Manitoba Hydro

Book of Documents

LCA – Volume 2

Economics

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No New Generation	Tab 6

TAB 1

Corporate Finance

Eighth Edition

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Summary and Conclusions

1. In this chapter, we covered different investment decision rules. We evaluated the most popular alternatives to the NPV: the payback period, the discounted payback period, the accounting rate of return, the internal rate of return, and the profitability index. In doing so we learned more about the NPV.
2. While we found that the alternatives have some redeeming qualities, when all is said and done, they are not the NPV rule; for those of us in finance, that makes them decidedly second-rate.
3. Of the competitors to NPV, IRR must be ranked above both payback and accounting rate of return. In fact, IRR always reaches the same decision as NPV in the normal case where the initial outflows of an independent investment project are followed only by a series of inflows.
4. We classified the flaws of IRR into two types. First, we considered the general case applying to both independent and mutually exclusive projects. There appeared to be two problems here:
   a. Some projects have cash inflows followed by one or more outflows. The IRR rule is inverted here: One should accept when the IRR is *below* the discount rate.
   b. Some projects have a number of changes of sign in their cash flows. Here, there are likely to be multiple internal rates of return. The practitioner must use either NPV or modified internal rate of return here.
5. Next, we considered the specific problems with the NPV for mutually exclusive projects. We showed that, due to differences in either size or timing, the project with the highest IRR need not have the highest NPV. Hence, the IRR rule should not be applied. (Of course, NPV can still be applied.)

   However, we then calculated incremental cash flows. For ease of calculation, we suggested subtracting the cash flows of the smaller project from the cash flows of the larger project. In that way the incremental initial cash flow is negative. One can always reach a correct decision by accepting the larger project if the incremental IRR is greater than the discount rate.
6. We described capital rationing as the case where funds are limited to a fixed dollar amount. With capital rationing the profitability index is a useful method of adjusting the NPV.

Concept Questions

1. **Payback Period and Net Present Value** If a project with conventional cash flows has a payback period less than the project's life, can you definitively state the algebraic sign of the NPV? Why or why not? If you know that the discounted payback period is less than the project's life, what can you say about the NPV? Explain.
2. **Net Present Value** Suppose a project has conventional cash flows and a positive NPV. What do you know about its payback? Its discounted payback? Its profitability index? Its IRR? Explain.
3. **Comparing Investment Criteria** Define each of the following investment rules and discuss any potential shortcomings of each. In your definition, state the criterion for accepting or rejecting independent projects under each rule.
   a. Payback period.
   b. Average accounting return.
   c. Internal rate of return.
   d. Profitability index.
   e. Net present value.
4. **Payback and Internal Rate of Return** A project has perpetual cash flows of C per period, a cost of I, and a required return of R. What is the relationship between the project's payback and its IRR? What implications does your answer have for long-lived projects with relatively constant cash flows?

2

TAB 2

Task 3b Report: Analysis of Economic Costs and Benefits of Solar Program

Prepared for the

Massachusetts Department of Energy Resources

By

La Capra Associates, Inc., and Sustainable Energy Advantage, LLC

In association with

Meister Consultants Group and Cadmus

September 30, 2013

3 Key Assumptions

Key assumptions specific to the SREC-II policy used throughout this report are summarized in this section.

- **Economic Life of Solar PV Installations.** A 25-year economic life is assumed for solar installations.
- **Time Horizon.** The time horizon of the analyses in this report is 2014-2045. This period covers 2014 (the first year of the expanded solar program) though 2021, the expected year of the last SREC-II installation. Systems installed in the last year of policy incentives are assumed to produce through 2045.
- **Nominal Dollars and Discounting.** All annual values shown in this chapter are shown in nominal dollars. Net present value (NPV) calculations use these values with a nominal discount rate of 5.0%.[7] Selection of a relevant discount rate is important, since higher interest rates will, all things equal, reduce the benefit-cost calculations shown here because toward the beginning of the study period solar cost programs are more heavily weighted than benefits.
- **Scale of the SREC-II Policy.** Subsequent to the commissioning of this study and through the adoption of emergency regulations, DOER has committed to set a value higher than the SREC-I policy's original target of 400 MW; however, the final total MW of SREC-I will not be finalized until mid-2014. Once finalized, the size of the SREC-II policy will be the difference between the 1600 MW target and the final SREC-I quantity. This analysis assumes that the SREC-II policy will add 1200 MW to the initial 400 MW target to reach a total goal of 1600 MW.
- **Federal Investment Tax Credits (ITC)** were not assumed to be extended beyond their current statutory timeframe.
- **Incremental Policy Analysis.** This study considers only the incremental benefits and costs beyond current policy already in place. The analysis does not include benefits and costs of existing renewable portfolio standards, state tax credits, and net metering policy.
- **Alternative Compliance Payment and Auction Floor.** Table 2 shows the floor prices and alternative compliance payment (ACP) used to calculate the low and high cost levels discussed throughout this report.

[7] Use of a 5% nominal rate and assumption of 2.5% inflation yields a real discount rate of approximately 2.4%, which is higher compared to the discount rate used, for example, in the most recent (2013) release of the Avoided Energy Supply Cost (AESC) study used in the cost-effectiveness analyses performed by Massachusetts energy efficiency program administrators. The 2013 AESC study uses a real discount rate of 1.36, which is based on 30-year U.S. Treasury yields as of February 2013, and thus is indicative of an extremely low-rate environment. We elected to use a slightly higher rate consistent with the 2011 AESC study to account for some potential increase in interest rates going forward.

TAB 3

PSNH GENERATION ASSET AND PPA VALUATION REPORT

TECHNICAL REPORT

PUBLIC VERSION

PREPARED FOR

New Hampshire
Public Utilities Commission

PREPARED BY

La Capra Associates, Inc.

One Washington Mall, 9th Floor
Boston, MA 02108

March 31, 2014

3. VALUATION METHODOLOGY

La Capra Associates' determination of the value of the generation assets is based primarily on a discounted cash flow ("DCF") analysis of anticipated future costs and revenues. This analysis is supported with an analysis of comparable sales. The determination of value of the PPAs is based on a mark-to-market analysis of anticipated future costs and revenues.

The DCF methodology is a common methodology employed for power generation asset valuations, being the predominant method used by asset buyers, asset valuation and appraisal organizations, and regulatory applications.

The DCF methodology requires assessments of the future market conditions, future operations of the generator, and future costs to operate and maintain the assets over their remaining useful life. Power generation assets are typically long-lived assets; valuation therefore requires that judgments be made pertaining to significant uncertainties and risks inherent in long-term forecasts of uncertain parameters. Nevertheless, asset buyers participating in a competitive market for assets will make such assessments of risk in arriving at an offer price for acquiring the asset.

Our DCF analysis presented herein makes those same assessments of uncertain parameters and seeks to make judgments of value consistent with those that would be expected in a competitive auction of the assets. We developed a Reference Scenario with forecasts of key parameters that are intended to represent an outlook that a typical third party buyer would use as "50/50 forecasts".[11] We accounted for uncertainty by developing additional scenarios and sensitivities to test alternative outlooks for key parameters such as natural gas prices and operating expenses.

The Comparable Sales method is an alternative valuation methodology that can, at times, provide useful benchmarks for valuing power generation assets. However, power generation assets are generally unique assets, limiting the availability of true comparable asset transactions.[12] There are typically few if any contemporaneous comparable asset transactions, which is the case in this instance. We use transactions most nearly comparable in time and type as a reasonableness check on our DCF results and consider that information in forming an opinion on reasonable value.

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11 A "50/50 forecast" is one that the forecaster believes has equal probability to overestimate actual values or underestimate them.

12 Determinations regarding the comparability of asset transactions must consider factors of asset characteristics, market characteristics, and time of the transaction. The attributes of the facility or facilities such as heat rate, age, river flow (for hydro) and fuel type are important considerations. The markets into which their output and services are sold are material due to significant variations by location. The time of the transactions has bearing on changes in market fundamentals that determine expected revenues. Some transactions also include additional assets such as administrative buildings, land and pondage that can significantly impact value.

The information on the costs, performance and condition of the Facility is based on information disclosed by PSNH in this proceeding. The statements of value contained in this report assume that there are no undisclosed liabilities associated with the facilities or facilities operations other than as expressly discussed herein. Any such additional liabilities, such as undisclosed issues with the condition of facilities and equipment could negatively impact the value of the Facility and are not considered in our valuation analysis.

The economic valuation of the PPAs relies on the same assessment of future market conditions relied upon for the generation asset valuations. Based on an analysis of the conditions in the contract, we compared the projected costs of power delivered under the contract relative to the cost of obtaining the same amount of power in the spot markets.

3.1 Discounted Cash Flow Analysis

Our DCF analysis uses a financial pro forma analysis for a hypothetical third party buyer ("Third Party Buyer") of the Facilities as of December 31, 2014. For this analysis, we assume 15 years of future operations for the thermal generation units and 33 to 40 years of future operations for the hydroelectric generation units under the remaining years of current FERC licenses and, in some cases, continued operations under a new 30-year license. Our method also assumes the Third Party Buyer will employ 15-year or 20-year, non-recourse financing typical of power asset transactions. This formulation includes the following inputs:

1. Revenues for Facility power output derived from La Capra Associates' Northeast Market model based on sales of Facility output into the New England wholesale market;
2. Revenues for Facility capacity output derived from La Capra Associates' forecast of New England Forward Capacity Market prices;
3. Additional revenues from the sale of RECs derived from La Capra Associates' forecast of relevant RPS market prices;
4. Power production levels based on the dispatch modeling for thermal units and historical operations for hydroelectric units;
5. Operating and maintenance expenses for the continued operation of the Facility, based on review of historical operations data and budget information disclosed by PSNH, as well as sensitivities based on analysis of expenses at comparable units;
6. Requirements for capital improvements, including consideration of the environmental assessment conducted by ESS; and
7. Costs of debt and equity and financing requirements based on current market conditions.

Our discounted cash flow analysis relies on a financial model which solves for an initial value or acquisition price that provides the cash flow to equity sufficient to meet the target internal rate of return over the life of the asset. This internal rate of return is different from the return on equity established for regulated utilities. A return on equity is typically measured over a one-year period. An internal rate of return is measured over the asset's life and is calculated differently. An internal rate of return analysis is what investors typically examine when evaluating an asset acquisition.

3.2 Comparable Sales

Our Comparable Sales analysis uses our survey of generation asset transactions over the past few years. Information from the market on values placed on similar assets can provide direct evidence of market value or reasonable indicators to supplement the DCF assessment of value. Each asset and transaction is unique, however, and the utility of comparable sales to assign fair market value to power assets is limited. Many transactions are for bundles of multiple generation and non-generation assets, and assumptions must be made about the division of value among individual components.

For hydroelectric units, we use an index to compare these transactions by dividing the sale price by the average annual energy production, as the Facility and comparable hydroelectric assets derive most of their value from energy markets. The comparable transactions are limited in number, particularly for assets of this size within the past few years in the New England Market.

Market prices and expectations of market prices have dropped significantly since 2008. Since energy revenue is the primary driver of asset value for hydroelectric power, the rapid erosion in market prices has made transaction prices for assets sold only three or four years ago no longer reflective of current market conditions.

3.3 Mark-to-Market Analysis

PPAs are valued in a mark-to-market analysis using many of the same forecast and assumptions used in the DCF analysis of the owned generation assets. For these agreements, we will compare the forecast of revenues from the sale of asset attributes to the annual payments under the contracts to determine if these PPAs are above market or below market. PPAs that are below market may be sold for positive prices. PPAs that are above market may require PSNH to pay the counterparty to "buy out" of the contract purchase obligations.

Table 21: Brookfield-comparable DCF Results

	Reference	Reference with 92% debt; No RECs
	$/kWh-year	
Ayers Island	0.32	0.45
Canaan	0.34	0.47
Gorham	0.29	0.40
Eastman Falls	0.20	0.30
Smith	0.41	0.51
Merrimack River Project	0.29	0.40
Jackman	0.20	0.30
PSNH Hydro Total	0.32	0.44
Brookfield/NextEra Transaction	*n/a*	*$0.43*

This analysis is further evidence that the Brookfield/NextEra sale should be used only as an upper bound on the value of PSNH assets, if at all.

11.2.5 Discussion and Conclusions

This evaluation of comparable hydroelectric sales provides a useful indicator of the market value of the assets, but it is important to note the limitations of this analysis. Any market transaction contains individual factors related to the parties, the asset, and the timing which impact the final sale price and conditions. These factors could include buyer/seller motivations, condition of the asset, additional components of the transaction (transmission, buildings, land, water rights, etc.), control of reservoirs, presence of PPAs, and REC eligibility, among many others.

In addition to these site-specific factors, a major driver of sale value is the outlook of energy markets at the time of the sale. The comparable sales identified in our analysis transacted between 2006 and 2013. During that time, energy markets in New England experience significant volatility. Since hydro assets derive the majority of their value from energy sales, the energy price forecasts contemporaneous with the transactions are key variables.

It is not possible to adjust for all the sale- and asset-specific factors to arrive at a completely comparable sale value. Rather than attempt to adjust for all these factors, we have used the comparable sales analysis as an indicative range of what valuation the market could assign to the hydro assets.

Based on the foregoing analysis, we estimate that a reasonable indicative range of market values for the hydro assets is between $0.35 and $0.45/kWh-yr. This range corresponds to a value of between $124 and $159 million for PSNH's assets. However, a closer examination of the comparable sales indicates

TAB 4

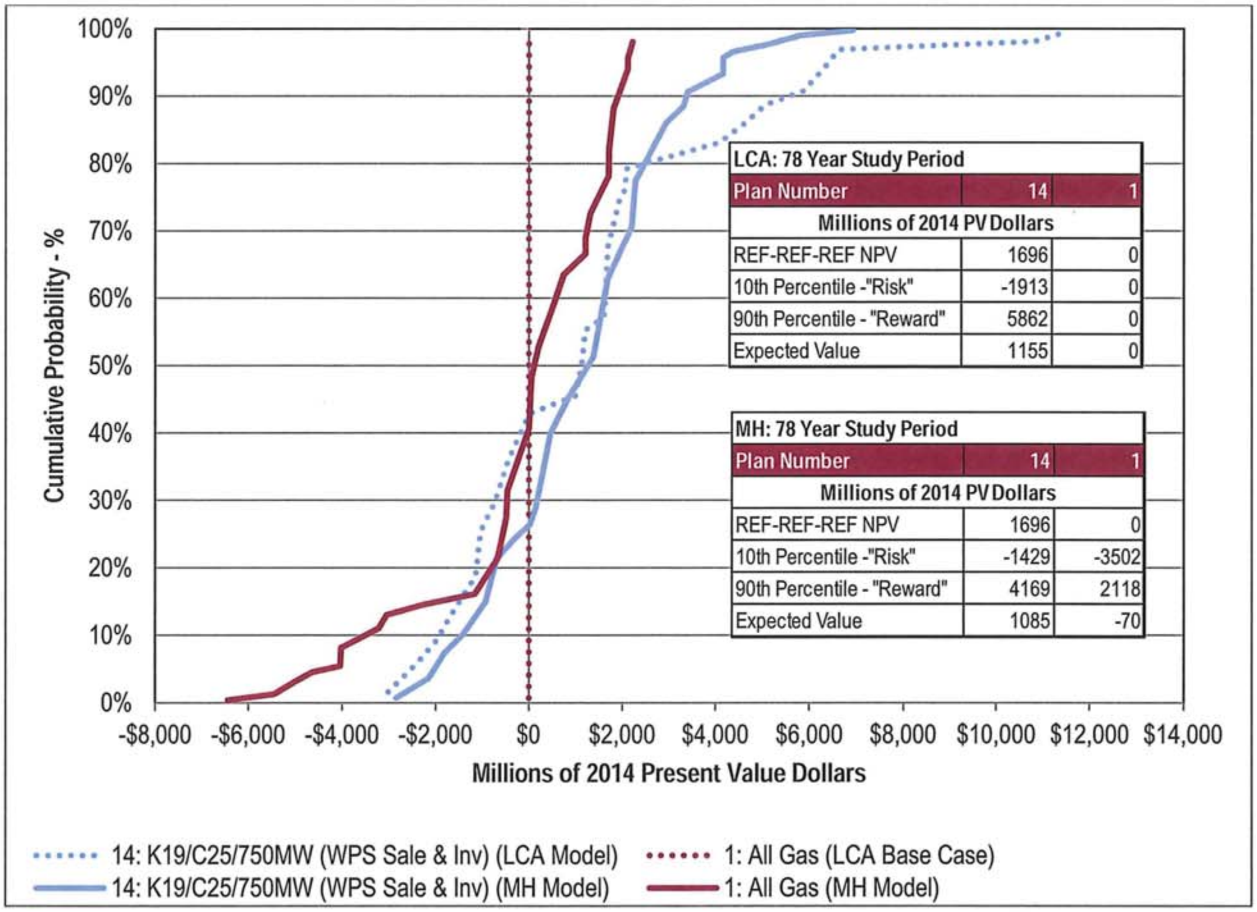


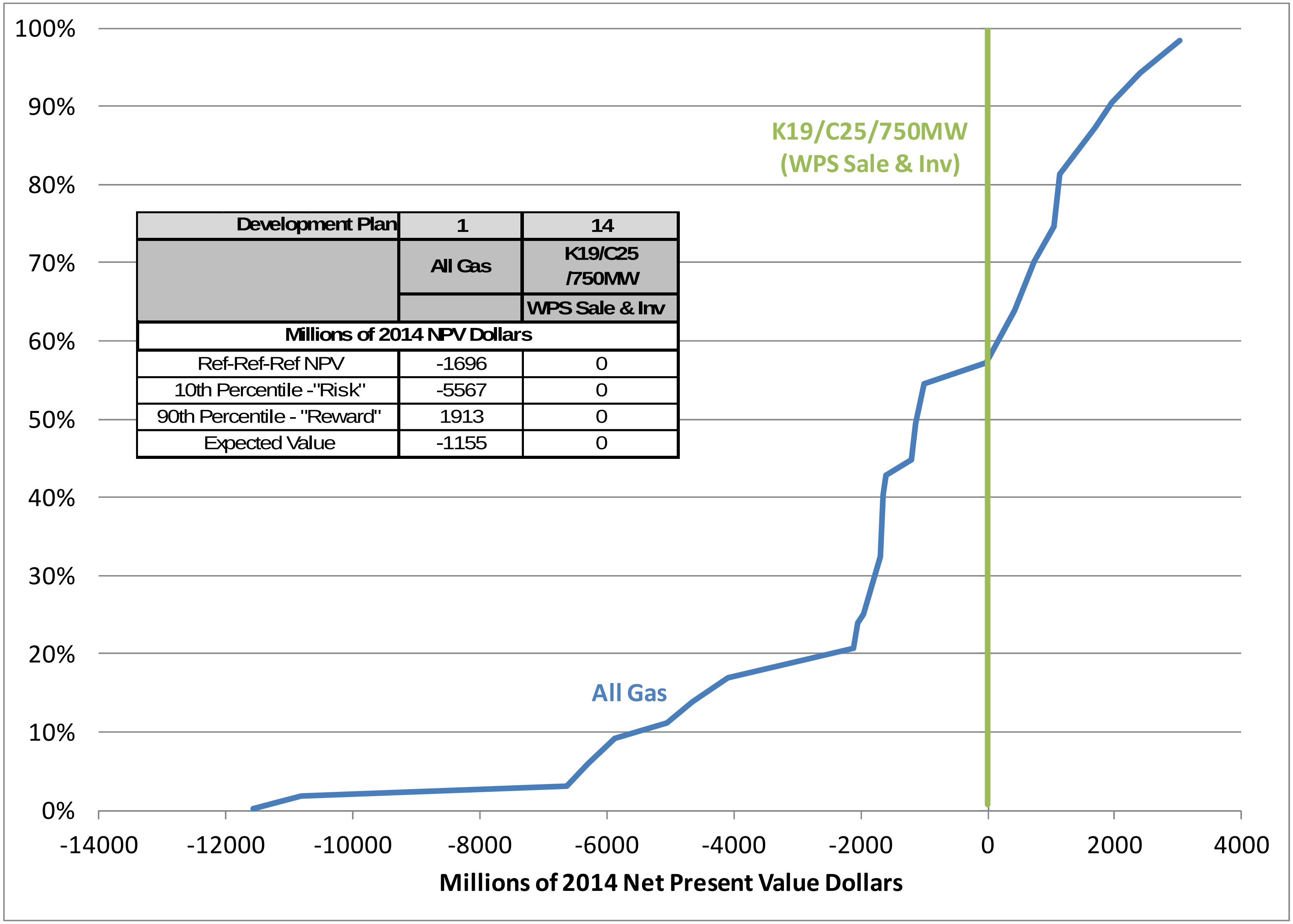
Figure 9-28: Plan 14 Preferred Development Plan S Curves, comparing MH & LCA Methodologies, NPV after 78 year

For the MH curve, the results show that there is a roughly 25% chance that the results of the Preferred Development Plan will be worse than the reference results of the Base Plan. For comparison, the LCA Methodology-derived S-Curve shows that there is a roughly 42% chance that in the future the Preferred Development Plan will end up with higher costs than the Base Plan.

The tail end of the upside of the curve is larger for the LCA curve which demonstrates that in this particular comparison, there is at least one future where the Preferred Development Plan provides a greater 78 year NPV cost savings as compared with the All Gas Plan than one could see in the MH Methodology S-Curves. While this

TAB 5

Original Submission 2012 NFAT Analysis - Regret Approach with respect to Preferred Plan



Development Plan	1	14
	All Gas	K19/C25 /750MW
		WPS Sale & Inv
Millions of 2014 NPV Dollars		
Ref-Ref-Ref NPV	-1696	0
10th Percentile -"Risk"	-5567	0
90th Percentile - "Reward"	1913	0
Expected Value	-1155	0

TAB 6

La Capra Associates

Plan Based on DSM, Fuel Switching, Imports

- **MH Prepared a "No Generation" Case at LCA's Request**
  - DSM at 150% of Reference Case Assumptions
  - Fuel Switching Program to mitigate electric space heat load growth
  - 750 MW transmission in 2029 (100% MH cost)
  - Increase in the reliance on imports to 20% (from 10%) in planning criteria
  - Capacity charge added to firm up imports
- **Purposes for the "No Gen" Case:**
  - All 15 MH Plans included added Gen and reference DSM and Load forecast
  - Add a case to illustrate an approach to an deferral of MH Generation adds
  - Add a test of demand side and import options

SUBJECT: Planning Criteria

REFERENCE: Technical Appendix 3A; Page 3A-27

PREAMBLE: Statement "…work in concert with a relaxed MH policy constraint on imports, allowing up to 20% of the dependable energy to come from net imports"

QUESTION:

Please provide any analysis used to develop the proposed 20% limitation on dependable energy from net imports?

RESPONSE:

LCA conducted a review of all MH documentation of its current 10% limitation and determined that MH did not have an analysis supporting that criterion (See LCA Technical Appendix 1, page 1-10 and, more generally, discussion in Section II of that report). LCA choose 20% as a sensitivity test of the MH 10% limit planning assumption. The implementation of the 20% criteria in the analysis was further specified by MH, as documented in the text of the email below from Terry Miles:

From: Miles, Terry <tmmiles@hydro.mb.ca>

Sent: Tuesday, November 19, 2013 4:37 PM

To: Dan Peaco; John Athas; Mary Neal

Cc: Wojczynski, Ed; Flynn, Joanne; Sever, Natalie; Johnson, Brad

Subject: RE: Hypothetical Load reduction/Import line plan

Dan

We have prepared the following assumptions for discussion during tomorrow's call.

Terry

Assumptions:

This hypothetical plan and related analysis addresses LCA-001 and LCA-002.

Manitoba Hydro will provide caveats and context associated with such a hypothetical plan.

Manitoba Hydro recognizes that making the assumption to build a large import line would require the relaxing of the 10% of Manitoba load import limit in its planning criteria. Manitoba Hydro's planning criteria which limits imports to 10% of Manitoba load was established in the context of the mid-west regulatory regime and market and utilities with which we contract.

2013 NFAT planning assumptions

Level 1 DSM represents load reduction

Representative of LCA 1 Attachment a, b & c load reductions

750 MW interconnection

Manitoba Hydro builds and funds the Manitoba portion of the line. A third party builds and Manitoba Hydro funds the US portion of the line.

Use same characteristics and capital and operating costs for 750 MW line as used in the NFAT submission

Additional costs associated with the US portion of the 750MW line: financing costs and rate of return of 15% to yield a 10% after tax return

Relaxing of the 10% of Manitoba load import limit

Permit use of import energy up to 20% of Manitoba load

Require firm import contracts for energy in excess of 10% of Manitoba load by adding the cost of capacity

Extension of 550 MW diversity exchange agreements to the end of the 35 year detailed study period

No increase in diversity reflecting no increase in winter-summer differential

Natural gas-fired generating resources would be added as required using Manitoba Hydro's optimization process post the 2035 timeframe.

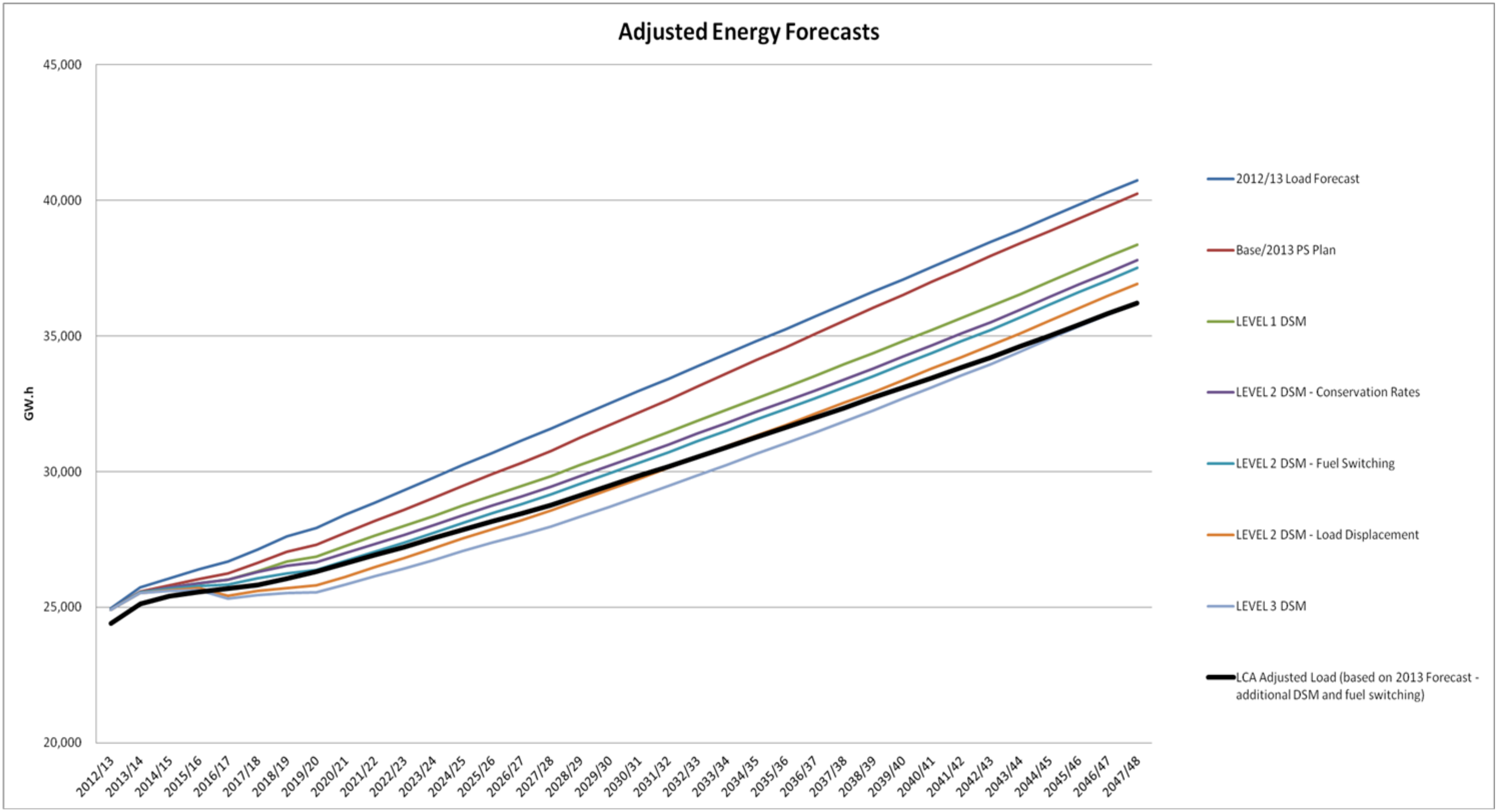
Updated DSM Evaluation

Development Plans
1. All Gas 5. K19/Gas/750MW (WPS Sale) 14. Preferred Development Plan

DSM Levels	2027/28 Energy levels	
2013 DSM	773 GWh	(1x DSM)
Level 1	1,704 GWh	(2x DSM)
Level 2	2,961 GWh	(4x DSM)
Level 2 DSM with Pipeline Load Net Reduction in Load	2,961 GWh -1,478 GWh 1,483 GWh	 (2x DSM)
Level 3 DSM	3,546 GWh	(5x DSM)
Level 3 DSM With Pipeline Load Net Reduction in Load	3,546 GWh -1,478 GWh 2,068 GWh	 (2.7x DSM)

Table 2 **- Change in Energy and Peak**

GROSS FIRM ENERGY AND GROSS TOTAL PEAK Change from Previous Forecast 2013/14 - 2032/33						
	Gross Firm Energy			Gross Total Peak		
Fiscal Year	2013 Forecast (GW.h)	2012 Forecast (GW.h)	Change (GW.h)	2013 Forecast (MW)	2012 Forecast (MW)	Change (MW)
2012/13 Act	24759			4559		
Weather Adj.	-356			-127		
2012/13 Wadj	24404	24961	(557)	4432	4491	(59)
2013/14	25239	25734	(495)	4601	4609	(8)
2014/15	25676	26071	(395)	4680	4677	3
2015/16	26013	26393	(380)	4742	4738	4
2016/17	26322	26677	(355)	4801	4794	7
2017/18	26606	27128	(522)	4857	4874	(17)
2018/19	27003	27616	(614)	4930	4959	(29)
2019/20	27398	27919	(521)	5002	5024	(22)
2020/21	27789	28400	(611)	5074	5109	(35)
2021/22	28197	28859	(661)	5147	5192	(45)
2022/23	28605	29322	(717)	5222	5276	(54)
10 Year	420	436		79	79	
Avg Gr.	1.6%	1.6%		1.7%	1.6%	
2023/24	29013	29779	(766)	5296	5360	(64)
2024/25	29418	30239	(821)	5369	5445	(76)
2025/26	29822	30691	(869)	5443	5528	(85)
2026/27	30225	31138	(913)	5516	5611	(95)
2027/28	30625	31594	(968)	5588	5695	(107)
2028/29	31041	32053	(1012)	5664	5779	(115)
2029/30	31453	32511	(1058)	5739	5863	(124)
2030/31	31863	32967	(1104)	5813	5947	(134)
2031/32	32265	33425	(1159)	5886	6032	(146)
19 Year	414	445	-32	77	81	-5
Avg Gr.	1.5%	1.5%	-0.1%	1.5%	1.6%	-0.1%



Adjusted Energy Forecasts
45,000
40,000
35,000
30,000
25,000
20,000
GW.h
2012/13
2013/14
2014/15
2015/16
2016/17
2017/18
2018/19
2019/20
2020/21
2021/22
2022/23
2023/24
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2035/36
2036/37
2037/38
2038/39
2039/40
2040/41
2041/42
2042/43
2043/44
2044/45
2045/46
2046/47
2047/48
2012/13 Load Forecast
Base/2013 PS Plan
LEVEL 1 DSM
LEVEL 2 DSM - Conservation Rates
LEVEL 2 DSM - Fuel Switching
LEVEL 2 DSM - Load Displacement
LEVEL 3 DSM
LCA Adjusted Load (based on 2013 Forecast - additional DSM and fuel switching)

La Capra Associates

Comparative Performance of "No Gen" Case

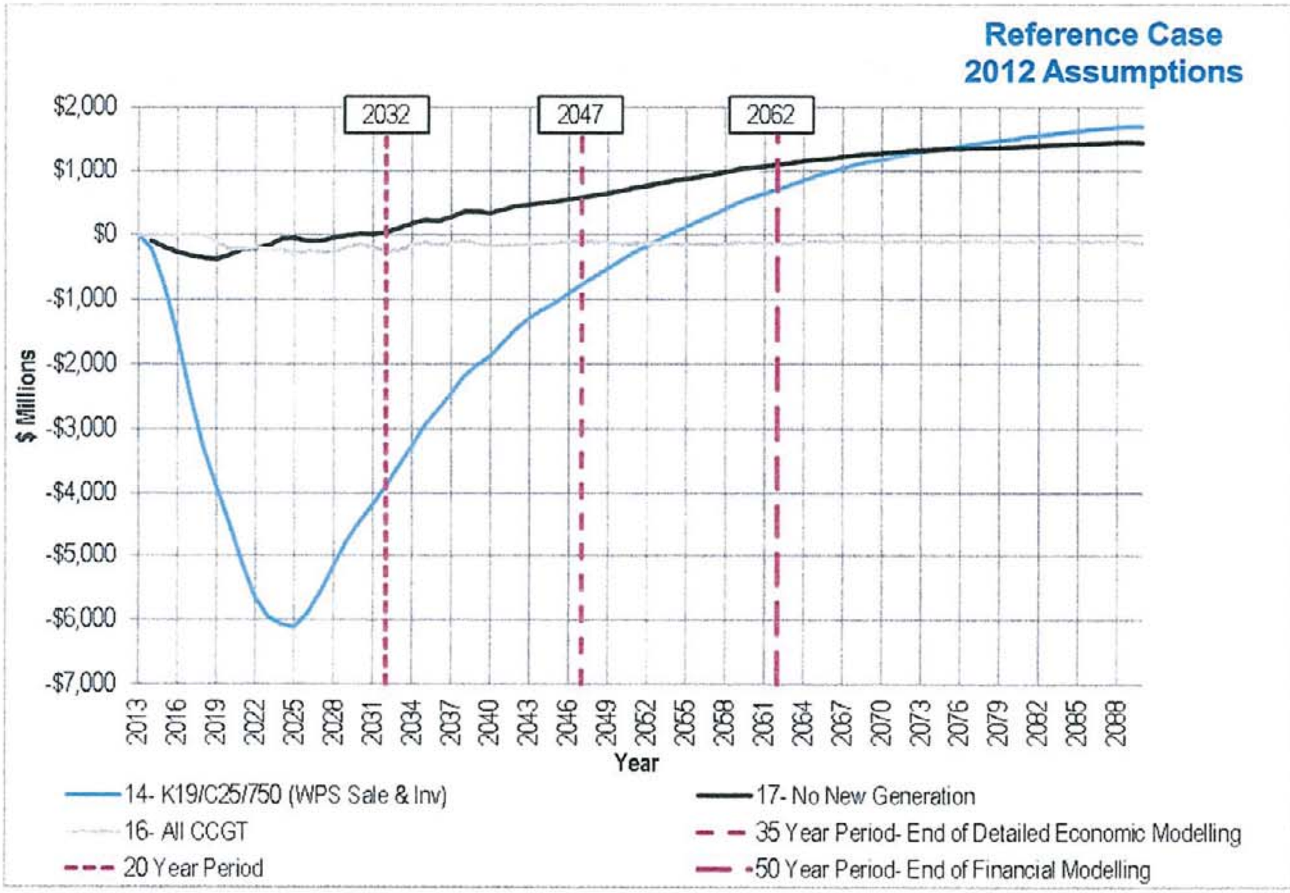

Figure 9-93: LCA Alternative Plans and Preferred Development Plan Relative to the All Gas Plan - Millions of 2014 Present Value Dollars; (page 9B-22))

DSM Analysis – 3 Additional Levels

What level of DSM is economic?

	Total Resource Cost Without Pipeline Load Includes all costs and does not account for changes in Domestic revenue [with pipeline load for level 2 to level 3 only] Incremental NPV (millions of 2014$) of implementing higher level of DSM		
	All Gas	K19/Gas/750MW	K19/C/750MW
Base to Level 1	535	497	285
Level 1 to Level 2	816	887	737
Level 2 to Level 3 [with pipeline]	-49 [-60]	-86 [-39]	-102 [-85]

Note: ISD changes with Level of DSM for Conawapa (DSM1:2030, DSM2:2031, DSM3:2033) and All Gas (DSM1:2028, DSM2:2031, DSM3:2033).

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.

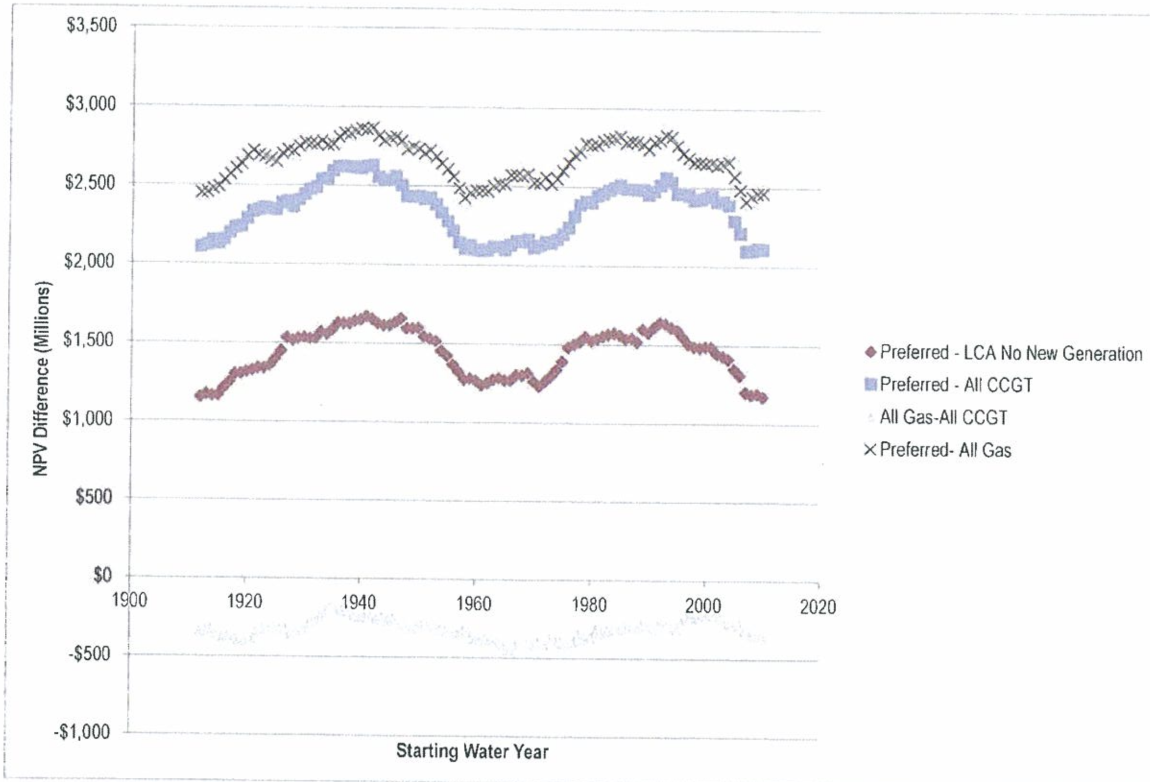

Figure 5-4: 34-year Net Revenue NPV Difference across the 99 SPLASH Sequences

	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

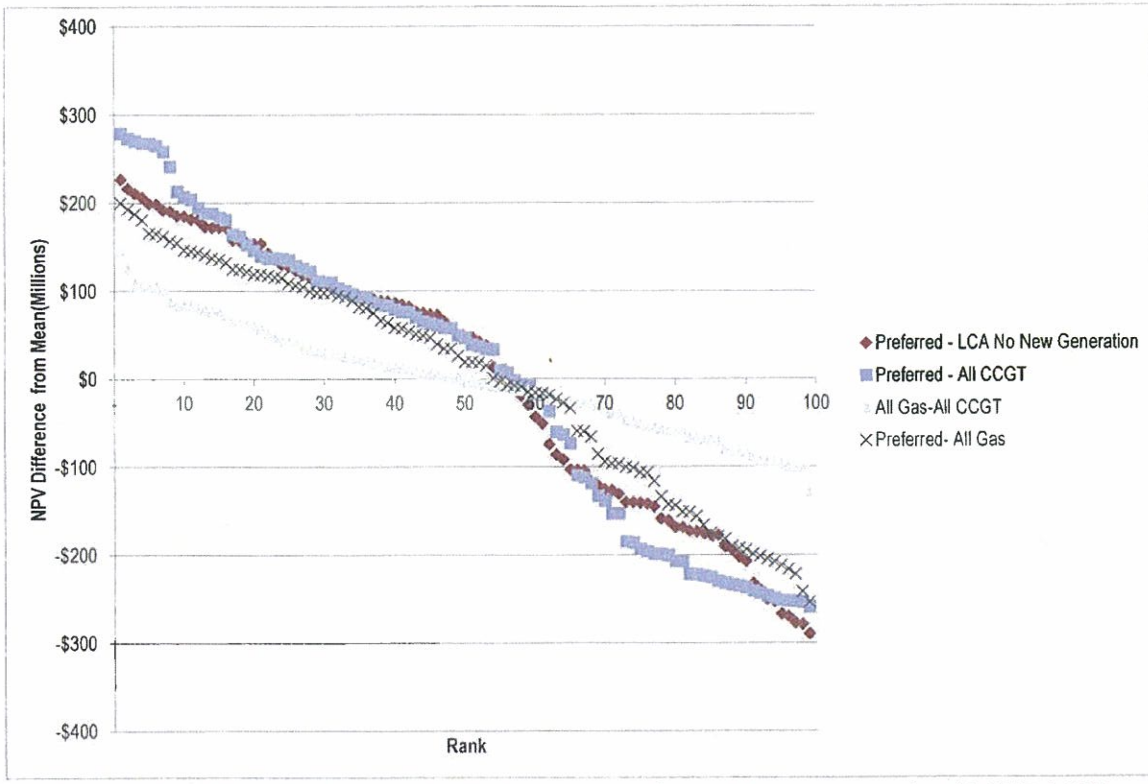

Figure 5-6: Plan Difference NPV Difference from Mean across the 99 SPLASH Sequences by Rank

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.

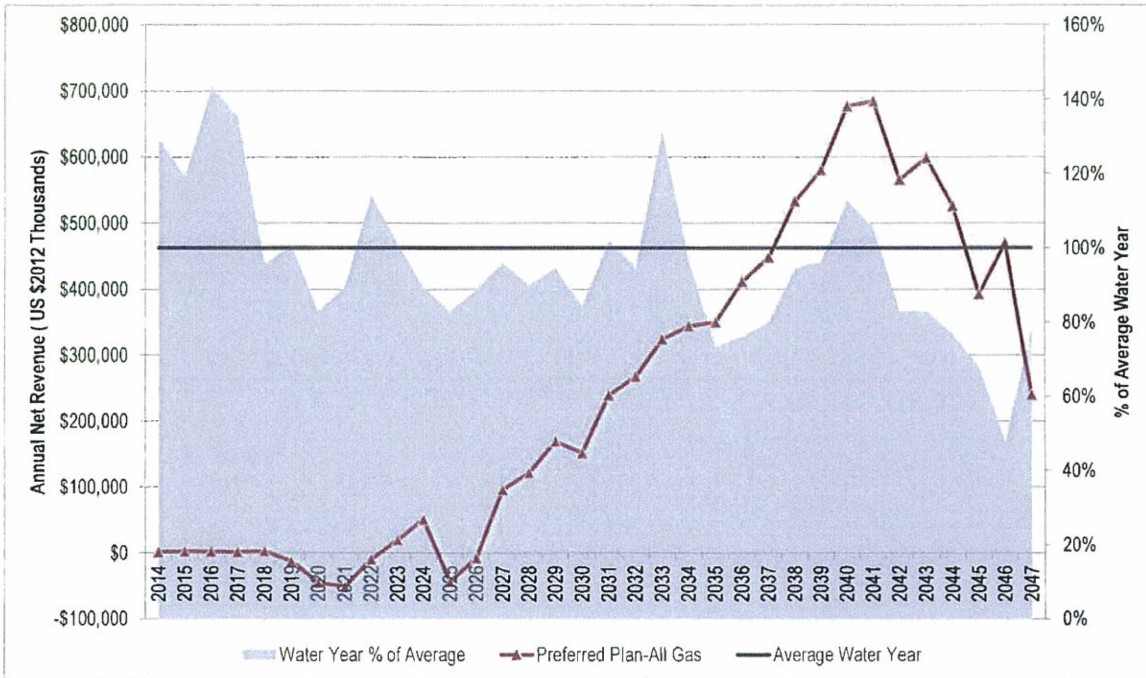

Figure 5-7: Minimum Net Revenue NPV Difference Preferred – All Gas

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.

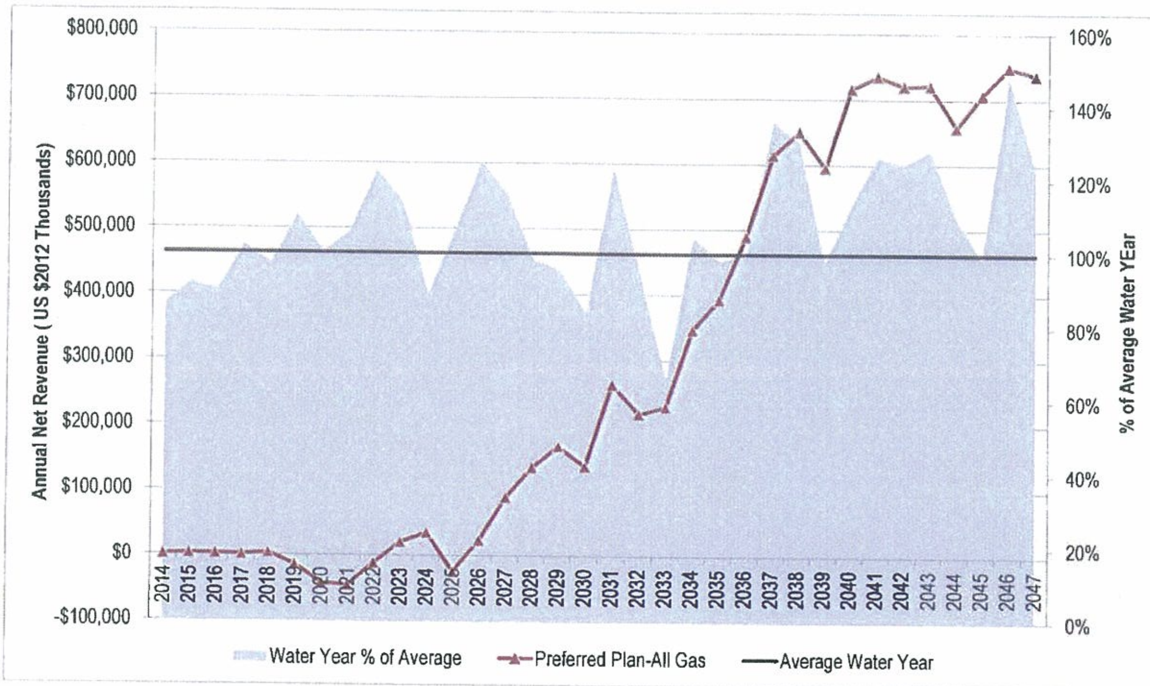

Figure 5-8: Maximum 34-year Net Revenue NPV Difference Preferred – All Gas

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.

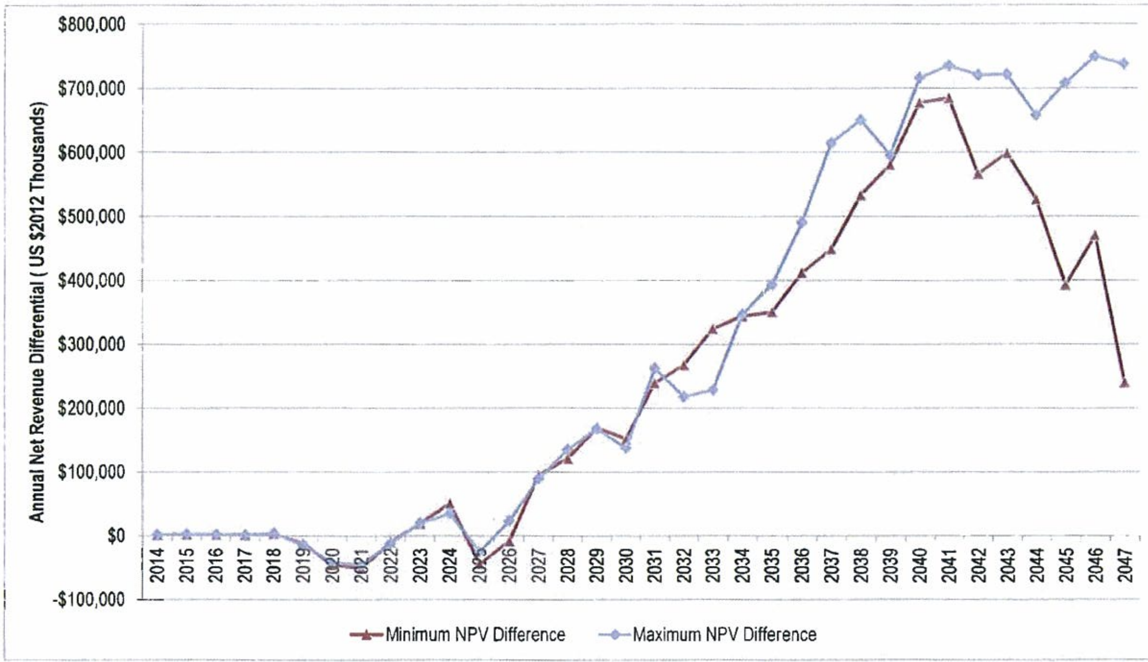

Figure 5-9: Annual Net Revenue Difference for Maximum and Minimum Net Revenue Difference: Preferred Development Plan minus All Gas Development Plan

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.

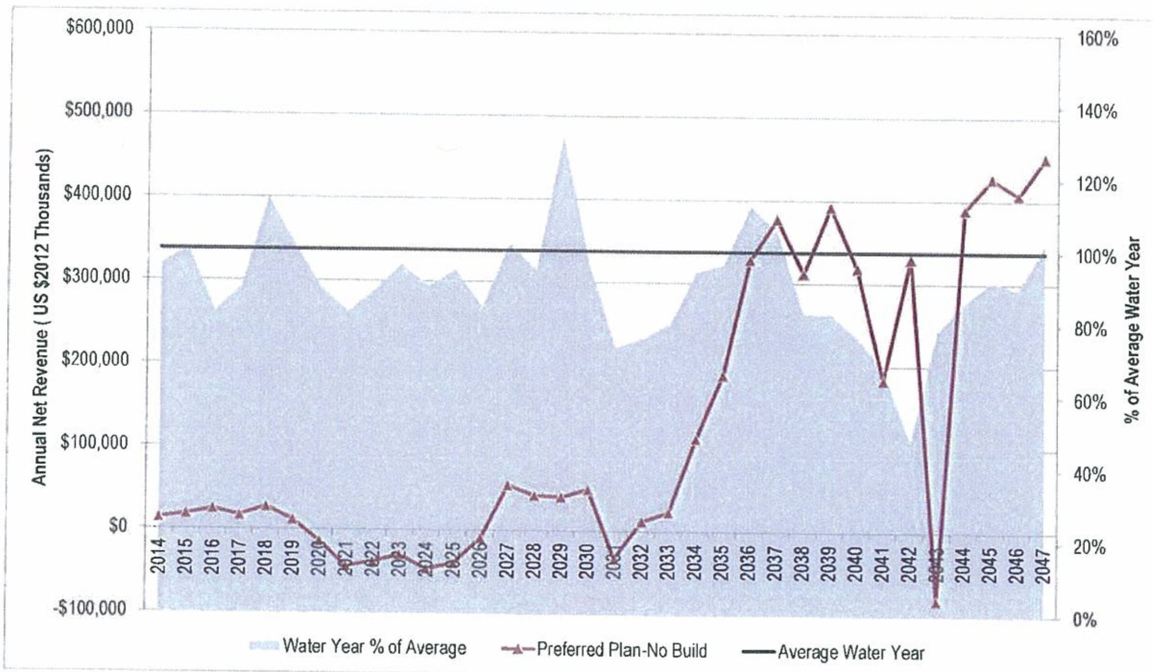

Figure 5-10: Minimum 34-year Net Revenue NPV Difference Preferred LCA No New Generation

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.

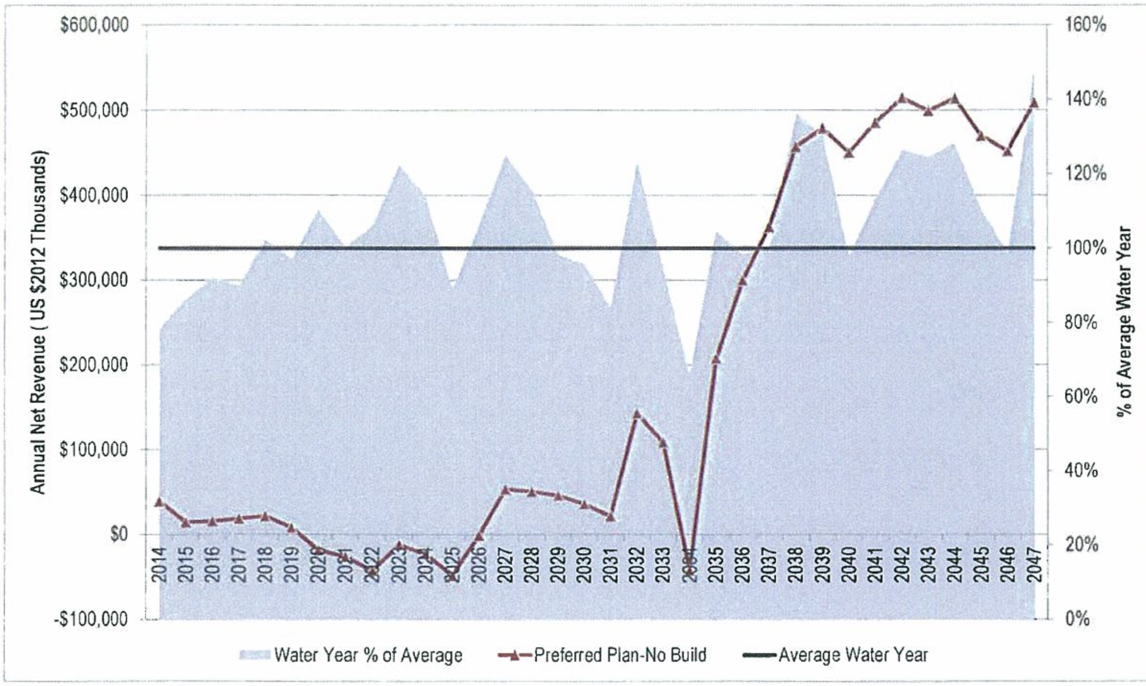

Figure 5-11: Maximum Net Revenue NPV Difference Preferred – LCA No New Generation

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.

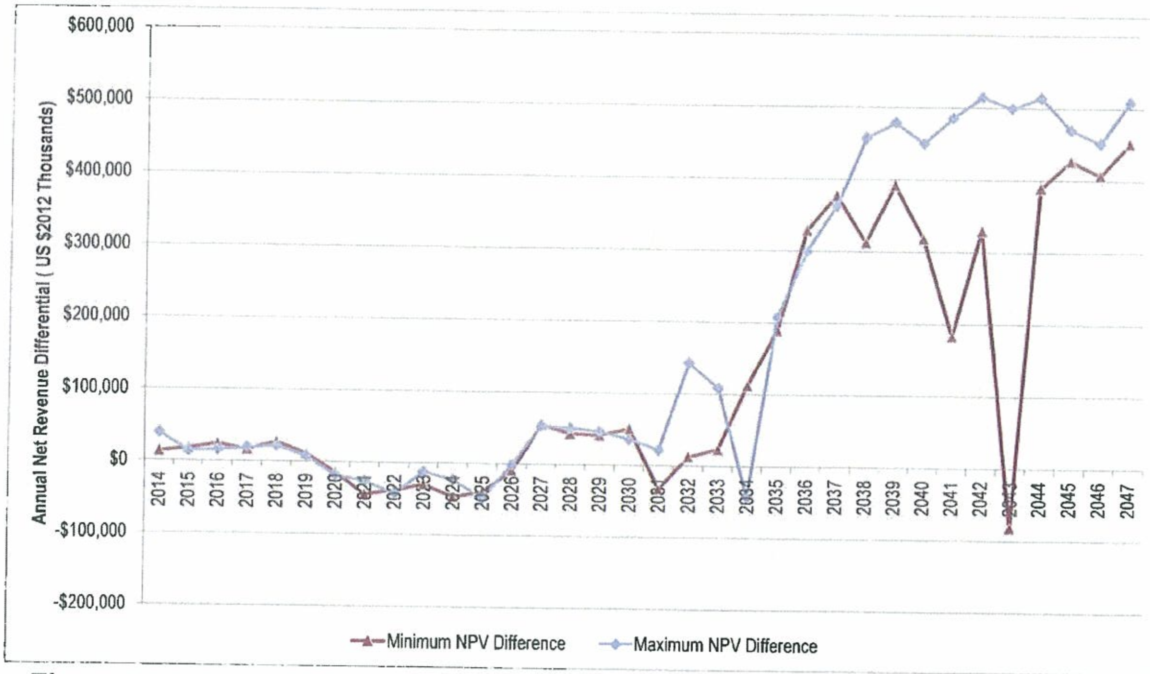

Figure 5-12: Annual 34-year Net Revenue Difference for Maximum and Minimum Net Revenue Difference: Preferred Development Plan minus LCA No New Generation Development Plan

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.

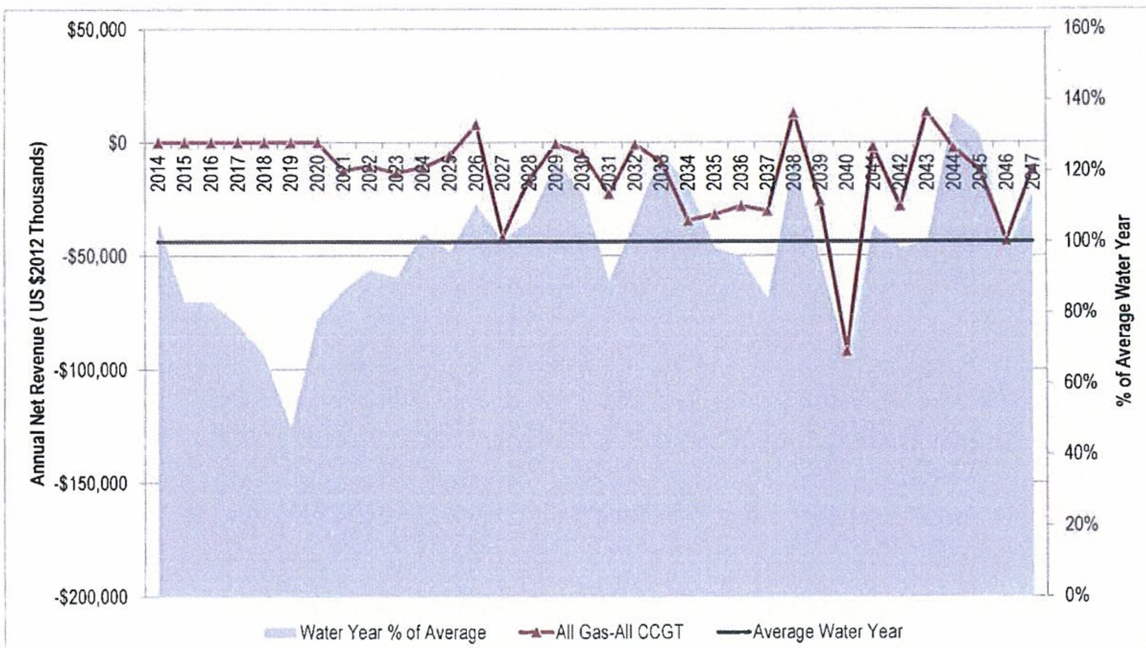

Figure 5-13: Minimum 34 year Net Revenue NPV Difference All Gas – All CCGT

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.

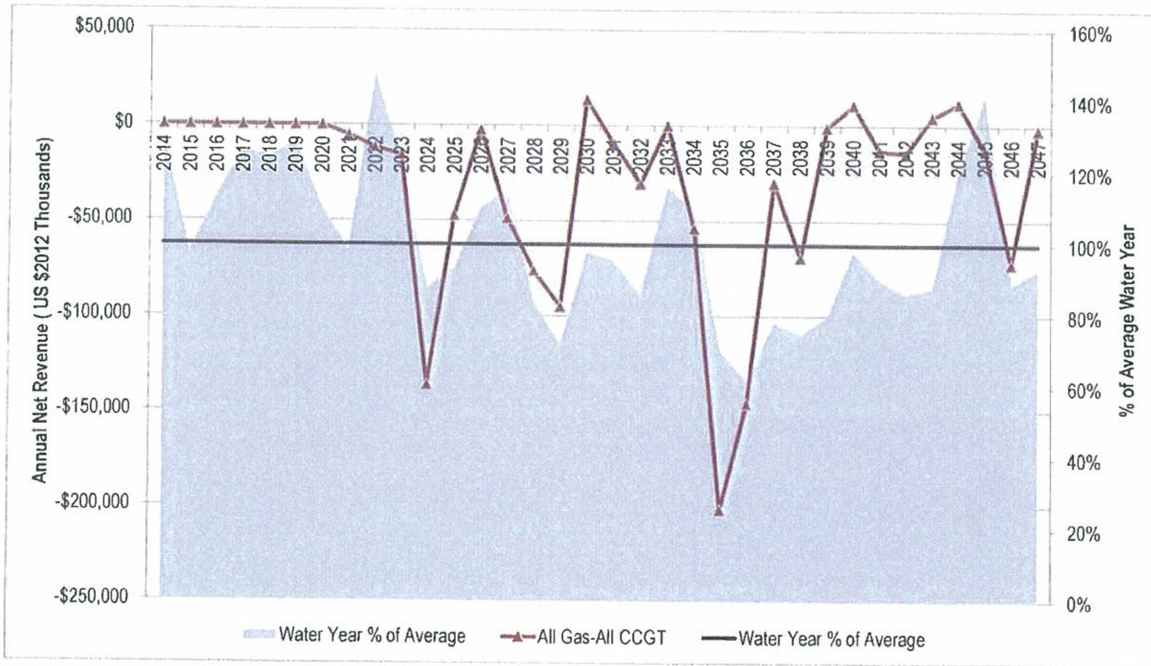

Figure 5-14: Maximum 34-year Net Revenue NPV Difference All Gas – All CCGT

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.

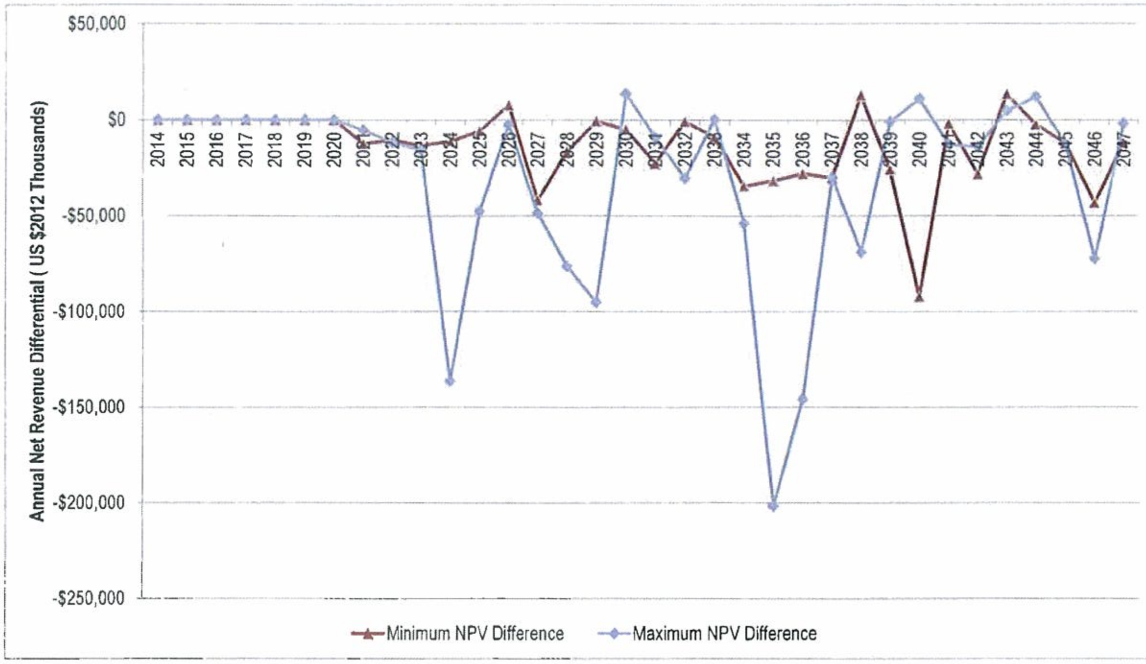

Figure 5-15: Annual Net Revenue Difference for Maximum and Minimum Net Revenue Difference: All Gas Development Plan minus All CCGT Development Plan

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.