February 20, 2014

Manitoba Public Utilities Board

Manitoba Hydro Keeyask and Conawapa NFAT
PUB to PE Information Request Responses
Public IR's

PROJECT NUMBER:
132171
PROJECT CONTACT:
Ron Beazer
EMAIL:
ron.beazer@powereng.com
PHONE:
208-288-6632

POWER ENGINEERS

PREPARED FOR: MANITOBA PUBLIC UTILITIES BOARD
PREPARED BY: POWER ENGINEERS, INC.

REVISION HISTORY			
DATE	REVISED BY	REVISION	DESCRIPTION
2-20-2014	MG, BF, PA, GD, RB	0	Issued for Client Use

TABLE OF CONTENTS

PUB TO PE IR 1

CSI material is in red font and should be redacted in any public document.

SUBJECT: Transmission

REFERENCE: Pages 3, 5, 6, & 8.

PREAMBLE: PE was asked to "Review and assess the completeness and reasonableness of Manitoba Hydro's AC transmission line capital cost and O&M estimates including the adequacy of the Management Reserve for the project.

QUESTION: Please provide PE's analysis with respect to the O&M estimates and Management Reserves for the project.

RESPONSE (O&M):

The NFAT filing, Table 9-1 Economic Evaluation – Summary of Revenue and Cost Inputs, lists Operating and Maintenance expenses including capital maintenance as a cost element in the Plan-Specific Inputs. They are described as "Manitoba Hydro's O&M estimates for each facility in each development plan…." Appendix 9-2 which describes the SPLASH model indicates on page 1 of 65 that "future operating costs" are in input element. Appendix 9.3, Economic Summary Tables, provide the O & M for the entire alternative. Transmission line O & M is not broken out. Appendix 9.3, section 3.1.7 Fixed O & M – Fixed Operating and Maintenance Costs, describes the types of costs considered. They are described as the "…labor, operating and overhead costs associated with operating, maintaining and administering the incremental generation, transmission and interconnection facilities…."

There were no hard dollar values of O&M for transmission lines provided in the NFAT filing. MH has indicated that they have used historic O&M costs based on their experience from lines on their system.

O&M expenses vary widely between utilities depending on what they include in this category. Overhead transmission line Operation costs generally include labor and expenses for control and dispatching, switching, and other costs associated with the routine operation of a transmission line. Maintenance costs include the costs of scheduled vegetation management, scheduled inspection and servicing of equipment and components, painting, general repairs, emergency repairs and all other activities required to keep the line in proper operating condition. POWER reviewed the O&M expenses directly related to the line itself. These expenses include vegetation management expenses, field inspection expenses, routine repairs to the line, switching, and other activities directly related to the physical care of the line to maintain its reliability. Supervision and Engineering supporting these field activities are also included. These expenditures are generally stated in terms of $/km of line.

MH provided a table indicating that they use a $[redacted]/km rate for O & M expenses related to the physical transmission line. In their economic analysis, MH ramped up the O & M expenses over the first 7 years from $[redacted]/km to $[redacted]/km reflecting reduced need for maintenance due to the "newness" of the line, and then held it at a constant rate of $[redacted]/km over the life of the line. This is not a realistic expense scenario, since the O & M expenses for a transmission line generally increase as a line ages.

MH has stated that the O & M rate is based on their historic experience on their system, and not industry averages. The $[redacted]/km rate is lower than we have seen for other systems. For comparison, a report prepared by KEMA for the Connecticut Siting Council[1] gave a transmission line maintenance cost of

[1] Life-Cycle 2012, Connecticut Siting Council Investigation into the Life-Cycle Costs of Electric Transmission Lines, prepared by KEMA, Inc. , November 15, 2012, Page 6-10.

$1,937 USD/km. It was noted that the maintenance costs were impacted by the NERC requirements regarding clearance of lines to trees. The study was performed for calendar year 2010. MH's line routes are through the Boreal Forest in the north and agricultural land in the south. For lines in the Boreal Forest, a clear-cut right of way with proper consideration of the removal of "danger trees" would still incur periodic vegetation management costs. Lines in agricultural areas would have significantly lower vegetation management costs, generally related to isolated wood lots and wind rows. They may incur greater maintenance costs for wind related damage (aeolian vibration and galloping) than lines in the forested area. The rate used by MH is based on their historic cost per km of line. Based on this assertion, PE can accept their value as valid, but we note that it is lower than we would expect.

Adding transmission lines to the existing MH transmission system incurs little additional cost to the Operations Center. The addition of the two large generating stations and Bipole III will have a noticeable effect on the Operations Center, thus any added O&M contributed by the operations center is largely to be attributed to, and accounted for, in the generating station cost analyses.

RESPONSE:(Management Reserve)

The management reserve is described in the NFAT Filing as being an amount in addition to the normal construction contingency that is designed to cover major items that can cause the point estimate to change. Examples of these items are:

- Major Scope changes
- Significant changes in the construction marketplace
- Changes to escalation rates

Management reserve is determined after the contingency is calculated. (Appendix 2.4 pages 10, 11) Contingency is an amount that is expected to be partially, or fully expended during the course of the project. It includes uncertainties in the prices of equipment and materials that are included in the estimate. It also covers the uncertainty in the contract bid amounts. Contingencies are normally calculated on the basis of a percentage of construction that has been experienced on previous similar projects, and flavored by the engineer's estimation of the accuracy of the estimated material and equipment prices. The contingency becomes part of the base cost. The management reserve covers the global items that the design team has no control over, such as the items enumerated above.

The MH process used a sensitivity analysis to identify the impact that labor and escalation can have on the project. (Appendix 2.4 pages 18, 19) The sensitivity analysis showed that at their highest, they would cause the entire contingency to be consumed. Thus the labor and contingency management reserve was developed.

Appendix 2.4, page 27 indicates that the management reserve was entirely associated with the Keeyask and Conawapa plants. There is no management reserve shown for the transmission lines associated with those plants. Note that for the Keeyask project the lines constitute only 3% of the total plant cost, and for the Conawapa plant the lines constitute only 0.09% of the total cost.

POWER cannot express an opinion as to the adequacy of the management reserve for the transmission lines, since they do not seem to be separately allocated to the lines. There is not enough information to determine if there is a management reserve amount for the North-South Transmission or the MMTP transmission. Management reserve is not shown as part of their cost estimates. If the process described for determining the management reserve has been followed, the calculation of the management reserve for the project is a very thoughtful and thorough analysis.

PUB TO PE IR 2

SUBJECT: Transmission

PREAMBLE: The HVDC portion of the North-South Transmission Upgrade Project is described on p.5, and in the NFAT, as collector system upgrades, whereas on p. 6 of the PE report, the HVDC portion is described as upgrades to Bipole III itself.

The PE report further states that "Manitoba Hydro's preferred option, identified as 2A in their 'Integrated Transmission Plan for Keeyask and Conawapa Generation,' SPD 2011/11 [7] requires that Bipole III rating increase from…."

QUESTION: Please clarify the apparent inconsistency between the North-South Transmission Upgrade Project as described in the NFAT and as described in the PE report. Does the project involve an increase to the rating for Bipole III, or does it involve only collector system upgrades?

REFERENCE: PE report, pp. 5-6.

RESPONSE: Subsequent clarification from MH confirms that the North – South Transmission Upgrade Project does not include an increase to the rating for Bipole III from 2000 MW to 2300 MW. The 300 MW increase is part of the Bipole III project and is included as a base line assumption and necessary component of all NFAT alternatives studied, including Option 2A.

PUB TO PE IR 3a

SUBJECT: Transmission

PREAMBLE: PE states that "Because a detailed list of improvements needed to enhance Bipole III rating by 300 MW was not included for the $143 million stated above it is not clear what additional equipment would need to be included in the estimate and due to the valve sparing requirements for Bipole III the estimated cost for the enhancement would need to be requested from HVDC converter manufacturers."

QUESTION: Please explain why this information could not be obtained from Manitoba Hydro.

REFERENCE: PE report, pp. 5-6.

RESPONSE: POWER has subsequently obtained the necessary information and clarifications from MH. POWER's report was based on enhancing Bipole III rating by 300 MW at a cost of $143million. This was subsequently found to be incorrect. The "HVDC system upgrades" in the NFAT report that, estimated at $143 million, include improvements to the 1.) Northern Collector System, and 2.) Southern Collector System. These costs are addressed in more detail in PUB TO PE IR 3B.

PUB TO PE IR 3b

SUBJECT: Transmission

PREAMBLE: PE states that "Because a detailed list of improvements needed to enhance Bipole III rating by 300 MW was not included for the $143 million stated above it is not clear what additional equipment would need to be included in the estimate and due to the valve sparing requirements for Bipole III the estimated cost for the enhancement would need to be requested from HVDC converter manufacturers."

QUESTION: Please provide PE's analysis once the information has been provided by Manitoba Hydro.

REFERENCE: PE report, pp. 5-6.

RESPONSE: Based on clarified information from Manitoba Hydro the Preamble stated above would be revised as follows:

The HVDC system upgrades and Equipment upgrades identified in the Reference 4 cost breakdown can be further quantified. The HVDC system upgrades include:

HVDC System Upgrades	(2011) Millions
1. Northern Collector System:	
a. Radisson 300 MVAR filter	$55.0
b. Radisson MOD to switch Kettle Units (200 MW)	$10.0
2. Southern Collector System:	
a. Reil Compensation 1x250 MVAR Synchronous Condenser	$68.1
b. Breaker Replacement (Laverendrye, Transcona)	$ 2.0
c. Sectionalization of one 230 kV line	$ 5.0
Total	$140.1

Equipment Upgrades that support the AC transmission for integrating Keeyask and Conawapa Generation are enumerated as follows:

Network Upgrades	**Includes**	**Cost Estimate (millions)**
Dauphin/Neepawa stations	230 kV breaker termination at Dauphin	2.5
	New 230 kV Neepawa station	10.0
Herblet Lake/Overflowing stations	230 kV breaker termination at each end	7.0
	50% series compensation – 43 MVA	3.2
Kelsey/Birchtree stations	230 kV breaker termination at each end	7.0
Birchtree/Wuskwatim stations	230 kV breaker termination at each end	7.0
SVC at Overflowing River	50 MVAR	7.5
230 kV line F10M	155 km line – re-tension	2.3
230 kV lines G1A and G2A	Replace risers on both lines at both ends	0.4
230 kV line G8P[3]	17 km line – re-tension – (Correction 176 km)	2.6

110 kV line MR11	Raven Lake-MR11 tap – replace risers and 50km line re-tension	0.8
	Replace CT at Brandon end of MR11	0.2
230-110 kV Raven Lake transformer	Replace transformer bank	6.0
230 kV line G9F	143 km line re-tension	2.0
	Total	58.5

Notes:

1. The $55 million estimated cost was based on a recently completed filter replacement project at Radisson for Bipole I. Based on Manitoba Hydro's preliminary assessment the 300 MVAR filter project will continue to replace some of the existing Bipole I filters at Radisson with a modified design that will increase the MVAR ratings and the addition of some new filters that will be determined upon completion of a detail design study that is being performed. The estimates include the engineering, procurement, design and constructions and associate yard work modifications.
2. A 2% escalation was applied to this estimate before including it into the NFAT filing resulting in $140 M x 1.02 = $143 million.
3. During investigation of Manitoba Hydro's cost information it was discovered that the G8P 230 kV line is 176 km in length and the 17 km was an entry error, with this correction all of the 230 kV line re-tension projects cost between $16k/km to $18/km.

PUB TO PE IR 4

SUBJECT: Transmission

PREAMBLE: PE identified Table 11 the "Integrated Transmission Plan for Keeyask and Conawapa" as the source of Table 3 of the PE report.

QUESTION: Please provide the referenced Table 11.

REFERENCE: PE report, p. 13.

RESPONSE: The ‘Integrated Transmission Plan for Keeyask and Conawapa’ report and thus Table 11 is designated by MH as confidential. MPUB likely has access to it. However, we are unsure whether to include it here. Table 11 will be included with the CSI IR response.

PUB TO PE IR 5

SUBJECT: Transmission

PREAMBLE: The last column in Table 3 of the PE report refers to Manitoba Hydro's Option 3 but appears to reflect Option 2A.

QUESTION: Please confirm whether this should refer to Option 2A.

REFERENCE: PE report, p. 13.

RESPONSE: Yes, this is part of Option 2A. Options 1, 2, and 3 in Table 3 refer to optional Kettle generation switching operating modes, not transmission plan options.

PUB TO PE IR 6

SUBJECT: Transmission

PREAMBLE: PE states that "MH is still investigating requirements and consequences for on-line valve group sparing for the split northern collector system. POWER concurs with the MH view that on-line valve group sparing over generation is mostly an economic choice, and not reliability issue."

QUESTION: Please explain why Manitoba Hydro and PE consider this to be an economic choice rather than a reliability choice.

REFERENCE: PE report, p. 15.

RESPONSE: PE considered the potential economic and reliability impact of 207 MW of non-firm transmission capacity to deliver all of the northern system generation connected to NCS1 and NCS2.

Under the preferred operating mode for Kettle generation, it would not be possible to deliver the full output of either Keeyask or Conawapa over firm transmission. If the operating mode is changed such that two of the switchable Kettle generator units were operated on NCS2, then the non-firm transmission on NCS1/BPI would be near zero and the non-firm transmission on NCS2/BPII & III would be 207 MW. This would be a better match for the last 200 MW of Conawapa generation, which MH indicated, is forecasted to have a low capacity factor. MH has correctly pointed out that Conawapa generation is last in the queue, so Keeyask would have priority access to firm transmission. This operating mode is not precluded in the preferred plan, Option 2A and provides the flexibility for Keeyask generation to be delivered over firm transmission as needed. Option 2 provides 300 MW of additional AC transmission, and provides full valve group over generation sparing and assurance that all of Conawapa and Keeyask can be delivered over firm transmission. The increase in cost between Option 2A and Option 2 is roughly $200 Million. Manitoba Hydro's preferred option 2A is based on their assessment that Option 2A is a more cost effective alternative than Option 2.

Notwithstanding the need to provide additional studies with the new Bipole III model, both Option 2 and Option 2A meet the NERC reliability standards. The choice between Option 2 and Option 2A may have an indirect relationship to reliability. Option 2 off loads the HVDC transmission system by an additional 200 MW, which provides more reliability margin. However, it won't be known until further study whether additional margin is required. For all of the above reasons, PE concluded that the amount of on-line valve group sparing is mostly an economic issue.

PUB TO PE IR 7

SUBJECT: Transmission

PREAMBLE: PE states that "However, the term Designated Network Resource is found in Section 28.3 of the MH transmission tariff which provides guidance on requiring firm transmission service from designated Network Resources to serve Network Loads."

QUESTION: Please advise why Manitoba Hydro's Tariff applies. Are exports considered Network Loads? If so, please explain why.

REFERENCE: PE report, p. 25.

RESPONSE: The MH Open Access Transmission Tariff does not apply. PE did not consider exports to be network loads. PE did, however, consider the question of how much on-line Valve Group sparing should be provided to assure delivery of NCS generation over firm transmission and reviewed the tariff to determine if it provided any guidance on providing firm transmission for all of Keeyask and Conawapa.

PE conducted a high level search of the MH Open Access Transmission Tariff to explore the definitions of a designated Network Resource or as an Energy Resource as discussed in the 'Integrated Transmission Plan for Keeyask and Conawapa' report. In that report, the Executive Summary states that, 'In order to qualify Keeyask and Conawapa as a Designated Network Resource, firm transmission is required for these plants. In the context of HVdc transmission, the capacity is considered firm when a spare valve group over generation is provided to cover for the most frequent outages. The non-firm transmission will result in portions of the proposed Keeyask and Conawapa generation being treated as Energy Resource (i.e. potential bottled generation)'. PE subsequently found a definition of Energy Resource Service in the MH Open Access Interconnection Tariff, section 1.1.7. , "Energy Resource Interconnection Service" shall mean an Interconnection Service that allows the Generator to connect its Facility to the System to be eligible to deliver the Facility's electric output using the existing firm or non-firm capacity of the Transmission System on an as available basis.

Section 2.3 of the 'Integrated Transmission Plan for Keeyask and Conawapa' report further states: 'The firm transmission schemes as discussed in Section 2.2 will provide capacity to cover both scheduled and forced VG outages but at a relative high cost. The Generator (Power Supply) has requested the evaluation of non-firm transmission options. The feature of such a scheme would be the capability to cover scheduled VG outages, lower capital cost and a transmission spare capacity better than the existing HVdc system [29]'. Since the generator has requested the investigation of non-firm transmission service, there would be no requirement to provide firm transmission for all of Conawapa.

PUB TO PE IR 8a

SUBJECT: Transmission

PREAMBLE: PE states that "POWER interprets the recommendation by the HVDC Task Force to mean that maintaining valve group sparing over generation on an individual collector system basis could provide an increased economic benefit over the preferred plan by reducing reliance on the reserve sharing pool for individual valve group outages. Additional benefits might also accrue from the ability to operate all collector system generation as a Designated Network Resource. If adequate spare capacity over generation is to be maintained on each collector system, it does not appear necessary to switch Kettle units to NCS2. However, there may be other benefits for switching Kettle generation during generator outages or reduced capacity at Limestone, Long Spruce, or Conawapa, or during times of reduced capacity on Bipole I. However, the most straight forward means of maintaining adequate sparing on the HVDC systems is to increase the new AC Transmission capacity by approximately 300 MW and permanently switch three Kettle units to the new AC transmission. This is Option 2 in the Preferred Development Plan."

QUESTION: Given the surplus of generation that should exist with the Preferred Development Plan starting in 2026, does PE consider it likely that there would be a benefit from reduced reliance on the reserve sharing pool?

REFERENCE: PE report, p. 28.

RESPONSE: PE considers it likely that any benefit from reduced reliance on the reserve sharing pool would diminish with an increase in generation surplus. However, PE has no specific data on which to base a conclusion. PE’s intent was to call attention to the apparent inconsistency in the Introduction section, second paragraph of the ‘Integrated Transmission Plan for Keeyask and Conawapa’ report, where the HVDC task force had cited that the lack of spare capacity has resulted in frequent reliance on the reserve sharing pool and recommended a minimum spare capacity over generation equal to the nominal rating of the largest valve group. The recommended solution, Option 2A, comes close, but does not follow this recommendation.

PUB TO PE IR 8b

SUBJECT: Transmission

PREAMBLE: PE states that "POWER interprets the recommendation by the HVDC Task Force to mean that maintaining valve group sparing over generation on an individual collector system basis could provide an increased economic benefit over the preferred plan by reducing reliance on the reserve sharing pool for individual valve group outages. Additional benefits might also accrue from the ability to operate all collector system generation as a Designated Network Resource. If adequate spare capacity over generation is to be maintained on each collector system, it does not appear necessary to switch Kettle units to NCS2. However, there may be other benefits for switching Kettle generation during generator outages or reduced capacity at Limestone, Long Spruce, or Conawapa, or during times of reduced capacity on Bipole I. However, the most straight forward means of maintaining adequate sparing on the HVDC systems is to increase the new AC Transmission capacity by approximately 300 MW and permanently switch three Kettle units to the new AC transmission. This is Option 2 in the Preferred Development Plan."

QUESTION: What are the other possible benefits associated with maintaining more spare capacity on the HVDC by moving more generation onto the AC network as in the more expensive option 2, does POWER agree that careful economic analysis would need to be done, including the increase in system losses?

REFERENCE: PE report, p. 28.

RESPONSE: Moving more northern system generation onto the AC will reduce HVDC loading. This may have some reliability benefits (which may also have some economic value) in addition to any economic benefits:

1. Improved reliability by increasing the frequency margin above the Underfrequency load shedding threshold for southern AC system faults (subject to studies with new Bipole III model).
2. Improved operational system robustness during times of equipment outages or abnormal operating conditions (additional system performance studies may be needed).
3. Increased valve group sparing improves the ability to firm up power and capacity sales for export.

PE agrees that a careful economic analysis would need to be done, including losses.

PUB TO PE IR 9

SUBJECT: Transmission

PREAMBLE: With respect to the future use of the 750 MW proposed transmission capacity, Manitoba Hydro indicated in discussions that it is actively marketing surplus capacity and energy to the US and that the likelihood of establishing those sales contracts is very high because the price for energy from Manitoba to the U.S. delivery points is substantially lower than U.S. prices.

QUESTION: Confirm that PE did not independently analyze Manitoba Hydro's energy prices relative to MISO prices and relied only on Manitoba Hydro's opinion.

REFERENCE: PE report, page 23.

RESPONSE: Yes, this is correct. PE did not analyze energy prices and only relied on Manitoba Hydro's opinion.