La Capra Associates

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

Technical Appendix 5

Hydrologic Risk

PUBLIC VERSION

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

PREPARED FOR

The Manitoba Public Utilities Board

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Technical Appendix 5: Hydrologic Risk

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Acronyms

Technical Appendix 5

CCGT	Combined Cycle Gas Turbines
CPV	Cumulative Present Value
DOP	Drought Operating Plan
DSR	Drought Storage Requirements
IRs	Information Requests
KM	Kubursi-Magee
LCA	La Capra Associates
LMP	Locational Marginal Price
MH	Manitoba Hydro
MHEB	Manitoba Hydro Electric Board
MISO	Midcontinent Independent System Operator
MP	Minnesota Power
MW	Megawatt
NFAT	Needs For and Alternatives To
NPV	Net Present Value
PDP	Preferred Development Plan
PUB	Public Utilities Board
SCGT	Simple Cycle Gas Turbines
SOW	Scope of Work
SPLASH	Simulation for Long-Term Analysis of System Hydraulics
US	United States
WPS	Wisconsin Public Service Corporation

I. Introduction

Manitoba Hydro (MH) has included some analysis of the impact of drought and the operation of its facilities during a drought in the Needs For and Alternatives To (NFAT) Submission and also performed analysis of the impact of the proposed projects on the operation of MH's other facilities.

This Appendix will include an independent analysis of the drought risk of the Preferred Development Plan (PDP) compared to other Development Plans, discuss previous drought analyses, and look at MH drought operational plans.

A. Scope

La Capra Associates (LCA) has prepared this Technical Appendix to address two elements of our NFAT Scope of Work (LCA SOW) and support other elements of our work that rely on the materials in this report. The two specific LCA SOW elements addressed here are:

Power Resource Planning and Economic Evaluation

3. *Review reservoir operations of Lake Winnipeg for Optimal Value; and*

15. *Test Manitoba Hydro's alternative scenarios and any new scenarios created for drought impacts.*

B. La Capra Associates' Approach to Reviewing Manitoba Hydro's Analysis of Generation Technologies

Our approach to evaluating MH's generation technology assumptions included the following:

1) LCA reviewed materials relevant to this assessment, including:

- The information contained in the NFAT Submission pertaining to drought; and
- MH's responses to Information Requests (IRs) and information provided to LCA in lieu of responses to IRs.

2) LCA held discussions with MH personnel regarding its assessment of drought in the NFAT Submission and its operations during a drought.
3) LCA conducted independent analysis using the detailed SPLASH data provided by MH.

II. Hydrological Record

Historically MH's flow record has been highly variable as shown below in Figure 5-1. MH considers any year with below average flows a drought year and has had several extended droughts in its history as shown on the figure below. Particularly significant were the 1929-1942 and 1987-1992 droughts. The lowest flows on record occurred in 1940.

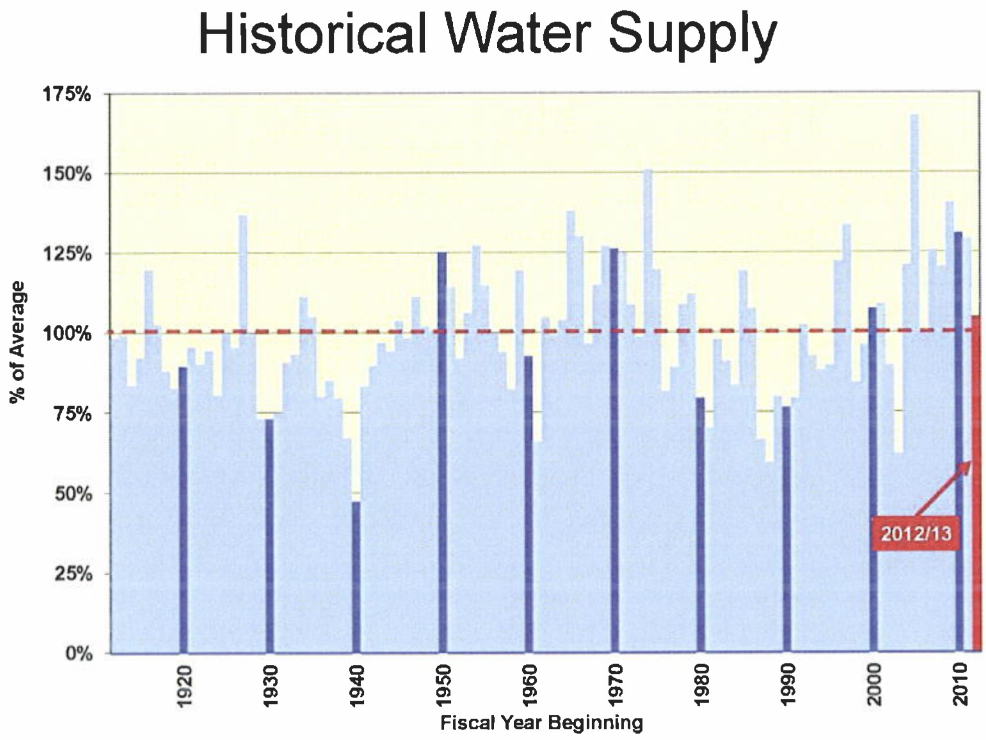

Figure 5-1: Historical Water Supply

III. Manitoba Hydro's Operational and Drought Management Plan

LCA has asked MH for its reservoir operation plan and its drought management plan. In response to LCA/MH II-461 provided a short description of its operational rules and 27 discovery responses from previous proceedings that deal with reservoir operations. Additionally MH provided a confidential document entitled, "Emergency Operations Planning—Drought Management" (November 2013 Draft). In this section, we will give a brief overview of these documents.

At a high level, MH plans its operations to export surplus energy (energy in excess of the reserve requirement) in the highest valued periods to the extent possible subject to operational constraints. Higher export prices are generally found in the June to September period.

The Drought Storage Requirement (DSR) is based on the 1940/41 inflow condition which is assumed to start on April 1st of the fiscal year following the operating horizon. The operating horizon ends on March 31st and is extended in the fall to include a second year, so is between five and seventeen months in duration. MH plans its operations through the operating horizon so that energy in storage is greater than the DSR at the end of the operating horizon.

A. Reservoir Operation

Figure 5-2 is a schematic of all the facilities in MH's system. In the brief overview in response to LCA/MH II-461, MH states that the operation of its reservoirs is restricted by a number of licenses and agreements and that the majority of restrictions are water level-based (maximum or minimum levels) which drive reservoir release operations. It then goes on to discuss the operation of one of the reservoirs, Lake Winnipeg as documented below. None of the other reservoirs are discussed.

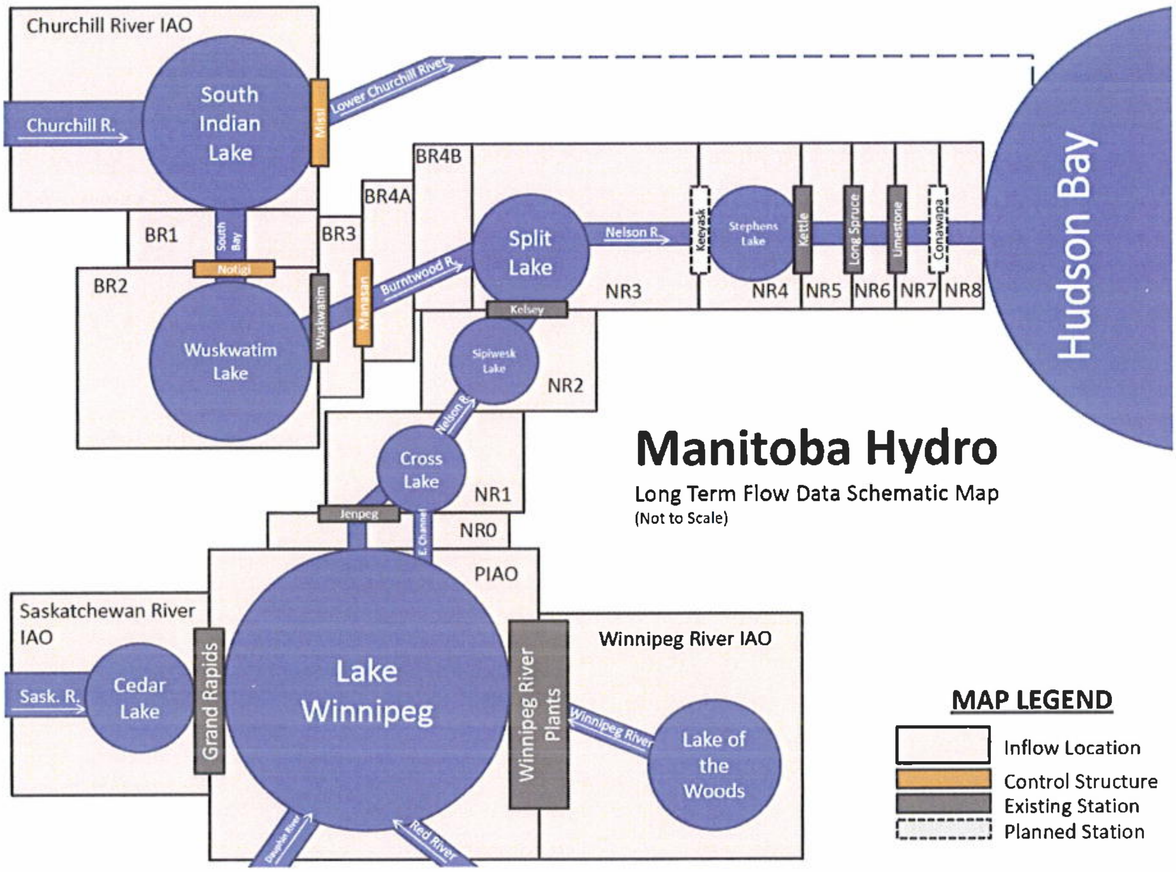

Figure 5-2: Manitoba Hydro System Schematic[1] Lake Winnipeg Regulation

MH has an interim license for Lake Winnipeg Regulation which was issued by the Province of Manitoba as provided for under the Manitoba Water Power Act. The License sets requirements for the control of outflow from Lake Winnipeg, based on its elevations:

- When the lake level is between 711-715 feet, outflows are set to meet the requirements for power production on the Nelson River;
- When the lake level is above 715 feet, MH must operate at maximum discharge until 715 feet is reached; and

[1] SP-121 NFAT Confidential – LTFD_DATA_1912-2010(CONFIDENTIAL).

- When the lake level is below 711 feet, MH must operate outflow as ordered by the Minister responsible for the Water Power Act.

Operational Rule Curve/Useable Energy Storage Requirement

MH plans its operations to ensure usable storage levels are, at a minimum, sufficient to supply firm domestic and export load under the most severe single historic drought of record inflow condition. This useable energy storage requirement is effectively the "rule curve."[2]

B. Hydraulic Generation Forecasts

On a weekly basis, MH prepares a production forecast for the generating system for the next 16 months into the future. The forecast includes generation plans for each of MH's facilities and import and export transaction necessary to serve MH's load obligations. Inputs into this process include:

- Reservoir storage; and
- Water supply forecast.[3]

If MH has surplus energy supplies available, these are scheduled for sale in the export market in a manner that maximizes net export revenue. The production forecast also includes a set of reservoir releases necessary for economic power system operation and to meet license requirements.

C. Drought Management Plan

As a follow-up to a conversation between MH and LCA, MH provided a confidential document entitled, "Energy Operations Planning- Drought Management (2013 Draft)." This document is a draft drought management plan. According to MH the purpose of this document is to outline the factors that MH must consider in maintaining an adequate supply of electricity for its customers in anticipation of and during drought.

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[2] 2010-2011 and 2011-2012 GRA and Risk Review PUB/MH I-74.

[3] 2010-2011 and 2011-2012 GRA and Risk Review PUB/MH I-163.

In the document provided, MH refers to the Drought Operating Plan (DOP), which is defined as a "sequence of planned reservoir releases, generation and import and export activities for a defined set of conservative assumptions."[4] The DOP is referred to numerous times in the document, but is not provided.

The document defines the operation priorities, responsibilities, committees, supply and demand, and monitoring and reporting.

[4] MH, Energy Operations Planning- Drought Management (2013 Draft), Page 5.

IV. History of Drought Analysis in Earlier Proceedings

Given that a large percentage of MH's power supply comes from its hydropower generating stations, drought is one of the most significant risks that MH faces. The length of drought and the historical drought to be modeled have been a subject of much debate in earlier rate cases.

A. Analysis of Proper Drought Length from Earlier Cases

KPMG and Drs. Kubursi and Magee filed MH risk review reports with the Public Utilities Board (PUB), which the PUB reviewed prior to issuing its final order with respect to MH's application for increased 2010/11 and 2011/12 rates.[5] These two consultant reports addressed drought length.

KPMG Report

KPMG looks at the effect of drought length on the relative value of several scenarios. KPMG asked MH to run several drought scenarios on its development plans in the 2009/2010 Power Resource Plan. The scenarios were run for two development plans:

- No Sale: Conawapa online 2021/22, combined cycle combustion turbine (CCGT) in 2033/34 and no Keeyask or export sales to Wisconsin Public Service (WPS) or Minnesota Power (MP); and
- Sale: Keeyask in 2018, Conawapa in 2022/23, new export contracts with WPS and MP.

MH had determined that the net present value (NPV) of the Sale development plan was [redacted] greater than the No Sale development plan.

KPMG requested runs of three drought lengths for the low, expected and high energy prices:

- 5-year drought mimicking 1937-1941 flows

[5] See discussion in Board Order 5/12, pp. 184-200.

- 10-year low flow of 1932-1941
- 15 year low flow of 1927-1941

The results are reproduced in CONFIDENTIAL Figure 5-3 below. The incremental NPV of the Sale Scenario verses the No Sale Scenario is shown in the figure below. KPMG concludes that the Sale Scenario is a good idea because the NPV difference between the scenarios remains positive no matter what drought scenario it tested. KPMG does not make any conclusions about the appropriate length of drought analysis.

[redacted]

CONFIDENTIAL Figure 5-3: KPMG Drought Analysis[6]

KM Report

In November 2010, Dr. Atif Kubursi and Dr. Lonnie Magee submitted the results of an independent risk review (i.e., the KM Report) to the PUB. The authors discuss a broad range of risks, including drought risk.

[6] KPMG, *Manitoba Hydro-External Quality Review: Main Report.* April 15, 2010. Page 176.

The KM Report discusses several different methods of water flow modeling and drought prediction, including Re-Sampling or Historical Simulation, Autoregressive Time Series Models, and Extreme Value Models. SPLASH is essentially a historical simulation model as it uses historical inflows to simulate future inflows. The KM Report notes that this type of modeling is limited in its usefulness, as it cannot predict future values that lie outside the range of historical experience.[7] However, the KM Report does not recommend a particular method of drought prediction, but instead compares several different Autoregressive Time Series and Extreme Value models. It also states that MH is correctly using the low flow years from 1937-1942 as the basis of its dependable energy calculations because while a more severe drought is possible its probability of occurrence is 24 times in 9,400 years.[8]

Using a Monte Carlo model, the KM Report authors studied the financial impact of a drought. Instead of using a five or seven-year drought, the authors modeled one year representative of the actual minimum of water flows over the period between 1912 and 2005.[9] The result was a mean loss of revenue on the order of $343 million.[10]

Board Order 5/12

In Board Order 5/12, the PUB stated that after reviewing the various consultant reports it was not convinced that the five-year drought was the proper drought to use in the analysis. The PUB stated, "It was not convinced that the drought events extending from 1929/30 to 1942/43 (including both the five-year and seven-year drought) would not serve as a more appropriate stress test."[11]

The PUB also cited the 2003/2004 drought and the financial losses suffered by Manitoba many times in its Order. In 2003/2004, the prices of import power were high and MH was forced to purchase high priced power due to the drought situation.

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[7] KM Report, p. 139.

[8] Id., p. 286.

[9] Id., p. 229.

[10] Id.

[11] Board Order 5/12, page 172.

V. Drought Modeling in the NFAT Analysis

In the NFAT Analysis, MH modeled the economic and financial impacts of a five-year drought. MH extracted data from particular SPLASH runs where drought water years align with particular fiscal years, such as the year Keeyask goes into service. MH extracted data only from the drought years and inserted the resulting cash flows from the drought years into the Economic Model. The cash flows in all other years in the Economic Model were left the same, i.e. at the average of the 99 water years modeled in SPLASH. MH has chosen to model a five year drought which corresponds to the historical flows that were available in fiscal years 1987/88 through 1991/92.

There are two potential five-year droughts MH could have modeled, the 1937/38 to 1941/42 and the 1987/88 to 1991/92 droughts. The earlier drought was more severe, but MH has modeled the 1987/88 to 1991/92 drought. MH explains its choice of historical drought sequence in its response to LCA/MH I-116. It asserts that in previous analyses, the financial impact of the earlier drought was not significantly greater than the 1987/88 to 1991/92 period and that the later period better reflected "current regulation patterns and water use practices in watersheds upstream of Manitoba."[12]

MH substitutes the plan results for that period assuming these drought conditions for the results for that same period under average water conditions.

MH provided several documents in response to LCA's inquiries into how it had selected a five-year drought for the NFAT. The first document was a response to an IR from the 2012/2013 and 2013/2014 Electric General Rate Application.[13] In this document, MH presents results from a five-year and seven-year drought analysis that it had done for a drought starting in 2021/22. This analysis shows that a seven-year drought would have a greater effect on net revenue than a five-year drought. It also states that MH plans to do more extensive drought analysis during the NFAT process.

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[12] LCA/MH I-116.

[13] 2012/2013 and 2013/2014 Electric General Rate Application, PUB/MH II-91 (Revised Based in IFF 12).

The second response related to drought length was in in response to LCA/MH I-116. In this response, MH stated that modeling a drought longer than five or seven years would include more years with more moderate flows, which would lessen the impact of the drought.

VI. Analysis of Data from Individual Water Years

MH's SPLASH modeling analysis uses sequences of historical water years to reflect the variability of water conditions in its analysis. MH simulates the future system operations with 99 different water year sequences and then averages those results to produce the plan results.

MH provided detailed data from the 99 SPLASH runs for each of the 15 development plans included in the NFAT as well as two additional development plans requested by LCA: the All CCGT Plan and the LCA No New Generation Plan. The All CCGT Plan is a variant of MH's All Gas Plan, which includes all CCGTs instead of a mix of single cycle gas turbines (SCGTs) and CCGTs. The All CCGT Plan was designed to test the impact of more efficient gas generation on the performance of the plan. The LCA No New Generation Plan allows for additional imports from the US, increased levels of Demand Side Management measures, and additional fuel switching for conversion of electric space heat to natural gas.

LCA analyzed the detailed SPLASH data to get a better understanding of how water conditions would affect the performance of different development plans. We focused our analysis on four plans: All Gas, Preferred, All CCGT and LCA No New Generation.

The first step in our analysis was to compare the relative NPVs of the net revenue from the detailed SPLASH data for different cases. The net revenue includes all the costs and revenues which vary by flow condition. It is defined as the revenue from opportunity exports minus the thermal variable costs, the water rental costs and import costs. It does not include any fixed costs, especially capital costs, so is not directly comparable to results shown in Technical Appendices 9A and 9B.

The detailed SPLASH data included runs which show the annual net revenue for 99 water year sequences per development plan. For each development plan, we calculated the NPV of the net revenue over the first 34 years of the study period for each of the 99 water year sequences. It was not possible to calculate the NPV beyond the first 34 years of the water year sequences because the detailed SPLASH data is not calculated for more than 34 years. Technical Appendix 9A discusses the SPLASH data and the extrapolation beyond the 34 years modeled in SPLASH for the 78-year economic analysis.

We have compared the NPV of the net revenues for each water year sequence for each of the four development plans. The difference between the NPV of net revenues for the 99 water year sequences are shown below for select development plans in Figure 5-4.

- Each data point on the graph is the difference in NPV over 34 years between two plans for one particular water sequence;
- Each set of data points is the range of differences in NPV over the 99 water sequences, sorted by the historical year that defines the first year of that sequence; and
- The comparison of the All Gas to the All CCGT case shows the smallest variance by water condition, indicating that the water variations affect those two plans similarly (a straight horizontal line would show that the plans perform identically across all water sequences).

Figure 5-6 shows the same data as Figure 5-4, but the data is organized by rank of NPV difference rather than the first year of the water flow sequence.

The two graphs show that there is variation in the difference between development plans of the NPV of net revenues over water year sequences. It shows that while the NPV of net revenues for the Preferred Development Plan is always greater than the NPV of net revenues for the All Gas, All CCGT or LCA No New Generation Plans, the amount by which the Preferred Development Plan net revenue is greater varies by water year sequence and therefore flow conditions. It also shows a similar variation between the All CCGT and All Gas Plans. With this data, the specific water sequence that causes a plan to perform the best/worst can be identified for further investigation of drought vulnerability and performance.

Our next step was to delve deeper into the NPV difference variations by water year. This is discussed more in the following sections.

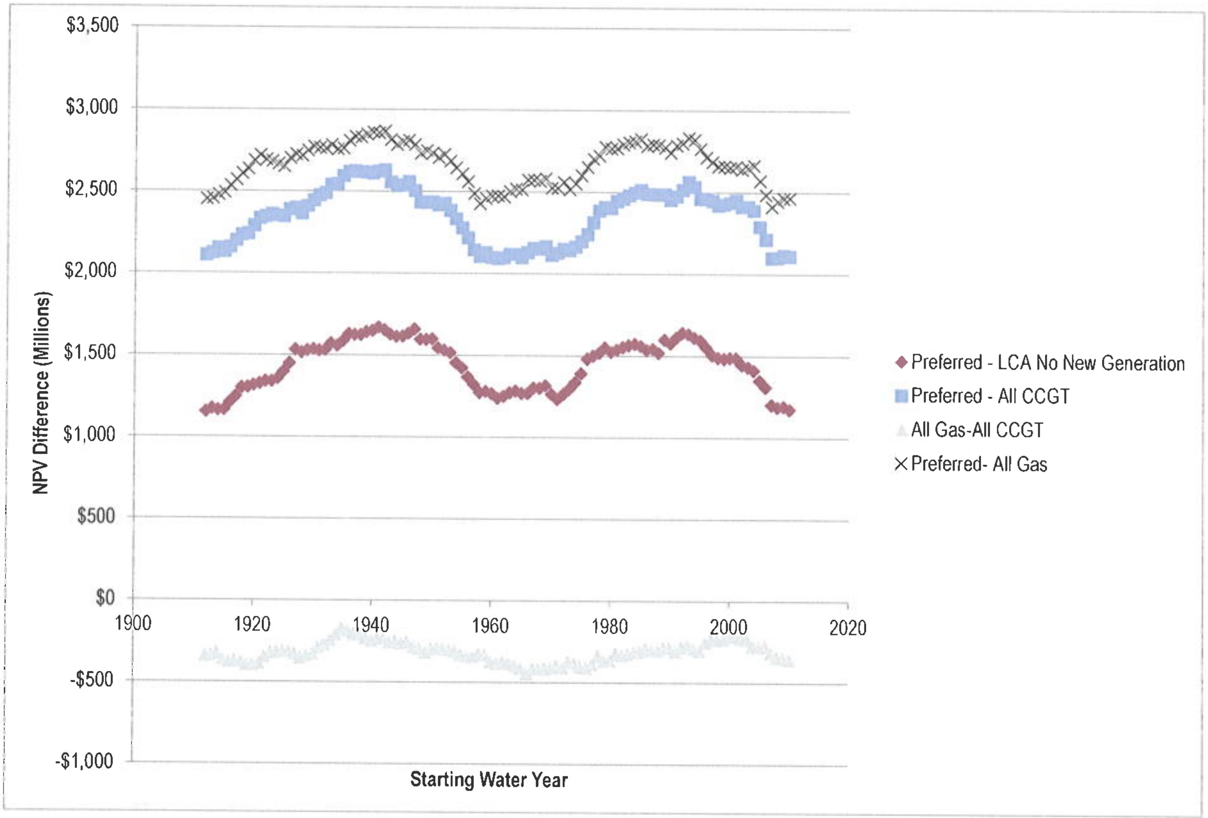

Figure 5-4: 34-year Net Revenue NPV Difference across the 99 SPLASH Sequences

	Range in Difference	Max	Min	Median
Preferred-LCA No New Generation	$517	$1668	$1151	$1488
Preferred-All CCGT	$538	$2630	$2092	$2398
All Gas-All CCGT	$276	$(169)	$(444)	$(318)
Preferred-All Gas	$454	$2,866	$2,413	$2,685

Figure 5-5: Summary of 34-year Net Revenue NPV Differential across the 99 SPLASH Sequences

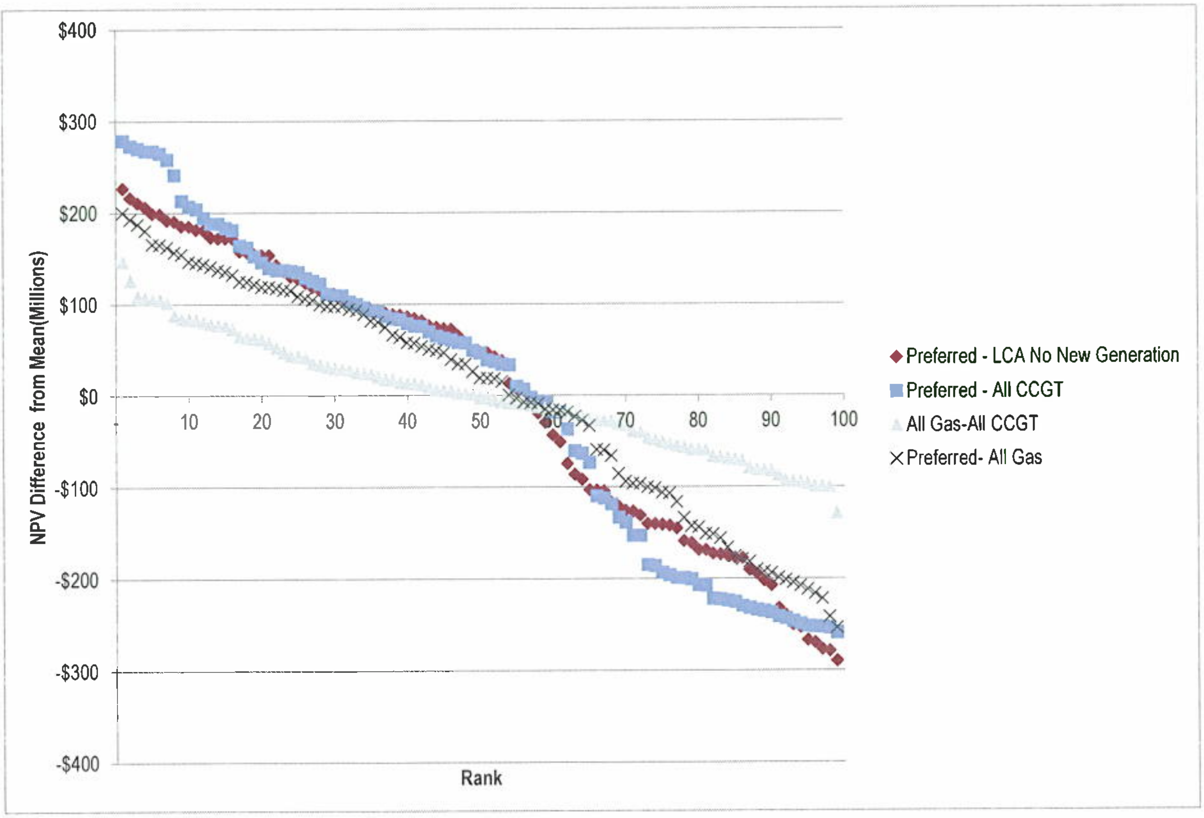

Figure 5-6: Plan Difference NPV Difference from Mean across the 99 SPLASH Sequences by Rank

The years that produce the largest difference between the development plans, shown in the figures and table above, are not necessarily the water year sequences where the individual plans perform the best. This analysis has been done for only the reference case fuel and capital cost scenarios, using different assumptions could change the results. Also note that the NPV differences shown in the figures and table above, reflect a difference in net revenue, but are not a measure of the years that could create the most financial stress. Technical Appendix 10B discusses the financial stress from drought.

The data in the figures and table above shows a smaller impact from drought than the scenarios that MH included in Chapters 10 and 11. That analysis looked at the impact of inserting a five-year drought in the economic or financial analysis for one development plan, where the analysis described above is looking at the comparative impact between two development plans.

A. Preferred Development Plan Compared to the All Gas Plan

LCA compared the SPLASH results for the PDP to the SPLASH results for the All Gas Plan for two water flow sequences: the water flow sequence starting at 2007 (i.e., the first fiscal year modeled in SPLASH aligns with flow year 2007) and the water flow sequence starting at 1942. These are the flow sequences in which the difference between net revenue NPV for the PDP and the All Gas Plan is the largest and the smallest. The maximum difference is $2.866 billion for the flow sequence beginning in 1942 and the minimum difference is $2.413 billion.[14] This means the swing between the difference between the PDP and the All Gas Plan is $2,685 plus $181 or minus $272 Million on an NPV basis over the first 34 years of the study period.

Lining up the water flow sequence starting at 2007 with the first 34 years of the analysis yielded the lowest difference in net revenue NPV between the PDP and the All Gas Plan. Because the net revenue for the PDP is higher than the All Gas Plan, the water flow sequences in which the difference between the two plans is lowest is the best for the All Gas Plan. This would be the instance in which the All Gas net revenue is closest to the Preferred Plan net revenue. This is shown in Figure 5-7 below.

Figure 5-7 shows that the water flow sequence starting in 2007 is a sequence of below average flow years. Given that the PDP contains Keeyask and Conawapa and the All Gas Plan does not, the All Gas Plan performs relatively better during dry periods than the more hydropower-focused PDP. Note that the driest period actually falls at the end of the sequence.

[14] The NPV difference reported here is the difference in Net Revenues. Net Revenues is defined as opportunity export revenue minus thermal variable costs, water rental fees and import costs. The difference in Net Revenues between the Preferred Development Plan and the All Gas Plan are greater than the difference in the NPV of the total plan expenses because of the structural difference in the plans. The PDP has greater fixed expenses, but also greater Net Revenues than the All Gas Development Plan as it includes additional export energy from the addition of Keeyask and Conawapa.

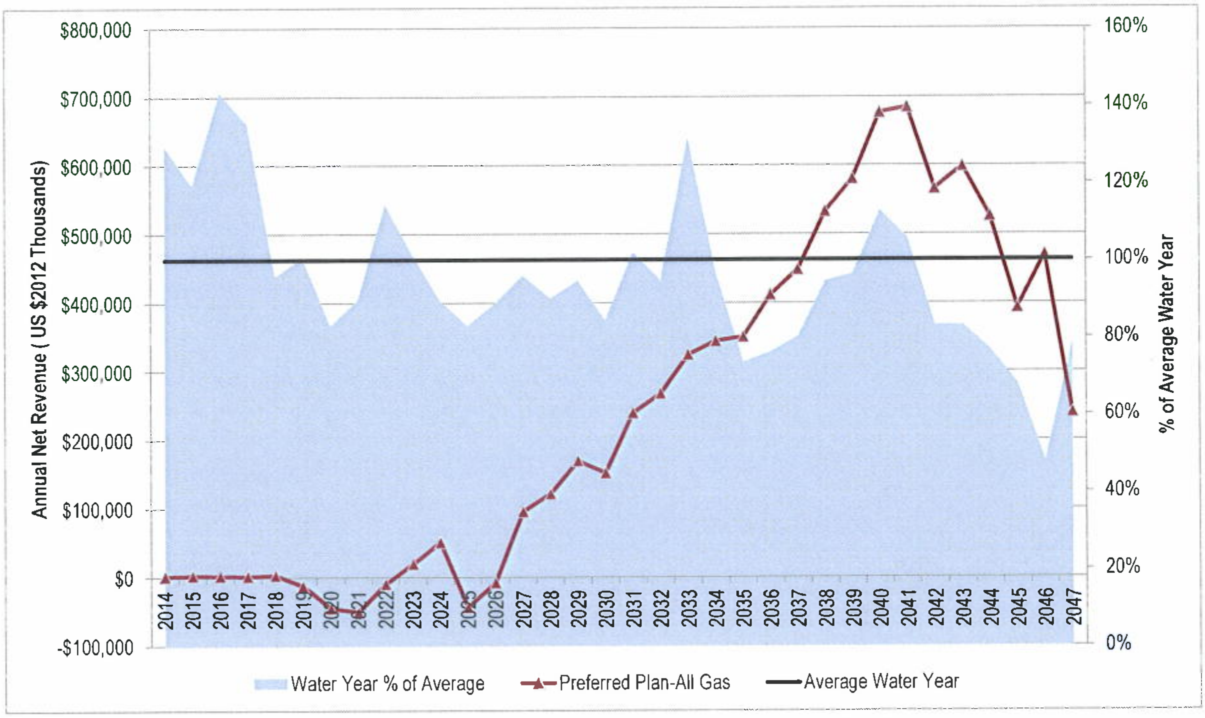

Figure 5-7: Minimum Net Revenue NPV Difference Preferred – All Gas

NPV Difference = $2.413 Billion, Start at Water Year 2007

Figure 5-8 shows the water years sequence with the maximum difference between the PDP and the All Gas Development Plan. This is the water flow sequence in which the PDP performs the best relative to the All Gas Development Plan. The graph shows that the water flow sequence starting in 1942 is a wetter than average sequence. The PDP performs better than the All Gas Development Plan over a wet sequence because the PDP has more hydropower than the All Gas Development Plan.

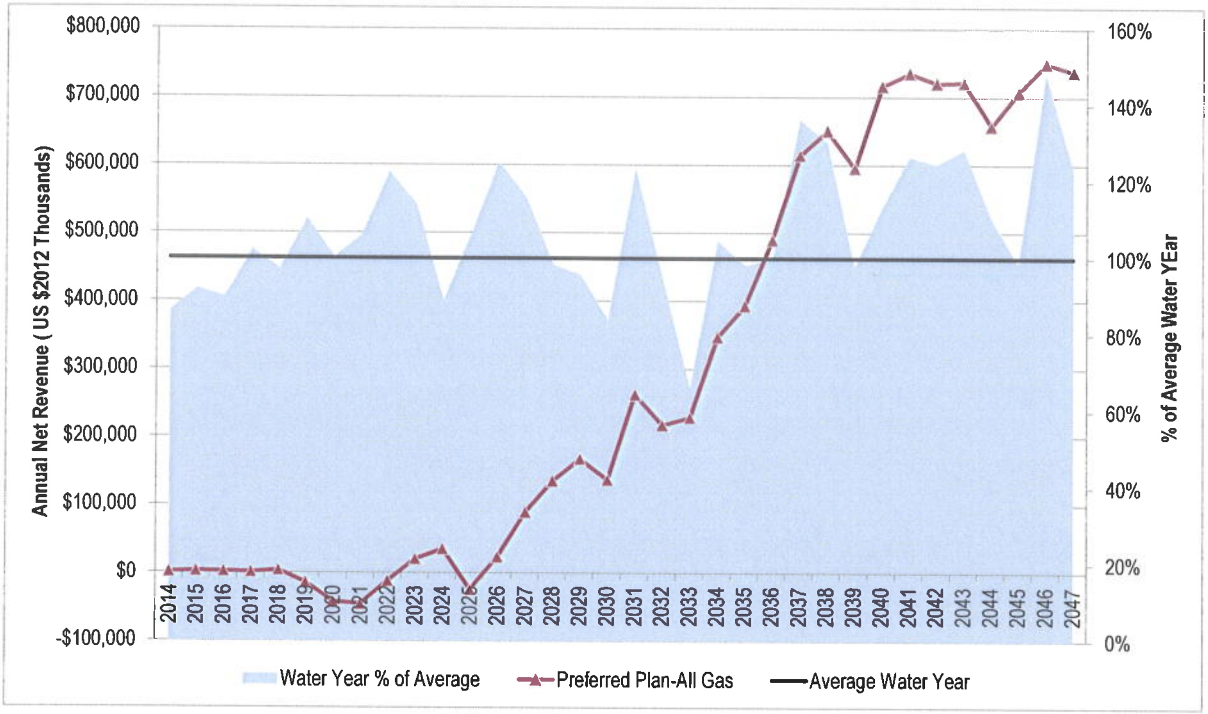

Figure 5-8: Maximum 34-year Net Revenue NPV Difference Preferred – All Gas

NPV Difference = $2.866 Billion, Start at Water Year 1942

Figure 5-9 does a direct comparison of the maximum and minimum NPV differences of the two water sequences shown in Figure 5-7 and Figure 5-8. The majority of the difference comes at the end of the SPLASH study period after Conawapa is added to the PDP.

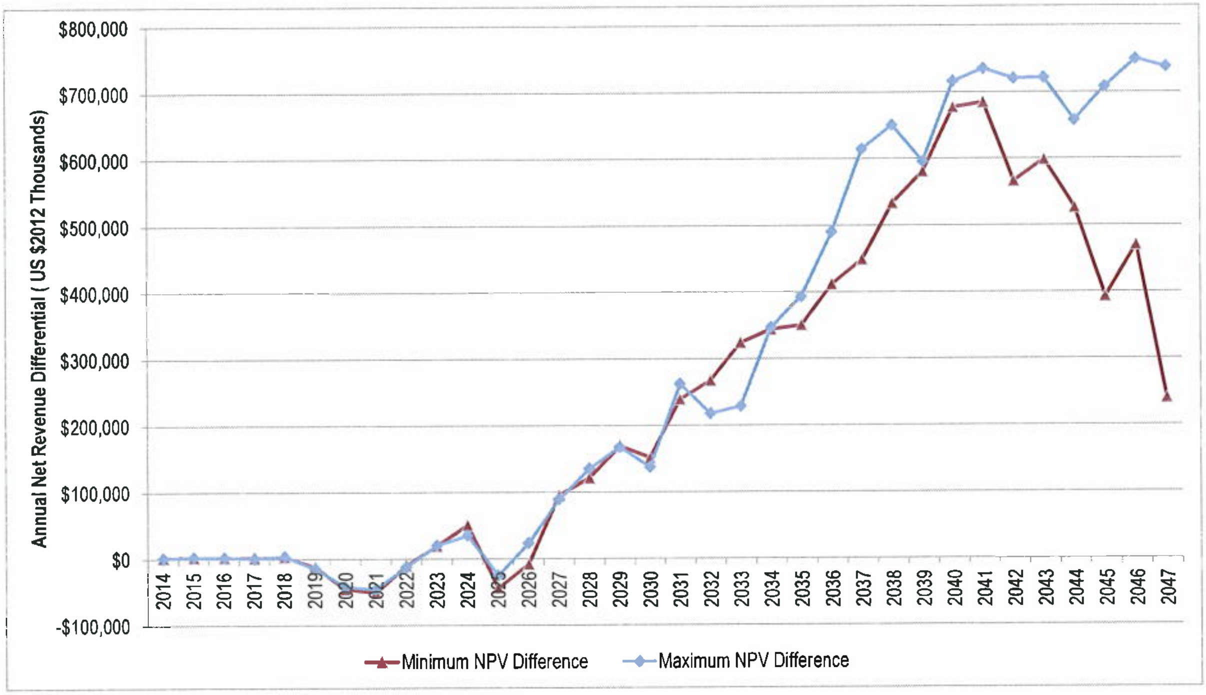

Figure 5-9: Annual Net Revenue Difference for Maximum and Minimum Net Revenue Difference: Preferred Development Plan minus All Gas Development Plan

B. Preferred Development Plan as compared to LCA No New Generation Development Plan

LCA looked at the comparison of the Preferred Development Plan to the LCA No New Generation Development Plan for two water flow sequences: the water flow sequence starting at 1912 and the water flow sequence starting at 1941. These are the flow sequences in which the difference between net revenue NPV for the PDP and the LCA No New Generation Development Plan is the largest and the smallest. The maximum difference is $1.667 billion for the flow sequence beginning in 1941 and the minimum difference is $1.151 billion. This means the swing between the difference between the PDP and the LCA No New Generation Development Plan is $1,488 plus $179 or minus $337 million on an NPV basis over the first 34 years of the study period.

Lining up the water flow sequence starting at 1912 with the first 34 years of the analysis yielded the lowest difference in net revenue NPV between the PDP and the LCA No New Generation Development Plan. This is the flow sequence in which the No

New Generation Development Plan performs the best relative to the PDP. This is shown in Figure 5-10 below.

Figure 5-10 shows that the water flow sequence starting in 1912 is a sequence of below average flow years. Given that the PDP contains Keeyask and Conawapa and the LCA No New Generation Plan does not, the LCA No New Generation Plan performs relatively better during dry periods than the more hydropower-focused PDP.

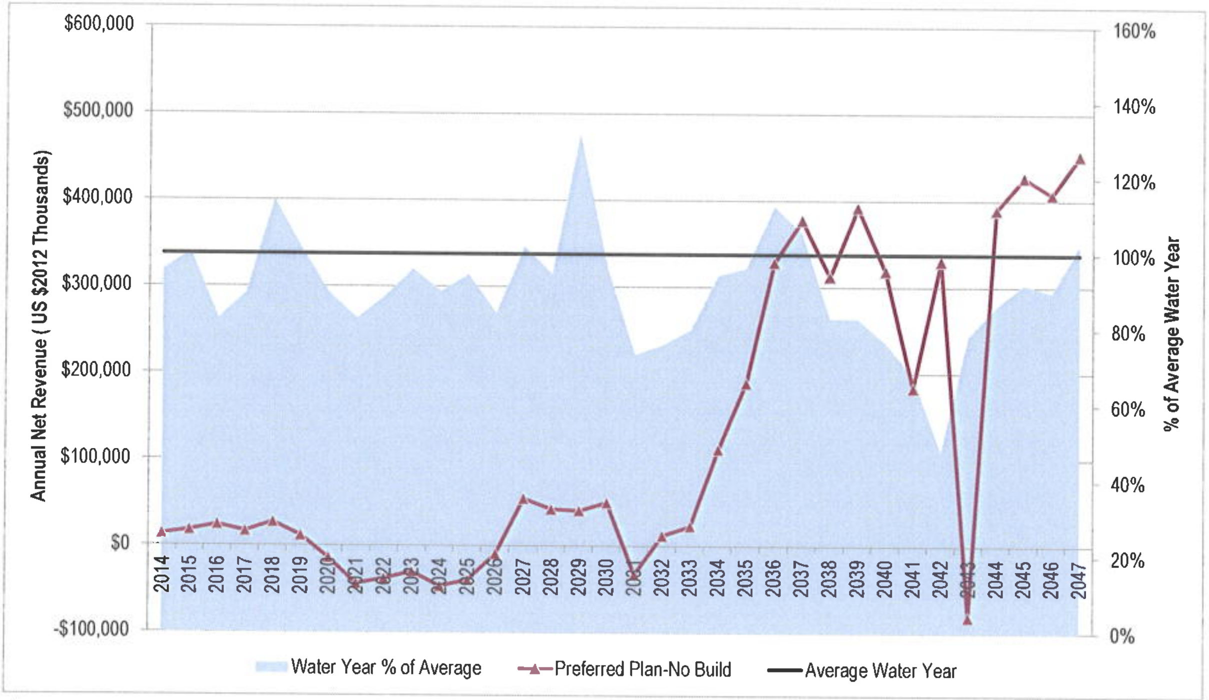

Figure 5-10: Minimum 34-year Net Revenue NPV Difference Preferred LCA No New Generation

NPV Difference = $1.151 Billion, Start at Water Year 1912

Figure 5-11 shows the water years sequence with the maximum difference between the PDP and the LCA No New Generation Development Plan. This is the water flow sequence in which the PDP performs the best relative to the LCA No New Generation Development Plan. The graph shows that the water flow sequence starting in 1941 is a wetter than average sequence. The PDP performs better than the LCA No New Generation Plan over a wet sequence because the PDP has more hydropower.

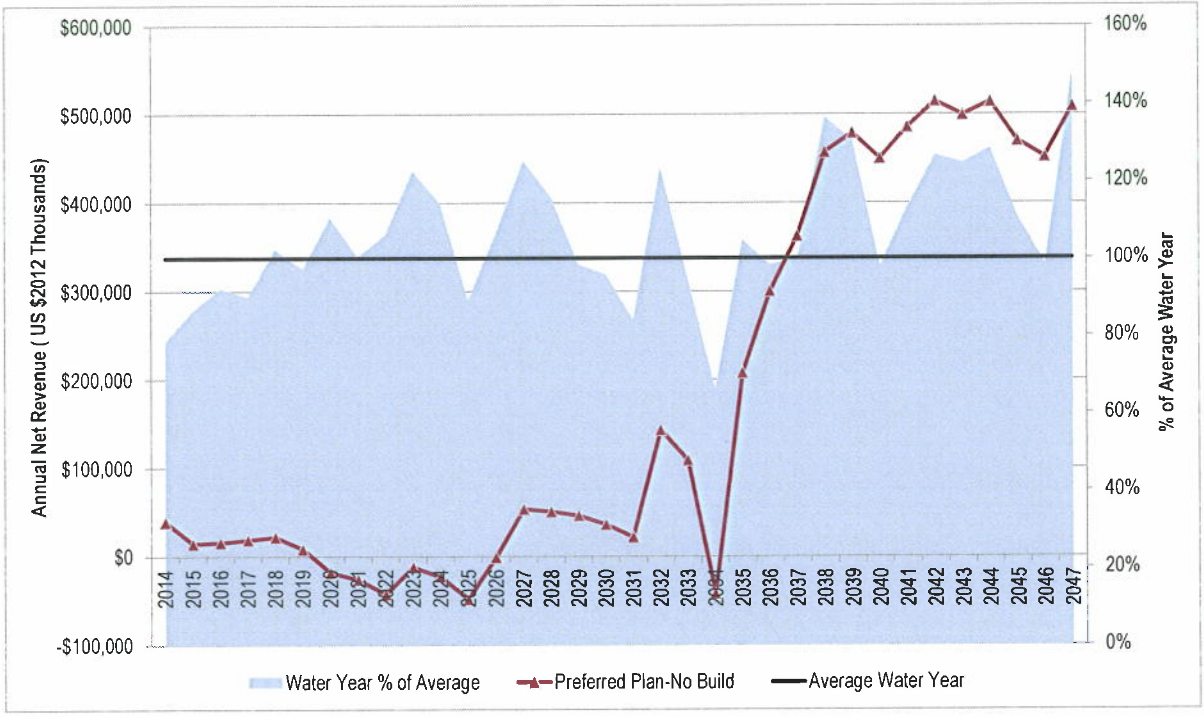

Figure 5-11: Maximum Net Revenue NPV Difference Preferred – LCA No New Generation

NPV Difference = $1.667 Billion, Start at Water Year 1941

Figure 5-12 does a direct comparison of the maximum and minimum NPV differences of the two water sequences shown in Figure 5-10 and Figure 5-11. The majority of the difference comes at the end of the SPLASH study period after Conawapa is added to the PDP and the transmission is added to the LCA No New Generation case.

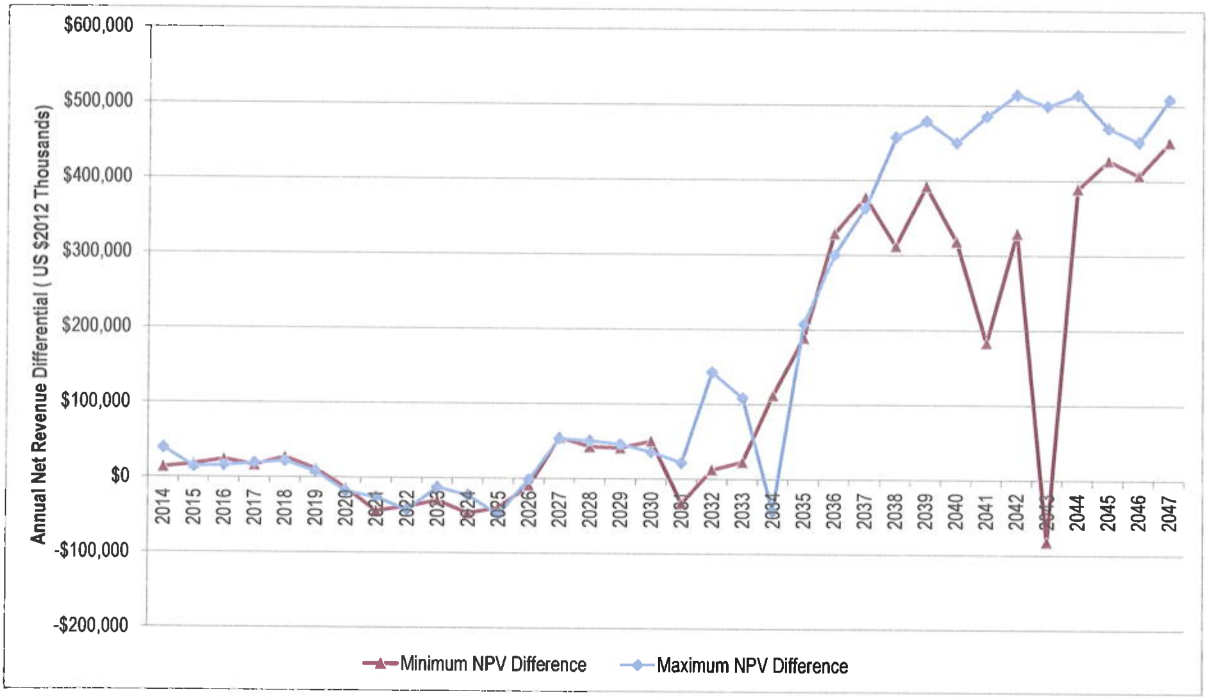

Figure 5-12: Annual 34-year Net Revenue Difference for Maximum and Minimum Net Revenue Difference: Preferred Development Plan minus LCA No New Generation Development Plan

C. All Gas Development Plan Compared to the All CCGT Development Plan

LCA compared the All Gas Plan to the All CCGT Plan for two water flow sequences: the water flow sequence starting at 1935 and the water flow sequence starting at 1966. These are the flow sequences in which the difference between net revenue NPV for the All Gas Development Plan and the All CCGT Development Plan is the largest and the smallest. The maximum difference is - $444 Million for the flow sequence beginning in 1966 and the minimum difference is - $168 Million. This means the swing between the difference between the All Gas Development Plan and the All CCGT Development Plan is $318 plus $126 or minus $150 Million on an NPV basis over the first 34 years of the study period.

Lining up the water flow sequence starting at 1935 with the first 34 years of the analysis yielded the lowest difference in net revenue NPV between the All Gas Development Plan and the All CCGT Development Plan. This is the flow sequence in which the All

Gas Development Plan performs the best relative to the All CCGT Development Plan. This is shown in Figure 5-13 below.

Figure 5-13 shows that the water flow sequence starting in 1935 is a sequence of below average flow years in the beginning of the study period and above average flows starting around 2025. Given that the All Gas and All CCGT Plans are identical for the early years of the plans, the wetter flow years corresponding with study years 2025 and beyond are driving the relative advantage of the All Gas Plan verses the All CCGT Plan as the CCGT generation is of limited advantage during above average water conditions.

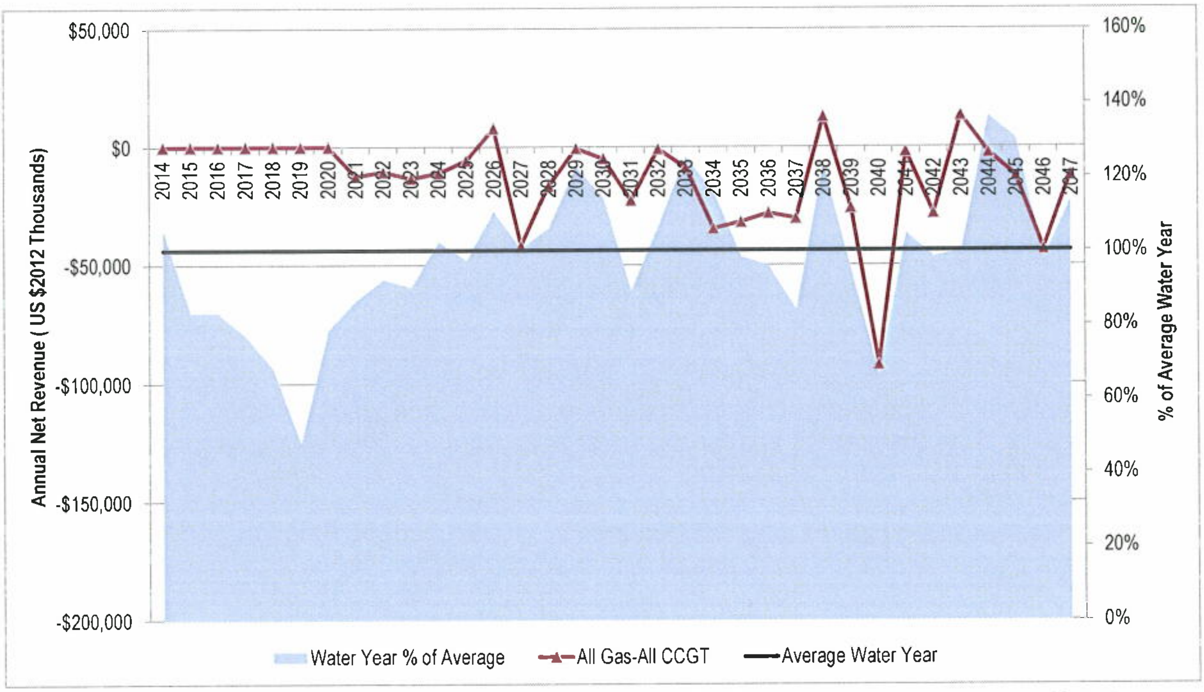

Figure 5-13: Minimum 34 year Net Revenue NPV Difference All Gas – All CCGT

NPV Difference =- $0.168 Billion, Start at Water Year 1935

Figure 5-14 shows that dry years are to the advantage of the All CCGT Plan over the All Gas Plan. The more efficient gas generation fleet of the All CCGT plan runs during the dry period, therefore reducing costs for the All CCGT Plan. This result illustrates the better dry period hedging performance of the plan with more CCGT capacity.

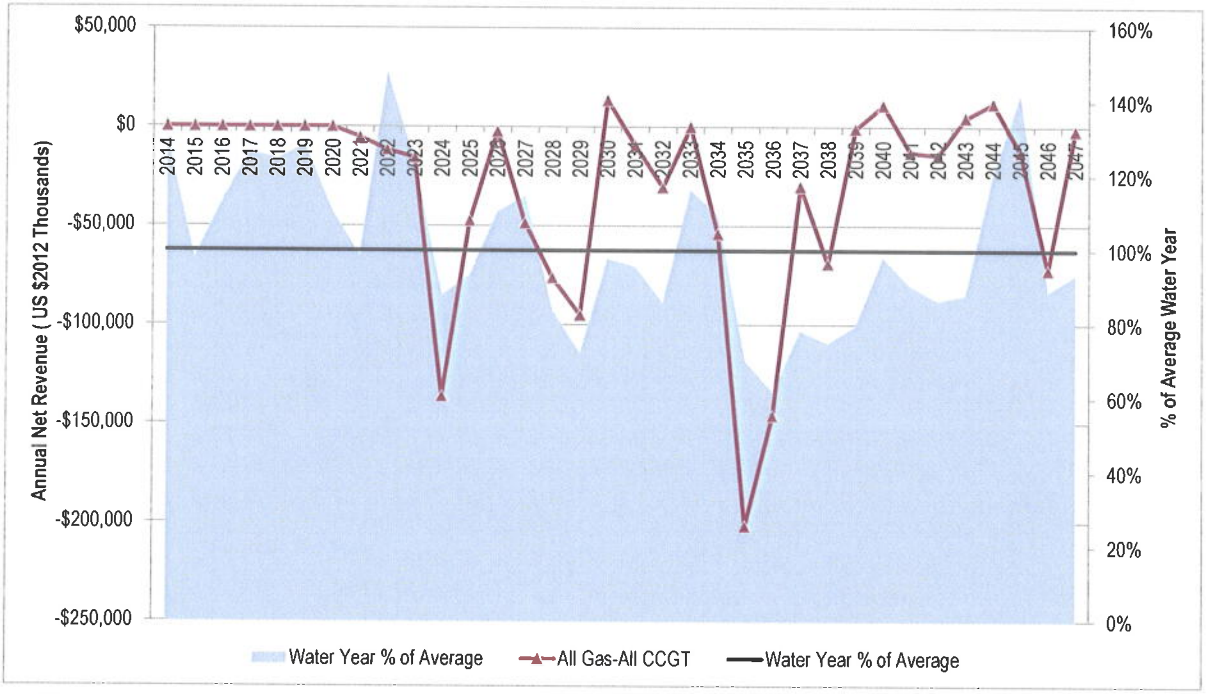

Figure 5-14: Maximum 34-year Net Revenue NPV Difference All Gas – All CCGT

NPV Difference = - $0.444 Billion, Start at Water Year 1966

Figure 5-15 does a direct comparison of the annual net revenue difference between the All Gas Development Plan and the All CCGT Development Plan water sequences shown in Figure 5-13 and Figure 5-14. In this case the maximum NPV difference is a negative number and the graph shows how the additional costs experienced by the All Gas Development Plan during the dry periods drive the differences in NPVs.

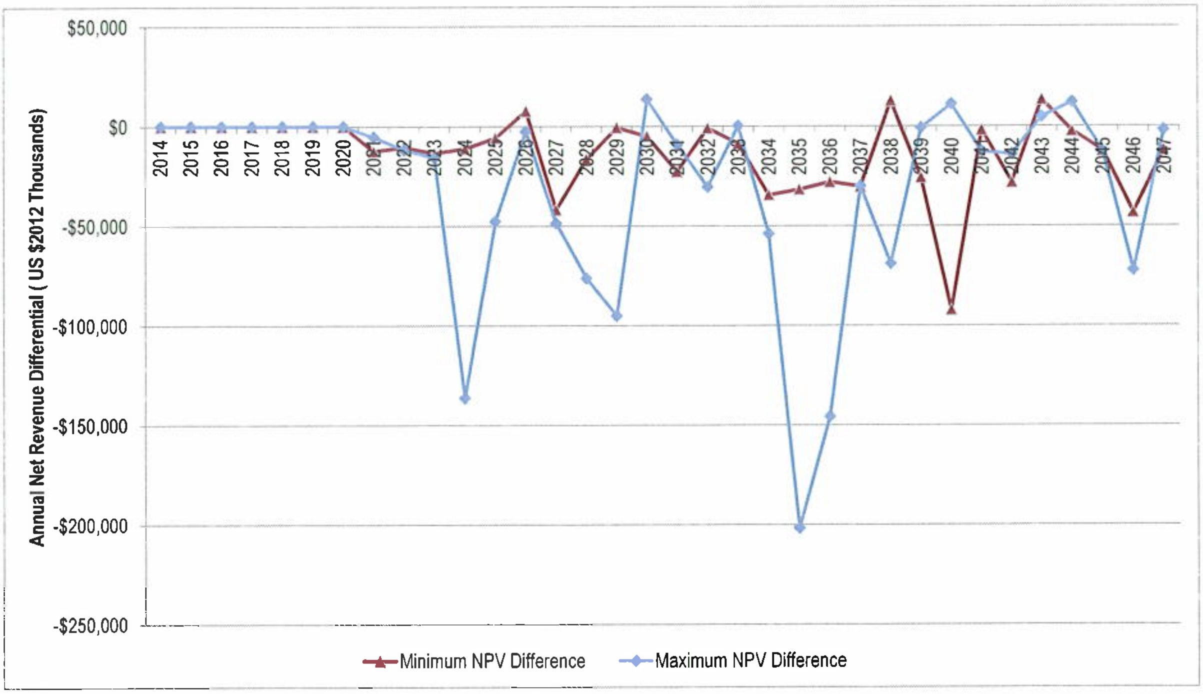

Figure 5-15: Annual Net Revenue Difference for Maximum and Minimum Net Revenue Difference: All Gas Development Plan minus All CCGT Development Plan

LCA took the worst case water sequences for the PDP verses the All Gas Plan and the LCA No New Generation Plan and entered the net revenue figures for these sequences into MH economic model. These were the water year sequences when the difference between the PDP and the All Gas and LCA No New Generation Plans were the smallest. These were the water year sequences which were the worst for the PDP verses the other two development plans. This was for the flow sequences starting in 2007 and 1912. The impact on the PDP 78-year NPV was -$777 Million for the water year sequence starting in 1912 and -$208 Million for the water year sequence beginning in 2007. Unlike the net revenue NPV's discussed above, these figures include fixed costs associated with each plan in addition to the net revenue. These results are shown below in Figure 5-16.

First Water Year in Sequence	78-year NPV Using Water Year Sequence	Difference from Average Water Years NPV
1912	$(3,699)	$(777)
2007	$(3,130)	$(208)

Figure 5-16: Impact of Worse Case Water Year Sequence on Preferred Development Plan 78-year NPV

D. Impact of 1929-1942 Drought on Development Plan NPV

LCA has also calculated the impact of the worst case water sequence on the PDP, the All Gas Development Plan and the LCA No New Generation Plan. The worst case water sequence modeled is the 1929-1942 drought specified by the PUB in Board Order 5-12 discussed above timed to start in 2025, the first year Conawapa would be online in the PDP. We have modeled this two ways, first with just the 1929-1942 drought SPLASH data inserted in the economic model starting in 2025, with average water year data used for the other years and second with the water sequence that results in the 1929-1942 drought beginning in 2025, but including all of the SPLASH data from the first years of this sequence in the first 34 years of the economic model. In all cases, the average water year data is used for years 2048 and beyond. The results of this analysis are shown in the table below. As with Figure 5-16, the results in Figure 5-17 include all fixed costs for each plan in addition to the net revenue results from SPLASH or average water years.

	Preferred	All Gas	LCA No New Generation
Average Water Years	$(2,921)	$(4,617)	$(3,197)
1929-1942 Drought Starting in 2025, entire 34 Year SPLASH Water Sequence Included	$(3,855)	$(5,348)	$(3,918)
1929-1942 Drought Starting in 2025, Average Water Years for Remaining Years	$(4,410)	$(5,848)	$(4,361)
Difference from Average Water Years NPV			
1929-1942 Drought Starting in 2025, entire 34 Year SPLASH Water Sequence Included	$(934)	$(731)	$(721)
1929-1942 Drought Starting in 2025, Average Water Years for Remaining Years	$(1489)	$(1231)	$(1164)

Figure 5-17: 78 -year NPV of Key Development Plans with 1929-1942 Drought

Figure 5-17 shows that the NPV of the LCA No New Generation Development Plan is about $276 Million less than the PDP under average conditions, but inserting the 1929-1942 drought starting at 2025 would change this so that the LCA No New Generation Development Plan has an NPV about $50 million greater than the PDP. The PDP has a higher NPV than the All Gas Development Plan with and without the drought sequence inserted.

Figure 5-18, Figure 5-19, Figure 5-20, show the cumulative NPV (CPV) of the three scenarios for average conditions and the two drought scenarios included in Figure 5-17. Under average conditions, it takes until 2054 and 2075 for the PDP CPV to exceed that of the All Gas and LCA No New Generation Development Plans. The figures below show that that crossover point moves to 2056 and 2086 for the entire water sequence containing the 1929-1942 drought. Figure 5-20 shows that the LCA No New Generation Development Plan never has a lower CPV than the PDP if the 1929-1942 drought is inserted in the economic model, with average data for all other years and that the All Gas Development Plan crossover point moves to 2057. The figures include all plan fixed and variable costs.

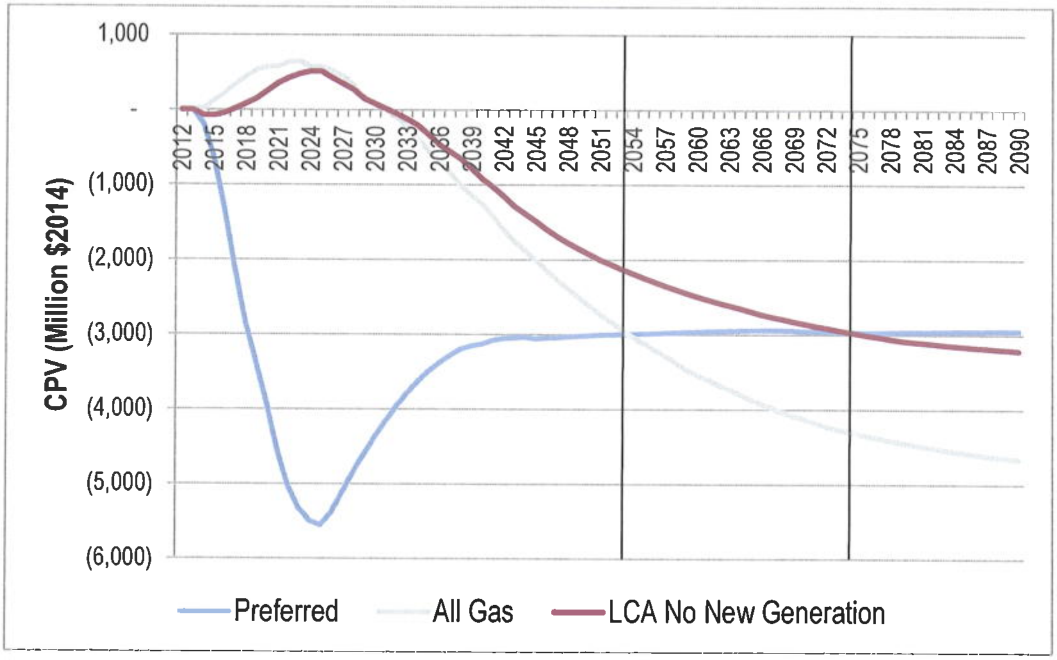

Figure 5-18: Cumulative NPV of Development Plans under Average Water Conditions

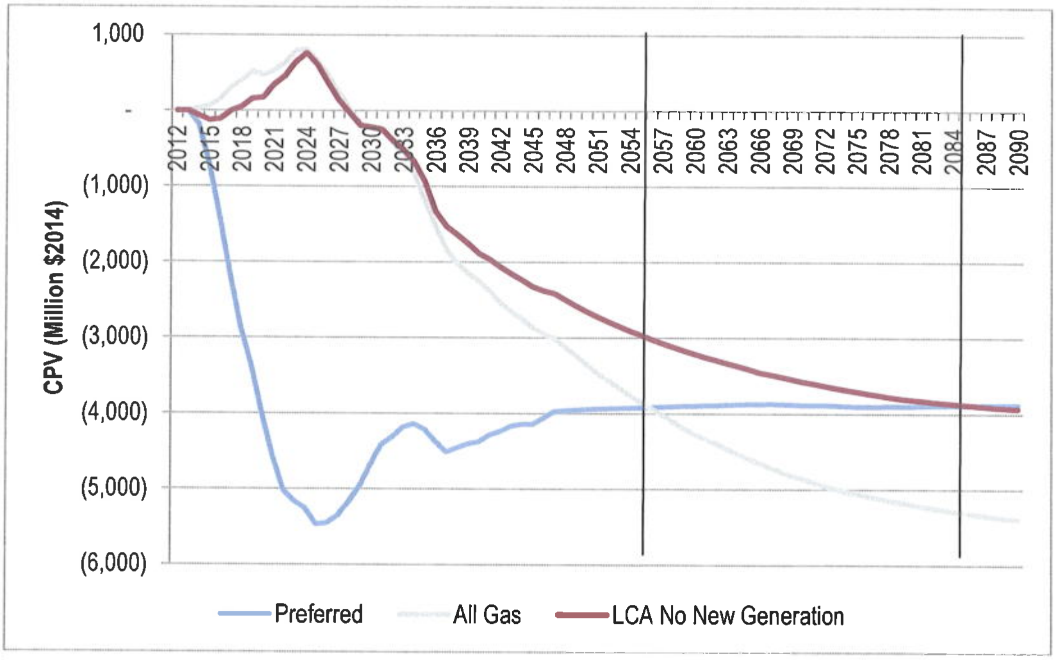

Figure 5-19: Cumulative NPV of Development Plans under 1929-1942 Drought Starting in 2025, entire 34 Year SPLASH Water Sequence Included

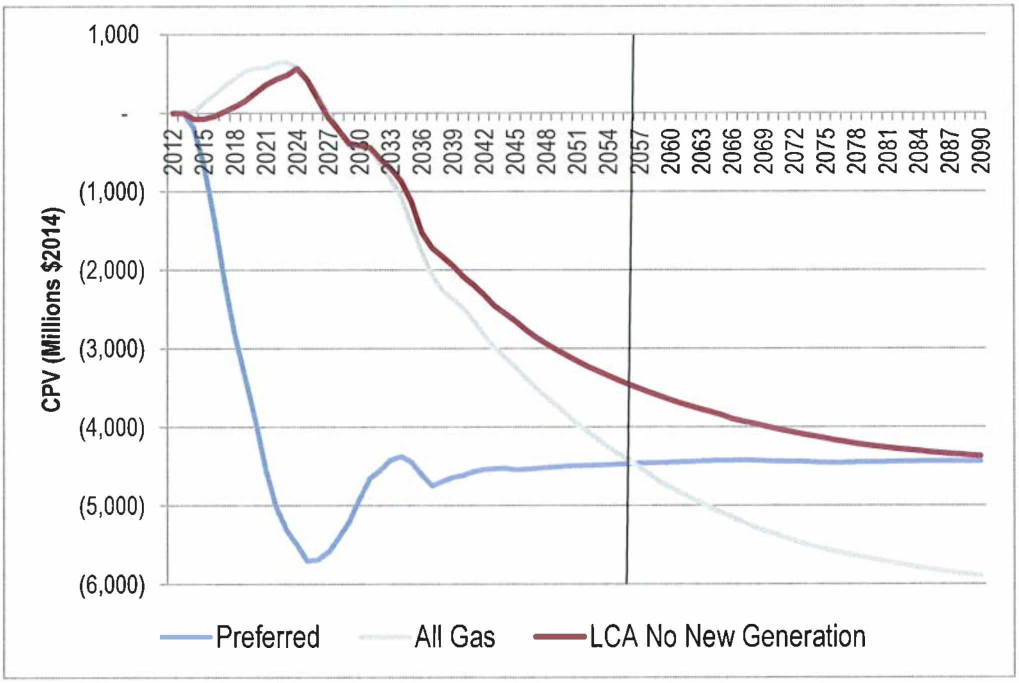

Figure 5-20: Cumulative NPV of Development Plans under 1929-1942 Drought Starting in 2025, Average Water Years for Remaining Years

E. Transmission as a Mitigating Factor in Drought Risk

The results discussed above show that while the PDP is more impacted by drought than the All Gas Development Plan or the LCA No New Generation Development Plan, the drought impact to the PDP is not significantly greater despite the additional hydropower generation in that plan. This can be explained by the impact that imports have on the plan economics. The PDP and the LCA No New Generation Development Plan have additional 750 MW transmission ties to the Midcontinent Independent System Operator (MISO) grid, while the All Gas Development Plan does not have any transmission additions. While the additional transmission was contemplated in the PDP as a means to export surplus power during average to wet years, it also serves as a hedge against drought risk as MH can import power from MISO during dry years.

Figure 5-21 shows the maximum imports for each forecast year for each of the development plans discussed above for the detailed SPLASH data. The maximum import for each development plan and each forecast year lines up with the water year 1940, which was the driest year on record. The fact that MH is maxing out its import capabilities in dry years in the PDP and the LCA No Generation Plan shows that imports are the least cost way for MH to make up for lost hydropower generation in drought conditions. The maximum imports for the No Generation plan shows the impact of the assumption to relax the import limitation policy that MH uses in its planning. Also, the PDP reduces its reliance on imports in drought conditions when CCGT capacity is added in the later years of the plan.

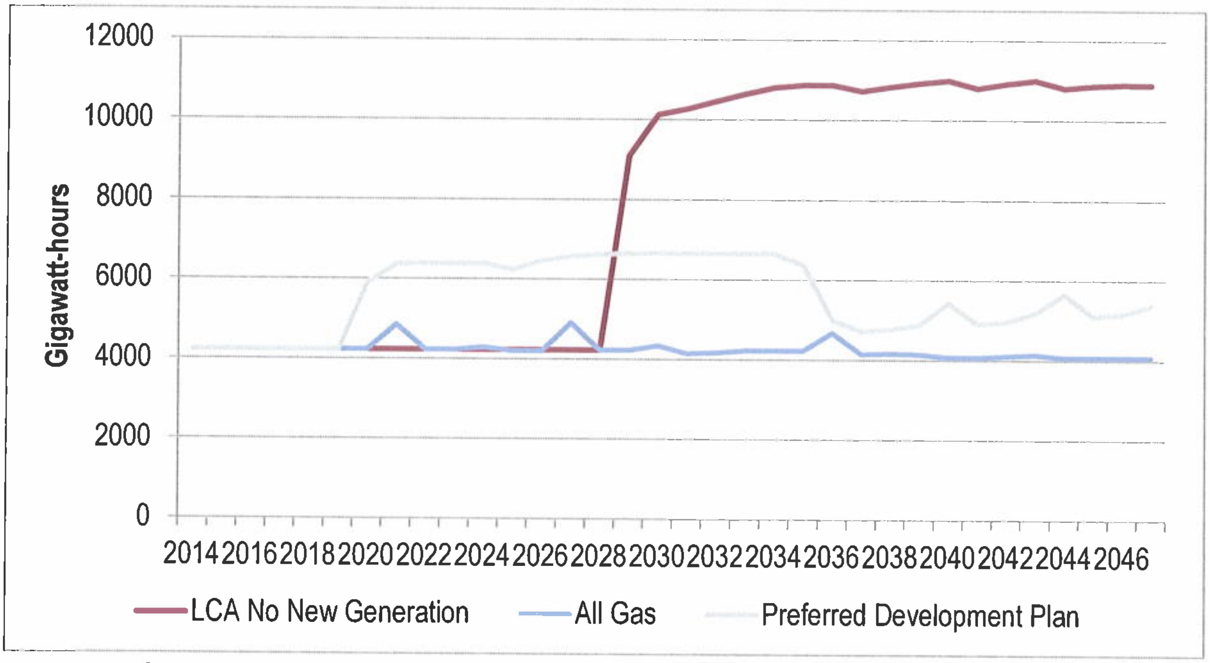

Figure 5-21: Maximum Imports During Any Year in Water Sequence

F. Benefits of Additional Transmission in Wet Years

Figure 5-22 shows that there is a benefit to additional transmission in wet years. This figure shows the difference in hydropower generation between the PDP and Development Plan 13 over the 99 water year conditions modeled in SPLASH. The primary difference between these two development plans is the size of the transmission connection to the US. The PDP has a new 750 MW interconnection and Plan 13 has a new 250 MW interconnection. The figure shows the plans have nearly identical generation over most water conditions, but in the wettest conditions shown on the right side of the graph, the PDP has more generation. This is because the PDP can use its extra transmission to sell the additional wet year generation, while Plan 13 has a lower export transfer capability, which limits exports in the highest water years with Keeyask and Conawapa in operation.

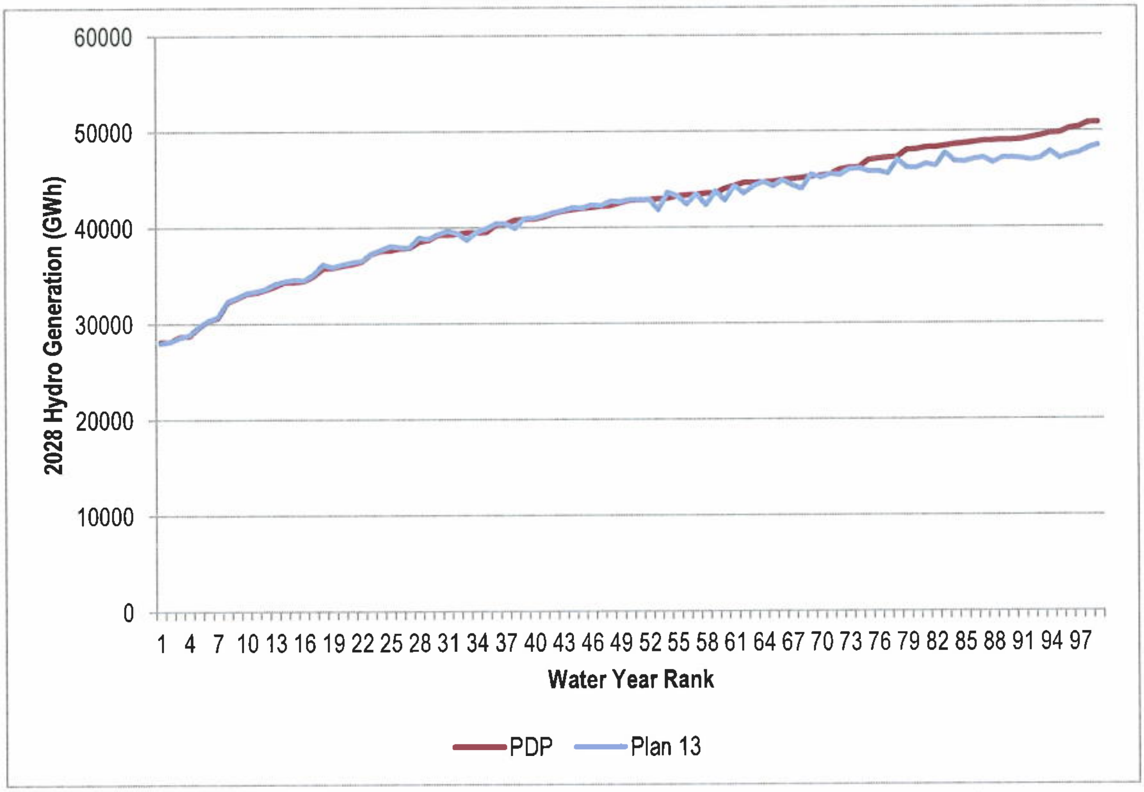

Figure 5-22: Hydro Generation Verses Water Year Rank

VII. Reservoir Optimal Value

The PUB has been concerned about how the addition of Keeyask and Conawapa will affect the operation of Lake Winnipeg and has asked LCA to review MH operations to determine the optimal operation of Lake Winnipeg. In Technical Appendix 4, LCA concluded that the addition of Keeyask and Conawapa would not affect the operation of Lake Winnipeg. In this Technical Appendix, we discuss the optimal operation of Lake Winnipeg.

Reviewing the detailed SPLASH data, it is apparent that the optimal operation of Lake Winnipeg differs by development plan. MH has provided Lake Winnipeg Levels from SPLASH runs for three development plans for two five-year drought runs. One drought run starts in 2021 and one starts in 2032. These runs are shown below in CONFIDENTIAL Figure 5-23 and CONFIDENTIAL Figure 5-24. The figures show that for both drought sequences the level of Lake Winnipeg for the All CCGT Development Plan diverges from the All Gas and Preferred Development Plans.

[redacted]

CONFIDENTIAL Figure 5-23: Lake Winnipeg Level during 5-Year Drought Beginning in 2021

[redacted]

CONFIDENTIAL Figure 5-24: Lake Winnipeg Level during 5-Year Drought Beginning in 2032

LCA's hypothesis is the addition of more efficient gas generation allows MH to use its hydropower resources differently during a drought in the All CCGT Development Plan than the All Gas or PDPs. To explore this hypothesis, LCA looked at the capacity factor of gas fired generation in the All CCGT Development Plan for both the year with a maximum capacity factor (a drought year) and an average year. This data is shown below in Figure 5-25. It shows that for almost all years, the maximum capacity factor for the CCGT generation is close to 100% in drought conditions. In average water years, the capacity factor is between 40 and 50%. Further analysis of this is presented in LCA Technical Appendix 3B.

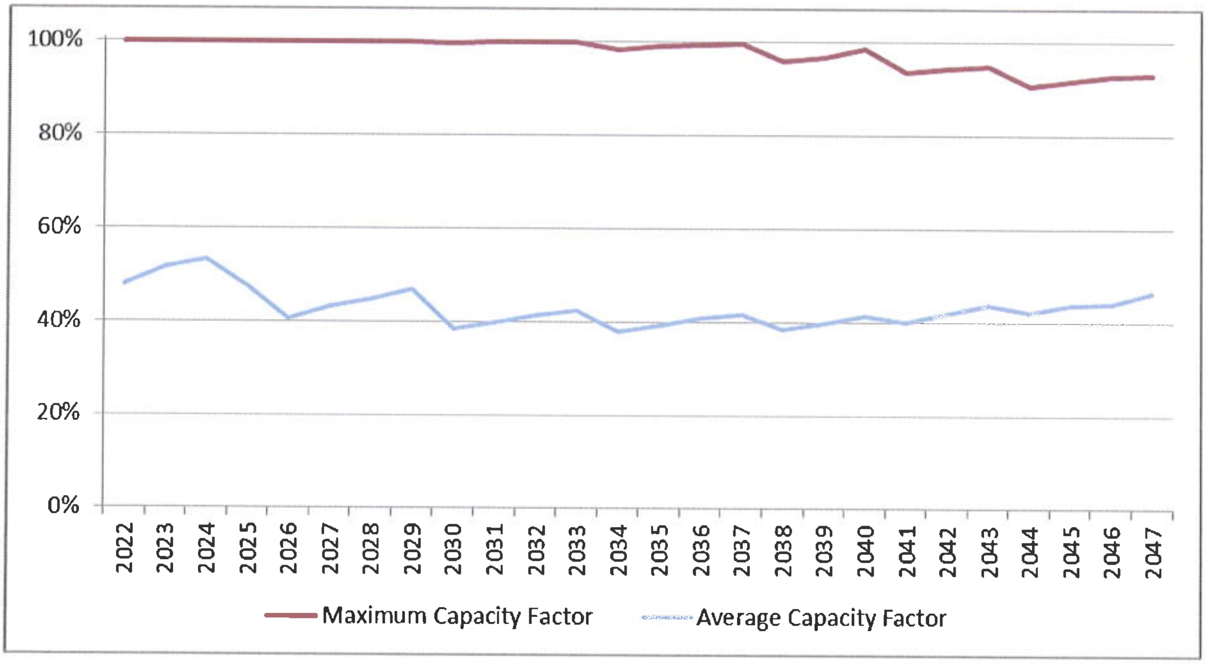

Figure 5-25: Capacity Factor of CCGTs in All CCGT Plan

LCA conducted an analysis to estimate how many hours a Manitoba-based CCGT would be economically dispatched in MISO under MH's Reference Case assumptions. Marginal dispatch costs were calculated using SPLASH gas turbine operating cost inputs,[15] with a 2% loss factor added to represent the difference in price between the generator node and MHEB. MH's 2012 Reference Case forecast of MHEB prices was used for MISO prices.[16] Using hourly MHEB locational marginal price (LMP) data from energy years 2010-2012, a price duration curve was developed to convert MH's annual forecast to an hourly price distribution. The figure below shows the percentage of hours in each year in which the loss-adjusted dispatch cost of a CCGT in Manitoba is less than the projected MHEB LMP. Assuming no other operational constraints, market conditions in MISO and CCGT operating costs assumed by MH in the 2012 Reference Case would predict that a CCGT would run between 20 - 35% of the time.

15 NFAT Confidential – Gas Turbine Operating Cost Inputs.pdf (SP-088). November 2013.

16 MH Response to PUB-I-056b.

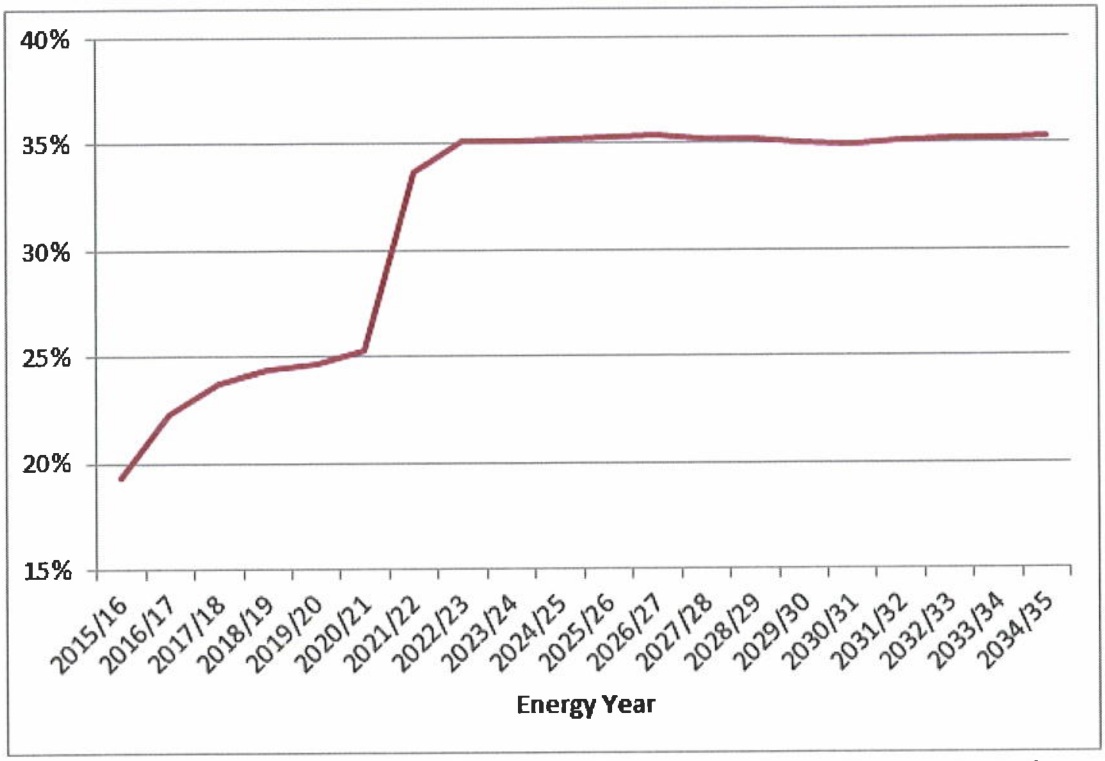

Figure 5-26: Forecast Economic Dispatch of New CCGT in MISO, MH Reference Case

The fact that the capacity factor of the CCGTs is greater than the level predicted by MISO and the lake levels drop more in the all CCGT case suggests that there is an economic reason for producing hydropower to sell power to MISO during its peak in the summer and relying on the CCGTs for relative inexpensive back-up to the hydropower during the drought.

VIII. Summary and Conclusions

LCA was able to conduct a review of information on the record from previous cases in front of the PUB, the NFAT Submission and information provided by MH in response to IRs in this case. These cases show that there have been some unresolved issues related to drought, including a determination of the proper way for MH to model drought to support long-term planning decisions and a determination of how drought factors into short- and medium-term operational decisions.

The information the LCA has been able to obtain on hydropower operations is incomplete at best. When asked for its reservoir operation plan and its drought management plan, MH provided a draft drought management plan and a set of discovery responses from previous cases in lieu of a reservoir operation plan. The reports reviewed from previous cases show that the consultants did not feel that modeling a drought longer than five years would change decisions in a specific case, but did not resolve the ideal drought length.

LCA has been able to conduct analysis on drought risk using the detailed SPLASH data. This analysis has yielded the following key results:

- The relative NPV of Net Revenue between two plans varies by which of the 99 water sequences is modeled in SPLASH. The maximum differential between the two plans is not the same years as the maximum impact on net revenue for an individual plan.
- The greatest impact on the PDP comes with inserting the 1929-1942 drought starting in 2025 in MH's economic model with an impact of approximately $1.5 billion on an NPV basis.
- Modeling the 1929-1942 drought in the economic analysis, shifts the date where the CPV of the PDP is greater than the LCA No New Generation and the All Gas Development Plans farther into the future. In the most severe drought scenario modeled, the LCA No New Generation Development Plan has a higher CPV for the entire study period.
- Transmission can serve as a hedge against drought risk. Both the PDP and the LCA No New Generation Plan contain an expanded interconnection with the

MISO market, which serves to reduce the impact of drought on the plan economics.

- There is not one optimal value for reservoir operations; the optimal value differs by development plan.

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