BC HYDRO RATE DESIGN 2015
EXHIBIT B-37

BC Hydro
Power smart

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August 4, 2016

Ms. Laurel Ross
Acting Commission Secretary
British Columbia Utilities Commission
Sixth Floor – 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Ms. Ross:

RE: Project No. 3698781
British Columbia Utilities Commission (BCUC or Commission)
British Columbia Hydro and Power Authority (BC Hydro)
2015 Rate Design Application (2015 RDA)
Evidentiary Update

On February 18, 2016 BC Hydro provided an update to its evidence in this proceeding regarding its load-resource balance and its long-run marginal cost of new supply (Exhibit B-17). That evidence was current to October 2015. In it BC Hydro indicated that a further update to that evidence would be prudent and would be filed in the summer of 2016.

On July 28, 2016 BC Hydro filed its Fiscal 2017 to Fiscal 2019 Revenue Requirements Application (**F17-F19 RRA**). Chapter 3 of that application is entitled Load and Revenue Forecast, and it contains BC Hydro's most current information and considerations regarding its load-resource balance and long-run marginal cost of new supply. In the interests of efficiency BC Hydro has decided that it should not re-write Chapter 3 of the F17-F19 RRA for the purposes of the 2015 RDA, but rather could simply submit an unaltered extract of the relevant information to the 2015 RDA as evidence in this proceeding in fulfillment of the commitment it made in Exhibit B-17. More specifically, BC Hydro includes pages 3-28 to 3-32 and 3-45 to 3-50 of the F17-F19 RRA. In this regard please refer to Attachment 1 to this letter.

BC Hydro will be pleased to answer questions about this evidentiary update in the context of the 2015 RDA at the oral hearing of that application commencing August 16, 2016.

For further information, please contact Gordon Doyle at 604-623-3815 or by email at bchydroregulatorygroup@bchydro.com.

Yours sincerely,

Tom Loski
Chief Regulatory Officer

gd/ma

Enclosure (1)

Copy to: BCUC Project No. 3698781 (2015 RDA) Registered Intervener Distribution List.

2015 Rate Design Application
Evidentiary Update

Attachment 1

Excerpt from Fiscal 2017 to Fiscal 2019 Revenue Requirements Application
Chapter 3
Updated Long-Run Marginal Costs

3.4.2.1 Key changes in Load Resource Balances Since 2013 Integrated Resource Plan

The Planning View of the Load Resource Balance in the context of the approved 2013 Integrated Resource Plan drives the need for resource acquisitions such as demand-side management savings, and IPP contract renewals. The Planning View of the updated Load Resource Balances with existing and committed resources[44] in Table 3-6 and Table 3-7 show that new energy and capacity resources are needed in fiscal 2022 and fiscal 2020 respectively (compared to fiscal 2017 for both energy and capacity in the 2013 Integrated Resource Plan). The Recommended Actions in the approved 2013 Integrated Resource Plan are still appropriate as discussed and the Load Resource Balances with planned resources per the Recommended Actions, in addition to existing and committed resources, are shown in Table 3-8 and Table 3-9 (refer to section 3.4.3 for more details on the Recommended Actions).

[44] Existing supply-side resources include BC Hydro's Heritage hydroelectric and thermal generating resources, as well as IPP facilities delivering electricity to BC Hydro. Committed supply-side resources are resources for which material regulatory and BC Hydro executive approvals have been secured (including Site C).

Table 3-6 Energy Load Resource Balance with Existing and Committed Resources

(GWh)		F2017	F2018	F2019	F2020	F2021	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036
Existing and Committed Heritage Resources																					
Heritage Resources (including Site C)	(a)	48,445	46,895	46,014	48,491	48,491	48,491	48,491	48,857	52,383	53,777	53,777	53,777	53,777	53,777	53,777	53,777	53,777	53,777	53,777	53,777
Existing and Committed IPP Resources	(b)	13,252	14,681	14,457	14,456	14,188	13,874	13,639	13,302	12,906	12,506	12,399	12,075	11,559	10,811	10,351	10,295	10,255	10,106	9,568	8,201
Total Supply (Operating View)**	(c) = a + b	61,697	61,576	60,471	62,947	62,680	62,366	62,130	62,159	65,289	66,283	66,176	65,853	65,336	64,589	64,129	64,073	64,033	63,884	63,345	61,979
Demand - Integrated System Total Gross Requirements																					
2016 May Mid Load Forecast Before DSM*		-58,334	-59,013	-60,413	-61,371	-62,309	-63,675	-64,836	-66,008	-67,109	-68,310	-69,267	-70,256	-71,222	-72,296	-73,374	-74,535	-75,462	-76,393	-77,215	-78,089
Expected LNG Load		-61	-148	-148	-252	-1,265	-2,299	-2,721	-2,848	-2,848	-2,848	-2,848	-2,848	-2,848	-2,848	-2,848	-2,848	-2,848	-2,848	-2,848	-2,848
Sub-total	(d)	-58,395	-59,162	-60,561	-61,624	-63,574	-65,974	-67,557	-68,856	-69,957	-71,158	-72,115	-73,104	-74,070	-75,144	-76,222	-77,383	-78,310	-79,241	-80,063	-80,937
Existing and Committed Demand Side Management & Others Measures																					
SMI Theft Reduction		83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83
Voltage and VAR Optimization		67	152	171	188	219	240	254	259	263	268	285	290	295	300	305	310	315	320	325	331
2016 DSM Plan F16 savings		982	970	939	940	935	926	923	917	912	885	863	855	848	844	807	770	760	758	757	736
Sub-total	(e)	1,131	1,204	1,193	1,211	1,237	1,249	1,260	1,258	1,258	1,235	1,231	1,228	1,226	1,227	1,195	1,163	1,157	1,161	1,165	1,150
		F2017	**F2018**	**F2019**	**F2020**	**F2021**	**F2022**	**F2023**	**F2024**	**F2025**	**F2026**	**F2027**	**F2028**	**F2029**	**F2030**	**F2031**	**F2032**	**F2033**	**F2034**	**F2035**	**F2036**
Surplus/(Deficit) (Operational View) **	(f) = c + d + e	**4,433**	**3,619**	**1,102**	**2,535**	**343**	**(2,359)**	**(4,167)**	**(5,439)**	**(3,410)**	**(3,640)**	**(4,708)**	**(6,023)**	**(7,508)**	**(9,328)**	**(10,898)**	**(12,148)**	**(13,120)**	**(14,197)**	**(15,553)**	**(17,808)**
Surplus / Deficit as % of Net Load (Planning View) **		**107%**	**106%**	**103%**	**108%**	**104%**	**99%**	**94%**	**92%**	**95%**	**95%**	**93%**	**91%**	**89%**	**87%**	**85%**	**84%**	**83%**	**82%**	**80%**	**78%**
Low Load Forecast Surplus/(Deficit) (Operational View) **		6,754	6,179	4,115	5,925	4,210	2,026	598	(400)	1,931	1,995	1,137	68	(1,156)	(2,710)	(4,054)	(4,965)	(5,680)	(6,578)	(7,881)	(10,007)
High Load Forecast Surplus/(Deficit) (Operational View) **		2,046	727	(2,492)	(1,870)	(4,669)	(8,111)	(10,807)	(12,442)	(10,787)	(11,403)	(12,634)	(14,277)	(16,143)	(18,433)	(20,276)	(21,819)	(23,058)	(24,417)	(26,190)	(28,795)

* 2016 Integrated System Load Forecast with losses

** See section 3.4.2 for description of Operational versus Planning View

Table 3-7 Peak Capacity Load Resource Balance with Existing and Committed Resources

(MW)		F2017	F2018	F2019	F2020	F2021	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036
Existing and Committed Heritage Resources																					
Heritage Resources (including Site C)	(a)	11,372	11,410	11,416	11,416	11,416	11,480	11,480	11,480	12,020	12,211	12,211	12,211	12,211	12,211	12,625	12,625	12,625	12,625	12,625	12,625
Existing and Committed IPP Resources	(b)	1,593	1,685	1,633	1,583	1,502	1,473	1,179	1,144	1,081	1,037	1,037	987	950	818	818	814	808	754	730	675
14% of Supply Requiring Reserves***	(c)	-1,787	-1,805	-1,798	-1,792	-1,780	-1,785	-1,744	-1,739	-1,813	-1,833	-1,833	-1,826	-1,821	-1,803	-1,861	-1,860	-1,859	-1,852	-1,848	-1,841
Effective Load Carrying Capability	(d) = a + b + c	11,178	11,290	11,250	11,208	11,138	11,168	10,915	10,885	11,289	11,414	11,414	11,372	11,340	11,226	11,582	11,579	11,574	11,528	11,506	11,459
Demand - Integrated System Peak																					
2016 May Mid Load Forecast Before DSM*		-10,776	-11,021	-11,209	-11,374	-11,541	-11,737	-11,930	-12,119	-12,313	-12,515	-12,708	-12,943	-13,155	-13,386	-13,614	-13,840	-14,074	-14,303	-14,542	-14,774
Expected LNG Load		-19	-19	-19	-72	-222	-329	-361	-361	-361	-361	-361	-361	-361	-361	-361	-361	-361	-361	-361	-361
Sub-total	(e)	-10,795	-11,039	-11,228	-11,447	-11,763	-12,066	-12,291	-12,480	-12,674	-12,876	-13,069	-13,304	-13,516	-13,747	-13,975	-14,201	-14,435	-14,664	-14,903	-15,135
Existing and Committed Demand Side Management & Others Measures																					
SMI Theft Reduction		11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
Voltage and VAR Optimization		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2016 DSM Plan F16 savings		216	214	210	211	210	207	204	201	198	193	189	185	183	180	174	168	165	165	165	162
Sub-total	(f)	227	226	222	222	221	218	215	212	209	204	200	197	194	192	186	179	176	176	176	173
		F2017	**F2018**	**F2019**	**F2020**	**F2021**	**F2022**	**F2023**	**F2024**	**F2025**	**F2026**	**F2027**	**F2028**	**F2029**	**F2030**	**F2031**	**F2032**	**F2033**	**F2034**	**F2035**	**F2036**
Surplus / (Deficit) **	(g) = d + e + f	**610**	**476**	**244**	**(17)**	**(404)**	**(680)**	**(1,160)**	**(1,383)**	**(1,176)**	**(1,258)**	**(1,455)**	**(1,735)**	**(1,982)**	**(2,329)**	**(2,208)**	**(2,443)**	**(2,685)**	**(2,960)**	**(3,221)**	**(3,502)**
Low Load Forecast Surplus / (Deficit) **		1,030	944	792	600	297	110	(300)	(472)	(208)	(235)	(390)	(617)	(810)	(1,102)	(933)	(1,102)	(1,286)	(1,523)	(1,764)	(2,004)
High Load Forecast Surplus / (Deficit) **		160	(74)	(434)	(845)	(1,348)	(1,758)	(2,398)	(2,683)	(2,542)	(2,690)	(2,916)	(3,260)	(3,578)	(4,013)	(3,943)	(4,232)	(4,527)	(4,863)	(5,213)	(5,559)

* 2016 Integrated System Load Forecast with losses
** Planning View is shown in this table. Capacity load resource balances are only shown in Planning View. See section 3.4.2.
*** This is also referred to as the Planning Reserve - the system generating capacity beyond that required to meet peak demand that is necessary to meet reliability criteria. See section 1.2.2 of the IRP for more details on the criteria.

Table 3-8 Energy Load Resource Balance after Planned Resources

(GWh)		F2017	F2018	F2019	F2020	F2021	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036
Existing and Committed Heritage Resources																					
Heritage Resources (including Site C)	(a)	48,445	46,895	46,014	48,491	48,491	48,491	48,491	48,857	52,383	53,777	53,777	53,777	53,777	53,777	53,777	53,777	53,777	53,777	53,777	53,777
Existing and Committed IPP Resources	(b)	13,252	14,681	14,457	14,456	14,188	13,874	13,639	13,302	12,906	12,506	12,399	12,075	11,559	10,811	10,351	10,295	10,255	10,106	9,568	8,201
Future Supply-Side Resources																					
IPP Renewals		61	234	569	647	779	936	1,114	1,349	1,628	1,951	2,032	2,223	2,617	3,328	3,788	3,828	3,863	4,011	4,549	5,515
Standing Offer Program		62	87	173	284	394	505	616	726	837	948	1,058	1,169	1,280	1,390	1,501	1,612	1,722	1,833	1,934	2,045
Revolstoke 6												26	26	26	26	26	26	26	26	26	26
Sub-total	(c)	123	321	742	931	1,173	1,441	1,730	2,075	2,465	2,899	3,117	3,418	3,923	4,745	5,315	5,466	5,612	5,870	6,509	7,585
Total Supply (Operational View) **	(d) = a + b + c	61,820	61,897	61,213	63,879	63,853	63,806	63,860	64,235	67,754	69,182	69,293	69,271	69,259	69,334	69,444	69,538	69,644	69,754	69,855	69,564
Demand - Integrated System Total Gross Requirements																					
2016 May Mid Load Forecast Before DSM*		-58,334	-59,013	-60,413	-61,371	-62,309	-63,675	-64,836	-66,008	-67,109	-68,310	-69,267	-70,256	-71,222	-72,296	-73,374	-74,535	-75,462	-76,393	-77,215	-78,089
Expected LNG Load		-61	-148	-148	-252	-1,265	-2,299	-2,721	-2,848	-2,848	-2,848	-2,848	-2,848	-2,848	-2,848	-2,848	-2,848	-2,848	-2,848	-2,848	-2,848
Sub-total	(e)	-58,395	-59,162	-60,561	-61,624	-63,574	-65,974	-67,557	-68,856	-69,957	-71,158	-72,115	-73,104	-74,070	-75,144	-76,222	-77,383	-78,310	-79,241	-80,063	-80,937
Existing and Committed Demand Side Management & Others Measures																					
SMI Theft Reduction		83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83
Voltage and VAR Optimization		67	152	171	188	219	240	254	259	263	268	285	290	295	300	305	310	315	320	325	331
2016 DSM Plan F16 savings		982	970	939	940	935	926	923	917	912	885	863	855	848	844	807	770	760	758	757	736
Planned Demand Side Management Measures																					
2016 DSM Plan F17 to F19 savings		389	988	1,679	1,896	1,931	1,969	1,956	1,935	1,917	1,908	1,896	1,853	1,787	1,694	1,613	1,547	1,462	1,300	1,224	1,190
2016 DSM Plan F20+ savings		0	0	0	292	904	1,454	1,897	2,310	2,637	2,946	3,229	3,500	3,758	4,006	4,248	4,473	4,690	4,908	5,116	4,976
Sub-total	(f)	1,521	2,192	2,873	3,399	4,072	4,672	5,112	5,502	5,811	6,089	6,356	6,581	6,770	6,927	7,055	7,183	7,310	7,368	7,505	7,317
		F2017	**F2018**	**F2019**	**F2020**	**F2021**	**F2022**	**F2023**	**F2024**	**F2025**	**F2026**	**F2027**	**F2028**	**F2029**	**F2030**	**F2031**	**F2032**	**F2033**	**F2034**	**F2035**	**F2036**
Surplus / (Deficit) (Operational View) **	(g) = d + e + f	**4,945**	**4,928**	**3,524**	**5,654**	**4,351**	**2,505**	**1,416**	**881**	**3,608**	**4,113**	**3,534**	**2,748**	**1,959**	**1,117**	**278**	**(662)**	**(1,355)**	**(2,118)**	**(2,704)**	**(4,056)**
Surplus / Deficit as % of Net Load (Planning View) **		**113%**	**115%**	**115%**	**114%**	**111%**	**108%**	**106%**	**105%**	**109%**	**110%**	**109%**	**107%**	**106%**	**105%**	**103%**	**102%**	**101%**	**99.97%**	**99%**	**97%**
Small Gap Surplus/(Deficit) (Operational View) **		7,266	7,487	6,536	9,044	8,219	6,890	6,181	5,920	8,949	9,749	9,380	8,839	8,311	7,735	7,122	6,521	6,085	5,500	4,968	3,745
Large Gap Surplus/(Deficit) (Operational View) **		2,559	2,036	*(70)*	1,250	*(661)*	*(3,248)*	*(5,224)*	*(6,122)*	*(3,768)*	*(3,650)*	*(4,392)*	*(5,505)*	*(6,676)*	*(7,987)*	*(9,100)*	*(10,334)*	*(11,294)*	*(12,339)*	*(13,341)*	*(15,043)*

* 2016 Integrated System Load Forecast with losses
** See section 3.4.2 for description of Operational versus Planning view

Table 3-9 Peak Capacity Load Resource Balance after Planned Resources

(MW)		F2017	F2018	F2019	F2020	F2021	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036
Existing and Committed Heritage Resources																					
Heritage Resources (including Site C)	(a)	11,372	11,410	11,416	11,416	11,416	11,480	11,480	11,480	12,020	12,211	12,211	12,211	12,211	12,211	12,625	12,625	12,625	12,625	12,625	12,625
Existing and Committed IPP Resources	(b)	1,593	1,685	1,633	1,583	1,502	1,473	1,179	1,144	1,081	1,037	1,037	987	950	818	818	814	808	754	730	675
Future Supply-Side Resources																					
IPP Renewals		9	23	55	79	120	135	419	441	450	486	486	514	538	671	671	674	680	705	862	901
Standing Offer Program		4	6	12	19	27	34	41	49	56	64	71	79	86	94	101	108	116	123	138	145
Revolstoke 6												488	488	488	488	488	488	488	488	488	488
Sub-total	(c)	13	29	66	98	147	169	460	490	507	550	1,045	1,080	1,112	1,252	1,260	1,271	1,284	1,316	1,488	1,534
Total Supply	(d) = a + b + c	12,978	13,124	13,115	13,098	13,065	13,122	13,120	13,113	13,608	13,797	14,293	14,279	14,273	14,281	14,702	14,709	14,717	14,695	14,843	14,834
14% of Supply Requiring Reserves***	(e)	-1,788	-1,809	-1,808	-1,805	-1,801	-1,809	-1,808	-1,807	-1,884	-1,910	-1,980	-1,978	-1,977	-1,978	-2,037	-2,038	-2,039	-2,036	-2,057	-2,055
Effective Load Carrying Capability	(f) = d + e	11,189	11,315	11,307	11,293	11,264	11,313	11,311	11,306	11,725	11,887	12,313	12,301	12,296	12,303	12,665	12,671	12,678	12,659	12,786	12,779
Demand - Integrated System Peak																					
2016 May Mid Load Forecast Before DSM*		-10,776	-11,021	-11,209	-11,374	-11,541	-11,737	-11,930	-12,119	-12,313	-12,515	-12,708	-12,943	-13,155	-13,386	-13,614	-13,840	-14,074	-14,303	-14,542	-14,774
Expected LNG Load		-19	-19	-19	-72	-222	-329	-361	-361	-361	-361	-361	-361	-361	-361	-361	-361	-361	-361	-361	-361
Sub-total	(g)	-10,795	-11,039	-11,228	-11,447	-11,763	-12,066	-12,291	-12,480	-12,674	-12,876	-13,069	-13,304	-13,516	-13,747	-13,975	-14,201	-14,435	-14,664	-14,903	-15,135
Existing and Committed Demand Side Management & Others Measures																					
SMI Theft Reduction		11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
Voltage and VAR Optimization		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2016 DSM Plan F16 savings		216	214	210	211	210	207	204	201	198	193	189	185	183	180	174	168	165	165	165	162
Planned Demand Side Management Measures																					
2016 DSM Plan F17 to F19 savings		66	167	272	310	314	316	311	305	299	295	290	282	272	259	247	237	225	207	198	195
2016 DSM Plan F20+ savings		0	0	0	47	170	285	358	421	468	514	554	593	629	663	696	725	753	788	822	808
Sub-total	(h)	293	392	494	578	706	818	884	938	977	1,013	1,045	1,072	1,095	1,114	1,128	1,142	1,154	1,171	1,196	1,176
		F2017	**F2018**	**F2019**	**F2020**	**F2021**	**F2022**	**F2023**	**F2024**	**F2025**	**F2026**	**F2027**	**F2028**	**F2029**	**F2030**	**F2031**	**F2032**	**F2033**	**F2034**	**F2035**	**F2036**
Surplus / (Deficit) **	(i) = f + g + h	**687**	**668**	**573**	**424**	**206**	**65**	**(96)**	**(236)**	**27**	**23**	**289**	**70**	**(124)**	**(330)**	**(182)**	**(389)**	**(603)**	**(833)**	**(921)**	**(1,180)**
Small Gap Surplus / (Deficit) **		1,107	1,136	1,121	1,041	908	856	765	675	995	1,046	1,354	1,188	1,048	897	1,093	953	796	604	536	317
Large Gap Surplus / (Deficit) **		237	118	(105)	(403)	(737)	(1,013)	(1,334)	(1,536)	(1,339)	(1,409)	(1,172)	(1,455)	(1,721)	(2,014)	(1,917)	(2,177)	(2,445)	(2,736)	(2,913)	(3,237)

* 2016 Integrated System Load Forecast with losses

** Planning View is shown in this table. Capacity load resource balances are only shown in Planning View. See section 3.4.2.

*** This is also referred to as the Planning Reserve - the system generating capacity beyond that required to meet peak demand that is necessary to meet reliability criteria. See section 1.2.2 of the IRP for more details on the criteria.

- The cost for developing some new clean energy resources has declined (e.g., wind and solar);
- The Pacific Northwest, including BC Hydro, has become more constrained in operation during the freshet oversupply period; and
- BC Hydro is expecting to have greater need for new capacity resources over energy resources.

Accordingly, BC Hydro is going through an optimization process for the Standing Offer Program and Micro-Standing Offer Program. This process will help to ensure the Standing Offer Program and Micro-Standing Offer Program reflect future system needs, consider recent advancements in technology, and are aligned with the 2013 10 Year Rates Plan. To ensure that projects that are significantly advanced are not unduly impacted, any changes to the programs are expected to apply to projects allocated to the Standing Offer Program volume in calendar 2020 and beyond, and not during the current test period.

3.4.4 Long-Run Marginal Costs

This section discusses the updated energy and capacity long-run marginal costs and compares them that with those set out in the approved 2013 Integrated Resource Plan.

3.4.4.1 How Long-Run Marginal Cost is Used

Long-run marginal cost can be defined as the price for acquiring resources to meet incremental customer demand beyond existing and committed resources. A consideration in setting the long-run marginal cost is providing a steady and consistent price signal for determining/screening the cost-effectiveness of different resources. BC Hydro does not expect to acquire all available resources up to the long-run marginal cost, nor does it expect the long-run marginal cost to be the clearing price.

BC Hydro uses long-run marginal costs as a price signal to determine cost-effectiveness of the resources that it acquires in circumstances where portfolio analysis cannot be effectively undertaken. In particular, the long-run marginal costs are benchmarks in determining:

- The cost-effectiveness of demand-side management expenditures in this application;
- The cost-effectiveness of IPP Electricity Purchase Agreement renewals; and
- The level of efficiency to specify in acquiring electric system equipment.

The Long Run Marginal Cost also informs the setting of conservation rate structures as per the current 2015 Rate Design Application.

Determination of the long-run marginal costs is guided by the government approved Integrated Resource Plan, which ensures reliable and cost-effective electricity service both in the near and long-term while balancing multiple policy objectives.

3.4.4.2 Energy Long-Run Marginal Cost Determination and Application

For many years prior to the 2013 Integrated Resource Plan, BC Hydro had a forecast need to acquire energy from greenfield clean or renewable IPP projects and they were the marginal resource that set the long-run marginal cost. The estimated cost of energy from greenfield clean or renewable IPPs[28] was revised from $135/MWh (fiscal 2013$)[29] to $125/MWh (fiscal 2013)[30] in the 2013 Integrated Resource Plan. It is now estimated at $100/MWh (fiscal 2015$).[31] The need for energy from greenfield clean and renewable IPPs

[28] The costs shown are adjusted Unit Energy Costs including delivery cost to the Lower Mainland/Vancouver Island region.

[29] Based upon the Clean Power Call results, the most recent and broadly-based power acquisition process at the time of the 2013 Integrated Resource Plan.

[30] Based upon resource cost estimate at the time of the 2013 Integrated Resource Plan, reflecting cost reduction since the Clean Power Call.

[31] Based upon BC Hydro’s most recent resource options updates, reflecting recent wind cost estimates.

shown in the updated Load Resource Balance in section 3.4.2 is not expected to occur until fiscal 2034.

The Greenfield clean or renewable IPP long-run marginal cost is still relevant in the case of:

- Demand-side management, reflecting "the authority's long-run marginal cost of acquiring electricity generated from clean or renewable resources in British Columbia for the purpose of section 4.1.1 of the *Demand Side Management Regulation*";[32]
- Longer term stable pricing signals for rates; and
- Long lived assets where electricity supply benefits extend to and beyond fiscal 2034.

A long-run marginal cost based on resources that have a lower cost than greenfield IPPs was introduced in the 2013 Integrated Resource Plan after lower Load Forecasts and modifications to *Clean Energy Act* self-sufficiency requirements reduced the need for new resources. Currently, and still consistent with the 2013 Integrated Resource Plan, BC Hydro's actions to meet future energy demand through to the late 2020's include the Site C Clean Energy Project and the Standing Offer Program, along with demand-side management and IPP Electricity Purchase Agreement renewals. Given that the Site C Clean Energy Project is a committed resource under construction and the Standing Offer Program is required pursuant to subsection 15(2) of the *Clean Energy Act*, they are not marginal resources. As a result, the marginal resources before the return of need for new resources from greenfield clean or renewable IPPs are

[32] Section 4.1.1 of the Demand-Side Management Regulation requires that "the authority's long-run marginal cost of acquiring electricity generated from clean or renewable resources in British Columbia" be used in the total resource cost test. BC Hydro interprets this long-run marginal cost in the Demand-Side Management Regulation to be the cost of acquiring greenfield clean or renewable IPP resources, which is estimated at $100/MWh (fiscal 2015$).

demand-side management programs and Electricity Purchase Agreement renewals.

Since the demand-side management and IPP renewal resource supply curves (price and volume relationship) are not easily visible until the actions have been undertaken, BC Hydro used a price signal (i.e., the Long Run Marginal Cost) to set the upper limit on these acquisitions. The long-run marginal cost set out in the 2013 Integrated Resource Plan was $85 to $100/MWh (fiscal 2013$). This was revised to $85/MWh based upon a reduced need for new resources and further information as set out in the Rate Design Application Evidentiary Update. BC Hydro expects it will be able to acquire sufficient resources to meet its need at or below this price.

- ***Electricity Purchase Agreement Renewals:*** As described in section 3.4.3.5., the cost of service for IPPs is one of the factors in Electricity Purchase Agreement renewal negotiations and could vary significantly among IPPs. BC Hydro is targeting renewal of contracts for those facilities that have the lowest cost, greatest certainty of continued operation and best system support characteristics. Due to the fact that Electricity Purchase Agreement renewals are related to existing projects for which the IPPs' initial capital investment has been fully or largely recovered during the term of the initial Electricity Purchase Agreement, BC Hydro expects to be able to negotiate a lower energy price than the initial Electricity Purchase Agreement. Since the 2013 Integrated Resource Plan, BC Hydro has carried out further analysis of the expected cost of service for existing projects. BC Hydro currently estimates that the renewal volumes in the plan can be acquired at or below $85/MWh (fiscal 2013$) although the relationship between price, volume, contract terms and other non-energy benefits has yet to be established through bilateral negotiations. As previously noted in this section, BC Hydro does not expect to acquire all available resources up to the long-run marginal cost nor does it expect the long-run marginal cost to be the clearing price;

- ***Demand-Side Management Plan:*** The $85/MWh amount was used to inform the development of the Demand-Side Management Plan including by ensuring that all demand-side management initiatives were cost-effective in a total resource cost test against the $85/MWh threshold.

Based on the updated load resource balances in section 3.4.2, the need for new energy resources beyond existing and committed resources is in fiscal 2022 (delayed from fiscal 2017 in the 2013 Integrated Resource Plan). Given planned resources pursuant to the 2013 Integrated Resource Plan Recommended Actions, greenfield IPPs will not be needed until fiscal 2034. The resulting marginal resources and related costs are as follows:

Table 3-10 Marginal Energy Resources and Related Cost

Marginal Resources	Period of Applicability	$/MWh
Demand-Side Management and Electricity Purchase Agreement renewals	fiscal 2022 to fiscal 2033	Less than: $87/MWh (fiscal 2016$) or $85/MWh (fiscal 2013$)
Greenfield IPPs	fiscal 2034 and beyond	$102/MWh (fiscal 2016$) or $100/MWh (fiscal 2015$)

3.4.4.3 Capacity Long-Run Marginal Cost Determination and Application

Consistent with the 2013 Integrated Resource Plan, the updated capacity Load Resource Balance continues to show a need to acquire additional capacity resources over and above the other resource acquisitions in the Plan. The next generation capacity resources that could be developed and are being advanced for contingency planning purposes are Revelstoke Unit 6 and natural gas-fired simple-cycle gas turbine generators. Revelstoke Unit 6 is the next most cost-effective generation capacity resource on a unit cost basis.

In the 2013 Integrated Resource plan, the long-run marginal cost for capacity was estimated at $50 to 55/kW-year based on Revelstoke Unit 6 and the unit capacity costs for simple-cycle gas turbine generators was estimated at $88/kW-year. These costs are both in fiscal 2013$ and are at point-of-interconnection. In BC Hydro's most recent resource options updates, the unit capacity costs of a simple-cycle gas turbine generators at point-of-interconnection has dropped to $79/kW-year (fiscal 2015$). To make the unit capacity costs comparable to the adjusted unit energy costs with delivery to Lower Mainland and to adjust for energy impacts, these unit capacity costs are adjusted to be $57/kW-year (fiscal 2015$) for Revelstoke Unit 6 and $115/kW-year (fiscal 2015$) for a simple-cycle gas turbine. The range of $50 to $55/kW-year (fiscal 2013$) continues to be reasonable for Revelstoke Unit 6.

As shown in the updated Load Resource Balance in section 3.4.2, "Peak Capacity Load Resource Balance after Planned Resources", there is still a small capacity need prior to the Site C Clean Energy Project coming fully into service in fiscal 2025. BC Hydro continues to plan to rely on the market to bridge this capacity need.

Revelstoke Unit 6 is the next capacity resource planned and is being advanced as either a contingency resource for its earliest in-service date in fiscal 2022 or for the need in the mid-level forecast in fiscal 2027. The next capacity resource after Revelstoke Unit 6 is not needed until fiscal 2029. The resulting marginal resources and related costs are as follows:

Table 3-11 Marginal Capacity Resources and Related Costs

Marginal Resources	Period of Applicability	$/kW-year
Revelstoke Unit 6	Fiscal 2020 to fiscal 2028	$50 - $55/kW-year (fiscal 2013$)
Simple-Cycle Gas Turbine	Fiscal 2029 and beyond	$117/kW-year (fiscal 2016$) or $115/kW-year (fiscal 2015$)