La Capra Associates

NEEDS FOR AND ALTERNATIVES TO (NFAT) REVIEW OF MANITOBA HYDRO'S PROPOSAL FOR THE KEEYASK AND CONAWAPA GENERATING STATIONS

Technical Appendix 3B

Alternative Resource Plans

PUBLIC VERSION

The Commercially Sensitive Information contained within this report has been redacted in accordance with the protective order.

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Technical Appendix 3B: Alternative Resource Plans

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Acronyms

Technical Appendix 3B

CCGT	Combined Cycle Gas Turbine
CPV	Cumulative Present Value
DSM	Demand Side Management
LCA	La Capra Associates
MH	Manitoba Hydro
MP	Minnesota Power
MW	Megawatt
NFAT	Needs For and Alternatives To
PUB	Public Utilities Board
SCGT	Simple Cycle Gas Turbines
SPLASH	Simulation Program for Long-Term Analysis of System Hydraulics
TA	Technical Appendix
US	United States

I. Introduction and Scope

A. Review of Technical Appendix 3A

Technical Appendix (TA) 3A reviewed Manitoba Hydro's (MH) process of identifying the timing of resource need, screening resource options to fulfill that need, and creating the alternate development plans it evaluated as part of the Needs For and Alternatives To (NFAT) process.

In Section IV of the Appendix we noted that La Capra Associates (LCA) had requested a number of additional development plans to examine and, through discussions with MH, MH agreed to model two additional plans. At the time of filing, MH had only recently provided the results from these additional plans. We have now reviewed the modeling results and provide our assessment in this supplement.

B. Overview of Additional Analysis/Material in TA 3B

Manitoba Hydro modeled two additional development plans in response to requests for additional case analysis from the PUB and LCA. The first is an alternative to the All Gas Plan in which only combined cycle gas turbines (CCGTs) are put in service, rather than a combination of simple cycle gas turbines (SCGTs) and CCGTs. This is referred to as the "CCGT Plan." The second plan (the "LCA No New Generation Plan") delays the construction of new generation resources until 2037 by combining load adjustments from additional Demand-Side Management (DSM) and fuel-switching with additional transmission and import capability. Our assessment of these two plans is presented in Sections II and III of this report.

Section IV of this appendix reviews MH's Wind/Gas Plan and discusses analysis which demonstrates potential areas in which the plan is not structured to optimize benefits.

Section V of this report discusses the benefits of modularity of resources added to the alternative development plans. This analysis reviews the timing and flexibility of necessary capital commitments under various scenarios to evaluate the advantages and disadvantages of various development plans.

C. Work scope items covered

This analysis addresses several elements of our NFAT Scope of Work (LCA SOW) and supports other elements of our work that rely on the materials in this report. The specific LCA SOW elements addressed here are:

Power Resource Planning and Economic Evaluation

2. *Assess whether Manitoba Hydro's approach to comparing generation sequences follows sound industry practice; and*
6. *Develop power resource plans and alternatives, including identifying other scenarios that could potentially compete on an economic basis with Manitoba Hydro's Preferred Development Plan; and*
9. *Comment on the practical role of merchant trading and energy imports; and*
10. *Examine the No New Generation scenario and the potential for extended use of imports to meet Manitoba Hydro's domestic load requirements.*

II. CCGT Plan

A. Plan Overview

MH prepared this plan to address questions raised by LCA and the PUB regarding MH's optimization process in determining the sequence of additions of natural gas-fired units to the All Gas Plan (Plan 1) and evaluate if there are additional benefits that can be achieved by the addition of CCGT resources rather than SCGT resources in a plan featuring natural gas generation development. Moreover, this plan evaluates whether MH's All Gas Plan achieved optimal results compared to other plans with only additional gas generation.

B. Plan Parameters and Modeling

Similar to the All Gas Plan, this plan was designed to only add natural gas resources whenever Manitoba has a need for capacity or dependable energy. Whereas the All Gas Plan included SCGT units and CCGT units, this alternative plan adds only CCGT units when needed. All other parameters and assumptions remain the same. The plan adds new CCGT units with 357 MW peak winter capacities in 2022, 2026, 2030, 2034, 2038, 2041, and 2044. Figure 3-8 below compares the peak demand with the capacity supply under the All Gas and CCGT Plans.

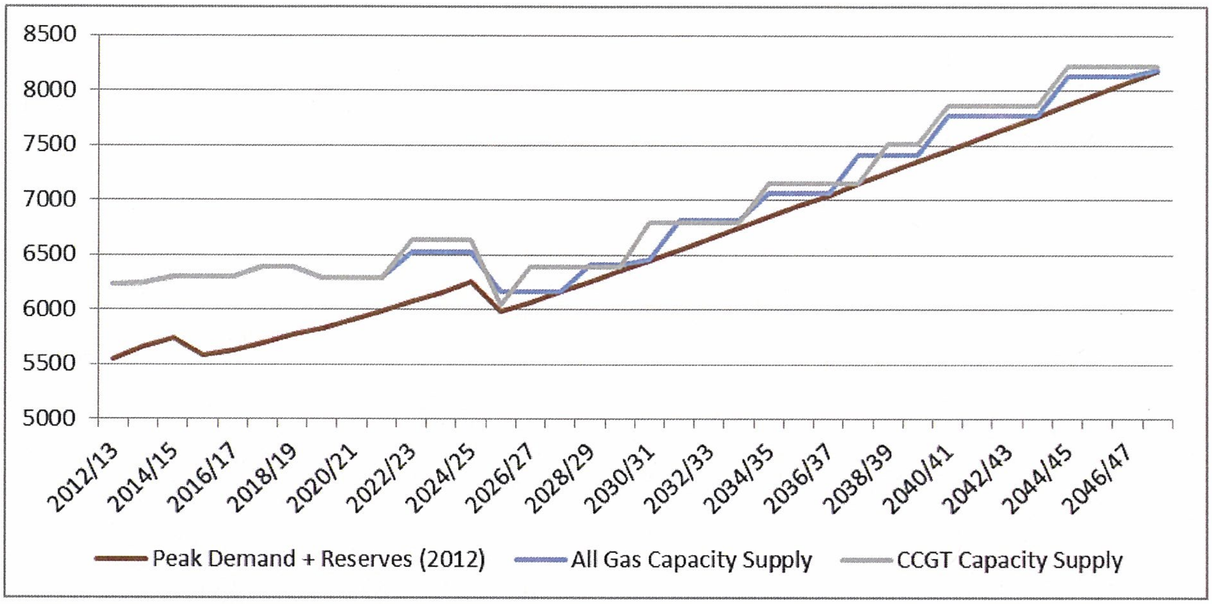

Figure 3-8: Capacity supply vs. demand in All Gas and CCGT Plans

This figure demonstrates that both plans have significant (and identical) excess capacity in the early years. When new resources are added in 2022 to address increased energy demand, the surplus capacity grows more under then CCGT Plan than the All Gas Plan due to the larger capacity of the CCGT unit added in the CCGT Plan compared to the SCGT unit added in the All Gas Plan.

MH provided detailed output data of all SPLASH runs related to the CCGT case. Figure 3-9 below depicts the maximum and average generation from the new CCGT units. The maximum generation represents the generation from the units during the driest water years. The average data is the average of all 99 SPLASH runs for that year.

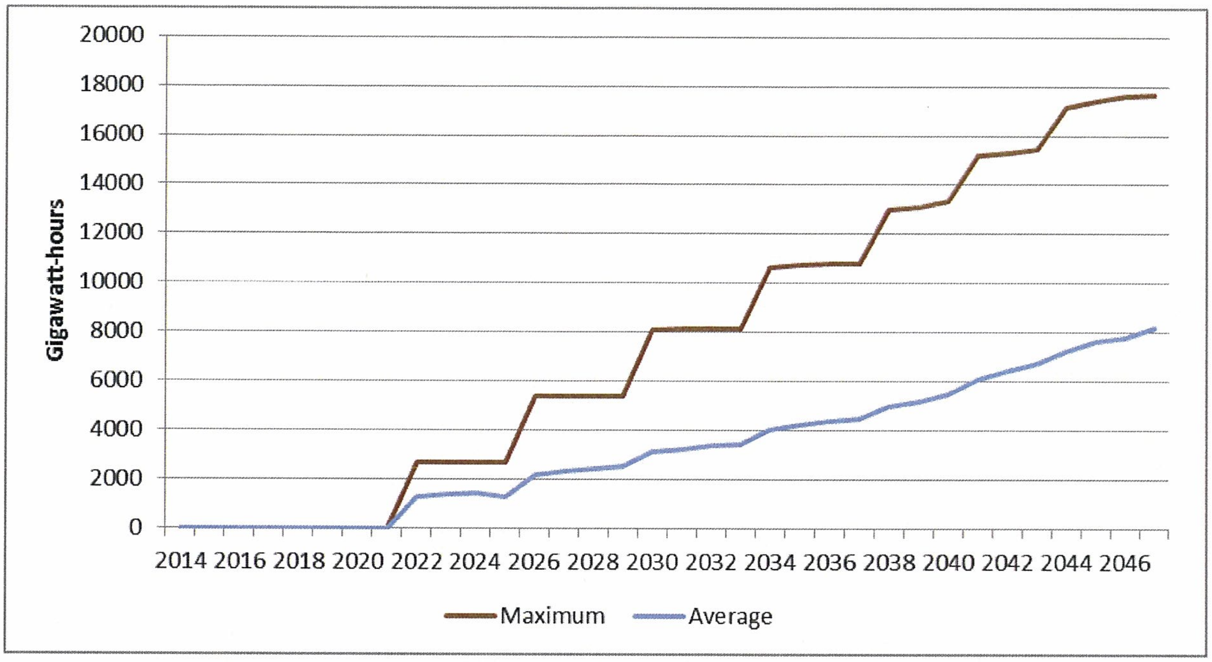

Figure 3-9: Maximum and average generation of CCGT units in the CCGT Plan

The maximum generation data confirm that new units were put into service in SPLASH in accordance with the schedule mentioned above. These results also demonstrate that in drought conditions, the first few combined cycle units operate at maximum production. Figure 3-10 below plots the same data on a capacity factor basis.[1]

[1] For the purposes of this analysis, capacity factor is calculated as the generation as a percentage of the maximum feasible generation for a unit. This is slightly different than a traditional calculation of capacity factor because it does not factor in outages.

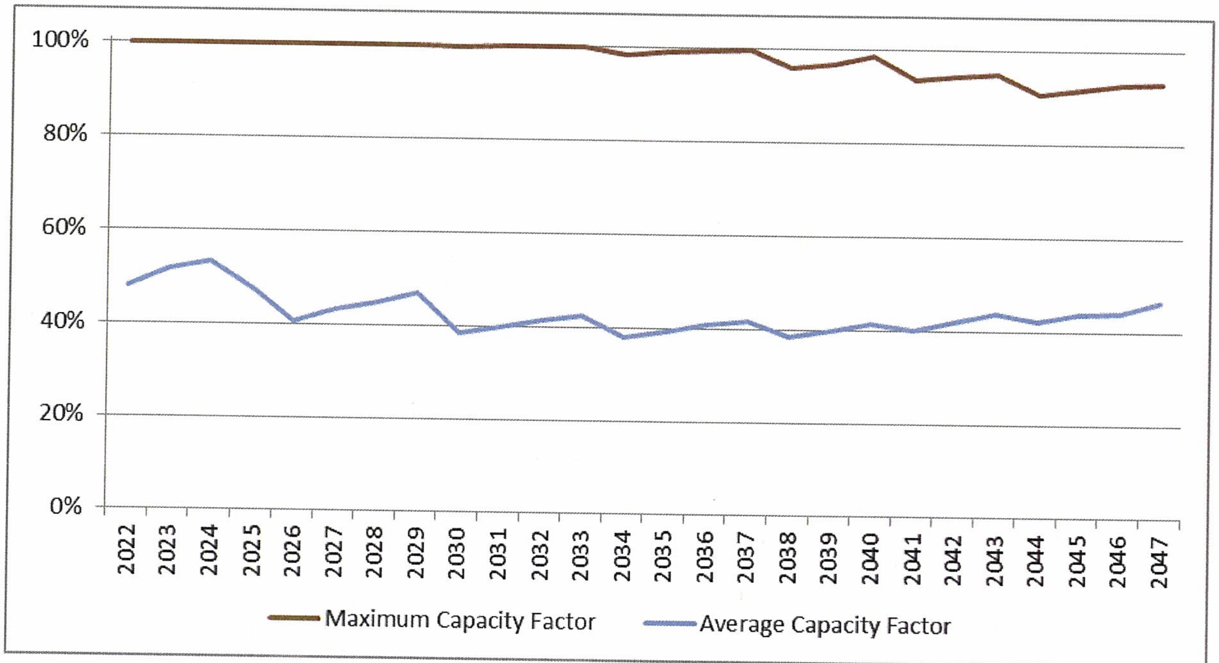

Figure 3-10: Maximum and average capacity factor of CCGT units in the CCGT Plan

This figure demonstrates that on both a maximum and average basis, the CCGT units put in service in the early years are utilized more fully than the later units. This indicates, in part, that the value of these units as a hedge against drought is significant, though somewhat diminished in the later years after the fifth unit addition is made, as the average capacity factor in drought conditions is somewhat below the full output level seen with the first four unit additions.

Figure 3-11 through Figure 3-14 below provide similar information on the performance of the CCGT units in the All Gas Plan. The first CCGT unit goes into service in 2031, with additional units placed in service in 2037, 2041, and 2044.

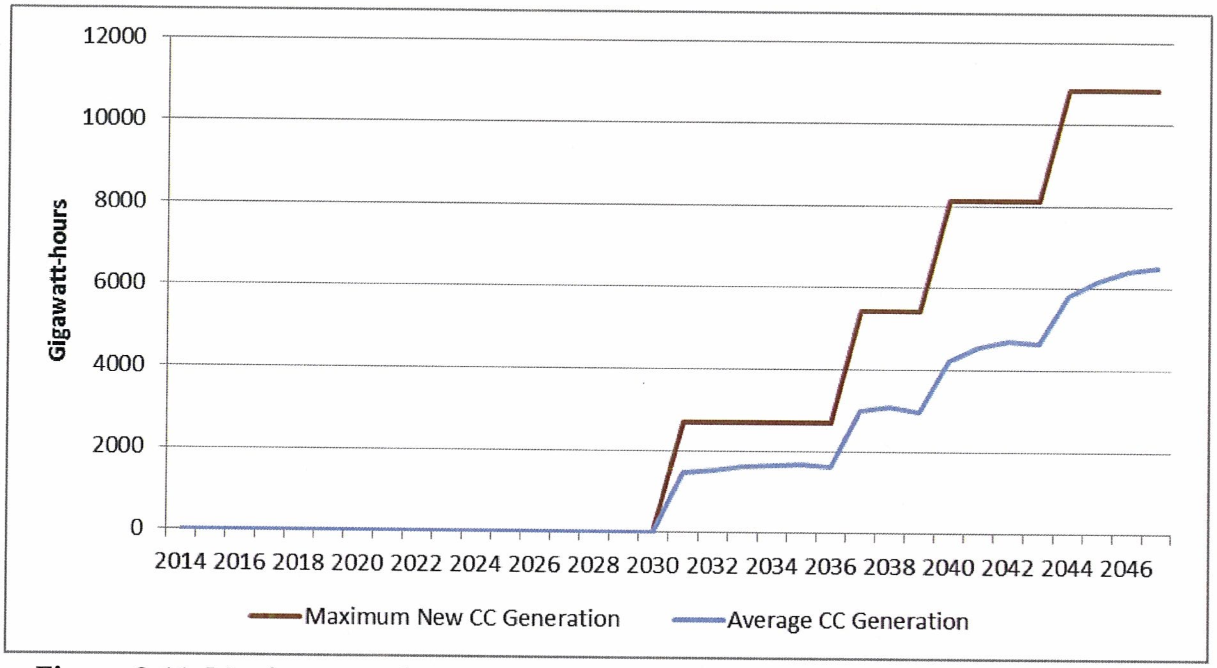

Figure 3-11: Maximum and average generation of CCGT units in the All Gas Plan

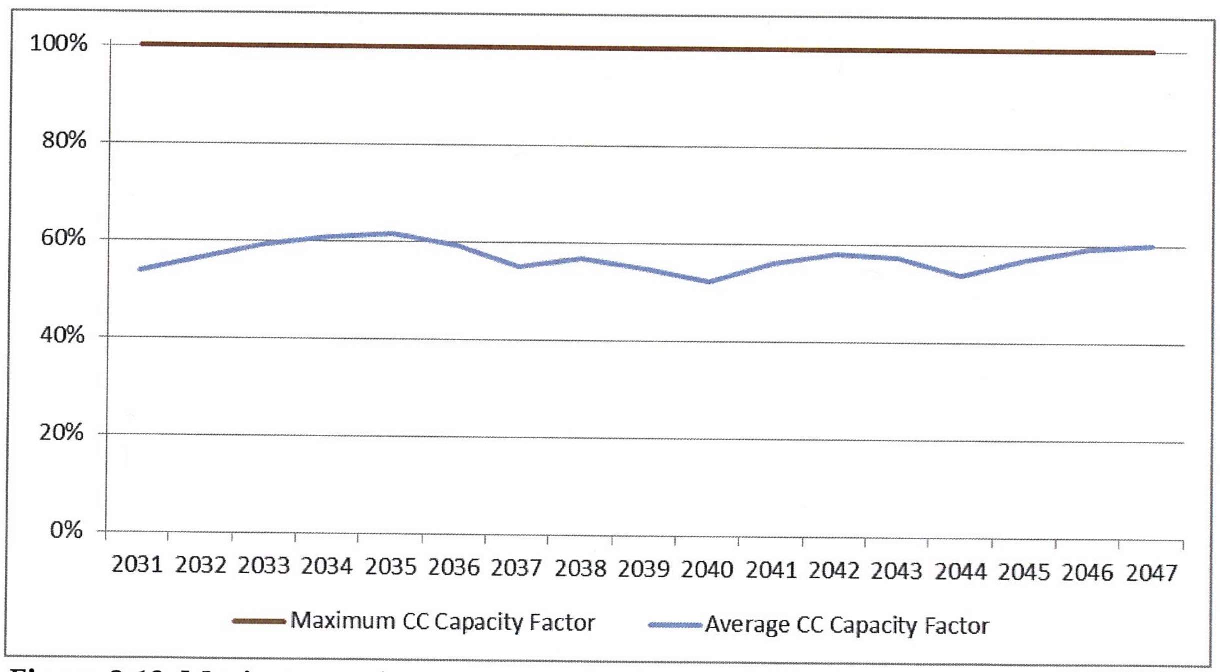

Figure 3-12: Maximum and average capacity factor of CCGT units in the All Gas Plan

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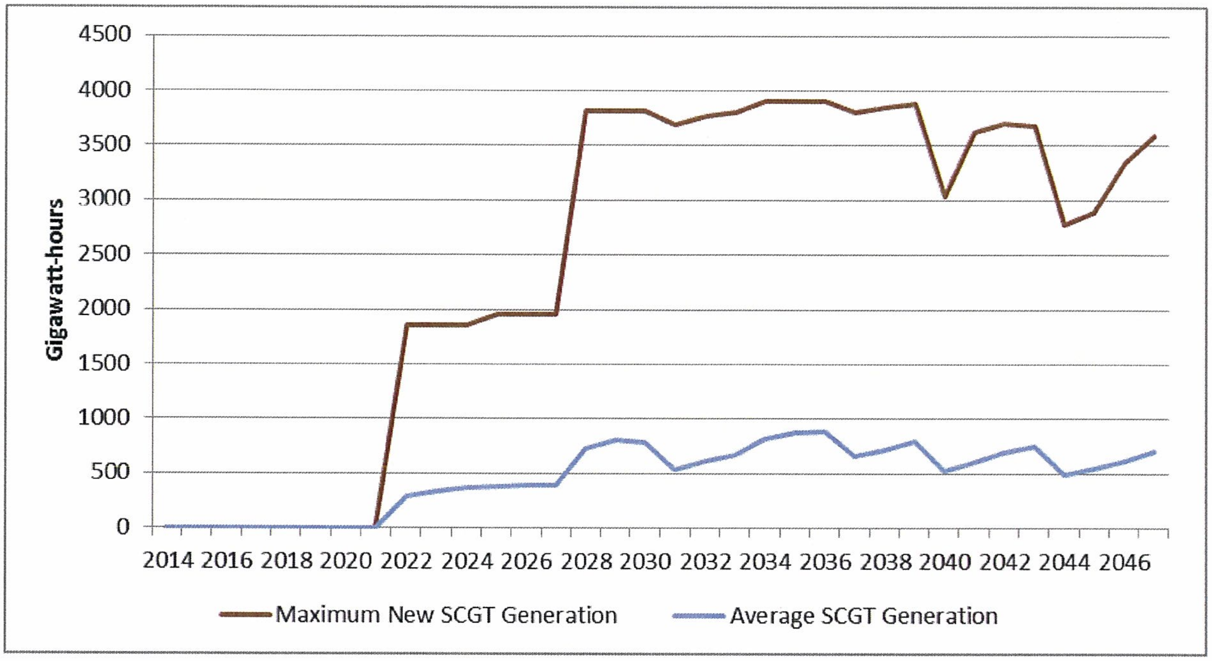

Figure 3-13: Maximum and average generation of SCGT units in the All Gas Plan

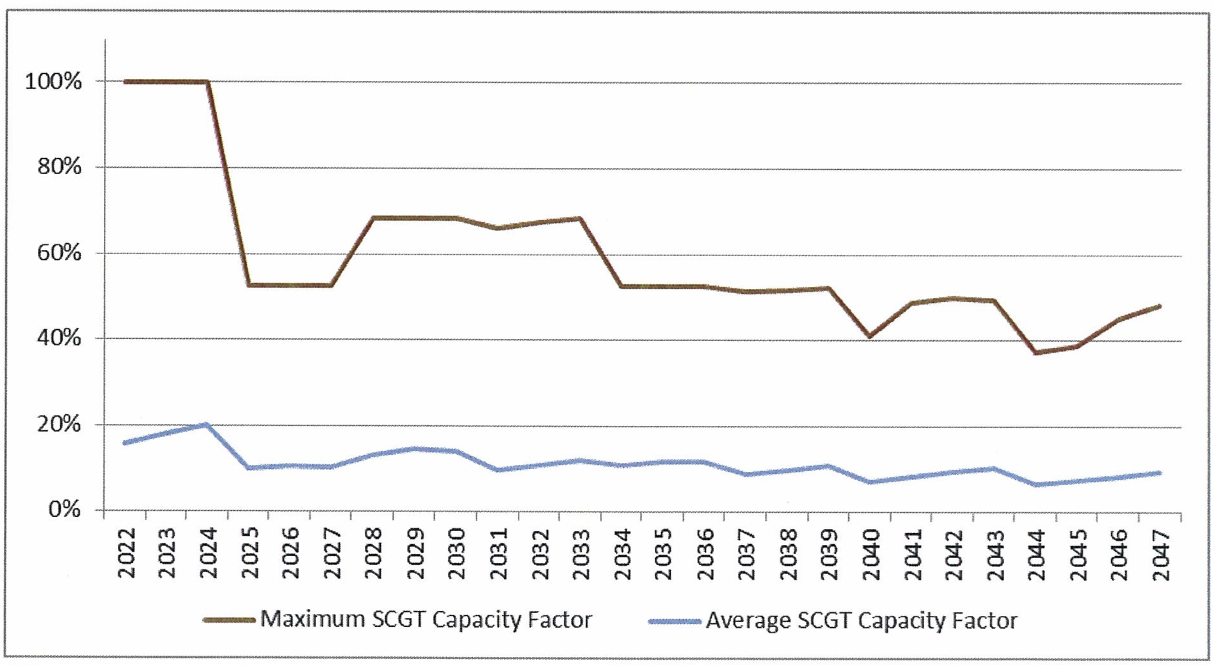

Figure 3-14: Maximum and average capacity factor of SCGT units in the All Gas Plan

The previous figures demonstrate several important points related to the performance of gas units. First, they show that that the CCGT units are more fully utilized in the All Gas Plan than they are in the CCGT Plan, as demonstrated by the higher average capacity factors and the fact that the units are fully utilized in the drought years.

Second, Figure 3-14 demonstrates that for average flow conditions, in the years prior to the first CCGT unit being constructed in the All Gas Plan, the SCGT units are operating more frequently and their capacity factor drops slightly when the CCGT becomes available. This point, combined with the fact that the CCGT operates more than the SCGT does in 2022 in the respective plans, suggests that a plan that constructs a new CCGT first, followed by SCGTs, may provide benefits over the All Gas Plan.

Finally, Figure 3-12 shows that the CCGTs added in 2031 and later in the All Gas Plan operate at higher maximum and average capacity factors than the CCGTs added during that time period in the CCGT Plan (see Figure 3-10). This suggests that the CCGT Plan may be over-developing CCGTs and a more balanced schedule of CCGTs and SCGTs would be more beneficial.

C. Results

Manitoba Hydro determined that, using the 2012 assumptions, the system will face a need for new dependable energy resources in 2022. Therefore, in both the All Gas Plan and the CCGT Plan, the first new generation resource comes online in 2022.

We have reviewed MH's analysis and model results under reference assumptions. Figure 3-15 compares the duration curve of generation by the new CCGT and SCGT in the first year of operation for each plan. This figure plots generation by the units over the 99 flow years modeled in SPLASH. In general the flow years at the left of the graph are characterized by the lowest water availability and years to the right have the highest flow levels.

[redacted]

CONFIDENTIAL Figure 3-15: Generation of first gas units added in All Gas and CCGT Plans

Figure 3-16 below plots the same data on a capacity factor basis to adjust for the differences in unit capacity of the generators.

[redacted]

CONFIDENTIAL Figure 3-16: Capacity factor of first gas units added in All Gas and CCGT Plans

These figures demonstrate that in the first year of operation, the new CCGT unit is being dispatched far more than the SCGT.

Figure 3-17 and Figure 3-18 show the duration curves of net opportunity exports for 2021 (before the units are in service)[2] and 2022. Net opportunity exports are calculated as opportunity exports minus imports. Firm exports are not included because they do not change between the plans. A negative value means that imports are larger than the opportunity exports. These results indicate that there are opportunities for the CCGT to displace imports and create opportunities for MH to export more energy during peak pricing periods.

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[2] MH has provided no information that explains why there are differences in the resource mix for 2021, the year before the new resources are commissioned. The difference in net exports seen in the separation between the curves in this figure is small, but indicates inconsistency in modeling results.

[redacted]

CONFIDENTIAL Figure 3-17: Net opportunity exports in All Gas and CCGT Plans (2021)

[redacted]

CONFIDENTIAL Figure 3-18: Net opportunity exports in All Gas and CCGT Plans (2022)

The comparison of these figures demonstrates that the commissioning of the CCGT, rather than the SCGT, increases net exports under all water conditions. This supports the conclusion that the CCGT is being dispatched in order to maximize exports during the high-priced hours.

When comparing the CCGT Plan and the All Gas Plan, the first difference in load or resources occurs in 2022. However, the data show that for 2021, the generation from existing hydro resources, import energy levels, and opportunity export levels in the two plans do not match between the cases. It is not clear from the data why the results would be different in 2021 between the plans. Since the resource mix and all other assumptions are the same between the plans in 2021, there is no explanation for the variation. The difference in gigawatt-hours is not large (approximately 250 GWh in hydro generation), but the fact that there is any difference at all could be a modeling error or change in prior year storage that we have not been able to reconcile with the material we have been provided.

Figure 3-19 and Figure 3-20 below provide an alternative view of the impact of gas generation choice on import utilization. In these scatter plots each point represents the 2022 energy data for one of the 99 flow years modeled in SPLASH.

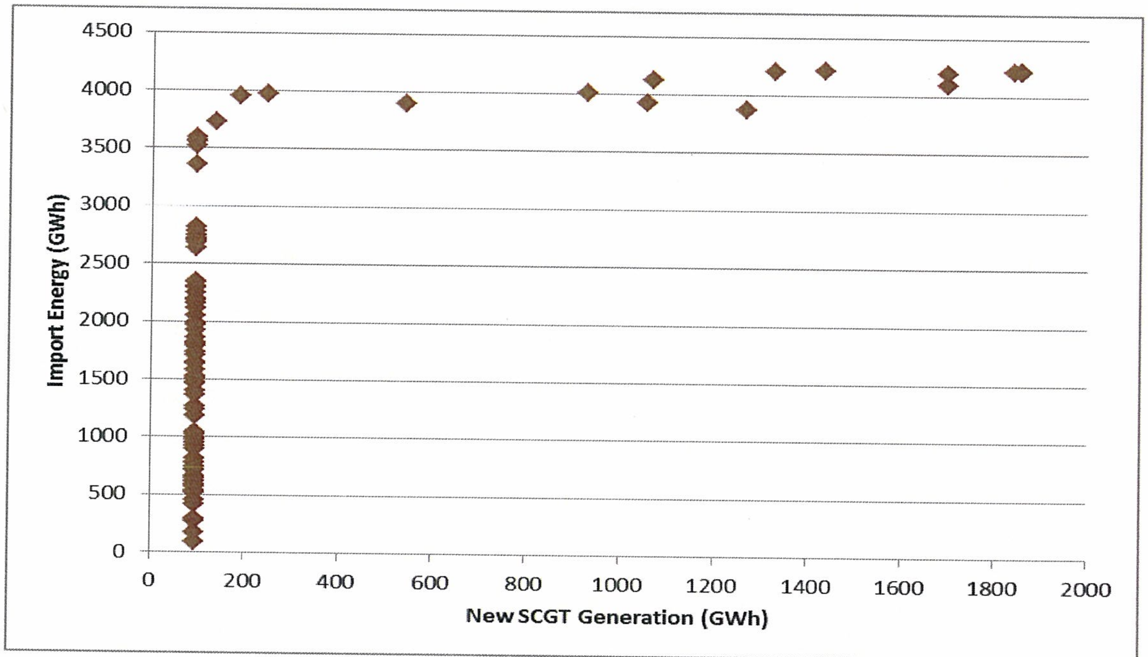

Figure 3-19: Import energy vs. generation from the new SCGT units in the All Gas Plan (2022)

[redacted]

CONFIDENTIAL Figure 3-20: Import energy vs. generation from the new CCGT unit in the All Gas Plan (2022)

In the figure comparing the new SCGT generation with imports, it is clear that under MH's modeling, SCGTs only run when the transfer limit on imports is reached. The vast majority of flow conditions result in SCGTs running at their minimum and imports filling the need for energy. Only in dry years when imports approach maximum utilization of the import transfer limits are the SCGTs dispatched.

In the second figure, plotting the same data but for the CCGT Plan, it is apparent that there is a more dynamic relationship between thermal generation and imports. This figure shows that there are conditions when it is most economical to keep the CCGT running at minimum capacity and import low cost energy to fulfill need (the points at the lower left side of the graph), conditions when it is most economical to run the CCGT at full capacity and import energy at varying levels to meet demand (points on the upper left side of the graph), and many conditions in between with varying levels of energy from both sources. This shows that the variation in pricing of import power over the year is, at times, lower than the variable cost of the CCGT and, at times, higher than the variable cost of the CCGT. The difference between the figure for the CCGT

Plan and the All Gas Plan is primarily explained by the lower variable costs of the CCGT versus the SCGT.

The fact that the CCGT is dispatched so often in the first year after commissioning (average [redacted] capacity factor), indicates that under MH's modeling methodology there may be additional benefits for putting the CCGT in service prior to the year of need. Additionally, because the CCGT is being dispatched at full capacity in more water years than the SCGT, there could be additional benefits of adding larger CCGT units.

Figure 3-21 provides the same data for 2026, which is the year when the second CCGT comes into service. This demonstrates a very similar trend and shape as in 2022, again suggesting that it is at least conceivable that there could be additional benefits to bringing units into service sooner.

[redacted]

CONFIDENTIAL Figure 3-21: Import energy vs. generation from the new CCGT unit in the All Gas Plan (2026)

The issues we have identified here indicate that there are alternative configurations of gas units that could potentially provide more benefits than either the All Gas Plan or the CCGT Plan. This suggests MH has not fully explored all potential options for alternative plans.

The results of our analysis also call into question MH's gas optimization process by which they decided whether to build a CCGT or SCGT in the development plans. This process was discussed in LCA's Technical Appendix 3A, pages 23-24. MH used an iterative process in which it first performed the SPLASH modeling using a generic gas plant with a heat rate equal to the average of the CCGT and SCGT heat rates. The test was performed for the average of water conditions. If the resulting capacity factor was above a certain threshold, MH selected a CCGT unit as the additional resource; otherwise a SCGT was included in the development plan.

Based on the analysis presented here, it is likely that MH's strategy does not, in fact, produce the optimal result. First, the units operate very differently depending on the water condition, and the value of the unit types, particularly as a hedge against drought, is not realized only in the average water condition. Therefore the use of the average condition to determine the unit type may not be optimal.

Second, the drastic difference in the dispatch of the CCGT and SCGT discussed above and presented in the scatter plots make it clear that the variable cost of generation (and thus the unit efficiency) has a profound impact on how it is dispatched in the SPLASH modeling. It is conceivable that the specific efficiency of the generic gas unit could have been such that the resulting capacity factor resulted in a SCGT being built when a CCGT would have provided more opportunities for economic exports. Therefore, the use of the average of the heat rates as the generic unit's efficiency is unlikely to produce the optimal result.

However, this analysis does not consider whether the benefits of the additional CCGT dispatch compared to the SCGT dispatch would outweigh the additional capital costs of the CCGT compared to the SCGT. See Technical Appendix 9B for more information on the economics of the CCGT Plan.

D. Conclusions on CCGT Plan

Based on the foregoing analysis, we present the following conclusions on the CCGT Plan.

First, the operation of the CCGT units interacts with the import levels and the hydro generation differently than the SCGT units. This is evident by the increase in hydro generation and increase in net exports when CCGT units are added instead of SCGT units. The addition of the CCGT units provides economic export opportunities that are not present in the All Gas case. Figure 3-18 above shows that there are higher net exports in almost all water conditions when CCGTs are added, rather than SCGTs. The CCGT Plan, however, was not designed to optimize these benefits, only to mirror the All Gas Plan. There is additional analysis and modeling that could be performed by MH on alternative configurations that would help determine if there is a plan that would provide additional benefits.

Second, the evidence shows that the first CCGT units are dispatched at a higher average and maximum capacity factor than the units that come online later in the study period. This suggests that the value of the CCGT units as a hedge against drought is diminished as multiple units are added to the system. It also shows that the potential value of the CCGTs is highest in early years, as evidenced by the higher levels of generation under the SPLASH economic dispatch method. As previously discussed, the evidence also shows that the CCGTs that are added in the later years of the CCGT Plan may not be the optimal choice. From this result, there appears to be potential for a more beneficial modified All Gas Plan, featuring a CCGT in 2022, followed by one or two SCGTs, and then a combination of units.

As is discussed in Technical Appendix 9B, the CCGT Plan is overall higher-cost than the All Gas Plan, so the additional revenue benefits that these additional plan configurations could provide would need to be balanced against the increased cost.

To address an additional benefit of the CCGT plants, Technical Appendix 5 discusses the optimal operation of the Lake Winnipeg reservoir and notes that the use of CCGTs allows additional flexibility in the management of the reservoir to maximize opportunity exports during high-priced hours.

Finally, the results of the analysis comparing imports with SCGT and CCGT generation demonstrate the importance of the level of import capacity, as the figures above show the difference between the plans in the use of import energy.

III. LCA No New Generation Plan

A. Plan Overview

The purpose of this analysis is to evaluate an alternative development plan which delays the construction of new generation resources for as long as possible. This plan combines load reductions from additional DSM and fuel-switching with additional transmission and import capability to delay new generation build until 2037.

B. Plan Parameters and Modeling

This plan makes several changes to assumptions in order to delay new generation. LCA's understanding of the specific plan parameters is based on verbal communications with MH personnel, and to date MH has provided output data, but has not provided a detailed written description of the plan. The following plan description is based on these verbal discussions and an email from MH.

First, it implements a higher DSM level of 1.5 times the reference assumption. This level is a sensitivity case evaluated by MH in the NFAT submission and was identified by an external consultant to MH as "achievable potential."[3] Second, this development plan implements fuel switching from electric heat to natural gas, further reducing demand. Lastly, this plan adds a 750 MW interconnection that increases import and export capacity, which further delays resource need. LCA also requested that MH relax the import limitation—defined in the planning criteria as 10% of domestic load plus export obligations[4]—and instead institute a 20% limit. The addition of the interconnection to facilitate imports allowed MH to increase the limit to 20% of Manitoba load, delaying the need for new resources to meet dependable energy requirements. However, MH required imports in excess of 10% of load to be backed by firm import contracts. The cost for the firm import contracts was modeled by adding

[3] See discussion of DSM potential levels in LCA's Technical Appendix 1, pages 1-24 – 1-26 and 1-35 – 1-37. See also LCA's Technical Appendix 3A, pages 3A-7 – 3A-8.

[4] See Technical Appendix 1: Resource Planning, for a full discussion of these criteria.

the cost of capacity. Finally, the plan also assumed diversity exchange agreements were extended to the end of the 35-year study period.[5]

Manitoba Hydro provided detailed output data of all of the SPLASH runs related to this case. Figure 3-22 below compares the Manitoba load adjusted for DSM compared to the All Gas Plan. This figure shows the impact on the DSM and fuel-switching measures. The decrease represents a 1.5% reduction in 2014, increasing to 5% in 2023 and 10% in 2042.

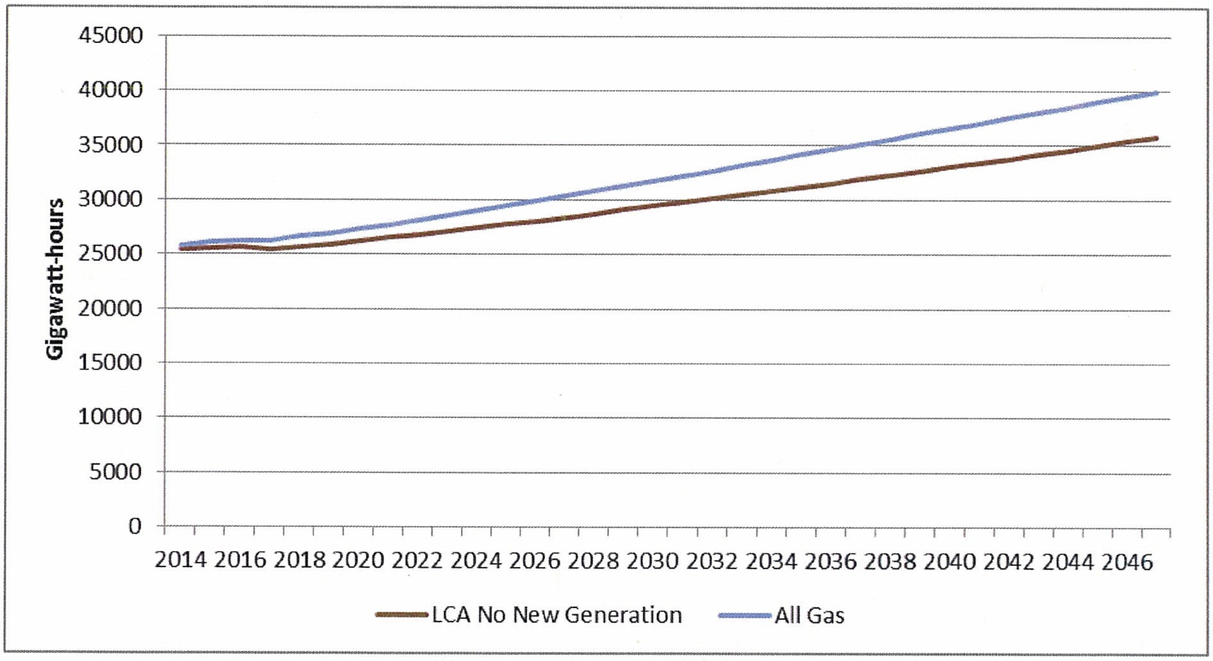

Figure 3-22: Comparison of Manitoba adjusted load in All Gas and LCA No New Generation Plans

Figure 3-23 depicts the maximum import quantities by year for any of the 99 SPLASH runs. These maximum quantities occur under the lowest flow conditions. The All Gas and PDP are provided for reference.

[5] This information was provided to LCA in an email from [redacted] at MH on November 19, 2013. LCA has not received any more formal documentation of the parameters of this development plan.

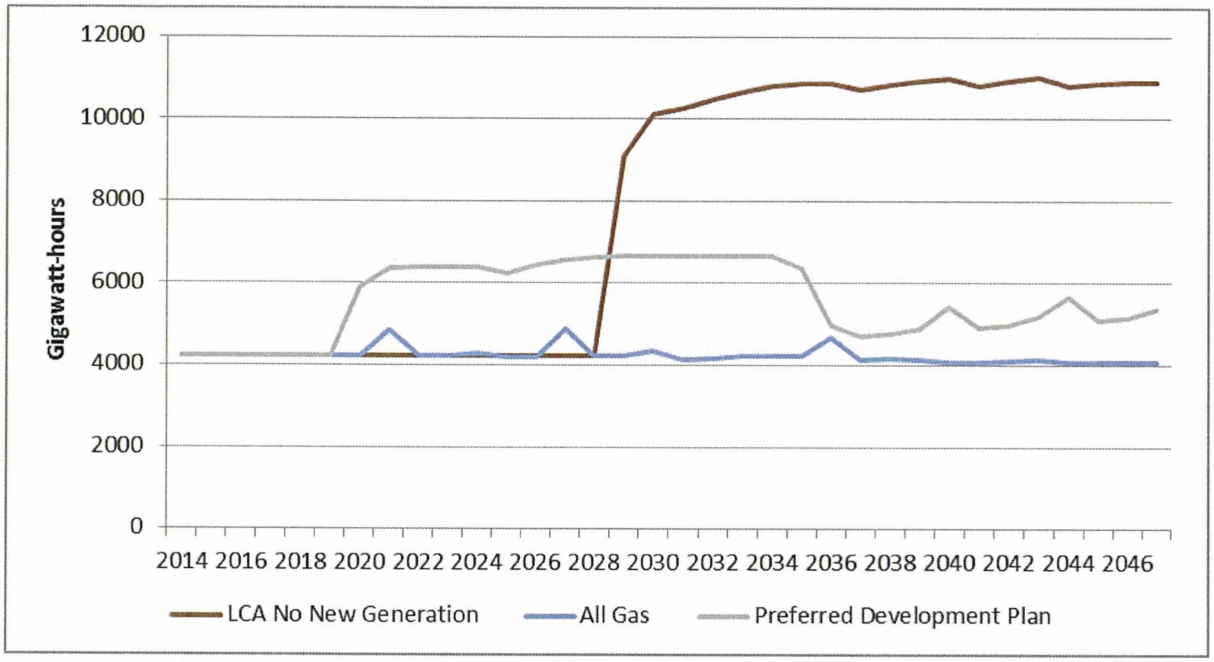

Figure 3-23: Maximum annual import quantities across development plans

This figure demonstrates that the large additional import capacity was implemented in 2029 with the addition of the 750 MW transmission tie to the US and is immediately utilized in the driest flow conditions. However, in the earlier years of the analysis, there is no difference in imports between the plans, which indicates that Manitoba Hydro did not change its method of modeling import limitations in years prior to the assumed transmission addition.

The data for the PDP show a similar, but smaller, increase in imports as soon as the additional capacity becomes available in 2019, deriving immediate benefits from the transmission line. The All Gas Plan does not exhibit any significant change in imports because there is no change to import capacity from an additional transmission tie line featured in that plan.

Figure 3-24 provides the same data as the average of all SPLASH runs, rather than the maximum. This figure demonstrates a couple of important points about average water conditions. First, this figure demonstrates that in the PDP, imports increase immediately after Keeyask and the new transmission interconnection are put in service.

So despite the additional capacity addition, import volumes grow, indicating that there are benefits to expanded imports even with the added generation capacity, with the increased import transfer limits providing a market hedge against drought. Second, this figure demonstrates that as soon as the additional import capacity is available under the LCA No New Generation Plan, imports increase dramatically and grow steadily thereafter.

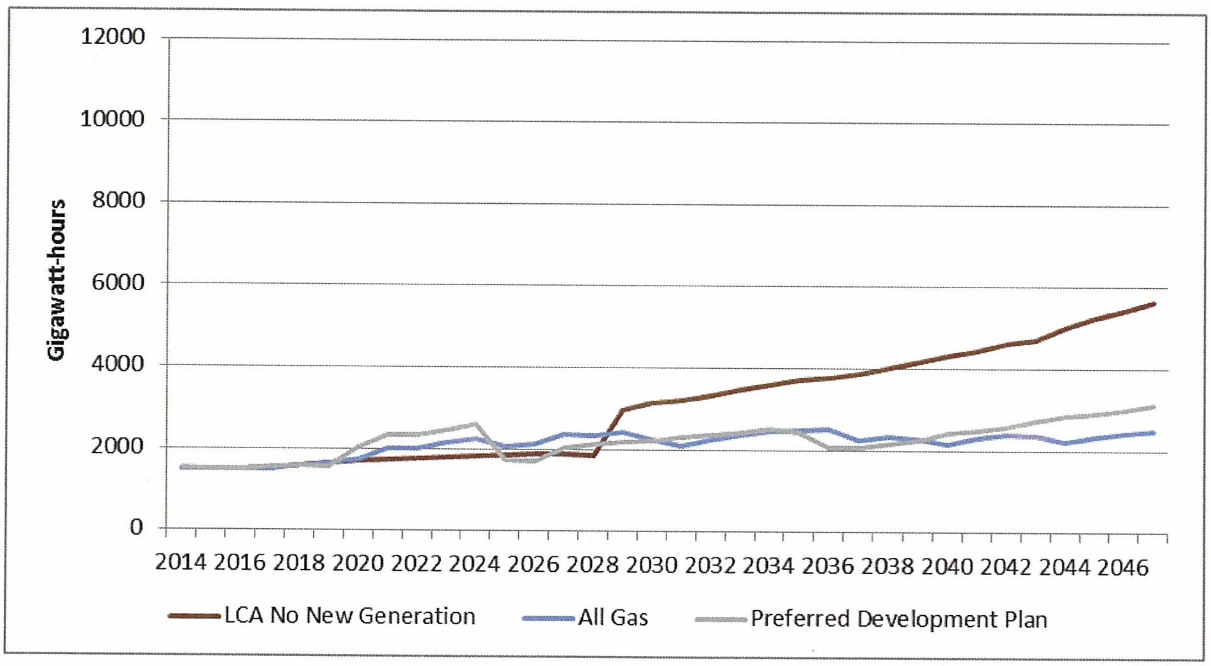

Figure 3-24: Average annual import quantities across development plans

Figure 3-25 below provides the total thermal generation in each of those plans (average of all SPLASH runs).

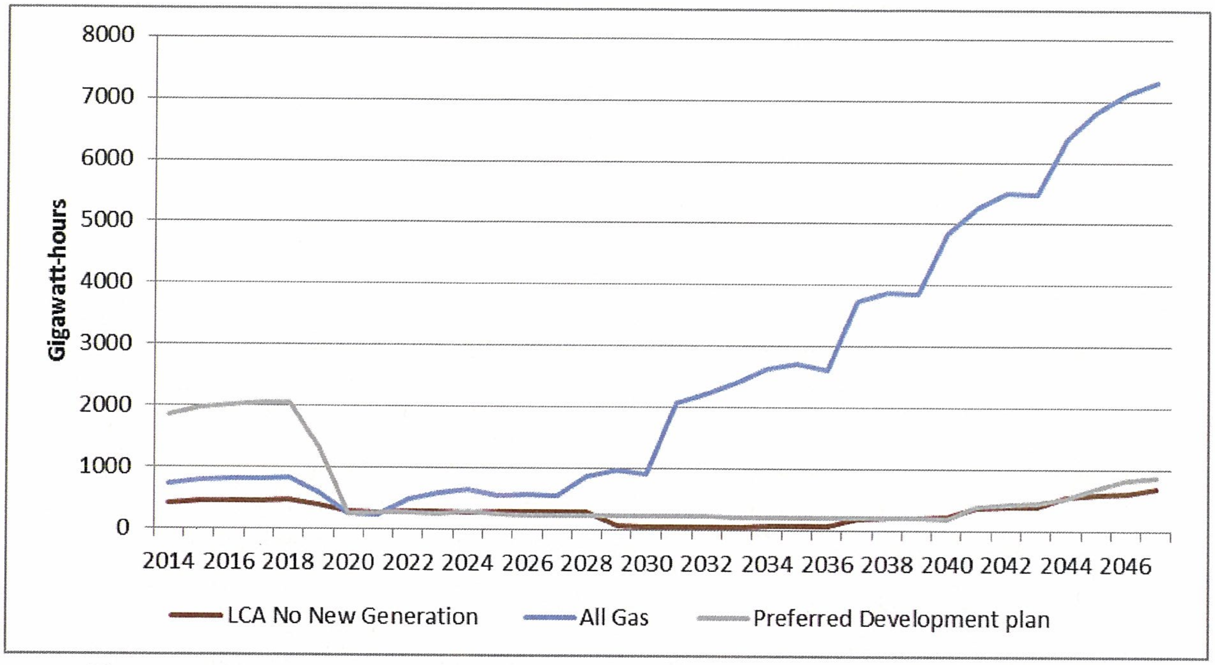

Figure 3-25: Average annual thermal generation across development plans

This figure shows that the LCA No New Generation Plan features minimal thermal generation, particularly after the new transmission capacity is added in 2029.

C. Results

The LCA No New Generation features a significantly different set of results and resource mix than the other development plans evaluated in the NFAT analysis.

Figure 3-26 below shows the resource mix for average years in this case, compared to Manitoba's domestic load, adjusted by DSM and fuel switching.

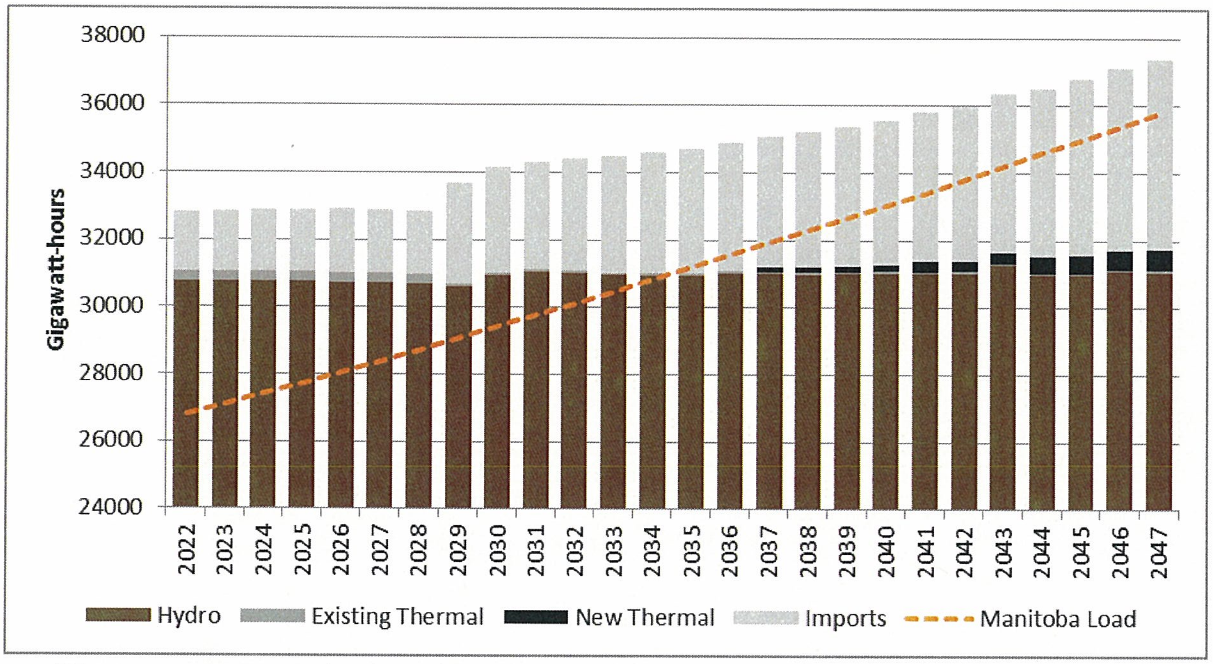

Figure 3-26: Annual resource generation mix in LCA No New Generation Plan

These data show that in the years leading up to 2029, the first year of additional transmission capacity, there is a relatively static resource mix consisting of hydro, imports, and existing thermal. Once the additional transmission capacity is added, the quantity of imports immediately increases and the use of existing thermal is almost eliminated. There is also an increase in exports, which is the difference between the load line and the top of the resource mix bar.

These results suggest that since MH only added the new transmission capacity in 2029 when needed to fulfill load, this plan does not fully evaluate the value of imports as a method to reduce supply costs. Existing gas plants operate more in years before new import capacity is added. More import capacity could allow higher imports in off-peak periods allowing exports of hydro during peak price periods. The value of these exports and of the additional capacity in this scenario is likely to be significant, but at this point is unknown, as that analysis has not been conducted by MH.

D. Conclusions on LCA No New Generation Plan

The foregoing analysis of the results of the LCA No New Generation Plan provides several key insights on MH's planning parameters.

First, the results of this alternative plan demonstrate that even with only moderate adjustments to assumptions on load, the need for new resources can be delayed until at least 2029. Furthermore, the addition of new transmission capacity for import can delay the need for new resources even further.

Second, the results show that further evaluation of the amount and timing of increased import capability could provide meaningful value to each of the plans, particularly those that do not include any increases in import capability. As discussed above, there is a dramatic shift in resource mix and export levels as soon as new import transmission capacity is available.

IV. Sub-optimality in the Wind/Gas Plan

A. Overview

The preceding sections provide the results of LCA's review of the optimality of the development plan design in the context of gas generation and non-generation options. Based on the observations we made regarding plan design and resource timing, LCA examined some of MH's original development plans for indications of suboptimal structure. This section provides the results of our review of the Wind/Gas Plan.

B. Analysis

In reviewing the Wind/Gas Plan, we first compared the annual cash flow and cumulative present value of the Wind/Gas Plan with the All Gas. The results are provided below.

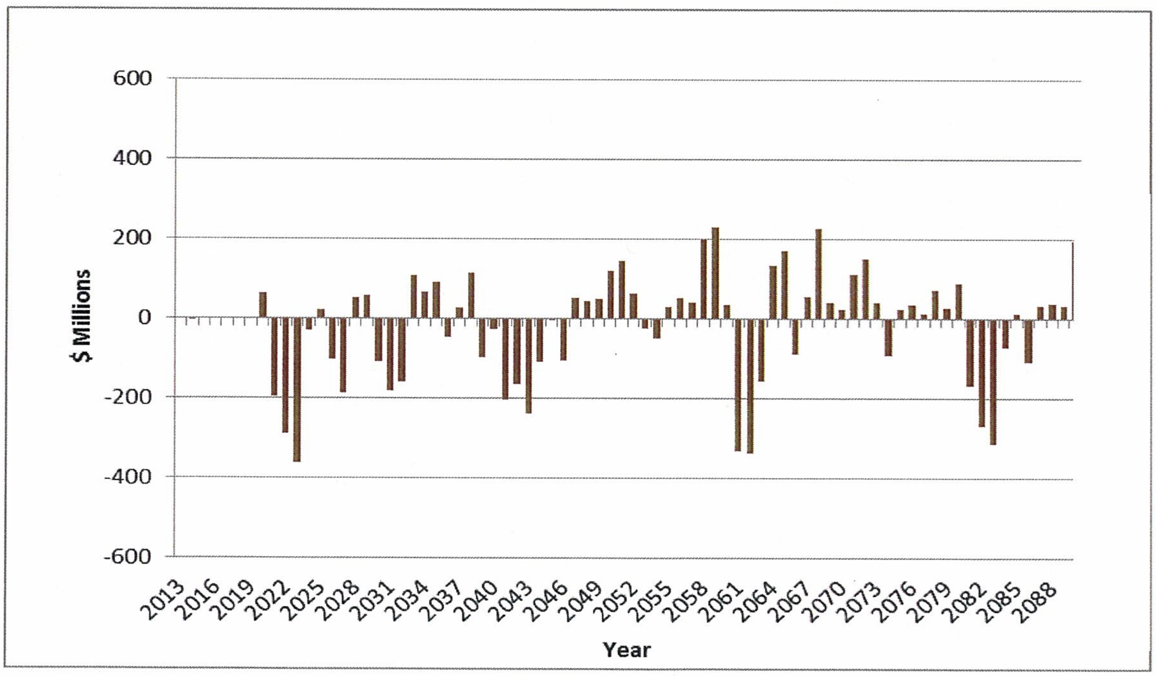

Figure 3-27: Annual cash flow difference (Wind/Gas minus All Gas)

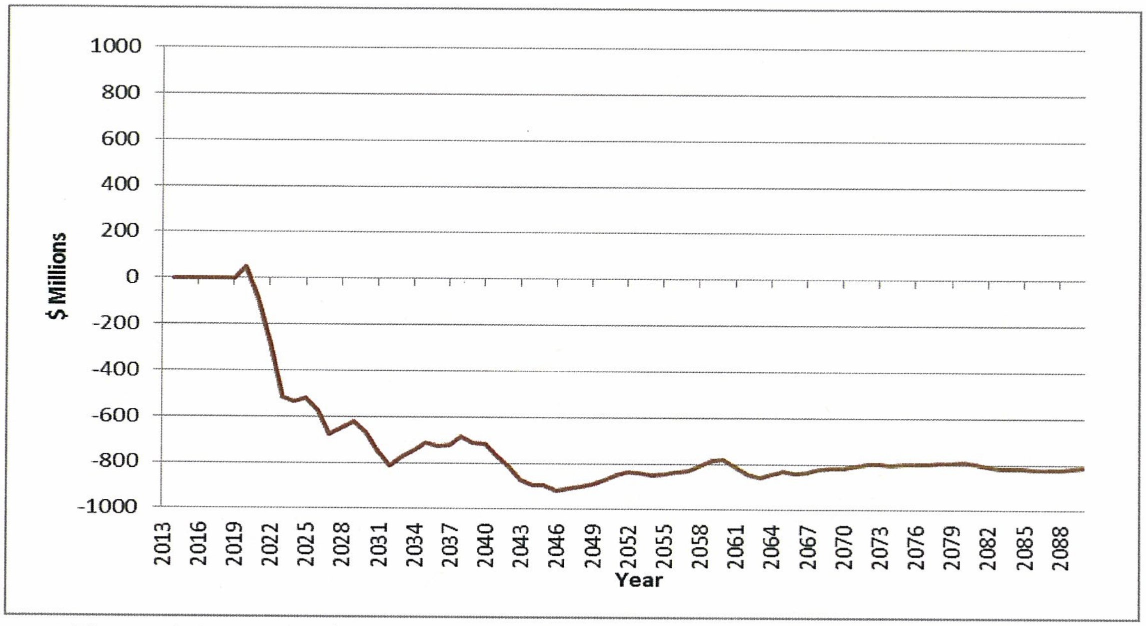

Figure 3-28: Cumulative present value difference (Wind/Gas minus All Gas)

These figures demonstrate that, in comparison to the All Gas Plan, the Wind/Gas Plan exhibits much higher capital expenditures in the early years after new generation is constructed. This expenditure starts the Wind/Gas Plan with a significantly lower cumulative present value (CPV) curve. After time the results stabilize, and the plans perform similarly, as evidenced by the lack of significant change in the CPV line after 2040.

The fact that the plans' CPV difference eventually levels off indicates that under certain circumstances the two plans can reach parity in economic performance. This suggests that there may be alternative configurations that could provide more optimal results. For example, based on MH's assumptions, wind energy performs poorly compared to gas in the near-term, but the economics shift farther out in time when gas prices are higher, export prices are higher, and carbon price sensitivities disadvantage fossil fuel generation.

Based on our experience reviewing the results of the CCGT Plan and the LCA No New Generation Plan, we know that, for example, CCGTs can provide benefits over SCGTs even in conditions where additional dependable energy is not needed. In MH's own description of the All Gas Plan the choice of adding either SCGT or CCGT natural gas generation was made through an optimization process. Even though LCA has expressed concerns that the optimization process used by MH did not fully accomplish the goal to optimize the choice of SCGT vs. CCGT,[6] it provides a lower cost outcome than simply assuming all CCGT or all SCGT. The Wind/Gas Plan is structured simply with wind for energy need and SCGTs for capacity need, even though we have shown that the optimal selection of gas generation type is not always that straightforward. Thus the Wind/Gas Plan as created by MH is likely biased to show poorer economics when compared with other plans because they did not perform this optimization and instead only added SCGTs.

We also know from our review of the LCA No New Generation Plan that additional transmission capacity provides significant benefits due to the ability to enhance opportunity export sales. The Wind/Gas Plan as presented by MH could be improved with additional export and import capacity, particularly due to the excess energy and intermittency associated with wind.

Based on these results depicted in Figure 3-28 above, rather than abandon wind as a resource option, it would have been reasonable for MH to evaluate alternative plans with different sequencing and timing of the wind and gas generation, plans with alternative capacity resources (such as CCGTs or demand response measures), and plans that varied the amounts of wind developed.

Furthermore, the results of MH's evaluation of the Wind/Gas Plan are largely reliant on its assumptions about wind generation cost. In Technical Appendix 3A we presented analysis demonstrating that if more current assumptions on wind generation (including capital cost, capacity factor, and project life) were used by MH, the Wind/Gas Plan would perform much better on an NPV basis.[7]

The following figures expands on the analysis from Technical Appendix 3A, comparing the All Gas Plan with MH's Wind/Gas Plan, and a modified version of the Wind/Gas

[6] LCA Technical Appendix 3A, Section V.D.

[7] LCA Technical Appendix 3A, Section VI.B.

plan with LCA's assumptions. Mirroring the figures above, these provide the annual cash flow differences from the All Gas Plan and the CPV of the cash flow over time.

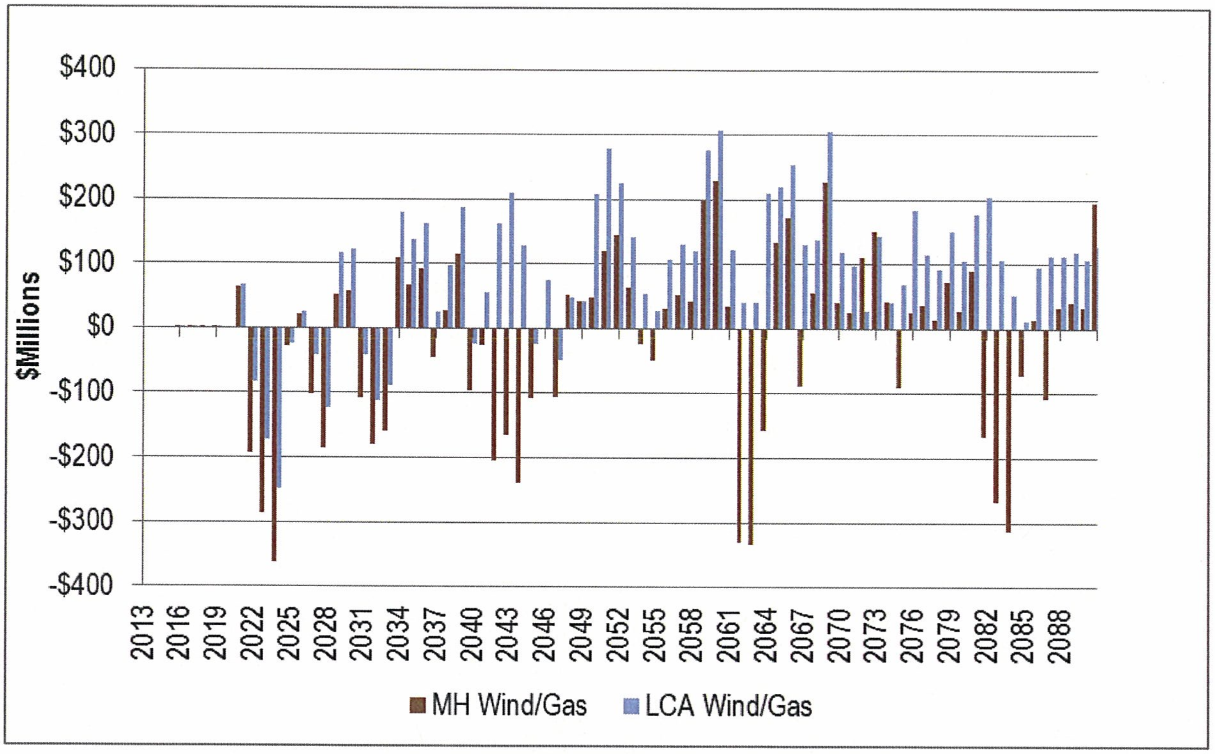

Figure 3-29: Annual cash flow difference, MH and LCA wind assumptions (Wind/Gas minus All Gas)

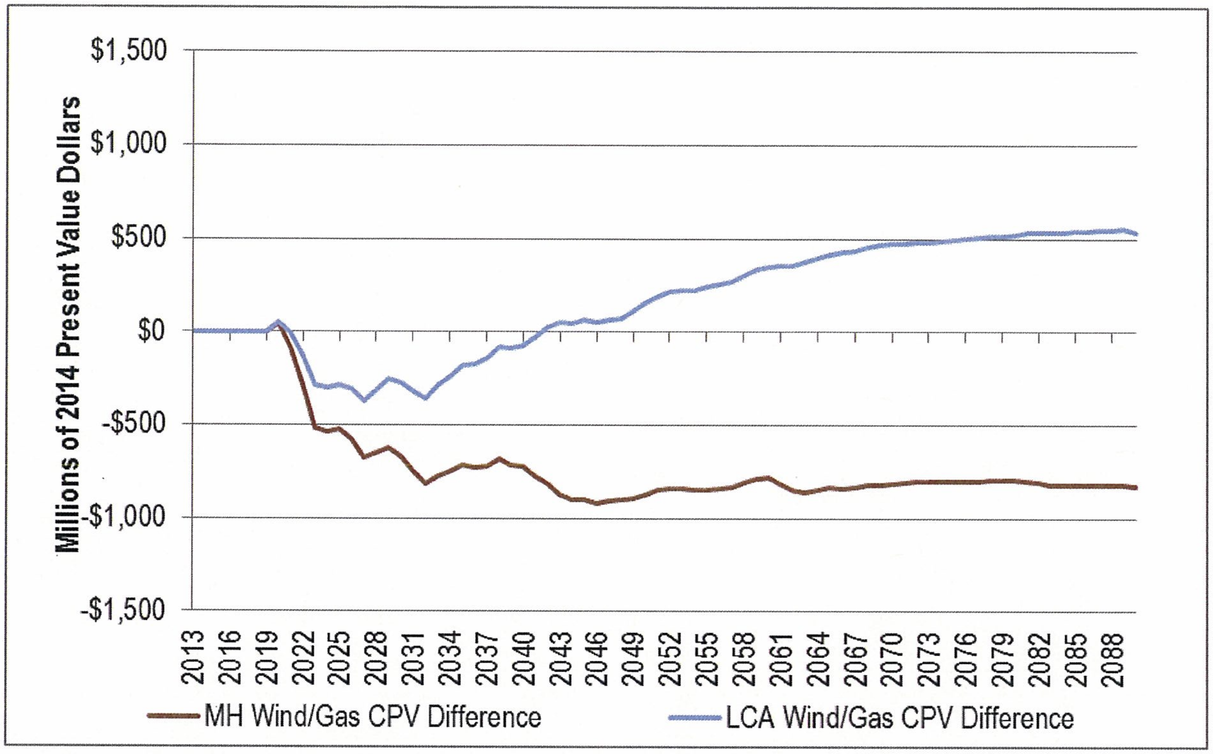

Figure 30: Cumulative present value difference, MH and LCA wind assumptions (Wind/Gas minus All Gas)

These figures demonstrate that with more reasonable assumptions about wind cost and performance, the initial drop in value of the Wind/Gas plan is cut in half, and over time the cumulative value of the plan significantly exceeds the All Gas Plan

C. Conclusion

Based on the insights gleaned from the results of the CCGT Plan and the LCA No New Generation Plan, our initial evaluation of the Wind/Gas plan identified several potential changes that could have developed a more optimal configuration than the one presented by MH. These potential revisions included choice of gas technology for capacity, timing and sequence of the wind and gas development, and consideration of additional import capacity. These changes could easily produce results closer to an optimal solution involving wind development. These alternatives have not been evaluated or modeled by MH, and our review of the NFAT Submission does not have the benefit of modeling results associated with these plans.

In addition, we further developed our prior analysis (presented in Technical Appendix 3A) demonstrating that MH's conservative and outdated wind cost assumptions inappropriately characterize the development plans featuring wind. Our additional analysis shows a substantially different CPV trajectory, one that could be further optimized with some of the changes and sensitivities previously discussed.

As we discussed in Technical Appendix 3A, Manitoba Hydro evaluated a narrow selection of development plans, and in most cases did not perform sufficient analysis to show that the plans were developed in an optimized way. Our review of the Wind/Gas Plan could be repeated for many other development plans and would likely find sub-optimal qualities of those plans as well, demonstrating some areas in which MH's analysis was not completely thorough.

V. Generation Modularity

A. Analysis Overview

Upon review of the alternative development plans in the initial NFAT Submission, as well as these supplemental plans, LCA determined that in many plans the modularity of smaller gas units, as opposed to large hydro units, could provide a flexibility benefit that the addition of larger increments of generation does not.

The long lead time of the hydro units, coupled with the high capital costs, means that high levels of capital commitments must be made well in advance of the year of need for the units being constructed. LCA has analyzed the individual impacts of the elements of the development plans to determine how different combinations of the elements can delay the year of need under reference conditions.

This analysis is related to Section V of LCA's Technical Appendix 9B, in which we evaluate the impact of individual components of the PDP on the economic analysis.

B. Results

LCA utilized MH's supply demand tables provided in the NFAT Appendix 4.2. As a reference case we used the No New Resources tables and the 2013 reference assumptions. We revised the capacity and energy balance tables to review three scenarios related to the Preferred Development Plan:

- Construction of Keeyask only
- Construction of Keeyask with a 250 MW export (50 MW import) transmission line and the Minnesota Power (MP) contract
- Construction of Keeyask with a 750 MW transmission line featured in the PDP as presented by MH.

Figure 3-31 and Figure 3-32 below display the supply-demand balance for dependable energy and capacity, respectively, with the development of the Keeyask project alone.

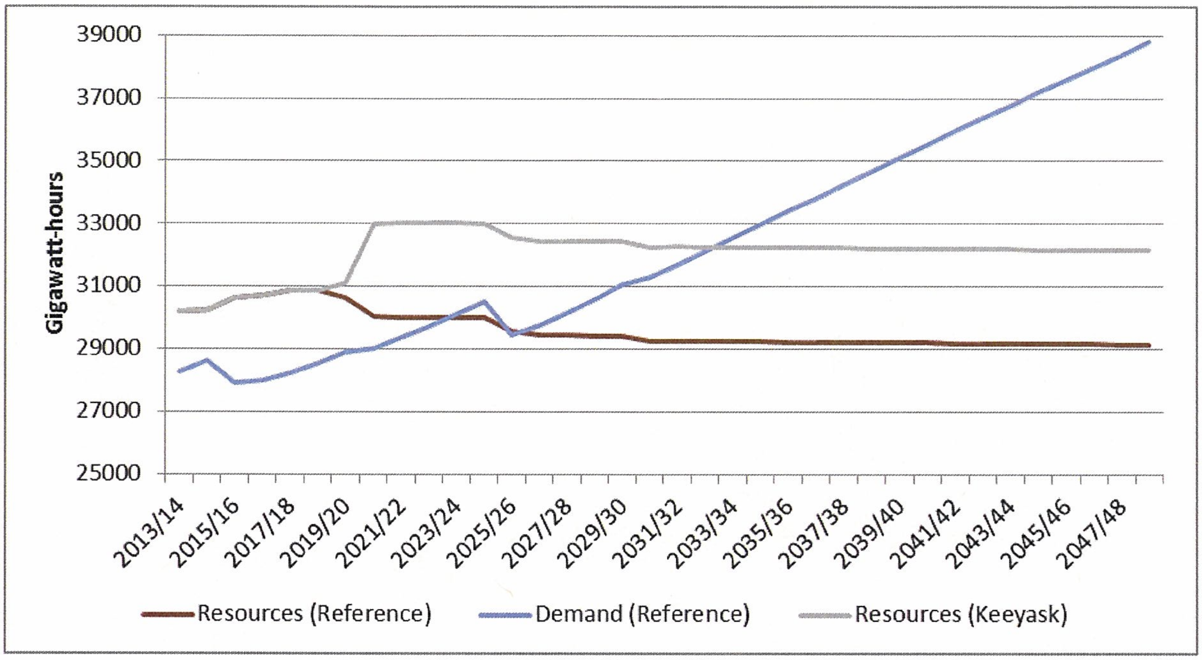

Figure 3-31: Supply vs. demand for dependable energy with Keeyask project

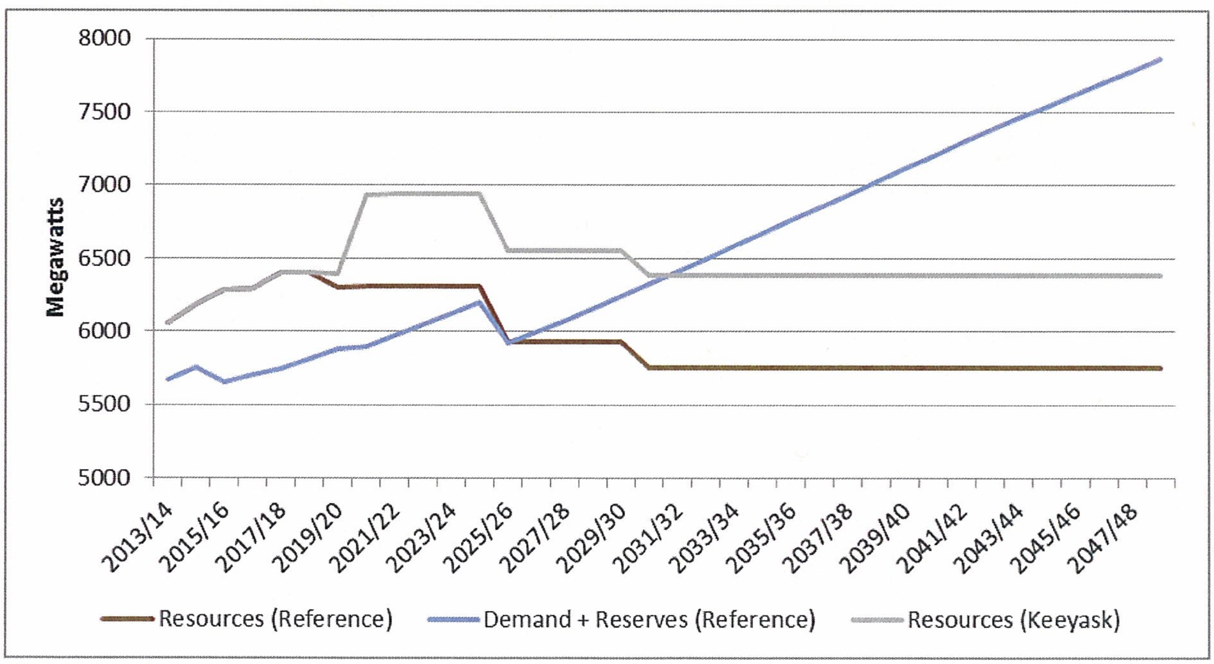

Figure 3-32: Supply vs. demand for capacity with Keeyask project

These figures demonstrate that the development of Keeyask alone delays the year of need for energy to 2034/35 and capacity to 2031/32. Given the short lead time needed for new SCGT and CCGT resources (estimated by MH at 3-5 years),[8] MH would not need to commit to additional new resources until as late as 2028.

Figure 3-33 and Figure 3-34 below display the supply-demand balance for dependable energy and capacity, respectively, with the development of Keeyask along with a new interconnection with 250 MW of export capacity and 50 MW of import capacity, along with the associated MP contract. Note that the addition of the transmission line alone does not impact the capacity balance; the MP contract provides the capacity incremental to the Keeyask only scenario.

[8] NFAT, Appendix 7.2, pp. 178, 187.

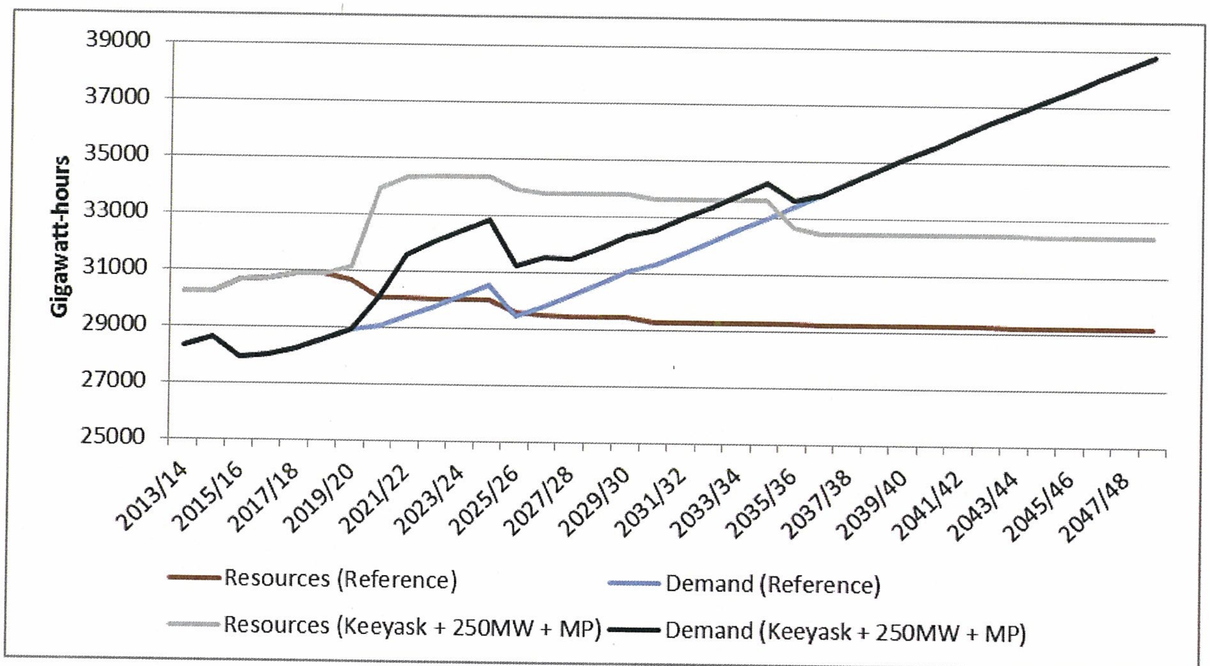

Figure 3-33: Supply vs. demand for dependable energy with Keeyask, 250/50 MW transmission and MP contract

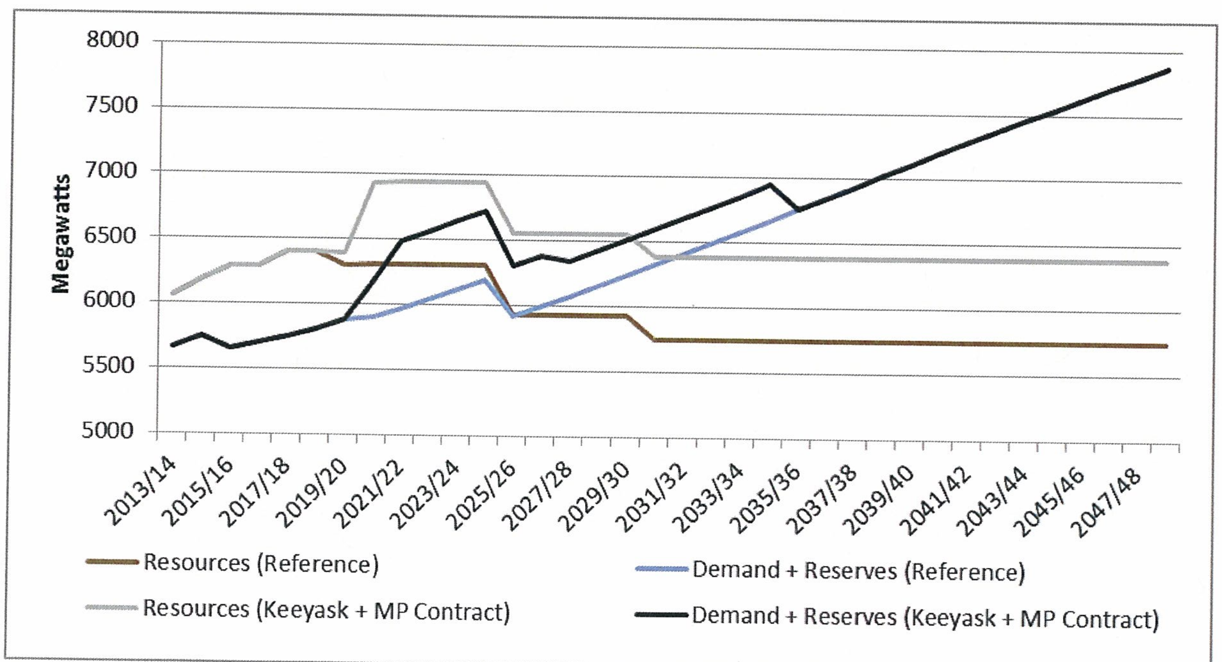

Figure 3-34: Supply vs. demand for capacity with Keeyask and MP contract

The addition of the smaller transmission project and the MP contract in addition to Keeyask does not impact the year of need for energy. Assessing the impact on capacity need is somewhat more unclear. MH's resource planning materials do not explicitly incorporate additional import capacity as a capacity resource. Therefore the figure actually shows that the capacity need is advanced to by one year due to the additional load from the MP contract.

Figure 3-35 and Figure 3-36 below display the supply-demand balance for dependable energy and capacity, respectively, with the development of both the Keeyask project and the new 750 MW transmission interconnection with the associated Minnesota Power contract.

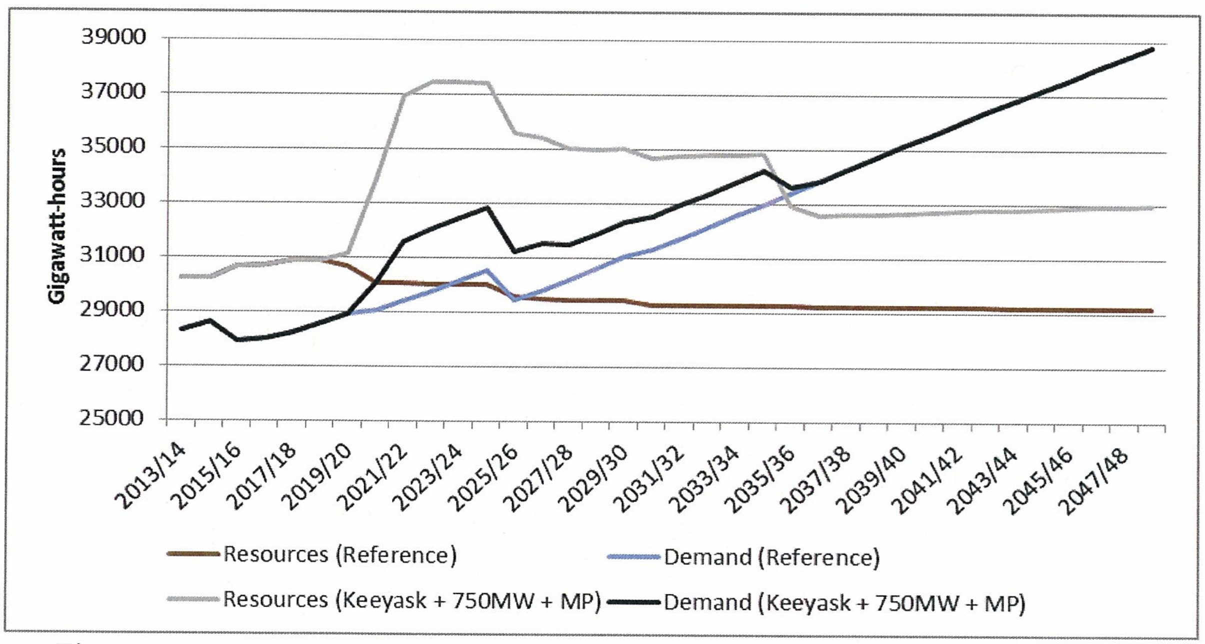

Figure 3-35: Supply vs. demand for dependable energy with Keeyask, 750 MW transmission and MP contract

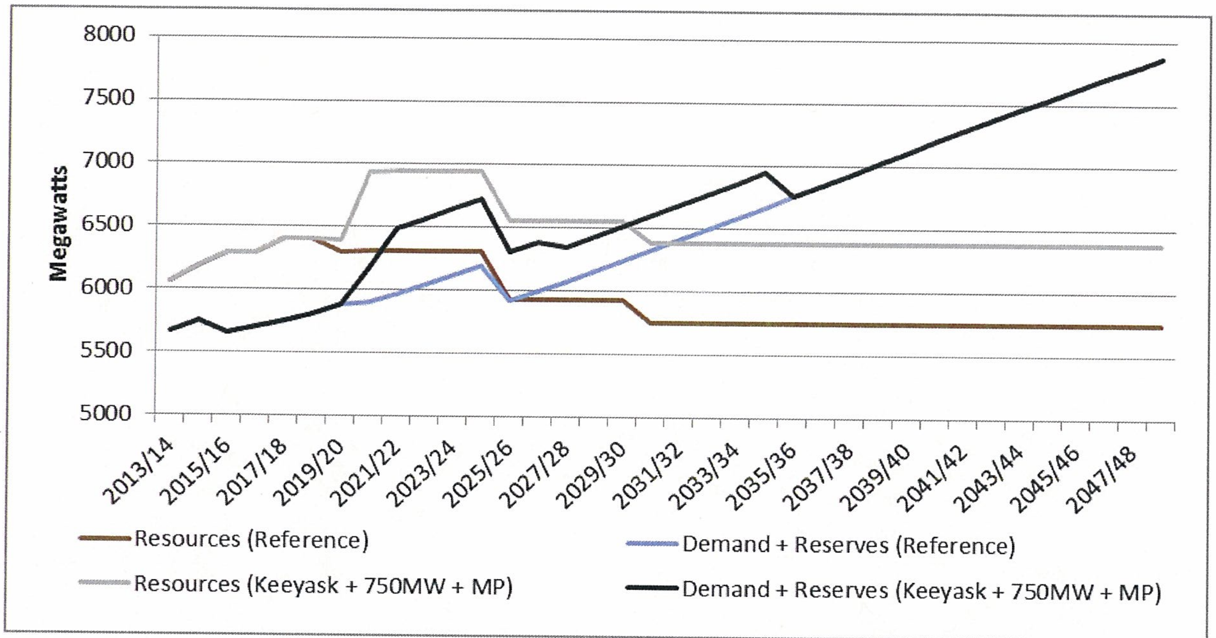

Figure 3-36: Supply vs. demand for capacity with Keeyask, 750 MW transmission and MP contract

The addition of the additional transmission capacity delays the year of need for energy to 2035/36 due to the additional import capacity. The capacity analysis has the same complexity as the prior example. Assuming the full use of the 750 MW line for import capacity, the capacity deficit doesn't exceed the 750 MW line capacity until 2040/41. Therefore, MH would not need to commit to additional new resources for domestic load capacity and energy requirements until as late as 2032 to fulfill the new energy need.

C. Conclusions on Generation Modularity

This analysis demonstrates that the resources being considered under the PDP individually and collectively delay the need for new resources considerably, well into a period where forecasts of conditions such as load or export prices are characterized by significant uncertainty.

VI. Conclusions

Our initial Technical Appendix 3A evaluated Manitoba Hydro's process of creating the various development plans. In this supplemental report, we have evaluated additional plans that we developed and MH modeled. After reviewing MH's modeling results, we can draw several conclusions about the components and timing of the development plans.

First, our review of the CCGT Plan showed that there is likely a better configuration for a gas-only plan than the one MH developed in its All Gas Plan. MH used an optimization method which likely did not in fact provide optimal results. The addition of CCGT plants earlier in the study period clearly shows benefits above the addition of SCGTs in the early years. However, adding only CCGTs appears to over-develop that resource. While we are not able to draw firm conclusions on how another plan would perform without additional modeling by MH, the evidence shows that a combination of CCGTs and SCGTs, with at least one CCGT developed first, would provide a better result.

Second, our review of the LCA No New Generation Plan shows that non-generation options (DSM, fuel-switching, and additional transmission capacity) can significantly delay investment in new generating plants. The configuration that was specifically modeled, with new transmission developed in 2029, appears to miss opportunities for economic imports and opportunity exports in the early years.

This second conclusion is supported by the analysis of how import energy is utilized differently in the All Gas and CCGT Plans. The combination of the evidence indicates that additional transmission capacity has a strong impact on dispatch of units and may provide significant benefits. This suggests that new transmission could be the best first investment, and that a development plan which builds transmission early could exhibit benefits incremental to the new development plans evaluated here.

From our analysis of the Wind/Gas scenario, we have identified additional areas in which Manitoba Hydro's process of creating the development plans and analyzing the results may not have led to optimal results. The results of the Wind/Gas as modeled suggest several areas in which the plan could have been modified to produce better economic results. These are areas which Manitoba Hydro has failed to pursue, and indicate that their evaluation of alternatives has not been entirely thorough.

Finally, our review of the potential benefits of generation modularity demonstrated that there is no pressing need to commit to all of the elements of the PDP at this time. A more incremental approach allowing investment in individual components will delay the need for new resources considerably, and gas units with shorter lead times can be utilized to fill capacity or energy need until a point when additional large hydro capacity is needed.