Bipole III, Keeyask and Tie-Line review

September 19, 2016

THE BOSTON CONSULTING GROUP

Exhibit 1: Assessment of complex program of three projects

Each with standalone objectives and integrated benefits

	Bipole III	Keeyask	Tie-line[1]
	Endorsed on reliability need	*Preferred generation option*	*Acceleration opportunity*
Project objective	**Mitigate longstanding system reliability risk** • Ensure reliability against losing Bipole I & II lines or Dorsey converter station	**Satisfy future Manitoba energy need** • Meet future domestic energy need • Leverage Manitoba's clean hydro resource	**Secure cost-effective dependable energy** • Reduce future need for domestic generation • Expand market access in MISO (MN & WI)
Secondary considerations	**Strengthen physical transmission capability** • Additional peak capacity (enabling new generation) • Redundancy for maintenance	**Leverage resource attributes to cover part of costs through export** • "New hydro" to satisfy US tie-line requirement • Leverage increased peak capacity from Bipole III	**Increase value of domestic resources** • Reduce Bipole corridor reliability requirement • Improve Keeyask value generation potential

1. Tie-line = MMTP plus GNTL

Exhibit 2: Core questions being addressed in this effort

1. **Were the original decisions the right ones?**
2. **Is there further downside risk?**
3. **Can they be stopped or paused without undue cost or risk?**

Exhibit 3: Summary of key messages

1 **Original decision on Bipole III justifiable but Keeyask (in hindsight) a less prudent decision**

- Bipole III East was lowest-cost option to address longstanding, untenable reliability risk but the Province directed Hydro not to consider it
  - Of remaining options, Bipole III West lowest cost vs. All gas and Import + gas
- Keeyask (with US Tie-line) long-run economics attractive on paper, but financial and execution risks not fully considered
  - Rationale existed for accelerating Keeyask, e.g.: sustainable energy solution that capitalizes on expiring export opportunity
  - However, several factors suggest decision imprudent, e.g.: lower / delayed capex alternatives (e.g. gas) not fully explored, costly constraints not fully challenged, permits not in place ahead of proceeding, discount rates did not reflect project risk
- Imprudence can be traced to systemic decision governance issues, e.g.: lack of clear objective function and criteria/constraints of Hydro and regulatory body, rates not linked to allowable returns, iterative (vs. upfront) approach to investment decisions

2 **Based on current outlook, project economics expected to worsen and remain sensitive to key uncertainties**

- Capital execution will likely overrun and export price assumptions expected to worsen (outside of carbon constrained scenario)
- Equity ratios dip into single digits - similar to 1970-1995, but Province with 30%+ net debt/GDP vs. ~20% before

3 **Despite these challenges, cancelling in flight projects to shift to alternatives is not a realistic option**

- ~$5B already sunk on Bipole III and Keeyask with cancellation costs of ~$1B each, bringing effective total to ~$7B
- ~$3.2B cost to complete Bipole III <u>West</u> clearly more favourable vs. ~$4.5B rerouting costs of Bipole III <u>East</u>
  - Furthermore, decision to reroute Bipole III would strand Keeyask, making it uneconomic and likely trigger cancellation
- ~$4.7B cost to complete Keeyask yields an NPV $3-5B more favourable vs. switching to gas option, and avoids strategic risks

Exhibit 4: Were the original decisions the right ones?

Bipole III East was lowest-cost option to address longstanding, untenable reliability risk but was refused

- Reliability risk associated with Bipole I&II and Dorsey has been untenable for a long time: High concentration (e.g., 70% of energy), high incidence risk (e.g.,1/20 years), high societal impact (~$4-20B), major political implications
- Bipole III East lowest cost option but Provincial decision not to pursue based on environmental grounds
- Of remaining options, Bipole III West lowest cost vs. All gas and Import + gas

Original decision on Keeyask (with Tie-line) an imprudent decision

- New generation capacity required to meet domestic demand … but not until 2024+
- Keeyask project represents 2019 acceleration option to leverage US Tie-line import and export opportunity
- On paper, represents most favourable NPV option vs. delayed Keeyask (without Tie-line) or delayed gas
- Hydro generation deemed favourable vs. gas considering fuel price volatility and regulatory (e.g. CO_2) risk
- But assessment did not fully consider execution risks and sensitivities, e.g., project risk, industrial account risk, export price risk
- Additional downside financial risks of additional leverage (with Bipole III running concurrently) and associated discount rates to account for these risks did not appear to be fully factored into decisions
- Fuller assessment of lower capital and lower risk options would have been more prudent action at the time
  - Gas alternative
  - More aggressive challenging of costly constraints, e.g., regulatory requirement of Tie-line
  - Greater scrutiny of scope and design decisions

Imprudence can be traced to systemic decision governance issues

- Lack of clear objective function and criteria/constraints of Hydro, Government and Regulator, e.g., role of Hydro to drive economic growth vs. service domestic needs; role of regulator to maintain low rates vs. govern responsible stewardship of assets
- Ineffective rate-setting regime, e.g., rates not linked to allowable return, creating disconnect with system investment plan
- Iterative (vs. upfront) approach to investment plan decisions, e.g., ensuring full project scope considered holistically (Bipole III, Keeyask, US Tie-line) to appropriate capture compounded execution and financial risks

Exhibit 5: Mitigating risk of Bipole I&II, Dorsey a necessity

Represent unusually large contingencies

Bipole I&II carry majority of MH electricity
- ~70% of energy (MWh)
- ~50% of generation capacity[1] (MW)

Unable to meet winter demand without Bipole I&II
- 1500MW short of peak demand in 2017
- Assumes max. imports and running all thermal plants

Significant and real risk of catastrophic failure

Fire significant risk to Dorsey
- 1/29yr expected frequency[2]

Tornado at Dorsey unlikely but catastrophic
- 1/4000yr; Ellie[3] was scare
- Could take years to rebuild

Freezing rain and wind significant risk to Bipole I&II
- 1/20yr expected frequency

Ground ice buildup also risk to Bipole I&II
- Near-miss with shifted tower bases

~$4-20B societal impact of prolonged outage

Outage likely to last weeks to months
- 5-8 weeks for Bipole I&II
- Weeks to year(s) for Dorsey

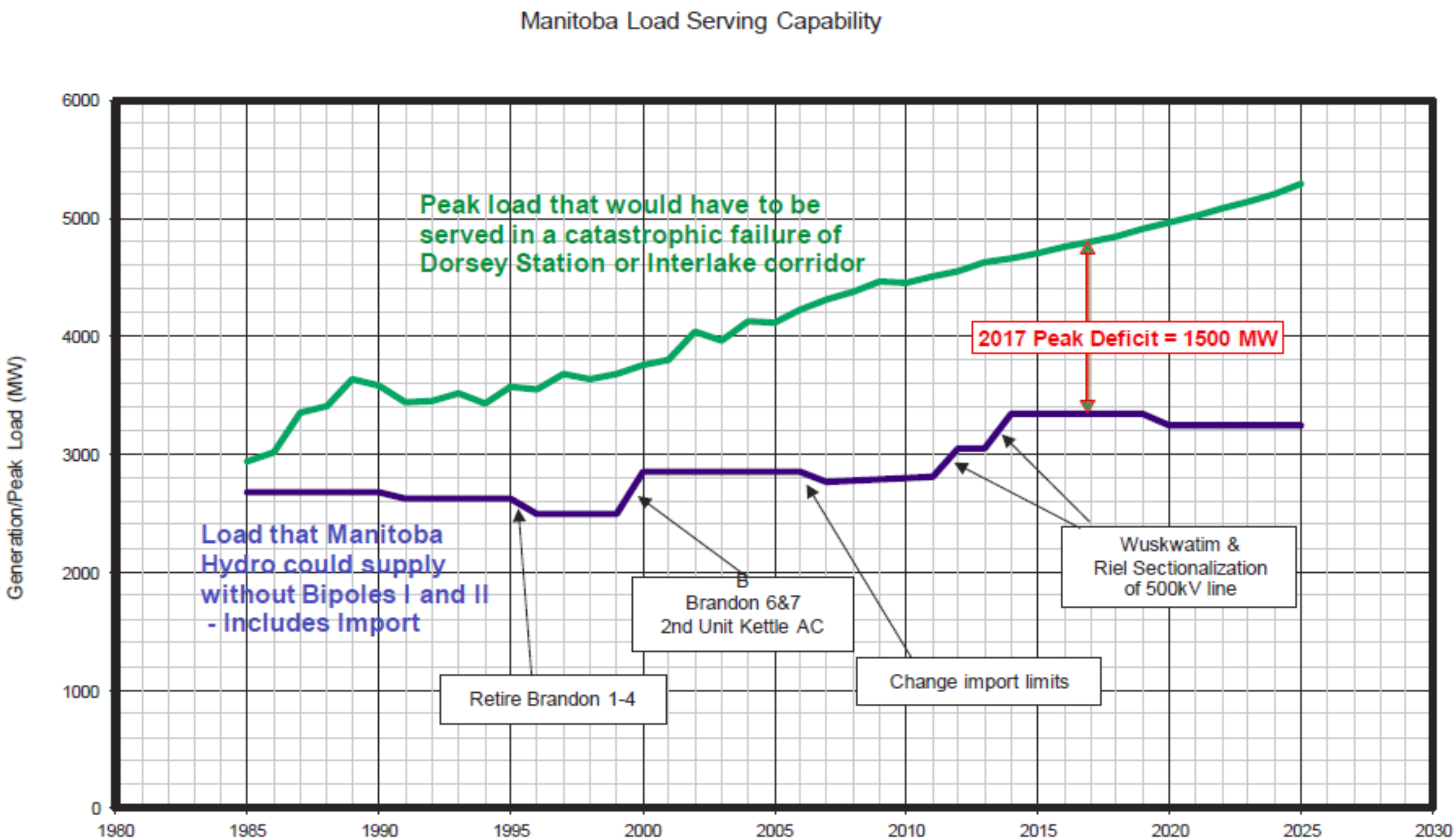
Rolling blackouts and/or demand curtailment
- Must force demand down to supply limit

~$4-20B cost depending of type and time of outage
- ~$10/kWh that fail to supply
- ~$4B for Jan. line outage
- ~$20B if full year

Popular backlash against MH and government likely
- Failure to honor Hydro Act

1. Total (100%) includes both generation and import line capacity. 2. After hardening of relay building in 2011 risk may be lower than stated in the reports.
3. Strongest tornado in Canadian history, 25km away.
Source: Teshmont (2001, 2006, 2012)

Exhibit 6: Peak load growth making loss of Dorsey or Bipole I & II consequences more severe (1.5 GW peak shortfall in '17)



Source: Reliability Alternatives for Mitigating the Risks of a Dorsey or Interlake Corridor Outage (2011)

Exhibit 7: Probabilistic studies show risk to Dorsey and Bipole I & II, and there have been several near misses

Threat	Dorsey[1]	Bipole I & II
Tornado, downburst	**1/4000yr** (summer) Down ***month to year(s)*** • 3km away (Sep. '96) • 25km away[2] (Jun. '07)	**1/17yr** (summer) Down ***days to weeks*** • 19 towers destroyed (Sep. '96)
Fire	**1/29yr** Down ***week to months*** • Exploding transformer	**N/A**
Wide-front wind	**1/200yr**	**1/90yr** Down ***week to months***
Freezing rain & wind	**1/50yr**	**1/20yr** Down ***week to months***
Ground ice buildup	**N/A**	Unknown; **likely significant** • Tower bases shifted from the ground
Sabotage	**Unknown**	**Unknown**

1. After hardening of relay building in 2011 several of the risks to Dorsey are likely lower than stated in the reports. 2. Elie; strongest tornado in Canadian history
Source: Teshmont (2001, 2006, 2012)

Exhibit 8: Societal impact of loss of Bipole I & II or Dorsey for month of January ~C$4B, and ~C$20B for full year

Low societal impact ⟷ High societal impact

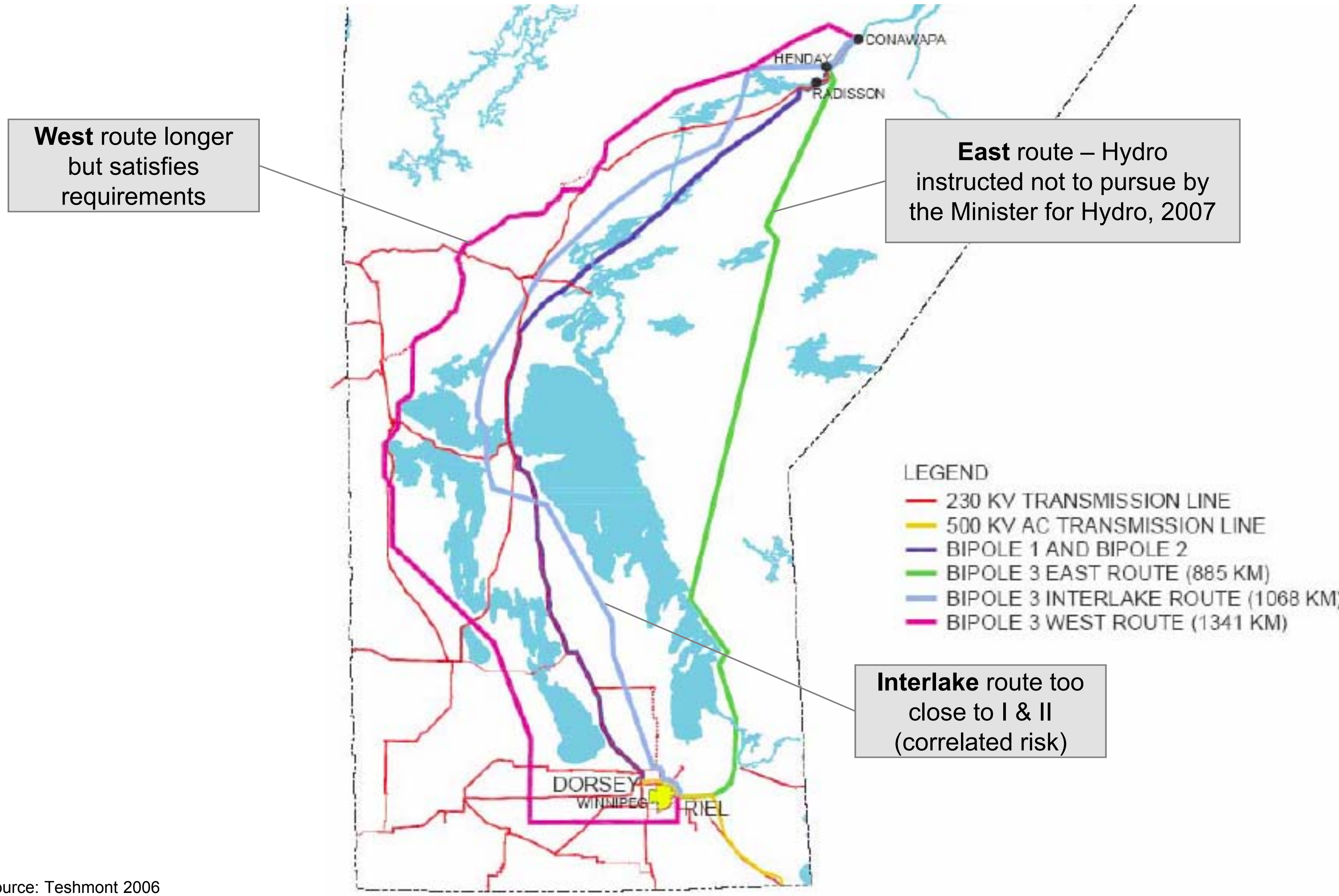
Short-term outage	Dorsey / Bipole I & II	Severe weather outage
Temporary (minutes–hours) inability to serve load • Black/brown-out	**Prolonged (week–year) inability to serve load** • Rolling blackouts • Shed industrial load • Prioritize residential heating	**Prolonged (day–week) inability to supply power** • Black-out until repair
MISO Value of Lost Load (VoLL) estimates: • Residential[1]: US$2/kWh • Small C/I: US$42/kWh • Large C/I: US$29/kWh	**MH VoLL estimate:** • C$10/kWh • Very unusual situation with uncertain long-term effects	**1998 Canada ice storm** • C$9/kWh **2012 Superstorm Sandy** • ~US$20B; 8.5M lost power

Bipole I & II transmission lines (for January)
- Un-served January demand * C$10/kWh = **~C$4B/mo**

Dorsey converter station (for a year)
- Un-served annual demand * C$10/kWh = **~C$20B/yr**

1. Likely higher for customers reliant on electric heating, and may underestimate modern reliance on electronics
Source: "Estimating the Value of Lost Load", London Economics (2013); "Manitoba Customer Interruption Cost Evaluation", R. Billington, PowerComp Associates (2001); "Economic Benefits of Increasing Electric Grid Resilience to Weather Outages", Executive Office of the President (2013)

Exhibit 9: Bipole III West route chosen to minimize risk correlation with Bipole I & II



Source: Teshmont 2006

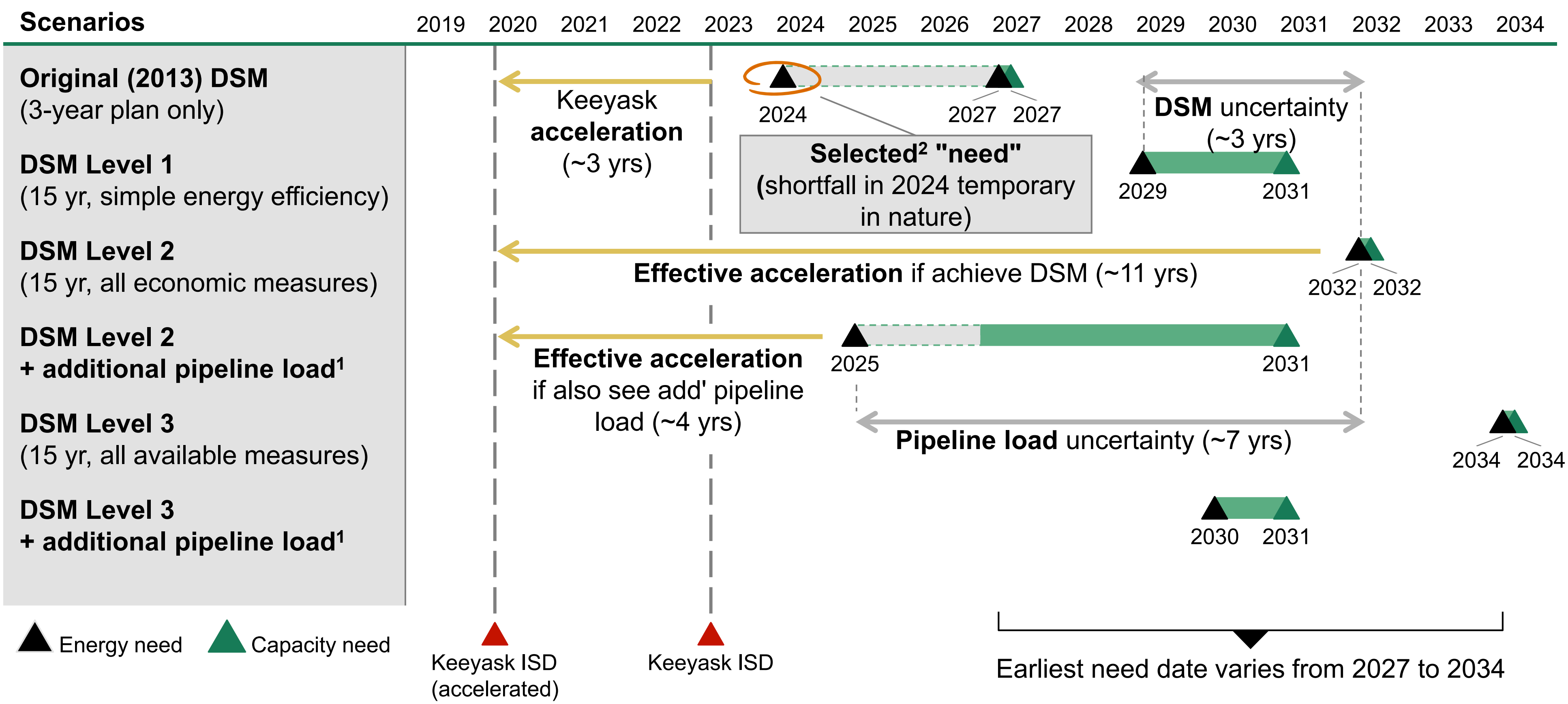
Exhibit 10: Bipole III East the most favourable option

But directed not to pursue by previous government, hence Bipole III West pursued

	Lowest cost, not selected **Bipole III East**	*Selected option* **Bipole III West**	**All-gas**	**Import + gas**
Description	**Alternative access to northern hydro** • 2000MW line • Could stage (line first, conv. stations later[1])	**Alternative access to northern hydro** • 2,300MW line • Cannot stage line and converter stations	**Backup generation** • 2000MW gas in the South	**Import line + backup generation** • 1500MW US line • 500MW gas
Cost estimate used in 2011 EIS[4]	Not formally assessed but estimated to be $900m less expensive • Staged converter station build • 700-900km shorter	**~$3.3B** (capital cost in-service dollars)	**~0.7B** more than BPIII on PV[2] basis **~$3B** gas turbine	**~$4.5B** (capital cost in-service dollars)
		~$10M/y annual cost	**~$181M/y** pipeline reservation fee + variable costs	Annual costs subject to contract terms and variable costs
Additional benefits	**$28M/yr from reduced losses[3]** **Additional capacity for new hydro**	**$26M/yr from reduced losses[3]** **Additional capacity for new hydro**	**More dependable energy**	**Larger import/ export potential** **More dependable energy**
Risks	**Route through Boreal forest**	**No specific risk**	**Environmental risk, pipeline reservation fee**	**Environmental risk, future price of securing capacity**
Verdict	✗ **In 2007 the province directed MH to study Western routes**	✓ **Lowest cost of available options**	✗ **Higher cost, CO_2-emitting**	✗ **Higher cost, CO_2-emitting, difficult to secure US partner**

1. Line primary concern, given low probability of Dorsey destruction. 2. Present Value. 3. Current Bipole I&II transmission losses 8.6%; Bipole III West 6.4% to 7.0%; Bipole III East 6.0% to 6.4%.
4. Environmental Impact Statement (2011)
Source: Manitoba Hydro, BCG analysis

Exhibit 11: Timing of domestic requirements



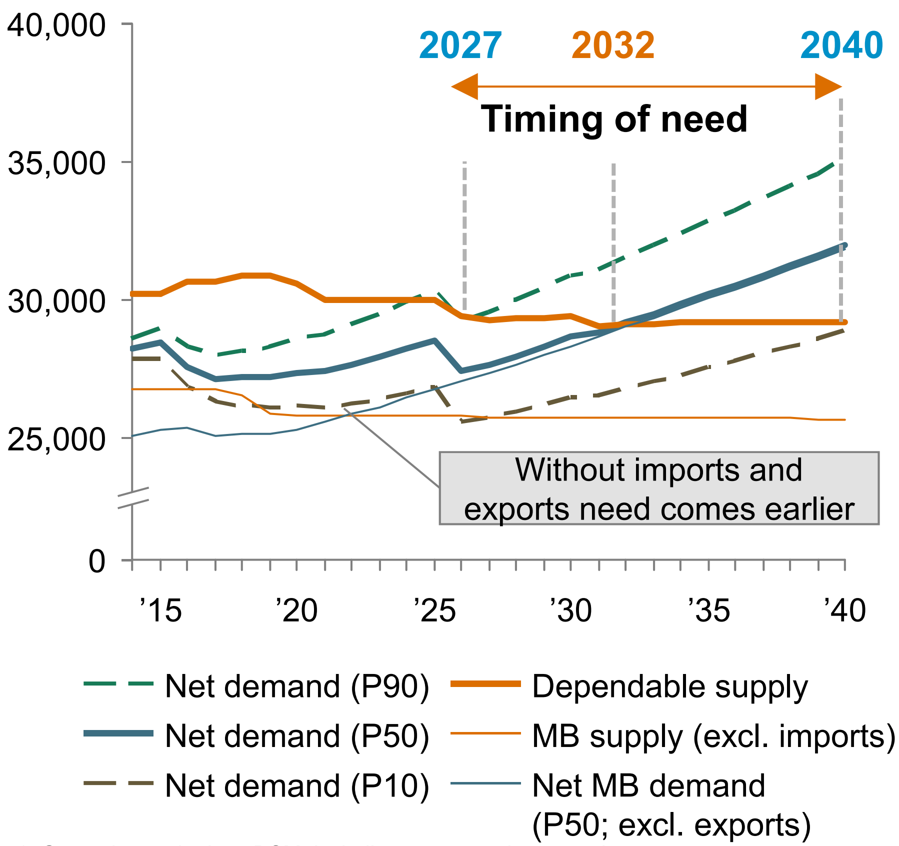
Realistic DSM pushed need date out, but expected additional pipeline load pulled it back to ~2027

1. 1700MWh additional load planned by pipeline customers. 2. Put forward by MH, and accepted by NFAT panel (partly because they expected additional pipeline load to materialize).
Source: NFAT Final Report

Exhibit 12: New generation capacity required, although not until 2027 or beyond

NFAT: Supply vs. net demand[1]

Dependable energy supply vs. net demand (GWh)



1. Gross demand minus DSM, including exports unless noted
Source: Manitoba Hydro (NFAT)

Timing subject to forecast uncertainty

Gross demand forecasted to grow by 1.5% p.a.

- ***Residential segment:*** Population growth and increased penetration of electric heating
- ***Mass market segment:*** GDP growth (2%) and population key drivers
- ***Top customers segment :*** 17 companies, "Potential Large Industrial Loads" longer term

Demand Side Mgmt. (DSM) expected to offset 66% of demand growth over 15 years

- ***Conservation rates:*** MH proposed higher rates for electricity beyond threshold
- ***Fuel switching:*** Switch to gas heating
- ***Load displacement:*** Industrial self-generation

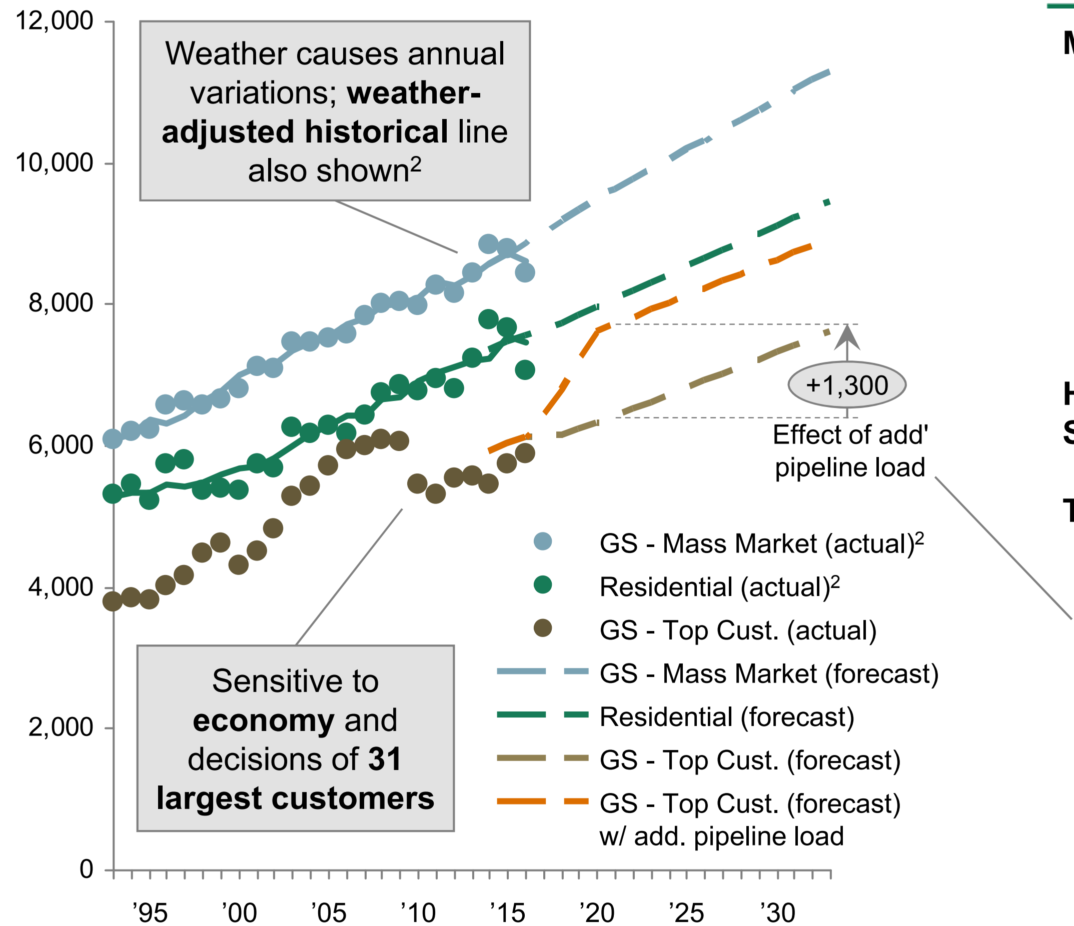
Uncertainty for both gross demand & DSM

- Decisions of larger industrial customers (e.g., pipeline load)
- DSM adoption may be lower than in other markets due to low retail rates

Exhibit 13: Gross demand forecast sensitive to Top Customers

Forecast methodology sound, but inherent risk in lumpy Industrial demand

Customer segment gross demand[1] (GWh)



Demand forecast by customer segment

Methodology to forecast demand by segment

- ***General Service – Mass market:*** GDP and residential customer number drive demand
- ***Residential segment:*** Population, electric heating penetration, etc. drive demand
- ***General Service – Top Customers:*** Individual forecasts for top 31 drive near-term demand; annual PLIL[3] increment beyond that

Historically, demand forecast accurate for General Service and Residential

Top Customers largest source of uncertainty

- Sensitive to largest customers and economic cycles
- E.g., expected 1700GWh add' pipeline load (+1300GWh over PLIL[3]) but only ~500GWh now expected to materialize

1. Gross MB demand shown; net demand is gross demand minus DSM, plus net exports. 2. Weather-adjusted line also shown (N/A to Top Cust.). 3. Potential Large Industrial Loads
Source: Manitoba Hydro

Exhibit 14: NPV & upside favoured Keeyask by 2019 + Tie-line

But at substantially higher capital risk vs. delayed gas option

			Selected option 
Criteria	**Gas generation 2022+**	**Keeyask 2025/26**	**Keeyask '19 + Tie-line**
Resource type	***Fossil*** *(CO_2 emitting; fully dispatchable)*	***Renewable*** *("new hydro"; dispatchable subject to water)*	***Renewable*** *("new hydro"; dispatchable subject to water)*
Cost structure	***Variable cost intensive*** *CAPEX (PV[1]): ~$2.8B* *Variable cost: ~$40-62/MWh* *LCOE[3]: ~75-265 $/MWh[4]*	***Capital intensive*** *CAPEX (PV[1]): ~$4.4B* *Variable cost[2]: ~$3-4/MWh* *LCOE[3]: ~68 $/MWh*	***Capital intensive*** *CAPEX (PV[1]): ~$6.2B* *Variable cost[2]: ~$3-4/MWh* *LCOE[3]:~68 $/MWh[5]*
NPV (NFAT)	***Reference case***	***–$38M*** *benefits to MH and* ***$591M*** *payments to province compared to gas reference*	***+$386M*** *benefits to MH and* ***$1148M*** *payments to province compared to gas reference*
Upside and risk	*Higher or lower* ***gas and CO_2 prices*** *than forecast* *Federal or provincial* ***restrictions on CO_2***	*Increased export prices from* ***US Clean Power Plan****, etc.* ***Cost*** *and* ***schedule overrun***	*Increased export prices from* ***US Clean Power Plan****, etc.* ***Cost*** *and* ***schedule overrun****, and tie-line* ***permitting***

1. Present Value of capital expenditure for scenario (including late-time gas generation) 2. Only water rental included here 3. Levelized Cost of Electricity. 4. Varies by utilization. 5. Keeyask only.
Source: NFAT, BCG analysis

Exhibit 15: Tie-line a key source of value for Keeyask project

Greatly improves economics of Keeyask given potential for export to subsidize low domestic rates

Minnesota Power needed rapid path to reduce CO^2

The problem

- MP legally mandated to achieve 26.5% RPS by 2025
- MP had set its own target to produce 1/3rd of current 1900 MW from renewables
- CPP may require MP to reduce 30% CO^2 from coal by ~2030
- Can only import <u>new source of renewable power</u>

MP were looking for a near-term solution

MP had several options to solve CO^2 challenge

Several options to solve

- Build out wind
- Wait for utility scale PV to drop in price (as per trend)
- Start build out of gas
- Lock in new source of hydro power to import (Keeyask provided the option)

Keeyask one of several viable options considered

Building Keeyask and tie line had benefits for MH

With the tie line, MH gets

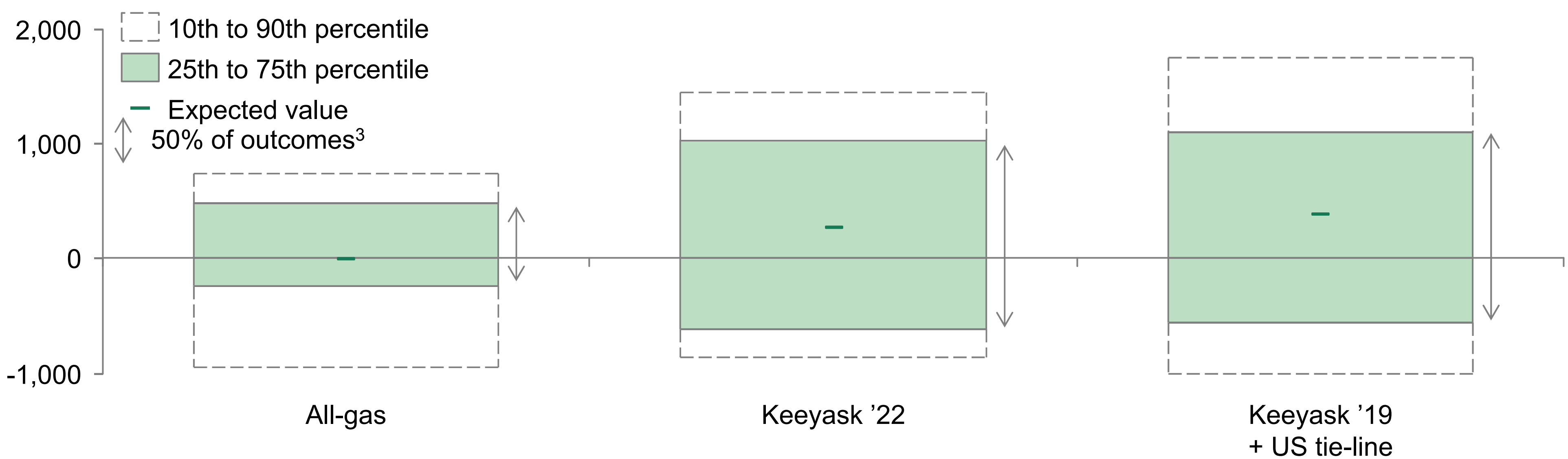
- ~3 TWh new cost-effective dependable energy
- Import capacity of ~700MW dependable capacity to offset hydro risk
- 885MW increase in export capacity used to offset construction cost of Keeyask

MH built early to capture benefits in a closing window

Exhibit 16: Gas carried less uncertainty, but Keeyask with tie-line had higher expected incremental NPV[1]

Gas generation 2022+	Keeyask 2025/26	Keeyask '19 + Tie-line
Smaller and staggered capital costs, with future fuel expense	**Large capital investment**	**Large capital investment and early additional export rev.**
Key sensitivities (discount rate, energy prices, capital costs) can vary NPV by -$1B to +$0.7B	**Expected incremental NPV ~$0.3B, but more sensitive (ranges from -$0.8B to + $1.4B)**	**Highest expected incremental NPV (~$0.4B), but also most sensitive (largest up/downside)**

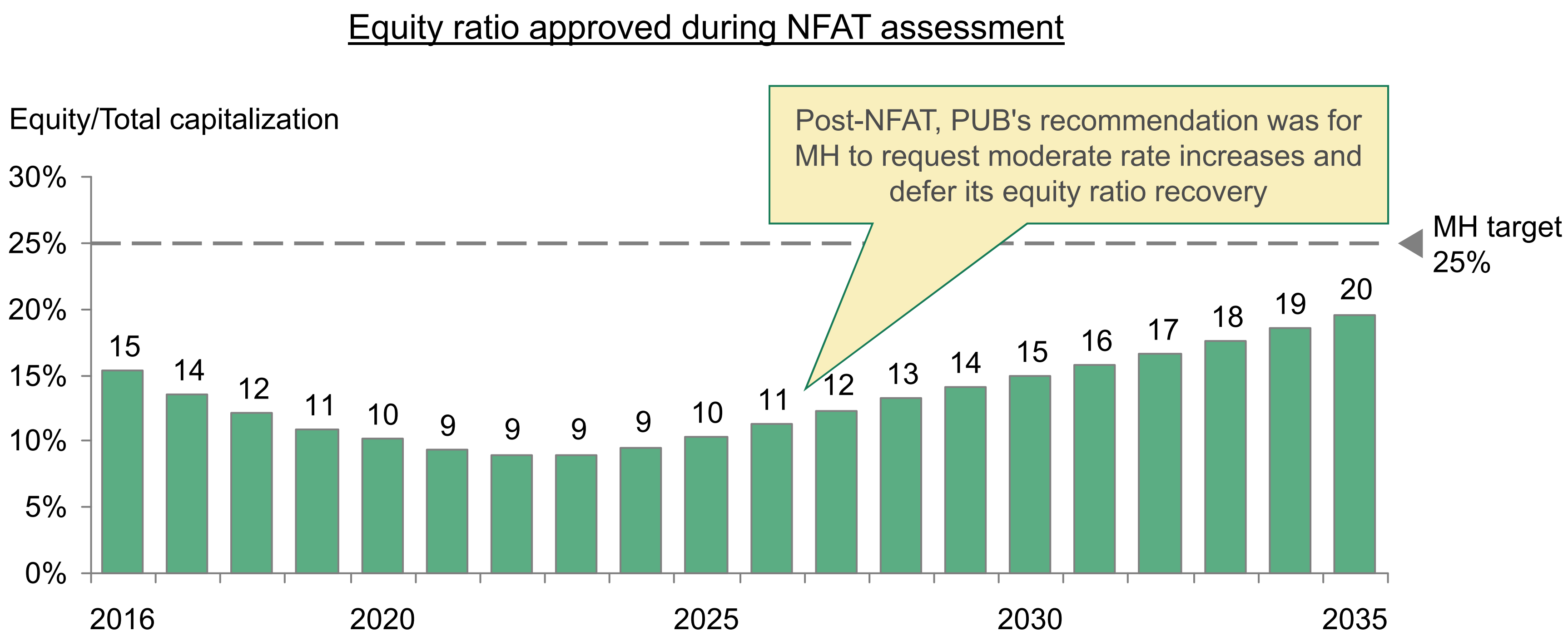
Incremental NPV[1] over all-gas reference case[2] ($M)



1. Having sunk $1.2B. NPV benefit to Manitoba Hydro only (excluding water rental and capital tax and guarantee fee payments) 2. All-gas reference case with reference values for discount rate, energy prices, and capital costs. 3. Considering uncertainty in discount rate, capital costs, and energy prices. Note: Manitoba Hydro did not update this analysis to reflect final DSM level 2 demand forecast
Source: NFAT final report

Exhibit 17: Implied equity ratios of NFAT submissions

NFAT and PUB supported equity ratio falling to 9%

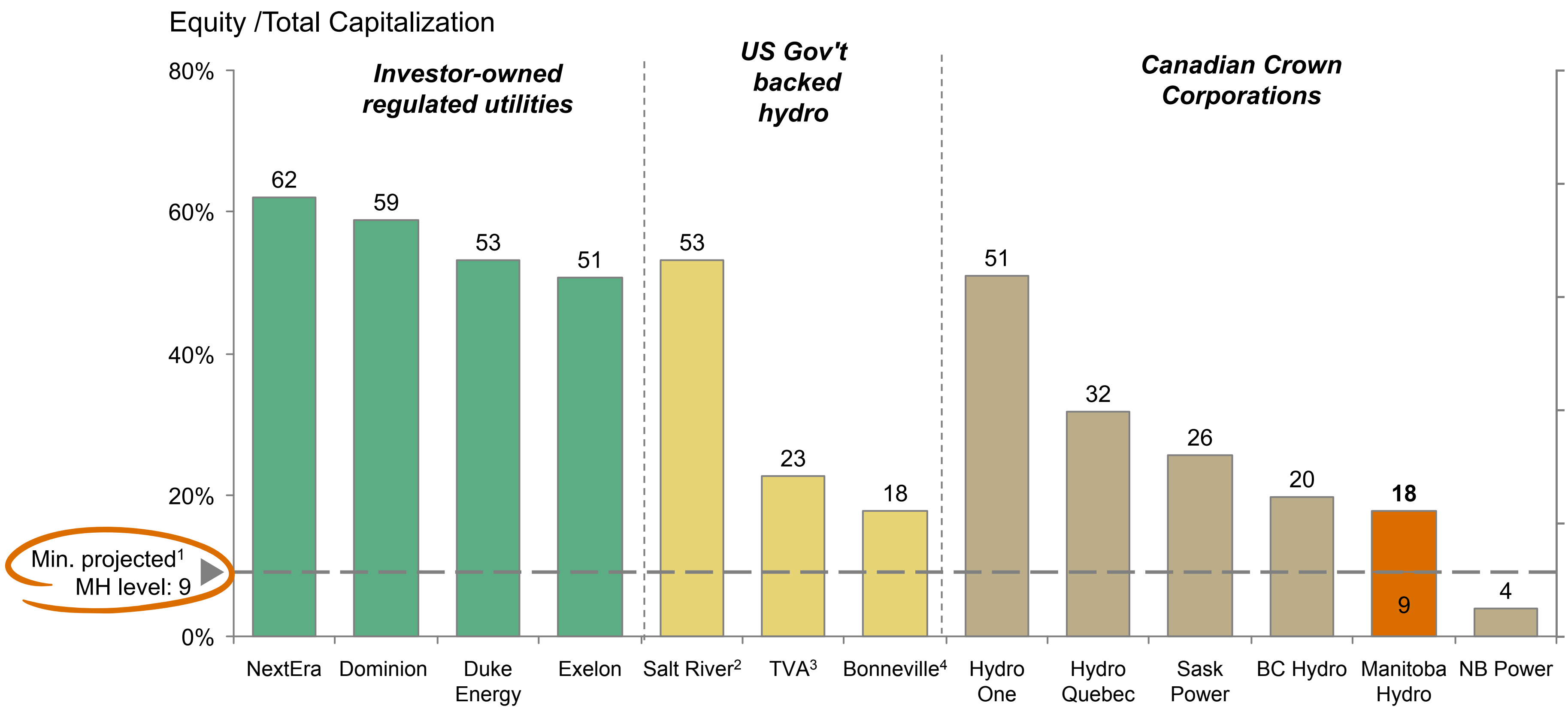


Single digit equity ratios were not highlighted as a significant risk when projects approved

Source: IFF '15; NFAT Projected Financial Statements for Plan K19/Gas/750MW – DSM Level 2

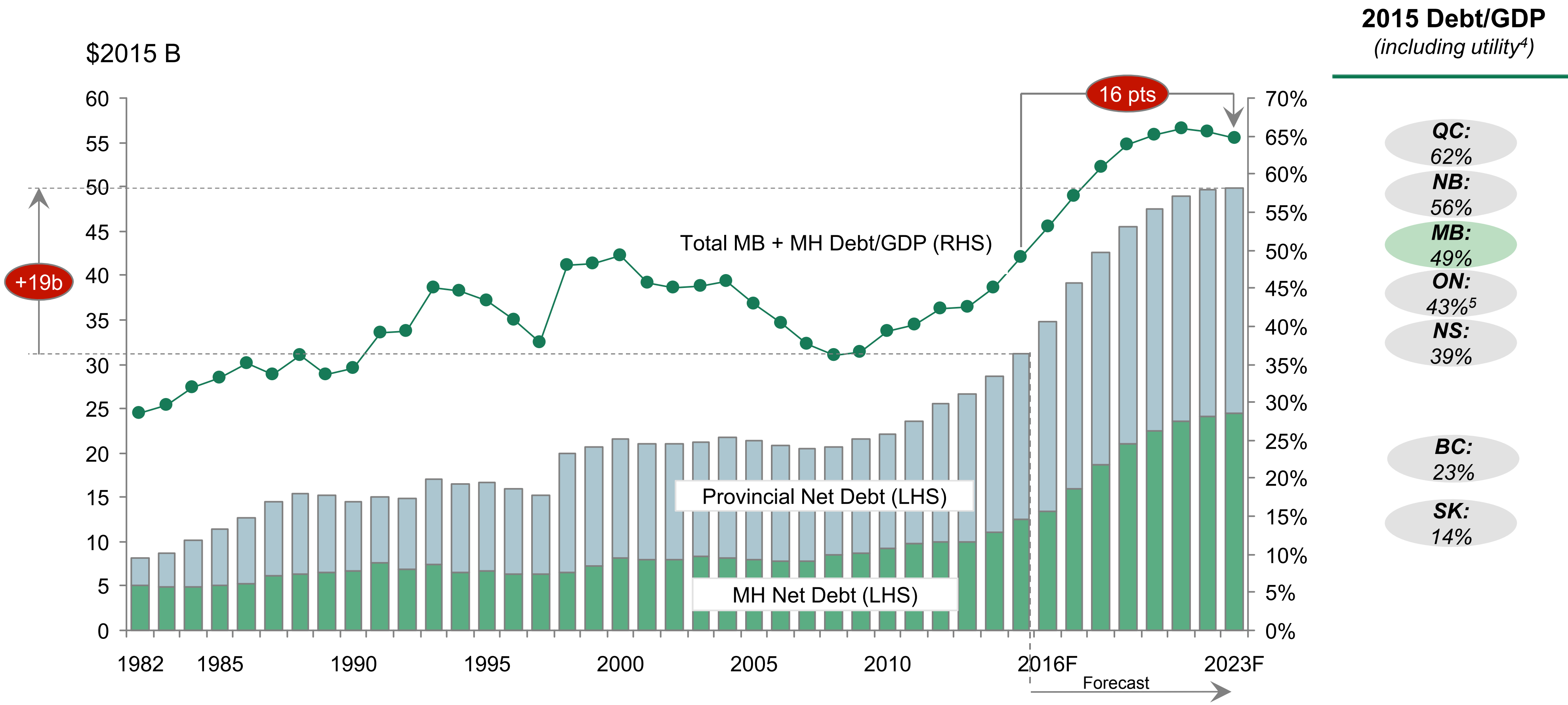
Exhibit 18: Equity ratios well-below most peers

Capital structure and credit rating for US and Canadian gov't and investor-owned regulated utilities



1. 2022 Expected Equity Ratio on NFAT Base Case 2. Salt River Project an entity of the State of Arizona 3. Federally owned corporation 4. US Federal administration within Dept. of Energy
Source: 2015 Audited Financial statements, SNL

Exhibit 19: Hydro debt included, total debt-to-GDP ratio forecast will increase to 65%



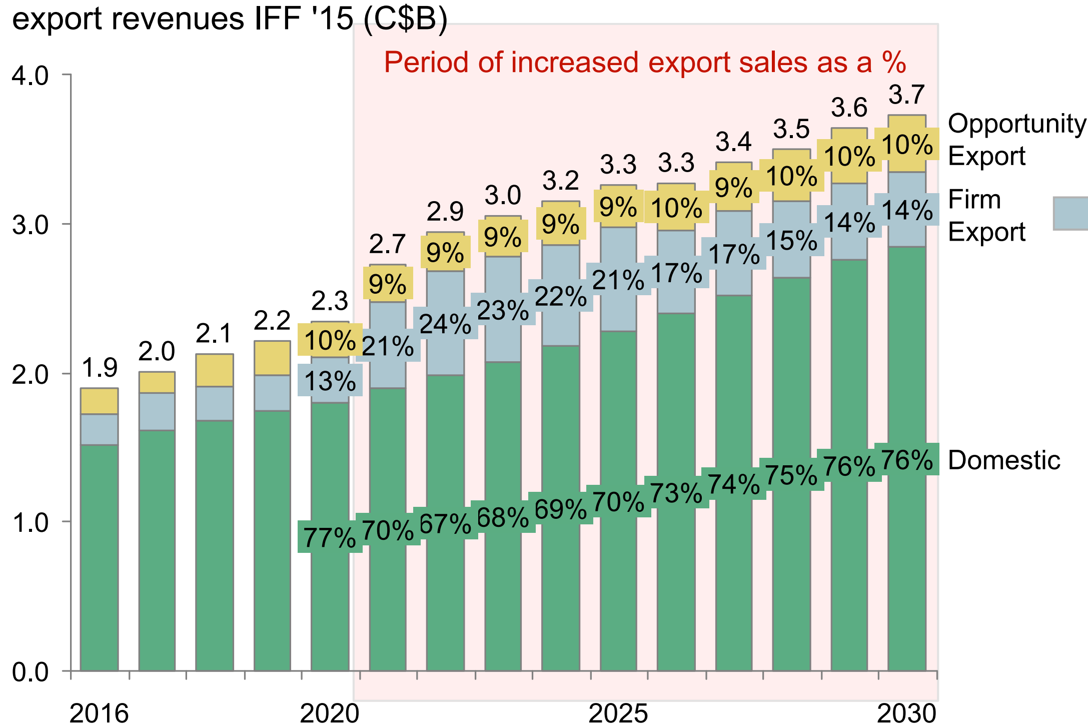
Limited capacity for the Province to provide debt backstop

Source: Canadian Department of Finance, Manitoba Hydro Debt Management Strategy Report, RBC, 2015 Utility Annual Reports
1. Total Debt calculated as Provincial Net Debt + Manitoba Hydro Net Debt in base case. 2. Debt to GDP ratio from RBC report; excludes Manitoba Hydro debt 3. Provincial debt forecasts modeled based on Provincial target to close budget gap within 8 years 4. Provincial net debt with utility crown corporation debt included 5. Ontario Provincial debt plus OPG debt (including asset removal and nuclear waste management liabilities)

Exhibit 20: Firm export volumes and prices benefit economics

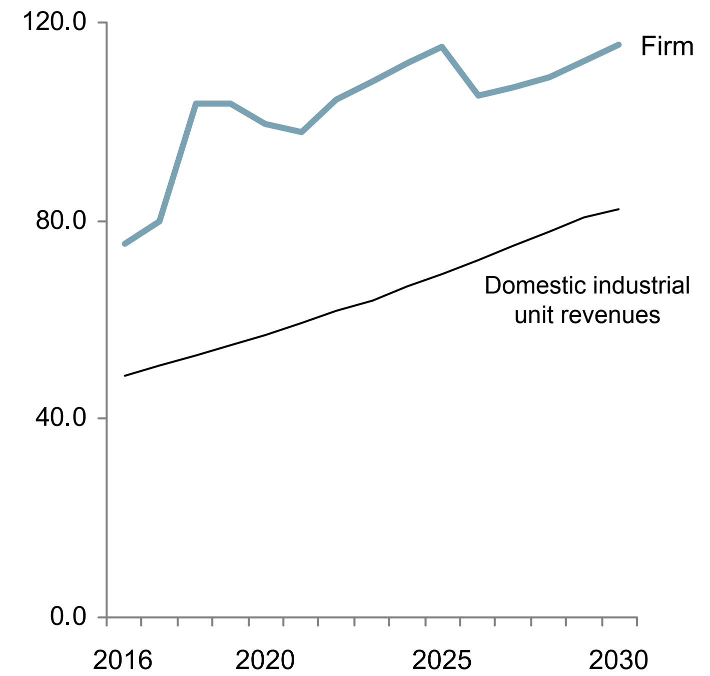
Revenue mix expectations: Firm export expected to grow to 20%+

Forecasted domestic demand and export revenues IFF '15 (C$B)



Price expectations: Firm export at 15% premium

Unit revenues IFF'15 ($C/MWh)



Source: Manitoba Hydro, BCG analysis

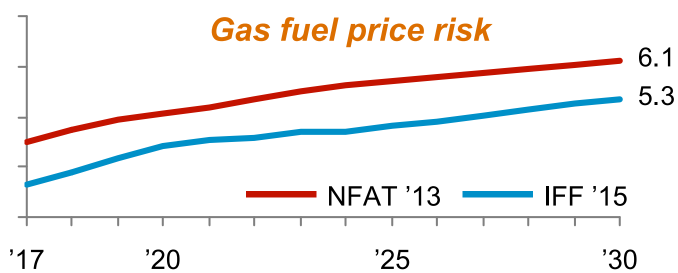
Exhibit 21: Gas & CO_2 price risk vs. Hydro & Export price risk

Manitoba's resources and the current regulatory model better fits with the hydro based risk profile

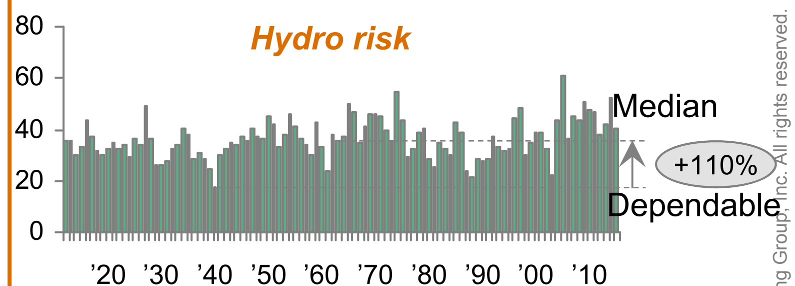
Selected option

Criteria	Gas generation	Hydro generation & US Tie-line
Risks	*Domestic price & fuel price volatility* *Environmental regulation risk incl. CO_2* *Fuel import dependency*	*Risk related to water levels* *Domestic & export price levels* *Execution risk (e.g. project complexity)*
Increase of Gas & CO2 prices with upward impact on Export prices and hence benefitting MH's hydro assets		

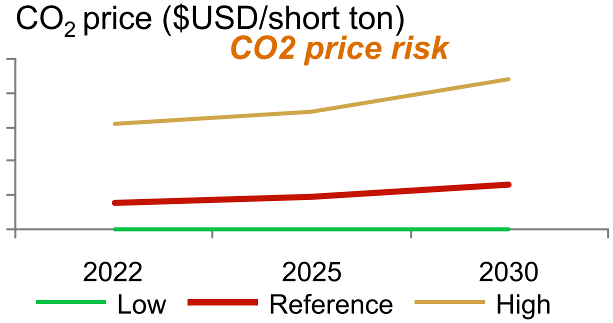
Price ($2015 USD/MWh)



Energy from water flow (TWh)



CO_2 price ($USD/short ton)



MISO Minnesota price forecasts ($/MWh)

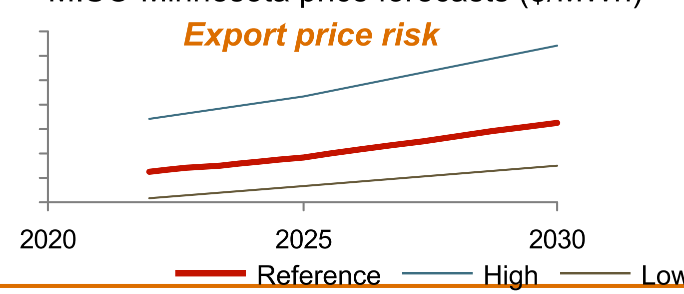


Exhibit 22: Manitoba Hydro's regulatory framework oriented towards maintaining consistent, low price increases

Hydro Act	**Outlines Manitoba Hydro's core purpose: to provide sufficient power for Provincial needs and engage in the activities required to provide power economically and efficiently** • Regulatory framework allows for exports of power **Directs that prices be set such that MH can recover operating and interest costs and build sufficient reserves to fund replacement of assets and new investment in property or plant** • Act also outlines MH's ability to borrow under Provincial guarantee
+	
PUB	**PUB mandate exclusively to review the price of power; no supervisory authority granted** **Track record of PUB to prioritize low, stable increases over time rather than implement lumpier price increases timed with capital expenditures**
+	
Provincial Cabinet	**Province reviews capital plans, export contracts and interconnect agreements** • Province may direct PUB to review other elements of MH's operations on its behalf
+	
Other legislation	**MH also subject to other legislation that influences PUB and public attitude towards price:** • Affordable Utility Rate Accountability Act requires Manitoba to have lowest combined price of gas, electricity and auto insurance among provinces • Clean energy legislation governing development of renewables prioritizes low rates

Exhibit 23: Manitoba regulatory construct different from traditional utility cost-of service model on several dimensions

	Manitoba PUB "Modified" Cost of Service	Traditional Cost of Service
Rate framework	**Price of power set based on PUB judgment** **PUB considerations:** • Operating expenses • Retained earnings reserves • Proposed capital plans • Smooth trajectory of rate increases	**Revenue requirement = Operating Expenses + (Gross value of the utility's tangible and intangible property – Accrued depreciation) * Allowed Return on Rate Base**
Objective function	• **Provide sufficient power for Provincial needs and engage in the activities required to provide power economically and efficiently**	• **Maximize return within regulatory bounds**
Investor	• **Government**	• **Institutions and individuals**
Return on equity	• **Outcome of rate setting process** • **Varies with revenue increases**	• **Primary lever of rate setting process** • **Set at level to attract private capital**
Capital Plan	**PUB informed of plan but no formal approval**	**Regulatory approval of CapEx required before addition to rate base**
Supervisory Authority	**PUB lacks supervisory authority**	**Regulatory supervisory authority granted**
Allowance/ disallowance	**No disallowance authority from PUB**	**Regulatory authority to disallow expenditures from rate base**

Exhibit 24: Decision making more iterative than consolidated

Reliability	*Energy and Capacity*		*Rate application*
Clean Energy Commission '13	**PUB in the NFAT '13-14**		**PUB rate process '15**
Bipole III West Route for 2018 ISD	**Keeyask 695MW Hydro for 2019 ISD**	**750MW US Tie Line for 2020 ISD**	**Increase Manitoba rates by 3.95%**
Bipole III East Route	All Gas (various types and ISDs)	250MW US Tie Line for 2020 ISD	Various rate increase scenarios presented
Gas	Keeyask 695MW Hydro for later ISD (2022)	DSM included in all options	
Import and Gas	Conawapa 1485MW later than 2026 ISD	Other resources (e.g. wind, solar)	
Import only	Increase of import and change planning guidelines[1]	Push out ISD of US tie-line for later	Efficiency measures

Current option

Alternatives considered

Alternatives not considered

1.Import can account for up 10% of Manitoba load plus export, overall capped at 50% of the off-peak load
Source: BCG analysis

Exhibit 25: Is there further downside risk?

Outlook under current assumptions already highly sensitive to performance across 6 key factors:

1) **Water flows / Hydro risk: No change to existing range of uncertainty for near term-impact**
   – High variability in range of possibilities

2) **Capital execution costs**: **Both projects likely to exceed P90**
   – Bipole III expected to run over by $0.3B with 12 month delay and Keeyask expected to run-over by $0.7B with 21 month delay, including interest
   – For Bipole III, transmission line construction productivity in winter and tower steel availability the main drivers

3) **Export prices: Expected to worsen (outside of longer term carbon constrained scenario)**
   – Most recent forecasts represent a ~13-17% decrease in long-term export prices vs. IFF '15
   – Firm energy premium reducing up to 10%

4) **Interest rates: Favorable movement since NFAT in long term rate**
   – Assumptions of long term rates fall from 6.3% to 4.4%, reducing debt service levels and discount rate

5) **Domestic rates: Potentially lower than forecast initially**
   – PUB granted 3.36% vs 3.95% as requested (partially due to lower interest rate and debt servicing cost)

6) **Net domestic demand: No change to expected case**

Equity ratios expected to dip to single digits, creating a potentially precarious position for the province

- Falls to <12% in expected scenario
- Under extreme sensitivities (severe capex overrun, sustained drought), feasible for equity to go below 5%
- While single-digit equity ratios observed 1970-1995, Province with 30%+ net debt/GDP vs. ~20% before

Exhibit 26: Project economics expected to worsen

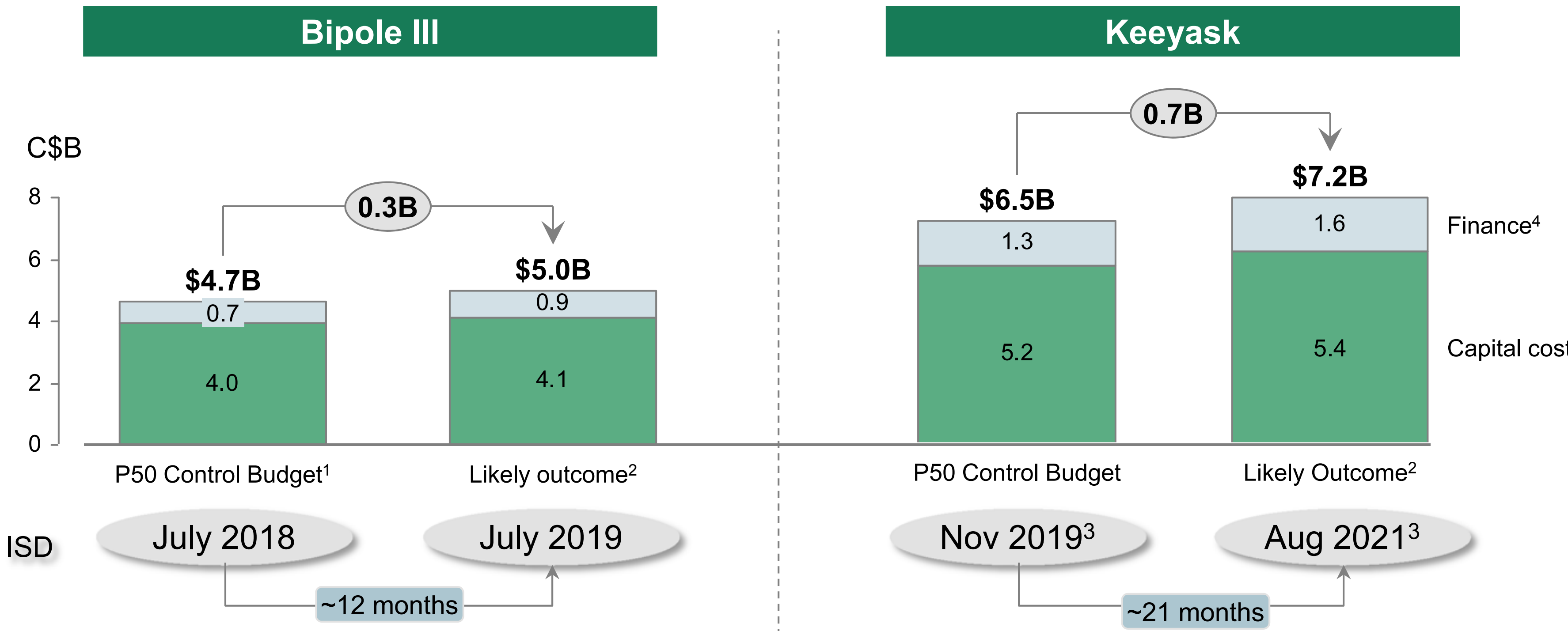
And remain sensitive to key uncertainties

		BCG view on assumptions
Water flows / Hydro risk	**Hydro risk influences total supply which drives opportunity sales** • 102 scenarios various sequences of drought and flood time periods • Climate change not explicitly modeled (impact unclear)	*Range of uncertainty unchanged*
Export prices	**Revenues sensitive to fluctuations in export price levels:** • Reference scenario below previous forecasts	*Adverse movement in MISO*
Capital Execution	**Cost and schedule overruns at one or both large projects can lead to increased borrowing and deterioration of capital profile:** • Scenarios modeled for cost and schedule overruns at Keeyask and Bipole	*Adverse movement in both projects*
Interest rates	**Canadian long-term interest rates influence MH borrowing costs** • +/- 100 bps change	*Favorable movement from NFAT to today*
Domestic Rates	**Domestic rates increases influence how quickly MH recoups its capital investments:** • 3% vs. 4% vs. 5% annual growth rate	*Range of uncertainty unchanged*
Net domestic demand	**Revenue and export quantities sensitive to domestic demand:** • Three levels considered: P50 (base) vs. P90 (high gross demand) vs. P10 (lower gross demand)	*Range of uncertainty unchanged*

Note: Exchange rate sensitivity limited given the company's internal FX net position, therefore there was no specific sensitivity analysis performed
Source: Manitoba Hydro

Exhibit 27: Capital cost & project schedules have deteriorated

~$1.0B in additional capital, ~12 month delay for BPIII and ~21 month delay for Keeyask



Transmission line construction productivity in winter main driver of schedule – 17% more than baseline must be completed in two remaining seasons

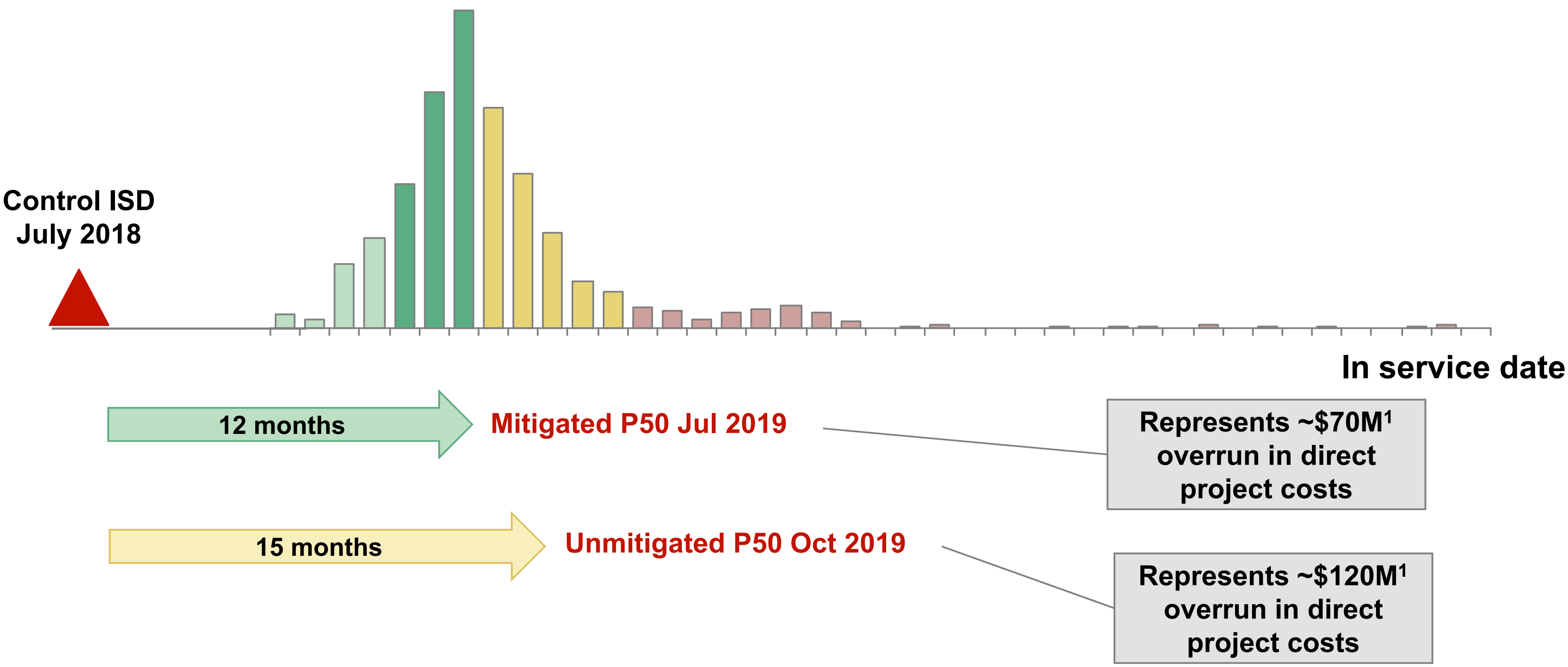
Loss of 1 complete summer construction season likely due to GCC contract underperformance, especially related to earthworks (at ~70% vs target) and concrete productivity (at ~40% vs target)

Sources: 1. Manitoba Hydro control budget. 2. BCG Analysis 3. First unit ISD 4. Includes interest & escalation

Exhibit 28: Bipole III 12 month delay is the most likely outcome

Bipole III ISD distribution

Based on current performance to date incorporating schedule mitigation activities



1. Excludes interest (Additional $0.2B in finance costs)

Note: This is based on mitigated estimates (August 15, 2016). Based on 1000 simulation runs

Source: MH durations estimates

Exhibit 29: Mitigated project delay expected to be ~21 months

Estimated in-service cost equal to ~$7.2B

Keeyask schedule distribution

Control ISD
Unit 1: Nov 2019

21 months — **Mitigated P50 Aug 2021**

Represents ~$0.4B[1] overrun in direct project costs

32 months — **Unmitigated P50 Jul 2022**

Represents ~$0.6B[2] overrun in direct project costs

1. Excludes interest (Additional $0.3B in finance costs) 2. Excludes interest (Additional $0.7B in finance costs)
Note: Activity durations and mitigation plans determined in conjunction with Manitoba Hydro. Based on 10000 simulation runs on 12-Aug-2016
Source: MH durations estimates. BCG analysis

Bipole III

Exhibit 30: Expected case $250M over control budget (incl interest), assumes some acceleration of construction

All numbers in nominal C$ B

	Control Budget P50	Current performance without mitigation (Downside case)	Mitigated schedule (Base case)
Spend to date	**1.8**	**1.8**	**1.8**
Transmission Line	0.6	1.1[2]	1.0
Converter Stations	1.1	1.2	1.2
Collector Lines	0.1	0.1	0.1
Community Development Initiative	0.0	0.0	0.0
Contingency	0.35	-	-
Escalation	0.2	0.1	0.1
Total project capex (excl interest)	**4.1**	**4.3**	**4.2**
Interest on incremental overrun	-	0.2	0.2
Interest on Control Budget P50 project cost	0.5	0.5	0.5
Total interest capex			
Total project capex (incl interest)	**4.65**	**5.0**	**4.9**
% of P50 control budget	**100%**	**108%**	**105%**
Schedule over run (months)	-	15 months	12 months
Project completion	July 2018	October 2019	July 2019

Excludes capitalized interest

~$15M/mo burn rate[1] for delay

Changed escalation rate reduces costs

*Potential **~$50-100M savings** through mitigations to manage schedule overrun. Preliminary est. of mitigation cost = $8M*

1. $15M/month burn rate applied to 12 months for Downside case and 9 months for mitigated case, with the remaining overrun charges relating to internal costs of the commissioning team and scaled down T-Line and Converter Station teams as needed. Includes $350M contingency allocation in addition to burn rate 2. Number rounded up to nearest billion

Source: MH control budget, CEF 2015, BCG analysis

Exhibit 31: Fully loaded project cost overrun forecast ~$700M

~$250M project capex benefit from schedule mitigation activities

(All numbers in nominal C$ B)	Control Budget P50	Current trajectory without mitigation	Mitigated schedule
Spend to date excl interest[1]	**2.1**	**2.1**	**2.1**
Generating Station (to-go)	2.4	3.3	3.1
Generating Outlet Transmission (to-go)	0.2	0.2	0.2
Contingency & Reserves (remaining)	0.3[2]	-	-
Escalation (total)	0.2	0.2	0.2
Total project capex (excl. interest)	**5.2**	**5.8**	**5.6**
Interest on incremental overrun[3]	-	0.7	0.3
Interest on Control Budget P50 project cost	1.3	1.3	1.3
Total capitalized interest	**1.3**	**2.0**	**1.6**
Total project capex (incl interest)	**6.5**	**7.8**	**7.2**
% of P50 control budget	**100%**	**120%**	**111%**
Schedule over run (months)	-	32	21
Unit 1 ISD date	November 2019	July 2022	August 2021

*Potential **~$250M benefit** from mitigations and avoided interest*

1. As at March 2016. 2. Original cont./reserves of $0.7B for project costs already partially allocated to contracts – $0.3B remaining. Assumed will be used up completely for overruns 3. Includes compounding effect due to schedule delay + additional interest on incremental project spend.

Note: Cost over run in fixed price, milestone based contracts (mainly equipment supply & install) reduced from previous phase due to greater certainty on risks (e.g. GGH contracts >50% complete, better SPI=0.94 vs 0.7 from previous phase on T&G, etc)

Source: MH control budget, CEF 2015, BCG analysis

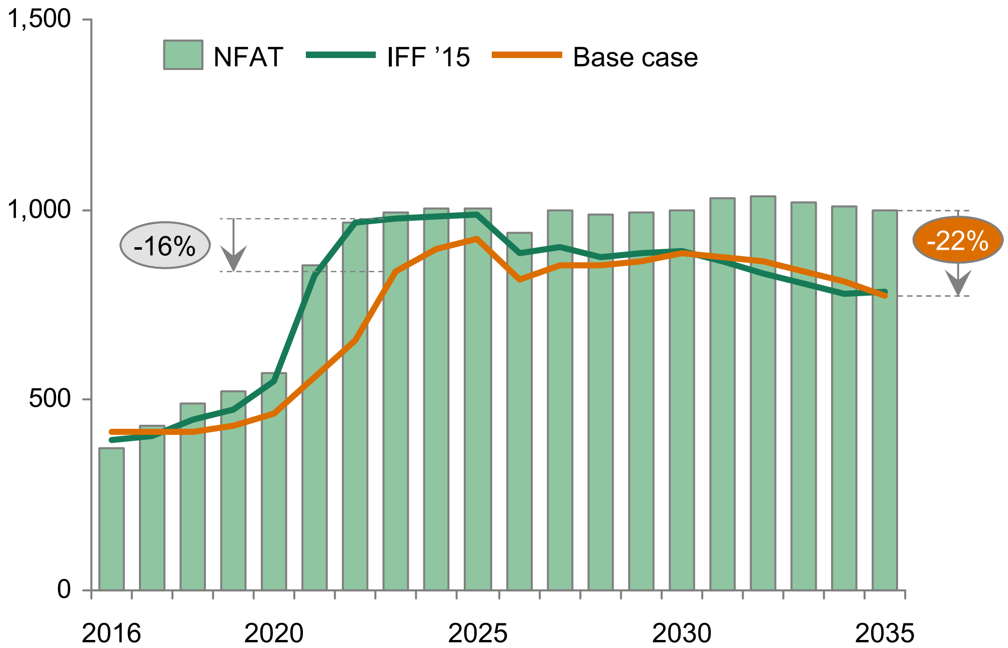
Exhibit 32: Keeyask delay and low export prices impact revenue

Reducing latest forecast of export revenues by 19-28%

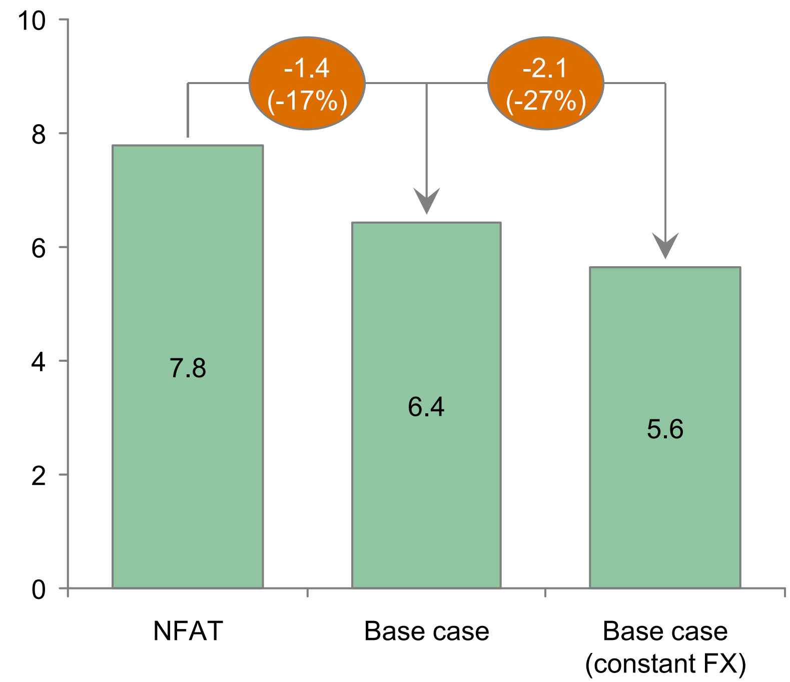
Export revenue forecasts have been revised downward since NFAT

Expected export revenues reduced by 19% to 28%

Export Revenues ($C M)



2017-2026 Total Export Rev. ($CB)



Secured firm contracts (30% of revenue[1]) reduce further downside; upside expected in case of Clean Power Plan approval

1. Including current contracts and term sheets, but not available uncommitted firm energy which could be contracted (17% of revenue).
Source: Manitoba Hydro, BCG analysis

Exhibit 33: Expected case equity ratios sustained at <15% through 2030

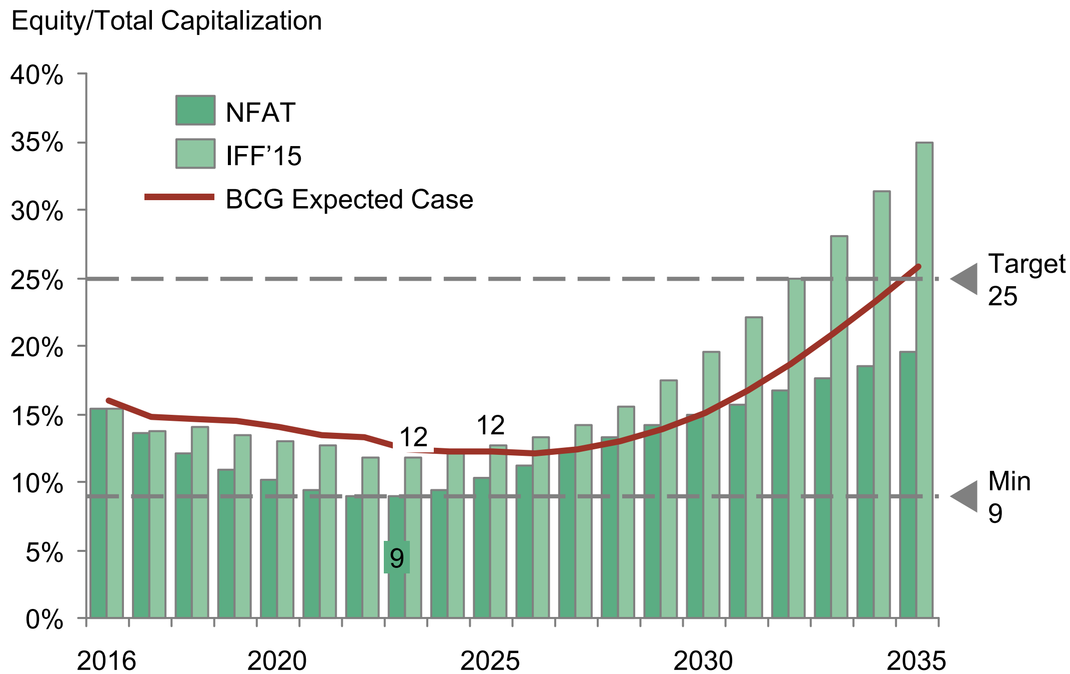
Key assumptions

NFAT
- Bipole in '19, Keeyask in '21, Tie-line in '20
- Level 2 DSM
- 2013 Interest rates

IFF '15
- Unchanged ISDs
- Reduced export price and slightly reduced demand
- Lower, 2015 interest rates

BCG Expected Case
- 12 mos. Bipole III delay
- 21 mos. Keeyask delay
- $1B total cost overrun
- Lower, 2016 reference export prices
- Lower, 2016 interest rate forecasts

Projected ratios have decreased materially under revised capital and price assumptions



Additional risks

- Additional project CapEx overrun
- Further export price deterioration
- Hydro risk
- Increasing interest rates
- Lower domestic rate increases

Exhibit 34: Stress test shows significant impact if further downside risk experienced – equity % dips to low single digits

Downside scenario modelled

Water flow	Low flow scenario
Capital project overruns *Schedule (months)*	Keeyask: 32mth delay BPIII: 15mth delay
Interest rates *Long range forecasts*	ST~3.85% LT ~5.4%
Export prices	Peak and off peak spot curve as per IFF'16 (no premium and reduced base)
Cost inflation *Overall OM&A cost increase*	2% in 2016-17 3.5% pa 2018 - 2021

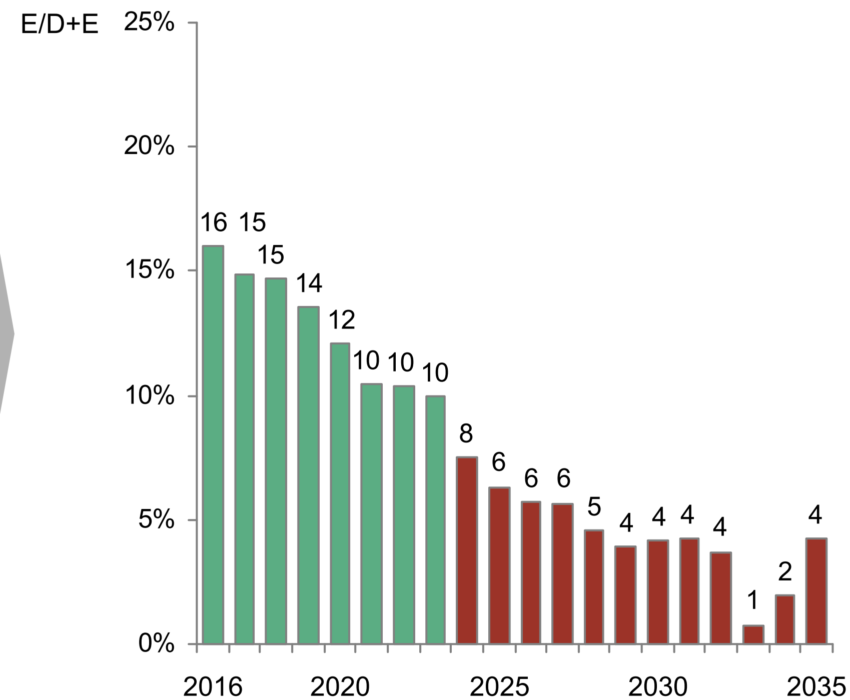


Exhibit 35: Can the projects be stopped / paused?

Bipole III and Keeyask are already well advanced in their construction with $5B already sunk

- Bipole III $2.5B (53%) spent of $4.7B control budget
- Keeyask with $2.5B (39%) of $6.5B control budget spent, including completion of milestones that prevent contractual cancellation

Cancelling Bipole III and Keeyask would bring total spend up to ~$7B

- In addition to sunk costs, Bipole III and Keeyask would both incur cancellation costs (e.g., breakage, remediation) of ~$1B each
- Decision to just cancel (or reroute) Bipole III would strand Keeyask, making it uneconomic and likely trigger cancellation
- Implication of cancelling both projects is ~$7B capital spent without completion of any functioning assets

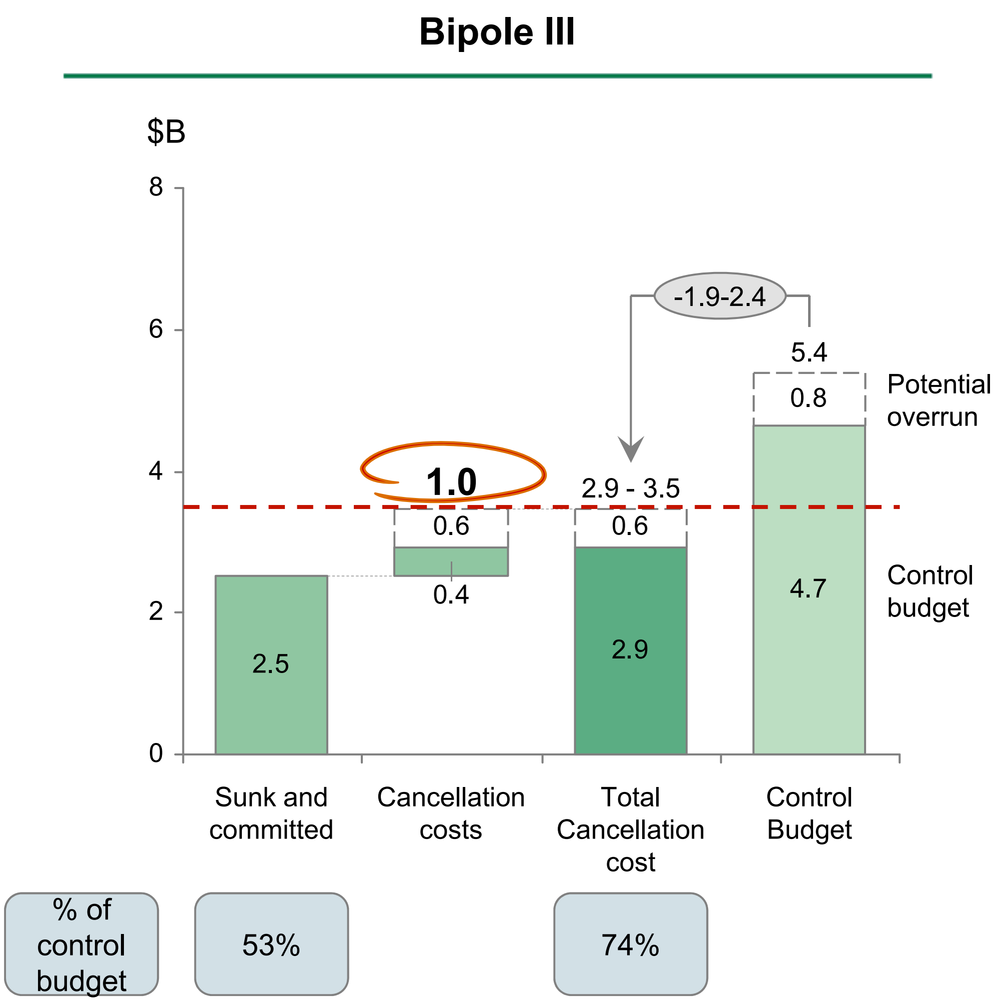
Economics remain in favour of continuing both projects when compared to alternatives

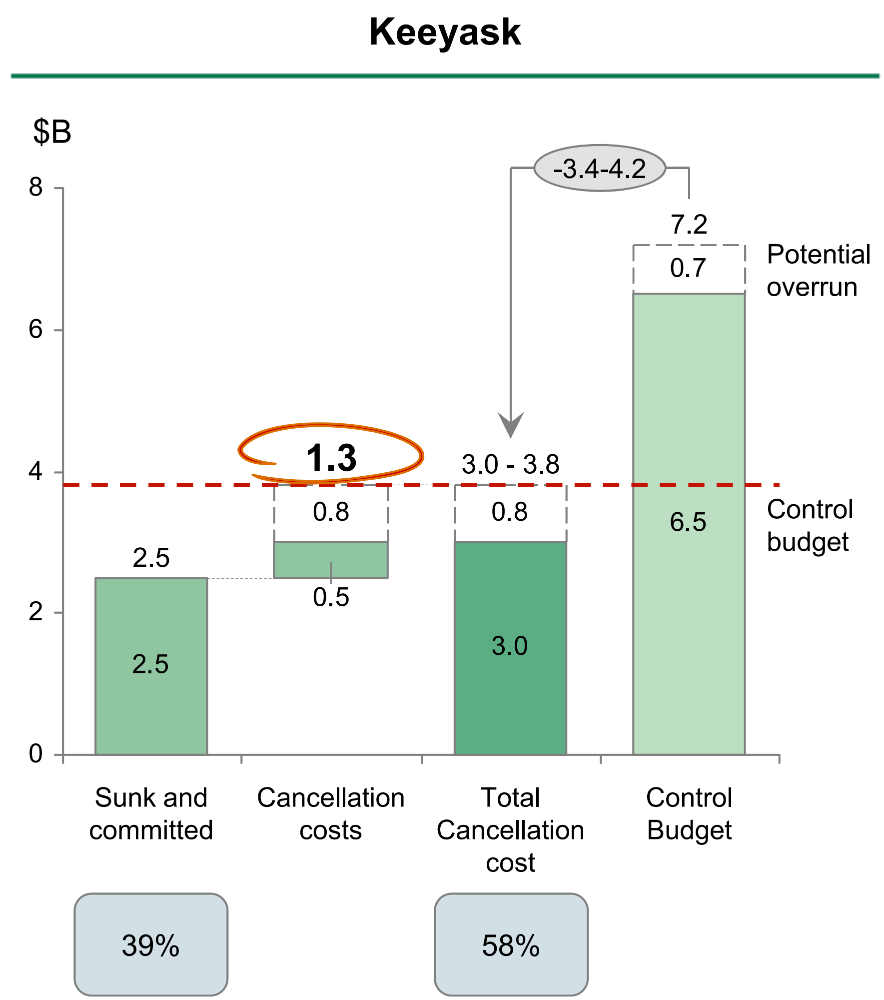
- ~$3.2B cost to complete Bipole III West clearly more favourable vs. ~$4.5B rerouting costs of Bipole III East
  - Construction cost of Bipole III East ~$3.0-3.5B on top of ~$1B Bipole III West cancellation costs
- $4.7B cost to complete Keeyask yields an NPV $3-5B more favourable vs. switching to gas option
  - Gas option with incremental $11.9B spend (including cancellation and capitalized cost of gas supply)

Further, several strategic risks to consider for stopping or pausing Keeyask

- Considerable trust and relationship damage with four First Nations partners likely to impede any future Hydro project
- Market risk of inability to supply MISO plus requirement to add domestic reserve
- Direct GDP impact of ~0.5%, particularly impacting First Nations communities

Exhibit 36: Cancellation of either project brings to bear significant further cost





Source: Manitoba Hydro estimate of cancelation; BCG analysis

Exhibit 37: Strategic impacts of cancellation potentially severe

Bipole III: Major risks relate to future reliability

- Continued system reliability risk: failure at Dorsey C.S. or on Bipole I or II will jeopardize the Province's energy supply
- Limited capacity and decreasing operational reliability on BP I & II
- Cancellation or rerouting of Bipole III strands Keeyask and likely implies cancellation due to deterioration of economics

Keeyask: Significant stakeholder impacts

- Considerable trust and relationship damage with four First Nation partners likely to impede any future Hydro project – social license to operate many years in the making
- Market risk of inability to supply MISO plus requirement to add domestic reserve
- Direct GDP impact of ~0.5%, particularly impacting First Nations communities

Source: Manitoba Hydro estimate of cancelation; BCG analysis

Exhibit 38: Completing Bipole III is the best go-forward option

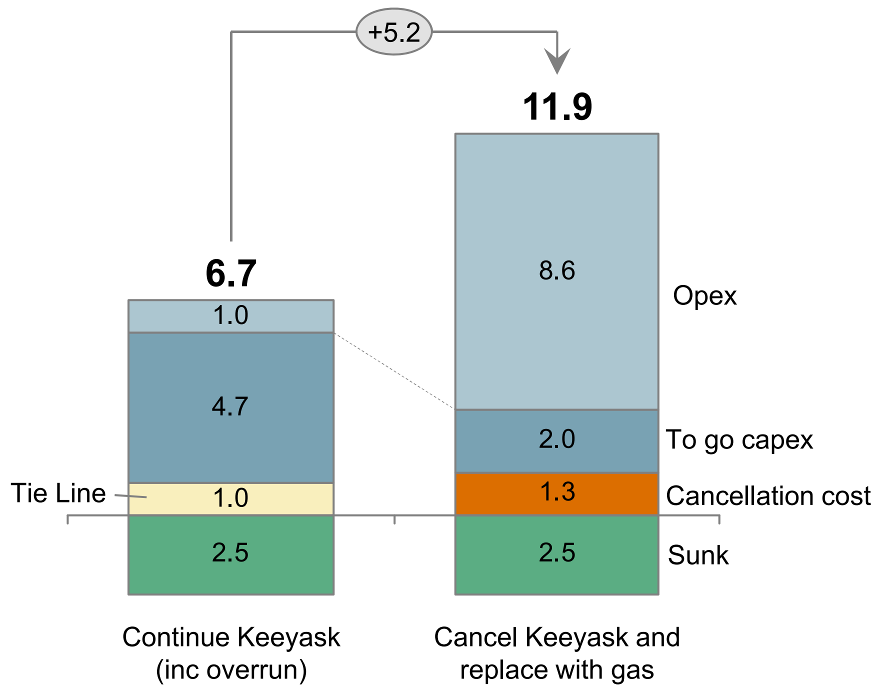
Shifting to the east route would be more costly and require at least 5 years for approvals

Go Forward Option	Verdict	Rationale	Incremental Cost	Likely ISD
Cancel Bipole III West	✗	• System still lacks redundancy and exposed to major outage risk • Strains relationship within MISO and risks exports	• **$400M to $1B** to cancel, wind-down and remediate	• N/A – no solution implemented
Selected option **Continue Bipole III West**	✓	• Fastest way to improve reliability • Supports Keeyask and future hydro generation	• **$2.2 – 3.2B** to complete	• 2018 – 2019
Shift to East Route	✗	• More costly with later in-service date • Negative environmental and First Nations impacts along east route	• **~$3.4 -4.5B+**, (~$2.3 – 3.4B for new East route work)[1]	• 2025 – 2026
All-Gas	✗	• Future input price volatility (gas, imports) • Loss of export revenue through lack of capacity for new Keeyask power • Damage to relationships with US partners and First Nations groups	• **$3.4-4.1B**[2] (NPC[3] of gas + Bipole III cancellation + addt'l O&M)	• 2021 – 2022
Import + Gas	✗		• **$4.9-5.5B**[4] (capital cost + Bipole III cancellation)	• 2021 – 2022

1. Assumes some work on collector lines and convertor stations continues. Estimate is purely factored at low levels of maturity 2. Based on MH and BCG scenario analysis, with contingency and over-run factors applied 3. NPC = net present cost 4. Capital cost from Manitoba Hydro Bipole III EIS + BCG analysis of Bipole III cancellation cost

Exhibit 39: Economically, continuing Keeyask is most attractive option

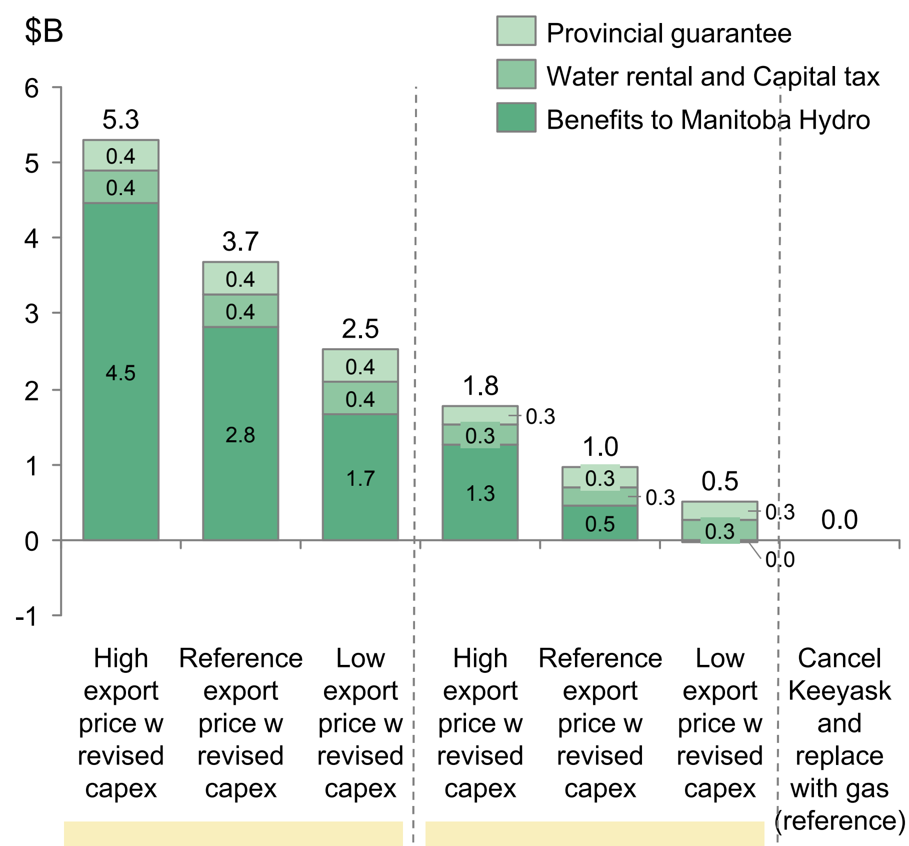
Forward capital and operating cost of gas vs Keeyask is ~$5B higher



Hydro = High upfront capital, low, stable opex

Gas = Low upfront capital, high, volatile opex

Relative NPV of continuing is $3-5B greater than replacing with gas



Source: Economic Bar Charts, Manitoba Hydro, BCG analysis