SUBJECT: Export Price Forecasts

REFERENCE: 2013 Export Price Forecast, Appendix C, Page 57-59, 79-82

QUESTION:

Please provide tables setting out the data points for Figures C–2 to C-4 and provide the determination of the consensus reference price of On-Peak, Off-Peak and Capacity [MINN hub]. Please provide the tables in Excel.

RESPONSE:

The requested tables contain commercially sensitive information and have been provided to the PUB in confidence, with formulas intact for reference purposes.

Please see tab "308a" in the Excel file named *"PUB-MH II-308a Att 1 CSI.xls"*.

REFERENCE: 2012 Export Price Forecast, Appendix G, Page 101

QUESTION:

Please update and refile comparison charts and tables of respective data points found in Appendix G , Figures G-1, G-2, G-3 and G-4 from the 2012 EEPF, adding the EIA 2013 energy price plot from the AOE 2013 Early release and comment on the change relative to the EIA 2012 and Corporate Outlook 2012.

RESPONSE:

Please see the attached PUB/MH II-313a Attachment.

The U.S. Energy Information Administration's forecasted natural gas price at Henry Hub shown in AEO 2013 has generally declined from the one EIA provided in AEO 2012. EIA natural gas price forecasts have declined for the past four years, and are consistent with private sector forecasters that have also reduced their long-term outlooks as knowledge on the size and economics of production of the technically recoverable natural gas resource in North America has improved.

The U.S. EIA's forecasted coal price at the Powder River Basin (PRB) minemouth has not changed significantly between the 2012 AEO and the 2013 AEO.

Henry Hub Natural Gas Price Forecasts

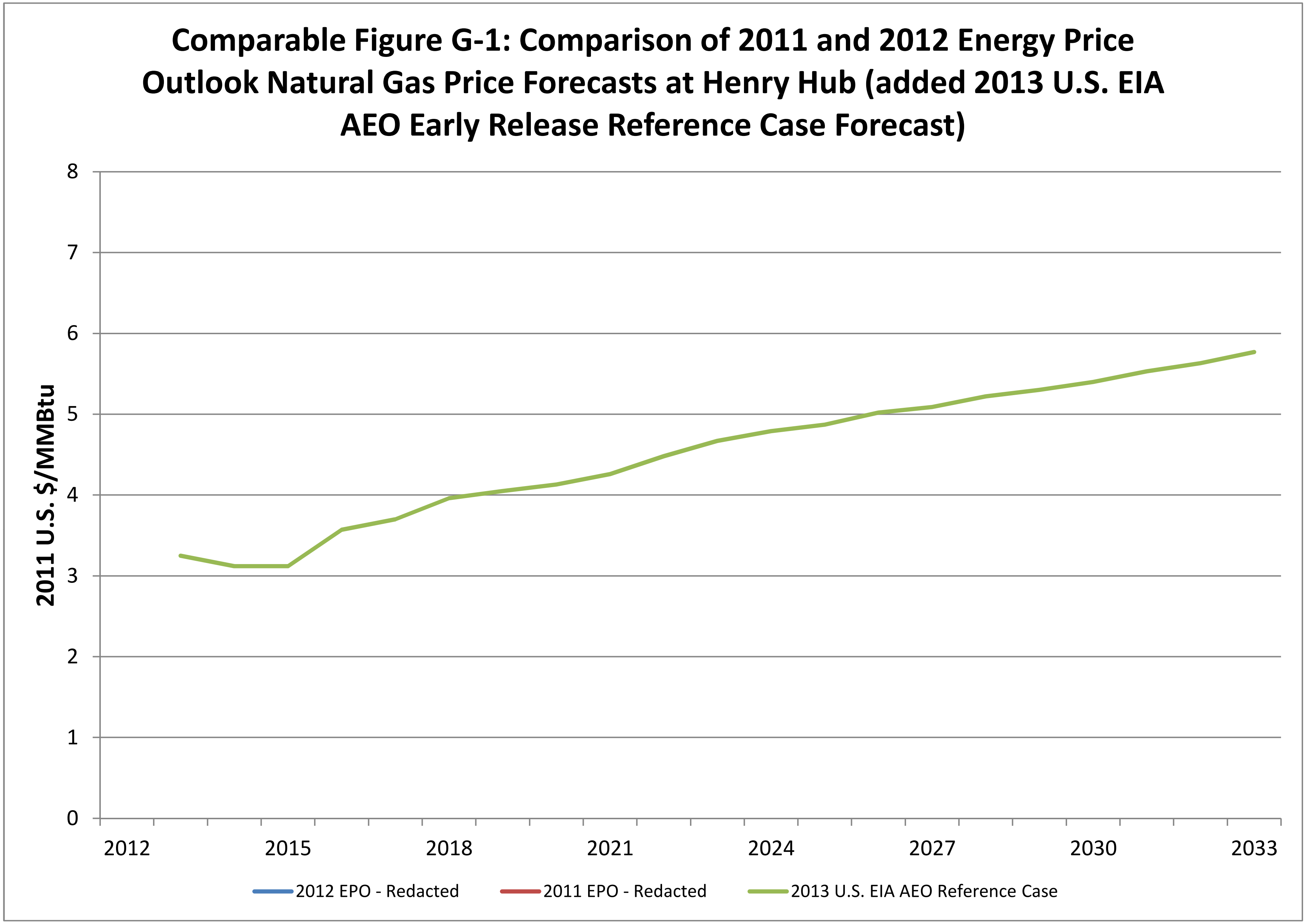
- all prices in 2011 U.S. $ / MMBtu

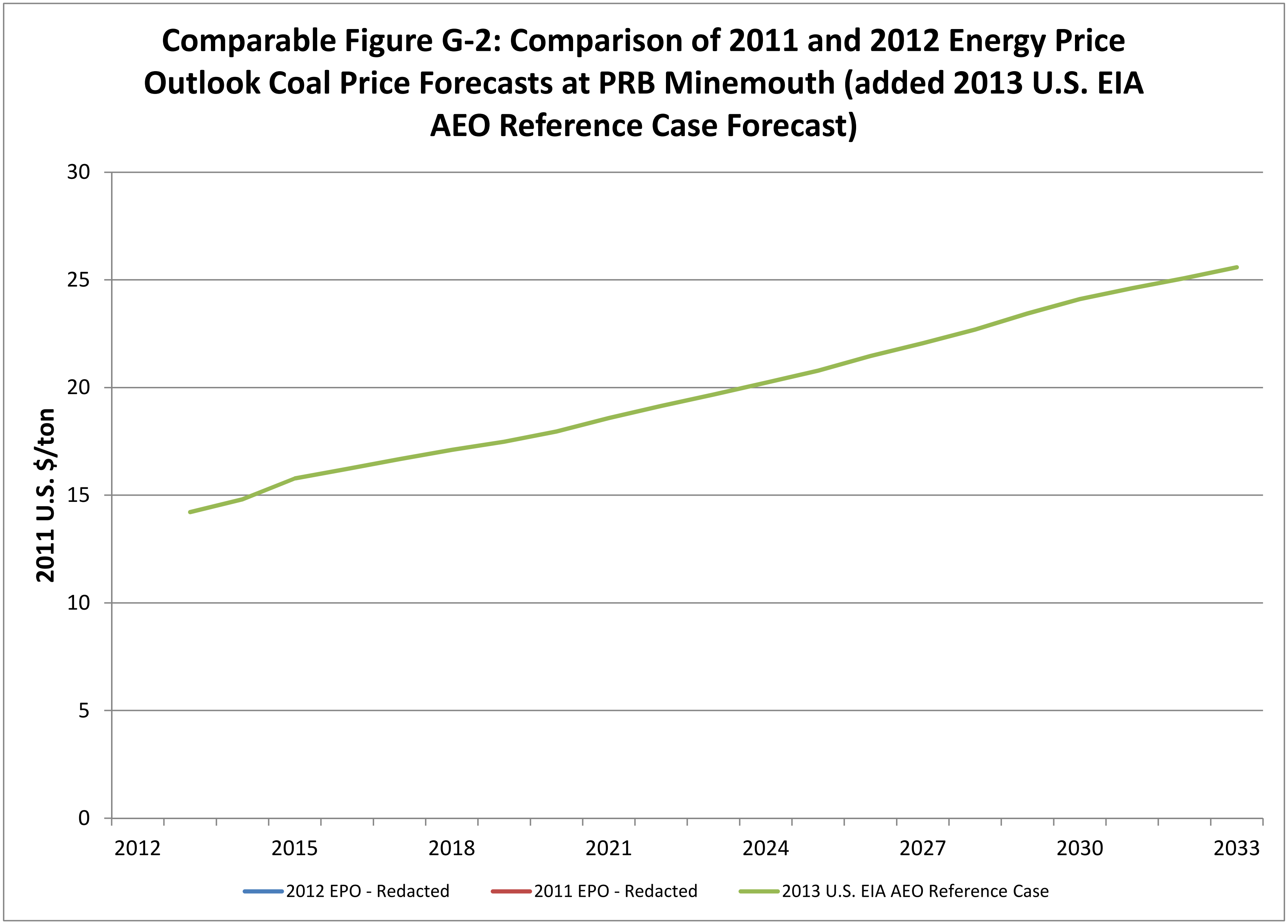
	2012 Energy Price Outlook Henry Hub Reference Case	2011 Energy Price Outlook Henry Hub Reference Case	U.S. EIA AEO 2013 Early Release Henry Hub Reference Case	U.S. EIA AEO 2012 Henry Hub Reference Case
2012	[redacted]	[redacted]		3.65
2013	[redacted]	[redacted]	3.25	4.15
2014	[redacted]	[redacted]	3.12	4.26
2015	[redacted]	[redacted]	3.12	4.38
2016	[redacted]	[redacted]	3.57	4.35
2017	[redacted]	[redacted]	3.70	4.38
2018	[redacted]	[redacted]	3.96	4.44
2019	[redacted]	[redacted]	4.05	4.56
2020	[redacted]	[redacted]	4.13	4.68
2021	[redacted]	[redacted]	4.26	4.93
2022	[redacted]	[redacted]	4.48	5.22
2023	[redacted]	[redacted]	4.67	5.43
2024	[redacted]	[redacted]	4.79	5.57
2025	[redacted]	[redacted]	4.87	5.75
2026	[redacted]	[redacted]	5.02	5.90
2027	[redacted]	[redacted]	5.09	6.07
2028	[redacted]	[redacted]	5.22	6.16
2029	[redacted]	[redacted]	5.30	6.28
2030	[redacted]	[redacted]	5.40	6.42
2031	[redacted]	[redacted]	5.53	6.56
2032	[redacted]	[redacted]	5.63	6.72
2033	[redacted]		5.77	6.85

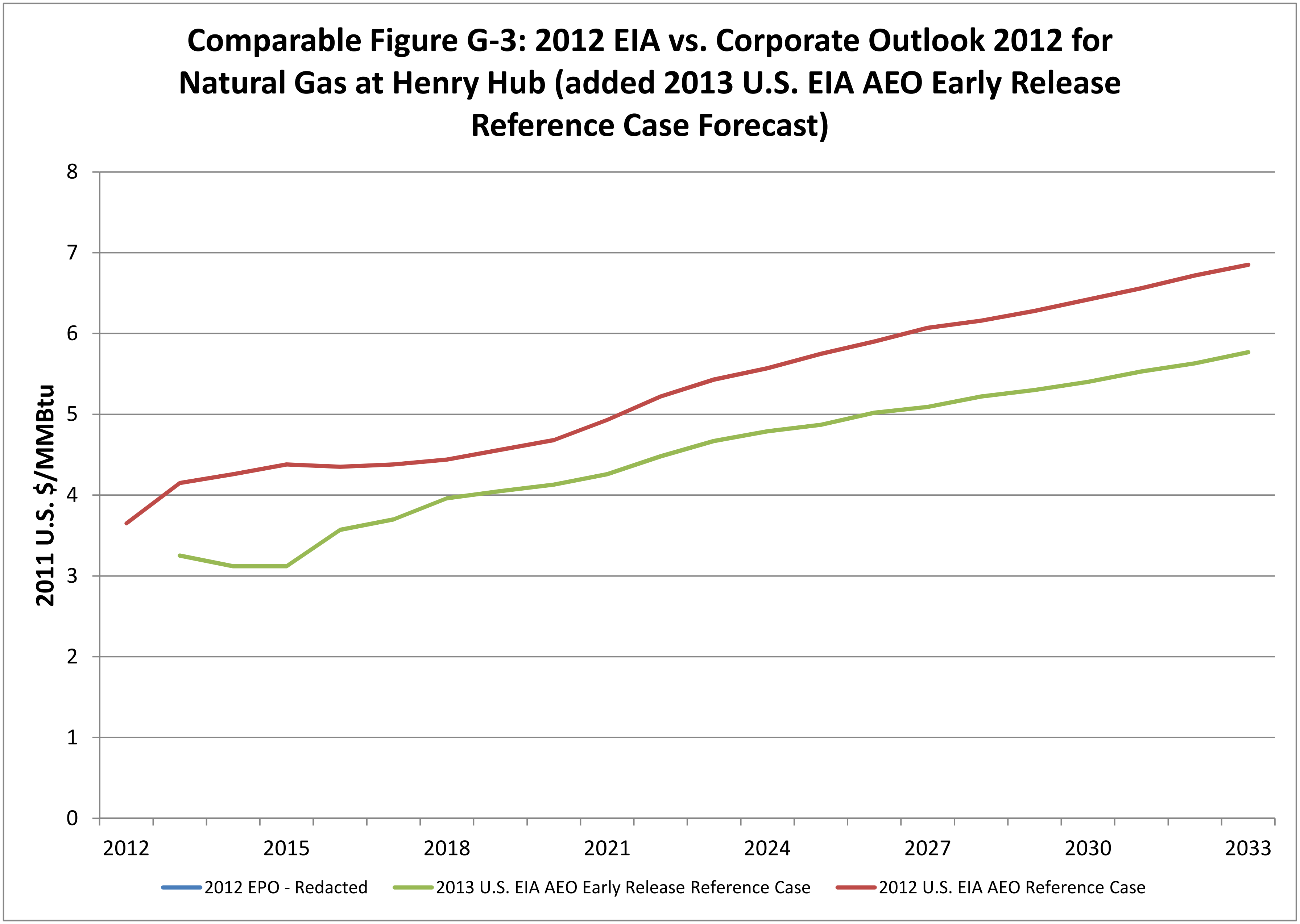
PRB Minemouth Coal Price Forecasts

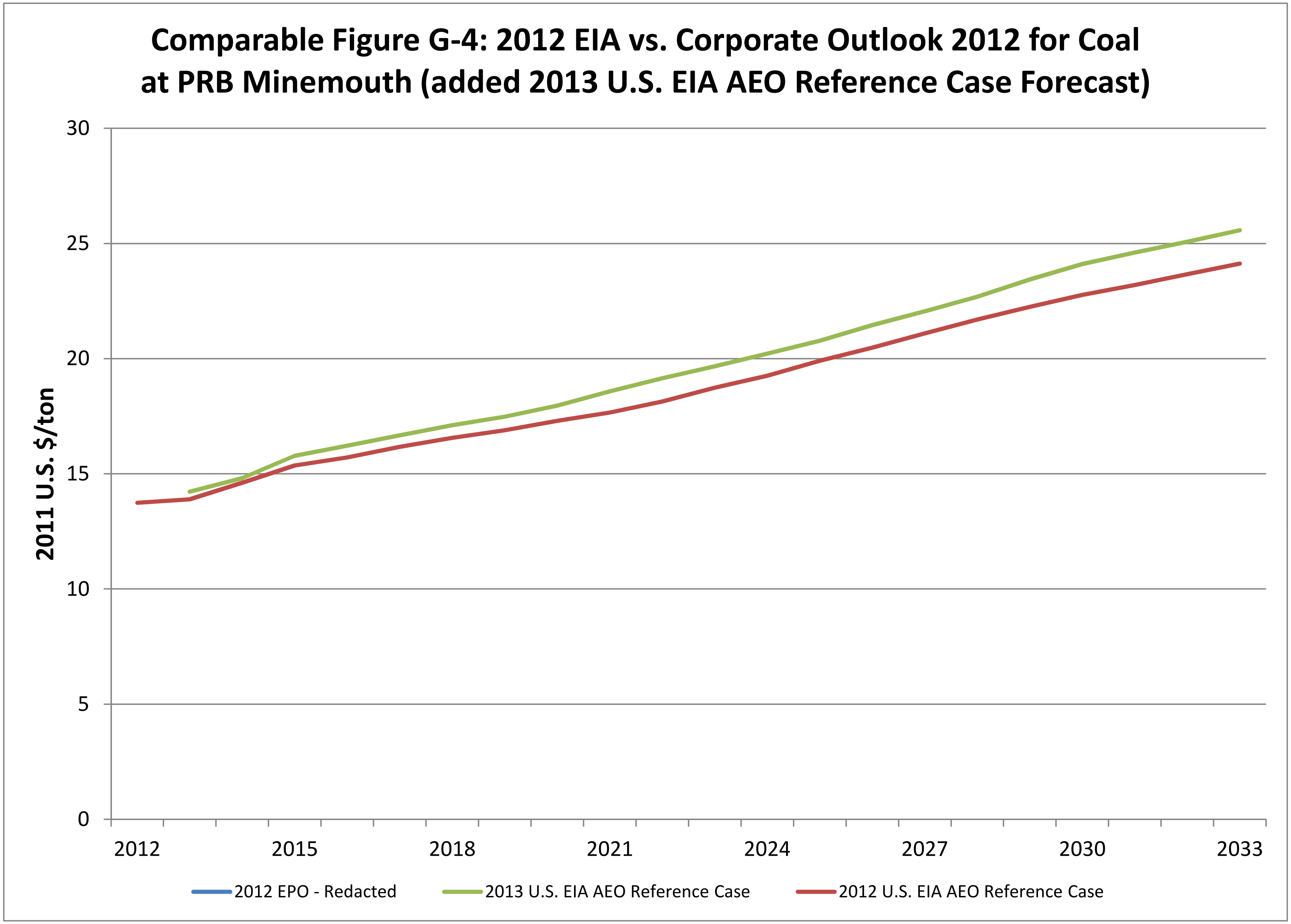
- all prices in 2011 U.S. $ / ton

	2012 EPO PRB Minemouth Reference Case	2011 EPO PRB Minemouth Reference Case	U.S. EIA AEO 2013 Early Release Henry Hub Reference Case	U.S. EIA AEO 2012 Henry Hub Reference Case
2012	[redacted]	[redacted]		13.74
2013	[redacted]	[redacted]	14.22	13.89
2014	[redacted]	[redacted]	14.81	14.61
2015	[redacted]	[redacted]	15.78	15.36
2016	[redacted]	[redacted]	16.22	15.71
2017	[redacted]	[redacted]	16.67	16.17
2018	[redacted]	[redacted]	17.11	16.56
2019	[redacted]	[redacted]	17.48	16.89
2020	[redacted]	[redacted]	17.96	17.30
2021	[redacted]	[redacted]	18.58	17.66
2022	[redacted]	[redacted]	19.15	18.14
2023	[redacted]	[redacted]	19.67	18.74
2024	[redacted]	[redacted]	20.22	19.26
2025	[redacted]	[redacted]	20.78	19.91
2026	[redacted]	[redacted]	21.46	20.48
2027	[redacted]	[redacted]	22.06	21.10
2028	[redacted]	[redacted]	22.69	21.70
2029	[redacted]	[redacted]	23.44	22.25
2030	[redacted]	[redacted]	24.11	22.77
2031	[redacted]	[redacted]	24.61	23.20
2032	[redacted]	[redacted]	25.08	23.67
2033	[redacted]		25.58	24.13


Comparable Figure G-1: Comparison of 2011 and 2012 Energy Price Outlook Natural Gas Price Forecasts at Henry Hub (added 2013 U.S. EIA AEO Early Release Reference Case Forecast)
2011 U.S. $/MMBtu
0
1
2
3
4
5
6
7
8
2012
2015
2018
2021
2024
2027
2030
2033
2012 EPO - Redacted
2011 EPO - Redacted
2013 U.S. EIA AEO Reference Case


Comparable Figure G-2: Comparison of 2011 and 2012 Energy Price Outlook Coal Price Forecasts at PRB Minemouth (added 2013 U.S. EIA AEO Reference Case Forecast)
2011 U.S. $/ton
30
25
20
15
10
5
0
2012
2015
2018
2021
2024
2027
2030
2033
2012 EPO - Redacted
2011 EPO - Redacted
2013 U.S. EIA AEO Reference Case


Comparable Figure G-3: 2012 EIA vs. Corporate Outlook 2012 for Natural Gas at Henry Hub (added 2013 U.S. EIA AEO Early Release Reference Case Forecast)
2011 U.S. $/MMBtu
0
1
2
3
4
5
6
7
8
2012
2015
2018
2021
2024
2027
2030
2033
2012 EPO - Redacted
2013 U.S. EIA AEO Early Release Reference Case
2012 U.S. EIA AEO Reference Case


Comparable Figure G-4: 2012 EIA vs. Corporate Outlook 2012 for Coal
at PRB Minemouth (added 2013 U.S. EIA AEO Reference Case Forecast)
2011 U.S. $/ton
30
25
20
15
10
5
0
2012
2015
2018
2021
2024
2027
2030
2033
2012 EPO - Redacted
2013 U.S. EIA AEO Reference Case
2012 U.S. EIA AEO Reference Case

QUESTION:

Please file the Energy Price Outlook 2012-2032 (EPO12-1) and EPO13-1. Please provide charts and respective table of datapoint comparing the natural gas and coal prices in the two forecasts and provide any summary observations.

RESPONSE:

See attached spreadsheet for charts and tables.

Forecasters have generally reduced their long-term price outlooks as knowledge on the size and economics of production of the technically recoverable natural gas resource in North America has improved. While forecasters acknowledge that new natural gas demand in the power generation sector will increase over the forecast period, outlooks concerning levels of new demand in the transportation sector and LNG export sector remain speculative. EPO 2013 illustrates a decline from EPO 2012 in the consensus natural gas price forecast throughout the forecast period, but particularly pronounced in the pre-2025 period. For the post-2025 period, the forecasts are not significantly different.

Despite slowing demand for coal for North American power generation, forecasters generally foresee continuing growth in demand for Powder River Basin (PRB) coal through the forecast period because of its lower cost and low sulphur content. Increasing production costs due to miners' needs to access deeper coal seams and declining productivity are reflected in the increase in the the EPO 2013 consensus forecast. The inclusion of a new consultant with a bullish PRB coal price forecast in the EPO 2013 is also noted as affecting the change from EPO 2012.

Henry Hub Natural Gas Price Forecasts

- all prices in 2013 US $/MMBtu

	2013 Energy Price Outlook	2012 Energy Price Outlook
2013	[redacted]	
2014		
2015		
2016		
2017		
2018		
2019		
2020		
2021		
2022		
2023		
2024		
2025		
2026		
2027		
2028		
2029		
2030		
2031		
2032		
2033		
2034		

PRB Coal at Minemouth Price Forecasts

- all prices in 2013 US $/ton

	2013 Energy Price Outlook	2012 Energy Price Outlook
2013	[redacted]	
2014		
2015		
2016		
2017		
2018		
2019		
2020		
2021		
2022		
2023		
2024		
2025		
2026		
2027		
2028		
2029		
2030		
2031		
2032		
2033		
2034		

[redacted]

[redacted]

SUBJECT: Export Contracts

REFERENCE: KPMG Report (2010 GRA), Section 4.9.3

QUESTION:

Please confirm that Manitoba Hydro sales and purchases under the Manitoba Hydro's diversity agreements in place since 2003 are as per the table below:

	MH Sales (GWh)	MH Purchases (GWh)
F 2003	400	230
F 2004	450	30
F 2005	460	40
F 2006	320	60
F 2007	790	20
F 2008	850	5
F 2009	400	30

RESPONSE:

The numbers in the table above appear to be based on calendar year. The numbers are off slightly for some years. Please see response to PUB/MH I-017 REVISED for correct numbers.

SUBJECT: Export Contracts

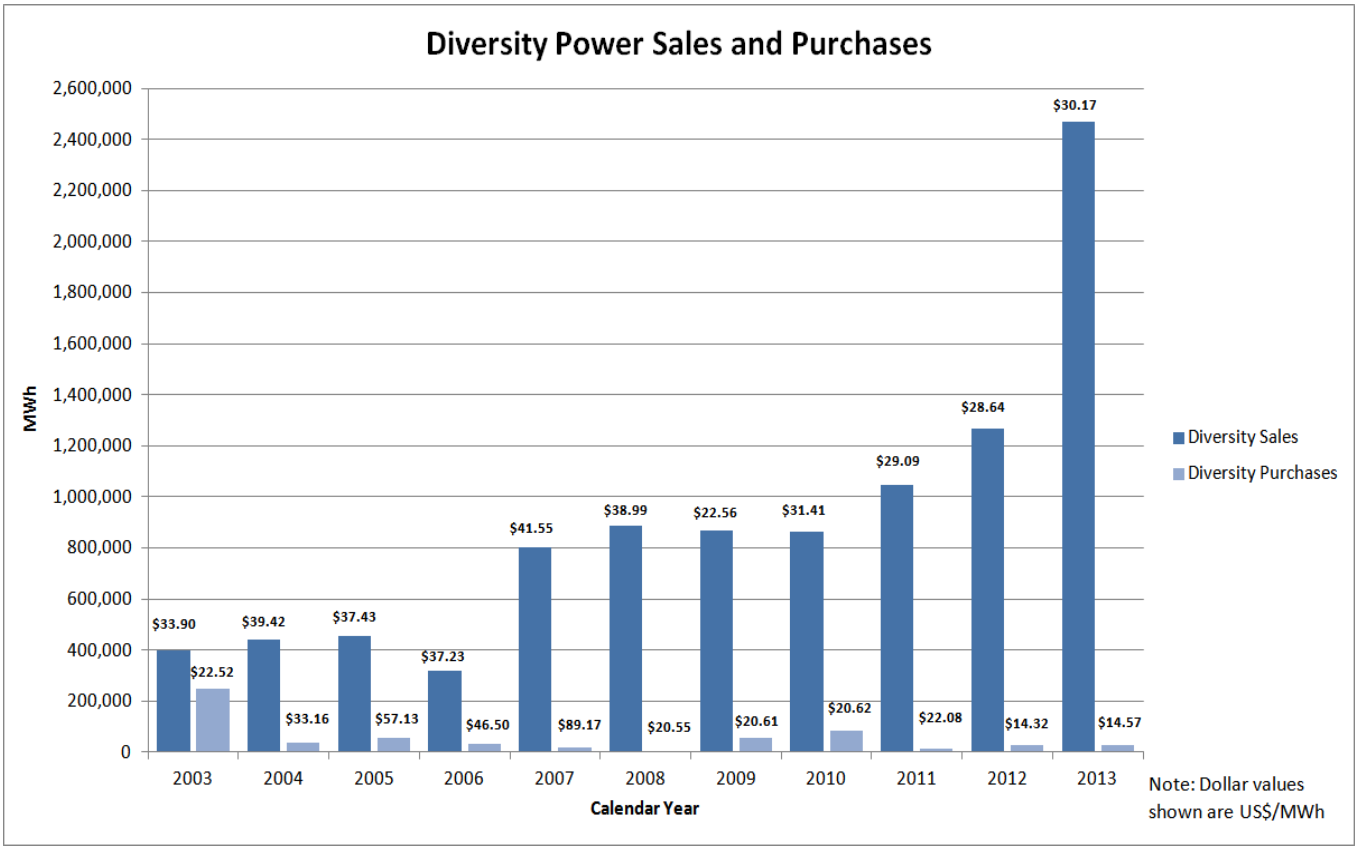
REFERENCE: KPMG Report (2010 GRA), Section 4.9.3

QUESTION:

Please update the above table to include F 2010, F 2011, F 2012 and F 2013.

RESPONSE:

Please note that the table in the KPMG report indicated fiscal year amounts however the data presented was based upon calendar year. The numbers indicated in the updated chart below for 2013 are up to the end of September.



April 2014 Redacted (No Redactions)

SUBJECT: Export Contracts

REFERENCE: KPMG Report (2010 GRA), Section 4.9.3

QUESTION:

Please confirm that the diversity agreements have allowed NSP & GRE to purchase firm energy at prices consistently below the prices in Manitoba Hydro's 500 MW NSP contract.

RESPONSE:

Manitoba Hydro does not confirm the statement.

Energy sold under the diversity capacity provided to both NSP and GRE in the summer season can be either fixed priced or at a price tied to the MISO market price. Since these contracts became effective in 1995, there have been many periods when fixed price energy sold under supplemental agreements to the diversity agreements [redacted]

SUBJECT: Transmission

REFERENCE: 2012/13 Power Resource Plan; 2010 GRA PUB/MH II 9(a)

QUESTION:

Please provide a detailed calculation of how Manitoba Hydro arrived at its assumed Bipole III line loss reductions of:

• dependable, 243 GWh

• average 392 GWh

• winter peak 89 MW

RESPONSE:

To estimate the HVDC losses that are included as part of the NFAT analysis, Manitoba Hydro used seven years of historical hourly generation data from 1993/94 through 1999/2000 (over 61000 hours). Losses on the HVDC system were calculated for each hour based on estimates for converter and inverter station losses, dc line losses, and losses incurred on the northern AC collector system (from generation to connection to the southern AC system). The total generation of Kettle, Long Spruce and Limestone was assumed to be shared between the available Bipoles based on equal current loading for each bipole.

Estimated Losses for the Converter and inverters was based on the formula:

$$\text{Losses} = A + B*(\text{Current})^2$$

Losses for the transmission line was based on the formula

$$\text{Losses} = 2*C * (\text{Current})^2$$

Losses on the northern AC collector system were assumed to total 30 MW for the 2 Bipole system, and 35 MW for the three Bipole system.

Where:

Current = the current loading on the bipole, and is equal to the MW loading divided by the bipole voltage, and is balanced between the available Bipoles.

A = No load losses for conversion equipment

B = Coefficient for I^2R losses in conversion equipment

C = Line resistance losses over a single line (2 lines per Bipole)

	A	B	C
Bipole I	6.40	12.4	13.6
Bipole II	8.90	8.5	14.7
Bipole III	10.24	6.55	16.54

The losses calculated at maximum plant generation of asbout 3600 MW (maximum historic generation from Kettle, Long Spruce and Limestone), without Bipole III, the transmission losses are calculated as 315.8 MW, with Bipole III the losses are calculated to be 234.2 MW, a reduction of 81.5 MW. Assuming that equivalent new generation would experience 10% losses, the equivalent displaced generation is 89.7 MW (81.5 * 1.1 = 89.7).

The average of the hourly losses calculated over the seven years of hourly data was multiplied by the number of hours in a year to determine the average annual transmission loss, and is shown in Appendix H of the 2012/13 Power Resource Plan. Average transmission losses of the existing system were calculated to be 1708.1 GW.h/yr. This was estimated to reduce to 1321.9 GW.h/yr with the addition of Bipole III, for a reduction of 386.1 GW.h/yr. This is equivalent to new generation of 424.7 GW.h assuming the new generation would experience 10% losses (386.1 * 1.1 = 424.7 GW.h).

Generation under dependable conditions provides about 75% of the energy that is generated on average. Given that the largest component of transmission losses is related to the I^2R loss, it was estimated that 56.25% (0.75^2) of the losses would be incurred under dependable conditions (0.75^2*386.1 = 217.2 GW.h). Again assuming that alternative generation would experience 10% transmission losses, the reduced need for new generation would be 238.9 GW.h (217.2 * 1.1 = 238.9).

With existing generation and only Bipole III added, Bipole III is assumed to reduce losses under dependable conditions by 238.9 GW.h/yr and under average conditions by 424.7 GW.h/yr, and reduce peak losses by 89.7 MW of capacity during the highest loaded hour.

Once Keeyask is placed into service maximum HVDC generation will increase to 4230 MW, and capacity losses over the 3 bipoles are estimated to be 300.9 MW, which is 14.9 MW less than the existing losses, and the equivalent displaced new generation would be 16.4 MW (14.9 * 1.1 = 16.4). In modeling, loads are increased by 10% (and adjusted by 11 MW) to reflect observed system losses. This results in estimated losses for the existing system of 316.3 MW (3600 * (1-1/1.1) - 11 = 316.3). With Keeyask in service, modeled losses increase to 373.5 MW (4230 * (1-1/1.1)-11 = 373.5 MW), suggesting losses should increase from existing by 57.2 MW (373.5 – 316.3 = 57.2) due to Keeyask, this would be equivalent to 63.0 MW alternative northern generation (57.2 * 1.1 = 63.0). The difference between the modeled and expected losses is 79.4 MW (expected loss reduction of 16.4 MW compared to an assumed increase in transmission losses of 63.0 MW is 79.4 MW), and is included as a benefit of Bipole III.

To determine the energy savings, the estimated losses based on a 10% loss assumption was calculated for each hour of 7 years of historic data, and compared to a similar calculation without Keeyask. Losses with Keeyask were estimated to be 2184.7 GW.h, while losses without Keeyask were estimated to be 1839.9 GW.h for an equivalent loss of generation equal to 379.3 GW.h that would be modeled. To calculated the actual energy savings after Keeyask is in service, the hourly historic loads were increased on a pro rata basis, by the increase in HVDC system capacity (each hour was multiplied by 4230/3600), and the losses were calculated based on HVDC loadings as before. The average energy lost was 1660.4 GW.h. This is a reduction of

47.7 GW.h from losses in the existing system, and would displace 52.4 GW.h of new generation assuming 10% transmission losses.

The difference between the 52.4 GW.h calculated decrease in system losses and the assumed 379.3 GW.h increase in assumed losses in SPLASH is 431.7 GW.h, which is attributed to Bipole III after Keeyask is in service. The calculation is repeated when Conawapa is in service increasing total HVDC generation to 5580 MW.

Dependable energy savings were based on the estimate that dependable generation is about 75% of the average generation, and thus losses would be about 0.75^2 or 56.25% of average, and loss savings would be 56.25% of the average savings. Thus 242.8 GW.h of dependable energy is included as a dependable energy benefit of Bipole III after Keeyask is in service.

Offset generation due to loss reductions compared to the 10% assumption modeled in SPLASH are as shown:

	---Losses Reduction from assumed 10%---		
	Capacity	Avg Energy	Dep Energy
Existing System	0 MW	0 GW.h	0 GW.h
Bipole III only	89.7MW	424.7 GW.h	238.9 GW.h
Keeyask & BPIII	79.4 MW	431.7 GW.h	242.8 GW.h
Con, Keey & BP III	17.6 MW	269.3 GW.h	151.5 GW.h

Loss calculations have varied modestly as the route of the HVDC transmission line and the capacity of the proposed generating stations evolved to these current estimates.

REFERENCE: Round 1 Information Requests

QUESTION:

Please file a list of any non-CSI information requests for all parties, including Interveners and IECs, that require CSI to be disclosed in order to provide an answer.

RESPONSE:

Manitoba Hydro has not compiled a listing of such IRs. Any such information request posed by an Intervenor which required the disclosure of confidential information has been answered to the extent possible on the public record, and an indication that all or a portion of the response has not been provided has been included within the filed response.

REFERENCE: PUB/MH I-291a

QUESTION:

Please indicate whether appendix- average unit revenue cost 11.3 and Appendix- Financial pro forma II.4 is based on IFF– 12 or IFF– 12 adjusted.

RESPONSE:

The average unit revenues and costs and pro forma financial statements provided in Appendices 11.3 and 11.4, respectively, are based on IFF12 assumptions adjusted for electricity export prices (see Section 1.5.1.3, Appendix 9.3) and development plan-specific inputs (see Section 9.2.1, Chapter 9).

SUBJECT: Capital Expenditures

REFERENCE: PUB/MH I-40

QUESTION:

Provide a detailed breakdown of the capital costs by category for Keeyask and Conawapa.

RESPONSE:

Keeyask Capital Costs – 2019/20 ISD	Billions ($)
Licensing and Planning	[redacted]
Generating Station Construction	[redacted]
Keeyask Infrastructure Project & PR280	[redacted]
Transmission G.O.T.	0.16
Contingency	0.53
Spent to March 2012	0.50
Escalation	0.42
Interest	1.07
Labour Management Reserve	0.12
Escalation Management Reserve	0.38
Total Project	**6.22**
Conawapa Capital Costs – 2025/26 ISD	**Billions ($)**
Licensing and Planning	[redacted]
Generating Station Construction	[redacted]
Conawapa Infrastructure Project & PR280 & PR290	[redacted]
Transmission G.O.T.	0.01
Contingency	0.75
Spent to March 2012	0.23
Escalation	1.24
Interest	2.59
Labour Management Reserve	0.51
Escalation Management Reserve	0.34
Total Project	**10.2**

SUBJECT: Capital Construction Costs

REFERENCE: PUB/MH I -155 Dave Bowen Presentation/Technical Conference

PREAMBLE: 2012 Base Estimate: P. 20 indicates a $4.08B for Keeyask GS and $6.13B for Conawapa.

QUESTION:

Please indicate for each project the component direct costs used for:

- spillways/dams/dikes
- powerhouse structures
- turbines
- generators

RESPONSE:

The Point Estimate amounts, expressed in 2012 base dollars, are listed below. Turbines and generators are included as a single line item.

Keeyask 2019/20 ISD	**Billions (2012$)**
Spillways, Dams, Dykes	[redacted]
Powerhouse (-T&G)	[redacted]
Turbines and Generators	[redacted]
Conawapa 2025/26 ISD	**Billions (2012$)**
Spillways, Dams, Dykes	[redacted]
Powerhouse (-T&G)	[redacted]
Turbines and Generators	[redacted]