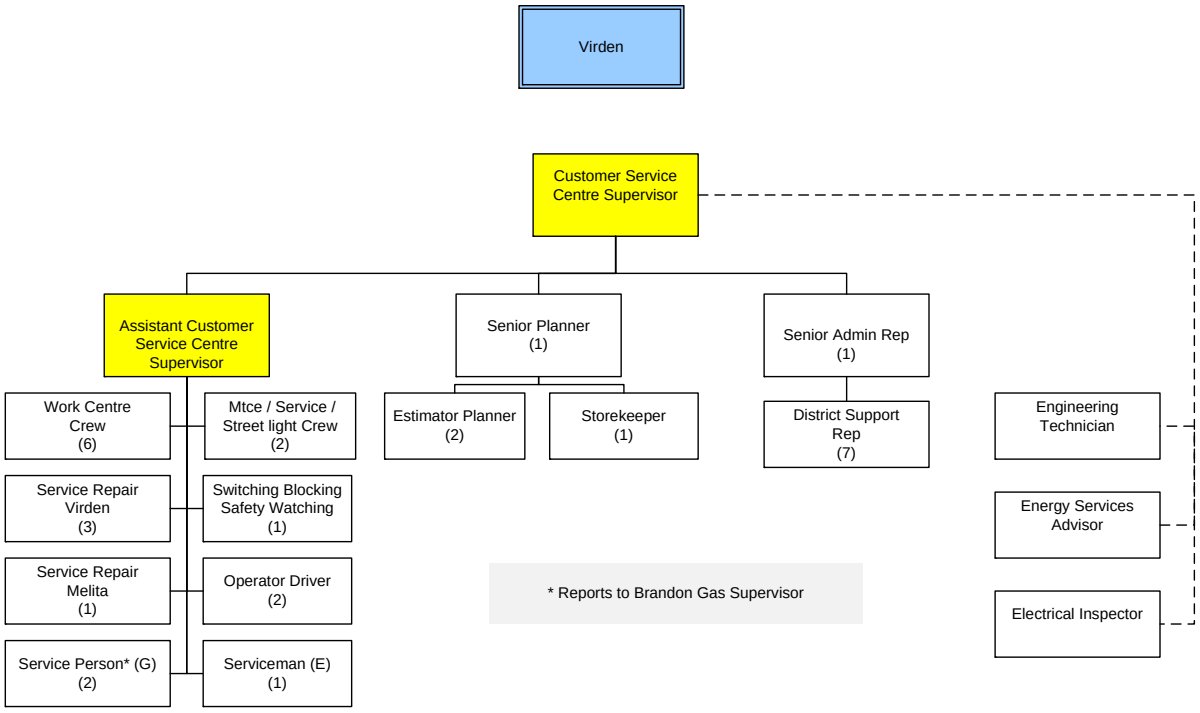
Revised Profile

The net impact of the station relocations is an increase of 1,562 customers and 1,144 km of electric distribution. The revised profile is 19,911 customers and 5,737 km of electric distribution.

Employees

The Virden CSC will combine the staff from the Virden, Melita, Hamiota and Reston districts. Melita will remain open as a satellite office to manage the workload and customer demand in the southwest corner of the province.

Organization Structure



Facilities

The current facility is not adequate to accommodate the additional staff without renovations. Positions to be relocated to the CSC include:

- Field staff – 6
- Administrative staff – 3

CUSTOMER SERVICE OPERATIONS

DISTRICT ORGANIZATIONAL ASSESSMENT

Terms of Reference

EXECUTIVE SPONSOR
Brent Reed – Vice President – Customer Service & Distribution

DIVISION SPONSORS
Scott Dunn – Division Manager Customer Service Operations - South Region
Dave Case – Division Manager Customer Service Operations – Winnipeg & North Region

PURPOSE
Review ***Customer Service Operations District Re-Organization Plan (2007)*** report and validate its findings in terms of utilization of staff, equipment, facilities and financial resources.

Provide a status update on the implementation of Phases 1 and 2 of the re-organization plan report.

Update recommendations and implementation plan for Phases 3 and 4 of the re-organization plan report.

BACKGROUND
In 2007 a plan was developed and approved to optimize the rural district organization within the Customer Service Operations Division to improve business and financial operations, while enhancing customer service and work life balance of employees. The implementation of a new district re-organization consisted of four phases as follows:

- Phase I: Establish new supervisory structure and placement of analyst/project manager
- Phase II: Introduce coordination and planning levels
- Phase III: Front office closures and district boundary re-alignment
- Phase IV: Closure of facilities

At this stage Phase I is complete and tasks yet to be completed as Part of Phase II relate to realignment of support resources to each CSC (Electrical Inspector, Distribution Engineering Tech and Energy Services Advisor), and facility upgrades of CSCs to accommodate future employee transfers. Phase III has not yet commenced and is a transitional step toward full district office closures and requires the promotion of alternative services for bill payment and inquiries. Phase IV, also not initiated, identified the closure of 36 district offices in short, medium and long term durations spanning a total of ten years.

With the Corporation in a situation to rationalize costs and streamline its levels of service, the full implementation of Phase III and IV now appears timely as the completion of these phases in the original analysis projected to yield a hard benefit of $13.4 million over 10 years plus $5.1 million in anticipated productivity improvements. Recognizing the evolution in CSO business operations over the past five years, it is necessary to update pertinent information in the original report to validate its merit.

SCOPE
The team will focus primarily on details provided within the 2007 re-organization plan report and specific to rural Manitoba only.

The review should consider the following:

- Establish new baseline of current staffing at each district
- Identification of EFT savings
- Identification of inventory savings
- Identification of fleet savings
- Categorization and staging of office closures
- Estimate of CSC facility upgrades/enhancements
- Listing and staging of activities to be undertaken as part of an office closure
- Update on impact to specific communities
- Communication plan
- Risk assessment

DELIVERABLES
An addendum report inclusive of updated cost/benefit summary and implementation plan inclusive of the following details:

- Status update on Phase I Implementation

- Status update on Phase II Implementation

- Validation of Concept for Phase III and IV
  - Updated rationale for front office closures, relocation of staff and divesting of facilities:
    - Customer impact
    - Financial benefit
    - Work process improvements
    - Employee benefit
    - Overall risk assessment

- Updated Implementation Plan
  - Schedule of front office closures and closing of facilities
  - Timeline of pre-closure activities including development of alternative front office services, CSC facility renovations, staffing, fleet acquisitions and material inventory transfers and communication notifications
  - Checklist describing staged activities to complete for each district office closure

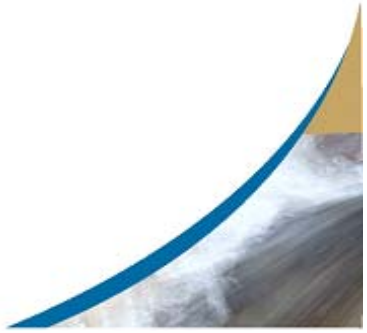
- Communication Plan

Team Members		Department
Leader:	Joe Thievin	Customer Service Operations – South Region
Facilitator:	Brian Rychlicki	Customer Service Operations – South Region
Members:	Audrey Schmidt Carolyn Nelson	Business Unit Support Services, CS&D Management Financial Services, F&A
Advisors:	Rob Isaac Dori Chudobiak Mark Prydun CSO Managers	Financial Systems & Reg. Support, F&A Human Resource Services, F&A Vice President Administration, CS&D (as required)

Timeframe	
Start Date	July 2, 2012
End Date	August 25, 2012 (Final Draft Report Complete)

Related Teams:

- Work Force Management (MWM)



Appendix A – Cost/Benefit and NPV Summar

Customer Service Operations Division
District Operations Organizational Review

Year	Staff Reductions (1)	Productivity (1)	Senior Staff Salaries (2)	Employee Relocation (3)	Facility Operating Costs (2)	Facility Renovations (3)	(Central Stores) (3)	Cash Handling (1)	Total
					Benefits / Cost Flows				
Projected Benefits/ Costs	$1,517,000	$1,716,000	$104,000	($810,000)	$331,000	($4,968,000)	$2,789,713	$319,000	$998,713
EFT's	19.0	21.5						4.0	
					Net Present Value				
5	$1,903,067	$2,152,712	$260,936	($700,406)	$830,475	($4,505,476)	$2,412,264	$400,182	$2,753,754
10	5,953,992	6,735,037	612,407	(700,406)	1,949,096	(4,505,476)	2,412,264	1,252,024	13,708,938
20	13,093,792	14,811,436	1,101,885	(700,406)	3,506,955	(4,505,476)	2,412,264	2,753,406	32,473,856
30	17,456,191	19,746,094	1,400,955	(700,406)	4,458,804	(4,505,476)	2,412,264	3,670,746	43,939,172

Notes:

(1) even over 10 yr timeframe, then continue to 30

(2) even over 5 yr timeframe, then continue to 30

(3) spread costs / benefits even over 5 yrs

(4) avg. salary - $79,834

(5) rate - 5.05%

Appendix B – Net Present Value Comparison – 2007 vs. 2012

Net Present Value Comparison - 2007 vs. 2012

2007 Summary

Year	Staff Reductions	Productivity	Senior Staff Salaries	Employee Relocation	Facility Operating Costs	Fleet	Inventory	Cash Handling	District Re-Org Total	MWM Staff Reductions including Productivity	Winnipeg Area Facilities Review	Total
5	$2,871,530	$1,682,347	$252,656	($695,039)	$402,062	$966,408	$1,076,259	$1,877,913	$8,434,136	$3,560,260		**$11,994,396**
10	8,737,913	5,119,293	580,019	(1,214,412)	1,223,456	2,218,572	1,880,502	5,714,389	24,259,732	10,833,683		**35,093,415**
20	18,453,561	10,811,415	1,007,442	(1,214,412)	2,583,813	3,853,463	1,880,502	12,068,193	49,443,977	22,879,607		**72,323,584**
30	23,878,728	13,989,866	1,246,113	(1,214,412)	3,343,428	4,766,379	1,880,502	15,616,124	63,506,728	29,605,987		**93,112,715**

2012 Summary

Year	Staff Reductions	Productivity	Senior Staff Salaries	Employee Relocation	Facility Operating Costs	Facility Renovation Costs	Inventory	Cash Handling	District Re-Org Total	MWM Staff Reductions including Productivity	Winnipeg Areas Facilities Review	Total
5	$1,903,067	$2,152,712	$260,936	($700,406)	$830,475	($4,505,476)	$2,412,264	$400,182	$2,753,754	$4,556,323	$1,196,424	**$8,506,501**
10	5,953,992	6,735,037	612,407	(700,406)	1,949,096	(4,505,476)	2,412,264	1,252,024	13,708,938	14,255,043	2,189,881	**30,153,862**
20	13,093,792	14,811,436	1,101,885	(700,406)	3,506,955	(4,505,476)	2,412,264	2,753,406	32,473,856	31,349,143	3,471,385	**67,294,384**
30	17,456,191	19,746,094	1,400,955	(700,406)	4,458,804	(4,505,476)	2,412,264	3,670,746	43,939,172	41,793,595	4,174,932	**89,907,699**

Appendix C - Facility Summary

Arborg
The closure of Gimli and Fisher Branch District offices will add 12 CSO positions (4 administrative staff and 8 field staff) along with three other positions from Gimli (Energy Services Advisor, Engineering Technician, and Electrical Inspector) for a total of 15 positions. While the offices will close, staff will continue to report to their current locations pending office renovations.

Ashern
The closure of St. Martin and Lundar District offices will add 9 CSO positions (2 administrative staff and 7 field staff) to the Ashern CSC office. The St. Martin District office will be immediately closed with the one field staff position relocating to Ashern. The Lundar District office will be closed to customers however staff will continue to report there while the new Ashern CSC facility is being completed.

Brandon
The closure of the Brandon 10th St, Carberry and Souris District offices will add 18 CSO positions (14 administrative staff and 4 field) to the Brandon CSC office. The Brandon 10th St. office will continue to be open to customers in the interim. The long term plan will be to close the front doors at 10th St as the corporation transitions away from accepting customer payments. Carberry staff will immediately relocate to the Brandon CSC office. The Souris District office will close to customers and staff will continue to report to that location while the Brandon CSC undergoes renovations.

Dauphin
The closure of Grandview, McCreary, Ste. Rose, and Winnipegosis Districts will add 14 CSO positions 4 administrative staff and 10 field staff) to the Dauphin CSC office. Both McCreary and Winnipegosis District offices will immediately close with staff relocating to the Dauphin CSC. Grandview and Ste. Rose Districts offices will close however staff will continue to report to their current locations while renovations at the Dauphin CSC are completed.

Killarney
The closure of Boissevain, Glenboro and Pilot Mount District offices will add 11 CSO positions (3 administrative staff and 8 field staff). Boissevain, Glenboro and Pilot Mound District office front doors will be immediately closed to customers. Staff movement to the Killarney CSC office will occur when the renovations are completed.

Lac du Bonnet
The closure of Falcon Lake, Powerview and Beausejour District offices will add 16 CSO positions (5 administrative staff and 11 field staff) along with an Energy Services Advisor and Electrical Inspector for a total of 18 positions to the Lac du Bonnet CSC office. The administrative position from Falcon Lake will immediately relocate, however no other staff movement can occur until renovations are completed.

Morden
The closure of Morris, Carman, Somerset and Altona District offices will add 18 CSO positions (6 administrative staff and 12 field staff) to the Morden CSC office. As an interim measure, consideration will be given to relocating the Morris administrative staff (1) and field staff (3) to Altona, enabling the Morris facility to be closed. Carman District office administrative staff (1) and field staff (4) front doors will be immediately closed and the administrative staff (2) will move to Morden. The balance of the Carman staff will move to Morden after minor renovations are completed. Somerset District office administrative staff (1) and field staff (1) will immediately move to Morden with the facility closing immediately.

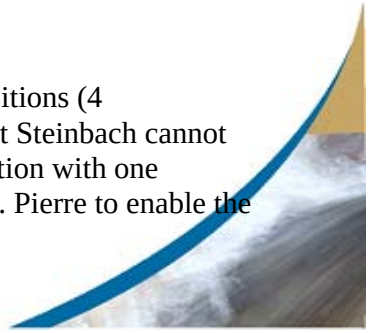
Neepawa
The closure of Gladstone, Erickson and Minnedosa District offices will add 14 CSO positions (2 administrative staff and 12 field staff) to the Neepawa CSC office. Consideration will be given to relocating the Erickson District office administrative staff (2) and field staff (2) to Minnedosa to enable the Erickson District office to close. Staff will remain in the Gladstone office until the new facility in Neepawa is completed.

Portage La Prairie
The closure of MacGregor, Elie, and Treherne District offices will add 8 CSO positions (3 administrative staff and 5 field staff) to the Portage La Prairie CSC office. MacGregor District office will immediately close with staff moving to the Portage CSC office. The Elie (1) and Treherne (1) administrative staff will immediately move to the Portage La Prairie CSC. The Elie field staff (2) and Treherne field staff (3) will remain working at their current locations until renovations are complete.

Russell
The closure of Birtle, Roblin, and Shoal Lake District offices will add 14 CSO positions (4 administrative staff and 10 field staff) along with one other position from Shoal Lake (Apparatus Maintenance) for a total of 15 positions to the Russell CSC office. No staff movement to the Russell CSC office can occur until renovations are made to accommodate the staff.

Selkirk
The closure of the Selkirk 177 Main Street front office and Stonewall District offices will add 7 CSO positions (3 administrative staff and 4 field staff) to the Selkirk CSC office. The administrative staff (1) at the Selkirk 177 Main Street office will immediately move to the Selkirk CSC. The Stonewall District office will close with staff remaining in the location until renovations have been completed in the Selkirk CSC.

Steinbach
The closure of Niverville, Piney and St. Pierre Districts will add 11 CSO positions (4 administrative staff and 7 field staff) to the Steinbach CSC office. Given that Steinbach cannot accommodate additional staff, all staff will remain in their current work location with one exception. Consideration will be given to relocating the Niverville staff to St. Pierre to enable the Niverville office to close completely.

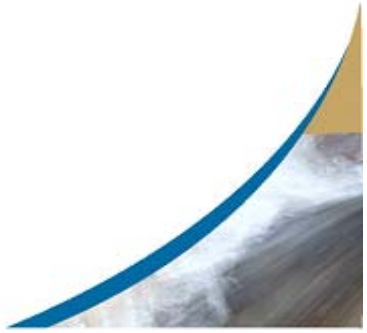


Swan River
Swan River CSC has 14 positions currently working in it (4 administrative staff and 10 field staff) along with one Apparatus Maintenance staff for a total of 15 positions. No changes will be made to this CSC.

The Pas
Snow Lake, Flin Flon and Grand Rapids district offices will remain open as satellite offices and continue to be open to customers.

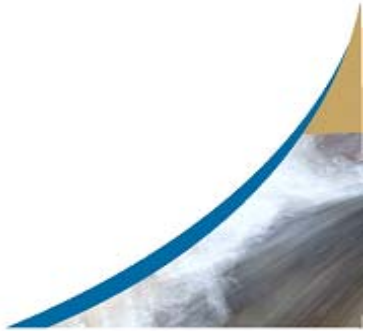
Thompson
Churchill, Gillam, Gods Lake Narrows, Island Lake, Leaf Rapids, Lynn Lake, Cross Lake and Norway House Districts will continue to remain open as satellite offices.

Virden
The Melita District office will remain open as a satellite office while activity in the oilfield remains high. The closure of Reston and Hamiota will add 4 CSO positions (2 administrative staff and 2 field staff) to the Virden CSC office. Due to the high demand in the oilfields, the Melita District office will remain as a Satellite with only field staff reporting to that location. Once these volumes change the Melita office will be reviewed.



Appendix D – Employee Relocation Summary

Employee Relocation Summary						
Actual Costs					Budget	
2008	**2009**	**2010**	**2011**	**2012**	**2013**	**Average**
$385,296	$578,552	$1,042,788	$487,455	$602,073	$610,300	$617,744
Estimated annual savings per year (i.e. assuming 25% reduction)						***$154,436***
Number of staff located in district proposed for closure						**108**
Average cost per move (approx)						**$30,000**
Estimated cost to relocate staff over and above normal attrition (approx 25%)						**$810,000**



Appendix E – District Office Closure Checklist

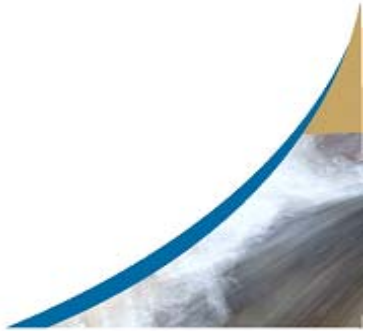
District Closure Communication Plan - Workback Schedule		
Letters	**Responsibility**	**Comments**
Customer & Electrical Contactor	**Internal Communications**	Review wording, dates, locations (sample available)
Mailing of all letters	**Business Communications Rep**	'Bill Insert' schedule to be confirmed, Business Communications to book 'Inserter' availability (required 3 to 4 weeks in advance of letter campaign)
Run queries for Customers & Contractors	**SAP & Customer Billing**	Create a SAP report for electrical permits issued to contractors in the **district office** in the previous 18 months and request Cusotmer Billing to run a Banner query on customers who paid their bill in person in the **district** office 3x or more in the last 18 months and provide Business Communications with the names & adresses (required 2 weeks in advance of letters being printed for campaign)
R.M.	**Energy Services & Sales Rep**	Personal contact
Chamber of Commerce	**Energy Services & Sales Rep**	Personal contact
Other Utlilities, MIT	**CSO Rep**	Letter
NewsPaper	**Responsibility**	**Comments**
Local	**CSO Rep**	Set up appointment (3 to 4 weeks in advance of letters going to customers) with local newspaper publisher to determine campaign, schedule and duration
Payment alternatives pamphlet	**Business Communications Rep**	Quantity required for mailing and hand out (3 to 4 weeks in advance of letter campaign)
		Contact Treasury 3 to 4 weeks in advance of
On-site posters, counter easels	**Business Communications Rep**	
before closure		Door poster is required (informing the customer that the office is closing) and # of counter easels required for the district office, Business Communications door size required 3 to 4 weeks in advance of letter campaign
after closure		Poster in windows and/or door poster informing the customer the office is closed, Business Communications needs window/door size(s) 3 to 4 weeks in advance of letters campaign
Free standing poster (at entrance)	**Business Communications Rep**	6 ft free standing poster with pockets for brochures $300 to $500 can be moved from one office to another as offices closures are implemented(4 weeks notice required to purchase the initial poster)
Q & A's and Know the Facts	**CSO Rep**	Consider Q&A's in a Hydrogram for all staff. Have Q&A's in the local office and the Contact Centre as a script the staff can use, (see sample edit, as required)
Website & Gram on line	**Internal Communications**	To work with PrePress to ensure all non relevant information related to district offices are deleted ie:remove reference to district on website.
Key/Major Accounts	**Key/Major accounts representative**	email
Energy Matters	**Internal Communications**	see the Notification spreadsheet

Appendix F – CSC Material Stock Levels

Inventory Levels June 2012			
	CSC Office and Satellite Stock	**Stock in Districts to be Closed**	**Spares**
Arborg	$228,690	$406,689	
Ashern	$115,752	$71,640	
Brandon			
Dauphin	$379,413		
Killarney	$380,323	$67,418	
Lac du Bonnet	$237,921	$124	
Morden	$414,402	$491,617	
Neepawa	$79,347	$207,998	
Portage la Prairie	$348,263	$191,722	
Russell*	$189,796	$175,567	$92,843
Selkirk		$191,279	
Berens River	$157,542		
Steinbach	$695,518	$335,576	$157,623
Swan River	$132,751		
The Pas	$603,680	$11,815	
Flin Flon	$200,389		
Grand Rapids	$43,144		
Thompson	$429,097	$148,529	$603,310
Gillam	$127,025		
Island Lake	$633,310		
Churchill	$67,932		
Gods Lake Narrows	$543,222		
Norway House	$392,308		
Lynn Lake	$109,902		
Virden	$399,457	$489,739	$624,035
Total Stock	**$6,909,184**	**$2,789,713**	**$1,477,811**
* Parkland spares placed in Russell CSC. Location not identified.			

Appendix G – Facility Renovation Costs

CSO Staff Relocation and Renovation Summary			
CSC	Administrative	Field	Renovations Budget
Arborg	2	8	$460,000.00
Ashern[1]	0	0	$0.00
Brandon	7	2	$414,000.00
Dauphin	2	10	$552,000.00
Killarney	2	11	$598,000.00
Lac du Bonnet	2	11	$598,000.00
Morden	3	6	$414,000.00
Neepawa[1]	0	0	$0.00
Portage la Prairie	0	5	$230,000.00
Russell	2	10	$552,000.00
Selkirk	2	7	$414,000.00
Steinbach	2	8	$460,000.00
Swan River	0	0	$0.00
The Pas	0	0	$0.00
Thompson	0	0	$0.00
Virden	0	6	$276,000.00
	24	84	$4,968,000.00
	Total Staff Movement	**108**	
[1] New facilities in process of construction			
Construction Cost sq. ft.)		$200.00	
Space requirements per staff (sq. ft.)		230	
Cost per employee space		$46,000.00	



D1876

CAPITAL PROJECT JUSTIFICATION FOR

RURAL DISTRICT REORGANIZATION

REVIEWED BY:
(Owning Dept Manager)

NOTED BY:
(if applicable)

Coordinating Division: 2015-02-23 *Scott Dunn

Constructing Division: Feb. 18, 2015 BRAD IRELAND

Financial Department:
(if over $1 million) GREG STOKOTELNY SEPT 2014

RECOMMENDED FOR IMPLEMENTATION:

Owning Div. Manager: 2015-02-23 *Scott Dunn

Business Unit V.P.: 2015-02-23 *Brent Reed

PRIMARY JUSTIFICATION:
Indicate key project driver(s):

☐ Safety	☐ Customer Service
☐ System Supply	☒ Efficiency
☐ System Reliability	☐ Environmental

NERC COMPLIANCE*: ☐ YES ☐ NO

*Determine if the project requires compliance with North American Electric Reliability Corporation (NERC) CIP Cyber Security Standards.

BUDGET $: (Total Net Cost)	$27,377,000
START DATE: (1st Cost Flow)	2014 08
IN-SERVICE DATE: (Last Major In-service Date)	2016 03
RISK MATRIX/ BUSINESS CASE TIER: (Optional)	
INVESTMENT REASONS: (Optional)	

OWNING DIVISION:

I.M. NODE NUMBER: 1.1.4.2 . 4.1 .05.1

W.B.S. NUMBERs: P:22348, P:22367, P:23710 .6.1

MAJOR ITEM ☐ **DOMESTIC ITEM** ☒

PREPARED BY: Tom Akerstream, Greg Stokotelny

DATE PREPARED: 2014 09 04

REPORT NUMBER:

FILE NUMBER (Optional):

Feb 26/15

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION

Project Name
Rural District Reorganization: includes Ashern District Office, Neepawa District Office, and Rural Relocation - Phase 2 (Renovations).

Recommendation
Construct two new district offices and undertake the renovation and retrofit of existing rural offices to accommodate the relocation of staff.

Project Scope
The project scope consists of two new district offices, including construction and fit out for; Ashern District Office $7.4 million, and the Neepawa District Office $8.9 million. The project scope also contains the renovation and retrofit of existing rural offices to accommodate the relocation of staff displaced from the closing of other district offices $11.0 million.

Background
Board approved Rural District Reorganization. To accommodate the requirements of Rural Relocations, Corporate Facilities needs to construct two new district offices and renovate 13 existing rural sites.

JUSTIFICATION—BUSINESS CASE ANALYSIS (SUMMARY):

Justification and Link to Corporate/Business Unit Goals
Executive approved Rural District Reorganization. The current district offices cannot accommodate the increase in staff displaced from the closure of other rural district offices and therefore need to be expanded. In some cases this expansion requires minor renovations of existing facilities, while in other facilities major additions need to be constructed. In the case of the two new district offices, renovations of the two existing facilities is not economically feasible requiring the construction of two new facilities (This was determined before the rural relocation plan was initiated). In addition, This project will also serve the needs of associated rural groups including Apparatus Maintenance, Line Maintenance, OH Construction, and others as required.

ANALYSIS OF ALTERNATIVES:

Economic Analysis		
Discount Rate	For current corporate rates see G911 %	For clarification on hurdle rates, contact the Economic Analysis Department

Recommended Option	NPV Benefits (Costs)
N/A	N/A

Capital Project Justification

Other Alternatives Considered	NPV Benefits/(Costs)
N/A	

Risk Analysis
If these projects are not undertaken Manitoba Hydro will not be able to service its rural customers appropriately.

Capital Budget Estimate

The annual net budget requirements are as follows (in thousands of dollars):

Fiscal Year	Proposed Budget	
Prev. Actuals	$	677
2014/15	$	10,500
2015/16	$	16,200
2016/17+	$	-
Total	$	27,377

Proposed Schedule

Nothing significant to note.

Related Projects

Rural District Reorganization.

Reference Documents

Rural District Reorganization.

CER(1) Rev. 97 12

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

Title		Investment Management Node:
Rural Relocation - Phase 2		1.1.4.2.6.1
Owning Division: Workplace Safety & Health and Corp Serv	Coordinating Division: Workplace Safety & Health and Corp Serv	ProjectNumber: P:23710

DESCRIPTION:
The project scope includes renovation and retrofit of existing offices to accommodate the relocation of staff displaced from the closing of other district offices $11.0 million.

This is part of the Rural Disrict Reorganization. This is one project of many which will see the construction of two new district offices and undertake the renovation and retrofit of 13 existing rural sites to accommodate the relocation of staff.

IN SERVICE DATES

Base estimate 2014/04/01 CLASS 0
Work start date 2014/10/01

PREV.AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Actual cost to date:						
(Over)under expend:						
V-DMA TOTAL						
REV. AMOUNTS:						
Actual cost to date:						
(Over)under expend:						
Auth 2014/15	3000					3000
Req: 2015/16	8000					8000
V-HLD TOTAL	11000					11000

Prepared by	yy mm dd	Approved by	yy mm dd	Approved by	yy mm dd	Approved by	yy mm dd
GS	14 09 19	OWNING DIVISION	15 02 23	COORDINATING DIVISION	15 02 10	VICE PRESIDENT	15 02 24

Feb 26/15

2014/09/19 11:16AM

CER(1) Rev. 97 12

CAPITAL EXPENDITURE REVISION

FORECAST HISTORY (in thousands of dollars)

ProjectNumber P:23710

Approved yy mm	TOTAL AMOUNT	COMMENTS

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
2014/15 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct	500					500	500
Nov	500					500	1000
Dec	500					500	1500
Jan	500					500	2000
Feb	500					500	2500
Mar	500					500	3000
TOTAL	3000					3000	3000
2015/16 Apr	667					667	667
May	667					667	1334
Jun	667					667	2001
Jul	667					667	2668
Aug	667					667	3335
Sep	667					667	4002
Oct	667					667	4669
Nov	667					667	5336
Dec	667					667	6003
Jan	667					667	6670
Feb	667					667	7337
Mar	663					663	8000
TOTAL	8000					8000	8000

2014/09/19 11:16AM

CER(1) Rev. 97 12

CAPITAL EXPENDITURE REVISION

(IN THOUSANDS OF DOLLARS)

Title		Investment Management Node:
Ashern District Office		1.1.4.2.4.1
Owning Division: Workplace Safety & Health and Corp Serv	Coordinating Division: Workplace Safety & Health and Corp Serv	ProjectNumber: P:22348

DESCRIPTION:

To build a new District Office in Ashern. Scope includes: Building Construction & Outfitting.

This is part of the Rural Disrict Reorganization. This is one project of many which will see the construction of two new district offices and undertake the renovation and retrofit of 13 existing rural sites to accommodate the relocation of staff.

IN SERVICE DATES						Base estimate 2014/04/01 CLASS 0
2015/12/31	7438					Work start date 2013/10/01
PREV.AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Actual cost to date:	238					238
(Over)under expend:	-238					-238
V-DMA TOTAL						
REV. AMOUNTS:						
Actual cost to date:	238					238
(Over)under expend:						
Auth 2014/15	3379	37	84			3500
Req: 2015/16	3384	87	229			3700
V-HLD TOTAL	7001	124	313			7438

Prepared by	yy mm dd	Approved by	yy mm dd	Approved by	yy mm dd	Approved by	yy mm dd
65	15 09 19	OWNING DIVISION	15 02 23	COORDINATING DIVISION	15 02 10	VICE-PRESIDENT	15 02 24

2014/09/19 11:16AM

CER(1) Rev. 97 12

CAPITAL EXPENDITURE REVISION

FORECAST HISTORY (in thousands of dollars)

ProjectNumber P:22348

Approved yy mm	TOTAL AMOUNT	COMMENTS

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
2014/15 Apr	13		1			14	14
May	14		1			15	29
Jun	28		1			29	58
Jul	378	2	1			381	439
Aug	363	2	3			368	807
Sep	363	3	5			371	1178
Oct	402	4	7			413	1591
Nov	344	4	9			357	1948
Dec	363	5	11			379	2327
Jan	383	5	13			401	2728
Feb	344	5	13			362	3090
Mar	384	7	19			410	3500
TOTAL	3379	37	84			3500	3500
2015/16 Apr	348	7	17			372	372
May	367	8	20			395	767
Jun	406	9	21			436	1203
Jul	406	10	24			440	1643
Aug	367	9	26			402	2045
Sep	367	10	27			404	2449
Oct	387	11	30			428	2877
Nov	367	11	31			409	3286
Dec	369	12	33			414	3700
Jan							3700
Feb							3700
Mar							3700
TOTAL	3384	87	229			3700	3700

2014/09/19 11:16AM

CER(1) Rev. 97 12

CAPITAL EXPENDITURE REVISION

(IN THOUSANDS OF DOLLARS)

Title		Investment Management Node:
Neepawa District Office		1.1.4.2.5.1
Owning Division: Workplace Safety & Health and Corp Serv	Coordinating Division: Workplace Safety & Health and Corp Serv	ProjectNumber: P:22367

DESCRIPTION:

To build a new District Office in Neepawa. Scope includes: Building Constructiong & outfitting.

This is part of the Rural Disrict Reorganization. This is one project of many which will see the construction of two new district offices and undertake the renovation and retrofit of 13 existing rural sites to accommodate the relocation of staff.

IN SERVICE DATES			Base estimate 2014/04/01 CLASS 0
2015/12/31	8938		Work start date 2013/10/01

PREV.AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Actual cost to date:	438		1			439
(Over)under expend:	-438		-1			-439
V-DMA TOTAL						
REV. AMOUNTS:						
Actual cost to date:	438		1			439
(Over)under expend:						
Auth 2014/15	3852	42	106			4000
Req: 2015/16	4119	106	275			4500
V-HLD TOTAL	8409	148	382			8939

Feb 26/15

Prepared by	yy mm dd	Approved by	yy mm dd	Approved by	yy mm dd	Approved by	yy mm dd
65	14 09 15	OWNING DIVISION	15 02 23	COORDINATING DIVISION	15 02 10	VICE PRESIDENT	15 02 24

2014/09/19 11:16AM

CER(1) Rev. 97 12

CAPITAL EXPENDITURE REVISION

FORECAST HISTORY (in thousands of dollars)

ProjectNumber P:22367

Approved yy mm	TOTAL AMOUNT	COMMENTS

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
2014/15 Apr	22		2			24	24
May	23		2			25	49
Jun	23		2			25	74
Jul	435	2	3			440	514
Aug	413	3	5			421	935
Sep	413	3	7			423	1358
Oct	457	4	9			470	1828
Nov	392	4	11			407	2235
Dec	413	5	13			431	2666
Jan	435	6	16			457	3123
Feb	392	6	16			414	3537
Mar	434	9	20			463	4000
TOTAL	3852	42	106			4000	4000
2015/16 Apr	424	8	21			453	453
May	447	9	24			480	933
Jun	494	11	25			530	1463
Jul	494	12	28			534	1997
Aug	447	12	31			490	2487
Sep	447	12	32			491	2978
Oct	471	14	36			521	3499
Nov	447	14	37			498	3997
Dec	448	14	41			503	4500
Jan							4500
Feb							4500
Mar							4500
TOTAL	4119	106	275			4500	4500

2014/09/19 11:16AM

Stokotelny, Greg

From: Lockhart, Barbara
Sent: Friday, September 12, 2014 8:44 AM
To: Stokotelny, Greg
Subject: Rural Restructuring Minute

Greg, this is the only minute I could find. It's from the April 24, 2013 meeting.

835-13-04

Rural District Reorganization

S.A. Dunn and J.B. Thievin entered the meeting and gave a presentation dealing with Rural District Reorganization.

Following discussion, the Board resolved to approve proceeding with this initiative.

Barb Lockhart | Executive Paralegal
Manitoba Hydro | blockhart@hydro.mb.ca
360 Portage Avenue (22) | Winnipeg, MB | R3C 0G8
t 204.360.4450 | f 204.360-6147

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E1910E

MANITOBA HYDRO
INTEROFFICE MEMORANDUM

FROM	G. B. (Brent) Reed Vice President Customer Service & Distribution	**TO**	Brad Ireland Division Manager Workplace Safety & Health and Corporate Services

DATE 2016 09 14

FILE

SUBJECT **CPJ ADDENDUMS 1) RURAL DISTRICT REORGANIZATION PHASE 2A – ADDENDUM #1 AND 2) RURAL DISTRICT REORGANIZATION PHASE 2B – PRE-CONSTRUCTION ADDENDUM #1**

Please find attached the two CPJ addendums that I had questioned a few weeks ago. I have signed each of them subject to consideration of this memorandum and associated comments.

In 2006 Customer Service Operations (CSO) began a phased approach moving toward a new customer service delivery model at the district level. The concept became known as the Customer Service Centre (CSC) model whereby we intended to begin a process for consolidation of many of the 66 rural district offices to 16 CSCs plus 12 rural satellite offices. In addition there was to be 5 CSCs in Winnipeg.

At that time I instructed Facilities to discontinue all planned capital and maintenance work on all CSO offices until the structure had final approval, etc. This unfortunately took until 2013 to occur. As a result there had been virtually nothing spent on these facilities for approximately 7 or 8 years. Also during this period various work groups such as Apparatus Maintenance and Transmission Line Maintenance continued with some controlled growth in terms of staffing. As a result of the hold on spend, the corporation saved capital and operating dollars over this 7 or 8 year period.

Moving forward subsequent to government approvals, we were able to make a decision on 24 buildings that will not be required, construction of two new buildings in Ashern and Neepawa and the requirement for renovations, additions and catch-up maintenance on a number of the remaining buildings.

The primary driver for some of the renovations was district consolidation, however other spending was required to properly maintain the existing buildings, expand some due to pre-existing overcrowding and other business needs outside of CSO requirements. A good example of this being the Selkirk and Steinbach Service Centres. The total CSC requirements aside from the new buildings represented approximately $6M.

In light of this background, I would have preferred to see these CPJs entitled "Facility Upgrades and Maintenance" versus the continued leveraging of "Rural District Re-organization" and that the CPJ addendums more accurately represented the detailed spend required. As it is, both addendums are very similar in their wording if not identical and are misleading from a justification perspective.

Please ensure that a copy of this memo is attached to each CPJ in order to put the situation into perspective. If you have any questions please advise.

Thank you.

GBR/rma
Atts. 1) CPJ Addendum – Rural District Re-organization Phase 2A Add. #1
2) CPJ Addendum – Rural District Re-organization Phase 2B Add. #1

C: Cyril Patterson
Greg Stoketelny

D1876(A)

CAPITAL PROJECT JUSTIFICATION ADDENDUM FOR

RURAL DISTRICT REORGANIZATION PHASE 2A Addendum Number 1

REVIEWED BY:
(Requesting Dept Manager) 2016/06/21

NOTED BY:
(if applicable)

Responsible Division:

Constructing Division: May 21/16

Financial Department: (if over $1 million) 2016/06/21

RECOMMENDED FOR IMPLEMENTATION:

Requesting Div. Manager:

Business Unit V.P.: See attached memo 16/09/14

PRIMARY JUSTIFICATION:
Indicate key project driver(s):

☐	Safety	☐	Customer Service
☐	System Supply	☒	Efficiency
☐	System Reliability	☐	Environmental

NERC COMPLIANCE*: ☐ YES ☐ NO

*Determine if the project requires compliance with North American Electric Reliability Corporation (NERC) CIP Cyber Security Standards.

PREV. APPROVED BUDGET $: (Use $ value from approved CPJ or last approved CPJ Addendum)	$10,500,000
REVISED BUDGET $: (Total Net Cost)	$18,828,000
START DATE: (1st Cost Flow)	2015 04
PREV. APPROVED ISD: (Use In-service Date from approved CPJ or last approved CPJ Addendum)	2017 03
REVISED ISD: (Last Major In-service Date)	2017 03

REQUESTING DIVISION:	50495
I.M. NODE NUMBER:	1.1.4.2.6.1
W.B.S. NUMBERs:	P:23710
MAJOR ITEM ☐	**DOMESTIC ITEM** ☒
PREPARED BY:	Tom Akerstream, Angelo Battistoni
DATE PREPARED:	2016 05 25
REPORT NUMBER:	
FILE NUMBER (Optional):	

Tuesday, May 31, 2016

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION ADDENDUM

Project Name (This section is required for all Addendums).

Rural District Reorganization: Rural Relocation Phase 2A (Renovations).

Recommendation (This section is required for all Addendums).

This includes renovations and retrofit of existing rural offices (Morden, Portage La Prairie, Virden, Russell, 805 Greenwood Selkirk, Brandon, and Steinbach) to accommodate the relocation of staff.

Project Scope (This section is be filled out only if there is a change to the scope).

The project scope also contains the renovation and retrofit and an increase due to additional requirements of existing rural offices (Morden, Portage La Prairie, Virden, Russell, 805 Greenwood Selkirk, Brandon, and Steinbach) to accommodate the relocation of staff displaced from the closing of other district offices $18.8 million.

Background (This section is be filled out only if there is information relevant to the recommendation).

Board approved Rural District Reorganization.

The original CPJ was created at level 4 of the IM node Corporate Buildings. It was decided to split this into 4 CPJs at the level 6 IM node. This CPJ was originally created with a value of $10.5 million. After a review during CEF 16 it was noted that the scope should increase due to additional requirements of $8.3 million.

To accommodate the requirements of Rural Relocations, Corporate Facilities needs to construct two new district offices and renovate 13 existing rural sites.

Justification (This section is required for all addendums).

Executive approved Rural District Reorganization.

The current district offices cannot accommodate the increase in staff displaced from the closure of other rural district offices and therefore need to be expanded. In some cases this expansion requires minor renovations of existing facilities, while in other facilities major additions need to be constructed. In the case of the two new district offices, renovations of the two existing facilities is not economically feasible requiring the construction of two new facilities (This was determined before the rural relocation plan was initiated). In addition, This project will also serve the needs of associated rural groups including Apparatus Maintenance, Line Maintenance, OH Construction, and others as required.

ANALYSIS OF ALTERNATIVES: (This section is be filled out only if there is a change to which alternative is being recommended).

Economic Analysis		
Discount Rate	% For current corporate rates see G911	For clarification on hurdle rates, contact Economic Analysis Department

Recommended Option	NPV Benefits/(Costs)
N/A	N/A

Other Alternatives Considered	NPV Benefits/(Costs)
N/A	

Risk Analysis – (This section is be filled out only if there is a change to the project risk):

If these projects are not undertaken Manitoba Hydro will not be able to service its rural customers appropriately.

Total Budget – (This section is required for all Addendums):

The impact on annual budget requirements is as follows (in thousands of dollars):

Fiscal Year	Prev. Approved CPJ/Addendum	Proposed CPJ Addendum	Increase (Decrease)
Prev. Actuals	$ 4	$ 4	$ -
2014/15	$ 2,996	$ 2,155	$ (841)
2015/16	$ 7,500	$ 6,697	$ (803)
2016/17	$ -	$ 9,972	$ 9,972
Total	$ 10,500	$ 18,828	$ 8,328

Proposed Schedule (This section is be filled out only if there is a change to the project schedule):

Related Projects (This section is be filled out only if changed).

Rural District Reorganization.

Reference Documents (This section is be filled out only if changed).
Rural District Reorganization.

CER(1) Rev. 97 12

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

Title		Investment Management Node:
Rural Relocation - Phase 2		1.1.4.2.6.1
Responsible Division	Requesting Division	ProjectNumber:
Workplace Safety & Health and Corp Serv	Workplace Safety & Health and Corp Serv	P:22810 - P:23838

DESCRIPTION:
Renovation and retrofit of existing offices to accommodate the relocation of staff displaced from the closing of other district offices.

This is part of the Rural District Reorganization. This is one project of many which will see the construction of two new district offices and undertake the renovation and retrofit of 13 existing rural sites to accommodate the relocation of staff.

JUSTIFICATION:
Executive approved Rural District Reorganization.

The current district offices cannot accommodate the increase in staff displaced from the closure of other rural district offices and therefore need to be expanded. In some cases this expansion requires minor renovations of existing facilities, while in other facilities major additions need to be constructed. In the case of the two new district offices, renovations of the two existing facilities is not economically feasible requiring the construction of two new facilities (This was determined before the rural relocation plan was initiated). In addition, This project will also serve the needs of associated rural groups including Apparatus Maintenance, Line Maintenance, OH Construction, and others as required.

REFERENCE:
CPJ - "RURAL DISTRICT REORGANIZATION".
Addendum #1 - "RURAL DISTRICT REORGANIZATION PHASE 2A"

REVISION:
May 3, 2016

The original CPJ was created at level 4 of the IM node Corporate Buildings. It was decided to split this into 4 CPJs at the level 6 IM node. This CPJ was originally created with a value of $10.5 million. After a review during CEF 16 it was noted that the scope should increase due to additional requirements of $8.3 million.

To accommodate the requirements of Rural Relocations, Corporate Facilities needs to construct two new district offices and renovate 13 existing rural sites.

Project scope includes the renovation and retrofit and an increase due to additional requirements of existing rural offices (Morden, Portage La Prairie, Virden, Russell, 805 Greenwood Selkirk, Brandon, and Steinbach) to accommodate the relocation of staff displaced from the closing of other district offices $18.8 million.

IN SERVICE DATES					Base estimate 2016/04/01 CLASS 0
2017/03/31	18828				Work start date 2014/02/01

PREV.AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Actual cost to date:	8625		231			8856
(Over)under expend:	2375		-231			2144
V-CPJ TOTAL	11000					11000
REV. AMOUNTS:						
Actual cost to date:	8625		231			8856
(Over)under expend:						
Auth 2016/17 Req.:	9595	107	270			9972
V-HLD TOTAL	18220	107	501			18828

Prepared by	yy mm dd	Approved by	yy mm dd	Approved by	yy mm dd	Approved by	yy mm dd
HB	16 06 21	RESPONSIBLE DIVISION	16 06 21	REQUESTING DIVISION		VICE PRESIDENT	16 09 14

2016/06/17 5:05PM

CER(1) Rev. 97 12

CAPITAL EXPENDITURE REVISION

FORECAST HISTORY (in thousands of dollars)

ProjectNumber P:22810 - P:23838

Approved yy mm	TOTAL AMOUNT	COMMENTS
2014 09	10,500	New Item

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
2016/17 Apr	46		32			78	78
May	49		34			83	161
Jun	979	3	1			983	1144
Jul	930	5	5			940	2084
Aug	1028	7	10			1045	3129
Sep	930	8	14			952	4081
Oct	930	10	19			959	5040
Nov	979	12	22			1013	6053
Dec	881	12	28			921	6974
Jan	930	15	32			977	7951
Feb	881	15	33			929	8880
Mar	1032	20	40			1092	9972
TOTAL	9595	107	270			9972	9972
2017/18 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

2016/06/17 5:05PM

E1910E

MANITOBA HYDRO
INTEROFFICE MEMORANDUM

FROM	G. B. (Brent) Reed Vice President Customer Service & Distribution	**TO**	Brad Ireland Division Manager Workplace Safety & Health and Corporate Services

DATE 2016 09 14

FILE

SUBJECT **CPJ ADDENDUMS 1) RURAL DISTRICT REORGANIZATION PHASE 2A – ADDENDUM #1 AND 2) RURAL DISTRICT REORGANIZATION PHASE 2B – PRE-CONSTRUCTION ADDENDUM #1**

Please find attached the two CPJ addendums that I had questioned a few weeks ago. I have signed each of them subject to consideration of this memorandum and associated comments.

In 2006 Customer Service Operations (CSO) began a phased approach moving toward a new customer service delivery model at the district level. The concept became known as the Customer Service Centre (CSC) model whereby we intended to begin a process for consolidation of many of the 66 rural district offices to 16 CSCs plus 12 rural satellite offices. In addition there was to be 5 CSCs in Winnipeg.

At that time I instructed Facilities to discontinue all planned capital and maintenance work on all CSO offices until the structure had final approval, etc. This unfortunately took until 2013 to occur. As a result there had been virtually nothing spent on these facilities for approximately 7 or 8 years. Also during this period various work groups such as Apparatus Maintenance and Transmission Line Maintenance continued with some controlled growth in terms of staffing. As a result of the hold on spend, the corporation saved capital and operating dollars over this 7 or 8 year period.

Moving forward subsequent to government approvals, we were able to make a decision on 24 buildings that will not be required, construction of two new buildings in Ashern and Neepawa and the requirement for renovations, additions and catch-up maintenance on a number of the remaining buildings.

The primary driver for some of the renovations was district consolidation, however other spending was required to properly maintain the existing buildings, expand some due to pre-existing overcrowding and other business needs outside of CSO requirements. A good example of this being the Selkirk and Steinbach Service Centres. The total CSC requirements aside from the new buildings represented approximately $6M.

In light of this background, I would have preferred to see these CPJs entitled "Facility Upgrades and Maintenance" versus the continued leveraging of "Rural District Re-organization" and that the CPJ addendums more accurately represented the detailed spend required. As it is, both addendums are very similar in their wording if not identical and are misleading from a justification perspective.

Please ensure that a copy of this memo is attached to each CPJ in order to put the situation into perspective. If you have any questions please advise.

Thank you.

GBR/rma
Atts. 1) CPJ Addendum – Rural District Re-organization Phase 2A Add. #1
2) CPJ Addendum – Rural District Re-organization Phase 2B Add. #1

C: Cyril Patterson
Greg Stoketelny

D1876(A)

CAPITAL PROJECT JUSTIFICATION ADDENDUM FOR

RURAL DISTRICT REORGANIZATION
PHASE 2B Pre-Construction
Addendum Number 1

REVIEWED BY:
(Requesting Dept Manager) 2016/06/21

NOTED BY:
(if applicable)

Responsible Division:

Constructing Division: 2016/06/21

Financial Department:
(if over $1 million) 2016/06/21

RECOMMENDED FOR IMPLEMENTATION:

Requesting Div. Manager:

Business Unit V.P.: see attached memo 16/09/14

PREV. APPROVED BUDGET $: (Use $ value from approved CPJ or last approved CPJ Addendum)	$500,000
REVISED BUDGET $: (Total Net Cost)	$1,522,000
START DATE: (1st Cost Flow)	2015 04
PREV. APPROVED ISD: (Use In-service Date from approved CPJ or last approved CPJ Addendum)	2017 03
REVISED ISD: (Last Major In-service Date)	2017 03

PRIMARY JUSTIFICATION:
Indicate key project driver(s):

☐ Safety	☐ Customer Service
☐ System Supply	☒ Efficiency
☐ System Reliability	☐ Environmental

NERC COMPLIANCE*: ☐ YES ☐ NO

*Determine if the project requires compliance with North American Electric Reliability Corporation (NERC) CIP Cyber Security Standards.

REQUESTING DIVISION:	50495
I.M. NODE NUMBER:	1.1.4.2.6.2
W.B.S. NUMBERs:	P:26957
MAJOR ITEM ☐	**DOMESTIC ITEM** ☒
PREPARED BY:	Tom Akerstream, Angelo Battistoni
DATE PREPARED:	2016 05 25
REPORT NUMBER:	
FILE NUMBER (Optional):	

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION ADDENDUM

Project Name (This section is required for all Addendums).

Rural District Reorganization: Rural Relocation Phase 2B (Renovations).

Recommendation (This section is required for all Addendums).

This includes renovations and retrofit of existing rural offices (Lac Du Bonnet, Arborg, Killarney, and Dauphin) to accommodate the relocation of staff.

Project Scope (This section is be filled out only if there is a change to the scope).

The project scope contains the pre-construction cost (design and site prep work) for four existing rural offices. If the project is approved by the government there will be an additional $13.5 million plus interest cost for the renovation and retrofit of the existing rural offices (Lac Du Bonnet, Arborg, Killarney, and Dauphin) to accommodate the relocation of staff displaced from the closing of other district offices.

Background (This section is be filled out only if there is information relevant to the recommendation).

Board approved Rural District Reorganization.

The original CPJ was created at level 4 of the IM node Corporate Buildings. It was decided to split this into four CPJs at the level 6 IM node. This CPJ was originally created with a value of $0.5 million. After a review during CEF 16 it was noted that the scope should increase due to additional pre-construction requirements of $1.0 million.

To accommodate the requirements of Rural Relocations, Corporate Facilities needs to construct two new district offices and renovate 13 existing rural sites.

Justification (This section is required for all addendums).

Executive approved Rural District Reorganization.

The current district offices cannot accommodate the increase in staff displaced from the closure of other rural district offices and therefore need to be expanded. In some cases this expansion requires minor renovations of existing facilities, while in other facilities major additions need to be constructed. In the case of the two new district offices, renovations of the two existing facilities is not economically feasible requiring the construction of two new facilities (This was determined before the rural relocation plan was initiated). In addition, This project will also serve the needs of associated rural groups including Apparatus Maintenance, Line Maintenance, OH Construction, and others as required.

ANALYSIS OF ALTERNATIVES: (This section is be filled out only if there is a change to which alternative is being recommended).

Economic Analysis		
Discount Rate	% For current corporate rates see G911	For clarification on hurdle rates, contact Economic Analysis Department

Recommended Option	NPV Benefits/(Costs)
N/A	N/A

Other Alternatives Considered	NPV Benefits/(Costs)
N/A	

Risk Analysis – (This section is be filled out only if there is a change to the project risk).

If these projects are not undertaken Manitoba Hydro will not be able to service its rural customers appropriately.

Total Budget – (This section is required for all Addendums).

The impact on annual budget requirements is as follows (in thousands of dollars):

Fiscal Year	Prev. Approved CPJ/Addendum	Proposed CPJ Addendum	Increase (Decrease)
Prev. Actuals	$ -	$ 461	$ 461
2016/17	$ -	$ 1,061	$ 1,061
Total	$ -	$ 1,522	$ 1,522

Proposed Schedule (This section is be filled out only if there is a change to the project schedule).

Related Projects (This section is be filled out only if changed).

Rural District Reorganization.

Capital Project Justification Addendum

Reference Documents (This section is be filled out only if changed).
Rural District Reorganization.

CER(1) Rev. 97 12

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

Title		Investment Management Node:
Rural Relocation - Phase 2B		1.1.4.2.6.2
Responsible Division: Workplace Safety & Health and Corp Serv	Requesting Division: Workplace Safety & Health and Corp Serv	ProjectNumber: P:24333 - P:26957

DESCRIPTION:
Renovation and retrofit of existing offices to accommodate the relocation of staff displaced from the closing of other district offices.

This is part of the Rural Disrict Reorganization. This is one project of many which will see the construction of two new district offices and undertake the renovation and retrofit of 13 existing rural sites to accommodate the relocation of staff.

JUSTIFICATION:
Executive approved Rural District Reorganization.

The current district offices cannot accommodate the increase in staff displaced from the closure of other rural district offices and therefore need to be expanded. In some cases this expansion requires minor renovations of existing facilities, while in other facilities major additions need to be constructed. In the case of the two new district offices, renovations of the two existing facilities is not economically feasible requiring the construction of two new facilities (This was determined before the rural relocation plan was initiated). In addition, This project will also serve the needs of associated rural groups including Apparatus Maintenance, Line Maintenance, OH Construction, and others as required.

REFERENCE:
CPJ - "RURAL DISTRICT REORGANIZATION".
Addendum #1 - "RURAL DISTRICT REORGANIZATION PHASE 2B Pre-Construction"

REVISION:
May 3, 2016

The original CPJ was created at level 4 of the IM node Corporate Buildings. It was decided to split this into 4 CPJs at the level 6 IM node. This CPJ was originally created with a value of $0.5 million. After a review during CEF 16 it was noted that the scope should increase due to additional pre-construction requirements of 1.0 million.

To accommodate the requirements of Rural Relocations, Corporate Facilities needs to construct two new district offices and renovate 13 existing rural sites.

The project scope includes the pre-construction cost (Design and site prep work) for 4 existing rural offices. If the project is approved by the government there will be an additional $13.5 million plus interest cost for the renovation and retrofit of the existing rural offices (Lac Du Bonnet, Arborg, Killarney, and Dauphin) to accommodate the relocation of staff displaced from the closing of other district offices.

IN SERVICE DATES				Base estimate 2016/04/01 CLASS 0
2017/03/31	1522			Work start date 2014/04/01

PREV.AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Actual cost to date:	447		14			461
(Over)under expend:	-447		-14			-461
V-CPJ TOTAL						
REV. AMOUNTS:						
Actual cost to date:	447		14			461
(Over)under expend:						
Auth 2016/17	1024	11	26			1061
Req.:						
V-HLD TOTAL	1471	11	40			1522

Prepared by	yy mm dd	Approved by	yy mm dd	Approved by	yy mm dd	Approved by	yy mm dd
	16 06 21	RESPONSIBLE DIVISION	16 06 21	REQUESTING DIVISION		VICE-PRESIDENT	16 09 14

2016/06/17 5:01PM

CER(1) Rev. 97 12

CAPITAL EXPENDITURE REVISION

FORECAST HISTORY (In thousands of dollars)

ProjectNumber P:24333 - P:26957

Approved yy mm	TOTAL AMOUNT	COMMENTS
2014 09	500	New Item

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
2016/17 Apr	10		2			12	12
May	10		2			12	24
Jun	103					103	127
Jul	98	1	1			100	227
Aug	109	1	1			111	338
Sep	98	1	1			100	438
Oct	98	1	2			101	539
Nov	103	1	2			106	645
Dec	93	1	3			97	742
Jan	98	2	3			103	845
Feb	93	2	4			99	944
Mar	111	1	5			117	1061
TOTAL	1024	11	26			1061	1061
2017/18 Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Jan							
Feb							
Mar							
TOTAL							

2016/06/17 5:01PM

D1876

CAPITAL PROJECT JUSTIFICATION FOR

Rosser Site Development

REVIEWED BY:
(Owning Dept Manager)

NOTED BY:
(if applicable)

Coordinating Division:

Constructing Division:

Financial Department:
(if over $1 million)

RECOMMENDED FOR IMPLEMENTATION:

Owning Div. Manager: Brad Ireland Nov. 2/15

Business Unit V.P.: Bryan Luce

BUDGET $: (Total Net Cost)	$3,500,000
START DATE: (1st Cost Flow)	2015 09
IN-SERVICE DATE: (Last Major In-service Date)	2018 03
RISK MATRIX/ BUSINESS CASE TIER: (Optional)	
INVESTMENT REASONS: (Optional)	
OWNING DIVISION:	Workplace Safety & Health and Corp Services
I.M. NODE NUMBER:	1.1.4.2.3.2
W.B.S. NUMBERs:	P:25470
MAJOR ITEM ☐	**DOMESTIC ITEM** ☒
PREPARED BY:	Tom Akerstream
DATE PREPARED:	2015 05 19
REPORT NUMBER:	
FILE NUMBER (Optional):	

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION

Project Name
Rosser Site Development

Recommendation
To develop the Rosser site to meet the objectives of the Corporate Facilities Master Plan.

Project Scope
Under the Corporate Facilities Master Plan, a number of business units will be moving services and activities to Rosser requiring site preparation to meet their functional requirements.

Background
Corporate Facilities developed the Master Plan establishing a strategy to meet the functional needs of Manitoba Hydro's business units. The plan contained development of the Rosser site to house a number of activities including the new Fleet Services building, the emergency fuel requirement storage, pole yard distribution centre and a mobilization site for a variety of work crews, etc. to meet these demands site preparation was required.

JUSTIFICATION—BUSINESS CASE ANALYSIS (SUMMARY):

Justification and Link to Corporate/Business Unit Goals
Master plan identified a number of opportunities to optimize business unit operation requirements. This saves time, money and staffing requirements. A business case is currently being prepared to rationalize the construction of the new Fleet Services building. Design work has been undertaken and completed for the building. Site preparation for the building needs to be completed to allow for the other business units to occupy the site. A second utilization of the site is to act as a pole yard distribution centre. This saves us a significant amount of money by implementing a supply chain management solution for the pole distribution process. The site will also house the emergency diesel fuel storage. This fuel will be used in the case of an emergency to ensure that Manitoba Hydro's key buildings are operational. The intent of the Rosser site is to create a distribution hub for a number of Manitoba Hydro services.

ANALYSIS OF ALTERNATIVES:

Economic Analysis		
Discount Rate	**For current corporate rates see G911** 4.75%	**For clarification on hurdle rates, contact the Economic Analysis Department**

Capital Project Justification

Recommended Option	NPV Benefits (Costs)
Name the recommended option and provide its Net Present Value (NPV).	NPV is usually negative in a "cost minimization" project where the justification is other than economic or financial i.e., safety, environment etc.

Other Alternatives Considered	NPV Benefits/(Costs)
List each alternative considered as well as its calculated NPV.	

Risk Analysis
Risk is minimal due to the flexibility of the project (site development can suspended if necessary).

Capital Project Justification

Capital Budget Estimate

The annual net budget requirements are as follows (in thousands of dollars):

Fiscal Year	Proposed Budget	
Prev. Actuals	$	-
2015/16	$	1,000
2016/17+	$	1,000
2017/18+	$	1,500
Total	$	3,500

Proposed Schedule

The Start Date and In-service Date should be on the cover sheet and do not need to be repeated here. Include information in this section that is pertinent to the schedule but in addition to those dates (i.e., Major Milestones).

Discussion about the risk of deferring the project past the recommended ISD should be covered under "Justification."

Related Projects

Fleet Services Building

Reference Documents

CER(1) Rev 97 12

CAPITAL EXPENDITURE REVISION

(IN THOUSANDS OF DOLLARS)

Title		Investment Management Node:
Rosser Site Master Plan Phase 1		1.1.4.2.3.2
Owning Division: Workplace Safety & Health and Corp Serv	Coordinating Division: Workplace Safety & Health and Corp Serv	ProjectNumber: P:25470

DESCRIPTION

Corporate Facilities developed the Master Plan establishing a strategy to meet the functional needs of Manitoba Hydro's business units. The plan contained development of the Rosser site to house a number of activities including the new Fleet Services building, the emergency fuel requirement storage, pole yard distribution centre and a mobilization site for a variety of work crews, etc. to meet these demands site preparation was required.

JUSTIFICATION

Master plan identified a number of opportunities to optimize business unit operation requirements. This saves time, money and staffing requirements. A business case is currently being prepared to rationalize the construction of the new Fleet Services building. Design work has been undertaken and completed for the building. Site preparation for the building needs to be completed to allow for the other business units to occupy the site.

A second utilization of the site is to act as a pole yard distribution centre. This saves us a significant amount of money by implementing a supply chain management solution for the pole distribution process.

The site will also house the emergency diesel fuel storage. This fuel will be used in the case of an emergency to ensure that Manitoba Hydro's key buildings are operational.

The intent of the Rosser site is to create a distribution hub for a number of Manitoba Hydro services.

REVISION

New item.

IN SERVICE DATES		Base estimate 2015/04/01 CLASS 0
2015/10/31	299	
2015/12/31	701	
2016/12/31	1000	Work start date 2015/07/01
2017/09/30	1500	

	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
PREV AUTHORITY						
Actual cost to date						
(Over)under expend						
V-CPJ TOTAL						
REV. AMOUNTS:						
Actual cost to date						
(Over)under expend						
Auth 2015/16	980	9	10			999
Req 2016/17	955	27	18			1000
2017/18	1417	66	17			1500
V-HLD TOTAL	3352	102	45			3499

Prepared by	yy mm dd	Approved by	yy mm dd	Approved by	yy mm dd	Approved by	yy mm dd
	15 10 05	OWNING DIVISION	15 11 02	COORDINATING DIVISION		VICE-PRESIDENT	

2015/10/01 11:39AM

CER(1) Rev. 97 12

CAPITAL EXPENDITURE REVISION

FORECAST HISTORY (in thousands of dollars)

ProjectNumber P:25470

Approved yy mm	TOTAL AMOUNT	COMMENTS

Forecasted Mthly Exp.		GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
2015/16	Apr							
	May							
	Jun							
	Jul	201	1				202	202
	Aug	182	1	1			184	386
	Sep	182	2	2			186	572
	Oct	192	2	3			197	769
	Nov	111	1	2			114	883
	Dec	112	2	2			116	999
	Jan							999
	Feb							999
	Mar							999
TOTAL		980	9	10			999	999
2016/17	Apr	104	2				106	106
	May	109	3				112	218
	Jun	109	3	1			113	331
	Jul	104	3	2			109	440
	Aug	115	3	2			120	560
	Sep	104	3	2			109	669
	Oct	104	3	3			110	779
	Nov	109	4	3			116	895
	Dec	97	3	5			105	1000
	Jan							1000
	Feb							1000
	Mar							1000
TOTAL		955	27	18			1000	1000

2015/10/01 11:39AM

DJ876(A)

CAPITAL PROJECT JUSTIFICATION ADDENDUM FOR

Rosser Site Development
Addendum Number 01

REVIEWED BY:
(Requesting Dept Manager)

NOTED BY:
(if applicable)

Responsible Division: Nov. 10/15

Constructing Division: Nov 10/15

Financial Department:
(if over $1 million) Nov/11/15

RECOMMENDED FOR IMPLEMENTATION:

Requesting Div. Manager: Nov. 10/15

Business Unit V.P.: Nov 19/15

PREV. BUDGET $: (Use $ value from approved CPJ or last approved CPJ Addendum)	$3,500,000
REVISED APPROVED BUDGET $: (Total Net Cost)	$1,000,000
START DATE: (1st Cost Flow)	2015 09
PREV. ISD: (Use In-service Date from approved CPJ or last approved CPJ Addendum)	2015 12
REVISED APPROVED ISD: (Last Major In-service Date)	2015 12
RISK MATRIX/ BUSINESS CASE TIER: (Optional)	
INVESTMENT REASONS: (Optional)	

REQUESTING DIVISION:	Workplace Safety & Health and Corp Services
I.M. NODE NUMBER:	1.1.4.2.3.2
W.B.S. NUMBERs:	P:25470
MAJOR ITEM ☐	**DOMESTIC ITEM** ☒
PREPARED BY:	Tom Akerstream
DATE PREPARED:	2015 11 02
REPORT NUMBER:	
FILE NUMBER (Optional):	

ADDENDUM NUMBER	DATE (yyyy mm dd)	REVISION	REVISED BY	APPROVED BY
1	2015 11 02	The utilization of the site to act as a pole yard distribution centre and the fleet bld parking lot and grounds has been removed from Phase 1, because these projects have been delayed.	Tom Akerstream	

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION ADDENDUM

Project Name (This section is required for all Addendums).
Rosser Site Development

Recommendation (This section is required for all Addendums).
To develop the Rosser site to meet the objectives of the Corporate Facilities Master Plan which has been adjusted to only include site preparation work to allow other business units to occupy the site.

Project Scope (This section is be filled out only if there is a change to the scope).
Under the Corporate Facilities Master Plan, a number of business units will be moving services and activities to Rosser requiring site preparation to meet their functional requirements.

Background (This section is be filled out only if there is information relevant to the recommendation).
Corporate Facilities developed the Master Plan establishing a strategy to meet the functional needs of Manitoba Hydro's business units. The plan contained development of the Rosser site to house a number of activities including the new Fleet Services building, the emergency fuel requirement storage, pole yard distribution centre and a mobilization site for a variety of work crews, etc. to meet these demands site preparation was required.

Justification (This section is required for all addendums).
Master plan identified a number of opportunities to optimize business unit operation requirements. This saves time, money and staffing requirements. Site preparation for the building needs to be completed to allow for the other business units to occupy the site.

ANALYSIS OF ALTERNATIVES: (This section is be filled out only if there is a change to which alternative is being recommended).

Economic Analysis		
Discount Rate	% For current corporate rates see G911	For clarification on hurdle rates, contact Economic Analysis Department

Recommended Option	**NPV Benefits/(Costs)**
Name the recommended option and provide its Net Present Value.	NPV may be negative in a "cost minimization" project where the justification is other than economic or financial i.e., safety, environment etc.

Other Alternatives Considered	**NPV Benefits/(Costs)**
List each alternative considered as well as its calculated NPV.	

Capital Project Justification Addendum

Other Alternatives Considered	**NPV Benefits/(Costs)**

Risk Analysis – (This section is be filled out only if there is a change to the project risk).

Risk is minimal due to the flexibility of the project (site development can suspended if necessary).

Total Budget – (This section is required for all Addendums).

The impact on annual budget requirements is as follows (in thousands of dollars):

Fiscal Year	Prev. Approved CPJ/Addendum	Proposed CPJ Addendum	Increase (Decrease)
Prev. Actuals	$ -	$ -	$ -
2015/16	$ 1,000	$ 1,000	$ -
2016/17	$ 1,000	$ -	$ (1,000)
2017/18	$ 1,500	$ -	$ (1,500)
Total	$ 3,500	$ 1,000	$ (2,500)

Proposed Schedule (This section is be filled out only if there is a change to the project schedule).

Related Projects (This section is be filled out only if changed).

Fleet Services Building

Reference Documents (This section is be filled out only if changed).

CER(1) Rev. 97 12

CAPITAL EXPENDITURE REVISION
(IN THOUSANDS OF DOLLARS)

Title		Investment Management Node:
Rosser Site Master Plan Phase 1		1.1.4.2.3.2
Responsible Division: Workplace Safety & Health and Corp Serv	Requesting Division: Workplace Safety & Health and Corp Serv	ProjectNumber: P:25470

DESCRIPTION:
Corporate Facilities developed the Master Plan establishing a strategy to meet the functional needs of Manitoba Hydro's business units. The plan contained development of the Rosser site to house a number of activities including the new Fleet Services building, the emergency fuel requirement storage, pole yard distribution centre and a mobilization site for a variety of work crews, etc. to meet these demands site preparation was required.

JUSTIFICATION:
Master plan identified a number of opportunities to optimize business unit operation requirements. This saves time, money and staffing requirements. A business case is currently being prepared to rationalize the construction of the new Fleet Services building. Design work has been undertaken and completed for the building. Site preparation for the building needs to be completed to allow for the other business units to occupy the site.

A second utilization of the site is to act as a pole yard distribution centre. This saves us a significant amount of money by implementing a supply chain management solution for the pole distribution process.

The site will also house the emergency diesel fuel storage. This fuel will be used in the case of an emergency to ensure that Manitoba Hydro's key buildings are operational.

The intent of the Rosser site is to create a distribution hub for a number of Manitoba Hydro services.

REVISION:
November 2, 2015

Total Project decreased by $2.5 million.

The utilization of the site to act as a pole yard distribution centre and the fleet bld parking lot and grounds has been removed from Phase 1, because these projects have been delayed.

IN SERVICE DATES		Base estimate 2015/04/01 CLASS 0
2015/10/31	481	
2016/12/31	541	Work start date 2015/04/01

PREV.AUTHORITY	GROSS	ESCALATION	INT.CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Actual cost to date:						
(Over)under expend:						
V-CPJ TOTAL						
REV. AMOUNTS:						
Actual cost to date:						
(Over)under expend:						
Auth 2015/16	973	7	20			1000
Req: 2016/17						
2017/18						
V-HLD TOTAL	973	7	20			1000

Prepared by	yy mm dd	Approved by	yy mm dd	Approved by	yy mm dd	Approved by	yy mm dd
AB	15 11 06	RESPONSIBLE DIVISION	15 11 10	REQUESTING DIVISION	15 11 10	VICE-PRESIDENT	15 11 19

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CAPITAL EXPENDITURE REVISION

FORECAST HISTORY (in thousands of dollars)

ProjectNumber P:25470

Approved yy mm	TOTAL AMOUNT	COMMENTS
2015 10	3,500	New Item

Forecasted Mthly Exp		GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
2015/16	Apr	52					52	52
	May	54					54	106
	Jun	60					60	166
	Jul	186	1	1			188	354
	Aug	168	1	2			171	525
	Sep	168	2	2			172	697
	Oct	177	2	3			182	879
	Nov	54	1	2			57	936
	Dec	54		2			56	992
	Jan			2			2	994
	Feb			2			2	996
	Mar			4			4	1000
TOTAL		973	7	20			1000	1000
2016/17	Apr							
	May							
	Jun							
	Jul							
	Aug							
	Sep							
	Oct							
	Nov							
	Dec							
	Jan							
	Feb							
	Mar							
TOTAL								

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