Dennis Swanson
Director, Regulatory Affairs

FortisBC Inc.
Suite 100 – 1975 Springfield Road
Kelowna, BC V1Y 7V7
Tel: (250) 717-0890
Fax: 1-866-335-6295
www.fortisbc.com

Regulatory Affairs Correspondence
Email: electricity.regulatory.affairs@fortisbc.com

September 20, 2013

Via Email
Original via Mail

B.C. Sustainable Energy Association
c/o William J. Andrews, Barrister & Solicitor
1958 Parkside Lane
North Vancouver, B.C.
V7G 1X5

Attention: Mr. William J. Andrews

Dear Mr. Andrews:

Re: FortisBC Inc. (FBC)

Application for Approval of a Multi-Year Performance Based Ratemaking Plan for 2014 through 2018 (the Application)

Response to the B.C. Sustainable Energy Association and the Sierra Club British Columbia, *et al* (BCSEA) Information Request (IR) No. 1

On July 5, 2013, FBC filed the Application as referenced above. In accordance with Commission Order G-109-13 setting out the Preliminary Regulatory Timetable for the review of the Application, FBC respectfully submits the attached response to BCSEA IR No. 1.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC INC.

Original signed:

Dennis Swanson

Attachments

cc: Commission Secretary
Registered Parties (e-mail only)

1.0 Topic: Legal framework

Reference: Exhibit B-1-1, Appendix H DSM, pp.3-4, Table H-1 BC's Energy Objectives Met by FBC DSM Activity; Clean Energy Act, s.2(a) and s.6(4); s.2(g)

1.1 Table H-1 lists four of the BC energy objectives and provides related comments on the FBC DSM Portfolio. Please confirm that Table H-1 does not list the BC energy objective to reduce greenhouse gas emissions (Clean Energy Act, s.2(g)) or the BC energy objective to achieve electricity self-sufficiency (Clean Energy Act, s.2(a) and s.6(4)).

Response:

Confirmed.

1.2 Why did FortisBC omit from Table H-1 the BC energy objective to reduce greenhouse gas emissions?

Response:

Table H-1 in Appendix H includes the following BC Energy Objective related to greenhouse gas reductions[1]:

(h) to encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia;

(i) to encourage communities to reduce greenhouse gas emissions and use energy efficiently.

1.2.1 Does FortisBC agree that the BC energy objective to reduce GHG emissions applies to FortisBC in terms of long-term resource and conservation planning? If not, why not?

[1] FortisBC Inc. Application for Approval of a Multi-Year Performance Based Ratemaking Plan for 2014 through 2018, Volume 2, Appendix H, Table H-1, page 4.

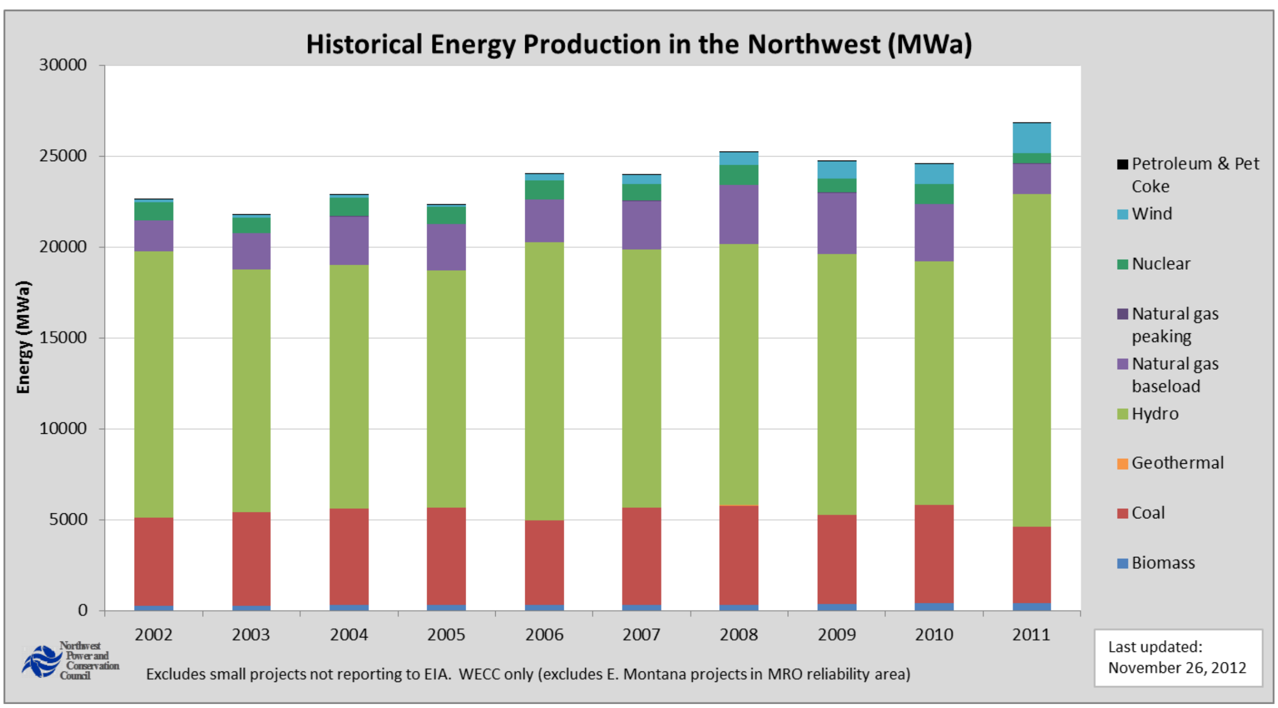
Response:

Yes. In the FortisBC 2012 Long-Term Resource Plan, Table 1.1-A[2] "Relevant Clean Energy Act Objectives" and Appendix F[3] includes the Clean Energy Act Objective "to reduce greenhouse gas emissions". Please also refer to the response to BCSEA IR1.1.2.

1.2.2 Does FortisBC agree that by increasing relatively carbon-intensive market imports and decreasing zero-carbon DSM savings the proposed 2014-2018 DSM Plan does not support the objective of reducing GHG emissions and would tend to increase rather than reduce GHG emissions?

Response:

FBC's purchases of energy at the Mid-C would be sourced from the generation resources available in the region. The following graph obtained from the Northwest Power Planning and Conservation Council illustrates the historical sources of generation. This data can be found at the following link: http://www.nwcouncil.org/energy/powersupply.



[2] FortisBC 2012 Long Term Resource Plan, Section 1.1, Table 1.1-A, Page 2.
[3] FortisBC 2012 Long Term Resource Plan, Appendix F, Page 2 of 3.

1.3 Why did FortisBC omit from Table H-1 the BC energy objective to achieve electricity self-sufficiency?

Response:

Table H-1 lists the British Columbia's energy objectives that are more directly achieved or achievable by FortisBC's DSM program.

> "Electricity self-sufficiency," which is listed as one of the British Columbia's energy objectives under section 2 of the Clean Energy Act (CEA), is defined as follows under the CEA:
>
> > **"electricity self-sufficiency"** means electricity self-sufficiency as described in section 6 (2);

By the very wording of Section 6(2) of the CEA, that section applies only to BC Hydro.

> Section 6(4) of the CEA states that
>
> > "A public utility, in planning in accordance with section 44.1 of the *Utilities Commission Act* for
> >
> > (a) the construction or extension of generation facilities, and
> >
> > (b) energy purchases,
> >
> > must consider British Columbia's energy objective to achieve electricity self-sufficiency."

Thus, the "electricity self-sufficiency" concept can be applied to a public utility in the utility's long-term resource and conservation planning, but in two specified circumstances: "(a) the construction or extension of generation facilities, and (b) energy purchase." DSM programs and expenditures do not fall under either circumstance, and thus are not directly related to the objective of achieving "electricity self-sufficiency".

1.3.1 Does FortisBC agree that the B.C. energy objective "to achieve electricity self-sufficiency" applies to FortisBC in terms of long-term resource and conservation planning? If not, why not?

Response:

Please refer to the response to BCSEA 1.1.3.

1.3.2 Does FortisBC agree that s.6(4) of the Clean Energy Act confirms that the electricity self-sufficiency objective applies to FortisBC (and not just to BC Hydro) in terms of resource planning and conservation? If not, why not?

Response:

Please refer to the response to BCSEA IR 1.1.3.

1.3.3 Does FortisBC agree that by increasing market imports and decreasing DSM savings the proposed 2014-2018 DSM Plan does not support the objective of achieving electricity self-sufficiency and would tend to decrease electricity self-sufficiency?

Response:

Please refer to the response to BCSEA IR 1.1.3.

1.4 Table H-1 states in row 2, column 2: "FBC supports pilot projects of new DSM technologies..." Please identify the pilot projects of new DSM technologies that are included in the proposed 2014-2018 DSM Plan.

Response:

FortisBC does not have a list of future pilot projects; the Company evaluates opportunities as they arise.

For example, a pilot project currently underway is evaluating the use of vortex-conditioned cold flood water for resurfacing the ice surface in arenas.

2.0 Topic: Legal framework

Reference: BC Energy Plan [http://www.energyplan.gov.bc.ca/]

2.1 Please file the BC Energy Plan, or identify its location in the filed materials.

Response:

Please refer to Attachment 2.1.

3.0 Topic: Substitution of imports for DSM savings

Reference: Exhibit B-1, A: Overview and Introduction, page 4; Exhibit B-1-1, Appendix H, Attachment H-4, LRMC Avoided Cost Derivation

"As set out in Appendix H, FBC seeks acceptance of a Demand Side Management (DSM) portfolio over a five year term. The DSM expenditures under FBC's DSM Plan (Attachment H1) are lower than the expenditure levels approved for 2012 and 2013. This reduction is driven by a marked decrease in the Long Run Marginal Cost (LRMC), which is used in the evaluation of DSM measures and programs pursuant to regulation. Fewer measures, and in some cases programs, are now cost-effective as defined by the Demand-Side Measures Regulation. FBC is also seeking approval for a change in the amortization period of existing and future DSM expenditures from 10 years to 15 years, as set out in Appendix H." [underline added]

3.1 Please confirm that FortisBC's proposed 2014-2018 DSM Plan assumes an avoided electricity cost based on estimated future Mid-C electricity prices.

Response:

The LRMC estimate used by FBC as an input to the TRC and UCT assumes FBC's avoided cost is based on annual average Mid-C market pricing, plus BPA wheeling and losses to deliver it to the BC/US border.

The LRMC estimate used for the modified TRC represents new BC renewable resources.

3.2 Please confirm that FortisBC's proposed 2014-2018 DSM Plan assumes that FortisBC's marginal supply of electric energy is market energy delivered at the Mid-Columbia Hub and wheeled to the FortisBC territory.

Response:

Not confirmed. The DSM plan assumes that FBC acquires market energy. Market energy could be acquired from the Mid-Columbia Trading Hub and wheeled to the FBC territory, or it could be market energy acquired from elsewhere, and priced at the FBC's avoided cost (Mid-C plus BPA wheeling and losses).

3.3 Does FortisBC agree that market energy delivered at Mid-C and wheeled to the FortisBC territory is not "made-in-BC supply" contemplated by the objective to achieve self-sufficiency? If FortisBC does not agree, why not?

Response:

Under the *Clean Energy Act*, FBC is under no requirement to only purchase "made-in-BC supply". As described in the response to BCSEA IR 1.1.3, a public utility other than BC Hydro has two specific circumstances when the provincial electricity self-sufficiency objective must be considered, one of them being energy purchases. Even in that, Section 6(4) of the *Act* is not prescriptive for public utilities on what actions they must take and by what dates, only that in planning they must be considered.

FBC does support the British Columbia objective to achieve electricity self-sufficiency. In support of electricity self-sufficiency, FBC has recently acquired a large block of capacity from the Waneta Expansion Project that achieves capacity self-sufficiency for FBC. Moreover, FBC's 2012 Long-Term Resource Plan forecasts FBC achieving energy self-sufficiency in the long-term. Therefore FBC believes it has fulfilled both the intent and its requirements under Section 6(4) of the *Act*.

While it is not possible to know the original source of power bought and sold at Mid-C as it is a regional trading point that acts as both a source and sink for power from all over the region (including BC), FBC agrees that for planning purposes, market energy purchased at Mid-C does not originate in BC.

3.4 If FortisBC purchases additional energy at the Mid-Columbia hub in lieu of additional DSM savings, what generation resources (location and type) would FortisBC expect would be the sources of that additional energy?

Response:

Please refer t the response to BCSEA IR 1.1.2.2.

3.5 Please provide FortisBC's estimate of the percentage of hours in which hydro-electric energy is available at Mid-Columbia that would otherwise be spilled.

Response:

FortisBC does not have this information.

3.6 Would FortisBC agree that incremental energy delivered to FortisBC from the Mid-Columbia hub would be provided primarily by operating additional gas and coal generation? If not, please explain why not.

Response:

No, that is an oversimplification. The Mid-C trading hub is complex, and trades surplus electricity generated by various resources, and may include hydro with storage, run of river hydro, wind, nuclear, gas and coal.

The marginal generation mix at any time will be impacted by both time of day as well as season. For example, gas generators typically do not run during freshet when the abundance of hydro and wind resources create Mid-C market prices that may not cover a gas plant's variable operating costs.

There are likely significant periods when thermal generators provide the marginal generation, however even then it typically will be gas plants providing this incremental generation, not coal. Please also refer to the response to BCSEA IR 1.1.2.2.

3.7 Please provide estimates available to FortisBC of (a) the average carbon intensity of market power sold through Mid-C and (b) the carbon intensity of Mid-C market power at the margin.

Response:

Please refer to the response to BCUC IR 1.230.1.2.

3.8 Please confirm that DSM savings are considered to be GHG neutral.

Response:

Confirmed.

4.0 Topic: Avoided energy, price and characteristics

Reference: FortisBC 2012 Long Term Resource Plan, Appendix B, Midgard 2011 FortisBC Energy & Capacity Market Assessment, section 5.1.3.3, page 25 of 54; Exhibit B-1-1, Appendix H, Attachment H4, last page [pdf p.883 of 887]

"Midgard forecast the USD to CAD conversion rate as a linear trend starting at 1 USD = 1 CAD in 2011 and ending at 1 USD = 1.25 CAD in 2040." [FortisBC Long-Term Resource Plan, Appendix B, p.25 of 54 (pdf page 129)]

4.1 Please file FortisBC Energy & Capacity Market Assessment," being Appendix B to the FortisBC 2012 Long Term Resource Plan.

Response:

Please refer to Attachment 4.1.

4.2 Please confirm that in its 2012 Long Term Resource Plan (Appendix B - Energy and Capacity Market Assessment), FortisBC used a USD to CAD conversion rate defined "as a linear trend starting at 1 USD = 1 CAD in 2011 and ending at 1 USD = 1.25 CAD in 2040.

Response:

Confirmed. Midgard Consulting provided an exchange rate forecast when it created the BC Market Energy Price Forecast for the 2012 Long Term Resource Plan.

4.3 Please confirm that FortisBC's proposed 2014-2018 DSM plan is based on a forecast foreign exchange rate of $1.00 CAD/USD for 2014 to 2043 [Exhibit B-1-1, Appendix H, Attachment H4, last page [pdf p.883 of 887].

Response:

Confirmed. The Long-Run Marginal cost of market purchases uses the exchange rate forecast from the GLJ January 1st, 2013 Commodity Price Report. This exchange rate forecast is that the Canadian and US dollars will be at par.

4.4 Please explain fully the basis for the change between the 2012 LTAP and the proposed 2014-2018 DSM Plan regarding the forecast foreign exchange rate over the planning period.

Response:

FBC directed Midgard to use the GLJ January 1, 2013 "Product Price and Market Forecasts for the Canadian Oil and Gas Industry"[4] for developing its market electricity price forecast update in order to be consistent with the gas price assumptions used by the Company's gas line of business in regulatory proceedings. The GLJ January 1, 2013 forecast also included an exchange rate forecast which Midgard was directed to use because it was an independent publically available forecast. Please refer to the response to BCUC IR 1.239.1.

4.5 Please reconcile the forecast of a constant 1.00 foreign-exchange ratio in Attachment H4 with recent foreign-currency futures.

Response:

FBC does not understand what is meant by reconciling to recent foreign currency futures as there could be many reasons for differences between today's quoted futures prices and what assumptions drove the rates in a spot rate forecast compiled by an independent third party at January 1, 2013. (http://www.glja.com/commodity-price-forecasts (01JAN2013 version direct link provided in footnote 4)). FBC assumes the question, in simple terms, means to compare foreign-currency futures as of today, to the foreign exchange rates provided in attachment H4 as sourced. Futures contracts do not come in 20 year forecasts; rather contracts settle out to a maximum of 5 years. The December settlement period quotes for each year are shown below:

[4] http://www.gljpc.com/sites/default/files/files/jan13.pdf

CAD/USD	
Settlement Date	**Futures Contract[1]**
Dec-13	0.9471
Dec-14	0.9387
Dec-15	0.9319
Dec-16	0.9292
Dec-17	0.9266

[1] Futures contract price Direct method CAD/USD Quotes from CME Group as at August 29, 2013

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5.0 Topic: Avoided energy, price and characteristics

Reference: Exhibit B-1-1, Appendix H, Attachment H4, LRMC Avoided Cost Derivation

5.1 Please provide any recent forward price quotes for Mid-Columbia energy available to FortisBC or Midgard.

<u>Response:</u>

Provided below are the September 2, 2013 Intercontenental Exchange (ICE) settlement data for the Mid-Columbia forward strip starting April, 2014 through 5 years. The prices are provided on a monthly basis for HLH and LLH blocks. Please note that beyond three years, trading the strip becomes thin and although there are prices shown, it is not liquid.

HUB	STRIP	Peak Price (HLH) US$/MWh	Off-Peak Price (LLH) US$/MWh
Mid C	Oct-13	$36.70	$30.45
Mid C	Nov-13	$38.35	$32.00
Mid C	Dec-13	$41.65	$34.90
Mid C	Jan-14	$38.60	$32.65
Mid C	Feb-14	$37.00	$32.10
Mid C	Mar-14	$33.25	$27.95
Mid C	Apr-14	$31.45	$19.20
Mid C	May-14	$27.70	$12.20
Mid C	Jun-14	$25.85	$8.50
Mid C	Jul-14	$44.25	$24.20
Mid C	Aug-14	$45.10	$33.20
Mid C	Sep-14	$43.50	$31.95
Mid C	Oct-14	$38.70	$31.85
Mid C	Nov-14	$39.35	$34.35
Mid C	Dec-14	$42.75	$37.25
Mid C	Jan-15	$39.30	$33.55
Mid C	Feb-15	$39.30	$33.55
Mid C	Mar-15	$39.30	$33.55
Mid C	Apr-15	$30.00	$15.40
Mid C	May-15	$30.15	$15.55
Mid C	Jun-15	$30.15	$15.55
Mid C	Jul-15	$44.95	$29.95
Mid C	Aug-15	$44.95	$29.95
Mid C	Sep-15	$44.85	$29.85
Mid C	Oct-15	$41.35	$34.95
Mid C	Nov-15	$41.35	$34.95
Mid C	Dec-15	$41.35	$34.95
Mid C	Jan-16	$43.20	$36.20

HUB	STRIP	Peak Price (HLH) US$/MWh	Off-Peak Price (LLH) US$/MWh
Mid C	Feb-16	$43.20	$36.20
Mid C	Mar-16	$43.20	$36.20
Mid C	Apr-16	$32.15	$16.95
Mid C	May-16	$32.15	$16.95
Mid C	Jun-16	$32.15	$16.95
Mid C	Jul-16	$44.85	$30.80
Mid C	Aug-16	$44.85	$30.80
Mid C	Sep-16	$44.85	$30.80
Mid C	Oct-16	$44.75	$37.60
Mid C	Nov-16	$44.75	$37.60
Mid C	Dec-16	$44.75	$37.60
Mid C	Jan-17	$45.90	$38.15
Mid C	Feb-17	$45.90	$38.15
Mid C	Mar-17	$45.90	$38.15
Mid C	Apr-17	$35.30	$20.75
Mid C	May-17	$35.30	$20.75
Mid C	Jun-17	$35.30	$20.75
Mid C	Jul-17	$49.35	$36.00
Mid C	Aug-17	$49.35	$36.00
Mid C	Sep-17	$49.35	$36.00
Mid C	Oct-17	$47.55	$38.55
Mid C	Nov-17	$47.55	$38.55
Mid C	Dec-17	$47.55	$38.55
Mid C	Jan-18	$49.00	$40.85
Mid C	Feb-18	$49.00	$40.85
Mid C	Mar-18	$49.00	$40.85
Mid C	Apr-18	$38.40	$22.35
Mid C	May-18	$38.40	$22.35
Mid C	Jun-18	$38.40	$22.35
Mid C	Jul-18	$53.10	$38.50
Mid C	Aug-18	$53.10	$38.50
Mid C	Sep-18	$53.10	$38.50

6.0 Topic: Avoided energy, price and characteristics

Reference: Exhibit B-1-1, Appendix H, Attachment H4; FortisBC 2012 Long Term Resource Plan, Appendix B, Midgard 2011 FortisBC Energy & Capacity Market Assessment, Table 5.1.2-B, BC Hydro Monthly Mid-C Price Variations, page 24 of 54 (pdf 128)

In Table 5.1.1-B in the Midgard 2011 Energy & Capacity Market Assessment used for FortisBC's 2012 LTRP, Midgard shows "BC Hydro Monthly Mid-C Price Variations."

6.1 Please provide an up to date version of estimated monthly Mid-C price variations.

Response:

Table 5.1.1-B is based on the BC Hydro "Integrated Resource Plan Technical Advisory Committee Meeting #2 – Meeting Presentation - Day 1" document, from January 2011, on Page 86.[5] The table is reproduced here:

Table 5.1.2-B: BC Hydro Monthly Mid-C Price Variations

Month	HLH Multiplier	LLH Multiplier
Jan	116%	105%
Feb	111%	102%
Mar	104%	96%
Apr	95%	89%
May	89%	81%
Jun	90%	82%
Jul	105%	91%
Aug	113%	97%
Sep	102%	94%
Oct	107%	95%
Nov	111%	101%
Dec	116%	106%
Average	**104.9%**	**94.9%**

FBC's view of the data in the table is that it continues to be a reasonable assessment of the average monthly price variations relative to base annual price forecast (assuming normalised conditions). FBC also notes that BC Hydro has not provided updated information in its current draft 2013 IRP that has been released for review, but sees no reason why BC Hydro would have changed its estimates.

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[5] https://www.bchydro.com/content/dam/hydro/medialib/internet/documents/planning_regulatory/iep_ltap/2011q1/irp_tac_mtg2_meeting0.pdf

6.2 In determining the avoided costs for each DSM measure or program, does FBC apply adjustments for monthly and HLH/LLH differentials, such as those shown in 2012 Long Term Resource Plan, Appendix B, Table 5.1.2-B?

Response:

No. The Long Run Marginal Cost is based on an annual average. No time of delivery factors have been applied. Likewise, no time of delivery factors are applied to the value of a DSM project when evaluating the value of such DSM to FBC.

6.2.1 If so, please provide the documents and spreadsheets that show those adjustments.

Response:

Please refer to the response to BCSEA IR 1.6.2.

6.2.2 If not, please explain why not.

Response:

The DSM projects are evaluated based on annual average avoided costs. Currently they do not distinguish between seasonal or time of day savings. Therefore it would be inconsistent to apply seasonal and time of day shaping factors to the avoided cost forecast.

7.0 Topic: Avoided energy, price and characteristics

Reference: Exhibit B-1-1, Appendix H, Attachment H4

7.1 Please provide in electronic form any data available to FortisBC regarding the hourly prices at the Mid-Columbia Hub for each hour over the period 2010–2013.

Response:

Please refer to Attachment 7.1.

7.2 Please provide in electronic form the hourly retail load for FortisBC for each hour over the period 2010–2013.

Response:

Until FBC's Advanced Metering Infrastructure is installed, FBC is not able to calculate the hourly retail load. FBC does have hourly gross load, which includes all retail load and system losses. That information is provided in Attachment 7.2.

7.3 For each rate class or customer class for which FortisBC has information, please provide in electronic form FortisBC's estimate of the hourly load for each hour over the period 2010–2013.

Response:

Until FBC's Advanced Metering Infrastructure is installed, FBC is not able to calculate this data on an hourly basis. Please refer to the response to BCSEA IR 1.7.2.

7.4 For each end use for which FortisBC has estimates, please provide in electronic form FortisBC's estimate of the hourly load for each hour over the period 2010–2013.

Response:

Until FBC's Advanced Metering Infrastructure is installed, FBC is not able to calculate this data on an hourly basis. Please see BCSEA IR1.7.2.

7.5 Please explain whether the energy avoided by DSM has the same hourly shape as a standard contract for HLH energy, LLH energy, or All-hours energy.

Response:

DSM programs are comprised of measures that reduce energy use (as opposed to time of use rates which specifically target peak loads). DSM savings will generally follow FBC's time of day and seasonal load profile.

A typical market contract for FBC has in the past been contracting for short-term supplies of firm power to be delivered to FortisBC during the on-peak hours during the peak demand months of December, January, and/or February. FortisBC has also acquired firm spot market energy in other seasons when spot market prices were below the BC Hydro RS3808 price, displacing RS3808 purchases. The advantage of this procurement method is that FortisBC has flexibility with regard to contract timings, quantity of contracts and contract durations.

Therefore DSM currently does not have the same hourly shape as a typical contract, DSM does not have the real-time flexibility to be displaced by market purchases when spot market prices are more attractive, and DSM is not regarded by FBC as firm.

7.5.1 If not, please explain how FortisBC has adjusted the Mid-Columbia prices to reflect the load shape of the DSM savings.

Response:

The proxy for LRMC of market purchases calculated from Midgard's 2013 BC Market Price Curve Update is an annual average price. No time of delivery shaping factors have been applied to the LRMC.

7.5.2 If FortisBC has not adjusted avoided energy cost to reflect the shape of savings, please explain why.

Response:

It is a simplifying assumption. FBC typically does not apply time of use shaping factors to screen its DSM programs to favor winter peak savings, nor does FBC apply time of use shaping factors in its calculation of the proxy for the LRMC of market purchases.

7.6 Please provide in electronic form FortisBC's hourly purchases of energy (not including the BC Hydro PPA, the Brilliant PPA and the Powerex CPB) for each hour of the last three years, differentiating among:

7.6.1 purchases from entities in BC,

Response:

FortisBC does not have this information compiled in segregated hourly form but does have this information separated monthly. The table below shows the monthly market purchases segregated by purchases from entities in BC, US entities through BC Hydro, US entities through Teck Metals Line 71 and from Alberta. Please refer to Attachment 7.6.1 for the electronic spreadsheet.

Date	Purchases from (MWh)				
	Entities in BC	US entities through BC Hydro	US through Teck Metals Line 71	Alberta	Total
Jan-10	-	-	4,038	-	4,038
Feb-10	-	-	-	-	-
Mar-10	385	-	316	-	701
Apr-10	-	-	2,710	-	2,710
May-10	5,356	-	30,943	-	36,299
Jun-10	2,600	-	39,866	-	42,466
Jul-10	4,593	-	10,609	-	15,202
Aug-10	1,752	-	28,563	-	30,315
Sep-10	2,460	-	17,700	25	20,185
Oct-10	20,351	-	15,910	1,034	37,295
Nov-10	28,297	-	26,602	-	54,899
Dec-10	18,700	-	28,585	-	47,285
2010 Total	**84,494**	**-**	**205,842**	**1,059**	**291,395**
Jan-11	20,608	-	36,159	-	56,767
Feb-11	5,565	-	47,579	-	53,144
Mar-11	6,184	-	59,977	-	66,161
Apr-11	4,966	-	41,703	-	46,669
May-11	360	-	25,170	-	25,530
Jun-11	2,363	-	45,670	-	48,033
Jul-11	2,382	-	29,464	-	31,846
Aug-11	1,004	-	22,159	-	23,163
Sep-11	262	-	11,010	-	11,272
Oct-11	1,210	-	43,970	-	45,180
Nov-11	12,962	-	34,954	-	47,916
Dec-11	23,270	-	10,932	-	34,202
2011 Total	**81,136**	**-**	**408,747**	**-**	**489,883**
Jan-12	31,338	-	23,733	-	55,071
Feb-12	23,009	-	30,847	-	53,856
Mar-12	20,102	-	30,053	-	50,155
Apr-12	804	-	27,958	-	28,762
May-12	1,956	-	21,413	-	23,369
Jun-12	4,378	-	26,774	-	31,152
Jul-12	16,044	-	25,564	-	41,608
Aug-12	6,342	-	12,806	-	19,148
Sep-12	10,024	-	34,731	-	44,755
Oct-12	11,113	-	38,581	-	49,694
Nov-12	22,436	-	32,062	-	54,498
Dec-12	15,325	-	56,860	-	72,185
2012 Total	**162,871**	**-**	**361,382**	**-**	**524,253**

7.6.2 purchases from US entities through BC Hydro,

Response:

Please refer to the response to BCSEA IR 1.7.6.1.

7.6.3 purchases from US entities through Teck Metals Line 71, and

Response:

Please refer to the response to BCSEA IR 1.7.6.1.

7.6.4 purchases from Alberta.

Response:

Please refer to the response to BCSEA IR 1.7.6.1.

7.7 Please provide in electronic form FortisBC's hourly purchases of energy (not including the BC Hydro PPA, the Brilliant PPA and the Powerex CPB) for each hour of the last three years, differentiating among:

7.7.1 Hourly economy purchases,

Response:

FBC does not have the hourly purchases segregated by hourly economy purchases, daily economy purchases, weekly purchases, monthly purchases, purchases for more than one month, but less than a year and purchases for one year or longer and it would be extremely difficult, if not impossible, to do so. Please refer to Attachment 7.7.1 for FBC's total hourly market purchases from March 15, 2012 to July 31, 2013. No data is available without manually adding it from the daily records one hour at a time prior to March 15, 2012.

7.7.2 Daily economy purchases,

Response:

Please refer to the response to BCSEA IR 1.7.7.1.

7.7.3 Weekly purchases,

Response:

Please refer to the response to BCSEA IR 1.7.7.1.

7.7.4 Monthly purchases,

Response:

Please see the response to BCSEA IR7.7.1.

7.7.5 Purchases for more than one month, but less than a year,

Response:

Please refer to the response to BCSEA IR 1.7.7.1.

7.7.6 Purchases for one year or longer, indicating the duration of each such purchase.

Response:

Please refer to the response to BCSEA IR 1.7.7.1.

7.8 Please provide a description of the penalties for the selling counter-party if contracted energy is not available at Mid-Columbia for delivery to FortisBC.

Response:

If contracted energy cannot be delivered, liquated damages may be available to FBC to cover the cost of replacement energy. FBC treats counter-party reliability very seriously and only rarely has contracted energy not been made available to FBC.

8.0 Topic: Delivery of Mid-Columbia Energy to FortisBC

Reference: FortisBC 2012 Long Term Resource Plan, Appendix B – Midgard 2011 FortisBC Energy & Capacity Market Assessment, p. 18 of 54 (pdf 122)

"Both the British Columbia/Alberta and the British Columbia/United States interconnections are often at their maximum transmission limit, which means wheeling additional power between utilities in the region is frequently not possible. Given that the key source of external (non-BC) wholesale market electricity for FortisBC is the United States, these constraints are a potential problem for FortisBC because they restrict access to the energy and capacity from the US market. As electricity demand continues to grow, absent sufficient new transmission infrastructure, transmission constraints between British Columbia and the United States will become ever more restrictive." [FortisBC Inc. 2012 Long Term Resource Plan, Appendix B – Energy and Capacity Market Assessment, p. 18 of 54 (pdf 122)]

8.1 Was the above-quoted description of FortisBC's BC/Alberta and BC/US transmission constraints accurate when it was made?

Response:

Yes, to the best of FBC's knowledge.

8.1.1 Is it accurate now? If not, why not?

Response:

Yes, to the best of FBC's knowledge.

8.2 Please quantify current and future restrictions on FortisBC's access to energy and capacity from the US market.

Response:

FBC does not understand the question as it does not seem possible to "quantify current and future restrictions". To further quote from the following paragraph of the Resource Plan quotation referenced above, "As a result it is reasonable to expect that FortisBC will be in competition with nearby regions for both energy supplies and transmission capacity during such peak demand periods." FBC agrees that it is risky to rely on the market to meet energy and capacity needs during periods of peak demand.

However, the availability of energy at times when capacity is not of concern is very reliable and secure. FBC's main requirement from the market at this time is energy, not capacity and FBC does not anticipate any difficulty in acquiring energy supplies from the US market on an as needed basis. However, over the longer term as FBC's requirements grow, it may be prudent to consider other options due to price risk. The 2016 Resource Plan will re-examine the best resource options for FBC to meet customer capacity and energy and stand alone energy needs at that time.

8.3 In light of this discussion, please explain how the cost of purchases from Mid-Columbia is relevant to the FortisBC avoided cost.

Response:

The Mid-Columbia electricity market is one of the most important electricity trading hubs in North America and, as measured by volume on the Intercontinental Exchange, the third largest electricity trading point in the US and second largest in the WECC region. In its FortisBC Energy & Capacity Market Assessment, Midgard states: "The wholesale electricity market in British Columbia has a limited number of buyers and sellers and as a consequence wholesale pricing in the province essentially amounts to the wholesale prices for the Mid- Columbia ("Mid-C") market adjusted to take into account the costs of moving electricity into BC."[6]

Purchasing capacity in the wholesale market is a strategy that FortisBC has historically employed. The Company can purchase these products directly from the US electricity market or from BC Hydro's trading subsidiary Powerex. Typically this can only be done on a short term basis and is achieved by contracting for short-term supplies of firm power to be delivered to FortisBC during the peak demand months of December, January, and/or February. The advantage of this procurement method is that FortisBC has flexibility with regard to contract timings, quantity of contracts and contract durations.

The consequences of transmission congestion are highest for FBC and its customers during on-peak hours during the winter peak. FortisBC may also be able to bypass the transmission congestion and purchase market energy from Powerex if it has power to sell. Given DSM is a broad measure to generally reduce load (as opposed to time of use rates which target peak loads), transmission congestion was not included in the assessment of FBC's avoided cost.

[6] FBC 2012 Long-Term Resource Plan, Appendix B, page 5 of 54.

In its Energy and Capacity Market Assessment in the Resource Plan, Midgard concluded: "FortisBC's continued reliance upon the wholesale electricity market to meet current and future needs is not an unreasonable strategy - especially in light of the modest sizes of FortisBC's energy and capacity deficits."[7] FBC believes this statement remains valid, even though some market condition such as price forecasts have changed since the plan was released. FBC will continue to monitor the risks, including transmission congestion, in using the Mid-C market for energy supply, and this will be part of the portfolio analysis of resource options in future resource plans.

8.4 Please provide the current Bonneville Power Administration Transmission and Ancillary Service Rate.

Response:

BPA's current transmission rates can be found at http://transmission.bpa.gov/Business/Rates/ and are provided in Attachment 8.4.

8.4.1 Please indicate which rate would apply to transmitting energy from Mid-Columbia to Teck Metals Line 71.

Response:

The rate that would apply to transmitting energy from Mid-C to Teck Metals Line 71 would be BPA's Hourly Firm and Non-Firm transmission service rate, under the Point to Point Rate, currently 3.74 mills per kilowatthour. Additionally, BPA's Scheduling, System Control and Dispatch Service would apply at 0.59 mills per kilowatthour and Regulation and Frequency Response Service at 0.13 mills per kilowatthour. In total, the rate for wheeling energy from Mid-C to Teck Metals Line 71 would be 4.46 mills per kilowatthour, equivalent to $4.46 per MWh. In addition, BPA would charge 1.9% real power losses for every MWh wheeled from Mid-C to Teck Metals Line 71.

8.5 Does the BPA 2012 White Book or any other BPA document forecast exports to FortisBC?

[7] FBC 2012 Long-Term Resource Plan, Appendix B, page 6 of 54

Response:

FortisBC is not aware of any BPA forecast of exports to FBC.

8.5.1 If so, please provide that forecast.

Response:

Please refer to the response to BCSEA IR 1.8.5.1.

8.6 Please provide the basis for the assumption that energy delivered to the Teck Metals Line 71 would be “transmitted into FortisBC territory at no additional cost or charge to FortisBC.” (2012 Long Term Resource Plan, Appendix B, p. 25 of 54)

Response:

Energy delivered to the FBC service area through Teck Metals Line 71 is subject to a wheeling cost per MWh of energy delivered. However, the exclusion of the wheeling cost for Teck Metals Line 71 in the Midgard study is not material.

8.6.1 Do Midgard and FBC continue to make this assumption?

Response:

Yes. However, as discussed in the response to BCSEA IR 1.8.3, transmission congestion does not change FBC’s avoided cost assessment for DSM.

8.7 Please provide any data available to FortisBC regarding the firmness of BPA’s capacity for delivery to the Teck Metals Line 71.

Response:

The firm transmission from Mid-C to the BC/US border (which includes Teck Metals Line 71) is fully subscribed. However, BPA routinely makes additional transmission available on a non-firm basis. It is a fully accepted practice in the Pacific North-West to carry firm Generation on non-firm transmission and refer to the combined product as firm. On an hourly basis, it is expected that there will be a certain amount of this non-firm transmission available, but no guarantee that there will be enough to fully meet the demand. In addition, purchases can be arranged through the holders of the firm transmission if longer term deals are desired.

Therefore, if transmission can be obtained, it is expected that BPA will deliver the power but there is no guarantee of this.

8.7.1 Please specify the capacity from Mid-Columbia to Teck Metals Line 71 that FortisBC has reserved.

Response:

FBC has not reserved any firm transmission capacity from Mid-C to Teck Metals Line 71. FBC only accepts power at the BC/US border and the sellers make the required arrangements for transmission.

8.7.2 If FortisBC does not have a firm capacity reservation from Mid-Columbia to Teck Metals Line 71, please provide the available firm transmission capacity on this path for each hour since January 2010.

Response:

The firm capacity on the US to BC path is fully subscribed and therefore there is no availability to purchase additional firm transmission from BPA. Please refer to the response to BCSEA IR 1.8.7 for a description of scheduling practices.

While BPA does not provide historical data on available transmission capacity nor what was utilized, attachment 8.7.2 contains the historical transmission flow data on a daily basis since January 2010, compiled by an external analytics provider retained by FortisBC. It contains the Actual Transmission Flow, which is how much actual power flowed north each hour, and the Transmission Limit available, which is the total amount BPA would authorize to flow. The difference between the two is the additional amount of non-firm transmission that could have been purchased in each hour. Of the actual flow, it is not known how much was on firm or how much actual non-firm transmission was reserved.

8.8 Please clarify whether the Teck Metals Line 71 is “the one merchant transmission line owned by Teck Metals at Trail, BC.” (2012 Long Term Resource Plan, Appendix B, page 17 of 54, footnote 20)

Response:

Confirmed.

8.8.1 Please explain why a “merchant” facility would not charge users.

Response:

Please refer to the response to BCSEA 1.8.6.

8.9 Please provide the wheeling charges that FortisBC would incur if it received power from Mid-Columbia through BC Hydro, rather than Teck Metals Line 71.

Response:

The BC Hydro Open Access Transmission Tariff can be found here: http://transmission.bchydro.com/regulatory_filings/tariff/tariff_documents/open_access_tariff.htm.

FBC would expect to pay the following charges:

- Schedule 01 – Point-to-Point Transmission Service: $5.97/MW of Reserved Capacity per hour;
- Schedule 03 – Scheduling, System Control, and Dispatch Service: $0.139 per MW of Reserved Capacity per hour;
- Schedule 10 – Real Power Losses: 6.28% on the energy delivered to the points of receipt.

8.10 Please explain why Teck Metals continues to maintain Line 71, if it "does not use the line to import power." [2012 Long Term Resource Plan, Appendix B, p. 25 of 54 (pdf 129)]

Response:

The Line 71 interconnection is an important piece of the overall FBC transmission system (which includes Teck transmission) to preserve system reliability. This has obvious benefits for both the Teck smelter load located in Trail and the Waneta generation facility.

In addition, Line 71 is available to Teck to import power in the event of a plant outage to Waneta.

8.10.1 How does Teck Metals use the line?

Response:

Please refer to the response to BCSEA IR 1.8.10.

9.0 Topic: Avoided cost methodology

Reference: Exhibit B-1-1, Appendix H, Attachment H-4

9.1 Who within Midgard is the author of the 1 June 2013 memo to FortisBC?

<u>Response:</u>

The primary author is Michael Walsh, Principal and co-founder of Midgard Consulting.

10.0 Topic: Avoided cost methodology, BC electricity price

Reference: Exhibit B-1-1, Appendix H, Attachment H4, LRMC Avoided Cost Derivation, Midgard Memorandum ("memo")

The memo's subject is "Derivation of the British Columbia Electricity Price Forecast 2014 to 2043." [p.1, pdf p.880 of 887]

"The memorandum outlines the methodology to generate the price of electricity within the British Columbia market, for the years 2014 through 2043." [p.1, pdf p.880 of 887]

"...there is no transparent or liquid electricity market in British Columbia." [p.1, pdf p.880 of 887]

"The forecast is not meant to represent the cost of importing power, but rather a proxy for the average price of electricity within the British Colombian context." [p.3, pdf p.882 of 887]

10.1 Please confirm that the Midgard memo does not forecast the price of electricity within British Columbia for sale by BC Hydro or by FortisBC.

Response:

Confirmed.

The Midgard memo forecasts the annual average price of market electricity sold on the liquid Mid-Columbia trading hub, and adds the delivery cost to BC. This is a good proxy for the annual average price of market power within BC. There is no comparable trading hub within BC on which to base a forecast of spot market prices. Any spot market transactions done within BC are done on a confidential, bilateral basis.

FortisBC currently purchases market power from both the Mid-C market and from Powerex (if available). Unless there were other considerations like transmission congestion, in principle, Powerex would not offer spot market power to FortisBC at prices lower than its sellers opportunity cost (Mid-C minus BPA wheeling and losses), and FortisBC would not pay for spot market power from Powerex at prices higher that its buyer's avoided cost (Mid-C plus BPA wheeling and losses).

10.2 Why does the memo characterize the forecast as a forecast of "British Columbia Electricity Price" and "the price of electricity within the British Columbia market" given the statement that "...there is no transparent or liquid electricity market in British Columbia"?

Response:

Please refer to the responses to BCSEA IRs 1.10.1 and 1.10.3.1.

10.3 Regarding Midgard's statement "The forecast is not meant to represent the cost of importing power, but rather a proxy for the average price of electricity within the British Colombian context":

10.3.1 Please explain why Midgard considers it important to confirm that the "forecast is not meant to represent the cost of importing power."

Response:

The factors that impact the supply, demand and price of electricity within the Mid-Columbia electricity trading hub are similar, but not necessarily identical, to the factors that that impact supply, demand and price of electricity within the British Columbian context. Consequently, the Mid-C price index is a proxy for the average price of electricity within the British Columbian context, not the cost of importing power because power imports would not occur on an average basis.

10.3.2 Does FortisBC agree that the methodology set out in Attachment H-4 appears to be for a forecast of FortisBC's cost of importing power, despite Midgard's statement to the contrary?

Response:

No. The methodology set out calculates FBC's avoided cost of market purchases based on annual average prices. Please refer to the response to BCSEA IR 1.10.3.1.

10.3.3 Please explain why Midgard considers it important to state that the forecast is "a proxy for the average price of electricity within the British Colombian context."

Response:

Please see the response to BCSEA IR 1.10.3.1.

10.3.3.1 Is there some guideline or rule that requires determination of DSM avoided cost using "the average price of electricity within the British Colombian context"? If so, please provide it.

Response:

No. The underlying principle FortisBC uses in determining its DSM avoided cost is that the cost should reflect FBC's LRMC of incremental supply. Based on FBC's specific circumstances and needs, FBC's avoided cost of power over the long term is the cost of market purchases. Paying for DSM above the Company's long-run marginal cost of market power creates inappropriate price signals and is not in the best interest of our customers.

10.3.3.2 Please explain why Midgard says the forecast is a proxy for the average price of electricity when the forecast is used to determine a marginal price of electricity.

Response:

The forecast provides a proxy for the average wholesale market price over each year. Wholesale market prices are actually determined on an hourly basis. The wholesale price in any hour is generally set by the marginal generation source that is dispatched in that hour to meet demand.

Please also refer to the responses to BCSEA IRs 1.10.3.1 and 1.10.3.2.

10.3.3.3 If Midgard's intention was to estimate the average price of electricity in B.C., please explain why Midgard did not analyze the prices offered by BC Hydro, FortisBC, Powerex and other sellers of electricity in B.C.

Response:

Please refer to the response to BCSEA IR 1.10.1.

11.0 Topic: Avoided cost methodology

Reference: Exhibit B-1-1, Appendix H-4, Attachment H-1, 2014-2018 Demand Side Management (DSM) Plan, p.3; pdf p.797 of 887

"The 2014-18 DSM Plan is a modified extension of the 2012-13 DSM Plan, which received approval via Commission Order G-110-12. The 2014-18 DSM Plan programs, and expenditures, are reduced commensurate with the advent of the lower Long Run Marginal Cost (LRMC) of $56.61/MWh. The LRMC affects the Total Resource Cost test by reducing the benefit of power purchase reductions, which in turn makes fewer demand-side management programs and measures economic as prescribed by the Demand-Side Measures Regulation (DSM Regulation)."

11.1 Does FortisBC use the term Long Run Marginal Cost (LRMC) as being synonymous with 'avoided cost' for the purpose of determining the 'total resource cost' (TRC) ratio of DSM programs and portfolio (setting aside the modified TRC in the DSM Regulation)?

Response:

Please refer to the response to BCUC IR 1.236.1.

11.1.1 If not, please provide a full explanation of the methodology and results by which FortisBC obtains an avoided cost for TRC purposes from the LRMC. And, please provide FortisBC's definition of "avoided cost."

Response:

Please refer to the response to BCUC IR 1.236.1.

11.1.2 If FortisBC uses "LRMC" as synonymous with avoided cost for TRC purposes, please provide FortisBC's definition of LRMC.

Response:

Please refer to the response to BCUC IR 1.238.1 for the Company's determination of LRMC.

11.2 Please describe in detail the method and results by which FortisBC determined (a) the LRMC used in the 2012-13 DSM Plan and (b) the LRMC of $56.61/MWh used in the proposed 2014-2018 DSM Plan. Please provide an explanation of each point of difference.

Response:

The LRMC is a levelization of the 30 year Midgard BC Energy Market Price Curve, using a 8% nominal discount rate and assuming 2.1% per annum inflation.

The BC Wholesale Market Energy Price Curve utilized in the 2012-13 DSM Plan came from the Midgard's 2011 FortisBC Energy & Capacity Market Assessment dated May 26, 2011.[8] It was based on years 2011-2040.

The BC Wholesale Market Energy Price Curve utilized in the proposed 2014-2018 DSM Plan came from the Midgard's British Columbia Electricity Price Forecast Update dated June 15, 2013. It was based on years 2014-2043

Please refer to the response to BCSEA IR 1.12.3 for details on the differences between the forecasts.

11.3 Please confirm that in the FortisBC Advanced Metering Infrastructure ("AMI") CPCN application proceeding, FortisBC used an estimate of $54.68 per MWh for 2012 as FortisBC's short-run marginal cost.

Response:

Confirmed. The 2012 estimate of $54.68 per MWh corresponds with the expected market price provided in Table 5.2.2.3-B from FortisBC's 2012 Integrated System Plan, Volume 2 (Exhibit B-1-2 from that proceeding).

[8] FortisBC 2012 Long Term Resource Plan, Appendix B, Table 5.1.3.3-A, page 26 of 54.

11.3.1 Please file page 86 of the Commission's July 23, 2013 AMI Decision.

Response:

Please refer to Attachment 11.3.1.

11.4 Please confirm that in the FortisBC Advanced Metering Infrastructure CPCN application proceeding, FortisBC used an estimate of $111.96/MWh (increased to $125.80/MWh by adding 11% for FortisBC system losses) as FortisBC's long-run marginal cost. [Reference: AMI Decision, p.86]

Response:

Although FBC did provide an estimate of $125.80/MWh as "the long-run marginal cost of acquiring energy from new resources" in the AMI proceeding (BCUC IR 2.61.1), FBC did not use this rate to evaluate the economics of the project as presented in the CPCN application. The Company did indicate however that it did not object to the use of this rate to evaluate the economics of the project.

The $125.80 figure, which is based on the long-run marginal cost of acquiring energy from new resources provided in the 2011 Residential Inclining Block application, is not comparable to the long-run marginal cost in this application, which is a current estimate of the long-run marginal cost of market-based resources.

11.5 Please reconcile FortisBC's short-run marginal cost of $54.68/MWh for 2012 in the AMI proceeding with the $56.61/MWh figure for LRMC in the proposed 2014-2018 DSM Plan. Is the basis for the two estimates the same, with the difference being explained by different 'as of' years?

Response:

The $54.68 was based on a levelization of a FBC internal 30 year BC Wholesale Market Energy Curve update, utilizing the Midgard methodology outlined in the 2012 Resource Plan, but assuming BC Hydro's low-gas, low carbon forecast, with prices commencing in 2011.

The $56.61 is based on the Midgard June 15, 2013 BC Wholesale Market Energy Curve update.

11.6 Please explain why FortisBC calls $56.61/MWh a long-run marginal cost in the current proceeding and calls what appears to be the same concept (estimated at $54.68/MWh for 2012) a short-run marginal cost in the AMI proceeding.

Response:

The short run marginal cost of $54.68 used in the AMI proceeding is the year 2012 expected price in the Midgard BC Wholesale Market Energy Price Curve developed in the Midgard 2011 Energy Market Assessment.[9]

The Long-Run Marginal Cost of market purchases of 56.61 is the levelization of the Midgard's BC Wholesale Market Energy Price Curve Update dated June 15, 2013.

11.7 Why did FortisBC not include in the present application any explanation of the methodology and results that caused the avoided cost for DSM benefit/cost analysis to fall from $84.94/MWh to $56.61/MWh?

Response:

FortisBC included Appendix Attachment H-4 that explained in detail the methodology by which the LRMC was calculated. Please refer to the response to BCSEA IR 1.12.3 for further explanation of the changes.

11.8 When applying the DSM Regulation, apart from modifications of the total resource cost ratio defined in the Regulation, what guidelines, such as the California Standard Practice Manual or other, does FortisBC use when determining the avoided cost for DSM benefit/cost purposes?

Response:

The California Standard Practice Manual provides the scope of what is included in determining avoided costs, but does not specify a methodology to ascertain the LRMC.

[9] FortisBC 2012 Long-Term Resource Plan, Appendix B, Section 5.1.3.3, Table 5.1.3.3-A, page 26 of 54.

"The benefits calculated in the Total Resource Cost Test are the avoided supply costs--the reduction in transmission, distribution, generation, and capacity costs valued at marginal cost--for the periods when there is a load reduction. The avoided supply costs should be calculated using net program savings, savings net of changes in energy use that would have happened in the absence of the program."[10]

FortisBC does not use any other guidelines in calculating the LRMC of market purchases.

11.8.1 Please provide copies of industry standard guidelines for determining avoided cost in DSM benefit/cost analysis.

Response:

As identified in the preamble to BCUC question 238.1, the NERA December 2011 paper titled "Estimating Long Run Marginal Cost in the National Electricity Market" includes a comparison of two broad methodologies used to estimate the capital component of the LRMC for a market. The link to that paper is provided here: http://www.aemc.gov.au/Media/docs/Technical%20paper-168ea920-eb90-446d-a033-ab07edf8a8a6-0.pdf

It also states a December 2012 report by the Alberta Market Surveillance Administrator (MSA) titled "A Comparison of the LRMC and Price of Electricity in Alberta" identifies four approaches used to measure LRMC on pages 4 to 6. A link to that paper is provided here: http://albertamsa.ca/uploads/pdf/Archive/2012/SOTM%20LRMC%20121012.pdf

The California Standard Practice Manual has been recognized by some in the industry as a reference guide. The guidelines in the California Standard Practice Manual have been written for the California market and were last updated in 2001. A link to the California Standard Practice Manual is provided here: http://www.energy.ca.gov/greenbuilding/documents/background/07-J_CPUC_STANDARD_PRACTICE_MANUAL.PDF

FBC finds there are multiple ways of calculating LRMC and avoided cost, even when following one of the general approaches identified in the studies above. Any utility application of these standards needs to be adapted to the particular circumstances of the utility using them.

[10] California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects, October 2001. p.24.

12.0 Topic: Avoided cost, planning context

References:

-- Exhibit B-1-1, Appendix H, p.4, pdf p.777 of 887;

-- Exhibit B-1-1, Appendix H, Attachment H-1 DSM Plan, Table H-1b – 2014-2018 DSM Plan Savings, p.4, pdf p.798 of 887;

-- Exhibit B-1-1, Appendix H, Table H-4, p.9, pdf p.782 of 887

"Under section 44.2 of the UCA, the Commission, in considering whether to accept an expenditure schedule by a utility, must consider that utility's most recent long-term resource plan filed under section 44.1 of the Act. The current Long Term Resource Plan (LTRP) as accepted by the Commission is the 2012 LTRP submitted in June of 2011. The 2014-2018 DSM Plan and the proposed expenditures are consistent with the methodology used in the 2012 LTRP, and the Commission's directives regarding the plan." [Appendix H, p.4, footnote reference removed]

"The 2012 LTRP and the associated 2012 Long Term DSM Plan were predicated on a levelized market price of $84.94/MWh. Since then, the Company has determined the LRMC has declined to $56.61/MWh (see attachment H4). The number and breadth of DSM measures and programs that pass the Total Resource Cost test, has diminished commensurate with the lower LRMC. The current LRMC, coupled with other non-program conservation drivers, e.g. Residential Conservation Rate, resulted in the 2014-2018 DSM Funding Request that follows in Section 5.1." [Appendix H, p.4, footnote reference removed]

12.1 Please confirm that, in determining whether to accept the proposed 2014-2018 DSM Plan, the Commission is required by s.44.2 of the UCA to consider FortisBC's 2012 LTRP, which has an LRMC of $84.94/MWh.

<u>Response:</u>

Confirmed. The Commission is also required by s.44.2 to consider the extent to which any demand-side measures are cost-effective within the meaning prescribed by regulation. Since LRMC has changed since the 2012 LTRP, this is an important consideration.

12.2 Please confirm that the LRMC estimate of $56.61/MWh in the current application is almost exactly two-thirds of the LRMC estimate of $84.94/MWh in the 2012 LTRP.

Response:

Confirmed.

12.2.1 Does FortisBC agree that a drop in the LRMC of one-third constitutes a step change? If not, why not?

Response:

FortisBC agrees that the LRMC has dropped by one-third, but cannot comment on whether this represents a "step change".

12.2.2 Is it a coincidence that the current LRMC estimate is a simple fraction (two-thirds) of the last-used LRMC estimate? If not, please explain.

Response:

It is a coincidence.

12.3 Please quantify the causes of the one-third drop in LRMC estimates, addressing all factors that contribute to the LRMC estimate, including (forecast) Mid-C prices, wheeling charges, line losses, GHG adder, foreign exchange rate and any other factors taken into account.

Response:

The following table describes the contributing factors to the drop in LRMC estimates:

Factor	Quantification & Description of Change	Impact of Change
Forecast Mid-C Electricity Price	The original LRMC ($84.94/MWh) is based on a BC Hydro forecast of Mid-C electricity prices completed by Black & Veatch on behalf of BC Hydro in 2010. In 2013 FortisBC commissioned Midgard Consulting Incorporated to create an updated Mid-C electricity price forecast based on then current information.	Reduced LRMC
Wheeling Charges	The original LRMC ($84.94/MWh) is based on a Bonneville Power Administration wheeling charge that is escalated at 2.1% per year (real dollar basis). The new LRMC ($56.61/MWh) is based on the Bonneville Power Administration wheeling charge escalated at 1.0% per year (real dollar basis).	Reduced LRMC
Line Losses	No Change.	None
GHG Adder	The original LRMC ($84.94/MWh) is based on BC Hydro's "Mid" GHG cost adder forecast represented in the January 27, 2011 presentation by BC Hydro titled "*Integrated Resource Plan Technical Advisory Committee Meeting #2 - Day 1*". The new LRMC ($56.61/MWh) is based on BC Hydro's "Low" GHG cost adder forecast from the same presentation.	Reduced LRMC
Foreign Exchange Rate	The original LRMC ($84.94/MWh) is based on an exchange rate beginning at parity in 2011 and increasing to a CAD to USD exchange ratio of 1.25 to 1 by 2040. The new LRMC ($56.61/MWh) assumes the exchange rate will remain at parity (1 to 1) for the length of the forecast.	Reduced LRMC

12.4 During the proceeding that led to approval of FortisBC's 2012 LTAP, what range of variability did FortisBC assign to the levelized market price of $84.94/MWh?

Response:

$84.94 is the expected value based on Table 5.1.3.3-A in Appendix B (page 26 of 54) of FortisBC's Long-Term Resource Plan.

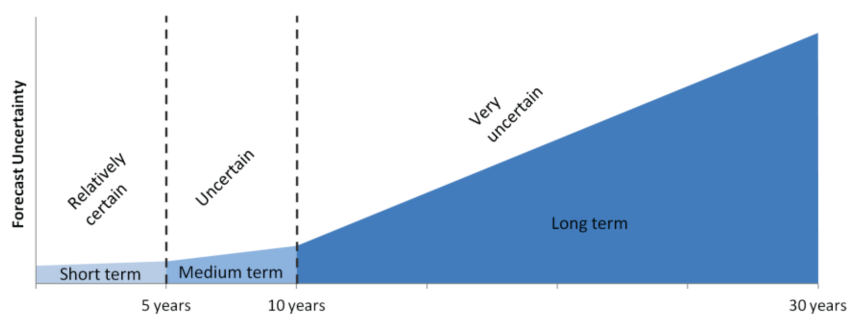
Table 5.1.3.3-A: British Columbia Wholesale Market Energy Curve (CAD)

Year	Expected	HLH	LLH
2011	$51.79	$54.24	$49.26
2012	$54.68	$57.27	$52.00
2013	$57.30	$60.01	$54.49
2014	$61.18	$64.08	$58.17
2015	$64.49	$67.55	$61.32
2016	$68.47	$71.73	$65.11
2017	$72.36	$75.81	$68.80
2018	$76.15	$79.77	$72.40
2019	$79.67	$83.46	$75.74
2020	$82.59	$86.52	$78.52
2021	$88.77	$93.00	$84.39
2022	$92.27	$96.68	$87.72
2023	$94.19	$98.68	$89.54
2024	$96.78	$101.40	$92.00
2025	$100.90	$105.72	$95.92

Year	Expected	HLH	LLH
2026	$104.73	$109.73	$99.56
2027	$108.45	$113.63	$103.09
2028	$112.55	$117.93	$106.99
2029	$117.90	$123.53	$112.07
2030	$122.45	$128.31	$116.40
2031	$128.10	$134.23	$121.77
2032	$130.48	$136.72	$124.03
2033	$134.80	$141.25	$128.13
2034	$139.16	$145.82	$132.28
2035	$143.58	$150.45	$136.47
2036	$148.04	$155.12	$140.72
2037	$152.55	$159.85	$145.00
2038	$157.11	$164.63	$149.34
2039	$161.73	$169.47	$153.72
2040	$167.50	$175.52	$159.22

Figure 3.3.1-A of FBC's 2012 Long-Term Resource Plan illustrates the uncertainty related to long-term energy and capacity price forecasts.

Figure 3.3.1-A - Forecast Period and Uncertainty



12.4.1 What range of variability does FortisBC assign to the LRMC of $56.61/MWh in the current application? Please address both negative and positive variation.

Response:

The LRMC of $56.61/MWh is based on the Midgard June 15, 2013 report. In this report, Midgard forecasted the expected value, and did not produce a high and low forecast. FBC did not assign a range of variability to the LRMC.

12.5 In the proceeding that led to approval of FortisBC's 2012 LTRP did FortisBC provide evidence or argument concerning the likelihood or possibility of a substantial drop in the LRMC occurring within three years? If so, please provide copies of excerpts.

Response:

No, a substantial drop in the LRMC was nor forecast at the time of the development of 2012 LTRP. However, under the DSM Regulation, cost-effectiveness is dependent on variables which, inherently, are not static. The proceeding that led to approval of FortisBC's 2012 LTRP and 2012 Long Term DSM Plan addressed at length the means by which cost-effectiveness are determined. The discussion included reference to the potential change in the variables that FortisBC had to address. For example, page 14 of the Long Term DSM Plan noted: "Over the time span of the 2012 DSM Plan the avoided costs will likely change, as will the measure costs, but the Company will ensure that the Benefit/Cost ratio of the future program mix will be above unity and continue to meet the requirements of the DSM Regulation." Approval was specifically not sought for 2014 and subsequent DSM expenditures, and FortisBC did not create a detailed DSM Plan for the years 2014-16; thus the expenditure levels were unknown at the time.

Specifically as to gas market price volatility, this was discussed by the Midgard Energy and Capacity Market Assessment.[11] It stated "Given the uncertainty inherent in forecasting it is helpful to forecast a range of possibilities in order to improve the usefulness of the forecast. The objective of this exercise is to present a range within which natural gas spot prices are expected to fall 19 times out of 20, that is to say a 95% confidence interval.[12]" In Figure A-1[13] and Table A-1[14], Midgard provided the following results. The low end of the range is a significant drop from the expected curve at the time of the 2012 LTRP.

[11] FBC 2012 Long Term Resource Plan, Appendix B, pages 46-50 (of 54).
[12] FBC 2012 Long Term Resource Plan, Appendix B, pages 46 of 55.
[13] FBC 2012 Long Term Resource Plan, Appendix B, pages 47 of 55.
[14] FBC 2012 Long Term Resource Plan, Appendix B, pages 48 of 55.

Figure A-1: Midgard Henry Hub Natural Gas Price Forecast (2010 USD/MMBtu)

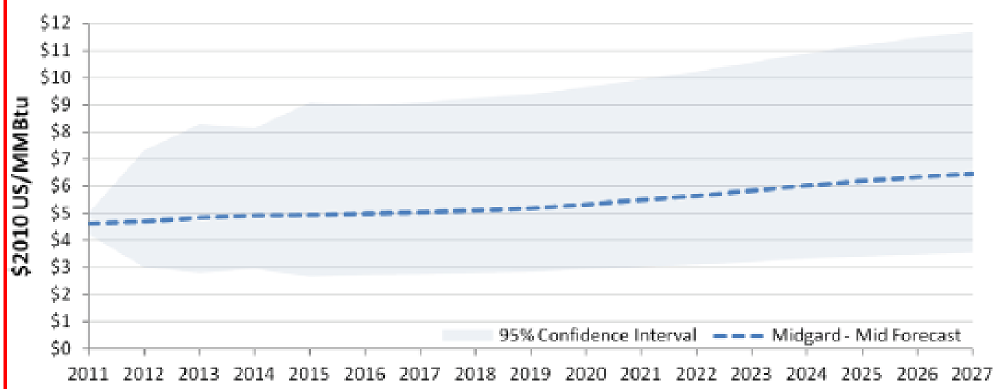


Table A-1: Midgard Henry Hub Natural Gas Price Forecast: Expected and High and Low Boundaries [95% Confidence Interval] (2010 USD/MMBtu)

Year	Expected	Low End	High End
2011	$4.61	$4.23	$5.03
2012	$4.70	$3.02	$7.33
2013	$4.84	$2.83	$8.29
2014	$4.91	$2.96	$8.14
2015	$4.95	$2.69	$9.09
2016	$4.98	$2.75	$9.02
2017	$5.03	$2.77	$9.10
2018	$5.11	$2.82	$9.25
2019	$5.19	$2.86	$9.39
2020	$5.33	$2.94	$9.66
2021	$5.49	$3.03	$9.94
2022	$5.65	$3.12	$10.23
2023	$5.83	$3.22	$10.57
2024	$6.02	$3.32	$10.90
2025	$6.19	$3.42	$11.21
2026	$6.33	$3.50	$11.47
2027	$6.47	$3.57	$11.71

12.6 In the current proceeding, what evidence is FortisBC providing concerning the likelihood or possibility of a substantial drop, or increase, in the LRMC occurring within the 2014-2018 test period?

Response:

In the current proceeding, FBC has provided the expected BC wholesale energy market forecast, and has based its LRMC of market purchases on that expected case.

12.7 Does FortisBC agree that one of the key functions of a long-term resource plan is to identify the planned combination of DSM savings and supply resources over the planning period? If not, why not?

Response:

The Long-Term Resource Plan is a planning document. One of the key aspects of the Resource Plan is to identify the planned resource stack. The actual resource stack can be modified if circumstances change, and that will be updated in future resource plans. Planned DSM savings are one component of the Resource Plan, and that component is derived from the DSM plan.

12.8 Does FortisBC agree that its approved 2012 LTRP contemplates continuation in 2014 and beyond of DSM savings at levels approximating the 2012-2013 DSM savings levels? If not, why not?

Response:

Agreed, however the reduction in the LRMC prompted FBC to revise the DSM savings targets over the PBR period.

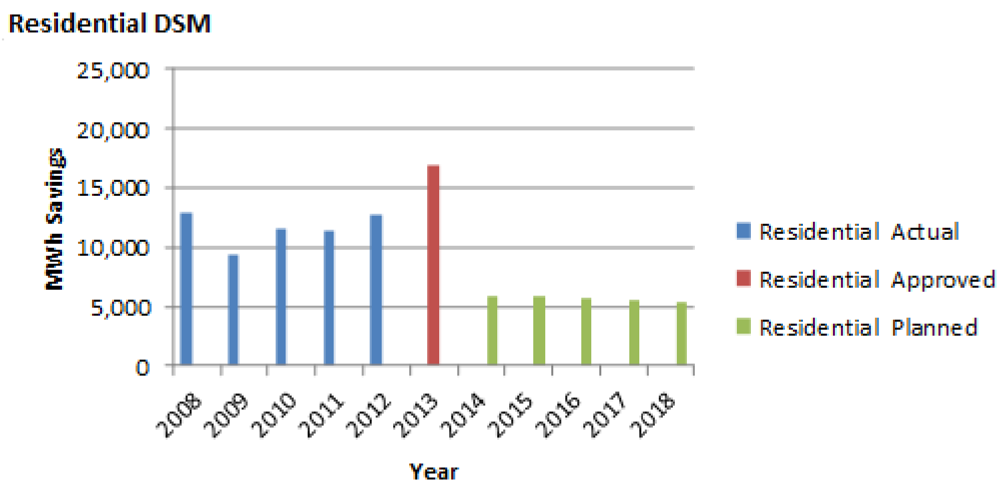
12.9 Please confirm that FortisBC proposes to cut its DSM savings (GWh) in 2014 to about 40% of the savings in 2012-2013, from about 31.5 GWh/y to about 12.8 GWh/y [Reference: Table H-4, pdf p.782 of 887]. Alternatively, please provide the correct percentage and show the calculation.

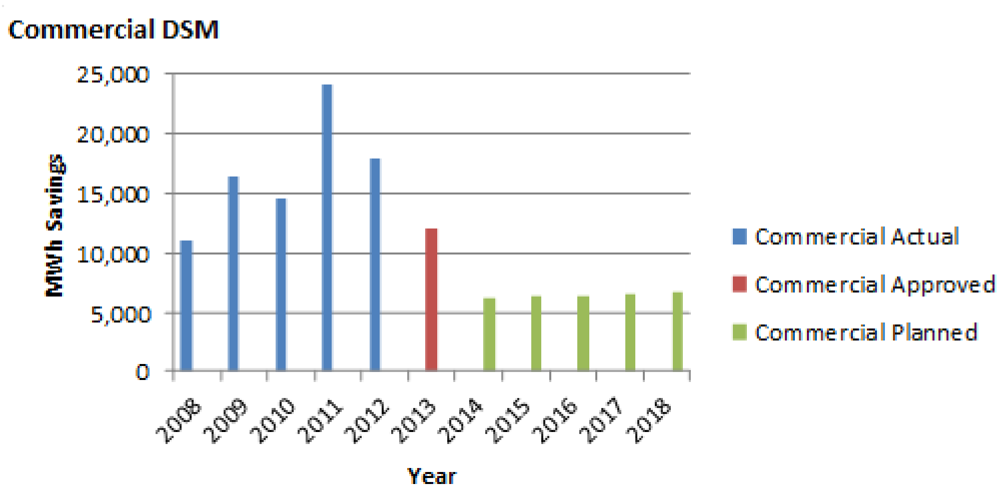
Response:

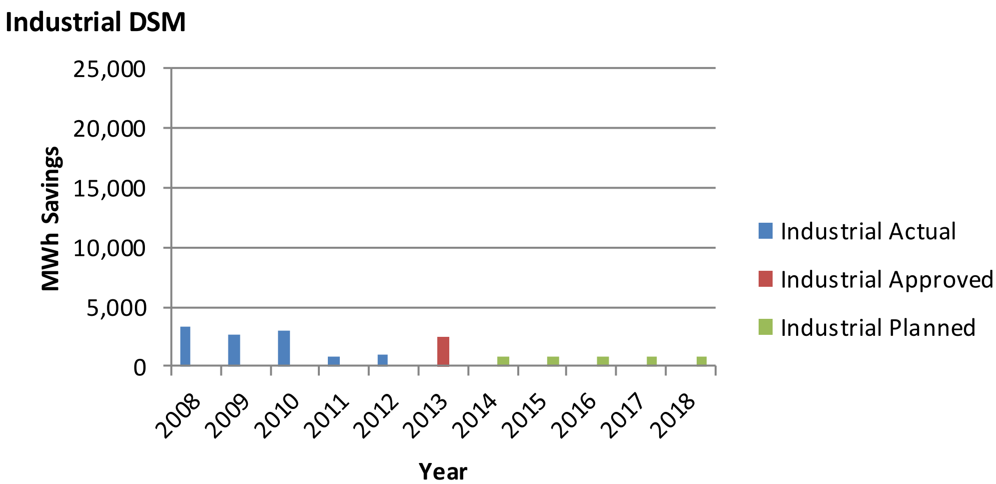
Confirmed.

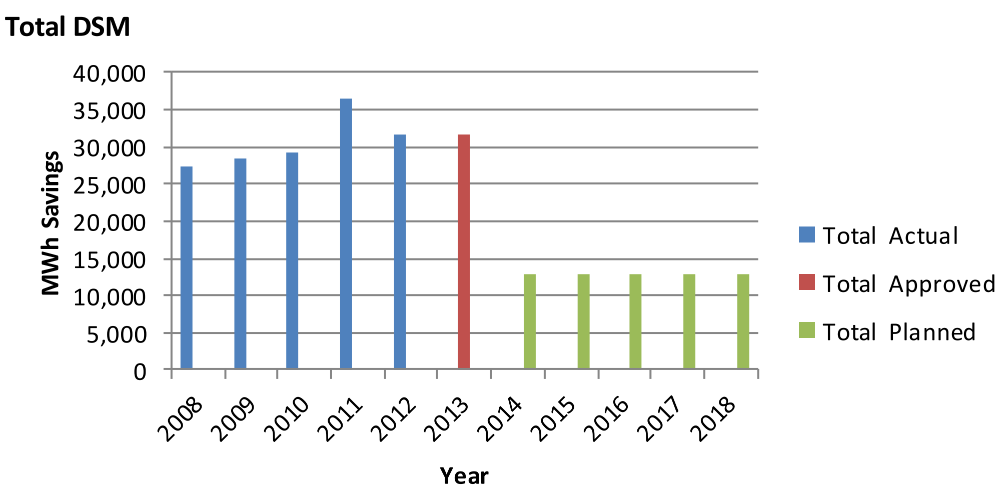
12.9.1 Please provide a bar graph showing approved, actual and planned DSM savings by Residential, Commercial, Industrial and Total, for 2010 to 2018.

Response:









12.10 Does FortisBC agree that its proposal to cut DSM savings in 2014-2018 to 40% of 2012-2013 levels, and to replace these DSM savings with increased imports of market electricity, represents a substantial change in its resource acquisition strategy from that of the 2012 LTRP?

Response:

As outlined in the quote above, the 2014-2018 DSM Plan and the proposed expenditures are consistent with the methodology used in the 2012 LTRP, and the Commission's directives regarding the plan.

Even at the higher level of DSM approved for 2012-2013 of approximately 30 GWh of incremental annual savings, DSM represents less than 1% of the total resource stack. Therefore, changes to DSM savings of the magnitude contemplated, by themselves, do not represent a substantial change in the FortisBC resource acquisition strategy.

FortisBC also notes a drop in the 2014 load forecast as compared to the 2012 forecast due to a lower forecast of residential customer additions which serves to reduce incremental resource requirements.

12.11 Does FortisBC agree that a substantial change in external conditions, such as a one-third drop in the LRMC, warrants revisiting and possibly revising the 2012 LTRP?

Response:

No. Please refer to the response to BCSEA IR 1.12.10.

12.11.1 If so, given that s.44.2 requires the commission to consider the utility's most-recently approved LTRP in determining whether to accept a DSM expenditure schedule, would FortisBC agree that the 2012 LTRP should be revisited and possibly revised prior to the commission considering the substantial spending reductions proposed in 2014-2018 DSM Plan?

Response:

FortisBC cannot agree that the 2012 LTRP should be revisited or revised prior to the Commission's consideration of spending expenditures proposed in the 2014-2018 DMS Plan for two main reasons.

First, the Company's 2012 LTRP approved under section 44.1 of the Utilities Commission Act (the UCA) provides a high level examination of the Company's future demand and supply source expectations over a 30-year planning period and outlines the Company's plan in its acquisition of new energy and capacity resources and management of its overall resources portfolio, in order to ensure that the actions the Company takes now are prudent over the 30-year planning horizon. The DSM measures contained in the LTRP similarly represent a long range plan.

Second, while long-term resource planning can support and provide some high-level context for expenditures approval for DSM programs, the long-term resource planning function does not replace the need for the approvals that may be required under the UCA for certain services and funding for the services to proceed. This is what the Company did under section 44.1 of the UCA with respect to its DSM expenditures for DSM programs for the proposed PBR period. Like its other applications to the Commission, the Company has used the best and the most current information available to support its approval.

The Company thus cannot also agree that the cost-effectiveness of 2012-2018 DSM spending should be based on the LRMC of $84.94/MWh when, as shown in Appendix H4, the more current information reflects that the LRMC has declined to $56.61/MWh.

12.11.2 If not, would FortisBC agree that the mix of DSM savings and supply resources contemplated in the 2012 LTRP should continue, that is, that the cost-effectiveness of 2012-2018 DSM spending should be based on the LRMC of $84.94/MWh in the approved 2012 LTRP?

Response:

Please refer to the response to BCSEA IR 1.12.11.1.

13.0 Topic: Greenhouse gas (GHG) emissions adder

Reference: Exhibit B-1-1, Appendix H, Attachment H4, LRMC Avoided Cost Derivation, Midgard Memorandum ("memo")

13.1 Please describe FortisBC's understanding of its responsibility for reducing GHG reductions, under the policies of the BC and Canadian governments.

Response:

FortisBC electric currently has no specific legislated requirements for GHG reductions under the BC and Canadian governmental regulations. The company does haves a responsibility to consider appropriate power sources to meet customer demand.

Further, the BC ***Clean Energy Act*** Section 6 (4) is applicable to FortisBC:

(4) A public utility, in planning in accordance with section 44.1 of the *Utilities Commission Act* for

(a) the construction or extension of generation facilities, and

(b) energy purchases,

must consider British Columbia's energy objective to achieve electricity self-sufficiency.

The ***Clean Energy Act*** outlines British Columbia's energy objectives in Section 2. These include:

(a) to achieve electricity self-sufficiency;

(b) to take demand-side measures and to conserve energy

(c) to generate at least 93% of the electricity in British Columbia from clean or renewable resources and to build the infrastructure necessary to transmit that electricity;

(h) to encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia;

(o) to achieve British Columbia's energy objectives without the use of nuclear power;

The Company has developed a significant number of demand side management programs that are operated in alignment with provincial energy management objectives.

13.2 Please file the "work performed by Black & Veatch for the [sic] BC Hydro for use within their current (2012/13) Integrated Resource Plan" or indicate where it is in the public record [reference: Attachment H4, Midgard memo, page 3]

Response:

The Midgard report references the work performed by Black & Veatch for the BC Hydro for use within their 2012/2013 Integrated Resource Plan. That Draft IRP can be found at:

http://www.bchydro.com/energy-in-bc/meeting_demand_growth/irp/document_centre/reports/draft_irp.html

The work performed by Black & Veatch can be found in Appendices:

- Appendix 4A-1: Greenhouse Gas Price Forecast Report;
- Appendix 4A-2: Greenhouse Gas Price Forecast Addendum: Additional Scenarios Report;
- Appendix 4B: Low Natural Gas Price Forecast Report;
- Appendix 4C: U.S. Renewable Energy Credit Markets Report;
- Appendix 4D: Renewable Market Competitiveness Report;
- Appendix 4E: Market Scenario Probability Assessment Report.

Subsequent to the Midgard memo, on August 2, 2013 BC Hydro submitted its 2013 Draft IRP to government. The 2013 Draft IRP can be found at:

http://www.bchydro.com/energy-in-bc/meeting_demand_growth/irp/document_centre/reports/august-2013-irp.html

The work performed by Black & Veatch can be found in Appendices:

- Appendix 5B-1: Greenhouse Gas Price Forecast Report;
- Appendix 5C: U.S. Renewable Energy Credit Markets Report;
- Appendix 5D: Renewable Market Competitiveness Report.

13.3 Please explain how Midgard determined that it "feels that the low GHG price adder scenario" from the "work performed by Black & Veatch for the [sic] BC Hydro for use within their current (2012/13) Integrated Resource Plan" is the most plausible scenario." [Attachment H4, Midgard memo page 3]

Response:

Note that the term "Midgard feels" should be interpreted as "it is Midgard's opinion".

When Midgard was compiling its 2014-2043 Electricity Price Forecast Memo, BC Hydro's 2013 (then "2011") Integrated Resource Plan ("IRP") had not been completed. Midgard used precursor documents (such as Technical Advisory Committee ("TAC") reports and presentations) and the data that those documents contained to model its GHG forecast.

Midgard's opinion on GHG pricing when compiling its 2014-2043 Electricity Price Forecast Memo was arrived at as follows:

(1) The BC Hydro Resources at the time of writing indicated that if economic growth was low, the implementation of widespread GHG regulations would be stalled and that this would keep GHG prices low.

In modeling possible scenarios for GHG pricing in a 2011 IRP TAC document titled "Meeting Summary Brief – Greenhouse Gas Price Forecast" (dated January 27/28, 2011, a part of TAC Meeting # 2), BC Hydro's "Scenario C", or Low GHG, is titled "Low economic growth delays national GHG market development", and includes the following:

> *"Lower natural gas prices and low electricity load growth delay spending on renewable energy and [Renewable Portfolio Standards] development."*

> *"Although some progressive governments continue with regional initiatives to regulate GHGs, national action is delayed until at least 2020."*

From these ideas, BC Hydro draws the conclusion that under such conditions, GHG pricing would be low.

(2a) Economic growth from the time of the document's publishing until Midgard's writing of its 2014-2043 electricity price forecast has been low.

It was, and is, Midgard's opinion that economic growth from 2011-2013 has been low, and that economic growth will continue to be low.

(2b) National GHG pricing/trading frameworks have not emerged and are not expected in the near future.

At the time of writing it electricity price forecast memo, it was, and is, Midgard's opinion that National GHG pricing/trading frameworks had not emerged, and were not emerging in the near future. As stated in BC Hydro's now-released 2013 IRP:

> *"To date, no U.S. federal legislative GHG proposal has successfully been passed by both the House of Representatives and the Senate for consideration by the U.S. President. On February 14, 2013, the Climate Protection Act of 2013 was introduced into the U.S. Senate which would, among other things, impose a carbon fee of $20 per ton on coal, oil and natural gas producers beginning in 2014. It is unlikely this bill will become law in the near future given the current realities of the U.S. Congress." (page 5-19)*

> *"The overarching principle informing the Canadian Federal Government's GHG policies is to harmonize GHG initiatives with those at the U.S. federal level. ... The Canadian Federal Government is implementing a sector-by-sector approach to reducing GHG emissions in major emitting sectors as one means of achieving this target."*

Furthermore, BC Hydro states that its "reference scenario" (page 5-36) includes only regional GHG initiatives, with no national intervention (2013 IRP Appendix 5A, Table 4).

(3) Given the points above, Midgard concluded that GHG pricing in its forecast should be low.

Midgard's opinion at the time of writing its 2014-2043 Electricity Price Forecast Memo was that after taking the above points into account, the low GHG price adder scenario from the work performed by Black & Veatch for the BC Hydro (2012/13) Integrated Resource Plan was a prudent choice of scenarios.

Midgard's opinion has since been corroborated in the release of BC Hydro's 2013 IRP. In it, BC Hydro's reference scenario (Scenario 1) envisions regional action only and no national frameworks for GHG pricing (Table 5-3, page 5-22). Elsewhere in the document, BC Hydro reiterates several other points that are consistent with Midgard's interpretation of the 2011 TAC documentation in Midgard's 2014-2043 Electricity Price Forecast Memo:

- "slower electricity demand growth since the 2008 recession" (page 5-36)
- "long term natural gas prices continue to be low" (page 5-37)
- "slower implementation of U.S. national and regional GHG policies and regulations" (page 5-37)

13.3.1 Please provide all analyses that Midgard conducted or reviewed that led to this 'feeling.'

Response:

Please refer to the response to BCSEA IR 1.13.3.

13.3.2 Please explain why Midgard rejected the Black and Veatch "mid GHG" case.

Response:

Midgard rejected the Black and Veatch "mid-GHG" case because it was Midgard's opinion that the Low GHG case was the more plausible scenario. Please refer to the response to BCSEA IR 1.13.3.

13.3.3 Please explain whether Midgard has estimated the global CO2 concentrations or global warming levels that would result from the low GHG prices being imposed across the developed world, and whether Midgard believes those levels are acceptable and consistent with the policies of the BC and Canadian governments.

Response:

Midgard has not estimated global CO2 concentrations or global warming levels that would result from the implementation of "low GHG" prices across the developed world. Midgard does not have an opinion on whether those levels are acceptable and consistent with the policies of the BC and Canadian governments.

13.4 Please explain why FortisBC chose to accept Midgard's 'feelings' about GHG price adders. Please provide any and all analysis FortisBC itself conducted in choosing to accept Midgard's feelings about GHG price adders.

Response:

Midgard has provided an independent market forecast. FortisBC had and has no reason to challange the Midgard assumptions about GHG price adders. Midgard's assumption is consistent with BC Hydro's messaging in 2012 and 2013, and with the BC Hydro 2012 Draft IRP.

BC Hydro has since released its Draft 2013 IRP which chooses Scenario 1, a Mid-Carbon (regional)/Mid gas case as the "most likely scenario". Scenario 1 projects current market conditions being prolonged over the long term, and predicts no US Federal CO2 policy. As seen in the table below, even accounting for the different base years, Midgard's Mid-C price forecast is still higher than BC Hydro's Scenario 1 until the last few years of the forecast.

Comparison of Mid-C Base Case Forecasts including GHG Compliance

Year	Midgard[15] (2013 US$)	BC Hydro Scenario 1 [16],[17] (2012 US$)
2014	$33.57	$25.0
2015	$37.07	$25.5
2016	$40.43	$25.8
2017	$41.75	$27.1
2018	$44.03	$27.1
2019	$44.16	$28.0
2020	$44.83	$28.0
2021	$40.82	$29.3
2022	$40.82	$30.1
2023	$41.09	$31.8
2024	$41.09	$33.0
2025	$41.89	$34.2
2026	$42.42	$34.9
2027	$42.69	$36.0
2028	$42.96	$36.3
2029	$43.63	$37.2
2030	$44.03	$37.6
2031	$44.03	$38.6

[15] Midgard June 15, 2013 Memorandum" Derivation of the British Columbia Electricity Forecast 2014 to 2043.
[16] BC Hydro 2013 Draft Integrated Resource Plan, Chapter 5, Table 5-5, page 5-36.
[17] BC Hydro 2013 Draft Integrated Resource Plan, Appendix 5A, Table 5, Page 5A-5.

Year	Midgard[15] (2013 US$)	BC Hydro Scenario 1 [16,17] (2012 US$)
2032	$44.29	$39.9
2033	$44.65	$41.5
3034	$45.03	$42.8
3035	$45.42	$44.6
2036	$45.80	$45.7
2037	$46.18	$47.8
2038	$46.57	$48.4
2039	$46.95	$48.9
2040	$47.34	$49.3

13.4.1 Please reconcile FortisBC's adoption of the Black and Veatch low-GHG prices with the B.C. energy objective to reduce greenhouse gas emissions.

Response:

FortisBC assumes the "B.C energy objective to reduce greenhouse gas emissions" referred to above are the British Columbia energy objectives outlined in Section 2 of the *Clean Energy Act*. Specifically:

2(g) to reduce BC greenhouse gas emissions

(i) by 2012 and for each subsequent calendar year to at least 6% less than the level of those emissions in 2007,

(ii) by 2016 and for each subsequent calendar year to at least 18% less than the level of those emissions in 2007,

(iii) by 2020 and for each subsequent calendar year to at least 33% less than the level of those emissions in 2007,

(iv) by 2050 and for each subsequent calendar year to at least 80% less than the level of those emissions in 2007, and

(v) by such other amounts as determined under the *Greenhouse Gas Reduction Targets Act*;

2(h) to encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia;

2(i) to encourage communities to reduce greenhouse gas emissions and use energy efficiently;

In FortisBC's view, there is no conflict as the Act is specific to reducing GHG emissions in BC. Market imports do not create GHG emissions within BC, although they can have a deemed carbon footprint. Currently there is no carbon compliance mechanism (such as a carbon tax or offset requirements) applied to electricity imports, only a carbon reporting requirement. FBC does not anticipate the BC government will impose a carbon compliance mechanism in the near future.

13.5 Please explain how Midgard derived the specific values in the GHG Adder column of the last page of Attachment H4 from the BC Hydro slide cited in footnote D [http://www.bchydro.com/content/dam/hydro/medialib/internet/documents/planning_regulatory/iep_ltap/2011q1/irp_tac_mtg2_meeting0.pdf, slide 87], which provides no numerical values and extends only to 2031.

Response:

Derivation of specific values:

Midgard read the specific values from the BC Hydro slide cited in the footnote reference (BC Hydro reference figure (Slide 87, Integrated Resource Plan Technical Advisory Committee Meeting #2 - Day 1, [January 27, 2011])). Subsequent to reading the data from the slide, a tabular version of the data set has been obtained from BC Hydro and the average error between reading the slide data and tabular data is 0.6%.

Creating numerical values beyond 2031:

Based on the extracted reference data, data for the dates beyond 2031 are a linear extrapolation of the data points from 2021 to 2031.

13.6 Please provide FortisBC's understanding of the numerical values of the BC Hydro Mid GHG Adder.

Response:

BC Hydro commissioned Black and Veatch in September 2009 to study GHG emission emerging policy and regulation with respect to potential impacts on the BC Hydro system. The study produced a series of plausible scenarios to predict a greenhouse gas price forecast. Midgard Consulting has recommended the use of the low GHG adder based on the actual low growth scenarios since the study. FortisBC generally agrees with June 15, 2013 Midgard Memorandum including using the low GHG adder and Mid-Columbia trading hub electricity forecast price based on henry Hub natural gas price forecast. The marginal cost of generating electricity in the Western Electric Coordinating Council (WECC) is linked to natural gas prices.

13.7 Please provide any data available to FortisBC or Midgard regarding the incremental CO2 emission rate for energy delivered at Mid-Columbia.

Response:

Please refer to the response to BCSEA IR 1.3.7.

13.8 Please explain how California energy prices affect Mid-Columbia energy prices.

Response:

California is the largest market along the North American Pacific coast. Historically, the Pacific Northwest (PNW) is winter peaking while California is summer peaking. Subject to any transmission constraints, California will typically sell surplus energy into the PNW during the winter, while the PNW will sell surplus electricity to California during the summer. Therefore California sales into the PNW during the winter would put downward pressure on PNW winter prices, and PNW sales into California during the summer would put upward pressure on PNW summer prices.

There are arbitrage opportunities between the two markets which help correlate the prices, but the cost of wheeling and of California GHG compliance for electricity imports must be factored in, and transmission congestion between the two markets can cause divergence. Generation shortages in the California market can significantly impact power prices in the PNW, as was demonstrated in the 2000/01 Western Energy Crisis.

REC sales had changed that dynamic somewhat, where wind producers were selling their RECs into the California market while dumping their physical energy into the Mid-C market, depressing prices. We understand that loophole has now been closed going forward.

13.9 Please explain how the price of California Carbon Allowances affect California energy prices.

Response:

FBC does not deal in the California electricity market, and has no specific expertise in the workings of that market or the impact of carbon allowances on electricity prices in that market. FBC suspects that the allowance cost would be added to the price of electricity based on the deemed carbon content of the region the power originated for unspecified sources, or the actual carbon content for specified sources. The result would be a price signal to electricity importers to encourage them to contract with specified sources with low or no GHG footprint, and to IPPs within California to develop clean powerplants.

BC currently only requires electricity importers to report the deemed carbon content of electricity imports. Since BC does not have a regulated cap and trade market, there is no equivalent carbon offsetting requirement for electricity imports.

13.10 Please provide any available information on the cost of refurbishment or replacement of the Upper Bonnington Plant. [FortisBC 2012 Long Term Resource Plan, p. 46 (pdf 52 of 697)]

Response:

The preliminary unloaded estimate for the Upper Bonnington Unit 1, 2, 4 refurbishment is $20.1 million.

14.0 Topic: Capacity cost

Reference: Exhibit B-1-1, Appendix H, Attachment H4, LRMC Avoided Cost Derivation Migard Memorandum; FortisBC 2012 Long Term Resource Plan, Appendix B, Midgard Consulting Inc. 2011 FortisBC Energy & Capacity Market Assessment

14.1 Please explain why the LRMC avoided cost derivation and the Midgard Memorandum do not include the capacity prices estimated in the 2012 Long Term Resource Plan, Appendix B, or any other capacity prices.

Response:

FBC is calculating the annual average LRMC of firm spot market energy, which if purchased on an hourly basis is firm for the hour and therefore has implicit capacity costs embedded in the hourly spot price. FortisBC can also buy a short-term firm blocks of energy from a third party such as power marketer (e.g. Morgan Stanley, Shell, Powerex, etc.) for up to a year (or possibly longer), with the price indexed to the spot market price. Again since these are firm blocks they have implicit capacity costs built into the price.

Conversely, not all DSM savings FBC realizes can be considered firm.

14.2 Please provide the pricing of the Powerex Capacity Power Block (CPB).

Response:

The cost of the Powerex Capacity Power Block is approximately $7,125 per MW in both January and February 2014 and $7,385 per MW in both November and December 2014. This purchase is a bridging arrangement that was entered into as a result of the sale of 1/3 of the Waneta Plant by Teck to BC Hydro. Up until that time, FBC had purchased surplus winter capacity from Teck based on the Waneta Plant and that capacity was no longer available.

The bridging arrangement was necessary to allow time for FBC to put a long-term replacement source of capacity in place. This was accomplished with the purchase of the surplus capacity from the Waneta Expansion Plant under the WAX CAPA. Once the Waneta Expansion plant is able to deliver capacity to FBC, the Powerex Capacity Block will be terminated as allowed for under the contract.

14.3 Reference: 2012 Long Term Resource Plan, Appendix B, Figure 4.3-B, page 19 of 54 (pdf 123). Since Midgard projects capacity shortages in the US Northwest in January, February, April, July, August and December of 2020:

14.3.1 Does FortisBC agree that it cannot count on procuring capacity from the US Northwest?

Response:

FBC agrees that relying on the spot market to meet long term load carries an element of risk. However, in the short to medium time frame the risk is much less. It is further lessened since as also stated in the 2012 Long Term Resource Plan, page 58 the 2020 June and December exposure is limited to only 4% of the super peak hours in both months, or about 4 hours per month. The most appropriate resources to meet FBC's long term load will be examined in the 2016 Resource Plan.

14.3.1.1 If not, please explain why.

Response:

Please refer to the response to BCSEA IR 1.14.3.1.

14.3.2 Does FortisBC agree that it cannot count on procuring energy from Mid-Columbia in all high-load hours, by 2020?

Response:

Energy purchased in high load hours is to meet capacity needs and therefore the response is the same as for BCSEA IR 1.14.3.1.

14.3.2.1 If not, please explain why.

Response:

Please refer to the response to BCSEA IR 1.14.3.2.

14.4 Please provide an update of Table 3.3.-A of the 2012 Long Term Resource Plan, Appendix B, Forecast FortisBC Capacity Gaps by Month and Year, page 11 of 54 (pdf 115).

Response:

FBC does not have a long term update of the required data available to update this table. This will be done as part of the 2016 Resource Plan. However, Appendix E2, page 24 of the Application provides the updated after-savings peak forecast through 2018. A table of the changes in this forecast compared to the information used in the 2012 Resource Plan (before planning reserve margin requirements) is provided below.

Table 1: Change in After-Savings Peak Load from 2013 Forecast Through 2018

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2013	11	(2)	(11)	(5)	(13)	(19)	3	4	5	(7)	11	12
2014	7	(6)	(14)	(7)	(15)	(21)	1	3	5	(8)	10	10
2015	5	(8)	(16)	(8)	(16)	(22)	(0)	2	4	(9)	8	9
2016	6	(6)	(15)	(7)	(14)	(21)	2	4	6	(8)	10	10
2017	6	(5)	(15)	(6)	(14)	(20)	2	4	7	(8)	10	10
2018	6	(5)	(15)	(6)	(14)	(20)	2	5	8	(8)	10	8

The referenced Table 3.3-A from the 2012 Resource Plan was based on an assessment of the adequacy of FBC resources to meet system requirements based on its 2012 Resource Plan long term load forecast and after consideration of planning reserve margin requirements. In its decision the Commission denied FBC's proposal for planning reserve margin, which in the absence of any other treatment would have reduced the capacity gaps. The 2016 Resource Plan will consider both changes in its long term load forecast and the long term strategy for meeting planning reserve margin requirements in its system.

15.0 Topic: Local Transmission and Distribution

Reference: None

15.1 Please provide any analyses prepared by or for FortisBC of the T&D costs avoided due to demand-response programs. Include reports, workpapers, spreadsheets (with cell references and formulas intact), and data relied on.

<u>Response:</u>

FBC has no T&D avoided cost analyses to provide. Prior to the deployment of AMI, the Company does not have a communications network available that is needed to make wide-scale deployment of demand-response control cost effective.

15.2 Please provide FortisBC's most recent marginal T&D cost study, including workpapers.

<u>Response:</u>

FBC is unclear on what "marginal costs" are being referred to in this question. Assuming that "marginal T&D cost" is referring to the potential avoided or deferred costs of new transmission/distribution infrastructure through the use of DSM or demand response (DR) programs which may mitigate load growth, then FBC has not conducted any formal studies. Refer also to the response to BCSEA IR 1.15.1.

FBC notes that the concept of capital deferral through the use of DSM or DR measures was fully explored during the FortisBC Inc. 2012-2013 Revenue Requirements regulatory process by the Load Forecast Technical Committee. Specifically, it was addressed in Section 4 ("Impact of Potential Changes in the Load Forecast on Long Term Plans") and Action Item 16 of the Load Forecast Committee Report which was filed as Exhibit B-16 of that process. The following excerpt is from page B-1-1 of that exhibit:

> *"In the 2012 – 2013 Revenue Requirements, (Tab 3, Page 3F-4), the Company discussed the incorporation of DSM into its load forecast for capital planning purposes. It stated that In [sic] local area transmission and distribution planning studies, a load forecast without DSM impacts is used, since DSM impacts are less predictable due to regional load diversity and the difficulty in allocating DSM to local circuits and feeders and, when project timelines may be impacted, DSM considerations are included in a sensitivity study to determine potential impacts on T&D projects. In planning the bulk transmission system, DSM impacts are included because they are more predictable for the reasons identified.*

> *Although an accurate DSM sensitivity assessment for transmission growth projects in the 2012-17 timeframe is not possible, because of the relatively small values of DSM and the need to allocate the impacts to local areas, the Company reviewed the timing of the following transmission growth-driven projects based on achievement of DSM forecast.*
>
> - *42 Line Meshed Operation (Huth and Oliver), 2014;*
> - *Kelowna Bulk Transformer Capacity Addition, 2015;*
> - *Capacitors at Bentley Terminal, 2016;*
> - *Summerland Substation Transformer Upgrade, 2016; and*
> - *RG Anderson Distribution Transformer Upgrade, 2017.*
>
> *Assuming proportionality of DSM deliveries by area, it was found that the impact of DSM on local area loads falls within the range of uncertainty of the load forecast and area load growth.* ***Therefore it was concluded that no projects in this timeframe would be advanced or deferred based on such marginality****."* [emphasis added]

On the basis of this conclusion cited in the above report, FBC does not consider there to be a basis on which to conduct further marginal cost studies.

15.3 If the marginal cost estimates differ from the avoided cost estimates to be used in the valuation of energy efficiency programs, please explain why.

Response:

Please refer to the response to BCSEA IR 1.15.2.

15.4 Please include the computation of marginal investment and O&M expenses for each of

15.4.1 transmission,

Response:

Please refer to the response to BCSEA IR 1.15.2.

15.4.2 subtransmission,

Response:

Please refer to the response to BCSEA IR 1.15.2.

15.4.3 primary distribution and

Response:

Please refer to the response to BCSEA IR 1.15.2.

15.4.4 secondary distribution.

Response:

Please refer to the response to BCSEA IR 1.15.2.

15.5 Please provide all avoided or marginal T&D cost estimates relied upon FortisBC in the last five years. For each, please:

15.5.1 document the derivation of the avoided costs, including all reports, analyses, workpapers, spreadsheets (with cell references and formulas intact), and data relied on, and

Response:

Please refer to the response to BCSEA IR 1.15.2.

15.5.2 explain how the avoided cost estimates were used.

Response:

Please refer to the response to BCSEA IR 1.15.2.

15.6 For each FortisBC substation, please provide

15.6.1 current and forecast summer peaks,

Response:

Please see the tables provided below:

North Okanagan	**Current**	**Forecast**					
	2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
	(kVA)						
SEX T1	25360	26882	25015	25456	25932	26156	26750
GLE T2	19745	19842	20498	20932	21274	21314	21927
GLE T3	26570	31393	31737	32321	32819	33167	33809
HOL T1	20475	21184	22799	23174	23579	24020	24454
HOL T3	13815	14592	14928	15205	15440	15623	15973
DGB T1	17750	18413	18750	19306	19640	19822	20217
DUC T1	7285	7477	7838	7927	8086	8176	8325
DUC BCH	22295	28560	26080	26560	26720	27200	27680
JOR T1	1500	1706	1748	1781	1813	1840	1873
OKM T1	14250	15262	15416	15458	15683	15907	16229
OKM T2	7940	8329	8514	8678	8827	8931	9122
LEE tert	12505	12816	6720	6844	6969	7074	7200
BLK T1	12100	12165	16089	16444	16764	17008	17270
ELL T1	12665	13368	17585	18471	18763	19070	19477
BWS T1	3039	3378	3462	3526	3589	3643	3709
BEV T1	22800	23011	23662	23944	24396	24781	25247
REC T1/T2	26134	26430	26567	27937	28416	28530	28629
SAU T1	22225	24091	25939	26400	26863	27525	27799

South Okanagan	**Current**	**Forecast**					
	2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
	(kVA)						
RGA T3	15815	17273	17371	17444	17516	17575	17647
OKF T1	7368	9159	9119	9162	9205	9243	9289

South Okanagan	Current	Forecast					
	2012	2013	2014	2015	2016	2017	2018
	(kVA)						
WEB T1	6150	6237	6336	6306	6343	6366	6394
AWA T1	3903	4637	4669	4693	4711	4727	4744
KAL T1	4066	4826	5003	5024	5045	5062	5083
SUM T2	12434	13668	13745	13802	13859	13907	13963
WAT T1	15960	17763	17863	17938	18012	18073	18146
WES T1/T2	20510	20626	20742	20829	20915	20986	21071
TRC T1	5660	6245	6440	6487	6609	6576	6549
PIN T1	5792	5825	5858	5882	5906	5927	5951
PIN T2	10237	10712	10779	10863	10882	10902	10958
OSO T1	7463	7505	7548	7579	7610	7636	7667
OSO T2	6295	6331	6566	6594	6621	6644	6670
NKM T1	12185	12434	12531	12511	12553	12642	12686
KER T1	10835	11100	11172	11214	11249	11267	11336
HED T1	1741	2246	2205	2213	2245	2192	2247
OLI T1	8232	8422	8383	9532	9552	9617	9668
PRI T4	14331	14653	14474	14577	14508	14715	14762
HUT T4/5/6/7	10216	10274	10332	10375	10418	10453	10496
HUT T8	6533	7148	7189	7219	7248	7273	7303

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Kootenay	Current	Forecast					
	2012	2013	2014	2015	2016	2017	2018
	(kVA)						
KAS T1	3635	4463	4486	4502	4581	4632	4587
COF T3	3499	4743	4693	4690	4613	4511	4706
CRA T5	2942	3859	3961	3974	3844	3775	3930
CRE T1	8256	8292	8340	8402	8438	8455	8486
CRE T2	6059	6737	6717	6713	6725	6790	6817
AAL T2	9803	8611	8808	8357	8466	8605	8673
VAL T1	2202	2288	2300	2310	2319	2327	2336
VAL T2	397	400	398	402	404	405	406
PAS T1	1954	2112	2121	2126	2117	2130	2147
PLA T1	5888	6626	6723	6680	6727	6735	6778
TAR T1	3200	3200	3198	3197	3197	3196	3197
COT T1	232	309	311	312	313	314	316
SAL T1	5023	5374	5421	5321	5350	5402	5438
HER T1	1163	1210	1217	1222	1227	1231	1236

Kootenay	Current	Forecast					
	2012	2013	2014	2015	2016	2017	2018
	(kVA)						
FRU T1	4000	4296	4322	4327	4316	4352	4375
YMR T1	1120	1256	1263	1268	1273	1278	1283
CAS T1	8678	9144	9386	9388	9397	9430	9461
BLU T1	6050	6559	6581	6595	6628	6645	6681
OOT T1	5038	5160	5156	5144	5153	5178	5220
BEP T1	7250	7614	7727	6730	6790	6860	7971
GLM T1	10544	12685	12856	12816	12967	12918	13002
STC T1	5977	6065	6185	6189	6188	6230	6245
CSC T1	4841	5013	5078	5165	5172	5216	5190

Boundary	Current	Forecast					
	2012	2013	2014	2015	2016	2017	2018
	(kVA)						
CHR T1	4143	4419	4570	4686	4803	4902	5023
RUC T1	6500	6920	7125	7417	7586	7723	7898
RUC T2	7240	8626	8875	9231	9480	9647	9850
GFT T3	6421	6566	6791	6963	7137	7284	7463
KET T1/T2	8300	11291	11241	11812	12050	12165	12583

15.6.2 current and forecast winter peaks,

Response:

Please see the tables provided below:

North Okanagan	Current	Forecast					
	2012	2013	2014	2015	2016	2017	2018
	(kVA)						
SEX T1	24079	27794	25863	26505	26869	27242	27760
GLE T2	16935	19146	19675	19947	20303	20508	21009
GLE T3	22386	29384	29979	30904	31438	31630	32148
HOL T1	23220	27813	29927	30491	31106	31587	32050
HOL T3	12361	13833	14157	14406	14620	14823	15127
DGB T1	16057	18341	18660	19011	19390	19613	20006
DUC T1	6968	7550	7664	7809	7871	7992	8189

North Okanagan	Current	Forecast					
	2012	2013	2014	2015	2016	2017	2018
	(kVA)						
DUC BCH	26154	35700	32600	33200	33400	34000	34600
JOR T1	2889	3338	3412	3479	3537	3596	3656
OKM T1	14523	16854	17070	17224	17459	17690	18061
OKM T2	7409	9581	9749	9926	10160	10291	10466
LEE tert	12112	13758	7648	7797	7929	8061	8194
BLK T1	12170	13619	17534	17961	18239	18527	18824
ELL T1	13247	15649	19978	20912	21202	21491	21999
BWS T1	14984	17036	17489	17806	18158	18442	18724
BEV T1	19736	23084	23698	24037	24546	24896	25321
REC T1/T2	25335	26078	27136	28587	28779	29251	29197
SAU T1	22264	25271	27662	28244	28781	29318	29855

South Okanagan	Current	Forecast					
	2012	2013	2014	2015	2016	2017	2018
	(kVA)						
RGA T3	18838	16880	17012	17103	17183	17261	17339
OKF T1	7889	10462	10286	10209	10091	9998	10361
WEB T1	6721	8046	8181	8158	8200	8242	8286
AWA T1	5621	7069	7125	7127	7186	7208	7248
KAL T1	5491	6799	6991	7030	7063	7096	7129
SUM T2	14153	17034	17140	17234	17316	17397	17478
WAT T1	15936	18966	19085	19189	19280	19370	19460
WES T1/T2	21788	27953	28127	28281	28415	28548	28681
TRC T1	6648	7873	7839	7950	8066	8076	8078
PIN T1	4091	4753	4783	4809	4832	4855	4877
PIN T2	10983	12088	12180	12258	12376	12405	12441
OSO T1	6041	7372	7418	7458	7493	7529	7564
OSO T2	4872	6046	6284	6319	6348	6378	6408
NKM T1	7929	9878	9902	9933	9993	10007	10089
KER T1	10924	13696	13772	13848	13915	13975	14045
HED T1	4516	4912	4945	4923	4920	4956	5004
OLI T1	9213	10780	10967	12090	12168	12206	12276
PRI T4	17778	19907	19723	19916	20107	20128	20250
HUT T4/5/6/7	10271	12732	12811	12881	12942	13003	13063
HUT T8	5888	6659	6701	6737	6769	6801	6833

Kootenay	Current	Forecast					
	2012	2013	2014	2015	2016	2017	2018
	(kVA)						
KAS T1	5895	8128	8274	8323	8355	8406	8462
COF T3	4730	5678	5698	5706	5702	5689	5809
CRA T5	4832	6330	6357	6373	6376	6370	6488
CRE T1	11589	13016	13163	13182	13199	13465	13468
CRE T2	8421	9560	9596	9661	9739	9761	9856
AAL T2	13158	12617	12558	13285	13296	13291	13267
VAL T1	3370	4150	4185	4216	4243	4269	4296
VAL T2	147	400	401	405	408	410	412
PAS T1	3263	3580	3765	3765	3819	3837	3828
PLA T1	11906	13273	13393	13466	13559	13614	13729
TAR T1	3027	3244	3200	3200	3200	3200	3200
COT T1	1337	1536	1549	1560	1570	1580	1590
SAL T1	6674	7979	8113	8042	8171	8268	8276
HER T1	1298	1530	1543	1554	1564	1574	1584
FRU T1	5684	7296	7322	7334	7336	7463	7497
YMR T1	1456	1536	1549	1560	1570	1580	1590
CAS T1	12253	13865	14235	14253	14181	14126	14414
BLU T1	7042	7651	7701	7766	7812	7875	7916
OOT T1	8011	10751	10910	10972	11020	11101	11169
BEP T1	7842	9028	9129	8159	8244	8327	9499
GLM T1	10905	12144	12185	12190	12234	12324	12460
STC T1	7095	8630	8786	8951	8943	8993	9037
CSC T1	8484	9382	9430	9564	9596	9700	9724

Boundary	Current	Forecast					
	2012	2013	2014	2015	2016	2017	2018
	(kVA)						
CHR T1	3583	4469	4497	4522	4543	4564	4585
RUC T1	6626	8846	8901	8950	8992	9035	9077
RUC T2	7550	8503	8602	8631	8651	8666	8737
GFT T3	8368	9848	9910	9964	10011	10058	10105
KET T1/T2	11895	16315	16150	16012	16141	16284	16419

15.6.3 maximum load that would be transferred to the substation in the event of a contingency on another substation or feeder,

Response:

Please table provided below. Values are in KVA

substation	Season	Maximum Load Transferred During A Contingency Situation *Contingency Plans are based on a 80% of Peak Demand
SEX T1	Summer	5827
SEX T1	Winter	5273
GLE T2	Summer	5199
GLE T2	Winter	3633
GLE T3	Summer	8601
GLE T3	Winter	8706
HOL T1	Summer	3782
HOL T1	Winter	3422
HOL T3	Summer	5240
HOL T3	Winter	6290
DGB T1	Summer	4220
DGB T1	Winter	4692
DUC T1	Summer	5244
DUC T1	Winter	4727
DUC BCH	Summer	N/A
DUC BCH	Winter	N/A
JOR T1	Summer	2773
JOR T1	Winter	8051
OKM T1	Summer	6588
OKM T1	Winter	7668
OKM T2	Summer	12880
OKM T2	Winter	13585
LEE tert	Summer	5740
LEE tert	Winter	6848
BLK T1	Summer	3808
BLK T1	Winter	4588
ELL T1	Summer	8720
ELL T1	Winter	9755

substation	Season	Maximum Load Transferred During A Contingency Situation *Contingency Plans are based on a 80% of Peak Demand
BWS T1	Summer	1365
BWS T1	Winter	2613
BEV T1	Summer	4000
BEV T1	Winter	4600
REC T1/T2	Summer	11785
REC T1/T2	Winter	13536
SAU T1	Summer	4493
SAU T1	Winter	5292
RGA T3	Summer	N/A
RGA T3	Winter	N/A
OKF T1	Summer	N/A
OKF T1	Winter	N/A
WEB T1	Summer	1722
WEB T1	Winter	1054
AWA T1	Summer	N/A
AWA T1	Winter	N/A
KAL T1	Summer	N/A
KAL T1	Winter	N/A
SUM T2	Summer	N/A
SUM T2	Winter	N/A
WAT T1	Summer	N/A
WAT T1	Winter	N/A
WES T1/T2	Summer	N/A
WES T1/T2	Winter	N/A
TRC T1	Summer	1464
TRC T1	Winter	2182
PIN T1	Summer	5382
PIN T1	Winter	4838
PIN T2	Summer	3255
PIN T2	Winter	3615
OSO T1	Summer	4226
OSO T1	Winter	2471
OSO T2	Summer	5861
OSO T2	Winter	5970

substation	Season	Maximum Load Transferred During A Contingency Situation *Contingency Plans are based on a 80% of Peak Demand
MCM T1	Summer	N/A
MCM T1	Winter	N/A
NKM T1	Summer	N/A
NKM T1	Winter	N/A
KER T1	Summer	4276
KER T1	Winter	5622
HED T1	Summer	1546
HED T1	Winter	1153
OLI T3	Summer	4701
OLI T3	Winter	5004
PRI T4	Summer	N/A
PRI T4	Winter	N/A
HUT T4/5/6/7	Summer	3036
HUT T4/5/6/7	Winter	3630
HUT T8	Summer	N/A
HUT T8	Winter	N/A
KAS T1	Summer	1392
KAS T1	Winter	1393
COF T3	Summer	1292
COF T3	Winter	2388
CRA T5	Summer	N/A
CRA T5	Winter	N/A
CRA T4	Summer	4256
CRA T4	Winter	4914
WYN T1	Summer	N/A
WYN T1	Winter	N/A
CRE T1	Summer	3514
CRE T1	Winter	5315
CRE T2	Summer	9436
CRE T2	Winter	13820
AAL T2	Summer	3014
AAL T2	Winter	3680
VAL T1	Summer	397
VAL T1	Winter	400

substation	Season	Maximum Load Transferred During A Contingency Situation *Contingency Plans are based on a 80% of Peak Demand
VAL T2	Summer	2202
VAL T2	Winter	3629
PAS T1	Summer	3701
PAS T1	Winter	1908
PLA T1	Summer	3244
PLA T1	Winter	3244
SLO T1	Summer	N/A
SLO T1	Winter	N/A
TAR T1	Summer	N/A
TAR T1	Winter	N/A
COT T1	Summer	N/A
COT T1	Winter	N/A
SAL T1	Summer	1044
SAL T1	Winter	1036
HER T1	Summer	2700
HER T1	Winter	1090
FRU T1	Summer	4623
FRU T1	Winter	3351
YMR T1	Summer	N/A
YMR T1	Winter	N/A
CAS T1	Summer	3174
CAS T1	Winter	5432
BLU T1	Summer	3824
BLU T1	Winter	4347
OOT T1	Summer	2814
OOT T1	Winter	3114
BEP T1	Summer	3591
BEP T1	Winter	4382
GLM T1	Summer	6064
GLM T1	Winter	7872
STC T1	Summer	7343
STC T1	Winter	8401
CSC T1	Summer	N/A
CSC T1	Winter	N/A

substation	Season	Maximum Load Transferred During A Contingency Situation *Contingency Plans are based on a 80% of Peak Demand
CHR T1	Summer	N/A
CHR T1	Winter	N/A
RUC T1	Summer	8064
RUC T1	Winter	7076
RUC T2	Summer	N/A
RUC T2	Winter	N/A
GFT T3	Summer	4079
GFT T3	Winter	N/A
KET T1/T2	Summer	N/A
KET T1/T2	Winter	N/A
MID T1	Summer	N/A
MID T1	Winter	N/A
MDY T1	Summer	2660
MDY T1	Winter	2660
MDY T2	Summer	3600
MDY T2	Winter	3600

15.6.4 summer capacity, and

Response:

Please see the table provide below:

Substation	**Capacity kVA**
SEX T1	32000
GLE T2	28000
GLE T3	32000
HOL T1	32000
HOL T3	32000
DGB T1	32000
DUC T1	23000
JOR T1	16000
OKM T1	32000

Substation	Capacity kVA
OKM T2	32000
LEE tert	52300
BLK T1	32000
ELL T1	32000
BWS T1	38000
BEV T1	32000
REC T1/T2	57600
SAU T1	32000
RGA T3	20000
OKF T1	15000
WEB T1	8000
AWA T1	10000
KAL T1	7500
SUM T2	20000
WAT T1	32000
WES T1/T2	30000
TRC T1	15000
PIN T1	15000
PIN T2	20000
OSO T1	15000
OSO T2	15000
NKM T1	20000
KER T1	20000
HED T1	10000
OLI T3	16000
PRI T4	32000
HUT T4/5/6/7	12000
HUT T8	32000
KAS T1	13300
COF T3	8400
CRA T5	15000
CRE T1	15000
CRE T2	15000
AAL T2	40000
VAL T1	8000

Substation	Capacity kVA
VAL T2	10000
PAS T1	5600
PLA T1	16000
SLO T1	4500
TAR T1	3500
COT T1	10000
SAL T1	13300
HER T1	1900
FRU T1	8000
YMR T1	1500
CAS T1	15000
BLU T1	10000
OOT T1	16000
BEP T1	10000
GLM T1	15000
STC T1	10000
CSC T1	15000
CHR T1	5000
RUC T1	16000
RUC T2	10000
GFT T3	15000
KET T1/T2	80000

15.6.5 winter capacity.

Response:

Please see the table provided below:

Substation	Capacity kVA
SEX T1	40000
GLE T2	35000
GLE T3	40000
HOL T1	40000
HOL T3	40000

Substation	Capacity kVA
DGB T1	40000
DUC T1	28750
JOR T1	20000
OKM T1	40000
OKM T2	40000
LEE tert	52300
BLK T1	40000
ELL T1	40000
BWS T1	47500
BEV T1	40000
REC T1/T2	72000
SAU T1	40000
RGA T3	25000
OKF T1	18750
WEB T1	10000
AWA T1	12500
KAL T1	9375
SUM T2	25000
WAT T1	40000
WES T1/T2	37500
TRC T1	18750
PIN T1	18750
PIN T2	25000
OSO T1	18750
OSO T2	18750
NKM T1	25000
KER T1	25000
HED T1	12500
OLI T3	20000
PRI T4	40000
HUT T4/5/6/7	15000
HUT T8	40000
KAS T1	16625
COF T3	10500
CRA T5	18750

Substation	Capacity kVA
CRE T1	18750
CRE T2	18750
AAL T2	50000
VAL T1	10000
VAL T2	12500
PAS T1	7000
PLA T1	20000
SLO T1	7000
TAR T1	3500
COT T1	12500
SAL T1	16625
HER T1	2375
FRU T1	10000
YMR T1	1875
CAS T1	18750
BLU T1	12500
OOT T1	20000
BEP T1	12500
GLM T1	18750
STC T1	12500
CSC T1	18750
CHR T1	6250
RUC T1	20000
RUC T2	12500
GFT T3	18750
KET T1/T2	100000

15.7 Please provide maps of

15.7.1 the FortisBC transmission system and

Response:

Please refer to Appendix B4 (Exhibit B-1-1) of the 2014-2018 PBR Application.

15.7.2 FortisBC's distribution substations and major feeders,

Response:

Please refer to Attachment 15.7.2.

15.8 Please provide maps of the T&D system showing recent, planned, and proposed T&D projects, including all projects that have entered service since 2010 and those projected through 2018.

Response:

FBC is unable to respond to this request given the vague wording of the question. For clarity, when considering the period of 2010 through 2018, essentially the entire transmission and distribution system will be touched in some way through a capital project. For example, the Condition Assessment programs for transmission lines and distribution feeders are conducted on an eight year cycle; substations are assessed on a 10 year cycle. When combined with ongoing sustainment and growth projects, virtually the entire system would be contained in a map.

FBC has not and does not prepare individual maps of all projects. Considering that over 100 individual projects are undertaken each year, producing the requested maps would be very costly and time consuming.

15.9 Please provide the current and previous three capital investment plans for FortisBC's transmission and distribution system, including a breakdown of expected T&D investments.

Response:

FBC's current capital plan is provided as Section C5 to the 2014-2018 Revenue Requirements Application, and includes detail regarding the forecast capital projects and programs for the 2014-2018 period.

Due to size constraints, links to FBC's three previous capital expenditure plans are provided below, which include detail on the expected investments in transmission and distribution. As well, links to applicable errata for the Capital Expenditure Plans are also provided below.

- The 2009-2010 Capital Expenditures Plan is available at: http://www.bcuc.com/Documents/Proceedings/2008/DOC_19175_B-1_2009-2010_Capital_Expenditure_Plan.pdf
  - Errata 1 - http://www.bcuc.com/Documents/Proceedings/2008/DOC_19442_B-1-2_FBC-Errata%201.pdf
  - Errata 2 - http://www.bcuc.com/Documents/Proceedings/2008/DOC_19654_B-1-3_Errata-2.pdf
- The 2011 Capital Expenditure Plan is available at: http://www.bcuc.com/Documents/Proceedings/2010/DOC_25750_B-1_FBC_2011-Capital-Expenditure-Plan-Application.pdf
  - Errata 2 - http://www.bcuc.com/Documents/Proceedings/2010/DOC_26057_B-1-2_FortisBC-Errata-2.pdf
  - Errata 3 - http://www.bcuc.com/Documents/Proceedings/2010/DOC_26247_B-1-3_FortisBC-2011-Capital-Expenditure-Plan-Errata3-1-October2010.pdf
- The 2012-2013 Capital Expenditure Plan is available at: http://www.bcuc.com/Documents/Proceedings/2011/DOC_28031_B-1_FBC-Revenue-Requirements-Application.pdf (Tab 6 provides the 2012-2013 Capital Expenditure Plan)
  - Errata 2 - http://www.bcuc.com/Documents/Proceedings/2011/DOC_28491_B-1-6_FBC-Errata-2.pdf

Note that the estimates for the previous capital plans include loadings, while the 2014-2018 plan does not. Please refer to Section E, Table1-A-1 of the Application for a reconciliation of the 2014 Expenditures to the capital expenditures.

15.10 Please provide the internal planning and budgeting documents justifying recent (since 2010), planned, and proposed T&D projects.

Response:

The justifications and costs estimates (calculated on a loaded basis) for 2014 and later projects were provided by FBC in the 2012 Long Term Capital Plan as part of its 2012 Integrated System Plan submission. Please refer to Exhibit B-1-1 and associated IRs which can be located at the BCUC archived proceedings website (http://www.bcuc.com/ApplicationView.aspx?ApplicationId=312). Given the nature of the current PBR application (which focuses on capital expenditures as an aggregate as opposed to individual projects), FBC considers that the level of detail provided in the application is sufficient and appropriate for the current PBR mechanism determination.

15.11 Please provide the Company's estimates of average energy line loss factors by month, time of day, and voltage level.

Response:

FBC is unable to provide the requested data as the company has insufficient information to calculate system losses in this manner. Currently, the Company only has knowledge of the estimated total system losses and these are calculated by subtracting the total energy billed in a given interval from the total energy generated or imported in the same interval. Since customers are on different read cycles and billing meters are read at different times over a multiple-month period, it is not possible to capture a "snapshot" of the total system consumption. Consequently it is not currently possible to accurately determine system losses for any specific point in time or for any specific part of the system. AMI deployment is expected to enable the collection of more accurate, more timely and more granular information on system losses.

15.12 Please provide the Company's T&D additions and retirements by account for each year from 2000 to 2012.

Response:

Please refer to Attachment 15.12.

15.13 Please provide the Company's T&D expenses by account for each year from 2000 to 2012.

Response:

Please refer to Attachment 15.13.

15.14 Please provide the Company's estimates of energy line loss factors at summer and winter peak conditions.

Response:

Please refer to the response to BCSEA IR 1.15.11.

15.15 Please provide any data available to FortisBC regarding marginal energy line loss factors.

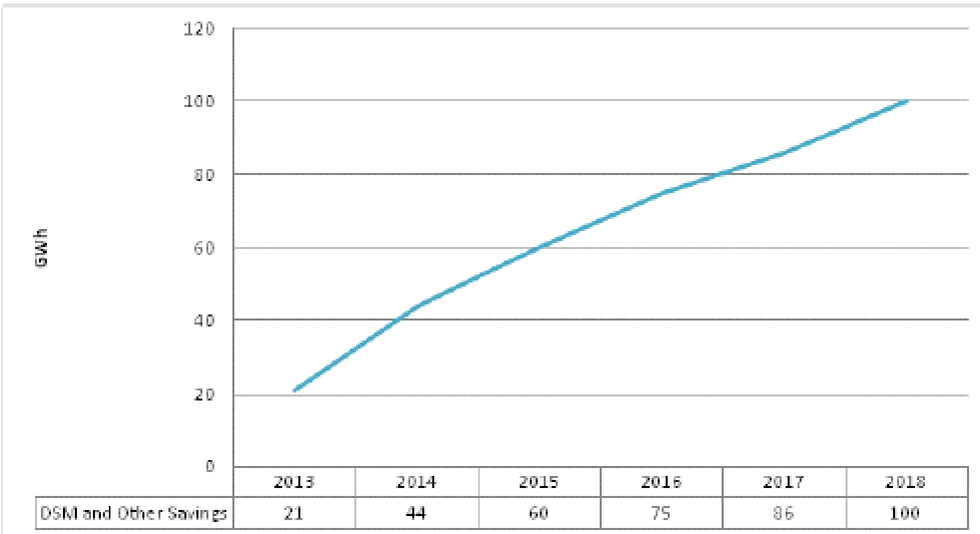
Response:

Please refer to the response to BCSEA IR 1.15.11.

16.0 Topic:

Reference: Exhibit B-1, Figure C1-4: Incremental DSM and Other Savings Forecast, p.81, pdf p.102 of 325

Figure C1-4: Incremental DSM and Other Savings Forecast (GWh)

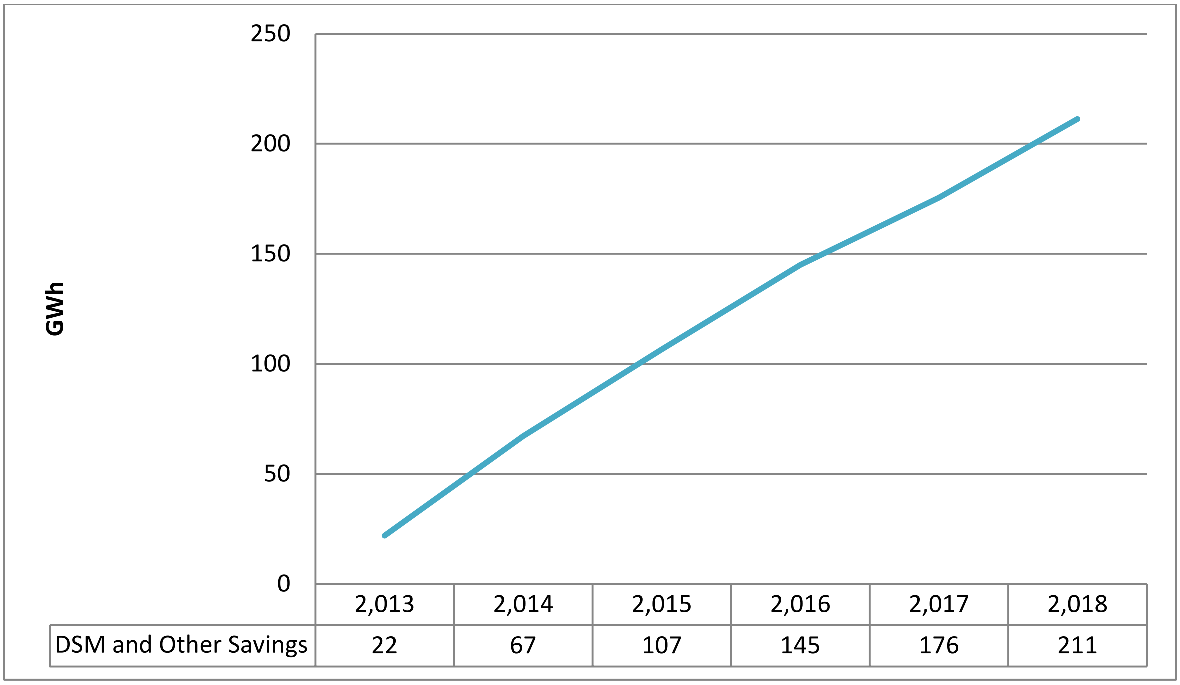


16.1 Please provide a revised version of Figure C1-4 showing incremental DSM and other savings on the assumption that DSM spending continued at the 2013 level throughout the 2014-2018 period.

<u>Response:</u>

The revised version of Figure C1-4 is shown below.

Figure 1-4: Incremental DSM and Other Savings Forecast (GWh)



17.0 Topic: Effect of DSM cuts on rates

Reference: Exhibit B-1, p.265, pdf p.286 of 385; Exhibit B1-1, Appendix H, p.1, pdf p.774 of 887

Exhibit B-1, p.265, pdf p.286 of 385:

> The lower program expenditure level will result in lower average customer rates over the test period by 0.2%-0.4% annually.

Exhibit B1-1, Appendix H, p.1, pdf p.774 of 887:

> as compared to the 2012-13 approved Plan. The lower program expenditure level will result in lower average customer rates over the test period by between 0.3 percent and 0.5 percent annually, and approximately 1.6 percent over the 2014 – 2018 PBR period, compared to continuing at the approximate level of expenditures previously approved.

17.1 Please reconcile the two estimates (quoted above) of the impact of the proposed lower DSM program expenditures on rates.

Response:

The correct range is between -0.2 and -0.5, and approximately -2.2% cumulative over the PBR period, based on an updated revenue requirements model. Please also refer to the response to BCSEA IR 1.21.2.

18.0 Topic: Effect of New PPA

Reference: None

18.1 To what extent is FortisBC's new LRMC estimate of $56.61/MWh dependent on an assumption that the Commission will approve the proposed New Power Purchase Agreement between BC Hydro and FortisBC that is now the subject of a separate proceeding before the Commission (Project No. 3698720)?

<u>Response:</u>

If the BCUC were to deny RS3808, and determine that FBC has no rights to BC Hydro energy at embedded costs under the Heritage Contract, FBC would need to replace that power immediately. FBC would likely contract a short-term replacement resource, possibly from BC Hydro, to give it time to contract or build a new long-term replacement resource. This would impact FBC's LRMC of $56.61, likely raising it significantly.

The Commission could also determine that 1041 GWh/year at BC Hydro's embedded costs was not the correct number, and could raise or lower that amount. This too may impact FBC's LRMC of $56.61

Either scenario would have an immediate and significant impact to customers through increases in power purchase expense, and through a degradation of the reliability and security of supply provided by FBC's firm power supply resources.

19.0 Topic: Load forecast

Reference: Exhibit B-1-1, Appendix E2 Load Forecast, pdf pp. 627-650

19.1 Please provide the following load forecast tables in MS Excel file format:

19.1.1 the monthly sectoral energy forecast tables at pdf pp. 627-631,

Response:

Please refer to Attachment 19.1.1.

19.1.2 at pdf pp. 638-650, the tables numbered:

E2-6
E2-7
E2-9
E2-10
E2-11
E2-12
E2-13
E2-14
E2-15
E2-23
E2-24

Response:

Please refer to Attachment 19.1.2.

20.0 Topic: DSM

Reference: Exhibit B-1-1, Appendix H DSM, pdf p. 774

At lines 12-17, FBC states:

"The 2014-2018 DSM expenditure filing reflects a marked reduction in the Long Run Marginal Cost (LRMC) … which is used in the Total Resource Cost (TRC) Benefit/Cost evaluation of DSM measures and programs. Fewer measures, and in some cases programs, are now cost-effective as defined by the Demand-Side Measures Regulation (the DSM Regulation). The result is a reduced DSM expenditure request for the 2014-2018 filing period as compared to the 2012-13 approved Plan."

20.1 Please provide all analysis conducted by or for the Company substantiating the claim that fewer measures and some programs are cost-effective under the TRC and/or modified TRC tests using the reduced LRMC Fortis proposes now.

Response:

Please refer to Attachment 20.1 for the fully functioning spreadsheet of the DSM Plan.

20.1.1 Please include in the response the spreadsheets used to perform the analysis in the form of functioning MS Excel files, with all inputs, assumptions, equations, and documentation.

Response:

Please refer to Attachment 20.1.1.

20.2 Please explain and demonstrate quantitatively exactly how the reduced number of cost-effective DSM measures and programs resulted in the reduced DSM expenditure request. Include in this response:

Response:

Please refer to the responses to BCSEA IRs 1.20.2.1 through 1.20.2.3.

20.2.1 a list of specific measures and programs that were removed;

Response:

The following table contains a list of the programs that were removed.

Sector	Program	Measure	TRC	mTRC
Residential	Building Envelope	Windows - Single	0.8	1.5
Residential	Building Envelope	Electronic Thermostat	0.8	1.5
Residential	Heat Pumps	Heat Pump Conversion - Air Source	0.5	1.0
Residential	Heat Pumps	Heat Pump Upgrade - Ductless	0.6	1.1
Residential	Heat Pumps	Heat Pump - GeoExchange	0.4	0.8
Residential	Appliances	Clothes Washer	0.4	0.8
Residential	Appliances	Refrigerator	0.6	1.2
Residential	Electronics	Computers etc.	0.9	1.8
General Service	Lighting	Streetlights	0.7	1.4
General Service	Lighting	Parking Lights	0.8	1.7
General Service	Municipal	Water Handling Infrastructure	1.0	1.9

20.2.2 the number of measures, program participants, and programs removed;

Response:

As provided in the response to BCSEA IR 1.20.2.1, in total we have removed 11 measures across six programs in the residential and general service sectors. The current DSM tracking system does not accurately track participant numbers (please refer to the response to BCSEA IR 1.25.2.2), and it is not a metric in the DSM Plan.

20.2.3 the cost-effectiveness analysis supporting the removal of each measure and program, with the spreadsheets used to perform the analysis in the form of functioning MS Excel files, with all inputs, assumptions, equations, and documentation.

Response:

Please refer to the response to BCSEA IR 1.20.1.1.

20.3 In assembling the portfolio with reduced spending and savings for the proposed DSM portfolio, did FortisBC increase spending and savings in any areas that were found to be relatively more cost-effective than others under the lower avoided costs it now projects?

Response:

No.

20.3.1 If so, please explain and demonstrate quantitatively how portfolio resources were reallocated, including the number of measures and program participants were added by program, and the cost-effectiveness analysis supporting the addition of each measure and program, with the spreadsheets used to perform the analysis in the form of functioning MS Excel files, with all inputs, assumptions, equations, and documentation.

Response:

Please refer to the response to BCSEA IR 1.20.3.

20.3.2 If not, please explain why no such reallocation was conducted to improve portfolio cost-effectiveness.

Response:

Please refer to the responses to CEC IRs 1.5.3.1 and 1.5.3.1.1.

20.4 In developing the new program plan, did FortisBC lower financial incentives offered participants in any program from those in equivalent 2012-13 programs in order to achieve lower spending levels?

Response:

Yes, the financial incentives available for residential insulation, residential lighting, residential hot water, commercial lighting, and new commercial construction are less than in the 2012-2013 plan.

20.4.1 If so, provide any analysis FBC conducted of how the reduction in incentive levels affected program participation levels, costs and benefits, along with the spreadsheets used to perform the analysis in the form of functioning MS Excel files, with all inputs, assumptions, equations, and documentation.

Response:

The reductions in incentive levels and the impact that they have on the costs, benefits and measure volumes are presented in the spreadsheets submitted for the Company's proposed plan (refer to Attachment 20.1, provided in response to BCSEA IR 1.20.1). For comparison refer to the response to BCSEA IR 20.1.1 for the $7 million draft plan.

21.0 Topic: DSM

Reference: Exhibit B-1-1, Appendix H DSM, pdf p. 774

At lines 17-20, FBC states:

"The lower program expenditure level will result in lower average customer rates over the test period by between 0.3 percent and 0.5 percent annually, and approximately 1.6 percent over the 2014 – 2018 PBR period, compared to continuing at the approximate level of expenditures previously approved."

21.1 Did FortisBC analyze the cost-effectiveness of "continuing at the approximate level of expenditures previously approved" by the Commission?

Response:

Yes, FBC did consider the cost effectiveness of "continuing at the approximate level of expenditures previously approved", referred to as the $7 million scenario (Refer to Attachment 20.1.1, provided in response to BCSEA IR 1.20.1.1). The overall TRC of programs was 1.0 at this expenditure level (using the maximum mTRC expenditure of 10%). However, a number of individual DSM measures fail the TRC and the residential portfolio also fails the TRC.

This expenditure level is not considered viable by FortisBC, in part because the residential program fails the cost-effectiveness test and in part because of the 2.2 per cent rate impact it creates (please refer to the response to BCSEA IR 1.17.1).

The following table shows the portfolio level costs and Benefit/Cost ratios:

Program Area	Cost $(000s)	TRC B/C ratio
Program Sector		
Residential	3,095	0.9
General Service	2,593	1.2
Industrial	187	3.4
Sub-total Programs:	**5,875**	**1.1**
Supporting Initiatives	525	
Planning & Evaluation	773	
Total (incl. Portfolio spend):	7,173	**1.0**

21.1.1 If so, please provide the spreadsheets used to perform the analysis in the form of functioning MS Excel files, with all inputs, assumptions, equations, and documentation.

Response:

FBC carried out some preliminary analysis to examine a $7 million scenario which approximated the level of expenditures previously approved. Please refer to Attachment 20.1.1, provided in response to BCSEA IR 1.20.1.1.

21.1.2 If not, please explain why FortisBC decided not to conduct such an analysis.

Response:

Please refer to the response to BCSEA IR 1.21.1.

21.2 Please provide the analysis resulting in the rate impacts presented, including the spreadsheets used to perform the analysis in the form of functioning MS Excel files, with all inputs, assumptions, equations, and documentation.

Response:

Attachment 21.2 shows that the higher expenditure level would result in average rates being 2.2 percent higher over the PBR term (not 1.6 percent as stated).

21.3 Did FortisBC analyze the differential impact on total customer bills of continuing with previously-approved expenditure levels as compared with the reduced expenditures proposed now?

Response:

Please refer to the response to BCSEA IR 1.21.2. Non-participant bills would be expected to be 2.2% higher over the PBR term if the previously-approved DSM expenditure levels were maintained.

21.3.1 If so, please provide the spreadsheets used to perform the analysis in the form of functioning MS Excel files, with all inputs, assumptions, equations, and documentation.

Response:

Please refer to the response to BCSEA IR 1.21.2.

21.3.2 If not, please explain why FortisBC chose not to conduct such an analysis.

Response:

Please refer to the response to BCSEA IR 1.21.2.

22.0 Topic: DSM

Reference: Exhibit B-1-1, Appendix H DSM, pdf p. 774

At lines 7-8, FortisBC states that "[t]he DSM funding request is also supported by the FBC 2012 Semi-Annual DSM Year-End Report included as Attachment H2."

22.1 Please explain and demonstrate quantitatively exactly how the 2012 actual results on program spending, savings, and cost-effectiveness support the levels of spending and savings that FBC proposes in the 2014-2018 DSM Plan.

Response:

Please refer to the response to BCSEA IR 1.28.4.4.

The 2012 actual results are provided in certain tables, e.g. Appendix H Table H-4, for information and comparative purposes, but are not directly linked to the 2014-18 DSM Plan.

22.1.1 Please trace how specific 2012 program results were used to project outcomes from the 2014-2018 DSM Plan, such as program cost per kWh saved, and/or savings per participant.

Response:

Please refer to the response to BCSEA IR 1.22.1. Past program results and trends were used to inform the 2013 CPR Update scenarios and make decisions on level of incentives paid and participation rates in the DSM Planning process.

22.1.2 Please provide any spreadsheets used to respond to this request in the form of functioning MS Excel files, with all inputs, assumptions, equations, and documentation.

Response:

Please refer to the response to BCSEA IR 1.22.1.

23.0 Topic: DSM

Reference: Exhibit B-1-1, Appendix H DSM, pdf p. 777

23.1 In what specific ways are the 2014-2018 DSM Plan and its expenditures "consistent with the methodology used in the 2012 LTRP"?

Response:

The consistent LTRP methodology determines the DSM economic potential at three different LRMC values (as was done in the 2013 CPR Update), and then selects the appropriate LRMC for the 2014-18 PBR filing period in order to create the DSM Plan. The energy savings in the DSM Plan are determined by multiplying the economic achievable potential by the appropriate ramp rate. The expenditures are determined by multiplying the plan savings by the requisite incentives plus the addition of program administration costs plus portfolio level expenditures, such as EM&V.

23.2 Given that the 2012 LTRP calculated costs, savings, and benefits from three competing levels of DSM investment (high, medium, and low), please explain and document how FBC's analysis and presentation of only a single, low-case DSM scenario in the proposed DSM plan is "consistent with the methodology used in the 2012 LTRP."

Response:

Please refer to Attachment 248.2 provided in response to BCUC IR 1.248.2 for the 2013 CPR Update.

The 2013 CPR Update does review three scenarios of DSM savings & investment, based on three LRMC avoided costs, and the 2014-18 DSM Plan proceeds with the LRMC that the Company believes is appropriate at this time.

23.3 Please provide all analysis supporting the statement that "the number and breadth of DSM measures and programs that pass the Total Resource Cost test, has diminished commensurate with the lower LRMC." Please include any spreadsheets used to respond to this request in the form of functioning MS Excel files, with all inputs, assumptions, equations, and documentation.

Response:

Please refer the DSM Plan workbook in Attachment 20.1.1, provided in response to BCSEA IR 1.20.1.1.

24.0 Topic: DSM

Reference: Exhibit B-1-1, Appendix H DSM, Attachment H1, DSM Plan, pdf p.797, line 17

24.1 Please provide the 2013 CPR Update, including any spreadsheets used to respond to this request in the form of functioning MS Excel files, with all inputs, assumptions, equations, and documentation.

<u>Response:</u>

Please refer to the response to BCUC IR 1.248.2.

25.0 Topic: DSM

Reference: Exhibit B-1-1, Appendix H DSM, Attachment H1, DSM Plan, pdf pp. 798-808

25.1 Provide the MS Excel spreadsheets supporting the following tables, with all inputs, assumptions, equations, and documentation.

25.1.1 Tables H1-1a and b

Response:

Please refer to Attachment 20.1.1, provided in response to BCSEA IR 1.20.1.1. Refer to tabs “TablesMWh” and “Tables$” in the MS Excel workbook.

25.1.2 Tables H1-2a and b

Response:

Please refer to Attachment 20.1.1, provided in response to BCSEA IR 1.20.1.1. Refer to tabs “TablesMWh” and “Tables$” in the MS Excel workbook.

25.1.3 Tables H1-3a and b

Response:

Please refer to Attachment 20.1.1, provided in response to BCSEA IR 1.20.1.1. Refer to tabs “TablesMWh” and “Tables$” in the MS Excel workbook.

25.1.4 Tables H1-4a and b

Response:

Please refer to Attachment 20.1.1, provided in response to BCSEA IR 1.20.1.1. Refer to tabs “TablesMWh” and “Tables$” in the MS Excel workbook.

25.1.5 Table H1-5

Response:

Please refer to Attachment 20.1.1, provided in response to BCSEA IR 1.20.1.1. Refer to tabs "TablesMWh" and "Tables$" in the MS Excel workbook.

25.1.6 Table H1-6

Response:

Please refer to Attachment 20.1.1, provided in response to BCSEA IR 1.20.1.1. Refer to tabs "TablesMWh" and "Tables$" in the MS Excel workbook.

25.1.7 Table H1-7

Response:

Please refer to Attachment 20.1.1, provided in response to BCSEA IR 1.20.1.1. Refer to tabs "TablesMWh" and "Tables$" in the MS Excel workbook.

25.2 If not provided in response to the previous request, please provide the following information for each program contained in the 2014-18 DSM Plan, including any MS Excel spreadsheets supporting the following tables, with all inputs, assumptions, equations, and documentation:

25.2.1 Definition and size of the eligible population in each year,

Response:

The DSM Plan savings are a product of economic potential savings (GWh) times a selected ramp-rate, as can be seen in the "kWh" tab of the DSM Plan worksheet in Attachment 20.1.1, provided in response to BCSEA IR 1.20.1.1. The ramp rate is representative of the size of eligible population each year.

25.2.2 Number of participating customers, by year,

Response:

FBC does not have this analysis. The DSM Plan estimates the number of unit measures (for instance, the number of CFL or LED light bulbs or the square feet of insulation incented), which is different from the number of participating customers.

There are two primary issues that make accurate customer participation statistics problematic. First, the LiveSmartBC program does not currently provide sufficient information for FortisBC to be able to automatically link incentive payments to specific customers in our CIS system. Second, some incentive programs (for example, speciality light bulbs) pay incentives to retailers or wholesalers in bulk and FortisBC cannot identify the end user.

These limitations aside, the PowerSense DSM Reporting Software that was approved as part of the 2012-2013 Capital Expenditure Plan will enhance the granularity of reporting by connecting many PowerSense customer interactions to a specific account in the Customer Information System. The PowerSense DSM Reporting Software is expected "go live" in early 2014.

25.2.3 Customer participation rate, as a percentage of the eligible population, by year,

Response:

Please refer to the response to BCSEA IR 1.25.2.2.

25.2.4 Average electricity savings per participant by year,

Response:

Please refer to the response to BCSEA IR 1.25.2.2.

25.2.5 Projected mix of efficiency measures per participant by year,

Response:

Please refer to the response to BCSEA IR 1.25.2.2.

25.2.6 Projected efficiency measure incremental or installed costs before program financial incentives, annual savings, life expectancy of each measure or mix of measures installed per participant by year,

Response:

Please refer to the response to BCSEA IR 1.25.2.2.

25.2.7 Any measure-level and/or participant-level TRC cost-effectiveness analysis supporting individual DSM program design, plans, or activity levels,

Response:

Please refer to the "TRC" tab of the DSM Plan workbook in Attachment 20.1.1, provided in response to BCSEA IR 1.20.1.1. Note this is available on a measure-level only.

25.2.8 The financial incentives proposed for all measures and measure packages per participant, expressed in dollars per measure, per participant, and as a percentage of measure incremental or installed cost,

Response:

The plan incentives are shown on the "$prog" tab of the DSM Plan workbook in Attachment 20.1.1, provided in response to BCSEA 1.20.1.1, expressed in percentage of measure cost, dollars per measure and kWh. As explained in the response to BCSEA IR 1.25.2.2, the analysis is not available per participant.

25.2.9 Detailed program implementation costs by year by program, broken down by function and distinguishing between program costs that are relatively fixed with respect to the number of participants, e.g., marketing, and between program costs that vary according to the number of participants.

Response:

Detailed implementation costs by year, by program and distinguished between variable costs (i.e. incentive budget, which is dependent on the number of unit measures installed) and relatively fixed costs (administration) are shown on the “$prog” tab of the DSM Plan workbook in Attachment 20.1.1, provided in response to BCSEA 1.20.1.1.

Note these costs are not broken down per participant for the reasons explained in the response to BCSEA IR 1.25.2.2.

26.0 Topic: DSM

Reference: Exhibit B-1-1, Appendix H DSM, Attachment H-2, Semi-Annual DSM Report Year Ended December 31, 2012, pdf pp. 810-828

26.1 Please provide the MS Excel spreadsheets supporting all tables in the 2012 report, with all inputs, assumptions, equations, and documentation.

Response:

Please refer to Attachment 26.1 for the requested functioning spreadsheet.

26.2 If not provided in response to the previous request, please provide the following information for each program contained in the this appendix, including any MS Excel spreadsheets supporting the following tables, with all inputs, assumptions, equations, and documentation.

26.2.1 Definition and size of the eligible population

Response:

The Semi-Annual DSM Report does not use eligible population as a metric. Only energy savings and expenditures are tracked relative to the DSM Plan in the Semi-Annual DSM Report.

26.2.2 Number of participating customers

Response:

Please refer to the response to BCSEA IR 1.25.2.2.

26.2.3 Customer participation rate, as a percentage of the eligible population

Response:

Please refer to the response to BCSEA IR 1.25.2.2.

26.2.4 Average electricity savings per participant

Response:

Please refer to the response to BCSEA IR 1.25.2.2.

26.2.5 Projected mix of efficiency measures per participant

Response:

Please refer to the response to BCSEA IR 1.25.2.2.

26.2.6 Projected efficiency measure incremental or installed costs before program financial incentives, annual savings, life expectancy of each measure or mix of measures installed per participant

Response:

Please refer to the response to BCSEA IR 1.25.2.2.

26.2.7 Any measure-level and/or participant-level TRC cost-effectiveness analysis supporting individual DSM program design, plans, or activity levels

Response:

Please refer to the "Financial Table" tab of the MS Excel workbook in Attachment 26.1, provided in response to BCSEA IR 1.26.1. Note that in the Semi-annul DSM Report this is only available at the program level.

26.2.8 The financial incentives offered for all measures and measure packages per participant, expressed in dollars per measure, per participant, and as a percentage of measure incremental or installed cost.

Response:

The financial incentives shown on the "BCUC Report Format" tab of the MS Excel workbook in Attachment 26.1, provided in response to BCSEA IR 1.26.1 are expressed as total incentive per program. The analysis is not available per participant for reasons explained in the response to BCSEA IR 1.25.2.2.

26.2.9 Detailed program implementation costs by program, broken down by function and distinguishing between program costs which are relatively fixed with respect to the number of participants, e.g., marketing, and between program costs that vary according to the number of participants.

Response:

Detailed implementation costs by program with differentiation between variable costs (i.e. incentives, which are dependent on the number of unit measures installed) and relatively fixed costs (program labour and direct information) are shown on the "BCUC Report Format" tab of Attachment 26.1, provided in response to BCSEA IR 1.26.1.

27.0 Topic: DSM

Reference: : Exhibit B-1-1, Appendix H DSM, Attachment H-2, Semi-Annual DSM Report Year Ended December 31, 2012, Table 2, pdf p. 817

27.1 Please explain why FBC has not integrated the following C/I programs with FortisBC Energy Utilities for a combined offer:

27.1.1 New building improvement

Response:

FBC and FEU staff are working collaboratively to provide seamless and effective customer service to New Building program customers. For example, the Company's representatives jointly meet and present recommendations and offers for energy studies and rebates with New Construction program customers (i.e., UBCO, Interior Health, City of Kelowna, Weyerhaeuser). Full integration of administration and some customer Key Account service has not yet been achieved, and a firm timeline to do so has not been set.

27.1.2 Existing building improvement

Response:

FBC and FEU staff are working collaboratively to provide seamless and effective customer service to commercial/industrial program customers. For example, the Company's representatives jointly meet and present recommendations and offers for energy studies and rebates with Building Improvement program customers (i.e., UBCO, Interior Health, City of Kelowna). Full integration of administration and some customer Key Account service has not yet been achieved, and a firm timeline to do so has not been set.

27.1.3 Partners in energy

Response:

FBC and FEU staff work closely together to provide excellent customer service to the Commercia/Industrial sector customers. Whenever appropriate, employees share information and costs for third-party energy assessments (i.e., engineering reports, walk-through audits). Other shared costs are also apportioned appropriately to the companies.

Service delivery and rebate processing has not been fully integrated due to the fact that the functions are delivered by different employee groups (including unionized employees) and external contractors, in each of the companies. FortisBC intends to work to more fully integrate these functions over the test period.

27.1.4 Industrial efficiency

Response:

Please refer to the response to BCSEA IR 1.27.1.3.

27.2 If FBC has plans to integrate its electric DSM programs with FEU's in the future, please indicate

27.2.1 The nature of the planned integration

Response:

Please refer to the response to BCSEA IR 1.27.2.2.

A definitive date has not been set for full integration of administrative and some service delivery processes, as agreements with the COPE bargaining units must be reached beforehand. However, integration for all external facing components of DSM programs and marketing has already been achieved or is in progress, to provide seamless customer experience.

27.2.2 The steps underway to accomplish integration

Response:

Whenever possible FBC has already integrated its program offers with FEU's EEC offers. All external communications and marketing, and program offers and application processes are for both natural gas and electric offers. For example, the Kootenay Energy Diet, the Okanagan Energy Diet, the New Home, the Home Improvement, the RELP (on-bill finance), the TLC heating system maintenance, the MURB Rental, the ESK Low-Income, the Trade Ally, and the Business Energy Rebate Centre programs are fully integrated offers. Although internal program administration has not been fully joined in all instances, the two programs' staffs work collaboratively so customers experience only one application process.

FBS is in the process of partnering with FEU and BC Hydro to offer a province-wide Low-Income ECAP program with one unified administration and implementation process.

The commercial custom program is not yet fully integrated; however, staffs have bi-weekly meetings and exchange information amongst themselves and with customers whenever appropriate. Joint requests for proposals for additional program offers (i.e., walk-through energy audit service) and pilot projects (ice arena improvements) are in progress.

27.2.3 The date by which FBC plans to accomplish full integration

<u>Response:</u>

Refer to the response to BCSEA IR 1.27.2.2.

A definitive date has not been set for full integration of administrative and some service delivery processes. However, integration for all external facing components of DSM programs and marketing has already been achieved or is in progress to provide seamless customer experience.

28.0 Topic: DSM

Reference: Exhibit B-1-1, Appendix H DSM, Attachment H-2, Semi-Annual DSM Report Year Ended December 31, 2012, Table 13, Financial Results for Year Ended December 31, 2012 by Program, pdf p. 824

28.1 Does FBC agree that the value of the new LRMC of $56.61/MWh is 66.6% the previous LRMC value of $84.94?

Response:

Agreed.

28.2 Please provide a version of Table 13 in which the reported program benefits are multiplied by the ratio of new LRMC to old LRMC.

Response:

Table 13 (Revised).

Financial Results for Year Ended December 31, 2012 by Program, with Program Benefits Multiplied by ratio of new LRMC ($56.61/MWh) to 2012 LRMC ($84.94/MWh)

Program	2012 Program Benefits	Program Benefits (multiplied by LRMC ratio)	Utility Program Costs	Planning & Evaluation Costs: Planning & Admin.	Monitoring & Eval.	Program Dev.	Customer Incurred Costs	Total Resource Costs	Benefits less Costs	Total Resource Benefit/Cost Ratio: TRC	MTRC
	($000s)										
Residential											
Home Improvement	4,961	3,306	969	66	57	13	1,819	2,924	383	1.1	1.2*
Low Income	376	251	308	12	10	2	42	374	(123)	0.7	0.9**
Residential Lighting	1,063	708	337	29	25	6	181	577	131	1.2	1.2
Heat Pumps	1,774	1,182	636	24	21	5	1,050	1,735	(553)	0.7	1.0*
New Home Program	1,121	747	314	12	10	2	441	780	(32)	1.0	1.0
Residential Total	**9,295**	**6,195**	**2,564**	**143**	**122**	**29**	**3,532**	**6,390**	**(195)**	**1.0**	**1.1**
Commercial											
Lighting	7,737	5,156	2,152	159	137	32	1,044	3,525	1,631	1.5	1.5
Building and Process Improvement	1,689	1,125	612	22	19	4	607	1,264	(138)	0.9	0.9
Water Handling Infrastructure	1,433	955	255	19	16	4	261	555	399	1.7	1.7
Commercial Total	**10,858**	**7,236**	**3,020**	**200**	**172**	**41**	**1,912**	**5,344**	**1,893**	**1.4**	**1.4**
Industrial											
Industrial Efficiency	541	361	163	10	9	2	89	274	87	1.3	1.3
Integrated EMIS	-	-	10	-	-	-	-	10	(10)	0.0	- *
Industrial Total	**541**	**361**	**173**	**10**	**9**	**2**	**89**	**284**	**77**	**1.3**	**1.3**
Supporting Initiatives			816					816		-	-
Total	**20,694**	**13,792**	**6,572**	**353**	**303**	**72**	**5,533**	**12,833**	**7,861**	**1.1**	**1.1**

Note: Minor differences due to rounding
** Modified TRC benefits used with some of program measures*
*** Low Income benefits increased by 30 percent*

28.3 Does FBC agree that multiplying the reported program benefits in Table 13 by the ratio of new LRMC to old LRMC provides a reasonable representation of the benefits of the same program savings under the new, lower LRMC?

Response:

Agreed, it provides a reasonable approximation of the $56.61/MWh LRMC.

28.3.1 If not, please explain in detail why not.

Response:

Please refer to the response to BCSEA IR 1.28.3.

28.3.2 If so, does FBC agree that multiplying the new/old LRMC ratio to the reported TRC benefit/cost ratio (BCR) provides a reasonable representation of the TRC BCR from the program savings and spending reported for 2012 valued at the new, lower LRMC?

Response:

Agreed, it provides a reasonable approximate of the TRC BCR valued at $56.61/MWh LRMC.

28.3.2.1 If not, please explain in detail why not.

Response:

Please refer to the response to BCSEA IR 1.28.3.2.

28.4 Pleas see the table of BCRs below, with reported and recalculated values. A working spreadsheet is attached.

Cost-effectiveness of FBCe actual 2012 DSM spending and savings				
Reported and Recalculated at claimed 2014 LRMC				
2012 IRP LRMC of market power		84.94		
2014 claimed LRMC		56.61	66.6%	of 2012 value
			33.4%	reduction
		TRC BCR @ LRMC =		
		$ 84.94	**$ 56.61**	
Results from actual 2012 spending and savings		**Reported**	**Recalculated**	
portfolio		1.6	1.07	
residential		1.5	1.00	
	Home Improvement	1.7	1.13	
commercial		2.0	1.33	
industrial		1.9	1.27	

28.4.1 Does FBC agree that the Reported and Recalculated BCRs are calculated correctly? If not, why not?

Response:

The table appears to correctly perform a recalculation the BCR as Recalculated = Reported * 56.61 / 84.94.

28.4.2 Does FBC agree that actual 2012 spending and savings for the portfolio as a whole, and for both commercial and industrial sector, would have been cost-effective under the new, lower LRMC of $56.61/MWh?

Response:

Agreed.

28.4.2.1 If not, please explain in detail why not.

Response:

Please refer to the response to BCSEA IR 1.28.4.2.

28.4.3 Does FBC agree that some of the programs, such as the residential home improvement program, would likewise be shown to be cost-effective under the new LRMC?

Response:

Agreed.

28.4.3.1 If not, please explain in detail why not.

Response:

Please refer to the response to BCSEA IR 1.28.4.3.

28.4.3.2 If so, does FBC agree that it could raise the combined residential program BCR of 1.0 under the lower avoided costs by increasing expenditures on, and savings from, programs within the sector with relatively high BCRs, such as the home improvement program?

Response:

FortisBC disagrees. FBC offers a slate of measures and programs to address the major end-uses in each sector. The take-up in each program is customer driven, and FBC cannot easily change market response in order to ensure that the BCR passes on a portfolio basis. Please refer to the response to CEC IR 1.5.3.1.

28.4.4 Based on the responses to these requests, please explain how the actual 2012 DSM program cost-effectiveness results in Appendix H2 “support” the Company’s proposal to decrease portfolio spending and savings from previously approved and achieved levels by roughly two thirds.

Response:

The term "support" was used in a general sense of the word; namely that the 2012 YE DSM Semi-Annual report was included for information purposes, that is, to provide background on prior DSM activities undertaken by FBC.

Also please refer to the response to CEC IR 1.9.1.

29.0 Topic: DSM

Reference: Exhibit B-1-1, Appendix H DSM, Attachment H-2, Semi-Annual DSM Report Year Ended December 31, 2012, Sub-Appendix C

29.1 Provide the full industrial program evaluation report.

Response:

Past practice, in alignment with a BCUC directive to BC Hydro, is to file executive summaries of M&E reports only, except if a program has ended. Additionally FBC wishes to safeguard the confidentially of the participants as the full report includes detailed site visit reports of named customers who expect their industrial processes and program experiences to remain confidential.

30.0 Topic: DSM

Reference: Exhibit B-1-1, Appendix H DSM, Attachment H-2, Semi-Annual DSM Report Year Ended December 31, 2012, Sub-Appendix D

30.1 Provide the full commercial lighting evaluation report.

Response:

Please refer to the response to BCSEA IR 1.29.1.

31.0 Topic: DSM

Reference: Exhibit B-1-1, Appendix H DSM, Attachments H1 and H2

31.1 What is the average "close rate" that FBC experienced in its residential and commercial retrofit programs in 2012, i.e., what percentage of customers to whom FBC made incentive offers went on to complete retrofit projects?

Response:

This metric is not tracked by FBC. FortisBC does not generally "offer" incentives to individual customers, but instead responds directly to customer questions regarding incentives and programs or simply processes rebates for purchases that have already been made.

31.2 What close rate does FBC project for each retrofit program in the 2014-18 DSM plan?

Response:

Please refer to the response to BCSEA IR 1.31.1.

31.3 How much on average did FBC spend on project development (including energy audits or assessment) per customer who was offered incentives for retrofit projects in 2012, stated separately for its residential and nonresidential retrofit programs?

Response:

In 2012 FBC spent $171,000 on project development, including energy audits or assessment. The amount spent on residential programs was $42,000 and the balance of $129,000 was spent on non-residential programs. These costs are for external service providers only and do not include DSM staff time to perform walk-through energy assessments and/or develop retrofit projects through to completion. This data is not available per customer for the reasons explained in the response to BCSEA IR 1.25.2.2.

31.4 How much does FBC budget per customer who will be offered incentives for retrofit projects in the 2014-18 DSM plan?

Response:

The DSM Plan budgets $1,462,000 for incentives in 2014, a figure that stays roughly the same for the PBR period. This figure cannot be converted to a budget cost per customer since the Plan does not include a participant count metric (for the reasons described in the response to BCSEA 1.25.2.2). In addition, many measures cannot easily be related to customers (for example, residential insulation measure is based on the area insulated, not the number of participating customers).

31.5 How much on average did FBC spend per participant on post-installation inspections in its residential and nonresidential retrofit programs in 2012?

Response:

FBC does not track this metric specifically, but there are a number of ways and means by which the Company ensures the measures are in place.

For some residential measures, contractor invoices are used as prima facie proof of installation and the customers sign the program application form to give FBC the right of inspection later. For example the 2009 Heat Pump M&E evaluation included two dozen site visits to inspect the installations. For the residential measures that are installed as part of the LiveSmart BC program, each participant receives a post-installation inspection by the 3rd party EnerGuide auditor.

Most non-residential custom retrofit projects receive a site visit from a PowerSense Technical Advisor as part of the project verification. Smaller projects may be processed with installation invoices, and again site visits were done on a random basis in the two prior BIP M&E reviews. As part of the FLIP (FortisBC/LiveSmart BC Lighting Incentive Program) implementation contract, the contractor had to conduct post-installation visits for 10 percent of the first 100 participating businesses and 5 percent of all additional installations, on behalf of FBC.

The 2012 Industrial Efficiency Program Evaluation costs were $49,000 and the study scope included ten site inspections.

31.6 How much is FBC budgeting per post-installation inspection in its retrofit programs in the 2014-18 DSM plan?

Response:

This metric is not tracked as a separate budget item in the 2014-2018 DSM Plan. The post-installation activities are embedded in the programs, as described in the response to BCSEA IR 1.31.5.

31.7 What percentage of retrofit program installations did FBC inspect in its retrofit programs in 2012?

Response:

Please refer to the response to BCSEA IR 1.31.5.

31.8 What post-installation inspection rate does FBC project in each of the retrofit programs in the 2014-18 DSM plan?

Response:

Post-installation inspection rate is not measured by FortisBC. Please refer to the response to BCSEA IR 1.31.5 for a description of the due diligence that FBC undertakes.

32.0 Topic: On-Bill Finance pilot project

Reference: B-1-1, Appendix H, Attachment H2, page 2; Appendix H, Attachment H1, 2014-18 DSM Plan, page 5

"The On-Bill Finance pilot project, which is marketed as the Residential Energy Efficiency Loan Program, was mandated by the provincial government and provides loans of up to $10,000 to residential customers in the South Okanagan to make energy efficiency improvements to their homes. The loans are to be repaid on the customers' electricity bills over the next 10 years. This pilot program was launched in the fall and by the end of 2012 none of the customers who applied had successfully met the eligibility requirements. The stringency of the eligibility requirements will be reviewed as part of the assessment of the pilot project." [Attachment H2, page 2]

"Complementary to the monetary rebates offered, the On-Bill Financing (OBF) pilot continues in the South Okanagan until November 2014, and commences in Kelowna in January 2014. Elsewhere the Company has arranged low cost, off-bill financing through regional credit unions for the Kootenay Energy Diet." [Attachment H1, page 5]

32.1 Please provide more details regarding the OBF pilot project.

Response:

Please refer to the response to BCUC IR 1.203.3 for details on loan terms, and program terms and conditions.

- Statistics to August 15, 2013
    - 24 enquiries
    - 7 applicants
    - 6 declines for ineligibility (poor credit ratings and/or missed electrical bill payments)
    - 1 successful applicant
- Marketing efforts to date
    - Two direct marketing campaigns to contractors, including face-to-face briefing meetings
    - $15,000 advertising campaign in South Okanagan (newspaper, direct mail, collateral, website)
    - Will also be promoted via the Okanagan Energy Diet

32.1.1 Please confirm that FortisBC intends to continue the OBF pilot project. When is it scheduled to be completed?

Response:

FortisBC intends to continue the OBF pilot project until its scheduled completion date of January 1, 2015.

32.1.2 Will there be any changes in the project design compared to the original concept?

Response:

At this point the only proposed change to the regulation is to relax the eligibility requirements to allow one late electricity utility payment within the past year. This change is expected to come into effect January 1, 2014.

32.1.3 When will FBC have reviewed the eligibility requirements?

Response:

FBC reviewed the eligibility requirements in Spring 2013 and reported back to the Ministry of Energy and Mines. The report resulted in the regulation being changed to allow one late electric utility payment in the previous year, effective January 1, 2014.

32.1.4 What steps does FBC intend to take if it determines that the eligibility requirements are too stringent?

Response:

Once the eligibility requirements are loosened to allow one late payment in the previous year in 2014 FBC will re-analyse the results of the change. FBC plans to undertake research to better understand the barriers to the program for those who enquired about a loan and did not proceed and/or did not meet eligibility requirements.

FortisBC will also evaluate the success of the program mandated by regulation against the off-bill financing offered through regional credit unions in the Kootenay Energy Diet.

32.2 Please describe the proposed evaluation of the OBF pilot project. Who will be conduct the evaluation? When will a report be completed? Will the report be filed with the Commission?

Response:

The DSM M&E Plan indicates a process evaluation for the OBF pilot project in 2013. This process evaluation will be completed by internal M&E staff. Further evaluation may be completed at the end of the pilot program in 2014 if participation rates increase. The evaluation report will be compiled after the pilot program and any final evaluation activities are completed, and filed with the Commission in 2015.

32.3 At this point in carrying out the OBF pilot project what lessons has FBC learned regarding whether and how OBF can enable and support DSM?

Response:

It appears that OBF is not supporting DSM in any significant way. Would-be participant inquiries are few, and qualifying customers only number in the single digits.

FortisBC believes there are three reasons for the low participation rate.

First, customers do not find the terms and/or eligibility requirements favourable. For example, in most instances they can get better terms from the financial institutions they deal with regularly. Further reducing loan rates, below the Company's cost of capital, would unacceptably increase the Company's costs and hence non-participant program subsidization.

Second, many customers do not like the requirement to get pre- and post-installation energy assessments, despite the fact that the assessments are important to maximize energy savings and that the assessment costs can be included in the value of the loan.

Third, contractors have not generally been promoting the program because in some instances it directly competes with the manufacturer's finance programs they offer.

FortisBC believes that the existing OBF program attributes are reasonable and are required 1) to ensure the program does not unduly increase rates, and 2) to ensure program effectiveness.

The first issue might be addressed by allowing lower-cost third-party off-bill financing as has been piloted in the Kootenay Energy Diets.

33.0 Topic: PBR and DSM

Reference: Exhibit B-1

33.1 Please confirm that FortisBC is proposing that DSM expenditures are not subject to the proposed Performance Base Ratemaking structure.

Response:

DSM program costs are not subject to the formula determination for O&M and capital expenditures. Please also refer to the response to BCSEA IR 1.33.1.1.

33.1.1 What if any expenditures related to DSM are proposed to fall within the PBR structure?

Response:

All direct DSM program costs are recorded in the rate base deferral account and are therefore not determined in accordance with the PBR formula. However the DSM program is supported by corporate functions including Executive, Human Resources, Finance and Accounting, and Regulatory Affairs for which the associated labour time is included in Base O&M Expense and determined according to the PBR formula.

In addition, DSM-related capital expenditures (IT capital) are included in Base Capital and subject to the PBR formula.

33.2 For clarification, please list all of the categories of spending that FortisBC proposes <u>not</u> to be subject to the PBR structure, such as DSM expenditures, CPCN capital spending and any other categories.

Response:

The expenditure categories that make up revenue requirements can be summarized by reviewing the Revenue Requirements Overview (Section E, page 277) identifying the Income Statement accounts and Schedule 1 – Utility Rate Base (Section E, page 278).

Of the Income Statement Accounts shown in the Revenue Requirements Overview, O&M Expenses at line 12 are set by formula under the PBR Plan. The other line items listed will be forecast annually.

Of the Utility Rate Base line items, Net Additions to Plant in Service (line 2) is determined by capital expenditures, which are also set by formula under the PBR Plan. The other line items listed will be forecast annually.

34.0 Topic: Balanced Scorecard

Reference: Exhibit B-1, section 5.1, page 18.

34.1 Please define the "balanced scorecard" and describe how FBC uses it.

Response:

FBC uses a Balanced Scorecard approach to deliver on a number of success measures key to the business. Additionally, the scorecard serves as a valuable communication tool used to describe in clear and objective terms success measures.

FBC's current balance scorecard is comprised of four categories of measures (Financial, Safety, Customer and Regulatory) which are standardized between the electric and gas businesses. In total, six measures describe and guide the Company's overall performance in meeting the targets, which are set annually. FBC employees receive annual incentive pay, based on the achievement of the corporate scorecard targets during a year. Performance targets guide employees to execute results in key areas and are weighted to balance the interests of our various stakeholders.

Please also refer to the response to BCUC IR 1.4.1.

34.2 Please provide copies of FBC's balanced scorecards for the past five years.

Response:

Please refer to Attachment 34.2 for FBC's scorecards from 2008 to 2012.

34.3 Please explain what regulatory approval FBC seeks in this proceeding regarding use of the balanced scorecard ?

Response:

FBC is not seeking, and does not require, any regulatory approval regarding the use of its balance scorecard.

The reference and discussion to FBC's balanced scorecard in Section 5.1 of Exhibit B-1 is to demonstrate that FBC is utilizing an industry accepted and effective practice to evaluating and monitoring organizational performance.

34.4 Please describe the pros and cons of including DSM performance in the balanced scorecard.

Response:

When evaluating performance measures to include on its Scorecard such as DSM performance, FBC does not necessarily consider a specific measure from a pro and con perspective. Instead, the Company seeks not only to select the appropriate success measures but also the optimal number of measures (i.e. how many). Additionally, as the scorecard is an important communication tool to improving organizational alignment, clarity and understanding of a measure, for employees and other stakeholders, is an important consideration.

FBC currently does not have any specific success measures on its Scorecard related to DSM performance. Instead, DSM related key success measures are included in individual employee objectives and performance plans, where applicable.

FBC reviews the appropriateness of its scorecard measures periodically and makes adjustments as required. At this time, FBC believes the six scorecard measures used best represent the overall priorities for Company.

35.0 Topic: FBC experience with PBR; consequences for DSM

Reference: Exhibit B-1, section 4.0, FBC Experience with PBR, pp. 31-34.

35.1 In FBC's past experiences with PBR, were the costs for DSM programs covered through PBR mechanisms or through cost-of-service mechanisms? Please provide details.

Response:

The Company's DSM programs were not included in either the previous PBR mechanisms or in its current PBR proposal. FBC's DSM program costs can be considered to be recovered under cost-of-service principles (an example of the hybrid form of PBR). Actual DSM expenditures are recorded in rate base and recovered in rates by way of amortization over a period of time approved by the Commission.

35.2 Please file any reports or third-party assessments on the effectiveness of FBC's or its predecessor's previous experience with performance-based rates.

Response:

Please refer to Attachment 35.2 for a copy of the Company's review of its 1996-2004 PBR Plan, filed on October 14, 2005.

35.3 Please provide any information or reports that FBC has regarding any effects that performance-based ratemaking has on the planning and execution of DSM programs by FBC or its predecessor.

Response:

Please refer to the response to BCSEA IR 1.36.1.

36.0 Topic: Jurisdictional comparison; consequences for DSM

Reference: Exhibit B-1, section 5.0, pp. 35-38

36.1 What experience have other jurisdictions had with performance-based ratemaking in terms of their encouragement or discouragement of planning and executing DSM?

Response:

The potential impact of PBR plans on DSM programs is studied by Comnes et al (1995) in their report titled "Performance-based ratemaking for electric utilities: Review of plans and analysis of economic and resource planning issues[18]". As discussed in Section 3.3.8 of the mentioned study, the impact of PBR on DSM plans can be examined based on three types of DSM incentive policies:

a) DSM cost recovery: Inclusion of DSM budget in the PBR formula may make it target of cost cutting measures. That is why in most jurisdictions DSM costs are recovered in a clause separate from base rates and therefore costs and revenues for DSM are not subject to the PBR formula. That is the case for FBC.

b) Net lost revenues: The main advantage of revenue cap formula (as a form of revenue decoupling mechanism) to price cap formula is in its ability to protect the utility from most or all of the variations in margin resulting from sales changes. That is why the DSM advocates generally favor revenue caps over price cap designs. However even in case of price cap, it is possible to add back lost revenues from specific DSM programs through rate adjustment mechanisms. The same revenue adjustment mechanisms are also applicable to cost of service regulation.

c) Shareholder incentives: Shareholder incentive schemes are not related to PBR plans and can continue under both cost of service or PBR without any change.

In 2004 Enbridge gas retained the services of IndEco strategic consulting and Navigant consulting to conduct a survey of DSM programs in North American gas utilities[19]. One of the research objectives of this study was to "explore the treatment of DSM in both cost of service and PBR regulatory frameworks". Besides FEI's DSM plan in its 2004 PBR plan, the research also reviewed the DSM programs of other utilities under PBR plans (such as utilities in Connecticut and California). The report concluded that "the DSM regulatory approval process is

[18] Comnes, G.A. et al. 1995. "Performance-based ratemaking for electric utilities: review of plans and analysis of economic and resource-planning issues", Volume I. Ernest Orlando Lawrence Berkeley National Laboratory, University of California, Berkeley, CA; Page 46-49

[19] http://indeco.com/www.nsf/602920ce130253a08525764e007a6418/abbfd4c9e05d712085256e38006d76b3/$FILE/EGD%20Report%20on%20DSM%20Jurisdictions.pdf

separate from, although linked to, rate setting. Where the utility is subject to a PBR framework, DSM is a pass-through however at the time of the PBR plan, there may be aspects of DSM that may be approved for the duration of the PBR plan".

In a separate report, Navigant consulting was retained by Natural Resource Canada, Canadian Electricity Association and Canadian Gas Association to undertake a study of energy efficiency and DSM programs in Canadian jurisdictions[20]. This study contains a detailed description of DSM programs of other Canadian utilities with incentive regulation (such as those in Ontario) where in majority of cases the costs associated with DSM programs are pass-through, the net lost revenues are compensated through rate adjustment mechanisms and DSM plans are treated under separate regulatory processes.

36.2 Please provide any studies FBC is aware of regarding the experiences of other jurisdictions with performance-based ratemaking in terms of their encouragement or discouragement of planning and executing DSM.

Response:

Please refer to the response to BCSEA IR 1.36.1.

[20] http://www.electricity.ca/media/pdfs/policy_statements/EEDSM%20PMR%20Report%20FINAL.pdf

37.0 Topic: Performance-based ratemaking and DSM costs

Reference: Exhibit B-1, Application

37.1 Please list all cost items (capital, operating, administrative, accounting) pertaining to FBC's DSM programs that FBC proposes would be covered by its performance-based ratemaking mechanism rather than under a cost-of-service ratemaking mechanism, and please list the relevant costs for each year of the test period.

<u>Response:</u>

The following capital expenditures are included in Base Capital, which is subject to determination by the PBR capital formula:

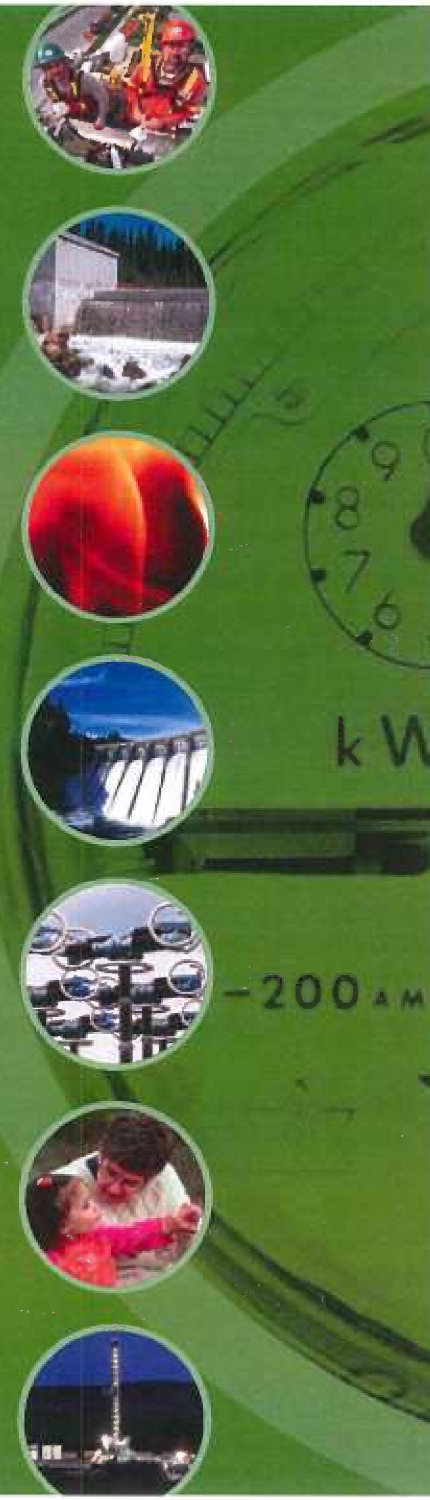
	2014	2015	2016	2017	2018
PowerSense DSM Reporting Software	104	106	108	55	56

The response to BCSEA IR 1.33.1.1 explains that some corporate functions which support the DSM department are included in the O&M formula under the PBR Plan. The Company does not track these costs according to the activity supported.

Attachment 2.1

The BC Energy Plan

A Vision for Clean Energy Leadership



BRITISH COLUMBIA
The Best Place on Earth

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MESSAGE FROM THE PREMIER

The BC Energy Plan: A Vision for Clean Energy Leadership is British Columbia's plan to make our province energy self-sufficient while taking responsibility for our natural environment and climate. The world has turned its attention to the critical issue of global warming. This plan sets ambitious targets. We will pursue them relentlessly as we build a brighter future for B.C.

The BC Energy Plan sets out a strategy for reducing our greenhouse gas emissions and commits to unprecedented investments in alternative technology based on the work that was undertaken by the Alternative Energy Task Force. Most importantly, this plan outlines the steps that all of us – including industry, environmental agencies, communities and citizens – must take to reach these goals for conservation, energy efficiency and clean energy so we can arrest the growth of greenhouse gases and reduce human impacts on the climate.

As stewards of this province, we have a responsibility to manage our natural resources in a way that ensures they both meet our needs today and the needs of our children and grandchildren. We will all have to think and act differently as we develop innovative and sustainable solutions to secure a clean and reliable energy supply for all British Columbians.

Our plan will make B.C. energy self-sufficient by 2016. To do this, we must maximize our conservation efforts. Conservation will reduce pressure on our energy supply and result in real savings for those who use less energy. Individual actions that reduce our own everyday energy consumption will make the difference between success and failure. For industry, conservation can lead to an effective, productive and significant competitive advantage. For communities, it can lead to healthier neighbourhoods and lifestyles for all of us.

We are looking at how we can use clean alternative energy sources, including bioenergy, geothermal, fuel cells, water-powered electricity, solar and wind to meet our province's energy needs. With each of these new options comes the opportunity for new job creation in areas such as research, development, and production of innovative energy and conservation solutions. The combination of renewable alternative energy sources and conservation will allow us to pursue our potential to become a net exporter of clean, renewable energy to our Pacific neighbours.

Just as the government's energy vision of 40 years ago led to massive benefits for our province, so will our decisions today. **The BC Energy Plan** will ensure a secure, reliable, and affordable energy supply for all British Columbians for years to come.

Premier Gordon Campbell

MESSAGE FROM THE MINISTER

The BC Energy Plan: A Vision for Clean Energy Leadership is a made-in-B.C. solution to the common global challenge of ensuring a secure, reliable supply of affordable energy in an environmentally responsible way. In the next decade government will balance the opportunities and increased prosperity available from our natural resources while leading the world in sustainable environmental management.

This energy plan puts us in a leadership role that will see the province move to eliminating or offsetting greenhouse gas emissions for all new projects in the growing electricity sector, end flaring from oil and gas producing wells, and put in place a plan to make B.C. electricity self-sufficient by 2016.

In developing this plan, the government met with key stakeholders, environmental non-government organizations, First Nations, industry representatives and others. In all, more than 100 meetings were held with a wide range of parties to gather ideas and feedback on new policy actions and strategies now contained in **The BC Energy Plan**.

By building on the strong successes of Energy Plan 2002, this energy plan will provide secure, affordable energy for British Columbia. Today, we reaffirm our commitment to public ownership of our BC Hydro assets while broadening our supply of available energy.

We look towards British Columbia's leading edge industries to help develop new, greener generation technologies with the support of the new **Innovative Clean Energy Fund**. We're planning for tomorrow, today. Our energy industry creates jobs for British Columbians, supports important services for our families, and will play an important role in the decade of economic growth and environmental sustainability that lies ahead.

The Ministry of Energy, Mines and Petroleum Resources is responding to challenges and opportunities by delivering innovative, sustainable ways to develop British Columbia's energy resources.

Honourable Richard Neufeld
Minister of Energy, Mines and Petroleum Resources

THE BC ENERGY PLAN HIGHLIGHTS

British Columbia's current electricity supply resources are 90 per cent clean and new electricity generation plants will have zero net greenhouse gas emissions.

In 2002, the Government of British Columbia launched an ambitious plan to invigorate the province's energy sector. Energy for Our Future: A Plan for BC was built around four cornerstones: low electricity rates and public ownership of BC Hydro; secure, reliable supply; more private sector opportunities; and environmental responsibility with no nuclear power sources. Today, our challenges include a growing energy demand, higher prices, climate change and the need for environmental sustainability. **The BC Energy Plan: A Vision for Clean Energy Leadership** builds on the successes of the government's 2002 plan and moves forward with new policies to meet the challenges and opportunities ahead.

Environmental Leadership

The BC Energy Plan puts British Columbia at the forefront of environmental and economic leadership by focusing on our key natural strengths and our competitive advantages of clean and renewable sources of energy. The plan further strengthens our environmental leadership through the following key policy actions:

- **Zero greenhouse gas emissions from coal fired electricity generation.**
- **All new electricity generation projects will have zero net greenhouse gas emissions.**
- **Zero net greenhouse gas emissions from existing thermal generation power plants by 2016.**
- **Ensure clean or renewable electricity generation continues to account for at least 90 per cent of total generation.**
- **No nuclear power.**
- **Best coalbed gas practices in North America.**
- **Eliminate all routine flaring at oil and gas producing wells and production facilities by 2016 with an interim goal to reduce flaring by half (50 per cent) by 2011.**

A Strong Commitment to Energy Conservation and Efficiency

Conservation is integral to meeting British Columbia's future energy needs. **The BC Energy Plan** sets ambitious conservation targets to reduce the growth in electricity used within the province. British Columbia will:

- **Set an ambitious target, to acquire 50 per cent of BC Hydro's incremental resource needs through conservation by 2020.**
- **Implement energy efficient building standards by 2010.**

Current per household electricity consumption for BC Hydro customers is about 10,000 Kwh per year. Achieving this conservation target will see electricity use per household decline to approximately 9,000 Kwh per year by 2020.

Energy Security

The Government of British Columbia is taking action to ensure that the energy needs of British Columbians continue to be met now and into the future. As part of ensuring our energy security, **The BC Energy Plan** sets the following key policy actions:

- **Maintain public ownership of BC Hydro and the BC Transmission Corporation.**
- **Maintain our competitive electricity rate advantage.**
- **Achieve electricity self-sufficiency by 2016.**
- **Make small power part of the solution through a set purchase price for electricity generated from projects up to 10 megawatts.**
- **Explore value-added opportunities in the oil and gas industry by examining the viability of a new petroleum refinery and petrochemical industry.**
- **Be among the most competitive oil and gas jurisdictions in North America.**
- **BC Hydro and the Province will enter into initial discussions with First Nations, the Province of Alberta and communities to discuss Site C to ensure that communications regarding the potential project and the processes being followed are well known.**

Investing in Innovation

British Columbia has a proven track record in bringing ideas and innovation to the energy sector. From our leadership and experience in harnessing our hydro resources to produce electricity, to our groundbreaking work in hydrogen and fuel cell technology, British Columbia has always met its future energy challenges by developing new, improved and sustainable solutions. To support future innovation and to help bridge the gap experienced in bringing innovations through the pre-commercial stage to market, government will:

- **Establish an Innovative Clean Energy Fund of $25 million.**
- **Implement the BC Bioenergy Strategy to take full advantage of B.C.'s abundant sources of renewable energy.**
- **Generate electricity from mountain pine beetle wood by turning wood waste into energy.**

POLICY ACTIONS

COMMITMENT TO CONSERVATION

- **Set an ambitious conservation target, to acquire 50 per cent of BC Hydro's incremental resource needs through conservation by 2020.**
- **Ensure a coordinated approach to conservation and efficiency is actively pursued in British Columbia.**
- **Encourage utilities to pursue cost effective and competitive demand side management opportunities.**
- **Explore with B.C. utilities new rate structures that encourage energy efficiency and conservation.**

Ambitious Energy Conservation and Efficiency Targets

The more energy that is conserved, the fewer new sources of supply we will require in the future. That is why British Columbia is setting new conservation targets to reduce growth in electricity demand.

Inefficient use of energy leads to higher costs and many environmental and security of supply problems.

Conservation Target

The BC Energy Plan sets an ambitious conservation target, to acquire 50 per cent of BC Hydro's incremental resource needs through conservation by 2020. This will require building on the "culture of conservation" that British Columbians have embraced in recent years.

The plan confirms action on the part of government to complement these conservation targets by working closely with BC Hydro and other utilities to research, develop, and implement best practices in conservation and energy efficiency and to increase public awareness. In addition, the plan supports utilities in British Columbia and the BC Utilities Commission pursuing all cost effective and competitive demand side management programs. Utilities are also encouraged to explore and develop rate designs to encourage efficiency, conservation and the development of renewable energy.

Future energy efficiency and conservation initiatives will include:

- Continuing to remove barriers that prevent customers from reducing their consumption.
- Building upon efforts to educate customers about the choices they can make today with respect to the amount of electricity they consume.
- Exploring new rate structures to identify opportunities to use rates as a mechanism to motivate customers either to use less electricity or use less at specific times.
- Employing new rate structures to help customers implement new energy efficient products and technologies and provide them with useful information about their electricity consumption to allow them to make informed choices.
- Advancing ongoing efforts to develop energy-efficient products and practices through regulations, codes and standards.

The average household uses about 10,000 kilowatt-hours of electricity per year.

Implement Energy Efficiency Standards for Buildings by 2010

British Columbia implemented *Energy Efficient Buildings: A Plan for BC* in 2005 to address specific barriers to energy efficiency in our building stock through a number of voluntary policy and market measures. This plan has seen a variety of successes including smart metering pilot projects, energy performance measurement and labelling, and increased use of Energy Star appliances. In 2005, B.C. received a two year, $11 million federal contribution from the Climate Change Opportunities Envelope to support implementation of this plan.

Working together industry, local governments, other stakeholders and the provincial government will determine and implement cost effective energy efficiency standards for new buildings by 2010. Regulated standards for buildings are a central component of energy efficiency programs in leading jurisdictions throughout the world.

The BC Energy Plan supports reducing consumption by raising awareness and enhancing the efforts of utilities, local governments and building industry partners in British Columbia toward conservation and energy efficiency.

Aggressive Public Sector Building Plan

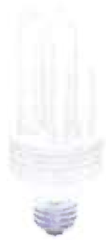
The design and retrofit of buildings and their surrounding landscapes offer us an important means to achieve our goal of making the government of British Columbia carbon neutral by 2010, and promoting Pacific Green universities, colleges, hospitals, schools, prisons, ferries, ports and airports.

British Columbia communities are already recognized leaders in innovative design practices. We know how to build smarter, faster and smaller. We know how to increase densities, reduce building costs and create new positive benefits for our environment. We know how to improve air quality, reduce energy consumption and make wise use of other resources, and how to make our landscapes and buildings healthy places for living, working and learning. We know how to make it affordable.

Government will set the following ambitious goals for all publicly funded buildings and landscapes and ask the Climate Action Team to determine the most credible, aggressive and economically viable options for achieving them:

- Require integrated environmental design to achieve the highest standards for greenhouse gas emission reductions, water conservation and other building performance results such as a certified standard.
- Supply green, healthy workspaces for all public service employees.
- Capture the productivity benefits for people who live and work in publicly funded buildings such as reduced illnesses, less absenteeism, and a better learning environment.
- Aim not only for the lowest impact, but also for restoration of the ecological features of the surrounding landscapes.

Gigawatt = 1,000,000 kilowatts
Kilowatt = amount of power to light ten 100-watt incandescent light bulbs.



Community Action on Energy Efficiency

British Columbia is working in partnership with local governments to encourage energy conservation at the community level through the Community Action on Energy Efficiency Program. The program promotes energy efficiency and community energy planning projects, providing direct policy and technical support to local governments through a partnership with the Fraser Basin Council. A total of 29 communities are participating in the program and this plan calls for an increase in the level of participation and expansion of the program to include transportation actions. The Community Action on Energy Efficiency Program is a collaboration among the provincial ministries of Energy, Mines and Petroleum Resources, Environment, and Community Services, Natural Resources Canada, the Fraser Basin Council, Community Energy Association, BC Hydro, FortisBC, Terasen Gas, and the Union of BC Municipalities.

Leading the Way to a Future with Green Buildings and Green Cities

British Columbia has taken a leadership role in the development of green buildings. Through the Green Buildings BC Program, the province is working to reduce the environmental impact of government buildings by increasing energy and water efficiency and reducing greenhouse gas emissions. Through this program, and the Energy Efficient Buildings Strategy that establishes energy efficiency targets for all types of buildings, the province is inviting businesses, local governments and all British Columbians to do their part to increase energy efficiency and reduce greenhouse gas emissions.

The Green Cities Project sets a number of strategies to make our communities greener, healthier and more vibrant places to live. British Columbia communities are already recognized leaders in innovative sustainability practices, and the Green Cities Project will provide them with additional resources to improve air quality, reduce energy consumption and encourage British Columbians to get out and enjoy the outdoors. With the Green Cities Project, the provincial government will:

- Provide $10 million a year over four years for the new LocalMotion Fund, which will cost share capital projects on a 50/50 basis with municipal governments to build bike paths, walkways, greenways and improve accessibility for people with disabilities.
- Establish a new Green City Awards program to encourage the development and exchange of best practices by communities, with the awards presented annually at the Union of British Columbia Municipalities convention.
- Set new financial incentives to help local governments shift to hybrid vehicle fleets and help retrofit diesel vehicles.
- Commit to making new investments in expanded rapid transit, support for fuel cell vehicles and other innovations.

Industrial Energy Efficiency Program

Government will establish an Industrial Energy Efficiency Program for British Columbia to address challenges and issues faced by the B.C. industrial sector and support the Canada wide industrial energy efficiency initiatives. The program will encourage industry driven investments in energy efficient technologies and processes; reduce emissions and greenhouse gases; promote self generation of power; and reduce funding barriers that discourage energy efficiency in the industrial sector. Some specific strategies include developing a results based pilot program with industry to improve energy efficiency and reduce overall power consumption and promote the generation of renewable energy within the industrial sector.

The 2010 Olympic and Paralympics Games: Sustainability in Action

In 2010 Vancouver and Whistler will host the Winter Olympic and Paralympic Games. The 2010 Olympic Games are the first that have been organized based on the principles of sustainability.

All new buildings for the Olympics will be designed and built to conserve both water and materials, minimize waste, maximize air quality, protect surrounding areas and continue to provide environmental and community benefits over their lifetimes. Existing venues will be upgraded to showcase energy conservation and efficiency and demonstrate the use of alternative heating/cooling technologies. Wherever possible, renewable energy sources such as wind, solar, micro hydro, and geothermal energy will be used to power and heat all Games facilities.

Transportation for the 2010 Games will be based on public transit. This system – which will tie event tickets to transit use – will help reduce traffic congestion, minimize local air pollution and limit greenhouse gas emissions.

POLICY ACTIONS

BUILDING STANDARDS, COMMUNITY ACTION AND INDUSTRIAL EFFICIENCY

- **Implement Energy Efficiency Standards for Buildings by 2010.**
- **Undertake a pilot project for energy performance labelling of homes and buildings in coordination with local and federal governments, First Nations and industry associations.**
- **New provincial public sector buildings will be required to integrate environmental design to achieve the highest standards for greenhouse gas emission reductions, water conservation and other building performance results such as a certified standard.**
- **Develop an Industrial Energy Efficiency Program for British Columbia to address specific challenges faced by British Columbia's industrial sector.**
- **Increase the participation of local governments in the Community Action on Energy Efficiency Program and expand the First Nations and Remote Community Clean Energy Program.**

British Columbia benefits from the public ownership of BC Hydro and the BC Transmission Corporation.

POLICY ACTIONS

SELF-SUFFICIENCY BY 2016

- **Ensure self-sufficiency to meet electricity needs, including "insurance."**
- **Establish a standing offer for clean electricity projects up to 10 megawatts.**
- **The BC Transmission Corporation is to ensure that British Columbia's transmission technology and infrastructure remains at the leading edge and has the capacity to deliver power efficiently and reliably to meet growing demand.**
- **Ensure adequate transmission system capacity by developing and implementing a transmission congestion relief policy.**
- **Ensure that the province remains consistent with North American transmission reliability standards.**

Electricity Security

Electricity, while often taken for granted, is the lifeblood of our modern economy and key to our entire way of life. Fortunately, British Columbia has been blessed with an abundant supply of clean, affordable and renewable electricity. But today, as British Columbia's population has grown, so too has our demand for electricity. We are now dependent on other jurisdictions for up to 10 per cent of our electricity supply. BC Hydro estimates demand for electricity to grow by up to 45 per cent over the next 20 years.

We must address this ever increasing demand to maintain our secure supply of electricity and the competitive advantage in electricity rates that all British Columbians have enjoyed for the last 20 years. There are no simple solutions or answers. We have an obligation to future generations to chart a course that will ensure a secure, environmentally and socially responsible electricity supply.

To close this electricity gap, and for our province to become electricity self-sufficient, will require an innovative electricity industry and the real commitment of all British Columbians to conservation and energy efficiency.

The New Relationship and Electricity

The Government of British Columbia is working with First Nations to restore, revitalize and strengthen First Nations communities. The goal is to build strong and healthy relationships with First Nations people guided by the principles of trust and collaboration. First Nations share many of the concerns of other British Columbians in how the development of energy resources may impact as well as benefit their communities. In addition, First Nations have concerns with regard to the recognition and respect of Aboriginal rights and title.

By focusing on building partnerships between First Nations, industry and government, tangible social and economic benefits will flow to First Nations communities across the province and assist in eliminating the gap between First Nations people and other British Columbians.

Government is working every day to ensure that energy resource management includes First Nations' interests, knowledge and values. By continuing to engage First Nations in energy related issues, we have the opportunity to share information and look for opportunities to facilitate First Nations' employment and participation in the electricity sectors to ensure that First Nations people benefit from the continued growth and development of British Columbia's resources. **The BC Energy Plan** provides British Columbia with a blueprint for facing the many energy challenges and opportunities that lay ahead. It provides an opportunity to build on First Nations success stories such as:

- First Nations involvement in independent power projects, such as the Squamish First Nation's participation in the Furry Creek and Ashlu hydro projects.

- Almost $4 million will flow to approximately 10 First Nations communities across British Columbia to support the implementation of Community Energy Action Plans as part of the First Nation and Remote Community Clean Energy Program.
- The China Creek independent power project was developed by the Hupacasath First Nation on Vancouver Island.

Achieve Electricity Self-Sufficiency by 2016

Achieving electricity self-sufficiency is fundamental to our future energy security and will allow our province to achieve a reliable, clean and affordable supply of electricity. It also represents a lasting legacy for future generations of British Columbians. That's why government has committed that British Columbia will be electricity self-sufficient within the decade ahead.

Through **The BC Energy Plan**, government will set policies to guide BC Hydro in producing and acquiring enough electricity in advance of future need. However, electricity generation and transmission infrastructure require long lead times. This means that over the next two decades, BC Hydro must acquire an additional supply of "insurance power" beyond the projected increases in demand to minimize the risk and implications of having to rely on electricity imports.

Small Power Standing Offer

Achieving electricity self-sufficiency in British Columbia will require a range of new power sources to be brought on line. To help make this happen, this policy will direct BC Hydro to establish a Standing Offer Program with no quota to encourage small and clean electricity producers. Under the Standing Offer Program, BC Hydro will purchase directly from suppliers at a set price.

Eligible projects must be less than 10 megawatts in size and be clean electricity or high efficiency electricity cogeneration. The price offered in the standing offer contract would be based on the prices paid in the most recent BC Hydro energy call. This will provide small electricity suppliers with more certainty, bring small power projects into the system more quickly, and help achieve government's goal of maintaining a secure electricity supply. As well, BC Hydro will offer the same price to those in BC Hydro's Net Metering Program who have a surplus of generation at the end of the year.

Ensuring a Reliable Transmission Network

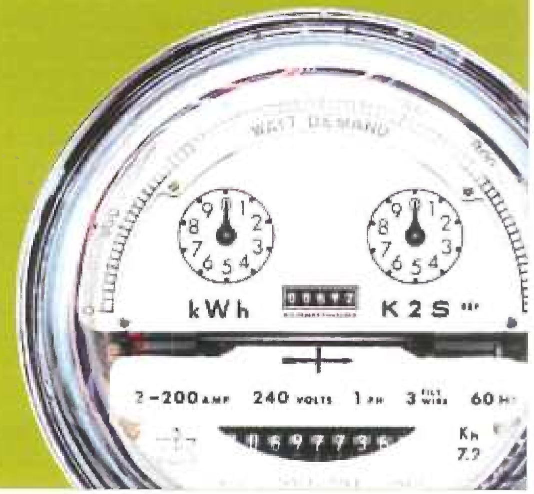
An important part of meeting the goal of self-sufficiency is ensuring a reliable transmission infrastructure is in place as additional power is brought on line. Transmission is a critical part of the solution as often new clean sources of electricity are located away from where the demand is. In addition, transmission investment is required to support economic growth in the province and must be planned and started in anticipation of future electricity needs given the long lead times required for transmission development. New and upgraded transmission infrastructure will be required to avoid congestion and to efficiently move the electricity across the entire power grid. Because our transmission system is part of a much larger, interconnected grid, we need to work with other jurisdictions to maximize the benefit of interconnection, remain consistent with evolving North American reliability standards, and ensure British Columbia's infrastructure remains capable of meeting customer needs.

BC HYDRO'S NET METERING PROGRAM: PEOPLE PRODUCING POWER

BC Hydro's Net Metering Program was established as a result of Energy Plan 2002. It is designed for customers with small generating facilities, who may sometimes generate more electricity than they require for their own use. A net metering customer's electricity meter will run backwards when they produce more electricity than they consume and run forward when they produce less than they consume.

The customer is only billed for their "net consumption"; the total amount of electricity used minus the total produced.

Net metering allows customers to lower their environmental impact and take responsibility for their own power production. It helps to move the province towards electricity self-sufficiency and expands clean electricity generation, making B.C.'s electricity supply more environmentally sustainable.



ELECTRICITY

In order for British Columbia to ensure the development of a secure and reliable supply of electricity, **The BC Energy Plan** provides policy direction to the BC Transmission Corporation to ensure that our transmission technology and infrastructure remains at the leading edge and has the capacity to deliver power efficiently and reliably to meet growing demand. This will include ensuring there is adequate transmission capacity, ongoing investments in technology and infrastructure and remaining consistent with evolving North American reliability standards.

BC Transmission Corporation Innovation and Technology

As the manager of a complex and high-value transmission grid, BC Transmission Corporation is introducing technology innovations that provide improvements to the performance of the system and allow for a greater utilization of existing assets, ensuring B.C. continues to benefit from one of the most advanced energy networks in the world. BC Transmission Corporation's innovation program focuses on increasing the power transfer capability of existing assets, extending the life of assets and improving system reliability and security. Initiatives include:

- System Control Centre Modernization Project: This project is consolidating system operations into a new control center and backup site and upgrading operating technologies with a modern management system that includes enhancements to existing applications to ensure the electric grid is operating reliably and efficiently. The backup site will take over complete operation of the electric grid if the main site is unavailable.
- Real-Time Phasors: British Columbia is among the first North American jurisdictions to incorporate phasor measurement into control centre operations. Phasors are highly accurate voltage, current and phase angle "snapshots" of the real-time state of the transmission system that enable system operators to monitor system conditions and identify any impending problems.
- Real-Time Rating: This is a temperature monitoring system which enables the operation of two 500 kilovolt submarine cable circuits at maximum capacity without overloading. The resulting increase in capacity is estimated to be up to 10 per cent, saving millions of dollars.
- Electronic Temperature Monitor Upgrades for Station Transformers: In this program, existing mechanical temperature monitors will be replaced with newer, more accurate electronic monitors on station transformers that allow transformers to operate to maximum capacity without overheating. In addition to improving performance, BC Transmission Corporation will realize reduced maintenance costs as the monitors are "self-checking."
- Life Extension of Transmission Towers: BC Transmission Corporation maintains over 22,000 steel lattice towers and is applying a special composite corrosion protection coating to some existing steel towers to extend their life by about 25 years.

Public Ownership

Public Ownership of BC Hydro and the BC Transmission Corporation

BC Hydro and the BC Transmission Corporation are publicly-owned crown corporations and will remain that way now and into the future. BC Hydro is responsible for generating, purchasing and distributing electricity. The BC Transmission Corporation operates, maintains, and plans BC Hydro's transmission assets and is responsible for providing fair, open access to the power grid for all customers. Both crowns are subject to the review and approvals of the independent regulator, the BC Utilities Commission.

BC Hydro owns the heritage assets, which include historic electricity facilities such as those on the Peace and Columbia Rivers that provide a secure, reliable supply of low-cost power for British Columbians. These heritage assets require maintenance and upgrades over time to ensure they continue to operate reliably and efficiently. Potential improvements to these assets, such as capacity additions at the Mica and Revelstoke generating stations, can make important contributions for the benefit of British Columbians.

Confirming the Heritage Contract in Perpetuity

Under the 2002 Energy Plan, a legislated heritage contract was established for an initial term of 10 years to ensure BC Hydro customers benefit from its existing low-cost resources. With **The BC Energy Plan**, government confirms the heritage contract in perpetuity to ensure ratepayers will continue to receive the benefits of this low-cost electricity for generations to come.

British Columbia's Leadership in Clean Energy

The BC Energy Plan will continue to ensure British Columbia has an environmentally and socially responsible electricity supply with a focus on conservation and energy efficiency.

British Columbia is already a world leader in the use of clean and renewable electricity, due in part to the foresight of previous generations who built our province's hydroelectric dams. These dams - now British Columbians' 'heritage assets' - today help us to enjoy 90 per cent clean electricity, one of the highest levels in North America.

All New Electricity Generation Projects Will Have Zero Net Greenhouse Gas Emissions

The B.C. government is a leader in North America when it comes to environmental standards. While British Columbia is a province rich in energy resources such as hydro electricity, natural gas and coal, the use of these resources needs to be balanced through effective use, preserving our environmental standards, while upholding our quality of life for generations to come. The government has made a commitment that all new electricity generation projects developed in British Columbia and connected to the grid will have zero net greenhouse gas emissions. In addition, any new electricity generated from coal must meet the more stringent standard of zero greenhouse gas emissions.

POLICY ACTIONS

PUBLIC OWNERSHIP

- **Continue public ownership of BC Hydro and its heritage assets, and the BC Transmission Corporation.**
- **Establish the existing heritage contract in perpetuity.**
- **Invest in upgrading and maintaining the heritage asset power plants and the transmission lines to retain the ongoing competitive advantage these assets provide to the province.**

POLICY ACTIONS

REDUCING GREENHOUSE GAS EMISSIONS FROM ELECTRICITY

- All new electricity generation projects will have zero net greenhouse gas emissions.
- Zero net greenhouse gas emissions from existing thermal generation power plants by 2016.
- Require zero greenhouse gas emissions from any coal thermal electricity facilities.
- Ensure clean or renewable electricity generation continues to account for at least 90 per cent of total generation.
- Government supports BC Hydro's proposal to replace the firm energy supply from the Burrard Thermal plant with other resources. BC Hydro may choose to retain Burrard for capacity purposes after 2014.
- No nuclear power.

Zero Net Greenhouse Gas Emissions from Existing Thermal Generation Power Plants by 2016

Setting a requirement for zero net emissions over this time period encourages power producers to invest in new or upgraded technology. For existing plants the government will set policy around reaching zero net emissions through carbon offsets from other activities in British Columbia. It clearly signals the government's intention to continue to have one of the lowest greenhouse gas emission electricity sectors in the world.

Ensure Clean or Renewable Electricity Generation Continues to Account For at Least 90 per cent of Total Generation

Currently in B.C., 90 per cent of electricity is from clean or renewable resources. **The BC Energy Plan** commits to maintaining this high standard which places us among the top jurisdictions in the world. Clean or renewable resources include sources of energy that are constantly renewed by natural processes, such as water power, solar energy, wind energy, tidal energy, geothermal energy, wood residue energy, and energy from organic municipal waste.

Zero Greenhouse Gas Emissions from Coal

The government is committed to ensuring that British Columbia's electricity sector remains one of the cleanest in the world and will allow coal as a resource for electricity generation when it can reach zero greenhouse gas emissions. Clean-coal technology with carbon sequestration is expected to become commercially available in the next decade. Therefore, the province will require zero greenhouse gas emissions from any coal thermal electricity facilities which can be met through capture and sequestration technology. British Columbia is the first Canadian jurisdiction to commit to using only clean coal technology for any electricity generated from coal.

Burrard Thermal Generating Station

A decision regarding the Burrard Thermal Natural Gas Generating Station is another action that is related to environmentally responsible electricity generation in British Columbia.

Even though it could generate electricity from Burrard Thermal, BC Hydro imports power primarily because the plant is outdated, inefficient and costly to run. However, Burrard Thermal still provides significant benefits to BC Hydro as it acts as a "battery" close to the Lower Mainland, and provides extra capacity or "reliability insurance" for the province's electricity supply. It also provides transmission system benefits that would otherwise have to be supplied through the addition of new equipment at Lower Mainland sub-stations.

By 2014, BC Hydro plans to have firm electricity to replace what would have been produced at the plant. Government supports BC Hydro's proposal to replace the firm energy supply from Burrard Thermal with other resources by 2014. However, BC Hydro may choose to retain the plant for "reliability insurance" should the need arise.

No Nuclear Power

As first outlined in Energy Plan 2002, government will not allow production of nuclear power in British Columbia.

Benefits to British Columbians

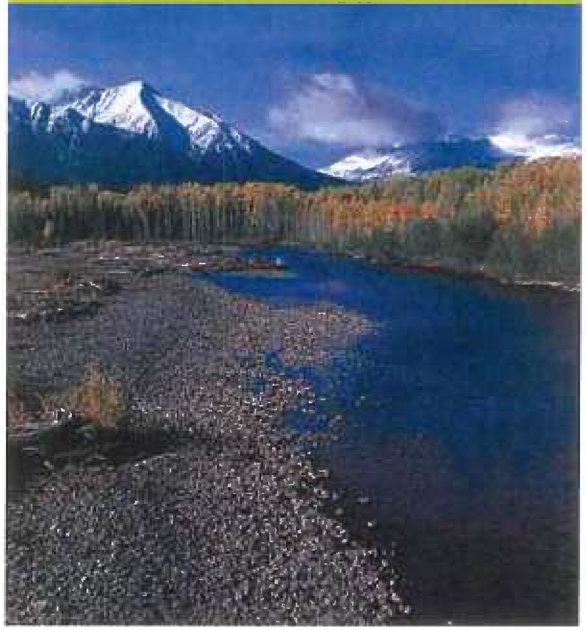
Clean or renewable electricity comes from sources that replenish over a reasonable time or have minimal environmental impacts. Today, demand for economically viable, clean, renewable and alternative energy is growing along with the world's population and economies. Consumers are looking for power that is not only affordable but creates minimal environmental impacts. Fortunately, British Columbia has abundant hydroelectric resources, and plenty of other potential energy sources.

Maintain our Electricity Competitive Advantage

British Columbians require a secure, reliable supply of competitively priced electricity now and in the future. Competitively priced power is also an incentive for investors to locate in British Columbia. It provides an advantage over other jurisdictions and helps sustain economic growth. We are fortunate that historic investments in hydroelectric assets provide electricity that is readily available, reliable, clean and inexpensive. By ensuring public ownership of BC Hydro, the heritage assets and the BC Transmission Corporation and confirming the heritage contract in perpetuity, we will ensure that ratepayers continue to receive the benefits of this low cost generation. Due to load growth and aging infrastructure, new investments will be required. Investments in maintenance and in some cases expansions can be a cost effective way to meet growth and reduce future rate increases.

CARBON OFFSETS AND HOW THEY REDUCE EMISSIONS

A carbon offset is an action taken directly, outside of normal operations, which results in reduced greenhouse gas emissions or removal of greenhouse gases from the atmosphere. Here's how it works: if a project adds greenhouse gases to the atmosphere, it can effectively subtract them by purchasing carbon offsets which are reductions from another activity. Government regulations to reduce greenhouse gases, including offsets, demonstrate leadership on climate change and support a move to clean and renewable energy.



Government will establish a $25 million ***Innovative Clean Energy Fund.***

POLICY ACTIONS

BENEFITS TO BRITISH COLUMBIANS

- **Review BC Utilities Commissions' role in considering social and environmental costs and benefits.**
- **Ensure the procurement of electricity appropriately recognizes the value of aggregated intermittent resources.**
- **Work with BC Hydro and parties involved to continue to improve the procurement process for electricity.**
- **Pursue Government and BC Hydro's planned Remote Community Electrification Program to expand or take over electricity service to remote communities in British Columbia.**
- **Ensure BC Hydro considers alternative electricity sources and energy efficiency measures in its energy planning for remote communities.**

British Columbia must look for new, innovative ways to stay competitive. New technologies must be identified and nurtured, from both new and existing industries. By diversifying and strengthening our energy sector through the development of new and alternative energy sources, we can help ensure the province's economy remains vibrant for years to come.

Ensure Electricity is Secured at Competitive Prices

One practical way to keep rates down is to ensure utilities have effective processes for securing competitively priced power. As part of **The BC Energy Plan**, government will work with BC Hydro and parties involved to continue to improve the Call for Tender process for acquiring new generation. Fair treatment of both buyers and sellers of electricity will facilitate a robust and competitive procurement process. Government and BC Hydro will also look for ways to further recognize the value of intermittent resources, such as run-of- river and wind, in the acquisition process – which means that BC Hydro will examine ways to value separate projects together to increase the amount of firm energy calculated from the resources.

Rates Kept Low Through Powerex Trading of Electricity

Profits from electricity trade also contribute to keeping our electricity rates competitive. BC Hydro, through its subsidiary, Powerex, buys and sells electricity when it is advantageous to British Columbia's ratepayers. Government will continue to support capitalizing on electricity trading opportunities and will continue to allocate trade revenue to BC Hydro ratepayers to keep electricity rates low for all British Columbians.

BC Utilities Commissions' Role in Social and Environmental Costs and Benefits

The BC Energy Plan clarifies that social, economic and environmental costs are important for ensuring a suitable electricity supply in British Columbia. Government will review the BC Utilities Commissions' role in considering social, environmental and economic costs and benefits, and will determine how best to ensure these are appropriately considered within the regulatory framework.

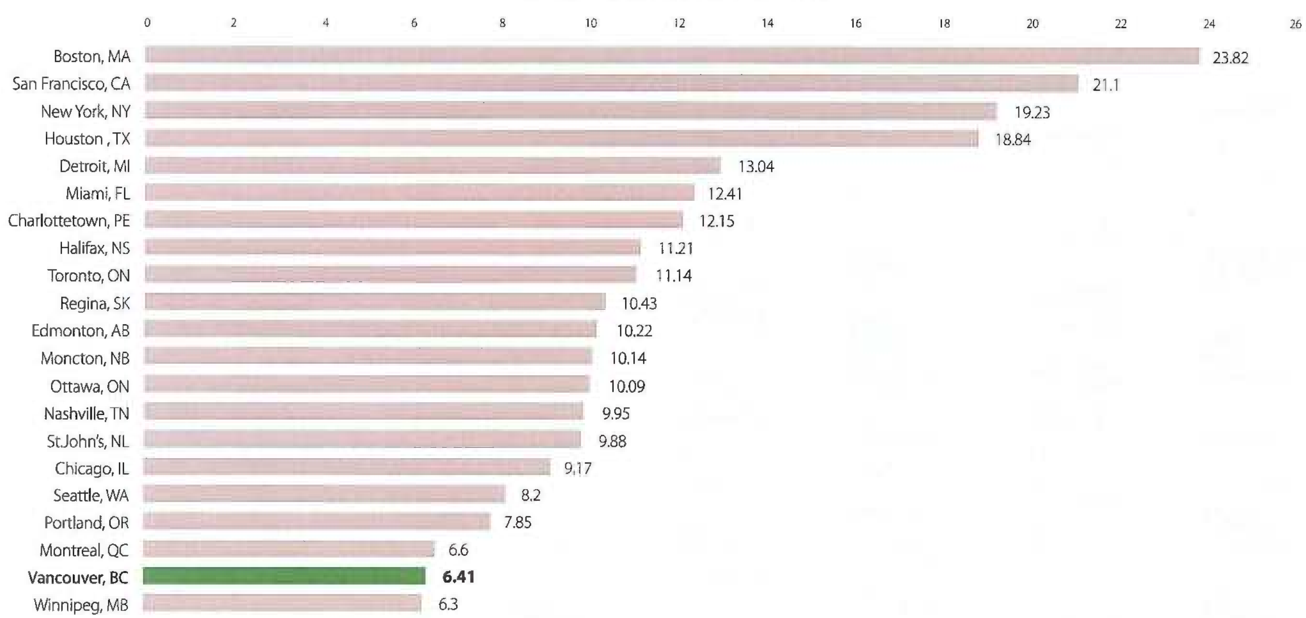
Bring Clean Power to Communities

British Columbia's electricity industry supports thousands of well-paying jobs, helps drive the economy and provides revenues to sustain public services. British Columbia's electricity industry already fosters economic development by implementing cost effective and reliable energy solutions in communities around the province. However, British Columbia covers almost one million square kilometres and electrification does not extend to all parts of our vast province.

Government and BC Hydro have established First Nation and remote community energy programs to implement alternative energy, energy efficiency, conservation and skills training solutions in a number of communities. The program focuses on expanding electrification services to as many as 50 remote and First Nations communities in British Columbia, enabling them to share in the benefits of a stable and secure supply of electricity. Government will put the policy framework in place and BC Hydro will implement the program over the next 10 years. The **Innovative Clean Energy Fund** can also support technological advancements to address the issue of providing a clean and secure supply of electricity to remote communities.

2006 Average Residential Electricity Price

Price (Canadian cents per kilowatt hour)



Source: Hydro Quebec comparison of Electricity Prices in Major North American Cities, April 2006

BRINGING CLEAN POWER TO ATLIN

Electricity in the remote community of Atlin in northwestern British Columbia is currently supplied by diesel generators. The First Nations and Remote Community Clean Energy Program is bringing clean power to Atlin.

The Taku Land Corporation, solely owned by the Taku River Tlingit First Nation will construct a two megawatt run-of-river hydroelectric project on Pine Creek, generating local economic benefits and providing clean power for Atlin. The Taku Land Corporation has entered into a 25 year Electricity Purchase Agreement with BC Hydro to supply electricity from the project to Atlin's grid. Over the course of the agreement, this will reduce greenhouse gas emissions by up to 150,000 tonnes as the town's diesel generators stand by.

The province is contributing $1.4 million to this $10 million project. This is the first payment from a $3.9 million federal contribution to British Columbia's First Nations and Remote Community Clean Energy Program. Criteria for federal funding included demonstrating greenhouse gas emissions reductions, cost-effectiveness, and partnerships with communities and industry.

Government will work with other agencies to maximize opportunities to develop, deploy and export British Columbia clean and alternative energy technologies.

POLICY ACTIONS

INVESTING IN INNOVATION

- **Establish the Innovative Clean Energy Fund to support the development of clean power and energy efficiency technologies in the electricity, alternative energy, transportation and oil and gas sectors.**
- **Implement a provincial Bioenergy Strategy which will build upon British Columbia's natural bioenergy resource advantages.**
- **Issue an expression of interest followed by a call for proposals for electricity from sawmill residues, logging debris and beetle-killed timber to help mitigate impacts from the provincial mountain pine beetle infestation.**

Innovative Clean Energy Fund

British Columbia's increasing energy requirements and our ambitious greenhouse gas emission reduction and clean energy targets require greater investment and innovation in the area of alternative energy by both the public and private sector.

To lead this effort, the government will establish an **Innovative Clean Energy Fund** of $25 million to help promising clean power technology projects succeed. The fund will be established through a small charge on energy utilities. The Minister of Energy, Mines and Petroleum Resources will consult with the energy utilities on the implementation of this charge.

Proponents of projects that will be supported through the fund will be encouraged to seek additional contributions from other sources. Government's new **Innovative Clean Energy Fund** will help make British Columbia a world leader in alternative energy and power technology. It will solve some of B.C.'s pressing energy challenges, protect our environment, help grow the economy, position the province as the place international customers turn to for key energy and environmental solutions, and assist B.C. based companies to showcase their products to world wide markets.

Following the advice of the Premier's Technology Council and the Alternative Energy and Power Technology Task Force, the fund will focus strictly on projects that:

- Address specific British Columbia energy and environmental problems that have been identified by government.
- Showcase B.C. technologies that have a strong potential for international market demand in other jurisdictions because they solve problems that exist both in B.C. and other jurisdictions.
- Support pre-commercial energy technology that is new, or commercial technologies not currently used in British Columbia.
- Demonstrate commercial success for new energy technologies.

Some problems that the fund could focus on include:

- Developing reliable power solutions for remote communities-particularly helping First Nations communities reduce their reliance on diesel generation for electricity.
- Advance conservation technologies to commercial application.
- Finding ways to convert vehicles to cleaner alternative fuels.
- Increasing the efficiency of power transmission through future grid technologies.
- Expanding the opportunities to generate power using alternative fuels (e.g.mountain pine beetle wood).

The British Columbia Bioenergy Strategy: Growing Our Natural Energy Advantage

Currently, British Columbia is leading Canada in the use of biomass for energy. The province has 50 per cent of Canada's biomass electricity generating capacity. In 2005, British Columbia's forest industry self-generated the equivalent of $150 million in electricity and roughly $1.5 billion in the form of heat energy. The use of biomass has displaced some natural gas consumption in the pulp and paper sector. The British Columbia wood pellet industry also enjoys a one-sixth share of the growing European Union market for bioenergy feedstock. The province will shortly release a bioenergy strategy that will build upon British Columbia's natural bioenergy resource advantages, industry capabilities and academic strength to establish British Columbia as a world leader in bioenergy development.

British Columbia's plan is to lead the bioeconomy in Western Canada with a strong and sustainable bioenergy sector. This vision is built on two guiding principles:

- Competitive, diversified forest and agriculture sectors.
- Strengthening regions and communities.

The provincial Bioenergy Strategy is aimed at:

- Enhancing British Columbia's ability to become electricity self-sufficient.
- Fostering the development of a sustainable bioenergy sector.
- Creating new jobs.
- Supporting improvements in air quality.
- Promoting opportunities to create power from mountain pine beetle-impacted timber.
- Positioning British Columbia for world leadership in the development and commercial adoption of wood energy technology.
- Advancing innovative solutions to agricultural and other waste management challenges.
- Encouraging diversification in the forestry and agriculture industries.
- Producing liquid biofuels to meet Renewable Fuel Standards and displace conventional fossil fuels.

Generating Electricity from Mountain Pine Beetle Wood: Turning Wood Waste into Energy

British Columbia is experiencing an unprecedented mountain pine beetle infestation that has affected several million hectares of trees throughout the province. This infestation is having a significant impact on forestry-based communities and industries, and heightens forest fire risk. There is a great opportunity to convert the affected timber to bioenergy, such as wood pellets and wood-fired electricity generation and cogeneration.

Through **The BC Energy Plan**, BC Hydro will issue a call for proposals for electricity from sawmill residues, logging debris and beetle-killed timber to help mitigate impacts from the provincial mountain pine beetle infestation.

MOUNTAIN PINE BEETLE INFESTATION: TURNING WOOD WASTE INTO ENERGY

British Columbia is experiencing an unprecedented mountain pine beetle infestation that has affected several million hectares of trees throughout the province. This infestation is having a significant economic impact on B.C.'s forestry industry and the many communities it helps to support and sustain. The forest fire risk to these communities has also risen as a result of their proximity to large stands of "beetle-killed" wood.

B.C. has developed a bioenergy strategy to promote new sources of sustainable and renewable energy in order to take advantage of the vast amounts of pine beetle-infested timber and other biomass resources. In the future, bioenergy will help meet our electricity needs, supplement conventional natural gas and petroleum supplies, maximize job and economic opportunities, and protect our health and environment.

The production of wood pellets is already a mature industry in British Columbia. Industry has produced over 500,000 tonnes of pellets and exported about 90 per cent of this product overseas in 2005, primarily to the European thermal power industry. Through **The BC Energy Plan**, BC Hydro will issue a call for proposals for further electricity generation from wood residue and mountain pine beetle-infested timber.

GOVERNMENT TO USE HYBRID VEHICLES ONLY

The provincial government is continuing the effort to reduce greenhouse gas emissions and overall energy consumption.

As part of this effort, government has more than tripled the size of its hybrid fleet since 2005 to become one of the leaders in public sector use of hybrid cars.

Hybrids emit much less pollution than conventional gas and diesel powered vehicles and thus help to reduce greenhouse gases in our environment. They can also be more cost-effective as fuel savings offset the higher initial cost.

As of 2007, all new cars purchased or leased by the B.C. government are to be hybrid vehicles. The province also has new financial incentives to help local governments shift to hybrid vehicle fleets and help retrofit diesel vehicles.

Addressing Greenhouse Gas Emissions from Transportation

The BC Energy Plan: A Vision for Clean Energy Leadership takes a first step to incorporate transportation issues into provincial energy policy. Transportation is a major contributor to climate change and air quality problems. It presents other issues such as traffic congestion that slows the movement of goods and people. The fuel we use to travel around the province accounts for about 40 per cent of British Columbia's greenhouse gas emissions. Every time we drive or take a vehicle that runs on fossil fuels, we add to the problem, whether it's a train, boat, plane or automobile. Cars and trucks are the biggest source of greenhouse gas emissions and contribute to reduced air quality in urban areas.

The government is committed to reducing greenhouse gas emissions from the transportation sector and has committed to adopting California's tailpipe emission standards from greenhouse gas emissions and champion the national adoption of these standards.

British Columbians want a range of energy options for use at home, on the road and in day-to-day life. Most people use gasoline or diesel to keep their vehicles moving, but there are other options that improve our air quality and reduce greenhouse gas emissions.

Natural gas burns cleaner than either gasoline or propane, resulting in less air pollution. Fuel cell vehicles are propelled by electric motors powered by fuel cells, devices that produce electricity from hydrogen without combustion.

Cars that run on blends of renewable biofuels like ethanol and biodiesel emit lower levels of greenhouse gases and air pollutants. Electricity can provide an alternative to gasoline vehicles when used in hybrids and electric cars.

By working with businesses, educational institutions, non-profit organizations and governments, new and emerging transportation technologies can be deployed more rapidly at home and around the world. British Columbia will focus on research and development, demonstration projects, and marketing strategies to promote British Columbia's technologies to the world.

Implementing a Five Per Cent Renewable Fuel Standard for Diesel and Gasoline

The BC Energy Plan demonstrates British Columbia's commitment to environmental sustainability and economic growth by taking a lead role in promoting innovation in the transportation sector to reduce greenhouse gas emissions, improve air quality and help improve British Columbians' health and quality of life in the future. The plan will implement a five per cent average renewable fuel standard for diesel by 2010 to help reduce emissions and advance the domestic renewable fuel industry. It will further support the federal action of increasing the ethanol content of gasoline to five per cent by 2010. The plan will also see the adoption of quality parameters for all renewable fuels and fuel blends that are appropriate for Canadian weather conditions in cooperation with North American jurisdictions. These renewable fuel standards are a major component and first step towards government's goal of reducing the carbon intensity of all passenger vehicles by 10 per cent by 2020.

Government will implement a five per cent average renewable fuel standard for diesel by 2010 to help reduce emissions and advance the domestic renewable fuel industry.

A Commitment to Extend British Columbia's Ground-breaking Hydrogen Highway

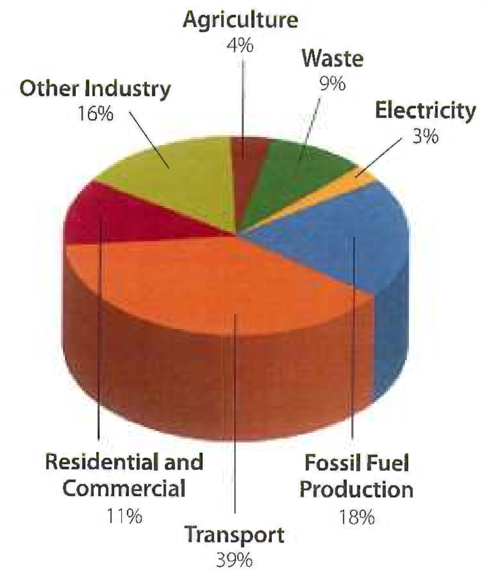
British Columbia is a world leader in transportation applications of the Hydrogen Highway, including the design, construction and safe operation of advanced hydrogen vehicle fuelling station technology. The Hydrogen Highway is a large scale, coordinated demonstration and deployment program for hydrogen and fuel cell technologies.

Vancouver's Powertech Labs established the world's first fast-fill, high pressure hydrogen fuelling station. The station anchors the Hydrogen Highway, which runs from Victoria through Surrey to Vancouver, North Vancouver, Squamish, and Whistler. Additional hydrogen fuelling stations are now in operation in Victoria and at the University of British Columbia.

The goal is to demonstrate and deploy various technologies and to one day see hydrogen filling stations around the province, serving drivers of consumer and commercial cars, trucks, and buses.

The unifying vision of the province's hydrogen and fuel cell strategy is to promote fuel cells and hydrogen technologies as a means of moving towards a sustainable energy future, increasing energy efficiency and reducing air pollutants and greenhouse gases. The Hydrogen Highway is targeted for full implementation by 2010. Canadian hydrogen and fuel cell companies have invested over $1 billion over the last five years, most of that in B.C. A federal-provincial partnership will be investing $89 million for fuelling stations and the world's first fleet of 20 fuel cell buses.

British Columbia will continue to be a leader in the new hydrogen economy by taking actions such as a fuel cell bus fleet deployment, developing a regulatory framework for micro-hydrogen applications, collaborating with neighbouring jurisdictions on hydrogen, and, in the long term, establishing a regulatory framework for hydrogen production, vehicles and fuelling stations.



B.C. Greenhouse Gas Emissions by Sector

(Based on 2004 data)
Source: Ministry of Environment

Cars and trucks are the biggest source of greenhouse gas emissions and reduce the quality of air in urban areas.

POLICY ACTIONS

ADDRESSING GREENHOUSE GAS EMISSIONS FROM TRANSPORTATION AND INCREASING INNOVATION

- **Implement a five per cent average renewable fuel standard for diesel by 2010 to help reduce emissions and advance the domestic renewable fuel industry.**
- **Support the federal action of increasing the ethanol content of gasoline to five per cent by 2010 and adopt quality parameters for all renewable fuels and fuel blends that are appropriate for Canadian weather conditions in cooperation with North American jurisdictions.**
- **Develop a leading hydrogen economy by continuing to support the Hydrogen and Fuel Cell Strategy for British Columbia.**
- **Establish a new, harmonized regulatory framework by 2010 for hydrogen by working with governments, industry and hydrogen alliances.**

Vehicles that run on electricity, hydrogen and blends of renewable biofuels like ethanol and biodiesel emit lower levels of greenhouse gases and air pollutants.

LOCALMOTION FUND: REDUCING AIR POLLUTION IN YOUR COMMUNITY

The province has committed $40 million over four years to help build cycling and pedestrian pathways, improve safety and accessibility, and support children's activity programs in playgrounds.

This fund will help local government shift to hybrid vehicle fleets and help retrofit diesel vehicles which will help reduce air pollution and ensure vibrant and environmentally sustainable communities. This investment will also include expansion of rapid transit and support fuel cell vehicles.

Promote Energy Efficiency and Alternative Energy

It is important for British Columbians to understand the appropriate uses of different forms of energy and utilize the right fuel, for the right activity at the right time. There is the potential to promote energy efficiency and alternative energy supplemented by natural gas. Combinations of alternative energy sources with natural gas include solar thermal and geothermal. Working with municipalities, utilities and other stakeholders the provincial government will promote energy efficiency and alternative energy systems, such as solar thermal and geothermal throughout the province.

Environmental Leadership in Action

The BC Energy Plan: A Vision for Clean Energy Leadership complements other related cross-government initiatives that include supporting transportation demand management, reducing traffic congestion and better integrating land use and transportation planning. These plans include actions across a broad range of activities. Some key initiatives and recent announcements include:

- Extending the tax break on hybrid vehicle purchases beyond the current March 2008 deadline.
- Government to purchase hybrid vehicles exclusively.
- Reducing diesel emissions through new financial incentives to help municipalities shift to hybrid vehicle fleets and retrofit diesel vehicles with cleaner technologies.
- Green Ports:
  - Working with ports and the shipping sector to reduce emissions from their activities and marine vessels.
  - The Port of Vancouver has established idle reduction zones and has reduced truck emissions with its container reservation system which has reduced average wait times from two hours to approximately 20 minutes.
  - The port is also evaluating port-side electrification which would see vessels using shore-side electrical power while berthed rather than diesel power.
- Improving upon the monitoring and reporting of air quality information.
- Highway Infrastructure and Rapid Transit Infrastructure funding including the Gateway Program, the Border Infrastructure Program, high occupancy vehicle lanes, construction of the Rapid Transit Canada Line linking Richmond, the Vancouver International Airport and Vancouver, and the Rapid Transit Evergreen Line linking Burnaby to Coquitlam.
- Expanding the AirCare on the Road Program to the Lower Fraser Valley and other communities.
- Implementing the LocalMotion Program for capital projects to improve physical fitness and safety, reduce air pollution and meet the diverse needs of British Columbians.

A Choice of Electricity Options

The range of supply options, both large and small, for British Columbia include:

Bioenergy: Bioenergy is derived from organic biomass sources such as wood residue, agricultural waste, municipal solid waste and other biomass and may be considered a carbon-neutral form of energy, because the carbon dioxide released by the biomass when converted to energy is equivalent to the amount absorbed during its lifetime.

A number of bioenergy facilities operate in British Columbia today. Many of these are "cogeneration" plants that create both electricity and heat for on-site use and in some cases, sell surplus electricity to BC Hydro.

Reliability[1]: FIRM
Estimated Cost[5]: $75 – $91

Coal Thermal Power: The BC Energy Plan establishes a zero emission standard for greenhouse gas emissions from coal-fired plants. This will require proponents of new coal facilities to employ clean coal technology with carbon capture and sequestration to ensure there are no greenhouse gas emissions.

Reliability[1]: FIRM
Estimated Cost[5 6]: $67– $82

Geothermal: Geothermal power is electricity generated from the earth. Geothermal power production involves tapping into pockets of superheated water and steam deep underground, bringing them to the surface and using the heat to produce steam to drive a turbine and produce electricity. British Columbia has potential high temperature (the water is heated to more than 200 degrees Celsius) geothermal resources in the coastal mountains and lower temperature resources in the interior, in northeast British Columbia and in a belt down the Rocky Mountains. Geothermal energy's two main advantages are its consistent supply, and the fact that it is a clean, renewable source of energy.

Reliability[1]: FIRM
Estimated Cost[2]: $44 - $60

Hydrogen and Fuel Cell Technology:
British Columbia companies are recognized globally for being leaders in hydrogen and fuel cell technology for mobile, stationary and micro applications. For example, BC Transit's fuel cell buses are planned for deployment in Whistler in 2009.

Reliability[1]: FIRM
Estimated Cost[2]: n/a

[1] Reliability refers to energy that can be depended on to be available whenever required
[2] Source: BC Hydro's 2006 IEP Volume 1 of 2 page 5-6
[3] Based on a 500 MW super ciritcal pulverized coal combustion unit. The BC Energy Plan requires coal power to meet zero GHG emissions
[4] Based on a 250 MW combined cycle gas turbine plant. The BC Energy Plan requires coal power to meet zero GHG emissions
[5] Source: BC Hydro's F2006 Open Call for Power Report
[6] These costs do not reflect the costs of zero GHG emissions for coal thermal power

GOVERNMENT'S COMMITMENT TO THE ENVIRONMENT – THE ENVIRONMENTAL ASSESSMENT PROCESS

The environmental assessment process in British Columbia is an integrated review process for major projects that looks at potential environmental, community and First Nation, health and safety, and socioeconomic impacts. Through the environmental assessment process, the potential effects of a project are identified and evaluated early, resulting in improved project design and helping to avoid costly mistakes for proponents, governments, local communities and the environment.

An assessment is begun when a proposed project that meets certain criteria under the *Environmental Assessment Act* makes an application for an environmental assessment certificate. Each assessment will usually include an opportunity for all interested parties to identify issues and provide input; technical studies of the relevant environmental, social, economic, heritage and/or health effects of the proposed project; identification of ways to prevent or minimize undesirable effects and enhance desirable effects; and consideration of the input of all interested parties in compiling the assessment findings and making decisions about project acceptability. The review is concluded when a decision is made to issue or not issue an environmental assessment certificate. Industrial, mining, energy, water management, waste disposal, food processing, transportation and tourist destination resort projects are generally subject to an environmental assessment.

ELECTRICITY CHOICES

WHAT IS THE DIFFERENCE BETWEEN FIRM AND INTERMITTENT ELECTRICITY?

Firm electricity refers to electricity that is available at all times even in adverse conditions. The main sources of reliable electricity in British Columbia include large hydroelectric dams, and natural gas. This differs from intermittent electricity, which is limited or is not available at all times. An example of intermittent electricity would be wind which only produces power when the wind is blowing.

Large Hydroelectric Dams: The chief advantage of a hydro system is that it provides a reliable supply with both dependable capacity and energy, and a renewable and clean source of energy. Hydropower produces essentially no carbon dioxide.

Site C is one of many resource options that can help meet BC Hydro's customers' electricity needs. No preferred option has been selected at this time; however; it is recognized that the Province will need to examine opportunities for some large projects to meet growing demand.

As part of **The BC Energy Plan**, BC Hydro and the Province will enter into initial discussions with First Nations, the Province of Alberta and communities to discuss Site C to ensure that communications regarding the potential project and the processes being followed are well known. The purpose of this step is to engage the various parties up front to obtain input for the proposed engagement process. The decision-making process on Site C includes public consultation, environmental impact assessments, obtaining a Certificate of Public Convenience and Necessity, obtaining an Environmental Assessment Certificate and necessary environmental approvals, and approval by Cabinet.

Reliability[1]: FIRM
Estimated Cost[2]: $43 - $62

Natural Gas: Natural gas is converted into electricity through the use of gas fired turbines in medium to large generating stations; particularly high efficiencies can be achieved through combining gas turbines with steam turbines in the combined cycle and through reciprocating engines and mini and macro turbines. Combined cycle power generation using natural gas is the cleanest source of power available using fossil fuels. Natural gas provides a reliable supply with both dependable capacity and firm energy.

Reliability[1]: FIRM
Estimated Cost[2 6]: $48 - $100

Small Hydro: This includes run-of-river and micro Hydro. These generate electricity without altering seasonal flow characteristics. Water is diverted from a natural watercourse through an intake channel and pipeline to a powerhouse where a turbine and generator convert the kinetic energy in the moving water to electrical energy.

Twenty-nine electricity purchase agreements were awarded to small waterpower producers by BC Hydro in 2006. These projects will generate approximately 2,851 gigawatt hours of electricity annually (equivalent to electricity consumed by 285,000 homes in British Columbia). There are also 32 existing small hydro projects in British Columbia that generate 3,500 gigawatt hours (equivalent to electricity consumed by 350,000 homes in British Columbia).

Reliability[1]: INTERMITTENT
Estimated Cost[3]: $60 – $95

Solar: With financial support from the Ministry of Energy, Mines and Petroleum Resources, the "Solar for Schools" program has brought clean solar photovoltaic electricity to schools in Vernon, Fort Nelson, and Greater Victoria.

The BC Sustainable Energy Association is leading a project which targets installing solar water heaters on 100,000 rooftops across British Columbia.

Reliability[1]: INTERMITTENT
Estimated Cost[2]: $700 - $1700

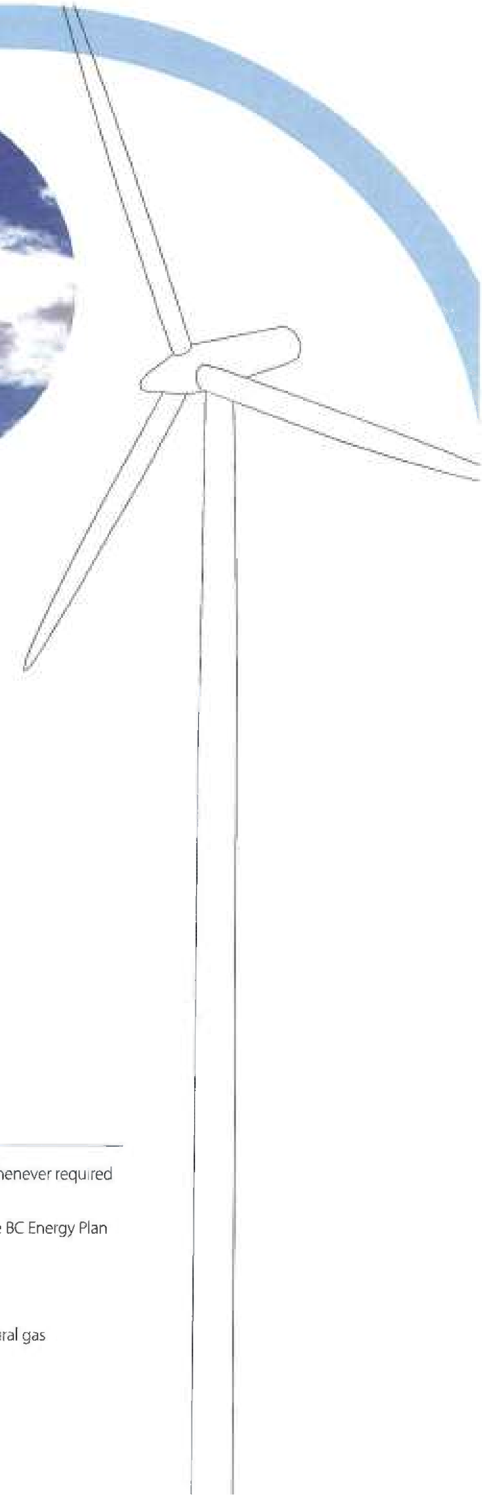
Tidal Energy: A small demonstration project has been installed at Race Rocks located west-southwest of Victoria. The Lester B. Pearson College of the Pacific, the provincial and federal government, and industry have partnered to install and test a tidal energy demonstration turbine at Race Rocks. The project will generate about 77,000 kilowatt hours on an annual basis (equivalent to electricity consumed by approximately eight homes).

Reliability[1]: INTERMITTENT
Estimated Cost[2]: $100 - $360

Wind: British Columbia has abundant, widely distributed wind energy resources in three areas: the Peace region in the Northeast; Northern Vancouver Island; and the North Coast. Wind is a clean and renewable source that does not produce air or water pollution, greenhouse gases, solid or toxic wastes.

Three wind generation projects have been offered power purchase contracts in BC Hydro's 2006 Open Call for Power. These three projects will have a combined annual output of 979 gigawatt hours of electricity (equivalent to electricity consumed by 97,900 homes).

Reliability[1]: INTERMITTENT
Estimated Cost[5]: $71 – $74



[1] Reliability refers to energy that can be depended on to be available whenever required
[2] Source: BC Hydro's 2006 IEP Volume 1 of 2 page 5-6
[3] Based on a 500 MW super ciritcal pulverized coal combustion unit. The BC Energy Plan requires coal power to meet zero GHG emissions
[4] Based on a 250 MW combined cycle gas turbine plant.
[5] Source: BC Hydro's F2006 Open Call for Power Report
[6] These costs do not reflect the costs of zero net GHG emissions for natural gas

RACE ROCKS TIDAL ENERGY PROJECT

Announced in early 2005, this demonstration project between the provincial and federal governments, industry, and Pearson College is producing zero emission tidal power at the Race Rocks Marine Reserve on southern Vancouver Island. Using a current-driven turbine submerged below the ocean surface, the project is producing about 77,000 kilowatt hours of electricity per year, enough to meet the needs of approximately eight households. The knowledge gained about tidal energy will help our province remain at the forefront of clean energy generation technology.

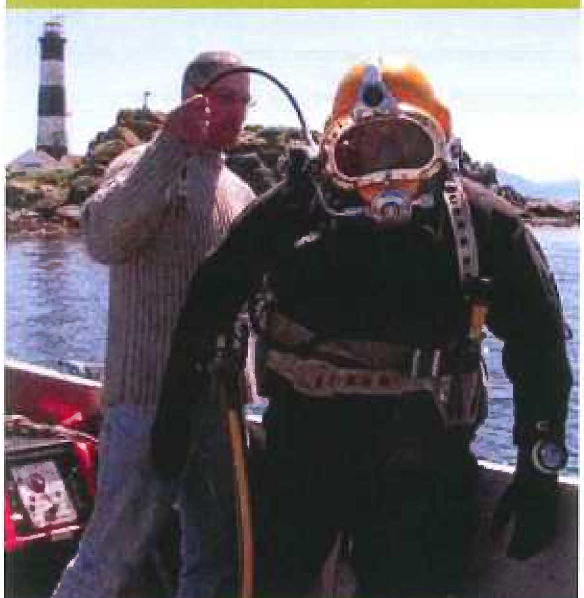


Table 1: Summary of Resource Options

Description	Estimated Cost[1] $ /megawatt hour	Reliable[2]	Greenhouse gas emissions[3] tonnes per gigawatt hour
Energy conservation/ efficiency	32 – 76	Yes	0
Large hydroelectric	43 – 62	Yes	0
Natural gas	48 – 100[8]	Yes	0 – 350[4,8]
Coal	67 – 82[9,10]	Yes	0 – 855[5,9]
Biomass	75 – 91[10]	Yes	0 – 500[6]
Geothermal	44 – 60	Yes	0 – 10
Wind	71 – 74[10]	Depends on the availability and speed of wind	0
Run-of-river small hydro	60 – 95[10]	Depends on the flow of water, which varies throughout the year	0
Ocean (wave and tidal)	100 – 360[7]	Future supply option which has great potential for British Columbia	0
Solar	700 – 1700[7]	Depends on location, cloud cover, season, and time of day	0

1 Source: BC Hydro's 2006 Integrated Electricity Plan Volume 1 of 2, page 5-6
2 Reliability refers to energy that can be depended on to be available whenever required
3 Source: BC Hydro's 2006 Integrated Electricity Plan, Volume 2 of 2, Appendix F page 5-14 and Table 10-2
4 Based on a 250 MW combined cycle gas turbine plant
5 Based on a 500 MW supercritical pulverized coal combustion unit
6 GHG are 0 for wood residue and landfill gas. GHG is 500 tonnes per gigawatt hour for municipal solid waste
7 Source: BC Hydro's 2004 Integrated Electricity Plan, page 69
8 The BC Energy Plan requires natural gas plants to offset to zero net greenhouse gas emissions. These costs do not reflect the costs of zero net GHG emissions
9 The BC Energy Plan requires zero greenhouse gas emissions from any coal thermal electricity facilities
The costs do not include the costs of requiring zero emissions from coal thermal power
10 Source: BC Hydro's F2006 Open Call for Power Report

The majority of B.C.'s electricity requirements over the next 10 years can be achieved through increased conservation by all British Columbians and new electricity from independent power producers.

British Columbia's Strength in Electricity Diversity

British Columbia is truly fortunate to have a wide variety of future supply options available to meet our growing demand for energy. A cost effective way to meet that demand is to conserve energy and be more energy efficient. However, British Columbia will still need to bring new power on line to meet demand growth in the years ahead. In order to ensure we have this critical resource available to British Columbians when they need it, government will be looking to secure a range of made-in-B.C. power to serve British Columbians in the years ahead.

Government's goal is to encourage a diverse mix of resources that represent a variety of technologies. Some resource technologies, such as large and small hydro, thermal power, wind and geothermal provide well-established, commercially available sources of electricity. Other emerging technologies that are not yet widely used include large ocean wave and tidal power, solar, hydrogen and advanced coal technologies.

2004 Total Electricity Production by Source (% of total)

	Other Renewables	Hydro Electric	Nuclear	Waste and Biomass	Natural Gas	Diesel Oil	Coal	TOTAL
British Columbia	**0.0**	**92.8**	**0.0**	**1.0**	**6.0**	**0.2**	**0.0**	**100**
Alberta	2.3	4.4	0.0	0.0	12.0	2.6	78.7	100
Australia	0.3	6.9	0.0	0.6	12.3	0.70	79.2	100
California	10.7	17.0	14.5	0.0	37.7	0.0	20.1	100
Denmark	16.3	0.1	0.0	8.8	24.7	4.0	46.1	100
Finland	0.4	17.6	26.5	12.4	14.9	0.7	27.5	100
France	0.2	11.3	78.3	1.0	3.2	1.0	5.0	100
Germany	4.2	4.5	27.1	2.6	10.0	1.6	50.0	100
Japan	0.4	9.5	26.1	1.9	22.6	12.3	27.2	100
Norway	0.3	98.8	0.0	0.5	0.3	0.0	0.1	100
Ontario	1.8	24.8	49.7	0.0	5.2	0.5	18.0	100
Oregon	2.3	64.4	0.0	0.0	26.3	0.1	6.9	100
Quebec	0.7	94.5	3.2	0.0	0.1	1.5	0.0	100
United Kingdom	0.5	1.9	20.2	2.1	40.3	1.2	33.8	100
Washington	2.3	70.0	8.8	0.0	8.6	0.1	10.2	100

SHARING SOLUTIONS ON ELECTRICITY

The BC Energy Plan has a goal that most of B.C.'s electricity requirements over the next 10 years can be achieved through increased conservation and energy efficiency by all British Columbians, coupled with generation by independent power producers. However, these new projects take time to plan and implement. In addition, many of these sources provide limited amounts of firm supply. The province will also need to consider options for new, large scale sources to meet forecasted demand growth in the next 10 to 20 years. Large scale options could include Site C, large biomass facilities, clean coal or natural gas plants. As with all large scale undertakings, these kinds of projects will require years of lead time to allow for careful planning, analysis, consultation and construction.

Perhaps the biggest challenge facing British Columbians is simply to begin choosing our electricity future together. Demand for electricity is projected to grow by up to 45 per cent over the next 20 years. To meet this projected growth we will need to conserve more, and obtain more electricity from small power producers and large projects. Given the critical importance of public participation and stakeholder involvement in addressing the challenges and choices of meeting our future electricity needs, government and BC Hydro will seek and share solutions.

Rapid expansion of our energy sector means a growing number of permanent, well-paying employment opportunities are available.

Taking Action to Meet the Demand for Workers

The energy sector has been a major contributor to British Columbia's record economic performance since 2001. **The BC Energy Plan** focuses on four under-represented groups that offer excellent employment potential: Aboriginal people, immigrants, women and youth.

At the same time, the energy sector must overcome a variety of skills training and labour challenges to ensure future growth.

These challenges include:

- An aging workforce that upon retirement will leave a gap in experience and expertise.
- Competition for talent from other jurisdictions.
- Skills shortages among present and future workers.
- Labour market information gaps due to a lack of in-depth study.
- The need to coordinate immigration efforts with the federal government.
- The need for greater involvement of under-represented energy sector workers such as Aboriginal people, immigrants, women, and youth.
- A highly mobile workforce that moves with the opportunities.
- The need to improve productivity and enhance competitiveness.

Innovative, practical and timely skills training, and labour management is required to ensure the energy sector continues to thrive. As part of **The BC Energy Plan**, government will work collaboratively with industry, communities, Aboriginal people, education facilities, the federal government and others to define the projected demand for workers and take active measures to meet those demands.

Attract Highly Skilled Workers

Demographics show that those born at the height of the baby boom are retired or nearing retirement, leaving behind a growing gap in skills and expertise. Since this phenomenon is taking place in most western nations, attracting and retaining skilled staff is highly competitive.

To ensure continued energy sector growth, we need to attract workers from outside the province, particularly for the electricity, oil and gas, and heavy construction industries where the shortage is most keenly felt. At this time, a significant increase in annual net migration of workers from other provinces and from outside Canada is needed to complement the existing workforce.

Government and its partners are developing targeted plans to attract the necessary workers. These plans will include marketing and promoting energy sector jobs as a career choice.

Develop a Robust Talent Pool of Workers

It is vital to provide the initial training to build a job-ready talent pool in British Columbia, as well as the ongoing training employees need to adapt to changing energy sector technologies, products and requirements. We can ensure a thriving pool of talent in British Columbia by retraining skilled employees who are without work due to downturns in other industries. Displaced workers from other sectors and jurisdictions may require some retraining and new employees may need considerable skills development.

Another way to help ensure there are enough skilled energy sector workers in the years ahead is to educate and inform young people today. By letting high school students know about the opportunities, they can consider their options and make the appropriate training and career choices. Government will work to enhance information relating to energy sector activities in British Columbia's school curriculum in the years ahead.

Retain Skilled Workers

Around the world, energy facility construction and operations are booming, creating fierce, global competition for skilled workers. While British Columbia has much to offer, it is critical that our jurisdiction presents a superior opportunity to these highly skilled and mobile workers. That is why we need to ensure our workplaces are safe, fair and healthy and our communities continue to offer an unparalleled lifestyle with high quality health care and education, affordable housing, and readily available recreation opportunities in outstanding natural settings.

Inform British Columbians

To be effective in filling energy sector jobs with skilled workers, British Columbians need to be informed and educated about the outstanding opportunities available. As part of **The BC Energy Plan**, a comprehensive public awareness and education campaign based on sound labour market analysis will reach out to potential energy sector workers. This process will recognize and address both the potential challenges such as shift work and remote locations as well as the opportunities, such as obtaining highly marketable skills and earning excellent compensation.

Be Among the Most Competitive Oil and Gas Jurisdictions in North America

Since 2001, British Columbia's oil and gas sector has grown to become a major force in our provincial economy, employing tens of thousands of British Columbians and helping to fuel the province's strong economic performance. In fact, investment in the oil and gas sector was $4.6 billion in 2005. The oil and gas industry contributes approximately $1.95 billion annually or seven per cent of the province's annual revenues.

The BC Energy Plan is designed to take B.C.'s oil and gas sector to the next level to enhance a sustainable, thriving and vibrant oil and gas sector in British Columbia. With a healthy, competitive oil and gas sector comes the opportunity to create jobs and build vibrant communities with increased infrastructure and services, such as schools and hospitals. Of particular importance is an expanding British Columbia-based service sector.

There is a lively debate about the peak of the world's oil and gas production and the impacts on economies, businesses and consumers. A number of countries, such as the UK, Norway and the USA, are experiencing declining fossil fuel production from conventional sources. Energy prices, especially oil prices have increased and are more volatile than in the past. As a result, the way energy is produced and consumed will change, particularly in developed countries.

The plan is aimed at enhancing the development of conventional resources and stimulating activity in relatively undeveloped areas such as the interior basins – particularly the Nechako Basin. It will also foster the development of unconventional resources such as as tight gas, shale gas, and coalbed gas. The plan will further efforts to work with the federal government, communities and First Nations to advance offshore opportunities.

The challenge for British Columbia in the future will be to continue to find the right balance of economic, environmental and social priorities to allow the oil and gas sector to succeed, while protecting our environment and improving our quality of life.

POLICY ACTIONS

ENVIRONMENTALLY RESPONSIBLE OIL AND GAS DEVELOPMENT

- **Eliminate all routine flaring at oil and gas producing wells and production facilities by 2016 with an interim goal to reduce flaring by half (50 per cent) by 2011.**
- **Establish policies and measures to reduce air emissions in coordination with the Ministry of Environment.**
- **Best coalbed gas practices in North America. Companies will not be allowed to surface discharge produced water. Any re-injected produced water must be injected well below any domestic water aquifer.**
- **Enhance the Oil and Gas Environmental Stewardship Program, ensuring sound environmental, land and resource management.**

The New Relationship and Oil and Gas

Working together with local communities and First Nations, the provincial government will continue to share in the many benefits and opportunities created through the development of British Columbia's oil and gas resources.

Government is working to ensure that oil and gas resource management includes First Nations' interests, knowledge and values. Government has recently concluded consultation agreements for oil and gas resource development with First Nations in Northeast British Columbia. These agreements increase clarity in the process and will go a long way to enhancing our engagement with these First Nations.

Government will continue to pursue opportunities to share information and look for opportunities to facilitate First Nations' employment and participation in the oil and gas industry to ensure that Aboriginal people benefit from the continued growth and development of British Columbia's resources.

The BC Energy Plan adopts a triple bottom line approach to competitiveness, with an attractive investment climate, environmentally sustainable development of B.C.'s abundant resources, and by benefiting communities and First Nations.

While striving to be among the most competitive oil and gas jurisdictions in North America, the province will focus on maintaining and enhancing its strong competitive environment for the oil and gas industry. This encompasses the following components:

- A competitive investment climate.
- An abundant resource endowment.
- Environmental responsibility.
- Social responsibility.

Leading in Environmentally and Socially Responsible Oil and Gas Development

The BC Energy Plan emphasizes conservation, energy efficiency, and the environmental and socially responsible management of the province's energy resources. It outlines government's efforts to meet this objective by working collaboratively with involved and interested parties, including affected communities, landowners, environmental groups, First Nations, the regulator (the Oil and Gas Commission), industry groups and others. Policy actions will support ways to address air emissions, impacts on land and wildlife habitat, and water quality.

The oil and gas sector in British Columbia accounts for approximately 18 per cent of greenhouse gas air emissions in the province. The main sources of air emissions from the oil and gas sector are flaring, fugitive gases, gas processing and compressor stations. While these air emissions have long been part of the oil and gas sector, they have also been a source of major concern for oil and gas communities.

Eliminate Flaring from Oil and Gas Producing Wells and Production Facilities By 2016

Through **The BC Energy Plan**, government has committed to eliminate all routine flaring at oil and gas producing wells and production facilities by 2016 with an interim goal to reduce flaring by half (50 per cent) by 2011. In addition, government will adopt policies to reduce natural gas flaring and venting at test sites and pipelines, and encourage compressor station efficiency to cut back emissions. Government will also explore opportunities and new technologies for safe, underground disposal of carbon dioxide or sequestration from oil and gas facilities. Sequestration is considered a cost effective mitigation strategy in reducing carbon dioxide emissions.

Enhance Carbon Dioxide Sequestration in British Columbia

British Columbia is a member of the Plains CO2 Reduction (PCOR) Partnership composed of nearly 50 private and public sector groups from nine states and three Canadian provinces that is assessing the technical and economic feasibility of capturing and storing carbon dioxide emissions from stationary sources in western sedimentary basins.

B.C. is also a member of the West Coast Regional Carbon Sequestration Partnership, made up of west coast state and provincial government ministries and agencies. This partnership has been formed to pursue carbon sequestration opportunities and technologies.

To facilitate and foster innovation in sequestration, government will develop market oriented requirements with a graduated schedule. In consultation with stakeholders, a timetable will be developed along with increasing requirements for sequestration.

BRITISH COLUMBIA COMPANIES RECOGNIZED AS WORLD ENERGY TECHNOLOGY INNOVATORS

The leadership of British Columbian companies can be seen in all areas of the energy sector through innovative, industry leading technologies.

Production of a new generation of chemical injection pump for use in the oil and gas industry is beginning. The pumps, developed and built in British Columbia, are the first solar powered precision injection pumps available to the industry. They will reduce emissions by replacing traditional gas powered injection systems for pipelines.

Other solar technologies developed in British Columbia provide modular power supplies in remote locations all over the globe for marine signals, aviation lights and road signs.

Roads in B.C. and around the world are hosting demonstrations of fuel cell vehicles built with British Columbia technology. Thanks to the first high pressure hydrogen fuelling station in the world, compatible fuel cell vehicles in B.C. can carry more fuel and travel farther than ever before.

The **Innovative Clean Energy Fund** will help to build B.C.'s technology cluster and keep us at the forefront of energy technology development.

Government will work to improve oil and gas tenure policies as well as develop new guidelines to determine areas that require special consideration prior to tenure approval.

POLICY ACTIONS

OFFSHORE OIL AND GAS DEVELOPMENT

- **Continue to work to lift the federal moratorium on offshore exploration and development and reiterate the intention to simultaneously lift the provincial moratorium.**
- **Work with the federal government to ensure that offshore oil and gas resources are developed in a scientifically sound and environmentally responsible way.**
- **Participate in marine and environmental planning to effectively manage marine areas and offshore oil and gas basins.**
- **Develop and implement a comprehensive community engagement program to establish a framework for a benefits sharing agreement resulting from offshore oil and gas development for communities, including First Nations.**

Environmental Stewardship Program

In 2004, the Ministry of Energy, Mines and Petroleum Resources initiated the Oil and Gas Environmental Stewardship Program having two components: the Environmental Policy Program and the Environmental Resource Information Project. The Environmental Policy Program identifies and mitigates environmental issues in the petroleum sector focusing on policy development in areas such as environmental waste management, habitat enhancement, planning initiatives, wildlife studies for oil and gas priority areas and government best management practices. Some key program achievements include the completion of guidelines for regulatory dispersion modeling, research leading to the development of soil quality guidelines for soluble barium, a key to northern grasses and their restorative properties for remediated well sites, and moose and caribou inventories in Northeast British Columbia.

The Environmental Resource Information Project is dedicated to increasing opportunities for oil and gas development, through the collection of necessary environmental baseline information. These projects are delivered in partnership with other agencies, industry, communities and First Nations.

The BC Energy Plan enhances the important Oil and Gas Environmental Stewardship Program. This will improve existing efforts to manage waste and preserve habitat, and will establish baseline data as well as development and risk mitigation plans for environmentally sensitive areas. Barriers need to be identified and steps taken for remediation, progressive reclamation, and waste management.

Best Coalbed Gas Practices in North America

Government will continue to encourage coalbed gas development with the intent of demonstrating that British Columbia is a leading socially and environmentally responsible coalbed gas developing jurisdiction. Coalbed gas, also known as coalbed methane, is natural gas found in coal seams. It is one of the cleanest burning of all fossil fuels. Proponents wanting to develop coalbed gas must adopt the following best practices:

- Fully engage local communities and First Nations in all stages of development.
- Use the most advanced technology and practices that are commercially viable to minimize land and aesthetic disturbances.
- Companies will not be allowed to surface discharge produced water. Any re-injected produced water must be injected well below any domestic water aquifer.
- Meet any other conditions the Oil and Gas Commission may apply.
- Demonstrate the company's previous experience with coalbed gas development, and information must be made publicly available as to how the company plans to meet and be accountable for these best practices.

Ensuring Offshore Oil and Gas Resources are Developed in a Scientifically Sound and Environmentally Responsible Way

The BC Energy Plan includes actions related to the province's offshore oil and gas resources. Since 1972, Canada and British Columbia have each had a moratorium in place on offshore oil and gas exploration and development. With advanced technology and

British Columbia's oil and gas industry supports thousands of well-paying jobs, helps drive the economy and provides revenues to sustain public services.

positive experiences in other jurisdictions, a compelling case exists for assessing British Columbia's offshore resource potential.

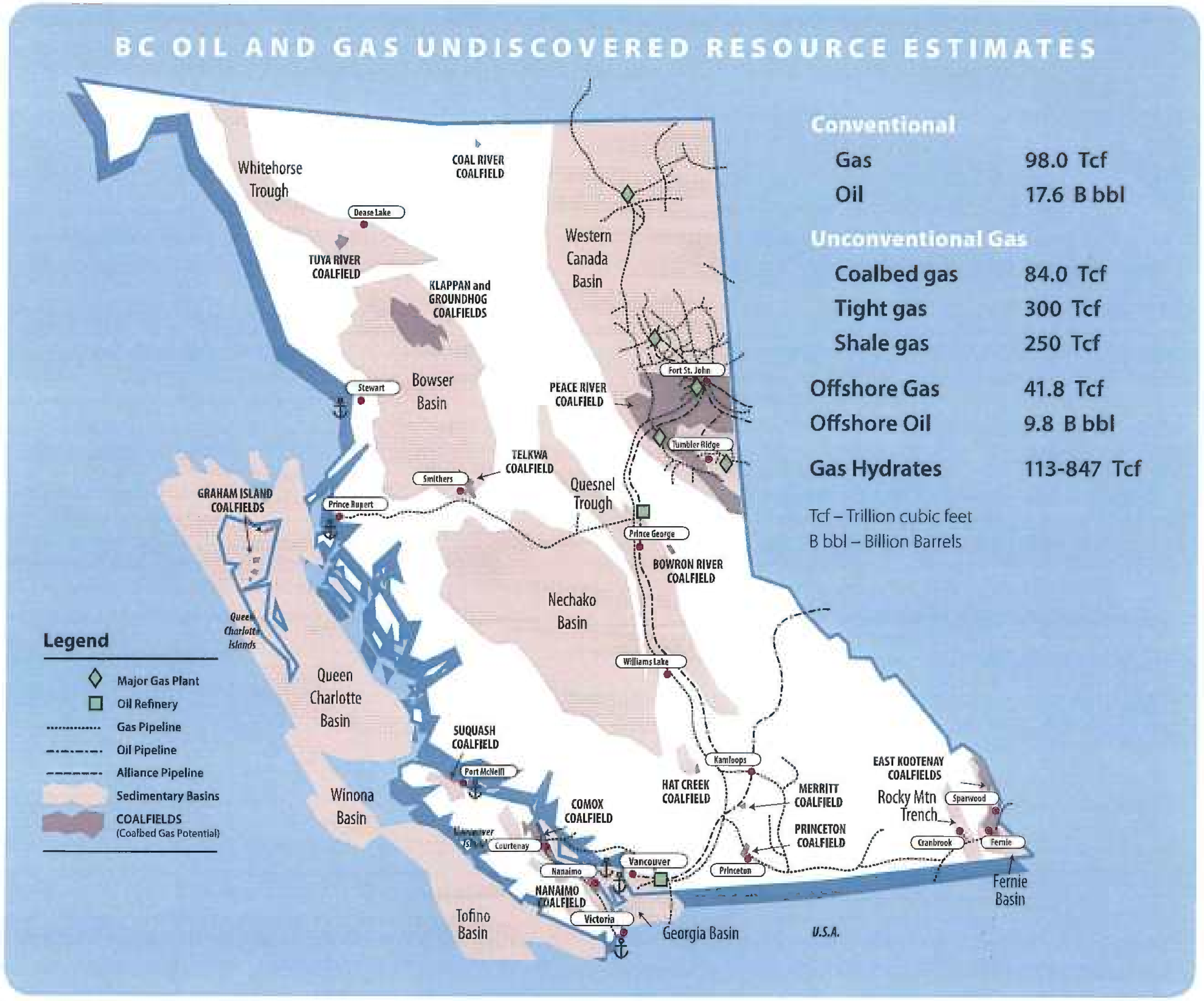
Government will work with coastal communities, First Nations, the federal government, environmental organizations, and others to ascertain the benefits and address the concerns associated with offshore oil and gas development.

Maintaining B.C.'s Competitive Advantage as an Oil and Gas Jurisdiction

British Columbia's oil and gas industry is thriving thanks to high resource potential, industry and service sector expertise, and a competitive investment climate that includes a streamlined regulatory environment. To attract additional investment in British Columbia's oil and gas industry, we need to compete aggressively with other jurisdictions that may offer lower taxes or other investment incentives.

Another key way to be more competitive is by spurring activity in underdeveloped areas while heightening activity in the northeast, where our natural gas industry thrives. The province will work with industry to develop new policies and technologies for enhanced resource recovery making, it more cost-effective to develop British Columbia's resources.

By increasing our competitiveness, British Columbians can continue to benefit from well-paying jobs, high quality social infrastructure and a thriving economy.



British Columbia's Enormous Natural Gas Potential

The oil and gas sector will continue to play an important role in British Columbia's future energy security. Our province has enormous natural gas resource potential and opportunities for significant growth. The BC Energy Plan facilitates the development of B.C.'s resources.

British Columbia has numerous sedimentary basins, which contain petroleum and natural gas resources. In north-eastern British Columbia, the Western Canada Sedimentary Basin is the focus of our thriving natural gas industry. The potential resources in the central and northern interior of the province, the Nechako and Bowser Basins and Whitehorse Trough, have gone untapped.

The delayed evaluation and potential development of these areas is largely due to geological and physical obstructions that make it difficult to explore in the area. Volcanic rocks that overlay the sedimentary package combined with complex basin structures, have hindered development.

The BC Energy Plan is aimed at enhancing the development of conventional resources and stimulating activity in undeveloped areas such as the interior basins – particularly the Nechako Basin. It will also foster the development of unconventional resources and take a more stringent approach on coalbed gas to meet higher environmental standards.

Attracting Investment and Developing our Oil and Gas Resources

The BC Energy Plan promotes competitiveness by setting out a number of important regulatory and fiscal measures including: monitoring British Columbia's competitive ranking, considering a Net Profit Royalty Program, promoting a B.C. service sector, harmonizing and streamlining regulations, and developing a Petroleum Registry to examine royalty and tenure incentives, and undertaking geoscience programs.

Establishment of a Petroleum Registry

The establishment of a petroleum registry that functions as a central database will improve the quality and management of key volumetric, royalty and infrastructure information associated with British Columbia's oil and gas industry and promote competition while providing transparency around oil and gas activity.

NEEMAC: SUCCESS THROUGH COMMUNICATION

As energy, mining and petroleum resource development increases in northeast B.C., so too does the need for input from local governments, First Nations, community groups, landowners and other key stakeholders. In 2006, the Northeast Energy and Mines Advisory Committee (NEEMAC) was created to provide an inclusive forum for representative organizations to build relationships with each other, industry and government to provide input on Ministry policy, and recommend innovative solutions to stakeholder concerns.

Since its creation, NEEMAC has identified and explored priority concerns, and is beginning to find balanced solutions related to environmental, surface disturbance, access and landowner rights issues. The Ministry is committed to implementing recommendations that represent the broad interests of community, industry and government and expects that the committee will continue to provide advice on energy, mining and petroleum development issues in support of The BC Energy Plan.

An opportunity to increase competitiveness exists in British Columbia's Interior Basins – namely the Nechako, Bowser and Whitehorse Basins – where considerable resource potential is known to exist.

Increasing Access

In addition to regulatory and fiscal mechanisms, the plan addresses the need for improving access to resources. Pipelines and road infrastructure are critical factors in development and competitiveness. The BC Energy Plan calls for new investment in public roads and other infrastructure. It will see government establish a clear, structured infrastructure royalty program, combining road and pipeline initiatives and increasing development in under-explored areas that have little or no existing infrastructure.

Developing Conventional and Unconventional Oil and Gas Resources

To support investment in exploration, The BC Energy Plan calls for partnerships in research and development to establish reliable regional data, as well as royalty and tenure incentives. The goal is to attract investment, create well-paying jobs, boost the regional economy and produce economic benefits for all British Columbians. We can be more competitive by spurring activity in underdeveloped areas while heightening activity in the northeast where our natural gas industry thrives. The plan advocates working with industry to develop new policies and technology to enhance resource recovery, including oil in British Columbia.

Improve Regulations and Research

The province remains committed to continuous improvement in the regulatory regime and environmental management of conventional and unconventional oil and gas resources. The opportunities for enhancing exploration and production of tight gas, shale gas, and coalbed gas will also be assessed and supported by geoscience research and programs. The BC Energy Plan calls for collaboration with other government ministries, agencies, industry, communities and First Nations to develop the oil and gas resources in British Columbia.

Focus on Innovation and Technology Development

The BC Energy Plan also calls for supporting the development of new oil and gas technologies. This plan will lead British Columbia to become an internationally recognized centre for technological advancements and commercialization, particularly in environmental management, flaring, carbon sequestration and hydrogeology. The service sector has noted it can play an important role in developing and commercializing new technologies; however, the issue for companies is accessing the necessary funds.

THE HUB OF B.C.'S OIL AND GAS SECTOR

Oil and gas is benefiting all British Columbians - not just those living in major centres. Nowhere is this more apparent than in booming Fort St. John, which has rapidly become the oil and gas hub of the province. Since 2001, more than 1,400 people have moved to the community, an increase of 6.3 per cent and two per cent faster growth than the provincial average. Construction permits are way up - from $48.7 million in 2004, to $50.6 million in 2005, to over $123 million in 2006. In the past five years, over 1,000 new companies have been incorporated in Fort St. John, as young families, experienced professionals, skilled trades-people and many others move here from across the country.

POLICY ACTIONS

BE AMONG THE MOST COMPETITIVE OIL AND GAS JURISDICTIONS IN NORTH AMERICA

- **Pursue regulatory and fiscal competitiveness in support of being among the most competitive oil and gas jurisdictions in North America.**
- **Enhance infrastructure to support the development of oil and gas in British Columbia and address impediments to economic development such as transportation and labour shortages.**
- **Encourage the development of conventional and unconventional resources.**
- **Support the growth of British Columbia's oil and gas service sector.**
- **Promote exploration and development of the Interior basins with a priority focus on the Nechako Basin.**
- **Encourage the development of new technologies.**
- **Add value to British Columbia's oil and gas industry by assessing and promoting the development of additional gas processing facilities in the province.**

Technology Transfer Incentive Program

A new Oil and Gas Technology Transfer Incentive Program will be considered to encourage the research, development and use of innovative technologies to increase recoveries from existing reserves and encourage responsible development of new oil and gas reserves. The program could recover program costs over time through increased royalties generated by expanded development and production of British Columbia's petroleum resources.

Scientific Research and Experimental Development

The BC Energy Plan supports the British Columbia Scientific Research and Experimental Development Program, which provides financial support for research and development leading to new or improved products and processes. Through credits or refunds, the expanded program could cover project costs directly related to commercially applicable research, and development or demonstration of new or improved technologies conducted in British Columbia that facilitate expanded oil and gas production.

Research and Development

The BC Energy Plan calls for using new or existing research and development programs for the oil and gas sector. Government will develop a program targeting areas in which British Columbia has an advantage such as well completion technology and hydrogeology.

A program to encourage oil and gas innovation and research in British Columbia's post-secondary institutions will be explored. These opportunities will be explored in partnership with the Petroleum Technology Alliance Canada and as part of the April 2006 Memorandum of Understanding between British Columbia and Alberta on Energy Research, Technology Development and Innovation.

Together with the Oil and Gas Centre of Excellence in Fort St. John, an oil and gas technology incubator, a site which provides innovators with space to build prototypes and carry out testing as well as providing business infrastructure and assistance accessing additional support will be established, allowing entrepreneurs to develop and test new innovations and commercialize new, innovative technologies and processes.

Nechako Initiative

The BC Energy Plan calls for government to partner with industry, the federal government, and Geoscience BC to undertake comprehensive research in the Nechako Basin and establish new data of the resource potential. It will include active engagement of communities and the development and implementation of a comprehensive pre-tenure engagement initiative for First Nations in the region. Specific tenures and royalties will be explored to encourage investment, as well as a comprehensive Environmental Information Program to identify baseline information needs in the area through consultations with government, industry, communities and First Nations.

By increasing our oil and gas industry's competitiveness, British Columbians can continue to benefit from well-paying jobs, high quality social infrastructure and a thriving economy.

Value-Added Opportunities

To improve competitiveness, **The BC Energy Plan** calls for a review of value-added opportunities in British Columbia. This will include a thorough assessment of the potential for processing facilities and petroleum refineries as well as petrochemical industry opportunities. The Ministry of Energy, Mines and Petroleum Resources will conduct an analysis to identify and address barriers and explore incentives required to encourage investment in gas processing in British Columbia. A working group of industry and government will develop business cases and report to the Minister by January 2008 with recommendations on the viability of a new petroleum refinery and petrochemical industry and measures, if any, to encourage investment.

Oil and Gas Service Sector

British Columbia's oil and gas service sector can also help establish our province as one of the most competitive jurisdictions in North America. The service sector has grown over the past four years and with increased activity, additional summer drilling, and the security of supply, opportunities for local companies will continue. Government can help maximize the benefits derived from the service sector by:

- Promoting British Columbia's service sector to the oil and gas industry through participation at trade shows and providing information to the business community.
- Identifying areas where British Columbian companies can play a larger role, expand into other provinces, and through procurement strategies.

The government also supports the Oil and Gas Centre of Excellence at the Fort St. John Northern Lights College campus, which will provide oil and gas, related vocational, trades, career and technical programs.

Improving Oil and Gas Tenures

Government will work to improve oil and gas tenure issuance policies as well as develop new guidelines to determine areas that require special consideration prior to tenure approval by the end of 2007. This will provide clear parameters for industry regarding areas where special or enhanced management practices are required. These measures will strike the important balance between providing industry with clarity and access to resources and the desire of local government, communities, landowners, stakeholders and First Nations for input into the oil and gas development process.

Create Opportunities for Communities and First Nations

Benefits for British Columbians from the Oil and Gas Sector

The oil and gas sector offers enormous benefits to all British Columbians through enhanced energy security, tens of thousands of good, well-paying jobs and tax revenues used to help fund our hospitals and schools. However, the day-to-day impact of the sector has largely been felt on communities and First Nations in British Columbia's northeast. Community organizations, First Nations, and landowners have communicated a desire for greater input into the pace and scope of oil and gas development in British Columbia.

Together with the Oil and Gas Centre of Excellence in Fort St. John, an oil and gas technology incubator will be established, allowing entrepreneurs to develop and test new innovations.

POLICY ACTIONS

WORKING WITH COMMUNITIES AND FIRST NATIONS

- **Provide information about local oil and gas activities to local governments, First Nations, education and health service providers to inform and support the development of necessary social infrastructure.**
- **Work with First Nations to identify opportunities to participate in and benefit from oil and gas development.**
- **Support First Nations in providing cross-cultural training to agencies and industry.**
- **Improve working relationships among industry and local communities and landowners by clarifying and simplifying processes, enhancing dispute resolution methods, and offering more support and information.**
- **Examine oil and gas tenure policies and develop guidelines to determine areas that require special consideration prior to tenure approval.**

Through The BC Energy Plan, government intends to develop stronger relationships with those affected by oil and gas development, including communities and First Nations. The aim is to work cooperatively to maximize benefits and minimize impacts. The plan supports improved working relationships among industry, local communities and landowners by increased and improved communication to clarify and simplify processes, enhancing dispute resolution methods, and offering more support and information.

The government will also continue to improve communications with local governments and agencies. Specifically, The BC Energy Plan calls for efforts to provide information about increased local oil and gas activities to local governments, education and health service providers to improve their ability to make timely decisions on infrastructure, such as schools, housing, and health and recreational facilities. By providing local communities and service providers with regular reports of trends and industry activities, they can more effectively plan for growth in required services and infrastructure.

Building Better Relationships with Landowners

The BC Energy Plan: A Vision for Clean Energy Leadership also supports improved working relationships between industry, local communities and landowners and First Nations. Landowners will be notified in a more timely way of sales of oil and gas rights on private land. Plain language information materials, including standardized lease agreements will be made available to help landowners deal with subsurface tenures and activity. There will be a review of the dispute resolution process between landowners and industry by the end of 2007. The existing setback requirements, the allowed distance of a well site from a residence, school or other public place, will also be examined. These measures seek to strike the important balance between providing industry with clarity and access to resources and the desire of local government, communities, landowners, stakeholders and First Nations for input into oil and gas development.

Working in Partnership with First Nations and Communities

Government will work with First Nations communities to identify opportunities to benefit from oil and gas development. By developing a greater ability to participate in and benefit from oil and gas development, First Nations can play a much more active role in the industry. The BC Energy Plan also supports increasing First Nations role in the development of cross-cultural training initiatives for agencies and industry.

Conclusion

The BC Energy Plan: A Vision for Clean Energy Leadership sets the standard for proactively addressing the opportunities and challenges that lie ahead in meeting the energy needs for all the citizens of the province, now and in the future. Appendix A provides a detailed listing of the policy actions of the plan.

The BC Energy Plan will attract new investments, help develop and commercialize new technology, build partnerships with First Nations, and ensures a strong environmental focus.

British Columbia has a proud history of innovation that has resulted in 90 per cent of our power generation coming from clean sources. This plan builds on that foundation and ensures B.C. will be at the forefront of environmental and economic leadership for years to come.

APPENDIX A The BC Energy Plan: Summary of Policy Actions

ENERGY CONSERVATION AND EFFICIENCY

1. Set an ambitious conservation target, to acquire 50 per cent of BC Hydro's incremental resource needs through conservation by 2020.
2. Ensure a coordinated approach to conservation and efficiency is actively pursued in British Columbia.
3. Encourage utilities to pursue cost effective and competitive demand side management opportunities.
4. Explore with B.C. utilities new rate structures that encourage energy efficiency and conservation.
5. Implement Energy Efficiency Standards for Buildings by 2010.
6. Undertake a pilot project for energy performance labeling of homes and buildings in coordination with local and federal governments, First Nations, and industry associations.
7. New provincial public sector buildings will be required to integrate environmental design to achieve the highest standards for greenhouse gas emission reductions, water conservation and other building performance results such as a certified standard.
8. Develop an Industrial Energy Efficiency Program for British Columbia to address specific challenges faced by British Columbia's industrial sector.
9. Increase the participation of local governments in the Community Action on Energy Efficiency Program and expand the First Nations and Remote Community Clean Energy Program.

ELECTRICITY

10. Ensure self-sufficiency to meet electricity needs, including "insurance" by 2016.
11. Establish a standing offer for clean electricity projects up to 10 megawatts.
12. The BC Transmission Corporation is to ensure that British Columbia's transmission technology and infrastructure remains at the leading edge and has the capacity to deliver power efficiently and reliably to meet growing demand.
13. Ensure adequate transmission system capacity by developing and implementing a transmission congestion relief policy.
14. Ensure that the province remains consistent with North American transmission reliability standards.
15. Continue public ownership of BC Hydro and its heritage assets, and the BC Transmission Corporation.
16. Establish the existing heritage contract in perpetuity.
17. Invest in upgrading and maintaining the heritage asset power plants and the transmission lines to retain the ongoing competitive advantage these assets provide to the province.
18. All new electricity generation projects will have zero net greenhouse gas emissions.
19. Zero net greenhouse gas emissions from existing thermal generation power plants by 2016.
20. Require zero greenhouse gas emissions from any coal thermal electricity facilities.
21. Ensure clean or renewable electricity generation continues to account for at least 90 per cent of total generation.
22. Government supports BC Hydro's proposal to replace the firm energy supply from the Burrard Thermal plant with other resources. BC Hydro may choose to retain Burrard for capacity purposes after 2014.
23. No nuclear power.
24. Review BC Utilities Commissions' role in considering social and environmental costs and benefits.
25. Ensure the procurement of electricity appropriately recognizes the value of aggregated intermittent resources.
26. Work with BC Hydro and parties involved to continue to improve the procurement process for electricity.
27. Pursue Government and BC Hydro's planned Remote Community Electrification Program to expand or take over electricity service to remote communities in British Columbia.
28. Ensure BC Hydro considers alternative electricity sources and energy efficiency measures in its energy planning for remote communities.

ALTERNATIVE ENERGY

29. Establish the **Innovative Clean Energy Fund** to support the development of clean power and energy efficiency technologies in the electricity, alternative energy, transportation and oil and gas sectors.
30. Implement a provincial Bioenergy Strategy which will build upon British Columbia's natural bioenergy resource advantages.
31. Issue an expression of interest followed by a call for proposals for electricity from sawmill residues, logging debris and beetle-killed timber to help mitigate impacts from the provincial mountain pine beetle infestation.
32. Implement a five per cent average renewable fuel standard for diesel by 2010 to help reduce emissions and advance the domestic renewable fuel industry.
33. Support the federal action of increasing the ethanol content of gasoline to five per cent by 2010 and adopt quality parameters for all renewable fuels and fuel blends that are appropriate for Canadian weather conditions in cooperation with North American jurisdictions.
34. Develop a leading hydrogen economy by continuing to support the Hydrogen and Fuel Cell Strategy for British Columbia.
35. Establish a new, harmonized regulatory framework by 2010 for hydrogen by working with governments, industry and hydrogen alliances.

OIL AND GAS

36. Eliminate all routine flaring at oil and gas producing wells and production facilities by 2016 with an interim goal to reduce flaring by half (50 per cent) by 2011.
37. Establish policies and measures to reduce air emissions in coordination with the Ministry of Environment.
38. Best coalbed gas practices in North America. Companies will not be allowed to surface discharge produced water. Any re-injected produced water must be injected well below any domestic water aquifer.
39. Enhance the Oil and Gas Environmental Stewardship Program, ensuring sound environmental, land and resource management.
40. Continue to work to lift the federal moratorium on offshore exploration and development and reiterate the intention to simultaneously lift the provincial moratorium.
41. Work with the federal government to ensure that offshore oil and gas resources are developed in a scientifically sound and environmentally responsible way.
42. Participate in marine and environmental planning to effectively manage marine areas and offshore oil and gas basins.
43. Develop and implement a comprehensive community engagement program to establish a framework for a benefits sharing agreement resulting from offshore oil and gas development for communities, including First Nations.
44. Pursue regulatory and fiscal competitiveness in support of being among the most competitive oil and gas jurisdictions in North America.
45. Enhance infrastructure to support the development of oil and gas in British Columbia and address impediments to economic development such as transportation and labour shortages.
46. Encourage the development of conventional and unconventional resources.
47. Support the growth of British Columbia's oil and gas service sector.
48. Promote exploration and development of the Interior basins with a priority focus on the Nechako Basin.
49. Encourage the development of new technologies.
50. Add value to British Columbia's oil and gas industry by assessing and promoting the development of additional gas processing facilities in the province.
51. Provide information about local oil and gas activities to local governments, education and health service providers to inform and support the development of necessary social infrastructure.
52. Work with First Nations to identify opportunities to participate in and benefit from oil and gas development.
53. Support First Nations in providing cross-cultural training to agencies and industry.
54. Improve working relationships among industry and local communities and landowners by clarifying and simplifying processes, enhancing dispute resolution methods, and offering more support and information.
55. Examine oil and gas tenure policies and develop guidelines to determine areas that require special consideration prior to tenure approval.

Energy in Action

POWERSMART
BC Hydro offers a variety of incentives to adopt energy saving technologies. Incentives such as rebates on efficient lighting or windows encourages British Columbians to improve the energy efficiency of their homes and businesses.

PROVINCIAL SALES TAX EXEMPTIONS
Tax breaks are offered for a wide variety of energy efficient items, making it easier to conserve energy. Tax concessions are in place for alternative fuel and hybrid vehicles as well as some alternative fuels. Bicycles and some bicycle parts are exempt from provincial sales tax, as are a variety of materials, such as Energy Star® qualified windows, that can make homes more energy efficient.

NET METERING
The Net Metering program offered by BC Hydro for customers with small generating facilities, allows customers to lower their environmental impact and take responsibility for their own power production. The customer is only billed for their "net consumption"; the total amount of electricity used minus the total produced. Net Metering helps to move the province towards electricity self sufficiency and expands clean electricity generation.

POWERING THE ECONOMY
The Oil and Gas sector invested $4.6 billion in B.C. in 2005 and contributed more to the provincial treasury than any other resource in 2005/06. In 2006 1,416 oil and gas wells were drilled in the province and between 2002 and 2005, summer drilling increased 242 per cent.

FRIDGE BUY-BACK PROGRAM
This program offers customers $30 in cash and no-cost pickup and disposal of an old, inefficient second fridge. If all second operating fridges in B.C. were recycled, we would save enough energy to power all the homes in the city of Chilliwack for an entire year.

LIGHTING REBATES
This program offers instant rebate coupons for the retail purchase of Energy Star® light fixtures and Energy Star® CFLs (Compact Fluorescent Lights).

WINDOWS REBATE
The Windows Rebate Program offers rebates for the installation of Energy Star® windows in new, renovated or upgraded single-family homes, duplexes, townhouses or apartments.

PRODUCT INCENTIVE PROGRAM
The Product Incentive Program provides financial incentives to organizations which replace inefficient products with energy efficient technologies or add on products to existing systems to make them more efficient.

HIGH-PERFORMANCE BUILDING PROGRAM FOR LARGE COMMERCIAL BUILDINGS
Financial incentives, resources, and technical assistance are available to help qualified projects identify energy saving strategies early in the design process; evaluate alternative design options and make a business case for the high-performance design; and, offset the incremental costs, if any, of the energy-efficient measures in the high-performance design.

HIGH-PERFORMANCE BUILDING PROGRAM FOR SMALL TO MEDIUM COMMERCIAL BUILDINGS
Incentives and tools are offered to help owners and their design teams create and install more effective and energy-efficient lighting in new commercial development projects.

NEW HOME PROGRAM
Builders and developers are encouraged to build energy efficient homes by offering financial incentives and Power Smart branding for homes that achieve energy efficient ratings.

ANALYZE MY HOME
BC Hydro offers an online tool that provides a free, personalized breakdown of a customer's home energy use and recommendations on where improvements can be made to lower consumption.

CONSERVATION RESEARCH INITIATIVE
A 12-month study in six communities that examines how adjusting the price of electricity at different times of day influences energy use by residential customers, and how individual British Columbians can make a difference in conserving power in their homes and help meet the growing demand for electricity in B.C.

THE GREEN BUILDINGS PROGRAM
Provides tools and resources to support school districts, universities, colleges, and health authorities to improve the energy efficiency of their buildings across the province.

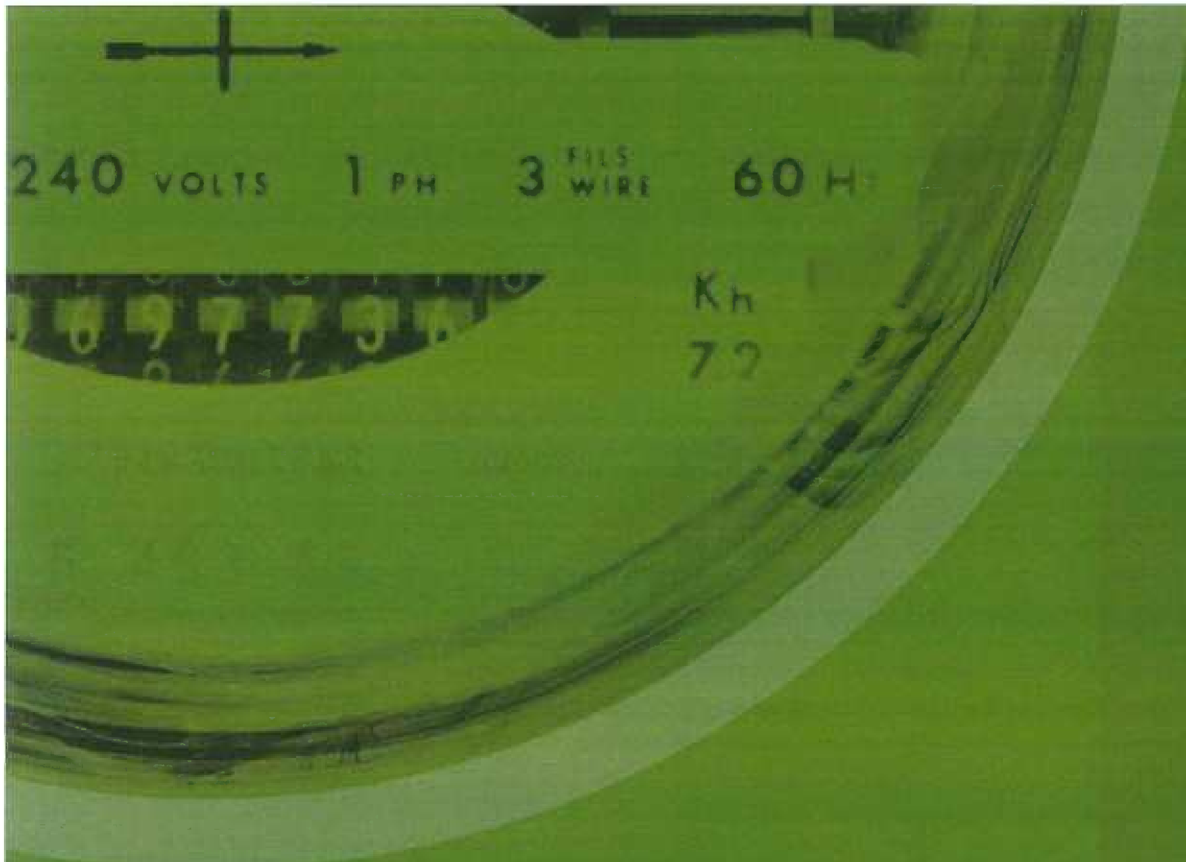
ATTRACTING WORKERS
The Ministry of Energy, Mines and Petroleum Resources hosts job fairs across B.C. to attract workers to the highly lucrative oil and gas sector. Job fairs were held in 14 communities in 2005 and 16 communities in 2006 attracting thousands of people and resulting in hundreds of job offers. Centre of Excellence Government is partnering with industry and the Northern Lights College in Fort St. John to build a centre for oil and gas excellence, more than doubling the number of students training for jobs in the oil and gas industry.

CENTRE OF EXCELLENCE
Government is partnering with industry and the Northern Lights College in Fort St. John to build a centre for oil and gas excellence, more than doubling the number of students training for jobs in the oil and gas industry.

100,000 SOLAR ROOFS FOR B.C.
The Ministers of Environment, and Energy, Mines and Petroleum Resources are sponsoring the development of a plan that will see the aggressive adoption of solar technology in B.C. The goal of the project is to see the installation of solar roofs and walls for hot water heating and photovoltaic electricity generation on 100,000 buildings around B.C.

PARTNERING FOR SUCCESS
Since 2003, the Province of B.C. has partnered in the construction of $158 million in new oil and gas road and pipeline infrastructure. The Sierra Yoyo Desan Road public private partnership improved the road allowing year round drilling activity in the Greater Sierra natural gas play. The project was recognized with the Gold Award for Innovation and Excellence from the Canadian Council for Public Private Partnerships in 2004.

ENERGY EFFICIENT BUILDINGS: A PLAN FOR BC
This strategy will lower energy costs for new and existing buildings by $127 million in 2010 and $474 million in 2020, and reduce greenhouse gas emissions by 2.3 million tonnes in 2020. The Province is implementing ten policy and market measures in partnership with the building industry, energy consumer groups, utilities, non-governmental organizations, and the federal government.



For more information on
The BC Energy Plan:
A Vision for Clean Energy Leadership, contact:

Ministry of Energy, Mines and Petroleum Resources
1810 Blanshard Street
PO Box 9318 Stn Prov Govt
Victoria, BC V8W 9N3

250.952.0241

www.energyplan.gov.bc.ca

BRITISH COLUMBIA
The Best Place on Earth

Ministry of
Energy, Mines and
Petroleum Resources

Attachment 4.1

MIDGARD
CONSULTING INC.

2011 FortisBC Energy & Capacity Market Assessment

Submitted By: Midgard Consulting Inc.

Date: May 26, 2011

Midgard Consulting Inc
+1 (604) 298 4997
midgard-consulting.com
4065 Edinburgh Street
Burnaby BC, Canada
V5C 1R4

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1 Executive Summary

FortisBC Inc. ("**FortisBC**") has retained Midgard Consulting Inc. ("**Midgard**") to assess the future outlook of the electricity markets in BC and surrounding areas and forecast the cost and availability of energy and capacity products accessible to FortisBC.

FortisBC is a regulated electric utility serving approximately 161,000 customers in the southern interior of British Columbia. In 2010 it sold 3,046,000 MWh of electricity to its customers, of which approximately half (1,530,000 MWh) came from the energy entitlements of its four hydroelectric generating facilities on the Kootenay River. Peak demand in 2010 was 707 MW, 223 MW of which was met by the four Kootenay River facilities[1].

FortisBC's service area peak system loads have exceeded the utility's reliable capacity resources since the 1990s. At that time it was both economical and reliable to address the relatively minor capacity gaps with market purchases. Since then the service area loads have grown significantly and the winter peak capacity gap presently exceeds 140 MW[2]. During this period historical regional capacity surpluses have eroded and regional transmission has become more constrained. Market prices have increased, as has market price volatility, especially during extreme regional weather conditions.

The recent acquisition of surplus capacity from the Waneta Expansion ("**WAX**") Project will satisfy FortisBC's capacity deficit after the project is commissioned in 2015. The WAX capacity is provided under the terms of the Canal Plant Agreement. FortisBC has acquired contractual capacity rights from Powerex to satisfy its capacity requirements in the interim.

The measures mentioned in the previous paragraph addresses FortisBC's capacity requirements in the medium term however they do not fully address immediate or long term capacity needs. As well, the measures do not address FortisBC's energy gaps in the short, medium, or long term (see Sections 3.2 and 3.4). FortisBC will choose to fill these gaps either by purchasing energy and/or capacity from the wholesale market, or by causing the construction of a new generation facility (referred to within this analysis as the new resources market).

1.1 Cost of Energy and Capacity in British Columbia

British Columbia is an integral member of the Western Electricity Coordination Council ("**WECC**"). Key factors influencing the traded price of electricity in the WECC region and consequently the electricity markets of British Columbia include the amount of annual precipitation in the region, the price of natural gas and regional transmission constraints. An abundance of precipitation, low natural gas prices, and

[1] FortisBC 2010 Annual Information Form

[2] Based upon the December 2011 peak load forecast and pre-Waneta Expansion Capacity Purchase Agreement (WAX CAPA) resource stack. The interim capacity purchase from Powerex arranged as part of the WAX CAPA has now addressed most of this gap.

lack of transmission constraints will lead to lower overall power prices in WECC while low precipitation levels, high natural gas prices and an abundance of transmission constraints push power prices higher.

The wholesale electricity market in British Columbia has a limited number of buyers and sellers and as a consequence wholesale pricing in the province essentially amounts to the wholesale prices for the Mid-Columbia ("**Mid-C**") market adjusted to take into account the costs of moving electricity into BC. Conversely, the pricing of the new resources market in the Province is derived by estimating the energy or capacity price that would be necessary to incent the construction of a new generation facility.

Figure 1.1-A graphs the forecast BC Wholesale Market Energy Curve against the BC New Resources Market Energy Curve, while Figure 1.1-B graphs the forecast BC Wholesale Market Capacity Curve against the BC New Resources Market Capacity Curve.

Figure 1.1-A: BC Wholesale Market Energy Curve vs. the BC New Resources Market Energy Curve

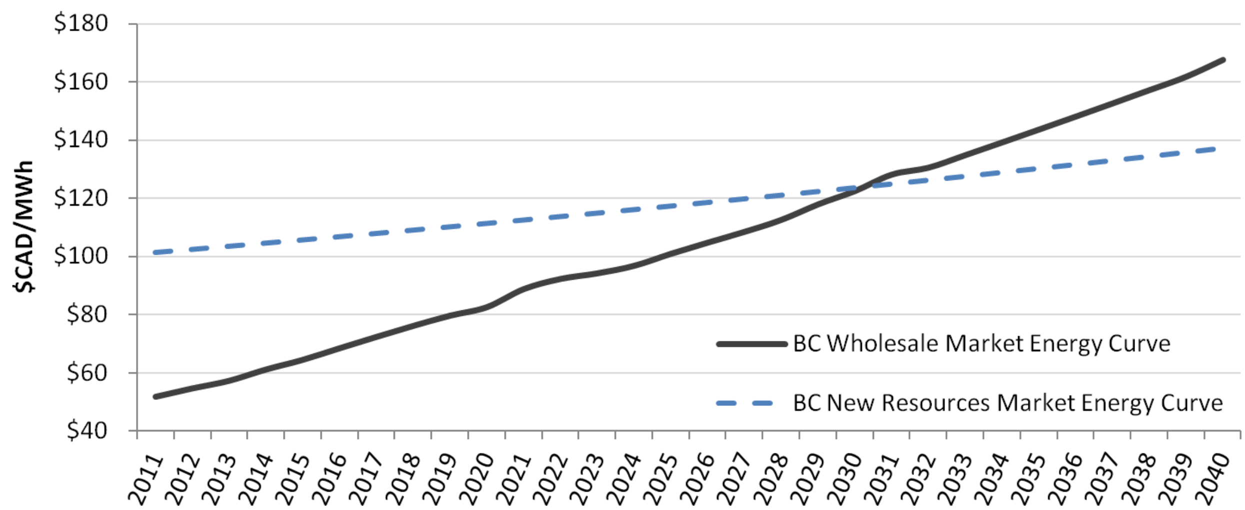
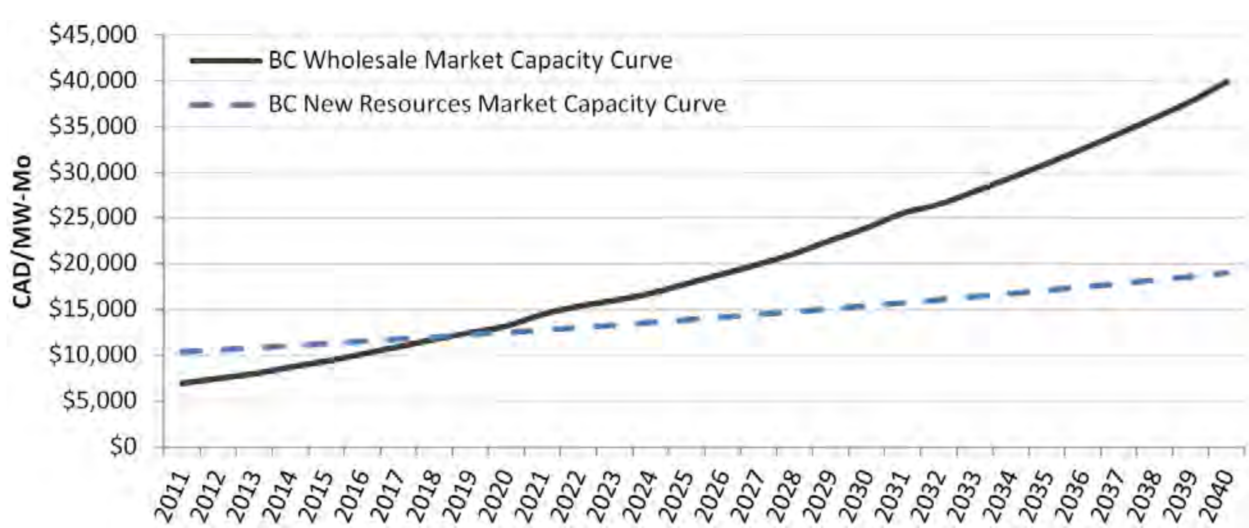


Figure 1.1-B: BC Wholesale Market Capacity Curve vs. BC New Resources Market Capacity Curve



1.2 WECC Trends Influencing the Wholesale and New Resources Markets

The market for energy and capacity in western North America is undergoing significant change, much of which is related to the integration of renewable generation resources into the grid. Table 1.2-A summarizes the potential impacts of key trends on the wholesale market and new resources market of British Columbia.

Table 1.2-A: Potential Impacts of Market Trends on BC Markets

WECC Market Trend	Wholesale Market	New Resources Market
Renewable Portfolio Standards & Additional Intermittent Resources	Risk to supply-certainty; risk of higher wholesale capacity prices	Limited impact
Demand Side Management Programs	Limited risk to supply certainty	Limited impact, but potential upward price pressure in long-term
Delays in New Transmission Construction	Risk to supply certainty; risk of higher wholesale market prices	Potential impact, resulting in upward price pressures
Clean Energy Act: • ***Generation Surplus*** • ***Export Mandate***	Potential positive impact for FortisBC / BC Wholesale Market energy and capacity buyers	Potential upward price pressures in medium-term
Alberta Market – Current State	Price risk and supply-certainty risk	Limited impact

1.3 Summary Conclusions

Midgard concludes as follows:

- FortisBC's continued reliance upon the wholesale electricity market to meet current and future needs is not an unreasonable strategy - especially in light of the modest sizes of FortisBC's energy and capacity deficits.
  - BC Wholesale Energy Market prices are projected to remain less expensive than comparable BC New Resources Market Energy prices until approximately 2030.
  - BC Wholesale Capacity Market prices for capacity products are projected to remain less expensive than comparable BC New Resources Market Capacity prices until approximately 2019.
- Overall market trends in the WECC region – chiefly renewable portfolio standards ("**RPS**"), DSM and the current state of the Alberta electricity market – are of a greater threat to the price and supply availability of capacity and energy in the wholesale markets than they are to the price and supply availability of energy and capacity from the new resources markets. Meanwhile, the impact of transmission delays and the BC *Clean Energy Act* are more ambiguous for both the wholesale

and new resources markets; they appear to have the potential to improve the relative cost competitiveness of the BC Wholesale Markets over the BC New Resources Markets.

- The BC New Resources Capacity Market is less expensive than the BC Wholesale Capacity Market when longer term transactions are evaluated. Up*ward price press*ures and product availability concerns in both the wholesale market energy and wholesale market capacity markets make new resources more competitive on a long term basis.

2 Introduction

FortisBC Inc. ("**FortisBC**") engaged Midgard Consulting Inc. ("**Midgard**") to perform a 30 year assessment of the electricity market in British Columbia. Midgard will also evaluate the relative risk of competing procurement strategies in the context of FortisBC's future energy and capacity needs.

The report contains the following deliverables:

1. British Columbia Wholesale Market Energy (electricity[3]) forecast curve
2. British Columbia New Resources Market Energy (electricity) forecast curve
3. British Columbia Wholesale Market Capacity forecast curve
4. British Columbia New Resources Market Capacity forecast curve
5. Natural Gas forecast price curve
6. Greenhouse Gases forecast price curve

[3] Throughout the analysis, the term energy is defined as the electricity produced or used over a period of time, usually measured in KWh, MWh, or GWh.

3 Background on the Energy and Capacity Needs of FortisBC

FortisBC is a regulated electric utility serving approximately 161,000 customers in the southern interior of British Columbia. In 2010 it sold 3,046,000 MWh of electricity to its customers, of which 1,530,000 MWh came from the energy entitlements of its four hydroelectric generating facilities on the Kootenay River. Peak demand in 2010 was 707 MW, 223 MW of which was provided by the four Kootenay River facilities. FortisBC also owns a transmission and distribution network consisting of 1,400 km of high voltage transmission lines, 5,600 km of distribution lines and 64 substations[4].

As a member of Western Electricity Coordinating Council ("**WECC**"), FortisBC can, theoretically, draw upon a large wholesale electricity market to help serve its load requirements. Energy and capacity are available in the WECC market from various utilities and independent power producers that have surplus power available for sale or exchange. These surpluses are typically the result of either the load demand not being as high as forecast or the supplies of electricity being higher than forecast and/or higher than needed. Additionally, energy may be procured from non-utility generation asset owners who have under-utilized generation capacity and available fuel.

The WECC region is a dual peaking electricity system, with the south peaking in the summer and the north peaking in the winter. FortisBC is primarily concerned about the availability and cost of energy and capacity during the winter months when FortisBC experiences its peak demand.

Surplus power is typically available in BC and the Pacific Northwest ("**PNW**") during the spring freshets (high river flows due to thaws and precipitation) and/or during years of above-average precipitation. Some utilities, with BC Hydro being the most prominent, can store energy in their hydroelectric reservoirs and for the right price are usually able to provide power to the market at any time.

3.1 Differentiating Between Energy and Capacity

The difference between energy and capacity is important to understand and key to thinking about the requirements of a utility. Put simply, energy is the consumable and capacity is the assurance that the consumable is available as and when required.

In practice, it is often impractical to completely separate energy from capacity since any agreement to procure energy will include provisions addressing the delivery of the energy.

To the extent the energy is delivered at a time, rate and place of the buyer’s preference, it inherently includes capacity characteristics. In other words, if the buyer dictates how much energy it receives and where and when it receives that energy then in the act of buying, the buyer has purchased capacity by having bought ‘the assurance’ that the consumable is available as and when required.

[4] FortisBC 2010 Annual Information Form

Similarly, to the extent that energy is delivered at the seller's discretion (time, rate & place), the product will be characterized as an energy only product with poor capacity characteristics (i.e. energy that cannot be reliably called upon when needed). An energy product that is not reliably available for the buyer's use to meet actual demand will not be as valuable to that buyer as an energy product with embedded capacity characteristics[5].

FortisBC obtains most of its capacity and energy through a combination of self-supply, long term power purchase agreements and other contractual arrangements including the Canal Plant Agreement[6]. In this report, these sources of capacity and energy are considered FortisBC resources.

After reaching the limits of its own resources, FortisBC covers its energy and capacity shortfalls with purchases from the wholesale electrical energy market. Generally, wholesale electrical energy market purchases are done by buying power in the spot market or through buying blocks of guaranteed delivered power (or 'firm power').

As described in Sections 3.2 and 3.3, FortisBC is facing both energy gaps and capacity gaps in the coming 30 years. This energy market analysis pays particular attention to the winter peak months, those months which are deemed to be the highest demand months for the northern portion of the WECC region and are therefore of greater importance to FortisBC.

3.2 FortisBC Energy Outlook

FortisBC is expected to require small but increasing amounts of new energy supplies over the coming three decades. The energy requirements are anticipated to grow by approximately 11 GWh per annum from a starting point of 5 GWh in 2011 to a gap of 311 GWh by 2040. FortisBC's energy load is expected to outpace its available resources at a rate outlined in Table 3.2-A. It is important to note that this forecast includes the effects of expected demand side management ("**DSM**") programs.

[5] BC Hydro's recent Clean Power Call contracts include provisions to ensure that BC Hydro pays a different price for the energy that is certain to be delivered (firm energy) and the energy that is not certain to be delivered (non-firm energy). The price differential between the firm energy and the non-firm energy is approximately $75-100/MWh higher for the firm energy than for non-firm energy.

[6] Under the Canal Plant Agreement, FortisBC is permitted to instruct BC Hydro to provide delivery of energy at a time of FortisBC's choosing, subject to certain capacity limitations – namely how much energy can be delivered in a given hour.

Table 3.2-A: Forecast FortisBC Energy Gap by Year (GWh)

Year	Energy Gap	Year	Energy Gap	Year	Energy Gap
2011	5	2021	46	2031	180
2012	9	2022	58	2032	195
2013	9	2023	69	2033	210
2014	12	2024	82	2034	224
2015	5	2025	95	2035	239
2016	6	2026	107	2036	253
2017	9	2027	120	2037	268
2018	14	2028	135	2038	282
2019	25	2029	151	2039	296
2020	35	2030	167	2040	311

3.3 FortisBC Capacity Outlook

Similar to energy, FortisBC faces capacity shortfalls over the next three decades. Until 2014 FortisBC faces expected capacity gaps of up to 107 MW in the summer (July 2014) and 125 MW in the winter (March 2014) (see Table 3.3-A).

After the Waneta Expansion Capacity Purchase Agreement comes into effect in 2015, FortisBC's expected peak summer and winter capacity gaps essentially fall to zero. The summer gap grows from 4 MW in 2015 to 112 MW in 2040. The winter gap remains at zero until 2017, but then expands at approximately 10 MW per year, reaching 223 MW in 2040. It is important to note that these forecasts take into account both the effects of DSM as well as FortisBC's planning reserve margin requirements.

Table 3.3-A: Forecast FortisBC Capacity Gaps By Month and Year (MW)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2011	4	39	101	0	0	34	84	36	0	29	40	74
2012	14	47	108	4	0	40	91	43	0	35	48	85
2013	24	56	117	11	0	47	100	50	0	43	58	96
2014	34	64	125	17	0	53	107	57	0	49	66	106
2015	0	0	1	0	0	4	0	0	0	0	0	0
2016	0	0	0	0	0	6	0	0	0	0	0	0
2017	0	0	0	0	0	9	0	0	0	0	0	2
2018	0	0	0	0	0	12	0	0	0	0	0	13
2019	0	0	0	0	0	16	0	0	0	0	0	23
2020	0	0	0	0	0	20	0	0	0	0	0	34
2021	0	0	0	0	0	24	0	0	0	0	0	45
2022	0	0	0	0	0	28	0	0	0	0	0	56

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2023	0	0	0	0	0	32	0	0	0	0	0	67
2024	6	0	0	0	0	36	3	0	0	0	0	79
2025	17	0	0	0	0	41	11	0	0	0	0	90
2026	27	0	0	0	0	45	18	0	0	0	0	101
2027	37	0	0	0	0	49	26	0	0	0	0	113
2028	48	0	0	0	0	54	34	0	0	0	0	125
2029	59	0	0	0	0	58	42	0	0	0	0	136
2030	69	0	0	0	0	62	50	0	0	0	0	147
2031	78	0	0	0	0	66	57	0	0	0	0	156
2032	89	0	0	0	0	70	65	0	0	0	0	164
2033	99	0	0	0	0	74	72	0	0	0	0	171
2034	109	7	0	0	0	78	80	0	0	0	0	179
2035	118	15	3	0	0	82	87	0	0	0	0	186
2036	128	23	11	0	0	86	92	0	0	0	0	194
2037	138	31	19	0	1	90	97	0	0	0	0	201
2038	148	39	27	0	4	94	102	0	0	0	0	208
2039	155	47	34	0	8	98	107	0	0	0	7	216
2040	161	55	42	0	11	102	112	0	0	0	16	223

4 Fundamentals of Market Pricing in the WECC Region

This section discusses the Western Electricity Coordinating Council region and factors that influence the price of WECC traded electricity.

4.1 Western Electricity Coordinating Council

As its website reports, WECC is the "…Regional Entity responsible for coordinating and promoting bulk electric system reliability in the Western Interconnection…(and) is geographically the largest and most diverse of the eight Regional Entities that have Delegation Agreements with the North American Electric Reliability Corporation ("**NERC**"). WECC's service territory extends from Canada to Mexico...(including) the provinces of Alberta and British Columbia, the northern portion of Baja California, Mexico, and all or portions of the 14 Western states between. Due to the vastness and diverse characteristics of the region, WECC and its members face unique challenges in coordinating the day-to-day interconnected system operation and the long-range planning needed to provide reliable electric service across nearly 1.8 million square miles."[7]

In 2010, the Total Internal Demand[8] (or coincidental peak demand) for the WECC region was 148,000 MW[9] while the available generation was 184,000 MW; annual energy use is projected at 863,355 GWh for 2010[10]. WECC is a dual peaking system, with the southern region experiencing peak demand during the summer months, and the northern region, which includes British Columbia, Alberta and the Pacific Northwest, experiencing peak demand during the winter months.

Within WECC, the two most heavily traded electricity hubs are SP-15 and Mid-Columbia ("**Mid-C**")[11]. SP-15 is the electricity trading hub for Southern California; Mid-C the trading point for the Pacific Northwest.

The composition of generation within WECC is characterized by large amounts of thermal generation (coal and natural gas fired generation), nuclear generation, and significant hydroelectric generation capacity. In recent years, the quantity of renewable generation, particularly wind generation, has grown appreciably.

[7] http://www.wecc.biz/About/Pages/default.aspx

[8] "Total Internal Demand is the sum of the metered (net) outputs of all generators within the system and the metered line that flows into the system, less the metered line that flows out of the system. Total Internal Demand includes adjustments for indirect Demand-Side Management programs such as conservation programs, improvements in efficiency of electric energy use, and all non-dispatchable demand response programs."

[8] North American Electric Reliability Corporation, 2010 Long-Term Reliability Assessment, October 2010, page 28, Table 4.

[9] North American Electric Reliability Corporation, 2010 Long-Term Reliability Assessment, October 2010, page 267

[10] North American Electric Reliability Corporation, 2010 Long-Term Reliability Assessment, October 2010, page 272

[11] Federal Energy Regulatory Commission, 2008 State of the Markets Report, August 2009, page 54

4.2 Market Forecasting

In a market where electricity is traded, the prices are set by the marginal cost of the last megawatt hour that was produced in order to meet the load requirement at that point in time. That marginal cost determines the clearing price in the marketplace.

The marginal cost of electricity generated from a natural gas fired generator is typically more expensive than the comparable cost of electricity from a nuclear or coal-fired plant. Load demand frequently rises during on-peak periods to a level where the output of natural gas generation facilities is required and that in turn determines the marginal cost of electricity in the wholesale market. Consequently, market electricity prices (especially on-peak prices) in WECC and across much of North America are strongly correlated to the price of natural gas that is fuelling that electrical generation.

During low demand periods, such as daily off-peak hours or certain days during the spring and fall seasons, the marginal cost of electricity will be determined by the marginal cost of base load generation. Base load generators include nuclear generators and coal-fired generators that produce power at a low marginal cost and are designed to be operated at or near their full output all hours of the day and night.

Intermittent generators such as wind, run-of-river (or must-run) hydro and solar fueled generation facilities are price takers. They sell their generation into the marketplace regardless of prevailing market prices because their fuel is ‘free’. Their intermittent nature means that regardless of market price they will generate when they have fuel - wind, water or sun - and will not generate when they do not have fuel. They are never considered to be the marginal cost assets for forecasting purposes. However, during times of abundant intermittent generation, such as during spring freshet or optimal wind conditions, the quantity of power produced will depress market prices since the marginal cost of electricity generated will be determined by the base load generators, rather than higher cost natural gas generators.

Hydroelectric assets will either behave as price takers - as described in the previous paragraph - or will ’shadow price‘ the highest marginal cost generation asset at the time of production. Shadow pricing is defined as the pricing of the generation at or just below the highest cost generation asset expected to be dispatched. Asset owners shadow price in order to capture the highest expected profit margin.

Other smaller generation technologies like biomass and geothermal do not represent a large enough source of energy to influence the forecast market price for electricity in the WECC region.

Transmission is required to move power from one location within the WECC region to another. The cost of transmission to get power from a generator to a trading point and from a trading point to the point of delivery adds to the price of electricity at the specified point of delivery (e.g. FortisBC territory). During certain times of year, such as extreme weather events in July or January, the transmission system can become fully utilized, at which point in time a transmission constraint is created. These transmission constraints force the constrained sub-region’s load demands to be met by a limited number of alternative electrical sources (that still have unconstrained transmission access to the load). The impact of transmission constraints is often to increase the market clearing price of electricity within the sub-region.

Forecasts of future electricity prices in the WECC region and sub-regions must account for the following key factors:

- Hydrology
- Natural Gas Prices
- Transmission Availability (to facilitate intra-regional energy trade).

4.2.1 Precipitation (Hydrology)

Over 30% of the generating capacity in the WECC region is hydroelectric generation and almost 55% of its northern region's generation capacity is fueled by water[12]. There are multiple major river basins in the WECC region that feed hydroelectric generation and, depending on precipitation levels, the amount of marketable energy available in a given year can vary dramatically in the different drainage basins. For example, BC Hydro's Heritage Hydro assets can experience annual generation variations of 10,000 GWh between BC's wettest and driest years (annual BC generation is approximately 60,000 GWh[13]). The variation in energy generated by the US Federal hydroelectric generation facilitates administered by Bonneville Power Administration (BPA) varies by approximately 24,500 GWh between the region's wettest and driest years (97,900GWh to 73,400 GWh)[14].

4.2.2 Natural Gas

Over 40% of the generating capacity in the WECC region is produced from either natural gas fired generation plants or dual fired generation plants (which typically use natural gas as the default fuel). Within the Pacific Northwest region, approximately 60% of merchant generation capacity is natural gas fuelled (see Table 4.2.2-A)[15]. A merchant plant owner will sell to the market when the market price of electricity will cover or exceed the variable cost of production; that cost is primarily dependent on the cost of natural gas and the plant's efficiency (heat rate) but also includes secondary non-fuel cost items like operating and maintenance costs (e.g. shut down / start up costs, overhaul costs etc.).

[12] North American Electric Reliability Corporation, 2009 Long-Term Reliability Assessment, October 2009, page 139 & 156

[13] BC Hydro, 2011 IRP Technical Advisory Committee Summary Brief: Exports, January 2011, page 1

[14] Bonneville Power Administration, 2010 Pacific Northwest Loads and Resources Study, May 2010, page 32, Table 6

[15] Bonneville Power Administration, 2010 Pacific Northwest Loads and Resources Study, May 2010, page 63, Table 15

Table 4.2.2-A: Expected Uncommitted PNW IPP[16] Resources

Project	Peak (MW)	% Total Peak	Energy (GWh)	% Total Energy	Fuel Type
Big Hanaford CCCT	248	6.9%	1964	7.1%	Natural Gas
Hermiston Power Project	630	17.4%	4979	17.9%	Natural Gas
Klamath Cogeneration Project	484	13.4%	3822	13.7%	Natural Gas
Klamath Peaking Unit	100	2.8%	123	0.4%	Natural Gas
Satsop	650	18.0%	5128	18.4%	Natural Gas
SP Newsprint Cogen	104	2.9%	912	3.3%	Natural Gas
Natural Gas Subtotal	**2216**	**61.3%**	**16927**	**60.8%**	
Centralia #1	670	18.5%	5487	19.7%	Coal
Centralia #2	670	18.5%	4856	17.4%	Coal
Coal Subtotal	**1340**	**37.1%**	**10344**	**37.1%**	
Sierra Pacific Aberdeen (Sierra Pacific)	15	0.4%	123	0.4%	Wood Waste
Weyerhaeuser Longview (Weyerhaeuser)	44	1.2%	307	1.1%	Wood Waste
Wood Waste Subtotal	**59**	**1.6%**	**430**	**1.5%**	
Star Point	0	0.0%	140	0.5%	Wind
White Creek Wind (1.5%)	0	0.0%	9	0.0%	Wind
Wind Subtotal	**0**	**0.0%**	**149**	**0.5%**	
Total	**3615**	**100.0%**	**27849**	**100.0%**	

4.2.3 Transmission Availability and Constraints

As noted WECC is a dual peaking system with seasonal demand diversity; the southern portion of WECC is summer peaking and the northern portion is winter peaking. This dual peaking system with demand diversity means that power flows tend to be from north to south during the summer months and south to north during winter months. Given these transfer patterns it is common that these summer and winter peaks result in regional or localized transmission constraints. For example, during the summer months when freshet energy is abundant in the Pacific Northwest and the economic dispatch of this energy to the southern and southwestern WECC regions makes sense, total southbound transmission is constrained at several key points, notably the California-Oregon border[17]. Numerous other constraints occur

[16] Independent Power Producer

[17] North American Electric Reliability Corporation, 2010 Long-Term Reliability Assessment, October 2010, page 275

throughout the WECC region, including localized constraints both within British Columbia as well as between British Columbia and its neighbours, Alberta and the US[18].

Seasonal North-South transmission constraints can be amplified by extreme weather events such as an extended cold snap in the north during the winter peak. During a cold snap, local hydroelectric assets typically do not produce enough energy to satisfy sub-regional needs and additional energy is imported from the south, potentially creating transmission constraints.

In response to emerging renewable portfolio standards (and generous US tax incentives), substantial amounts of intermittent generation are being built in the WECC region. Because these intermittent generation resources are primarily energy sources characterized by poor capacity attributes, local balancing authorities and utilities will be required to introduce measures to effectively manage them. These measures may include tapping into existing capacity resources to firm the energy produced by intermittent generation resources[19]. The need to retain and access additional capacity resources will likely change historical transmission flow patterns and potentially create new transmission constraints.

Although additional transmission has been added in recent years in WECC, and further additions are planned for the coming decade, north-south transmission constraints are expected to persist in both directions for the foreseeable future, dependent upon the season and the sub-regional electrical supply/demand balances.

4.3 Competition with Neighbouring Jurisdictions

The FortisBC service territory abuts BC Hydro service territory, which in turn interconnects with Alberta and the US Pacific Northwest. The transmission transfer limit at the three interconnections on the British Columbia / United States border[20] and at the two interconnections on the British Columbia / Alberta border are:

- British Columbia / United States: 2,000 MW northbound into British Columbia and 3,150 MW southbound into the United States. These limits reflect the combined capability of the two 500 kV lines between BC Hydro's Ingledow substation and Bonneville Power Administration's Custer substation, and the two 230 kV lines between Boundary and Nelway near Trail, BC.

- British Columbia / Alberta: 1000 MW westbound into British Columbia and 1200 MW eastbound into Alberta. These limits reflect the combined capability of two 138 kV lines and one 500 kV line connecting the Alberta and BC Hydro integrated systems. In practice, the transfer capabilities with Alberta are far lower (approximately half) due to transmission constraints within Alberta[21].

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[18] As part of their Integrated Resource Plan, BC Hydro is examining transmission requirements to facilitate export activities.

[19] North American Electric Reliability Corporation, 2010 Long-Term Reliability Assessment, October 2010, page 279

[20] Includes the one merchant transmission line owned by Teck Metals at Trail, BC.

[21] Alberta Electric System Operator, AESO Long-term Transmission System Plan, 2009, Appendix H, page 303

Both the British Columbia / Alberta[22] and the British Columbia / United States interconnections are often at their maximum transmission limit, which means wheeling additional power between utilities in the region is frequently not possible. Given that the key source of external (non-BC) wholesale market electricity for FortisBC is the United States, these constraints are a potential problem for FortisBC because they restrict access to the energy and capacity from the US market. As electricity demand continues to grow, absent sufficient new transmission infrastructure, transmission constraints between British Columbia and the United States will become ever more restrictive.

Figure 4.3-A illustrates that the summer peak demand and winter peak demand periods in the Pacific Northwest coincides with the demand peaks within FortisBC territory. This coincidence of demand peaks is of particular interest during the winter peak because during extreme regional weather events, such as an extended cold period, both FortisBC and the Pacific Northwest region would seek additional power supplies to meet their increased local demands. As a result it is reasonable to expect that FortisBC will be in competition with nearby regions for both energy supplies and transmission capacity during such peak demand periods.

Figure 4.3-A: Projected Loads in the FortisBC and PNW Regions

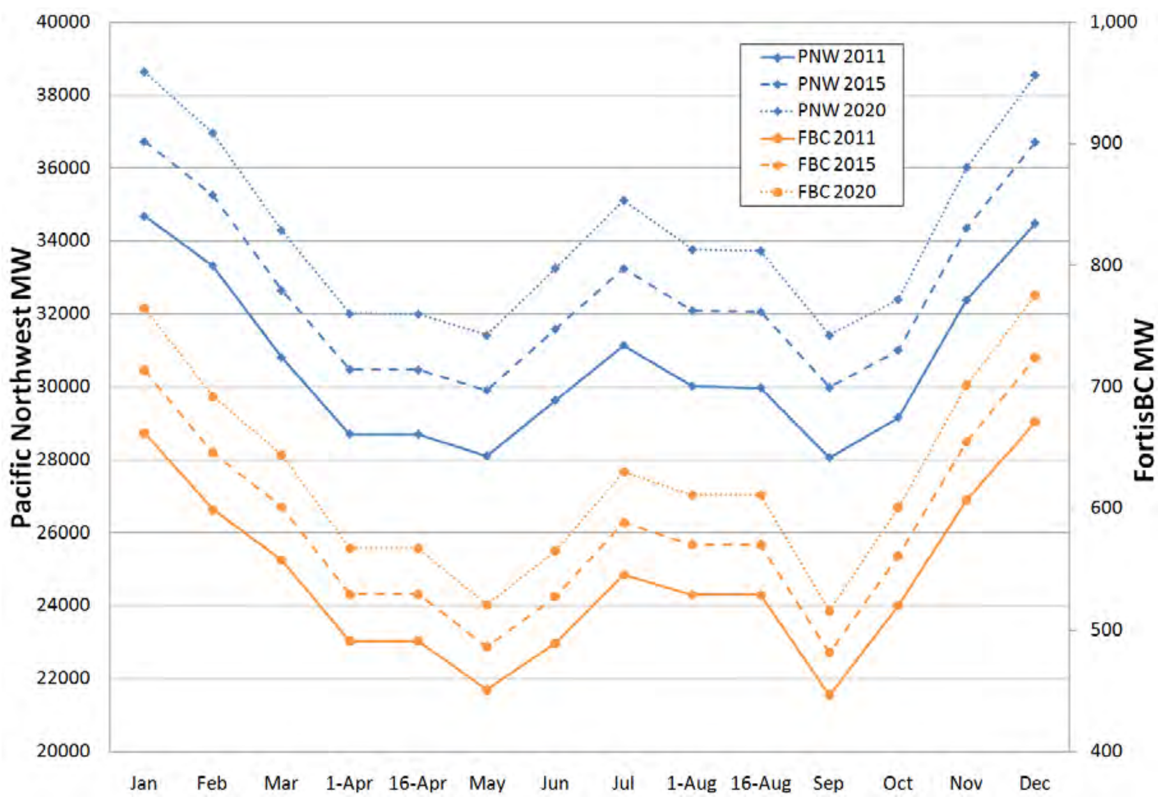


Figure 4.3-A also shows that the forecast monthly loads for the PNW region and for FortisBC will continue to grow into the future, resulting in increased competition for generation and transmission resources. This

[22] The current Alberta market situation will be discussed in more detail in Section 7 – Market Trends

potential scarcity of accessible energy is further illustrated in Figure 4.3-B[23], which shows the trend towards a deficit of one hour capacity resources in the Pacific Northwest region. In the 2011 operating year, the Pacific Northwest region has a forecast surplus one hour capacity but by the 2020 operating year the region is forecast to be in a deficit position during both the winter peak and summer peak months. Moving from surplus to deficit implies that during critical winter peak and summer peak months the Pacific Northwest region will move from a potential net source of one hour capacity to a net consumer of one hour capacity, thus becoming a competitor to FortisBC.

Figure 4.3-B: Projected Pacific Northwest Trends in 1-Hour Capacity Surplus/Deficit

[23] Bonneville Power Administration, 2010 Pacific Northwest Loads and Resources Study, May 2010, pg 66

5 British Columbia Energy Market Analysis

FortisBC has two broad alternatives they can employ to address their forecast energy shortfalls:

1. **BC Wholesale Market Energy Purchases**: FortisBC can continue to purchase energy in the wholesale electricity market as it has historically done in recent years.
2. **New Resource Market Energy**: FortisBC could contract for new generation resources either by developing and constructing a new generation resource that is owned and operated by FortisBC, or by entering into a long term Power Purchase Agreement[24] with a third party to supply FortisBC energy from a new generation resource.

This section will discuss the BC Wholesale Market Energy prices relevant to FortisBC, the forecast market price for new resources in BC, and then compare the two energy price curves.

5.1 BC Wholesale Market Energy Analysis

Pricing of BC Wholesale Market Energy is influenced by the cost of electricity in neighbouring jurisdictions. The BC market has two immediate neighbours: Alberta to the east and the United States to the south. Because of the limited transmission linkages (see Section 4.3) between BC and Alberta relative to those between BC and the United States, Alberta's electricity market price curves play only a limited role in determining the expected cost of energy (and capacity) in British Columbia. As a result, in this report it is the Mid-Columbia electricity market and not the Alberta market that serves as the primary driver for forecast wholesale electricity prices in BC.

5.1.1 Mid-Columbia Electricity Market

The Mid-Columbia electricity market is one of the most important electricity trading hubs in North America and, as measured by volume on the Intercontinental Exchange, the third largest electricity trading point in the US and second largest in the WECC region[25]. FortisBC benefits from its proximity to this large liquid and price transparent Mid-C market and, if it chooses, is able to obtain market supplies of energy priced against the Mid-C index.

The Mid-C market is dominated by bilateral trading, which is generally the case throughout the WECC region. Mid-C has traditionally been influenced by large asset owning entities that engage in physical transactions of power, including BC Hydro in the form of Powerex, Bonneville Power Administration and other investor owned utilities. However, a growing quantity of the trading transaction volume in the electricity market is moving to the financial arena, typically the purview of banks and financial trading houses. This trend underpins the liquidity of the Mid-C market and expands the number of potential

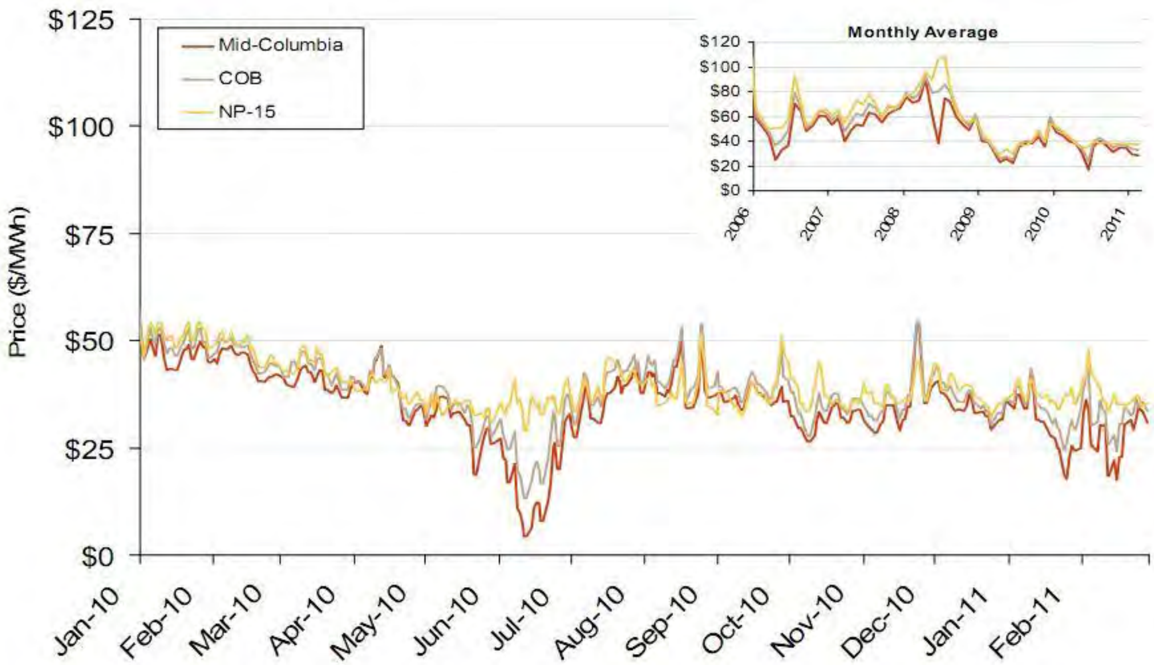
[24] It is common for the contract for new generation to have a term of 20 years or longer.

[25] Federal Energy Regulatory Commission, 2008 State of the Markets Report, August 2009, page 52

energy market counterparts with whom FortisBC could conduct business. In 2008, the volume of Mid-C financial transactions was larger than the volume of physical transactions[26].

Similar to most other electricity markets, electricity prices are prone to spiking during high demand periods, such as those induced by extreme weather events (e.g. a cold spell in December, or a heat wave in July), or during times of supply scarcity. Given the large quantity of hydro capacity in the WECC region in general, and the Pacific Northwest region in particular, a large freshet tends to depress electricity prices, while a drought boosts prices. Figure 5.1.1-A provides a snapshot of historical market prices and a sketch of the price volatility in the Mid-C market. Figure 5.1.1-A also shows the historical prices of the California-Oregon border (COB) electricity index as well as the Northern California (North Path 15 or NP-15) index, both of which are highly correlated to Mid-C.

Figure 5.1.1-A: Historical Mid-C Electricity Price (Daily and Monthly Averages)



Energy markets in general and electricity markets in particular have experienced substantial price volatility over the past decade. The most infamous bout of electricity price volatility in WECC occurred in 2000 and 2001 when California suffered a series of rotating blackouts and the western electricity market experienced unprecedented price spikes that were facilitated by factors including high natural gas prices, capacity shortages and transmission constraints.

The western transmission system continues to remain very constrained, and as growth returns to the economy and electricity demand rises, price volatility should continue to worry electricity buyers in the foreseeable future.

[26] Federal Energy Regulatory Commission, 2008 State of the Markets Report, August 2009, page 52, Figure 26

5.1.2 Mid-Columbia Forecast Price Curve

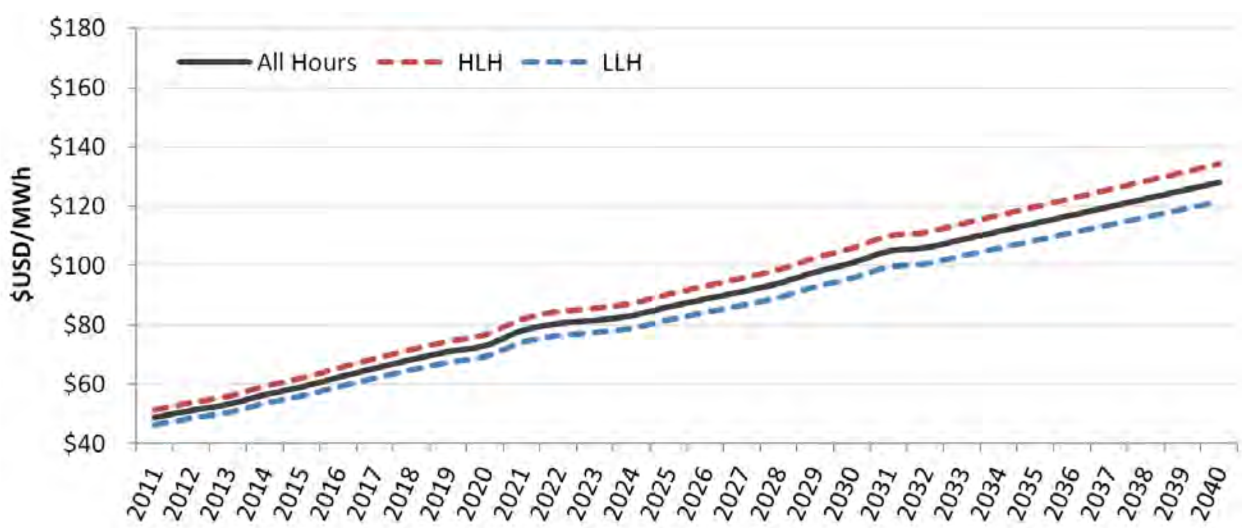
As part of their 2011 Integrated Resource Plan activities, BC Hydro established several projections for the Mid-C forecast price curve. Midgard used BC Hydro's "mid scenario" price curve as the basis for this report's Mid-C forecast price curve. For the years 2032 through 2040, Midgard extrapolated the forecast curve based upon the "mid scenario" price forecast for the years 2022 through 2031[27].

The BC Hydro Mid-C "mid-scenario" price forecast was constructed based upon the following key assumptions[28]:

- A "mid scenario" projected natural gas prices (discussed further in Appendix A)
- A "mid scenario" projected greenhouse gas prices (discussed in Appendix B)
- Projections of other project fuel costs, including coal and uranium
- A description of the architecture of WECC, the sub-regional demand forecasts and the transmission constraints.

Figure 5.1.2-A and Table 5.1.2-A shows the 30 year BC Hydro Mid-C forecast price curve[29]. The black line represents the all-hours price forecast, the red line represents the high-load hours price forecast and the blue line represents the low-load hours price forecast.

Figure 5.1.2-A: BC Hydro Mid-C Forecast Price Curve (30 Years) (USD)



[27] In Addition to the "mid scenario" Mid-C price forecasts, BC Hydro also published four other scenarios and their subsequent price forecasts. The scenarios combined various permutations of high, medium, and low price forecasts for natural gas and greenhouse gas prices. Midgard selected the "mid scenario" as the base case for the purposes of this report.

[28] BC Hydro, 2011 IRP Technical Advisory Committee Summary Brief: Electricity Spot Market Price Forecast, January 2011, page 2-3, and 2011 IRP Presentation to the Technical Advisory Committee, Meeting #2 – Day 1, January 2011

[29] Note that the years 2032 to 2040 of the Mid-C Forecast Price Curve were interpolated from the previous 10 years (2022-2031).

Table 5.1.2-A: BC Hydro Mid-C Forecast Price Curve (30 Years) (USD)

Year	Expected	HLH	LLH	Year	Expected	HLH	LLH
2011	$48.91	$51.31	$46.42	2026	$88.74	$93.10	$84.23
2012	$51.26	$53.78	$48.65	2027	$91.23	$95.72	$86.59
2013	$53.31	$55.93	$50.60	2028	$94.02	$98.64	$89.24
2014	$56.53	$59.31	$53.66	2029	$97.82	$102.63	$92.85
2015	$59.16	$62.07	$56.15	2030	$100.90	$105.86	$95.77
2016	$62.38	$65.45	$59.21	2031	$104.85	$110.01	$99.52
2017	$65.46	$68.68	$62.13	2032	$106.01	$111.23	$100.62
2018	$68.39	$71.75	$64.91	2033	$108.76	$114.11	$103.23
2019	$71.03	$74.52	$67.42	2034	$111.51	$116.99	$105.84
2020	$73.08	$76.67	$69.37	2035	$114.26	$119.88	$108.45
2021	$78.05	$81.89	$74.08	2036	$117.01	$122.76	$111.06
2022	$80.54	$84.50	$76.45	2037	$119.76	$125.64	$113.67
2023	$81.57	$85.58	$77.42	2038	$122.50	$128.53	$116.28
2024	$83.18	$87.27	$78.95	2039	$125.25	$131.41	$118.89
2025	$86.11	$90.34	$81.73	2040	$128.00	$134.30	$121.50

The high load hours ("**HLH**") and low load hours ("**LLH**") price forecasts were derived by multiplying the all-hours forecast price curve by 104.9% and 94.9% respectively. The HLH premium (and LLH discount) is the average of the monthly variations for HLH (and LLH) versus the annual mean forecast price. The monthly variation of Mid-C forecast prices versus the all hours annual forecast prices is detailed in Table 5.1.2-B[30].

[30] BC Hydro, 2011 IRP Presentation to the Technical Advisory Committee, Meeting #2 – Day 1, January 2011, page 86

Table 5.1.2-B: BC Hydro Monthly Mid-C Price Variations

Month	HLH Multiplier	LLH Multiplier
Jan	116%	105%
Feb	111%	102%
Mar	104%	96%
Apr	95%	89%
May	89%	81%
Jun	90%	82%
Jul	105%	91%
Aug	113%	97%
Sep	102%	94%
Oct	107%	95%
Nov	111%	101%
Dec	116%	106%
Average	**104.9%**	**94.9%**

For the purposes of this analysis, Midgard's Mid-C wholesale market forecast price curve is the exact same as the BC Hydro Mid-C Forecast Price Curve, as represented in Table 5.1.2-A. The forecast Mid-C wholesale market price curve is the starting point from which the BC Wholesale Market forecast price curve was generated.

5.1.3 Translating the Mid-C Forecast Price Curves to the BC Wholesale Market Energy

5.1.3.1 Forecast Curves

Midgard calculated the British Columbia Wholesale Market Energy Forecast Curve by taking the Mid-C Forecast Price Curve as the starting point, adding the cost of transmitting power from Mid-C to FortisBC territory, and then converting the resulting price into Canadian dollars.

5.1.3.2 Transmission Costs

The projected cost of transmitting a megawatt hour of electrical energy from Mid-Columbia to FortisBC territory is $1.917/MWh[31]. Midgard assumed that the transmission tariff will escalate in cost at 100% of CPI[32].

[31] Bonneville Power Administration, 2010 Transmission and Ancillary Service Rate (summary), October 2009, page 1

[32] The consumer price index - or CPI - utilized throughout this analysis is pegged at 2.1% per annum. Not coincidentally, this is the CPI projection commonly employed by BC Hydro.

In addition to the transmission tariff, the cost of moving electricity must also take into account the line losses. Line losses were forecast at 1.9%[33]. Midgard assumed that the transmission losses would remain constant for the 30 year period.

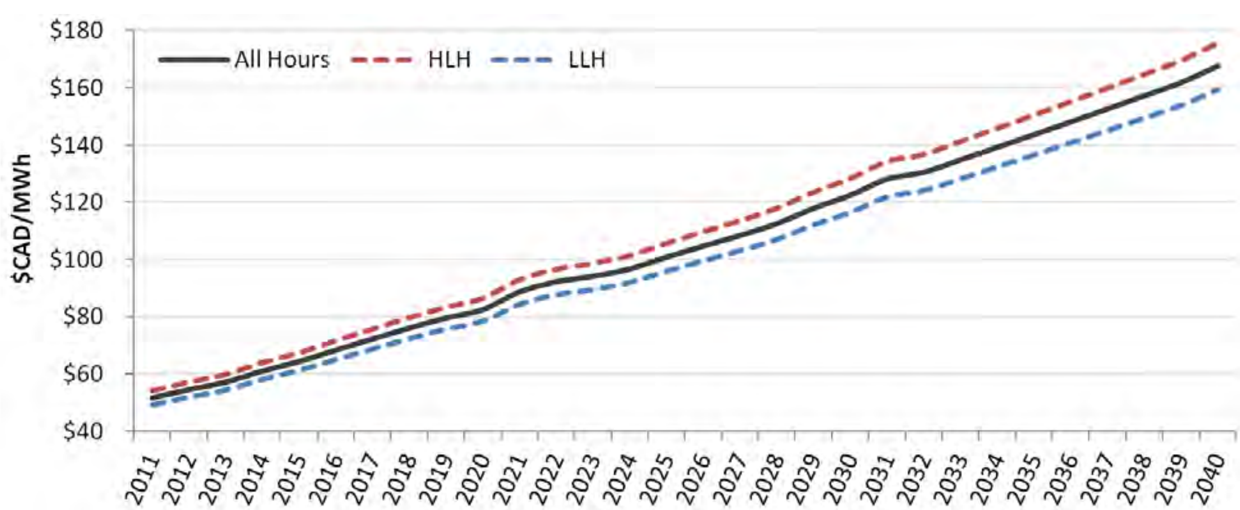
Midgard also assumed that the power would be delivered from the US to Teck Metals' Line 71 and then transmitted into FortisBC territory at no additional cost or charge to FortisBC. Teck Metals' Line 71 has a transmitting capacity of several hundred megawatts. Teck Metals does not use the line to import power and BC Hydro has no import transmission rights on the line. Consequently, Midgard has assumed that the transmission capacity on the line would be available unconstrained to FortisBC for imports of energy from the US.

5.1.3.3 Foreign Exchange Conversion

Midgard forecast the USD to CAD conversion rate as a linear trend starting at 1 USD = 1 CAD in 2011 and ending at 1 USD = 1.25 CAD in 2040. This foreign exchange conversion rate was employed to recognize the historical norm of the Canadian dollar trading at a discount to the US dollar. Midgard chose to represent this foreign exchange conversion forecast in a simplistic manner because a more elaborate foreign exchange forecast, in Midgard's opinion, would not significantly improve the validity of the final BC Wholesale Market Energy Curve.

The resultant British Columbia Wholesale Market Energy Curves (all hours, HLH, and LLH) are shown in Figure 5.1.3.3-A and Table 5.1.3.3-A.

Figure 5.1.3.3-A: BC Wholesale Market Energy Curves (CAD)



[33] Bonneville Power Administration, Open Access Transmission Tariff, August 2010, Schedule 9 "Real Power Loss Calculation"

Table 5.1.3.3-A: British Columbia Wholesale Market Energy Curve (CAD)

Year	Expected	HLH	LLH	Year	Expected	HLH	LLH
2011	$51.79	$54.24	$49.26	2026	$104.73	$109.73	$99.56
2012	$54.68	$57.27	$52.00	2027	$108.45	$113.63	$103.09
2013	$57.30	$60.01	$54.49	2028	$112.55	$117.93	$106.99
2014	$61.18	$64.08	$58.17	2029	$117.90	$123.53	$112.07
2015	$64.49	$67.55	$61.32	2030	$122.45	$128.31	$116.40
2016	$68.47	$71.73	$65.11	2031	$128.10	$134.23	$121.77
2017	$72.36	$75.81	$68.80	2032	$130.48	$136.72	$124.03
2018	$76.15	$79.77	$72.40	2033	$134.80	$141.25	$128.13
2019	$79.67	$83.46	$75.74	2034	$139.16	$145.82	$132.28
2020	$82.59	$86.52	$78.52	2035	$143.58	$150.45	$136.47
2021	$88.77	$93.00	$84.39	2036	$148.04	$155.12	$140.72
2022	$92.27	$96.68	$87.72	2037	$152.55	$159.85	$145.00
2023	$94.19	$98.68	$89.54	2038	$157.11	$164.63	$149.34
2024	$96.78	$101.40	$92.00	2039	$161.73	$169.47	$153.72
2025	$100.90	$105.72	$95.92	2040	$167.50	$175.52	$159.22

5.2 BC New Resources Market Energy Analysis

The alternative approach to procuring energy in the BC Wholesale Market is to self supply (or contract with a third party) to provide energy from a newly constructed generation resource.

BC Hydro has been actively procuring new generation resources from independent power producers ("**IPPs**") for the past decade. As such, the cost and conditions of competitive new generation procurement can be rationally forecast because activity over the past decade has created a well-developed IPP industry in BC with market tested pricing.

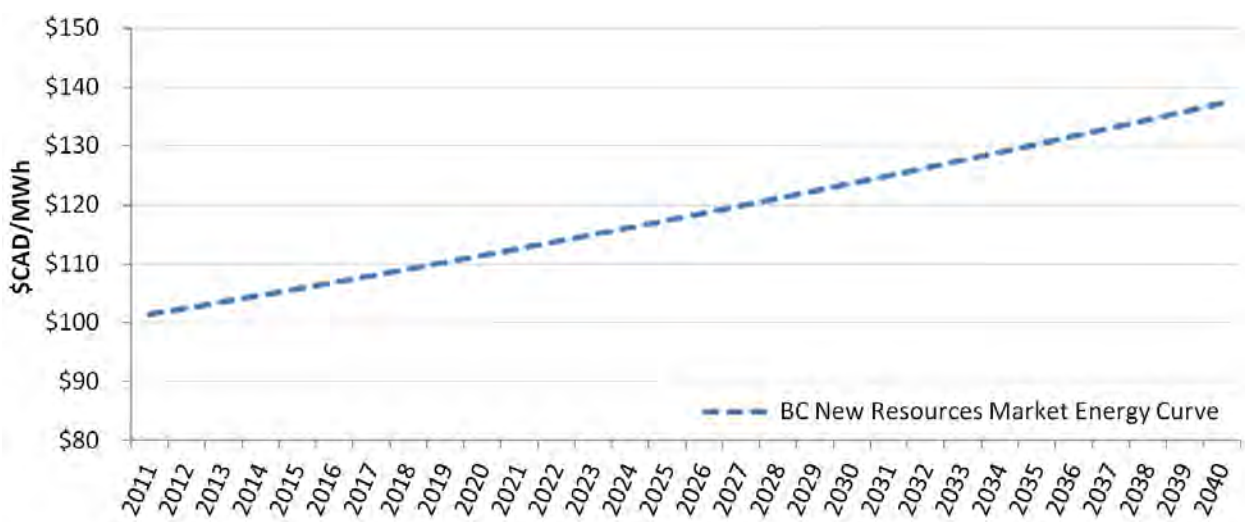
At present, BC Hydro is operating a Standard Offer Program ("**SOP**") that presents IPP developers the opportunity to sign long-term contracts with BC Hydro whereby the IPP may sell their generation output to BC Hydro at a preset price. The SOP has recently been through a two-year review which produced a number of changes and updates. The eligibility requirements for the program include a 15MW maximum size limit, the need for generation to meet government defined clean or renewable qualification standards and for the generation to be located within British Columbia[34].

[34] BC Hydro, Standard Offer Program: Program Rules, Version 2.0, January 2011, page 1

Unlike the recent BC Hydro Clean Power Call, the SOP does not discriminate between firm energy and non-firm energy. Consequently, after adjusting for month of delivery and time of day, all energy generated under an SOP contract receives the same preset price regardless of the certainty of production[35]. Stated another way, BC Hydro assumes the intermittent and volumetric risk on the generation and therefore is in essence procuring an energy only product.

As a result, the current BC Hydro SOP represents an accurate estimate of the cost of procuring a BC based energy only product (with the added benefit of being consistent with the prescriptions of the *Clean Energy Act*). Because of this, Midgard has estimated the forecast price curve for the BC New Resources Market Energy based on the current SOP price offering which is $101.39/MWh in 2011 CAD[36]. Therefore the 2011 price point for the Midgard British Columbia New Resources Market Energy curve is $101.39/MWh. This price was escalated at 50% of CPI[37] annually between 2011 and 2040 to generate the remainder of the BC New Resources Market Energy Curve. The BC New Resources Market Energy Curve is represented in Figure 5.2-A and Table 5.2-A.

Figure 5.2-A: BC New Resources Electricity Market Curve (CAD)



[35] In contrast with this treatment, BC Hydro's Clean Power Call contract stipulates a different price for power that is certain to be provided (i.e. firm power) than for power that is uncertain to be generated (i.e. non-firm power). Consequently, the prices paid for firm power can be a multiple of that paid for non-firm power. The firm power price notionally includes a premium for the inherent capacity of that power.

[36] $99.30/MWh in 2010 CAD

[37] The 50% of CPI escalation factor was selected to match the escalation factor embedded in an executed SOP contract. A 100% CPI escalation factor would overstate the future cost of contracted energy, although it might better represent the starting price for the energy at the time it is first contracted.

Table 5.2-A: BC New Resources Market Energy Curve (CAD)

Year	Price	Year	Price	Year	Price
2011	$101.39	2021	$112.55	2031	$124.94
2012	$102.45	2022	$113.73	2032	$126.25
2013	$103.53	2023	$114.92	2033	$127.58
2014	$104.61	2024	$116.13	2034	$128.92
2015	$105.71	2025	$117.35	2035	$130.27
2016	$106.82	2026	$118.58	2036	$131.64
2017	$107.94	2027	$119.83	2037	$133.02
2018	$109.08	2028	$121.09	2038	$134.42
2019	$110.22	2029	$122.36	2039	$135.83
2020	$111.38	2030	$123.64	2040	$137.26

5.3 BC Wholesale Market Energy vs. BC New Resources Market Energy

The analysis has taken two distinct approaches to valuing the price of energy in British Columbia. The first approach started with a forecast Mid-C electricity curve and translated it into an electricity price equivalent for delivery into FortisBC territory. The second approach estimated the required contractual price to procure energy from a newly constructed generation resource. Figure 5.3-A graphs these two curves together.

Figure 5.3-A: Projected BC Wholesale vs. BC New Resources Market Energy (CAD)

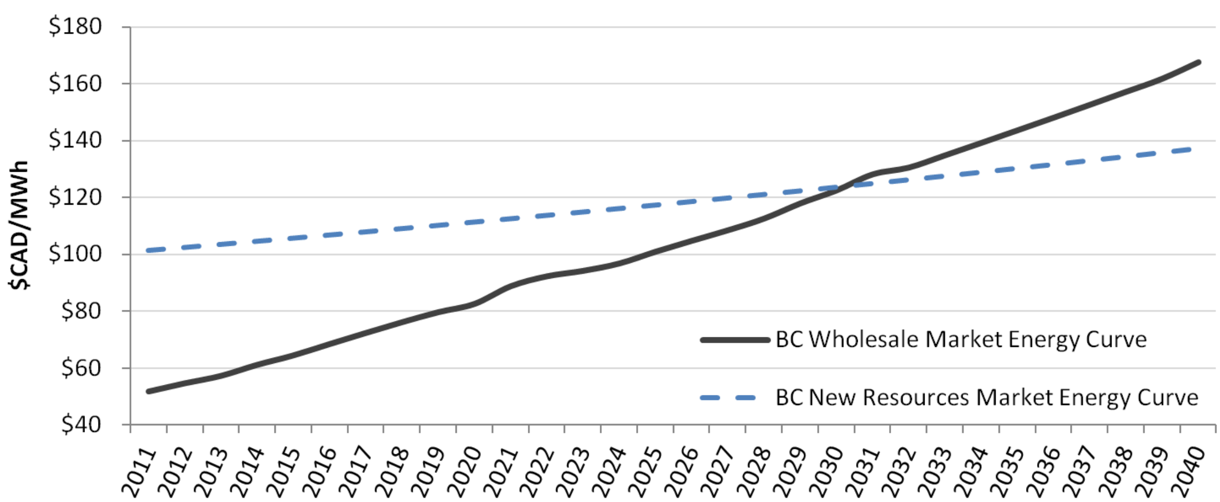


Figure 5.3-A shows that BC Wholesale Market Energy costs are projected to remain less expensive than BC New Resources Market Energy costs until 2030. Therefore, from an energy only product standpoint BC Wholesale Market Energy solutions are projected to be less expensive that new contracted generation solutions from BC New Resources Market sources until 2030.

6 British Columbia Capacity Market Analysis

FortisBC has two alternatives to address their forecast capacity shortfalls. One strategy is to purchase capacity in the wholesale market and the other strategy is to acquire it from new generation resources.

Purchasing capacity in the wholesale market is a strategy that FortisBC has historically employed. Typically this can only be done on a short term basis and is achieved by contracting for short-term supplies of firm power[38] to be delivered to FortisBC during the peak demand months of December, January, and/or February. The advantage of this procurement method is that FortisBC has flexibility with regards contract timings, quantity of contracts and contract durations. The disadvantage of this strategy is that FortisBC may misread the market and either pay a high price for the firm power or be unable to secure the quantity and quality of firm power that FortisBC is seeking. Short term market prices of electricity can be volatile (see Section 5.1.1) and unanticipated spikes in prices or scarcity of available supply cannot be predicted. Consequently, relying upon short term market purchases in the wholesale electricity market entails certain cost and supply-certainty risks for FortisBC and its ratepayers.

The second strategy is to contract for new generation resources either by developing and constructing a new firm capacity generation resource that is owned and operated by FortisBC, or by contracting with a third party to provide long term supply of firm capacity to FortisBC from a new generation resource. Similar to the case for energy, it is common for the power purchase agreement to have a term of 20 years or longer.

This section will discuss the wholesale market price curve for capacity available to FortisBC, the forecast market price for new contracted generation in BC and compare the two BC capacity price curves with each other.

6.1 BC Wholesale Capacity Price Curve

Capacity is essentially the timing and rate of energy delivery.

6.1.1 Translating the BC Wholesale Market Energy Curve into the BC Wholesale Market Capacity Curve

Starting from the BC Wholesale Market Energy Curve that was presented in Section 5.1.3, the cost (in $/MW-month) of a series of wholesale market purchases of firm delivered power can be estimated. This assumes that a block of firm energy could and would be procured today for delivery over multiple years into the future.

[38] In practice, FortisBC has been unable to procure a pure capacity option product whereby they could call on the energy as and when needed. Rather FortisBC has had to contract for firm power deliveries in order to ensure delivery and then resell any unneeded power back to the spot market at the then prevailing market price.

The block of energy would cover the high load hours of the four FortisBC high load months of January, July, November, and December. The notional cost of procuring this block of power for a year is summed and then divided by twelve months to obtain an annualized price ($/MW month) estimate.

The wholesale market price for high load hours during the months of January, July, November, and December was estimated by multiplying the annual BC Wholesale Market Energy Curve by the monthly average premiums for these four months. 112% is the average premium that these four months trade above the annual average price, as per Table 5.1.2-b (Jan=116%, Jul = 105%, Nov=111%, and Dec=116%).

Wholesale markets tend to be very liquid in the short term but increasingly less so in the medium and long term, as you move further out the forecast curve. The cost premium of purchasing a ten year hedge is far more than the premium for purchasing a one year hedge. These additional costs relate to a number of factors including:

- Credit costs required to secure the transaction (such as letters of credit requirements)
- The low number of credit worthy counterparts with whom to transact
- The liquidity cost premium that long-term transactions incur
- The wider bid/ask spreads that extraordinary transactions attract

Consequently, the cost of a wholesale market transaction was adjusted upwards to take into account the above factors. Specifically, the annual price estimates were increased by 2% per year to represent the increasingly costly nature of long term wholesale market transactions.

Table 6.1.1-A shows the results of all these calculations and includes a subjective assessment of the likelihood of being able to find a party with whom to transact. The table reveals that today's cost of procuring wholesale market supply of capacity becomes increasingly expensive as the term of the transaction extends into the future.

Table 6.1.1-A: BC Wholesale Market Capacity Curve Estimations (CAD)

Year	Expected Fortis BC: On-Peak for Jan-Jul-Nov-Dec incl. Fin. Costs (CAD/MW.mo)	Likelihood of actually procuring a hedge	Year	Expected Fortis BC: On-Peak for Jan-Jul-Nov-Dec incl. Fin. Costs (CAD/MW.mo)	Likelihood of actually procuring a hedge
2011	$6,942	very likely	2026	$18,894	unlikely
2012	$7,476	likely	2027	$19,955	unlikely
2013	$7,991	likely	2028	$21,125	unlikely
2014	$8,702	potentially	2029	$22,571	unlikely
2015	$9,356	potentially	2030	$23,912	unlikely
2016	$10,133	difficult	2031	$25,515	unlikely
2017	$10,923	difficult	2032	$26,509	unlikely
2018	$11,724	difficult	2033	$27,934	unlikely
2019	$12,512	difficult	2034	$29,415	unlikely
2020	$13,230	difficult	2035	$30,955	unlikely
2021	$14,504	unlikely	2036	$32,555	unlikely
2022	$15,379	unlikely	2037	$34,219	unlikely
2023	$16,012	unlikely	2038	$35,947	unlikely
2024	$16,781	unlikely	2039	$37,742	unlikely
2025	$17,846	unlikely	2040	$39,872	unlikely

6.2 BC New Resources Market Capacity Curve

The alternative strategy for closing FortisBC's forecast capacity gaps is to procure the capacity product from a new power generation facility (e.g. self-supply or IPP). A new power generation facility is a more concrete means of ensuring long term supply-certainty, especially if the facility is constructed close to the load requirement. Nevertheless, this strategy carries its own risks; the cost of fixing the price of long-term supply may prove to be more expensive than the cost of a series of short term wholesale market purchases.[39]

6.2.1 Resources Options Report

In 2010, FortisBC contracted Midgard to renew the Company's resource option analysis and prepare a 2010 Resource Options Report ("2010 ROR"). The 2010 ROR reviewed potential resources and estimated various resource costs for both capacity and energy. This section will draw on the 2010 ROR

[39] This opportunity cost can only be assessed after the fact, and is not dissimilar to the decision that households face when they decide whether to lock in a fixed rate or a floating rate mortgage.

findings, specifically the conclusions of the least costly capacity resources that met FortisBC's requirements; it will use those findings to help generate the BC New Resources Market Capacity Curve.

6.2.1.1 Evaluation Criteria

To enable consistent evaluation of resources that represent a wide range of technologies and fuel sources, the 2010 ROR employed a simplified cost metric named Unit Capacity Cost ("**UCC**"). The metric condensed the economic characteristics of the different resource options[40] into a resource specific Unit Capacity Cost.

The Unit Capacity Cost is the annual cost of providing dependable capacity using each resource option, expressed in $/MW-month units. Annual costs used in the calculation include the interest on debt, return on equity and amortization, all derived from the project capital cost. Annual costs also include the fixed operating costs that must be spent to keep the project's dependable capacity available regardless of the amount of energy generated each year. UCC was used to rank the various capacity resources under consideration.

Non-Economic Criteria

In addition to economic criteria the resources identified in the 2010 ROR were passed through additional filters that measured the resource's effectiveness in meeting FortisBC's planning needs. The filters included an assessment to ensure that the resources:

- Were based upon proven commercially viable technology
- Adhered to the directives and principles of the *Clean Energy Act* including assessing the resources' environmental impacts
- Were assessed based upon the ancillary benefits[41] they might provide to the FortisBC system

6.2.1.2 Results of the 2010 Resource Options Report

Table 6.2.1.2-A summarizes the least expensive capacity resources available to FortisBC, ranked using the UCC metric. The list includes a simple cycle gas turbine followed by a combined cycle gas turbine, pumped storage hydro, and a small hydro resource with capacity.

[40] Representative capacity resources included Simple Cycle Gas Turbines ("**SCGT**") and pumped storage hydro plants.

[41] Examples of ancillary benefits include reactive power/voltage support, AGC/load following, spinning reserves, dispatch ability and most notably Transmission Must Run service, where the resource can be dispatched as required to relieve transmission path congestion.

Table 6.2.1.2-A: Competitive Unit Capacity Cost Resource Options (CAD 2010)

Project	Dependable Capacity (MW)	Capital Cost (k$)	UCC @6% ($/MW-month)	UCC @8% ($/MW-month)
Simple Cycle Gas Turbine	39	44,269	8,481	10,163
Combined Cycle Gas Turbine	243	329,445	10,624	12,708
Potential Pumped Storage Hydro	180	340,000	13,668	17,412
Similkameen - Small Hydro with Capacity	60	283,117	29,274	38,003

6.2.1.3 Translating UCC Results into a BC New Resources Market Capacity Curve

The result of the 2010 ROR analysis was that a simple cycle gas turbine would be FortisBC's most cost effective capacity resource solution. Based upon this conclusion, and the UCC metric of $10,163/MWh-month, Midgard derived a BC New Resources Market Capacity Curve.

The UCC derived cost of $10,163 was used as the starting point and escalated at 100% of CPI for years 2011 through 2040. Table 6.2.1.3-A depicts the results of the exercise.

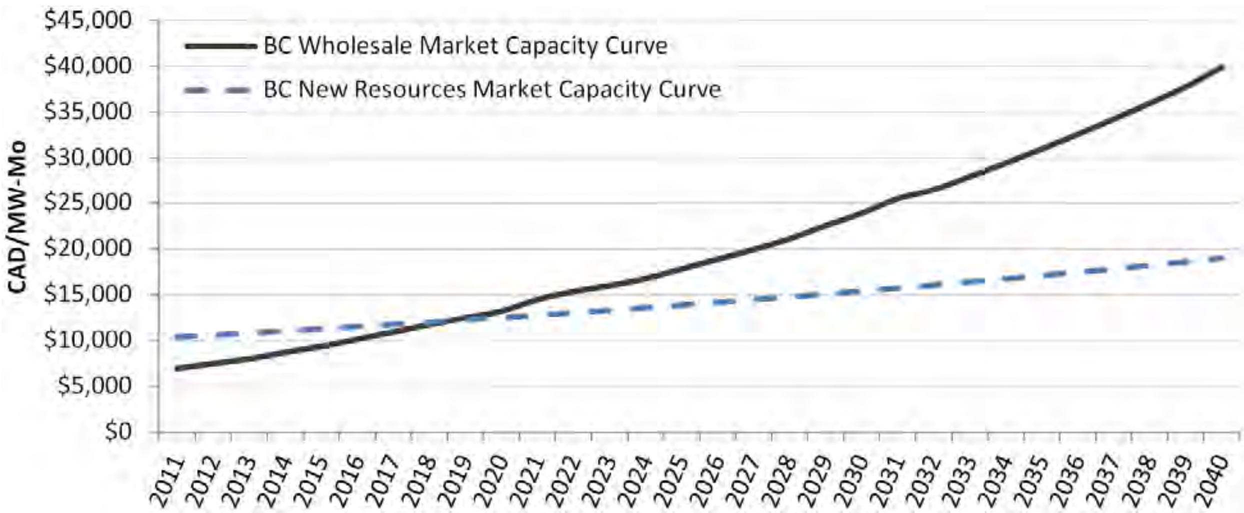
Table 6.2.1.3-A: BC New Resources Market Capacity Curve: Based on Escalated UCC Cost of SCGT (CAD)

Year	New Resources: UCC Costs (SCGT) (CAD/MW-Mo)	Year	New Resources: UCC Costs (SCGT) (CAD/MW-Mo)
2011	$10,376	2026	$14,172
2012	$10,594	2027	$14,470
2013	$10,817	2028	$14,774
2014	$11,044	2029	$15,084
2015	$11,276	2030	$15,401
2016	$11,513	2031	$15,724
2017	$11,754	2032	$16,054
2018	$12,001	2033	$16,391
2019	$12,253	2034	$16,736
2020	$12,511	2035	$17,087
2021	$12,773	2036	$17,446
2022	$13,042	2037	$17,812
2023	$13,315	2038	$18,186
2024	$13,595	2039	$18,568
2025	$13,881	2040	$18,958

6.3 BC Wholesale Market Capacity vs. BC New Resources Market Capacity

Figure 6.3-A compares the capacity cost of the two methods of deriving British Columbia based capacity cost curves.

Figure 6.3-A: BC Wholesale Market Capacity Curve vs. BC New Resources Market Capacity Curve (CAD)



Comparing the "wholesale" and "new resources" curves shows that wholesale market capacity is more cost effective than building new resources until 2019.

This conclusion must be qualified by two important considerations:

1. Contracting a new resource (the "BC New Resources" curve is intended to represent the cost of this option) is typically done on a long term basis of up to 20 years or more. In contrast, contracting in the wholesale market is typically done on a one to five year basis. Consequently, if FortisBC is looking to secure long term sources of capacity, the BC New Resources Market Capacity becomes progressively more cost competitive versus the BC Wholesale Market Capacity as the term length increases.

2. The potential price volatility of wholesale markets tends to be higher than is the case for the price volatility of new resources markets. This is because the underlying price drivers for wholesale markets, such as the price of natural gas, tends to display much greater price volatility than the underlying price drivers for new resources markets[42] (e.g. labour costs and cost of equipment).

Section 7 will take a closer look at several market trends that could have an impact upon the availability and price of energy and capacity products within wholesale markets and for new resources markets in the future.

[42] Note that the price of natural gas does not affect the capacity cost estimate (UCC calculation) of a SCGT. See Appendix 3 for details.

7 Market Trends

The market for energy and capacity in western North America is undergoing significant change. This section is an overview of the current trends impacting the energy and capacity markets in the WECC region that may have a material impact upon FortisBC's interests.

The trends that will be examined are:

- Changes to WECC supply mix due to mandatory Renewable Portfolio Standards ("**RPS**")
- Potential impact of DSM on energy and capacity markets
- Delays to new transmission construction in WECC
- British Columbia's *Clean Energy Act*
- The current state of the Alberta electricity market

Note that these regional trends are more likely to have an impact upon wholesale market prices than they are to impact new resources market prices. Wholesale market prices are influenced, as discussed in Section 4, by regional factors, such as natural gas prices and regional transmission constraints.

In contrast, new resources market prices (in BC) are influenced to a great extent by factors local to British Columbia, such as labour costs, the cost of permitting new projects, and competition in BC for new generation resources. The closer the capacity resource is installed to the load centre, the easier it becomes for the load to access it as a capacity or energy resource. Therefore, construction of new generation is largely built to serve local needs.

7.1 Renewable Portfolio Standards

Table 7.1-A displays the current NERC resource mix and the resource mix that is anticipated in 2019. The percentages indicate the contribution to the on-peak capacity for each type of generation resource. Renewables' capacity is anticipated to experience a fivefold increase between 2010 and 2019. The changes to the supply mix are being driven to a great extend by Renewable Portfolio Standards.

Table 7.1-A: On-Peak Capacity by Resource Type: 2010 and 2019[43]

Fuel Type	2010	2019 Projected
Coal	31%	26%
Gas	29%	30%
Nuclear	11%	12%
Hydro	13%	9%
Renewables	1%	5%
Dual Fuel	11%	13%
Other	4%	5%
TOTAL	100%	100%

Most provinces and states in the WECC region have a mandated Renewable Portfolio Standard or a renewable energy goal. Table 7.1-B lists the US states that are WECC members and their RPS mandates[44].

Table 7.1-B: RPS Standards in WECC US States

State	RPS
Arizona	15% by 2025
California	33% by 2020
Colorado	30% by 2020
Idaho	none
Montana	15% by 2015
Nevada	25% by 2025
New Mexico	20% by 2020
Oregon	25% by 2025
Utah	20% by 2025
Washington	15% by 2020
Wyoming	none

States that have adopted an RPS have chosen a minimum of 15% of energy to come from renewable resources, with the latest of those occurring by 2025 (Arizona). California has the most aggressive standard at 33% of energy supplied from renewables by 2020.

[43] North American Electric Reliability Corporation, 2010 Long-Term Reliability Assessment, October 2010, page 45

[44] PEW Center on Global Climate Change: http://www.pewclimate.org/what_s_being_done/in_the_states/rps.cfm

California's RPS is arguably the most significant in the WECC region (if not the US) given that the state consumes almost 300,000 GWh[45] of energy annually (approximately one third of WECC's annual load). As of 2009 the state received 13.9% of its power from renewables, leaving a further 19.1% requirement to be fulfilled. This suggests a need to more than double its current installed renewable generation capacity in the 11 years leading up to 2020.

7.1.1 Wind Resource Introduction

Wind is being increasingly relied upon to meet the demand for renewable resources in WECC, with 19,000 MW of capacity planned for installation in the WECC region by 2019[46]. Wind can be expected to generate a reliable amount of yearly energy but it is not dependable because its capacity is entirely dependent on the weather; hence only a small fraction of its installed capacity amount is being counted upon.

The majority of the non-construction/transmission costs associated with integrating wind into the grid relate to reserving flexible resources to ensure reliable service despite wind's variability[47]. Integration of wind power requires some firming of its energy. Although short-term wind forecasting techniques have diminished the need for regulating reserves, there remain challenges associated with integrating an intermittent resource such as wind into the transmission grid.

Impact upon Energy and Capacity Availability

Larger quantities of intermittent resources are likely to consume currently available wholesale market capacity resources within WECC as regulating authorities are required to commit what was previously excess capacity to act as regulating reserves for wind capacity. This will threaten the supply certainty of wholesale market capacity resources for FortisBC. As it pertains to wholesale market energy resources, the new intermittent resources will add energy supply to the market and create downward pressure on wholesale market energy prices during periods of optimal wind and/or renewable fuel conditions.

RPS standards generally require that the renewable generation resources be located within the jurisdiction mandating the RPS standard. Therefore, the impact upon BC New Resources Markets is expected to be immaterial (aside from those impacts discussed in section 7.4 below).

7.2 Demand Side Management

Demand Side Management programs are being widely introduced into WECC jurisdictions. Actual measurement of DSM results can be difficult given that actual consumption levels can only be compared to projected consumption levels that would have existed in the absence of the DSM program. It may be some years before actual DSM successes can be properly discerned from theoretical successes as many

[45] California Energy Almanac Total System Power Reporting: http://www.energyalmanac.ca.gov/electricity/total_system_power.html

[46] North American Electric Reliability Corporation, 2010 Long-Term Reliability Assessment, October 2010, page 271, Table WECC-4

[47] Utility Wind Integration Group Northwest Wind Integration Action Plan, 2007

of the DSM measures do not have a long 'in service' history, particularly for proactive 'demand response' programs. Aggressive DSM targets are a potential peril to the wholesale capacity markets because:

- they may be used to rationalize the delay of installing new resources
- load shaping and peak shaving measures of DSM programs may not materialize in practice as theorized (not the least because voluntary DSM participants may simply decide not to abide by their promised behaviour)

Impact upon Energy and Capacity Availability

DSM programs will have a material impact upon resource planning for the foreseeable future as they are predicted to have a mitigating impact upon load growth. However, there may be a gap between the theoretical impact and the reality. Consequently, DSM programs may end up tying up currently available capacity resources within the WECC region in the event that the load that DSM is intended to displace does not get fully displaced. This may jeopardize supply certainty of wholesale market capacity resources for FortisBC. That said the impact of DSM programs on the wholesale markets is likely to be less than that of RPS.

The impact of DSM programs on the new resources markets for energy and capacity is unlikely to be material, although their failure, or partial failure, may put pressure on new resource markets in the medium to long term if it triggers a boom in the construction of new resources.

7.3 Potential Delays in WECC Transmission Construction

Table 7.3-A lists transmission construction plans in NERC. Although WECC totals may seem high in comparison to other NERC jurisdictions, the physical distances involved with the western grid mean that longer transmission lines are generally needed to make any given supply-load connection.

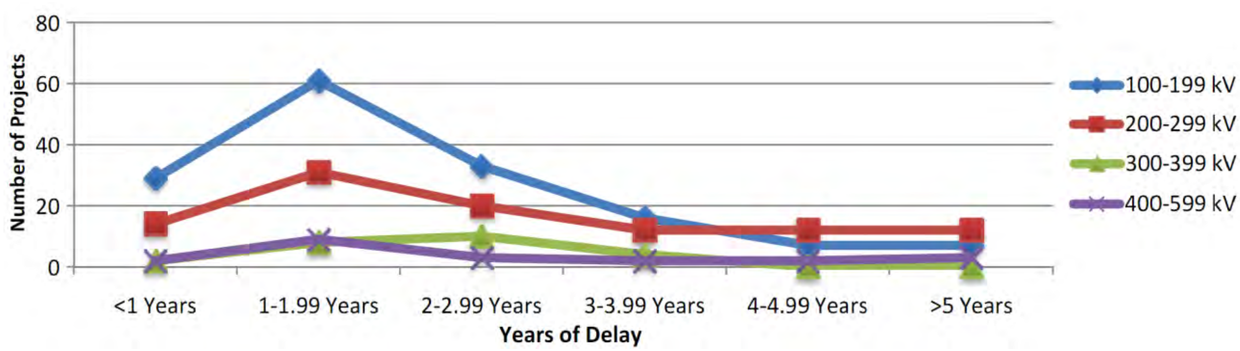
Table 7.3-A: Current and Planned Transmission in NERC by Circuit Mile Additions[48]

Area	2009 Existing	Planned Additions	Total by 2019
FRCC	12,016	377	12,393
MRO	49,763	4,773	54,536
NPCC	59,294	2,289	61,583
RFC	60,088	1,831	61,919
SERC	98,296	5,013	103,309
SPP	23,814	2,766	26,580
TRE	28,665	5,090	33,755
WECC	**120,763**	**17,249**	**138,012**

[48] North American Electric Reliability Corporation, 2010 Long-Term Reliability Assessment, October 2010, page 22

Of the 27,000 miles of transmission projects in NERC that are either under construction or in the planning stage, roughly 6,500 miles of these transmission projects are currently considered "delayed"[49] (as illustrated by Figure 7.3-A). In the event that the transmission construction patterns in WECC (and British Columbia) prove to be consistent with those of NERC, delays can be expected in the addition of new transmission capacity, especially for higher voltage lines.

Figure 7.3-A: Transmission Project Delays in Currently Planned Projects[50]



Impact upon Energy and Capacity Availability

Delays in new transmission construction will have an adverse impact upon FortisBC's ability to access wholesale markets. Growing regional loads without corresponding additional transmission capacity will certainly lead to more serious transmission constraints. This trend will generally have a negative impact upon both wholesale energy markets and wholesale capacity markets.

The impact on the new resources markets for energy and capacity in BC is unlikely to be material unless it increases the transmission constraints between the location of the new resources and FortisBC. In other words, if transmission constraints to move power from the interior of the Province to the Lower Mainland become more severe, it does not necessarily have an adverse impact upon FortisBC. However, if transmission constraints made it more difficult to move power from a newly constructed facility to FortisBC territory, it would have a negative impact upon the new resources market prices that FortisBC's would face.

7.4 British Columbia's Clean Energy Act

The *Clean Energy Act* was passed into law by the BC government in 2010. The *Clean Energy Act* advanced 16 specific energy objectives, which can be grouped into three priority areas[51]:

1. Ensuring Electricity Self-Sufficiency at Low Rates
2. Harnessing B.C.'s Clean Power Potential to Create Jobs in every Region

[49] North American Electric Reliability Corporation, 2010 Long-Term Reliability Assessment, October 2010, page 23

[50] North American Electric Reliability Corporation, 2010 Long-Term Reliability Assessment, October 2010, page 24

[51] BC news release 2010PREM0090-000483:http://www2.news.gov.bc.ca/news_releases_2009-2013/2010PREM0090-000483.htm

3. Strengthening Environmental Stewardship and Reducing Greenhouse Gases

The two provisions within the *Clean Energy Act* that will be examined here are:

i. The provision for BC Hydro to target creating an energy surplus[52]
ii. The provision for BC Hydro to facilitate the export of power out of BC[53]

The *Clean Energy Act* also mandates aggressive DSM targets; however these were covered earlier in this section and will therefore not be repeated here.

Under the *Clean Energy Act*, BC Hydro is mandated to secure, by 2020, rights to 3,000 GWh of energy above its anticipated needs. This amount of energy is equivalent to approximately 5% of BC's current annual energy consumption. This is on top of the fact that BC Hydro has been mandated to become self-sufficient, defined as being able to meet their domestic electricity demand during a critical water year (i.e. a low water year) by 2016. The combination of the 3,000 GWh surplus energy with the surplus energy BC Hydro would have available for sale in the average year would mean that BC Hydro (and Powerex) will be active sellers of energy in the medium term.

Related to the above, BC Hydro is mandated "to be a net exporter of electricity from clean or renewable resources with the intention of benefiting all British Columbians and reducing greenhouse gas emissions in regions in which British Columbia trades electricity". Increased exports from British Columbia would obviously be facilitated by the construction of new transmission both within BC and inter-regionally.

Impact upon Energy and Capacity Availability

BC Hydro's securing of 3,000 GWh of energy beyond their critical water year requirements suggests an abundance of conveniently located energy potentially available for sale to FortisBC. Improvements to BC's interconnection infrastructure with neighbouring jurisdictions also implies potentially positive impacts for FortisBC and their ability to access to wholesale markets outside of BC.

BC Hydro may be active in the BC New Resources Markets in order to secure the 3,000 GWh of surplus energy and achieve self-sufficiency. As they contract for the most cost effective new resources (the 'low hanging fruit'), their activities are likely to put upwards pressure on the BC New Resources Market Capacity and Energy curves.

7.5 Alberta Electricity Market

The Alberta electricity market is approximately the same size as the British Columbia electricity market.

The Alberta electricity market is deregulated, which means that the price of electricity can and does vary by the hour and that decisions to add new generation capacity are driven by market forces.

[52] Clean Energy Act, Part 1, 6 (2) (b)

[53] Clean Energy Act, Part 1, 2 (n)

The Alberta projected 2010-2011 winter reserve margin is equal to or below the prescribed target reserve margin of 13.2%[54], highlighting the need for Alberta to add generation resources. Alberta loads are expected to grow by 2.6% annually[55] for the next decade, a rate that is higher than most other sub-regions in WECC. Moreover, a considerable amount of wind generation has been constructed in Alberta over the past fifteen years, with more planned. This wind generation adds limited dependable capacity despite the much larger nameplate capacity of the generators[56].

Alberta, like British Columbia, is a winter-peaking system. There is a high coincidence between British Columbia (including FortisBC territory) and Alberta for extreme winter weather events.

From a transmission point of view, Alberta can theoretically export 1000 MW to British Columbia and import 1200 MW from British Columbia. However, the transfer capabilities are rated at approximately half these amounts due to transmission constraints within Alberta[57]. (Alberta also has a 150 MW intertie with Saskatchewan.)

Alberta's electrical system faces some challenges in the coming years.

Impact upon Energy and Capacity Availability

The combination of healthy economic growth, tight reserve margins, and intermittent generation resource additions suggest that Alberta requires new generation capacity (and transmission additions) sooner rather than later. To the extent Alberta does not construct new capacity in its own jurisdiction it sets the stage for the province to be a potential competitor for WECC wholesale market capacity resources in the coming years. Given the similarity of Alberta's peak demand patterns with those of FortisBC, FortisBC must be aware of the likelihood of competing with Alberta when seeking to secure firm capacity supplies (and potentially energy supplies) from the wholesale markets.

The impact on the new resources markets in BC for energy and capacity is unlikely to be material, since Alberta is unlikely to seek to have new resources constructed in British Columbia that are meant to service domestic Alberta requirements.

7.6 Market Trend Conclusions

Overall, the risks of the market trends have limited or delayed impact upon the expected cost of procuring energy and capacity from the new resources markets. This is because new resources markets are more prone to local cost influences and, particularly in the short run, region wide trends do not tend to impact

[54] North American Electric Reliability Corporation, 2010 Long-Term Reliability Assessment, October 2010, page 284

[55] North American Electric Reliability Corporation, 2010 Long-Term Reliability Assessment, October 2010, page 284

[56] North American Electric Reliability Corporation, 2010 Long-Term Reliability Assessment, October 2010, page 287; "the WECC-Canada sub-region [currently] has 591 MW[of installed nameplate capacity –wind], which is derated to 33 MW during the summer peak period."

[57] Alberta Electric System Operator, AESO Long-term Transmission System Plan, 2009, Appendix H, page 303

local new resources markets. The exception to this is the *Clean Energy Act*, which will have an important impact upon BC and will influence the cost of constructing new resources in BC.

These same market trends could have a more serious impact upon prices in the wholesale markets. This is particularly true with wholesale capacity markets as all the trends, except the *Clean Energy Act* and certain BC transmission line delays, could have an adverse impact upon the availability of capacity resources in the BC Wholesale Market. The potential impacts of all five trends are summarized in Table 7.6-A.

Table 7.6-A: Summary of Market Trends' Impacts on BC Markets

WECC Market Trend	Wholesale Market	New Resources Market
Renewable Portfolio Standards & Additional Intermittent Resources	Risk to supply-certainty; risk of higher wholesale capacity prices	Limited impact
Demand Side Management Programs	Limited risk to supply certainty	Limited impact, but potential upward price pressure in long-term
Delays in New Transmission Construction	Risk to supply certainty; risk of higher wholesale market prices	Potential impact, resulting in upward price pressures
Clean Energy Act: • ***Generation Surplus*** • ***Export Mandate***	Potential positive impact for FortisBC / BC Wholesale Market energy and capacity buyers	Potential upward price pressures in medium-term
Alberta Market – Current State	Price risk and supply-certainty risk	Limited impact

8 Conclusions

FortisBC faces some gaps between its currently contracted supply of energy and capacity and its forecast load requirement over the next 30 years. Midgard Consulting Inc. was contracted to assess the future outlook of the electricity markets in BC and surrounding areas and assess the cost and availability of energy and capacity products therein. This report analyzed the cost and availability of power supply to FortisBC over the next 30 years and compared the cost of procuring these power supplies from either British Columbia's Wholesale Market or its New Resources Market.

For the purposes of this paper, the wholesale market referred to any transaction whereby the power is procured by means of a short term, physically or financially settled transaction that is tied to a notional or actual existing generation assets. The new resources market referred to a transaction that would lead to the installation of new generation resources, which is to say 'steel in the ground'.

Given the findings of this report, Midgard concludes as follows:

- FortisBC's continued reliance upon the wholesale electricity market to meet current and future needs is not an unreasonable strategy, particularly given the size of FortisBC's energy and capacity gaps over the next few years.
    - BC Wholesale Energy Market prices are projected to remain less expensive than comparable BC New Resources Market Energy prices until approximately 2030.
    - BC Wholesale Capacity Market prices for capacity products are projected to remain less expensive than comparable BC New Resources Market Capacity prices until approximately 2019.
- Overall WECC market trends – chiefly RPS, DSM and the current state of the Alberta electricity market – are of a greater threat to the price and supply availability of capacity and energy in the wholesale markets than they are to the price and supply availability of energy and capacity from the new resources markets.
- The impact of transmission delays and the BC *Clean Energy Act* are more ambiguous for both the wholesale and new resources markets, although they potentially improve the relative cost competitiveness of the BC Wholesale Markets versus the BC New Resources Markets.
- The BC New Resources Capacity Market is less expensive than the BC Wholesale Capacity Market when longer term transactions are evaluated. Up*ward price press*ures and product availability concerns in both the wholesale market energy and wholesale market capacity markets make new resources more competitive on a long term basis.

Appendix A: Natural Gas and Greenhouse Gas Forecast Price Curves

Natural gas generation resources rank higher in the dispatch stack than base load generation resources. In other words, the marginal cost of electricity generated from a natural gas fired generator is typically more expensive than the comparable cost of electricity from a nuclear or coal-fired plant. Load demand frequently rises during on-peak periods to the point where natural gas generation facilities are required and hence determine the marginal cost of electricity in the wholesale market. Consequently, market electricity prices (and especially on-peak prices) in the ("**WECC**") region, and across much of North America, are strongly correlated to the price of natural gas.

Over 40% of the generating capacity in the WECC region is produced from natural gas fired generation plants (or dual fired generation plants, which typically use natural gas as the default fuel). In addition, as per WECC's 2008 Information Summary, almost 50% of new resources in the WECC region are expected to be natural gas-fired[58]. A plant owner will sell to the market when the expected market price of electricity will cover the variable cost of production, which is primarily dependent of the cost of natural gas and the efficiency or heat rate of the plant[59].

Natural gas prices have a history of volatility as evidenced by the experience of the last 10 years. On an annual average basis from 1997 to 2008 the price ranged from US$1.96 to US$8.07 with an annual average price of US$4.63 and a standard deviation of $2.10 (all in nominal US dollars)[60]. Mid-2008 spot prices were near to or at an all-time high (over US$13 per MMBtu in July 2008 for example), while current prices, US$4.38[61], are significantly lower. Long-term forecasts tend to be influenced by current spot prices, suggesting that current pricing would tend to have brought longer term price forecasts down relative to forecasts in 2008. In short, natural gas prices are unpredictable, potentially causing material variations in their price forecasts from one year to the next.

The remainder of this section presents a forecast curve for natural gas spot pricing. A statistical analysis has been prepared to define an upper and lower bound for the natural gas forecast curve to account for the commodity's historical price volatility.

Sourcing a Base Case Forecast Curve

The Base Case Curve relies on the early release of the United States Department of Energy's Energy Information Agency's (EIA) Annual Energy Outlook 2011 (AEO2011), specifically the Henry Hub natural gas price forecast[62]. The EIA is the primary US Federal Government authority on energy statistics and

58 Western Electricity Coordinating Council, 2008 Information Summary

59 There are other contributing factors such as non-fuel operating, overhaul and maintenance costs.

60 EIA Historic Natural Gas Wellhead Prices

61 NYMEX Henry Hub price as of March 23, 2011

62 US Energy Information Administration, AEO 2011 Early Release Overview, December 2010, Table 13: Natural Gas Supply, Disposition, and Price

analysis. EIA data and forecasts are a widely quoted and relied upon source of energy data throughout the world.

The AEO2011 projections are based on results from the EIA's National Energy Modeling System (NEMS). NEMS is a computer-based, energy-economy modeling system of the US (looking forward until 2035). NEMS projects the production, imports, conversion, consumption, and prices of energy (prices subject to assumptions on macroeconomic and financial factors). NEMS also projects world energy markets, resource availability, resource costs, behavioral and technological choice criteria, cost and performance characteristics of energy technologies and the demographics. The EIA has been forecasting natural gas prices since 1982, although the NEMS model has only been in use since 1994[63].

Midgard views the AEO2011 Henry Hub price forecast as a reasonable estimate of natural gas pricing. This view is based on the following facts:

- The AEO2010 forecast price curve is transparent and readily available. The forecast is derived from a model based upon fundamental inputs. Furthermore, the EIA is a non-political entity and is recognized as an independent agent. The EIA has no inherent bias in forecasting natural gas spot prices.
- Henry Hub natural gas is the benchmark trading point for natural gas in North America, with other natural gas trading (or transfer) points being priced as a basis (that is, as a premium or discount) to Henry Hub natural gas prices.
- The benchmark natural gas futures contract that trades on the New York Mercantile Exchange (NYMEX), North America's primary energy commodities exchange, physically settles at the Henry Hub natural gas delivery point.
- The EIA forecast price curve resembles the current short-term NYMEX natural gas futures curve although it escalates less acutely than does the NYMEX natural gas futures curve. While the NYMEX futures curve is not necessarily a more accurate predictor of future spot prices as compared to forecasts derived from a computer model, it is a legitimate reference against which the base case price curve should be checked. In particular, the shorter end of the NYMEX curve (where trading is more frequent) represents a fair and transparent measure to assess the wider markets' valuation of expected spot prices.
- The EIA forecast price is frequently referenced by natural gas industry stakeholders throughout North America. For example, California's key energy regulatory agencies, namely the California Energy Commission and the California Public Utilities Commission frequently reference the EIA price forecasts in their analysis and decisions. As a significant consumer of energy, California and its regulatory agencies invest a great deal of resources in assessing the future prices of

[63] Description taken from "The National Energy Modeling System: An Overview" found at: http://www.eia.doe.gov/oiaf/aeo/overview/index.html

energy. In Canada, our Federal and Provincial regulatory agencies also rely frequently on the data and analysis produced by the EIA.

There are a number of potential sources of natural gas price forecasts from government organizations as well as private sector consultants. Nevertheless, weighing the sum of the advantages and disadvantages of the various sources, Midgard is confident in the reasonableness of the EIA natural gas price forecast. Consequently, it forms the basis of the base case natural gas price forecast for this 2011 FortisBC Energy and Capacity Market Assessment.

Accounting for Price Volatility

Given the uncertainty inherent in forecasting it is helpful to forecast a range of possibilities in order to improve the usefulness of the forecast. The objective of this exercise is to present a range within which natural gas spot prices are expected to fall 19 times out of 20, that is to say a 95% confidence interval.

The EIA has been forecasting natural gas prices since 1982, and has been using the NEMS model since 1994. Annually, the EIA reviews its prior years' forecasts, measures their accuracy versus the actual results and summarizes their findings in a document called "Annual Energy Outlook Retrospective Review: Evaluation of Reference Case Projections in Past Editions"[64]. The review analyses the accuracy of the AEO forecasts and compares the actual figures versus the forecast figures. It is worth noting that the accuracy of the forecasts has improved measurably since 1994. It is also important to note that the underpinning assumption from which the NEMS results are derived is that the major factors impacting the supply and demand (and hence price) of natural gas will continue to trend in a manner that resembles their recent historical record.

In order to derive the high case and low case natural gas price curves, Midgard assumed that the AEO forecasts going forward will be approximately as accurate as they have been going back to 1994. That is to say, Midgard believes that the accuracy of the AEO2011 natural gas price forecast will be similar to its accuracy for the years 1994 to 2008[65].

In order to derive the high and low natural gas curves, Midgard assessed the variance of previous years' forecasts versus the actual natural gas price, grouping the data into forecasts by years into the future. For example, the AEO1994 forecast for the 1994 natural gas price was bucketed into the 1 year-ahead grouping, the AEO1994 forecast for the 1995 natural gas price was bucketed into the 2 year-ahead grouping, and so forth. The sample size for the 1 year-ahead grouping was the largest (at 15) and the sample sizes for each proceeding year was reduced by one (i.e. the sample size for the 2 year-ahead was 14, the sample size for the 3 year-ahead grouping was 13, and so forth).

[64] Located at: http://www.eia.doe.gov/oiaf/analysispaper/retrospective/index.html

[65] 2009 figures were not analyzed as part of the most recent Retrospective Review.

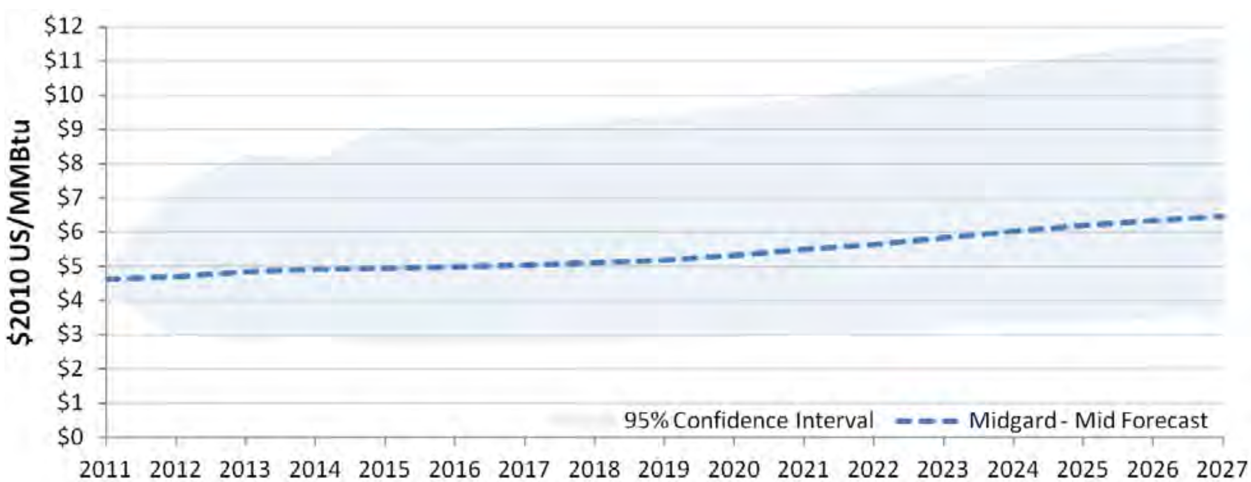
Once the standard deviations for each grouping were assessed (using a normalized data set)[66], Midgard calculated a 95% confidence interval based upon the forecast price curve acting as the mean price[67]. The calculation of the high and low price curves for the years 2016 to 2040 assumes a standard deviation equal to that calculated for 2016 (the 6th year-ahead)[68].

The end result is a long-term low case price scenario that is approximately 45% lower than the base case, and a long-term high case scenario that is approximately 80% higher than the base case.

Final Midgard Natural Gas Forecast Curve (with High & Low Cases)

Given the statistical price volatility analysis performed in the previous section, a final FortisBC natural gas forecast curve (with high and low boundaries) was established. The Figure A-1 below graphically represents the low/mid/high curves. Table A-1 presents the same data in tabular form.

Figure A-1: Midgard Henry Hub Natural Gas Price Forecast (2010 USD/MMBtu)



[66]Specifically, the differences between forecast and actual were translated into a percentage of actual

[67]Given that natural gas pricing cannot fall below zero, its pricing curve is expected to resemble that of a log-normal distribution curve. Therefore, the calculated confidence interval was based upon a log-normal distribution.

[68]The 7th year-ahead grouping and longer had a sample sizes which Midgard judged to be too small to use for this exercise.

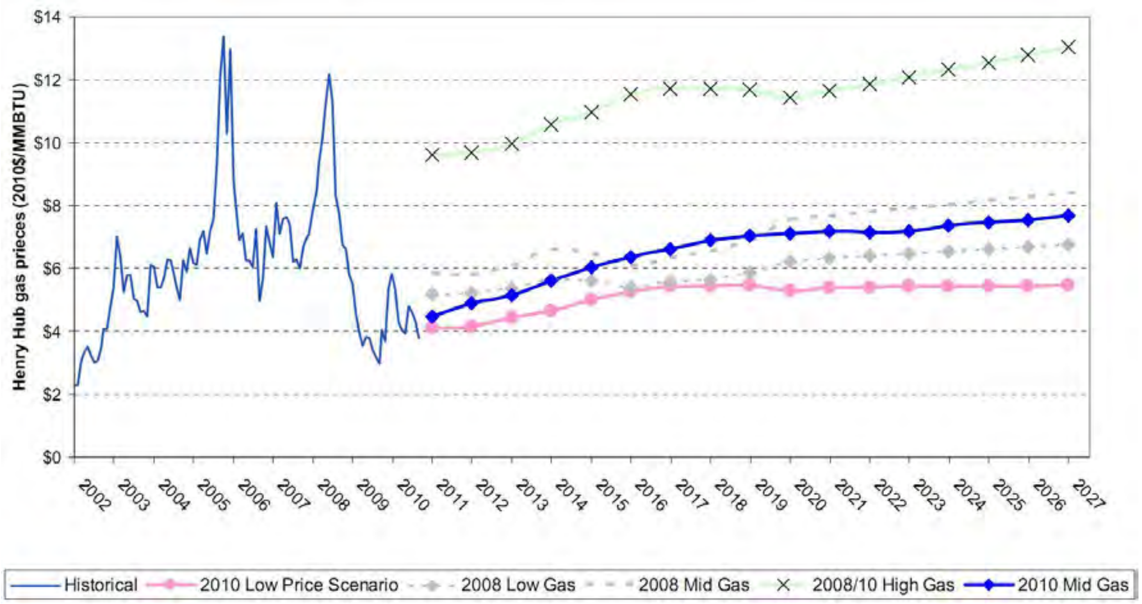
Table A-1: Midgard Henry Hub Natural Gas Price Forecast: Expected and High and Low Boundaries [95% Confidence Interval] (2010 USD/MMBtu)

Year	Expected	Low End	High End
2011	$4.61	$4.23	$5.03
2012	$4.70	$3.02	$7.33
2013	$4.84	$2.83	$8.29
2014	$4.91	$2.96	$8.14
2015	$4.95	$2.69	$9.09
2016	$4.98	$2.75	$9.02
2017	$5.03	$2.77	$9.10
2018	$5.11	$2.82	$9.25
2019	$5.19	$2.86	$9.39
2020	$5.33	$2.94	$9.66
2021	$5.49	$3.03	$9.94
2022	$5.65	$3.12	$10.23
2023	$5.83	$3.22	$10.57
2024	$6.02	$3.32	$10.90
2025	$6.19	$3.42	$11.21
2026	$6.33	$3.50	$11.47
2027	$6.47	$3.57	$11.71

BC Hydro Natural Gas Forecast Curves

In preparation for its 2011 Integrated Resource Plan, BC Hydro produced and released a set of forecast price projections for natural gas. Their predictions are based on a California Energy Commission price forecast and accounts for the introduction of abundant supplies of shale gas into the natural gas market (predicted to lower the long-term price of natural gas). Figure A-2 represents BC Hydro's forecast natural gas curves for 2010 as well as those used in the 2008 LTAP.

Figure A-2: BC Hydro Henry Hub Natural Gas Price Forecast: 2011 IRP (2010 USD/MMBtu)



It is noteworthy that the 2010 BC Hydro forecast natural gas curves are lower than the natural gas price forecasts used in the 2008 LTAP (except for the high case, which is the same).

Figure A-3 graphs BC Hydro's expected natural gas forecast against the Midgard expected natural gas forecast. Prices are in US dollars per MMBtu. Table A-2 compares the differences in the two data sets (and also includes the differences from the respective high and low forecasts).

Figure A-3: BC Hydro vs. Midgard Henry Hub Natural Gas Price Forecast (2010 USD/MMBtu)

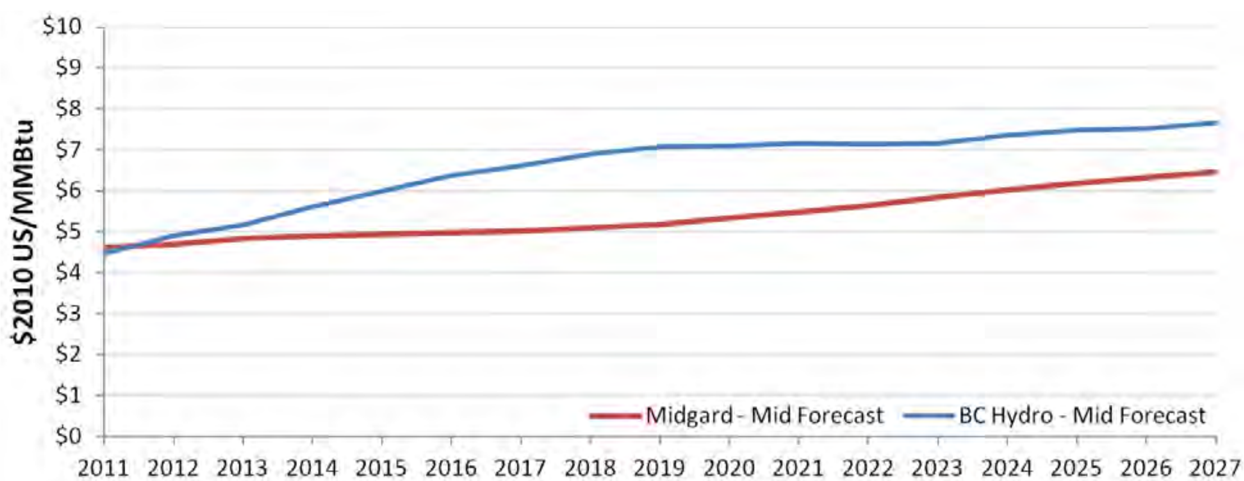


Table A-2: Hydro vs. Midgard Henry Hub Natural Gas Price Forecast (2010 USD/MMBtu)

BCH Curve - Midgard Curve ($)			
Date	Expected	Low	High
2011	($0.25)	($0.22)	n/a[69]
2012	$0.09	$1.08	$2.17
2013	$0.21	$1.57	$1.49
2014	$0.60	$1.63	$2.26
2015	$0.94	$2.25	$1.68
2016	$1.28	$2.46	$2.33
2017	$1.47	$2.60	$2.39
2018	$1.68	$2.58	$2.27
2019	$1.77	$2.54	$2.06
2020	$1.65	$2.29	$1.56
2021	$1.55	$2.30	$1.47
2022	$1.36	$2.23	$1.41
2023	$1.19	$2.13	$1.29
2024	$1.20	$2.02	$1.18
2025	$1.15	$1.92	$1.09
2026	$1.03	$1.87	$1.05
2027	$1.04	$1.80	$1.04

BCH Curve - Midgard Curve (%)			
Date	Expected	Low	High
2011	-5%	-5%	n/a[71]
2012	2%	35%	29%
2013	4%	54%	18%
2014	12%	54%	27%
2015	19%	82%	18%
2016	25%	87%	25%
2017	29%	91%	26%
2018	32%	90%	24%
2019	33%	87%	21%
2020	30%	76%	16%
2021	28%	74%	14%
2022	23%	70%	13%
2023	20%	64%	12%
2024	20%	59%	11%
2025	18%	55%	9%
2026	16%	52%	9%
2027	16%	49%	9%

Midgard's natural gas price forecasts are consistently below those used by BC Hydro, although for the most important of these pairings, the mid scenario, the forecasts are similar.

Interestingly, the BC Hydro mid scenario natural gas forecast begins at a similar spot but is thereafter consistently higher than the Midgard mid-scenario natural gas forecast. This is not unlike how the NYMEX Henry Hub natural gas futures curve compares with the Midgard mid scenario natural gas forecast curve.

Despite differences, it is Midgard's opinion that the similarities between the two sets of natural gas curves – and particularly the mid scenario curves – are sufficient to conclude that the BC Hydro natural gas curves are both reasonable and viable. And as such they represent a pragmatic basis from which the Mid-Columbia electricity curves could justifiably be derived.

[69] The Midgard methodology of generating high scenario natural gas curve renders the comparison of the 2011 high case findings with the BC Hydro method of generating the high scenario natural gas curve for 2011 moot.

Appendix B: Greenhouse Gas Cost Forecast Curve

Background

With various levels of government policy increasingly favoring and encouraging renewable and clean energy sources, there has been growing consideration of taxing carbon emissions. Such taxes are meant to discourage carbon emissions and, in some cases, provide funding for investment in cleaner energy generation sources.

In BC the *Carbon Tax Act* taxes greenhouse gas emissions and sets price increases through 2012 (increasing $5/Tonne CO2 per year to $30/Tonne CO2 in 2012[70]) with the price set to remain at 2012 levels until further notice.

BC is currently one of few regions in North America to have a carbon tax system, with neither Canada nor the US having national policies[71]. The futures of such national policies will have a direct impact on greenhouse gas ("**GHG**") prices. It should be highlighted that there is a limited history to the pricing of GHGs and that pricing is largely a function of government regulation rather than being driven by a genuine market demand.

BC Hydro Forecast GHG Curves

Consultants Black and Veatch (B&V) were retained by BC Hydro to forecast GHG prices[72]. Their analysis focused on policy and economic recovery as the main influencing factors of GHG prices.

BC currently has aggressive GHG reduction policies (specified in the *Clean Energy Act*). The B&V report suggests that in the future, US policy will have a strong impact on worldwide GHG prices (given the size and importance of their economy in the global context). However, it also suggests that a US national GHG policy is unlikely in the near future. Given Canada's propensity to align its national policies with those of the US, a national GHG pricing policy in Canada is equally unlikely in the near future.

The report also links GHG prices to economic recovery, suggesting that the increased GHG emissions resulting from strong economic growth, combined with increased public and government interest in GHG reduction resulting from said growth, would result in aggressive environmental policies. Conversely, slow economic growth is predicted to mean slower growth of GHG emissions which, combined with government focus on issues other than environmental protection, would reduce interest in such environmental policies.

[70] BC Budget and Fiscal Plan 2011/12-2013/14

[71] US National Renewable Energy Laboratory, "Carbon Taxes: A Review of Experience and Policy Design Considerations", 2009

[72] BC Hydro, 2011 IRP Technical Advisory Committee Summary Brief: GHG Price Forecast, January 2011

Using a variety of scenarios that combine possible outcomes of the above factors, B&V developed the following forecast (see Figure B-1and Table B-1), with the various lines representing the different scenarios presented.

Figure B-1: BC Hydro Forecast GHG Price Curves (2010 CAD)

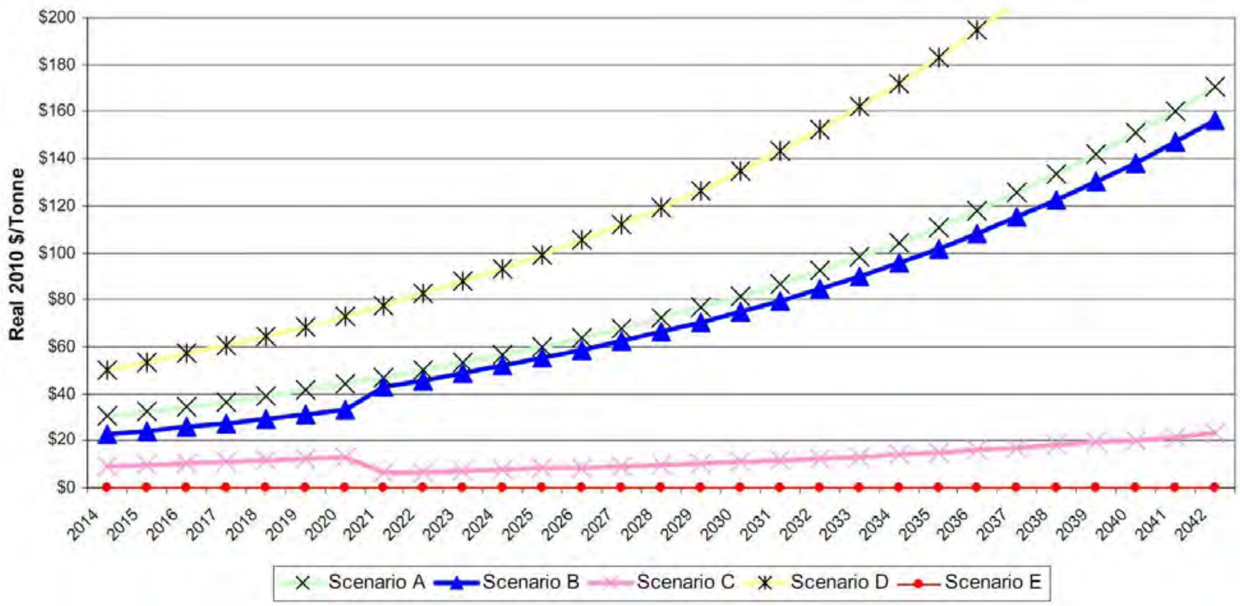


Table B-1: BC Hydro Forecast GHG Price Curves (2010 CAD)

Year	A	B	C	D	E
2014	$50.07	$22.19	$8.82	$30.44	$0.00
2015	$53.20	$23.90	$9.39	$32.43	$0.00
2016	$57.18	$25.89	$10.24	$34.14	$0.00
2017	$60.31	$27.31	$10.81	$36.42	$0.00
2018	$64.30	$29.02	$11.38	$38.98	$0.00
2019	$68.28	$31.29	$11.95	$41.54	$0.00
2020	$72.83	$33.29	$12.80	$44.10	$0.00
2021	$77.38	$42.67	$6.26	$46.66	$0.00
2022	$82.50	$45.23	$6.26	$49.79	$0.00
2023	$87.62	$48.65	$6.83	$53.20	$0.00
2024	$93.03	$51.78	$7.40	$56.33	$0.00
2025	$99.00	$55.19	$8.25	$59.46	$0.00
2026	$105.55	$58.32	$8.25	$63.73	$0.00
2027	$111.81	$62.30	$8.82	$67.43	$0.00

Year	A	B	C	D	E
2028	$118.92	$66.29	$9.39	$72.26	$0.00
2029	$126.32	$69.99	$9.96	$76.53	$0.00
2030	$134.85	$74.82	$10.81	$81.37	$0.00
2031	$143.10	$79.37	$11.38	$86.49	$0.00
2032	$152.20	$84.50	$11.95	$92.46	$0.00
2033	$162.16	$89.62	$12.80	$98.15	$0.00
2034	$171.83	$95.59	$13.94	$104.13	$0.00
2035	$182.93	$101.28	$14.51	$110.67	$0.00
2036	$194.59	$107.82	$15.93	$117.78	$0.00
2037	$207.15	$115.22	$16.79	$125.46	$0.00
2038	$220.30	$122.62	$17.92	$133.43	$0.00
2039	$234.30	$130.30	$19.35	$141.68	$0.00
2040	$249.18	$137.98	$19.91	$151.07	$0.00
2041	$265.01	$147.08	$21.05	$160.17	$0.00
2042	$281.84	$156.19	$23.04	$170.70	$0.00

BC Hydro defines the five scenarios as follows[73]:

- *Scenario A: High global economic growth leads to high commodity demand and broad environmental regulation*
- *Scenario B: Slow but steady global economic growth sees regional leaders paving the way for national GHG markets*
- *Scenario C: Low economic growth delays national GHG market development*
- *Scenario D: Delayed high economic growth and lower international cooperation stifles national action, leaving the regions to regulate GHG emissions*
- *Scenario E: Low economic growth and activity lead to lower GHG emissions and the absence of market prices*

Validation of GHG Curves

While the B&V report was prepared for BC Hydro, it addresses GHG costs in a very general, regional context. Forecasting GHG prices is inherently uncertain, perhaps even more so than most commodities given the greater influence of politics in their price setting. Despite the very wide range of the B&V

[73] BC Hydro, 2011 IRP Technical Advisory Committee Summary Brief: GHG Price Forecast, January 2011

predictions (an unavoidable product of said uncertainty), Midgard finds no fault with their logic and consequently no reason to disagree with their conclusions.

Midgard recommends the use of the Scenario B GHG price curve as the most likely GHG price forecast.

Attachment 7.1

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 7.2

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 7.6.1

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 7.7.1

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 8.4

B O N N E V I L L E   P O W E R   A D M I N I S T R A T I O N

2012 Transmission and Ancillary Service Rate Schedules

General Rate Schedule Provisions (FY 2012-2013)

October 2011

B O N N E V I L L E   P O W E R   A D M I N I S T R A T I O N

2012 Transmission and Ancillary Service Rate Schedules

General Rate Schedule Provisions (FY 2012-2013)

October 2011

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United States Department of Energy
Bonneville Power Administration
905 N.E. 11th Avenue
Portland, OR 97232

Bonneville Power Administration's 2012 Transmission, Ancillary and Control Area Service Rate Schedules and General Rate Schedule Provisions, effective October 1, 2011, and contained herein, were approved on an interim basis by the Federal Energy Regulatory Commission on September 22, 2011. *U.S. Dep't of Energy – Bonneville Power Admin.*, 136 FERC ¶62,253 (2011).

v

These rate schedules and General Rate Schedule Provisions reflect all errata corrections as of the date of publication.

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INDEX

2012 TRANSMISSION, ANCILLARY AND CONTROL AREA SERVICE

RATE SCHEDULES

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RATE SCHEDULES

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FPT-12.1
FORMULA POWER TRANSMISSION RATE

SECTION I. AVAILABILITY

This schedule supersedes Schedule FPT-10.1 for all firm transmission agreements that provide for application of FPT rates that may be adjusted not more frequently than once a year. This schedule is applicable only to such transmission agreements executed prior to October 1, 1996. It is available for firm transmission of non-Federal power using the Main Grid and/or Secondary System of the Federal Columbia River Transmission System. This schedule is for full-year and partial-year service and for either continuous or intermittent service when firm transmission service is required. For facilities at voltages lower than the Secondary System, a different rate schedule may be specified. Service under this schedule is subject to BPA-TS's General Rate Schedule Provisions (GRSPs).

SECTION II. RATES

The monthly charge per kilowatt (kW) shall be one-twelfth of the sum of the Main Grid Charge and the Secondary System Charge, as applicable and as specified in the agreement.

The Main Grid and Secondary System charges are calculated each quarter beginning October 2007 according to the following formula:

$$\left(1 + \frac{GSR_q}{\$1.327/\text{kW/mo}}\right) * \text{ FPT Base Charges}$$

Where:

GSR_q = The ACS-12 Reactive Supply and Voltage Control From Generation Sources Service Rate for Long-Term Firm PTP Transmission Service and NT Service, section II.B.1.a., that is effective for the quarter for which the FPT rate is being calculated, in $/kW/mo.

FPT Base Charges = The following annual Main Grid and Secondary System charges:

MAIN GRID CHARGES		
1.	Main Grid Distance	$0.0587 per mile
2.	Main Grid Interconnection Terminal	$0.61/kW
3.	Main Grid Terminal	$0.68/kW
4.	Main Grid Miscellaneous Facilities	$3.35/kW
SECONDARY SYSTEM CHARGES		
1.	Secondary System Distance	$0.5772 per mile
2.	Secondary System Transformation	$6.31/kW
3.	Secondary System Intermediate Terminal	$2.44/kW
4.	Secondary System Interconnection Terminal	$1.73/kW

Main Grid Distance and Secondary System Distance charges shall be calculated to four decimal places. All other Main Grid and Secondary System charges shall be calculated to two decimal places.

The Main Grid Charge per kilowatt shall be the sum of one or more of the Main Grid annual charges, as specified in the agreement. The Secondary System Charge per kilowatt shall be the sum of one or more of the Secondary System annual charges, as specified in the agreement.

SECTION III. BILLING FACTORS

Unless otherwise stated in the agreement, the Billing Factor for the rates specified in section II shall be the largest of:

A. The Transmission Demand;

B. The highest hourly Scheduled Demand for the month; or

C. The Ratchet Demand.

SECTION IV. ADJUSTMENTS, CHARGES, AND OTHER RATE PROVISIONS

A. ANCILLARY SERVICES

Ancillary Services that may be required to support FPT transmission service are available under the ACS rate schedule. FPT customers do not pay the ACS charges for Scheduling, System Control, and Dispatch Service or Reactive Supply and Voltage

Control from Generation Sources Service, because these services are included in FPT service.

B. FAILURE TO COMPLY PENALTY

Customers taking service under this rate schedule are subject to the Failure to Comply Penalty Charge, specified in section II.B. of the GRSPs.

C. POWER FACTOR PENALTY

Customers taking service under this rate schedule are subject to the Power Factor Penalty Charge, specified in section II.C. of the GRSPs.

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FPT-12.3
FORMULA POWER TRANSMISSION RATE

SECTION I. AVAILABILITY

This schedule supersedes Schedule FPT-10.3 for all firm transmission agreements that provide for application of FPT rates that may be adjusted not more frequently than once every three years. This schedule is applicable only to such transmission agreements executed prior to October 1, 1996. It is available for firm transmission of non-Federal power using the Main Grid and/or Secondary System of the Federal Columbia River Transmission System. This schedule is for full-year and partial-year service and for either continuous or intermittent service when firm transmission service is required. For facilities at voltages lower than the Secondary System, a different rate schedule may be specified. Service under this schedule is subject to BPA-TS's General Rate Schedule Provisions (GRSPs).

SECTION II. RATES

The monthly charge per kilowatt (kW) shall be one-twelfth of the sum of the Main Grid Charge and the Secondary System Charge, as applicable and as specified in the agreement.

The Main Grid and Secondary System charges are calculated each quarter beginning October 2007 according to the following formula:

$$\left(1 + \frac{GSR_q}{\$1.327/\text{kW/mo}}\right) * \text{FPT Base Charges}$$

Where:

GSR_q = The ACS-12 Reactive Supply and Voltage Control From Generation Sources Service Rate for Long-Term Firm PTP Transmission Service and NT Service, section II.B.1.a., that is effective for the quarter for which the FPT rate is being calculated, in $/kW/mo.

FPT Base Charges = The following annual Main Grid and Secondary System charges:

MAIN GRID CHARGES		
1.	Main Grid Distance	$0.0587 per mile
2.	Main Grid Interconnection Terminal	$0.61/kW
3.	Main Grid Terminal	$0.68/kW
4.	Main Grid Miscellaneous Facilities	$3.35/kW
SECONDARY SYSTEM CHARGES		
1.	Secondary System Distance	$0.5772 per mile
2.	Secondary System Transformation	$6.31/kW
3.	Secondary System Intermediate Terminal	$2.44/kW
4.	Secondary System Interconnection Terminal	$1.73/kW

Main Grid Distance and Secondary System Distance charges shall be calculated to four decimal places. All other Main Grid and Secondary System charges shall be calculated to two decimal places.

The Main Grid Charge per kilowatt shall be the sum of one or more of the Main Grid annual charges, as specified in the agreement. The Secondary System Charge per kilowatt shall be the sum of one or more of the Secondary System annual charges, as specified in the agreement.

SECTION III. BILLING FACTORS

Unless otherwise stated in the agreement, the Billing Factor for the rates specified in section II shall be the largest of:

A. The Transmission Demand;

B. The highest hourly Scheduled Demand for the month; or

C. The Ratchet Demand.

SECTION IV. ADJUSTMENTS, CHARGES, AND OTHER RATE PROVISIONS

A. ANCILLARY SERVICES

Ancillary Services that may be required to support FPT transmission service are available under the ACS rate schedule. FPT customers do not pay the ACS charges for Scheduling, System Control, and Dispatch Service or Reactive Supply and Voltage Control from Generation Sources Service, because these services are included in FPT service.

B. FAILURE TO COMPLY PENALTY

Customers taking transmission service under FPT agreements are subject to the Failure to Comply Penalty Charge, specified in section II.B. of the GRSPs.

C. POWER FACTOR PENALTY

Customers taking transmission service under FPT agreements are subject to the Power Factor Penalty Charge, specified in section II.C. of the GRSPs.

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IR-12
INTEGRATION OF RESOURCES RATE

SECTION I. AVAILABILITY

This schedule supersedes Schedule IR-10 and is available for transmission of non-Federal power for full-year firm transmission service and non-firm transmission service in amounts not to exceed the customer's total Transmission Demand using Federal Columbia River Transmission System Network and Delivery facilities. This schedule is applicable only to Integration of Resource (IR) agreements executed prior to October 1, 1996. Service under this schedule is subject to BPA-TS's General Rate Schedule Provisions (GRSPs).

SECTION II. RATES

The IR rates in sections A and B, below, are calculated each quarter beginning October 2007. These rates shall be calculated to three decimal places. The monthly IR rate shall be as provided in section A or section B.

A. BASE RATE

The Base Rate shall be the sum of:

1. $1.498 per kilowatt per month ($/kW/mo); and

2. ACS-12 Reactive Supply and Voltage Control From Generation Sources Service Rate for Long-Term Firm PTP Transmission Service and NT Service, section II.B.1.a., effective for the quarter for which the IR rate is being calculated, in $/kW/mo.

B. SHORT DISTANCE DISCOUNT (SDD) RATE

For Points of Integration (POI) specified in the IR agreement as being short-distance POIs, for which Network facilities are used for a distance of less than 75 circuit miles, the monthly rate shall be the sum of:

1. $0.203/kW/mo; and

2. ACS-12 Reactive Supply and Voltage Control From Generation Sources Service Rate for Long-Term Firm PTP Transmission Service and NT Service, section II.B.1.a., effective for the quarter for which the IR rate is being calculated, in $/kW/mo; and

3. (0.6 + (0.4 x transmission distance/75)) x $1.295/kW/mo

Where:

The transmission distance is the circuit miles between a designated POI for a generating resource of the customer and a designated Point of Delivery serving load of the customer. Short-distance POIs are determined by BPA-TS after considering factors in addition to transmission distance.

SECTION III. BILLING FACTORS

The Billing Factor for rates specified in section II shall be the largest of:

A. The annual Transmission Demand, or, if defined in the agreement, the annual Total Transmission Demand;

B. The highest hourly Scheduled Demand for the month; or

C. The Ratchet Demand.

To the extent that the agreement provides for the IR customer to be billed for transmission service in excess of the Transmission Demand or Total Transmission Demand, as defined in the agreement, at an hourly non-firm rate, such excess transmission service shall not contribute to the Billing Factor for the IR rates in section II; provided that the IR customer requests such treatment and BPA-TS approves such request in accordance with the prescribed provisions in the agreement. The rate for transmission service in excess of the Transmission Demand will be pursuant to the Point-to-Point Rate (PTP-12) for Hourly Non-Firm Service.

When the Scheduled Demand or Ratchet Demand is the Billing Factor, short-distance POIs shall be charged the Base Rate specified in section II.A. for the amount in excess of Transmission Demand.

SECTION IV. ADJUSTMENTS, CHARGES, AND OTHER RATE PROVISIONS

A. ANCILLARY SERVICES

Ancillary Services that may be required to support IR transmission service are available under the ACS rate schedule. IR customers do not pay the ACS charges for Scheduling, System Control, and Dispatch Service or Reactive Supply and Voltage Control from Generation Sources Service, because these services are included in IR service.

B. DELIVERY CHARGE

Customers taking service over Delivery facilities are subject to the Delivery Charge, specified in section II.A. of the GRSPs.

C. FAILURE TO COMPLY PENALTY

Customers taking service under this rate schedule are subject to the Failure to Comply Penalty Charge, specified in section II.B. of the GRSPs.

D. POWER FACTOR PENALTY

Customers taking service under this rate schedule are subject to the Power Factor Penalty Charge, specified in section II.C. of the GRSPs.

E. RATCHET DEMAND RELIEF

Under appropriate circumstances, BPA-TS may waive or reduce the Ratchet Demand. An IR customer seeking a reduction or waiver must demonstrate good cause for relief, including a demonstration that:

1. The event that resulted in the Ratchet Demand

    a. was the result of an equipment failure or outage that could not reasonably have been foreseen by the customer; and

    b. did not result in harm to BPA's transmission system or transmission services, or to any other Transmission Customer; or

2. The event that resulted in the Ratchet Demand

    a. was inadvertent;

    b. could not have been avoided by the exercise of reasonable care;

    c. did not result in harm to BPA's transmission system or transmission services, or to any other Transmission Customer; and

    d. was not part of a recurring pattern of conduct by the IR customer.

If the IR customer causes a Ratchet Demand to be established in a series of months during which the IR customer has not received notice from BPA-TS of such Ratchet Demands by billing or otherwise, and the Ratchet Demand(s) established after the first Ratchet Demand were due to the lack of notice, then BPA-TS may establish a Ratchet Demand for the IR customer based on the highest Ratchet Demand in the series. This highest Ratchet Demand will be charged in the month it is established and the following

11 months. All other Ratchet Demands based on such a series (including the Ratchet Demand established in the first month if it is not the highest Ratchet Demand) will be waived.

Ratchet Demand Relief is not available in the month in which the Ratchet Demand was established. For that month, the Customer will be assessed charges based upon the highest hourly Scheduled Demand Billing Factor.

F. SELF-SUPPLY OF REACTIVE SUPPLY AND VOLTAGE CONTROL FROM GENERATION SOURCES SERVICE

A credit for self-supply of Reactive Supply and Voltage Control from Generation Sources Service will be available for IR customers on an equivalent basis to the credit for PTP Transmission Customers.

NT-12
NETWORK INTEGRATION RATE

SECTION I. AVAILABILITY

This schedule supersedes Schedule NT-10. It is available to Transmission Customers taking Network Integration Transmission (NT) Service over Federal Columbia River Transmission System Network and Delivery facilities and to Transmission Customers taking Conditional Firm Service. Terms and conditions of service are specified in the Open Access Transmission Tariff. This schedule is available also for transmission service of a similar nature that may be ordered by the Federal Energy Regulatory Commission (FERC) pursuant to sections 211 and 212 of the Federal Power Act (16 U.S.C. §§ 824j and 824k). Service under this schedule is subject to BPA-TS's General Rate Schedule Provisions (GRSPs).

SECTION II. RATES

The monthly charge will be the sum of A and B.

A. BASE CHARGE

$1.298 per kilowatt per month

B. LOAD SHAPING CHARGE

$0.367 per kilowatt per month

SECTION III. BILLING FACTORS

A. BASE CHARGE

The monthly Billing Factor for the Base Charge specified in section II.A. shall be the customer's Network Load on the hour of the Monthly Transmission Peak Load.

B. LOAD SHAPING CHARGE

The monthly Billing Factor for the Load Shaping Charge specified in section II.B. shall be the customer's Network Load on the hour of the Monthly Transmission Peak Load.

SECTION IV. ADJUSTMENTS, CHARGES, AND OTHER RATE PROVISIONS

A. ANCILLARY SERVICES

Customers taking service under this rate schedule are subject to the ACS Scheduling, System Control, and Dispatch Service Rate and the Reactive Supply and Voltage Control from Generation Sources Service Rate. Other Ancillary Services that are required to support NT Service are also available under the ACS rate schedule.

B. DELIVERY CHARGE

Customers taking NT Service over Delivery facilities are subject to the Delivery Charge, specified in section II.A. of the GRSPs.

C. FAILURE TO COMPLY PENALTY

Customers taking NT Service are subject to the Failure to Comply Penalty Charge, specified in section II.B. of the GRSPs.

D. METERING ADJUSTMENT

At those Points of Delivery that do not have meters capable of determining the demand on the hour of the Monthly Transmission Peak Load, the Billing Demand shall be calculated by substituting 1) the sum of the highest hourly demand that occurs during the billing month at all Points of Delivery multiplied by 0.79 for 2) Network Load on the hour of the Monthly Transmission Peak Load.

E. POWER FACTOR PENALTY

Customers taking service under this rate are subject to the Power Factor Penalty Charge, specified in section II.C. of the GRSPs.

F. SHORT-DISTANCE DISCOUNT (SDD)

A Customer’s monthly NT bill shall be adjusted to reflect a Short Distance Discount (SDD) when a Customer has a resource that (1) is designated as a Network Resource (DNR) in the customer’s NT Service Agreement for at least 12 months, and (2) uses FCRTS facilities for less than 75 circuit miles for delivery to the Network Load. A DNR that is a system sale (the DNR is not associated with a specific generating resource) does not qualify for the SDD. Any DNR that is eligible for the SDD (DNR SD) must be noted as such in the NT Service Agreement.

The NT monthly bill will be reduced by a credit equal to:

$$\text{Avg. Generation of the DNR SD during HLH} \times \text{NT Rate} \times \frac{75 - \text{Tx Distance}}{75} \times 0.4$$

Where:

Average Generation during HLH =	The output serving Network Load during HLH on a firm basis over the billing month, divided by the number of HLH during the month, multiplied by the ratio of the Qualifying Capacity of the DNR SD output serving the Customer's POD(s) to the total DNR SD designated capacity. The output serving Network Load is: 1. in the case of a scheduled DNR SD, the sum of firm schedules to Network Load; and 2. in the case of Behind the Meter Resources, the metered output of the resource.
NT Rate =	NT Base Charge
Tx Distance =	The contractually specified distance measured in circuit miles between the DNR SD POR and the Customer's nearest POD(s) within 75 circuit miles of the DNR SD. 1. BPA shall use the peak load for the prior calendar year for the POD nearest to the DNR SD to calculate how much of the DNR SD's designated capacity is allocated to that POD. If the peak load for the prior calendar year of the closest POD is less than the DNR SD's designated capacity, then BPA shall use the next nearest POD that is within 75 circuit miles of the DNR SD, continuing until the DNR SD's designated capacity is fully allocated to the qualifying PODs, subject to section 2 below. The Tx Distance shall be the sum of the distance from the DNR SD to each of the PODs, weighted by the DNR SD designated capacity allocated to each POD. 2. The amount of designated capacity from all DNR SD allocated to any POD may not exceed the POD's peak load. 3. For a DNR SD directly connected to the customer's system (including Behind the Meter Resources) or a DNR SD that does not use BPA's network facilities, the TX Distance shall be zero.

Qualifying Capacity =	The sum of all DNR SD designated capacity allocated to the Customer's POD(s). For a DNR SD directly connected to the customer's system (including Behind the Meter Resources) or a DNR SD that does not use BPA's network facilities, the Qualifying Capacity shall be the total DNR SD designated capacity.
Behind the Meter Resource =	A resource that is used solely to serve the NT Customer's Network Load and is internal to the NT Customer's system.

G. DIRECT ASSIGNMENT FACILITIES

BPA-TS shall collect the capital and related costs of a Direct Assignment Facility under the Advance Funding (AF) rate or the Use-of-Facilities (UFT) rate. Other associated costs, including but not limited to operations, maintenance, and general plant costs, also shall be recovered from the Network Customer under an applicable rate schedule.

H. INCREMENTAL COST RATES

The rates specified in section II are applicable to service over available transmission capacity. Network Customers that integrate new Network Resources, new Member Systems, or new native load customers that would require BPA-TS to construct Network Upgrades shall be subject to the higher of the rates specified in section II or incremental cost rates for service over such facilities. Incremental cost rates would be developed pursuant to section 7(i) of the Northwest Power Act.

I. RATE ADJUSTMENT DUE TO FERC ORDER UNDER FPA § 212

Customers taking service under this rate schedule are subject to the Rate Adjustment Due to FERC Order under FPA § 212, specified in section II.D. of the GRSPs.

PTP-12
POINT-TO-POINT RATE

SECTION I. AVAILABILITY

This schedule supersedes Schedule PTP-10. It is available to Transmission Customers taking Point-to-Point (PTP) Transmission Service over Federal Columbia River Transmission System (FCRTS) Network and Delivery facilities, for hourly non-firm service over such FCRTS facilities for customers with Integration of Resources agreements, and to customers taking Conditional Firm (CF) Transmission Service, if BPA adopts CF Transmission Service. Terms and conditions of PTP are specified in the Open Access Transmission Tariff. This schedule is available also for transmission service of a similar nature that may be ordered by the Federal Energy Regulatory Commission (FERC) pursuant to sections 211 and 212 of the Federal Power Act (16 U.S.C. §§ 824j and 824k). Service under this schedule is subject to BPA-TS's General Rate Schedule Provisions (GRSPs).

SECTION II. RATES

A. LONG-TERM FIRM PTP TRANSMISSION SERVICE

$1.298 per kilowatt per month

B. SHORT-TERM FIRM AND NON-FIRM PTP TRANSMISSION SERVICE

For each reservation, the rates shall not exceed:

1. Monthly, Weekly, and Daily Firm and Non-Firm Service

a. Days 1 through 5 $0.060 per kilowatt per day

b. Day 6 and beyond $0.046 per kilowatt per day

2. Hourly Firm and Non-Firm Service

3.74 mills per kilowatthour

SECTION III. BILLING FACTORS

A. ALL FIRM SERVICE AND MONTHLY, WEEKLY, AND DAILY NON-FIRM SERVICE

The Billing Factor for each rate specified in sections II.A. and II.B. for all service shall be the Reserved Capacity, which is the greater of:

1. the sum of the capacity reservations at the Point(s) of Receipt, or

2. the sum of the capacity reservations at the Point(s) of Delivery.

B. REDIRECT SERVICE

Redirecting Long-Term Firm PTP to Short-Term Firm PTP service will not result in an additional charge if the capacity reservation does not exceed the amount reserved in the existing service agreement.

SECTION IV. ADJUSTMENTS, CHARGES, AND OTHER RATE PROVISIONS

A. ANCILLARY SERVICES

Customers taking service under this rate schedule are subject to the ACS Scheduling, System Control, and Dispatch Service Rate and the Reactive Supply and Voltage Control from Generation Sources Service Rate. Other Ancillary Services that are required to support PTP Transmission Service on the Network are available under the ACS rate schedule.

B. DELIVERY CHARGE

Customers taking PTP Transmission Service over Delivery facilities are subject to the Delivery Charge, specified in section II.A. of the GRSPs.

C. FAILURE TO COMPLY PENALTY

Customers taking service under this rate schedule are subject to the Failure to Comply Penalty Charge, specified in section II.B. of the GRSPs.

D. INTERRUPTION OF NON-FIRM PTP TRANSMISSION SERVICE

If daily, weekly, or monthly Non-Firm PTP Transmission Service is interrupted, the rates charged under section II.B.1 shall be prorated over the total hours in the day to give credit for the hours of such interruption.

When Reserved Capacity becomes the Billing Factor for Hourly Non-Firm Service, the following shall apply:

1. If the need for Curtailment is caused by conditions on the FCRTS, the Billing Factor will be as follows:

    a. If Hourly Non-Firm PTP Transmission Service is Curtailed or Interrupted before the close of the hourly non-firm scheduling window, the Billing Factor will be the Reserved Capacity minus the curtailed capacity.

b. If Hourly Non-Firm PTP Transmission Service is Curtailed or Interrupted after the close of the hourly non-firm scheduling window, the Billing Factor will be the Transmission Customer's actual schedule in the hour.

2. If the need for Curtailment is caused by conditions on another transmission provider's transmission system, the Billing Factor will be the Reserved Capacity.

E. POWER FACTOR PENALTY

Customers taking service under this rate schedule are subject to the Power Factor Penalty Charge, specified in section II.C. of the GRSPs.

F. RESERVATION FEE

Customers that postpone the commencement of Long-Term Firm Point-To-Point Transmission Service by requesting an extension of the Service Commencement Date will be subject to the Reservation Fee, specified in section II.E. of the GRSPs.

G. SHORT-DISTANCE DISCOUNT (SDD)

When a Point of Receipt (POR) and Point of Delivery (POD) use FCRTS facilities for a distance of less than 75 circuit miles and are designated as being short distance in the PTP Service Agreement, the monthly capacity reservations for the relevant POR and POD shall be adjusted, for the purpose of computing the monthly bill for annual service, by the following factor:

$$0.6 + (0.4 \text{ x transmission distance}/75)$$

Such adjusted monthly POR and POD reservations shall be used to compute the billing factors in section III.A to calculate the monthly bill for Long-Term Firm PTP Transmission Service. The POD capacity reservation eligible for the SDD may be no larger than the POR capacity reservation. The distance used to calculate the SDD will be contractually specified and based upon path(s) identified in power flow studies. If a set of contiguous PODs qualifies for an SDD, the transmission distance used in the calculation of the SDD shall be between the POR and the POD farthest from the POR.

If the customer requests secondary PORs or PODs that use SDD-adjusted capacity reservations for any period of time during a month, the SDD shall not be applied that month.

H. UNAUTHORIZED INCREASE CHARGE

Customers that exceed their capacity reservations at any Point of Receipt (POR) or Point of Delivery (POD) shall be subject to the Unauthorized Increase Charge, specified in section II.G. of the GRSPs.

I. DIRECT ASSIGNMENT FACILITIES

BPA-TS shall collect the capital and related costs of a Direct Assignment Facility under the Advance Funding (AF) rate or the Use-of-Facilities (UFT) rate. Other associated costs, including but not limited to operations, maintenance, and general plant costs, also shall be recovered from the PTP Transmission Customer under an applicable rate schedule.

J. INCREMENTAL COST RATES

The rates specified in section II. are applicable to service over available transmission capacity. Customers requesting new or increased firm service that would require BPA-TS to construct Network Upgrades to alleviate a capacity constraint may be subject to incremental cost rates for such service if incremental cost is higher than embedded cost. Incremental cost rates would be developed pursuant to section 7(i) of the Northwest Power Act.

K. RATE ADJUSTMENT DUE TO FERC ORDER UNDER FPA § 212

Customers taking service under this rate schedule are subject to the Rate Adjustment Due to FERC Order under FPA § 212, specified in section II.D. of the GRSPs.

IS-12
SOUTHERN INTERTIE RATE

SECTION I. AVAILABILITY

This schedule supersedes Schedule IS-10. It is available to Transmission Customers taking Point-to-Point Transmission Service over Federal Columbia River Transmission System (FCRTS) Southern Intertie facilities. Terms and conditions of service are specified in the Open Access Transmission Tariff or, for customers that executed Southern Intertie agreements with BPA before October 1, 1996, will be as provided in the customer's agreement with BPA. This schedule is available also for transmission service of a similar nature that may be ordered by the Federal Energy Regulatory Commission (FERC) pursuant to sections 211 and 212 of the Federal Power Act (16 U.S.C. §§ 824j and 824k). Service under this schedule is subject to BPA-TS's General Rate Schedule Provisions (GRSPs).

SECTION II. RATES

A. LONG-TERM FIRM PTP TRANSMISSION SERVICE

$1.293 per kilowatt per month

B. SHORT-TERM FIRM AND NON-FIRM PTP TRANSMISSION SERVICE

For each reservation, the rates shall not exceed:

1. **Monthly, Weekly, and Daily Firm and Non-Firm Service**

    a. **Days 1 through 5** $0.060 per kilowatt per day

    b. **Day 6 and beyond** $0.045 per kilowatt per day

2. **Hourly Firm and Non-Firm Service**

    3.72 mills per kilowatthour

SECTION III. BILLING FACTORS

A. ALL FIRM SERVICE AND MONTHLY, WEEKLY, AND DAILY NON-FIRM SERVICE

The Billing Factor for each rate specified in sections II.A. and II.B. for all service shall be the Reserved Capacity, which is the greater of:

1. the sum of the capacity reservations at the Point(s) of Receipt, or

2. the sum of the capacity reservations at the Point(s) of Delivery.

For Southern Intertie transmission agreements executed prior to October 1, 1996, the Billing Factor shall be as specified in the agreement.

B. REDIRECT SERVICE

Redirecting Long-Term Firm PTP to Short-Term Firm PTP service will not result in an additional charge if the capacity reservation does not exceed the amount reserved in the existing service agreement.

SECTION IV. ADJUSTMENTS, CHARGES, AND OTHER RATE PROVISIONS

A. ANCILLARY SERVICES

Customers taking service under this rate schedule are subject to the ACS Scheduling, System Control, and Dispatch Service Rate and the Reactive Supply and Voltage Control from Generation Sources Service Rate. Other Ancillary Services that are required to support PTP Transmission Service on the Southern Intertie are available under the ACS rate schedule.

B. FAILURE TO COMPLY PENALTY

Customers taking service under this rate schedule are subject to the Failure to Comply Penalty Charge specified in section II.B. of the GRSPs.

C. INTERRUPTION OF NON-FIRM PTP TRANSMISSION SERVICE

If daily, weekly, or monthly Non-Firm PTP Transmission Service is interrupted, the rates charged under section II.B.1. shall be prorated over the total hours in the day to give credit for the hours of such interruption.

When Reserved Capacity becomes the Billing Factor for Hourly Non-Firm Service, the following shall apply:

1. If the need for Curtailment is caused by conditions on the Federal Columbia River Transmission System, the Billing Factor will be as follows:

   a. If Hourly Non-Firm PTP Transmission Service is Curtailed or Interrupted before the close of the hourly non-firm scheduling window, the Billing Factor will be the Reserved Capacity minus the curtailed capacity.

   b. If Hourly Non-Firm PTP Transmission Service is Curtailed or Interrupted after the close of the hourly non-firm scheduling window, the Billing Factor will be the Transmission Customer's actual schedule in the hour.

2. If the need for Curtailment is caused by conditions on another transmission provider's transmission system, the Billing Factor will be the Reserved Capacity.

D. POWER FACTOR PENALTY

Customers taking service under this rate schedule are subject to the Power Factor Penalty Charge specified in section II.C. of the GRSPs.

E. RESERVATION FEE

Customers that postpone the commencement of Long-Term Firm Point-To-Point Transmission Service by requesting an extension of their Service Commencement Date will be subject to the Reservation Fee specified in section II.E of the GRSPs.

F. UNAUTHORIZED INCREASE CHARGE

Customers that exceed their capacity reservations at any Point of Receipt (POR) or Point of Delivery (POD) shall be subject to the Unauthorized Increase Charge, specified in section II.G. in the GRSPs.

G. DIRECT ASSIGNMENT FACILITIES

BPA-TS shall collect the capital and related costs of a Direct Assignment Facility under the Advance Funding (AF) rate or the Use-of-Facilities (UFT) rate. Other associated costs, including but not limited to operations, maintenance, and general plant costs, also shall be recovered from the Transmission Customer under an applicable rate schedule.

H. INCREMENTAL COST RATES

The rates specified in section II. are applicable to service over available transmission capacity. Customers requesting new or increased firm service that would require BPA-TS to construct new facilities or upgrades to alleviate a capacity constraint may be subject to incremental cost rates for such service if incremental cost is higher than embedded cost. Incremental cost rates would be developed pursuant to section 7(i) of the Northwest Power Act.

I. RATE ADJUSTMENT DUE TO FERC ORDER UNDER FPA § 212

Customers taking service under this rate schedule are subject to the Rate Adjustment Due to FERC Order under FPA § 212, specified in section II.D. of the GRSPs.

IM-12
MONTANA INTERTIE RATE

SECTION I. AVAILABILITY

This schedule supersedes Schedule IM-10. It is available to Transmission Customers taking Point-to-Point (PTP) Transmission Service on the Eastern Intertie. Terms and conditions of service are specified in the Open Access Transmission Tariff. This transmission capacity schedule is available also for transmission service of a similar nature that may be ordered by the Federal Energy Regulatory Commission (FERC) pursuant to sections 211 and 212 of the Federal Power Act (16 U.S.C. §§ 824j and 824k). Service under this schedule is subject to BPA-TS's General Rate Schedule Provisions (GRSPs).

SECTION II. RATES

A. LONG-TERM FIRM PTP TRANSMISSION SERVICE

$0.598 per kilowatt per month

B. SHORT-TERM FIRM AND NON-FIRM PTP TRANSMISSION SERVICE

For each reservation, the rates shall not exceed:

1. **Monthly, Weekly, and Daily Short-Term Firm and Non-Firm Service**

    a. **Days 1 through 5** $0.028 per kilowatt per day

    b. **Day 6 and beyond** $0.020 per kilowatt per day

2. **Hourly Firm and Non-Firm Service**

    1.72 mills per kilowatthour

SECTION III. BILLING FACTORS

A. ALL FIRM SERVICE AND MONTHLY, WEEKLY, AND DAILY NON-FIRM SERVICE

The Billing Factor for each rate specified in section II.A. and II.B. for all service shall be the Reserved Capacity, which is the greater of:

1. the sum of the capacity reservations at the Point(s) of Receipt, or

2. the sum of the capacity reservations at the Point(s) of Delivery.

B. REDIRECT SERVICE

Redirecting Long-Term Firm PTP to Short-Term Firm PTP service will not result in an additional charge if the capacity reservation does not exceed the amount reserved in the existing service agreement.

SECTION IV. ADJUSTMENTS, CHARGES, AND OTHER RATE PROVISIONS

A. ANCILLARY SERVICES

Customers taking service under this rate schedule are subject to the ACS Scheduling, System Control, and Dispatch Service Rate and the Reactive Supply and Voltage Control from Generation Sources Service Rate. Other Ancillary Services that are required to support PTP Transmission Service on the Montana Intertie are available under the ACS rate schedule.

B. FAILURE TO COMPLY PENALTY CHARGE

Customers taking service under this rate schedule are subject to the Failure to Comply Penalty Charge, specified in section II.B. of the GRSPs.

C. INTERRUPTION OF NON-FIRM PTP TRANSMISSION SERVICE

If daily, weekly, or monthly Non-Firm PTP Transmission Service is interrupted, the rates charged under section II.B.1. shall be prorated over the total hours in the day to give credit for the hours of such interruption.

When Reserved Capacity becomes the Billing Factor for Hourly Non-Firm Service, the following shall apply:

1. If the need for Curtailment is caused by conditions on the Federal Columbia River Transmission System, the Billing Factor will be as follows:

   a. If Hourly Non-Firm PTP Transmission Service is Curtailed or Interrupted before the close of the hourly non-firm scheduling window, the Billing Factor will be the Reserved Capacity minus the curtailed capacity.

   b. If Hourly Non-Firm PTP Transmission Service is Curtailed or Interrupted after the close of the hourly non-firm scheduling window, the Billing Factor will be the Transmission Customer’s actual schedule in the hour.

2. If the need for Curtailment is caused by conditions on another transmission provider’s transmission system, the Billing Factor will be the Reserved Capacity.

D. RESERVATION FEE

Customers that postpone the commencement of Long-Term Firm Point-To-Point Transmission Service by requesting an extension of their Service Commencement Date will be subject to the Reservation Fee, specified in section II.E. of the GRSPs.

E. UNAUTHORIZED INCREASE CHARGE

Customers that exceed their capacity reservations at any Point of Receipt (POR) or Point of Delivery (POD) shall be subject to the Unauthorized Increase Charge, specified in section II.G. of the GRSPs.

F. DIRECT ASSIGNMENT FACILITIES

BPA-TS shall collect the capital and related costs of a Direct Assignment Facility under the Advance Funding (AF) rate or the Use-of-Facilities (UFT) rate. Other associated costs, including but not limited to operations, maintenance, and general plant costs, also shall be recovered from the Transmission Customer under an applicable rate schedule.

G. INCREMENTAL COST RATES

The rates specified in section II. are applicable to service over available transmission capacity. Customers requesting new or increased firm service that would require BPA-TS to construct new facilities or upgrades to alleviate a capacity constraint may be subject to incremental cost rates for such service if incremental cost is higher than embedded cost. Incremental cost rates would be developed pursuant to section 7(i) of the Northwest Power Act.

H. RATE ADJUSTMENT DUE TO FERC ORDER UNDER FPA § 212

Customers taking service under this rate schedule are subject to the Rate Adjustment Due to FERC Order under FPA § 212, specified in section II.D. of the GRSPs.

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UFT-12
USE-OF-FACILITIES TRANSMISSION RATE

SECTION I. AVAILABILITY

This schedule supersedes Schedule UFT-10 unless otherwise provided in the agreement, and is available for firm transmission over specified Federal Columbia River Transmission System (FCRTS) facilities. Service under this schedule is subject to BPA-TS's General Rate Schedule Provisions (GRSPs).

SECTION II. RATE

The monthly charge per kilowatt of Transmission Demand/capacity reservations specified in the agreement shall be one-twelfth of the annual cost of capacity of the specified facilities divided by the sum of Transmission Demands/capacity reservations (in kilowatts) using such facilities. Such annual cost shall be determined in accordance with section III.

SECTION III. DETERMINATION OF TRANSMISSION RATE

A. From time to time, but not more often than once a year, BPA-TS shall determine the following data for the facilities that have been constructed or otherwise acquired by BPA-TS and that are used to transmit electric power:

1. The annual cost of the specified FCRTS facilities, as determined from the capital cost of such facilities and annual cost ratios developed from the Federal Columbia River Power System financial statement, including interest and amortization, operation and maintenance, administrative and general, and general plant costs.

   The annual cost per kilowatt of facilities listed in the agreement that are owned by another entity and used by BPA-TS for making deliveries to the transferee shall be determined from the costs specified in the agreement between BPA-TS and such other entity.

2. The yearly noncoincident peak demands of all users of such facilities or other reasonable measurement of the facilities' peak use.

B. The monthly charge per kilowatt of billing demand shall be one-twelfth of the sum of the annual cost of the FCRTS facilities used divided by the sum of Transmission Demands/capacity reservations. The annual cost per kilowatt of Transmission Demand/capacity reservation for a facility constructed or otherwise acquired by BPA-TS shall be determined in accordance with the following formula:

$$\frac{A}{D}$$

Where:

A = The annual cost of such facility as determined in accordance with A.1. above.
D = The sum of the yearly noncoincident demands on the facility as determined in accordance with A.2. above.

For facilities used solely by one customer, BPA-TS may charge a monthly amount equal to the annual cost of such sole-use facilities, determined in accordance with section III.A.1., divided by 12.

For facilities used by more than one customer, BPA-TS may charge a monthly amount equal to the annual cost of such facilities prorated based on relative use of the facilities, divided by 12.

SECTION IV. DETERMINATION OF BILLING FACTORS

Unless otherwise stated in the agreement, the Billing Factor shall be the largest of:

A. The Transmission Demand/capacity reservation in kilowatts specified in the agreement;

B. The highest hourly Measured or Scheduled Demand for the month; or

C. The Ratchet Demand.

SECTION V. ADJUSTMENTS, CHARGES, AND OTHER RATE PROVISIONS

A. ANCILLARY SERVICES

Ancillary services that are required to support UFT transmission service are available under the ACS rate schedule.

B. FAILURE TO COMPLY PENALTY

Customers taking service under this rate schedule are subject to the Failure to Comply Penalty Charge, specified in section II.B. of the GRSPs.

C. POWER FACTOR PENALTY CHARGE

Customers taking service under this rate schedule are subject to the Power Factor Penalty Charge, specified in section II.C. of the GRSPs.

AF-12
ADVANCE FUNDING RATE

SECTION I. AVAILABILITY

This schedule supersedes Schedule AF-10 and is available to customers that execute an agreement that provides for BPA-TS to collect capital and related costs through advance funding or other financial arrangement for specified BPA-owned Federal Columbia River Transmission System (FCRTS) facilities used for:

A. Interconnection or integration of resources and loads to the FCRTS;

B. Upgrades, replacements, or reinforcements of the FCRTS for transmission service; or

C. Other transmission service arrangements, as determined by BPA-TS.

Service under this schedule is subject to BPA-TS's General Rate Schedule Provisions (GRSPs).

SECTION II. CHARGE

The charge is:

A. The sum of the actual capital and related costs for specified FCRTS facilities, as provided in the agreement. Such actual capital and related costs include, but are not limited to, costs of design, materials, construction, overhead, spare parts, and all incidental costs necessary to provide service as identified in the agreement; or

B. An advance payment equal to the sum of the capital and related costs for specified FCRTS facilities, as provided in an agreement. A credit for some or all of the amount advanced will be applied against charges for transmission service, as provided in the agreement. The charges for transmission service shall be at the rate for the applicable transmission service.

SECTION III. PAYMENT

A. ADVANCE PAYMENT

Payment to BPA-TS shall be specified in the agreement as either:

1. A lump sum advance payment;

2. Advance payments pursuant to a schedule of progress payments; or

3. Other payment arrangement, as determined by BPA-TS.

Such advance payment or payments shall be based on an estimate of the capital and related costs for the specified FCRTS facilities as provided in the agreement.

B. ADJUSTMENT TO ADVANCE PAYMENT

For charges under section II.A., BPA-TS shall determine the actual capital and related costs of the specified FCRTS facilities as soon as practicable after the date of commercial operation, as determined by BPA-TS. The customer will either receive a refund from BPA-TS or be billed for additional payment for the difference between the advance payment and the actual capital and related costs.

TGT-12
TOWNSEND-GARRISON TRANSMISSION RATE

SECTION I. AVAILABILITY

This schedule supersedes Schedule TGT-10 and is available to Companies that are parties to the Montana Intertie Agreement (Contract No. DE-MS79-81BP90210, as amended), which provides for firm transmission over BPA's section (Garrison to Townsend) of the Montana Intertie. Service under this schedule is subject to BPA-TS's General Rate Schedule Provisions (GRSPs).

SECTION II. RATE

The monthly charge shall be one-twelfth of the sum of the annual charges listed below, as applicable and as specified in the agreements for firm transmission. The Townsend-Garrison 500-kV lines and associated terminal, line compensation, and communication facilities are a separately identified portion of the Federal Columbia River Transmission System. Annual revenues plus credits for government use should equal annual costs of the facilities, but in any given year there may be either a surplus or a deficit. Such surpluses or deficits for any year shall be accounted for in the computation of annual costs for succeeding years. Revenue requirements for firm transmission use will be decreased by any revenues received from non-firm use and credits for all government use. The general methodology for determining the firm rate is to divide the revenue requirement by the total firm capacity requirements. Therefore, the higher the total capacity requirements, the lower will be the unit rate.

If BPA provides firm transmission service in its section of the Montana [Eastern] Intertie in exchange for firm transmission service in a customer's section of the Montana Intertie, the payment by BPA for such transmission services provided by such customer will be made in the form of a credit in the calculation of the Intertie Charge for such customer. During an estimated 1- to 3-year period following the commercial operation of the third generating unit at the Colstrip Thermal Generating Plant at Colstrip, Montana, the capability of the Federal Transmission System west of Garrison Substation may be different from the long-term situation. It may not be possible to complete the extension of the 500-kV portion of the Federal Transmission System to Garrison by such commercial operation date. In such event, the 500/230 kV transformer will be an essential extension of the Townsend-Garrison Intertie facilities, and the annual costs of such transformer will be included in the calculation of the Intertie Charge.

However, starting 1 month after extension to Garrison of the 500-kV portion of the Federal Transmission System, the annual costs of such transformer will no longer be included in the calculation of the Intertie Charge.

A. NON-FIRM TRANSMISSION CHARGE:

This charge will be filed as a separate rate schedule, the Eastern intertie (IE) rate.

B. INTERTIE CHARGE FOR FIRM TRANSMISSION SERVICE:

$$\text{Intertie Charge} = \left[\left((TAC/12)-NFR\right) \times \frac{(CR-EC)}{TCR}\right]$$

SECTION III. DEFINITIONS

A. TAC = Total Annual Costs of facilities associated with the Townsend-Garrison 500-kV Transmission line including terminals, and prior to extension of the 500-kV portion of the Federal Transmission System to Garrison, the 500/230 kV transformer at Garrison. Such annual costs are the total of: (1) interest and amortization of associated Federal investment and the appropriate allocation of general plant costs; (2) operation and maintenance costs; (3) allowance for BPA's general administrative costs that are appropriately allocable to such facilities, and (4) payments made pursuant to section 7(m) of Public Law 96-501 with respect to these facilities. Total Annual Costs shall be adjusted to reflect reductions to unpaid total costs as a result of any amounts received, under agreements for firm transmission service over the Montana Intertie, by BPA on account of any reduction in Transmission Demand, termination, or partial termination of any such agreement or otherwise to compensate BPA for the unamortized investment, annual cost, removal, salvage, or other cost related to such facilities.

B. NFR = Non-firm Revenues, which are equal to (1) the product of the Non-firm Transmission Charge described in II.A above, and the total non-firm energy transmitted over the Townsend Garrison line segment under such charge during such month; plus (2) revenue received by BPA under any other rate schedules for non-firm transmission service in either direction over the Townsend-Garrison line segment during such month.

C. CR = Capacity Requirement of a customer on the Townsend-Garrison 500-kV transmission facilities as specified in its firm transmission agreement.

D. TCR = Total Capacity Requirement on the Townsend-Garrison 500-kV transmission facilities as calculated by adding (1) the sum of all Capacity Requirements (CR) specified in transmission agreements described in section I; and (2) BPA's firm capacity requirement. BPA's firm capacity requirement shall be no less than the total of the amounts, if any, specified in firm transmission agreements for use of the Montana Intertie.

E. EC = Exchange Credit for each customer, which is the product of (1) the ratio of investment in the Townsend-Broadview 500-kV transmission line to the investment in the Townsend-Garrison 500-kV transmission line; and (2) the capacity BPA obtains in the Townsend-Broadview 500-kV transmission line through exchange with such customer. If no exchange is in effect with a customer, the value of EC for such customer shall be zero.

IE-12
EASTERN INTERTIE RATE

SECTION I. AVAILABILITY

This schedule supersedes IE-10 and is available to Companies that are parties to the Montana Intertie Agreement (Contract No. DE-MS79-81BP90210, as amended), for non-firm transmission service on the portion of Eastern Intertie capacity above BPA's firm transmission rights. Service under this schedule is subject to BPA-TS's General Rate Schedule Provisions (GRSPs).

SECTION II. RATE

The rate shall not exceed 1.13 mills per kilowatthour.

SECTION III. BILLING FACTORS

The Billing Factor shall be the scheduled kilowatthours, unless otherwise specified in the agreement.

SECTION IV. ADJUSTMENTS, CHARGES, AND OTHER RATE PROVISIONS

A. ANCILLARY SERVICES

Ancillary services that may be required to support IE transmission service are available under the ACS rate schedule.

B. FAILURE TO COMPLY PENALTY

Customers taking service under this rate schedule are subject to the Failure to Comply Penalty Charge, specified in section II.B. of the GRSPs.

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ACS-12
ANCILLARY AND CONTROL AREA SERVICES RATES

SECTION I. AVAILABILITY

This schedule supersedes Schedule ACS-10. It is available to all Transmission Customers taking service under the Open Access Transmission Tariff and other contractual arrangements. This schedule is available also for transmission service of a similar nature that may be ordered by the Federal Energy Regulatory Commission (FERC) pursuant to sections 211 and 212 of the Federal Power Act (16 U.S.C. §§ 824j and 824k). Service under this schedule is subject to BPA-TS's General Rate Schedule Provisions (GRSPs).

A. ANCILLARY SERVICES

Ancillary Services are needed with transmission service to maintain reliability within and among the Control Areas affected by the transmission service. The Transmission Provider is required to provide, and the Transmission Customer is required to purchase, the following Ancillary Services: (a) Scheduling, System Control, and Dispatch, and (b) Reactive Supply and Voltage Control from Generation Sources.

In addition, the Transmission Provider is required to offer to provide the following Ancillary Services only to the Transmission Customer serving load within the Transmission Provider's Control Area: (a) Regulation and Frequency Response, and (b) Energy Imbalance. The Transmission Customer serving load within the Transmission Provider's Control Area is required to acquire these Ancillary Services, whether from the Transmission Provider, from a third party, or by self-supply.

The Transmission Provider is also required to offer to provide (a) Operating Reserve – Spinning and (b) Operating Reserve – Supplemental to the Transmission Customer in accordance with applicable NERC, WECC, and NWPP standards. The Transmission Customer taking these services in the Transmission Provider's Control Area is required to acquire these Ancillary Services, whether from the Transmission Provider, from a third party, or by self-supply in accordance with applicable NERC, WECC, and NWPP standards.

The Transmission Customer may not decline the Transmission Provider's offer of Ancillary Services unless it demonstrates that it has acquired the Ancillary Services from another source. The Transmission Customer must list in its Application which Ancillary Services it will purchase from the Transmission Provider.

Ancillary Services available under this rate schedule are:

1. Scheduling, System Control, and Dispatch Service
2. Reactive Supply and Voltage Control from Generation Sources Service
3. Regulation and Frequency Response Service

4. Energy Imbalance Service
5. Operating Reserve – Spinning Reserve Service
6. Operating Reserve – Supplemental Reserve Service

B. CONTROL AREA SERVICES

Control Area Services are available to meet the Reliability Obligations of a party with resources or loads in the BPA Control Area. A party that is not satisfying all of its Reliability Obligations through the purchase or self-provision of Ancillary Services must purchase Control Area Services to meet its Reliability Obligations. Control Area Services are also available to parties with resources or loads in the BPA Control Area that have Reliability Obligations, but do not have a transmission agreement with BPA. Reliability Obligations for resources or loads in the BPA Control Area shall be determined consistent with the applicable NERC, WECC, and NWPP standards.

Control Area Services available under this rate schedule are:

1. Regulation and Frequency Response Service
2. Generation Imbalance Service
3. Operating Reserve – Spinning Reserve Service
4. Operating Reserve – Supplemental Reserve Service
5. Variable Energy Resource Balancing Service
6. Dispatchable Energy Resource Balancing Service

SECTION II. ANCILLARY SERVICE RATES

A. SCHEDULING, SYSTEM CONTROL, AND DISPATCH SERVICE

The rates below apply to Transmission Customers taking Scheduling, System Control, and Dispatch Service from BPA-TS. These rates apply to both firm and non-firm transmission service. Transmission arrangements on the Network, on the Southern Intertie, and on the Montana Intertie are each charged separately for Scheduling, System Control, and Dispatch Service.

1. RATES

a. Long-Term Firm PTP Transmission Service and NT Service

The rate shall not exceed $0.203 per kilowatt per month.

b. Short-Term Firm and Non-Firm PTP Transmission Service

For each reservation, the rates shall not exceed:

(1) Monthly, Weekly, and Daily Firm and Non-Firm Service

(a) Days 1 through 5 $0.010 per kilowatt per day

(b) Day 6 and beyond $0.006 per kilowatt per day

(2) Hourly Firm and Non-Firm Service

The rate shall not exceed 0.59 mills per kilowatthour.

2. BILLING FACTORS

a. Point-To-Point Transmission Service

For Transmission Customers taking Point-to-Point Transmission Service (PTP, IS, and IM rates), the Billing Factor for each rate specified in section 1.a., 1.b.(1), and for the Hourly Firm PTP Transmission Service rate specified in 1.b.(2) shall be the Reserved Capacity, which is the greater of:

(1) the sum of the capacity reservations at the Point(s) of Receipt, or

(2) the sum of the capacity reservations at the Point(s) of Delivery.

The Reserved Capacity for Firm PTP Transmission Service shall not be adjusted for any Short-Distance Discounts or for any modifications on a non-firm basis in determining the Scheduling, System Control and Dispatch Service Billing Factor.

The Billing Factor for the rate specified in section 1.b.(2) for Hourly Non-Firm Service shall be the Reserved Capacity, and the following shall apply:

(1) If the need for Curtailment is caused by conditions on the Federal Columbia River Transmission System, the Billing Factor will be as follows:

(a) If Hourly Non-Firm PTP Transmission Service is Curtailed or Interrupted before the close of the hourly non-firm scheduling window, the Billing Factor will be the Reserved Capacity minus the curtailed capacity.

(b) If Hourly Non-Firm PTP Transmission Service is Curtailed or Interrupted after the close of the hourly non-firm scheduling window, the Billing Factor will be the Transmission Customer's actual schedule in the hour.

(2) If the need for Curtailment is caused by conditions on another transmission provider's transmission system, the Billing Factor will be the Reserved Capacity.

These Billing Factors apply to all PTP transmission service under the Open Access Transmission Tariff regardless of whether the Transmission Customer actually uses (schedules) the transmission.

b. Network Integration Transmission Service

For Transmission Customers taking Network Integration Transmission Service, the Billing Factor for the rate specified in section 1.a. shall equal the NT Base Charge Billing Factor determined pursuant to section III.A. of the Network Integration Rate Schedule (NT-12).

c. Adjustment for Customers Subject to the Unauthorized Increase Charge (UIC)

For Transmission Customers taking Point-to-Point Transmission Service (PTP, IS, and IM rate schedules) that are subject to a UIC in a billing month, the Billing Factor for the billing month shall be the Billing Factor calculated above plus the UIC Billing Factor calculated under section II.G.2.a. of the GRSPs.

B. REACTIVE SUPPLY AND VOLTAGE CONTROL FROM GENERATION SOURCES SERVICE

The rates below apply to Transmission Customers taking Reactive Supply and Voltage Control from Generation Sources (GSR) Service from BPA-TS. These rates apply to both firm and non-firm transmission service. Transmission arrangements on the Network, on the Southern Intertie, and on the Montana Intertie are each charged separately for Reactive Supply and Voltage Control from Generation Sources Service.

1. RATES

The rates for GSR Service will be set on a quarterly basis, beginning October 2011, according to the formulas below. Rates for Long-Term PTP and NT Service and for Short-Term Monthly, Weekly and Daily Service (sections a. and b.(1), below) shall be calculated to three decimal places. Rates for Hourly Service (section b.(2), below) shall be calculated to two decimal places.

a. Long-Term Firm PTP Transmission Service and NT Service

The rate, in dollars per kilowatt per month ($/kW/mo), shall not exceed:

$$\frac{4(N_q + U_{q-1} + Z_{q-1})}{bd - 4S_q}$$

Where:

bd = 470,532 MW-mo = Average of forecasted FY 2010 and FY 2011 GSR Service billing determinants. Each annual billing determinant is the sum of the 12 monthly billing determinants.

N_q = Non-Federal GSR cost to be paid by BPA-TS under a FERC-approved rate during the relevant quarter, as anticipated prior to the quarter. ($)

U_{q-1} = Payments of non-Federal GSR cost made in the preceding quarter(s) that were not included in the effective rate for the preceding quarter(s). Any refunds received by BPA-TS would reduce this cost. U_{q-1} is a true-up for any deviation of non-Federal GSR costs from the amount used in a previous quarter's GSR rate calculation. For calculating the GSR rate effective October 1, 2011, U_{q-1} is zero. ($)

S_q = Reduction in effective billing demand for approved self-supply of reactive during the relevant quarter, as anticipated prior to the quarter. (MW-mo)

Z_{q-1} = A dollar true-up for under- or overstatement of reactive self-supply in rate calculations for the preceding quarter(s). For calculating the GSR rate effective October 1, 2011, Z_{q-1} is zero. Z_{q-1} will be calculated by multiplying the under- or overstated megawatt amount of self-supply by the GSR rate that was effective during the quarter of self-supply deviation. ($)

"Relevant quarter" refers to the 3-month period for which the rate is being determined.

b. Short-Term Firm and Non-Firm PTP Transmission Service

(1) Monthly, Weekly, and Daily Firm and Non-firm Service

For each reservation, the rates shall not exceed:

(a) Days 1 through 5 ($/kW/day)

$$\text{Long-Term Service Rate} \quad * \quad \frac{\text{12 months}}{\text{52 weeks * 5 days}}$$

(b) Day 6 and beyond ($/kW/day)

$$\text{Long-Term Service Rate} \quad * \quad \frac{\text{12 months}}{\text{52 weeks * 7 days}}$$

(2) Hourly Firm and Non-Firm Service (mills/kilowatthour)

The rate shall not exceed:

$$\text{Long-Term Service Rate} \quad * \quad \frac{\text{12 months}}{\text{52 weeks * 5 days * 16 hours}}$$

Where:

The "Long-Term Service Rate" specified in the formulas in sections 1.b.(1)(a) and (b), and 1.b.(2), above, is the rate determined in section 1.a., Long-Term Firm PTP Transmission Service and NT Service, in $/kW/mo.

2. BILLING FACTORS

a. Point-To-Point Transmission Service

For Transmission Customers taking Point-to-Point Transmission Service (PTP, IS, and IM rates), the Billing Factor for each rate specified in section 1.a., 1.b.(1) and for Hourly Firm PTP Transmission Service specified in 1.b.(2) shall be the Reserved Capacity, which is the greater of:

(1) the sum of the capacity reservations at the Point(s) of Receipt, or

(2) the sum of the capacity reservations at the Point(s) of Delivery.

The Reserved Capacity for Firm PTP Transmission Service shall not be adjusted for any Short-Distance Discount or for any modifications on a non-firm basis in determining the Reactive Supply and Voltage Control from Generation Sources Service Billing Factor.

The Billing Factor for the rate specified in section 1.b.(2) for Hourly Non-Firm Service shall be the Reserved Capacity, and the following shall apply:

(1) If the need for Curtailment is caused by conditions on the Federal Columbia River Transmission System, the Billing Factor will be as follows:

   (a) If Hourly Non-Firm PTP Transmission Service is Curtailed or Interrupted before the close of the hourly non-firm scheduling window, the Billing Factor will be the Reserved Capacity minus the curtailed capacity.

   (b) If Hourly Non-Firm PTP Transmission Service is Curtailed or Interrupted after the close of the hourly non-firm scheduling window, the Billing Factor will be the Transmission Customer’s actual schedule in the hour.

(2) If the need for Curtailment is caused by conditions on another transmission provider’s transmission system, the Billing Factor will be the Reserved Capacity.

These Billing Factors apply to all PTP transmission service under the Open Access Transmission Tariff regardless of whether the Transmission Customer actually uses (schedules) the transmission.

b. Network Integration Transmission Service

For Transmission Customers taking Network Integration Transmission Service, the Billing Factor for the rate specified in section 1.a. shall equal the NT Base Charge Billing Factor determined pursuant to section III.A. of the Network Integration Rate Schedule (NT-12).

c. Adjustment for Self-Supply

The Billing Factors in sections 2.a. and 2.b. above may be reduced as specified in the Transmission Customer's Service Agreement to the extent the Transmission Customer demonstrates to BPA-TS's satisfaction that it can self-provide Reactive Supply and Voltage Control from Generation Sources Service.

d. Adjustment for Customers Subject to the Unauthorized Increase Charge (UIC)

For Transmission Customers taking Point-to-Point Transmission Service (PTP, IS, and IM rate schedules) that are subject to a UIC in a billing month, the Billing Factor for the billing month shall be the Billing Factor calculated above plus the UIC Billing Factor calculated under section II.G.2.a. of the GRSPs.

C. REGULATION AND FREQUENCY RESPONSE SERVICE

The rate below for Regulation and Frequency Response (RFR) Service applies to Transmission Customers serving loads in the BPA Control Area. Regulation and Frequency Response Service provides the generation capability to follow the moment-to-moment variations of loads in the BPA Control Area and maintain the power system frequency at 60 Hz in conformance with NERC and WECC reliability standards.

1. RATE

The rate shall not exceed 0.13 mills per kilowatthour.

2. BILLING FACTOR

The Billing Factor is the customer's total load in the BPA Control Area, in kilowatthours.

D. ENERGY IMBALANCE SERVICE

The rates below apply to Transmission Customers taking Energy Imbalance Service from BPA-TS. Energy Imbalance Service is taken when there is a difference between scheduled and actual energy delivered to a load in the BPA Control Area during a scheduling period. Accounting for hourly schedules will be on an hourly basis and accounting for intra-hour schedules will be on the same basis as the intra-hour scheduling period.

1. RATES

a. Imbalances Within Deviation Band 1

Deviation Band 1 applies to deviations that are less than or equal to: i) ± 1.5% of the scheduled amount of energy, or ii) ± 2 MW, whichever is larger in absolute value. BPA-TS will maintain deviation accounts showing the net Energy Imbalance (the sum of positive and negative deviations from schedule for each period) for Heavy Load Hour (HLH) and Light Load Hour (LLH) periods. Return energy may be scheduled at any time during the month to bring the deviation account balances to zero at the end of each month. BPA-TS will approve the hourly schedules of return energy. The customer shall make the arrangements and submit the schedule for the balancing transaction.

The following rates will be applied when a deviation balance remains at the end of the month:

(i) When the monthly net energy (determined for HLH and LLH periods) taken by the Transmission Customer is greater than the energy scheduled, the charge is BPA's incremental cost based on the applicable average HLH and average LLH incremental cost for the month.

(ii) When the monthly net energy (determined for HLH and LLH periods) taken by the Transmission Customer is less than the energy scheduled, the credit is BPA's incremental cost based on the applicable average HLH and LLH incremental cost for the month.

b. Imbalances Within Deviation Band 2

Deviation Band 2 applies to the portion of the deviation i) greater than ± 1.5% of the scheduled amount of energy or ± 2 MW, whichever is larger in absolute value, ii) up to and including ± 7.5% of the scheduled amount of energy or ± 10 MW, whichever is larger in absolute value.

(i) When energy taken by the Transmission Customer in a schedule period is greater than the energy scheduled, the charge is 110% of BPA's incremental cost.

(ii) When energy taken by the Transmission Customer in a schedule period is less than the scheduled amount, the credit is 90% of BPA's incremental cost.

c. Imbalances Within Deviation Band 3

Deviation Band 3 applies to the portion of the deviation i) greater than ± 7.5% of the scheduled amount of energy, or ii) greater than ± 10 MW of the scheduled amount of energy, whichever is larger in absolute value.

(i) When energy taken by the Transmission Customer in a schedule period is greater than the energy scheduled, the charge is 125% of BPA's highest incremental cost that occurs during that day. The highest daily incremental cost shall be determined separately for HLH and LLH.

(ii) When energy taken by the Transmission Customer in a schedule period is less than the scheduled amount, the credit is 75% of BPA's lowest incremental cost that occurs during that day. The lowest daily incremental cost shall be determined separately for HLH and LLH.

2. OTHER RATE PROVISIONS

a. BPA Incremental Cost

BPA's incremental cost will be based on an hourly energy index in the Pacific Northwest. If no adequate hourly index exists, an alternative index will be used. BPA-TS will post the name of the index to be used on the OASIS at least 30 days prior to its use. BPA-TS will not change the index more often than once per year unless BPA-TS determines that the existing index is no longer a reliable price index.

For any hour(s) that the energy index is negative, no credit is given for positive deviations (actual energy delivered is more than scheduled).

b. **Spill Conditions**

For any day that the Federal System is in a Spill Condition, no credit is given for negative deviations (actual energy delivered is less than scheduled) for any period of that day.

If the energy index is negative in any hour that the Federal System is in a Spill Condition:

(i) For negative deviations (energy taken is less than the scheduled energy) within Band 1, no credit will be given.

(ii) For negative deviations (energy taken is less than the scheduled energy) within Band 2, the charge is the energy index for that hour.

(iii) For negative deviations (energy taken is less than the scheduled energy) within Band 3, the charge is the energy index for that hour.

c. **Persistent Deviation**

The following penalty charges shall apply to each Persistent Deviation:

(1) No credit is given when energy taken is less than the scheduled energy.

(2) When energy taken exceeds the scheduled energy, the charge is the greater of: i) 125% of BPA's highest incremental cost that occurs during that day, or ii) 100 mills per kilowatthour.

If the energy index is negative in any hour(s) in which there is a negative deviation (energy taken is less than the scheduled energy) that BPA-TS determines to be a Persistent Deviation, the charge is the energy index for that hour.

If BPA-TS assesses a persistent deviation penalty charge in any scheduled period for a positive deviation, BPA-TS will not also assess a charge pursuant to Section II.D.1 of this ACS-12 schedule.

Reduction or Waiver of Persistent Deviation Penalty

BPA-TS, at its sole discretion, may waive all or part of the Persistent Deviation penalty charge if (a) the customer took mitigating action(s) to avoid or limit the Persistent Deviation, including but not limited to changing its schedule to mitigate the magnitude or duration of the deviation, or (b) the Persistent Deviation was caused by extraordinary circumstances.

E. OPERATING RESERVE -- SPINNING RESERVE SERVICE

The rates below apply to Transmission Customers taking Operating Reserve – Spinning Reserve Service from BPA-TS and to generators in the BPA Control Area for settlement of energy deliveries. Spinning Reserve Service is needed to serve load immediately in the event of a system contingency. BPA-TS will determine the Transmission Customer's Spinning Reserve Requirement in accordance with applicable NERC, WECC and NWPP standards.

1. RATES

a. Spinning Reserve Service

(i) For customers that elect to purchase Operating Reserve –Spinning Reserve Service from BPA-TS, the rate shall not exceed 11.20 mills per kilowatthour.

(ii) For customers that are required to purchase Operating Reserve – Spinning Reserve Service from BPA-TS because they defaulted on their self-supply or third-party supply obligations, the rate shall be 12.88 mills per kilowatthour.

b. For energy delivered, the generator shall, as directed by BPA-TS, either:

(i) Purchase the energy at the hourly market index price, but not less than zero, applicable at the time of occurrence, or

(ii) Return the energy at the times specified by BPA-TS.

2. BILLING FACTORS

a. The Billing Factor for the rates specified in section 1.a. is the Transmission Customer's Spinning Reserve Requirement determined in accordance with applicable WECC and NWPP standards. BPA-TS will post on its OASIS Web site the Spinning Reserve Requirement. If the Federal Energy Regulatory Commission approves a new Spinning Reserve Requirement during the FY 2012-2013 rate period, such Spinning Reserve Requirement will go into effect on the effective date set by FERC, and BPA will update the Spinning Reserve Requirement posted on its OASIS Web site accordingly.

b. The Billing Factor for energy delivered when Spinning Reserve Service is called upon is the energy delivered, in kilowatthours.

F. OPERATING RESERVE – SUPPLEMENTAL RESERVE SERVICE

The rates below apply to Transmission Customers taking Operating Reserve – Supplemental Reserve Service from BPA-TS and to generators in the BPA Control Area for settlement of energy deliveries. Supplemental Reserve Service is needed to serve load immediately in the event of a system contingency. BPA-TS will determine the Transmission Customer's Supplemental Reserve Requirement in accordance with applicable NERC, WECC and NWPP standards.

1. RATES

a. Supplemental Reserve Service

(i) For customers that elect to purchase Operating Reserve--Supplemental Reserve Service Transmission Services, the rate shall not exceed 9.52 mills per kilowatthour.

(ii) For customers that are required to purchase Operating Reserve --Supplemental Reserve Service from BPA-TS because they defaulted on their self-supply or third-party supply obligations, the rate shall be 10.95 mills per kilowatthour.

b. For energy delivered, the Transmission Customer (for interruptible imports only) or the generator shall, as directed by BPA-TS, either:

(i) Purchase the energy at the hourly market index price, but not less than zero, applicable at the time of occurrence, or

(ii) Return the energy at the times specified by BPA-TS.

The Transmission Customer shall be responsible for the settlement of delivered energy associated with interruptible imports. The generator shall be responsible for the settlement of delivered energy associated with generation in the BPA Control Area.

2. BILLING FACTORS

a. The Billing Factor for the rates specified in section 1.a. is the Transmission Customer's Supplemental Reserve Requirement determined in accordance with applicable WECC and NWPP standards. BPA-TS will post on its OASIS Web site the Supplemental Reserve Requirement. If the Federal Energy Regulatory Commission approves a new Supplemental Reserve Requirement during the FY 2012-2013 rate period, such Supplemental Reserve Requirement will go into effect on the effective date set by FERC, and BPA will update the Supplemental Reserve Requirement posted on its OASIS Web site accordingly.

b. The Billing Factor for energy delivered when Supplemental Reserve Service is called upon is the energy delivered, in kilowatthours.

SECTION III. CONTROL AREA SERVICE RATES

A. REGULATION AND FREQUENCY RESPONSE SERVICE

The rate below applies to all loads in the BPA Control Area that are receiving Regulation and Frequency Response Service from the BPA Control Area, and such Regulation and Frequency Response Service is not provided for under a BPA-TS transmission agreement. Regulation and Frequency Response Service provides the generation capability to follow the moment-to-moment variations of loads in the BPA Control Area and maintain the power system frequency at 60 Hz in conformance with NERC and WECC reliability standards.

1. RATE

The rate shall not exceed 0.13 mills per kilowatthour.

2. BILLING FACTOR

The Billing Factor is the customer's total load in the BPA Control Area, in kilowatthours.

B. GENERATION IMBALANCE SERVICE

The rates below apply to generation resources in the BPA Control Area if Generation Imbalance Service is provided for in an interconnection agreement or other arrangement. Generation Imbalance Service is taken when there is a difference between scheduled and actual energy delivered from generation resources in the BPA Control Area during a scheduling period. Accounting for hourly schedules will be on an hourly basis and accounting for intra-hour schedules will be on the same basis as the intra-hour scheduling period.

1. RATES

a. Imbalances Within Deviation Band 1

Deviation Band 1 applies to deviations that are less than or equal to: i) ± 1.5% of the scheduled amount of energy, or ii) ± 2 MW, whichever is larger in absolute value. BPA-TS will maintain deviation accounts showing the net Generation Imbalance (the sum of positive and negative deviations from schedule for each period) for Heavy Load Hour (HLH) and Light Load Hour (LLH) periods. Return energy may be scheduled at any time during the month to bring the deviation account balances to zero at the end of each month. BPA-TS will approve the hourly schedules of return energy. The customer shall make the arrangements and submit the schedule for the balancing transaction.

The following rates will be applied when a deviation balance remains at the end of the month:

(i) When the monthly net energy (determined for HLH and LLH periods) delivered from a generation resource is less than the energy scheduled, the charge is BPA's incremental cost based on the applicable average HLH and average LLH incremental cost for the month.

(ii) When the monthly net energy (determined for HLH and LLH periods) delivered from a generation resource is greater than the energy scheduled, the credit is BPA's incremental cost based on the applicable average HLH and LLH incremental cost for the month.

b. Imbalances Within Deviation Band 2

Deviation Band 2 applies to the portion of the deviation i) greater than ± 1.5% of the scheduled amount of energy or ± 2 MW, whichever is larger in absolute value, ii) up to and including ± 7.5% of the scheduled amount of energy or ± 10 MW, whichever is larger in absolute value.

(i) When energy delivered in a schedule period from the generation resource is less than the energy scheduled, the charge is 110% of BPA's incremental cost.

(ii) When energy delivered in a schedule period from the generation resource is greater than the scheduled amount, the credit is 90% of BPA's incremental cost.

c. Imbalances Within Deviation Band 3

Deviation Band 3 applies to the portion of the deviation i) greater than ± 7.5% of the scheduled amount of energy, or ii) greater than ± 10 MW of the scheduled amount of energy, whichever is larger in absolute value.

(i) When energy delivered in a schedule period from the generation resource is less than the energy scheduled, the charge is 125% of BPA's highest incremental cost that occurs during that day. The highest daily incremental cost shall be determined separately for HLH and LLH.

(ii) When energy delivered in a schedule period from the generation resource is greater than the scheduled amount, the credit is 75% of BPA's lowest incremental cost that occurs during that day. The lowest daily incremental cost shall be determined separately for HLH and LLH.

2. OTHER RATE PROVISIONS

a. BPA Incremental Cost

BPA's incremental cost will be based on an hourly energy index in the Pacific Northwest. If no adequate hourly index exists, an alternative index will be used. BPA-TS will post the name of the index to be used on the OASIS at least 30 days prior to its use. BPA-TS will not change the index more often than once per year unless BPA-TS determines that the existing index is no longer a reliable price index.

For any hour(s) that the energy index is negative, no credit is given for positive deviations (actual generation less than scheduled).

b. Spill Conditions

For any day that the Federal System is in a Spill Condition, no credit is given for negative deviations (actual generation greater than scheduled) for any period of that day.

If the energy index is negative in any hour that the Federal System is in a Spill Condition:

(i) For negative deviations (actual generation greater than scheduled) within Band 1, no credit will be given.

(ii) For negative deviations (actual generation greater than scheduled) within Band 2, the charge is the energy index for that hour.

(iii) For negative deviations (actual generation greater than scheduled) within Band 3, the charge is the energy index for that hour.

c. Persistent Deviation

The following penalty charges shall apply to each Persistent Deviation:

No credit is given for negative deviations (actual generation greater than scheduled) for any hour(s) that the imbalance is a Persistent Deviation (as determined by BPA-TS).

For positive deviations (actual generation less than scheduled) which are determined by BPA-TS to be Persistent Deviations, the charge is the greater of: i) 125% of BPA's highest incremental cost that occurs during that day, or ii) 100 mills per kilowatthour.

If the energy index is negative in any hour(s) in which there is a negative deviation (actual generation greater than scheduled) that BPA-TS determines to be a Persistent Deviation, the charge is the energy index for that hour.

If BPA-TS assesses a Persistent Deviation Penalty charge in any scheduled period for a positive deviation, BPA-TS will not also assess a charge pursuant to Section III.B.1 of this ACS-12 schedule.

For variable energy resources (wind and solar resources), BPA-TS will remove specific scheduled periods for billing purposes from a persistent deviation event when the deviation is equal to or less than the deviation that would result from 30-minute persistence scheduling for those scheduled periods.

New generation resources undergoing testing before commercial operation are exempt from the Persistent Deviation penalty charge for up to 90 days.

Participants in BPA's Committed Intra-Hour Scheduling Pilot are exempt from the Persistent Deviation penalty charge.

Reduction or Waiver of Persistent Deviation Penalty

BPA-TS, at its sole discretion, may waive all or part of the Persistent Deviation penalty charge if (a) the customer took mitigating action(s) to avoid or limit the Persistent Deviation, including but not limited to changing its schedule to mitigate the magnitude or duration of the deviation, or (b) the Persistent Deviation was caused by extraordinary circumstances.

d. Exemptions from Deviation Band 3

The following resources are not subject to Deviation Band 3:

(i) wind resources;
(ii) solar resources; and
(ii) new generation resources undergoing testing before commercial operation for up to 90 days.

All such deviations greater than ± 1.5% or ± 2 MW will be charged consistent with section 1.b., Imbalances Within Deviation Band 2.

C. OPERATING RESERVE – SPINNING RESERVE SERVICE

Operating Reserve – Spinning Reserve Service must be purchased by a party with generation in the BPA Control Area that is receiving this service from BPA-TS, and such Spinning Reserve Service is not provided for under a BPA-TS transmission agreement. Service is being received if there are no other qualifying resources providing this required reserve service in conformance with NERC, WECC and NWPP standards. BPA-TS will determine the Transmission Customer's Spinning Reserve Requirement in accordance with applicable NERC, WECC and NWPP standards.

1. RATES

a. Spinning Reserve Service

(i) For customers that elect to purchase Operating Reserve--Spinning Reserves from BPA-TS, the rate shall not exceed 11.20 mills per kilowatthour.

(ii) For customers that are required to purchase Operating Reserve--Spinning Reserve Service from BPA-TS because they defaulted on their self-supply or third-party supply obligations, the rate shall be 12.88 mills per kilowatthour.

b. For energy delivered, the customer shall, as directed by BPA-TS, either:

(i) Purchase the energy at the hourly market index price, but not less than zero, applicable at the time of occurrence, or

(ii) Return the energy at the times specified by BPA-TS.

2. BILLING FACTORS

a. The Billing Factor for the rates specified in section 1.a. is the Spinning Reserve Requirement determined in accordance with applicable WECC and NWPP standards. BPA-TS will post on its OASIS Web site the Spinning Reserve Requirement. If the Federal Energy Regulatory Commission approves a new Spinning Reserve Requirement during the FY 2012-2013 rate period, such Spinning Reserve Requirement will go into effect on the effective date set by FERC, and BPA will update the Spinning Reserves Requirement posted on its OASIS Web site accordingly.

b. The Billing Factor for energy delivered when Spinning Reserve Service is called upon is the energy delivered, in kilowatthours.

D. OPERATING RESERVE – SUPPLEMENTAL RESERVE SERVICE

Operating Reserve – Supplemental Reserve Service must be purchased by a party with generation in the BPA Control Area that is receiving this service from BPA-TS, and such Supplemental Reserve Service is not provided for under a BPA-TS transmission agreement. Service is being received if there are no other qualifying resources providing this required reserve service in conformance with NERC, WECC and NWPP standards. BPA-TS will determine the Transmission Customer's Supplemental Reserve Requirement in accordance with applicable NERC, WECC and NWPP standards.

1. RATES

a. Supplemental Reserve Service

(i) For customers that elect to purchase Operating Reserve--Supplemental Reserve Service from BPA-TS, the rate shall not exceed 9.52 mills per kilowatthour.

(ii) For customers that are required to purchase Operating Reserve--Supplemental Reserve Service from BPA-TS because they defaulted on their self-supply or third-party supply obligations, the rate shall be 10.95 mills per kilowatthour.

b. For energy delivered, the customer shall, as directed by BPA-TS, either:

(i) Purchase the energy at the hourly market index price, but not less than zero, applicable at the time of occurrence, or

(ii) Return the energy at the times specified by BPA-TS.

2. BILLING FACTORS

a. The Billing Factor for the rates specified in section 1.a. is the Supplemental Reserve Requirement determined in accordance with applicable WECC and NWPP standards. BPA-TS will post on its OASIS Web site the Supplemental Reserve Requirement. If the Federal Energy Regulatory Commission approves a new Supplemental Reserve Requirement during the FY 2012-2013 rate period, such Supplemental Reserve Requirement will go into effect on the effective date set by FERC, and BPA will update the Supplemental Reserves Requirement posted on its OASIS Web site accordingly

b. The Billing Factor for energy delivered when Supplemental Reserve Service is called upon is the energy delivered, in kilowatthours.

E. VARIABLE ENERGY RESOURCE BALANCING SERVICE

1. APPLICABILITY

The rates contained in this rate schedule apply to all wind and solar generating facilities of 200 kW nameplate rated capacity or greater in the BPA Control Area except as provided in section 2(c) of this rate schedule.

Variable Energy Resource Balancing Service is comprised of three components: regulating reserves (which compensate for moment-to-moment differences between generation and load), following reserves (which compensate for larger differences occurring over longer periods of time during the hour), and imbalance reserves (which compensate for differences between the generator's schedule and the actual generation during an hour). Variable Energy Resource Balancing Service is required to help maintain the power system frequency at 60 Hz and to conform to NERC and WECC reliability standards.

Provisional Variable Energy Resource Balancing Service ("Provisional Balancing Service") cannot be requested, but is offered to customers integrating variable energy resources in the BPA Control Area that: (1) have elected to self-supply in accordance with section 2(c) but are unable to continue self-supplying one or more components to Variable Energy Resource Balancing Service; or (2) have a projected interconnection date after FY 2013, but interconnect during the FY 2012-2013 rate period.

Variable Energy Resource Balancing Service Supplemental Service ("Supplemental Service") is an optional monthly service. BPA offers this service only upon request to Variable Energy Resource Balancing Service customers in accordance with BPA business practices. Purchase of this Supplemental Service augments balancing reserves available to the Customer to mitigate the effects of DSO 216 curtailments on variable energy resource schedules.

The rates that apply to participants in BPA's Committed Intra-Hour Scheduling Pilot are also included in this rate schedule.

2. VARIABLE ENERGY RESOURCE BALANCING SERVICE FOR WIND RESOURCES

(a) RATES

Except as provided in section 7, Formula Rate Adjustments, below, the total rate for Variable Energy Resource Balancing Service for wind resources shall not exceed $1.23 per kilowatt per month and each component of the rate shall not exceed the following:

(i)	Regulating Reserves	$0.08 per kilowatt per month
(ii)	Following Reserves	$0.37 per kilowatt per month
(iii)	Imbalance Reserves	$0.78 per kilowatt per month

(b) BILLING FACTOR

The Billing Factor is as follows:

(i) For each wind plant, or phase of a wind plant, that has completed installation of all units no later than the 15th of the month prior to the billing month the billing factor in kW will be the greater of the maximum one-hour generation or the nameplate of the plant. A unit has completed installation when it has generated and delivered power to the BPA system.

(ii) For each wind plant, or phase of a wind plant, for which some but not all units have been installed by the 15th day of the month prior to the billing month, the billing factor will be the maximum measured hourly output of the plant through the 15th day of the prior month in kW.

(c) EXCEPTIONS

(i) The rates in section 2(a) above will not apply to a variable energy resource, or portion of a variable energy resource, that, in BPA's determination, has put in place, tested, and successfully implemented in conformance to the criteria specified in BPA-TS business practices, no later than the 15th day of the month prior to the billing month, the dynamic transfer of plant output out of BPA's Balancing Authority Area to another Balancing Authority Area.

(ii) Any component of the rates in section 2(a) above will not apply to a variable energy resource, or portion of a variable energy resource, that, in BPA's determination, has put in place, tested, and successfully implemented in conformance to criteria specified in BPA-TS business practices, no later than the 15th day of the month prior to the billing month, self-supply of that component of balancing service, including by contractual arrangements for third-party supply.

3. PROVISIONAL BALANCING SERVICE

(a) RATES

The total rate for Provisional Balancing Service shall not exceed the total rate specified in section 2(a) above, as adjusted pursuant to section 7, Formula Rate Adjustments.

(b) BILLING FACTOR

See section 2(b) above.

(c) EXCEPTIONS

(i) Dynamic Transfer Capability Provision: If BPA recalls an award of dynamic transfer capability from a customer that elected to self-supply one or more components of Variable Energy Resource Balancing Service on May 1, 2011, the total rate for such customer taking Provisional Balancing Service shall not exceed 70 percent of the total rate specified in section 2(a) above, as adjusted pursuant to section 7, Formula Rate Adjustments.

(ii) See section 2(c) above.

4. VARIABLE ENERGY RESOURCE BALANCING SERVICE FOR SOLAR RESOURCES

(a) RATES

The total rate for Variable Energy Resource Balancing Service for solar resources shall not exceed $0.22 per kilowatt per month and each component of the rate shall not exceed the following:

(i)	Regulating Reserves	$0.04 per kilowatt per month
(ii)	Following Reserves	$0.18 per kilowatt per month

(b) BILLING FACTOR

For each solar plant that has completed installation no later than the 15th of the month prior to the billing month, the billing factor in kW will be the greater of the maximum one-hour generation or the nameplate of the plant. A unit has completed installation when it has generated and delivered power to the BPA system.

(c) EXCEPTIONS

See section 2(c) above.

5. COMMITTED INTRA-HOUR SCHEDULING PILOT PARTICIPANTS

(a) RATES

The total rate for Variable Energy Resource Balancing Service for participants in BPA's Committed Intra-Hour Pilot shall not exceed 66 percent the total rate specified in section 2(a) above, as adjusted pursuant to section 7, Formula Rate Adjustments.

(b) BILLING FACTOR

See section 2(b) above.

(c) EXCEPTIONS

None.

6. SUPPLEMENTAL SERVICE

(a) RATES

The monthly Supplemental Service rate in $/MW shall equal:

(Purchase Cost / Imbalance Reserve)

+ Administrative Charge

Where:

Purchase Cost = The sum of all purchase costs incurred by BPA to supply Supplemental Service for the relevant number of months to customers that commit to take such service, in dollars ($).

Imbalance Reserve = The sum of all imbalance reserves purchased by BPA to supply Supplemental Service for the relevant month or months for customers that commit to take such Administrative Charge service in MW-months.

Administrative Charge = $134 per MW-month

(b) BILLING FACTOR

The billing factor shall be the monthly amount of reserve that the Supplemental Service customer has contractually committed to purchase or supply.

(c) EXCEPTIONS

None.

7. FORMULA RATE ADJUSTMENTS

The Imbalance Reserves rate specified in section 2(a)(iii) above may be adjusted by: (1) Formula Rate I below to recover the costs of replacing Federal balancing reserve capacity that becomes unavailable during the rate period with non-Federal balancing reserve capacity; or (2) Formula Rate II below to increase non-Federal sources of balancing reserve capacity for the imbalance component to Variable Energy Resource Balancing Service.

Public Notification Process for Rate Adjustment:

Purchases of balancing reserve capacity for a term not longer than two months: BPA-TS will post on its OASIS a notice stating the adjusted rate at least 30 days in advance of the effective date of the adjusted rate.

Purchases of balancing reserve capacity for a term of longer than two months: BPA-TS will provide 15 calendar days advance notice on its OASIS of a public meeting to discuss the proposed purchase of balancing reserve capacity and the expected adjusted rate. Written comments on the proposed purchase will be accepted for 15 calendar days after the public meeting. BPA-TS will notify customers on its OASIS within 30 days of the public meeting of its decisions regarding the purchase and the adjusted Variable Energy Resources Balancing Service rate.

(i) Formula Rate I for Replacement of Federal Balancing Reserve Capacity that Becomes Unavailable

BPA may apply Formula Rate I to adjust the imbalance reserves rate set forth in section 2(a)(iii) of this rate schedule if BPA determines that it can no longer provide the level of balancing reserve capacity for Variable Energy Resource Balancing Service that BPA forecast it could provide for the rate period and BPA purchases non-Federal balancing reserve capacity to replace the unavailable Federal balancing reserve capacity.

Formula Rate I:

Adj Imb Rate = Imb rate + (Avg Net Cost / Avg Sales)

Where:

Adj Imb Rate = The adjusted Imbalance Reserves rate that replaces section 2(a)(iii), in $/kW/mo.

Imb Rate = The Imbalance Reserves rate identified in section 2(a)(iii) plus any previous adjustments under this section (Formula Rate I or Formula Rate II), in $/kW/mo.

Avg Net Cost = The average, spread over the remaining months of the rate period, of the net costs associated with acquiring replacement balancing reserve capacity, in $/mo.

Avg Sales = The average forecasted billing factor for the remaining months of the rate period, as identified in the rate case, in kilowatts.

(ii) Formula Rate II for Purchases of Balancing Reserve Capacity to Increase the Amount of Balancing Reserve Capacity to Provide the Imbalance Component for Variable Energy Resource Balancing Service

BPA may apply Formula Rate II to adjust the imbalance reserve rate set forth in section 2(a)(iii) of this rate schedule, with a commensurate increase in non-Federal sources of balancing reserve capacity for Variable Energy Resources Balancing Service, if:

a. one or more participants in the Pacific Northwest utility industry, including regional organizations, asks the Administrator to increase the amount of balancing reserve capacity provided for Variable Energy Resource Balancing Service; or

b. because of a legal challenge to DSO 216, BPA is prevented from implementing DSO 216 or is required to amend it materially.

Formula Rate II:

Adj Imb Rate = Imb rate + (Avg Cost / Avg Sales)

Where:

Adj Imb Rate = The adjusted Imbalance Reserves rate that replaces section 2(a)(iii), in $/kW/mo.

Imb Rate = The Imbalance Reserves rate identified in section 2(a)(iii) plus any previous adjustments under this section (Formula Rate I or Formula Rate II), in $/kW/mo.

Avg Cost = The average, spread over the remaining months of the rate period, of the costs associated with acquiring additional balancing reserve capacity, in $/mo.

Avg Sales = The average forecasted billing factor for the remaining months of the rate period, as identified in the rate case, in kilowatts.

F. DISPATCHABLE ENERGY RESOURCE BALANCING SERVICE

The rate below applies to all non-Federal Dispatchable Energy Resources of 3 MW nameplate rated capacity or greater in the BPA Control Area except as provided in sections III.F.3. Dispatchable Energy Resource Balancing Service is required to help maintain the power system frequency at 60 Hz and to conform to NERC and WECC reliability standards.

1. RATES

The rates for Dispatchable Energy Resource Balancing Service shall not exceed:

(i) Incremental Reserves = 14.50 mills per kW maximum hourly deviation
(ii) Decremental Reserves = 3.60 mills per kW maximum hourly deviation

2. BILLING FACTOR

(a) The hourly billing factor for use of Incremental Reserves is the maximum of the absolute value of the one-minute average negative station control error (under-generation), including ramp periods, that exceeds 2 MW for that hour.

(b) The hourly billing factor for use of Decremental Reserves is the maximum of the one-minute average positive station control error (over-generation), including ramp periods, that exceeds 2 MW for that hour.

3. EXCEPTIONS

(a) This rate will not apply to a Dispatchable Energy Resource, or portion of a Dispatchable Energy Resource, that, in BPA's determination, has put in place, tested, and successfully implemented no later than the 15th day of the month prior to the billing month, the dynamic transfer of plant output out of BPA's Balancing Authority Area to another Balancing Authority Area.

(b) This rate will not apply to a Dispatchable Energy Resource, or portion of a Dispatchable Energy Resource, for any schedule period in which the Dispatchable Energy Resource has called on contingency reserve.

(c) This rate will not apply to a Dispatchable Energy Resource, or portion of a Dispatchable Energy Resource, for any hour in which the Dispatchable Energy Resource has been ordered by BPA or a host utility within BPA's Balancing Authority Area to generate at a level different from the schedule or generation estimate that the Dispatchable Energy Resource submitted to BPA for any schedule period during that hour.

SECTION IV. ADJUSTMENTS, CHARGES, AND OTHER RATE PROVISIONS

A. RATE ADJUSTMENT DUE TO FERC ORDER UNDER FPA § 212

Customers taking service under this rate schedule are subject to the Rate Adjustment Due to FERC Order under FPA § 212 specified in section II.D of the GRSPs.

B. RATE ADJUSTMENT DUE TO BPA POWER SERVICES ADJUSTMENTS, CHARGES, AND SPECIAL RATE PROVISIONS

Customers taking Regulation and Frequency Response Service, Operating Reserve - Spinning Reserve Service, Operating Reserve - Supplemental Reserve Service, Variable Energy Resource Balancing Service, Provisional Variable Energy Resource Balancing Service, or Dispatchable Energy Resource Balancing Service under this rate schedule are subject to the Cost Recovery Adjustment Clause, Dividend Distribution Clause, and NFB Mechanisms specified in section II.H of the GRSPs.

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GENERAL RATE SCHEDULE PROVISIONS

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SECTION I. GENERALLY APPLICABLE PROVISIONS

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A. APPROVAL OF RATES

These 2012 rate schedules and General Rate Schedule Provisions (GRSPs) for Transmission and Ancillary Service Rates shall become effective upon interim approval or upon final confirmation and approval by the Federal Energy Regulatory Commission (FERC or Commission). Bonneville Power Administration (BPA) has requested that FERC make these rates and GRSPs effective on October 1, 2011. All rate schedules shall remain in effect until they are replaced or expire on their own terms.

B. GENERAL PROVISIONS

These 2012 rate schedules and the GRSPs associated with these schedules supersede BPA's 2010 rate schedules (which became effective October 1, 2009) to the extent stated in the Availability section of each rate schedule. These schedules and GRSPs shall be applicable to all BPA-TS contracts, including contracts executed both prior to, and subsequent to, enactment of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act). All sales under these rate schedules are subject to the following acts, as amended: the Bonneville Project Act (P.L. 75-329), 16 U.S.C.§ 832; the Pacific Northwest Consumer Power Preference Act (P.L. 88-552), 16 U.S.C.§ 837; the Federal Columbia River Transmission System Act (P.L. 93-454), 16 U.S.C.§ 838; the Northwest Power Act (P.L. 96-501), 16 U.S.C.§ 839; and the Energy Policy Act of 1992 (P.L. 102-486), 16 U.S.C.§ 824(i)–(l).

These 2012 rate schedules do not supersede any previously established rate schedule that is required, by agreement, to remain in effect.

If a provision in an executed agreement is in conflict with a provision contained herein, the former shall prevail.

C. NOTICES

For the purpose of determining elapsed time from receipt of a notice applicable to rate schedule and GRSP administration, a notice shall be deemed to have been received at 0000 hours on the first calendar day following actual receipt of the notice.

D. BILLING AND PAYMENT

1. BILLING PROCEDURE

Within a reasonable time after the first day of each month, BPA-TS shall submit an invoice to the Transmission Customer for the charges for all services furnished under the Tariff and other agreements during the preceding month. The invoice shall be paid by the Transmission Customer within twenty (20) days of receipt. All payments shall be made in immediately available funds payable to BPA-TS, or by wire transfer to a bank named by BPA-TS.

2. INTEREST ON UNPAID BALANCES

Interest on any unpaid amounts (including amounts placed in escrow) shall be calculated in accordance with the methodology specified for interest on refunds in the Commission's regulations at 18 C.F.R. § 35.19a(a)(2)(iii). Interest on delinquent amounts shall be calculated from the due date of the bill to the date of payment. When payments are made by mail, bills shall be considered as having been paid on the date of receipt by BPA-TS.

3. CUSTOMER DEFAULT

In the event the Transmission Customer fails, for any reason other than a billing dispute as described below, to make payment to BPA-TS on or before the due date as described above, and such failure of payment is not corrected within thirty (30) calendar days after BPA-TS notifies the Transmission Customer to cure such failure, a default by the Transmission Customer shall be deemed to exist. Upon the occurrence of a default, BPA-TS may notify the Transmission Customer that it plans to terminate services in sixty (60) days. The Transmission Customer may use the dispute resolution procedures to contest such termination. In the event of a billing dispute between BPA-TS and the Transmission Customer, BPA-TS will continue to provide service under the Service Agreement as long as the Transmission Customer (i) continues to make all payments not in dispute, and (ii) pays into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If the Transmission Customer fails to meet these two requirements for continuation of service, then BPA-TS may provide notice to the Transmission Customer of its intention to suspend service in sixty (60) days, in accordance with Commission policy.

SECTION II. ADJUSTMENTS, CHARGES, AND SPECIAL RATE PROVISIONS

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A. DELIVERY CHARGE

Transmission Customers shall pay a Delivery Charge for service over DSI Delivery facilities and Utility Delivery facilities.

1. RATES

a. DSI Delivery

Use-of-Facilities (UFT-12) Rate, section III.B.1 or III.B.2

b. Utility Delivery

$1.119 per kilowatt per month

2. BILLING FACTOR

a. Utility Delivery

The monthly Billing Factor for the Utility Delivery rate in section 1.b. shall be the total load on the hour of the Monthly Transmission Peak Load at the Points of Delivery specified as Utility Delivery facilities.

The monthly Utility Delivery Billing Factor shall be adjusted for customers that pay for Utility Delivery facilities under the Use-of-Facilities (UFT) rate schedule. The kilowatt credit shall equal the transmission service over the Delivery facilities used to calculate the UFT charge. This adjustment shall not reduce the Utility Delivery Charge billing factor below zero.

b. Metering Adjustment

At those Points of Delivery that do not have meters capable of determining the demand on the hour of the Monthly Transmission Peak Load, the Billing Factor under section 2.a. shall equal the highest hourly demand that occurs during the billing month at the Point of Delivery multiplied by 0.79.

B. FAILURE TO COMPLY PENALTY CHARGE

1. RATE FOR FAILURE TO COMPLY PENALTY CHARGE

If a party fails to comply with BPA-TS's dispatch, curtailment, redispatch, or load shedding orders, the party will be assessed the Failure to Comply Penalty Charge. The Failure to Comply Penalty Charge shall be the greater of 500 mills per kilowatthour or 150 percent of an hourly energy index in the Pacific Northwest.

If no adequate hourly index exists, an alternative index will be used. At least 30 days prior to the use of such index BPA-TS will post on the OASIS the name of the index to be used. BPA-TS will not change the index more often than once per year unless BPA-TS determines that the existing index is no longer a reliable price index

Parties that are unable to comply with a dispatch, curtailment, load shedding, or redispatch order due to a force majeure on their system will not be subject to the Failure to Comply Penalty Charge provided that they immediately notify the BPA-TS of the situation upon occurrence of the force majeure.

2. BILLING FACTORS

The Billing Factor for the Failure to Comply Penalty Charge shall be the kilowatthours that were not curtailed, redispatched, shed, changed, or limited within ten (10) minutes after issuance of the order in any of the following situations:

a. Failure to shed load when directed to do so by BPA-TS in accordance with the Load Shedding provisions of the Open Access Transmission Tariff or any other applicable agreement between the parties. This includes failure to shed load pursuant to such orders within the time period specified by the North American Electric Reliability Council (NERC), Western Electricity Coordinating Council (WECC), or Northwest Power Pool (NWPP) criteria.

b. Failure of a generator in the BPA Control Area or which directly interconnects to the FCRTS to change or limit generation levels when directed to do so by the BPA-TS in accordance with Good Utility Practice as defined in the OATT. This includes failure to change generation levels pursuant to such orders within the time period specified by NERC, WECC, or NWPP criteria.

c. Failure to curtail or redispatch a reservation or schedule or failure to curtail or redispatch actual transmission use of the Contract or Service Agreement when directed to do so by BPA-TS in accordance with the curtailment or redispatch provisions of the Open Access Transmission Tariff or any other applicable agreement between the parties. This includes failure to curtail or redispatch pursuant to such scheduling protocols or orders within the time period specified by NERC, WECC, or NWPP criteria.

3. ASSESSMENT OF OTHER COSTS RESULTING FROM THE FAILURE TO COMPLY

In addition to the Failure to Comply Penalty Charge, the party will be assessed the costs of alternate measures taken by BPA-TS in order to manage the reliability of the FCRTS due to the failure to comply.

The party will also be assessed monetary penalties imposed on BPA by a Regional Reliability Organization, Electric Reliability Organization, or FERC for a violation of a Reliability Standard authorized under section 215 of the Energy Policy Act of 2005, if the violation was caused by the party's failure to comply.

C. POWER FACTOR PENALTY CHARGE

1. DESCRIPTION OF THE POWER FACTOR PENALTY CHARGE

Any party that is interconnected with the Federal Columbia River Transmission System (FCRTS) shall be charged for its reactive power requirements as described in this section, unless otherwise specified in an agreement existing prior to October 1, 1995.

Each point of interconnection or point of delivery shall be monitored and billed independently for determining the party's total reactive power requirements and all associated billing factors, including the Reactive Deadband. If a party is taking transmission service under multiple rate schedules, the party will pay for its reactive power requirements as if it is taking delivery under only one rate schedule.

2. CONDITIONS FOR APPLICATION OF THE POWER FACTOR PENALTY CHARGE

a. Measured Data

The Power Factor Penalty Charge will apply to only the party's reactive power requirements for which measured data exist.

b. Party's Generating Resource Connected to the FCRTS

Irrespective of the direction of real power flow, the Power Factor Penalty Charge shall apply to points of interconnection where a party's generating resource is directly connected to the FCRTS, *unless* the party's generating resource is either:

(1) a synchronous generator equipped with a voltage regulator, or

(2) equipped with reactive power control devices that comply with BPA-TS's applicable interconnection standards.

Such resource must actively support the voltage schedule at the point of integration at all times when the resource is in service, as determined by BPA-TS, for this exemption to apply. Generating resources that do not satisfy the above criteria shall not be exempt from the Power Factor Penalty Charge.

c. Bi-directional Real Power Flow

For points other than those specified in section 2.b, the Power Factor Penalty Charge will *not* be applied, and no new Ratchet Demand for reactive power will be established, at a specific point if the metered real power (on an hourly integrated basis) flows from the party's system to the FCRTS at that point for as little as one hour during the billing period. However, the party will still pay any previously incurred demand ratchet charges. The direction of the real power flow will be determined based on metered quantities, not on scheduled quantities.

d. Service by Transfer

Points of delivery that are served by transfer over another utility's transmission system will *not* be subject to the Power Factor Penalty Charge *unless* there are significant BPA-TS Network facilities between the party's points of delivery and the transferor's system.

e. Specific Points Exempt from the Power Factor Penalty Charge

The Power Factor Penalty Charge will *not* apply to the following points:

Nevada-Oregon Border (NOB)
Big Eddy 500 kV
Big Eddy 230 kV
John Day 500 kV
Malin 500 kV
Captain Jack 500 kV
Garrison 500 kV
Townsend 500 kV

f. Special Circumstances

The party may submit requests to BPA-TS for consideration of unique circumstances. BPA-TS will evaluate the request and may make arrangements with the party to address the special circumstances.

3. RATES

BPA-TS will bill the party for reactive power at each point each month as follows:

<u>Reactive Demand</u>

$0.28 per kVAr of lagging reactive demand in excess of the Reactive Deadband during HLH in all months of the year.

$0.24 per kVAr of leading reactive demand in excess of the Reactive Deadband during LLH in all months of the year.

No charge for leading reactive demand during HLH.

No charge for lagging reactive demand during LLH.

4. BILLING FACTORS

a. Reactive Deadband

The Reactive Deadband (measured in kVAr) is used to determine the Reactive Billing Demand and Ratchet Demand for the Power Factor Penalty Charge.

The Reactive Deadband for each billing period is the maximum hourly integrated metered real power demand (measured in kW) at each point during the billing period multiplied by 25 percent.

The Reactive Deadband for either HLH or LLH:

(1) is computed once per billing period (the same quantity is used for both HLH and LLH),

(2) does not vary during the billing period, and

(3) is based on the maximum hourly integrated metered real power demand during that billing period.

b. Reactive Billing Demand

The party's Reactive Billing Demand shall be calculated independently for lagging reactive power and leading reactive power at each point for which a Power Factor Penalty Charge is assessed.

All reactive demands shall be established in the particular HLH or LLH at each point during which the party's maximum applicable reactive demand is placed on BPA-TS, regardless of the time of the real power peak at each point.

All reactive demand at each point shall be established on a non-coincidental basis, regardless of whether the party is billed for real power or transmission at such point on a coincidental or non-coincidental basis, *unless* otherwise specified in the agreement between BPA-TS and the party, *or* coincidental billing is, in BPA-TS's sole determination, more practical for BPA-TS.

There will be separate reactive demands for lagging (HLH) and leading (LLH) demands. The party's Reactive Billing Demand for each point for the billing month shall be the *larger* of:

(1) the largest measured reactive demand in excess of the Reactive Deadband during the billing period, *or*

(2) the Ratchet Demand for reactive power.

The Ratchet Demand for reactive power is equal to 100 percent of the largest measured reactive demand in excess of the Reactive Deadband during the preceding 11-month period. Each point shall have a separate Ratchet Demand for lagging (HLH) and leading (LLH) reactive demand.

5. ADJUSTMENTS FOR REACTIVE LOSSES

Measured data shall be adjusted for reactive losses, if applicable, before determination of the Reactive Billing Demand.

D. RATE ADJUSTMENT DUE TO FERC ORDER UNDER FPA § 212

If, after review by FERC, the NT, PTP, ACS, IS, or IM rate schedule, as initially submitted to FERC, is modified to satisfy the standards of section 212(i)(1)(B)(ii) of the Federal Power Act (16 U.S.C. § 824k(i)(1)(B)(ii)) for FERC-ordered transmission service, then such modifications shall automatically apply to the rate schedule for non-section 212(i)(1)(B)(ii) transmission service. The modifications for non-section 212(i)(1)(B)(ii) transmission service, as described above, shall be effective, however, only prospectively from the date of the final FERC order granting final approval of the rate schedule for FERC-ordered transmission service pursuant to section 212(i)(1)(B)(ii). No refunds shall be made or additional costs charged as a consequence of this prospective modification for any non-section 212(i)(1)(B)(ii) transmission service that occurred under the rate schedule prior to the effective date of such prospective modification.

E. RESERVATION FEE

The Reservation Fee is a nonrefundable fee that shall be charged to any PTP Transmission Service customer that postpones the commencement of service by requesting an extension of the Service Commencement Date specified in the executed Service Agreement.

The Reservation Fee shall be specified in the executed agreement for transmission service.

1. FEE

The Reservation Fee shall be a nonrefundable fee equal to one month's charge for the requested Long-Term Firm Point-to-Point Transmission Service for each year or fraction of a year for which the customer chooses to extend the Service Commencement Date. The Reservation Fee shall be paid annually until transmission service begins or the reservation period ends, whichever occurs first.

2. PAYMENT

The Reservation Fee for the first extension of the Service Commencement Date shall be paid in a lump sum within 30 days of the original Service Commencement Date. For subsequent extensions, the Reservation Fee shall be paid in a lump sum within 30 days of the anniversary date of the original Service Commencement Date.

F. TRANSMISSION AND ANCILLARY SERVICES RATE DISCOUNTS

BPA-TS may offer discounted rates for transmission and ancillary services available under the Open Access Transmission Tariff and to the extent provided for in the PTP, IS, IM, and ACS rate schedules.

Three principal requirements apply to discounts for transmission service and Ancillary Services provided by the Transmission Provider in conjunction with its provision of transmission service, as follows:

1. any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS;

2. any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an affiliate's use) must occur solely by posting on the OASIS; and

3. once a discount is negotiated, details must be immediately posted on the OASIS.

For any discount agreed upon for transmission service on a path, from point(s) of receipt to point(s) of delivery, the Transmission Provider must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

A discount agreed upon for an Ancillary Service must be offered for the same period to all Eligible Customers on the Transmission Provider's System.

G. UNAUTHORIZED INCREASE CHARGE (UIC)

Transmission Customers taking Point-to-Point Transmission Service under the PTP, IS, and IM rate schedules shall be assessed the UIC when they exceed their capacity reservations at any Point of Receipt (POR) or Point of Delivery (POD). BPA-TS will notify a Transmission Customer that is subject to a UIC once BPA-TS has verified the UIC amount.

1. RATE

a. Point-To-Point Transmission Service (PTP, IS, and IM Rate Schedules)

The UIC rate shall be the lower of (i) 100 mills per kilowatthour plus the price cap established by FERC for spot market sales of energy in the WECC, or (ii) 1000 mills per kilowatthour. If FERC eliminates the price cap, the rate will be 500 mills per kilowatthour.

2. BILLING FACTORS

a. Point-To-Point Transmission Service (PTP, IS, and IM Rate Schedules

For each hour of the monthly billing period, BPA-TS shall determine the amount by which the Transmission Customer exceeds its capacity reservation at each POD and POR, to the extent practicable. BPA-TS shall use hourly measurements based on a 10-minute moving average to calculate actual demands at PODs associated with loads that are one-way dynamically scheduled and at PORs associated with resources that are one-way dynamically scheduled. To calculate actual demands at PODs and PORs that are associated with two-way dynamic schedules, BPA-TS shall use instantaneous peak demands for each hour. Actual demands at all other PODs and PORs will be based on 60-minute integrated demands or transmission schedules.

For each hour, BPA-TS will sum these amounts that exceed capacity reservations: (1) for all PODs, and (2) for all PORs. The Billing Factor for the monthly billing period shall be the greater of the total of the POD hourly amounts or the total of the POR hourly amounts.

3. UIC RELIEF

a. Criteria for Waiving or Reducing the UIC

Under appropriate circumstances, BPA-TS may waive or reduce the UIC to a Transmission Customer on a non-discriminatory basis. A

Transmission Customer seeking a reduction or waiver must demonstrate good cause for relief, including demonstrating that the event that resulted in the UIC:

(1) was inadvertent or was the result of an equipment failure or outage that the Transmission Customer could not have reasonably foreseen;

(2) could not have been avoided by the exercise of reasonable care; and

(3) did not result in harm to BPA-TS's transmission system or transmission services, or to any other Transmission Customer.

If a waiver or reduction is granted to a Transmission Customer, notice of such waiver or reduction will be posted on the BPA-TS OASIS.

b. Transmission Rate if BPA-TS Waives or Reduces the UIC

If BPA-TS waives or reduces the UIC, the Transmission Customer remains subject to the applicable rates, including Ancillary Services rates, for the Transmission Customer's transmission demand. The following rates shall apply to transmission demand that exceeds the capacity reservations of a Transmission Customer taking service under the PTP, IS, or IM rate schedules if BPA-TS waives or reduces the UIC:

(1) If BPA-TS waives or reduces the UIC for excess transmission demand in one or more hours in the same calendar day, the rate for one day of service under section II.B.1 of the applicable PTP, IS, or IM rate schedule shall apply.

(2) If BPA-TS waives or reduces the UIC for excess transmission demand on multiple calendar days in the same calendar week, the rate for seven days of service under section II.B.1 of the applicable PTP, IS, or IM rate schedule shall apply.

(3) If BPA-TS waives or reduces the UIC for excess transmission demand in one or more hours in multiple calendar weeks in the same calendar month, the rate for the number of days in the month of service under section II.B.1 of the applicable PTP, IS, or IM rate schedule shall apply.

For a Transmission Customer taking Point-to-Point Transmission Service under the PTP, IS, or IM rate schedules, the Billing Factor for rates in this section 3.b shall be: (a) the Transmission Customer's highest excess transmission demand for which BPA-TS waives the UIC; or (b) if BPA-TS reduces the UIC, the Transmission Customer's highest excess transmission demand that is not subject to the UIC as a result of the reduction.

H. CRAC, DDC, AND THE NFB MECHANISMS

The Cost Recovery Adjustment Clause (CRAC), Dividend Distribution Clause (DDC), and NFB Mechanisms (the NFB Adjustment and the Emergency NFB Surcharge) are detailed in the BPA Power Rate Schedules, GRSPs, sections II.C, II.D, and II.K.

The CRAC and the Emergency NFB Surcharge are upward adjustments to certain Power and Transmission rates. The DDC is a downward adjustment to certain Power and Transmission rates. The NFB Adjustment is an upward adjustment to the cap on the amount of incremental BPA revenue that can be generated by a CRAC during a fiscal year. Except as otherwise provided, the CRAC, DDC, and Emergency NFB Surcharge apply to the following Ancillary and Control Area Service (ACS) rate schedules:

- Regulation and Frequency Response Service
- Operating Reserve - Spinning Reserve Service
- Operating Reserve - Supplemental Reserve Service
- Variable Energy Resource Balancing Service

  Exception: The CRAC, DDC and Emergency NFB Surcharge apply only to the base unadjusted Variable Energy Resource Balancing Service rates specified in section III.E.2(a) of the Variable Energy Resource Balancing Service rate schedule, and not to the difference between that base unadjusted Variable Energy Resource Balancing Service rate and any adjusted Variable Energy Resource Balancing Service rate calculated under Formula Rates I or II in Section III.E.7 in the Variable Energy Resource Balancing Service rate schedule. In addition, the CRAC does not apply to the Variable Energy Resource Balancing Service Supplemental Service rate.

- Dispatchable Energy Resource Balancing Service

1. CUSTOMER CHARGES FOR THE ACS CRAC

The ACS CRAC Amount is the share, in dollars, of the total CRAC Amount that is to be recovered from the ACS rates specified above; the balance of the CRAC Amount is to be recovered from specified Power rates. The ACS CRAC Amount is converted to an ACS CRAC Percentage by dividing the ACS CRAC Amount by the most recent forecast of revenues for the relevant fiscal year at the ACS rates subject to the CRAC.

Line items will be added to the bills for each service during the 12 months of the applicable year by multiplying the ACS CRAC Percentage times each of the applicable rates times the billing factors for each rate for each customer.

2. CUSTOMER CREDIT FOR THE ACS DDC

The ACS DDC Amount is the share, in dollars, of the total DDC Amount that is to be distributed via the ACS rates specified above; the balance of the DDC Amount is to be distributed via specified Power rates. The ACS DDC Amount is converted to an ACS DDC Percentage by dividing the ACS DDC Amount by the most recent forecast of revenues for the relevant fiscal year at the ACS rates subject to the DDC.

Line items showing a credit will be added to the bills for each service during the 12 months of the applicable year by multiplying the ACS DDC Percentage times each of the applicable rates times the billing factors for each rate for each customer.

3. CUSTOMER CHARGES FOR THE ACS EMERGENCY NFB SURCHARGE

The ACS Surcharge amount is the share, in dollars, of the total Surcharge Amount that is to be collected from the ACS rates specified above; the balance of the Surcharge Amount is to be collected from specified Power rates. The ACS Surcharge is converted to an ACS Surcharge Percentage by dividing the ACS Surcharge by the most recent forecast of revenues for the relevant fiscal year at the ACS rates subject to the Emergency NFB Surcharge.

Line items will be added to the bills for each service during the 12 months of the applicable year by multiplying the ACS Surcharge Percentage times each of the applicable rates times the billing factors for each rate.

4. CRAC, DDC, AND NFB MECHANISM RATE PROVISIONS

The CRAC, DDC and NFB Mechanism rate provisions specified in the Power Rate Schedules, GRSPs, sections II.C, II.D, and II.K, are incorporated by reference.

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SECTION III. DEFINITIONS

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1. ANCILLARY SERVICES

Ancillary Services are those services that are necessary to support the transmission of energy from resources to loads while maintaining reliable operation of the BPA-TS's Transmission System in accordance with Good Utility Practice. Ancillary Services include:

1. Scheduling, System Control, and Dispatch; and
2. Reactive Supply and Voltage Control from Generation Sources;
3. Regulation and Frequency Response;
4. Energy Imbalance;
5. Operating Reserve – Spinning; and
6. Operating Reserve – Supplemental

Ancillary Services are available under the ACS rate schedule.

2. BILLING FACTOR

The *Billing Factor* is the quantity to which the charge specified in the rate schedule is applied. When the rate schedule includes charges for several products, there may be a Billing Factor for each product.

3. CONTROL AREA

A *Control Area* (also known as *Balancing Authority Area*) is an electric power system or combination of electric power systems to which a common automatic generation control scheme is applied in order to:

1. match at all times the power output of the generators within the electric power system(s) and the import of energy from entities outside the electric power system(s) with the load within the electric power system(s) and the export of energy to entities outside the electric power system(s);

2. maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;

3. maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice; and

4. provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

4. CONTROL AREA SERVICES

Control Area Services are available to meet the Reliability Obligations of a party with resources or loads in the BPA Control Area. A party that is not satisfying all of its

Reliability Obligations through the purchase or self-provision of Ancillary Services may purchase Control Area Services to meet its Reliability Obligations. Control Area Services are also available to parties with resources or loads in the BPA Control Area that have Reliability Obligations, but do not have a transmission agreement with BPA-TS. Reliability Obligations for resources or loads in the BPA Control Area are determined by applying the North American Electric Reliability Council (NERC), Western Electricity Coordinating Council (WECC), and the Northwest Power Pool (NWPP) reliability criteria. Control Area Services, include, without limitation:

1. Regulation and Frequency Response Service
2. Generation Imbalance Service
3. Operating Reserve – Spinning Reserve Service
4. Operating Reserve – Supplemental Reserve Service
5. Variable Energy Resource Balancing Service
6. Dispatchable Energy Resource Balancing Service

5. DAILY SERVICE

Daily Service is service that starts at 00:00 of any date and stops at 00:00 at least one (1) day later, but less than or equal to six (6) days later.

6. DIRECT ASSIGNMENT FACILITIES

Direct Assignment Facilities are facilities or portions of facilities that are constructed by BPA-TS for the sole use/benefit of a particular Transmission Customer requesting service under the Open Access Transmission Tariff, the costs of which may be directly assigned to the Transmission Customer in accordance with applicable Federal Energy Regulatory Commission policy. Direct Assignment Facilities shall be specified in the service agreement that governs service to the Transmission Customer.

7. DIRECT SERVICE INDUSTRY (DSI) DELIVERY

The *DSI Delivery* segment is the segment of the FCRTS that provides service to DSI customers at voltages of 34.5 kV and below.

8. DISPATCHABLE ENERGY RESOURCE BALANCING SERVICE

Dispatchable Energy Resource Balancing Service (DERBS) is a control area service that provides imbalance reserves (which compensate for differences between a thermal generator's schedule and the actual generation during an hour). DERBS is required to help maintain the power system frequency at 60 Hz and to conform to NERC and WECC reliability standards.

9. DYNAMIC SCHEDULE

See definition in Dynamic Transfer Operating and Scheduling Business Practice.

10. DYNAMIC TRANSFER

See definition in Dynamic Transfer Operating and Scheduling Business Practice.

11. EASTERN INTERTIE

The *Eastern Intertie* is the segment of the Federal Columbia River Transmission System (FCRTS) for which the transmission facilities consist of the Townsend-Garrison double-circuit 500 kV transmission line segment, including related terminals at Garrison.

12. ENERGY IMBALANCE SERVICE

Energy Imbalance Service is provided when a difference occurs between the scheduled and the actual delivery of energy to a load located within a Control Area. The BPA-TS must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the BPA-TS or make alternative comparable arrangements specified in the Transmission Customer's Service Agreement to satisfy its Energy Imbalance Service obligation.

13. FEDERAL COLUMBIA RIVER TRANSMISSION SYSTEM

The *Federal Columbia River Transmission System* (FCRTS) is the transmission facilities of the Federal Columbia River Power System, which include all transmission facilities owned by the government and operated by BPA, and other facilities over which BPA has obtained transmission rights.

14. FEDERAL SYSTEM

The *Federal System* is the generating facilities of the Federal Columbia River Power System, including the Federal generating facilities for which BPA is designated as marketing agent; the Federal facilities under the jurisdiction of BPA; and any other facilities:

1. from which BPA receives all or a portion of the generating capability (other than station service) for use in meeting BPA's loads to the extent BPA has the right to receive such capability. "BPA's loads" do not include any of the loads of any BPA customer that are served by a non-Federal generating resource purchased or owned directly by such customer which may be scheduled by BPA;

2. which BPA may use under contract or license; or

3. to the extent of the rights acquired by BPA pursuant to the 1961 U.S.-Canada Treaty relating to the cooperative development of water resources of the Columbia River Basin.

15. GENERATION IMBALANCE

Generation Imbalance is the difference between the scheduled amount and actual delivered amount of energy from a generation resource in the BPA Control Area.

16. GENERATION IMBALANCE SERVICE

Generation Imbalance Service is taken when there is a difference between scheduled and actual energy delivered from generation resources in the BPA Control Area during a schedule period.

17. HEAVY LOAD HOURS (HLH)

Heavy Load Hours (HLH) are all those hours in the peak period hour ending 7 a.m. through hour ending 10 p.m., Monday through Saturday, Pacific Prevailing Time (Pacific Standard Time or Pacific Daylight Time, as applicable). BPA matches NERC Standards in classifying six holidays as Light Load Hour.

18. HOURLY NON-FIRM SERVICE

Hourly Non-firm Service is non-firm transmission service under Part II of the Open Access Transmission Tariff in hourly increments.

19. INTEGRATED DEMAND

Integrated Demand is the quantity derived by mathematically “integrating” kilowatthour deliveries over a 60-minute period. For one-way dynamic schedules, demand is integrated on a rolling ten-minute basis.

20. LIGHT LOAD HOURS (LLH)

Light Load Hours (LLH) are all those hours in the off-peak period hour ending 11 p.m. through hour ending 6 a.m., Monday through Saturday and all hours Sunday, Pacific Prevailing Time (Pacific Standard Time or Pacific Daylight Time, as applicable). BPA matches six holidays classified according to NERC Standards as LLH. Memorial Day, Labor Day and Thanksgiving occur on the same day each year; Memorial Day is the last Monday in May, Labor Day is the first Monday in September and Thanksgiving Day is the fourth Thursday in November. New Year’s Day, Independence Day, and Christmas Day fall on predetermined dates each year. In the event that they fall on a Sunday, the holiday is celebrated the Monday immediately following that Sunday, so that Monday is also LLH all day. If these days fall on a Saturday, the holiday remains on that Saturday, and that Saturday is classified as LLH.

21. LONG-TERM FIRM POINT-TO-POINT (PTP) TRANSMISSION SERVICE

Long-Term Firm Point-to-Point Transmission Service is Firm Point-To-Point Transmission Service under Part II of the Open Access Transmission Tariff with a term of one year or more.

22. MAIN GRID

As used in the FPT rate schedule, the *Main Grid* is that portion of the Network facilities with an operating voltage of 230 kV or more.

23. MAIN GRID DISTANCE

As used in the FPT rate schedules, *Main Grid Distance* is the distance in airline miles on the Main Grid between the Point of Integration (POI) and the Point of Delivery (POD), multiplied by 1.15.

24. MAIN GRID INTERCONNECTION TERMINAL

As used in the FPT rate schedules, *Main Grid Interconnection Terminal* refers to Main Grid terminal facilities that interconnect the FCRTS with non-BPA facilities.

25. MAIN GRID MISCELLANEOUS FACILITIES

As used in the FPT rate schedules, *Main Grid Miscellaneous Facilities* refers to switching, transformation, and other facilities of the Main Grid not included in other components.

26. MAIN GRID TERMINAL

As used in the FPT rate schedules, *Main Grid Terminal* refers to the Main Grid terminal facilities located at the sending and/or receiving end of a line, exclusive of the Interconnection terminals.

27. MEASURED DEMAND

The *Measured Demand* is that portion of the customer's Metered or Scheduled Demand for transmission service from BPA-TS under the applicable transmission rate schedule. If transmission service to a point of delivery, or from a point of receipt, is provided under more than one rate schedule, the portion of the measured quantities assigned to any rate schedule shall be as specified by contract. The portion of the total Measured Demand so assigned shall be the Measured Demand for transmission service for each transmission rate schedule.

28. METERED DEMAND

Except for dynamic schedules, the *Metered Demand* in kilowatts shall be the largest of the 60-minute clock-hour Integrated Demands at which electric energy is delivered (received) for a transmission customer:

1. at each point of delivery (receipt) for which the Metered Demand is the basis for the determination of the Measured Demand;

2. during each time period specified in the applicable rate schedule; and

3. during any billing period.

Such largest Integrated Demand shall be determined from measurements made in accord with the provisions of the applicable contract and these GRSPs. This amount shall be adjusted as provided herein and in the applicable agreement between BPA-TS and the customer.

For one-way Dynamic Schedules, the Metered Demand in kilowatts shall be the largest ten-minute moving average of the load (generation) at the point of delivery (receipt). The ten-minute moving average shall be assigned to the hour in which the ten-minute period ends. For two-way Dynamic Schedules, the Metered Demand in kilowatts shall be the largest instantaneous value of the Dynamic Schedule during the hour.

29. MONTANA INTERTIE

The *Montana Intertie* is the double-circuit 500 kV transmission line and associated substation facilities from Broadview Substation to Garrison Substation.

30. MONTHLY SERVICE

Monthly Service is service that starts at 00:00 on any date and stops at 00:00 at least 28 days later, but less than or equal to 364 days later.

31. MONTHLY TRANSMISSION PEAK LOAD

Monthly Transmission Peak Load is the peak loading on the Federal Transmission System during any hour of the designated billing month, determined by the largest hourly integrated demand produced from the sum of Federal and non-Federal generating plants in BPA’s Control Area and metered flow into BPA’s Control Area.

32. NETWORK (OR INTEGRATED NETWORK)

The *Network* is the segment of the Federal Columbia River Transmission System (FCRTS) for which the transmission facilities provide the bulk of transmission of electric power within the Pacific Northwest.

33. NETWORK INTEGRATION TRANSMISSION (NT) SERVICE

Network Integration Transmission (NT) Service is the transmission service provided under Part III of the Open Access Transmission Tariff.

34. NETWORK LOAD

Network Load is the load that a Network Customer designates for Network Integration Transmission Service under Part III of the Open Access Transmission Tariff. The Network Customer's Network Load shall include all load served by the output of any Network Resources designated by the Network Customer. A Network Customer may elect to designate less than its total load as Network Load but may not designate only part of the load at a discrete Point of Delivery.

Where an Eligible Customer has elected not to designate a particular load at discrete Points of Delivery as Network Load, the Eligible Customer is responsible for making separate arrangements under Part II of the Tariff for any Point-to-Point Transmission Service that may be necessary for such non-designated load.

35. NETWORK UPGRADES

Network Upgrades are modifications or additions to transmission-related facilities that are integrated with and support the BPA Transmission System for the general benefit of all users of such Transmission System.

36. NON-FIRM POINT-TO-POINT (PTP) TRANSMISSION SERVICE

Non-Firm Point-To-Point Transmission Service is Point-To-Point Transmission Service under the Open Access Transmission Tariff that is reserved and scheduled on an as-available basis and is subject to Curtailment or Interruption as set forth in Section 14.7 under Part II of the Tariff. Non-Firm PTP Transmission Service is available on a stand-alone basis for periods ranging from one hour to one month.

37. OPERATING RESERVE -- SPINNING RESERVE SERVICE

Operating Reserve -- Spinning Reserve Service is needed to serve load immediately in the event of a system contingency. Spinning Reserve Service may be provided by generating units that are on-line and loaded at less than maximum output. The BPA-TS must offer this service in accordance with applicable NERC, WECC, and NWPP standards. The Transmission or Control Area Service Customer must either purchase this service from the BPA-TS or make alternative comparable arrangements to satisfy its Spinning Reserve Service obligation. The Transmission or Control Area Service Customer's obligation is determined consistent with North American Electric Reliability Council (NERC), Western Systems Coordinating Council (WECC) and Northwest Power Pool (NWPP) criteria.

38. OPERATING RESERVE – SUPPLEMENTAL RESERVE SERVICE

Operating Reserve – Supplemental Reserve Service is needed to serve load in the event of a system contingency; however, it is not available immediately to serve load but rather within a short period of time. Supplemental Reserve Service may be provided by generating units that are on-line but unloaded, by quick-start generation or by interruptible load. The BPA-TS must offer this service in accordance with applicable NERC, WECC, and NWPP standards. The Transmission or Control Area Service Customer must either purchase this service from the BPA-TS or make alternative but comparable arrangements to satisfy its Supplemental Reserve Service obligation. The Transmission Customer's obligation is determined consistent with North American Electric Reliability Council (NERC), Western Electricity Coordinating Council (WECC) and Northwest Power Pool criteria.

39. OPERATING RESERVE REQUIREMENT

Operating Reserve Requirement is a party's total operating reserve obligation (spinning and supplemental) to the BPA Control Area. A party is responsible for purchasing or otherwise providing Operating Reserves associated with its transactions which impose a reserve obligation on the BPA Control Area.

The specific amounts required are determined consistent with North American Electric Reliability Council (NERC) Policies, the Northwest Power Pool (NWPP) Operating Manual, "Contingency Reserve Sharing Procedure," and the Western Electricity Coordinating Council (WECC) Standards.

40. PERSISTENT DEVIATION

A Persistent Deviation event is one or more of the following:

1. <u>For Generation Imbalance Service only</u>:

   All hours or scheduled periods in which either a negative deviation (actual generation greater than scheduled) or positive deviation (generation is less than scheduled) exceeds:

   (a) both 15% of the schedule and 20 MW in each scheduled period for four consecutive hours or more in the same direction;

(b) both 7.5% of the schedule and 10 MW in each scheduled period for six consecutive hours or more in the same direction;

(c) both 1.5% of the schedule and 5 MW in each scheduled period for twelve consecutive hours or more in the same direction; or

(d) both 1.5% of the schedule and 2 MW in each scheduled period for twenty-four consecutive hours or more in the same direction.

2. <u>For Energy Imbalance Service only:</u>

All hours or scheduled periods in which either a negative deviation (energy taken is less than the scheduled energy) or positive deviation (energy taken is greater than energy scheduled) exceeds:

(a) both 15% of the schedule and 20 MW in each scheduled period for four consecutive hours or more in the same direction;

(b) both 7.5% of the schedule and 10 MW in each scheduled period for six consecutive hours or more in the same direction;

(c) both 1.5% of the schedule and 5 MW in each scheduled period for twelve consecutive hours or more in the same direction; or

(d) both 1.5% of the schedule and 2 MW in each scheduled period for twenty-four consecutive hours or more in the same direction.

3. A pattern of under or over delivery or over or under use of energy occurs generally or at specific times of day.

Upon 90 days written notice on BPA-TS's OASIS that BPA-TS has implemented intra-hour scheduling for exports and imports of energy within and out of the BPA Balancing Authority Area**,** parts 1(a) and 2(a) above shall be deemed replaced with the following:

(a) both 15% of the schedule and 20 MW in each scheduled period for three consecutive hours or more in the same direction.

41. POINT OF DELIVERY (POD)

A *Point of Delivery* is a point on the BPA Transmission System, or transfer points on other utility systems pursuant to Section 36 of the Open Access Transmission Tariff, where capacity and energy transmitted by the BPA-TS will be made available to the Receiving Party under Parts II and III of the Tariff or to the Transmission Customer under other BPA transmission service agreements. The Point(s) of Delivery shall be specified in the Service Agreement for Long-Term Firm Point-to-Point Service, Network Integration Transmission Service, and other BPA-TS.

42. POINT OF INTEGRATION (POI)

A *Point of Integration* is the contractual interconnection point where power is received from the customer. Typically, a point of integration is located at a resource site, but it could be located at some other interconnection point.

43. POINT OF INTERCONNECTION (POI)

A *Point of Interconnection* is a point where the facilities of two entities are interconnected. This term is used in certain pre-Open Access Transmission Tariff service agreements and has the same meaning as “Point of Integration” and “Point of Receipt.”

44. POINT OF RECEIPT (POR)

A *Point of Receipt* is a point of interconnection on the BPA Transmission System where capacity and energy will be made available to BPA-TS by the Delivering Party under Parts II and III of the Open Access Transmission Tariff. The Point(s) of Receipt shall be specified in the Service Agreement for Long-Term Firm Point-to-Point Service, Network Integration Transmission Service, and other BPA-TS.

45. PROVISIONAL VARIABLE ENERGY RESOURCE BALANCING SERVICE

Provisional Variable Energy Resource Balancing Service is a type of Variable Energy Resource Balancing Service (VERBS) that is offered during a rate period to customers that lose their status as a self-supplier of one or more components of VERBS and to customers that did not have an expected interconnection date during the rate period and accelerate their interconnection date into the rate period.

46. RATCHET DEMAND

The *Ratchet Demand* in kilowatts or kilovars is the maximum demand established during a specified period of time either during, or prior to, the current billing period. The Ratchet Demand shall be the maximum demand established during the previous 11 billing months. If a Transmission Demand has been decreased pursuant to the terms of the transmission agreement during the previous 11 billing months, such decrease will be reflected in determining the Ratchet Demand. The Ratchet Demand for reactive power is defined in the Power Factor Penalty Charge at section II.C of these GRSPs.

47. REACTIVE POWER

Reactive Power is the out-of-phase component of the total volt-amperes in an electric circuit. Reactive Power has two components: reactive demand (expressed in kilovars or kVAr) and reactive energy (expressed in kilovarhours or kVArh).

48. REACTIVE SUPPLY AND VOLTAGE CONTROL FROM GENERATION SOURCES SERVICE

Reactive Supply and Voltage Control from Generation Sources Service is required to maintain voltage levels on BPA-TS's transmission facilities within acceptable limits. In order to maintain transmission voltages on BPA-TS's transmission facilities within acceptable limits, generation facilities (in the Control Area where the BPA-TS transmission facilities are located) are operated to produce (or absorb) reactive power. Thus, Reactive Supply and Voltage Control from Generation Sources Service must be provided for each transaction on BPA-TS's transmission facilities. The amount of Reactive Supply and Voltage Control from Generation Sources Service that must be supplied with respect to the Transmission Customer's transaction will be determined based on the reactive power support necessary to maintain transmission voltages within limits that are generally accepted in the region and consistently adhered to by BPA-TS. The Transmission Customer must purchase this service from BPA-TS.

49. REGULATION AND FREQUENCY RESPONSE SERVICE

Regulation and Frequency Response Service is necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled Interconnection frequency at sixty cycles per second (60 Hz). Regulation and Frequency Response Service is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generating control equipment) as necessary to follow the moment-by-moment changes in load. The obligation to maintain this balance between resources and load lies with the BPA-TS. The BPA-TS must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the BPA-TS or make alternative comparable arrangements to satisfy its Regulation and Frequency Response Service obligation.

50. RELIABILITY OBLIGATIONS

Reliability Obligations are the obligations that a party with resources or loads in the BPA Control Area must provide in order to meet minimum reliability standards. Reliability Obligations shall be determined consistent with applicable North American Electric Reliability Council (NERC), Western Electricity Coordinating Council (WECC), and Northwest Power Pool (NWPP) standards. BPA-TS offers Ancillary Services and Control Area Services to allow resources or loads to meet their Reliability Obligations.

51. RESERVED CAPACITY

Reserved Capacity is the maximum amount of capacity and energy that BPA-TS agrees to transmit for the Transmission Customer over the BPA Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under Part II of the Open Access Transmission Tariff. Reserved Capacity shall be expressed in terms of whole megawatts on a sixty (60)-minute interval (commencing on the clock hour) basis. In cases where Dynamic Schedules are involved, the Reserved Capacity must be set at a level to accommodate (i) a demand equal to the largest ten-minute moving average of the load or generation expected to occur during the contract period for one-way Dynamic Schedules used to transfer generation or load from one Control Area to another Control Area; or (ii) a demand equal to the instantaneous peak demand, for each direction, of the supplemental Control Area service request expected to occur during the contract period for two-way Dynamic Transfers used to provide supplemental Control Area services. The supplemental Control Area service response shall always be the lesser of the Control Area service request or the Reserved Capacity associated with the supplemental Control Area service.

52. SCHEDULED DEMAND

Scheduled Demand is the hourly demand at which electric energy is scheduled for transmission on the FCRTS.

53. SCHEDULING, SYSTEM CONTROL, AND DISPATCH SERVICE

Scheduling, System Control, and Dispatch Service is an Ancillary Service required to schedule the movement of power through, out of, within, or into a Control Area. This service can be provided only by the operator of the Control Area in which the transmission facilities used for transmission service are located. The Transmission Customer must purchase this service from BPA-TS.

54. SECONDARY SYSTEM

As used in the FPT rate schedules, *Secondary System* is that portion of the Network facilities with an operating voltage greater than or equal to 69 kV and less than 230 kV.

55. SECONDARY SYSTEM DISTANCE

As used in the FPT rate schedules, *Secondary System Distance* is the number of circuit miles of Secondary System transmission lines between the secondary Point of Integration and either the Main Grid or the secondary Point of Delivery (POD), or between the Main Grid and the secondary POD.

56. SECONDARY SYSTEM INTERCONNECTION TERMINAL

As used in the FPT rate schedules, *Secondary System Interconnection Terminal* refers to the terminal facilities on the Secondary System that interconnect the FCRTS with non-BPA facilities.

57. SECONDARY SYSTEM INTERMEDIATE TERMINAL

As used in the FPT rate schedules, *Secondary System Intermediate Terminal* refers to the first and final terminal facilities in the Secondary System transmission path, exclusive of the Secondary System Interconnection terminals.

58. SECONDARY TRANSFORMATION

As used in the FPT rate schedules, *Secondary Transformation* refers to transformation from Main Grid to Secondary System facilities.

59. SHORT-TERM FIRM POINT-TO-POINT (PTP) TRANSMISSION SERVICE

Short-Term Firm Point-To-Point Transmission Service is Firm Point-To-Point Transmission Service under Part II of the Open Access Transmission Tariff with a term of less than one year. Short-Term Firm Point-To-Point Transmission Service with a duration of less than one calendar day is sometimes referred to as Hourly Firm Point-To-Point Transmission Service.

60. SOUTHERN INTERTIE

The *Southern Intertie* is the segment of the FCRTS that includes, but is not limited to, the major transmission facilities consisting of two 500-kV AC lines from John Day Substation to the Oregon-California border; a portion of the 500-kV AC line from Buckley Substation to Summer Lake Substation; and the 500-kV AC Intertie facilities, which include Captain Jack Substation, the Alvey-Meridian AC line, one 1,000-kV DC line between the Celilo Substation and the Oregon-Nevada border, and associated substation facilities.

61. SPILL CONDITION

Spill Condition, for the purpose of determining credit or payment for Deviations under the Energy Imbalance and Generation Imbalance rates, exists when spill physically occurs on the BPA system due to lack of load or market. Spill due to lack of load or market typically occurs during periods of high flows or flood control implementation, but can also occur at other times. Discretionary spill, where BPA may choose whether to spill, does not constitute a Spill Condition. Spill for fish is included in discretionary spill and is not a Spill Condition.

62. SPINNING RESERVE REQUIREMENT

Spinning Reserve Requirement is a portion of a party's Operating Reserve Requirement to the BPA Control Area. A party is responsible for purchasing or otherwise providing Operating Reserve - Spinning Reserve Service associated with its transactions which impose a reserve obligation on the BPA Control Area.

The specific amounts required are determined consistent with North American Electric Reliability Council (NERC) Policies, the Northwest Power Pool (NWPP) Operating Manual, "Contingency Reserve Sharing Procedure," and the Western Electricity Coordinating Council (WECC) Standards.

63. SUPPLEMENTAL RESERVE REQUIREMENT

Supplemental Reserve Requirement is a portion of a party's Operating Reserve Requirement to the BPA Control Area. A party is responsible for purchasing or otherwise providing Operating Reserve – Supplemental Reserve Service associated with its transactions which impose a reserve obligation on the BPA Control Area.

The specific amounts required are determined consistent with North American Electric Reliability Council (NERC) Policies, the Northwest Power Pool (NWPP) Operating Manual, "Contingency Reserve Sharing Procedure," and the Western Electricity Coordinating Council (WECC) Standards.

64. TOTAL TRANSMISSION DEMAND

Total Transmission Demand is the sum of all the transmission demands as defined in the applicable agreement.

65. TRANSMISSION CUSTOMER

A *Transmission Customer* is any Eligible Customer (or its Designated Agent) under the Open Access Transmission Tariff that (i) executes a Service Agreement, or (ii) requests in writing that BPA-TS file with the Commission a proposed unexecuted Service Agreement to receive transmission service under Part II of the Tariff. In addition, a Transmission Customer is an entity that has executed any other transmission service agreement with BPA-TS.

66. TRANSMISSION DEMAND

Transmission Demand is the maximum amount of capacity BPA-TS agrees to make available to transmit energy for the Transmission Customer over the BPA Transmission System between the Point(s) of Integration/Interconnection/Receipt and the Point(s) of Delivery.

67. TRANSMISSION PROVIDER

A *Transmission Provider*, such as BPA-TS, owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce and provides transmission service under the Open Access Transmission Tariff and other agreements.

68. UTILITY DELIVERY

The *Utility Delivery* segment is that segment of the FCRTS that provides service to utility customers at voltages below 34.5 kV.

69. VARIABLE ENERGY RESOURCE BALANCING SERVICE

Variable Energy Resource Balancing Service (VERBS) is a control area service comprised of three components: regulating reserves (which compensate for moment-to-moment differences between generation and load), following reserves (which compensate for larger differences occurring over longer periods of time during the hour), and imbalance reserves (which compensate for differences between the generator’s schedule and the actual generation during an hour). Variable Energy Resource Balancing Service is required to help maintain the power system frequency at 60 Hz and to conform to NERC and WECC reliability standards.

70. WEEKLY SERVICE

Weekly Service is service that starts at 00:00 on any date and stops at 00:00 at least seven (7) days later, but less than or equal to 27 days later.

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BONNEVILLE POWER ADMINISTRATION

DOE/BP-4361 • October 2011

Attachment 8.7.2

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 11.3.1

Commission Determination

The Panel accepts FortisBC's assumption regarding the theft detection rate and recovered revenue as conservative. **The Panel accepts FortisBC's evidence that it will be able to yield an additional 20 percent reduction in the theft ratio under AMI as reasonable.**

8.3.2.4 Valuing the Decreased Network Electricity Losses from the Project

FortisBC valued the electricity theft from marijuana grow-operations at its short-term avoided cost using the estimated BC Wholesale Market Energy Price ($54.68 per MWh for 2012) (Exhibit B-6, BCUC 1.81.2). FortisBC states that it elected to use the short-term avoided cost as part of its overall conservative approach to modelling the benefits associated with the AMI Application, and believes this to be an appropriate approach. However, FortisBC states that it would not object to valuing the energy lost due to theft at the full long-run marginal cost of acquiring energy from new resources (Exhibit B-14, BCUC 2.61.2.1). FortisBC estimates the long-run marginal cost for acquisition of new resources is $111.96/MWh. Adding 11 percent FortisBC system losses increases the estimate to $125.80/MWh (Exhibit B-14, BCUC 2.61.1).

Commission Determination

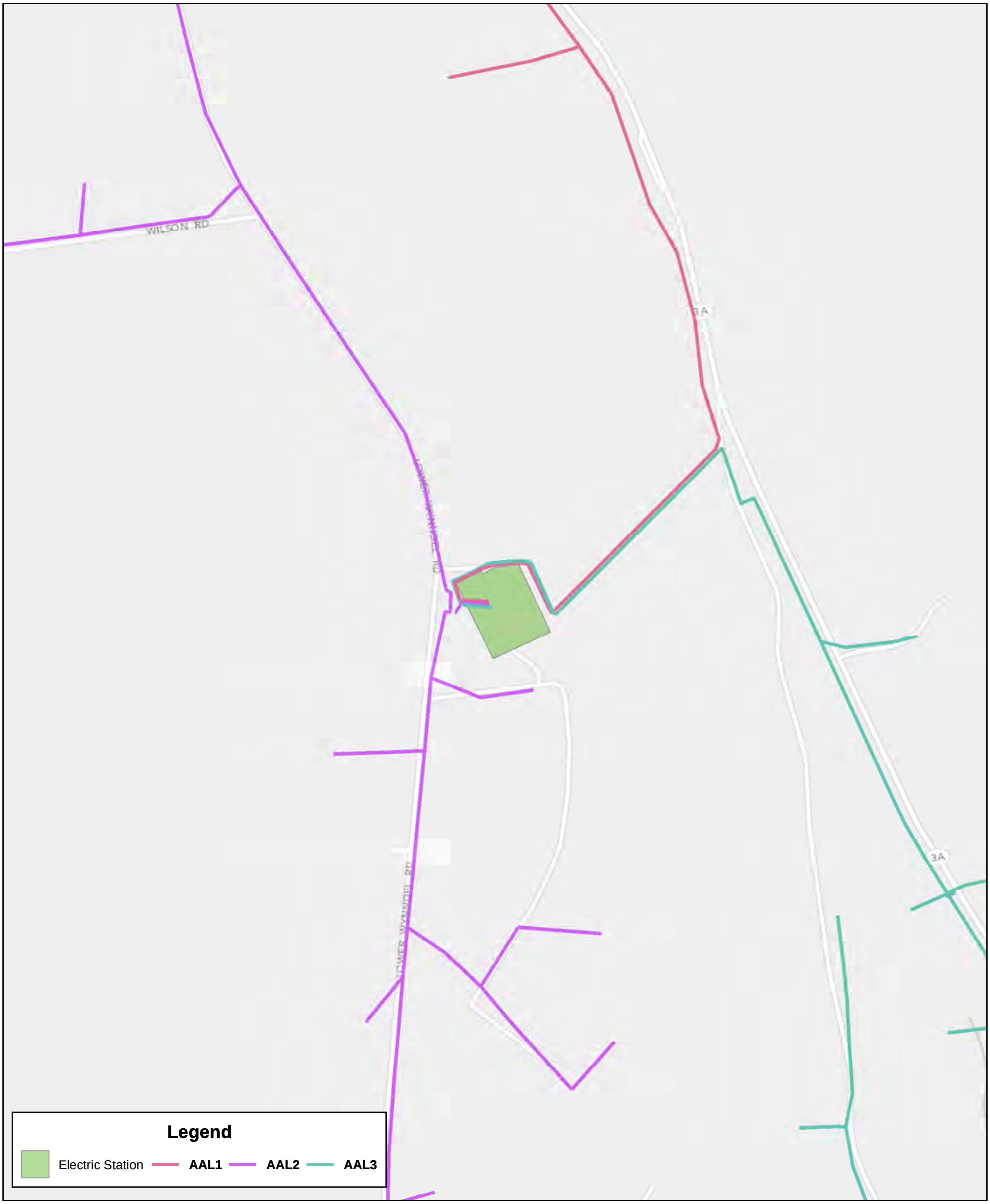
In valuing the reduction in electricity lost to theft, the Panel does not consider that the decision should be based on picking whichever of the short-run or long-run cost estimate happens at that time to provide the lowest benefit estimate. The Panel considers that a matching principle should apply. Where the energy saving benefit occurs over the long-term, a long-term cost of energy should be used to calculate the value of that benefit.

The Panel considers that the reduction in energy lost to theft as a result of AMI provides a long-term benefit to customers. Accordingly, in examining the Project over the long-term in the Economic Analysis, the Panel considers that the cost of energy should be valued at FortisBC's long-run marginal cost of $125.80/MWh.

The Panel considers that while using the long-run marginal cost of energy is appropriate to measure the long-term benefit in the Economic Analysis, this is not appropriate to use when examining the short-term rate impact of the Project. Accordingly, for the purposes of determining the rate impact of the Project over the short-term, the Panel has used the short-term avoided cost

Attachment 15.7.2

A.A. LAMBERT TERMINAL



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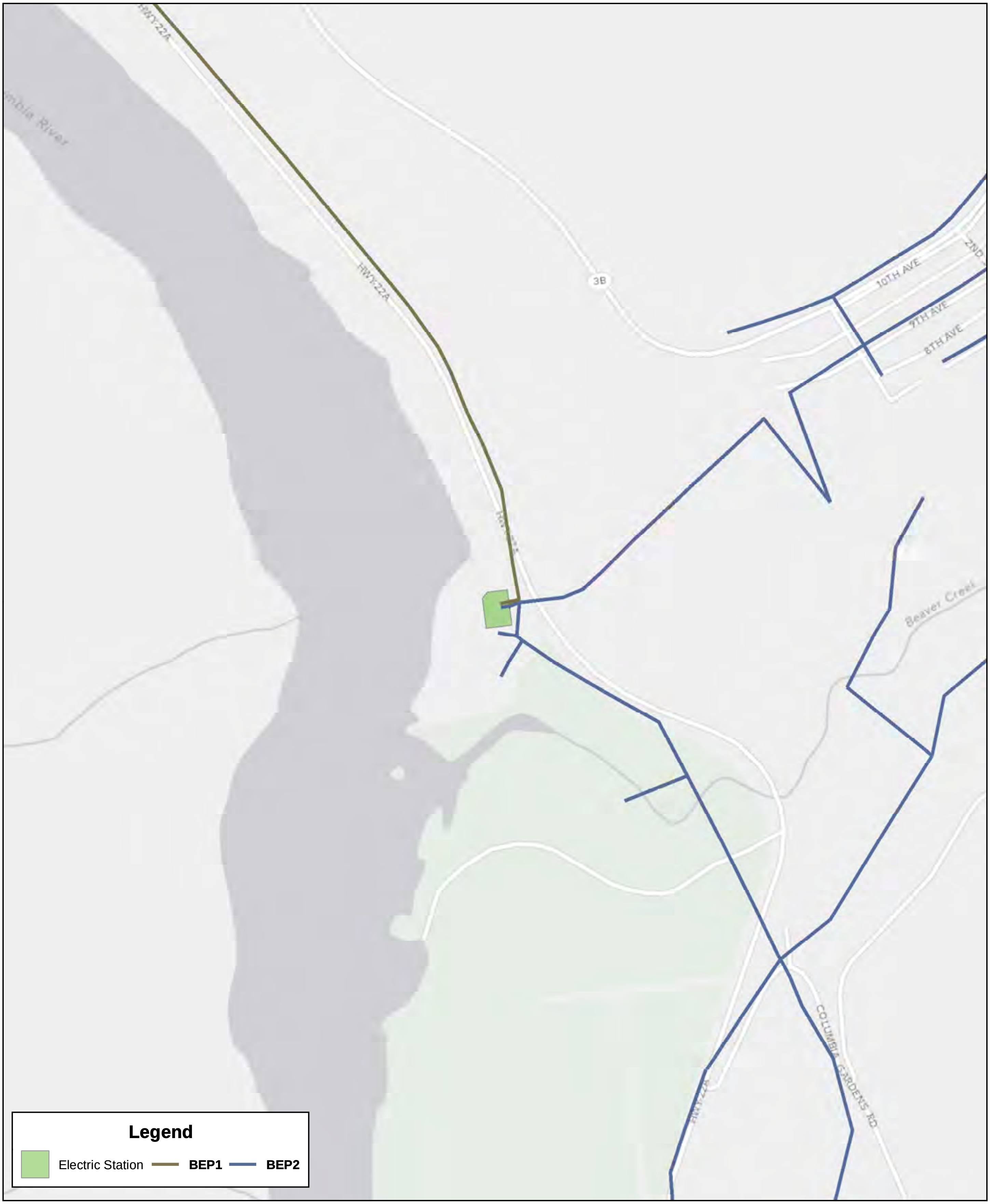

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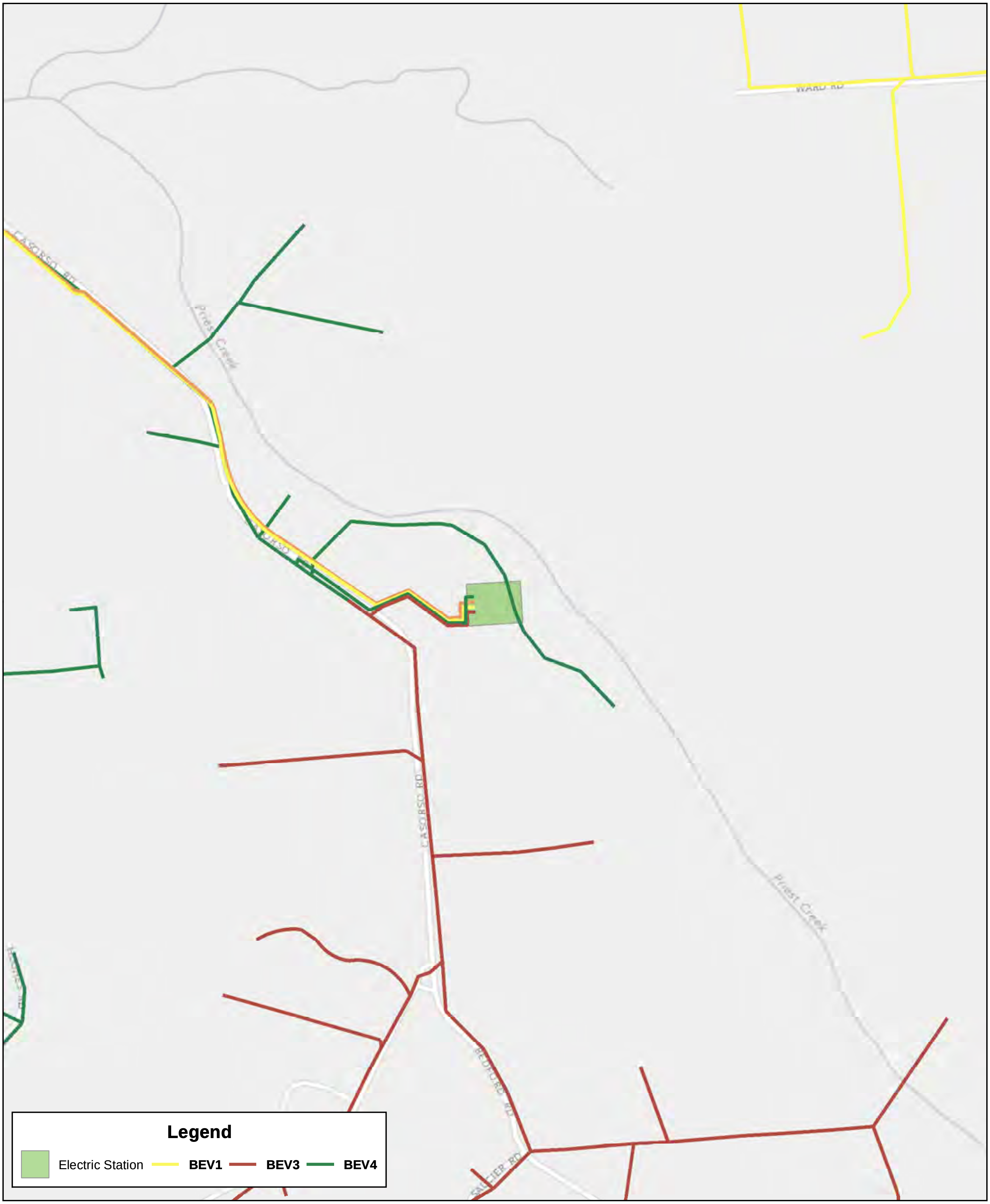
BENVOULIN



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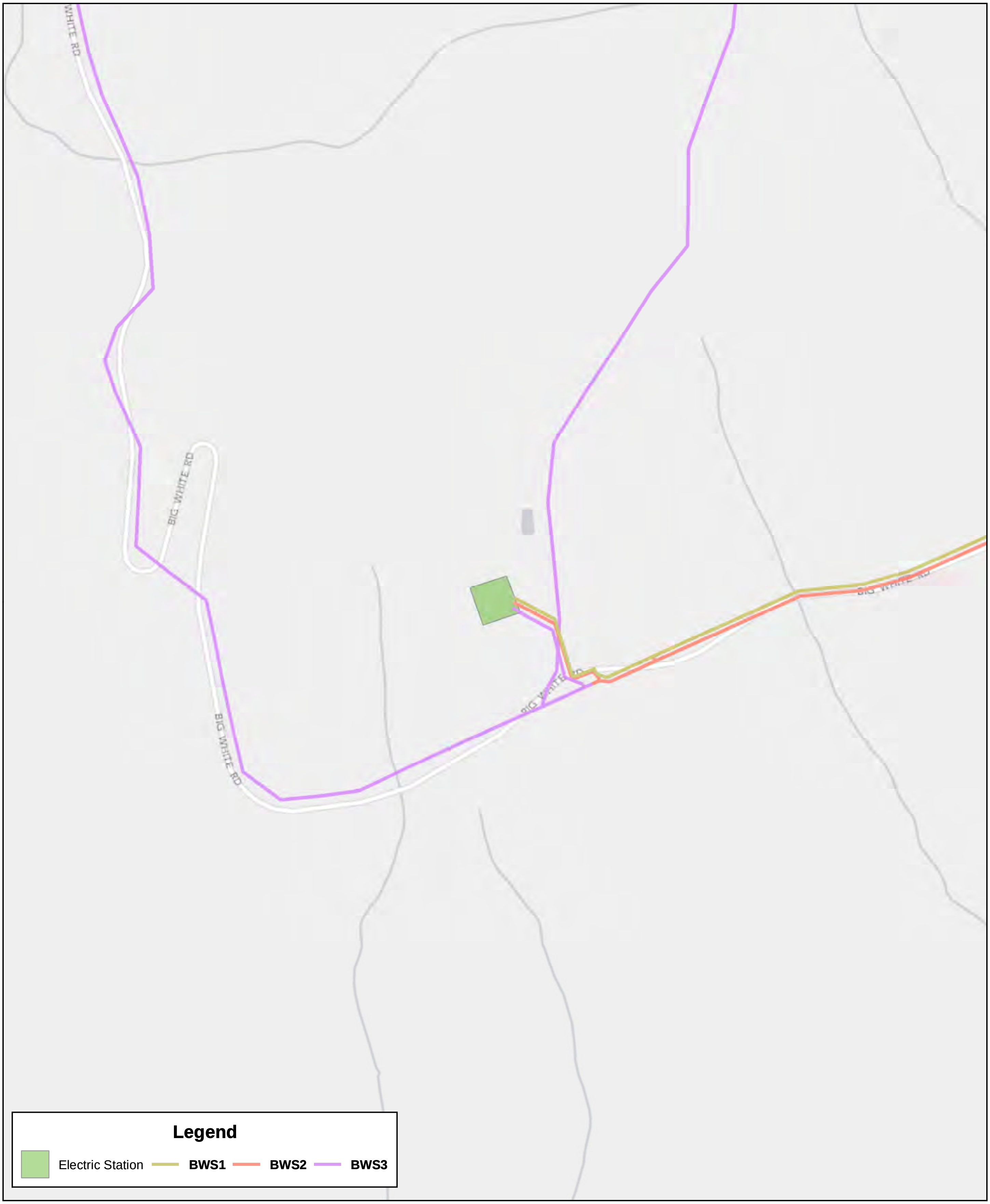
BIG WHITE



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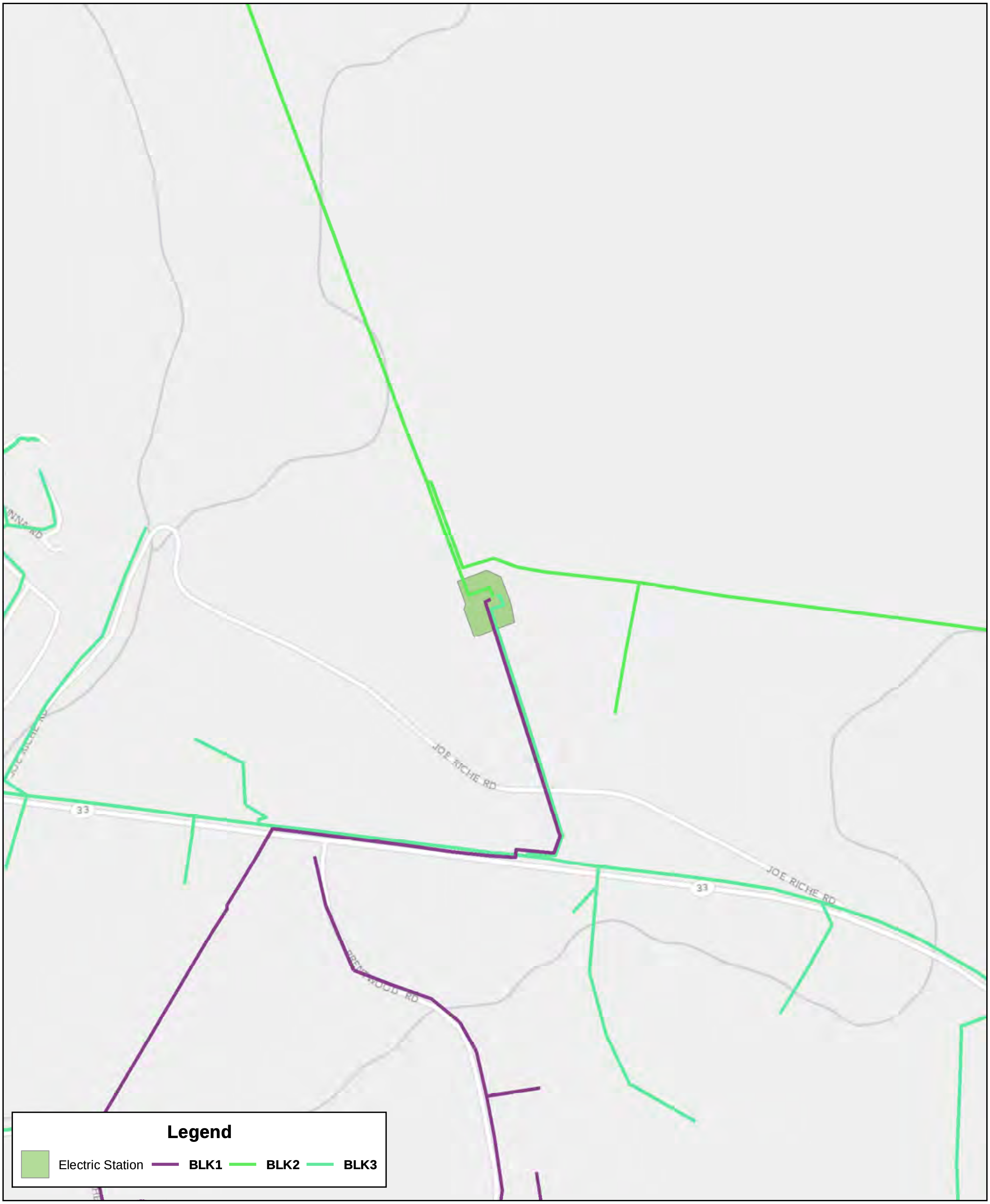
BLACK MOUNTAIN



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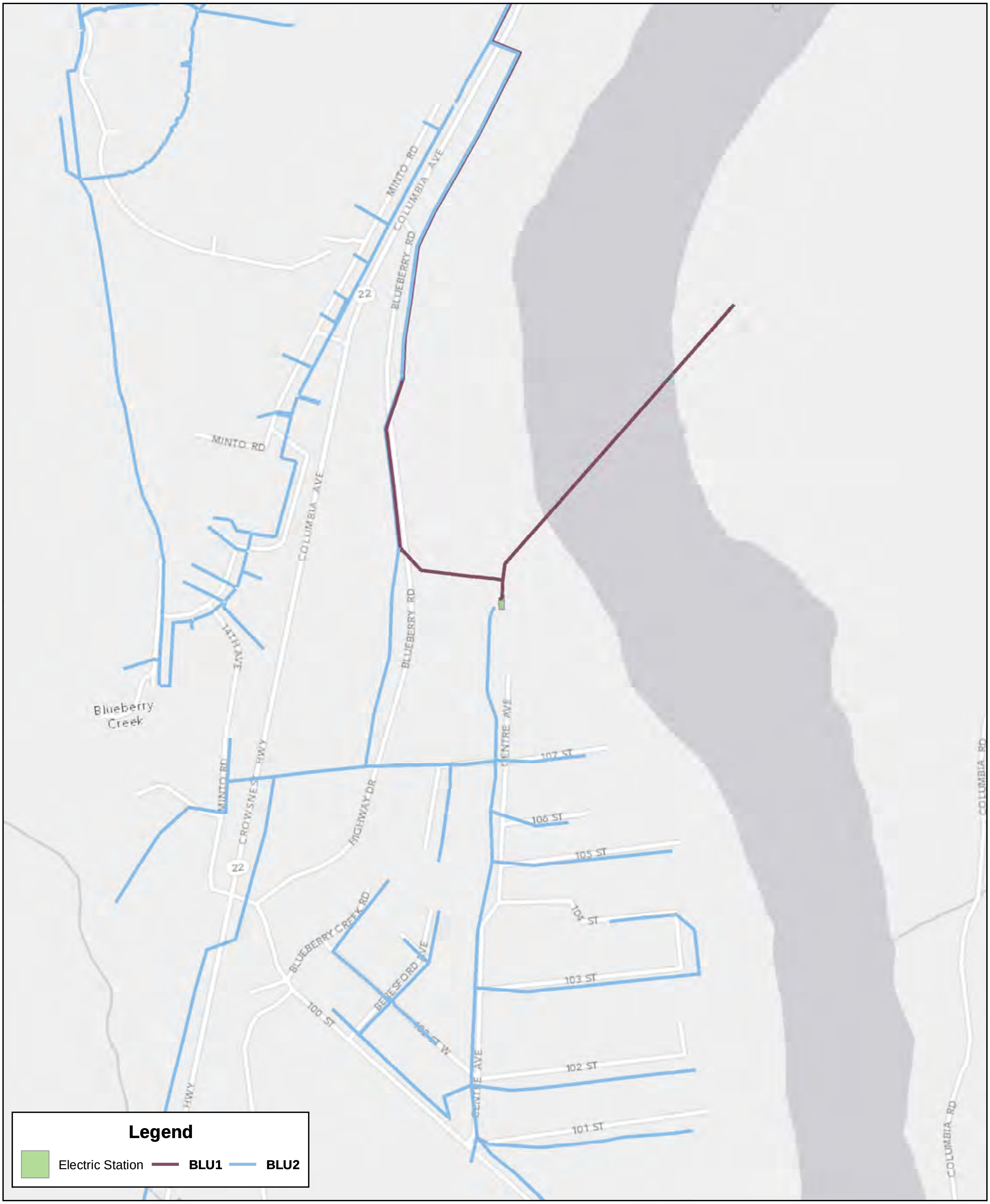
BLUEBERRY



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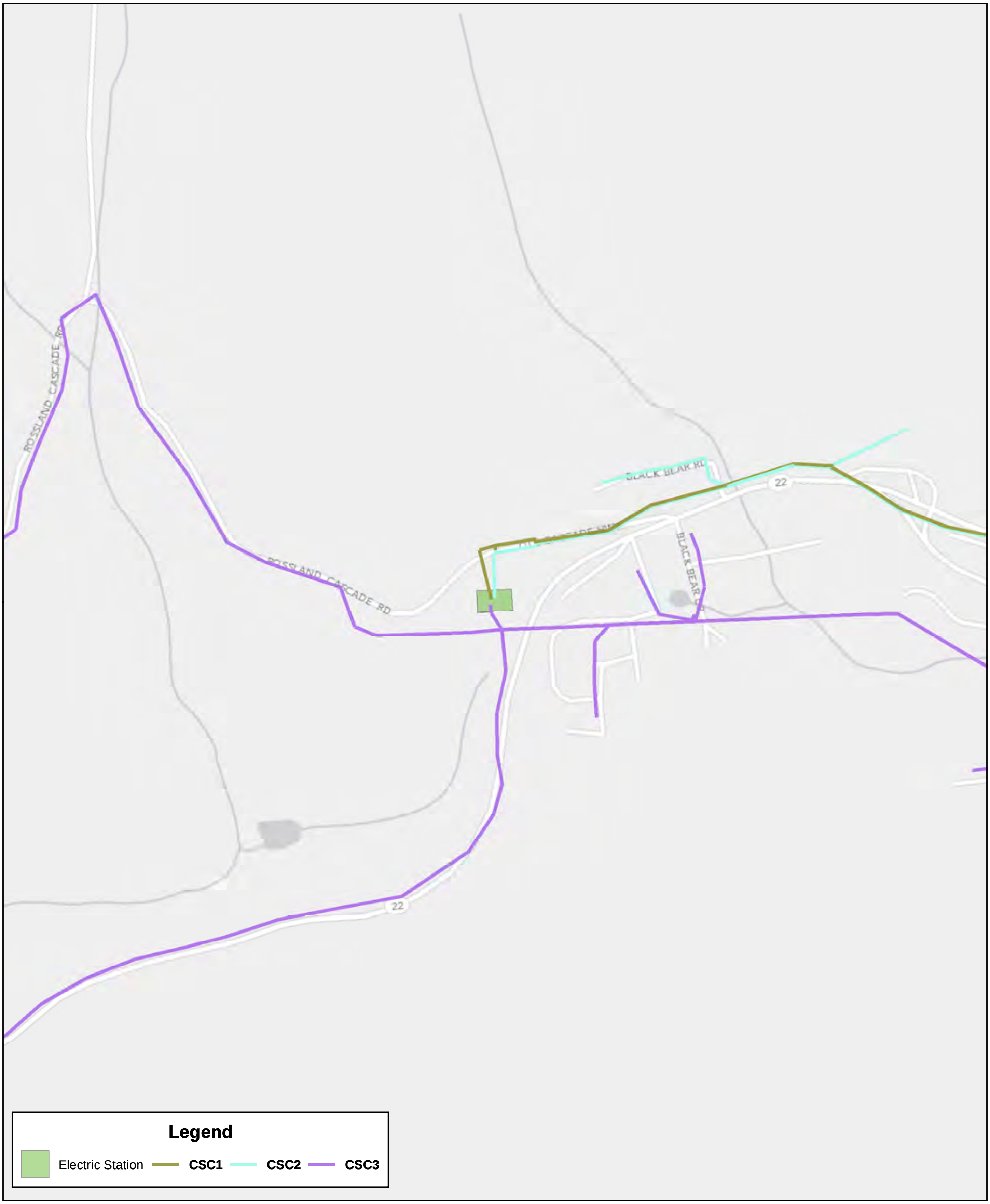
CASCADE



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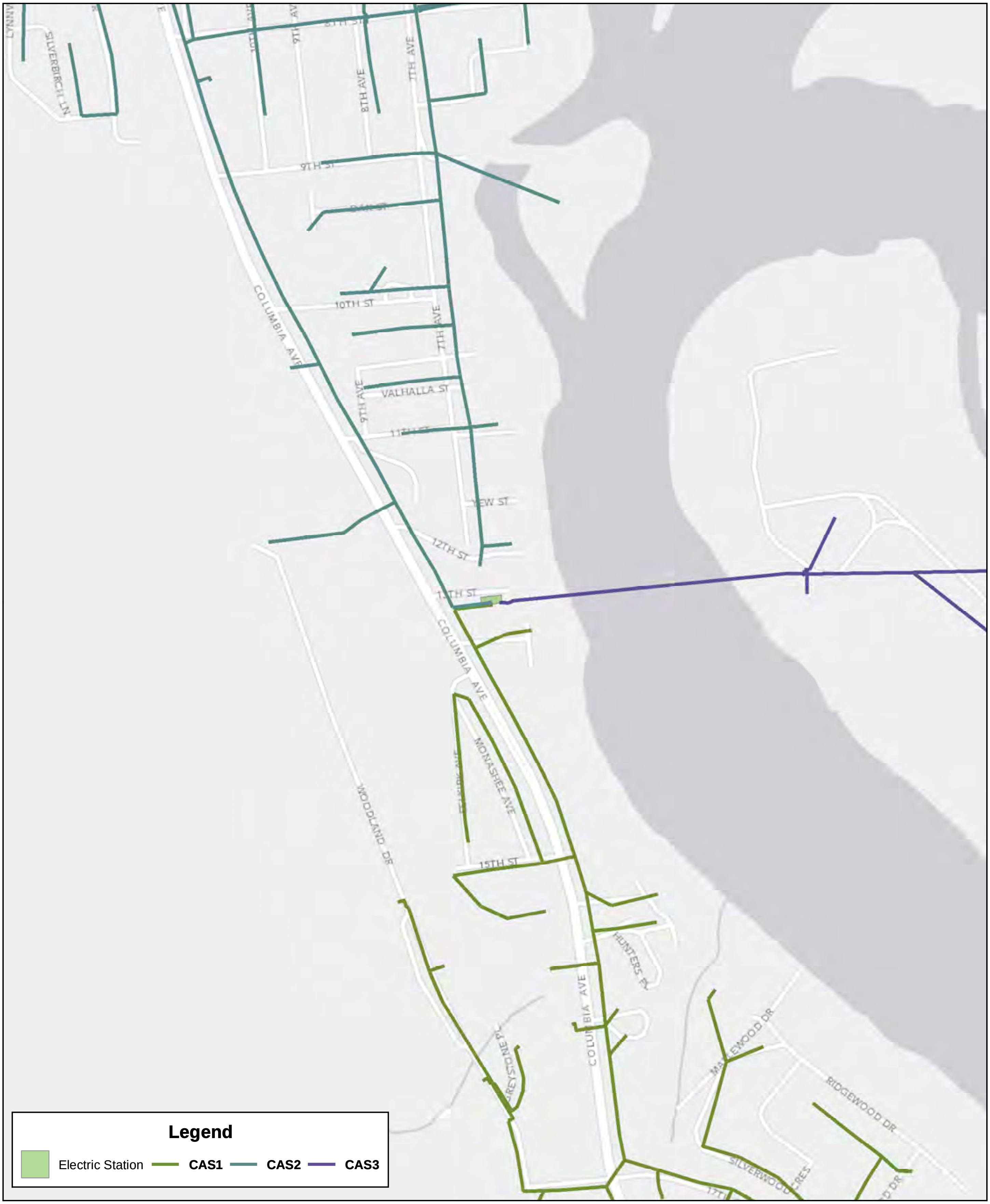
CASTLEGAR



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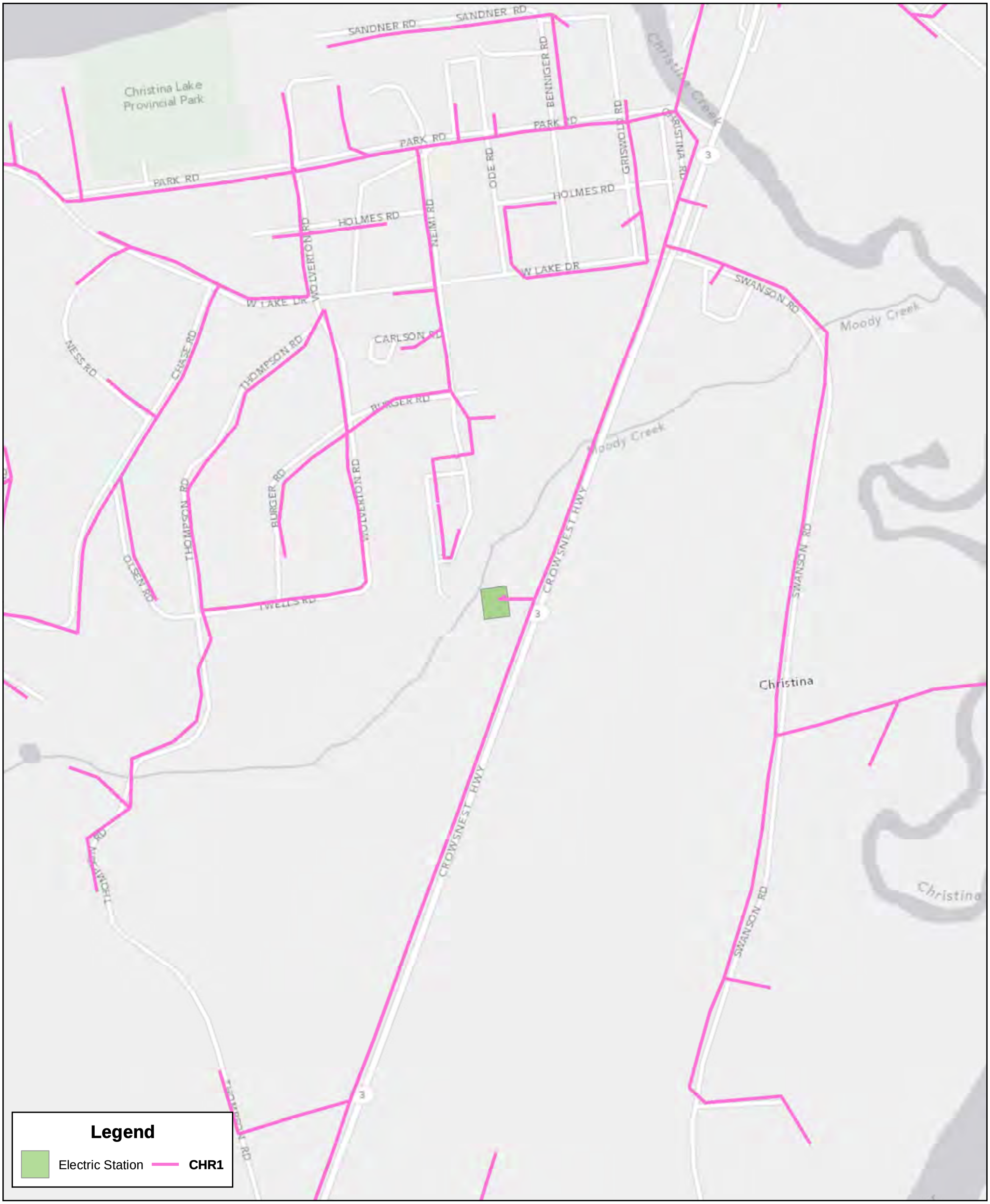

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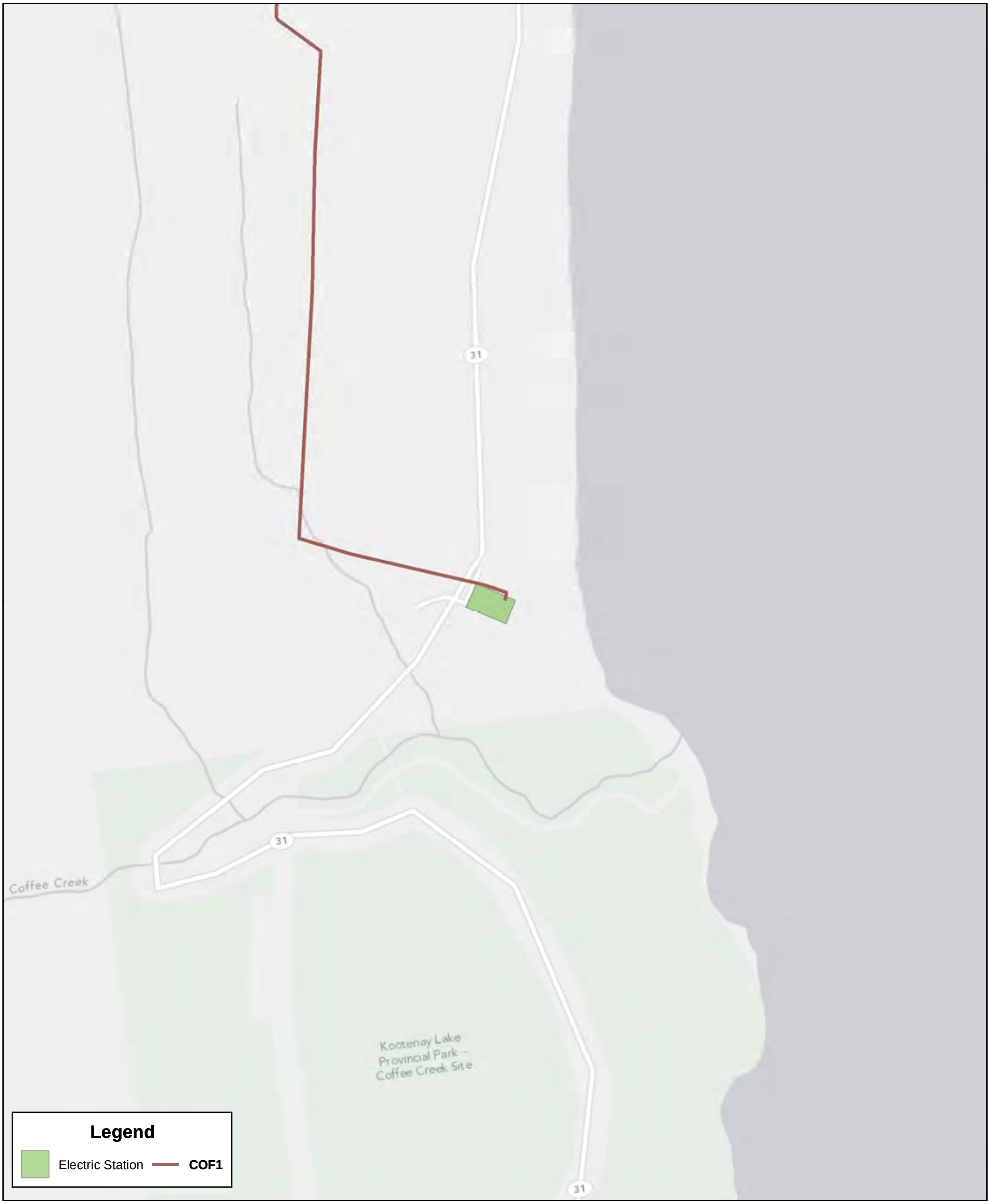

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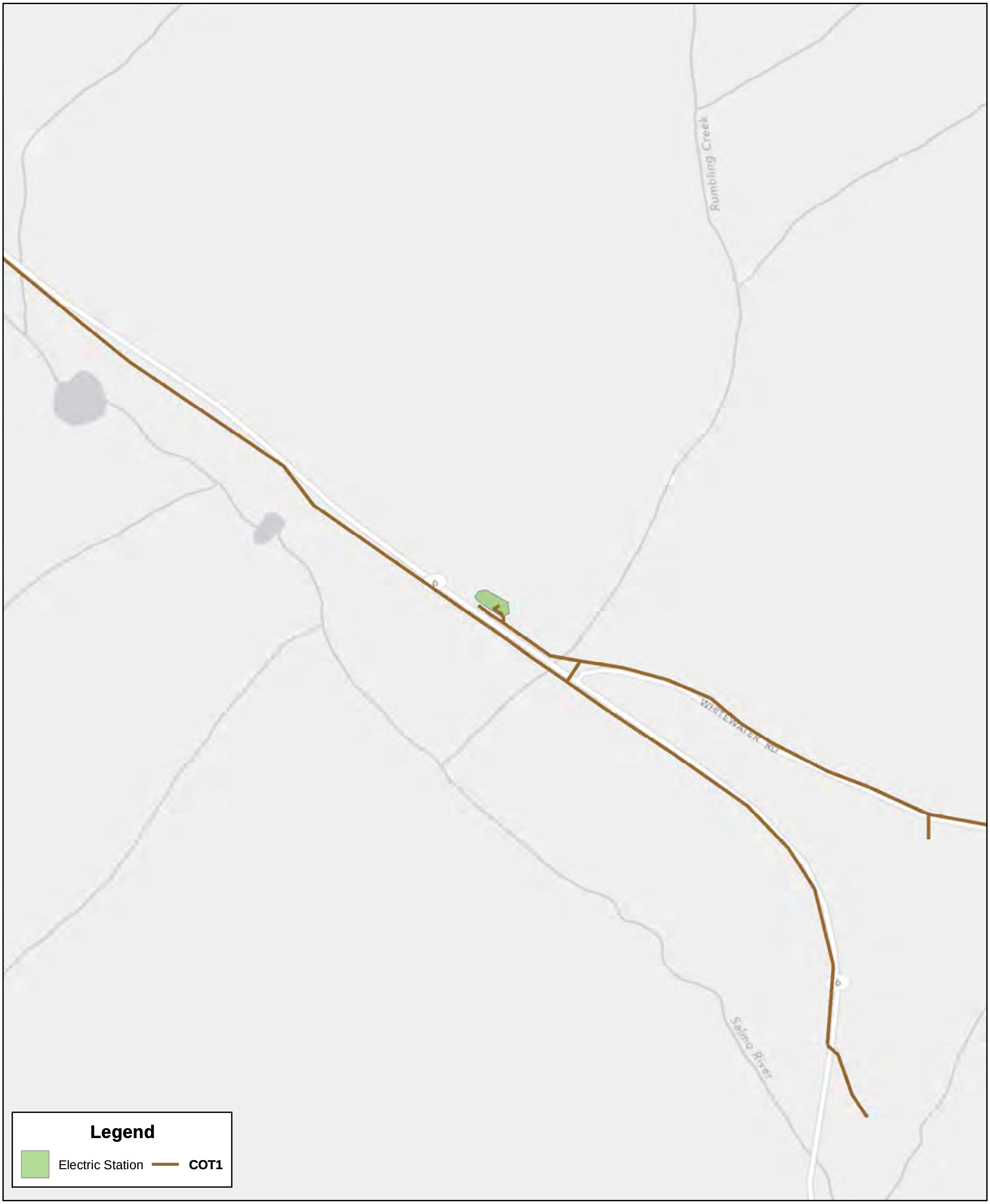

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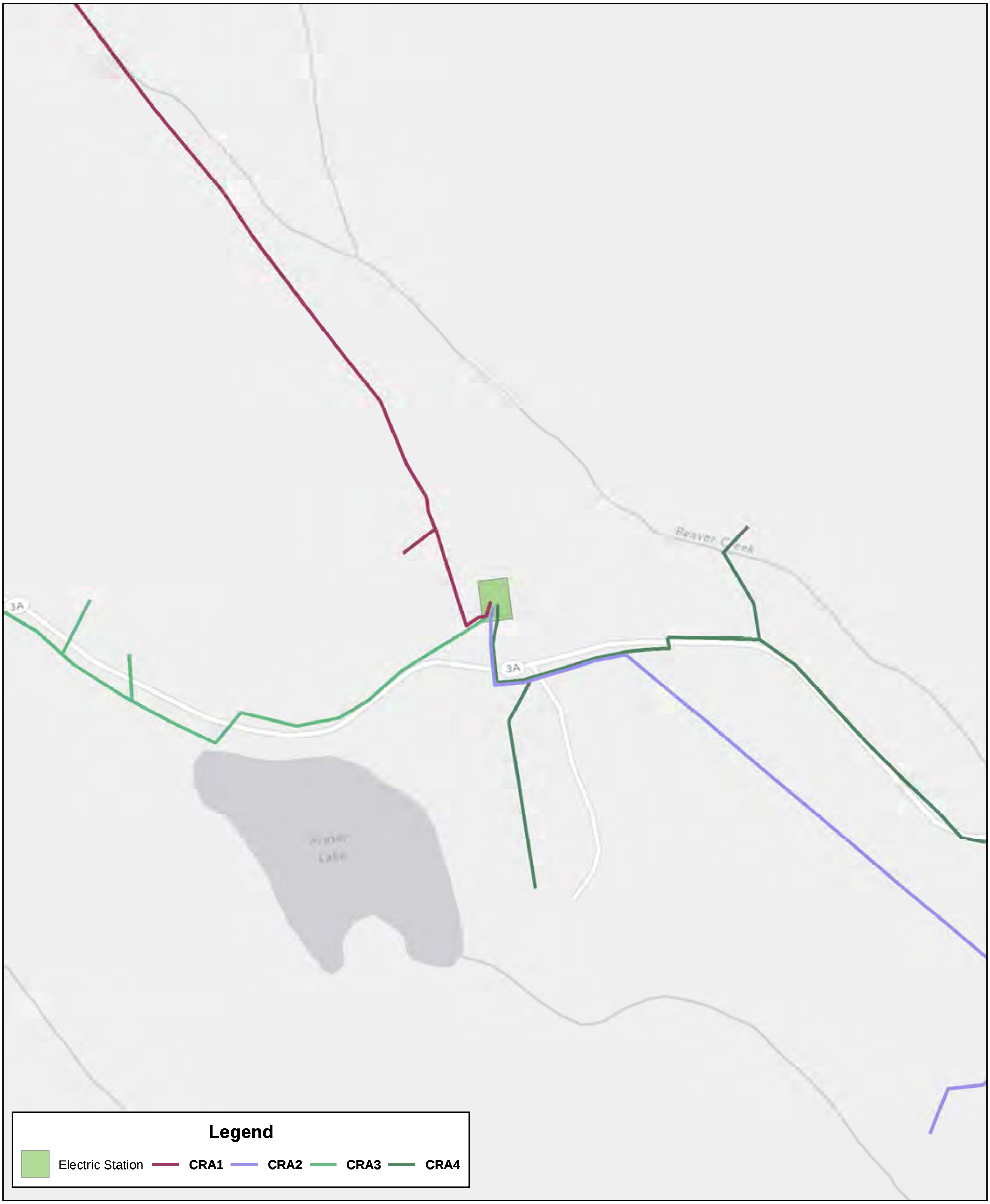
CRAWFORD BAY



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CRESTON

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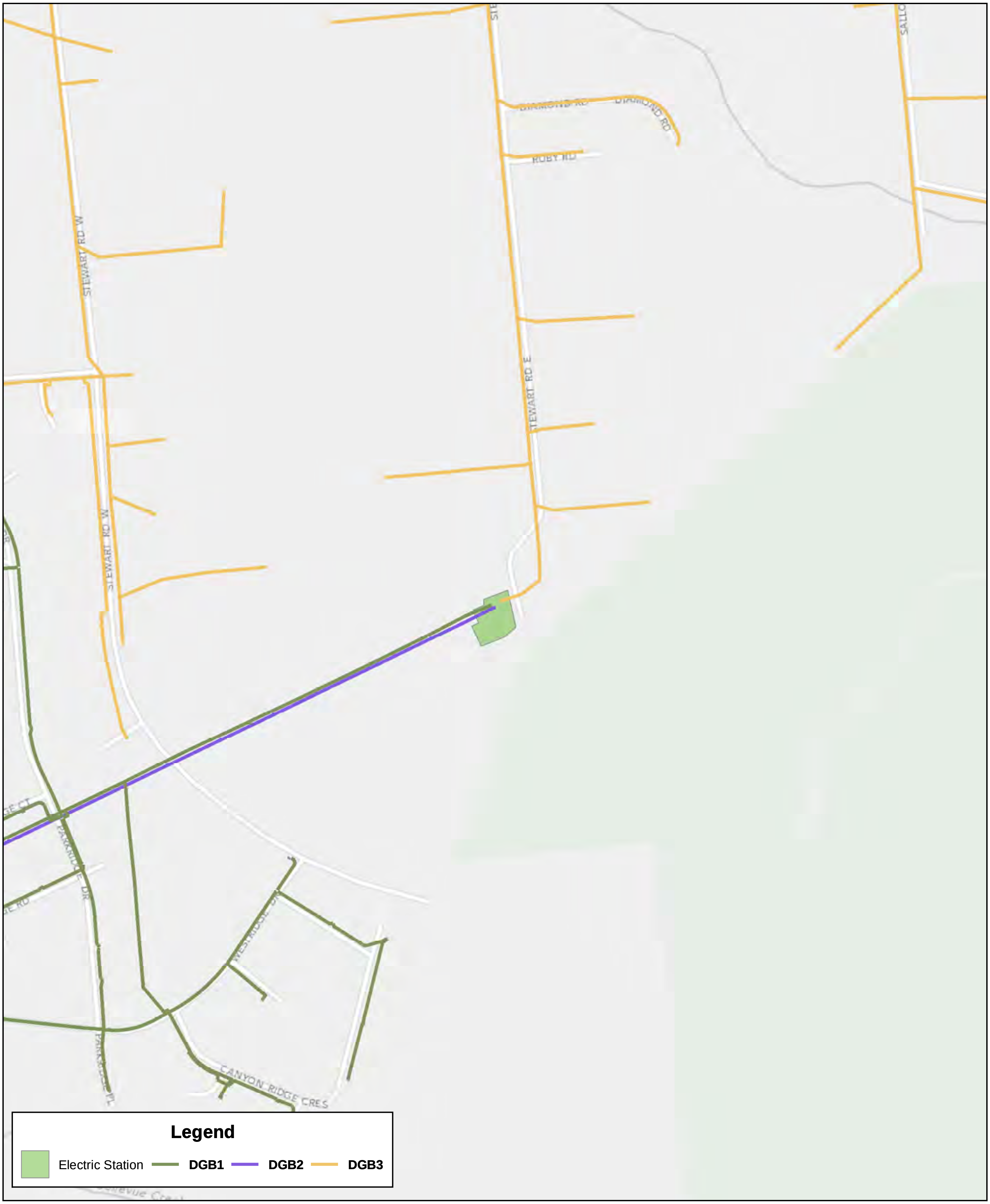
D.G. BELL TERMINAL



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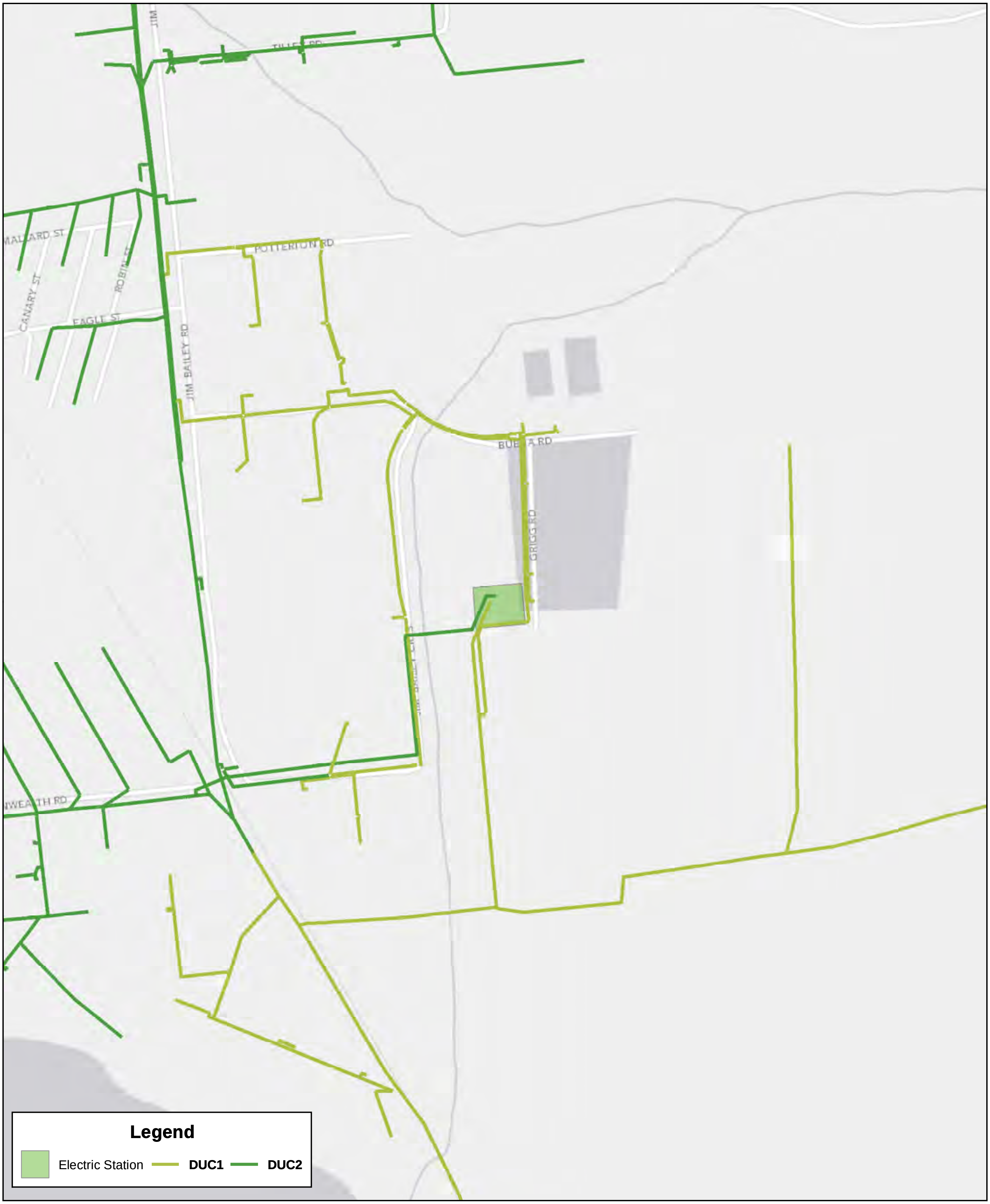
DUCK LAKE



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ELLISON

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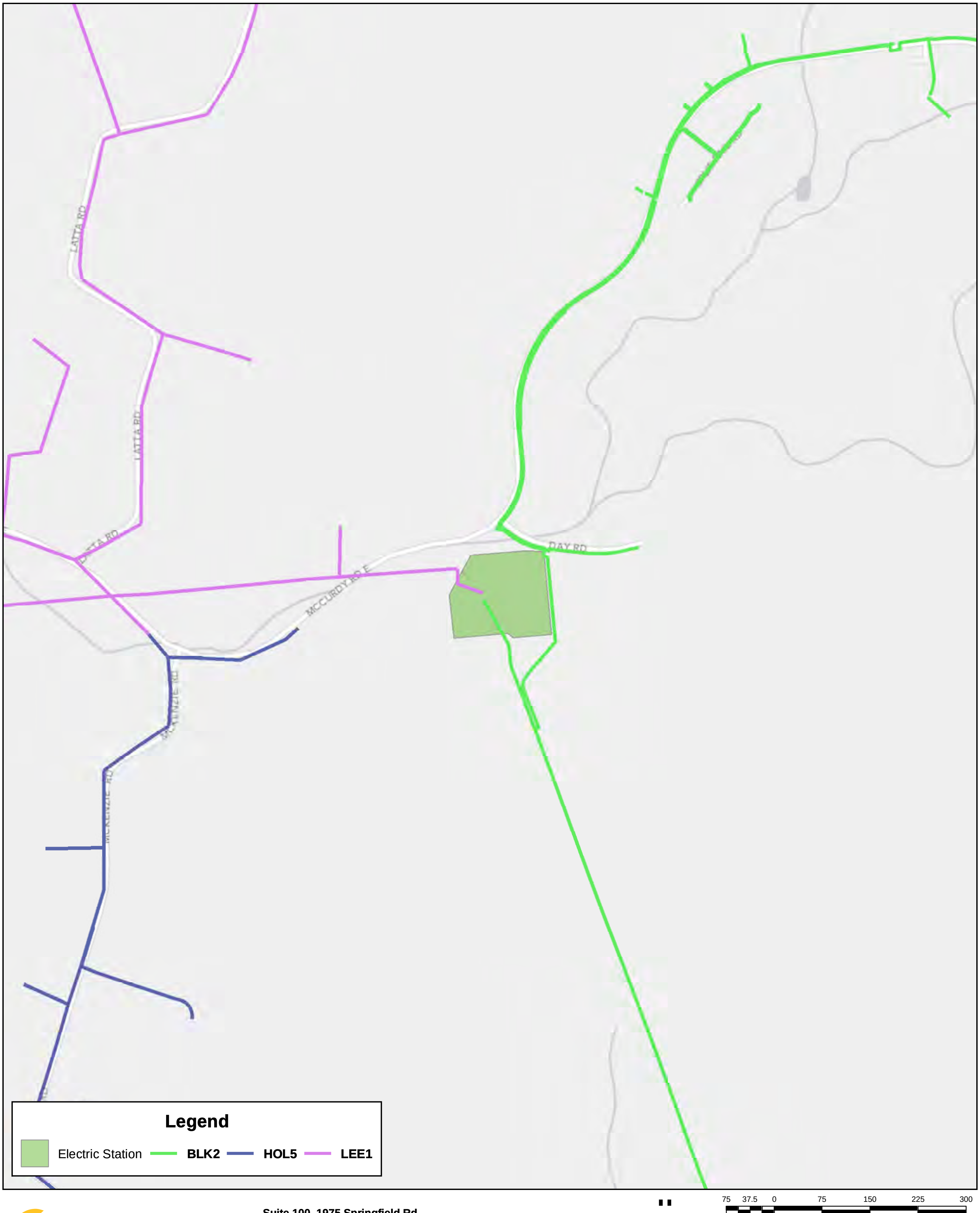
F.A. LEE TERMINAL



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FRUITVALE

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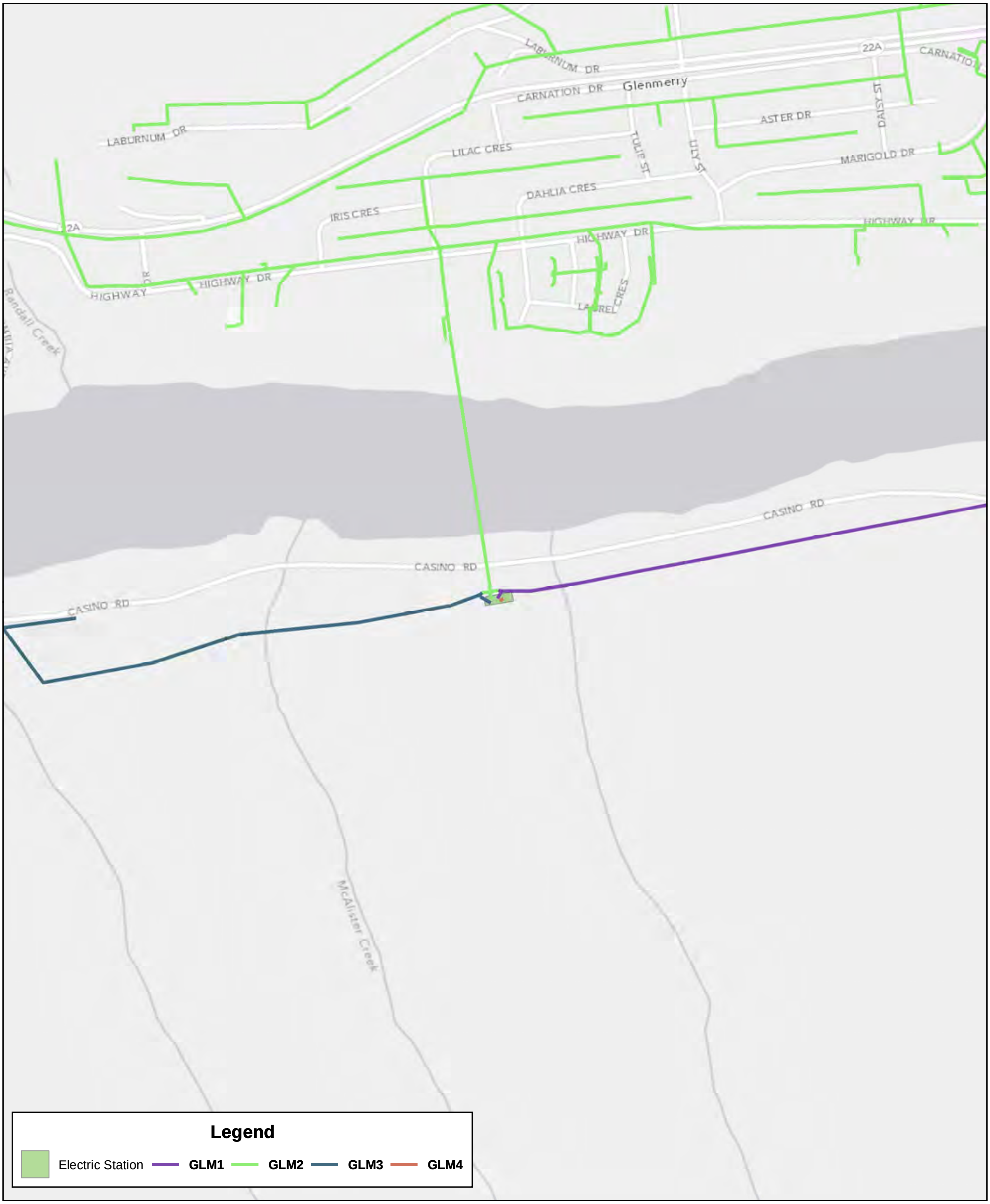
GLENMERRY



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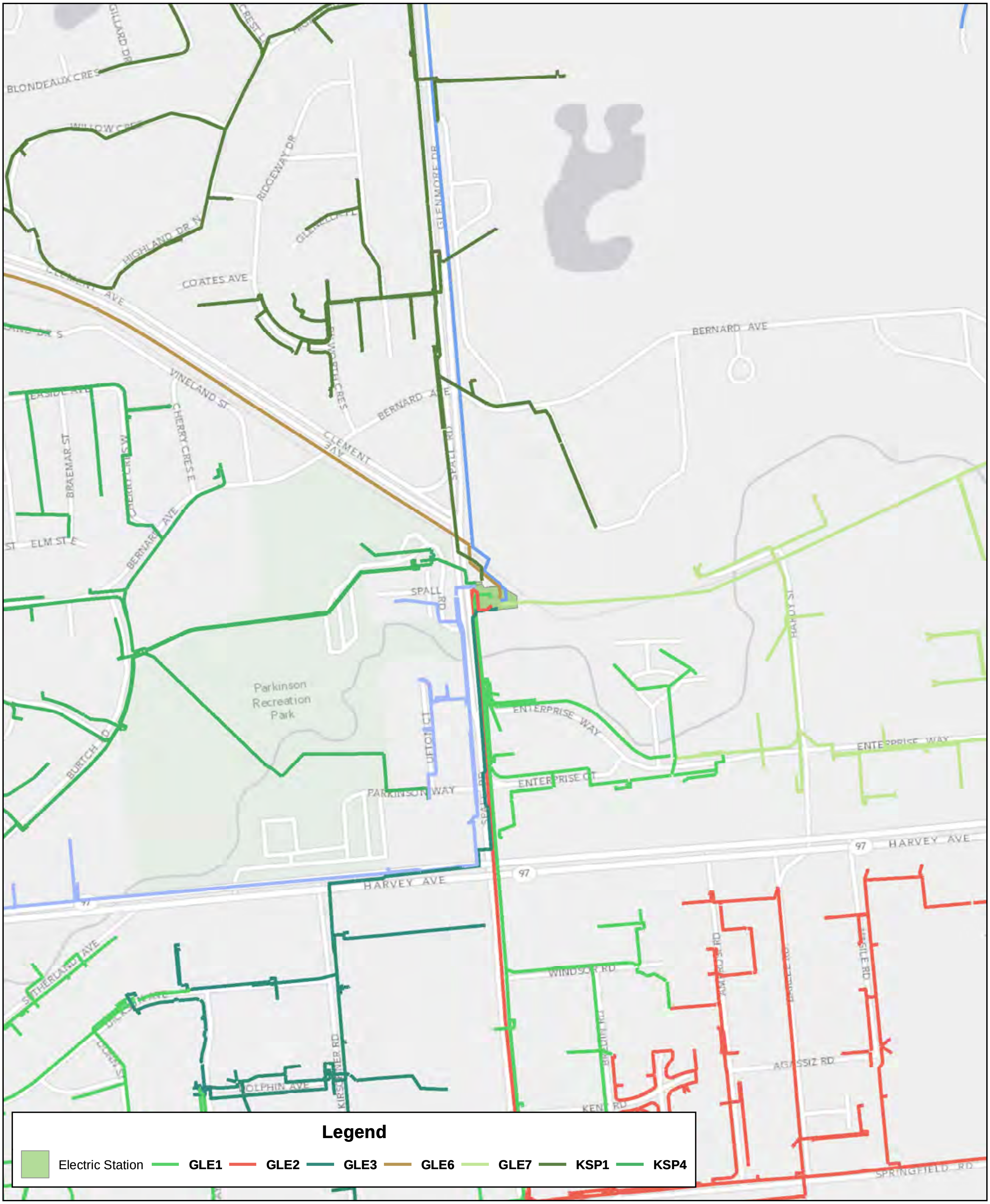
GLENMORE



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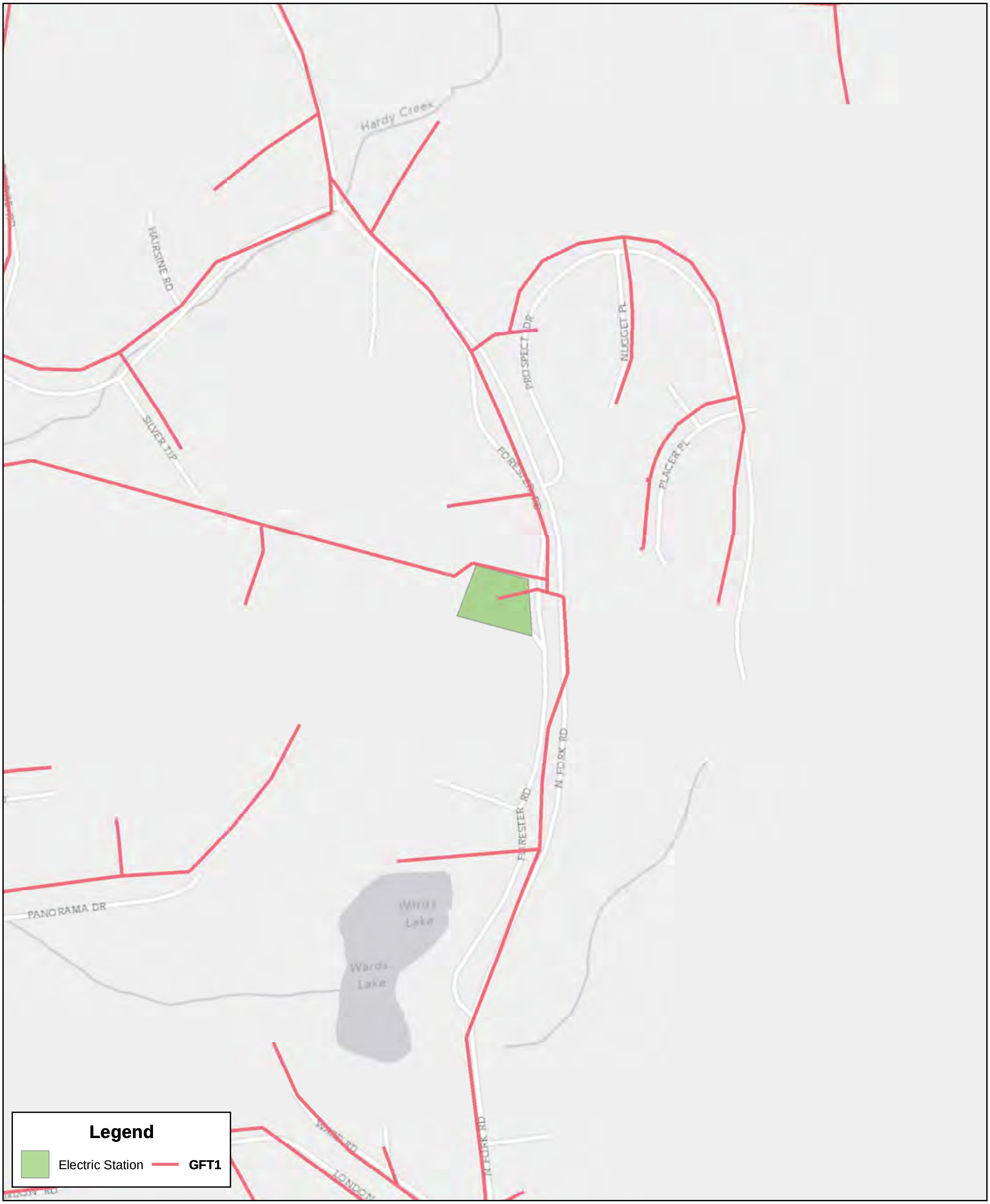
GRAND FORKS TERMINAL



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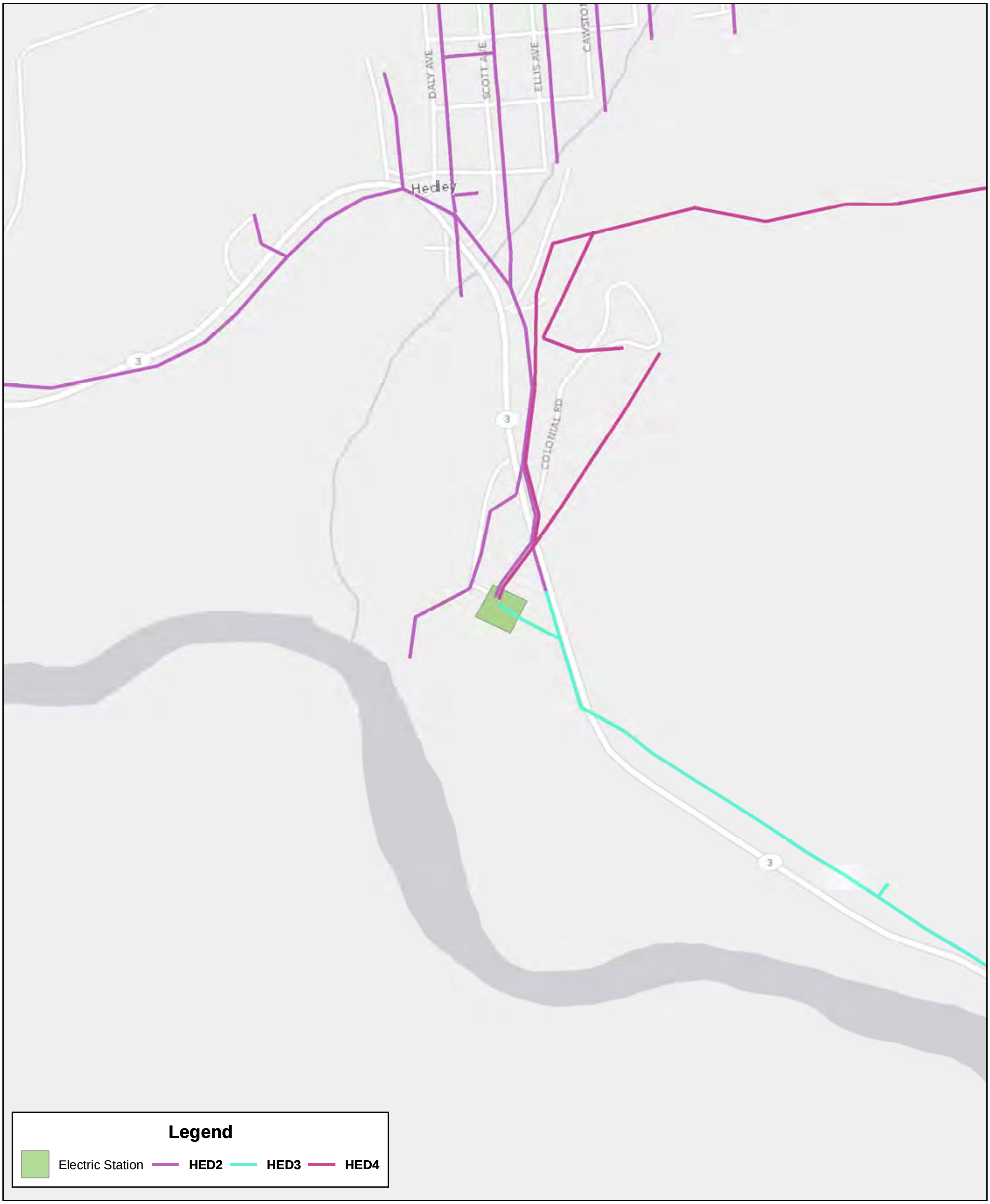
HEDLEY



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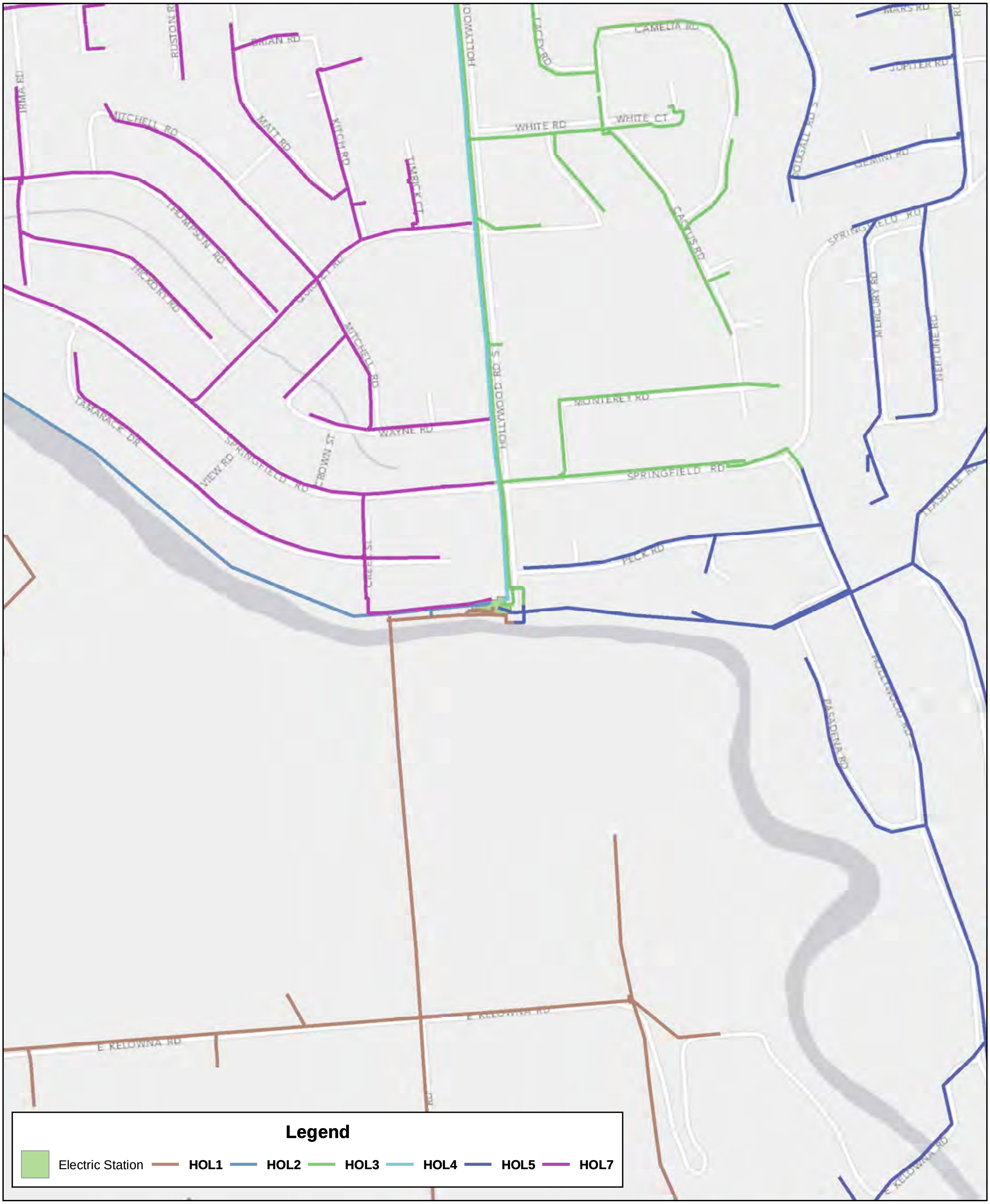

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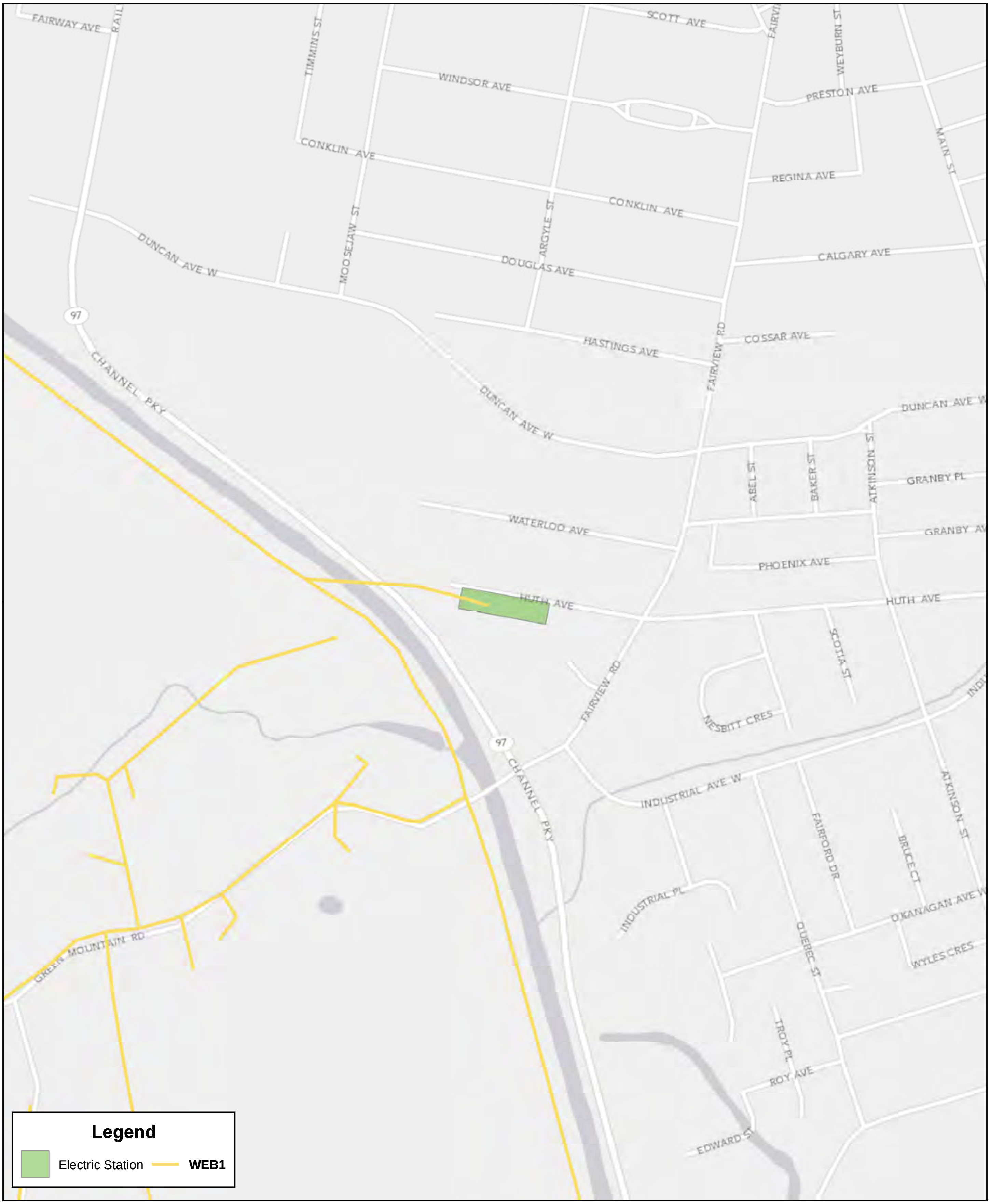

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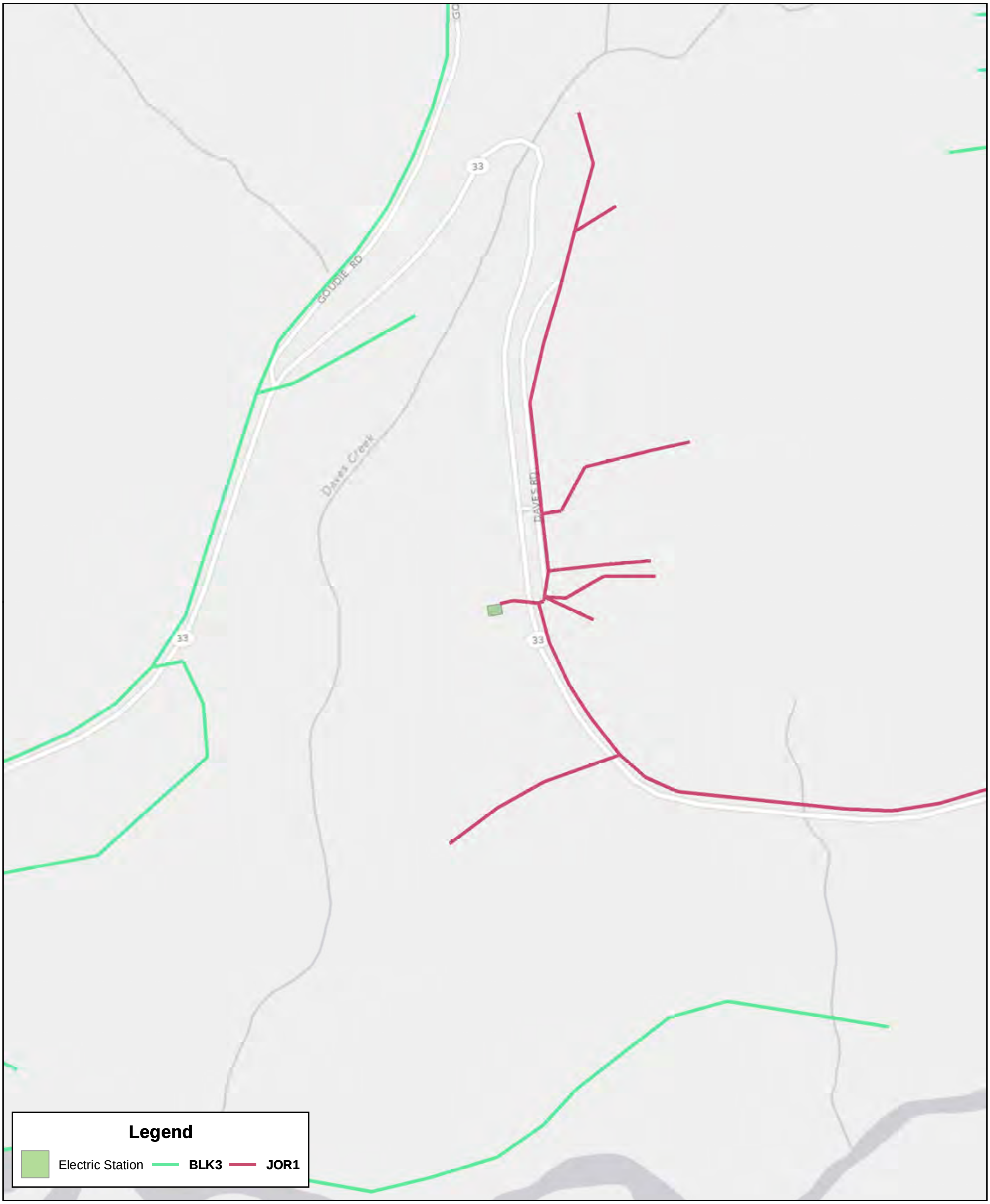

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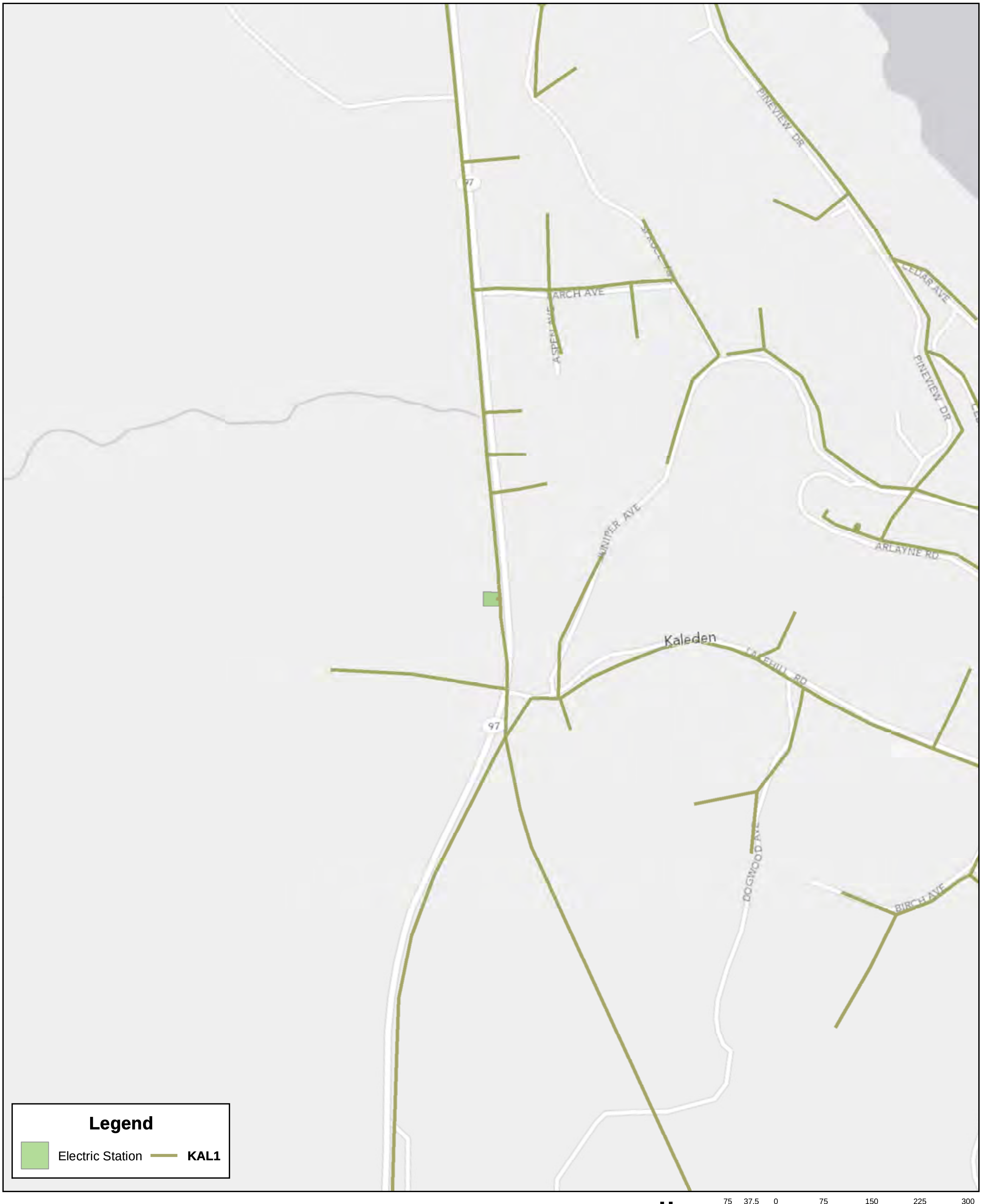

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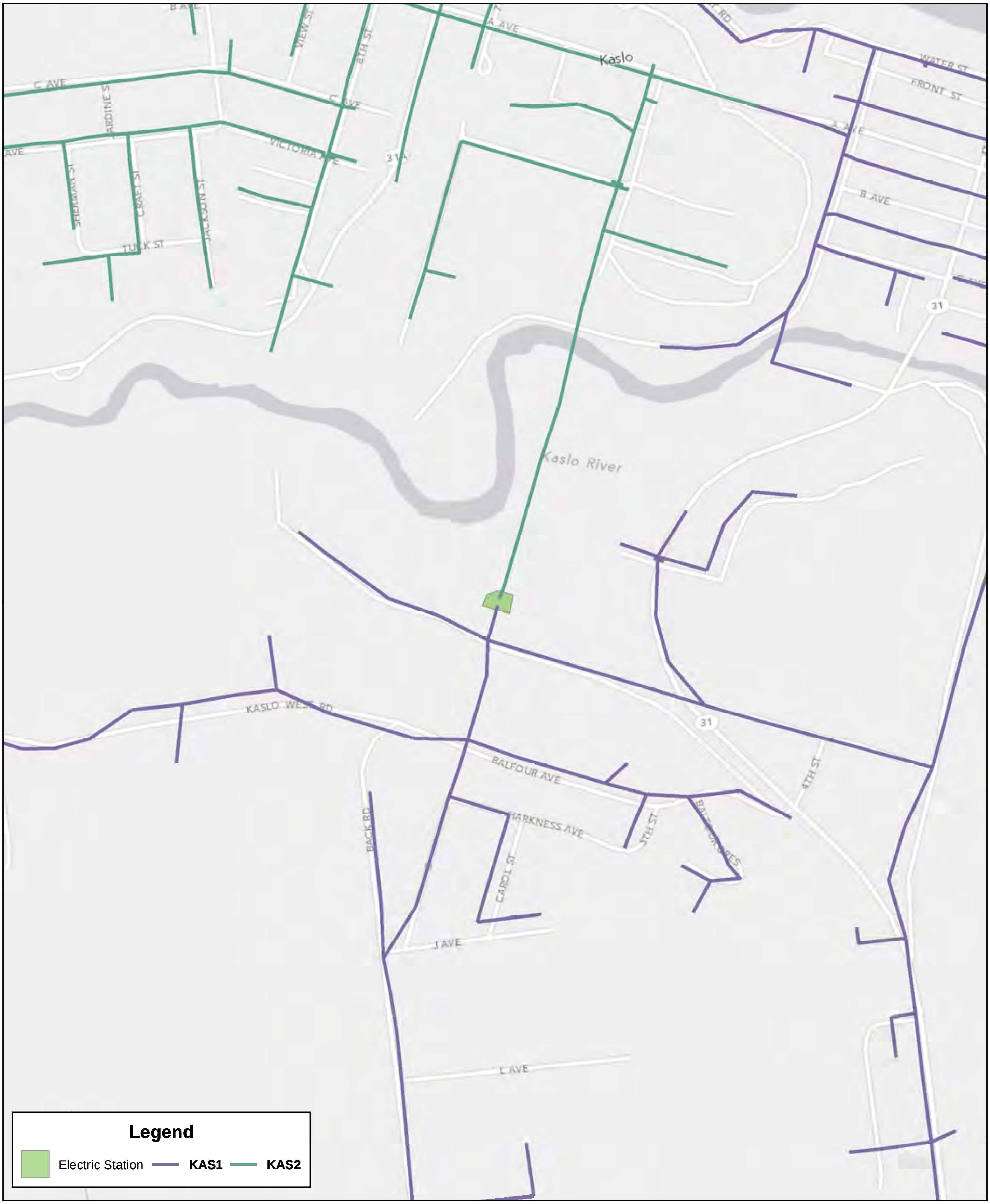

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KEREMEOS

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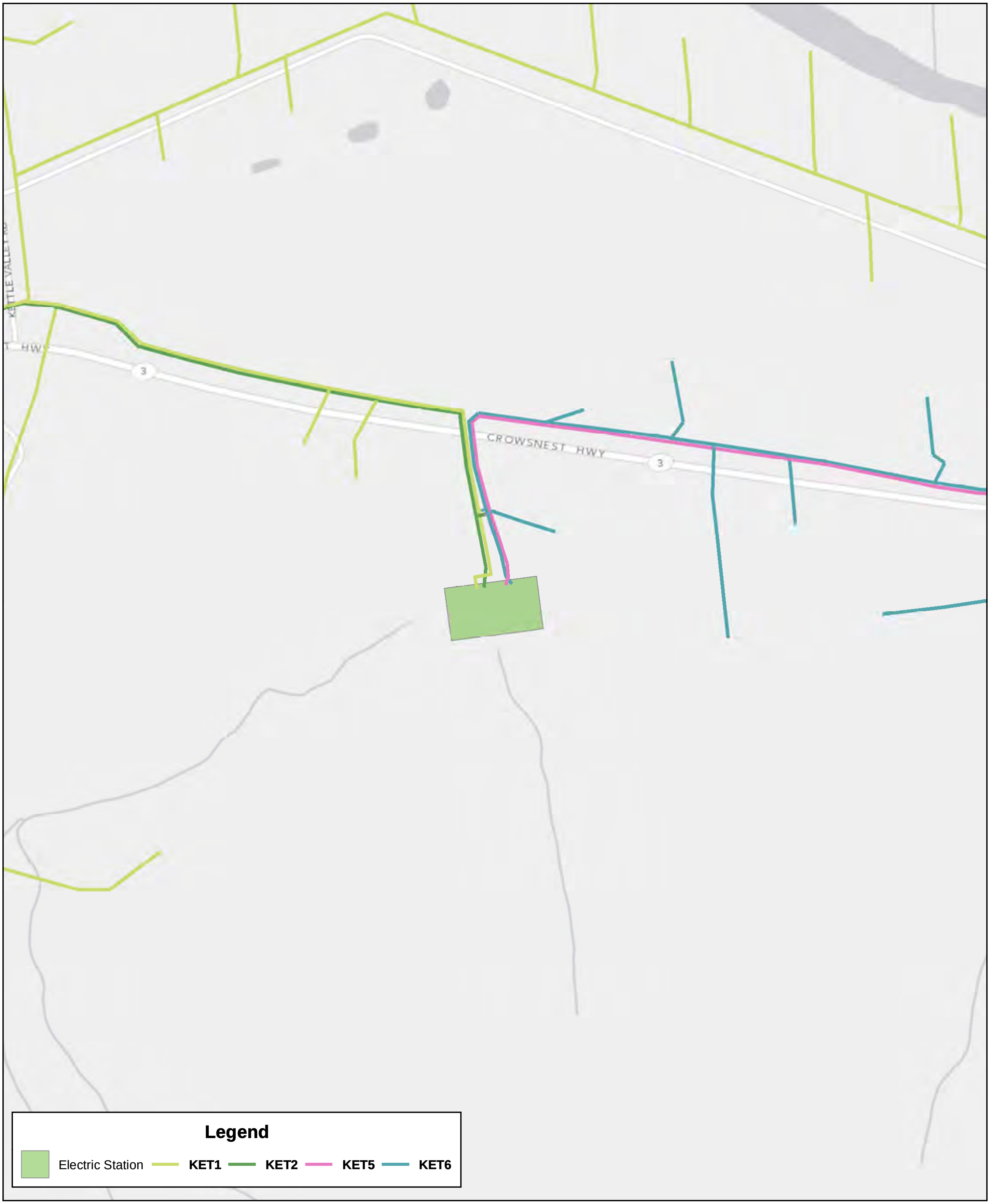

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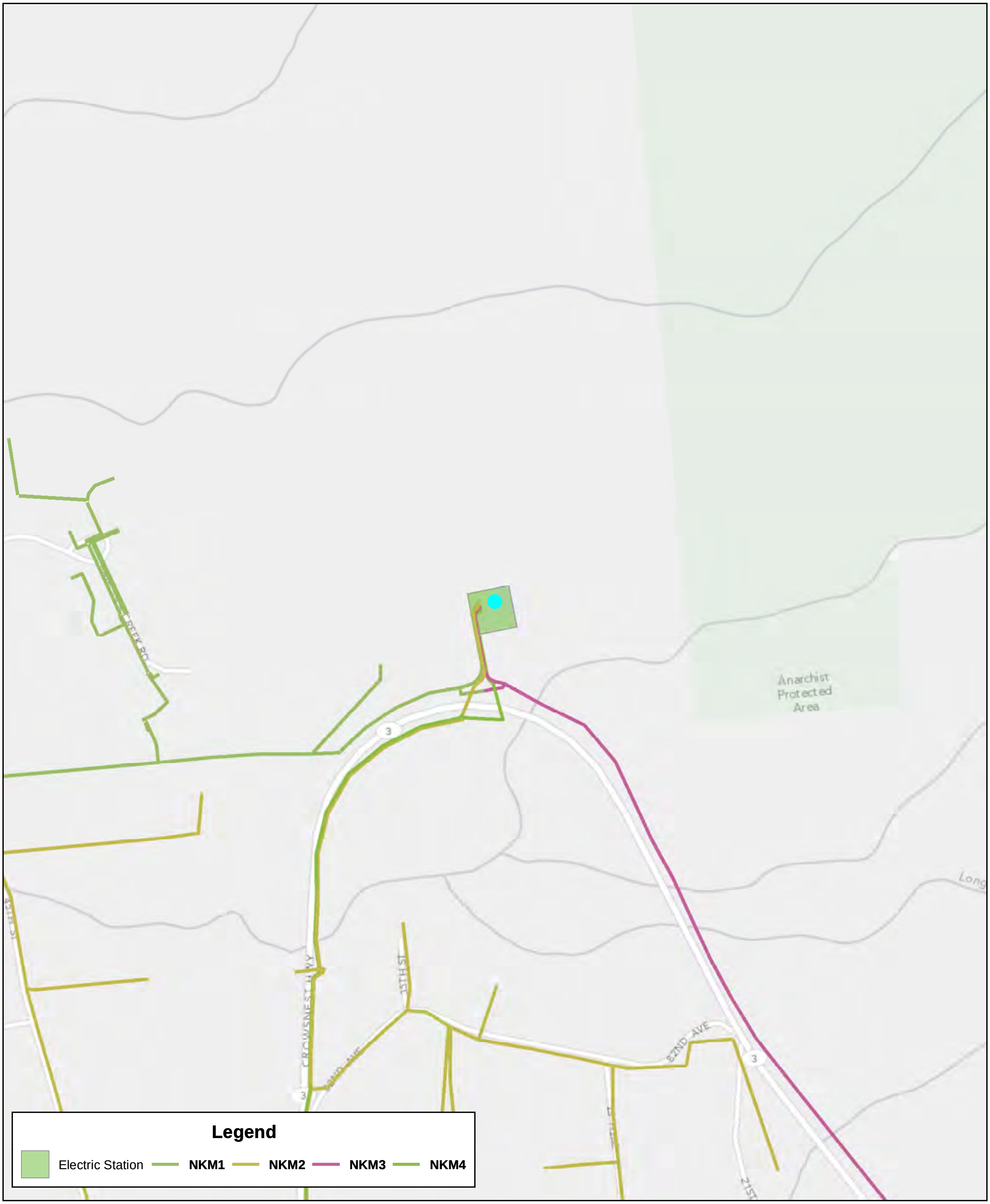
NK'MIP



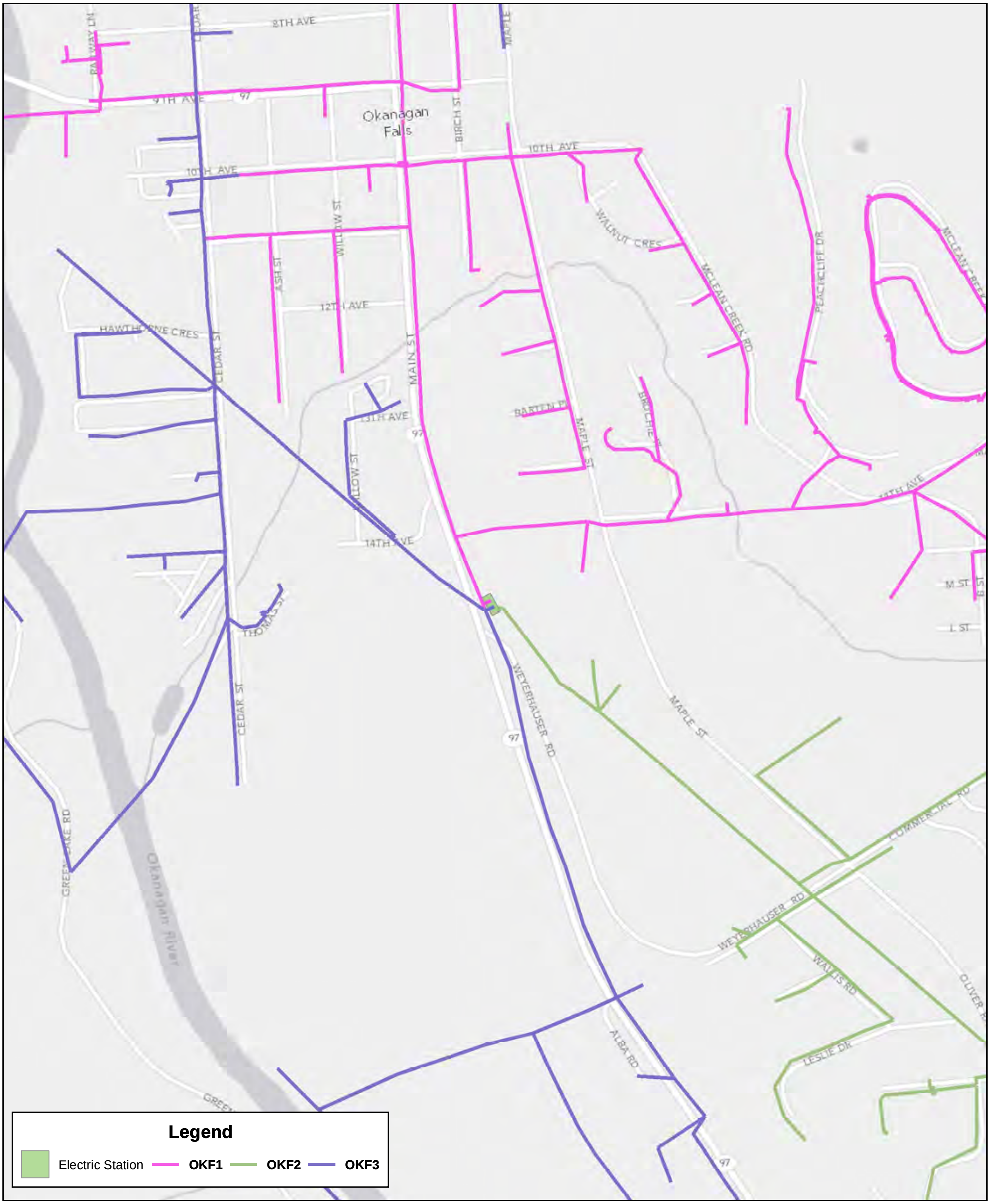
75 37.5 0 75 150 225 300
Meters
Projection: BC Standard Albers - Datum:

1:8,000

FORTIS BC™

Suite 100, 1975 Springfield Rd.
Kelowna, British Columbia, V1Y 7V7
1-866-4FORTIS
http://www.fortisbc.com

O.K. FALLS



8TH AVE
9TH AVE
10TH AVE
12TH AVE
13TH AVE
14TH AVE
Okanagan Falls
CEDAR ST
ASH ST
WILLOW ST
MAIN ST
BIRCH ST
MAPLE ST
HAWTHORNE CRES
WALNUT CRES
MCLEAN CREEK RD
PEACHCLIFF DR
BARTEN PL
WEYERHAUSER RD
COMMERCIAL RD
WALLIS RD
LESLIE DR
ALBA RD
GREEN LAKE RD
Okanagan River
M ST
L ST
Legend
Electric Station
OKF1
OKF2
OKF3

OKANAGAN MISSION

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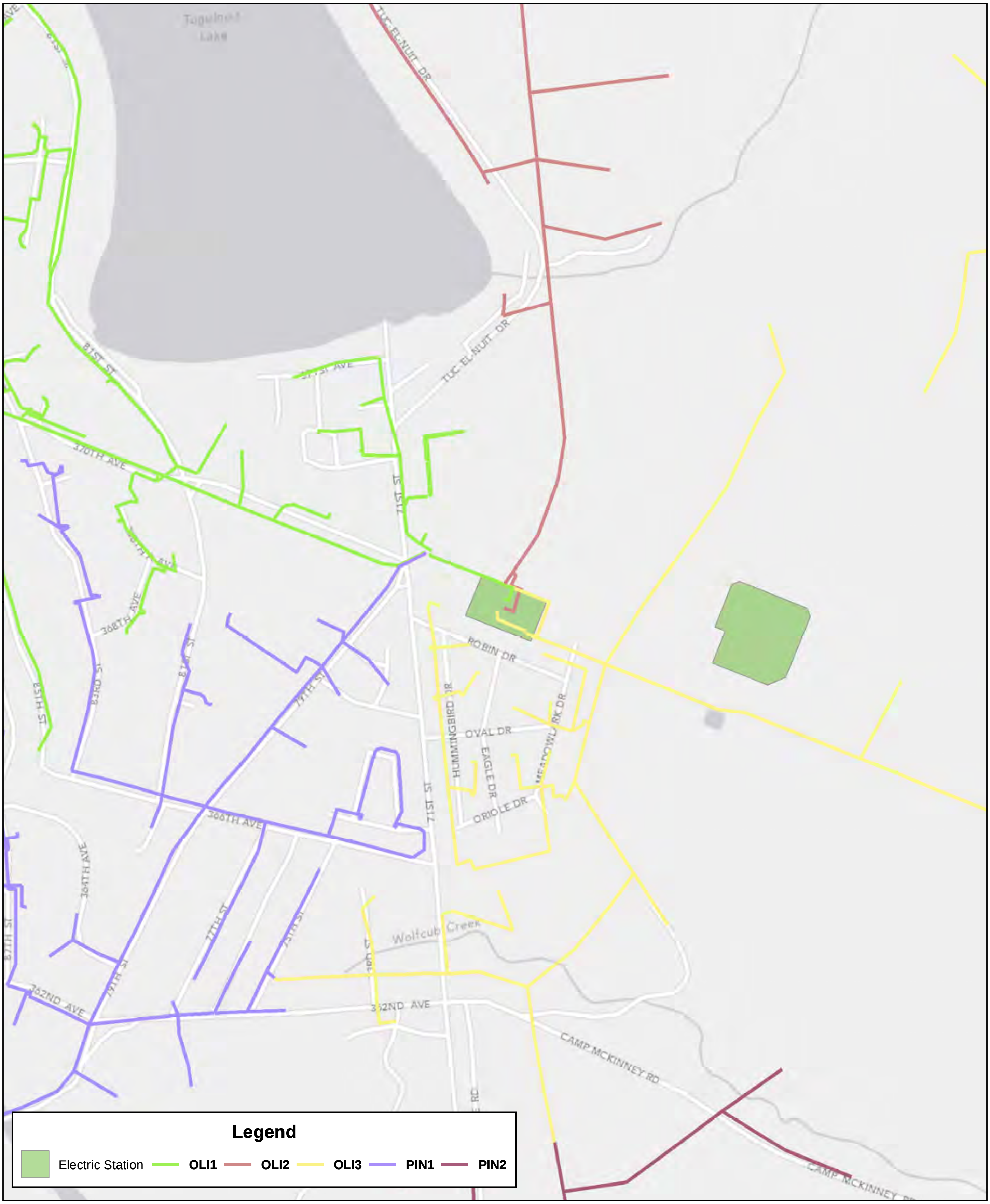
1:8,000

Projection: BC Standard Albers - Datum:

Data has been developed using the most current available information, but errors or ommissions may exist. Please forward any questions or ommissions to the FortisBC Corporate Mapping Group.

OLIVER TERMINAL



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75 37.5 0 75 150 225 300
Meters

Projection: BC Standard Albers - Datum:

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OOTISCHENIA

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Meters

Projection: BC Standard Albers - Datum:

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OSOYOOS

75 37.5 0 75 150 225 300
Meters

Projection: BC Standard Albers - Datum:

1:8,000

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PASSMORE

Projection: BC Standard Albers - Datum:

1:8,000

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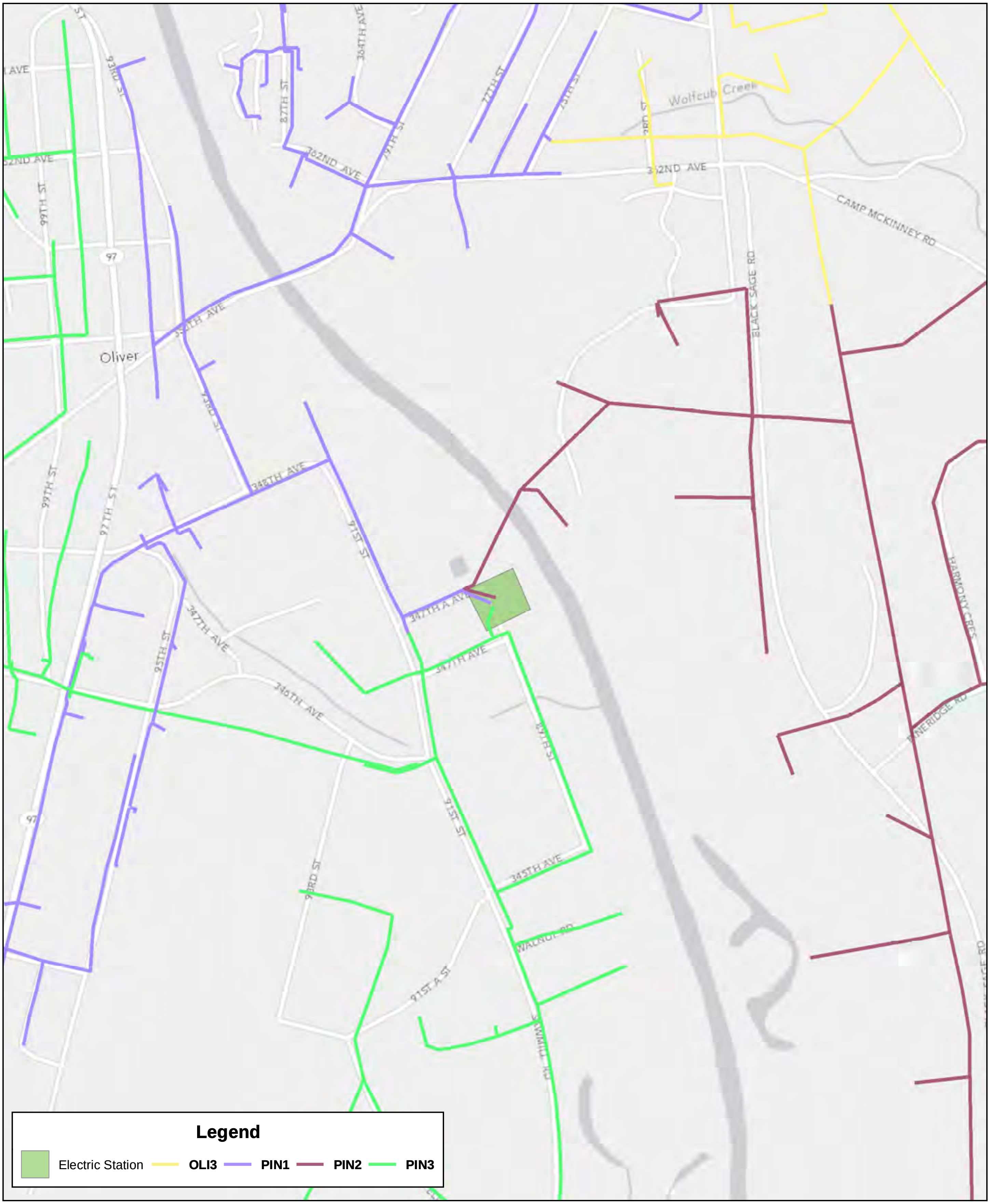
http://www.fortisbc.com

PINE STREET



75 37.5 0 75 150 225 300
Meters

Projection: BC Standard Albers - Datum:

1:8,000

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PLAYMORE

Legend

Electric Station — PLA1 — PLA2 — PLA3 — PLA4

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Kelowna, British Columbia, V1Y 7V7
1-866-4FORTIS
http://www.fortisbc.com

75 37.5 0 75 150 225 300
Meters

Projection: BC Standard Albers - Datum:

1:8,000

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PRINCETON

Suite 100, 1975 Springfield Rd.
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http://www.fortisbc.com

FORTIS BC™

1:8,000

75 37.5 0 75 150 225 300
Meters

Projection: BC Standard Albers - Datum:

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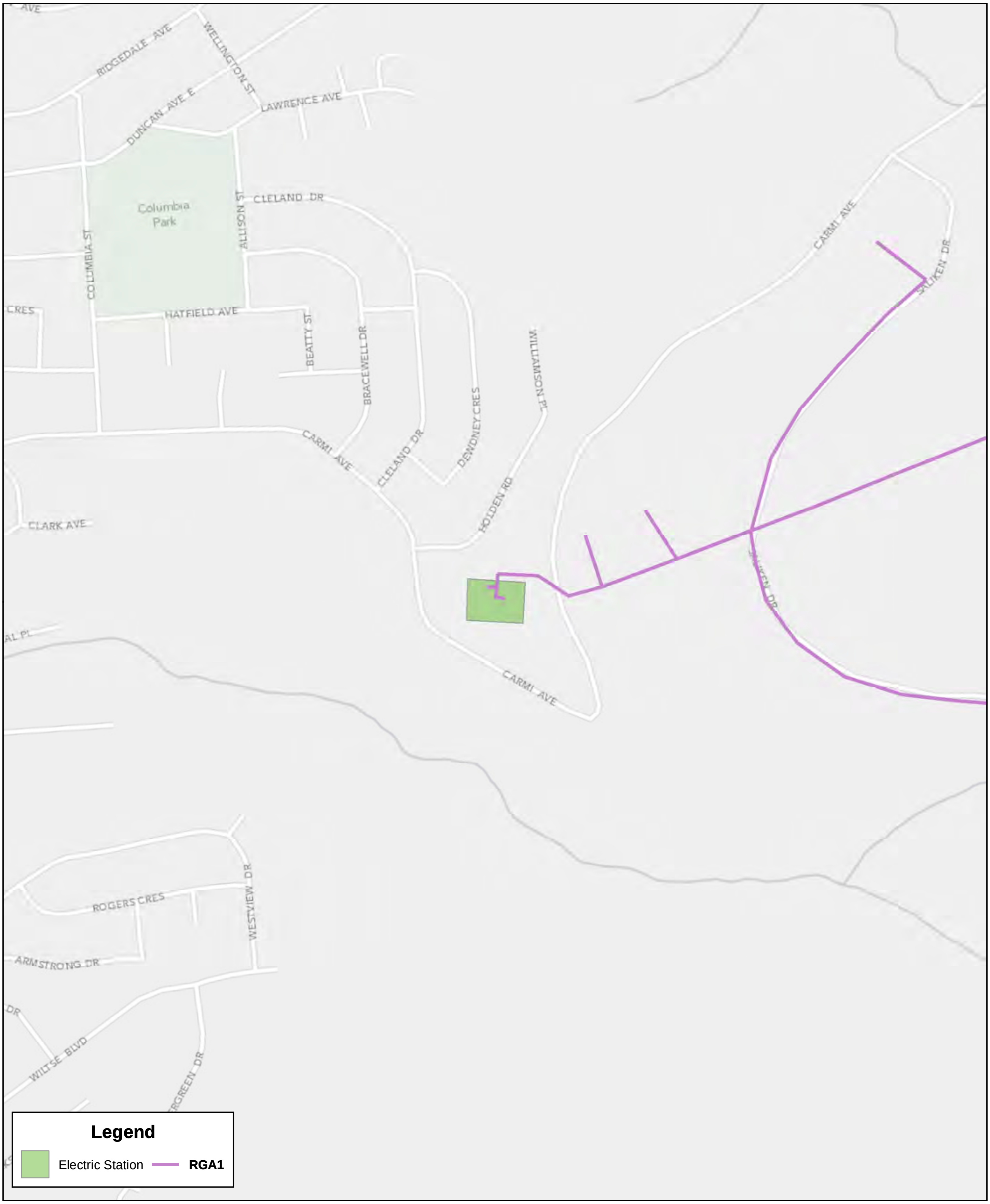
R.G. ANDERSON TERMINAL



Suite 100, 1975 Springfield Rd.
Kelowna, British Columbia, V1Y 7V7
1-866-4FORTIS
http://www.fortisbc.com

75 37.5 0 75 150 225 300
Meters

Projection: BC Standard Albers - Datum:

1:8,000

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RECREATION

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http://www.fortisbc.com

75 37.5 0 75 150 225 300
Meters

Projection: BC Standard Albers - Datum:

1:8,000

Data has been developed using the most current available information, but errors or ommissions may exist. Please forward any questions or ommissions to the FortisBC Corporate Mapping Group.

RUCKLES

Legend

Electric Station | GFT1 | RUC1 | RUC4 | RUC5

FORTIS BC

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http://www.fortisbc.com

1:8,000

75 37.5 0 75 150 225 300
Meters

Projection: BC Standard Albers - Datum:

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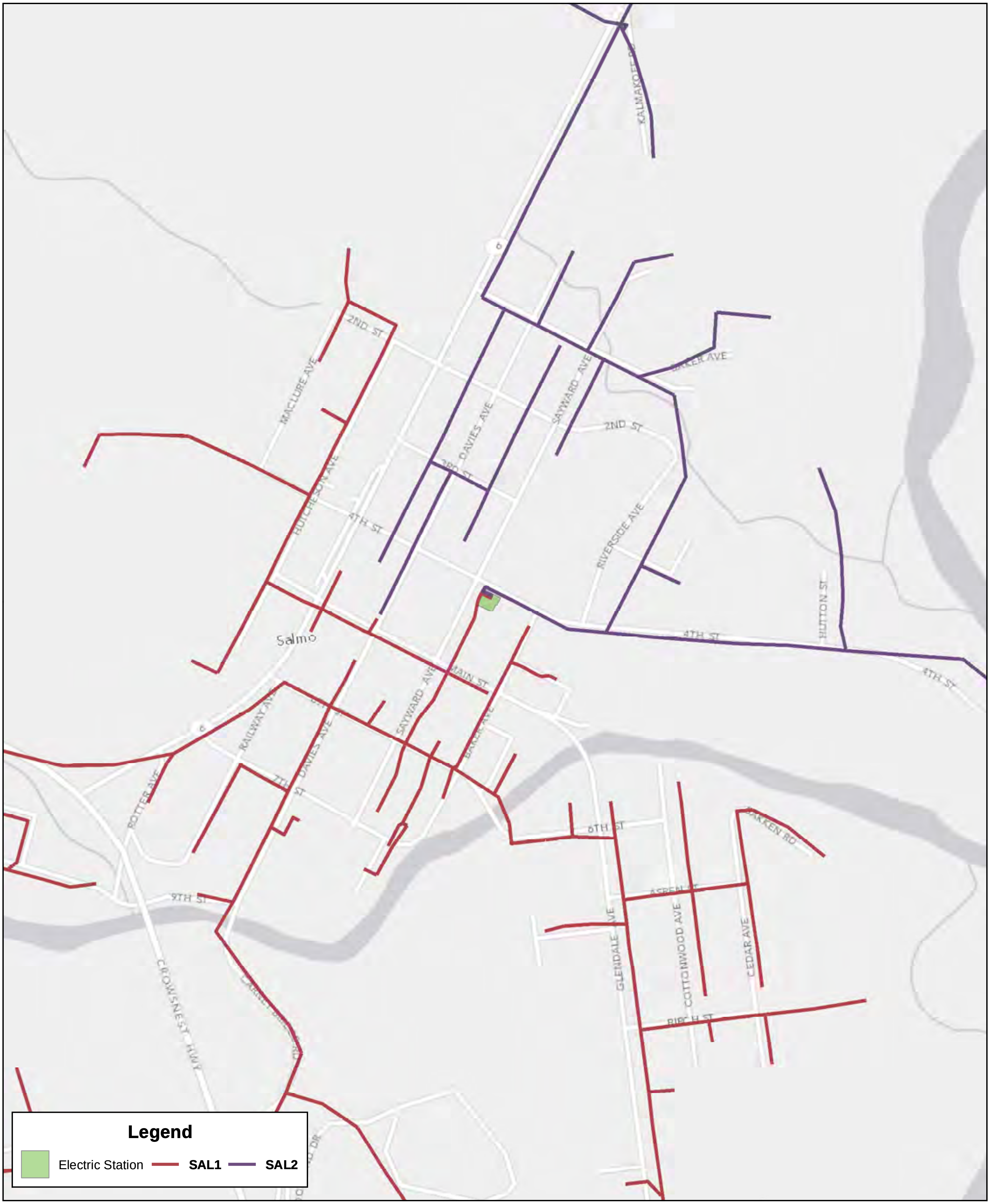
SALMO



Suite 100, 1975 Springfield Rd.
Kelowna, British Columbia, V1Y 7V7
1-866-4FORTIS
http://www.fortisbc.com

75 37.5 0 75 150 225 300
Meters
Projection: BC Standard Albers - Datum:

1:8,000

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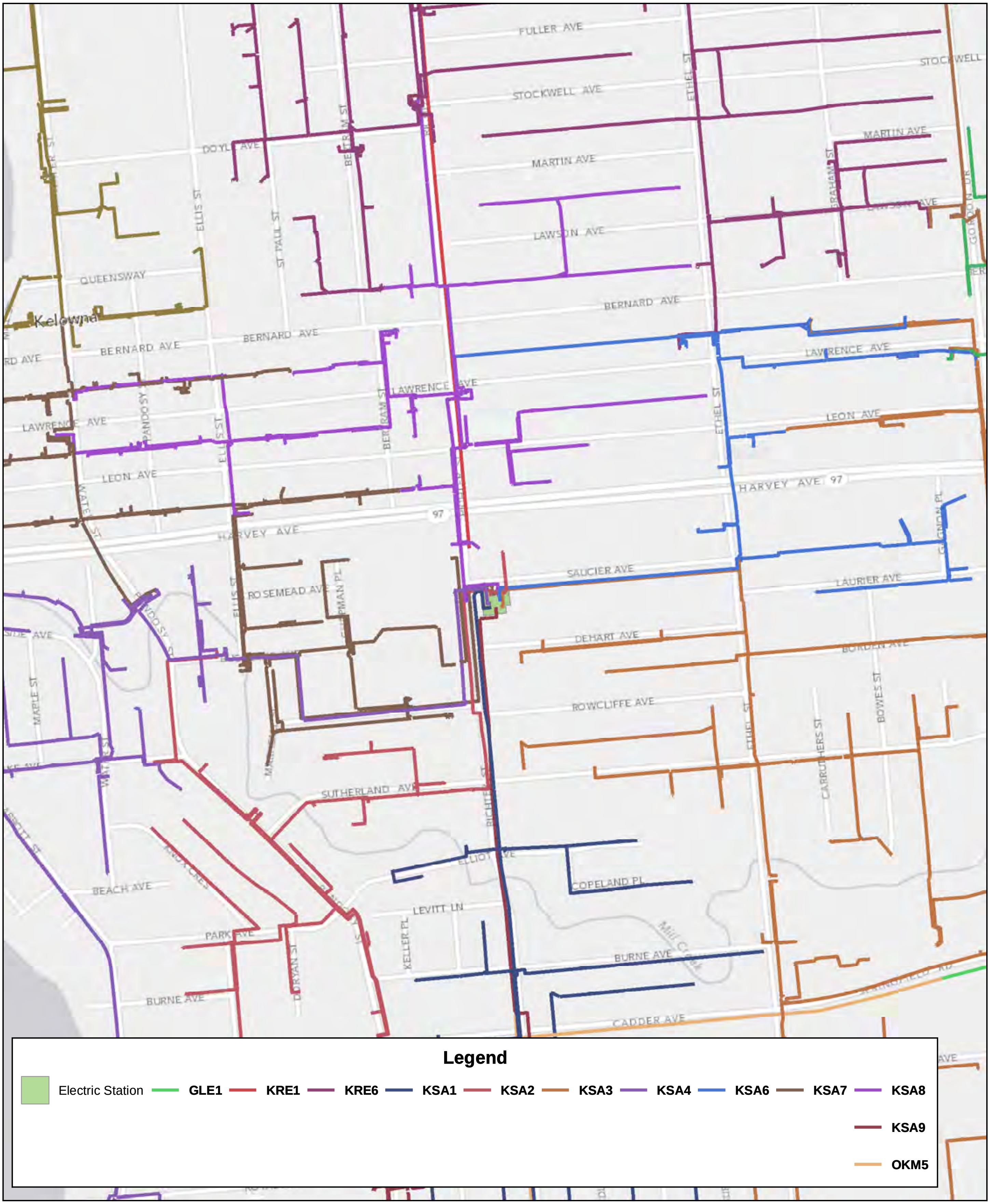
SAUCIER



Legend

Electric Station — GLE1 — KRE1 — KRE6 — KSA1 — KSA2 — KSA3 — KSA4 — KSA6 — KSA7 — KSA8 — KSA9 — OKM5

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75 37.5 0 75 150 225 300
Meters

Projection: BC Standard Albers - Datum:

1:8,000

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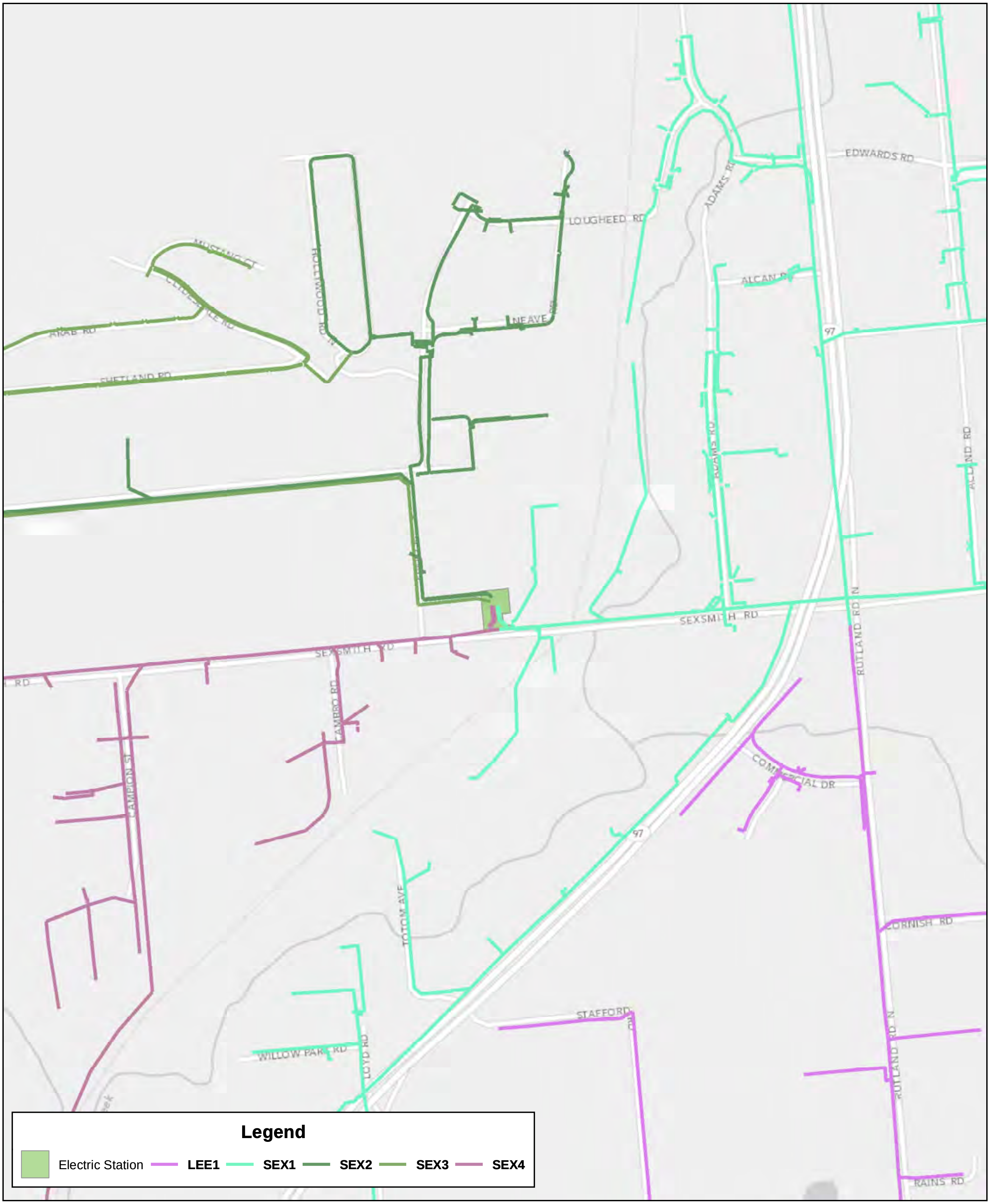
SEXSMITH



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75 37.5 0 75 150 225 300
Meters

Projection: BC Standard Albers - Datum:

1:8,000

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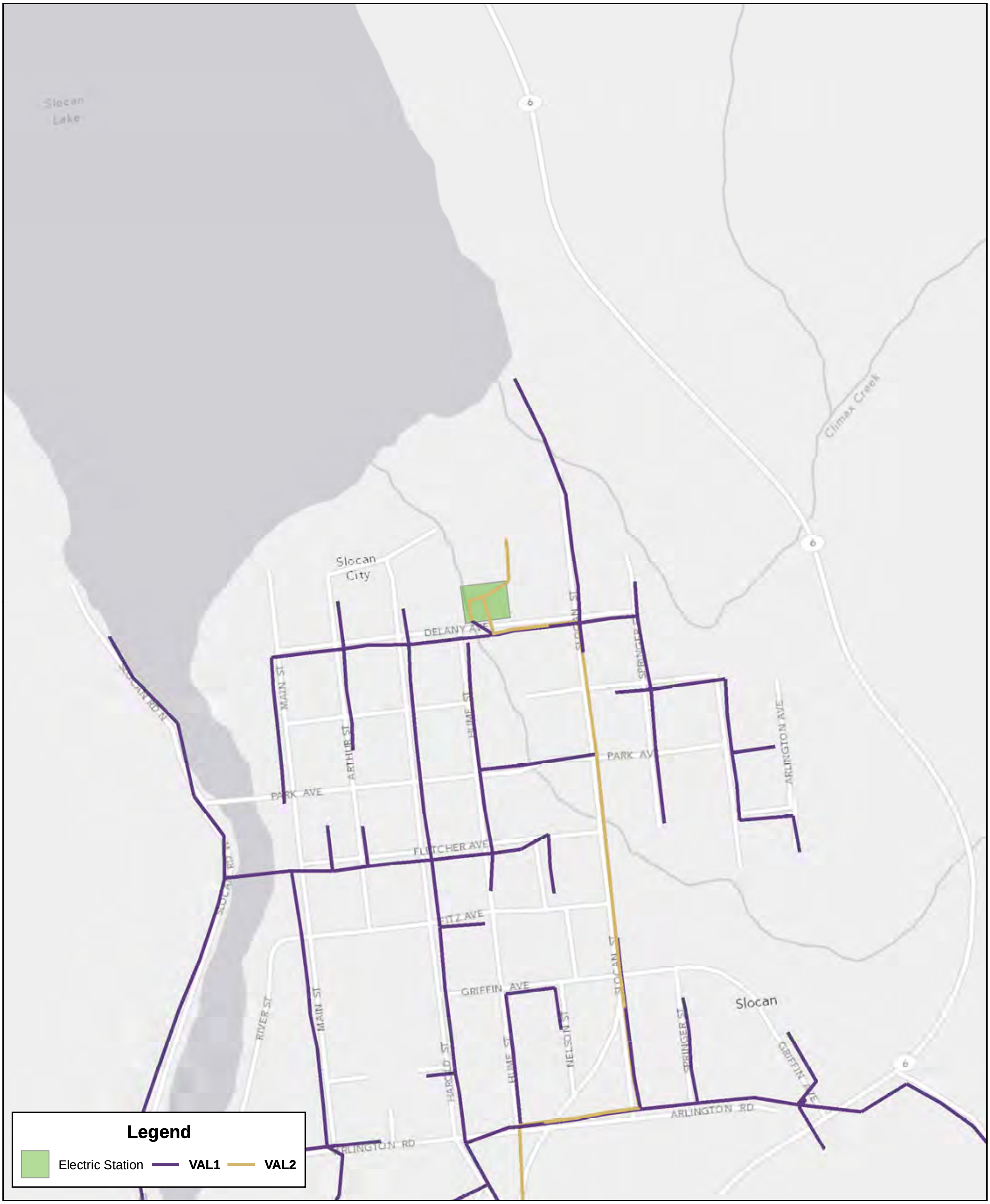
SLOCAN



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Kelowna, British Columbia, V1Y 7V7
1-866-4FORTIS
http://www.fortisbc.com

1:8,000

75 37.5 0 75 150 225 300
Meters

Projection: BC Standard Albers - Datum:

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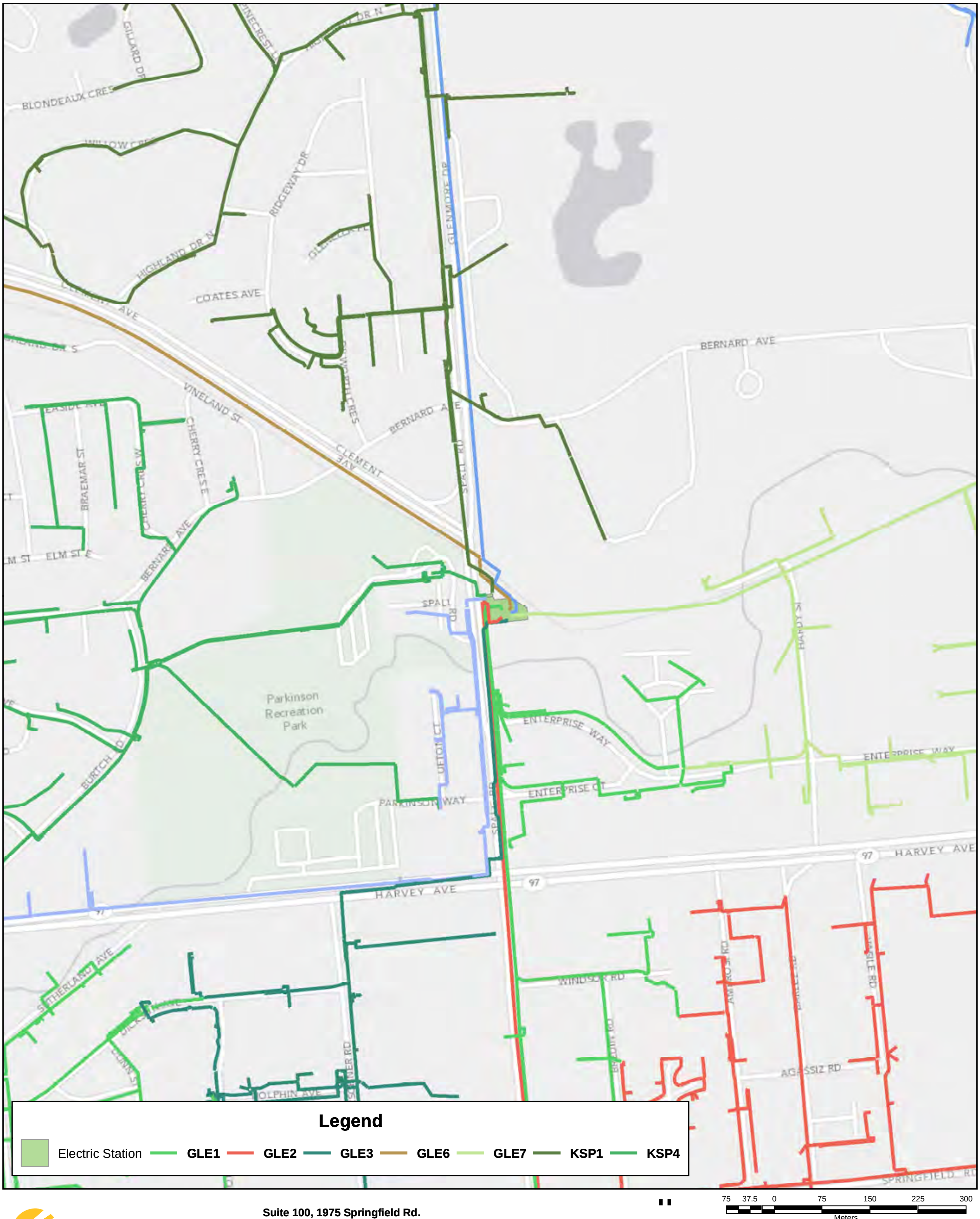
SPALL



Projection: BC Standard Albers - Datum:

1:8,000

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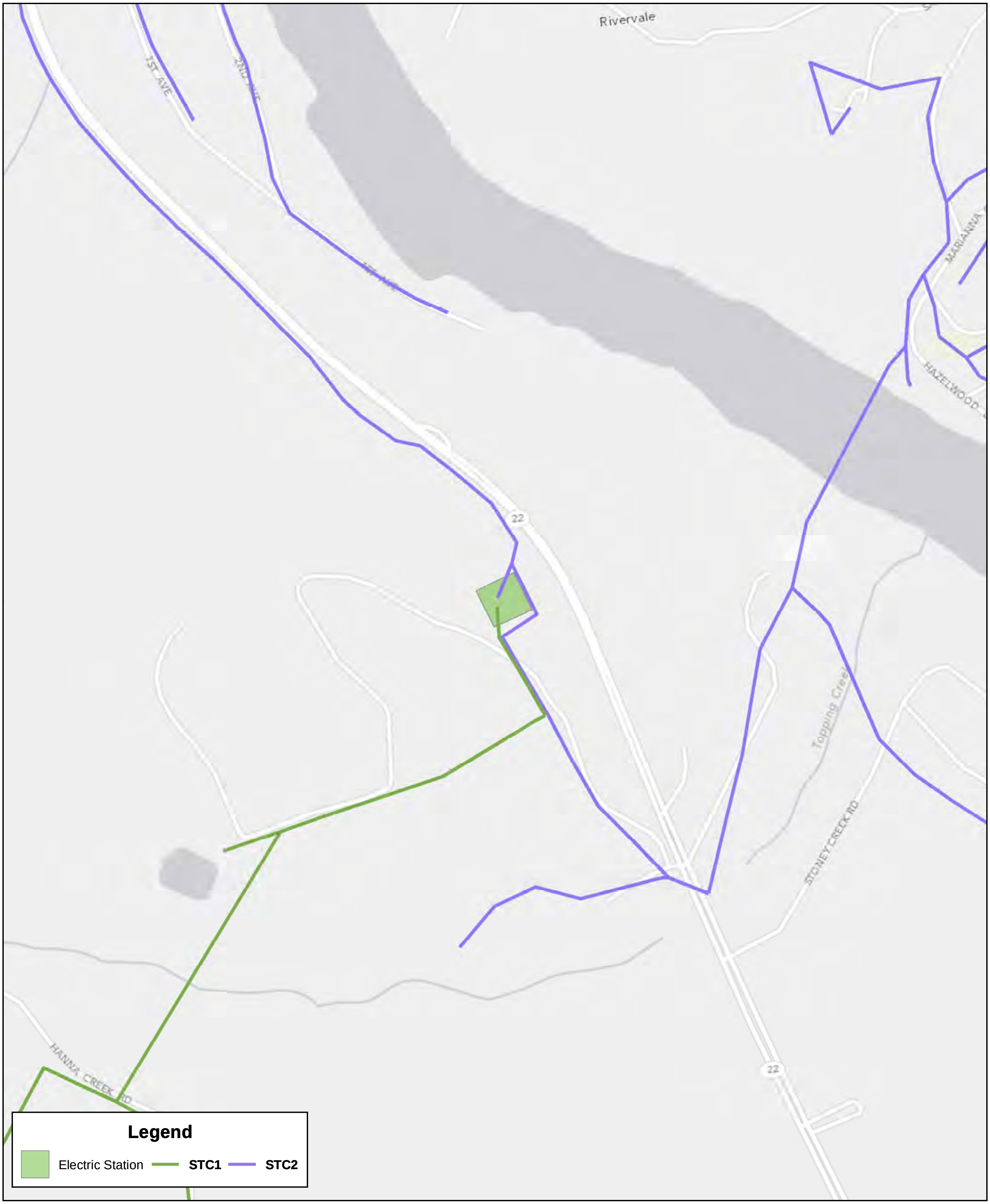
STONEY CREEK



75 37.5 0 75 150 225 300
Meters

Projection: BC Standard Albers - Datum:

1:8,000

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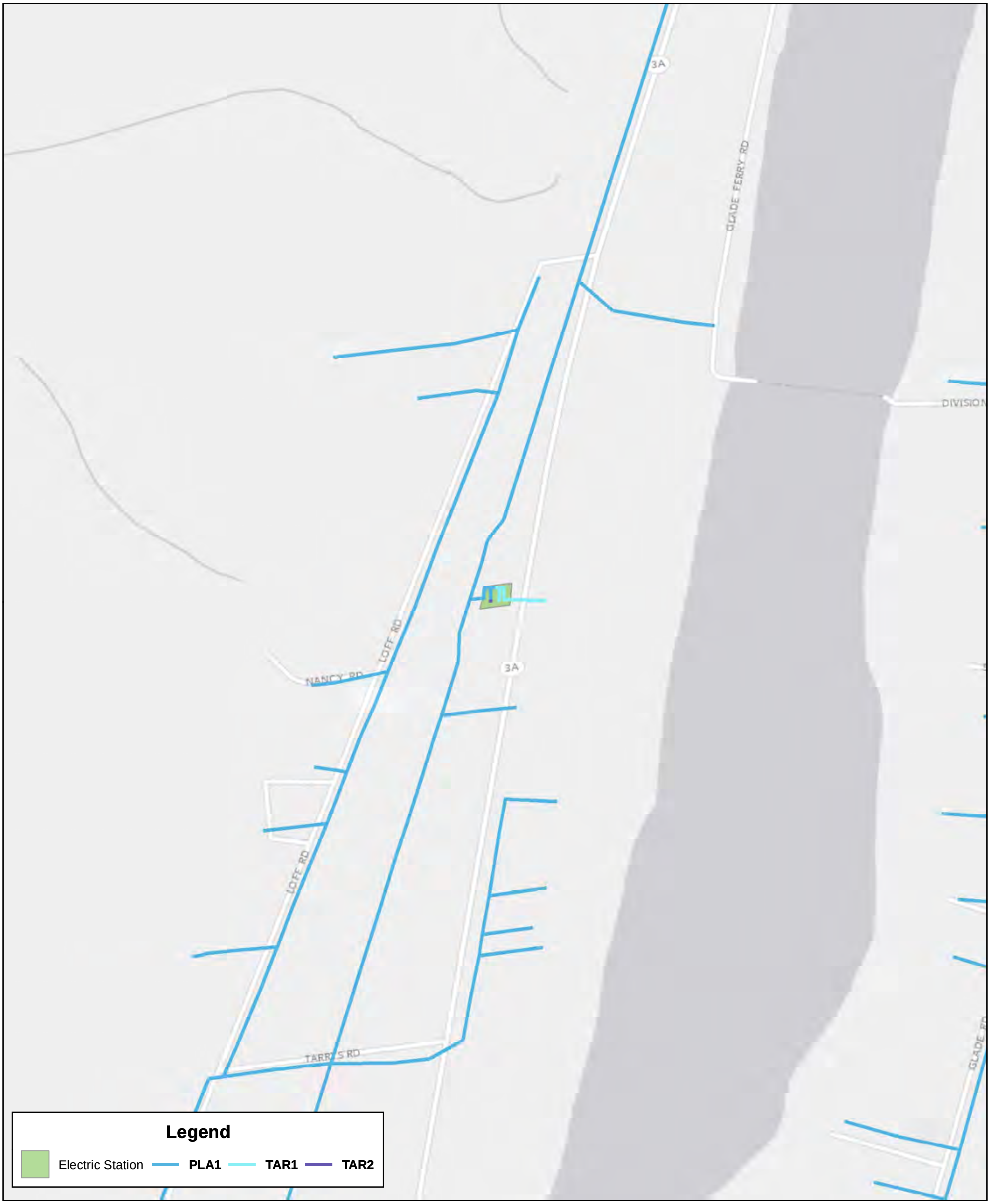
TARRYS



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75 37.5 0 75 150 225 300
Meters

Projection: BC Standard Albers - Datum:

1:8,000

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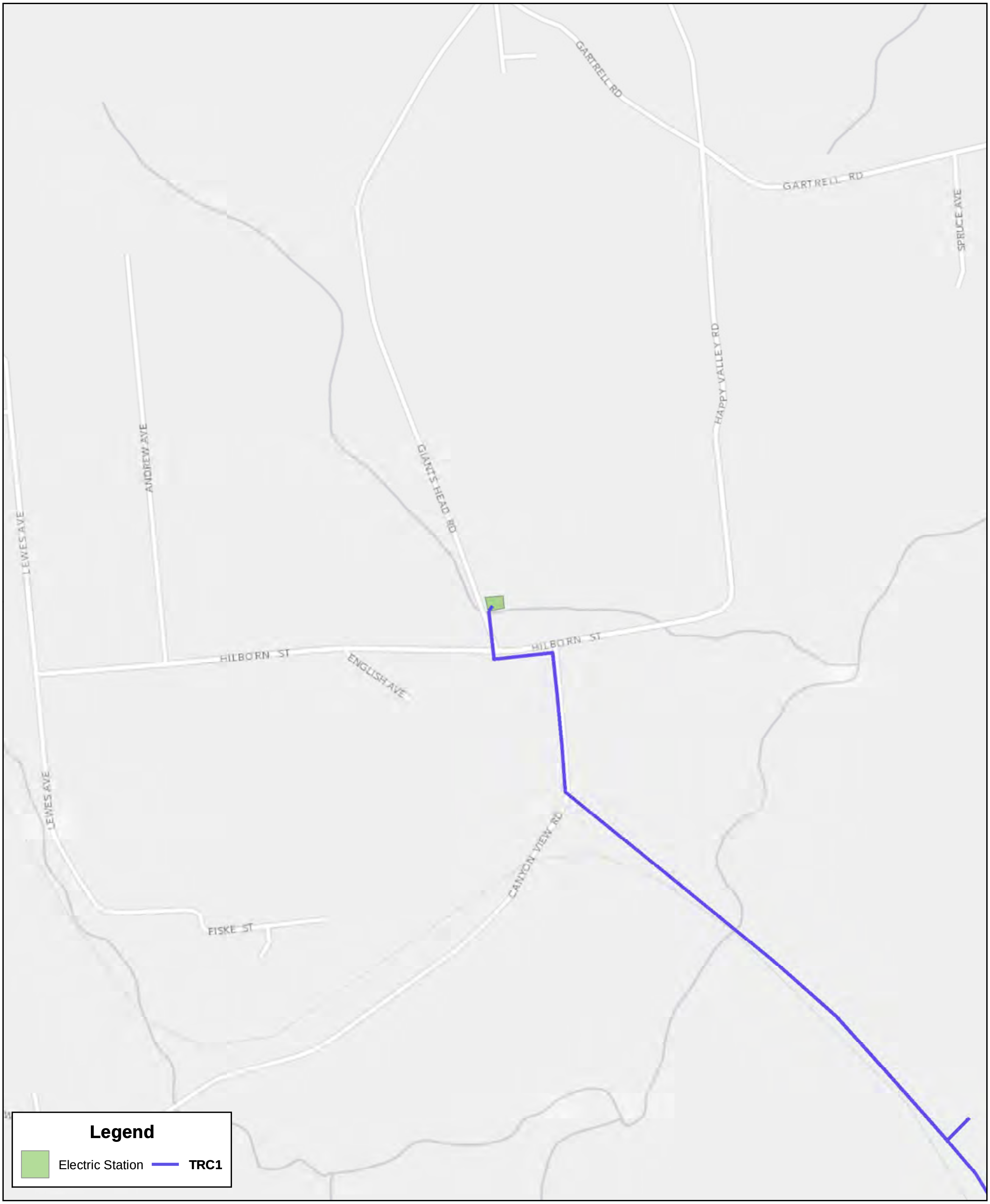
TROUT CREEK



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75 37.5 0 75 150 225 300
Meters

Projection: BC Standard Albers - Datum:

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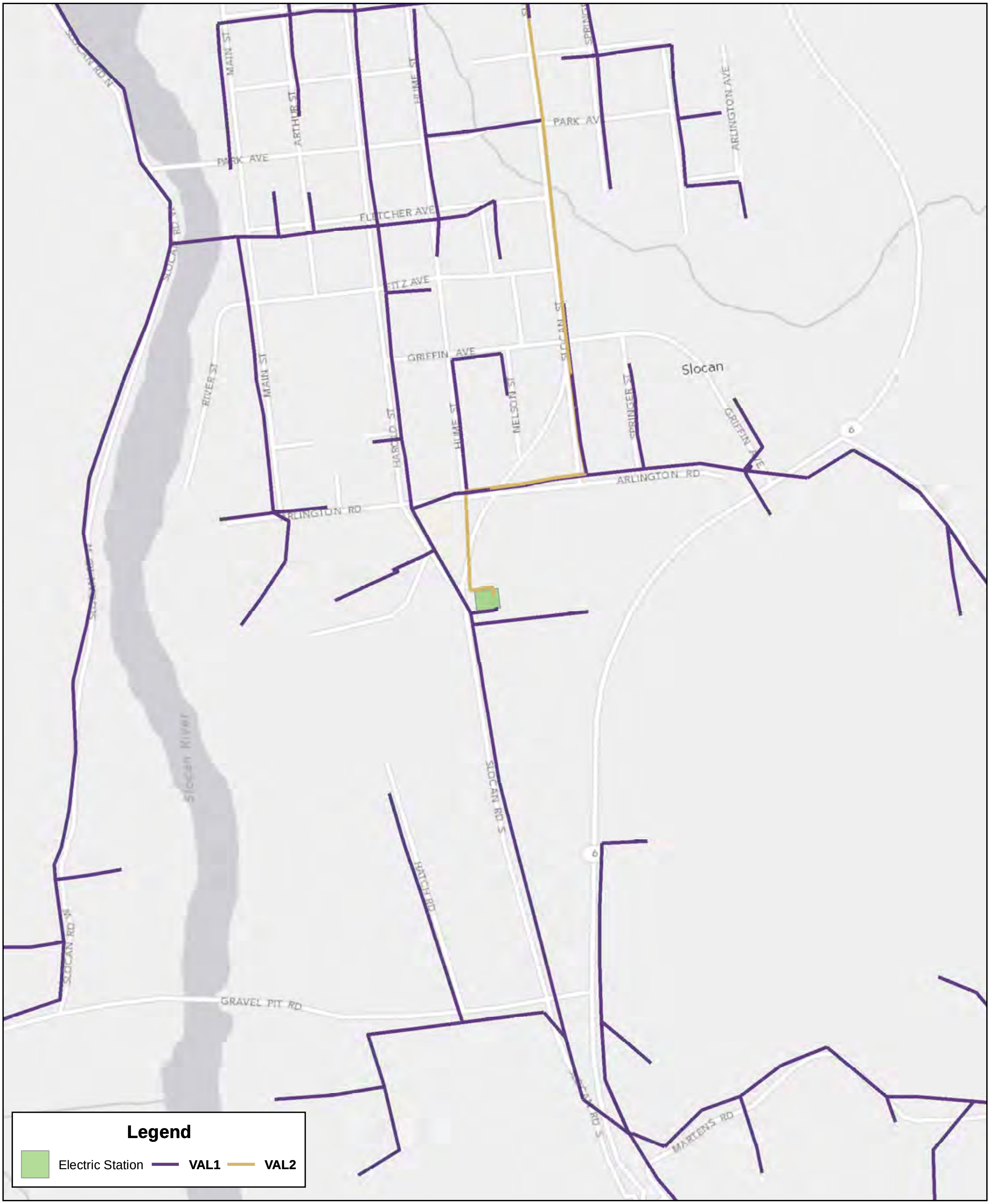
VALHALLA



75 37.5 0 75 150 225 300

Meters

Projection: BC Standard Albers - Datum:

1:8,000

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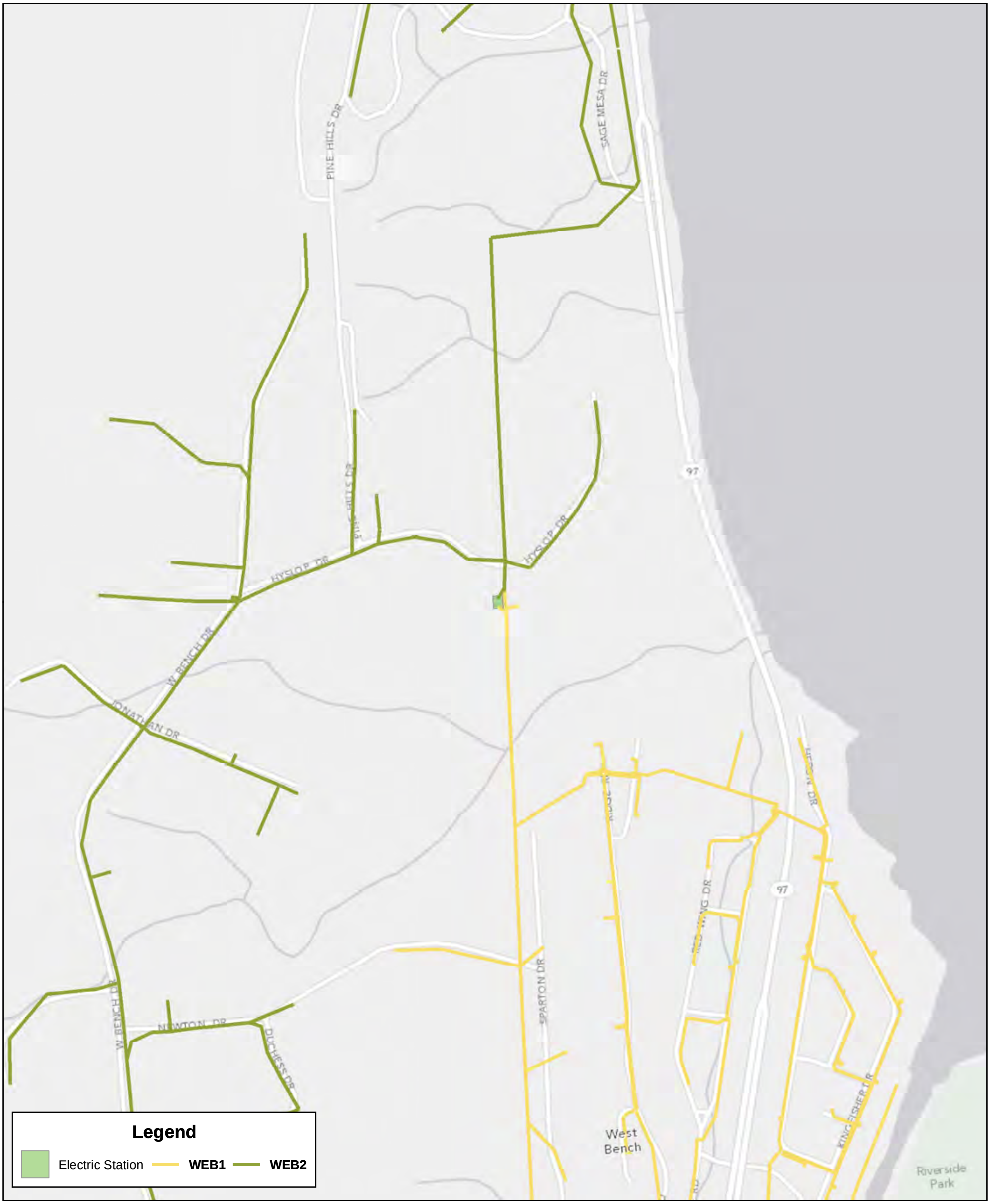
WEST BENCH



75 37.5 0 75 150 225 300
Meters

Projection: BC Standard Albers - Datum:

1:8,000

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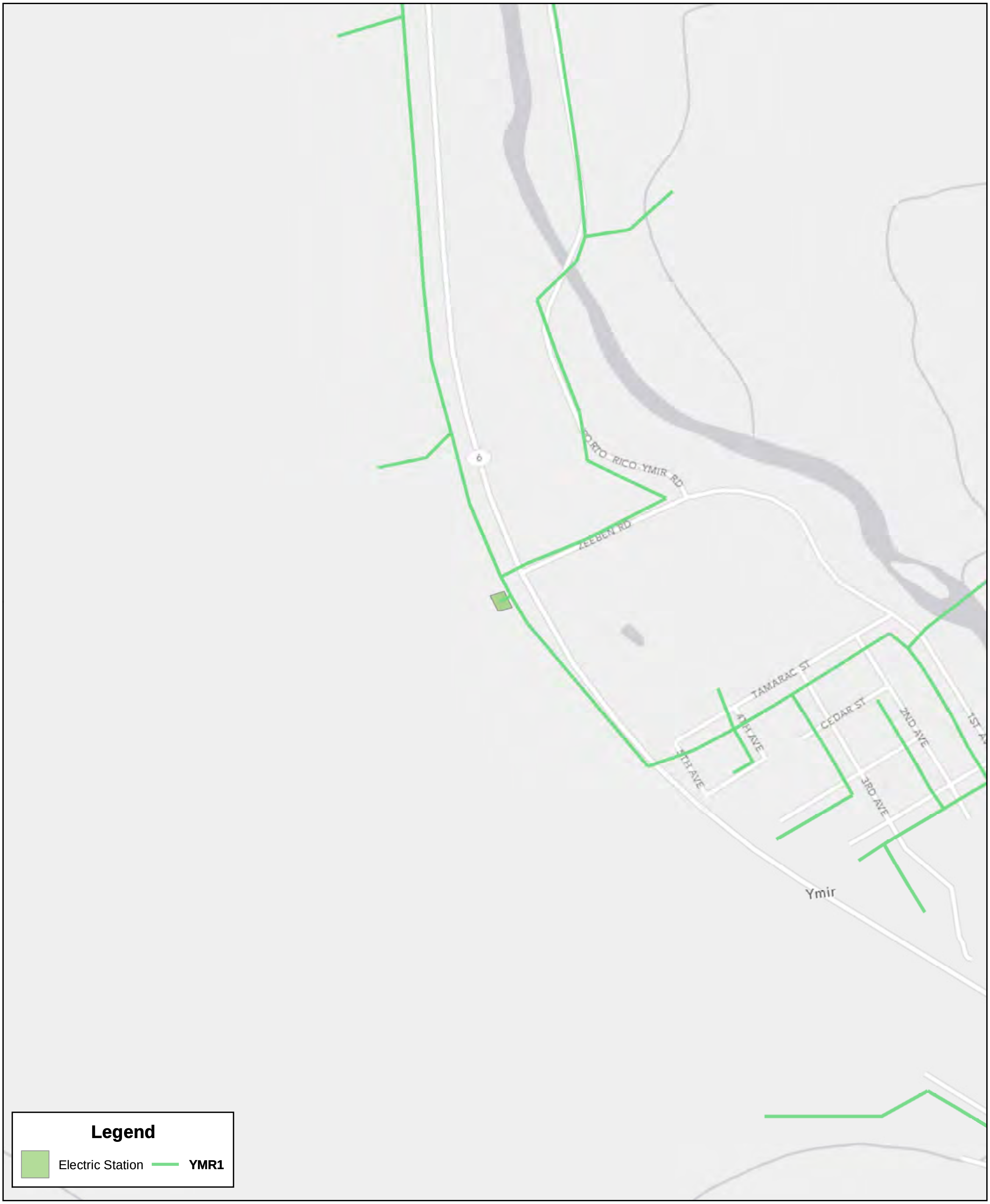
YMIR



FORTIS BC
Suite 100, 1975 Springfield Rd.
Kelowna, British Columbia, V1Y 7V7
1-866-4FORTIS
http://www.fortisbc.com

75 37.5 0 75 150 225 300
Meters
Projection: BC Standard Albers - Datum:

1:8,000

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Attachment 15.12

UTILITY PLANT IN SERVICE
AS AT DECEMBER 31, 2000

	Account	December 31, 1999	Additions	Retirements	December 31, 2000
	Hydraulic Production Plant 2,3,&4 Plant				
330.1	Land Rights	$ 14,974	$	$	$ 14,974
331	Structures and Improvements	6,638,680	466,944.06		7,105,624
332	Reservoirs, Dams & Waterways	9,712,322	375,118		10,087,440
333	Water Wheels, Turbines and Gen.	4,856,761	4,590,649	(46,847)	9,400,563
334	Accessory Equipment	2,112,632	4,436,560	(44,390)	6,504,801
335	Other Power Plant Equipment	2,053,665	310,133	(44,390)	2,319,407
336	Roads, Railroads and Bridges	998,633	43,038	-	1,041,671
		26,387,666	10,222,442	(135,628)	36,474,480
	Hydraulic Production Plant #1 Plant				
330.1	Land Rights	83,965			83,965
331	Structures and Improvements	583,437	14,870		598,307
332	Reservoirs, Dams & Waterways	2,580,497			2,580,497
333	Water Wheels, Turbines and Gen.	6,952,704	32,159		6,984,862
334	Accessory Equipment	1,497,840	19,638		1,517,478
335	Other Power Plant Equipment	3,418,752	415,663		3,834,415
		15,117,195	482,329	-	15,599,524
	Other Production Plant				
346	Other Power Plant Equipment	1,352,834			1,352,834
	Transmission Plant				
350.1	Land Rights-R/W	2,158,423	615,109		2,773,532
350.1	Land Rights-Clearing	2,807,226			2,807,226
353	Station Equipment	32,306,070	1,091,373		33,397,443
355	Poles Towers & Fixtures	29,258,749	2,584,547	(97,794)	31,745,501
356	Conductors and Devices	29,035,396	2,591,947	(97,794)	31,529,549
359	Roads and Trails	159,228			159,228
		95,725,092	6,882,976	(195,589)	102,412,479
	Distribution Plant				
360.1	Land Rights-R/W	440,313	21,239		461,552
360.1	Land Rights-Clearing	286,616			286,616
362	Station Equipment	47,557,027	1,446,854	(15,306)	48,988,575
364	Poles Towers & Fixtures	50,516,008	3,387,063	(90,275)	53,812,795
365	Conductors and Devices	92,495,858	5,080,879	(90,275)	97,486,462
368	Line Transformers	30,680,161	2,728,416		33,408,577
369	Services	6,090,373			6,090,373
370	Meters	9,610,627	870,999		10,481,627
371	Installation on Customers' Premises	937,832			937,832
373	Street Lighting and Signal System	1,005,293	32,182	(7,038)	1,030,436
		239,620,108	13,567,633	(202,895)	252,984,846
	General Plant				
389	Land	1,314,488			1,314,488
390	Structures-Frame & Iron	271,502			271,502
390	Structures-Masonry	10,011,428	249,871		10,261,298
391	Office Furniture & Equipment	4,561,355	157,775		4,719,130
391.1	Computer Equipment	11,833,471	4,257,486		16,090,958
392	Transportation Equipment	6,749,857	158,916	(427,908)	6,480,864
394	Tools and Work Equipment	4,527,885	342,710		4,870,594
397	Communication Structures and Equipment	4,298,623	114,983		4,413,606
		43,568,609	5,281,741	(427,908)	48,422,441
101	Plant in Service	421,771,504	36,437,121	(962,020)	457,246,605
107.1	Plant under construction not subject to AFUDC	11,200,971			13,929,823
107.2	Plant under construction subjec to AFUDC	11,754,265			10,522,864
114	Utility Plant Acquisition Adjustment	11,912,000			11,912,000
105	Plant held for future use	740,932			740,932
	Utility Plant per Balance Sheet	$ 457,379,672			$ 494,352,225

UtiliCorp Networks Canada
An Aquila Company

UTILITY PLANT IN SERVICE
AS AT DECEMBER 31, 2001

Account		December 31, 2000	Additions	Retirements	December 31, 2001
	Hydraulic Production Plant 2,3,&4 Plant				
330.1	Land Rights	$ 14,974	$	$	$ 14,974
331	Structures and Improvements	7,105,624	983,027		8,088,651
332	Reservoirs, Dams & Waterways	10,087,440			10,087,440
333	Water Wheels, Turbines and Gen.	9,400,563	6,758,634		16,159,197
334	Accessory Equipment	6,504,801	3,403,884		9,908,685
335	Other Power Plant Equipment	2,319,407	710,087		3,029,494
336	Roads, Railroads and Bridges	1,041,671	1,398		1,043,069
		36,474,480	11,857,030	0	48,331,510
	Hydraulic Production Plant #1 Plant				
330.1	Land Rights	83,965			83,965
331	Structures and Improvements	598,307			598,307
332	Reservoirs, Dams & Waterways	2,580,497			2,580,497
333	Water Wheels, Turbines and Gen.	6,984,862			6,984,862
334	Accessory Equipment	1,517,478			1,517,478
335	Other Power Plant Equipment	3,834,415			3,834,415
		15,599,524	0	0	15,599,524
	Other Production Plant				
346	Other Power Plant Equipment	1,352,834			1,352,834
	Transmission Plant				
350.1	Land Rights-R/W	2,773,532	12,089		2,785,621
350.1	Land Rights-Clearing	2,807,226			2,807,226
353	Station Equipment	33,397,443	2,879,134		36,276,578
355	Poles Towers & Fixtures	31,745,501	1,207,646	(2,513)	32,950,635
356	Conductors and Devices	31,529,549	2,382,391	(6,889)	33,905,052
359	Roads and Trails	159,228			159,228
		102,412,479	6,481,261	(9,401)	108,884,339
	Distribution Plant				
360.1	Land Rights-R/W	461,552	24,516		486,068
360.1	Land Rights-Clearing	286,616			286,616
362	Station Equipment	48,988,575	1,668,838	(17,833)	50,639,580
364	Poles Towers & Fixtures	53,812,795	4,618,005	(87,489)	58,343,311
365	Conductors and Devices	97,486,462	7,554,111	(44,964)	104,995,609
368	Line Transformers	33,408,577	3,258,447	(227,756)	36,439,268
369	Services	6,090,373			6,090,373
370	Meters	10,481,627	416,562		10,898,189
371	Installation on Customers' Premises	937,832			937,832
373	Street Lighting and Signal System	1,030,436	79,960		1,110,397
		252,984,846	17,620,440	(378,042)	270,227,244
	General Plant				
389	Land	1,314,488			1,314,488
390	Structures-Frame & Iron	271,502	65,863		337,364
390.1	Structures-Masonry	10,261,298	94,162		10,355,460
391	Office Furniture & Equipment	4,719,130	85,974		4,805,105
391.1	Computer Equipment	16,090,958	2,944,452	(793,770)	18,241,640
392	Transportation Equipment	6,480,864	4,011	(51,790)	6,433,085
394	Tools and Work Equipment	4,870,594	673,802		5,544,396
397	Communication Structures and Equipment	4,413,606	34,762		4,448,368
		48,422,441	3,903,025	(845,560)	51,479,906
101	Plant in Service	457,246,605	39,861,755	(1,233,003)	495,875,357
107.1	Plant under construction not subject to AFUDC	13,929,823			5,855,300
107.2	Plant under construction subject to AFUDC	10,522,864			20,978,776
114	Utility Plant Acquisition Adjustment	11,912,000			11,912,000
105	Plant held for future use	740,932			740,932
	Utility Plant per Balance Sheet	$ 494,352,225			$ 535,362,365

Aquila

UTILITY PLANT IN SERVICE

AS AT DECEMBER 31, 2002

Account		December 31, 2001	Additions	Retirements	December 31, 2002
	Hydraulic Production Plant 2,3,&4 Plant				
330.1	Land Rights	$ 14,974	$	$	$ 14,974
331	Structures and Improvements	8,088,651	360,357		8,449,008
332	Reservoirs, Dams & Waterways	10,087,440	-		10,087,440
333	Water Wheels, Turbines and Gen.	16,159,197	148,152		16,307,349
334	Accessory Equipment	9,908,685	1,009,130		10,917,815
335	Other Power Plant Equipment	3,029,494	480,080		3,509,574
336	Roads, Railroads and Bridges	1,043,069	-		1,043,069
		48,331,510	1,997,719	0	50,329,229
	Hydraulic Production Plant #1 Plant				
330.1	Land Rights	83,965			83,965
331	Structures and Improvements	598,307	26,086		624,393
332	Reservoirs, Dams & Waterways	2,580,497	-		2,580,497
333	Water Wheels, Turbines and Gen.	6,984,862	19,790		7,004,652
334	Accessory Equipment	1,517,478	-		1,517,478
335	Other Power Plant Equipment	3,834,415	15,030		3,849,445
		15,599,524	60,906	0	15,660,430
	Other Production Plant				
346	Other Power Plant Equipment	1,352,834	-		1,352,834
	Transmission Plant				
350.1	Land Rights-R/W	2,785,621	48,274		2,833,895
350.1	Land Rights-Clearing	2,807,226			2,807,226
353	Station Equipment	36,276,578	256,593		36,533,171
355	Poles Towers & Fixtures	32,950,635	921,555		33,872,189
356	Conductors and Devices	33,905,052	910,886		34,815,938
359	Roads and Trails	159,228			159,228
		108,884,339	2,137,308	0	111,021,647
	Distribution Plant				
360.1	Land Rights-R/W	486,068			486,068
360.1	Land Rights-Clearing	286,616			286,616
362	Station Equipment	50,639,580	620,188		51,259,768
364	Poles Towers & Fixtures	58,343,311	3,065,086		61,408,397
365	Conductors and Devices	104,995,609	4,922,271		109,917,880
368	Line Transformers	36,439,268	6,098,399		42,537,667
369	Services	6,090,373			6,090,373
370	Meters	10,898,189	611,561	(648,603)	10,861,148
371	Installation on Customers' Premises	937,832			937,832
373	Street Lighting and Signal System	1,110,397			1,110,397
		270,227,244	15,317,505	(648,603)	284,896,146
	General Plant				
389	Land	1,314,488			1,314,488
390	Structures-Frame & Iron	337,364			337,364
390.1	Structures-Masonry	10,355,460	3,098,524	(132,286)	13,321,698
391	Office Furniture & Equipment	4,805,105	204,331		5,009,436
391.1	Computer Equipment	18,241,640	10,417,155		28,658,795
392	Transportation Equipment	6,433,085	136,630	(204,972)	6,364,743
394	Tools and Work Equipment	5,544,396	449,258		5,993,654
397	Communication Structures and Equipment	4,448,368	29,999		4,478,367
		51,479,906	14,335,898	(337,258)	65,478,545
101	Plant in Service	495,875,357	33,849,335	(985,861)	528,738,831
107.1	Plant under construction not subject to AFUDC	5,855,300			13,535,567
107.2	Plant under construction subject to AFUDC	20,978,776			62,957,310
114	Utility Plant Acquisition Adjustment	11,912,000			11,912,000
105	Plant held for future use	740,932			740,932
	Utility Plant per Balance Sheet	$ 535,362,365			$ 617,884,641

Aquila

UTILITY PLANT IN SERVICE

AS AT DECEMBER 31, 2003

Acct.		December 31, 2002	Additions	Adjustments (000s)	Retirements	December 31, 2003
	Hydraulic Production Plant 2,3,&4 Plant					
330.1	Land Rights	$ 15	$ -	$ -	$ -	$ 15
331	Structures and Improvements	8,449	568	-	-	9,017
332	Reservoirs, Dams & Waterways	10,087	848	-	-	10,935
333	Water Wheels, Turbines and Gen.	16,307	47	-	(362)	15,993
334	Accessory Equipment	10,918	196	-	(189)	10,925
335	Other Power Plant Equipment	3,510	14,822	-	-	18,332
336	Roads, Railroads and Bridges	1,043	2	-	-	1,045
		50,329	16,484	-	(551)	66,263
	Hydraulic Production Plant #1 Plant					
330.1	Land Rights	84	-	-	-	84
331	Structures and Improvements	624	8	-	-	633
332	Reservoirs, Dams & Waterways	2,580	-	-	-	2,580
333	Water Wheels, Turbines and Gen.	7,005	64	-	-	7,069
334	Accessory Equipment	1,517	-	-	-	1,517
335	Other Power Plant Equipment	3,849	3,416	-	-	7,266
		15,660	3,488	-	-	19,149
	Other Production Plant					
346	Other Power Plant Equipment	1,353	-	-	-	1,353
	Transmission Plant					
350.1	Land Rights-R/W	2,834	2,747	-	(50)	5,531
350.1	Land Rights-Clearing	2,807	392	-	(153)	3,046
353	Station Equipment	36,533	10,432	-	-	46,965
355	Poles Towers & Fixtures	33,872	8,533	-	(1,091)	41,314
356	Conductors and Devices	34,816	8,687	-	(856)	42,648
359	Roads and Trails	159	310	-	(98)	371
		111,022	31,101	-	(2,247)	139,876
	Distribution Plant					
360.1	Land Rights-R/W	486	93	-	-	579
360.1	Land Rights-Clearing	287	1,042	-	-	1,329
362	Station Equipment	51,260	26,183	-	(383)	77,059
364	Poles Towers & Fixtures	61,408	5,968	(13)	(55)	67,309
365	Conductors and Devices	109,918	9,068	-	(76)	118,910
368	Line Transformers	42,538	4,682	-	(235)	46,985
369	Services	6,090	-	-	-	6,090
370	Meters	10,861	951	-	(2,805)	9,007
371	Installation on Customers' Premises	938	-	-	-	938
373	Street Lighting and Signal System	1,110	966	-	(8)	2,068
		284,896	48,953	(13)	(3,562)	330,275
	General Plant					
389	Land	1,314	-	-	-	1,314
390	Structures-Frame & Iron	337	-	-	-	337
390.1	Structures-Masonry	13,322	5,117	10	(573)	17,876
391	Office Furniture & Equipment	5,009	451	(1,159)	(458)	3,844
391.1	Computer Equipment	28,659	2,146	153	-	30,957
392	Transportation Equipment	6,365	264	13	(946)	5,696
394	Tools and Work Equipment	5,994	514	-	-	6,508
397	Communication Structures and Equipment	4,478	2,750	-	-	7,229
		65,479	11,242	(984)	(1,976)	73,761
101	Plant in Service	528,739	111,270	(996)	(8,337)	630,676
107.1	Plant under construction not subject to AFUDC	13,536				5,025
107.2	Plant under construction subject to AFUDC	62,957				20,448
114	Utility Plant Acquisition Adjustment	11,912				11,912
105	Plant held for future use	741				741
	Utility Plant per Balance Sheet	$ 617,885				$ 668,802

Note: Adjustments represent a reversal of 2002 software costs ($ 996,000) and a reclassification of certain plant items between accounts. The majority of the reclassification was between Account 391, Office Furniture and Equipment, and Account 391.1, Computer Equipment.

UTILITY PLANT IN SERVICE

AS AT DECEMBER 31, 2004

Account		December 31 2003	Additions	Adjustments	Retirements	December 31 2004
	Hydraulic Production Plants 2, 3, & 4					
330.1	Land Rights	15				15
331	Structures and Improvements	9,017	174			9,191
332	Reservoirs, Dams & Waterways	10,935	1,104		(68)	11,971
333	Water Wheels, Turbines and Gen.	15,993	13,220		(167)	29,046
334	Accessory Equipment	10,925	5,247		(69)	16,103
335	Other Power Plant Equipment	18,332	9,293			27,625
336	Roads, Railroads and Bridges	1,045	1			1,046
		66,263	29,039	-	(304)	94,997
	Hydraulic Production Plant #1 Plant					
330.1	Land Rights	84				84
331	Structures and Improvements	633	0		(41)	592
332	Reservoirs, Dams & Waterways	2,580				2,580
333	Water Wheels, Turbines and Gen.	7,069	590		(4)	7,655
334	Accessory Equipment	1,517	13		(0)	1,530
335	Other Power Plant Equipment	7,266	1,111			8,376
		19,149	1,714	-	(45)	20,817
	Other Production Plant					
346	Other Power Plant Equipment	1,353				1,353
	Transmission Plant					
350.1	Land Rights-R/W	5,531	284	(1)	(12)	5,802
350.1	Land Rights-Clearing	3,046	169	(1)	(13)	3,202
353	Station Equipment	46,965	9,131			56,096
355	Poles Towers & Fixtures	41,314	7,043	(14)	(223)	48,120
356	Conductors and Devices	42,648	7,278	(15)	(211)	49,700
359	Roads and Trails	371	401	(0)	(11)	760
		139,876	24,306	(31)	(470)	163,681
	Distribution Plant					
360.1	Land Rights-R/W	579	91	1		671
360.1	Land Rights-Clearing	1,329	811	1		2,141
362	Station Equipment	77,059	1,574	35	(162)	78,507
364	Poles Towers & Fixtures	67,309	5,410	9	(152)	72,575
365	Conductors and Devices	118,910	7,969	20	(122)	126,777
368	Line Transformers	46,985	4,864	-	(481)	51,368
369	Services	6,090				6,090
370	Meters	9,007	1,116		(0)	10,124
371	Installation on Customers' Premises	938				938
373	Street Lighting and Signal System	2,068	886	-	(26)	2,928
		330,275	22,722	66	(944)	352,120
	General Plant					
389	Land	1,314		741		2,055
390	Structures-Frame & Iron	337				337
390.1	Structures-Masonry	17,876	116	(2)	(20)	17,970
391	Office Furniture & Equipment	3,844	601		(62)	4,383
391.1	Computer Equipment	30,957	1,083		(437)	31,603
392	Transportation Equipment	5,696	214	(35)		5,874
394	Tools and Work Equipment	6,508	518			7,026
397	Communication Structures and Equipment	7,229	316	2		7,547
		73,761	2,848	706	(519)	76,795
101	Plant in Service	630,676	80,628	741	(2,283)	709,762
107.1	Plant under construction not subject to AFUDC	3,959				3,186
107.2	Plant under construction subject to AFUDC	21,514				32,241
114	Utility Plant Acquisition Adjustment	11,912				11,912
105	Plant held for future use	741		(741)		-
105	Utility Plant per Balance Sheet	668,802				757,102

Note: Differences due to rounding.

UTILITY PLANT IN SERVICE
AS AT DECEMBER 31, 2005

Line	Account		December 31 2004	Additions	Retirements	December 31 2005
				($000s)		
		Hydraulic Production Plants 2, 3, & 4				
1	330.1	Land Rights	15	21	-	36
2	331	Structures and Improvements	9,191	303	(52)	9,443
3	332	Reservoirs, Dams & Waterways	11,971	159	(2)	12,128
4	333	Water Wheels, Turbines and Gen.	29,046	227		29,273
5	334	Accessory Equipment	16,103	70	(5)	16,167
6	335	Other Power Plant Equipment	27,625	847	(21)	28,451
7	336	Roads, Railroads and Bridges	1,046		-	1,046
8			94,997	1,627	(80)	96,544
9		Hydraulic Production Plant #1 Plant				
10	330.1	Land Rights	84	-	-	84
11	331	Structures and Improvements	592	133		725
12	332	Reservoirs, Dams & Waterways	2,580	84	(367)	2,297
13	333	Water Wheels, Turbines and Gen.	7,655	-	-	7,655
14	334	Accessory Equipment	1,530	35	(65)	1,501
15	335	Other Power Plant Equipment	8,376	75	(55)	8,396
16			20,817	328	(487)	20,658
17		Other Production Plant				
18	346	Other Power Plant Equipment	1,353	-	(1,353)	-
19						
20		Transmission Plant				
21	350.1	Land Rights-R/W	5,802	985		6,787
22	350.1	Land Rights-Clearing	3,202	1,090		4,292
23	353	Station Equipment	56,096	47,660		103,756
24	355	Poles Towers & Fixtures	48,120	6,231	(64)	54,287
25	356	Conductors and Devices	49,701	4,767		54,468
26	359	Roads and Trails	760	57	-	817
27			163,681	60,790	(64)	224,407
28		Distribution Plant				
29	360.1	Land Rights-R/W	671	351	-	1,022
30	360.1	Land Rights-Clearing	2,141	364		2,505
31	362	Station Equipment	78,507	9,620		88,127
32	364	Poles Towers & Fixtures	72,575	7,815	(124)	80,266
33	365	Conductors and Devices	126,777	11,363	(274)	137,866
34	368	Line Transformers	51,368	6,211	(578)	57,001
35	369	Services	6,090			6,090
36	370	Meters	10,124	874	(1)	10,997
37	371	Installation on Customers' Premises	938	-		938
38	373	Street Lighting and Signal System	2,928	1,088	(23)	3,992
39			352,120	37,685	(1,000)	388,805
40		General Plant				
41	389	Land	2,055	9	(11)	2,053
42	390	Structures-Frame & Iron	337	-		337
43	390.1	Structures-Masonry	17,970	1,198	(19)	19,150
44	391	Office Furniture & Equipment	4,383	315	(9)	4,689
45	391.1	Computer Equipment	31,603	2,902	(199)	34,306
46	392	Transportation Equipment	5,874	2,923		8,797
47	394	Tools and Work Equipment	7,026	759		7,785
48	397	Communication Structures and Equipment	7,547	5,360		12,907
49			76,795	13,466	(238)	90,023
50						
51	101	Plant in Service	709,762	113,896	(3,222)	820,437
52	107.1	Plant under construction not subject				
53		to AFUDC	7,705			9,869
54	107.2	Plant under construction				
55		subject to AFUDC	32,241			29,490
56	114	Utility Plant Acquisition Adjustment	11,912			11,912
57	105	Plant held for future use	-			
58						
59	105	Utility Plant per Balance Sheet	761,620			871,708

Note: Differences due to rounding.

UTILITY PLANT IN SERVICE

AS AT DECEMBER 31, 2006

Line	Account		December 31 2005	Additions	Retirements	December 31 2006
		Hydraulic Production Plants 1,2, 3, & 4		(000s)		
1	330	Land Rights	120	-	-	120
2	331	Structures and Improvements	10,168	173	(4)	10,337
3	332	Reservoirs, Dams & Waterways	14,425	2,898	(3)	17,320
4	333	Water Wheels, Turbines and Gen.	36,928	10,137	(1)	47,064
5	334	Accessory Equipment	17,668	2,101	(38)	19,731
6	335	Other Power Plant Equipment	36,847	777	-	37,624
7	336	Roads, Railroads and Bridges	1,046	7	-	1,053
8			117,202	16,093	(46)	133,249
9		Transmission Plant				
10	350.1	Land Rights-R/W	6,787	292	-	7,079
11	350.1	Land Rights-Clearing	4,292	72		4,364
12	353	Station Equipment	103,756	12,993	(496)	116,253
13	355	Poles Towers & Fixtures	54,287	2,764	(50)	57,001
14	356	Conductors and Devices	54,468	2,557		57,025
15	359	Roads and Trails	817	-	-	817
16			224,407	18,678	(546)	242,539
17		Distribution Plant				
18	360.1	Land Rights-R/W	1,022	427	-	1,449
19	360.1	Land Rights-Clearing	2,505	995		3,500
20	362	Station Equipment	88,127	16,008	(780)	103,355
21	364	Poles Towers & Fixtures	80,266	11,425	(249)	91,442
22	365	Conductors and Devices	137,866	18,284	(418)	155,732
23	368	Line Transformers	57,001	13,537	(943)	69,595
24	369	Services	6,090	-	-	6,090
25	370	Meters	10,997	782	(508)	11,271
26	371	Installation on Customers' Premises	938	-	-	938
27	373	Street Lighting and Signal System	3,992	1,602	(49)	5,545
28			388,805	63,060	(2,947)	448,917
29		General Plant				
30	389	Land	2,053	1,466	-	3,519
31	390	Structures-Frame & Iron	337	-	-	337
32	390.1	Structures-Masonry	19,150	1,104	(12)	20,242
33	391	Office Furniture & Equipment	4,689	243	-	4,932
34	391.1	Computer Equipment	34,306	5,605	(196)	39,715
35	392	Transportation Equipment	8,797	3,337	(404)	11,730
36	394	Tools and Work Equipment	7,785	860	-	8,645
37	397	Communication Structures and Equipment	12,907	1,710	(130)	14,487
38			90,023	14,325	(742)	103,607
39						
40	101	Plant in Service	820,437	112,156	(4,281)	928,312
41	107.1	Plant under construction not subject				
42		to AFUDC	9,869			7,381
43	107.2	Plant under construction				
44		subject to AFUDC	29,490			25,827
45	114	Utility Plant Acquisition Adjustment	11,912			11,912
46	105	Plant held for future use	-			-
47						
48	105	Utility Plant per Balance Sheet	871,708			973,432

Note: Differences due to rounding.

UTILITY PLANT IN SERVICE

AS AT DECEMBER 31, 2007

Line	Account		December 31 2006	December 31 2006 PLP	January 1 2007	Additions	Retirements	December 31 2007
		Hydraulic Production Plants 1,2, 3, & 4			(000s)			
1	330	Land Rights	120		120	727	-	847
2	331	Structures and Improvements	10,337		10,337	621	(11)	10,947
3	332	Reservoirs, Dams & Waterways	17,320		17,320	2,189	(76)	19,433
4	333	Water Wheels, Turbines and Gen.	47,064		47,064	7,806	(367)	54,503
5	334	Accessory Equipment	19,731		19,731	2,773	(133)	22,370
6	335	Other Power Plant Equipment	37,624		37,624	684	(31)	38,277
7	336	Roads, Railroads and Bridges	1,053		1,053	-	-	1,053
8			133,249	-	133,249	14,799	(617)	147,430
9		Transmission Plant						
10	350.1	Land Rights-R/W	7,079		7,079	-	-	7,079
11	350.1	Land Rights-Clearing	4,364		4,364	132		4,496
12	353	Station Equipment	116,253		116,253	19,201	(76)	135,378
13	355	Poles Towers & Fixtures	57,001		57,001	8,143	(2)	65,142
14	356	Conductors and Devices	57,025		57,025	5,575	-	62,601
15	359	Roads and Trails	817		817	-	-	817
16			242,539	-	242,539	33,051	(78)	275,513
17		Distribution Plant						
18	360.1	Land Rights-R/W	1,449	79	1,528	208	-	1,736
19	360.1	Land Rights-Clearing	3,500	653	4,153	1,703		5,856
20	362	Station Equipment	103,355	296	103,651	11,877	(233)	115,295
21	364	Poles Towers & Fixtures	91,442	4,447	95,889	9,788	(285)	105,392
22	365	Conductors and Devices	155,732	3,718	159,450	16,964	(429)	175,985
23	368	Line Transformers	69,595	2,052	71,647	13,078	(1,026)	83,699
24	369	Services	6,090	1,202	7,292	-	-	7,292
25	370	Meters	11,271	715	11,986	1,023	(255)	12,754
26	371	Installation on Customers' Premises	938	-	938	-	-	938
27	373	Street Lighting and Signal System	5,545	146	5,691	1,679	(53)	7,318
28			448,917	13,308	462,225	56,320	(2,281)	516,264
29		General Plant						
30	389	Land	3,519		3,519	2,281	-	5,800
31	390	Structures-Frame & Iron	337		337		-	337
32	390.1	Structures-Masonry	20,242	802	21,044	1,922	-	22,966
33	391	Office Furniture & Equipment	4,932	54	4,986	247	-	5,233
34	391.1	Computer Equipment	39,715	206	39,921	2,707	(449)	42,179
35	392	Transportation Equipment	11,730	935	12,665	4,431	(649)	16,447
36	394	Tools and Work Equipment	8,645	303	8,948	936	-	9,884
37	397	Communication Structures and Equipment	14,487		14,487	5,529		20,016
38			103,607	2,300	105,907	18,054	(1,098)	122,863
39								
40	101	Plant in Service	928,312	15,608	943,920	122,224	(4,074)	1,062,070
41	107.1	Plant under construction not subject						
42		to AFUDC	7,381		7,381			13,112
43	107.2	Plant under construction						
44		subject to AFUDC	25,827		25,827			44,956
45	114	Utility Plant Acquisition Adjustment	11,912		11,912			11,912
46	105	Plant held for future use	-		-			-
47								
48	105	Utility Plant per Balance Sheet	973,432		989,040			1,132,050

Note: Differences due to rounding.

UTILITY PLANT IN SERVICE

AS AT DECEMBER 31, 2008

Line	Account		December 31 2007	Additions	Retirements	December 31 2008
		Hydraulic Production Plant		($000s)		
1	330	Land Rights	847	-	-	847
2	331	Structures and Improvements	10,947	333	-	11,280
3	332	Reservoirs, Dams & Waterways	19,433	1,611	(5)	21,040
4	333	Water Wheels, Turbines and Gen.	54,503	2,223	(181)	56,545
5	334	Accessory Equipment	22,370	683	(142)	22,911
6	335	Other Power Plant Equipment	38,277	102	(30)	38,349
7	336	Roads, Railroads and Bridges	1,053	-	-	1,053
8			147,430	4,952	(358)	152,024
9		**Transmission Plant**				
10	350	Land Rights	7,079	-	-	7,079
11	350.1	Land Rights - Clearing	4,496	-	-	4,496
12	353	Station Equipment	135,378	32,151	-	167,529
13	355	Poles Towers & Fixtures	65,142	9,372	(15)	74,499
14	356	Conductors and Devices	62,601	9,354	-	71,955
15	359	Roads and Trails	817	-	-	817
16			275,513	50,876	(15)	326,374
17		**Distribution Plant**				
18	360	Land Rights	1,736	1,250	-	2,986
19	360.1	Land Rights - Clearing	5,856	1,250	-	7,106
20	362	Station Equipment	115,295	1,720	(73)	116,942
21	364	Poles Towers & Fixtures	105,392	9,172	(354)	114,210
22	365	Conductors and Devices	175,985	11,144	(588)	186,542
23	368	Line Transformers	83,699	6,695	(1,462)	88,933
24	369	Services	7,292	-	-	7,292
25	370	Meters	12,754	733	(298)	13,189
26	371	Installation on Customers' Premises	938	4,398	-	5,336
27	373	Street Lighting and Signal System	7,318	-	(46)	7,272
28			516,264	36,363	(2,821)	549,806
29		**General Plant**				
30	389	Land	5,800	-	-	5,800
31	390	Structures-Frame & Iron	337	-	-	337
32	390.1	Structures-Masonry	22,966	1,567	-	24,533
33	391	Office Furniture & Equipment	5,233	363	(1)	5,596
34	391.1	Computer Equipment	42,179	8,961	(163)	50,977
35	392	Transportation Equipment	16,447	1,628	(1,512)	16,563
36	394	Tools and Work Equipment	9,884	682	-	10,566
37	397	Communication Structures and Equipment	20,016	2,864	-	22,880
38			122,863	16,065	(1,675)	137,252
39						
40	101	**Plant in Service**	1,062,070	108,256	(4,869)	1,165,457
41	107.1	Plant under construction not subject				
42		to AFUDC	13,112			7,214
43	107.2	Plant under construction				
44		subject to AFUDC	44,956			54,177
45	114	Utility Plant Acquisition Adjustment	11,912			11,912
46	105	Plant held for future use	-			-
47						
48	105	Utility Plant per Balance Sheet	1,132,050			1,238,760

Note: Differences due to rounding.

UTILITY PLANT IN SERVICE

AS AT DECEMBER 31, 2009

Line	Account		December 31 2008	Additions	Retirements & Reclass	December 31 2009
		Hydraulic Production Plant		($000s)		
1	330	Land Rights	847	-	115	962
2	331	Structures and Improvements	11,280	295	439	12,014
3	332	Reservoirs, Dams & Waterways	21,040	1,549	1,855	24,444
4	333	Water Wheels, Turbines and Gen.	56,545	8,256	(3,419)	61,382
5	334	Accessory Equipment	22,911	4,883	(301)	27,493
6	335	Other Power Plant Equipment	38,349	2,308	236	40,893
7	336	Roads, Railroads and Bridges	1,053	-	234	1,287
8			152,024	17,292	(840)	168,476
9		**Transmission Plant**				
10	350	Land Rights	7,079	116	10	7,205
11	350.1	Land Rights - Clearing	4,496	450	852	5,798
12	353	Station Equipment	167,529	1,766	(31,060)	138,235
13	355	Poles Towers & Fixtures	74,499	4,498	(6,370)	72,627
14	356	Conductors and Devices	71,955	4,735	(6,241)	70,448
15	359	Roads and Trails	817	304	-	1,121
16			326,374	11,870	(42,809)	295,435
17		**Distribution Plant**				
18	360	Land Rights	2,986	338	(868)	2,456
19	360.1	Land Rights - Clearing	7,106	2,113	(742)	8,477
20	362	Station Equipment	116,942	32,446	31,843	181,231
21	364	Poles Towers & Fixtures	114,210	10,240	2,529	126,978
22	365	Conductors and Devices	186,542	15,691	6,754	208,987
23	368	Line Transformers	88,933	7,679	1,845	98,457
24	369	Services	7,292	-	-	7,292
25	370	Meters	13,189	665	(577)	13,277
26	371	Installation on Customers' Premises	5,336	-	(4,398)	938
27	373	Street Lighting and Signal System	7,272	1,312	1,691	10,275
28			549,806	70,484	38,077	658,368
29		**General Plant**				
30	389	Land	5,800	4,589	909	11,297
31	390	Structures-Frame & Iron	337	-	-	337
32	390.1	Structures-Masonry	24,533	1,614	(63)	26,083
33	391	Office Furniture & Equipment	5,596	5	(127)	5,475
34	391.1	Computer Equipment	50,977	5,837	71	56,886
35	392	Transportation Equipment	16,563	2,342	(1,353)	17,552
36	394	Tools and Work Equipment	10,566	658	(355)	10,869
37	397	Communication Structures and Equipment	22,880	1,083	(1,264)	22,698
38			137,252	16,127	(2,182)	151,197
39						
40	101	**Plant in Service**	1,165,457	115,773	(7,754)	1,273,476
41	107.1	Plant under construction not subject				
42		to AFUDC	7,214			5,913
43	107.2	Plant under construction				
44		subject to AFUDC	54,177			52,429
45	114	Utility Plant Acquisition Adjustment	11,912			11,912
46	105	Utility Plant per Balance Sheet	1,238,760			1,343,729

Note: Minor differences due to rounding

UTILITY PLANT IN SERVICE

AS AT DECEMBER 31, 2010

Line	Account		December 31 2009	Additions	Retirements & Reclass	December 31 2010
		Hydraulic Production Plant		($000s)		
1	330	Land Rights	962	-	-	962
2	331	Structures and Improvements	12,014	596	(2)	12,609
3	332	Reservoirs, Dams and Waterways	24,444	2,210	(10)	26,644
4	333	Water Wheels, Turbines and Gen.	61,382	12,327	(262)	73,448
5	334	Accessory Equipment	27,493	5,819	(379)	32,934
6	335	Other Power Plant Equipment	40,893	756	(7)	41,642
7	336	Roads, Railroads and Bridges	1,287	-	-	1,287
8			168,476	21,708	(659)	189,525
9		**Transmission Plant**				
10	350	Land Rights	7,205	66	-	7,271
11	350.1	Land Rights - Clearing	5,798	438	-	6,236
12	353	Station Equipment	138,235	12,766	(77)	150,925
13	355	Poles, Towers and Fixtures	72,627	20,100	(3,693)	89,033
14	356	Conductors and Devices	70,448	20,119	(3,664)	86,903
15	359	Roads and Trails	1,121	-	-	1,121
16			295,435	53,488	(7,434)	341,489
17		**Distribution Plant**				
18	360	Land Rights	2,456	232	-	2,689
19	360.1	Land Rights - Clearing	8,477	1,486	-	9,964
20	362	Station Equipment	181,231	18,301	(446)	199,086
21	364	Poles, Towers and Fixtures	126,978	10,917	(398)	137,498
22	365	Conductors and Devices	208,987	16,740	(770)	224,957
23	368	Line Transformers	98,457	7,659	(1,384)	104,732
24	369	Services	7,292	-	-	7,292
25	370	Meters	13,277	526	(210)	13,593
26	371	Installation on Customers' Premises	938	-	-	938
27	373	Street Lighting and Signal System	10,275	1,258	(47)	11,485
28			658,368	57,121	(3,255)	712,234
29		**General Plant**				
30	389	Land	11,297	796	-	12,093
31	390	Structures-Frame and Iron	337	-	-	337
32	390.1	Structures-Masonry	26,083	961	-	27,045
33	391	Office Furniture and Equipment	5,475	255	-	5,729
34	391.1	Computer Equipment	56,886	6,100	(111)	62,875
35	392	Transportation Equipment	17,552	932	(729)	17,755
36	394	Tools and Work Equipment	10,869	495	(68)	11,296
37	397	Communication Structures and Equipment	22,698	540	-	23,238
38			151,197	10,079	(908)	160,368
39						
40	101	**Plant in Service**	1,273,476	142,396	(12,256)	1,403,617
41	107.1	Plant under construction not subject				
42		to AFUDC	5,913			7,213
43	107.2	Plant under construction				
44		subject to AFUDC	52,429			50,769
45	114	Utility Plant Acquisition Adjustment	11,912			11,912
46	105	Utility Plant per Balance Sheet	1,343,729			1,473,511

Note: Minor differences due to rounding.

UTILITY PLANT IN SERVICE

AS AT DECEMBER 31, 2011

Line	Account		December 31 2010	Additions	Retirements & Reclass	December 31 2011
		Hydraulic Production Plant		($000s)		
1	330	Land Rights	962	-	-	962
2	331	Structures and Improvements	12,609	184	-	12,793
3	332	Reservoirs, Dams & Waterways	26,644	705	-	27,349
4	333	Water Wheels, Turbines and Gen.	73,448	20,665	-	94,113
5	334	Accessory Equipment	32,934	6,649	(593)	38,990
6	335	Other Power Plant Equipment	41,642	255	-	41,897
7	336	Roads, Railroads and Bridges	1,287	-	-	1,287
8			189,525	28,458	(593)	217,390
9		**Transmission Plant**				
10	350	Land Rights	7,271	40	-	7,311
11	350.1	Land Rights - Clearing	6,236	40	-	6,276
12	353	Station Equipment	150,925	32,617	(2,068)	181,474
13	355	Poles Towers & Fixtures	89,033	2,845	(80)	91,799
14	356	Conductors and Devices	86,903	2,798	(80)	89,621
15	359	Roads and Trails	1,121	-	-	1,121
16			341,489	38,342	(2,228)	377,603
17		**Distribution Plant**				
18	360	Land Rights	2,689	200	-	2,889
19	360.1	Land Rights - Clearing	9,964	53	-	10,017
20	362	Station Equipment	199,086	26,346	(1,633)	223,800
21	364	Poles Towers & Fixtures	137,498	7,924	(183)	145,239
22	365	Conductors and Devices	224,957	12,265	(300)	236,922
23	368	Line Transformers	104,732	6,792	(729)	110,795
24	369	Services	7,292	-	-	7,292
25	370	Meters	13,593	809	(300)	14,102
26	371	Installation on Customers' Premises	938	-	-	938
27	373	Street Lighting and Signal System	11,485	747	(23)	12,208
28			712,234	55,136	(3,168)	764,202
29		**General Plant**				
30	389	Land	12,093	63	-	12,157
31	390	Structures-Frame & Iron	337	-	-	337
32	390.1	Structures-Masonry	27,045	1,345	-	28,390
33	391	Office Furniture & Equipment	5,729	173	-	5,902
34	391.1	Computer Equipment	62,875	6,452	(193)	69,134
35	392	Transportation Equipment	17,755	3,509	(264)	21,000
36	394	Tools and Work Equipment	11,296	492	(4)	11,784
37	397	Communication Structures and Equipment	23,238	694	-	23,932
38			160,368	12,728	(461)	172,635
39						
40	101	**Plant in Service**	1,403,617	134,663	(6,450)	1,531,831
41	107.1	Plant under construction not subject				
42		to AFUDC	7,213			7,488
43	107.2	Plant under construction				
44		subject to AFUDC	50,769			4,197
45	114	Utility Plant Acquisition Adjustment	11,912			11,912
46	105	Utility Plant per Balance Sheet	1,473,511			1,555,427

Note: Minor differences due to rounding.

UTILITY PLANT IN SERVICE

AS AT DECEMBER 31, 2012

Line	Account		December 31 2011	Additions	Retirements & Reclass	December 31 2012
		Hydraulic Production Plant		($000s)		
1	330	Land Rights	962	-	-	962
2	331	Structures and Improvements	12,793	1,026	(13)	13,805
3	332	Reservoirs, Dams & Waterways	27,349	2,081	(73)	29,357
4	333	Water Wheels, Turbines & Gen.	94,113	1,387	(2)	95,497
5	334	Accessory Equipment	38,990	3,474	(447)	42,017
6	335	Other Power Plant Equipment	41,897	1,508	(380)	43,024
7	336	Roads, Railroads and Bridges	1,287	-	-	1,287
8			217,390	9,475	(916)	225,949
9		**Transmission Plant**				
10	350	Land Rights	7,311	1,397	-	8,708
11	350.1	Land Rights - Clearing	6,276	1,704	-	7,981
12	353	Station Equipment	181,474	(8,249)	(68)	173,158
13	355	Poles, Towers & Fixtures	91,799	2,234	(90)	93,943
14	356	Conductors and Devices	89,621	2,235	(105)	91,751
15	359	Roads and Trails	1,121	-	-	1,121
16			377,603	(678)	(263)	376,663
17		**Distribution Plant**				
18	360	Land Rights	2,889	394	-	3,283
19	360.1	Land Rights - Clearing	10,017	195	-	10,212
20	362	Station Equipment	223,800	18,934	(104)	242,630
21	364	Poles, Towers & Fixtures	145,239	7,785	(462)	152,562
22	365	Conductors and Devices	236,922	11,968	(376)	248,514
23	368	Line Transformers	110,795	5,579	(965)	115,409
24	369	Services	7,292	-	-	7,292
25	370	Meters	14,102	673	(514)	14,261
26	371	Installation on Customers' Premises	938	-	-	938
27	373	Street Lighting and Signal System	12,208	23	(57)	12,174
28			764,202	45,551	(2,479)	807,275
29		**General Plant**				
30	389	Land	12,157	(3,007)	-	9,150
31	390	Structures-Frame & Iron	337	-	-	337
32	390.1	Structures-Masonry	28,390	1,698	-	30,087
33	391	Office Furniture & Equipment	5,902	113	-	6,015
34	391.1	Computer Equipment	69,134	4,776	(128)	73,783
35	392	Transportation Equipment	21,000	1,959	(781)	22,178
36	394	Tools and Work Equipment	11,784	531	(86)	12,229
37	397	Communication Structures and Equipment	23,932	2,307	-	26,239
38			172,635	8,377	(994)	180,018
39						
40	101	**Plant in Service**	1,531,831	62,725	(4,651)	1,589,904
41	107.1	Plant under construction not subject				
42		to AFUDC	7,488			8,136
43	107.2	Plant under construction				
44		subject to AFUDC	4,197			5,503
45	114	Utility Plant Acquisition Adjustment	11,912			11,912
46	105	Utility Plant per Balance Sheet	1,555,427			1,615,456

Note: Minor differences due to rounding.

Attachment 15.13

ELECTRIC OPERATING AND MAINTENANCE EXPENSE

Acct.		2001	2000	Change
			(000s)	
	GENERATION			
535R	Supervision & Administration	$ 278	$ 297	$ (19)
536	Water Fees	7,178	7,157	21
542	Structures	611	642	(31)
543	Dams and Waterways	104	281	(177)
544	Electric Plant	265	239	26
545	Other Plant	169	284	(115)
		8,604	8,900	(296)
	OTHER POWER SUPPLY			
555	Purchased Power	51,051	47,659	3,392
556	System Control	578	645	(67)
		51,629	48,304	3,325
	TRANSMISSION & DISTRIBUTION			
560R-1	Supervision & Administration	1,921	1,945	(24)
560R-2	System Planning	372	871	(499)
561	Load Dispatching	518	686	(168)
562	Transmission Station Expense	889	800	89
563R-1	Transmission Line Maintenance	286	156	130
563R-2	Transmission ROW Maintenance	555	653	(98)
565	Wheeling	4,334	3,601	733
567	Rents	239	239	-
583R-1	Distribution Line Maintenance	2,012	1,784	228
583R-2	Distribution ROW Maintenance	1,438	1,154	284
586	Meter Expenses	839	295	544
587	Customer Installations	236	513	(277)
592	Distribution Station Expense	458	813	(355)
596	Street Lighting	220	138	82
598	Other Plant	15	52	(37)
		14,334	13,702	634

ELECTRIC OPERATING AND MAINTENANCE EXPENSE

Acct.		2003	2002	Change
	GENERATION			
535R	Supervision & Administration	$ 757	$ 391	$ 366
536	Water Fees	7,370	7,120	250
542	Structures	568	636	(68)
543	Dams and Waterways	161	88	73
544	Electric Plant	383	337	46
545	Other Plant	394	216	178
		9,633	8,788	845
	OTHER POWER SUPPLY			
555	Purchased Power	58,436	52,261	6,175
556	System Control	732	445	287
		59,168	52,706	6,462
	TRANSMISSION & DISTRIBUTION			
560R-1	Supervision & Administration	2,460	2,254	206
560R-2	System Planning	1,272	681	591
561	Load Dispatching	873	935	(62)
562	Transmission Station Expense	659	663	(4)
563R-1	Transmission Line Maintenance	129	133	(4)
563R-2	Transmission ROW Maintenance	353	657	(304)
565	Wheeling	3,727	3,996	(269)
567	Rents	239	239	-
583R-1	Distribution Line Maintenance	707	1,004	(297)
583r-2	Distribution ROW Maintenance	1,219	1,172	47
586	Meter Expenses	633	970	(337)
587	Customer Installations	-	28	(28)
592	Distribution Station Expense	1,060	1,118	(58)
596	Street Lighting	35	256	(221)
		13,366	14,108	(742)

ELECTRIC OPERATING AND MAINTENANCE EXPENSE

FOR THE YEAR ENDING DECEMBER 31, 2005

	Acct.		2005	2004 [(1)]	Change
				($000s)	
1		GENERATION			
2	535R	Supervision & Administration	664	887	(223)
3	536	Water Fees	7,679	7,399	280
4	542	Structures	650	756	(106)
5	543	Dams and Waterways	71	66	5
6	544	Electric Plant	412	505	(93)
7	545	Other Plant	409	204	205
8			9,885	9,819	66
9					
10		OTHER POWER SUPPLY			
11	555	Purchased Power	60,404	59,014	1,390
12	556	System Control	675	660	15
13			61,079	59,674	1,405
14		TRANSMISSION & DISTRIBUTION			
15	560R-1	Supervision & Administration	(30)	(26)	(4)
16	560R-2	System Planning	952	937	15
17	561	Load Dispatching	895	874	21
18	562	Transmission Station Expense	376	274	102
19	563R-1	Transmission Line Maintenance	125	61	64
20	563R-2	Transmission ROW Maintenance	640	982	(342)
21	565	Wheeling	3,956	3,831	125
22	567	Rents [(2)]	2,961	3,216	(255)
23					
24	583R-1	Distribution Line Maintenance	2,207	1,297	910
25	583r-2	Distribution ROW Maintenance	1,189	1,094	95
26	586	Meter Expenses	753	681	72
27	587	Customer Installations	-	-	-
28	592	Distribution Station Expense	1,032	466	566
29	596	Street Lighting	91	245	(154)
30	598	Other Plant	322	204	118
31			15,469	14,136	1,333

[(1)] *2004 expenses have been restated among accounts to improve consistency of reporting. Total O&M expense is unchanged.*

[(2)] *Account 567 Rents includes Teck Cominco transmission facilities rental in 2003 and 2004, and lease of the Brilliant Terminal Station beginning in 2004.*

ELECTRIC OPERATING AND MAINTENANCE EXPENSE

FOR THE YEAR ENDING DECEMBER 31, 2007

	Acct.		2007	2006	Change
1		GENERATION			
2	535R	Supervision & Administration	586	370	216
3	536	Water Fees	7,918	8,371	(453)
4	542	Structures	552	653	(101)
5	543	Dams & Waterways	203	239	(36)
6	544	Electric Plant	352	272	80
7	545	Other Plant	235	595	(360)
8			9,846	10,499	(653)
9					
10		OTHER POWER SUPPLY			
11	555	Purchased Power	66,629	67,576	(947)
12	556	System Control	960	713	247
13			67,589	68,289	(700)
14					
15		TRANSMISSION & DISTRIBUTION			
16	560R-1	Supervision & Administration	1,171	1,149	22
17	560R-2	System Planning	948	1,004	(56)
18	561	Load Dispatching	1,272	945	327
19	562	Transmission Station Expense	623	668	(45)
20	563R-1	Transmission Line Maintenance	171	89	82
21	563R-2	Transmission ROW Maintenance	650	654	(4)
22	565	Wheeling	3,471	3,840	(369)
23	567	Rents	3,268	2,503	765
24					0
25	583R-1	Distribution Line Maintenance	2,545	2,254	291
26	583R-2	Distribution ROW Maintenance	1,516	1,595	(79)
27	586	Meter Expenses	1,027	906	121
28	587	Customer Installations	0	0	0
29	592	Distribution Station Expense	1,112	832	280
30	596	Street Lighting	70	66	4
31	598	Other Plant	255	195	60
32			18,099	16,698	1,401
33					
34		CUSTOMER SERVICE			
35	901	Supervision & Administration	855	826	29
36	902	Meter Reading	1,841	1,702	139
37	903	Customer Billing	597	408	189
38	904	Credit & Collections	1,002	1,427	(425)
39	910	Customer Assistance	1,940	1,867	73
40	911	Energy Management Promotion	0	0	0
41			6,235	6,230	5

ELECTRIC OPERATING AND MAINTENANCE EXPENSE

FOR THE YEAR ENDING DECEMBER 31, 2009

	Acct.		2009	2008	Change
				($000s)	
1		GENERATION			
2	535R	Supervision & Administration	791	360	431
3	536	Water Fees	8,656	7,878	778
4	542	Structures	637	596	41
5	543	Dams & Waterways	117	168	(50)
6	544	Electric Plant	443	504	(61)
7	545	Other Plant	211	254	(43)
8			10,854	9,759	1,095
9					
10		OTHER POWER SUPPLY			
11	555	Purchased Power	70,776	66,010	4,766
12	556	System Control	1,646	1,371	275
13			72,422	67,381	5,041
14					
15		TRANSMISSION & DISTRIBUTION			
16	560R-1	Supervision & Administration	886	616	270
17	560R-2	System Planning	1,290	1,321	(31)
18	561	Load Dispatching	1,182	1,099	82
19	562	Transmission Station Expense	782	713	69
20	563R-1	Transmission Line Maintenance	127	296	(169)
21	563R-2	Transmission ROW Maintenance	472	505	(34)
22	565	Wheeling	4,003	3,655	348
23	567	Rents	3,100	3,252	(151)
24					-
25	583R-1	Distribution Line Maintenance	3,263	3,294	(32)
26	583R-2	Distribution ROW Maintenance	1,741	1,628	112
27	586	Meter Expenses	999	922	77
28	592	Distribution Station Expense	1,304	1,153	151
29	596	Street Lighting	96	85	12
30	598	Other Plant	353	273	79
31			19,596	18,813	784
32					
33		CUSTOMER SERVICE			
34	901	Supervision & Administration	831	769	62
35	902	Meter Reading	1,763	1,762	1
36	903	Customer Billing	669	654	15
37	904	Credit & Collections	625	1,299	(674)
38	910	Customer Assistance	2,240	1,927	313
39			6,129	6,411	(283)

Note: Minor differences due to rounding.

ELECTRIC OPERATING AND MAINTENANCE EXPENSE

FOR THE YEAR ENDING DECEMBER 31, 2011

Line	Account		2011	2010	Change
				($000s)	
1		GENERATION			
2	535R	Supervision & Administration	666	584	82
3	536	Water Fees	9,047	9,256	(209)
4	542	Structures	697	651	47
5	543	Dams & Waterways	270	204	65
6	544	Electric Plant	534	627	(93)
7	545	Other Plant	271	134	137
8			11,485	11,456	29
9					
10		OTHER POWER SUPPLY			
11	555	Purchased Power	71,519	71,964	(446)
12	556	System Control	1,805	1,653	152
13			73,324	73,617	(293)
14					
15		TRANSMISSION & DISTRIBUTION			
16	560R-1	Supervision & Administration	1,634	768	866
17	560R-2	System Planning	2,148	1,450	699
18	561	Load Dispatching	1,193	1,107	86
19	562	Transmission Station Expense	902	658	245
20	563R-1	Transmission Line Maintenance	570	179	391
21	563R-2	Transmission ROW Maintenance	1,218	264	954
22	565	Wheeling	4,281	4,050	231
23	567	Rents	3,033	3,115	(82)
24	583R-1	Distribution Line Maintenance	3,304	2,926	379
25	583R-2	Distribution ROW Maintenance	3,684	2,153	1,531
26	586	Meter Expenses	1,030	986	44
27	592	Distribution Station Expense	1,313	1,273	41
28	596	Street Lighting	78	81	(3)
29	598	Other Plant	249	297	(48)
30			24,639	19,306	5,333
31					
32		CUSTOMER SERVICE			
33	901	Supervision & Administration	1,128	1,224	(95)
34	902	Meter Reading	2,030	1,791	238
35	903	Customer Billing	646	615	30
36	904	Credit & Collections	683	639	45
37	910	Customer Assistance	2,462	2,202	259
38			6,949	6,471	478

Note: Minor differences due to rounding.

ELECTRIC OPERATING AND MAINTENANCE EXPENSE

FOR THE YEAR ENDING DECEMBER 31, 2012

Line	Account		2012	2011	Change
				($000s)	
1		GENERATION			
2	535R	Supervision & Administration	561	666	(106)
3	536	Water Fees	9,253	9,047	206
4	542	Structures	642	697	(55)
5	543	Dams & Waterways	308	270	38
6	544	Electric Plant	574	534	40
7	545	Other Plant	224	271	(47)
8			11,561	11,485	76
9					
10		OTHER POWER SUPPLY			
11	555	Purchased Power	75,999	71,519	4,480
12	556	System Control	1,867	1,805	62
13			77,866	73,324	4,542
14					
15		TRANSMISSION & DISTRIBUTION			
16	560R-1	Supervision & Administration	1,678	1,634	45
17	560R-2	System Planning	2,136	2,148	(13)
18	561	Load Dispatching	1,179	1,193	(14)
19	562	Transmission Station Expense	1,230	902	328
20	563R-1	Transmission Line Maintenance	738	570	168
21	563R-2	Transmission ROW Maintenance	1,506	1,218	288
22	565	Wheeling	4,813	4,281	533
23	567	Rents	3,206	3,033	173
24	583R-1	Distribution Line Maintenance	3,377	3,304	72
25	583R-2	Distribution ROW Maintenance	3,809	3,684	125
26	586	Meter Expenses	918	1,030	(112)
27	592	Distribution Station Expense	1,150	1,313	(164)
28	596	Street Lighting	74	78	(4)
29	598	Other Plant	255	249	6
30			26,069	24,639	1,430
31					
32		CUSTOMER SERVICE			
33	901	Supervision & Administration	1,461	1,128	333
34	902	Meter Reading	2,010	2,030	(20)
35	903	Customer Billing	596	646	(50)
36	904	Credit & Collections	782	683	98
37	910	Customer Assistance	2,306	2,462	(156)
38			7,154	6,949	206

Note: Minor differences due to rounding.

Attachment 19.1.1

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 19.1.2

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 20.1

REFER TO LIVE SPREADSHEET MODELS

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 20.1.1

REFER TO LIVE SPREADSHEET MODELS

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 21.2

REFER TO LIVE SPREADSHEET MODELS

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 26.1

REFER TO LIVE SPREADSHEET MODELS

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(accessible by opening the Attachments Tab in Adobe)

Attachment 34.2

FORTISBC 2008

PERFORMANCE RESULTS

	2008 Target	2008 Result	Weight	Weighted Outcome
Productivity ($ millions)	38.60	38.56	25%	25%
Safety (AIFR)	1.75	2.87	25%	0%
Customer Satisfaction (CSI)	8.70	8.60	20%	17.5%
Reliability (SAIDI)	2.44	2.42	20%	20%
Environment (kWh)	12469	13253	10%	10%

72.5%
OVERALL

Message From John Walker

FortisBC achieved 72.5% on its 2008 corporate scorecard. Our aggressive targets will keep us on track to becoming an industry leader.

We had excellent results in productivity, customer service and reliability. Our new corporate measure, Environment, showed that we can reduce energy consumption through implementing energy saving initiatives. Adding this measure to our corporate scorecard appropriately puts focus on this issue and we showed steady improvement in lowering kWh used. The targets established for the Environment measure were aggressive in this first year. As such, the year end result has been awarded at 10% (full points) in recognition of the positive trending over each quarter. Throughout 2008 we faced a number of challenges. Disappointing safety results were driven by 13 incidents (nine lost time injuries; four medical aids), up from 10 incidents in 2007. I cannot stress enough the importance of safety as our top priority and that every employee return home healthy at the end of the day.

I appreciate the contributions of each and every employee in 2008. I am confident that with continued hard work and focus we will attain our corporate goals for 2009.

FORTISBC 2008

PERFORMANCE RESULTS

How is the incentive payment calculated?
The following formula is used in calculating the final dollar value of your payout:

2008 Base Salary x Incentive Max % x Company 2008 performance
= Incentive payout

Who is eligible for an incentive payment?
All regular permanent non-union employees, hired on or before December 31, 2008, who are on active rolls at year-end, are eligible. Employees must be employed on both December 31, 2008 and on the payment date, which is February 27, 2009, to receive the 2008 incentive payout.

What happens to my incentive if I changed positions during the year?
Your incentive amount will be pro-rated for your incentive payment.

Are new hires eligible?
All regular non-union employees hired on or before December 31 of the incentive year, will receive an incentive payment on a prorated basis.

What if I terminate or retire from the Company before the payout occurs?
Eligible employees must be employed by FortisBC on the payment date to receive the payout.

Is the short term incentive payment treated as pensionable earnings?
Yes, and therefore applicable deductions will be taken.

What about employees on leaves throughout the year?
Incentive amounts have been pro-rated for time actively at work, for reasons such as maternity leaves, disability leaves greater than 30 calendar days (including WCB), and will be paid out upon return from leave.

How will I receive my incentive pay?
Incentives will be paid out on the February 27th pay. You will receive two direct deposit statements, one that captures regular pay and one that captures the incentive payment. Incentive payments will be reflected as "INCENT " on this statement.

Are there any deductions?
Payments are subject to income, CPP, and EI taxes.

Will employees be able to roll a portion of their total incentive into their group RRSP through payroll?
Yes, employees who currently participate in the E*LEX Group RRSP, will have the option of transferring all or part of their STI into their Group RRSP Account. The form is attached to this e-mail and must be submitted to Payroll no later than 4:00 pm February 20, 2009.

Will the incentive targets be changing for 2009?
In 2009, the Short Term Incentive (STI) targets will change. Information on the changes will be sent out shortly.

For more information please contact:
Suzanne Mancer at 250-469-8109

72.5%
OVERALL

FORTISBC

2009

Q4 YEAR END PERFORMANCE RESULTS

Category	Threshold (0%)	Fair (50%)	Good (75%)	Excellent (100%)	Weight	Year End Results	Factor	Weighted Performance
Productivity	Budget $40.30M	Budget -0.5% $40.10M	Budget -1% $39.89M	Budget -2% $39.49M	20%	39.64	91.00%	18.20%
Safety	3 Year Average +5% 2.24	3 Year Average +2.5% 2.18	3 Year Average +0% 2.13	3 Year Average -5% 2.02	25%	1.41	100.00%	25.00%
Customer Satisfaction	Customer Satisfaction Rating of 8.3	Customer Satisfaction Rating of 8.4	Customer Satisfaction Rating of 8.5	Customer Satisfaction Rating of 8.7	20%	8.60	87.50%	17.50%
Reliability	3 Year Average +5% 2.74	3 Year Average +2.5% 2.68	3 Year Average +0% 2.61	3 Year Average -5% 2.48	15%	2.28	100.00%	15.00%
Capital Optimization	Apprvd Cap Plan	-2.5%	-5.0%	-10.0%	20%	-10.51	100.00%	20.00%

95.70%

Year-to-date

Message From John Walker

FortisBC achieved 95.7% for the year 2009 on the corporate scorecard. A year of exceptional results.

Last year we embarked on an aggressive target program to ensure our place as an industry leader. This year superior results were achieved though we faced some very real challenges, in all departments. Reliability and Customer Satisfaction ended the year strongly. Our new measurement, Capital Optimization, was quite aggressive with targets this year and we were able as a team to produce excellent results. As a company we stress Safety as our top priority – the number of recordable incidents in 2009 was 6, a significant improvement from the 13 in the prior year. This is a very positive move towards our ultimate goal of zero (0) incidents. Again – I want to stress the importance of safety and ensuring that all employees return healthy to their families from their work day.

The Board of Directors and I appreciate each employee's contribution in 2009. With hard work and renewed focus we can maintain our corporate goals and exceed them in 2010.

FORTISBC **2010**

Q4 YEAR END PERFORMANCE RESULTS

Category	Threshold (0%)	Fair (50%)	Good (75%)	Excellent (100%)	Weight	Year End Results	Factor	Weighted Performance
Productivity	Budget $40.42M	Budget -0.5% $40.22M	Budget -1% $40.02M	Budget -2% $39.61M	20%	39.19	100.00%	20.00%
Safety	3 Year Average +5% 2.10	3 Year Average +2.5% 2.05	3 Year Average +0% 2.00	3 Year Average -5% 1.90	25%	1.72	100.00%	25.00%
Customer Satisfaction	Customer Satisfaction Rating of 8.3	Customer Satisfaction Rating of 8.4	Customer Satisfaction Rating of 8.5	Customer Satisfaction Rating of 8.7	15%	8.80	100.00%	15.00%
Reliability	3 Year Average +5% 2.52	3 Year Average +2.5% 2.46	3 Year Average +0% 2.40	3 Year Average -5% 2.28	20%	2.84	00.00%	0.00%
Capital Optimization	Apprvd Cap Plan	-2.5%	-5.0%	-10.0%	20%	-9.11	95.55%	19.11%

79.11%
Year-to-date

Message From John Walker

FortisBC achieved 79.11% for 2010 on the corporate scorecard. We had excellent results in productivity, safety, and customer satisfaction.

In its second year as a corporate measure, the targets for Capital Optimization were aggressive and we were able as a team to produce excellent results.

The number of recordable incidents in 2010 was eight, up slightly from the six incidents that were recorded in 2009. Our ultimate goal is zero incidents. Again – I want to stress the importance of safety and ensuring that all employees return healthy to their families from their work day.

As we move towards integrating our two companies, FortisBC and Terasen Gas, we will continue to build upon the successes that we achieved in 2010 and make sure we are well-positioned to meet the challenges of 2011. The Board of Directors and I appreciate each employee's contribution in 2010.

Q4 YEAR END PERFORMANCE RESULTS 2011

Category	Threshold (0%)	Fair (50%)	Good (75%)	Excellent (100%)	Weight	Year End Results	Factor	Weighted Performance
Productivity	Budget $40.42M	Budget -0.5% $40.22M	Budget -1% $40.02M	Budget -2% $39.61M	20%	45.01	99.46%	19.90%
Safety	3 Year Average +5% 2.10	3 Year Average +2.5% 2.05	3 Year Average +0% 2.00	3 Year Average -5% 1.90	25%	1.48	100.00%	25.00%
Customer Satisfaction	Customer Satisfaction Rating of 8.3	Customer Satisfaction Rating of 8.4	Customer Satisfaction Rating of 8.5	Customer Satisfaction Rating of 8.7	15%	8.70	100.00%	15.00%
Reliability	3 Year Average +5% 2.52	3 Year Average +2.5% 2.46	3 Year Average +0% 2.40	3 Year Average -5% 2.28	20%	1.86	100.00%	20.00%
Regulatory	Subjective	-2.5%	-5.0%	-10.0%	20%	15.00	100.00%	20.00%

99.9%

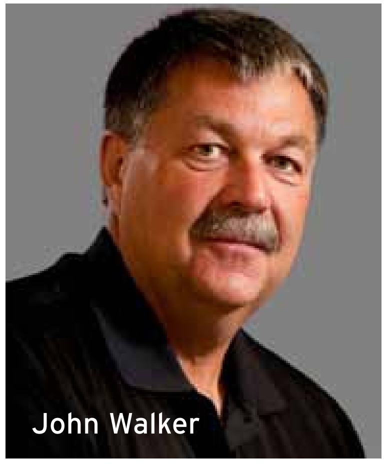
Year-to-date

FortisBC 2012 Electric corporate scorecard

Q4 performance results

FortisBC (Electric) achieved 125.6 per cent for 2012, with the fourth quarter capping a year of solid performance in almost all target areas.

We maintained our focus on customer service throughout the year with satisfaction results consistent with the target. Additionally, SAIDI results were better than the previous three year average.



The Customer Service Index average for the four quarters was 8.4 and measured customers' overall satisfaction with the company, field services, accuracy of meter reading, energy conservation information and contact centre services. Customers indicated that price and reliability were primary areas of concern, however we can continue to improve by focusing on positive drivers such as high first call resolution, friendly and knowledgeable staff and the company's environmental responsibility.

2012 marked a year of improvement for driver safety performance with a lower number of vehicle accidents compared to the previous year. The ongoing focus on the **Drive to Zero** was communicated often and to all employees throughout the year. Still, we must remain vigilant and remember that avoiding preventable accidents is of the utmost importance to FortisBC and should be a priority for all employees. The All Injury Frequency Rate (AIFR) did not meet its target and serves as a reminder of the need to maintain our safety focus in all aspects of our work.

On the regulatory front, 2012 was an intense and successful year. A number of applications proceeded through the regulatory process, such as the Advanced Metering Infrastructure project and the 2012/2013 Revenue Requirement application, the largest and most complex filing that the company has undertaken in recent history. The electric division filed nine major applications, responding to over 5,000 information requests, continuing the upward trend from 3,000 in 2011 and 2,300 in 2010. In total, 174 different BCUC filings were completed.

As we move forward on all major aspects of our business and focus our productivity, this scorecard will continue to serve as a gauge by which to measure our success.

Customer satisfaction

Customer service results were 8.4. Customers have indicated satisfaction through FortisBC's high first call resolutions, knowledgeable staff and environmental responsibility.

Safety

Vehicle accidents remained on track in the fourth quarter, with the annual results achieving a top-out rating while the AIFR did not meet the annual target.

Regulatory

Work continued on moving forward the Advanced Metering Infrastructure project with the company responding to information requests during the quarter. An application was also filed with the BCUC seeking approval for the purchase of the City of Kelowna distribution assets. Approval by the BCUC would result in approximately 15,000 customers located in central Kelowna becoming FortisBC customers.

Financial

We finished the year with strong financial results. Regulated earnings totalled $48.5 million, more than our target of $44.1 million and greater than the $47.5 million earned in 2011.

Q4 fourth quarter performance results

Category	Measurement	Target	Results	Status
Customer	Customer Service Index (CSI)	8.5	8.4 (9.38%)	Below target
	System average interruption duration index (SAIDI)	2.33	1.95 (18.75%)	Ahead of target
Safety	All Injury Frequency Rate (AIFR)	1.54	1.72 (0.0%)	Below target
	Recordable vehicle incidents	31	22 (15.0%)	Ahead of target
Regulatory	Regulatory Performance	Subjective	(37.5%)	Ahead of target
Financial	Regulated Earnings $ millions	$44.1	$48.5 (45.0%)	Ahead of target

Q4 performance results: 125.6%

Attachment 35.2

George Isherwood
Director Regulatory Affairs

FortisBC Inc.
1290 Esplanade PO Box 130
Trail, BC V1R 4L4
Tel 250 368 0313
Fax 1 866 605 9431
George.Isherwood@fortisbc.com
www.fortisbc.com

October 14, 2005

Mr. R.J. Pellatt
Commission Secretary
British Columbia Utilities Commission
Sixth Floor, 900 Howe St. Box 250
Vancouver, BC V6Z 2N3

Dear Mr. Pellatt:

Re: BCUC Order G-52-05
Filing of Performance Based Regulation Review

Pursuant to Commission Order G-52-05 please find enclosed 15 copies of a review of FortisBC's experience with Performance Based Regulation, prepared by Elenchus Research Associates. The Company has considered the report's conclusions, and will incorporate these in its 2006 Revenue Requirements Application, which will contain a proposal for a new PBR mechanism. We anticipate filing this Application in November of this year.

Should you require further information on this filing, please contact the undersigned.

Yours truly

(original signed by L. Humphrey for G. Isherwood)

George Isherwood
Director, Regulatory Affairs

cc: Registered Intervenors
2005 Revenue Requirements

Review of FortisBC Performance under PBR, 1996 to 2004

A Report Prepared by
Elenchus Research Associates Inc.

On Behalf of
FortisBC

August 2, 2005

Table of Contents

1 BACKGROUND

1.1 FORTISBC PBR PLAN

In 1996, West Kootenay Power (subsequently Aquila Networks and more recently FortisBC) made a request to the BCUC for an incentive mechanism (also known as PBR) to replace cost of service regulation as part of its 1996 Revenue Requirements Application. Subsequently, the BCUC approved a negotiated settlement in this matter. The settlement established a mechanism to approve annual revenue requirements and set rates based upon indexed and targeted cost categories. Although the initial period of the PBR mechanism was to run for three years, the plan was subsequently 'rolled-over' and extended in various forms until 2004. The plan consisted of 'targeted' cost categories with cost drivers, escalators, productivity improvement factors (PIFs) and a sharing mechanism. The major cost categories established in the 1996 settlement agreement[1] and the constituent components are:

Cost Accounts
- Power Purchases

Operating Expenses
- Labour
- Materials, Vehicles, Contracts
- Capitalized Overhead
- Wheeling
- Water Fees
- Other Income

Financing Costs
- Interest Expense
- Preferred Shares
- Cost of Equity
- Amortization Expense
- Amortization of Deferred Charges
- AFUDC

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[1] BCUC Order G-73-96, Appendix A.

Taxes
- Income tax
- Property tax
- BC Capital Tax

Base Capital Expenditures
- Generation Plant
- Distribution Plant-Upgrades
- Distribution Plant-Extensions
- General Plant
- DSM

Extraordinary Capital Expenditures

The initial settlement agreement established productivity improvement factors (or PIFs) for selected cost categories (*i.e.*, labour and materials, generation, distribution and general plant, *etc.*). It also established sharing mechanisms for selected categories, such as Labour, Materials, and Capitalized Overhead categories from Operating Expenses and Base Capital Expenditures. Other cost categories initially had no sharing of variances (Power Purchases, Wheeling, Water Fees)[2].

As the Commission, stakeholders and the Company gained more experience with the plan, subsequent agreements modified some of the incentive mechanisms. For example, in the initial settlement PIFs for O&M accounts were established at 4%, 3% and 3% for the first 3 years, respectively. Subsequently, these were modified (0% for 1999, 2% for 2000-2002, 1% for 2003, and 0% in 2004). Likewise, PIFs for Base Capital accounts were established at 2% for the initial 3 years, and subsequently modified to 0% for 1999, 2% for 2000-2002, 1% for 2003, and 0% in 2004. While the Power Purchase account initially had no sharing mechanism, this was subsequently changed in 1999 with the introduction of a power purchase variance mechanism[3] and market

[2] Details of each cost category, the cost driver, escalation factor, PIF and sharing mechanism is contained in Appendix A of BCUC Order G-73-96 and is attached as an Appendix to this report.
[3] In response to the company "doing too well" in power purchase performance vs. targets.

incentive mechanism. This was again modified in 2000 with a change in the sharing mechanism.[4] In 1999, capitalized overhead was excluded from the sharing mechanism.

In addition to cost categories, performance standards such as customer satisfaction and system reliability were subject to review. The plan was subject to an annual public comment and review process.

1.2 PBR REVIEW

In its recent Decision on FortisBC's 2005 Revenue Requirements based on the first cost of service review since PBR was introduced in 1996 (Order G-52-05), the BCUC directed FortisBC to undertake a review of its PBR regime.

> *The Commission Panel directs FortisBC to complete its review of PBR prior to submitting its 2006 Revenue Requirements Application and to propose to the Commission its preferred process for review and implementation of its recommendations. The Commission will determine at that time an appropriate review process going forward.*

In response to this directive, FortisBC has asked Elenchus Research Associates (ERA) Inc. to undertake an independent review in accordance with the BCUC directive.

This initial review has assembled and summarized (in tabular and graphical form) the performance of FortisBC using key data from the PBR period plus data up to 5 years prior (where available) to the initial implementation of the FortisBC PBR regime. Key categories examined include O&M expenditures, capital expenditures, power purchase costs, utility performance indicators (reliability and customer service, ROE). As well, FortisBC's performance in key categories is compared to the performance of other Canadian utilities, where possible, being mindful that local operating conditions, scale, type of operation, and other such peculiarities must be considered when making such comparisons.

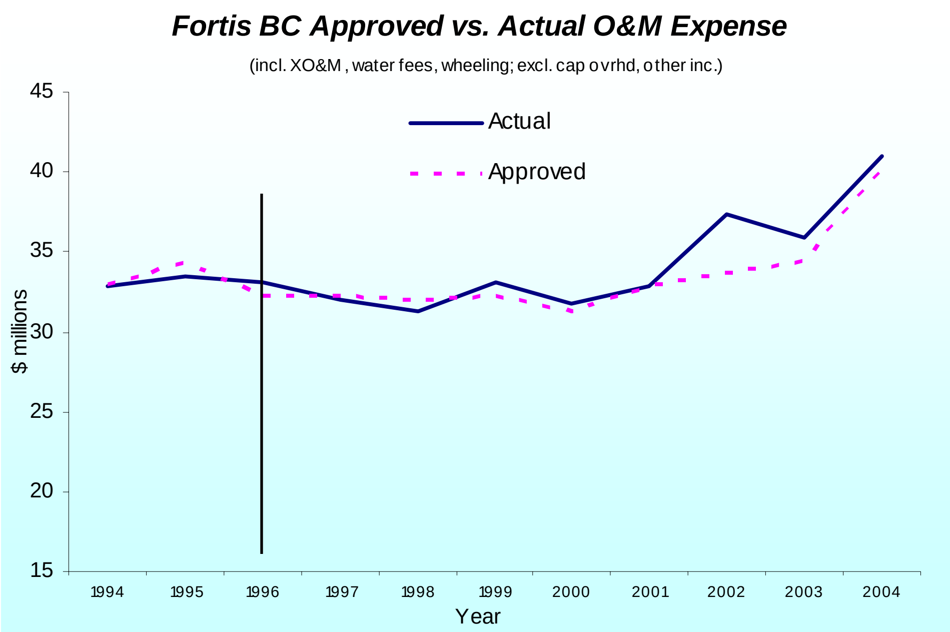
[4] In Appendix A to Order G-134-99, parties accepted a Power Purchase Price Variance (PPPV) mechanism. Up to $1 million in PPPV, the sharing of PPPV for any year will be 65% to the ratepayer and 35% to the company, and will be 75% to the ratepayer and 25% to the company on any remaining amount.

2 PERFORMANCE OVERVIEW

2.1 OPERATING COSTS

Data on actual versus approved (targeted) total O&M expenses are available from 1994. *Chart 1* below summarizes total annual O&M expense, including extraordinary O&M expense, water fees, and wheeling costs. Capitalized overhead and other income are deducted from the total, for consistency with the most recent version of the FortisBC PBR regime.

Chart 1



As can be seen from the above chart, actual vs. approved O&M generally track each other fairly closely, both before and after the PBR plan implementation until 2002, when actual O&M exceeded approved. Up until 2002, the variance of actual from approved was less than ± 3 per cent, and averaged less than +0.2 per cent 1994 to 2001. In 2002, O&M actual exceeded approved by almost 11 per cent. Discussions with the Company indicate the variance in 2002 is due primarily to the BC/Alberta integration. Of course, variances in the individual cost sub-categories may have exceeded the ±3% maximum variance that was observed for the total O&M expenses in *Chart 1* during the 1994 – 2001 period.

Chart 2

Inflation Adjusted Total O&M Expense - Fortis BC

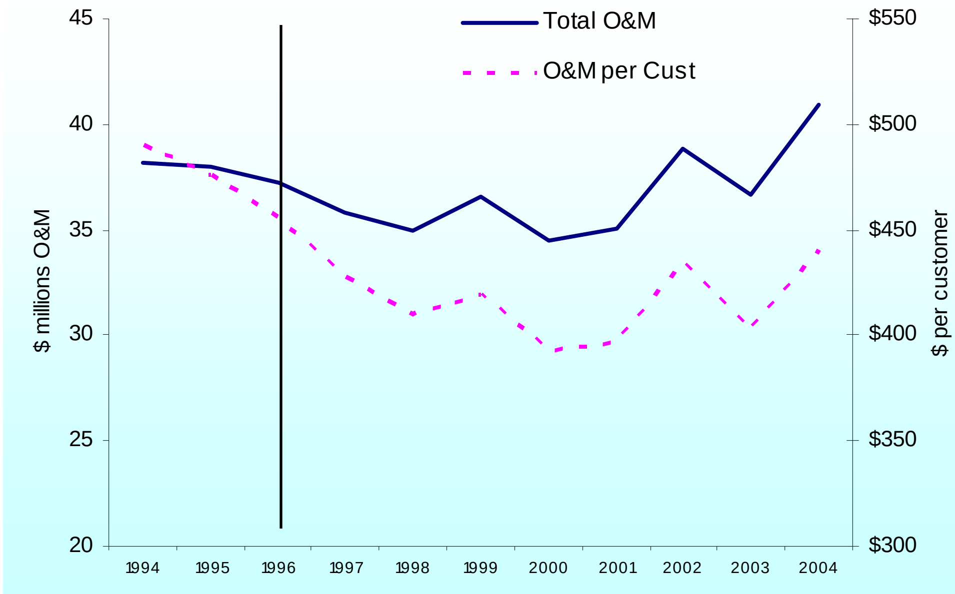


Chart 2 illustrates inflation-adjusted O&M costs and inflation-adjusted O&M costs per customer. Inflation-adjusted O&M is calculated using the BC All-Items CPI[5] and revaluing all prior years to 2004 dollar values.

From 1994 to 1995, inflation adjusted O&M per customer dropped 3.1 per cent. From 1996 to 2000, the inflation adjusted O&M declined at an annual average of 3.6 per cent. From 2001 to 2004, this reversed and O&M increased an average of 3.5 per cent per year. From the above chart, it is evident that 2002 and 2004 are anomalous years. As indicated above, the 2002 result is due to the BC/Alberta integration. Discussions with the company indicate the subsequent de-integration is responsible for the 2004 result.

[5] It should be noted that the CPI, or consumer price index, is not necessarily the most appropriate inflation measure for utility costs. Other more precise measures exist, such as electric utility construction price indexes. However CPI is well known, is used by many (including BCUC), and is recognized by consumers. In Fortis' PBR, the BC CPI was used for O&M cost categories while the Canadian CPI was used for capital cost categories.

Conclusion: Inflation-adjusted O&M Expenses were declining prior to implementation of the PBR plan and continued to decline for several years after PBR implementation. After 2000, inflation-adjusted O&M has increased very slowly in "normal years", with significant up-ticks in years affected by extraordinary events (BC/Alberta integration/de-integration).

2.1.1 LABOUR & MATERIALS

Data on labour and benefits, and materials (including vehicles and contracts) costs are available from 1991. Inflation adjusted labour and materials costs are plotted in *Chart 3* and summarized in *Table 1*.

Chart 3

Inflation Adjusted Labour and Materials Cost: FortisBC

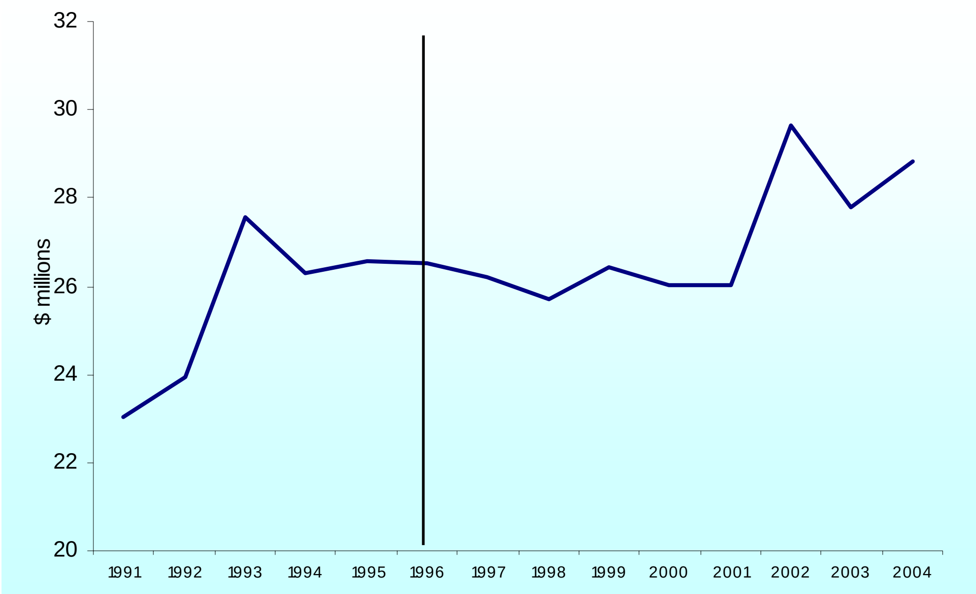


Table 1

Inflation Adjusted Labour & Materials Costs for FortisBC; Annual Averages: 1991-95, 1996-2001, 2002-04		
Period	**$000s (2004)**	**Within period % change[6]**
'91 – '95	$25,478	3.7%
'96 – '01	$26,153	-0.4%
'01 – '02	$27,837	13.8%
'02 – '04	$28,751	-1.4%

As can be seen from *Chart 3*, Labour & Materials costs are relatively stable from 1994 to 2001 after an initial period of increase (1991 to 1993). After a 15 per cent increase in 1993, annual increases/decreases are limited to less than 3 per cent from 1994 to 2001, with a simple annual average growth rate of –0.7 per cent from 1994 to 2001. While Labour & Materials costs decline slightly within the PBR period prior to 2002, the costs had stabilized prior to PBR implementation. In 2002, Labour & Materials costs increased significantly, likely due to the BC/Alberta integration.

Conclusion: Labour & Materials costs declined slightly after implementation of PBR but increased substantially in 2002. PBR may have helped to limit increases in Labour & Materials costs in the first 5 years of the plan.

2.2 CAPITAL COSTS

Chart 4 outlines inflation adjusted[7] net capital additions since 1991. The large increase after 2002 reflects coming into service of the large facility renewal projects that had been undertaken by FortisBC. Prior to 2002, net additions per customer remained in a fairly stable range with the 3 year moving average fluctuating between $300-$400 per customer and the rate of growth slowing slightly after 1996. One common concern with PBR type plans is the incentive to trim costs such that reinvestment in new plant is sub-

[6] All Percentage changes in this document are calculated using geometric means, where applicable or unless otherwise indicated.
[7] Using CPI – Canada.

optimal. *Chart 4* indicates that the FortisBC plan did not inhibit continued investment in new plant and a major commitment to system upgrades after 2002. *Table 2* illustrates the continued investment in plant additions at historic levels after PBR implementation.

Chart 4

Inflation Adjusted Net Capital Additions Per Customer

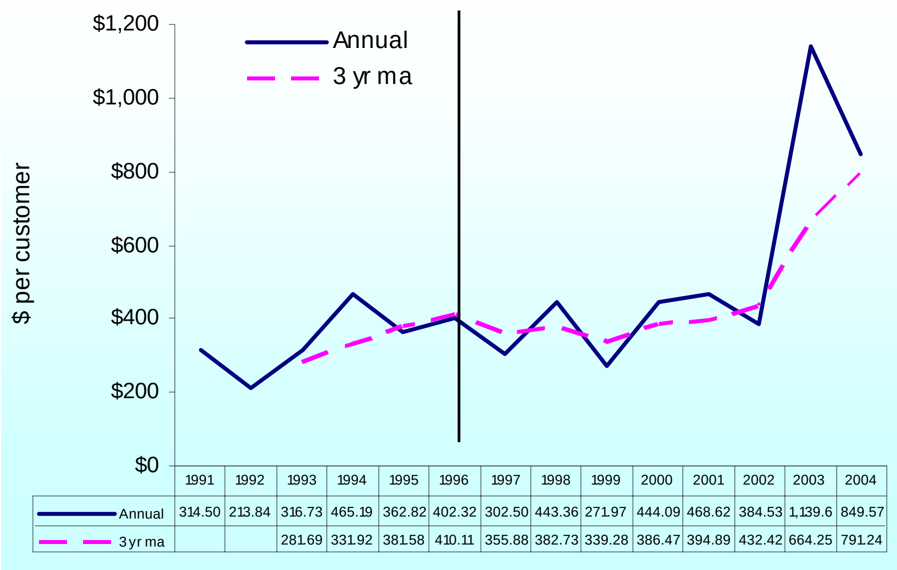
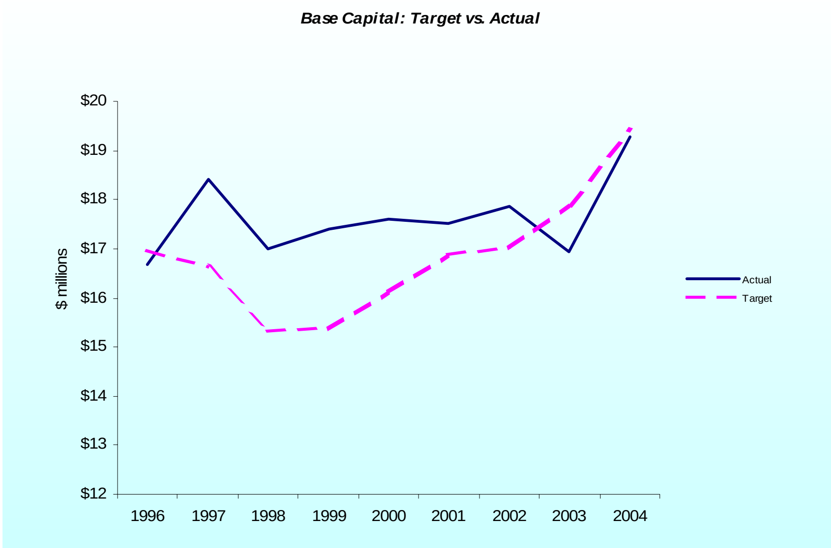


Table 2

Inflation Adjusted Per Customer Capital Additions & Plant In Service: FortisBC; Annual Averages: 1991-95, 1996-2001, 2002-04					
$ per customer				***Within period per cent change (annual)***	
Period	**Plant**	**Net Additios**		**Plant**	**Net Additions**
’91 – ‘95	$4,258	$335		2.9%	3.6%
‘96 – ‘01	$5,247	$389		3.9%	3.1%
’02 – ‘04	$6,558	$791		9.6%	48.6%

Chart 5 below compares targeted base capital under the PBR plan to actual base capital expenditures. As can be seen, actual base capital costs have exceeded targeted in most years during the incentive plan.

Chart 5



Base capital costs are not shown in the preceding chart because pre-1996 capital costs cannot be separated into base and extraordinary capital costs. These concepts were defined specifically for use in the PBR regime and related to the specific capital plans of FortisBC during PBR period

Conclusion: It does not appear that the PBR plan had a material effect on capital expenses.

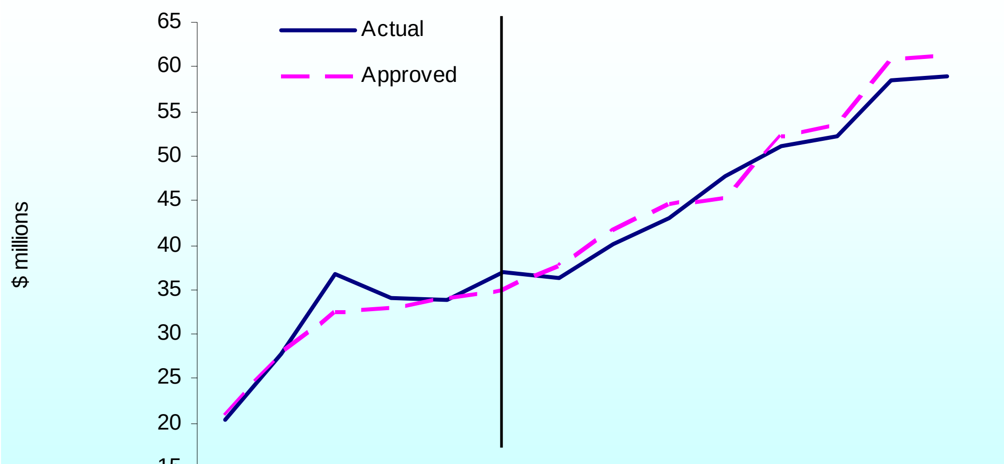
2.3 POWER PURCHASE COSTS

Chart 6 compares actual power purchase costs with approved power purchase costs since 1991. Prior to 1996, there were several years where actual power purchase costs exceeded approved, the most notable being 1993. Since 1997, actual power purchase costs have not exceeded approved with the exception of 2000. Discussions with the Company indicate this is due to the challenges in forecasting power purchases accurately for a period of 2–3 years that was required for the traditional rate case approach prior to 1996. After the introduction of PBR, an annual forecast of power purchases was used in setting rates.

In the years of 1997 and 1998, the excess of target costs over actuals lead to a change in the treatment of power purchase cost from flow-through to an incentive mechanism.

Chart 6

Fortis BC Approved vs. Actual Power Purchase Costs



	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
Actual	20,461	27,775	36,676	33,999	33,767	37,059	36,345	40,060	42,919	47,659	51,051	52,261	58,436	59,014
Approved	20,873	27,775	32,463	32,849	33,961	35,000	37,629	41,650	44,574	45,365	52,172	53,673	60,635	61,366

Power purchase costs are a major expense for the utility, totalling about $60 million in 2004 (or almost 3 times the cost of labour, including benefits). It should be noted that although in the first few years of the incentive plan there was no sharing mechanism associated with power purchase costs, this changed in 1999, after which the Company shared savings with customers.

Chart 7 illustrates cost per MWh for total power purchases from 1991 to 2004. Annual power purchase costs and volumes are displayed in *Table 3* below.

Chart 7

FortisBC Actual Power Purchase Costs ($/MWh)

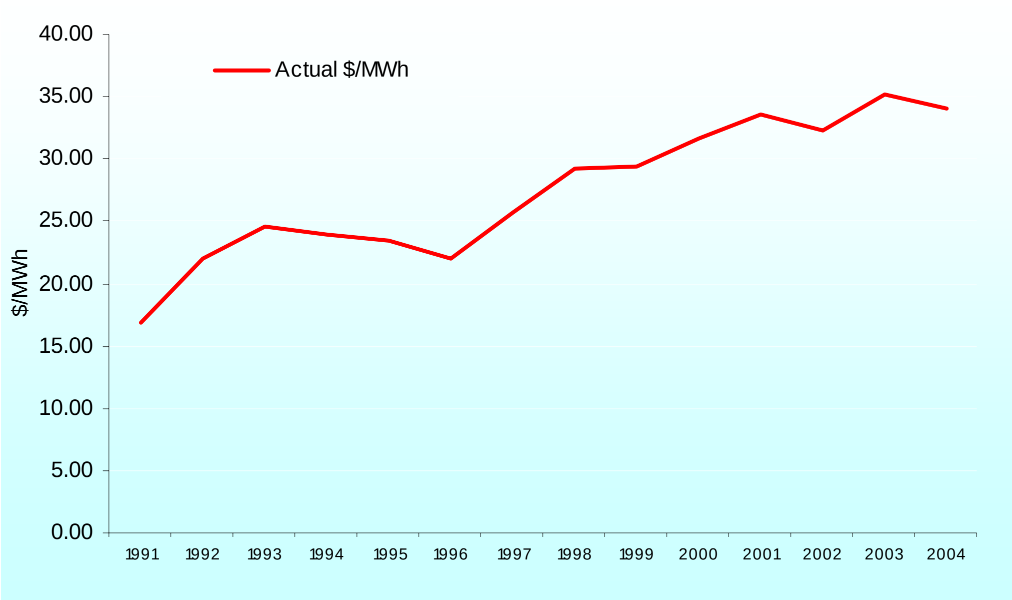


Table 3

Power Purchase Costs - FortisBC			
	Total Power Purchase Expense		
	Cost (000s)	GWh	$/MWh
1991	20,461	1,210	16.91
1992	27,775	1,260	22.04
1993	36,676	1,490	24.61
1994	33,999	1,419	23.96
1995	33,767	1,443	23.40
1996	37,059	1,685	21.99
1997	36,345	1,414	25.70
1998	40,060	1,372	29.20
1999	42,919	1,458	29.44
2000	47,659	1,504	31.69
2001	51,051	1,517	33.65
2002	52,261	1,620	32.26
2003	58,436	1,664	35.12
2004	59,014	1,736	33.99

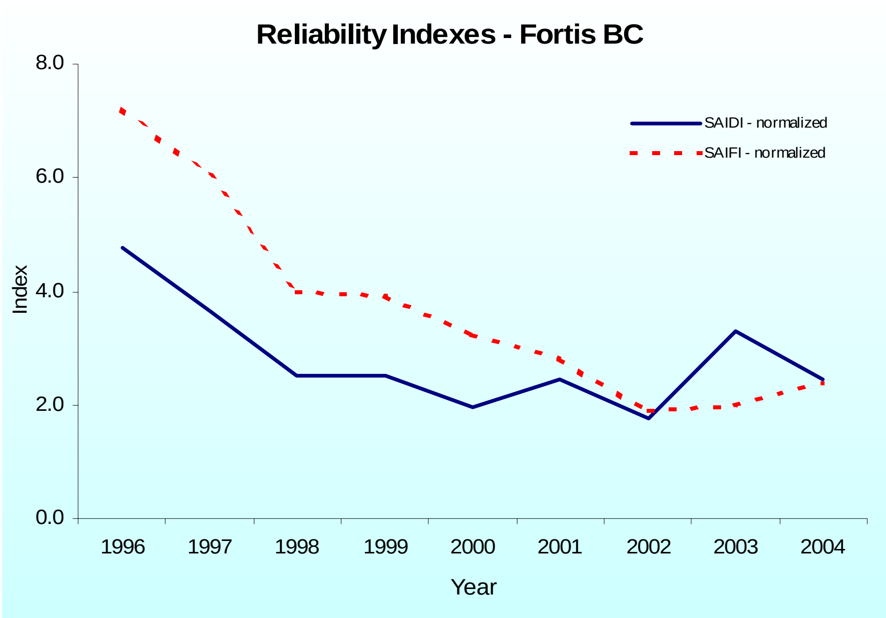
Conclusion: While power purchase actuals tracked targets more closely after 1996, this is a result of the annual review rather than any incentive mechanism.

2.4 UTILITY PERFORMANCE INDICATORS

2.4.1 RELIABILITY AND CUSTOMER SERVICE INDICATORS

Data on service reliability, such as SAIDI (System Average Interruption Duration Index) and SAIFI (System Average Interruption Frequency Index) are available from 1996 to 2004 (up to October). Normalized data take into account extraordinary events that are beyond the control of the utility, such as a large windstorms or ice storms. FortisBC also has available an index of customer service satisfaction. *Chart 8* displays total system reliability data (both transmission and distribution) for 1996 to 2004.

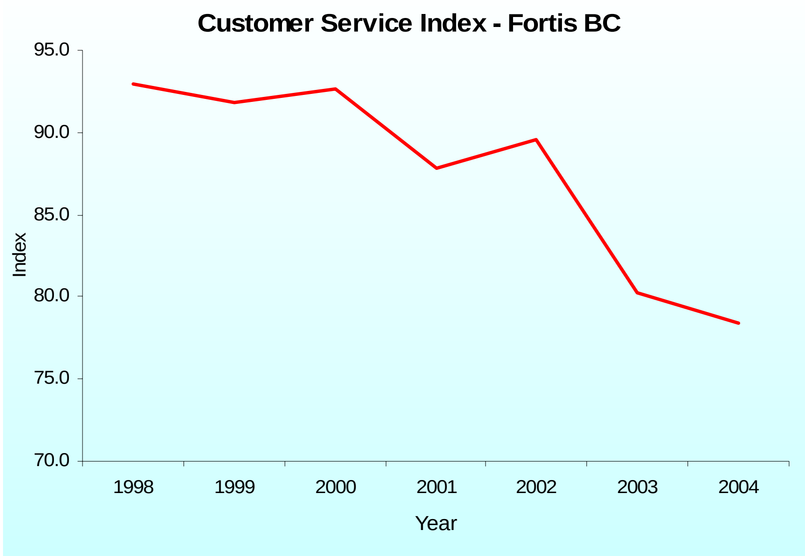
Chart 8



The chart indicates that service reliability increased significantly after the introduction of PBR in 1996. However, in 2003, duration of interruptions increases significantly, although frequency increased only slightly.

From 2001 to 2004, the customer service index declined substantially (from over 90 to under 80), indicating a major customer service issue (as shown in *Chart 9*). Given the service reliability statistics, this decline in customer views does not appear to be related to reliability, which has improved during the PBR plan period. Discussions with the company indicate this is a result of the BC/Alberta integration and the Calgary call centre, a problem that has now been remedied with a call centre located in Trail.

Chart 9

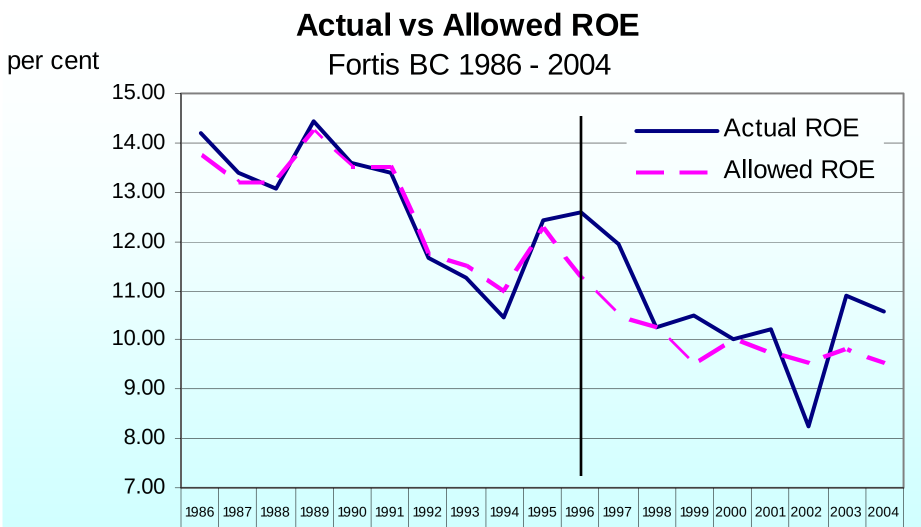


2.4.2 PROFITABILITY INDICATOR: ROE – ACTUAL VS. ALLOWED

Chart 10 displays actual versus allowed ROE from 1986 to 2004. Prior to 1996 and the implementation of the PBR plan, actual ROE closely tracked allowed ROE. From 1986 to 1995, the deviation between actual and approved ROE averaged 0, with a standard deviation of 0.26. Since 1996, actual ROE has diverged from allowed, exceeding it in several years. From 1996 to 2004, the deviation between actual and approved ROE averaged 0.56, with a standard deviation of 0.82.

As noted in *Section 2.3*, a power purchase sharing mechanism was introduced in 1999 due, in part, to perceived over-earning resulting from target power purchases exceeding actuals in 1997 and 1998. If we consider the period since the power purchase sharing mechanism was introduced, the deviation between actual and approved ROE averaged 0.25 (with a standard deviation of 0.87).

Chart 10



	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
Actual ROE	14.18	13.39	13.09	14.43	13.60	13.39	11.65	11.28	10.44	12.42	12.57	11.94	10.26	10.48	10.00	10.20	8.24	10.88	10.59
Allowed ROE	13.75	13.20	13.20	14.25	13.50	13.50	11.75	11.50	11.00	12.25	11.25	10.50	10.25	9.50	10.00	9.75	9.53	9.82	9.55

2.5 CONCLUSIONS

The incentive mechanism (or PBR plan) implemented for FortisBC is essentially an indexed cost-of-service plan rather than a full-fledged performance-based regulation plan. The incentive mechanism is a non-litigious, streamlined way of setting revenue requirement and rates using a traditional cost-of-service approach.

After PBR implementation, total O&M expenses (on an inflation-adjusted per customer basis) continued to decline, as they had prior to 1996. This decline did not continue after 2001, however. Inflation-adjusted Labour & Materials Costs followed a similar pattern, declining slightly after PBR implementation, but increasing markedly after 2001.

It appears that PBR did not have a material effect on capital expenditures. There is no evidence that capital expenditures were reduced to sub-optimal levels to enhance earnings (a criticism of some incentive-based plans). Actual Base Capital expenditures exceeded targets for most years in which data are available. Reliability statistics (SAIDI, SAIFI) improved during the PBR plan.

An important attraction of PBR is the promise that it can reduce the regulatory effort/burden for all participants: FortisBC, the regulator and customer representatives.

There would seem to be little doubt that the overall regulatory burden has been reduced by the Commission's reliance on the FortisBC PBR regime that has been in place since 1996. The BCUC's own benchmarking shows it to be a low-cost regulator compared to those that rely more heavily on cost of service regulation. The company reports that less of its staff resources are required to prepare for, and participate in, rate proceedings. The time spent by annually by customer groups appears to have been far less than is the norm for cost of service hearings. This regulatory streamlining would demonstrate a net benefit resulting from PBR even if the regime had little demonstrable impact on the company's costs and rates. To the extent that there may be cost-reduction benefits attributable to the PBR regime, it would be reasonable to declare the regime a "success" in comparison to traditional cost of service regulation, with its regular and often lengthy proceedings to scrutinize all of the company's costs.

Overall Conclusion:

- ***Performance in all cost categories was enhanced modestly, if at all, by the incentive plan.***
- ***Reliability increased during the plan, but it is unclear whether this is attributable in any way to the incentive mechanism. It is clear, however, that PBR did not have a negative affect on reliability.***
- ***The Customer Service Index declined during the plan, but this also appears to be outside the influence of the incentive mechanism and is a result of corporate decisions.***
- ***Regulatory cost and burden for FortisBC, stakeholders, and the Commission (BCUC) appear to be significantly reduced under the plan. The BCUC compares favourably to every other Canadian energy regulator in terms of the cost of regulation (on a per capita or per energy unit basis) as well as on cycle time for decisions. This may be due in part to adoption of incentive regulation and negotiated settlements such as with FortisBC in the past.***

3 BENCHMARK COMPARISONS

This section compares the FortisBC's trends in key performance areas with other Canadian utilities.

Comparison of ROE (Actual %)

Year	2000	2001	2002	2003
FortisBC	10.00	10.20	8.24	10.88
BC Hydro	16.69	16.59	15.24	15.47
ATCO Electric	11.32	10.25	10.30	n/a
NSPI	10.90	10.90	9.80	10.20
Fortis (Nfld)	10.80	11.35	10.32	n/a
Enbidge Gas Distr.	10.83	10.03	11.81	n/a

O&M per Customer (nominal $/customer)

Year	2000	2001	2002	2003
FortisBC	363	372	417	394
BC Hydro	298	469	338	347
Manitoba Hydro[8]	415	438	455	433

[8] Includes natural gas operations and customers.

4 APPENDIX A – PBR COST CATEGORIES (1996)

West Kootenay Power
Revenue Requirements Application
Negotiation Worksheet

Description	Application	Settlement	Notes
COST ACCOUNTS			
POWER PURCHASES	Not included in Incentive Plan	$35 million in 1996 with no sharing	
OPERATING EXPENSES			
Labour			
Cost Driver	Average Number of Direct Customers	Average Number of Direct Customers	
Base Cost	$241 per Customer	$234 per Customer	
Base Cost Escalator	CPI - Canada	CPI - B.C.	
PIF	1%	4%,4%,3%	
Sharing of Variances from Target	Equally with Customer	Equally with Customer	
Materials, Vehicles, Contracts			
Cost Driver	Average Number of Direct Customers	Average Number of Direct Customers	
Base Cost	$97 per Customer	$101 per Customer	
Base Cost Escalator	CPI - Canada	CPI - B.C.	
PIF	1%	4%,4%,3%	
Sharing of Variances from Target	Equally with Customer	Equally with Customer	
Capitalized Overhead			
Cost Driver	Capital Expenditures	Capital Expenditures	
Base Cost	7%	7%	
Base Cost Escalator	Not Applicable	Not Applicable	
PIF	Not Applicable	Not Applicable	
Sharing of Variances from Target	Equally with Customer	Equally with Customer	
Wheeling			
Cost Driver	BC Hydro Nomination	BC Hydro Nomination	
Base Cost	1995 BCH Rate	1995 BCH Rate	
Base Cost Escalator	BCH Escalation	BCH Escalation	
PIF	Not Applicable	Not Applicable	
Sharing of Variances from Target	Not Applicable	Target to become Actual	
Water Fees			
Cost Driver	Generation	Generation	
Base Cost	Provincial Rates	Provincial Rates	
Base Cost Escalator	BCH Escalation	BCH Escalation	
PIF	Not Applicable	Not Applicable	
Sharing of Variances from Target	Not Applicable	Target to become Actual	
Other Income			
Cost Driver	Average Number of Direct Customers	Average Number of Direct Customers	
Base Cost	$34 per Customer	$34 per Customer	Changes to BCUC Tariffs to be put in the Base
Base Cost Escalator	CPI - Canada	CPI - Canada	
PIF	Not Applicable	Not Applicable	

West Kootenay Power
Revenue Requirements Application
Negotiation Worksheet

Description	Application	Settlement	Notes
FINANCING COSTS			
Interest Expense			
Cost Driver	Capital Expenditures	Capital Expenditures	
Base Cost	1995 Weighted Average Cost of Debt Outstanding	1995 Weighted Average Cost of Debt Outstanding	
Base Cost Escalator	Canada 10 Year Bonds + 125 bp	Canada 10 Year Bonds + 125 bp	
PIF	Not Applicable	Not Applicable	
Sharing of Variances from Target	Equally with Customer	Volume variances shared equally with Customer	
Preferred Shares			Wind out ASAP
Cost Driver	Capital Expenditures	Capital Expenditures	
Base Cost	Current Dividend Yield	Current Dividend Yield	
Base Cost Escalator	Not Applicable	Not Applicable	
PIF	Not Applicable	Not Applicable	
Sharing of Variances from Target	Equally with Customer	Volume variances shared equally with Customer	
Cost of Equity			
Cost Driver	Capital Expenditures	Capital Expenditures	
Base Cost	BCUC ROE Adjustment Mechanism	BCUC ROE Adjustment Mechanism	
Base Cost Escalator	Not Applicable	Not Applicable	
PIF	Not Applicable	Not Applicable	
Sharing of Variances from Target	Equally with Customer	Volume variances shared equally with Customer	
Amortization Expense			
Cost Driver	Capital Expenditures	Capital Expenditures	
Base Cost	Current blended Amortization Rate	Current blended Amortization Rate	
Base Cost Escalator	Not Applicable	Not Applicable	
PIF	Not Applicable	Not Applicable	
Sharing of Variances from Target	Not Applicable	Target to become Actual	
Amortization of Deferred Charges			
DSM	Over 8 years	Over 8 years	
BC Hydro Costs	Recover over 5 years	Recover over 5 years	
IRP	Recover over 5 years	Recover over 5 years	
FST	Recover over 2 years	Recover over 2 years	
Property Tax	Recover over 2 years	Recover over 2 years	
EMR	Recover over 2 years	Recover over 3 years	
Rate Application	Recover over 2 years	Recover over 3 years	
EMF	Recover over 3 years	Defer	Application when justified

West Kootenay Power
Revenue Requirements Application
Negotiation Worksheet

Description	Application	Settlement	Notes
AFUDC			
Cost Driver	Capital Expenditures	Capital Expenditures	
Base Cost	8%	8%	
Base Cost Escalator	Not Applicable	Not Applicable	
PIF	Not Applicable	Not Applicable	
Sharing of Variances from Target	Taken into rates in the next year	Taken into rates in the next year	
TAXES			
Income Tax			
Sharing of Variances from Target	Effective Tax Variances to be Shared Equally with Customer	Effective Tax Variances to be Shared Equally with Customer	Changes to Statutory Tax rate to be borne by Customer
Property Tax			
Sharing of Variances from Target	Taken into rates in the next year	Taken into rates in the next year	
BC Capital Tax			
Sharing of Variances from Target	Taken into rates in the next year	Taken into rates in the next year	
CAPITAL EXPENDITURES			
BASE CAPITAL EXPENDITURES			
Generation Plant			
Cost Driver	Number of Generation Plant Units	Number of Generation Plant Units	
Base Cost	$1,400,000 in Total	$1,300,000 in Total	
Base Cost Escalator	CPI - Canada	CPI - Canada	
PIF	1%	2%	
Sharing of Variances from Target	Equally with Customer	Equally with Customer	
Transmission Plant		Remove 44L and 49L	
Cost Driver	Normalized Peak Load	Normalized Peak Load	
Base Cost	$9,600 per MW	$8,000 per MW	
Base Cost Escalator	CPI - Canada	CPI - Canada	
PIF	1%	2%	
Sharing of Variances from Target	Equally with Customer	Equally with Customer	
Distribution Plant-Upgrades			
Cost Driver	Normalized Peak Load	Normalized Peak Load	
Base Cost	$7,040 per MW	$6,500 per MW	
Base Cost Escalator	CPI - Canada	CPI - Canada	
PIF	1%	2%	
Sharing of Variances from Target	Equally with Customer	Equally with Customer	

West Kootenay Power
Revenue Requirements Application
Negotiation Worksheet

Description	Application	Settlement	Notes
Distribution Plant-Extensions			
Cost Driver	Number of New Customers	Number of New Customers	
Base Cost	$1,766 per New Customer	$1,600 per New Customer	For 1996 only. 1997 and 1998 will reflect new extension tests.
Base Cost Escalator	CPI - Canada	CPI - Canada	
PIF	1%	2%	
Sharing of Variances from Target	Equally with Customer	Equally with Customer	
General Plant			
Cost Driver	Average Number of Direct Customers	Average Number of Direct Customers	
Base Cost	$46 per Customer	$46 per Customer	
Base Cost Escalator	CPI - Canada	CPI - BC	
PIF	1%	2%	
Sharing of Variances from Target	Equally with Customer	Equally with Customer	
DSM			
Cost Driver		kW.h savings	
Base Cost		Variable costs only	
Base Cost Escalator		CPI - Canada	
PIF		Incentive to take effect only if 90% of Target met	
Sharing of Variances from Target		50/50 equally with Customer	
EXTRAORDINARY CAPITAL EXPENDITURES			
Turbine Upgrade		To be approved by project	
Dam Rehabilitation		To be approved by project	
43 Line Upgrade		To be approved by project	
46 Line Upgrade		To be approved by project	
44 Line Upgrade		To be approved by project	
49 Line Upgrade		To be approved by project	
OTHER ITEMS			
Review Period		Review before 4th year	
Performance Standards		Compare to WKP Trend as guideline	
Customer Satisfaction			
System Reliability			
Safety			
Losses		Include as PS measure	
Capital Structure	Equity level of 40%	Equity level of 40%	
Load Forecast		Accept 1996 forecast. 1997 to include regression studies. Annual Review	Form Working Committee