ROUND ONE INTERROGATORY RESPONSES

[2016 and 2017 Rate Application]

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SRRP Q1:

Reference: **Application**

When were the revenue and expenditure forecasts used in the application prepared? Please confirm whether the application reflects the March 2016 Business Plan, the May 2016 update or a combination of the two.

Response:

The rate application is based on the May 2016 Business Plan Update.

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SRRP Q2:

Reference: Application

Please discuss what SaskPower considers to be the 4 largest financial risks it faces (e.g. natural gas prices; interest rates; sales growth or decline) and provide an estimate of the potential upper and lower range of effects of these risks on operating income and return on equity in 2016-17 and 2017-18.

Response:

SaskPower considers the following items to be the largest financial risks to the Corporation over the two-year period covered by the Rate Application.

1. Rate increase
2. Electricity sales
3. Natural gas prices
4. Hydro levels

Rate increase

SaskPower's Business Plan assumes rate increases of 5% effective July 1, 2016, and a second rate increase of 5% effective January 1, 2017. The rate increase is subject to review by the Saskatchewan Rate Review Panel with final approval by Cabinet.

Each 1% change in the recommended rate increase is estimated to have a $22 million annual impact on SaskPower's net income.

Saskatchewan electricity sales volumes

SaskPower is forecasting Saskatchewan electricity sales growth of 3.7% in 2016-17, for total annual electricity sales of 22,419 GWh. In 2017-18, the Corporation is forecasting 1.8% growth, for a total annual sales volume of 22,828 GWh. However, actual sales volumes are subject to a number of variables, including economic conditions, number of customers and weather.

The impact of a change in the sales volumes forecast will differ by customer class. For example, the financial impact of a 100 GWh change in sales volumes to the Residential customer class is forecast to have a $9 million impact on SaskPower's bottom line. A 100 GWh change in Power customer class sales is estimated to have a $4 million impact on SaskPower's financial results. These estimates were calculated before applying the impact of the proposed rate increases.

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Natural gas prices

SaskPower uses a diversified fleet of generation and fuel sources to produce electricity in Saskatchewan. This includes natural gas, coal, hydro, wind, and imports. Natural gas generation is forecast to provide about 35% of the Corporation's electrical needs in 2016-17 and 2017-18, which is second only to coal generation in terms of percentage of electricity supplied. SaskPower is forecasting to consume 74.3 million GJ of natural gas in 2016-17 and 71.9 million GJ in 2017-18.

Natural gas prices are subject to significant volatility due to fluctuations in the market price. To mitigate that risk, the Corporation has hedges in place to fix the price of natural gas on up to 80% of its forecasted natural gas purchases in the coming calendar year.

The estimated impact of a $1/GJ change in the price of natural gas is a $16 million change in SaskPower's fuel and purchased power costs in 2016-17 and $23 million in 2017-18.

Hydro volumes

Hydro generation is forecast to provide approximately 12% - 15% of SaskPower's generation needs in 2016-17 and 2017-18. Next to wind, hydro generation is the least expensive marginal cost source of electricity in SaskPower's fleet. When hydro generation is lower than expected, it must be replaced by other, more expensive sources of electricity such as natural gas or imports.

The actual amount of hydro generation is largely dependent on water levels in the rivers that feed our hydro generation facilities. A 10% change in the level of hydro generation is estimated to have a $13 million impact on SaskPower's fuel and purchased power budget.

The attached sensitivity analysis provides some additional information on the financial impact of changes in the Corporation's planning assumptions.

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Business Plan Sensitivity Analysis

Item	Assumptions 2016 - 17	Assumptions 2017-18	Sensitivity Analysis (Annual Impact)	NI Impact (Millions $)
Revenue				
Rate Increase (%)	10.0%	0.0%	1% change in the rate increase assumption	$ 22
Sask Sales Growth (%)	3.7%	1.8%	100 GWh change in Power Class	$ 4
			100 GWh change in Residential Class	$ 9
Export Profit & Trading Margin (Millions $)	$ 10	$ 11	$10 million change in export sales	$ 5
Fuel & Purchased Power				
Natural Gas Price ($/GJ)	$ 3.79	$ 4.25	$1 / GJ change in the natural gas price	$ 16
Hydro Generation (GWh)	3,068	3,634	10% change in the hydro assumption	$ 13
Coal Generation (GWh)	10,916	11,016	10% change in the coal generation	$ 18
Capital				
Capital Spending (Millions $)	$ 899	$ 952	$100 million change in capital budget	$ 7
Short-Term Interest Rates	0.8%	1.0%	1% change in short-term interest rates	$ 11
Long-Term Interest Rates	3.1%	3.9%	1% change in interest rate assumption	$ 4

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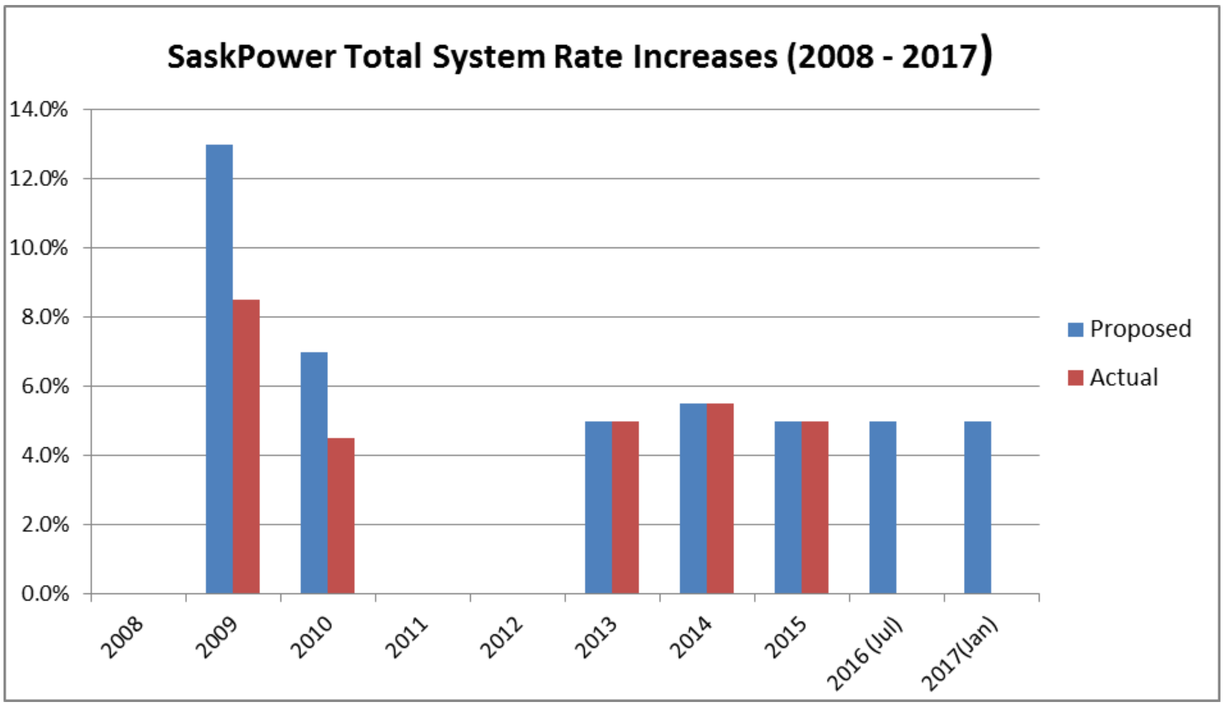
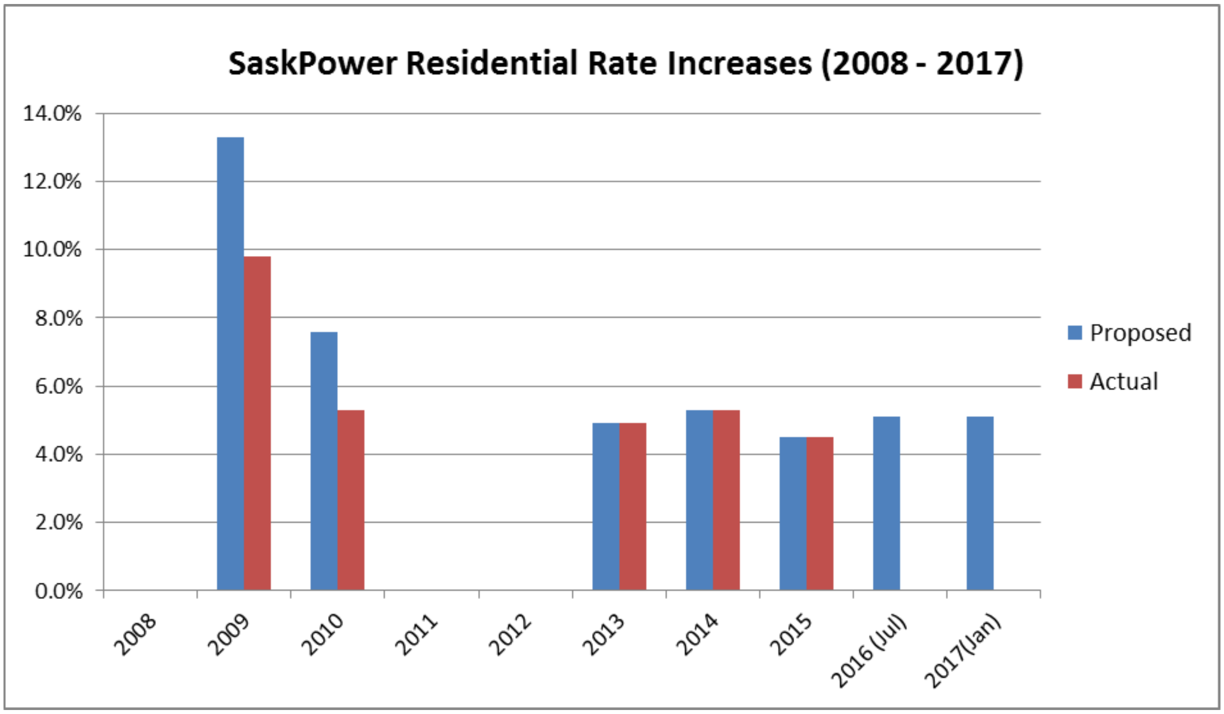
SRRP Q3:
Reference: **Application**
Please provide a graph which illustrates the actual and proposed percentage increases for each major customer group from 2008 through 2017-18.

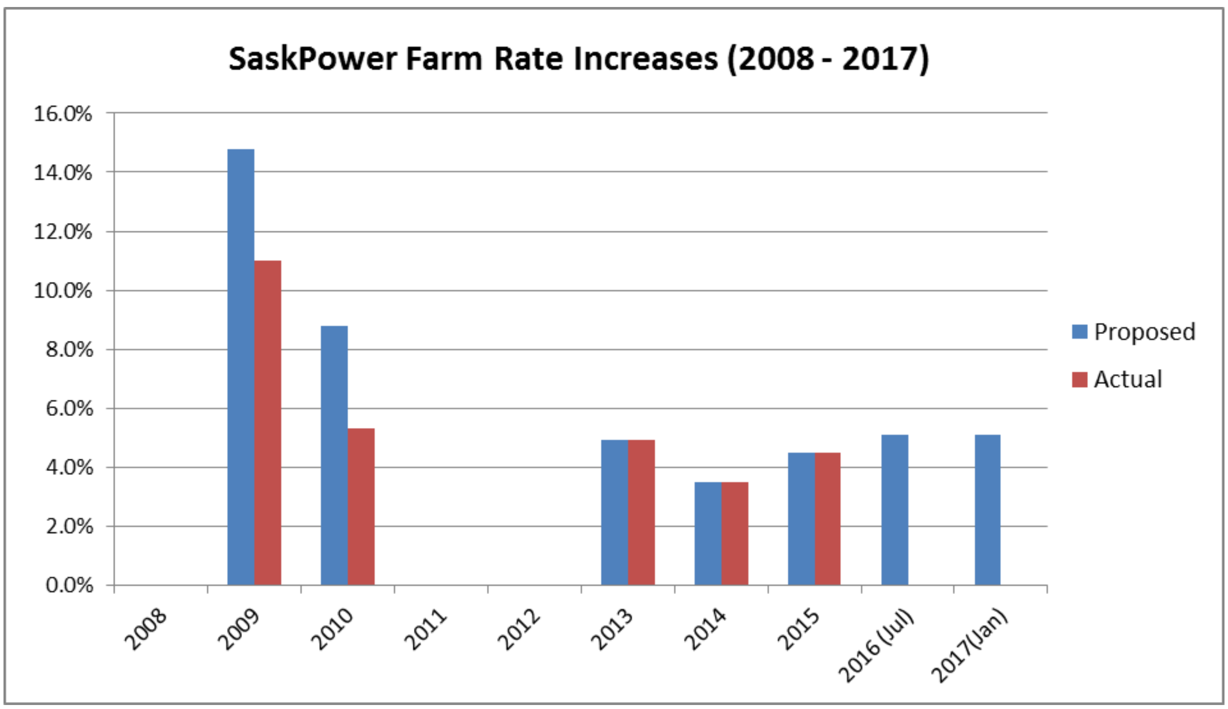
Response:

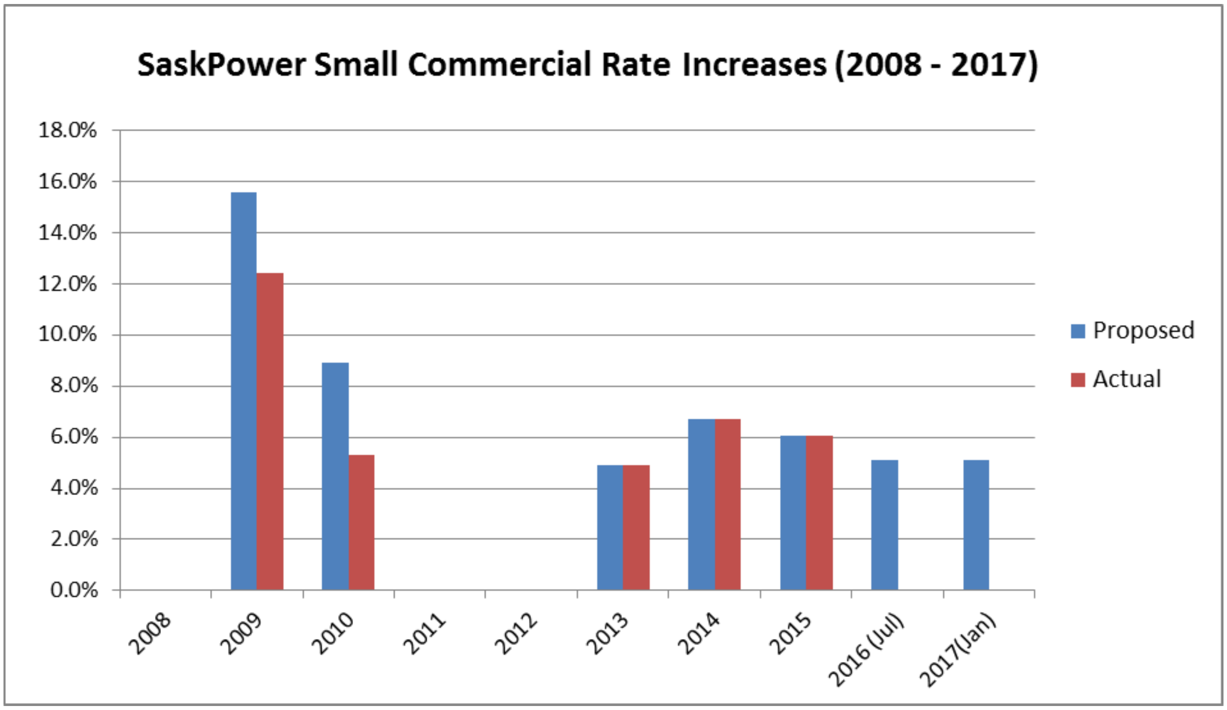
SaskPower's rate increases per major customer group from 2008 to 2017 are as follows:

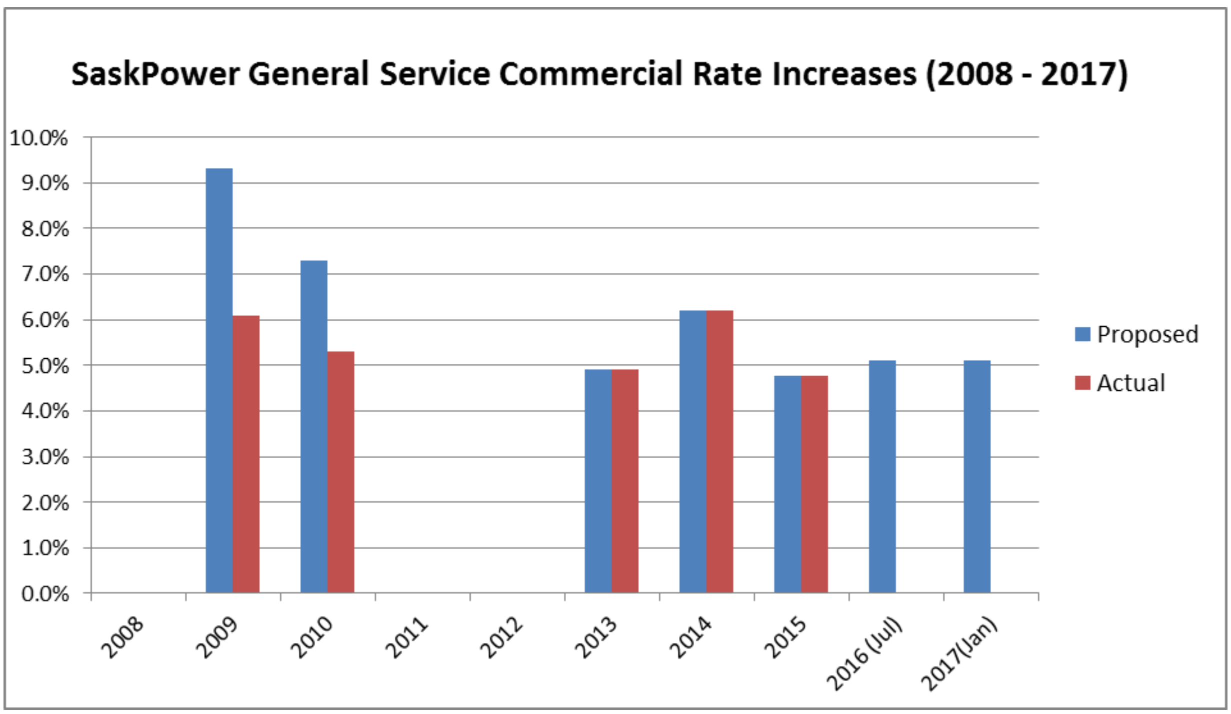
* No data in 2008, 2011, and 2012 indicates no rate increase was applied in those years.
* Please note that 2018 is not included as no increase is planned at this time.

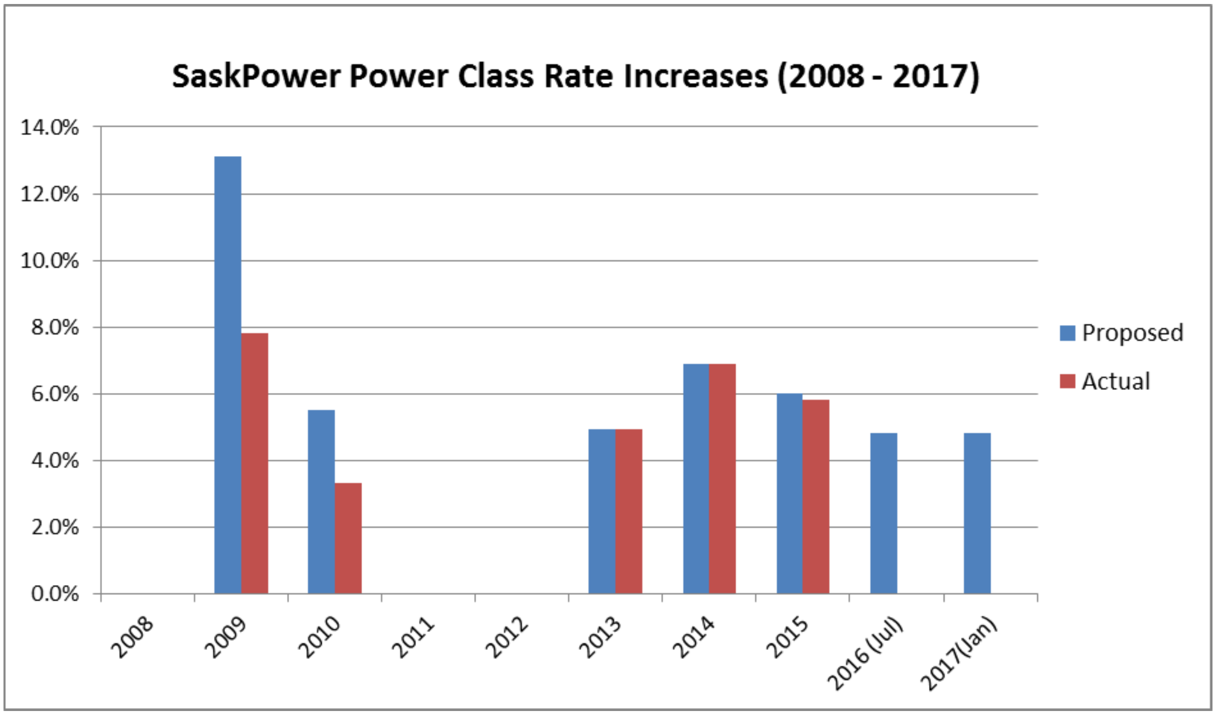


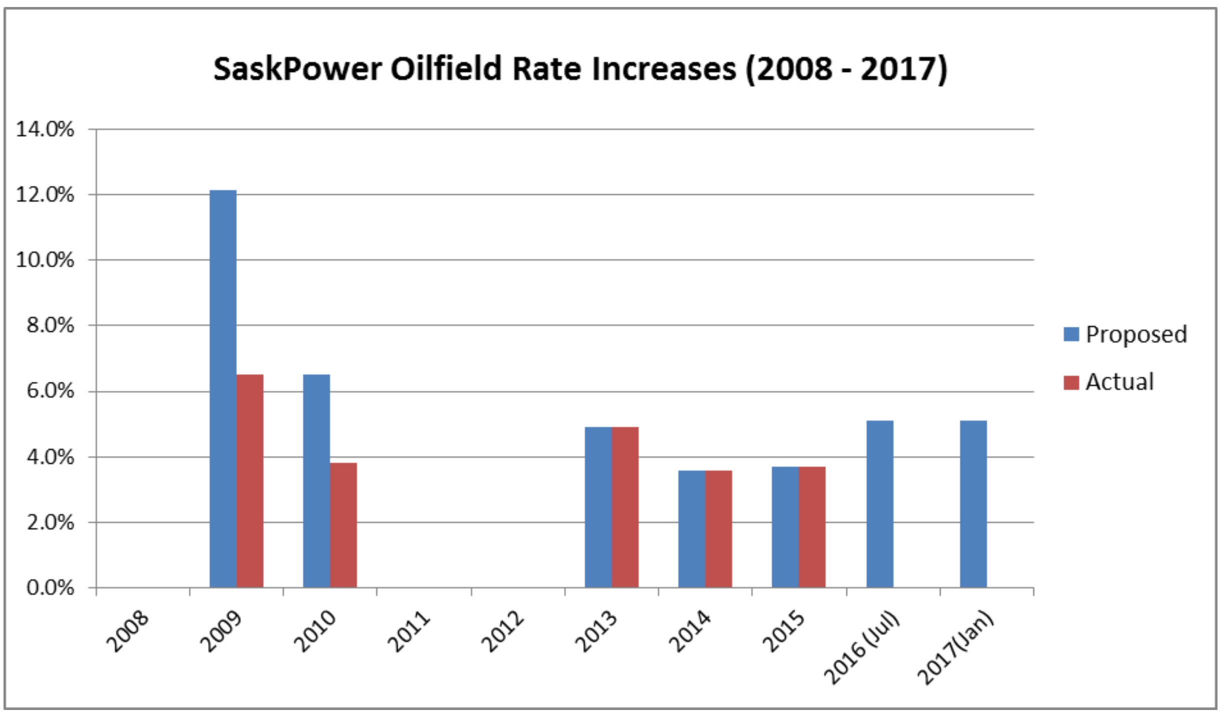

SaskPower Residential Rate Increases (2008 - 2017)
14.0%
12.0%
10.0%
8.0%
6.0%
4.0%
2.0%
0.0%
2008
2009
2010
2011
2012
2013
2014
2015
2016 (Jul)
2017(Jan)
Proposed
Actual


SaskPower Farm Rate Increases (2008 - 2017)
16.0%
14.0%
12.0%
10.0%
8.0%
6.0%
4.0%
2.0%
0.0%
2008
2009
2010
2011
2012
2013
2014
2015
2016 (Jul)
2017(Jan)
Proposed
Actual


SaskPower Small Commercial Rate Increases (2008 - 2017)
18.0%
16.0%
14.0%
12.0%
10.0%
8.0%
6.0%
4.0%
2.0%
0.0%
2008
2009
2010
2011
2012
2013
2014
2015
2016 (Jul)
2017(Jan)
Proposed
Actual


SaskPower General Service Commercial Rate Increases (2008 - 2017)
10.0%
9.0%
8.0%
7.0%
6.0%
5.0%
4.0%
3.0%
2.0%
1.0%
0.0%
2008
2009
2010
2011
2012
2013
2014
2015
2016 (Jul)
2017(Jan)
Proposed
Actual


SaskPower Power Class Rate Increases (2008 - 2017)
14.0%
12.0%
10.0%
8.0%
6.0%
4.0%
2.0%
0.0%
2008
2009
2010
2011
2012
2013
2014
2015
2016 (Jul)
2017(Jan)
Proposed
Actual


SaskPower Oilfield Rate Increases (2008 - 2017)
14.0%
12.0%
10.0%
8.0%
6.0%
4.0%
2.0%
0.0%
2008
2009
2010
2011
2012
2013
2014
2015
2016 (Jul)
2017(Jan)
Proposed
Actual

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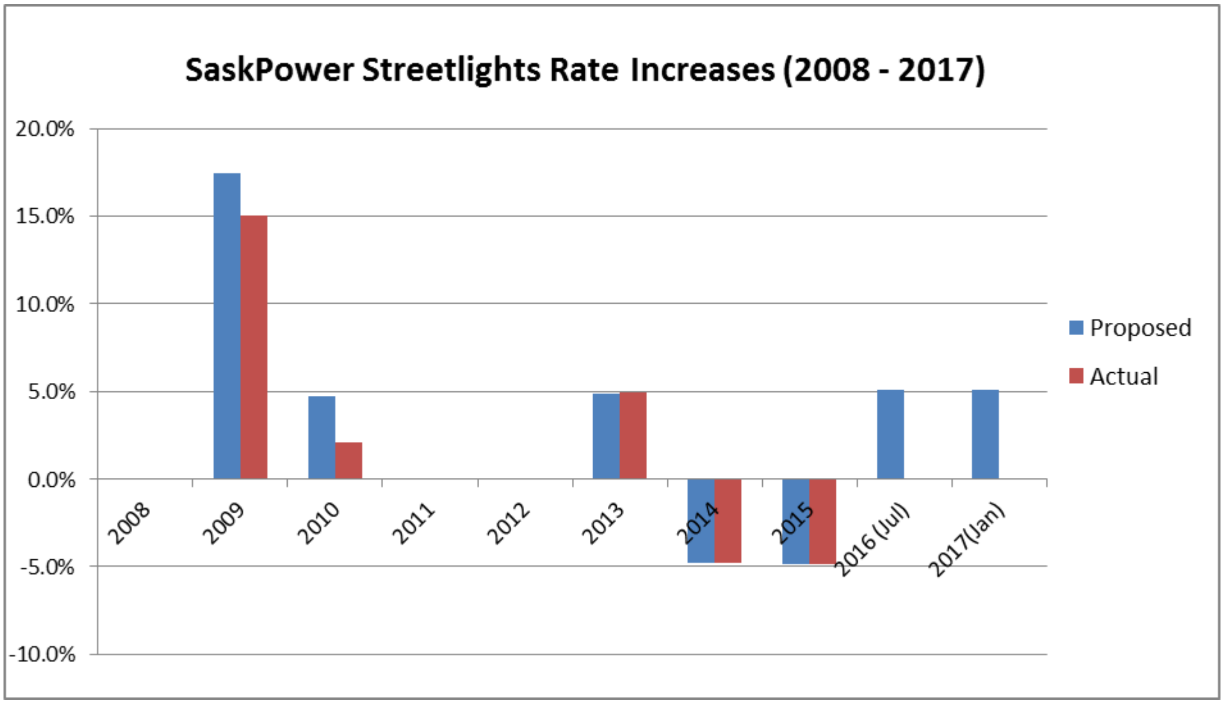

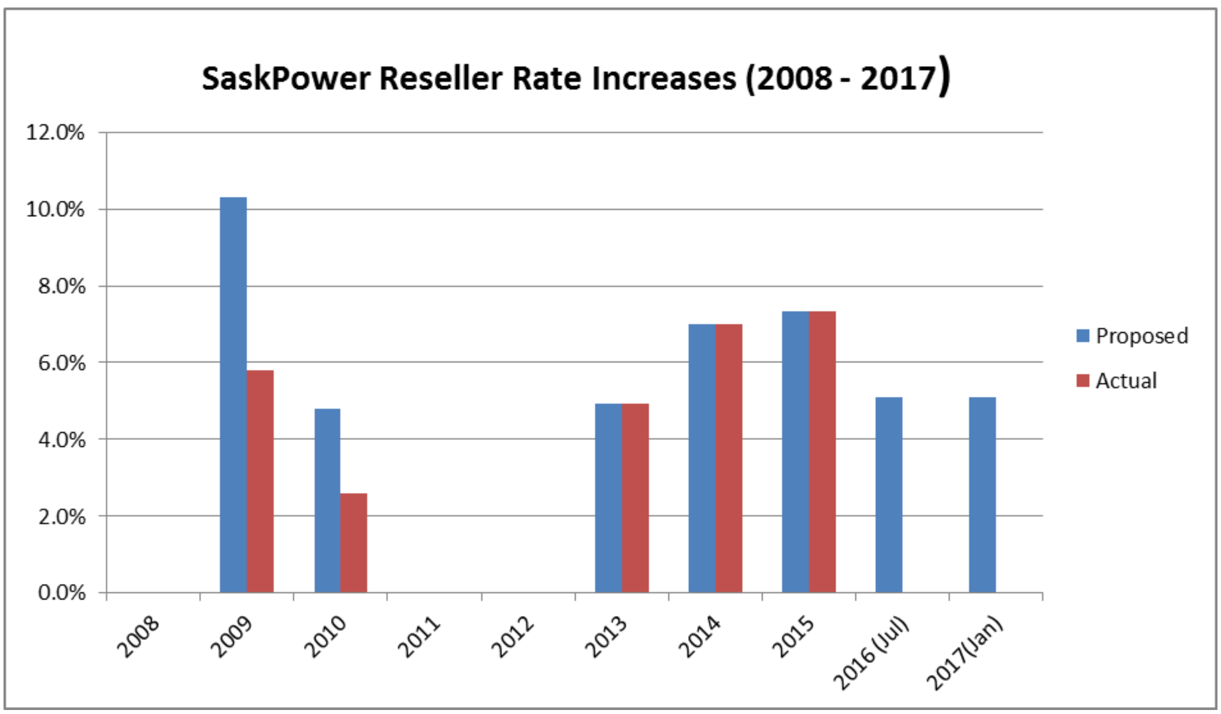

SRRP Q4:

Reference: **Application**

Please provide a schedule showing SaskPower's total domestic electricity sales revenue; operating income; return on equity and debt to equity ratio for 2016-17 and 2017-18 assuming for each of the following potential rate scenarios:

i) Confirmation of a 5% average rate increase effective July 1, 2016, and no rate increase in 2017.

ii) Confirmation of a 5% average rate increase effective July 1, 2016, and a 2.5% average rate increase effective January 2017.

iii) Confirmation of a 5% average rate increase effective July 1, 2016, and a 5% average rate increase effective April 1, 2017

iv) A 10% average rate increase effective September 1, 2016, and no other rate increases in 2016-17 or 2017-18.

Response:

The following is a summary of the various rate increase scenarios noted above.

SRRP Q4 i) - 5% Jul 1, 2016; 0% in 2017

Financial/Productivity Indicators	December 2014	December 2015	2016/17	2017/18
Avg customer rate increase (%)	5.5	5.0	**5.0**	-
Operating income (millions $)	43.2	103.6	**126.9**	87.9
Net Income (millions $)	59.6	39.7	**152.3**	87.9
Total Domestic electricity sales revenue	2,042.7	2,127.7	**2,299.2**	2,359.7
Return on equity (%)	2.0	4.7	**5.6**	3.7
Debt ratio incl. capital leases (%)	73.1	74.8	**75.0**	75.2

SRRP Q4 ii) - 5% Jul 1, 2016; 2.5% Jan 1, 2017

Financial/Productivity Indicators	December 2014	December 2015	2016/17	2017/18
Avg customer rate increase (%)	5.5	5.0	**7.5**	-
Operating income (millions $)	43.2	103.6	**141.4**	147.3
Net Income (millions $)	59.6	39.7	**166.8**	147.3
Total Domestic electricity sales revenue	2,042.7	2,127.7	**2,313.7**	2,418.7
Return on equity (%)	2.0	4.7	**6.3**	6.1
Debt ratio incl. capital leases (%)	73.1	74.8	**74.8**	74.4

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SRRP Q4 iii) - 5% Jul 1, 2016; 5% Apr 1, 2017

Financial/Productivity Indicators	December 2014	December 2015	2016/17	2017/18
Avg customer rate increase (%)	5.5	5.0	**5.0**	5.0
Operating income (millions $)	43.2	103.6	**126.9**	206.5
Net Income (millions $)	59.6	39.7	**152.3**	206.5
Total Domestic electricity sales revenue	2,042.7	2,127.7	**2,299.2**	2,477.6
Return on equity (%)	2.0	4.7	**5.6**	8.5
Debt ratio incl. capital leases (%)	73.1	74.8	**75.0**	74.0

SRRP Q4 iv) - 10% Sept 1, 2016; 0% in 2017/18

Financial/Productivity Indicators	December 2014	December 2015	2016/17	2017/18
Avg customer rate increase (%)	5.5	5.0	**10.0**	-
Operating income (millions $)	43.2	103.6	**173.2**	201.1
Net Income (millions $)	59.6	39.7	**198.6**	201.1
Total Domestic electricity sales revenue	2,042.7	2,127.7	**2,345.4**	2,472.0
Return on equity (%)	2.0	4.7	**7.6**	8.2
Debt ratio incl. capital leases (%)	73.1	74.8	**74.5**	73.6

SRRP Q5:

Reference: **Application**

Please provide a continuity schedule of Plant in Service and Total Property, Plant and Equipment by function (generation, transmission, distribution, general) for 2013 through 2017-18.

Response:

Please see the schedule below.

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Property, plant and equipment							
		Leased				Construction	
(in millions)	Generation	assets	Transmission	Distribution	Other	in progress	**Total**
Cost or deemed cost							
Balance, January 1, 2013	$ 4,431	$ 533	$ 1,057	$ 2,849	$ 562	$ 840	**$ 10,272**
Additions	24	700	95	245	75	1,318	**2,457**
Disposals and/or retirements	(121)	-	(6)	(20)	(17)	-	**(164)**
Transfers	-	-	-	-	-	(493)	**(493)**
Balance, December 31, 2013	**$ 4,334**	**$ 1,233**	**$ 1,146**	**$ 3,074**	**$ 620**	**$ 1,665**	**$ 12,072**
Additions	1,356	-	174	264	132	1,279	**3,205**
Disposals and/or retirements	(81)	-	(4)	(19)	(30)	-	**(134)**
Impairment losses	-	-	-	(19)	-	-	**(19)**
Transfers	-	-	-	-	-	(1,891)	**(1,891)**
Balance, December 31, 2014	**$ 5,609**	**$ 1,233**	**$ 1,316**	**$ 3,300**	**$ 722**	**$ 1,053**	**$ 13,233**
Additions	676	-	521	258	74	991	**2,520**
Disposals and/or retirements	(15)	-	(12)	(22)	(33)	-	**(82)**
Transfers	-	-	-	-	-	(1,542)	**(1,542)**
Balance, December 31, 2015	**$ 6,270**	**$ 1,233**	**$ 1,825**	**$ 3,536**	**$ 763**	**$ 502**	**$ 14,129**
Additions	107	-	65	59	13	187	**431**
Disposals and/or retirements	(22)	-	(1)	(6)	(6)	-	**(35)**
Transfers	1	-	-	-	-	(247)	**(246)**
Balance, March 31, 2016	**$ 6,356**	**$ 1,233**	**$ 1,889**	**$ 3,589**	**$ 770**	**$ 442**	**$ 14,279**
Additions							**-**
Disposals and/or retirements							**-**
Transfers	29		(246)	(3)	44	247	**71**
Forecast, March 31, 2016	**$ 6,385**	**$ 1,233**	**$ 1,643**	**$ 3,586**	**$ 814**	**$ 689**	**$ 14,350**
Additions	169		788	216	137	899	**2,209**
Disposals and/or retirements	(7)			(6)	(40)		**(53)**
Transfers	1					(1,311)	**(1,310)**
Forecast, March 31, 2017	**$ 6,548**	**$ 1,233**	**$ 2,431**	**$ 3,796**	**$ 910**	**$ 277**	**$ 15,196**
Additions	152		361	212	123	952	**1,799**
Disposals and/or retirements	(7)			(5)	(41)		**(53)**
Transfers			0			(847)	**(847)**
Forecast, March 31, 2018	**$ 6,693**	**$ 1,233**	**$ 2,792**	**$ 4,004**	**$ 991**	**$ 382**	**$ 16,095**

(in millions)	Generation	Leased assets	Transmission	Distribution	Other	Construction in progress	**Total**
Accumulated depreciation							
Balance, January 1, 2013	$ 2,197	$ 181	$ 437	$ 1,190	$ 237	$ -	**$ 4,242**
Depreciation expense	132	42	30	92	37	-	**333**
Disposals and/or retirements	(110)	-	(3)	(16)	(15)	-	**(144)**
Transfers	-	-	-	-	-	-	**-**
Balance, December 31, 2013	**$ 2,219**	**$ 223**	**$ 464**	**$ 1,266**	**$ 259**	**$ -**	**$ 4,431**
Depreciation expense	143	56	28	96	40	-	**363**
Disposals and/or retirements	(75)	-	(3)	(15)	(14)	-	**(107)**
Impairment losses	-	-	-	(2)	-	-	**(2)**
Transfers	-	-	-	-	-	-	**-**
Balance, December 31, 2014	**$ 2,287**	**$ 279**	**$ 489**	**$ 1,345**	**$ 285**	**$ -**	**$ 4,685**
Depreciation expense	187	57	36	101	40	-	**421**
Disposals and/or retirements	(13)	-	(3)	(18)	(14)	-	**(48)**
Transfers	-	-	-	-	-	-	**-**
Balance, December 31, 2015	**$ 2,461**	**$ 336**	**$ 522**	**$ 1,428**	**$ 311**	**$ -**	**$ 5,058**
Depreciation expense	51	14	10	25	11	-	**111**
Disposals and/or retirements	(21)	-	(1)	(4)	(4)	-	**(30)**
Transfers	-	-	-	-	-	-	**-**
Balance, March 31, 2016	**$ 2,491**	**$ 350**	**$ 531**	**$ 1,449**	**$ 318**	**$ -**	**$ 5,139**
Depreciation expense						-	**-**
Disposals and/or retirements						-	**-**
Transfers	(25)	(14)	(6)		97	-	**52**
Forecast, March 31, 2016	**$ 2,466**	**$ 336**	**$ 525**	**$ 1,449**	**$ 415**	**$ -**	**$ 5,191**
Depreciation expense	154	56	48	102	125	-	**486**
Disposals and/or retirements					(39)	-	**(39)**
Transfers	52				(52)	-	**-**
Forecast, March 31, 2017	**$ 2,671**	**$ 392**	**$ 573**	**$ 1,551**	**$ 450**	**$ -**	**$ 5,639**
Depreciation expense	193	56	72	108	99	-	**528**
Disposals and/or retirements					(40)	-	**(40)**
Transfers						-	**-**
Forecast, March 31, 2018	**$ 2,864**	**$ 449**	**$ 645**	**$ 1,659**	**$ 510**	**$ -**	**$ 6,127**

SRRP Q6:

Reference: Application

For the period 2013 – 2017-18 please provide a table itemizing all actual or forecast payments to the Province of Saskatchewan including water rentals, corporate capital taxes, coal royalties, dividends and any other payments to the Province.

Response:

The following table summarizes the various payments made to the province for the years 2013 to 2017-18.

Payments to the Province of Saskatchewan						
	Actual	Actual	Actual	Actual	Forecast	Budget
(in $ millions)	2013	2014	2015	2016	2016/2017	2017/2018
Water Rentals	$21.0	$23.2	$17.8	$4.6	$16.7	$20.4
Capital Taxes	31.7	35.2	38.8	9.8	42.5	45.2
Coal Royalties	24.2	28.0	39.9	7.9	32.2	32.0
Dividends	0.0	0.0	0.0	0.0	20.7	22.2
Total Payments	**$76.9**	**$86.4**	**$96.5**	**$22.3**	**$112.1**	**$119.8**

SRRP Q7:

Reference: **Finance Expense**

Please provide a schedule showing all long term debt (including any long-term lease obligations) including date of issue, date of maturity, effective interest rate, coupon rate, par value, unamortized premium and outstanding amount.

Response:

Long-term debt is comprised of recourse debt – advances from the Government of Saskatchewan's General Revenue Fund – and non-recourse debt which is used to finance the Cory Cogeneration Station. Under the terms of the non-recourse debt, lenders have recourse limited to the station's assets.

Please refer to the table below for details on SaskPower's recourse debt (advances from the Government of Saskatchewan's General revenue fund) as at March 31, 2016 (in millions):

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Date of Issue	Date of Maturity	Effective Interest Rate (%)	Coupon Rate (%)	Par Value	Unamortized Premiums (Discounts)	Outstanding Amount
December 12, 2013	December 12, 2016	Floating	CDOR[1]	$ 100	$ -	$ 100
May 27, 2014	June 5, 2017	Floating	CDOR[1]	100	-	100
December 20, 1990	December 15, 2020	11.23	9.97	129	-	129
February 4, 1992	February 4, 2022	9.27	9.60	240	4	244
July 21, 1992	July 15, 2022	10.06	8.94	256	(1)	255
May 30, 1995	May 30, 2025	8.82	8.75	100	-	100
August 8, 2001	September 5, 2031	6.49	6.40	200	(2)	198
January 15, 2003	September 5, 2031	5.91	6.40	100	5	105
May 12, 2003	September 5, 2033	5.90	5.80	100	(1)	99
January 14, 2004	September 5, 2033	5.68	5.80	200	3	203
October 5, 2004	September 5, 2035	5.50	5.60	200	2	202
February 15, 2005	March 5, 2037	5.09	5.00	150	(2)	148
May 6, 2005	March 5, 2037	5.07	5.00	150	(1)	149
February 24, 2006	March 5, 2037	4.71	5.00	100	4	104
March 6, 2007	June 1, 2040	4.49	4.75	100	4	104
April 2, 2008	June 1, 2040	4.67	4.75	250	3	253
December 19, 2008	June 1, 2040	4.71	4.71	100	-	100
September 8, 2010	June 1, 2040	4.27	4.75	200	14	214
November 7, 2012	February 3, 2042	3.22	3.40	200	6	206
February 20, 2013	February 3, 2042	3.54	3.40	200	(5)	195
October 2, 2013	June 2, 2045	3.97	3.90	400	(5)	395
January 10, 2014	June 2, 2045	3.95	3.90	200	(2)	198
October 2, 2014	June 2, 2045	3.43	3.90	200	18	218
February 5, 2015	June 2, 2045	2.73	3.90	200	48	248
May 26, 2015	December 2, 2046	3.15	2.75	200	(16)	184
October 15, 2015	December 2, 2046	3.43	2.75	200	(26)	174
January 19, 2016	December 2, 2046	3.34	2.75	200	(23)	177
March 6, 2014	March 5, 2054	3.76	3.75	100	-	100
May 2, 2014	March 5, 2054	3.71	3.75	175	1	176
				$ 5,050	**$ 28**	**$ 5,078**

1. CDOR: Canadian Dealer Offer Rate less a margin payable quarterly

Please refer to the table below for details on SaskPower's non-recourse debt as at March 31, 2016 (in millions):

Date of Issue	Date of Maturity	Effective Interest Rate (%)	Coupon Rate (%)	Par Value	Unamortized Premiums (Discounts)	Outstanding Amount
April 26, 2001	June 30, 2016 to December 31, 2025	7.87	7.59	$ 28	$ (1)	$ 27
April 26, 2001	June 30, 2016 to June 30, 2026	7.88	7.60	25	-	25
				$ 53	**$ (1)**	**$ 52**

Please refer to the table below for details on SaskPower's long-term lease obligations as at March 31, 2016 (in millions):

(in millions)	**March 31 2016**
Total future minimum lease payments	**$ 3,155**
Less: future finance charges on finance leases	**(2,022)**
Present value of finance lease obligations	**$ 1,133**
Less: current portion of finance lease obligations	**(11)**
	$ 1,122

SRRP Q8:

Reference: Finance Expense

For each year from 2010 through 2015, please provide a schedule showing the forecast short-term and long-term interest rates for new debt in each business plan and the actual short-term and long-term debt interest rates for new debt.

Response:

The following table shows a summary of forecasted and actual borrowing rates for the years 2010 to 2015.

Borrowing rate assumptions

	2010		2011		2012		2013		2014		2015	
	Forecast	Actual	Forecast	Actual	Forecast	Actual	Forecast	Actual	Forecast	Actual	Forecast	Actual
Short-term interest rates*	N/A	0.4%	1.6%	1.0%	1.1%	1.0%	1.2%	1.0%	1.1%	1.0%	1.2%	0.7%
Long-term interest rates**	5.7%	4.3%	4.6%	N/A	4.1%	3.2%	3.4%	3.8%	3.7%	3.7%	4.2%	3.1%

* Actual short-term interest rate was calculated average throughout the calendar year

** Actual long-term interest rates are calculated weighted average based on multiple borrowings in calendar year

Note: SaskPower had no long-term borrowings in 2011

Note: Forecasted rates are based on the business plan produced in the year specified and the actual is based on actual borrowings done during the year

2016 and 2017 RATE APPLICATION
SRRP INTERROGATORIES

SRRP Q9:

Reference: **Finance Expense**

Please provide a schedule showing details of the total finance charges for the period 2013 through 2017-18 (actual & forecast), including interest on long-term debt; interest on short-term debt; finance leases; interest capitalized; debt retirement fund earnings and other finance charges.

Response:

The following table summarizes actual finance charges for the years 2013 to 2016 and forecasted finance charges for the years 2016-17 and 2017-18.

Finance Charges
(millions)

	2013	2014	2015	2016*	2016/17	2017/18
Interest on long-term debt	$ 191	$ 217	$ 238	$ 62	$ 254	$ 262
Interest on finance lease	119	165	165	43	165	164
Interest on short-term debt	8	7	6	1	8	10
Accretion	4	6	5	1	5	5
Interest capitalized	(57)	(62)	(31)	(4)	(5)	(11)
Amortization of debt premiums/discounts	(1)	(1)	(2)	-	(1)	(1)
Interest on Employee Benefits	15	11	9	3	11	10
Other interest and charges	1	1	1	-	2	1
Finance expense	**280**	**344**	**391**	**106**	**439**	**440**
Debt retirement fund earnings	(18)	(18)	(28)	(5)	(19)	(25)
Interest income	-	-	(1)	-	(1)	(1)
Finance income	**(18)**	**(18)**	**(29)**	**(5)**	**(20)**	**(26)**
TOTAL FINANCE CHARGES	**$ 262**	**$ 326**	**$ 362**	**$ 101**	**$ 419**	**$ 414**

** 2016 - Three month reporting period to accommodate fiscal yearend change*

SRRP Q10:

Reference: Finance Expense

Please provide details with respect to the sinking fund requirements for long-term debt and discuss whether there have been any recent changes to the provincial government's sinking fund requirements for new debt.

Response:

Under conditions attached to certain advances from the Government of Saskatchewan's General Revenue Fund, the Corporation is required to pay annually into debt retirement funds administered by the Government of Saskatchewan Ministry of Finance amounts at least equal to 1% of certain debt outstanding. There have been no recent changes to the provincial government's sinking fund requirements for new debt.

SRRP Q11:

Reference: Finance Expense

Please provide details of the actual and forecast sinking fund balances, earnings, contributions and average returns for 2013 through 2017-18.

Response:

The following is a continuity schedule relating to annual sinking fund balances for the years 2013 to 2017-18:

Sinking Funds
(millions)

	2013	**2014**	**2015**	**2016***	**2016/17**	**2017/18**
DRF Opening Balance	390	368	457	511	533	599
DRF Installments	27	36	43	13	46	48
DRF earnings	18	18	28	5	20	25
DRF redemptions	(34)	-	-	-	-	-
DRF market value gain (loss)	(33)	35	(17)	4	-	-
Debt retirement funds	368	457	511	533	599	672
Return	**4.9%**	**3.9%**	**5.5%**	**0.9%**	**3.3%**	**3.7%**

** 2016 - Three month reporting period to accommodate fiscal yearend change*

SRRP Q12:

Reference: **Finance Expense**

Please provide an explanation for why capitalized interest is forecast to be lower in 2016-17 and 2017-18 than in the actual period from 2013 to 2015.

Response:

During the years 2013 to 2015, SaskPower was in the process of completing three major, multi-year capital projects (the Boundary Dam Integrated Carbon Capture and Storage Demonstration Project, the I1K Transmission Line and the Queen Elizabeth Power Station Expansion). These three projects were the primary drivers behind the significant increase in capitalized interest. The following is a summary of total interest capitalized in the years 2013 to 2015:

2013: $57 million
2014: $62 million
2015: $31 million

In the years 2016-17 and 2017-18, there are no significant, multi-year capital projects included in the capital plan. As a result, the amount of interest being capitalized will drop to more historic levels. In the years 2006 to 2011, capitalized interest averaged approximately $10.5 million per year, in-line with the current three year projection, which averages $12.2 million per year.

SRRP Q13:

Reference: Depreciation

Please discuss if SaskPower has made any changes to the depreciation rates recommended in the 2010 Gannett Fleming report. If so, please provide a qualitative explanation for these changes.

Response:

SaskPower annually conducts a review of retirement dates/average service lives for continued appropriateness. Please see the attached approved Decision Items.

DECISION ITEM

Presented to: SaskPower Executive
January 10, 2012

Re: SaskPower 2012 Depreciation Rates

RECOMMENDATION:

That the SaskPower Executive approve the following revisions to the estimated asset retirement dates effective January 1, 2012.

Depreciable Property Group	Current Estimated Retirement Date	Revised Estimated Retirement Date	Change
Landis (2014)	2014	2020	6
Meadow Lake (2015)	2015	2020	5

KEY ISSUES:

According to SaskPower's policy, a detailed depreciation study is conducted every five years to update the Corporation's depreciation rates with annual reviews for continued appropriateness. The last comprehensive depreciation study was completed in 2010 by Gannett Fleming and the revised depreciation rates were implemented effective January 1, 2011.

The recommended adjustments are based on the annual review of the retirement dates / average service lives for continued appropriateness. This review was conducted internally by C&FS and is based on discussions with management and operating personnel from the Business Units.

Landis and Meadow Lake were the only two assets that were identified as requiring an adjustment to their retirement date / average service life. C&FS uses the retirement date / average service life information to determine the appropriate depreciation rate to apply within SAP.

BACKGROUND:

SaskPower's policy is to calculate depreciation on a straight-line basis over the estimated average service life (ASL) of the asset. This is referred to as the Average Group Life – Whole Life procedure. As per Gannett Fleming, this is a widely used method for calculation of depreciation rates and has been accepted as a reasonable method in a number of regulatory jurisdictions throughout North America.

IMPLICATIONS:

1) Business Plan and Financial Risk Implications

Check the two boxes which apply:	
√ Item is under $5M	√ included in entirety in Business Plan
☐ Item is over $5M but under $10 M	☐ partially included in Business Plan
☐ Item is over $10M	☐ not included in Business Plan

The estimated annual impact of the recommended adjustment to the retirement date for Landis and Meadow Lake is a $1.6 million reduction in depreciation expense.

2) Other Risk Implications

Check the box (or boxes) that apply:		
☐ Technology / IT	☐ Environment	☐ Owner / Other
☐ Customers / Public	☐ Labour Relations / HR	☐ Regulatory
☐ Employees	☐ Legal / Land	☐ Safety

There are no other risk implications.

ALTERNATIVES:

1. **Do not change the depreciation rates**
   In order to be in compliance with IFRS, the Corporation needs update its depreciation rates for 2012.

ADVANCE CONSULTATIONS:

The depreciation review was conducted by C&FS through discussions with management from Power Production; Transmission & Distribution; Customer Services; CI&T and Corporate Services.

COMMUNICATIONS APPROACH:

The General Manager, Corporate Relations, has reviewed and is in agreement with the approach.

Key strategic considerations:
Given the nature of this Decision Item, no communication is required at this time.

Timing: Upon final governance approval.

Profile: Low (scale is low-medium-high).

Key messages:

- According to SaskPower policy, a detailed depreciation study is conducted every five years to update the corporation's depreciation rates. Annual reviews also take place to ensure the continued appropriateness of the rates.
- The last comprehensive depreciation study was completed in 2010, and the revised depreciation rates were implemented January 1, 2011.
- SaskPower has revised the estimated retirement dates for the Landis and Meadow Lake generating stations based on the annual review of asset retirement dates.

TIME FRAME/CONSEQUENCE OF DEFERRMENT

The new depreciation rates are to be implemented effective January 1, 2012. Deferring approval will result in SaskPower using inappropriate depreciation rates for reporting its 2012 Q1 results.

SUBMITTED BY:

Sandeep Kalra, Vice-President & Chief Financial Officer
Finance & Enterprise Risk Management

Prepared by: Troy King, Controller
Date: Dec 15, 2011

SaskPower

DECISION ITEM

Presented to: SaskPower Executive
February 26, 2013

Re: SaskPower 2013 Depreciation Rates

RECOMMENDATION:

That the SaskPower Executive approve the following revisions to the estimated asset retirement dates effective January 1, 2013.

Depreciable Property Group	Current Retirement Date	Revised Retirement Date	Change
Boundary Dam Unit 1	2014	2013	(1)
Boundary Dam Unit 2	2016	2015	(1)
Queen Elizabeth #3	2017	2022	5
Electric & Mechanical Meters	2014	2015	1

KEY ISSUES:

According to SaskPower's policy, a detailed depreciation study is conducted every five years to update the Corporation's depreciation rates with annual reviews for continued appropriateness. The last comprehensive depreciation study was completed in 2010 by Gannett Fleming and the revised depreciation rates were implemented effective January 1, 2011.

The recommended adjustments are based on the annual review of the retirement dates / average service lives for continued appropriateness. This review was conducted internally by Finance and is based on discussions with management and operating personnel from the operating areas.

Boundary Dam Units 1 & 2; QE #3; and the electrical and mechanical meters were identified as requiring an adjustment to their retirement date / average service life. Finance uses the retirement date / average service life information to determine the appropriate depreciation rate to apply within SAP.

BACKGROUND:

At the request of the Saskatchewan Rate Review Panel, Gannett Fleming conducted an independent study of SaskPower's depreciation rates during 2010 that were implemented January 1, 2011.

SaskPower's accounting policy is to calculate depreciation on a straight-line basis over the estimated average service life (ASL) of the asset. This is referred to as the Average Group Life – Whole Life procedure. As per Gannett Fleming, this is a widely used method for calculation of depreciation rates and has been accepted as a reasonable method in a number of regulatory jurisdictions throughout North America.

The decision to advance the planned retirement date for Boundary Dam Unit #1 to 2013 (from 2014) and Unit #2 to 2015 (from 2016) was approved at the Executive on November 14, 2010. An information item went to the Board on December 16, 2010.

The advancement of the retirement dates for Boundary Dam Units 1 and 2 was not communicated to Gannett Fleming during their study, likely because the field work would have been completed before the retirement decision was finalized in November / December 2010.

In 2011, Finance conducted a review of the deprecation rates. While updates were made to the retirement dates for Landis and Meadow Lake, a change in the retirement dates for Boundary Dam Units 1 and 2 were not identified.

IMPLICATIONS:

1) Business Plan and Financial Risk Implications

Check the two boxes which apply:	
√ Item is under $5M	√ included in entirety in Business Plan
☐ Item is over $5M but under $10 M	☐ partially included in Business Plan
☐ Item is over $10M	☐ not included in Business Plan

The estimated annual impact of the recommended adjustment to the retirement date for Boundary Dam Units 1 and 2 and QE #3 is a $5.8 million increase in depreciation expense made up of the following:

Unit	Change in Depreciation Expense
Boundary Dam Unit 1	5,283,221
Boundary Dam Unit 2	1,003,341
Queen Elizabeth Unit 3	(46,862)
Electric & Mechanical Meters	(446,031)
Total	**5,793,669**

2) Other Risk Implications

Check the box (or boxes) that apply:		
☐ Technology / IT	☐ Environment	☐ Owner / Other
☐ Customers / Public	☐ Labour Relations / HR	☐ Regulatory
☐ Employees	☐ Legal / Land	☐ Safety

There are no other risk implications.

ALTERNATIVES:

1. Do not change the depreciation rates
In order to be in compliance with IFRS, the Corporation needs update its depreciation rates for 2013.

ADVANCE CONSULTATIONS:

The depreciation review was conducted by Finance through discussions with management from Power Production; Transmission; Distribution; Customer Services; IT&S and Supply Chain.

COMMUNICATIONS APPROACH:

Given the nature of this Decision Item, no communication is required at this time.

TIME FRAME/CONSEQUENCE OF DEFERRMENT:

The new depreciation rates are to be implemented effective January 1, 2013. Deferring approval will result in SaskPower using inappropriate depreciation rates for reporting its 2013 Q1 results.

SUBMITTED BY:

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Sandeep Kalra, Vice-President & Chief Financial Officer
Finance and Enterprise Risk Management

Prepared by: Troy King, Controller
Date: February 6, 2012

PRESENTED TO: **SaskPower Executive**

SUBJECT: **SaskPower 2014 Depreciation Rates**

MEETING DATE: **February 4, 2014**

Review Process

SaskPower Executive: February 4, 2014

Issue

The 2013 annual review of the retirement dates / average service lives was completed and there were no changes identified. This review was conducted internally by Finance and is based on discussions with management and operating personnel from the operating areas.

The only item to note is the depreciation rates for meters have changed. While the retirement date for meters (2015) has not changed, due to the purchase of additional electronic (non-AMI) meters in 2013, the depreciation rate has been increased to ensure these asset values are fully depreciated by the end of 2015. The impact of the rate changes is $885 thousand increase in depreciation expense each year.

Also, a Decision Item is being prepared to recommend permanently removing Boundary Dam Unit #2 from service on July 1, 2014, one year advanced from the original retirement date of June 30, 2015. If approved, the depreciation would be accelerated by one year resulting in an additional depreciation charge of $3.8 M in 2014. This charge is a non-cash item that will be offset by an equal reduction in depreciation expense in 2015.

Background

According to SaskPower's policy, a detailed depreciation study is to be conducted every five years to update the Corporation's depreciation rates with annual reviews for continued appropriateness. The last comprehensive depreciation study was completed in 2010 by Gannett Fleming and the revised depreciation rates were implemented effective January 1, 2011.

Depreciation is calculated on a straight-line basis over the estimated average service life (ASL) of the asset. This is referred to as the Average Group Life – Whole Life procedure. This is a widely used method for calculation of depreciation rates and has been accepted as a reasonable method in a number of regulatory jurisdictions throughout North America.

Action

Information only.

Implications

Information only.

Submitted by:

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Sandeep Kalra, Vice-President & Chief Financial Officer

Prepared by: Randeen Kaczmar, Acting Controller

PRESENTED TO: SaskPower Executive

SUBJECT: SaskPower 2014 Depreciation and Asset Retirement Obligation Study

MEETING DATE: January 27, 2015

Executive Summary

As per SaskPower's policy, depreciation and asset retirement obligation (ARO) studies were performed in 2014. The results are summarized below.

Approvals Required

SaskPower Executive: January 27, 2015

Recommendation

Depreciation Study

That the SaskPower Executive approve the following revisions to the estimated asset retirement dates and depreciation rates effective January 1, 2015:

Depreciable Property Group	Retirement Date	Revised Depreciation Rate	Current Depreciation Rate	Change
Boundary Dam Unit 4	2021	8.04%	3.78%	4.26%
Boundary Dam Unit 5	2022	4.73%	3.15%	1.58%
Boundary Dam Unit 6	2023	6.63%	3.97%	2.66%
Poplar River Unit 1	2028	4.41%	3.80%	0.61%
Poplar River Unit 2	2026	5.58%	3.97%	1.61%

ARO Study

That the SaskPower Executive approve the following revisions to the estimated decommissioning dates and estimates effective December 31, 2014:

Power Station	Decommission Year	Revised Cost Estimates	Current Cost Estimates	Change
Boundary Dam Power Station	2055	$79,065,000	$40,015,000	$39,050,000
Poplar River Power Station	2061	26,767,300	23,860,000	2,907,300
Shand Power Station	2045	15,747,000	14,150,000	1,597,000
Queen Elizabeth Power Station	2068	17,051,000	14,250,000	2,801,000
Success Power Station	2014	744,000	637,000	107,000
Landis Power Station	2023	853,000	865,000	(12,000)
Meadow Lake Power Station	2033	1,147,000	615,000	532,000
Ermine Power Station	2062	1,305,000	1,341,000	(36,000)
Yellowhead Power Station	2063	3,192,000	2,221,000	971,000
Cypress Wind Facility	2024	931,000	880,000	51,000
Centennial Wind Facility	2031	7,482,400	7,110,000	372,400
Total		$154,284,700	$105,944,000	$48,340,700

Key Issues

Depreciation Study

Issue	Analysis
Rates	The recommended depreciation rate adjustments are based on the annual review of the retirement dates / average service lives for continued appropriateness. The depreciation rate review was conducted internally by Finance and is based on discussions with management and personnel from the operating areas.
Coal Unit Retirement Dates	Based on discussions with management, Boundary Dam Units 4, 5 & 6 and Poplar River Units 1 & 2 were identified as requiring an adjustment to their retirement date / average service life based on the most recent supply plan. It was assumed that the coal plant units would be retrofitted for carbon capture prior to the Federal Regulations required retirement dates. Finance uses these retirement dates to determine the appropriate depreciation rates to apply within SAP. No adjustment for depreciation rates to the Shand Power Station are required as it is anticipated that a major capital upgrade will be required in 2022 to achieve the planned retirement date.
Carbon Capture Retrofit Impact	The impact of using the planned retirement dates assuming carbon capture versus the Federal regulated retirement dates from Environment Canada would result in an increase to annual depreciation expense of $9.1 million compared to $34.5 million.
Meters	As a result of the decision to not proceed with implementation of the AMI meters the average services lives of the electronic meters have now reverted back to an average of 8 years.

ARO Study

Issue	Analysis
Decommissioning Costs	Based on the results of the ARO study the estimated decommissioning costs increased $48.3 million. The majority of the increase relates to the addition of the Boundary Dam ICCS facility which added $34.9 million in decommissioning costs as estimated by Stantec based on construction costs. The remainder of the increase relates to inflationary cost increases. KGS Group was engaged to perform site visits and had discussions with operations management to support the revised decommissioning estimates for the remainder of the plants.
Decommissioning Dates	Decommissioning dates are based on plant asset retirement dates, however decommissioning activities can take 1 -5 years to complete after the plant retirement date. Therefore the decommissioning dates were extended to include an estimated average number of years to complete all removal activities.

Background and Analysis

According to SaskPower's policy, a detailed depreciation and ARO study is conducted every five years to update the Corporation's depreciation rates and decommissioning plans with annual reviews for continued appropriateness.

The last comprehensive depreciation study was completed in 2010 by Gannett Fleming and the next study is expected to be performed in 2015. SaskPower's policy is to calculate depreciation on a straight-line basis over the estimated average service life (ASL) of the asset. This is referred to as the Average Group Life – Whole Life procedure. As per Gannett Fleming, this is a widely used method for calculation of depreciation rates and has been accepted as a reasonable method in a number of regulatory jurisdictions throughout North America.

ARO studies have been performed internally over the last number of years however in 2014 management decided to engage KGS Group to perform a detailed analysis of our decommissioning cost estimates. Stantec was used to estimate the decommissioning costs of the Boundary Dam ICCS Facility.

SaskPower has established AROs to decommission its coal, natural gas, cogeneration and wind generation facilities. SaskPower also recognizes provisions for the decommissioning of assets containing PCBs in excess of federal regulations. SaskPower has not setup an ARO for its transmission, distribution or hydro generation assets as the Corporation expects to maintain and operate these assets indefinitely.

Implications

BUSINESS PLAN AND FINANCIAL:

☐ Under $5M
☒ Over $5M and under $20M
☐ Over $20M

☒ Fully included in Business Plan
☐ Partially included in Business Plan
☐ Not included in Business Plan

☐ Not Applicable

The estimated annual impact of the recommended adjustment to the asset retirement dates is a $7 million increase in depreciation expense made up of the following:

Unit	Change in Depreciation Expense
Boundary Dam Unit 4	$2,638,450
Boundary Dam Unit 5	1,226,188
Boundary Dam Unit 6	2,577,798
Poplar River Unit 1	869,623
Poplar River Unit 2	1,790,472
Electronic Meters	(2,040,873)
Other	(51,775)
Total	**$7,009,883**

The increase in decommissioning costs as a result of the ARO study does not have an immediate impact on the income statement as the Corporation builds up these provisions over time. As at December 31, 2014, property, plant and equipment and asset retirement obligations will increase $34 million respectively. The impact to net income in 2015 is immaterial.

CUSTOMER/STAKEHOLDER IMPACT ASSESSMENT:

Impact Rating: High ☐ Medium ☐ Low ☐ None ☒

ABORIGINAL IMPACT ASSESSMENT:

Impact Rating: High ☐ Medium ☐ Low ☐ None ☒

OTHER IMPLICATIONS:

☐ Shareholder (e.g. CIC, Government)
☐ Human Resources/Employees/Labour Relations
☐ Other Stakeholders:

☐ Regulatory/Environmental
☐ Technology/IT/Security
☐ Legal/Land/Privacy

☐ Safety
☒ None

Alternatives

1. **Do not use the assumption that the coal plant units will be retrofitted for carbon capture**
   If the units are not retrofitted for carbon capture prior to the Federal Regulations required retirement dates the depreciation expense would increase $34.5 million annually.

2. **Do not change the depreciation rates**
   In order to be in compliance with IFRS, the Corporation needs to review and update its depreciation rates annually.

Advance Consultation

Estimated average service lives were discussed and reviewed with the following:

- Blake Taylor, Director, Asset Management – Generation
- Scott Bannerman, Director, Engineering Services – Power Production
- Gary Erickson, Director, Asset Management and Field Services
- Amie Sanheim, Manager, Business Performance and Planning
- Jim Linnell, Manager, Fuel Business
- Mark Wagner, Engineer, Fleet Specifications
- Wendy McEwen, Manager, Business Support
- Geoffrey Trofimuk, Manager, Communications Eng
- Bonnie Hilts, Director, Properties & Shared Services
- Dean Mozdzen, Director, Operations Support

The ARO cost estimates and decommissioning dates were reviewed by the following:

- Ron Bend, Senior Business Advisor, Power Production
- Tony Finn, Director, Construction - North
- Blake Taylor, Director, Asset Management – Generation
- Doug Daverne, Director, CCS Initiatives – Boundary Dam
- Peter Hein, Engineer, SR Technical Services - Environment

Communications Plan

The Manager of Corporate Communications has reviewed and agrees with the following approach:

KEY STRATEGIC CONSIDERATIONS:

Timing: The new depreciation rates will be implemented effective January 1, 2015.

Profile: High ☐Medium ☐Low ☒

Key Messages: According to SaskPower's policy, depreciation rates and ARO's are reviewed annually for reasonability. The 2014 Depreciation and ARO Studies recommended revisions to the depreciation rates and decommissioning cost estimates and decommissioning years.

Governance

TYPE OF DECISION ITEM:

- ☐ Project
- ☐ Real Property Purchase/Sale
- ☒ Corporate Policy
- ☐ Procurement: Consistent with Procurement Policy & Procedures
- ☐ Procurement: Single Source
- ☐ Other:

Alignment with Strategic Plan

- ☐ Infrastructure management, renewal and growth
- ☐ Supply mix diversification
- ☐ Customer experience
- ☐ Stakeholder relations
- ☐ Technology enablement
- ☐ Environmental stewardship
- ☒ Process efficiency and cost management
- ☐ Workforce excellence

Submitted by:

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Sandeep Kalra, Vice-President and Chief Financial Officer

Prepared by: Daniella Kulcsar, Financial Reporting Consultant

Attachments:

#1 – ASL Financial Impact

#2 – 2015 Depreciation Rates for Generation Plants with Final Retirement Dates

#3 – Depreciation Impact on Generation Plants if Not Fitted for Carbon Capture

#4 – Decommissioning Estimates Comparison

#5 – ARO Balances- December 31, 2014

SaskPower

DECISION ITEM

PRESENTED TO: **SaskPower Executive**

SUBJECT: **SaskPower 2015 Depreciation Rate Review**

MEETING DATE: **March 22, 2016**

Executive Summary

As per SaskPower's policy, a depreciation rate review was performed in 2015. The results are summarized below.

Governance

APPROVALS REQUIRED:

SaskPower Executive: March 22, 2016

TYPE OF DECISION ITEM:

- ☐ Project
- ☐ Real Property Purchase/Sale
- ☐ Corporate Policy
- ☐ Report
- ☐ Procurement: Consistent with Procurement Policy & Procedures
- ☐ Procurement: Single Source
- ☒ Other: Corporate Depreciation Rates

RISK PROFILE:

This risk profile of this item has been assessed as Complex/High Risk (refer to attached Appendix entitled "Determination of Risk Profile") ☐ Yes ☒ No

BUSINESS PLAN AND FINANCIAL:

Estimated Value: $10.7 million

There are no cash flows associated with this item. The $10.7 million represents the incremental depreciation expense that would be recorded in SaskPower's 2016 -17 financial statements.

Portion included in Business Plan: ☐ Full ☐ Partial $<insert value> ☒ No ☐ N/A

Costs incurred for this project to date $N/A

Recommendation

That the SaskPower Executive approve the following:

1. Management apply the revisions noted in Appendix B to the estimated average service lives / retirement dates and depreciation rates effective April 1, 2016 for the year ending March 31, 2017.

2. It is management's expectation (best estimate) that either (a) SaskPower will convert Boundary Dam Units 4 & 5 to carbon capture in accordance with the timelines in the existing Federal regulations regarding greenhouse gas emissions for coal fired generation or (b) SaskPower and the Province of Saskatchewan will reach an Equivalency Agreement with the Federal Government that will permit SaskPower to operate Boundary Dam Units 4 & 5 beyond 2019.

Key Issues / Major Risks / Key Benefits / Implications

Issues / Risks / Benefits	Analysis / Implications
Depreciation Policy	SaskPower's policy is to calculate depreciation on a straight-line basis over the estimated average service life (ASL) of the asset. The recommended depreciation rate adjustments are based on the annual review of SaskPower's asset's estimated average service life for continued appropriateness. The depreciation rate review was conducted internally by Finance and is based on discussions with management and personnel from the operating areas.
Depreciation Rate Calculation for Generating Units a) Component Based Depreciation Rate	SaskPower uses the following approaches to establish the depreciation rates for its generating units. SaskPower's assets are broken down into depreciable property groups or components for amortization purposes. An average service life is developed for each component which in turn is used to calculate the appropriate deprecation rate for that component. Most of SaskPower's assets are depreciated using this approach.
        b) Final Retirement Date Based Depreciation Rate	For example, generating units are made up of several different components (turbine, generator, boiler, feed water heaters, etc.). Under the component based approach, each component that makes up the generating unit is amortized based on its own individual estimated useful life. A component based depreciation rate is applied to generating facilities that are expected to be kept operating over the long-term. In cases where a generation unit is expected to be retired or mothballed in the near future, all of the components that make up the generating unit are given the same useful life. This is done to ensure all components that make up the generating unit are fully amortized by the expected retirement date of the facility.

c) Conversion to Carbon Capture Based Depreciation Rate	In other cases, SaskPower has assumed that its coal generating units will be converted to carbon capture. In this situation, SaskPower uses a hybrid of the component based approach and the final retirement date approach. Based on SaskPower's experience with BD Unit #3, certain components within the generating unit are expected to be retired upon conversion to carbon capture. The depreciation rate for these components is set using the final retirement date approach. The remaining components are expected to continue to operate to the end of their expected useful life. The depreciation rate for these components is set using the component approach.
Coal Generation Unit Retirement Date Scenarios	SaskPower is recommending that it continue to assume that all coal facilities will be converted to carbon capture and no change be made to the final retirement dates on any of its coal generating units due to the uncertainty regarding the future of these assets. SaskPower is continuing to explore the possibility of converting its coal units to carbon capture in accordance with the deadlines established in the GHG Emission Guidelines. At the same time, SaskPower is also pursuing an Equivalency Agreement with the Federal Government that would provide SaskPower with more flexibility with regards to the GHG Emission Guidelines and timing of conversion of the coal generating units to carbon capture. A final scenario is the potential to retire the coal units in accordance with the GHG Emission Guidelines. Appendix C provides a summary of the impact of the various scenarios on SaskPower's depreciation expense.
Potential Loss on Retirement	SaskPower faces a significant risk if the Corporation does not either convert Boundary Dam Units 4 and 5 to clean coal or negotiate an Equivalency Agreement to extend the life of BD 4 and 5 beyond 2019. At the current depreciation rates, it is estimated SaskPower would be faced with an approximate $100 million write off in 2019 if the units were retired or mothballed at the end of that calendar year.
Controls and Protection Equipment	Electrical-mechanical protection relays and hydraulic-mechanical control systems have been replaced with digital computer based systems. As a result, the life expectancy of this equipment has decreased to due technology obsolescence. Therefore, management is recommending reducing the average service life from 25 to 15 years to reflect the fact that the equipment is being replaced more frequently.
Vehicles	As vehicle repairs and maintenance costs are so expensive, the Corporation's vehicle replacement policy has changed. As such, management is recommending reducing the average service lives for power operated and track mounted vehicles to 15 years from 20 and 25 years respectively.

Background and Analysis

According to SaskPower's policy, a detailed depreciation study is conducted every five years to update the Corporation's depreciation rates and decommissioning plans with annual reviews for continued appropriateness.

The last comprehensive depreciation study was completed in 2010 by Gannett Fleming and an updated review was supposed to occur in 2015. However, due to a cost-cutting initiative, it was decided by management to defer the external study to 2016. SaskPower's policy is to calculate depreciation on a straight-line basis over the estimated average service life (ASL) of the asset. This is referred to as the Average Group Life – Whole Life procedure. As per Gannett Fleming, this is a widely used method for calculation of depreciation rates and has been accepted as a reasonable method in a number of regulatory jurisdictions throughout North America.

Alignment with Strategic Plan

☐ Customer Experience & Stakeholder Relations
☒ Efficiency, Quality & Cost Management
☐ Workforce Excellence
☐ Sustainable Infrastructure & Reliability

Alternatives

1. **Third Party Review.**
   The Executive could direct that the Corporation bring in an independent 3rd party such as Gannett Fleming to conduct the depreciation review. That would require addition time and money to complete.

Advance Consultation

- Blake Taylor, Director, Generation Asset Management
- Iqbal Dhami, Director, Transmission Asset Management and Planning
- Grant Crawford, Director, Distribution Asset Management and Planning
- Jim Linnell, Manager, Fuel Business
- Mark Wagner, Engineer, Fleet Specifications
- Wendy McEwen, Manager, Business Support
- Geoffrey Trofimuk, Manager, Communications Eng
- Bonnie Hilts, Director, Properties & Shared Services
- Dean Mozdzen, Director, Operations Support
- Kevin Lalonde, Director, Business Support Services
- Debbie Nielson, Director, Environment

Communications Plan

Keith Moen, Director of Communications, has reviewed and agrees with the following approach.

Given the nature of this decision, no communication is required beyond the corporate governance process.

KEY STRATEGIC CONSIDERATIONS:

Timing: The new depreciation rates will be implemented effective January 1, 2016.

Profile: High ☐Medium ☐Low ☒

Key Messages:

According to SaskPower's policy, depreciation rates are reviewed annually for reasonability. The 2015 Depreciation rate review recommended revisions to the depreciation rates.

Submitted by:

Sandeep Kalra, Chief Financial Officer

Reviewed by: Troy King, Director, Corporate Planning & Controller

Prepared by: Daniella Kulcsar, Manager, Financial Reporting

Appendix A: Determination of Risk Profile
Appendix B: Recommended Changes to Retirement Dates / Useful Lives and Depreciation Rates
Appendix C: Average Service Life Financial Impact
Appendix D: SaskPower Coal Unit Depreciation Scenarios

Appendix A

Determination of Risk Profile
The risk rating / profile determination is intended to provide an early assessment of the business case / initiative /project under consideration and is to be supported by a more comprehensive assessment and analysis of key risks and mitigation plans. In addition, the risk profile is intended to identify any new risks to be considered.

The Before risk column represents a baseline for making the decision and is a reflection of the current risk assessment of the item. The Residual column reflects the risk to the company that will exist after implementation of the initiative / project and any significant risks that are implementation-related or remain after proposed mitigation is in place.

Each evaluation dimension is assessed a score of **L** for “Low Impact”, **M** for “Medium Impact” and **H** for “High Impact”. Low Impact items are to be managed at the Project Manager/ Sponsor level. Medium Impact items should be raised to the VP level. If any dimension is rated as high impact, the Decision Item is rated as complex/high risk and appropriate risk mitigation steps, including constituting a cross-functional risk committee for the duration of the project, will be implemented.

Risk Profile

Evaluation Dimensions	Description	Before L/M/H	Residual L/M/H
Safety (employee & public)	• Potential for injury/ disability/ fatality. • Absence of Standard Operating Procedures (or new Procedures) causing increased risk.	L	L
Impact on employees	• Potential for impacting employee engagement and well-being.	L	L
System security, reliability or availability	• Potential for damage to critical infrastructure and/or major system denial of service. • Risk due to a Major Investment Decision (Supply Decision / Major Transmission Decision).	L	L
Impact on **customers**	• Potential for impact to the customer experience and customer relationship related to: billing, service delivery time, outage frequency or duration, energy efficiency or self-generation.	L	L
Cost or Financial Exposure including: changes to capital cost, major critical financial assumptions and the correlation of assumptions used in forecasts and models.	• Value at Risk (Consider > $100 million = H ; < 10 million = L). • Potential impairment to billings and/or revenue stream or financial position. • Increased exposure to credit risk, interest rate or market condition volatility. • Significant changes in cost / benefit assumptions resulting in increased costs or lower benefits.	L	L
Supply relationships	• Impact on supplier relationships and/or opportunity for obtaining substitution.	L	L
Stakeholder engagement (includes owner, land owners, suppliers, community associations, aboriginal communities etc.)	• Essential consultation with shareholder; potential for opposition which may significantly influence the outcome of the decision and result in cancelation or deferment of the initiative / project. • Essential consultation with Stakeholder; potential for intervention by the shareholder, alter project scope/schedule, and / or significantly influence the outcome of a decision. • Potential for impact to land and / or change in resource availability. Potential to damage established relationship. Matter may result in political debate and / or extended media attention.	L	L
Legal, regulatory, compliance or environmental considerations	• New or expected changes to complex/non-routine legal, regulatory or compliance considerations. • Environment - regulatory impact, significant potential for fines or penalties, known impact to environment including pollution, biodiversity / habitat, and resource extraction. • Potential for permanent or widespread damage to air, water or land.	L	L
Complexity	• Reliance on experts/ external resources including contractors and/or consultants. • New and complex technology.	L	L
Opportunity forgone, lost or deferred	• Opportunity to achieve strategic priority may be lost or indefinitely postponed.	L	L
Implications and impact to the Corporation **overall**.	• Potential for impact on reputation, the business model, business operations or processes. • Regulatory, political, social or international profile.	L	L
Other	• Provide example • ______________________________		
New Risks	• New risk (not covered above) arising due to undertaking this project/initiative. Provide examples below. • ______________________________		

Recommended Changes to Retirement Dates / Useful Lives and Depreciation Rates

Depreciable Property Group	Recommended Retirement Date	Current Retirement Date	Recommended Depreciation Rate	Current Depreciation Rate	Change	Est Annual $ Impact (000's)
Boundary Dam Unit 4	2021	2021	9.27%	8.04%	1.23%	$ 683
Boundary Dam Unit 5	2022	2022	6.70%	4.73%	1.97%	1,218
Boundary Dam Unit 6	2023	2023	6.86%	6.63%	0.23%	223
Poplar River Unit 1	2028	2028	4.96%	4.41%	0.55%	701
Poplar River Unit 2	2026	2026	5.61%	5.58%	0.03%	37
Landis	2020	2020	7.14%	3.29%	3.85%	1,278
Meadow Lake	2020	2020	7.15%	6.65%	0.50%	14
Queen Elizabeth Unit 3	2022	2022	13.30%	4.58%	8.72%	1,426

Note: The depreciation rates for the above power plants increased despite no change in the assumed retirement date as a result of capital expenditures during 2015 that require an increase in the depreciation rate to ensure the compnenets are fully amortized by the expected retirement date.

Depreciable Property Group	Recommended Average Service Life (years)	Current Average Service Life (years)	Recommended Depreciation Rate	Current Depreciation Rate	Change	Est Annual $ Impact (000's)
Generation – Controls and Protection	15	25	6.67%	4.00%	2.67%	$ 4,701
Vehicles – Power Operated	15	20	6.00%	4.50%	1.50%	164
Vehicles – Track Mounted	15	25	6.00%	3.60%	2.40%	264

Total	**$ 10,709**

SaskPower

2015 Average Service Life (ASL) Study
Financial Impact

Depreciable Property Group	Acquisition Value Dec 31, 2015	Acc Dep'n Dec 31, 2015	Net Book Value Dec 31, 2015	Current ASL (Years)	Current ASL (%)	Current Salvage Value	Estimated 2016 Dep'n Exp @ Current Rates	Recommended ASL (Years)	Recommended ASL (%)	Recommended Salvage Value	Estimated 2016 Dep'n Exp Recommended	Dep'n Exp Variance
Generation:												
Turbine - Thermal	$ 136,210,634	$ (36,321,641)	$ 99,888,994	25	4.00%	-	$ 5,383,242	25	4.00%	-	$ 5,383,242	$ -
Turbine - Hydro	$ 210,267,187	$ (76,329,328)	$ 133,937,859	50	2.00%	-	$ 4,021,140	50	2.00%	-	4,021,140	$ -
Compressor - Gas	$ 186,059,752	$ (54,717,998)	$ 131,341,754	25	4.00%	-	$ 7,442,390	25	4.00%	-	7,442,390	$ -
Turbine - Gas - H25 Units (QE#4-12 Units)	$ 147,720,111	$ (23,125,895)	$ 124,594,216	15	6.67%	-	$ 9,875,541	15	6.67%	-	9,875,541	$ -
Turbine - Gas - LM6000 Units (Ermine & Yellowhead)	$ 76,345,657	$ (23,404,446)	$ 52,941,210	15	6.67%	-	$ 5,092,255	15	6.67%	-	5,092,255	$ -
Turbine - Wind	$ 176,397,397	$ (88,121,406)	$ 88,275,991	20	5.00%	-	$ 8,819,870	20	5.00%	-	8,819,870	$ -
Generator - Thermal	$ 123,984,745	$ (36,474,672)	$ 87,510,072	25	4.00%	-	$ 4,708,549	25	4.00%	-	4,708,549	$ -
Generator - Hydro	$ 129,548,048	$ (64,597,751)	$ 64,950,297	40	2.50%	-	$ 3,015,986	40	2.50%	-	3,015,986	$ -
Generator - Gas	$ 158,830,029	$ (46,344,349)	$ 112,485,679	25	4.00%	-	$ 6,353,326	25	4.00%	-	6,353,326	$ -
Generator and Gearboxes Wind	$ 58,324,092	$ (33,901,937)	$ 24,422,155	15	6.67%	-	$ 3,890,217	**15**	6.67%	-	3,890,217	$ -
Boiler - Conventional	$ 482,404,924	$ (132,974,893)	$ 349,430,031	25	4.00%	-	$ 18,224,990	25	4.00%	-	18,224,990	$ -
Boiler - HRSG/OTSG	$ 101,599,186	$ (4,891,187)	$ 96,707,999	25	4.00%	-	$ 4,063,722	**25**	4.00%	-	4,063,722	$ -
High Energy Piping	$ 229,804,000	$ (23,703,381)	$ 206,100,619	50	2.00%	-	$ 4,531,003	50	2.00%	-	4,531,003	$ -
High Pressure Feedwater Heaters	$ 10,702,342	$ (6,829,176)	$ 3,873,167	20	5.00%	-	$ 476,065	20	5.00%	-	476,065	$ -
Low Pressure Feedwater Heaters	$ 3,101,060	$ (1,093,425)	$ 2,007,634	35	2.86%	-	$ 88,690	35	2.86%	-	88,690	$ -
Condenser	$ 19,776,607	$ (10,538,048)	$ 9,238,559	30	3.33%	-	$ 472,194	30	3.33%	-	472,194	$ -
Pulverizer, Feeders and Stabilizing Fuel Equip	$ 90,192,834	$ (58,466,426)	$ 31,726,409	35	2.86%	-	$ 1,710,454	35	2.86%	-	1,710,454	$ -
High Voltage > 1KV	$ 70,586,651	$ (16,855,989)	$ 53,730,662	35	2.86%	-	$ 1,989,119	35	2.86%	-	1,989,119	$ -
Low Voltage < 1KV	$ 85,589,632	$ (19,486,488)	$ 66,103,145	25	4.00%	-	$ 3,237,479	25	4.00%	-	3,237,479	$ -
Underground Ducts and Cable Trays	$ 12,301,776	$ (4,906,442)	$ 7,395,333	50	2.00%	-	$ 239,993	50	2.00%	-	239,993	$ -
Controls and Protection	$ 164,046,930	$ (44,403,442)	$ 119,643,488	25	4.00%	-	$ 7,051,542	**15**	6.67%	-	11,752,569	$ 4,701,028
Flue Gas and Ash System	$ 231,144,918	$ (147,026,623)	$ 84,118,295	25	4.00%	-	$ 7,109,124	25	4.00%	-	7,109,124	$ -
Large Motors, Pumps and Fans	$ 29,971,701	$ (9,057,094)	$ 20,914,606	35	2.86%	-	$ 767,271	35	2.86%	-	767,271	$ -
Dams, Waterways and Reservoirs	$ 250,921,789	$ (162,605,185)	$ 88,316,604	100	1.00%	-	$ 2,503,854	100	1.00%	-	2,503,854	$ -
Spillways	$ 254,185,575	$ (118,854,380)	$ 135,331,195	60	1.67%	-	$ 4,241,761	60	1.67%	-	4,241,761	$ -
Penstock and Intake Structures	$ 126,179,048	$ (72,555,032)	$ 53,624,016	75	1.33%	-	$ 1,532,594	75	1.33%	-	1,532,594	$ -
Water Treatment Plant Equipment	$ 85,703,488	$ (47,529,713)	$ 38,173,775	25	4.00%	-	$ 2,876,069	25	4.00%	-	2,876,069	$ -
Misc Air/ Water/Steam/Sewer/Sump/Fire Systems	$ 48,968,259	$ (18,262,286)	$ 30,705,973	40	2.50%	-	$ 1,048,074	40	2.50%	-	1,048,074	$ -
Coal and Auxiliary Fuel Handling Equipment	$ 65,407,771	$ (40,722,173)	$ 24,685,598	35	2.86%	-	$ 1,539,323	35	2.86%	-	1,539,323	$ -
Gas and Auxiliary Fuel Handling Equipment	$ 57,989,256	$ (6,559,167)	$ 51,430,089	50	2.00%	-	$ 1,155,045	50	2.00%	-	1,155,045	$ -
Lagoons (Ash)	$ 83,112,260	$ (45,312,379)	$ 37,799,881	20	5.00%	-	$ 3,196,198	20	5.00%	-	3,196,198	$ -
Cooling Water Equipment and Lines	$ 99,422,062	$ (46,443,306)	$ 52,978,756	40	2.50%	-	$ 1,951,162	40	2.50%	-	1,951,162	$ -
Boiler House	$ 172,571,511	$ (86,800,815)	$ 85,770,697	50	2.00%	-	$ 2,515,140	50	2.00%	-	2,515,140	$ -
Turbine House	$ 196,825,731	$ (104,197,008)	$ 92,628,723	50	2.00%	-	$ 3,295,449	50	2.00%	-	3,295,449	$ -
Administration/ Shop and Auxiliary Buildings	$ 197,903,244	$ (55,721,232)	$ 142,182,012	50	2.00%	-	$ 3,591,948	50	2.00%	-	3,591,948	$ -
Water Treatment Plant and Pond Buildings	$ 34,820,080	$ (25,913,026)	$ 8,907,054	50	2.00%	-	$ 478,829	50	2.00%	-	478,829	$ -
Coal Handling Facilities	$ 74,941,171	$ (54,360,753)	$ 20,580,417	50	2.00%	-	$ 980,953	50	2.00%	-	980,953	$ -
Polish Ponds Recirculation House	$ 11,847,079	$ (11,847,079)	$ -	50	2.00%	-	$ -	50	2.00%	-	-	$ -
Cooling Water Pump House	$ 53,923,211	$ (22,810,021)	$ 31,113,191	50	2.00%	-	$ 836,059	50	2.00%	-	836,059	$ -
Land Rights	$ 1,155,148	$ (541,196)	$ 613,951	25	4.00%	-	$ 45,612	25	4.00%	-	45,612	$ -
Roads, Railroads and Airfields	$ 58,741,857	$ (32,451,081)	$ 26,290,775	30	3.33%	-	$ 1,645,472	30	3.33%	-	1,645,472	$ -
Experimental Emissions Control Equipment	$ 78,703,476	$ (18,608,516)	$ 60,094,960	5	20.00%	-	$ 14,704,514	5	20.00%	-	14,704,514	$ -
CO2 Compressor Facility	$ 81,319,981	$ (3,254,857)	$ 78,065,124	30	3.33%	-	$ 2,708,114	30	3.33%	-	2,708,114	$ -
Acid Plant	$ 26,082,425	$ (1,151,790)	$ 24,930,636	30	3.33%	-	$ 868,720	30	3.33%	-	868,720	$ -
SO2 & CO2 Capture Equipment	$ 291,059,155	$ (12,752,866)	$ 278,306,289	30	3.33%	-	$ 9,697,630	30	3.33%	-	9,697,630	$ -
Flue Gas Cooling	$ 45,044,014	$ (1,989,426)	$ 43,054,588	30	3.33%	-	$ 1,500,080	30	3.33%	-	1,500,080	$ -
Environmental Control Buildings	$ 90,771,173	$ (2,379,046)	$ 88,392,126	50	2.00%	-	$ 1,816,254	50	2.00%	-	1,816,254	$ -
Generator - Diesel	$ 167,562	$ (167,562)	$ -	5	20.00%	-	$ -	5	20.00%	-	-	$ -
Lease Assets	$ 1,233,210,594	$ (336,136,175)	$ 897,074,419	25	4.00%	-	$ 56,328,424	25	4.00%	-	56,328,424	$ -
Generation excluding Plants Total	**6,655,887,132**	**(2,293,498,107)**	**4,362,389,025**				**229,621,442**				**234,322,469**	**4,701,028**

Depreciable Property Group	Acquisition Value Dec 31, 2015	Acc Dep'n Dec 31, 2015	Net Book Value Dec 31, 2015	Current ASL (Years)	Current ASL (%)	Current Salvage Value	Estimated 2016 Dep'n Exp @ Current Rates	Recommended ASL (Years)	Recommended ASL (%)	Recommended Salvage Value	Estimated 2016 Dep'n Exp Recommended	Dep'n Exp Variance
					2015 Depreciation Rate	Date of Retirement			2016 Suggested Depreciation Rate	Date of Retirement		
Generation Plants with Final Retirement Dates:												
Boundary Dam Unit #4	$ 77,808,424	$ (46,999,726)	$ 30,808,698		8.04%	2021	$ 4,451,325		9.27%	2021	5,134,783	683,458
Boundary Dam Unit #5	$ 79,991,558	$ (51,036,296)	$ 28,955,262		4.73%	2022	$ 2,918,271		6.70%	2022	4,136,466	1,218,195
Boundary Dam Unit #6	$ 138,236,372	$ (84,437,413)	$ 53,798,959		6.63%	2023	$ 6,502,015		6.86%	2023	6,724,870	222,855
Poplar River Unit #1	$ 218,256,763	$ (136,656,613)	$ 81,600,150		4.41%	2028	$ 5,576,414		4.96%	2028	6,276,935	700,520
Poplar River Unit #2	$ 193,409,918	$ (123,908,408)	$ 69,501,510		5.58%	2026	$ 6,280,964		5.61%	2026	6,318,319	37,355
Landis	$ 43,391,302	$ (31,540,493)	$ 11,850,809		3.29%	2020	$ 1,091,932		7.14%	2020	2,370,162	1,278,230
Meadow Lake	$ 13,232,050	$ (12,270,283)	$ 961,768		6.65%	2020	$ 178,975		7.15%	2020	192,354	13,379
Queen Elizabeth Unit #3	$ 22,923,838	$ (7,700,797)	$ 15,223,040		4.58%	2022	748,682		13.30%	2022	2,174,720	1,426,038
Generation Plants Total	**787,250,225**	**(494,550,029)**	**292,700,196**				**27,748,578**				**33,328,608**	**5,580,030**
Generation Total	**7,443,137,357**	**(2,788,048,136)**	**4,655,089,221**				**257,370,020**				**267,651,077**	**10,281,057**
Transmission:												
Conductors	$ 217,958,041	$ (88,851,632)	129,106,409	55	1.82%	-	$ 3,969,078	55	1.82%	-	3,969,078	-
Control & Auxiliaries	$ 127,058,587	$ (58,390,498)	68,668,089	35	2.86%	-	$ 3,650,404	35	2.86%	-	3,650,404	-
Devices	$ 93,165,121	$ (42,048,120)	51,117,001	35	2.86%	-	$ 2,338,076	35	2.86%	-	2,338,076	-
Line Devices	$ 109,955,212	$ (25,272,989)	84,682,223	25	4.00%	-	$ 4,357,085	25	4.00%	-	4,357,085	-
Land Rights	$ 174,290,627	$ (31,528,988)	142,761,639	45	2.22%	-	$ 3,856,399	45	2.22%	-	3,856,399	-
Switching Station Conductor & Devices	$ 16,425,274	$ (12,634,934)	3,790,340	40	2.50%	-	$ 410,652	40	2.50%	-	410,652	-
Power Transformers	$ 107,138,595	$ (39,485,369)	67,653,226	50	2.00%	-	$ 2,153,053	50	2.00%	-	2,153,053	-
Protective Relays	$ 14,178,376	$ (3,909,931)	10,268,446	20	5.00%	-	$ 698,197	20	5.00%	-	698,197	-
Site Improvements	$ 33,435,280	$ (5,790,998)	27,644,282	40	2.50%	-	$ 835,966	40	2.50%	-	835,966	-
Superstructures	$ 58,228,033	$ (17,339,687)	40,888,346	45	2.22%	-	$ 1,307,033	45	2.22%	-	1,307,033	-
Steel Structures	$ 610,084,127	$ (94,275,805)	515,808,321	50	2.00%	-	$ 12,181,790	50	2.00%	-	12,181,790	-
Buildings, Roads, Rail & Airfields	$ 19,128,416	$ (5,905,601)	13,222,815	50	2.00%	-	$ 382,825	50	2.00%	-	382,825	-
Wood Structures	$ 219,569,769	$ (89,123,100)	130,446,669	45	2.22%	-	$ 4,825,956	45	2.22%	-	4,825,956	-
Temporary Services	$ 7,041,295	$ (7,029,973)	11,322	3	33.33%	-	$ 14,458	3	33.33%	-	14,458	-
Transmission Total	**1,807,656,753**	**(521,587,626)**	**1,286,069,127**				**40,980,973**				**40,980,973**	**-**
Distribution:												
Substation Equipment	$ 152,409,520	$ (61,434,571)	90,974,949	35	2.86%	-	$ 4,319,888	35	2.86%	-	4,319,888	-
Buildings & Improvements	$ 31,809,278	$ (4,410,119)	27,399,160	40	2.50%	-	$ 789,066	40	2.50%	-	789,066	-
Land Rights	$ 13,586,968	$ (3,245,232)	10,341,736	35	2.86%	-	$ 386,555	35	2.86%	-	386,555	-
Apparatus	$ 424,763,133	$ (131,821,003)	292,942,130	35	2.86%	-	$ 12,126,828	35	2.86%	-	12,126,828	-
Overhead Distribution	$ 1,271,535,928	$ (590,370,460)	681,165,468	35	2.86%	-	$ 30,507,882	35	2.86%	-	30,507,882	-
Overhead Services	$ 79,980,515	$ (18,913,328)	61,067,188	35	2.86%	-	$ 2,313,841	35	2.86%	-	2,313,841	-
Overhead Streetlights	$ 21,090,037	$ (14,538,954)	6,551,084	35	2.86%	-	$ 366,752	35	2.86%	-	366,752	-
Power Transformers	$ 96,522,356	$ (24,428,703)	72,093,653	40	2.50%	-	$ 2,233,613	40	2.50%	-	2,233,613	-
Structures & Foundations	$ 23,903,824	$ (5,132,383)	18,771,441	40	2.50%	-	$ 590,373	40	2.50%	-	590,373	-
Underground Distribution	$ 939,924,365	$ (415,387,790)	524,536,575	35	2.86%	-	$ 26,855,992	35	2.86%	-	26,855,992	-
Underground Services	$ 282,250,656	$ (66,793,715)	215,456,942	35	2.86%	-	$ 8,139,826	35	2.86%	-	8,139,826	-
Underground Streetlights	$ 63,819,171	$ (24,488,114)	39,331,057	30	3.33%	-	$ 2,114,174	30	3.33%	-	2,114,174	-
Temporary Distribution Services	$ 2,722,858	$ (2,297,069)	425,790	3	33.33%	-	$ 406,871	3	33.33%	-	406,871	-
Distribution Total	**3,404,318,610**	**(1,363,261,439)**	**2,041,057,171**				**91,151,661**				**91,151,661**	**-**
Mining:												
Mining - Surface Rights	$ 24,077,540	$ (8,319,171)	15,758,369	15	4.67%	30%	$ 752,362	15	4.67%	30%	752,362	-
Mining - Miscellaneous Mining Buildings	$ 280,269	$ (204,750)	75,518	40	2.50%	-	$ 7,007	40	2.50%	-	7,007	-
Mining - Transmission Facilities	$ 7,612,543	$ (6,093,591)	1,518,953	40	2.50%	-	$ 134,939	40	2.50%	-	134,939	-
Mining - Dragline & Mining Equipment	$ 3,438,179	$ (1,933,975)	1,504,203	20	5.00%	-	$ 171,909	20	5.00%	-	171,909	-
Mining Total	**35,408,531**	**(16,551,488)**	**18,857,043**				**1,066,217**				**1,066,217**	**-**

Depreciable Property Group	Acquisition Value Dec 31, 2015	Acc Dep'n Dec 31, 2015	Net Book Value Dec 31, 2015	Current ASL (Years)	Current ASL (%)	Current Salvage Value	Estimated 2016 Dep'n Exp @ Current Rates	Recommended ASL (Years)	Recommended ASL (%)	Recommended Salvage Value	Estimated 2016 Dep'n Exp Recommended	Dep'n Exp Variance
Other Assets:												
V&E - Light Weight	$ 48,458,132	$ (26,281,130)	22,177,002	7	13.29%	7%	$ 4,896,785	7	13.29%	7%	4,896,785	-
V&E - Medium Weight	$ 32,151,161	$ (15,651,480)	16,499,681	12	7.75%	7%	$ 2,176,814	12	7.75%	7%	2,176,814	-
V&E - Heavy Weight	$ 43,290,163	$ (17,652,493)	25,637,670	12	7.75%	7%	$ 2,879,901	12	7.75%	7%	2,879,901	-
V&E - Power Operated	$ 11,517,514	$ (3,934,912)	7,582,603	20	4.50%	10%	$ 492,763	15	6.00%	10%	657,017	164,254
V&E - Miscellaneous	$ 4,394,805	$ (2,119,184)	2,275,621	20	4.50%	10%	$ 167,288	20	4.50%	10%	167,288	-
V&E - Stores	$ 5,881,931	$ (1,934,499)	3,947,432	20	4.50%	10%	$ 258,102	20	4.50%	10%	258,102	-
V&E - Track Mounted	$ 10,624,626	$ (2,148,534)	8,476,093	25	3.60%	10%	$ 395,515	15	6.00%	10%	659,192	263,677
V&E - Trailers	$ 11,204,526	$ (3,046,016)	8,158,510	20	5.00%	-	$ 550,832	20	5.00%	-	550,832	-
Computer Application Development	$ 244,413,721	$ (186,278,825)	58,134,896	5	20.00%	-	$ 24,840,248	5	20.00%	-	24,840,248	-
Computer Equipment	$ 98,468,740	$ (75,717,866)	22,750,875	4	25.00%	-	$ 10,609,774	4	25.00%	-	10,609,774	-
CP&C - Telecontrol - Equipment	$ 80,476,884	$ (47,221,525)	33,255,360	10	10.00%	-	$ 6,434,163	10	10.00%	-	6,434,163	-
CP&C - Master Control Equipment	$ 17,177,129	$ (14,140,874)	3,036,255	5	20.00%	-	$ 1,121,640	5	20.00%	-	1,121,640	-
CP&C - Networks	$ 4,457,243	$ (1,040,468)	3,416,775	4	25.00%	-	$ 1,129,943	4	25.00%	-	1,129,943	
CP&C - Cable & Land Rights	$ 43,996,033	$ (12,548,909)	31,447,124	35	2.86%	-	$ 1,190,790	35	2.86%	-	1,190,790	-
CP&C - Buildings	$ 10,286,366	$ (4,834,646)	5,451,720	50	2.00%	-	$ 205,727	50	2.00%	-	205,727	-
Head Office Building	$ 47,484,455	$ (2,569,349)	44,915,106	60	1.00%	40%	$ 474,788	60	1.00%	40%	474,788	-
Research & Development Building	$ 15,032,628	$ (4,847,673)	10,184,955	50	1.00%	50%	$ 150,326	50	1.00%	50%	150,326	-
PCB Building	$ 2,823,523	$ (2,823,523)	0				$ -					
Other Buildings	$ 97,432,514	$ (13,668,440)	83,764,074	40	1.88%	25%	$ 1,818,406	40	1.88%	25%	1,818,406	-
Shand Greenhouse	$ 5,120,101	$ (2,613,368)	2,506,732	40	2.50%	-	$ 128,003	40	2.50%	-	128,003	-
Shand Greenhouse - Other	$ 397,981	$ (361,899)	36,082				$ 9,584				9,584	-
Tools & Equipment	$ 26,884,219	$ (11,274,727)	15,609,492	10	10.00%	-	$ 2,312,029	10	10.00%	-	2,312,029	-
Office Machines	$ 1,915,058	$ (1,320,523)	594,535	10	10.00%	-	$ 150,767	10	10.00%	-	150,767	-
Modular Work Systems	$ 17,861,483	$ (8,236,944)	9,624,539	15	6.67%	-	$ 1,191,361	15	6.67%	-	1,191,361	-
Furniture	$ 12,420,239	$ (3,725,269)	8,694,970	15	6.67%	-	$ 856,857	15	6.67%	-	856,857	-
Meters - Mechanical	$ 15,352,870	$ (9,311,399)	6,041,471	15	6.67%	-	$ 697,921	15	6.67%	-	697,921	-
Meters - Electronic	$ 71,277,271	$ (34,405,233)	36,872,038	8	12.50%	-	$ 6,270,141	8	12.50%	-	6,270,141	-
Meters - Revenue	$ 4,332,218	$ (3,895,105)	437,113	8	12.50%	-	$ 176,224	8	12.50%	-	176,224	-
Other Assets Total	**985,133,535**	**(513,604,814)**	**471,528,721**				**71,586,692**				**72,014,623**	**427,931**
Total Depreciable Property Groups	**$ 13,675,654,786**	**$ (5,203,053,503)**	**$ 8,472,601,283**				**$ 462,155,562**				**$ 472,864,550**	**$ 10,708,989**

Appendix D

SaskPower Coal Unit Depreciation Scenarios

Generation Facility	Asset Net Book Value Dec 31 / 15	Scenario 1 - Status Quo: Conversion / Retirement Date	Dep'n Index	Annual Dep'n Expense	Scenario 2 - Carbon Capture: Conversion / Retirement Date	Dep'n Index	Annual Dep'n Expense	Dep'n Expense Variance	Scenario 3 -Equivalency Agreement: Conversion / Retirement Date	Dep'n Index	Annual Dep'n Expense	Dep'n Expense Variance	Scenario 4 - Retire at Regulation Date: Retirement Date	Dep'n Index	Annual Dep'n Expense	Dep'n Expense Variance
BD Unit 3 - Power Island	572,244,443	2044	C	20,408,872	2044	C	20,408,872	-	2044	C	20,408,872	-	2044	C	20,408,872	-
BD Unit 3 - Carbon Capture	636,507,698	2044	C	20,486,631	2044	C	20,486,631	-	2044	C	20,486,631	-	2044	C	20,486,631	-
BD Unit 4	79,368,295	2021	R	6,968,324	2023	R	6,368,086	(600,238)	2029	F	5,669,164	(1,299,160)	2019	F	19,842,074	12,873,750
BD Unit 5	57,447,959	2022	R	4,465,967	2025	R	4,443,223	(22,744)	2029	F	4,103,426	(362,541)	2019	F	14,361,990	9,896,023
BD Unit 6	98,938,824	2023	R	9,368,326	2027	R	7,349,557	(2,018,769)	2027	F	8,244,902	(1,123,424)	2027	F	8,244,902	(1,123,424)
BD Common Assets	146,429,055	2044	C	5,480,928	2044	C	5,480,928	-	2044	C	5,480,928	-	2044	C	5,480,928	-
Poplar River Unit 1	125,550,245	2028	R	7,825,144	2029	R	8,077,312	252,168	2040	F	5,022,010	(2,803,134)	2029	F	8,967,875	1,142,731
Poplar River Unit 2	117,425,250	2026	R	8,953,294	2029	R	7,636,723	(1,316,571)	2035	F	5,871,262	(3,082,032)	2029	F	8,387,518	(565,776)
Poplar River Common Assets	56,512,810	2059	C	2,830,714	2059	C	2,830,714	0	2040	F	2,260,512	(570,202)	2029	F	4,036,629	1,205,915
Shand	239,260,196	2042	C	20,796,466	2042	C	20,796,466	-	2022	R	24,881,214	4,084,748	2042	C	20,796,466	-
Total	**2,129,684,774**			**107,584,667**			**103,878,513**	**(3,706,154)**			**102,428,922**	**(5,155,745)**			**131,013,886**	**23,429,219**

Depreciation Index

C = Component Based Depreciation

F = Final Retirement Date

R = Replace with Carbon Capture Components

SRRP Q14:

Reference: Depreciation

Has SaskPower's auditor reviewed and accepted all changes to depreciation rates or service lives proposed by SaskPower since the last external review of depreciation rates was completed?

Response:

Yes. SaskPower's external auditors – Deloitte and the Office of the Provincial Auditor of Sasaktchewan – have reviewed and accepted all changes to deprecation rates and estimated service lives since the last external depreciation review was completed.

SRRP Q15:
Reference: Depreciation
As part of its annual review of depreciation rates does SaskPower review or survey depreciation rates used by peer electric utilities? If so, please discuss the process used by SaskPower and how this information is used to inform any changes to SaskPower's proposed depreciation rates.

Response:

SaskPower reviews the depreciation rates used by its peer electric utilities as part of the external depreciation review which typically occurs every five years. The last external depreciation study was performed in 2010 by Gannett Fleming. During the review, the estimated service lives of SaskPower's assets were compared with those of utilities across Canada. The results of the external consultant's review determined that SaskPower's depreciation rates were comparable with other utilities across Canada.

On an annual basis, SaskPower reviews its depreciation rates with internal personnel to determine whether any changes to the estimated useful lives are required based on manufacturers' guidance, past experience and future expectations.

SaskPower also has appointed a representative from the Finance Department as a member of the Canadian Electricity Association Finance & Accounting Committee. This forum provides management with the opportunity to attend meetings with other utilities across Canada on a semi-annual basis and participate in various surveys and discussion topics, including depreciation.

It is important to note that there are only a handful of utilities across Canada that prepare financial statements in accordance with International Financial Reporting Standards (IFRS). As such, depreciation rates set by other utilities may not be comparable.

SRRP Q16:

Reference: **Depreciation**

When does SaskPower anticipate completing its next external depreciation study?
Has SaskPower retained an external consultant to perform its next depreciation study?

Response:

SaskPower anticipates performing the next external deprecation study in fiscal 2017-18. Therefore, the Corporation has not retained an external consultant as of yet to perform the study.

The last external depreciation study was completed in 2010 by Gannett Fleming. The impact of the external consultant's review was a reduction in depreciation expense of $1.3 million in 2011.

An updated external depreciation review was supposed to occur in 2015. However, due to a cost-cutting initiative, it was decided by management to defer the external study to 2016.

As these cost-cutting restraint measures continue, management has once again decided to defer the study to 2017-18. Instead, this year management will focus its efforts on internally reviewing transmission and distribution asset estimated service lives and depreciation rates to determine whether or not any changes need to be made.

SRRP Q17:

Reference: **Forecast Saskatchewan Sales Revenues**

a) Please confirm whether the revenues for 2016-17 and 2017-18 in the table on page 23 of the application are at existing rates or proposed rates.

b) Please provide a proof of revenue schedule showing the billing determinants (e.g. number of customers, billed demand, energy), rates and revenues for the existing rates and SaskPower's proposed rates for each customer class for 2016/17 and 2017/18.

Response:

a) The fiscal year forecasts for 2016-17 and 2017-18 are based on proposed rates.

b) Please see the following tables.

Proof of Revenue
2016/2017 - Annualized Basis

Rate Code	Residential	Determinant	Revenue 2015 Rates	Blended Rate	Revenue 2016 July 1 Rates	Blended Rate	Difference	Blended Rate Pct Diff	Revenue Pct Difference
E01, E02	**Basic (Customers)**	330,207	$ 80,114,380	$ 20.22	$ 84,202,901	$ 21.25	$ 4,088,521	5.1%	5.1%
	Energy (Gwh)	2,545.0	$ 321,255,712	$ 0.12623	$ 337,645,531	$ 0.13267	$ 16,389,819	5.1%	5.1%
E03, E04	**Basic (Customers)**	56,507	$ 19,792,886	$ 29.19	$ 20,803,588	$ 30.68	$ 1,010,702	5.1%	5.1%
	Energy (Gwh)	737.0	$ 93,044,501	$ 0.12625	$ 97,780,725	$ 0.13268	$ 4,736,224	5.1%	5.1%
	Total Residential		$ 514,207,479		$ 540,432,745		$ 26,225,266		5.1%
Rate Code	**Commercial**								
E05, E06, E07, E08, E10, E12	**Basic (Customers)**	2,760	$ 2,090,928	$ 63.13	$ 2,197,496	$ 66.35	$ 106,568	5.1%	5.1%
	Energy (Gwh)	2,152.7	$ 163,486,020	$ 0.07594	$ 171,817,929	$ 0.07981	$ 8,331,909	5.1%	5.1%
	Demand (kVa)	6,480,851	$ 64,869,111	$ 10.01	$ 68,177,745	$ 11	$ 3,308,634	5.1%	5.1%
E15, E16, E17, E18, E35, E36, E37, E38	**Basic (Customers)**	2,331.00	$ 442,978	$ 15.84	$ 465,481	$ 16.64	$ 22,503	5.1%	5.1%
	Energy (Gwh)	11.8	$ 1,282,793	$ 0.10902	$ 1,347,819	$ 0.11455	$ 65,026	5.1%	5.1%
E75, E76, E77, E78	**Basic (Customers)**	53,094	$ 19,002,951	$ 29.83	$ 19,973,177	$ 31.35	$ 970,226	5.1%	5.1%
	Energy (Gwh)	1,617.4	$ 191,626,760	$ 0.11847	$ 201,392,100	$ 0.12451	$ 9,765,340	5.1%	5.1%
	Demand (kVa)	2,715,203	$ 2,860,185	$ 1.05	$ 3,005,973	$ 1.11	$ 145,788	5.1%	5.1%
Streetlights	**Basic (Customers)**	2,841	$ 15,675,844	$ 459.81	$ 16,472,981	$ 483.19	$ 797,137	5.1%	5.1%
	Energy (Gwh)	62.9		$ -		$ -			
	Total Commercial		$ 461,337,570		$ 484,850,701		$ 23,513,131		5.1%
Rate Code									
E34, E19, E41	**Farm**								
	Basic (Customers)	60,578	$ 22,598,440.00	$ 31.09	$ 23,749,132.00	$ 32.67	$ 1,150,692	5.1%	5.1%
	Energy (Gwh)	1,331.9	$ 140,987,866.00	$ 0.10586	$ 148,180,972.00	$ 0.11126	$ 7,193,106	5.1%	5.1%
	Demand (kVa)	895,020	$ 4,458,559.00	$ 4.98	$ 4,686,213.00	$ 5.24	$ 227,654	5.1%	5.1%
	Total Farm		$ 168,044,865.00		$ 176,616,317.00		$ 8,571,452.00		5.1%
Rate Code									
E43	**Oilfield**								
	Basic (Customers)	19,069	$ 12,482,453	$ 54.55	$ 13,118,589	$ 57.33	$ 636,136	5.1%	5.1%
	Energy (Gwh)	2,638.4	$ 177,495,599	$ 0.06727	$ 186,539,624	$ 0.07070	$ 9,044,025	5.1%	5.1%
	Demand (kVa)	6,262,391	$ 74,409,730	$ 11.88	$ 78,204,739	$ 12.49	$ 3,795,009	5.1%	5.1%
E46, E47, E48, E86, E87, E88									
	Basic (Customers)	24	$ 1,621,428	$ 5,629.96	$ 1,704,035	$ 5,916.79	$ 82,607	5.1%	5.1%
	Energy (Gwh)	840.6	$ 48,833,084	$ 0.05809	$ 51,320,982	$ 0.06105	$ 2,487,898	5.1%	5.1%
	Demand (kVa)	1,335,407	$ 11,601,329	$ 8.69	$ 12,192,382	$ 9.13	$ 591,053	5.1%	5.1%
	Total Oilfield		$ 326,443,623		$ 343,080,350		$ 16,636,727		5.1%
Rate Code									
E31, E32, E33	**Reseller**								
	Basic (Customers)	3	$ 296,064	$ 8,224.00	$ 311,180	$ 8,643.88	$ 15,116	5.1%	5.1%
	Energy (Gwh)	1,290.9	$ 52,750,581	$ 0.04086	$ 55,443,806	$ 0.04295	$ 2,693,225	5.1%	5.1%
	Demand (kVa)	2,444,262	$ 41,475,077	$ 16.97	$ 43,592,621	$ 17.83	$ 2,117,544	5.1%	5.1%
	Total Reseller		$ 94,521,722		$ 99,347,607		$ 4,825,885		5.1%
Rate Code									
E22, E23, E24, E25, E82, E83, E84, E85	**Power**								
	Basic (Customers)	89	$ 6,285,179	$ 5,885.00	$ 6,605,636	$ 6,185.05	$ 320,457	5.1%	5.1%
	Energy (Gwh)	6,749.7	$ 370,634,506	$ 0.05491	$ 389,527,265	$ 0.05771	$ 18,892,759	5.1%	5.1%
	Demand (kVa)	15,298,697	$ 99,038,668	$ 6.47	$ 104,088,829	$ 6.80	$ 5,050,162	5.1%	5.1%
E50	**Power - Contract**								
	Basic (Customers)	14	$ 708,552	$ 4,217.57	$ 744,688	$ 4,432.67	$ 36,136	5.1%	5.1%
	Energy (Gwh)	2,440.7	$ 139,801,727	$ 0.05728	$ 144,739,307	$ 0.05930	$ 4,937,580	3.5%	3.5%
	Demand (kVa)	3,599,626	$ 35,027,971	$ 9.73	$ 36,813,386	$ 10.23	$ 1,785,415	5.1%	5.1%
	Total Power		$ 651,496,603		$ 682,519,111		$ 31,022,508		4.8%
Total	**Basic (Customers)**	527,517	$ 181,112,083	$ 28.61	$ 190,348,884	$ 30.07	$ 9,236,800	5.1%	5.1%
	Energy (Gwh)	22,419.0	$ 1,701,199,148	$ 0.07588	$ 1,785,736,059	$ 0.07965	$ 84,536,911	5.0%	5.0%
	Demand (kVa)	39,031,457	$ 333,740,630	$ 8.55	$ 350,761,888	$ 8.99	$ 17,021,258	5.1%	5.1%
	Total		**2,216,051,861**		**2,326,846,831**		**110,794,970**		**5.0%**

2017/2018 - Annualized Basis

Rate Code	Residential	Determinant	Revenue July 1, 2016 Rates		Revenue 2017 Jan 1 Rates		Difference		Pct Difference
E01, E02	Basic (Customers)	330,207	$ 84,202,901	$ 21.25	$ 88,482,390	$ 22.33	$ 4,279,489	5.1%	5.1%
	Energy (Gwh)	2,545.0	$ 337,645,531	$ 0.13267	$ 354,849,750	$ 0.13943	$ 17,204,219	5.1%	5.1%
E03, E04	Basic (Customers)	56,507	$ 20,803,588	$ 30.68	$ 21,861,398	$ 32.24	$ 1,057,810	5.1%	5.1%
	Energy (Gwh)	737.0	$ 97,780,725	$ 0.13268	$ 102,762,621	$ 0.13944	$ 4,981,896	5.1%	5.1%
	Total Residential		$ 540,432,745		$ 567,956,159		$ 27,523,414		5.1%
Rate Code	Commercial								
E05, E06, E07, E08, E10, E12	Basic (Customers)	2,760	$ 2,197,496	$ 66.35	$ 2,309,405	$ 69.73	$ 111,909	5.1%	5.1%
	Energy (Gwh)	2,152.7	$ 171,817,929	$ 0.07981	$ 180,576,353	$ 0.08388	$ 8,758,424	5.1%	5.1%
	Demand (kVa)	6,480,851	$ 68,177,745	$ 10.52	$ 71,651,018	$ 11	$ 3,473,273	5.1%	5.1%
E15, E16, E17, E18, E35, E36, E37, E38	Basic (Customers)	2,331.00	$ 465,481	$ 16.64	$ 489,184	$ 17.49	$ 23,703	5.1%	5.1%
	Energy (Gwh)	11.8	$ 1,347,819	$ 0.11455	$ 1,416,514	$ 0.12038	$ 68,695	5.1%	5.1%
E75, E76, E77, E78	Basic (Customers)	53,094	$ 19,973,177	$ 31.35	$ 20,991,066	$ 32.95	$ 1,017,889	5.1%	5.1%
	Energy (Gwh)	1,617.4	$ 201,392,100	$ 0.12451	$ 211,648,223	$ 0.13085	$ 10,256,123	5.1%	5.1%
	Demand (kVa)	2,715,203	$ 3,005,973	$ 1.11	$ 3,159,167	$ 1.16	$ 153,194	5.1%	5.1%
Streetlights	Basic (Customers)	2,841	$ 16,472,981	$ 483.19	$ 17,309,420	$ 507.73	$ 836,439	5.1%	5.1%
	Energy (Gwh)	62.9				$ -			
	Total Commercial		$ 484,850,701		$ 509,550,350		$ 24,699,649		5.1%
Rate Code									
E34, E19, E41	Farm								
	Basic (Customers)	60,578	$ 23,749,132.00	$ 32.67	$ 24,958,082.00	$ 34.33	$ 1,208,950	5.1%	5.1%
	Energy (Gwh)	1,331.9	$ 148,180,972.00	$ 0.11126	$ 155,726,712.00	$ 0.11692	$ 7,545,740	5.1%	5.1%
	Demand (kVa)	895,020	$ 4,686,213.00	$ 5.24	$ 4,924,808.00	$ 5.50	$ 238,595	5.1%	5.1%
	Total Farm		$ 176,616,317.00		$ 185,609,602.00		$ 8,993,285.00		5.1%
Rate Code									
E43	Oilfield								
	Basic (Customers)	19,069	$ 13,118,589	$ 57.33	$ 13,786,761	$ 60.25	$ 668,172	5.1%	5.1%
	Energy (Gwh)	2,638.4	$ 186,539,624	$ 0.07070	$ 196,033,205	$ 0.07430	$ 9,493,581	5.1%	5.1%
	Demand (kVa)	6,262,391	$ 78,204,739	$ 12.49	$ 82,187,619	$ 13.12	$ 3,982,880	5.1%	5.1%
E46, E47, E48, E86, E87, E88									
	Basic (Customers)	24	$ 1,704,035	$ 5,916.79	$ 1,790,838	$ 6,218.19	$ 86,803	5.1%	5.1%
	Energy (Gwh)	840.6	$ 51,320,982	$ 0.06105	$ 53,935,261	$ 0.06416	$ 2,614,280	5.1%	5.1%
	Demand (kVa)	1,335,407	$ 12,192,382	$ 9.13	$ 12,813,459	$ 9.60	$ 621,077	5.1%	5.1%
	Total Oilfield		$ 343,080,350		$ 360,547,143		$ 17,466,793		5.1%
Rate Code									
E31, E32, E33	Reseller								
	Basic (Customers)	3	$ 311,180	$ 8,643.88	$ 327,032	$ 9,084.23	$ 15,852	5.1%	5.1%
	Energy (Gwh)	1,290.9	$ 55,443,806	$ 0.04295	$ 58,268,273	$ 0.04514	$ 2,824,467	5.1%	5.1%
	Demand (kVa)	2,444,262	$ 43,592,621	$ 17.83	$ 45,813,355	$ 18.74	$ 2,220,734	5.1%	5.1%
	Total Reseller		$ 99,347,607		$ 104,408,660		$ 5,061,054		5.1%
Rate Code									
E22, E23, E24, E25, E82, E83, E84, E85	Power								
	Basic (Customers)	89	$ 6,605,722	$ 6,185.13	$ 6,942,159	$ 6,500.15	$ 336,437	5.1%	5.1%
	Energy (Gwh)	6,749.7	$ 389,526,976	$ 0.05771	$ 409,363,590	$ 0.06065	$ 19,836,614	5.1%	5.1%
	Demand (kVa)	15,298,697	$ 104,089,033	$ 6.80	$ 109,393,033	$ 7.15	$ 5,304,000	5.1%	5.1%
E50	Power Contract								
	Basic (Customers)	14	$ 744,688	$ 4,432.67	$ 782,623	$ 4,658.47	$ 37,935	5.1%	5.1%
	Energy (Gwh)	2,440.7	$ 144,739,314	$ 0.05930	$ 149,930,830	$ 0.06143	$ 5,191,516	3.6%	3.6%
	Demand (kVa)	3,599,626	$ 36,813,389	$ 10.23	$ 38,688,794	$ 10.75	$ 1,875,406	5.1%	5.1%
	Total Power		$ 682,519,122		$ 715,101,030		$ 32,581,908		4.8%
Total	Basic (Customers)	527,517	$ 190,348,970	$ 30.07	$ 200,030,359	$ 31.60	$ 9,681,389	5.1%	5.1%
	Energy (Gwh)	22,419.0	$ 1,785,735,778	$ 0.07965	$ 1,874,511,333	$ 0.08361	$ 88,775,555	5.0%	5.0%
	Demand (kVa)	39,031,457	$ 350,762,094	$ 8.99	$ 368,631,254	$ 9.44	$ 17,869,159	5.1%	5.1%
	Total		**2,326,846,842**		**2,443,172,945**		**116,326,103**		**5.0%**

SRRP Q18:

Reference: **Export Revenues**

Please provide an overview of the export markets SaskPower participates in, the types of export sales (long-term contract; short-term contract; sport market sales) and details of any firm transmission contracts or positions with other markets or jurisdictions.

Response:

SaskPower participates in several organized deregulated markets. The organized markets are called Independent System Operators (ISOs) or Regional Transmission Organizations (RTOs), and they are listed below:

<u>ISO</u>
Alberta Electric System Operator (AESO) – Alberta

<u>RTOs</u>
Southwest Power Pool (SPP) – Midwestern US, including North and South Dakota

Midcontinent Independent System Operator (MISO) – Midwestern US, including Manitoba and Minnesota

SaskPower may also engage in bi-lateral transactions with counterparties in the AESO, MISO and SPP footprints.

Based on the description of long-term and short-term sales in SRRP Q20, all of SaskPower's export sales are spot market transactions. SaskPower has occasionally entered into single-month export transactions.

SaskPower has firm transmission rights on export paths within Saskatchewan:

1. 15 megawatts (MW) to AESO, which is scheduled to become 153 MW in 2018
2. 150 MW to US

SRRP Q19:

Reference: **Export Revenues**

Please provide an explanation for the year over year variation in export volumes (from 71.4 GWh in 2015 to 419.3 GWh forecast in 2017-18). Please elaborate on the degree to which each of: system supply characteristics (e.g. water flows); market prices (e.g. electricity markets in other jurisdictions and/or the cost of natural gas or coal); and transmission availability contribute to these variations.

Response:

The year-over-year variation between 2015 and fiscal year 2017-18 in export volumes is minimally impacted by the cost of natural gas or coal, or the water flows.

The increased year over year export volume can be attributed to an expected price recovery in electricity markets in neighbouring jurisdictions and growth in US markets.

In 2015, transmission availability negatively impacted export volumes due to a 40-day unplanned outage on the Saskatchewan/Alberta interconnection.

SRRP Q20:

Reference: **Export Revenues**

Please discuss the degree to which SaskPower's export revenues relate to long-term contracts (i.e. longer than one year); short-term contracts (e.g. seasonal contracts or contracts of several months); and spot market sales.

Response:

For the reporting period (2013 to 2018-19), SaskPower has not, nor has in place going forward, any long-term or short-term export contracts. All export activity has been and is forecasted to be spot market activity.

SRRP Q21:

Reference: **Net Sales from Trading**

Please provide a table showing net sales (actual & forecasts) for electricity trading for the period 2010 to 2015, and explain any variances.

Response:

Year	Actual	Forecast	Variance Explanations
2010	$3,429,543	$16,375,000	The yearly average AESO (Alberta Electric System Operator) market price of $51.45/MWh was lower than the expected price of $76.73/MWh. In addition, minimal volatility and lack of spreads between markets reduced opportunities for trading.
2011	$13,601,473	$5,230,000	The yearly average AESO market price of $71.69/MWh was higher than the expected price of $45.09/MWh.
2012	$14,339,887	$6,350,000	The high average AESO market prices resulted in higher electricity sales volumes. The yearly average AESO market price was $85.4/MWh compared to an expected price of $55.38/MWh.
2013	$2,882,096	$11,810,000	The yearly average AESO market price of $80.09/MWh was slightly lower than the expected price of $85.00/MWh. However, the low market spread meant that the volume of electricity traded was significantly lower than expected.
2014	-$1,656,762	$7,200,000	The yearly average AESO market price of $49.42/MWh was lower than the expected price of $74.72/MWh. Trading remained profitable, however given the low market prices in Alberta the opportunity was not great enough to exceed the fixed cost of transmission service.
2015	-$1,629,483	$4,500,000	The average AESO market price was $33.34/MWh, whereas it was expected to be $57.41/MWh. Trading remained profitable, however given the low market prices in Alberta the opportunity was not great enough to exceed the fixed cost of transmission service.

SRRP Q22:

Reference: **Net Sales from Trading**

Please discuss how SaskPower prepares its forecasts of net sales from trading.

Response:

The forecast of net sales from trading is based on an internal market transaction model that uses Monte Carlo simulations to derive an estimate of overall trading volume and expected profit.

This hourly model considers numerous variables specific to each market in which SaskPower transacts. These variables include current spot and forward price forecasts, estimates of transmission availability, market tariffs, and foreign exchange rates. Markets in which SaskPower considers trading opportunities include the U.S. Pacific Northwest; Alberta; Southwest Power Pool; Ontario; and Pennsylvania, New Jersey and Maryland (PJM).

Monte Carlo simulation is a computerized mathematical technique to account for risk in quantitative analysis and decision making.

Input variables and results of the simulations are checked for reasonability given the level of actual trading experience within the markets. Where deemed appropriate, adjustments may be made.

SRRP Q23:

Reference: Net Sales from Trading

Please elaborate on the statement on page 25 of the application that "trading activities are intended to deliver positive gross margins to SaskPower's bottom line while operating within an acceptable level of risk". What level of risk or types of risks does SaskPower consider to be acceptable versus unacceptable?

Response:

Generally speaking, acceptable risk is where transaction attributes and forecast expected revenue is within all Board-approved and internal limits.

SaskPower is relatively risk averse when it comes to engaging in energy trading activity. The Board-approved Risk Management Manual (RMM) addresses the types of risks and establishes limits on what is considered acceptable and unacceptable.

There are two types of risk addressed in the RMM – market risk and credit risk. Market risk is the exposure to adverse movements in commodity prices that may impact the value of the underlying positions as measured by mark to market (MTM). MTM is the value of the future cash flow based on current market pricing.

Another measure of market risk is value at risk or VaR. VaR is a market risk exposure quantification and estimates the potential income impacts as a result of a change in market pricing.

Credit risk is the risk that a counterparty will fail to perform, including payment, with respect to its present and/or future obligations. The RMM provides trading parameters, VaR limits, and reporting requirements to control these risks.

SRRP Q24:

Reference: **Net Sales from Trading**

Please discuss whether SaskPower believes recent market changes in Alberta and/or the United States have impacted the degree to which trading activities can continue to be a revenue positive endeavor for SaskPower?

Response:

SaskPower believes trading activity will continue to be revenue positive.

Market changes in Alberta and the United States have reduced both the frequency and magnitude of profitable spreads for trading activity. Profitable market spreads do however exist in the current market and market forecasts support the business view that trading will continue to be revenue positive for SaskPower.

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SRRP Q25:

Reference: Other Revenue

Please provide an explanation for the material increase in customer contribution revenue in 2015.

Response:

Customer contributions are funds received from certain customers toward the costs of service extensions. The following table shows the customer contribution breakdown of revenue:

(in millions)	**2015**	**2014**	**Change**
Customer connects - Distribution	$ 51	$ 40	$ 11
Customer connects - Transmission	42	7	35
	$ 93	$ 47	$ 46

In 2015, customer contribution revenue increased $46 million compared to 2014. The $35 million increase in the transmission customer connects can be attributed to a number of large industrial customers requiring new transmission lines to be built to connect to their facilities. Distribution customer connects also increased as a result of the growth in the province.

SRRP Q26:

Reference: **Other Revenue**

Please explain how SaskPower forecasts customer contribution revenues in the test years. Is the forecast approximately consistent with the five or ten year average of actual customer contributions?

Response:

The $50 million forecast for customer contribution revenue is based on the five-year average for the years 2010-14. The average customer contribution revenue received in these years was $48.4 million per year.

SRRP Q27:

Reference: **Other Revenue**

Please confirm that SaskPower fully recognizes customer contribution revenue in the year it is received, rather than deferring and amortizing the contribution revenue over the life of the associated asset.

Response:

Customer contributions are funds received from certain customers towards the costs of service extensions. These contributions are recognized immediately in profit or loss as other revenue when the related property, plant and equipment is available for use.

SRRP Q28:

Reference: Other Revenue

Please elaborate on how the gas and electrical inspection revenues arise and clarify if these revenues are net of any related costs incurred by SaskPower.

Response:

Gas and electrical inspection revenues are fees collected by the department for permits, plan and code reviews, field approvals and inspections. The Gas and Electrical Inspections Department is a full cost-recovery department within the Law, Land & Regulatory Affairs Business Unit of SaskPower. In 2015, the net income for Gas and Electrical Inspections was $5.7 million.

Gas and Electrical Inspections		
		2015
Permits	$	19.7
Plan & Code Review		0.1
Field Approvals		0.8
Inspections		0.1
Revenue	$	20.7
Expenses	$	15.0
Net Income	$	5.7

SRRP Q29:

Reference: Other Revenue

a) Please explain if the forecast increases in CO_2 sales revenues from 2015 to 2017-18 reflect escalation in the selling price of the CO_2 or an increase in volume of CO_2 sales or both.

b) Please discuss how the CO_2 sales revenue forecasts are prepared, do the forecasts assume SaskPower captures and sells the maximum amount of CO_2?

Response:

A. The increase is based on both an increase in volumes and an increase in sales price, based on the escalation incorporated into the contract.

B. The forecasts are based on the off-taker, Cenovus, taking the contracted minimum daily commitment. Cenovus has the option of taking more at its discretion.

SRRP Q30:

Reference: **Other Revenue**

Please provide details of the lease arrangement of the Carbon Capture Test Facility for the time period covered by this application together with the annual lease payments.

Response:

SaskPower is presently providing testing services to Mitsubishi Hitachi Power Systems (MHPS) at the CCTF. The revenues associated with these services are part of the "other revenue" category on the operating statement.

The details of the contract with MHPS are confidential. The arrangements are complex as they involved a partnership with SaskPower to build the facility, including the provision by MHPS of some equipment on an in-kind basis. SaskPower built the facility, with the ownership of the MHPS equipment reverting to SaskPower at the conclusion of the test period. MHPS is the first contract for the CCTF, and expects to complete its work at the end of the first quarter of 2017.

Future contracts beyond MHPS are being sought. There is also a possible use of the facility by SaskPower to do some internal tests on its own behalf.

SRRP Q31:

Reference: **Other Revenue**

Please provide a detailed schedule for Miscellaneous Revenue in the Other Revenue category together with an explanation for the $8 million reduction forecasted in 2016-17.

Response:

The following table provides a summary of the different revenue sources that are included in miscellaneous revenues.

Miscellaneous Revenue Summary

(in $ thousands)	**2015-16**	**2016-17**	**Variance**
Late payment charges	5,686	4,050	(1,636)
Joint use charge	4,658	4,775	117
Connect fees	1,219	1,250	31
Rental income	314	385	71
Meter reading	3,258	2,000	(1,258)
Custom work	4,756	4,180	(576)
Trans tariff revenue - external	677	150	(527)
Green power premium	167	165	(2)
WPPI grants	4,783	500	(4,283)
Flyash	6,890	8,223	1,333
Sulphuric acid sales	-	553	553
External training	493	480	(13)
Miscellaneous	2,524	389	(2,135)
Total	**35,425**	**27,100**	**(8,325)**

More than half of the total variance is due to the completion of the 10-year Wind Power Production Incentive (WPPI) Program that was offered by the Government of Canada when the Centennial Wind Power Facility was commissioned in 2006.

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SRRP Q32:
Reference: **Business Plan**
Please provide a description of SaskPower's annual business planning cycle, including inputs required and review and approval processes.

Response:

The following is a summary of SaskPower's typical business planning cycle:

Q4 (January to March):
- Preliminary fuel and purchased power and revenue forecasts are prepared based on the Q4 load forecast.
- Preliminary capital targets are set for the various Business Units.

Q1(April to June):
- Executive reviews and approves capital targets set for each of the Business Units, as well as the corporate OM&A budget.
- Depreciation expense and finance charges are updated based on the assumed level of capital spending.
- Executive reviews and approves preliminary Business Plan.
- SaskPower's Audit and Finance Committee and Board of Directors review and approve the preliminary Business Plan.
- *Note – the preliminary Business Plan is used in developing SaskPower's rate application.*

Q2 (July to September):
- Business Units prepare detailed capital plans based on the targets set during Q1.
- Individual Business Unit OM&A budgets are established and new initiative requests or funding shortfalls are identified. The Executive then meets to prioritize new initiatives and finalize the OM&A budgets.
- Revenue and fuel budgets are updated based on the Q1 load forecast.
- Executive reviews and approves SaskPower's full 10-Year Business Plan.

Q3 (October to December):
- SaskPower's Audit and Finance Committee and Board of Directors review and approve SaskPower's 10-Year Business Plan.
- Crown Investments Corporation of Saskatchewan reviews and approves SaskPower's 10-Year Business Plan.

Q4 (January to March)

- The Government of Saskatchewan Ministry of Finance consolidates SaskPower's financial results as part of the Province's financial reporting package.
- SaskPower responds to any direction from the Province to make modifications to SaskPower's Business Plan.

SRRP Q33:

Reference: **Business Plan**

Please expand the tables in the May 2016 Business Plan Update to include the years from 2020 through 2026.

Response:

The May 2016 Business Plan Update only considered the fiscal years 2016-17, 2017-18 and 2018-19. A full 10-Year Business Plan is being developed and the results will be provided to the Saskatchewan Rate Review Panel as part of September's Mid-Application Update.

SRRP Q34:
Reference: **Business Plan**
Please discuss any changes to inputs or assumptions between the March 2016 Business Plan and the May 2016 Business Plan Update.

Response:

The following is a summary of significant changes to the May 2016 Business Plan Update:

A. Capital expenditures:
- Capital spending has been reduced in each of the next three years, as compared to the original 2016-17 Business Plan.
- The annual reductions are as follows:
  - 2016-17 - $192.2 million;
  - 2017-18 - $360.4 million;
  - 2018-19 - $237.4 million

Total reduction - $790 million

B. Operating, maintenance and administration expense (OM&A):
- OM&A spending has been reduced in each of the next three years, as compared to the original 2016-17 Business Plan.
- The annual reductions are as follows:
  - 2016-17 - $20.1 million;
  - 2017-18 - $13.7 million;
  - 2018-19 - $19.1 million

Total reduction - $52.9 million

C. Weighted average cost of gas:
- The weighted average cost of gas has been reduced in each of the next three years, as compared to the original 2016-17 Business Plan.
- The annual reductions in the assumed $/GJ are as follows:
  - 2016-17 - $0.53/GJ
  - 2017-18 - $0.16/GJ
  - 2018-19 - $0.14/GJ

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D. Load forecast – Saskatchewan sales

- Total Saskatchewan sales volumes have been reduced in each of the next three years, as compared to the original 2016-17 Business Plan.
- The annual reductions (in GWh) are as follows:
  - 2016-17 – 54.4
  - 2017-18 – 180.2
  - 2018-19 – 486.7

E. Export and trading revenues:

- Export and trading revenues have been reduced in each of the next three years, as compared to the original 2016-17 Business Plan.
- The annual reduction is as follows:
  - 2016-17 - $11.6 million
  - 2017-18 - $ 9.8 million
  - 2018-19 - $13.9 million

F. Hydro assumptions:

- Hydro generation has been reduced by 573 GWh, or 15.7%, in the 2016-17 budget.
- Hydro levels are assumed to be median for 2017-18 and 2018-19, consistent with the assumptions in the 2016-17 Business Plan.

SRRP Q35:

Reference: Fuel and Purchased Power (F&PP)

Please discuss in detail how SaskPower prepares its forecast fuel and purchased power costs. Please explain which types of fuel or generation are assumed to be resourced first and then how subsequent resources are forecast to meet the total forecast generation requirements.

Response:

Fuel and purchased power costs are forecast using an hourly dispatch model. The major inputs to the model are the provincial load forecast, the unit maintenance forecast, the natural gas price forecast, the unit forced outage rate forecast, the hydro generation forecast, the wind forecast, the import and export contracts, and the market price forecast.

In each hour, the dispatched units are determined as follows:

1) The projected must-run hydro generation (generation from run-of-river plants or for environmentally required flow); projected wind generation; must-run (take or pay) portion of PPA contracted generation; contracted imports; and minimum generating points of SaskPower baseload units are summed as SaskPower's cumulative must-run generation for the hour.

2) The difference between the hour's projected load and SaskPower's cumulative must-run generation is the load required to be served by dispatchable generation.

3) Available units are dispatched in order from the least incremental cost unit available through to the unit required to serve the generation requirement at the load center.

4) The incremental cost of the last unit dispatched to meet the forecast load (this is the marginal cost) is compared to the projected spot import costs from SaskPower neighboring jurisdictions for the hour. If the import costs at the load center are less and if there is tie line availability then spot imports replace dispatchable generation up to the corresponding import transfer capability. This creates a new marginal cost.

5) This new marginal cost is then compared to the projected spot export prices of SaskPower neighboring jurisdictions for the hour. If the export prices are greater than the marginal cost to supply from the load center and if there is tie line availability then generation is committed to facilitate the spot export. This creates a final projected System Marginal Cost for the hour.

The model then sums each units generation on a monthly basis. The product of the summed energy and the units' monthly expected fuel cost per MWh results in the units' fuel cost for the month. The monthly costs are then summed annually.

After must-run units are accounted for the order of dispatch is: dispatchable hydro generation, dispatchable coal generation, and finally dispatchable gas generation, all dispatched in the order from least incremental cost.

SRRP Q36:

Reference: Fuel and Purchased Power (F&PP)

Please expand the fuel and purchased power volume table on page 28 of the application to show actual and forecast generation volumes for each individual plant and indicate which are owned by SaskPower and from which power is acquired through a power purchase agreement.

Response:

		Electrical Energy Supplied by 12 Month Period (GWh)					
Fuel Type	Plant	2013	2014	2015	2016-17	2017-18	2018-19
Gas	Queen Elizabeth	1,331	1,201	1,943	3,410	3,135	2,858
	Landis	69	42	48	50	52	33
	Meadow Lake	26	34	21	21	22	15
	Success	1	0				
	Ermine	219	230	278	227	225	173
	Yellowhead	332	243	319	245	254	181
	Gas Total	1,978	1,750	2,609	3,953	3,688	3,260
Coal	Boundary Dam	4,792	4,172	5,176	4,822	4,878	4,903
	Poplar River	3,942	4,149	3,928	4,326	4,105	4,087
	Shand	2,113	1,898	1,907	1,768	2,034	1,889
	Coal Total	10,846	10,219	11,011	10,916	11,016	10,880
Wind	Centennial	493	482	478	518	518	519
	Cypress	34	31	31	34	34	34
	Wind Total	527	513	509	552	552	553
Hydro	Coteau Creek	1,004	1,148	677	613	686	686
	E.B. Campbell	1,291	1,348	937	775	1,018	1,018
	Nipawin	1,266	1,329	979	867	1,097	1,097
	Island Falls	795	825	739	704	723	723
	Athabasca	93	56	94	109	110	110
	Hydro Total	4,449	4,706	3,426	3,068	3,634	3,634
Imports	Short Term Total	548	797	482	489	456	423
IPP	PPA	4,807	5,439	5,707	5,520	5,580	6,570
Total		23,155	23,424	23,744	24,498	24,926	25,320

SRRP Q37:

Reference: Fuel and Purchased Power (F&PP)

a) Please identify any actual or forecast energy volumes subject to "Take or Pay" (TOP) obligations under the PPAs (in total) for each year from 2013 through 2017-18.

b) Please discuss whether SPC has been required to pay for unused energy because of Take or Pay provisions and indicate whether any such costs are forecast to be incurred in 2016-17 or 2017-18.

Response:

a) Table Q37a

Year	Take or pay energy (MWh)
2013	91,000
2014	107,000
2015	186,000
Jan – Mar 2016	83,000
2016/17	360,000
2017/18	362,000

b) A response has been submitted to the Saskatchewan Rate Review Panel for their review. However, the response contains confidential information and cannot be released publicly.

SRRP Q38:

Reference: **Fuel and Purchased Power (F&PP)**

Please discuss the reasons for the variance in unit costs for gas, coal, wind, hydro, imports and other for 2015 and forecast for 2016-17 and 2017-18.

Response:

Coal and hydro unit costs ($/MWh) increase based on contractual inflationary mechanisms.

Gas unit costs ($/MWh) change with the movement of the commodity price, the timing and volume of gas-based generation requirements, the impact of transacted hedges, and the impacts of acquiring increasing amounts of firm gas transmission capacity and related services to supply an expanding natural gas generation fleet.

Wind and other unit costs ($/MWh) change with the weighted change in contracted capacity and contracted price.

Import unit costs ($/MWh) change based on market prices and the timing and volume of imported electrical energy.

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SRRP Q39:

Reference: **Fuel and Purchased Power (F&PP)**

To the extent possible without requiring the disclosure of confidential information, please provide the average power price for generation owned by SPC and separately the average purchase price for PPAs by fuel type and explain any differences in unit costs.

Response:

Table 1 outlines the unit costs for each applicable fuel type for Independent Power Producers (IPPs) and SaskPower.

The fuel cost for gas-fired generation owned by IPPs is lower than SaskPower's gas-fired fleet because two of the major IPP units are fuel efficient cogeneration facilities and two other IPP units are relatively new technology which is more efficient than the older units in SaskPower's fleet.

The fuel cost for IPP wind is higher than SaskPower's wind because the IPP price includes capital recovery and O&M costs, whereas SaskPower's price only reflects fuel.

IPPs do not operate any coal or hydro. SaskPower, through an IPP, imports 25 MW of energy to serve the northern portion of Saskatchewan's electrical system.

IPPs' "Other" includes green technologies such as heat recovery and flare gas or landfill gas-fired generation. SaskPower does not have any comparable facilities.

Table 1

	Hydro ($/MWh)	Coal ($/MWh)	Gas ($/MWh)	Wind ($/MWh)	Imports ($/MWh)	Other ($/MWh)
SaskPower	$5	$25	$35	$0	$26	N/A
IPPs	N/A	N/A	$29	$96	See Note 1	$89

Note 1: The IPP import contract contains a confidentiality clause and cannot be released publicly. A complete response has been submitted to the Saskatchewan Rate Review Panel for their review.

SRRP Q40:

Reference: **Fuel and Purchased Power (F&PP)**

Please describe SaskPower's net metering program, the annual volume and cost of purchases and benefits to date to SaskPower.

Response:

- Net metering offers SaskPower customers the opportunity to generate their own grid-connected power using environmentally-preferred technologies up to 100 kW(dc) in capacity size. If more electricity is produced than consumed in the monthly billing period the net electricity is added to the power grid and banked on the customer's account as kilowatt-hour (kWh) credits to be applied against future consumption. Any excess kWh credits are carried forward to the next billing period for up to one year.

- There are approximately 600 net metering customers across Saskatchewan today, with 400 using solar self-generation and 200 using wind turbine self-generation. (Over the past three years nearly all new customers participating in the program are generating using solar photovoltaic (PV) systems). While the total number of customers on net metering remains relatively low today, awareness, interest, and participation in the program continues to increase and given the improving economics of self-generation (especially with solar), it is anticipated that significant growth in customer self-generation will occur in the coming years.

- Market research completed in Q3, 2014, indicated most Saskatchewan residential and business customers (approximately 7.5 out of 10) believe SaskPower should be involved in offering and promoting self-generation options. Additionally, roughly a third of residential respondents and a quarter of business respondents indicated they either definitely will or are likely to self-generate power over time.

- The annual generated electricity from SaskPower net metered customers is 6 million kWh (estimate) reducing annual greenhouse gases (GHG) by 3.8 million kg of CO_2e (estimate). Reduced revenue on net metered generated electricity year to date is estimated at $350,000 based on a blended power rate of farm, rural, and urban customers of $0.12/kWh.

- The SaskPower Net Metering Rebate has been extended for two years, and will be available until November 30, 2018. SaskPower will provide net metered customers with a one-time capital incentive equivalent to 20% of eligible costs (equipment and installation) up to a maximum payment of $20,000. All net metered customers of Saskatchewan electrical utilities are eligible for the rebate. Net Metering Rebate payments made to customers in 2016 so far total $263,205. The rebate program has made payments totaling $1,513,043.23 since 2013 (when SaskPower began solely funding the rebate).

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- A common challenge affecting utilities with traditional net metering programs is that as the number of self-generating customers continues to grow, the costs to maintain and operate the grid are spread across a smaller customer base, raising rates and increasing customers' economic incentive to self-generate. In Saskatchewan, net metering research indicates that the majority of customers adopting solar in Saskatchewan fall into a higher income bracket, thus burdening the remaining non self-generating customers, including lower income segments.

- From an opportunity perspective, in the current environment of increasing demand for power, rising prices, and infrastructure renewal, customer self-generation programs (like net metering) help demonstrate SaskPower's commitment to renewable energy and are part of a strategy to offer customers service options, improve the customer experience, and can be factored into a long-term supply solution.

- SaskPower is currently developing a Self-Generation Strategy to manage longer-term (1) financial implications, (2) implications to the operability of the power system, (3) alignment to the Integrated Resource Plan and SaskPower's up to 50% renewable goal by 2030, and to (4) meet customer service expectations.

SRRP Q41:

Reference: **Natural Gas**

Please describe SaskPower's natural gas procurement processes including details on any firm contracted transmission and/or storage volumes for the three most recent actual years and forecasts for 2016-17 and 2017-18.

Response:

SaskPower secures natural gas for the short- to long-term needs to meet the gas-fired generation and storage requirements. The term of the purchases ranges from daily to transactions 10 years in the future under the long-term hedge program.

SaskPower contracts enough market access to ensure the supply of natural gas during a firm hydro year, which is a 1 in 50 low-flow year. In addition, SaskPower has to contract enough market access and storage to ensure that all of the natural gas-fired facilities can reach full load during on-peak hours.

As SaskPower has added gas generation, incremental receipt and delivery service has been contracted. The most recent instance coincided with the Queen Elizabeth Power Station gas plant expansion in 2015.

SaskPower is also in the queue for:

1. Incremental firm storage withdrawal service;
2. Incremental firm receipt border service; and
3. Incremental firm delivery transport service for the addition of the 2019 gas plant.

SaskPower continually rebalances the transmission and storage service portfolio as the supply plans evolve and as the operating requirements unfold.

SaskPower's amount of contracted service is limited based on TransGas' availability of service.

SRRP Q42:

Reference: **Natural Gas**

Please describe any changes to SaskPower's or NorthPoint's procedures, Risk Management Policy and/or Risk Management Manual related to procurement and pricing of natural gas supplies, including storage and hedging since the last application.

Response:

There were updates to the following corporate policies since the last application:

- Signing Authority Policy & Matrix effective January 1, 2016;
- Governance Manual effective January 1, 2016; and
- Long-Term Natural Gas Exposure Management Policy effective February 2015.

The primary objectives of the Governance Manual and Signing Authority Policy & Matrix changes were:

- To clarify the current approval requirements;
- To reflect the current organizational structure of the organization;
- To reflect the increase in spending authority of all Vice-Presidents from $5 million to $10 million;
- To clarify the language to confirm Board approval for capital projects with a value exceeding $20 million; and
- To further streamline the governance requirements for SaskPower's subsidiaries, including the removal of duplication of items presented to both the subsidiary Board and the SaskPower Executive.

These changes affect the natural gas portfolio by:

- Clarifying the capital project language for the negotiation of the 2019 gas plant pipeline construction agreement and approval;
- Updating the organizational structure; and
- Creating better alignment of the Risk Management Manual and the Corporate signing authority, which allows for greater clarity in terms of natural gas signing authority.

The Long-Term Natural Gas Exposure Management Policy was updated in February 2015. The three objectives of the policy (security of supply, market access and price management) remain unchanged. The policy continues to consist of a passive (mechanistic) portion and a discretionary (optional) portion.

The discretionary portion of the program was amended to:

- Between 0-20% of hedge transactions could be undertaken for each year of the 10-year horizon, based on approval from the SaskPower CFO and the CEO of NorthPoint.
- The Board approved minimum and maximums were updated to include the 0-20% of the discretionary portion.

The previous criteria included the total hedged exposure could not exceed 50% in a given year and the timeframe was limited to the first three years of the 10-year horizon. Therefore, there was a change in the percentage and the eligible period.

The Risk Management Manual, which has been in effect since June 18, 2012, is being updated in 2016.

SRRP Q43:

Reference: Natural Gas

Please discuss whether there are any differences in procurement procedures, hedging activities or pricing considerations between natural gas supplies used for SPC generation and for PPA generation.

Response:

There are no differences in procurement procedures, hedging activities, or pricing considerations between natural gas supplies used for SPC generation and for PPA generation where SPC purchases the gas supply.

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SRRP Q44:

Reference: **Natural Gas**

Please provide a table showing natural gas purchases within Saskatchewan and outside Saskatchewan including total volumes; average unit costs; and total natural gas expense for each year from 2013 to 2017-18.

Response:

As Saskatchewan supply continues to decline, SaskPower and other Saskatchewan end users have become dependent on Alberta supply. SaskPower has contracted service to import gas from Alberta, yet the amount is limited based on TransGas' availability.

	Gas Purchased in Saskatchewan			Gas Purchased Outside Saskatchewan		
	Volume (Million GJs)	Total Cost (Millions)	$/GJ	Volume (Million GJs)	Total Cost (Millions)	$/GJ
2013	9	30	$ 3.33	27	115	$ 4.18
2014	9	40	$ 4.35	25	108	$ 4.31
2015	8	24	$ 2.82	33	124	$ 3.72
Jan-Mar '16	2	4	$ 1.96	10	31	$ 3.20
2016/17	3	5	$ 1.80	25	95	$ 3.86
2017/18	-	-	$ -	20	88	$ 4.49

Gas purchased in Saskatchewan includes open market gas, which has been favourably priced as a result of a declining price environment.

Gas purchased outside of Saskatchewan includes open market gas in addition to gas purchased as part of the long-term hedging program.

SRRP Q45:

Reference: **Natural Gas**

Please provide a schedule showing actual natural gas hedged volumes for 2013 to 2015 and currently hedged volumes for 2016-17 and 2017-18. Please summarize the types of financial instruments used each year and indicate the overall annual cost of hedged volumes in aggregate and on a unit basis.

Response:

Under the long-term hedge program, SaskPower undertakes physical and financial transactions to stabilize a portion of the projected gas costs. The physical transactions are fixed price purchases and the financial transactions are fixed price swaps.

	GJ (Millions)	Notional Value (Millions)	$/GJ
2013	35	$ 147	$ 4.17
2014	37	$ 160	$ 4.28
2015	40	$ 163	$ 4.05
Jan-Mar '16	13	$ 49	$ 3.69
2016/17	52	$ 195	$ 3.73
2017/18	46	$ 181	$ 3.93

SRRP Q46:

Reference: **Natural Gas**

Please provide a schedule showing SaskPower's actual cost of natural gas for 2013-2015 and the estimated impact of hedging activities on the natural gas costs for the same period.

Response:

Natural Gas Costs				
	Actual	**Actual**	**Actual**	**Actual**
(in $ millions)	**2013**	**2014**	**2015**	**2016***
Natural Gas	143.0	142.1	148.6	40.6
Natural Gas Transportation	21.1	22.5	28.3	8.9
Natural Gas Storage	5.1	5.6	5.6	1.4
Spyhill (Buy/Sale)	0.6	0.2	0.4	-
Realized Natural Gas Management Activities	8.8	(0.3)	20.3	10.8
Total Natural Gas Costs	178.6	170.1	203.2	61.7
Costs include only gas costs managed by SPC.				

* 2016 - Three month reporting period to accommodate fiscal year-end change.

- This table only includes the cost of SaskPower's natural gas purchases. It does not include the gas component of our PPAs where the IPP supplies its own gas.

- "Realized Natural Gas Management Activities" only refers to the impact of financial hedges. The impact of physical natural gas contracts on natural gas held in inventory is included as part of SaskPower's "Natural Gas" line item.

SRRP Q47:

Reference: **Natural Gas**

Please discuss whether SaskPower has had any recent discussions with SaskEnergy with respect to combining the gas purchases for the two utilities.

Response:

SaskPower collaborates with SaskEnergy on a daily basis to optimize our services and discuss market opportunities. The utilities have different purchase and consumption profiles due to the nature of the respective businesses.

SaskEnergy's natural gas purchases are resold or passed through to its consumers, while SaskPower uses the natural gas as a fuel input for power generation. There is no current plan to combine the gas procurement of the utilities.

SRRP Q48:

Reference: **Natural Gas**

Please provide a schedule showing the average cost of transmission and storage per GJ for 2013-2015 and forecast for 2016-17 and 2017-18.

Response:

SaskPower contracts firm transportation service with TransGas for the purpose of transporting gas into and within Saskatchewan. SaskPower pays the tariff rates posted by TransGas. The table below displays the average cost of transportation (transport into Saskatchewan and within Saskatchewan).

SaskPower contracts storage capacity and withdrawal capability with TransGas. The average cost is in the table below.

Both transportation and storage unit costs are relative to consumption and assume a 3% rate increase for 2017-18.

	Average Transportation Cost ($/GJ)	Average Storage Cost ($/GJ)
2013	$ 0.57	$ 0.14
2014	$ 0.70	$ 0.17
2015	$ 0.68	$ 0.13
Jan-Mar '16	$ 0.69	$ 0.11
2016/17	$ 0.75	$ 0.12
2017/18	$ 0.77	$ 0.12

SRRP Q49:

Reference: **Natural Gas**

Please discuss what strategies SaskPower intends to pursue to mitigate risks associated with increasing reliance on natural gas and the associated price volatility.

Response:

With the increased reliance on natural gas and the associated price and volumetric volatility, the continued strength of the supply and hedge program is critical.

SaskPower plans to:

- Fully integrate the long-term hedge program into the on-going comprehensive strategic and resource planning efforts;
- Continue to improve the long-term hedge program, including addressing the recommendations in a recent third-party review of the program;
- Continue to rebalance the supply, transmission and storage service portfolio as the supply plan evolves;
- Continue to collaborate with SaskEnergy and other market participants to optimize assets;
- Continue to enhance tools, analytics and reporting; and
- Continue to evaluate the long-term people, process, technology and governance requirements associated with SaskPower's changing natural gas requirements and impending paradigm shift from fossil fuels to renewables.

Overall, SaskPower is dedicated to optimizing the future fuel and service requirements as the generation mix evolves to meet the 2030 renewable target.

SRRP Q50:

Reference: **Coal**

Please provide details regarding each of SPC's coal supply contracts including the contract period, supply volumes, and pricing or price escalation provisions.

Response:

The details of SaskPower's coal supply contracts are confidential and cannot be released publicly. A complete response has been submitted to the Saskatchewan Rate Review Panel for their review.

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2016 and 2017 RATE APPLICATION
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SRRP Q51:
Reference: Coal
Please provide the actual or forecast coal volumes supplied, average heat values, locations of sources, and unit costs by source for each year from 2013 through 2017-18.

Response:

This response contains confidential information and cannot be released publicly. A complete response has been submitted to the Saskatchewan Rate Review Panel for their review.

SRRP Q52:

Reference: Coal

Please provide an update on whether SPC believes it will retire Boundary Dam Units #4 and #5 or build carbon capture technology for these units. Please identify any costs included in the 2016-17 and 2017-18 revenue requirements related to studying or planning related to these alternatives.

Response:

A decision as to the future of Boundary Dam Power Station Units #4 & #5 is dependent on the Equivalency Agreement being negotiated between the Province of Saskatchewan and Government of Canada.

If no agreement can be reached, then in accordance with the regulations from the federal government, SaskPower will have to commit to converting the two units to the emission standard of 420 Kg/MWh by the end of 2019. The actual conversion can be accomplished in the early years of the 2020s.

The work being undertaken in the current and next fiscal years is budgeted at $1,743,400 and $1,750,000 respectively. These are preliminary in that if the Equivalency Agreement is in place, changes from these expenditures are possible. At the very least, the Equivalency Agreement will permit a longer time horizon over which to make a decision and hence spread the development costs accordingly.

No decision is certain at present as to the future of the two units.

SRRP Q53:

Reference: **Coal**

Please provide an update on negotiations with the federal government on an emissions Equivalency Agreement. Does SPC believe it will be able to negotiate such an agreement before a decision must be made to retire Boundary Dam Units #4 and #5?

Response:

The ongoing negotiations are confidential and cannot be released publicly. A complete response has been submitted to the Saskatchewan Rate Review Panel for their review.

SRRP Q54:

Reference: Coal

Please provide an update on whether SaskPower believes it will have the opportunity to earn revenue from the implementation of carbon capture technology processes in other jurisdictions. If SaskPower believes such revenues are possible, please provide a summary of how those revenues might arise (from what types of products or services) and indicate whether any such revenues are included in the 2016-17 and 2017-18 forecasts.

Response:

No revenues are budgeted by SaskPower for external sales of our expertise gained from the operations of the Carbon Capture Test Facility and/or the Boundary Dam Integrated Carbon Capture and Storage Demonstration Project.

Revenues are possible if an external party seeks our formal input, likely via a consulting contract, into any potential carbon capture and storage (CCS) design or project. The expertise that SaskPower possesses is associated with project management, operations and integration of the power plant with the carbon capture facility.

The intellectual property (IP) associated with equipment and process design belongs to the contractors who provided both to SaskPower. This relationship is completely normal. SaskPower does not, as a generalisation, own IP for the equipment it operates.

One initiative has arisen that involves Saskatchewan economic benefits is the establishment of the BHP Billiton-SaskPower Knowledge Centre. This investment by BHP Billiton is without cost to SaskPower and represents a direct investment of $20 million over a five-year period and will generate a number of studies or other collaborative research efforts into CCS. This will help maintain Saskatchewan's undoubted lead in this area and potentially help SaskPower implement future CCS projects at lower costs and/or with improved operational outcomes.

SRRP Q55:

Reference: **Hydro**

Please provide the volume of hydro generation available at median flow levels now, and anticipated after the development of the Tazi Twé project.

Response:

The current volume of hydro generation available at median flow levels is 3,634 GWh.

The forecasted volume of hydro generation available at median flow levels after the development of the Tazi Twé Hydrolectric Project is 4,036 GWh.

SRRP Q56:

Reference: Hydro

Please provide a schedule showing the actual and forecast water rental rates from 2013 through 2017-18.

Response:

The following table contains the water rental fee rate paid or forecasted to be paid in the years 2013 through 2017-18:

Year	Water Rental Fee ($/MWh)
2013	4.69
2014	4.89
2015	5.10
2016 Q1	5.32
Fiscal 2016-17	5.37
Fiscal 2017-18	5.57

SRRP Q57:

Reference: **Hydro**

Please discuss the basis of the specific flow conditions forecast for 2016-17 and 2017-18.

Response:

The basis of the specific flow conditions forecast in March 2016 for 2016-17 was for between lower quartile and median flow on the Saskatchewan River System, and well below lower quartile on the Churchill River System.

The basis of the specific flow conditions forecast for 2017-18 is for median flow conditions on both river systems.

SRRP Q58:

Reference: **Hydro**

Please confirm if the 40 year data series used for forecasting median flow conditions is rolling time series or not, i.e. as each new year of flow data becomes available does SaskPower drop the oldest year from the series when it adds the newer year of data?

Response:

The 40-year data series is not a rolling time series. The current data set being used is 1970-2009 adjusted for the current level of Alberta development. The data set will be updated in 2016.

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SRRP Q59:
Reference: **Hydro**
Please provide an update on the status of the partnership agreement, regulatory approvals and other planning requirements for the Tazi Twé project.

Response:

- SaskPower has been actively working with the Black Lake First Nation to develop the 50 MW Tazi Twé Hydroelectric Project since 2011. Although the site has been known about for decades, the need for the project has only recently made sense as a result of increasing demand for power in the North.
- The project has several benefits: long-term cost certainty, as the majority of the costs are front loaded; improved reliability to northern customers; a hedge against future greenhouse gas regulations; and, helps to meet SaskPower's goal of up to 50% renewables by 2030
- Partnership negotiations with the Black Lake First Nation are nearing completion. The partnership is very typical of other deals across Canada for similar projects and includes an equity ownership structure and provides other economic benefits to the community of Black Lake and surrounding region.
- The key risk to proceeding with the project is resolution of a dispute between the federal and provincial governments over who has jurisdictional authority over the use of the water. A resolution to this issue is expected by the end of 2016.
- Federal environmental approval for the project has been received. Provincial environmental approval is expected in the latter part of Q3 2016.
- A decision to proceed with the project will be sought starting in Q4 2016, with construction targeted to begin in August 2017. SaskPower Board, Crown Investments Corporation of Saskatchewan, and Provincial Cabinet approvals will all be required prior to proceeding with the project.

SRRP Q60:

Reference: **Export Power**

Please provide a schedule showing variances between actual and forecast export quantities and revenues for 2013 to 2015 and provide variance explanations.

Response:

		Forecast	Actual
2013	**Export Volume (GWh)**	552	497
	Export Revenue ($ Millions)	$28	$62

Variance explanation: Higher Alberta Power Pool prices resulting in greater sales opportunities.

		Forecast	Actual
2014	**Export Volume (GWh)**	486	90
	Export Revenue ($ Millions)	$28	$7

Variance explanation: Lower Alberta Power Pool prices resulting in fewer opportunities to sell into Alberta, coupled with an extended outage on the Saskatchewan/Alberta interconnection as a result of ongoing maintenance.

		Forecast	Actual
2015	**Export Volume (GWh)**	229	71
	Export Revenue ($ Millions)	$14	$8

Variance explanation: Lower Alberta Power Pool prices resulting in fewer opportunities to sell into Alberta. The Saskatchewan/Alberta interconnection was off unplanned until February 10.

SRRP Q61:

Reference: **Export Power**

Please discuss whether SaskPower's Generation Planning and future resource planning is based only on Saskatchewan's domestic supply requirements and excludes provisions for export power.

Response:

SaskPower's generation planning and future resource planning excludes provisions for export power.

SRRP Q62:

Reference: **Export Power**

Please describe any changes to SaskPower's Risk Management Policy and/or Risk Management Manual related to export sales since the last rate application.

Response:

There have been no changes to the Risk Management Manual related to export sales.

SRRP Q63:

Reference: Wind

Please discuss if SaskPower considers there is a maximum amount of wind generation, given its intermittent, non-dispatchable nature, that can be successfully integrated into the Saskatchewan electricity system.

Response:

There is no “theoretic” limit to the amount of variable non-dispatchable generation, such as wind and solar power, which could be added in Saskatchewan as long SaskPower has the ability to balance the system.

Balancing the system requires things such as storage, imports from neighbouring jurisdictions and dispatchable generation, such as natural gas turbines. The limit to variable renewable generation really becomes one of economics, as it becomes increasingly more expensive to deal with higher and higher levels of variable generation on the system.

SaskPower is currently undertaking a renewable generation integration study to determine what steps will be required to deal with increasing levels of renewable generation in Saskatchewan.

SRRP Q64:

Reference: **Wind**

Please provide a schedule showing actual and forecast monthly wind generation in GWh and wind capacity factors for wind facilities from 2013 through 2017/18.

Response:

The following tables contain actual data through March of 2016. The values for April 2016 and later are forecasted.

Generation (GWh)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2013	75.3	62.1	55.9	53.1	51.5	41.1	32.4	27.6	56.0	53.4	66.6	71.3
2014	91.9	61.2	46.2	51.9	41.5	42.2	29.3	30.1	42.1	73.8	64.1	62.0
2015	80.0	54.6	59.1	65.0	50.3	37.5	43.8	45.8	46.6	66.5	69.6	65.8
2016	61.2	60.8	69.4	65.8	68.4	55.6	51.0	52.7	58.7	67.7	66.8	75.3
2017	74.8	65.6	70.1	65.6	68.2	55.4	50.8	52.5	58.5	67.5	66.6	87.8
2018	91.8	75.3	81.8									

Capacity Factor	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2013	51%	47%	38%	37%	35%	29%	22%	19%	39%	36%	47%	48%
2014	62%	46%	31%	36%	28%	30%	20%	20%	29%	50%	45%	42%
2015	54%	41%	40%	37%	28%	21%	24%	25%	27%	37%	40%	36%
2016	37%	39%	42%	41%	42%	35%	31%	32%	37%	41%	42%	46%
2017	45%	44%	43%	41%	41%	35%	31%	32%	37%	41%	42%	46%
2018	48%	44%	43%									

SRRP Q65:

Reference: **Wind**

Please discuss if SaskPower incurs any costs to integrate wind energy into the system and if so how these costs are reflected in the cost of wind energy.

Response:

SaskPower does incur costs to integrate wind energy into the system. The costs incurred include maintaining adequate generation sources to supply electrical energy during periods of low wind generation; maintaining incremental automatic generation control units to compensate for quick up and down changes in wind generation; running gas, coal and hydro units at non-optimal efficiency points to accommodate wind generation; and incremental wear and tear on units providing automatic generation control.

These costs are not reflected in the cost of wind energy, they are reflected in fuel costs and O&M costs in other fuel sources.

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SRRP Q66:

Reference: **Imports**

Please provide a schedule showing actual and forecast import volumes and average prices separately for firm import contracts and spot market or short-term contracts for each year from 2013 through 2017-18.

Response:

Firm Import Contracts

	Actual			Forecast		
	Volume (GWh)	**Cost ($ Million)**	**Average Price ($/MWh)**	**Volume (GWh)**	**Cost ($ Million)**	**Average Price ($/MWh)**
2015	24.4	$2.1	$85.56			
2016	36.2	$3.1	$85.75			
2016-17				See Note 1		
2017-18						

Spot Market & Short-term Contracts

	Actual			Forecast		
	Volume (GWh)	**Cost ($ Million)**	**Average Price ($/MWh)**	**Volume (GWh)**	**Cost ($ Million)**	**Average Price ($/MWh)**
2013	548.2	$31.2	$56.94			
2014	796.7	$38.5	$48.34			
2015	481.3	$27.0	$56.15			
2016	31.6	$2.2	$68.43			
2016-17				488.7	$16.4	$33.56
2017-18				455.7	$21.3	$46.66

Note 1: SaskPower has one firm import contract in 2016-17 and 2017-18. This contract contains a confidentiality clause and cannot be released publicly. A complete response has been submitted to the Saskatchewan Rate Review Panel for their review.

SRRP Q67:

Reference: **Operating, Maintenance and Administration (OM&A)**

Please provide a table or chart depicting the actual or forecast OM&A spending per customer for the period 2010 to 2017-18.

Response:

OM&A/Customer								
	Actual	Actual	Actual	Actual	Actual	Actual	Forecast	Forecast
	2010	2011	2012	2013	2014	2015	2016/2017	2017/2018
OM&A (millions)	512	577	616	618	656	634	682	708
Total of Saskatchewan customer accounts	473,007	481,985	490,611	500,879	511,941	520,315	527,389	534,658
OM&A per Saskatchewan customer account	1,082.4	1,197.1	1,255.6	1,233.8	1,281.4	1,218.5	1,293.2	1,324.2

SRRP Q68:

Reference: Operating, Maintenance and Administration (OM&A)

Please provide a chart showing the number of customers/FTE for the years 2010 through 2015 and forecast for 2016-17 and 2017-18.

Response:

Customers/FTE

	Actual 2010	Actual 2011	Actual 2012	Actual 2013	Actual 2014	Actual 2015	Forecast 2016/2017	Forecast 2017/2018
Total Saskatchewan customer accounts	473,007	481,985	490,611	500,879	511,941	520,315	527,389	534,658
FTE	3,281	3,290	3,419	3,627	3,829	3,664	3,821	3,821
Customers/FTE	144.2	146.5	143.5	138.1	133.7	142.0	138.0	139.9

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SRRP Q69:

Reference: Operating, Maintenance and Administration (OM&A)

Please provide a schedule that breaks out actual and forecast total OM&A costs (i.e. before any amounts that are capitalized or any offsetting revenues or transfers) for standard time salaries and wages; overtime; vacation; retirement expenses; benefits; pension expense; external services; materials & supplies; travel and accommodation; marketing and communications; donations and sponsorships; and other administration for the period 2013 to 2017-18. Please separately show any reductions to OM&A for amounts that are capitalized or offset by additional sources of revenue to reconcile to the total annual OM&A shown on page 31 of the application.

Response:

The following table summarizes SaskPower's actual OM&A expenses by cost category for the years 2013 to 2016. It also contains the forecast for the years 2016-17 and 2017-18.

It should be noted that SaskPower reduced its OM&A budget from $702 million to $682 million prior to the release of the Rate Application.

Management will be reviewing SaskPower's actual Q1 OM&A spending in early July and will then allocate the $20 million reduction to the Business Units based in part on the year-to-date spending trends.

As a result of this reduction, the actual allocation between the OM&A cost categories may be different then the numbers presented below for the years 2016-17 and 2017-18.

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Operating, Maintenance and Administration by Category
(millions)

	2013	2014	2015	2016*	2016/17	2017/18
Salaries and wages	$277	$304	$305	$ 75	$ 316	$ 327
Premium pay	44	53	40	7	42	43
Benefits	62	66	67	24	69	72
Wages and salaries	383	423	412	106	427	442
Labour credits	(69)	(81)	(78)	(18)	(65)	(68)
Subtotal wages & salaries	314	342	334	88	362	374
Materials and supplies	24	30	30	9	31	32
Contract services	174	185	182	39	189	197
Consulting services	27	24	18	5	21	22
Advertising expenses	5	5	3	-	4	4
External services	206	214	203	44	214	223
Training expenses	3	4	2	1	4	4
Travel expenses	16	14	12	2	13	14
Administrative expenses	24	21	22	7	22	23
Insurance expenses	6	5	5	1	6	6
Bad debt expense	3	3	6	2	6	6
Tools and equipment expense	3	3	3	1	3	3
Vehicle expenses	12	12	9	2	12	13
Property expenses	7	8	8	2	9	10
Other	74	70	67	18	75	79
TOTAL OM&A	**$618**	**$656**	**$634**	**$159**	**$ 682**	**$ 708**

** 2016 - Three month reporting period to accommodate fiscal yearend change*

SRRP Q70:

Reference: **Operating, Maintenance and Administration (OM&A)**

Please file the most recent actuarial report relative to the Pension Plan(s) for employees.

Response:

The report was filed with the Saskatchewan Rate Review Panel but cannot be made public because it contains confidential information.

SRRP Q71:

Reference: Operating, Maintenance and Administration (OM&A)

Please provide a schedule detailing the original Business Plan OM&A and the revised OM&A for 2015 to 2017-18 showing the impact of each of the measures totaling $52.9 million in savings discussed on page 31 of the application.

Response:

The following table compares the annual OM&A budget assumed in the original 2016 Business Plan versus the OM&A budget assumed in the Business Plan Update:

Operating, Maintenance and Administration Expense

(in $millions)	**2016/17**	**2017/18**	**2018/19**	**3 Year Total**
Original Business Plan OM&A	$ 702.2	$ 721.4	$ 748.0	$ 2,171.6
Business Plan Update OM&A	682.1	707.7	728.9	2,118.7
Variance	$ (20.1)	$ (13.7)	$ (19.1)	$ (52.9)

Further to the response in Q69, the OM&A savings included in the Business Plan Update have been targeted at the corporate level. Management will review actual OM&A spending that took place during Q1 2016-17 and will look to allocate the $20 million budget reduction to the various Business Units during Q2.

The allocation of the $20 million reduction in 2016-17 will impact the Business Unit targets in future years. As a result, updated Business Unit OM&A targets will be included in the Mid-Application Update.

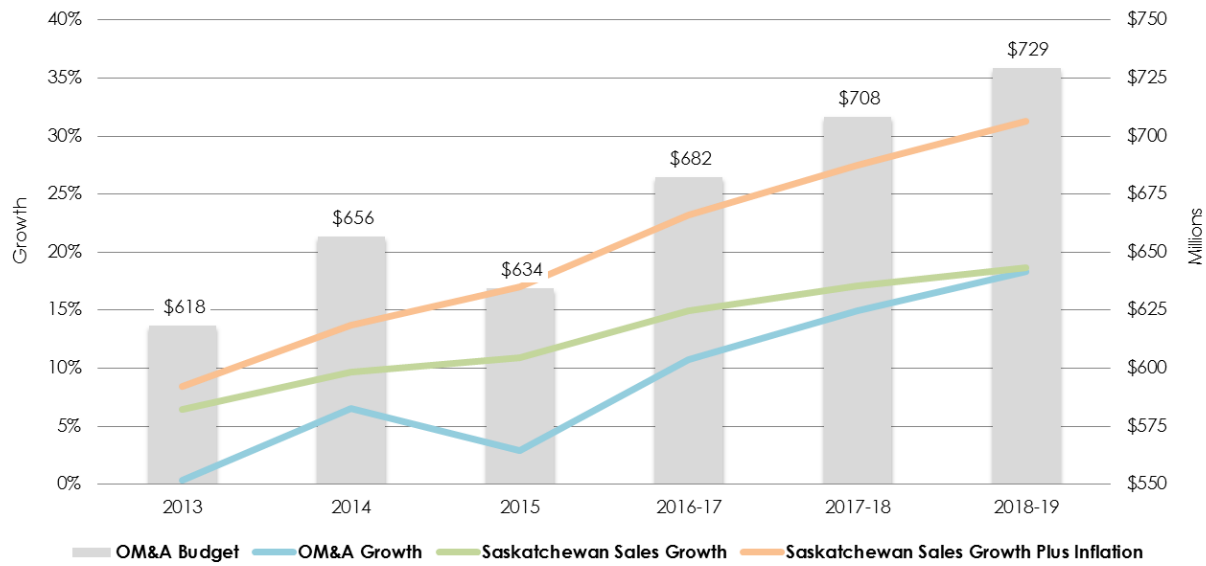
SRRP Q72:

Reference: **Operating, Maintenance and Administration (OM&A)**

Please provide a table with the information supporting the data in the figure provided on page 32 of the application.

Response:

OM&A vs. Saskatchewan sales growth



Sask Power
OM&A and Sales Volume Growth

	2012	2013	2014	2015	2016-17	2017-18	2018-19
OM&A	$ 616	$ 618	$ 656	$ 634	$ 682	$ 708	$ 729
Year over Year		$ 2	$ 38	$ (22)	$ 48	$ 26	$ 21
Year over Year		0.3%	6.2%	-3.4%	7.6%	3.8%	3.0%
Total Growth		0.3%	6.5%	2.9%	10.7%	14.9%	18.3%
Sask Sales Volumes	19,497	20,753	21,389	21,625	22,419	22,828	23,135
Year over Year		6.4%	3.1%	1.1%	3.7%	1.8%	1.3%
Total Growth		6.4%	9.7%	10.9%	15.0%	17.1%	18.7%
Inflation	100	102.0	104.0	106.1	108.2	110.4	112.6
Total Inflation		2.0%	4.0%	6.1%	8.2%	10.4%	12.6%

	2013	2014	2015	2016-17	2017-18	2018-19
OM&A Budget	$ 618	$ 656	$ 634	$ 682	$ 708	$ 729
OM&A Growth	0.3%	6.5%	2.9%	10.7%	14.9%	18.3%
Sask Sales Gwth	6.4%	9.7%	10.9%	15.0%	17.1%	18.7%
Sask Sales Gwth Plus Inflation	8.4%	13.7%	17.0%	23.2%	27.5%	31.3%

SRRP Q73:

Reference: **Operating, Maintenance and Administration (OM&A)**

Please provide the actual overhaul spending for 2013 to 2015 and indicate the total overhaul spending forecast for 2016-17 and 2017-18.

Response:

The following is a summary of actual and forecasted overhaul costs for the years 2013 to 2017-18 (in $millions).

Gas plants:

2013	$0.3
2014	$2.7
2015	$7.1
2016-17	$12.8
2017-18	$6.7

Coal plants:

2013	$10.8
2014	$31.8
2015	$23.5
2016-17	$45.1
2017-18	$50.7

SRRP Q74:

Reference: Operating, Maintenance and Administration (OM&A)

Please provide the actual transmission and distribution maintenance spending in 2013 to 2015 and forecast for 2016-17 and 2017-18. Please elaborate on the additional initiatives described on page 32 of the application.

Response:

The 2013 through 2015 actuals (revised to reflect the new SAP re-org structure) are:

Operations & Maintenance Actuals

	Distribution	Transmission
2013	38.9	25.1
2014	47.8	26.5
2015	46.8	24.6

The 2016-17 and 2017-18 forecasts are:

Operations & Maintenance Forecast

	Distribution	Transmission
2016/2017	42.1	30.7
2017/2018	43.0	31.3

***** The above figures include emergency, vegetation, corrective and planned/preventative maintenance *****

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The additional 4.8M in initiative funding includes:

Funding for 2016 OM&A Initiatives				
	Department	Initiative	FTE	2016
Funded				
Transmission	Enterprise Systems	Specialist, SAP Centre (Repatriation)	1.0	-
	Enterprise Systems	Specialist, GIS Centre (Repatriation)	1.0	-
	System Planning	Provincial Hardware Maintenance Program		1,000.0
	Field Services	Vegetation Management Funding and Resources	1.0	2,310.0
	Construction	Transmission Line Construction Inspector (Repatriation)	2.0	80.0
	Construction	Transmission Station Inspector (Repatriation)	2.0	80.0
	TOMS	Transmission Construction Crews (Repatriation)	10.0	200.0
Total			17.0	3,670.0
Distribution	Business Support	High Load Move Technical Support	1.0	100.0
	Vice President	Business Transformation	4.0	249.0
	Operations Support	Emergency Planning FTE	1.0	225.0
	Operations Support	Regina Distribution Control Centre FTE's required to handle existing work load	2.0	240.0
	South Operations	Resources for Regina City Operations	3.0	300.0
Total			11.0	1,114.0

SRRP Q75:

Reference: **Operating, Maintenance and Administration (OM&A)**

Please provide the actual and forecast vacancy rates for 2013 through 2017-18.

Response:

The following table summarizes budgeted vs actual permanent FTEs for the years 2013 to 2015 and budgeted vs. forecasted FTEs for the years 2016-17 and 2017-18.

Permanent FTE's

	2013	2014	2015	2016/17	2017/18
Actual/Forecast Permanent FTE's	3,001	3,091	3,125	3,210	3,210
Budgeted Permanent FTE's	3,109	3,281	3,268	3,328	3,328
Variance	(108)	(190)	(143)	(118)	(118)
Vacancy Rate (%)	3.5%	5.8%	4.4%	3.5%	3.5%

Note: each business unit typically assumes a 3.5% vacancy rate when preparing their wages and salaries budget.

SRRP Q76:

Reference: **Operating, Maintenance and Administration (OM&A)**

Please indicate when the current collective agreements are set to expire and provide an update on the status of any negotiations for future collective agreements.

Response:

Both collective agreements are set to expire December 31, 2016. Internal bargaining preparations have been started. Dates for negotiations have not yet been set.

SRRP Q77:

Reference: Operating, Maintenance and Administration (OM&A)

Please provide a table of SaskPower's Other Expense category for the period 2013 to 2015 and forecasts for 2016-17 and 2017-18 with a break-out of Asset Disposals, Asset Retirements, Foreign exchange (if any) and Environmental Expense.

Response:

The following table shows the actual breakdown of other expense for the years 2013 to 2016 and the forecasted amounts for the years 2016-17 and 2017-18.

Other Expenses
(millions)

	2013	2014	2015	2016*	2016/17	2017/18
Gain/Loss on asset retirements	$ 19	$ 12	$ 21	$ 4	$ 8	$ 8
Gain/Loss on asset disposal	4	3	3	1	5	5
Inventory adjustments	3	7	2	-	3	3
Loss on impairment of assets	-	17	-	-	-	-
Foreign exchange	-	-	(2)	-	-	-
Environmental expense	12	7	7	2	7	7
TOTAL OTHER	**$ 38**	**$ 46**	**$ 31**	**$ 7**	**$ 23**	**$ 23**

** 2016 - Three month reporting period to accommodate fiscal yearend change*

SRRP Q78:

Reference: **Debt and Equity**

Please discuss how SaskPower determines the appropriate mix of short-term and long-term debt in its capital structure.

Response:

SaskPower has a current strategy of maintaining a 15% short-term debt mix as a percentage of the total debt. The objective of this strategy is to take advantage of short-term interest rates which are lower than the long-term interest rates. There is some flexibility around the 15% ratio. This strategy was initiated in 2009. At the time, SaskPower reviewed the use of short-term debt within other utilities across Canada with 15% being an average amongst the utilities.

While utilizing short debt will result in short-term savings and gives the Corporation some flexibility in financing, there are several risks inherent with the short-term debt. One risk is re-financing; with short term debt, the debt matures and is re-issued frequently. There is a risk that adverse market conditions may result in a lack of liquidity and the debt may not be able to be re-financed or would be re-financed at a higher rate. There is also a risk that long-term interest rates may increase, making the long-term debt more costly and the debt mix strategy more costly in the long run. SaskPower currently implements a bond forward strategy to reduce the risk of rising long-term interest rates.

Other considerations include the impact on the market for short-term debt. SaskPower borrows short-term through the Province of Saskatchewan Ministry of Finance. The Ministry of Finance amalgamates the requirements of SaskPower and other Crowns with the Province's requirements to issue into the market. The liquidity and the credit risk within the total capital market for short-term debt is a consideration, so the Province carefully manages the size of the total short-term borrowings within this market. SaskPower has worked with the Ministry of Finance to determine that the requirements of SaskPower to maintain a 15% debt ratio fit within the Province's requirements with an acceptable amount of risk.

Utilizing long-term fixed rate debt allows the Corporation to have stability and surety in interest costs over the long term.

SRRP Q79:

Reference: **Debt and Equity**

With respect to the DBRS September 2015 report Tab 16 -

a) Please confirm that the DBRS ratings for SPC are a flow through of the ratings for the Province of Saskatchewan.

b) Please confirm the current borrowing limit for SaskPower pursuant to the *Power Corporation Act*.

c) Please provide SaskPower's actual unused credit capacity at the end of 2015, and forecasts for 2016-17 and 2017-18.

Response:

a) The DBRS ratings for SaskPower are a flow through of the ratings of the Province of Saskatchewan.

b) The current borrowing limit for SaskPower pursuant to the *Power Corporation Act* is $8 billion. SaskPower has requested a change in its legislation to increase the borrowing limit from $8 billion to $10 billion. This is currently going through the legislative review process.

c)

2015-16:	Total debt -	$6.1 billion
	Unused -	$1.9 billion
2016-17:	Total debt -	$6.4 billion
	Unused -	$1.6 billion
2017-18:	Total debt -	$6.7 billion
	Unused -	$1.3 billion

Note:

1) Unused credit assumes current $8.0 billion limit under *Power Corporation Act*

SRRP Q80:

Reference: **Debt and Equity**

Please provide a schedule showing SaskPower's actual and forecast capital structure (long-term debt; short-term debt, equity, other sources of financing) for 2010 through 2017-18.

Response:

The following table shows SaskPower's capital structure for the years 2010 to 2017-18.

Debt and Equity
(millions)

	2010	2011	2012	2013	2014	2015	2016*	2016/17	2017/18
Gross long-term debt	2,783	2,778	2,980	3,568	4,355	4,954	5,130	$5,372	$5,614
Finance lease obligation	294	437	435	1,137	1,138	1,136	1,133	1,130	1,119
Short-term advances	159	251	763	804	890	950	981	1,066	1,122
Debt retirement funds	(291)	(353)	(390)	(368)	(457)	(511)	(533)	(599)	(672)
Cash and cash equivalents	5	4	(2)	2	2	2	(28)	(25)	(46)
Total net debt	$2,950	$3,117	$3,786	$5,143	$5,928	$6,531	$6,683	$6,944	$7,137
Equity advances	$660	$660	$660	$660	$660	$660	$660	$660	$660
Retained earnings	1,095	1,332	1,347	1,461	1,521	1,561	1,546	1,697	1,885
Accumulated OCI	3	(128)	(149)	102	(3)	(17)	(61)	-	-
Total capital	$4,708	$4,981	$5,644	$7,366	$8,106	$8,735	$8,828	$9,301	$9,682
Percent debt ratio	62.7%	62.6%	67.1%	69.8%	73.1%	74.8%	75.7%	74.7%	73.7%

** 2016 - Three month reporting period to accommodate fiscal yearend change*

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SRRP Q81:

Reference: **Debt and Equity**

Please provide the calculation of the operating return on equity percentage for each year from 2010 through 2015 and forecasts for 2016-17 and 2017-18 showing both the operating income and the equity component of SaskPower's total capital structure. Please confirm if the calculation includes an allowance for working capital as part of SaskPower's ratebase and if so, provide an explanation for how the working capital amounts were determined.

Response:

The following table shows the calculation of the operating return on equity for the years 2010 to 2017-18:

Return on Equity (Operating)
(millions)

	2010	2011	2012	2013	2014	2015	2016*	2016/17	2017/18
Operating Income	216	228	129	167	43	104	79	$156	$209
Equity advances	660	660	660	660	660	660	660	660	660
Retained earnings	1,095	1,332	1,347	1,461	1,521	1,561	1,546	1,697	1,885
Accumulated OCI	3	(128)	(149)	102	(3)	(17)	(61)	0	0
Average Equity	$1,657	$1,811	$1,861	$2,041	$2,201	$2,191	$2,175	$2,251	$2,451
Operating Return on Equity	13.0%	12.6%	7.0%	8.2%	2.0%	4.7%	3.6%	6.9%	8.5%

** 2016 - Three month reporting period to accommodate fiscal yearend change, operating income annualized for calculation*

The calculation used to determine SaskPower's return on equity does not include an allowance for working capital.

SaskPower models working capital changes based on historic trends to the categories that make up working capital (i.e. payables, receivables, inventory, etc.)

Any changes to SaskPower's working capital would be offset by an increase or decrease to the amount of floating rate debt held by SaskPower. With interest rates currently at less than 1%, the impact on SaskPower's financial results would be minimal.

SRRP Q82:

Reference: Debt and Equity

Please confirm that SaskPower's long-term debt is guaranteed by the Provincial Government and discuss whether the province charges SaskPower a guarantee fee.

Response:

SaskPower does not directly issue long-term debt in the capital markets and therefore the Province does not guarantee the borrowing. The debt is issued through the Province of Saskatchewan through a bond issue that is tied to the Province of Saskatchewan. These are considered Province of Saskatchewan bonds within the capital markets. The Province transfers this financing to SaskPower at the exact terms and conditions of the Provincial borrowing.

The Province does not charge a guarantee fee.

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SRRP Q83:

Reference: Debt and Equity

Please provide a table showing the actual and budgeted return on equity in dollars and in percentage terms for the period 2006 to 2015, on an actual and weather normalized basis.

Response:

The following table shows the calculation of SaskPower's net return on equity for the years 2006 to 2017-18:

Return on Equity
(millions)

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016*	2016/17	2017/18
Net (Loss) Income	93	138	64	103	197	237	135	114	60	40	(55)	181	209
Equity advances	660	660	660	660	660	660	660	660	660	660	660	660	660
Retained earnings	808	853	870	973	1,095	1,332	1,347	1,461	1,521	1,561	1,546	1,697	1,885
Accumulated OCI	-	2	(1)	(1)	3	(128)	(149)	102	(3)	(17)	(61)		
Average Equity	$1,452	$1,492	$1,522	$1,581	$1,657	$1,811	$1,861	$2,041	$2,201	$2,191	$2,175	$2,251	$2,451
Return on Equity - Net	6.4%	9.3%	4.2%	6.5%	11.9%	13.1%	7.3%	5.6%	2.7%	1.8%	-2.5%	8.0%	8.5%

** 2016 - Three month reporting period to accommodate fiscal yearend change, operating income annualized for calculation*

Notes:

- SaskPower does not recalculate its actual ROE on a weather normalized basis.
- All forecasted ROE is reported on a weather normalized basis.

SRRP Q84:

Reference: **Debt and Equity**

Please provide a table showing the actual and forecast debt-equity ratio for the period 2006-2015.

Response:

Debt-Equity Ratio

	December 31										March 31
	2006	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
Per cent debt ratio	61.0%	59.7%	60.7%	61.4%	62.7%	62.6%	67.1%	69.8%	73.1%	74.8%	75.7%

Note: 2006-2009 reported under CGAAP; 2010 forward IFRS

SRRP Q85:

Reference: **Tax Expense**

Please provide a table showing the detailed calculation of SaskPower's corporate capital tax obligation for 2015 and forecast for 2016-17 and 2017-18.

Response:

(in millions)

Computation of Taxable Paid-Up Capital		2015	2016/2017	2017/2018
Surpluses - Earned		1,682	1,518	1,530
- Contributed		660	660	660
Loans and Advances from shareholders, related persons and related corporations		1,105	1,087	1,177
Reserves deducted from income and not allowed as a deduction for income tax		248	252	261
Indebtedness		4,387	5,094	5,520
Subtotal		8,082	8,611	9,148
purposes in excess of amounts recorded in books.				
Excess of Net Book Value(NBV) over Undepreciated Capital Cost (UCC)		(1,438)	(1,620)	(1,757)
Total Paid- Up Capital		6,644	6,991	7,391
Deduct Allowances				
Standard Exemption		10	10	10
Additional Exemption		4	4	4
Investment Allowance		51	37	38
Total Deductions		65	51	52
Taxable Paid-Up Capital		6,579	6,940	7,339
Tax Rate		0.6%	0.6%	0.6%
Corporation Capital Tax Payable		39	42	44

SRRP Q86:

Reference: **Tax Expense**

Please discuss if the calculation of SaskPower's corporate capital tax obligation is affected by unrealized gains or losses.

Response:

Unrealized gains or losses are not allowed as deductions from income for income tax purposes and they are added back to paid up capital for the purposes of calculating the corporate capital tax obligation.

SRRP Q87:

Reference: **Business Renewal (BR) Program**

Please elaborate on how the new connect Joint Servicing Program operates and the source of the savings (e.g. reduced staff time; contributions from other utilities).

Response:

The Joint Servicing Program with SaskPower, SaskEnergy and SaskTel went live on March 1, 2015. Under an agreement amongst these Crowns, a cost sharing structure was developed and contracts awarded through a competitively bid process for the joint installation of certain new residential services. The program covers typical residential installations in Regina, Saskatoon, Dalmeny, Martensville and Warman.

The overall process is as follows:

1. Customers request service by phone or online where information for all three crowns is collected.
2. SaskPower expeditors design and coordinate the installation with the customer.
3. Contractor installs SaskEnergy, SaskPower, SaskTel, and local cable company facilities under the supervision of an on-site SaskEnergy Inspector.
4. Contractor bills SaskPower directly for the power and communication portions of the installation. Communication companies are usually billed for the installation by SaskPower in advance of construction under a prepaid services arrangement.

The benefits associated with this initiative are:

- Improved customer experience by using one point of contact to initiate all urban residential requests for new service installations for all three Crowns.
- Improved timeliness of service installations. SaskPower's goal is to have 70% of services installed within 10 calendar days of the customer request (the 10-day KPI). YTD we are achieving this 10-day target over 80% of the time.
- Fewer problems (delays, rework, conflicts, customer complaints, etc.) than previously encountered, especially in scenarios with narrow lots and limited access.
- Cost benefits resulting from the coordinated installation of power, gas, and communication service lines by one contract crew, usually in a shared trench.

SaskPower has achieved an overall 15% cost saving since the project started. This is almost entirely related to the very competitive pricing received by having a unit-based contract that is focussed entirely on a very narrow spectrum of work. SaskPower's financial benefits are significantly less than those seen by SaskEnergy, largely due to the fact that joint installation and cost sharing with the communications companies is something SaskPower has always done.

SRRP Q88:

Reference: **Business Renewal (BR) Program**

Please provide an update on whether SaskPower has observed any reliability or plant availability issues as a result of the overhaul maintenance management program.

Response:

The following is a summary of SaskPower's observations relating to the overhaul maintenance management program:

- Coal plant overhaul maintenance intervals have been extended as part of the Business Renewal Program. This extension provides more operating time, thus increased energy production from the unit.

- In 2011, the thermal steam unit fleet in equivalent availability factor (EAF) was 2.6% under the corporate target. That declining trend continued, peaked in 2014, and recovered in 2015 to be within target ranges. The 2016-17 EAF is on target.
  - A large contributor to recovery is due to the overhaul maintenance management program execution.
  - Other significant contributors are from various targeted reliability sustainment capital investments and operating investments.

- The overhaul maintenance program continues to improve.
  - Major capital spare components procured and rotated for use on five gas generation units will reduce each future major maintenance outage duration by approximately 60%. The first application of this strategy took place in 2016.

- Overhaul maintenance management program issues addressed during implementation:
  - Realigned planned preventative maintenance activities to new longer intervals.
  - Reviewed and revised preventative maintenance activities to ensure the longer interval is achieved.
  - Adapted labour resources to execute the revised maintenance program.
  - Adapted planning cycles to the revised maintenance program.
  - Ensured adequate operating funding for the changes in overhaul work scope.

SRRP Q89:

Reference: **Business Renewal (BR) Program**

Please comment on whether there are any risks associated with eliminating the IT&S disaster recovery contract.

Response:

Elimination of an IT&S disaster recovery contract was associated with the repatriation of disaster recovery capabilities from an external service provider into our own data centers (completed in 2012). The repatriation was done in order to improve flexibility, reduce time to recover IT services, and reduce overall costs.

Over time, IT services are becoming a larger part of SaskPower's critical business functions and therefore requirements to recover them have grown. Bringing the capability in-house increases our ability to meet business needs and reduces risk. Since disaster recovery capabilities were brought in-house, the third party contract was no longer required.

SRRP Q90:

Reference: **Business Renewal (BR) Program**

Please provide a table showing the calculation of savings related to the debt-mix program and comment on the degree to which other electric utilities include short-term debt in their financing structure.

Response:

The savings from implementing the strategy of 15% short-term debt is tracked monthly and reported quarterly. The table below shows the savings on a quarterly basis and since the inception of the strategy.

Treasury Balanced Scorecard Measure
As at May 31, 2016

Balance Sheet Management - Debt Mix Savings

Purpose:
► To demonstrate savings for SaskPower with utilizing short term debt

(dollars are in millions)	2016					
	Year-to-Date	Q1	Q2	Q3	Q4	Inception
Debt Mix Savings (Costs) 1	$13.1	$8.1	$5.0	$0.0	$0.0	$123.4

Comments:

1. Measures the savings of using floating debt in place of fixed rate debt:
   a) Average monthly floating debt balances are used.
   b) When fixed rate debt leaves the 'pool' it leaves at the weighted average cost of the pool. New fixed rate debt is based on the average rate for the month of new 30 year debt.
   c) Inception is March 2009.

2. General info:
   a) Secondary 'compounding' impacts are not calculated.
   b) Average monthly rates used in the analysis are based off Bloomberg daily 30 year Province of Saskatchewan rates and actual floating rate debt expense from the GL.

The savings are from the rate differential between short-term borrowing rates (currently at between 0.5% and 0.6%) and long-term (30-year or greater) borrowing rates for the Corporation, which are approximately 3.2% to 3.4%. The last borrowing by the Corporation was done through the Province in January 2016 at a cost of 3.34%.

In terms of debt management strategies by other electrical utilities in Canada, there is a wide variation in the use of short-term debt. BC Hydro has the ability to borrow up to $4.5 billion in revolving borrowings from the Province. As of March 31, 2015, the outstanding amount under the short-term borrowing program was $3.547 billion. With total debt of $16.8 billion, this represents 21% short-term debt as opposed to 15% that SaskPower targets.

Manitoba Hydro and Quebec Hydro do not currently use any short-term debt as part of their debt management strategy.

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References:

BC Hydro and Power Authority 2014-15 Annual Report, Pages 69 and 70.

Manitoba Hydro Debt Management Strategy, Manitoba Hydro Treasury Division, December 2014

Quebec Hydro, 2014-15 Annual Report, Note 12, Page 66.

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SRRP Q91:

Reference: **Business Renewal (BR) Program**

Please quantify the OM&A reductions in 2015 associated with the elimination of FTEs; salary rollback for out-of-scope employees; overtime reductions; and reduction in discretionary consulting and advertising spend.

Response:

In early Q1, 2015, Crown Investments Corporation of Saskatchewan directed SaskPower to come up with OM&A savings totalling $18.2 million. The following is a summary of the cost categories from which these savings were achieved:

• Salary rollback	$4.0 million
• Short-term incentive reductions	$2.5 million
• FTE reductions	$3.2 million
• Training and travel reductions	$3.7 million
• Consulting and advertising reductions	$1.8 million
• Plant overhaul deferral	$3.0 million
Total	$18.2 million

SRRP Q92:

Reference: **Capital Program**

Please provide a copy of SaskPower's most recent capital plan.

Response:

SaskPower is in the process of developing our 10-Year Capital Plan. This information will be provided to the SRRP during the Mid-Application Update.

SRRP Q93:

Reference: **Capital Program**

For each capital project or program with final costs in excess of $10 million for each year from 2013 to 2015 please provide:

i) The justification for the project (e.g. capacity or system growth requirements; infrastructure renewal; operating efficiencies/savings)
ii) the original budget allocation
iii) the final actual project direct costs
iv) capitalized interest, overheads, and other charges;
v) an explanation for any variances of more than 10% from the original budget
vi) the annual depreciation, finance, corporate capital tax and other related costs in the 2016-17 revenue requirement related to each project or program.

Response:

1. For i, ii, iii, & v: see attached capital expenditure documents.

2. For iv: see attached interest capitalized document. Interest capitalized is itemized for major projects with annual interest capitalized greater than $100,000 per year. SaskPower capital project costs do not include overhead costs.

3. For vi: SaskPower does not calculate or forecast depreciation, finance charges, corporate capital tax and other related costs by individual project or program.

CAPITAL EXPENDITURES
As at December 2013
($000's)

CURRENT YEAR				PROJECT					
YTD Actual	2013 Budget	Variance		PTD Actual	Original CPA Value	Total CPR Value	% CNG	Total CPA Value	Variance
			Operations						
			Power Production						
			Poplar River						
356.1	1,750.0	(1,393.9)	Poplar River #1 Maintenance Platform	362.9	3,382.0	0.0		3,382.0	(3,019.1)
124.2	1,300.0	(1,175.8)	Poplar River #1 Precipitator Mechanical Upgrades	3,414.0	4,865.0	0.0		4,865.0	(1,451.0)
1,016.8	1,000.0	16.8	Poplar River #2 Ashpit and Refractory Design Improvement	1,016.8	1,006.2	0.0		1,006.2	10.6
1,680.3	700.0	980.3	Poplar River #2 Air Heater Expansion Joint	1,680.3	1,310.5	0.0		1,310.5	369.7
1,695.4	0.0	1,695.4	Poplar River #2 Grinding Zone Upgrades - Mill 2A	1,695.4	1,962.0	0.0		1,962.0	(266.6)
91.7	1,340.0	(1,248.3)	Poplar River #2B SBAC Upgrade	1,127.5	2,840.0	0.0		2,840.0	(1,712.5)
1,442.1	0.0	1,442.1	Poplar River #3N Ash Lagoon Renewal	2,131.0	6,450.0	0.0		6,450.0	(4,319.0)
499.4	1,125.0	(625.6)	Poplar River Ash Disposal Improvements	499.4	2,350.0	0.0		2,350.0	(1,850.6)
32.6	2,000.0	(1,967.4)	Poplar River Controls Simulator	32.6	4,450.0	0.0		4,450.0	(4,417.4)
100.4	4,000.0	(3,899.7)	Poplar River CW Discharge - Riprap	188.4	433.6	0.0		433.6	(245.2)
3,070.2	0.0	3,070.2	Poplar River Dry Stack from Ash Lagoon #2	3,070.2	5,825.9	0.0		5,825.9	(2,755.6)
312.7	1,671.0	(1,358.3)	Poplar River Facilities Improvement	1,964.6	2,700.0	0.0		2,700.0	(735.4)
5.4	1,700.0	(1,694.6)	Poplar River Maint. Contractor Facility Improvements	7.7	0.0	0.0		0.0	7.7
10,427.1	16,586.0	(6,158.9)	**Total Poplar River Projects**	17,190.7	37,575.2	0.0		37,575.2	(20,384.4)
			Boundary Dam						
7,355.9	0.0	7,355.9	BD #3 Life Extension	7,355.9	8,005.9	0.0		8,005.9	(650.0)
2,952.7	0.0	2,952.7	BD #3 Secondary Air Heaters Upgrade	3,485.9	3,550.0	0.0		3,550.0	(64.1)
1,978.6	2,764.0	(785.4)	BD #4 Life Extension	1,981.2	34,975.0	0.0		34,975.0	(32,993.8)
518.8	1,636.0	(1,117.2)	BD #5 Asbestos Removal	518.8	5,196.8	0.0		5,196.8	(4,678.0)
1,453.0	1,600.0	(147.0)	BD #5 Plant Coated Waterwall Panels	1,453.0	2,777.1	0.0		2,777.1	(1,324.1)
1,056.3	1,056.0	0.3	BD Asbestos Removal 2012 - 2020	7,527.4	8,414.7	0.0		8,414.7	(887.3)
1.1	1,000.0	(998.9)	BD Ash Lagoon Surcharging	840.6	0.0	0.0		0.0	840.6
4,676.9	4,000.0	676.9	BD CW Pipe Upgrades	4,676.9	4,748.2	636.8	13.4	5,385.0	(708.1)
696.4	1,996.0	(1,299.6)	BD Facilities Upgrade	714.7	2,447.4	0.0		2,447.4	(1,732.7)
1,164.6	0.0	1,164.6	BD Flyash Road	1,781.6	1,200.0	0.0		1,200.0	581.6
2,061.1	0.0	2,061.1	BD Roof Replacement	2,088.8	2,474.7	0.0		2,474.7	(385.8)
466.7	1,863.0	(1,396.3)	BD Waste Water Mgt Phase III	575.6	2,600.0	0.0		2,600.0	(2,024.4)
9,043.4	0.0	9,043.4	CO2 Disposal Well	9,043.4	9,000.0	0.0		9,000.0	43.4
5,479.4	0.0	5,479.4	CO2 Pipeline	5,503.3	5,600.0	0.0		5,600.0	(96.7)
2,635.5	0.0	2,635.5	ICCS Lab Equipment	2,635.5	3,430.3	0.0		3,430.3	(794.7)
41,540.3	15,915.0	25,625.3	**Total Boundary Dam Projects**	50,182.7	94,420.1	636.8	0.7	95,056.9	(44,874.2)
			Shand						
127.1	1,200.0	(1,072.9)	Shand Chemical Storage Building	127.1	1,200.0	0.0		1,200.0	(1,072.9)
127.1	1,200.0	(1,072.9)	**Total Shand Projects**	127.1	1,200.0	0.0		1,200.0	(1,072.9)

CURRENT YEAR				PROJECT					
YTD Actual	2013 Budget	Variance		PTD Actual	Original CPA Value	Total CPR Value	% CNG	Total CPA Value	Variance
			Northern Hydro						
3,598.9	4,801.0	(1,202.1)	Coteau Creek Rewind	19,287.9	20,100.0	0.0		20,100.0	(812.1)
3,301.3	2,586.0	715.3	EB Campbell Plant Control Monitoring System	12,153.8	11,000.0	4,500.0	40.9	15,500.0	(3,346.2)
3.5	1,750.0	(1,746.5)	EB Campbell Draft Tube Piers	3.5	4,782.5	0.0		4,782.5	(4,779.0)
713.5	1,490.0	(776.5)	EB Campbell N. Dyke Overflow	739.2	5,575.1	0.0		5,575.1	(4,835.9)
4.2	1,000.0	(995.8)	EB Campbell Plant Fire Suppression	4.2	0.0	0.0		0.0	4.2
2,682.8	0.0	2,682.8	Island Falls Camp Infrastructure	2,682.8	2,943.4	0.0		2,943.4	(260.6)
170.5	4,050.0	(3,879.5)	Island Falls Concrete Rehabilitation	170.5	4,250.0	0.0		4,250.0	(4,079.5)
140.1	1,007.0	(866.9)	Island Falls #1, 2, 3 & 7 Exciters	635.5	0.0	0.0		0.0	635.5
2,069.0	0.0	2,069.0	Island Falls #5 Refurbishment	21,810.2	21,000.0	4,500.0	21.4	25,500.0	(3,689.8)
13,565.0	14,078.0	(513.0)	Island Falls #6 Refurbishment	20,589.3	21,000.0	2,305.0	11.0	23,305.0	(2,715.7)
3,251.8	2,587.0	664.8	Island Falls Plant Control Monitoring System	11,025.5	11,000.0	4,500.0	40.9	15,500.0	(4,474.5)
1,314.6	1,987.0	(672.4)	Island Falls Roof Upgrades	1,330.9	2,300.0	0.0		2,300.0	(969.1)
(5.2)	1,750.0	(1,755.2)	Island Falls Ventilation Improvements	30.1	50.0	0.0		50.0	(19.9)
17.9	1,800.0	(1,782.2)	Tazin Weir Replacement	17.9	12,297.3	0.0		12,297.3	(12,279.4)
870.7	3,350.0	(2,479.3)	Tazin Weir Tunnel Intake Replacement	1,405.8	3,861.1	0.0		3,861.1	(2,455.3)
31,698.6	42,236.0	(10,537.4)	**Total Northern Hydro**	91,887.1	120,159.4	15,805.0	13.2	135,964.4	(44,077.3)
			Western Plants						
9,621.9	10,300.0	(678.1)	GT Capital Component Replacements	19,678.4	20,604.6	0.0		20,604.6	(926.3)
695.1	1,000.0	(304.9)	Landis Exhaust Gas Housing	990.5	1,693.0	0.0		1,693.0	(702.5)
433.0	1,834.0	(1,401.0)	QE 480V MCC Replacement	1,211.8	3,895.4	(1,008.9)	(25.9)	2,886.5	(1,674.7)
1,604.2	2,664.0	(1,059.8)	QE Facility Upgrade	7,560.7	9,127.0	1.0	0.0	9,128.0	(1,567.3)
12,354.2	15,798.0	(3,443.8)	**Total Western Plants**	29,441.4	35,320.0	(1,007.9)	**(2.9)**	34,312.1	(4,870.8)
			Power Production Other						
427.4	1,700.0	(1,272.6)	ECRF-PAVAC Demonstration	466.8	4,300.0	0.0		4,300.0	(3,833.2)
427.4	1,700.0	(1,272.6)	**Total Power Production Other**	466.8	4,300.0	0.0		4,300.0	(3,833.2)
14,427.1	30,808.0	(16,380.9)	Power Production Miscellaneous Projects Under $1,000,000	0.0	0.0	0.0		0.0	0.0
111,001.9	124,243.0	(13,241.1)	**Total Power Production Infrastructure**	189,295.8	292,974.7	15,433.9	**5.3**	308,408.6	(119,112.8)
80,842.6	114,160.0	(33,317.4)	QE Repowering	106,534.4	531,970.0	0.0		531,970.0	(425,435.6)
191,844.5	**238,403.0**	**(46,558.5)**	**Total Power Production**	**295,830.1**	**824,944.7**	**15,433.9**	**1.9**	**840,378.6**	**(544,548.4)**
			Distribution						
			Customer Connects						
131,979.3	115,000.0	16,979.3	Program - Distribution Customer Connects	131,979.3	115,000.0	25,000.0	21.7	140,000.0	(8,020.7)
131,979.3	**115,000.0**	**16,979.3**	**Total Customer Connects**	**131,979.3**	**115,000.0**	**25,000.0**		**140,000.0**	**(8,020.7)**
			Infrastructure Capacity Increase						
2,037.8	3,000.0	(962.2)	Initiative - Cumberland House Rebuild	2,037.8	5,000.0	(2,000.0)	(40.0)	3,000.0	(962.2)
4,500.1	4,600.0	(99.9)	Program - Economic Rebuild (Rural)	4,500.1	4,600.0	0.0		4,600.0	(99.9)
1,256.7	1,000.0	256.7	Program - Economic Rebuild (Urban)	1,256.7	1,000.0	700.0	70.0	1,700.0	(443.3)
3,805.9	0.0	3,805.9	Substation - Clarence - 138kV - 25kV - New	12,374.5	9,603.0	0.0		9,603.0	2,771.5
7,348.0	4,920.1	2,427.9	Substation - Estevan East -138kV-25kV - New	9,143.7	9,036.0	0.0		9,036.0	107.7
1,316.6	1,914.0	(597.4)	Substation - Fleet Street - 138kV-25kV - Expansion	2,553.6	8,059.4	0.0		8,059.4	(5,505.8)
39.5	2,420.1	(2,380.6)	Substation - Halbrite East - 138kV-25kV - New	45.6	500.0	0.0		500.0	(454.4)
2,723.0	0.0	2,723.0	Substation - Handsworth - 72kV-25kV - Temp	2,748.8	1,817.0	0.0		1,817.0	931.8
5,422.3	7,667.0	(2,244.7)	Substation - Kisbey - 230kV-25kV - New	5,572.3	20,296.4	0.0		20,296.4	(14,724.1)
3,546.5	7,338.0	(3,791.5)	Substation - Lloydminster - 138kV-25kV - New	3,750.5	7,027.0	360.0	5.1	7,387.0	(3,636.5)
2,671.7	1,153.0	1,518.7	Substation - Neudorf - 138kV-25kV - New	4,766.0	4,534.3	503.3	11.1	5,037.6	(271.6)
1,359.2	1,025.0	334.2	Substation - Shaunavon - 138kV-25kV - Expansion	1,544.7	4,397.4	0.0		4,397.4	(2,852.7)
218.5	2,400.0	(2,181.5)	Substation - Superb - 138kV-25kV - New	251.8	17,608.0	0.0		17,608.0	(17,356.2)
249.7	2,700.0	(2,450.3)	Substation - Winter - 138kV-25kV - New	306.6	12,534.0	0.0		12,534.0	(12,227.4)
36,495.4	**40,137.2**	**(3,641.8)**	**Total Infrastructure Capacity Increase**	**50,852.5**	**106,012.5**	**(436.7)**		**105,575.8**	**(54,723.3)**

CURRENT YEAR				PROJECT					
YTD Actual	2013 Budget	Variance		PTD Actual	Original CPA Value	Total CPR Value	% CNG	Total CPA Value	Variance
			Infrastructure Sustainment						
1,131.3	10,200.0	(9,068.7)	Initiative - City of Regina Aging Infrastructure Replacement	2,503.1	3,000.0	7,200.0	240.0	10,200.0	(7,696.9)
0.0	3,000.0	(3,000.0)	Initiative - Mobile Substation	0.0	3,000.0	0.0		3,000.0	(3,000.0)
4,307.9	0.0	4,307.9	Initiative - Wollaston Lake Submarine Cable Installations	4,650.3	4,500.0	0.0		4,500.0	150.3
439.3	1,520.0	(1,080.7)	Program - Distribution Automation	439.3	1,520.0	0.0		1,520.0	(1,080.7)
7,149.7	5,500.0	1,649.7	Program - Distribution Defective Apparatus	7,149.7	5,500.0	1,760.0	32.0	7,260.0	(110.3)
4,992.7	3,576.0	1,416.7	Program - Distribution Reliability Improvements (Rural & Urban)	4,992.7	3,576.0	1,624.0	45.4	5,200.0	(207.3)
9,607.5	19,000.0	(9,392.5)	Program - Distribution Wood Assets	9,607.5	19,000.0	0.0		19,000.0	(9,392.5)
2,527.3	2,500.0	27.3	Program - Farmyard Line Relocation	2,527.3	2,500.0	28.0	1.1	2,528.0	(0.7)
6.1	2,000.0	(1,993.9)	Program - Large Power Transformer Replacement	6.1	2,000.0	0.0		2,000.0	(1,993.9)
1,916.3	3,706.0	(1,789.7)	Program - Power Quality Upgrades	1,916.3	3,706.0	0.0		3,706.0	(1,789.7)
410.3	2,036.3	(1,626.0)	Program - Protection Upgrades	410.3	2,036.0	0.0		2,036.0	(1,625.7)
12,832.8	12,750.0	82.8	Program - Rural Rebuild & Improvement	12,832.8	12,750.0	83.0	0.7	12,833.0	(0.2)
6,290.6	4,554.0	1,736.6	Program - Underground Cable Replacements	6,290.6	4,554.0	2,946.0	64.7	7,500.0	(1,209.4)
910.9	2,500.0	(1,589.1)	Program - Urban/ Rural Hazards Mitigation	910.9	2,500.0	0.0		2,500.0	(1,589.1)
2,631.7	0.0	2,631.7	Program - Wood Substation Rebuild	2,631.7	4,000.0	0.0		4,000.0	(1,368.3)
0.0	1,800.0	(1,800.0)	Scada - Distribution Control System	0.0	0.0	0.0		0.0	0.0
55,154.3	**74,642.3**	**(19,488.1)**	**Total Infrastructure Sustainment**	**56,868.6**	**74,142.0**	**13,641.0**	18.4	**87,783.0**	**(30,914.4)**
223,628.9	**229,779.6**	**(6,150.7)**	**Total Distribution**	**239,700.3**	**295,154.5**	**38,204.3**	**12.9**	**333,358.8**	**(93,658.4)**
			Transmission						
33,043.3	**71,904.8**	**(38,861.5)**	**Total Customer Connects**	**88,024.7**	**189,366.2**	**14,347.0**	7.6	**203,713.2**	**(115,688.5)**
			Infrastructure Capacity Increase						
0.0	1,050.0	(1,050.0)	CP&C - GIS OT Upgrade	0.0	0.0	0.0		0.0	0.0
110.0	160.0	(50.0)	CP&C - P52E Powerline Carrier Rep	165.8	266.8	0.0		266.8	(100.9)
0.0	1,800.0	(1,800.0)	CP&C - Smart Grid Enterprize Service Bus	0.0	0.0	0.0		0.0	0.0
981.8	0.0	981.8	CP&C - W1Y - Fibre - New	4,726.5	5,102.0	0.0		5,102.0	(375.5)
7,618.5	28,982.0	(21,363.5)	Line - Aberdeen to Wolverine - 230kV - New	8,593.2	35,000.0	2,464.4	7.0	37,464.4	(28,871.2)
140.3	480.0	(339.7)	Line - Beatty to Wolverine Area - 230kV - New	141.1	500.0	0.0		500.0	(358.9)
1,685.5	0.0	1,685.5	Line - Dundonald to QE14 - 138kV - New	1,723.0	1,455.1	0.0		1,455.1	267.9
0.0	1,500.0	(1,500.0)	Line - GOPP Interconnections	0.0	0.0	0.0		0.0	0.0
67,985.4	121,518.0	(53,532.6)	Line - I1K - 230kV - New	99,355.4	380,000.0	0.0		380,000.0	(280,644.6)
2,502.5	2,804.0	(301.5)	Line - Pasqua to Swift Current - 230kV-138kV - New	3,231.9	98,701.6	0.0		98,701.6	(95,469.7)
113.0	0.0	113.0	Line - Swift Current to Coteau Creek - 230kV - Expansion	138.0	990.0	0.0		990.0	(852.0)
127.0	500.0	(373.0)	Line - Wind Interconnection - Chaplin 175 MW IPP	148.8	1,000.0	0.0		1,000.0	(851.2)
928.4	823.0	105.4	Scada - EMS Lifecycle Management	4,433.1	7,604.0	0.0		7,604.0	(3,170.9)
9,957.5	8,533.0	1,424.5	Switching Station - Aberdeen - 230kV - New	13,382.6	17,811.0	0.0		17,811.0	(4,428.4)
3,840.8	5,421.0	(1,580.2)	Switching Station - Boundary Dam - 230kV-138kV - Expansion	3,865.7	9,065.0	0.0		9,065.0	(5,199.3)
1,312.6	0.0	1,312.6	Switching Station - Breaker Rep	1,962.9	3,496.0	0.0		3,496.0	(1,533.0)
300.4	2,528.0	(2,227.6)	Switching Station - Ermine - 138kV-72kV - Expansion	302.0	4,216.5	0.0		4,216.5	(3,914.5)
6,262.4	0.0	6,262.4	Switching Station - Fleet Street - 230kV-138kV - Expansion	13,821.6	11,000.0	6,920.4	62.9	17,920.4	(4,098.8)
2,477.4	0.0	2,477.4	Switching Station - Fleet Street - Land - New	2,529.4	4,680.0	0.0		4,680.0	(2,150.6)
204.0	3,000.0	(2,796.0)	Switching Station - Key Lake - 230kV-138kV - New	250.2	5,000.0	0.0		5,000.0	(4,749.8)
578.2	4,500.0	(3,921.8)	Switching Station - Lloydminster - 230kV-25kV - New	578.2	28,000.0	2,825.0	10.1	30,825.0	(30,246.8)
22,865.9	32,890.0	(10,024.1)	Switching Station - Martensville - 230kV-138kV - New	27,345.6	48,873.0	0.0		48,873.0	(21,527.4)
10,992.9	7,337.0	3,655.9	Switching Station - Points North - 25kV Capacitors	11,159.8	7,594.0	1,647.0	21.7	9,241.0	1,918.8
0.0	1,140.0	(1,140.0)	Switching Station - Prot Sys Beatty – 230 kV – New	0.0	0.0	0.0		0.0	0.0
329.7	0.0	329.7	Switching Station - Queen Elizabeth - 138 kV - Exp	347.2	18,430.8	0.0		18,430.8	(18,083.6)
212.4	6,917.0	(6,704.6)	Switching Station - Regina South - 230kV Expansion	226.5	750.0	0.0		750.0	(523.5)
8.8	0.0	8.8	Switching Station - Relay System Improvement Program	45.5	1,506.1	0.0		1,506.1	(1,460.6)
1,693.8	6,400.0	(4,706.2)	Switching Station - Swift Current - 138kV - New	2,128.0	8,074.3	0.0		8,074.3	(5,946.3)
2,087.0	22,230.0	(20,143.0)	Switching Station - Tantallon - 230kV-138kV - Expansion	10,851.2	54,000.0	8,686.0	16.1	62,686.0	(51,834.8)
0.0	1,123.0	(1,123.0)	Switching Station - Terminal Equipment Ratings Upgrades	0.0	263.0	0.0		263.0	(263.0)
1,275.1	0.0	1,275.1	Switching Station - Tisdale - 138kV/72kV - Expansion	2,818.0	3,355.8	0.0		3,355.8	(537.8)
325.6	480.0	(154.4)	Switching Station - Under Frequency Load Shedding Prot Sys - Expansion	325.6	1,471.0	0.0		1,471.0	(1,145.4)
146,916.6	**262,116.0**	**(115,199.4)**	**Total Infrastructure Capacity Increase**	**214,596.8**	**758,205.9**	**22,542.8**	3.0	**780,748.7**	**(566,151.9)**

CURRENT YEAR				PROJECT					
YTD Actual	2013 Budget	Variance		PTD Actual	Original CPA Value	Total CPR Value	% CNG	Total CPA Value	Variance
			Infrastructure Sustainment						
19.1	1,100.0	(1,080.9)	Initiative - BBC, LZ96, LZ92, LIZ6	19.1	1,100.0	0.0		1,100.0	(1,080.9)
0.0	2,000.0	(2,000.0)	Initiative - Codette Regulator	0.0	2,000.0	0.0		2,000.0	(2,000.0)
0.0	2,000.0	(2,000.0)	Initiative - Regina South Reactor Switchgear Replacement	0.0	1,500.0	500.0	33.3	2,000.0	(2,000.0)
18.5	1,100.0	(1,081.5)	Initiative - Reyrolle Distance Relay Replacements	18.5	1,100.0	0.0		1,100.0	(1,081.5)
9.4	1,692.0	(1,682.6)	Initiative - Westinghouse Jet Aire Replacements	9.4	1,692.0	0.0		1,692.0	(1,682.6)
18.6	1,000.0	(981.4)	Program - Breaker Fail Relay Replacement	18.6	1,000.0	0.0		1,000.0	(981.4)
27.1	2,000.0	(1,972.9)	Program - DCF & DCVF Replacements	27.1	2,000.0	0.0		2,000.0	(1,972.9)
930.5	1,000.0	(69.5)	Program - Line Program Up-rating	930.5	1,000.0	0.0		1,000.0	(69.5)
604.8	1,500.0	(895.2)	Program - Line Switch Replacements	604.8	1,500.0	0.0		1,500.0	(895.2)
0.0	2,000.0	(2,000.0)	Program - Protective Relay Replacements	0.0	2,000.0	0.0		2,000.0	(2,000.0)
0.5	1,000.0	(999.5)	Program - Station Bus and Foundation Replacements	0.5	1,000.0	0.0		1,000.0	(999.5)
419.6	1,000.0	(580.4)	Program - Switching Station System Improvement	419.6	1,000.0	0.0		1,000.0	(580.4)
3,332.4	0.0	3,332.4	Program - Transmission Lattice Remediation	3,332.4	4,500.0	0.0		4,500.0	(1,167.6)
600.5	1,000.0	(399.5)	Program - Transmission Line System Improvement	600.5	1,000.0	0.0		1,000.0	(399.5)
992.6	1,500.0	(507.4)	Program - Transmission Reliability Improvements	992.6	750.0	0.0		750.0	242.6
20,287.1	3,000.0	17,287.1	Program - Wood Line Remediation	20,287.1	20,000.0	0.0		20,000.0	287.1
27,260.5	**22,892.0**	**4,368.5**	**Total Infrastructure Sustainment**	**27,260.5**	**43,142.0**	**500.0**	1.2	**43,642.0**	**(16,381.5)**
			Transmission Other						
2,268.5	2,325.0	(56.5)	Transmission Tools	2,268.5	2,425.0	0.0		2,425.0	(156.5)
2,268.5	**2,325.0**	**(56.5)**	**Total Transmission Other**	**2,268.5**	**2,425.0**	**0.0**	**0.0**	**2,425.0**	**(156.5)**
209,488.9	**359,237.8**	**(149,748.9)**	**Total Transmission**	**332,150.5**	**993,139.1**	**37,389.8**		**1,030,528.9**	**(698,378.4)**
17,514.5	46,355.3	(28,840.8)	T&D Miscellaneous Projects Under $1,000,000	0.0	0.0	0.0		0.0	0.0
0.0	(64,600.0)	64,600.0	T&D Contingency	0.0	0.0	0.0		0.0	0.0
450,632.3	**570,772.6**	**(120,140.4)**	**Total Transmission & Distribution**	**571,850.8**	**1,288,293.6**	**75,594.1**	5.9	**1,363,887.7**	**(792,036.9)**
			Operations - Other						
3,953.5	3,800.0	153.5	Meter Purchases	3,953.5	3,800.0	0.0		3,800.0	153.5
0.0	1,500.0	(1,500.0)	Spare Equipment Storage Sites	0.0	0.0	0.0		0.0	0.0
20,113.5	16,427.0	3,686.5	Vehicles & Equipment	20,113.5	16,426.9	4,236.4	25.8	20,663.3	(549.8)
24,067.0	**21,727.0**	**2,340.0**	**Total Operations - Other**	**24,067.0**	**20,226.9**	**4,236.4**	**20.9**	**24,463.3**	**(396.3)**
666,543.8	**830,902.6**	**(164,358.9)**	**Total Operations**	**891,747.9**	**2,133,465.1**	**95,264.4**	**4.5**	**2,228,729.5**	**(1,336,981.7)**
			Integrated Carbon Capture Sequestration						
200,838.0	172,700.0	28,138.0	BD #3 ICCS - Carbon Capture	602,255.0	648,000.0	(19,000.0)	(2.9)	629,000.0	(26,745.0)
310,707.0	162,600.0	148,107.0	BD #3 ICCS - Power Island	457,615.7	354,000.0	139,000.0	39.3	493,000.0	(35,384.3)
511,545.0	335,300.0	176,245.0	**Total BD #3 ICCS**	1,059,870.7	1,002,000.0	120,000.0	12.0	1,122,000.0	(62,129.3)
17,702.9	33,900.0	(16,197.1)	Carbon Capture Test Facility	19,800.0	51,821.4	0.0		51,821.4	(32,021.4)
529,247.8	**369,200.0**	**160,047.8**	**Total Integrated Carbon Capture Sequestration**	**1,079,670.7**	**1,053,821.4**	**120,000.0**	**11.4**	**1,173,821.4**	**(94,150.7)**
			Business Development						
11,622.1	0.0	11,622.1	Elizabeth Falls	11,622.1	5,500.0	9,656.0	175.6	15,156.0	(3,533.9)
11,622.1	**0.0**	**11,622.1**	**Total Business Development**	**11,622.1**	**5,500.0**	**9,656.0**	**175.6**	**15,156.0**	**(3,533.9)**
			Commercial						
			Supply Chain						
2,120.0	1,600.0	520.0	Furniture & Equipment	2,120.0	1,600.0	0.0		1,600.0	520.0
3,723.1	1,500.0	2,223.1	Head Office Elevator Refurbishment	3,747.3	2,500.0	4,800.0	192.0	7,300.0	(3,552.7)
285.7	5,000.0	(4,714.3)	Head Office Refurbishment	285.7	0.0	0.0		0.0	285.7
804.1	2,000.0	(1,195.9)	Lloydminster District Office/Shop	804.1	7,000.0	0.0		7,000.0	(6,195.9)
25,104.2	5,000.0	20,104.2	Logistics Warehouse Complex	25,823.4	25,000.0	0.0		25,000.0	823.4
0.1	1,000.0	(999.9)	Regina Rural East - Purchase Land	0.1	3,000.0	0.0		3,000.0	(2,999.9)
1,943.8	6,000.0	(4,056.2)	Saskatoon Stores	1,949.9	7,000.0	0.0		7,000.0	(5,050.1)
31.6	2,500.0	(2,468.4)	Stony Rapids	54.9	1,040.0	0.0		1,040.0	(985.1)
1,195.5	3,000.0	(1,804.5)	Swift Current Service Centre	3,849.3	2,575.0	0.0		2,575.0	1,274.3
1.6	2,000.0	(1,998.4)	Tisdale Office/Shop	1.6	1,000.0	0.0		1,000.0	(998.4)
15.2	1,000.0	(984.8)	TS&R Roof Replacement	2,138.9	2,500.0	0.0		2,500.0	(361.1)
0.0	500.0	(500.0)	Warman - Office/Shop - Purchase Land	0.0	3,500.0	0.0		3,500.0	(3,500.0)
2,421.3	2,000.0	421.3	Weyburn Service Center T&D	18,923.4	16,000.0	0.0		16,000.0	2,923.4
2,743.2	1,800.0	943.2	Miscellaneous Projects Under $1,000,000	0.0	0.0	0.0		0.0	0.0
40,389.5	**34,900.0**	**5,489.5**	**Total Supply Chain**	**59,698.8**	**72,715.0**	**4,800.0**	**6.6**	**77,515.0**	**(17,816.2)**

CURRENT YEAR				PROJECT					
YTD Actual	2013 Budget	Variance		PTD Actual	Original CPA Value	Total CPR Value	% CNG	Total CPA Value	Variance
			Service Delivery Renewal						
37,268.9	61,730.0	(24,461.1)	SDR - Advanced Metering Infrastructure	55,798.4	26,088.9	139,608.6	535.1	165,697.5	(109,899.1)
2,876.8	1,810.0	1,066.8	SDR - Field Worker Technology Phase II - Schedule & Dispatch	20,877.3	18,891.9	2,742.8	14.5	21,634.7	(757.4)
9.3	2,880.0	(2,870.7)	SDR - Field Worker Technology Phase III - Outage Mgmt System	534.3	0.0	0.0		0.0	534.3
0.0	0.0	0.0	Miscellaneous Projects Under $1,000,000	0.0	0.0	0.0		0.0	0.0
40,155.0	**66,420.0**	**(26,265.0)**	**Total Service Delivery Renewal**	**77,210.0**	**44,980.7**	**142,351.4**	**316.5**	**187,332.1**	**(110,122.1)**
80,544.5	**101,320.0**	**(20,775.5)**	**Total Commercial**	**136,908.8**	**117,695.7**	**147,151.4**	**125.0**	**264,847.1**	**(127,938.4)**
			Resource Planning & NorthPoint						
743.8	1,102.0	(358.2)	Coronach Land Purchase	4,838.1	4,594.0	1,604.0	34.9	6,198.0	(1,359.9)
2,641.9	2,255.0	386.9	Estevan Land Purchase	6,273.3	8,713.0	300.0	3.4	9,013.0	(2,739.7)
161.9	4,000.0	(3,838.1)	Land for Future Gas Turbine	161.9	1,000.0	0.0		1,000.0	(838.1)
0.0	3,500.0	(3,500.0)	New Transformer Draglines	0.0	0.0	0.0		0.0	0.0
620.7	30.0	590.7	Miscellaneous Projects Under $1,000,000	0.0	0.0	0.0		0.0	0.0
4,168.3	**10,887.0**	**(6,718.7)**	**Total Resource Planning & NorthPoint**	**11,273.3**	**14,307.0**	**1,904.0**	**13.3**	**16,211.0**	**(4,937.7)**
			Information Technology & Security						
537.5	3,000.0	(2,462.5)	**Business Application Rationalization (Lotus Notes) Portfolio**	537.5	316.0	65.0	20.6	381.0	156.5
0.0	1,500.0	(1,500.0)	**Business Intelligence Small Projects Portfolio**	0.0	0.0	0.0		0.0	0.0
685.7	0.0	685.7	BI Projects	1,051.8	1,334.4	94.1	7.1	1,428.5	(376.7)
0.0	0.0	0.0	Miscellaneous BI	0.0	0.0	0.0		0.0	0.0
685.7	**1,500.0**	**(814.3)**	**Total Business Intelligence Small Projects Portfolio**	**1,051.8**	**1,334.4**	**94.1**	**7.1**	**1,428.5**	**(376.7)**
0.0	3,380.0	(3,380.0)	**Effective & Efficient Operations Portfolio**	0.0	0.0	0.0		0.0	0.0
1,522.7	0.0	1,522.7	Miscellaneous Effective & Efficient Operations Portfolio Projects	0.0	0.0	0.0		0.0	0.0
1,522.7	**3,380.0**	**(1,857.3)**	**Total Effective & Efficient Operations Portfolio**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
			Information Technology & Security						
2,989.9	2,967.0	22.9	Contact Centre & Outage IVR	4,250.4	1,680.0	1,833.4	109.1	3,513.4	737.0
4,245.7	2,704.0	1,541.7	Desktop Management	7,454.3	2,704.0	2,500.0	92.5	5,204.0	2,250.3
0.0	4,000.0	(4,000.0)	Enterprise Content Management	0.0	0.0	0.0		0.0	0.0
0.0	1,950.0	(1,950.0)	Enterprise Learning	0.0	0.0	0.0		0.0	0.0
3,899.3	3,500.0	399.3	Infrastructure Refresh and Renewal	6,914.3	3,500.0	617.0	17.6	4,117.0	2,797.3
1,584.2	0.0	1,584.2	Perimeter Security Enhancement	2,498.7	3,356.5	2,793.5	83.2	6,150.0	(3,651.3)
0.0	1,543.0	(1,543.0)	Process Automation	0.0	0.0	0.0		0.0	0.0
0.0	1,000.0	(1,000.0)	Procurement	0.0	0.0	0.0		0.0	0.0
984.0	0.0	984.0	SAP License Purchases	984.0	1,583.0	0.0		1,583.0	(599.0)
13,703.2	**17,664.0**	**(3,960.8)**	**Total Information Technology & Security**	**22,101.7**	**12,823.5**	**7,743.9**	**302.4**	**20,567.4**	**1,534.3**
0.0	4,100.0	(4,100.0)	**Infrastructure Portfolio**	0.0	0.0	0.0		0.0	0.0
1,602.7	0.0	1,602.7	ECM Collaboration & Integration	2,439.9	2,000.0	1,442.5	72.1	3,442.5	(1,002.6)
1,648.6	0.0	1,648.6	Enterprise Monitoring & Alerting	2,812.4	2,965.0	1,148.0	38.7	4,113.0	(1,300.6)
2,763.3	0.0	2,763.3	Electric Office	3,443.5	5,000.0	523.0	10.5	5,523.0	(2,079.5)
2,640.2	0.0	2,640.2	Miscellaneous Infrastructure	0.0	0.0	0.0		0.0	0.0
8,654.9	**4,100.0**	**4,554.9**	**Total Infrastructure Portfolio**	**8,695.8**	**9,965.0**	**3,113.5**	**121.3**	**13,078.5**	**(4,382.8)**
0.0	1,040.0	(1,040.0)	**Loyal & Satisfied Customers Portfolio**	0.0	0.0	0.0		0.0	0.0
0.0	1,040.0	(1,040.0)	**Proud & Productive Employees Portfolio**	0.0	0.0	0.0		0.0	0.0
733.8	0.0	733.8	Miscellaneous Proud & Productive Employees	0.0	0.0	0.0		0.0	0.0
733.8	**1,040.0**	**(306.2)**	**Total Proud & Productive Employees Portfolio**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
0.0	1,094.0	(1,094.0)	**Prudent Financial Management Portfolio**	0.0	0.0	0.0		0.0	0.0
577.6	0.0	577.6	Miscellaneous Financial Management	0.0	0.0	0.0		0.0	0.0
577.6	**1,094.0**	**(516.4)**	**Total Proud & Productive Employees Portfolio**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
26,415.4	**32,818.0**	**(6,402.6)**	**Total Information Technology & Security**	**32,386.8**	**24,438.9**	**11,016.5**	**45.1**	**35,455.4**	**(3,068.6)**
0.0	**(195,100.0)**	**195,100.0**	**Corporate Contingencies**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
1,318,541.9	**1,150,027.6**	**168,514.3**	**Total SaskPower Capital Expenditures**	**2,163,609.6**	**3,349,228.1**	**384,992.3**	**11.5**	**3,734,220.5**	**(1,570,610.9)**

Total SaskPower capital budget for 2013 is $1.150 billion. Expenditures were $0.169 billion over budget.

Operations

Power Production

- Total Power Production capital budget is $238.4 million; $124.2 million for Infrastructure Renewal and $114.2 million for QE Repowering. Expenditures were $46.6 million under budget.
- Poplar River #1 Maintenance Platform capital budget is $1.8 million. Expenditures were $1.4 million under budget due to resource constraints resulting in deferral to 2014 to match contractor schedule.
- Poplar River #1 Precipitator Mechanical Upgrades project capital budget is $1.3 million. Expenditures were $1.2 million under budget due to project scope revisions.
- Poplar River Air Heater Expansion Joint capital budget is $0.7 million. Expenditures were $1.0 million over budget due to the degree of difficulty to install new equipment.
- Poplar River #2 Grinding Zone Upgrades – Mill 2A capital budget is zero. Expenditures were $1.7 million over budget due to design specification changes and advanced 2015 scheduled work.
- Poplar River #2B SBAC Upgrade capital budget is $1.3 million. Expenditures were $1.2 million under budget due to deferral to 2014.
- Poplar River #3N Ash Lagoon Renewal capital budget is zero. Expenditures were $1.4 million over budget due to carry over from 2012.
- Poplar River Controls Simulator project capital budget is $2.0 million. Expenditures were $2.0 million under budget due to delayed procurement scheduling.
- Poplar River CW Discharge-Riprap capital budget is $4.0 million. Expenditures were $3.9 million under budget due to deferral to future years.
- Poplar River Dry Stack from Ash Lagoon #2 capital budget is zero. Expenditures were $3.1 million over budget due to the advancement of the project from 2014 to ensure continuous operation of Ash Dry Stack.
- Poplar River Facilities Improvement capital budget is $1.7 million. Expenditures were $1.4 million under budget due to resource constraints resulting in deferral to future years.
- Poplar River Maintenance Contractor Facility Improvements capital budget is $1.7 million. Expenditures were $1.7 million under budget due to resource constraints resulting in deferral to future years.

- BD #3 Life Extension capital budget is zero. Expenditures were $7.4 million over budget due to requirements recognized after completion of boiler inspections.
- BD #3 Secondary Air Heaters Upgrade capital budget is zero. Expenditures were $3.0 million over budget due to carry overs from 2012 and higher than anticipated installation costs.
- BD #5 Asbestos Removal capital budget is $1.6 million. Expenditures were $1.1 million under budget due to deferral to future years.
- BD Ash Lagoon Surcharging capital budget is $1.0 million. Expenditures were $1.0 million under budget due to resource constraints resulting in deferral to future years.
- BD Facilities Upgrade capital budget is $2.0 million. Expenditures were $1.3 million under budget due to resource constraints caused by ICCS resulting in deferral to future years.
- BD Flyash Road capital budget is zero. Expenditures were $1.2 million over budget due to additional scope added to the existing project.
- BD Roof Replacement capital budget was zero. Expenditures were $2.1 million over budget due to carry overs from 2012.
- BD Waste Water Management Phase III capital budget is $1.9 million. Expenditures were $1.4 million under budget due to the scheduling deferral of Unit #4 to 2014.
- Shand Chemical Storage Building capital budget is $1.2 million. Expenditures were $1.1 million under budget due to deferral to 2014.
- Coteau Creek Rewind capital budget is $4.8 million. Expenditures were $1.2 million under budget due to resource constraints and execution taking longer than expected resulting in deferral to 2014.
- EB Campbell Draft Tube Piers capital budget is $1.8 million. Expenditures were $1.7 million under budget due to resource constraints resulting in deferral to future years.
- EB Campbell Plant Fire Suppression capital budget is $1.0 million. Expenditures were $1.0 million under budget due to resource constraints resulting in deferral to future years.
- Island Falls Camp Infrastructure capital budget is zero. Expenditures were $2.7 million over budget due to scope changes to the original plan.
- Island Falls Concrete Rehabilitation capital budget is $4.0 million. Expenditures were $3.9 million under budget due to deferral to future years.
- Island Falls #5 Refurbishment capital budget is zero. Expenditures were $2.1 million over budget due to carry overs from 2012.

- Island Falls Ventilation Improvements capital budget is $1.8 million. Expenditures were $1.8 million under budget due to resource constraints resulting in deferral to future years.
- Tazin Weir Replacement capital budget is $1.8 million. Expenditures were $1.8 million under budget due to resource constraints resulting in deferral to future years.
- Tazin Weir Tunnel Intake Replacement capital budget is $3.4 million. Expenditures were $2.5 million under budget due to deferral to future years.
- QE 480V MMC Replacement capital budget is $1.8 million. Expenditures were $1.4 million under budget due to advanced procurement costs in 2012.
- QE Facility Upgrade capital budget is $2.7 million. Expenditures were $1.1 million under budget due to funds advanced in 2012.
- ECRF-PAVAC Demonstration capital budget is $1.7 million. Expenditures were $1.3 million under budget due to resource constraints resulting in deferral to future years.
- QE Repowering capital budget is $114.2 million. Expenditures were $33.3 million under budget due to updated project costs.

Transmission and Distribution

- Total Transmission & Distribution capital budget is $570.8 million. Expenditures were $120.1 million under budget.
- Distribution Customer Connects Program capital budget is $115.0 million. Expenditures were $17.0 million over budget due to higher project activity and increased costs.
- Distribution Infrastructure Capacity Increase capital budget is $40.1 million. Expenditures were $3.7 million under budget due to lack of resources and schedule deferments.
- Distribution Infrastructure Sustainment capital budget is $74.6 million. Expenditures were $19.5 million under budget due primarily to the lack of engineering and construction resources and schedule deferments.
- Transmission Customer Connects capital budget is $71.9 million. Expenditures were $38.9 million under budget due to deferred scheduling and revised customer requirements partially offset by carry-overs from 2012.
- Transmission Infrastructure Capacity Increase capital budget is $262.1 million. Expenditures were $115.2 million under budget primarily due to delays in the I1K schedule; delays in Board approvals in the Aberdeen – Wolverine 230kV Line and the Martinsville Switching Station projects; and delays in material availability for the Tantallon Switching Station Expansion.
- Transmission Infrastructure Sustainment capital budget is $22.9 million. Expenditures were $4.4 million over budget due primarily to an increase to the Wood Line Remediation Program.

Operations - Other

- Total Operations - Other capital budget is $21.7 million. Expenditures were $2.3 million over budget.
- Spare Equipment Storage Sites capital budget is $1.5 million. There were no expenditures due to uncertainty regarding requirements.
- Vehicles and Equipment capital budget is $16.4 million. Expenditures were $3.7 million over budget due to carry overs from 2012.

ICCS

- The ICCS total capital budget is $369.2 million. Expenditures were $160.0 million over budget.
- BD#3 ICCS – Carbon Capture project capital budget is $172.7 million. Expenditures were $28.1 million over budget due to project carry overs from 2012.
- BD#3 ICCS – Power Island project capital budget it $162.6 million. Expenditures were $148.1 million over budget due to project carry overs from 2012 and increased costs.
- Carbon Capture Test Facility project capital budget is $33.9 million. Expenditures were $16.2 million under budget due to deferral to future years.

Business Development

- Elizabeth Falls project capital budget is zero. Expenditures were $11.6 million over budget due to a decision in late 2012 to capitalize project costs effective January 1, 2013.

Commercial

Supply Chain

- Total Supply Chain capital budget is $34.9 million.   Expenditures were $5.5 million over budget.
- Head Office Elevator Refurbishment capital budget is $1.5 million. Expenditures were $2.2 million over budget due to increased construction costs.

- Head Office Refurbishment capital budget is $5.0 million. Expenditures were $4.7 million under budget due to limited planning in 2013.
- Lloydminster District Office/Shop capital budget is $2.0 million. Expenditures were $1.2 million under budget due to delayed scheduling in 2013.
- Logistics Warehouse Complex capital budget is $5.0 million. Expenditures were $20.1 million over budget due to land purchase finalized in December.
- Regina Rural East Purchase Land capital budget is $1.0 million. Expenditures were $1.0 million under budget due to schedule delays to future years.
- Saskatoon Stores capital budget is $6.0 million. Expenditures were $4.1 million under budget due to delayed construction.
- Stony Rapids capital budget is $2.5 million. Expenditures were $2.5 million under budget due to deferral of construction to 2014.
- Swift Current Service Centre capital budget is $3.0 million. Expenditures were $1.8 million under budget due to construction delays.
- Tisdale Office/Shop capital budget is $2.0 million. Expenditures were $2.0 million under budget due to deferral of the in-service date to 2015.
- TS&R Roof Replacement capital budget is 1.0 million. Expenditures were $1.0 million under budget due to construction delays.

Service Delivery Renewal

- Total Service Delivery Renewal capital budget is $66.4 million. Expenditures were $26.3 million under budget.
- SDR – Advanced Metering Infrastructure capital budget is $61.7 million. Expenditures were $24.5 million under budget due to delayed meter purchases and development.
- SDR- Field Worker Technology Phase II – Schedule and Dispatch capital budget is $1.8 million. Expenditures were $1.1 million over budget due to remediation works for the first project release.
- SDR-Field Worker Technology Phase III – Outage Management System capital budget is $2.9 million. Expenditures were $2.9 million under budget due to a delay in the start date.

Resource Planning & NorthPoint

- Total Resource Planning & NorthPoint capital budget is $10.9 million. Expenditures were $6.7 million under budget.
- Land for Future Gas Turbine capital budget is $4.0 million. Expenditures were $3.8 million under budget due to deferral of land purchases to 2014.
- New Transformer Draglines capital budget is $3.5 million. Expenditures were $3.5 million under budget due to a duplication of budget.

Information Technology & Security

- Total Information Technology & Security capital budget is $32.8 million. Expenditures were $6.4 million under budget.
- Business Application Rationalization (Lotus Notes) Portfolio capital budget is $3.0 million. Expenditures were $2.5 million under budget due to focus on infrastructure based projects.
- The Effective and Efficient Operations Portfolio’s capital budget is $3.4 million. Expenditures were $1.9 million under budget due to fewer projects being undertaken.
- Desktop Management capital budget is $2.7 million. Expenditures were $1.5 million over budget due to the addition of Toughbooks and Schedule & Dispatch Modules to the Refresh program.
- Enterprise Content Management capital budget is $4.0 million. Expenditures were $4.0 million under budget due to the focus on infrastructure based projects.
- Enterprise Learning capital budget is $2.0 million. Expenditures were $2.0 million under budget due to a non-capital funding business solution.
- Perimeter Security Enhancement capital budget is zero. Expenditures were $1.6 million over budget due to project carryover from 2012.
- Process Automation project capital budget is $1.5 million. Expenditures were $1.5 million under budget due to lack of resources.
- Procurement capital budget is $1.0 million. Expenditures were $1.0 million under budget due to the focus on infrastructure based projects.
- SAP Licence Purchase capital budget is zero. Expenditures were $1.0 million over budget due to an opportunity to leverage a significant discount on purchases.
- Infrastructure portfolio capital budget is $4.1 million. Expenditures were $4.6 million over budget due to the increased focus on infrastructure requirements to support efficiency and effectiveness.

- The Loyal and Satisfied Customers Portfolio capital budget is $1.0 million. Expenditures were $1.0 million under budget due to the focus on infrastructure related projects.

CAPITAL EXPENDITURES

As at December 2014

($000's)

CURRENT YEAR					PROJECT					
YTD Actual	2014 Budget	2014 Forecast	Variance		PTD Actual	Original CPA Value	Total CPR Value	% CNG	Total CPA Value	Variance
				Operations						
				Power Production						
				Poplar River						
1,226.6	890.0	1,307.0	336.6	Poplar River #1 Grinding Zone Upgrades - Mill 1A	2,074.3	2,613.8	0.0		2,613.8	(539.5)
2,018.1	2,150.0	2,228.0	(131.9)	Poplar River #1 Maintenance Platform	2,381.0	3,382.0	1,206.0	35.7	4,588.0	(2,207.0)
1,015.4	5,325.0	1,350.0	(4,309.6)	Poplar River #3N Ash Lagoon Renewal	3,146.4	6,450.0	0.0		6,450.0	(3,303.6)
1,436.0	1,400.0	1,500.0	36.0	Poplar River Ash Disposal Improvements (CN)	1,935.4	2,350.0	(451.0)	(19.2)	1,899.0	36.4
1,213.6	0.0	0.0	1,213.6	Poplar River CW Canal Upgrade	1,402.0	5,172.1	0.0		5,172.1	(3,770.1)
1,271.6	255.0	1,175.0	1,016.6	Poplar River Diagnostics Room	1,271.7	4,925.0	1,425.0	28.9	6,350.0	(5,078.3)
2,574.0	3,110.0	2,807.0	(536.0)	Poplar River Facilities Upgrade	4,538.6	11,500.0	0.0		11,500.0	(6,961.4)
133.5	1,500.0	170.0	(1,366.5)	Poplar River Man Lift Replacement	136.8	4,000.0	0.0		4,000.0	(3,863.2)
11,332.2	13,250.0	13,500.0	(1,917.8)	Poplar River Morrison Dam Spillway Capacity	11,848.1	26,500.0	0.0		26,500.0	(14,651.9)
909.2	0.0	1,180.0	909.2	Poplar River Pulverizer Monorail	1,666.0	4,100.0	0.0		4,100.0	(2,434.0)
23,130.3	27,880.0	25,217.0	(4,749.7)	**Total Poplar River Projects**	30,400.4	70,992.9	2,180.0	3.1	73,172.9	(42,772.4)
				Boundary Dam						
37,907.5	39,406.0	39,000.0	(1,498.5)	BD #4 Life Extension	39,888.7	34,975.0	6,413.0	18.3	41,388.0	(1,499.3)
982.8	1,063.0	982.8	(80.2)	BD #5 Economizer Life Extension	1,026.2	1,916.3	1,143.9	59.7	3,060.2	(2,034.0)
4,785.1	5,725.0	4,766.4	(939.9)	BD #5 Front Water Wall & Corner 3 Life Extension	4,785.1	6,543.4	1,587.7	24.3	8,131.1	(3,346.1)
2,302.7	2,267.0	2,276.1	35.7	BD #5 Plant Coated Waterwall Panels	3,755.6	2,777.1	1,773.8	63.9	4,550.9	(795.3)
1,027.4	1,100.0	1,023.2	(72.7)	BD #5 Shielding Upgrades	1,027.4	2,274.7	811.1	35.7	3,085.8	(2,058.4)
1,815.9	2,575.0	2,571.0	(759.1)	BD #6 Economizer Life Extension	5,353.7	7,609.2	0.0		7,609.2	(2,255.5)
3,215.7	3,573.0	3,515.0	(357.3)	BD #6 Plant Coated Waterwall Panels	3,552.4	4,769.2	0.0		4,769.2	(1,216.8)
153.7	1,000.0	181.0	(846.3)	BD A Plant Heating	153.7	1,842.1	0.0		1,842.1	(1,688.4)
4,074.4	0.0	0.0	4,074.4	BD Ash Lagoon Surcharging	4,915.0	5,119.0	981.0	19.2	6,100.0	(1,185.0)
492.2	1,200.0	1,024.0	(707.8)	BD B Plant Elevator Upgrades	1,195.4	2,018.6	(117.6)	(5.8)	1,901.0	(705.6)
2,958.1	3,464.0	3,620.0	(505.9)	BD Facilities Upgrade	3,672.7	2,447.4	5,863.6	239.6	8,311.0	(4,638.3)
7,986.2	6,000.0	10,200.0	1,986.2	CO2 Pipeline	13,489.5	5,600.0	11,400.0	203.6	17,000.0	(3,510.5)
1,020.2	0.0	0.0	1,020.2	ICCS Lab Equipment	3,655.7	3,430.3	0.0		3,430.3	225.4
68,721.7	67,373.0	69,159.5	1,348.7	**Total Boundary Dam Projects**	86,471.2	81,322.3	29,856.5	36.7	111,178.8	(24,707.6)
				Shand						
1,739.3	0.0	1,683.3	1,739.3	Shand Ash Pit Life Extension	1,739.3	2,605.0	0.0		2,605.0	(865.7)
1,739.3	0.0	1,683.3	1,739.3	**Total Shand Projects**	1,739.3	2,605.0	0.0		2,605.0	(865.7)
				Northern Hydro						
3,188.3	4,788.0	4,200.0	(1,599.7)	EB Campbell N. Dyke Overflow	3,927.5	5,575.1	5,555.9	99.7	11,131.0	(7,203.5)
2,138.4	1,800.0	2,132.7	338.4	EB Campbell Plant Control Monitoring System	14,292.2	11,000.0	4,500.0	40.9	15,500.0	(1,207.8)
3,409.2	4,082.0	3,492.0	(672.8)	Island Falls A Dam Concrete Rehabilitation	3,579.8	4,250.0	0.0		4,250.0	(670.2)
1,960.6	1,912.0	2,069.0	48.6	Island Falls Plant Control Monitoring System (TS)	12,986.0	11,000.0	4,500.0	40.9	15,500.0	(2,514.0)
877.9	1,000.0	1,000.0	(122.1)	Tazin Weir Replacement	895.8	12,297.3	0.0		12,297.3	(11,401.5)
2,588.3	2,915.0	3,400.0	(326.7)	Tazin Weir Tunnel Intake Replacement	3,994.1	3,861.1	0.0		3,861.1	133.0
1,006.7	0.0	0.0	1,006.7	Wellington Surge Tank	1,282.6	1,351.3	0.0		1,351.3	(68.6)
1,292.7	1,500.0	1,337.8	(207.3)	Whitesands Dam Upgrades	1,317.7	1,500.0	0.0		1,500.0	(182.3)
16,462.1	17,997.0	17,631.5	(1,534.9)	**Total Northern Hydro**	42,275.6	50,834.7	14,555.9	28.6	65,390.6	(23,115.0)
				Western Plants						
5,938.7	7,863.0	7,000.0	(1,924.3)	Landis Life Extension	6,630.8	8,549.5	0.0		8,549.5	(1,918.7)
1,098.0	0.0	1,625.0	1,098.0	QE Facility Upgrade	8,658.7	9,127.0	521.4	5.7	9,648.4	(989.7)
7,036.7	7,863.0	8,625.0	(826.3)	**Total Western Plants**	15,289.5	17,676.5	521.4	**2.9**	18,197.8	(2,908.3)
				Power Production Other						
19,140.2	11,887.0	23,883.7	7,253.2	Power Production Miscellaneous Projects Under $1,000,000	0.0	0.0	0.0		0.0	0.0
136,230.2	133,000.0	146,200.0	3,230.2	**Total Power Production Infrastructure**	176,176.0	223,431.3	47,113.7	**21.1**	270,545.0	(94,369.1)
216,094.1	225,000.0	217,000.0	(8,905.9)	QE Repowering	322,628.4	531,970.0	0.0		531,970.0	(209,341.6)
352,324.3	**358,000.0**	**363,200.0**	**(5,675.7)**	**Total Power Production**	**498,804.4**	**755,401.3**	**47,113.7**	**6.2**	**802,515.0**	**(303,710.6)**

CURRENT YEAR					PROJECT					
YTD Actual	2014 Budget	2014 Forecast	Variance		PTD Actual	Original CPA Value	Total CPR Value	% CNG	Total CPA Value	Variance
				Distribution						
				Customer Connects						
149,504.0	100,000.0	150,000.0	49,504.0	Program - Distribution Customer Connects	149,504.0	150,000.0	0.0		150,000.0	(496.0)
149,504.0	**100,000.0**	**150,000.0**	**49,504.0**	**Total Customer Connects**	**149,504.0**	**150,000.0**	**0.0**		**150,000.0**	**(496.0)**
				Infrastructure Capacity Increase						
1,840.0	1,500.0	1,811.0	340.0	Initiative - Cumberland House Rebuild	3,877.8	5,000.0	(500.0)	(10.0)	4,500.0	(622.2)
7,118.4	6,500.0	7,700.0	618.4	Initiative - Stanley Mission Rural Rebuild	7,118.4	6,700.0	2,400.0	35.8	9,100.0	(1,981.6)
1,164.1	0.0	1,100.0	1,164.1	Program - Economic Rebuild (Rural)	1,164.1	2,300.0	0.0		2,300.0	(1,135.9)
978.6	1,000.0	1,100.0	(21.4)	Program - Economic Rebuild (Urban)	978.6	1,000.0	0.0		1,000.0	(21.4)
1,372.0	0.0	1,320.3	1,372.0	Substation - 2013 Dragline Walk (Advance)	3,405.0	2,359.0	272.0	11.5	2,631.0	774.0
2,745.4	3,500.0	3,500.0	(754.6)	Substation - Albert Park -138kV-25kV - Expansion	2,745.4	8,999.0	0.0		8,999.0	(6,253.6)
699.7	0.0	1,202.9	699.7	Substation - Bromhead -138kV-25kV - Expansion	4,673.7	6,210.0	0.0		6,210.0	(1,536.3)
1,274.8	985.6	1,174.6	289.2	Substation - Fleet Street Capacity Increase Stage 1	3,828.4	8,059.4	1,064.6	13.2	9,124.0	(5,295.6)
21,627.3	20,427.9	21,677.9	1,199.4	Substation - Kisbey - 230kV-25kV - New	27,199.6	20,296.4	6,549.6	32.3	26,846.0	353.6
5,026.4	6,043.0	5,605.5	(1,016.6)	Substation - Lloydminster 138-25kV - New	8,776.8	7,027.0	1,908.0	27.2	8,935.0	(158.2)
663.4	3,000.0	749.9	(2,336.6)	Substation - Rutland - 138kV - 25kV - New	970.0	12,534.0	0.0		12,534.0	(11,564.0)
3,249.0	2,852.7	3,265.0	396.3	Substation - Shaunavon - 138kV-25kV - Expansion	4,793.7	4,397.4	0.0		4,397.4	396.3
0.0	2,021.0	0.0	(2,021.0)	Substation - Stadium Supply - 138kV-25kV - New	0.0	0.0	0.0		0.0	0.0
4,788.1	3,000.0	3,197.9	1,788.1	Substation - Superb - 138kV-25kV - New	5,039.9	17,608.0	0.0		17,608.0	(12,568.1)
52,547.2	**50,830.2**	**53,405.0**	**1,717.0**	**Total Infrastructure Capacity Increase**	**74,571.5**	**102,490.2**	**11,694.2**		**114,184.4**	**(39,612.9)**
				Infrastructure Sustainment						
4,126.9	2,600.0	4,120.0	1,526.9	Program - City of Regina Aging Infrastructure Replacement	4,126.9	7,500.0	0.0		7,500.0	(3,373.1)
6,818.1	5,700.0	6,750.0	1,118.1	Program - Distribution Defective Apparatus	6,818.1	6,500.0	600.0	9.2	7,100.0	(281.9)
1,242.2	1,000.0	1,200.0	242.2	Program - Distribution Reliability Improvements (Rural & Urban)	1,242.2	2,000.0	0.0		2,000.0	(757.8)
6,739.0	7,910.0	8,000.0	(1,171.0)	Program - Distribution Wood Assets	6,739.0	18,000.0	0.0		18,000.0	(11,261.0)
1,098.2	0.0	1,150.0	1,098.2	Program - Farmyard Line Relocation	1,098.2	2,500.0	0.0		2,500.0	(1,401.8)
1,057.5	0.0	1,100.0	1,057.5	Program - High Load Move Corridors	1,057.5	1,000.0	200.0	20.0	1,200.0	(142.5)
1,059.1	0.0	0.0	1,059.1	Program -Substation 4kV Sub Rebuild	1,059.1	750.0	350.0	46.7	1,100.0	(40.9)
7,625.3	6,200.0	7,500.0	1,425.3	Program - Rural Rebuild & Improvement	7,625.3	15,000.0	0.0		15,000.0	(7,374.7)
4,460.8	2,000.0	4,000.0	2,460.8	Program - Underground Cable Replacements	4,460.8	6,000.0	0.0		6,000.0	(1,539.2)
1,269.8	0.0	1,200.0	1,269.8	Program - Urban/ Rural Hazard Mitigation	1,269.8	2,500.0	0.0		2,500.0	(1,230.2)
1,917.6	3,000.0	2,000.0	(1,082.4)	Program - Wood/Steel Substation Rebuild	1,917.6	3,500.0	0.0		3,500.0	(1,582.4)
37,414.4	**28,410.0**	**37,020.0**	**9,004.4**	**Total Infrastructure Sustainment**	**37,414.4**	**65,250.0**	**1,150.0**	1.8	**66,400.0**	**(28,985.6)**
239,465.6	**179,240.2**	**240,425.0**	**60,225.4**	**Total Distribution**	**261,489.9**	**317,740.2**	**12,844.2**	**4.0**	**330,584.4**	**(69,094.5)**
				Transmission						
80,206.9	**56,025.3**	**73,816.5**	**24,181.6**	**Total Customer Connects**	**98,479.7**	**178,960.8**	**1,185.0**	0.7	**180,145.8**	**(81,666.1)**
				Infrastructure Capacity Increase						
2,384.1	7,419.0	1,522.5	(5,034.9)	Line - Aberdeen to Wolverine - 230kV - New	10,977.2	73,350.0	0.0		73,350.0	(62,372.8)
135,446.9	100,000.0	132,000.0	35,446.9	Line - I1K - 230kV - New	234,802.3	363,292.0	0.0		363,292.0	(128,489.7)
1,218.4	0.0	0.0	1,218.4	Line - Pasqua - Swift Current 230/138kV New	4,532.2	101,527.6	0.0		101,527.6	(96,995.4)
3,214.0	6,000.0	4,632.7	(2,786.0)	Substation - Edam Area - New	3,558.7	37,455.0	0.0		37,455.0	(33,896.3)
9,467.8	3,000.0	10,322.1	6,467.8	Switching Station - Aberdeen - 230kV - New	22,850.4	17,811.0	8,364.0	47.0	26,175.0	(3,324.6)
1,004.1	0.0	1,113.4	1,004.1	Switching Station - Auburnton - Expansion	6,243.4	7,463.9	0.0		7,463.9	(1,220.5)
6,463.8	5,199.5	6,393.3	1,264.3	Switching Station - Boundary Dam 230-138kV - Expansion	10,329.5	9,065.0	1,435.0	15.8	10,500.0	(170.5)
1,374.5	2,500.0	1,463.0	(1,125.5)	Switching Station - Ermine - 138kV-72kV - Expansion	1,676.4	4,216.5	0.0		4,216.5	(2,540.1)
4,823.1	4,104.5	5,702.0	718.6	Switching Station - Fleet Street - 230kV-138kV - Expansion	18,644.7	11,000.0	8,599.7	78.2	19,599.7	(955.0)
18,498.2	10,085.1	19,389.8	8,413.1	Switching Station - Maidstone Area - 230kV-25kV - New	19,076.4	28,000.0	2,958.5	10.6	30,958.5	(11,882.1)
34,571.9	45,492.6	34,265.5	(10,920.7)	Switching Station - Martensville - 230kV-138kV - New	61,917.5	48,873.0	30,601.0	62.6	79,474.0	(17,556.5)
2,205.8	3,266.0	3,266.0	(1,060.2)	Switching Station - Pasqua 72-25kV - New	2,205.8	3,266.0	0.0		3,266.0	(1,060.2)
3,942.5	4,377.5	5,554.7	(435.0)	Switching Station - Points North 25kV Capacitors	15,102.3	7,594.0	1,647.0	21.7	9,241.0	5,861.3
10,381.5	6,800.0	9,747.8	3,581.5	Switching Station - Swift Current - 138kV - New	12,427.7	26,600.0	3,947.9	14.8	30,547.9	(18,120.2)
2,705.6	1,271.9	2,609.1	1,433.7	Switching Station - Tantallon - 230kV-138kV - Expansion	13,556.8	54,000.0	8,686.0	16.1	62,686.0	(49,129.2)
1,001.3	0.0	1,453.0	1,001.3	Switching Station - Tisdale - 138kV-72kV - Expansion	3,608.3	3,355.8	493.2	14.7	3,849.0	(240.7)
238,703.6	**199,516.1**	**239,434.9**	**39,187.5**	**Total Infrastructure Capacity Increase**	**441,509.8**	**796,869.8**	**66,732.3**	8.4	**863,602.1**	**(422,092.3)**

CURRENT YEAR					PROJECT					
YTD Actual	986 Budget	1175 21,677.9	Variance		PTD Actual	Original CPA Value	Total CPR Value	% CNG	Total CPA Value	Variance
				Infrastructure Sustainment						
5,785.4	6,000.0	5,700.0	(214.6)	Initiative - Q1H Structure Replacements	5,785.8	9,980.0	0.0		9,980.0	(4,194.2)
351.7	1,000.0	500.0	(648.3)	Program - Line Switch Replacements	351.7	2,000.0	0.0		2,000.0	(1,648.3)
1,153.0	0.0	1,000.0	1,153.0	Program - Line Uprating	1,153.0	2,000.0	0.0		2,000.0	(847.0)
4,371.9	2,500.0	4,200.0	1,871.9	Program - Transmission Lattice Steel Remediation	4,371.9	4,500.0	0.0		4,500.0	(128.1)
1,026.9	0.0	0.0	1,026.9	Progran - Transmission Reliabilty Improvementrs	1,026.9	1,000.0	0.0		1,000.0	26.9
10,948.9	10,000.0	11,000.0	948.9	Program - Wood Line Remediation	10,948.9	18,400.0	0.0		18,400.0	(7,451.1)
23,637.7	**19,500.0**	**22,400.0**	**4,137.7**	**Total Infrastructure Sustainment**	**23,638.1**	**37,880.0**	**0.0**		**37,880.0**	**(14,241.9)**
				Transmission Other						
1,606.0	1,720.0	1,720.0	(114.0)	Transmission Tools	1,606.0	1,720.0	0.0		1,720.0	(114.0)
1,606.0	**1,720.0**	**1,720.0**	**(114.0)**	**Total Transmission Other**	**1,606.0**	**1,720.0**	**0.0**	**0.0**	**1,720.0**	**(114.0)**
344,154.2	**276,761.4**	**337,371.4**	**67,392.8**	**Total Transmission**	**565,233.6**	**1,015,430.6**	**67,917.3**		**1,083,347.9**	**(518,114.2)**
13,483.9	28,933.4	15,115.4	(15,449.5)	T&D Miscellaneous Projects Under $1,000,000	0.0	0.0	0.0		0.0	0.0
597,103.8	**484,935.0**	**592,911.8**	**112,168.8**	**Total Transmission & Distribution**	**826,723.5**	**1,333,170.8**	**80,761.5**	6.1	**1,413,932.3**	**(587,208.7)**
				Operations - Other						
821.2	1,300.0	1,311.0	(478.8)	Materials Racking	1,305.9	600.0	0.0		600.0	705.9
4,474.5	2,000.0	5,000.0	2,474.5	Meter Purchases	4,474.5	2,500.0	2,750.0	110.0	5,250.0	(775.5)
827.1	1,000.0	1,000.0	(172.9)	Steel Pole Yard	827.1	1,000.0	0.0		1,000.0	(172.9)
13,976.5	19,265.0	17,000.0	(5,288.5)	Vehicles & Equipment	13,976.5	22,564.5	0.0		22,564.5	(8,588.0)
20,099.3	**23,565.0**	**24,311.0**	**(3,465.7)**	**Total Operations - Other**	**20,584.0**	**26,664.5**	**2,750.0**	10.3	**29,414.5**	**(8,830.5)**
969,527.3	**866,500.0**	**980,422.8**	**103,027.3**	**Total Operations**	**1,346,111.9**	**2,115,236.6**	**130,625.2**	**10.3**	**2,245,861.8**	**(899,749.9)**
				Integrated Carbon Capture Sequestration						
83,584.9	70,000.0	86,266.0	13,584.9	BD #3 ICCS - Carbon Capture	685,839.9	648,000.0	38,000.0	5.9	686,000.0	(160.1)
87,669.5	100,000.0	90,666.0	(12,330.5)	BD #3 ICCS - Power Island	545,285.2	354,000.0	202,000.0	57.1	556,000.0	(10,714.8)
171,254.5	170,000.0	176,932.0	1,254.5	**Total BD #3 ICCS**	1,231,125.1	1,002,000.0	240,000.0	**24.0**	1,242,000.0	(10,874.9)
16,613.3	0.0	16,613.3	16,613.3	BD #3 Boiler Buckstay Reinforcement	16,613.3	17,025.7	0.0		17,025.7	(412.4)
4,423.4	0.0	5,100.0	4,423.4	BD #3 Boilerhouse Horizontal Bracing	4,423.4	5,100.0	0.0		5,100.0	(676.6)
35,344.5	17,500.0	34,800.0	17,844.5	Carbon Capture Test Facility	55,144.5	51,821.4	18,178.6	35.1	70,000.0	(14,855.5)
450.0	0.0	0.0	450.0	Miscellaneous Projects <$1,000,000	0.0	0.0	0.0		0.0	0.0
228,085.7	**187,500.0**	**233,445.3**	**40,585.7**	**Total Integrated Carbon Capture Sequestration**	**1,307,306.3**	**1,075,947.0**	**258,178.6**	**24.0**	**1,334,125.6**	**(26,819.3)**
				Business Development						
4,317.3	9,000.0	4,500.0	(4,682.7)	Tazi Twe Hydroelectric - Elizabeth Falls	15,939.4	5,500.0	18,542.7	337.1	24,042.7	(8,103.3)
4,317.3	**9,000.0**	**4,500.0**	**(4,682.7)**	**Total Business Development**	**15,939.4**	**5,500.0**	**18,542.7**	**337.1**	**24,042.7**	**(8,103.3)**
				Resource Planning						
1,803.6	700.0	0.0	1,103.6	Furniture & Equipment	1,803.6	0.0	0.0		0.0	1,803.6
2,711.9	4,140.0	2,700.0	(1,428.1)	Head Office Elevator Refurbishment	6,459.2	2,500.0	4,800.0	192.0	7,300.0	(840.8)
950.1	1,413.2	1,040.0	(463.1)	Head Office Refurbishment	1,235.9	1,625.0	0.0		1,625.0	(389.1)
1,221.0	1,000.0	1,000.0	221.0	Logistic Warehouse Complex	27,044.4	36,500.0	0.0		36,500.0	(9,455.6)
2,317.2	2,070.0	2,450.0	247.2	Moose Jaw 6-8 Bay Crew/Storage Building	2,973.9	3,000.0	0.0		3,000.0	(26.1)
321.8	1,677.0	600.0	(1,355.2)	Prince Albert Service Center - 1 Bay & Office Addition	344.7	3,000.0	0.0		3,000.0	(2,655.3)
3,001.8	2,500.0	3,000.0	501.8	Saskatoon Service Center Roof	3,001.8	3,000.0	260.0	8.7	3,260.0	(258.2)
4,592.6	5,025.1	5,025.1	(432.5)	Saskatoon Stores	6,542.5	7,000.0	0.0		7,000.0	(457.5)
8,158.8	8,630.7	8,700.0	(471.9)	Swift Current Service Centre	12,008.1	12,500.0	0.0		12,500.0	(491.9)
101.0	1,000.0	135.0	(899.0)	TS&R Equipment	912.9	1,800.0	0.0		1,800.0	(887.1)
831.0	1,144.0	1,825.8	(313.0)	Miscellaneous Projects Under $1,000,000	0.0	0.0	0.0		0.0	0.0
26,010.8	**29,300.0**	**26,475.9**	**(3,289.2)**	**Total Resource Planning**	**62,327.1**	**70,925.0**	**5,060.0**	**7.1**	**75,985.0**	**(13,657.9)**

CURRENT YEAR					PROJECT					
YTD Actual	2014 Budget	2014 Forecast	Variance		PTD Actual	Original CPA Value	Total CPR Value	% CNG	Total CPA Value	Variance
				Service Delivery Renewal						
5,374.9	11,539.2	6,097.5	(6,164.3)	SDR - AMI - IT Project	31,486.2	31,411.2	0.0		31,411.2	74.9
5,412.7	12,797.8	5,680.3	(7,385.1)	SDR - AMI - Network Communication	13,407.2	26,262.9	0.0		26,262.9	(12,855.7)
(3,103.3)	40,663.0	(3,111.0)	(43,766.3)	SDR - AMI - Meters & Modules	18,589.3	93,023.4	0.0		93,023.4	(74,434.0)
10,701.3	0.0	11,449.3	10,701.3	AMI Replacement Project	10,701.3	15,000.0	0.0		15,000.0	(4,298.7)
18,385.6	65,000.0	20,116.1	(46,614.4)	**Total SDR - Advanced Metering Infrastructure**	74,184.0	165,697.5	0.0		165,697.5	(91,513.5)
1.8	0.0	0.0	1.8	Miscellaneous Projects Under $1,000,000	0.0	0.0	0.0		0.0	0.0
18,387.4	**65,000.0**	**20,116.1**	**(46,612.6)**	**Total Service Delivery Renewal**	**74,184.0**	**165,697.5**	**0.0**		**165,697.5**	**(91,513.5)**
				NorthPoint & Fuel Supply						
588.8	1,500.0	1,881.0	(911.2)	Coronach Land Purchase	708.7	2,320.0	0.0		2,320.0	(1,611.3)
786.8	1,200.0	1,100.0	(413.2)	Estevan Land Purchase	3,538.6	6,893.0	279.0	4.0	7,172.0	(3,633.4)
0.0	0.0	0.0	0.0	Miscellaneous Projects Under $1,000,000	0.0	0.0	0.0		0.0	0.0
1,375.6	**2,700.0**	**2,981.0**	**(1,324.4)**	**Total NorthPoint & Fuel Supply**	**4,247.3**	**9,213.0**	**279.0**	**3.0**	**9,492.0**	**(5,244.7)**
				Information Technology & Security						
				IT Foundational & Sustainment						
256.3	1,520.0	403.9	(1,263.7)	Communications - Wireless Communications	270.8	2,844.5	0.0		2,844.5	(2,573.6)
3,796.1	2,877.4	3,100.0	918.7	Core Infrastructure	3,796.1	2,640.0	0.0		2,640.0	1,156.1
1,974.7	2,500.0	1,865.7	(525.3)	Critical Systems Center	1,974.7	3,500.0	0.0		3,500.0	(1,525.3)
3,358.0	4,857.7	3,615.1	(1,499.7)	Desktop Management (including laptops for trucks)	3,358.0	4,312.0	0.0		4,312.0	(954.0)
0.0	1,075.0	0.0	(1,075.0)	ECM (RIM Compliance)	0.0	0.0	0.0		0.0	0.0
2,564.6	2,448.6	2,542.7	116.0	Electric Office - Asset Management/Smart Grid	6,008.0	5,000.0	1,026.6	20.5	6,026.6	(18.6)
1,287.7	0.0	1,287.7	1,287.7	Enterprise Monitoring & Alerting	4,100.1	2,965.0	1,148.0	38.7	4,113.0	(12.9)
400.0	1,120.6	678.0	(720.6)	Enterprise Security	482.7	1,116.7	0.0		1,116.7	(634.0)
1,734.9	3,845.0	3,182.2	(2,110.1)	Enterprise Services Business- Asset Management/Smart Grid	1,734.9	3,040.0	0.0		3,040.0	(1,305.1)
1,205.9	0.0	1,248.4	1,205.9	ECM Collaboration & Integration	3,645.8	2,000.0	2,137.4	106.9	4,137.4	(491.6)
1,093.8	0.0	0.0	1,093.8	Optical Transport Network Phase II	1,143.8	1,000.0	0.0		1,000.0	143.8
1,014.4	0.0	0.0	1,014.4	SAP Fiori Implementation	1,145.9	334.3	0.0		334.3	811.6
1,755.4	0.0	0.0	1,755.4	SAP Licence Purchases	2,739.4	1,583.0	1,633.0	103.2	3,216.0	(476.6)
5,404.5	7,296.5	6,199.5	(1,892.0)	Miscellaneous Projects <$1,000,000	0.0	0.0	0.0		0.0	0.0
25,846.4	**27,540.8**	**24,123.2**	**(1,694.4)**	**Total IT Foundational & Sustainment Projects**	**30,400.5**	**30,335.5**	**5,945.0**	**19.6**	**36,280.5**	**(5,880.0)**
				Corporate Strategic						
0.0	4,338.0	0.0	(4,338.0)	Corporate Strategic Projects Portfolio	0.0	0.0	0.0		0.0	0.0
1,581.6	0.0	1,533.3	1,581.6	Miscellaneous Projects <$1,000,000	0.0	0.0	0.0		0.0	0.0
1,581.6	**4,338.0**	**1,533.3**	**(2,756.4)**	**Total Corporate Strategic Projects**	**0.0**	**0.0**	**0.0**		**0.0**	**0.0**
				Non-Discretionary						
0.0	4,053.2	0.0	(4,053.2)	Non-Discretionary Projects Portfolio	0.0	0.0	0.0		0.0	0.0
3,230.2	3,652.0	3,613.5	(421.8)	Perimeter Security Enhancement	5,729.0	3,356.5	2,793.5	83.2	6,150.0	(421.0)
222.1	0.0	310.0	222.1	Miscellaneous Projects <$1,000,000	0.0	0.0	0.0		0.0	0.0
3,452.3	**7,705.2**	**3,923.5**	**(4,252.9)**	**Total Non-Discretionary Projects**	**5,729.0**	**3,356.5**	**2,793.5**	**83.2**	**6,150.0**	**(421.0)**
				Discretionary						
0.0	0.0	0.0	0.0	Discretionary Projects Portfolio	0.0	0.0	0.0		0.0	0.0
419.3	416.0	420.0	3.3	Miscellaneous Projects <$1,000,000	0.0	0.0	0.0		0.0	0.0
419.3	**416.0**	**420.0**	**3.3**	**Total Discretionary Projects**	**0.0**	**0.0**	**0.0**		**0.0**	**0.0**
31,299.6	**40,000.0**	**30,000.0**	**(8,700.4)**	**Total Information Technology & Security**	**36,129.4**	**33,692.0**	**8,738.5**	**25.9**	**42,430.5**	**(6,301.1)**
1,279,003.7	**1,200,000.0**	**1,297,941.1**	**79,003.7**	**Total SaskPower Capital Expenditures**	**2,846,245.5**	**3,476,211.1**	**421,424.1**	**12.1**	**3,897,635.1**	**(1,051,389.7)**

Total SaskPower capital budget for 2014 is $1.2 billion. Year to date expenditures were $79.0 million over budget.

Operations

Power Production

- Total Power Production capital budget is $358.0 million; $133.0 million for Infrastructure Renewal and $225.0 million for QE Repowering. Year to date expenditures were $5.7 million under budget.
- Poplar River #3N Ash Lagoon Renewal capital budget is $5.3 million. Year to date expenditures were $4.3 million under budget due to revised estimates.
- Poplar River Cooling Water Canal Upgrade has no capital budget. Year to date expenditures were $1.2 million over budget due to project being moved forward from 2015.
- Poplar River Diagnostics Room capital budget is $0.3 million. Year to date expenditures were $1.0 million over budget due to urgent need.
- Poplar River Man Lift Replacement project capital budget is $1.5 million. Year to date expenditures were $1.4 million under budget due to award of the contracts being behind schedule.
- Poplar River Morrison Dam spillway Capacity project capital budget is $13.3 million. Year to date expenditures were $1.9 million under budget due to work schedule being deferred because of site conditions.
- Boundary Dam #4 Life Extension capital budget is $39.4 million. Year to date expenditures were $1.5 million under budget due to updated cost estimates.
- BD Ash Lagoon Surcharging has no capital budget. Year to date expenditures were $4.0 million over budget due to water levels increasing significantly when BD #3 came back on line. The work was done under emergency conditions to prevent another breach of the ash lagoon system.
- Shand Ash Pit Life Extension has no capital budget. Year to date expenditures were $1.7 million over budget due to structural deterioration posing serious safety and reliability issues.
- EB Campbell N Dyke Overflow project has a capital budget of $4.8 million. Year to date expenditures were $1.6 million under budget due to updated project estimates.
- Wellington Surge Tank project has no capital budget. Year to date expenditures were $1.0 million over budget due to delays causing tank roof to collapse requiring more work to fix it.
- Landis Life Extension project capital budget is $7.9 million. Year to date expenditures were $1.9 million under budget due to updated project cost estimates.

- QE Facility Upgrade has no capital budget. Year to date expenditures were $1.1 million over budget due to asbestos abatement and revised estimates.
- QE Repowering project capital budget is $225.0 million. Year to date expenditures were $8.9 million under budget due to deferrals to 2015.

Transmission and Distribution

- Total Transmission & Distribution capital budget is $484.9 million. Year to date expenditures were $112.2 million over budget.
- Distribution Customer Connects Program capital budget is $100.0 million. Year to date expenditures were $49.5 million over budget due to higher project activity and increased costs.
- Distribution Infrastructure Capacity Increase capital budget is $50.8 million. Year to date expenditures were $1.7 million over budget mainly due to the addition of the Substation Dragline Walk (Advance) project at $1.4 million and the Substation – Kisbey 230-25kV New project at $1.2 million partially offset by the deferral of the Substation – Rutland 138-25kV New and the Substation Stadium Supply 138-25kV New.
- Distribution Infrastructure Sustainment capital budget is $28.4 million. Year to date expenditures were $9.0 million over budget primarily due to additional spending on all programs except Distribution Wood Assets and Wood/Steel Substation Rebuilds projects.
- Transmission Customer Connects capital budget is $56.0 million. Year to date expenditures were $24.2 million over budget primarily due to increases required to complete a new 230kV New Line connect.
- Transmission Infrastructure Capacity Increase capital budget is $199.5 million. Year to date expenditures were $39.2 million over budget primarily due to the I1K Project accelerated schedules for the completion of the north section as well as for the brush clearing activities on the south section.
- Transmission Infrastructure Sustainment capital budget is $19.5 million. Year to date expenditures were $4.1 million over budget primarily due to an increase in Lattice Steel Remediation projects.

Operations - Other

- Total Operations - Other capital budget is $23.6 million. Year to date expenditures were $3.5 million under budget.
- Meter Purchases capital budget is $2.0 million. Year to date expenditures were $2.5 million over budget due to delays in the AMI rollout requiring the purchase of more commercial and industrial meters.
- Vehicles & Equipment capital budget is $19.3 million. Year to date expenditures were $5.3 million under budget due to delays in equipment delivery.

ICCS

- The ICCS total capital budget is $187.5 million. Year to date expenditures were $40.6 million over budget.
- BD#3 ICCS – Carbon Capture project capital budget is $70.0 million. Year to date expenditures were $13.6 million over budget based on revised estimated of work remaining including an increase to chemical cleaning of $7.0 million and interest expense of $2.4 million.
- BD#3 ICCS – Power Island project capital budget is $100.0 million. Year to date expenditures were $12.3 million under budget based on revised estimated of work remaining.
- BD#3 Boiler Buckstay Reinforcement project has no capital budget. Year to date expenditures $16.6 million over budget to upgrade the structural reinforcing system surrounding the boiler to ensure adequate protection to prevent negative draft pressure from imploding the boiler walls.
- BD #3 Boilerhouse Horizontal Bracing project has no capital budget. Year to date expenditures were $4.4 million over budget due to the need to bring the BD #3 Boilerhouse structural system up to current building code requirements for the loads and load combinations.
- Carbon Capture Test Facility project capital budget is $17.5 million. Year to date expenditures were $17.8 million over budget due to carryover of work from 2013.

Business Development

- Elizabeth Falls project capital budget is $9.0 million. Year to date expenditures were $4.7 million under budget due to the delay in the resolution of a regulatory issue.

Resource Planning

- Total Resource Planning capital budget is $29.3 million. Year to date expenditures were $3.3 million under budget.
- Furniture & Equipment capital budget was $0.7 million. Year to date expenditures were $1.1 million over budget due to unplanned furniture purchases for new Service Centers in Swift Current, Saskatoon and Prince Albert.
- Head Office Elevator Refurbishment project capital budget is $4.1 million. Year to date expenditures were $1.4 million under budget due to costs being lower than anticipated
- Prince Albert Service Center – 1 Bay & Office Addition capital budget is $1.7 million. Year to date expenditures were $1.4 million under budget due to design delays resulting in less construction in 2014 than anticipated.

Service Delivery Renewal

- Total Service Delivery Renewal capital budget is $65.0 million. Year to date expenditures were $46.6 million under budget due to the cancellation of the AMI Meter Installations on July 30 and the directive to return the meters to the supplier. As well there were less tower installations required than originally anticipated.

NorthPoint & Fuel Supply

- Total NorthPoint & Fuel Supply capital budget is $2.7 million. Year to date expenditures were $1.3 million under budget due to deferrals to 2015.

Information Technology & Security

- Total Information Technology & Security capital budget is $40.0 million. Year to date expenditures were $8.7 million under budget.
- Wireless Communications capital budget is $1.5 million. Year to date expenditures were $1.3 million under budget primarily due to resourcing issues resulting in delays.
- Desktop Management project capital budget is $4.9 million. Year to date expenditures were $1.5 million under budget due to fewer requests for new hardware than anticipated and delays due to compatibility.
- ECM (RIM Compliance) project capital budget is $1.1 million. There was no capital spending due to realignment of priorities within Foundational/Sustainment portfolio.
- Enterprise Monitoring & Alerting has no capital budget. Year to date expenditures were $1.3 million over budget due to carryover of work from 2013.
- Enterprise Service Business – Asset Management Smart Grid project capital budget is $3.8 million. Year to date expenditures were $2.1 million under budget due to insufficient resources to meet project demands.
- ECM Collaboration & Integration has no capital budget. Year to date expenditures were $1.2 million over budget due to carryover of work from 2013.
- Optical Transport Network Phase II has no capital budget. Year to date expenditures were over budget by $1.1 million due to the requirement for a replacement MPLS connection between Regina and Saskatoon Data Centers.
- SAP Fiori Implementation project has no capital budget. Year to date expenditures were over budget by $1.0 million due to increased focus on mobile SAP applications to mobilize the SaskPower workforce.
- SAP Licence Purchases project has no capital budget. Year to date expenditures were over budget by $1.8 million due to an opportunity to leverage a significant discount on SAP licence purchases.

- Corporate Strategic projects capital budget is $4.3 million. Year to date expenditures were $2.8 million under budget due to reallocation of resources to support higher priority initiatives.
- Non-Discretionary projects capital budget is $7.7 million. Year to date expenditures were $4.3 million under budget primarily due to procurement delays resulting in deferral to 2015.

CAPITAL EXPENDITURES
As at December 2015
($000's)

CURRENT YEAR				PROJECT					
YTD Actual	2015 Budget	Variance		PTD Actual	Original CPA Value	Total CPR Value	% CNG	Total CPA Value	Variance
			Power Production						
			Poplar River						
1,427.8	900.0	527.8	Poplar River #1 Grinding Zone Upgrades - Mill 1A	3,502.1	2,613.8	0.0		2,613.8	888.3
1,358.3	966.0	392.3	Poplar River #1 Maintenance Platform	3,739.4	3,382.0	1,206.0	35.7	4,588.0	(848.6)
1,229.7	0.0	1,229.7	Poplar River #2 Coal Pipe & Elbow Replacement	1,611.7	2,143.2	0.0		2,143.2	(531.6)
1,693.0	0.0	1,693.0	Poplar River #2 Grinding Zone Upgrades - Mill 2A	3,507.4	1,962.0	0.0		1,962.0	1,545.5
16,187.6	12,700.0	3,487.6	Poplar River #2 Long Term Expenditures	16,496.8	19,000.0	500.0	2.6	19,500.0	(3,003.2)
289.7	2,616.5	(2,326.8)	Poplar River Controls Simulator	341.9	4,450.0	0.0		4,450.0	(4,108.1)
3,400.6	4,420.0	(1,019.4)	Poplar River CW Canal Upgrade	4,802.6	5,172.1	0.0		5,172.1	(369.5)
4,461.6	3,050.0	1,411.6	Poplar River Diagnostics Room	5,733.3	4,925.0	1,425.0	28.9	6,350.0	(616.7)
3,334.7	7,000.0	(3,665.3)	Poplar River Facilities Upgrade	7,873.4	11,500.0	6,500.0	56.5	18,000.0	(10,126.6)
19.2	3,856.7	(3,837.5)	Poplar River Man Lift Replacement	156.0	4,000.0	0.0		4,000.0	(3,844.0)
14,060.2	12,100.0	1,960.2	Poplar River Morrison Dam Spillway Capacity	25,908.3	26,500.0	0.0		26,500.0	(591.7)
325.4	1,194.5	(869.1)	Poplar River Plant HVAC	403.5	1,342.0	0.0		1,342.0	(938.5)
2,282.4	1,600.0	682.4	Poplar River Pulverizer Monorail	3,948.4	4,100.0	0.0		4,100.0	(151.6)
1,269.0	0.0	1,269.0	Poplar River Site Infrastructure	1,487.9	4,902.7	0.0		4,902.7	(3,414.8)
51,339.2	50,403.7	935.5	**Total Poplar River Projects**	79,512.6	95,992.7	9,631.0	10.0	105,623.7	(26,111.1)
			Boundary Dam						
489.2	1,696.0	(1,206.8)	BD #5 Asbestos Removal	1,859.3	5,196.8	0.0		5,196.8	(3,337.5)
1,075.3	0.0	1,075.3	BD #5 Life Extension	1,075.3	15,094.8	0.0		15,094.8	(14,019.5)
1,415.8	1,681.0	(265.2)	BD A Plant Heating	1,569.5	1,842.1	0.0		1,842.1	(272.6)
1,089.3	1,500.0	(410.7)	BD Acid Caustic Bulk Tanks	1,089.3	1,500.0	1,200.0	80.0	2,700.0	(1,610.7)
1,318.7	0.0	1,318.7	BD Ash Lagoon Surcharging	6,233.6	5,119.0	1,531.0	29.9	6,650.0	(416.4)
1,025.8	3,510.5	(2,484.7)	BD - CO2 Pipeline	14,515.3	5,600.0	11,400.0	203.6	17,000.0	(2,484.7)
1,099.9	1,235.0	(135.1)	BD CW Instrumentation	1,168.0	1,355.0	0.0		1,355.0	(187.0)
4,166.7	3,906.0	260.7	BD Facilities Upgrade	7,839.5	2,447.4	5,863.6	239.6	8,311.0	(471.5)
104.5	2,800.0	(2,695.5)	BD Landfill	140.1	409.7	0.0		409.7	(269.5)
1,088.4	0.0	1,088.4	BD Public Safety Measures	1,105.0	4,505.2	0.0		4,505.2	(3,400.2)
6.7	3,689.3	(3,682.6)	BD Manlift Replacement	16.7	4,500.0	0.0		4,500.0	(4,483.3)
1,021.5	3,000.0	(1,978.5)	BD Sewage Lagoon Expansion	1,177.8	4,763.7	0.0		4,763.7	(3,585.9)
1,456.0	2,430.4	(974.4)	BD Spillway Upgrades	1,530.9	3,700.0	0.0		3,700.0	(2,169.1)
15,357.6	25,448.2	(10,090.6)	**Total Boundary Dam Projects**	39,320.3	56,033.6	19,994.6	35.7	76,028.2	(36,707.9)
			Shand						
131.4	2,200.0	(2,068.6)	Shand Ash Conveyor Belt	979.6	1,271.3	0.0		1,271.3	(291.7)
1,154.2	2,900.0	(1,745.8)	Shand Chemical Storage Building	1,277.1	3,604.3	0.0		3,604.3	(2,327.2)
193.3	1,110.0	(916.7)	Shand LIFAC Reactor Upgrade	1,741.6	1,750.0	2,250.0	128.6	4,000.0	(2,258.4)
9.0	3,647.3	(3,638.3)	Shand Manlift Replacement	11.9	4,200.0	0.0		4,200.0	(4,188.1)
1,109.1	3,000.0	(1,890.9)	Shand Roof Replacement	1,109.8	3,020.0	0.0		3,020.0	(1,910.2)
2,597.0	12,857.3	(10,260.3)	**Total Shand Projects**	5,120.0	13,845.6	2,250.0	16.3	16,095.6	(10,975.6)

CURRENT YEAR				PROJECT					
YTD Actual	2015 Budget	Variance		PTD Actual	Original CPA Value	Total CPR Value	% CNG	Total CPA Value	Variance
			Northern Hydro						
495.7	2,700.0	(2,204.3)	Athabasca Mobitel	531.9	6,140.0	0.0		6,140.0	(5,608.1)
1,973.7	0.0	1,973.7	Coteau Creek GSU Replacement	1,973.7	3,197.9	0.0		3,197.9	(1,224.2)
877.3	2,806.0	(1,928.7)	EB Campbell #2 Wicket Gate	877.3	2,775.8	0.0		2,775.8	(1,898.5)
16.5	2,000.0	(1,983.5)	EB Campbell Licence Mitigation	16.5	0.0	0.0		0.0	16.5
2,198.9	5,782.0	(3,583.1)	EB Campbell N. Dyke Overflow	6,126.5	5,575.1	5,555.9	99.7	11,131.0	(5,004.5)
2,554.8	1,600.0	954.8	EB Campbell Plant Control Monitoring System	16,846.9	11,000.0	6,500.0	59.1	17,500.0	(653.1)
1,914.6	1,589.0	325.6	Island Falls Plant Control Monitoring System (TS)	14,900.6	11,000.0	4,500.0	40.9	15,500.0	(599.4)
985.2	250.0	735.2	Nipawin Roof Replacement	985.2	1,522.1	0.0		1,522.1	(536.8)
4,049.6	5,000.0	(950.4)	Tazin Weir Replacement	4,945.3	12,297.3	0.0		12,297.3	(7,352.0)
2,013.1	5,710.0	(3,696.9)	Wellington Refurbishment	2,033.5	6,046.1	0.0		6,046.1	(4,012.6)
1,084.7	1,300.0	(215.3)	Whitesands Dam Upgrades	2,402.4	1,500.0	900.0	60.0	2,400.0	2.4
18,164.2	28,737.0	(10,572.8)	**Total Northern Hydro**	51,639.9	61,054.3	17,455.9	28.6	78,510.2	(26,870.3)
			Western Plants						
1,012.5	0.0	1,012.5	QE 'A' Plant 4160V Cable Replacement	1,012.5	6,056.1	0.0		6,056.1	(5,043.6)
2,343.4	1,330.0	1,013.4	QE CW Pumphouse	2,363.3	1,394.5	1,167.5	83.7	2,562.0	(198.7)
11,218.7	1,175.9	10,042.8	WP Spare Engine	11,218.7	11,902.2	0.0		11,902.2	(683.5)
14,574.6	2,505.9	12,068.7	**Total Western Plants**	14,594.5	19,352.8	1,167.5	**6.0**	20,520.3	(5,925.8)
			Power Production Other						
24,165.1	24,235.0	(69.9)	Power Production Miscellaneous Projects Under $1,000,000	0.0	0.0	0.0		0.0	0.0
126,197.7	144,187.1	(17,989.4)	**Total Power Production Infrastructure**	190,187.2	246,279.0	50,499.0	**20.5**	296,778.0	(106,590.8)
167,479.3	130,000.0	37,479.3	QE Repowering	490,107.8	531,970.0	0.0		531,970.0	(41,862.2)
293,677.1	**274,187.1**	**19,490.0**	**Total Power Production**	**680,295.0**	**778,249.0**	**50,499.0**	**6.5**	**828,748.0**	**(148,453.0)**
			Distribution						
			Customer Connects						
125,060.8	150,000.0	(24,939.2)	Program - Distribution Customer Connects	125,060.8	150,000.0	0.0		150,000.0	(24,939.2)
125,060.8	**150,000.0**	**(24,939.2)**	**Total Customer Connects**	**125,060.8**	**150,000.0**	**0.0**		**150,000.0**	**(24,939.2)**
			Infrastructure Capacity Increase						
7,376.9	3,500.0	3,876.9	Program - Economic Rebuild (Rural)	7,376.9	5,000.0	3,000.0	60.0	8,000.0	(623.1)
838.0	1,500.0	(662.0)	Program - Economic Rebuild (Urban)	838.0	1,500.0	0.0		1,500.0	(662.0)
6,650.2	6,196.8	453.4	SUB - Albert Park -138kV-25kV - Expansion	9,395.6	8,999.0	1,310.0	14.6	10,309.0	(913.4)
10,302.5	12,831.6	(2,529.1)	SUB - Bromhead -138kV-25kV - Expansion	14,976.2	27,552.0	0.0		27,552.0	(12,575.8)
0.0	1,935.0	(1,935.0)	SUB - Canora Capacity Increase - 72kV Expansion	0.0	361.0	0.0		361.0	(361.0)
28,575.0	33,198.5	(4,623.5)	SUB - Edam Area - New	32,133.7	38,000.0	4,303.0	11.3	42,303.0	(10,169.3)
6,365.7	5,412.1	953.6	SUB - Fleet Street Capacity Increase Stage 1 - 138kV - New	10,194.1	8,059.4	1,765.6	21.9	9,825.0	369.1
0.0	2,089.0	(2,089.0)	SUB - Harbour Landing- 138kV-25kV - New	0.0	2,089.0	0.0		2,089.0	(2,089.0)
8,438.1	10,686.1	(2,248.0)	SUB - Rutland - 138kV - 25kV - New	9,408.0	16,000.0	3,509.0	21.9	19,509.0	(10,101.0)
859.4	1,095.8	(236.4)	SUB - Shaunavon - 138kV-25kV - Expansion	5,653.1	4,397.4	1,602.6	36.4	6,000.0	(346.9)
10,931.2	15,300.2	(4,369.0)	SUB - Superb - 138kV-25kV - New	15,971.2	17,608.0	1,717.4	9.8	19,325.4	(3,354.2)
80,336.9	**93,745.1**	**(13,408.2)**	**Total Infrastructure Capacity Increase**	**105,946.8**	**129,565.8**	**17,207.6**	13.3	**146,773.4**	**(40,826.6)**

CURRENT YEAR				PROJECT					
YTD Actual	2015 Budget	Variance		PTD Actual	Original CPA Value	Total CPR Value	% CNG	Total CPA Value	Variance
			Infrastructure Sustainment						
6,699.9	5,000.0	1,699.9	Program - City of Regina Aging Infrastructure Replacement	6,699.9	5,000.0	1,500.0	30.0	6,500.0	199.9
6,770.1	6,000.0	770.1	Program - Distribution Defective Apparatus	6,770.1	6,000.0	1,000.0	16.7	7,000.0	(229.9)
1,239.4	750.0	489.4	Program - Urban/Rural Hazards Mitigation	1,239.4	750.0	0.0		750.0	489.4
1,900.2	1,250.0	650.2	Program - Distribution Reliability Improvements (Rural & Urban)	1,900.2	1,250.0	150.0	12.0	1,400.0	500.2
10,716.0	9,200.0	1,516.0	Program - Distribution Wood Assets	10,716.0	9,200.0	1,025.0	11.1	10,225.0	491.0
2,448.9	1,500.0	948.9	Program - Farmyard Line Relocation	2,448.9	1,500.0	100.0	6.7	1,600.0	848.9
577.9	750.0	(172.1)	Program - High Load Move Corridors	577.9	750.0	350.0	46.7	1,100.0	(522.1)
129.3	1,250.0	(1,120.7)	Program - Power Quality Upgrades	129.3	1,250.0	100.0	8.0	1,350.0	(1,220.7)
706.7	0.0	706.7	Program - Protection Upgrades - Stations	706.7	500.0	2,250.0	450.0	2,750.0	(2,043.3)
14,196.9	8,350.0	5,846.9	Program - Rural Rebuild & Improvement	14,196.9	8,350.0	2,600.0	31.1	10,950.0	3,246.9
4,591.9	2,380.0	2,211.9	Program - Underground Cable Replacements	4,591.9	2,380.0	2,820.0	118.5	5,200.0	(608.1)
69.3	2,000.0	(1,930.7)	Program - Wood/Steel SUB Rebuild	69.3	2,000.0	0.0		2,000.0	(1,930.7)
50,046.6	**38,430.0**	**11,616.6**	**Total Infrastructure Sustainment**	**50,046.6**	**38,930.0**	**11,895.0**	30.6	**50,825.0**	**(778.4)**
255,444.3	**282,175.1**	**(26,730.8)**	**Total Distribution**	**281,054.1**	**318,495.8**	**29,102.6**	**9.1**	**347,598.4**	**(66,544.3)**
			Transmission						
45,131.9	**86,604.4**	**(41,472.5)**	**Total Customer Connects**	**153,236.9**	**234,234.5**	**(10,688.8)**	(4.6)	**223,545.7**	**(70,308.8)**
			Infrastructure Capacity Increase						
16,982.4	3,350.0	13,632.4	LN - Aberdeen to Wolverine - 230kV - New	27,959.7	73,350.0	0.0		73,350.0	(45,390.3)
81,574.3	129,000.0	(47,425.7)	LN - I1K - 230kV - New	316,376.6	380,000.0	(16,708.0)	(4.4)	363,292.0	(46,915.4)
0.0	1,529.7	(1,529.7)	LN - Pasqua - Condie - New	0.0	575.0	0.0		575.0	(575.0)
(6.3)	1,977.6	(1,983.9)	LN - Pasqua - Rowatt - New	0.3	575.0	0.0		575.0	(574.7)
(5,006.5)	7,500.0	(12,506.5)	LN - Pasqua - Swift Current - 238kV-138kV -New	11,953.4	101,527.6	(84,254.5)	(83.0)	17,273.1	(5,319.7)
1,265.9	985.0	280.9	SS - Auburnton - 230-138/72kV - New	7,509.3	7,463.9	0.0		7,463.9	45.4
0.0	1,346.0	(1,346.0)	SS - Beauval - 138-72kV - New	0.0	0.0	0.0		0.0	0.0
1,155.2	1,500.0	(344.8)	SS - Boundary Dam #3 Clean Coal 230kV - Expansion	6,991.9	6,770.0	745.4	11.0	7,515.4	(523.5)
1,374.1	0.0	1,374.1	SS - Boundary Dam to Pasqua Transformer Move - Exp	1,546.0	200.0	1,667.7	833.9	1,867.7	(321.7)
1,421.5	0.0	1,421.5	SS - Breaker Replacement	3,521.9	0.0	0.0		0.0	3,521.9
14.1	1,000.0	(985.9)	SS - Fleet Street - Land Purchase - New	2,563.1	4,680.0	0.0		4,680.0	(2,116.9)
153.2	1,115.0	(961.8)	SS - Kennedy - 230-138kV - Expansion	153.2	12,842.0	0.0		12,842.0	(12,688.8)
169.8	5,800.0	(5,630.2)	SS - Lloydminster 230-138kV - Expansion	169.8	270.0	0.0		270.0	(100.2)
6,330.7	12,267.6	(5,936.9)	SS - Maidstone Area - 230kV-25kV - New	25,407.1	28,000.0	6,710.0	24.0	34,710.0	(9,302.9)
9,955.8	138.0	9,817.8	SS - Martinsville - 230-138kV - New	71,873.3	48,873.0	32,240.0	66.0	81,113.0	(9,239.7)
583.2	1,155.0	(571.8)	SS - Pasqua SS - 138kV - Upgrade	583.2	1,155.0	0.0		1,155.0	(571.8)
20,101.3	17,100.0	3,001.3	SS - Pasqua SVS - 138kV - New	20,101.3	26,600.0	3,947.9	14.8	30,547.9	(10,446.6)
512.0	1,150.0	(638.0)	SS - Peebles 230-138kV Exp	2,168.8	4,278.4	2,492.4	58.3	6,770.8	(4,602.0)
248.4	1,431.8	(1,183.4)	SS - Relay System Improvement Program 230-138kV - New	323.0	1,506.1	865.4	57.5	2,371.5	(2,048.5)
307.7	1,142.1	(834.4)	SS - Rowatt - 230kV - New	1,016.6	2,090.5	0.0		2,090.5	(1,073.9)
26,619.0	40,000.0	(13,381.0)	SS - Tantallon - 230kV-138kV - Expansion	40,175.8	113,000.0	28.0	0.0	113,028.0	(72,852.2)
8.4	1,230.6	(1,222.2)	SS - TFDR/DDR Installations - 230-138kV - New	747.3	1,936.6	0.0		1,936.6	(1,189.3)
163,764.1	**230,718.4**	**(66,954.3)**	**Total Infrastructure Capacity Increase**	**541,141.6**	**815,693.1**	**(52,265.7)**	(6.4)	**763,427.4**	**(222,285.8)**

CURRENT YEAR				PROJECT					
YTD Actual	2015 Budget	Variance		PTD Actual	Original CPA Value	Total CPR Value	% CNG	Total CPA Value	Variance
			Infrastructure Sustainment						
617.3	1,200.0	(582.7)	Initiative - Q1H Structure Replacements	6,403.2	9,980.0	250.0	2.5	10,230.0	(3,826.8)
1,800.0	2,000.0	(200.0)	Initiative - Regina South Reactor Switchgear Replacement	1,827.4	2,000.0	530.0	26.5	2,530.0	(702.6)
940.3	1,148.2	(207.9)	LN - Coteau Creek to Swift Current - 230kV - River Crossing	1,118.7	1,693.0	0.0		1,693.0	(574.3)
2,343.5	6,650.0	(4,306.5)	Program - Circuit Breaker Replacements	2,343.5	6,650.0	0.0		6,650.0	(4,306.5)
2,019.9	2,000.0	19.9	Program - Line Switch Replacements	2,019.9	2,000.0	500.0	25.0	2,500.0	(480.1)
2,062.8	1,500.0	562.8	Program - Line Uprating	2,062.8	1,500.0	500.0	33.3	2,000.0	62.8
1,655.3	2,200.0	(544.7)	Program - Relay Replacements	1,655.3	2,200.0	2,800.0	127.3	5,000.0	(3,344.7)
34.0	1,000.0	(966.0)	Program - Station Bus & Foundation Replacements	34.0	1,000.0	500.0	50.0	1,500.0	(1,466.0)
1,493.2	500.0	993.2	Program - Transmission Apparatus Accessories	1,493.2	750.0	800.0	106.7	1,550.0	(56.8)
3,944.0	150.0	3,794.0	Program - Transmission Ground Grid & Fencing Upgrades	3,944.0	450.0	5,000.0	1,111.1	5,450.0	(1,506.0)
10,134.6	4,500.0	5,634.6	Program - Transmission Lattice Steel Remediation	10,134.6	4,500.0	1,500.0	33.3	6,000.0	4,134.6
8,996.5	3,200.0	5,796.5	Program - Transmission Reliability Improvements	8,996.5	3,200.0	8,500.0	265.6	11,700.0	(2,703.5)
3,691.2	1,000.0	2,691.2	Program - Weathering Steel Below Ground Remediation	3,691.2	1,000.0	1,000.0	100.0	2,000.0	1,691.2
21,428.7	9,000.0	12,428.7	Program - Wood Line Remediation	21,428.7	9,200.0	7,500.0	81.5	16,700.0	4,728.7
705.2	835.9	(130.7)	SC - EMS Lifecycle Management	5,684.0	7,604.0	0.0		7,604.0	(1,920.0)
61,866.6	**36,884.1**	**24,982.5**	**Total Infrastructure Sustainment**	**72,837.0**	**53,727.0**	**29,380.0**	54.7	**83,107.0**	**(10,270.0)**
17,939.8	18,652.5	(712.7)	Miscellaneous Transmission Projects Under $1,000,000	0.0	0.0	0.0		0.0	0.0
288,702.3	**372,859.4**	**(84,157.1)**	**Total Transmission**	**767,215.5**	**1,103,654.6**	**(33,574.4)**	(3.0)	**1,070,080.2**	**(302,864.6)**
			Operations - Other						
3,759.4	3,381.9	377.5	AMI Replacement Project	14,460.7	15,000.0	0.0		15,000.0	(539.3)
0.0	1,000.0	(1,000.0)	Capital Spares	0.0	0.0	0.0		0.0	0.0
22,477.3	19,200.5	3,276.8	Meter Purchases	22,477.3	19,200.5	5,000.0	26.0	24,200.5	(1,723.2)
203.1	0.0	203.1	Miscellaneous Projects <$1,000,000	0.0	0.0	0.0		0.0	0.0
26,439.8	**23,582.4**	**2,857.4**	**Total Operations - Other**	**36,938.0**	**34,200.5**	**5,000.0**	14.6	**39,200.5**	**(2,262.5)**
			Integrated Carbon Capture Sequestration						
5,365.4	0.0	5,365.4	BD #3 - ICCS Demo - Carbon Capture	691,205.3	648,000.0	38,000.0	5.9	686,000.0	5,205.3
1,421.8	0.0	1,421.8	BD #3 ICCS - Power Island	546,707.0	354,000.0	202,000.0	57.1	556,000.0	(9,293.0)
6,787.2	0.0	6,787.2	**Total BD#3 ICCS**	1,237,912.3	1,002,000.0	240,000.0	24.0	1,242,000.0	(4,087.7)
23,741.0	4,357.4	19,383.6	BD #3 Capital Improvements	23,741.0	6,313.7	22,027.8	348.9	28,341.5	(4,600.5)
1,236.6	0.0	1,236.6	BD Boilerhouse Bracing	5,660.0	5,100.0	0.0		5,100.0	560.0
0.0	0.0	0.0	BD #3 Boiler Buckstay Reinforcement	16,613.3	17,026.0	0.0		17,026.0	(412.7)
24,977.7	4,357.4	20,620.3	**Total BD#3 ICCS Other**	46,014.4	28,439.7	22,027.8	77.5	50,467.5	(4,453.1)
31,764.8	4,357.4	27,407.4	**Total BD #3 Carbon Capture**	1,283,926.7	1,030,439.7	262,027.8	25.4	1,292,467.5	(8,540.8)
13,084.3	14,855.5	(1,771.2)	Carbon Capture Test Facility	68,259.8	51,821.4	18,178.6	35.1	70,000.0	(1,740.2)
44,849.1	**19,212.9**	**25,636.2**	**Total Integrated Carbon Capture Sequestration**	**1,352,186.5**	**1,082,261.1**	**280,206.4**	**25.9**	**1,362,467.5**	**(10,281.0)**
			Planning, Environment & Sustainable Development						
523.4	0.0	523.4	Swift Current CCGT Project	523.4	2,000.0	0.0		2,000.0	(1,476.6)
4,858.7	6,600.0	(1,741.3)	Tazi Twe Hydroelectric - Elizabeth Falls	20,798.1	5,500.0	17,039.4	309.8	22,539.4	(1,741.3)
267.7	0.0	267.7	Miscellaneous Projects Under $1,000,000	0.0	0.0	0.0		0.0	
5,649.8	**6,600.0**	**(950.2)**	**Total Planning, Environment & Sustainment**	**21,321.5**	**7,500.0**	**17,039.4**	**227.2**	**24,539.4**	**(3,217.9)**
			Procurement & Supply Chain						
751.9	10,000.0	(9,248.1)	Critical Systems Center	2,757.9	38,500.0	0.0		38,500.0	(35,742.1)
19.0	3,750.0	(3,731.0)	Estevan District Service Centre	42.0	3,510.0	0.0		3,510.0	(3,468.0)
2,465.2	1,000.0	1,465.2	Furniture & Equipment	2,465.2	1,600.0	1,000.0	62.5	2,600.0	(134.8)
1,549.1	2,000.0	(450.9)	Head Office Refurbishment	2,784.9	4,740.0	0.0		4,740.0	(1,955.1)
2,147.9	4,600.0	(2,452.1)	Lloydminster District Service Centre	3,226.1	7,000.0	0.0		7,000.0	(3,773.9)
1,449.9	8,525.0	(7,075.1)	Logistic Warehouse Complex	28,494.4	36,500.0	0.0		36,500.0	(8,005.6)
7.4	1,078.0	(1,070.6)	North Battleford Service Centre	54.5	0.0	0.0		0.0	54.5
1,288.1	2,650.0	(1,361.9)	Prince Albert Service Center - 1 Bay & Office Addition	1,632.8	3,000.0	0.0		3,000.0	(1,367.2)
1,159.1	1,465.0	(305.9)	TS&R Equipment	2,072.1	1,800.0	472.0	26.2	2,272.0	(199.9)
131.8	1,000.0	(868.2)	TS&R Roof Replacement	198.0	2,500.0	0.0		2,500.0	(2,302.0)
0.1	1,000.0	(999.9)	TS&R Site Grading & Paving	0.1	0.0	0.0		0.0	0.1
22,705.6	20,965.0	1,740.6	Vehicles & Equipment	22,705.6	20,000.0	2,650.0	13.3	22,650.0	55.6
2,927.9	1,732.0	1,195.9	Miscellaneous Projects Under $1,000,000	0.0	0.0	0.0		0.0	0.0
36,603.0	**59,765.0**	**(23,162.0)**	**Total Procurement & Supply Chain**	**66,433.4**	**119,150.0**	**4,122.0**	**3.5**	**123,272.0**	**(56,838.6)**

CURRENT YEAR				PROJECT					
YTD Actual	2015 Budget	Variance		PTD Actual	Original CPA Value	Total CPR Value	% CNG	Total CPA Value	Variance
			Commercial & Industrial Operations						
1,234.6	1,400.0	(165.4)	Coronach Land Purchase	1,943.3	3,320.0	0.0		3,320.0	(1,376.7)
229.0	3,600.0	(3,371.0)	Estevan Land Purchase	3,767.6	10,243.0	1,179.0	11.5	11,422.0	(7,654.4)
0.0	0.0	0.0	Miscellaneous Projects Under $1,000,000	0.0	0.0	0.0		0.0	0.0
1,463.6	**5,000.0**	**(3,536.4)**	**Total Commercial & Industrial Operations**	**5,710.9**	**13,563.0**	**1,179.0**	**8.7**	**14,742.0**	**(9,031.1)**
			Information Technology & Security						
			IT Foundational & Sustainment						
0.0	2,466.0	(2,466.0)	Application Enablement Services	0.0	0.0	0.0		0.0	0.0
203.2	1,069.0	(865.8)	Application Integration Services (Includes ESB)	1,938.1	3,040.0	0.0		3,040.0	(1,101.9)
1,206.8	0.0	1,206.8	Backup Renewal	1,206.8	1,020.0	197.5	19.4	1,217.5	(10.6)
1,304.7	1,500.0	(195.3)	Business Intelligence	1,304.7	1,046.1	464.0	44.3	1,510.1	(205.4)
356.3	1,800.0	(1,443.7)	Communications - Wireless Communications	627.1	2,844.5	0.0		2,844.5	(2,217.4)
2,899.0	3,713.0	(814.0)	Core Infrastructure	2,899.0	1,404.0	1,613.7	114.9	3,017.7	(118.7)
0.0	3,368.0	(3,368.0)	Data Services	663.5	545.4	521.9	95.7	1,067.3	(403.8)
3,024.1	2,868.0	156.1	Desktop Management (including laptops for trucks)	3,024.1	2,867.9	0.0		2,867.9	156.3
1,383.8	1,400.0	(16.2)	Enterprise Security	1,866.6	1,911.2	352.0	18.4	2,263.2	(396.6)
2,224.5	1,560.0	664.5	SDR - AMI - Network Communication	15,631.7	26,262.9	(10,000.0)	(38.1)	16,262.9	(631.2)
0.0	1,550.0	(1,550.0)	Service Management Services	0.0	0.0	0.0		0.0	0.0
0.0	1,550.0	(1,550.0)	Storage Management Services	0.0	0.0	0.0		0.0	0.0
88.0	1,250.0	(1,162.0)	User Interface Services	88.0	65.0	0.0		65.0	23.0
7,994.9	1,880.0	6,114.9	Miscellaneous Projects <$1,000,000	0.0	0.0	0.0		0.0	0.0
20,685.3	**25,974.0**	**(5,288.7)**	**Total IT Foundational & Sustainment Projects**	**29,249.5**	**41,006.9**	**(6,851.0)**	**(16.7)**	**34,155.9**	**(4,906.4)**
			Corporate Strategic						
0.0	7,872.0	(7,872.0)	Corporate Strategic Projects Portfolio	0.0	0.0	0.0		0.0	0.0
1,101.6	0.0	1,101.6	CR&B Collections	1,249.8	384.0	1,393.0	362.8	1,777.0	(527.2)
1,638.1	0.0	1,638.1	Electric Office Optimization - Capital	1,638.1	1,247.4	632.6	50.7	1,880.0	(241.9)
1,319.9	0.0	1,319.9	Procurement- Renew SAP Functionality	1,319.9	931.0	1,348.4	144.8	2,279.4	(959.5)
520.5	0.0	520.5	SAP GIS Integration	520.5	2,700.0	0.0		2,700.0	(2,179.5)
3,993.6	2,420.0	1,573.6	SDR - AMI - IT Project	35,479.8	31,411.2	10,000.0	31.8	41,411.2	(5,931.4)
642.5	0.0	642.5	Warehouse Management	642.5	4,591.5	0.0		4,591.5	(3,949.0)
3,133.2	0.0	3,133.2	Miscellaneous Projects <$1,000,000	0.0	0.0	0.0		0.0	0.0
12,349.5	**10,292.0**	**2,057.5**	**Total Corporate Strategic Projects**	**40,850.7**	**41,265.1**	**13,374.0**	**32.4**	**54,639.1**	**(13,788.4)**
			Non-Discretionary						
0.0	5,000.0	(5,000.0)	Non-Discretionary Projects Portfolio	0.0	0.0	0.0		0.0	0.0
656.0	0.0	656.0	GEIS Replacement	863.5	2,550.0	0.0		2,550.0	(1,686.5)
2,174.9	0.0	2,174.9	IT&S Perimeter Security HW/SW	7,413.7	3,356.5	4,258.5	126.9	7,615.0	(201.3)
1,260.8	0.0	1,260.8	Miscellaneous Projects <$1,000,000	0.0	0.0	0.0		0.0	0.0
4,091.7	**5,000.0**	**(908.3)**	**Total Non-Discretionary Projects**	**8,277.2**	**5,906.5**	**4,258.5**	**72.1**	**10,165.0**	**(1,887.8)**
			Discretionary						
0.0	2,384.0	(2,384.0)	Discretionary Projects Portfolio	0.0	0.0	0.0		0.0	0.0
346.5	330.0	16.5	Miscellaneous Projects <$1,000,000	0.0	0.0	0.0		0.0	0.0
346.5	**2,714.0**	**(2,367.5)**	**Total Discretionary Projects**	**0.0**	**0.0**	**0.0**		**0.0**	**0.0**
37,473.0	**43,980.0**	**(6,507.0)**	**Total Information Technology & Security**	**78,377.4**	**88,178.5**	**10,781.5**	**12.2**	**98,960.0**	**(20,582.7)**
	112,638.1	**(112,638.1)**	**SaskPower Contingency**						
990,302.0	**1,200,000.0**	**(209,698.0)**	**Total SaskPower Capital Expenditures**	**3,289,532.3**	**3,545,252.5**	**364,355.5**	**10.3**	**3,909,608.0**	**(620,075.7)**

Total SaskPower capital budget for 2015 is $1.2 billion. Year to date expenditures were $209.7 million under budget.

Power Production

- Total Power Production capital budget is $274.2 million; $144.2 million for Infrastructure Renewal and $130.0 million for QE Repowering. Year to date expenditures were $19.5 million over budget.
- Poplar River #2 Coal Pipe Elbow project has no capital budget. Year to date expenditures were $1.2 million over budget due to funds being available during 2015 overhaul.
- Poplar River #2 Grinding Zone Upgrades – Mill 2A project has no capital budget. Year to date expenditures were $1.7 million over budget due to funds required to complete 3 additional pulverizer grinding zones in 2015.
- Poplar River #2 Long Tern Expenditures project capital budget is $12.7 million. Year to date expenditures were $3.5 million over budget due to the addition of the primary air duct and expansion joint supply.
- Poplar River Controls Simulator project capital budget is $2.6 million. Year to date expenditures were $2.3 million under budget due to limited resources.
- Poplar River Cooling Water Canal upgrade capital budget is $4.4 million. Year to date expenditures were $1.0 million under budget due to contract delays.
- Poplar River Diagnostics Room capital budget is $3.1 million. Year to date expenditures were $1.4 million over budget due to additional funds required for project completion in 2015.
- Poplar River Facilities Upgrades project capital budget is $7.0 million. Year to date expenditures were $3.7 million under budget due to contract delays.
- Poplar River Man Lift Replacement project capital budget is $3.9 million. Year to date expenditures were $3.8 million under budget due to delays in awarding the elevator Engineering, Procurement & Construction contract.
- Poplar River Morrison Dam Spillway Capacity project capital budget is $12.1 million. Year to date expenditures were $2.0 million over budget due to carry forward from 2014.
- Poplar River Site Infrastructure project has no capital budget. Year to date expenditures were $1.3 million over budget due to bringing the project forward from 2016 due to fund and resource availability in 2015.
- Boundary Dam #5 Asbestos Removal project capital budget is $1.7 million. Year to date expenditures were $1.2 million under budget due to reduced scope.
- Boundary Dam #5 Life Extension project had no capital budget. Year to date expenditures were $1.1 million over budget due to funds being available during 2015.

- BD Ash Lagoon Surcharging has no capital budget. Year to date expenditures were $1.3 million over budget due to carry forward from 2014.
- Boundary Dam CO2 Pipeline project capital budget is $3.5 million. Year to date expenditures were $2.5 million under budget due to deferral of $1.0 million to 2016 for testing and stimulating the well because of the lack of CO2 for injection into the well in 2015.
- Boundary Dam Landfill project capital budget is $2.8 million. Year to date expenditures were $2.7 million under budget due to deferral to 2016.
- Boundary Dam Public Safety Measures project has no capital budget. Year to date expenditures were $1.1 million over budget due to public safety requirements.
- Boundary Dam Man Lift Replacement project capital budget is $3.7 million. Year to date expenditures $3.7 million under budget due to deferrals caused by project delays.
- Boundary Dam Sewage Lagoon project capital budget is $3.0 million. Year to date expenditures were $2.0 million under budget due to a delay in contract awards.
- Boundary Dam Spillway Upgrades project capital budget is $2.4 million. Year to date expenditures were $1.0 million under budget due to revised estimates for work as completion is expected by the end of 2015.
- Shand Ash Conveyor Belt project capital budget is $2.2 million. Year to date expenditures were $2.1 million under budget due to deferrals to 2016 while waiting for study requirements results.
- Shand Chemical Storage Building project capital budget is $2.9 million. Year to date expenditures were $1.7 million under budget due to revised estimates.
- Shand Man Lift Replacement project capital budget is $3.6 million. Year to date expenditures were $3.6 million under budget due to delays in awarding the elevator Engineering, Procurement & Construction contract.
- Shand Roof Replacement project capital budget is $3.0 million. Year to date expenditures were $1.9 million under budget due contract delays and resource availability resulting in deferrals to 2016.
- Athabasca Mobitel project capital budget is $2.7 million. Year to date expenditures were $2.2 million under budget due to delays in fabrication.
- Coteau Creek GSU Replacement project had no capital budget. Year to date expenditures were $2.0 million over budget due to unexpected failure.
- EB Campbell #2 Wicket Gate project capital budget is $2.8 million. Year to date expenditures were $1.9 million under budget due to the use of refurbished gates rather than procuring new gates.

- EB Campbell Licence Mitigation project capital budget is $2.0 million. Year to date expenditures were $2.0 million under budget due to revisions to project estimate and schedule.
- EB Campbell North Dyke Overflow project capital budget is $5.8 million. Year to date expenditures were $3.6 million under budget due to revisions to project estimate and schedule.
- EB Campbell Plant Control Monitoring System project capital budget is $1.6 million. Year to date expenditures were $1.0 million over budget due to unbudgeted scope and increased costs for construction.
- Wellington Refurbishment project capital budget is $5.7 million. Year to date expenditures were $3.7 million under budget due to reduced scope and timing of contracts.
- Tazin Wier Replacement project capital budget is $5.0 million. Year to date expenditures were $1.0 million under budget due to revised estimates.
- QE ‘A’ Plant 4160V Cable Replacement project has no capital budget. Year to date expenditures were $1.0 million over budget due to the availability to purchase and install cable.
- QE Pumphouse project capital budget is $1.3 million. Year to date expenditures were $1.0 million over budget due to the need for additional funds to complete project in 2015.
- Western Plants Spare Engine project capital budget is $1.2 million. Year to date expenditures were $10.0 million over budget due to unit arriving earlier than anticipated.
- QE Repowering project capital budget is $130.0 million. Year to date expenditures were $37.5 million over budget due to carry forward from 2014.

Distribution

- Total Distribution capital budget is $282.2 million. Year to date expenditures were $26.7 million under budget.
- Distribution Customer Connects Program capital budget is $150.0 million. Year to date expenditures were $24.9 million under budget due to lower project activity particularly in the oilfield resulting from lower oil prices and an overall slowdown in the economy in general.
- Distribution Infrastructure Capacity Increase capital budget is $93.7 million. Year to date expenditures were $13.4 million under budget mainly due to decreases in the Edam & Superb Sub projects partially offset by an increase to the Economic Rebuild program.
- Distribution Infrastructure Sustainment capital budget is $38.4 million. Year to date expenditures were $11.6 million over budget primarily due a focus on system improvement projects.

Transmission

- Total Transmission capital budget is $372.9 million. Year to date expenditures were $84.2 million under budget.
- Transmission Customer Connects capital budget is $86.6 million. Year to date expenditures were $41.5 million under budget primarily due to customer delays.
- Transmission Infrastructure Capacity Increase capital budget is $230.7 million. Year to date expenditures were $67.0 million under budget primarily due to the deferral of I1K project works to 2016, the Pasqua to Swift Current Line project and the Tantallon Switching Station Expansion project, partially offset by the 2014 carry forward of the Aberdeen – Wolverine 230kV Line project and the Martinsville Switching Station project.
- Transmission Infrastructure Sustainment capital budget is $36.9 million. Year to date expenditures were $25.0 million over budget primarily due to a focus on system improvement projects.

Operations - Other

- Total Operations - Other capital budget is $23.6 million. Year to date expenditures were $2.9 million over budget.
- Capital Spares budget is $1.0 million. Year to date expenditures were $1.0 million under budget due to deferrals to 2016.
- Meter Purchases capital budget is $19.2 million. Year to date expenditures were $3.3 million over budget due to increased meter exchanges.

ICCS

- The ICCS total capital budget is $19.2 million. Year to date expenditures were $25.6 million over budget.
- BD#3 ICCS – Carbon Capture project has no capital budget. Year to date expenditures were $5.4 million over budget due to carry forward from 2014
- BD#3 ICCS – Power Island project has no capital budget. Year to date expenditures were $1.4 million over budget due to carry forward from 2014
- BD #3 Capital Improvements project capital budget is $4.4 million. Year to date expenditures were $19.4 million over budget due to commencement of Phase I of BD #3 ICCS Seven Point Plan to correct deficiencies.
- BD #3 Boilerhouse Horizontal Bracing project has no capital budget. Year to date expenditures were $1.2 million over budget due carry forward from 2014.
- Carbon Capture Test Facility project capital budget is $14.9 million. Year to date expenditures were $1.8 million under budget due to project final costs being lower than anticipated.

Planning, Environment & Sustainment

- Tazi Twe Hydro Electric - Elizabeth Falls project capital budget is $6.6 million. Year to date expenditures were $1.7 million under budget due to the delay in the resolution of a regulatory issue.

Procurement & Supply Chain

- Total Procurement & Supply Chain capital budget is $59.8 million. Year to date expenditures were $23.2 million under budget.
- Critical Systems Center project capital budget is $10.0 million. Year to date expenditures were $9.2 million under budget due to the cancellation of the project.
- Estevan District Service Center project capital budget is $3.8 million. Year to date expenditures were $3.7 million under budget due to reduction in estimates for 2015. The project is expected to be complete in 2017.
- Furniture & Equipment capital budget was $1.0 million. Year to date expenditures were $1.5 million over budget due to unplanned renovations at SaskTel Mobility Building near the airport for Customer Services.
- Lloydminster District Service Center project capital budget is $4.6 million. Year to date expenditures were $2.5 million under budget due to costs being lower than anticipated
- Logistics Warehouse Complex project capital budget is $8.5 million. Year to date expenditures were $7.1 million under budget due to delays in design.
- North Battleford Service Center project capital budget is $1.1 million. Year to date expenditures were $1.1 million under budget due to changed requirements and land will no longer be required.
- Prince Albert Service Center – 1 Bay & Office Addition capital budget is $2.7 million. Year to date expenditures were $1.4 million under budget due delays in construction in 2015.
- Vehicles & Equipment capital budget is $21.0 million. Year to date expenditures were $1.7 million over budget due to wire tensioning equipment delivery in 2015.

Commercial & Industrial Operations

- Total Commercial & Industrial Operations capital budget is $5.0 million. Year to date expenditures were $3.5 million under budget due to deferrals to 2017.

Information Technology & Security

- Total Information Technology & Security capital budget is $44.0 million. Year to date expenditures were $6.5 million under budget.
- IT Foundational & Sustainment projects capital budget is $26.0 million. Year to date expenditures were $5.3 million under budget due to reallocation of resources to support higher priority initiatives.
- Corporate Strategic projects capital budget is $10.3 million. Year to date expenditures were $2.1 million over budget primarily due to increased cost of the AMI – IT project.
- Non-Discretionary projects capital budget is $5.0 million. Year to date expenditures were $0.9 million under budget.
- Discretionary projects capital budget is $2.7 million. Year to date expenditures were $2.4 million under budget due to reallocation of resources to support higher priority initiatives

Interest Capitalized

Project	Project Description	2013	2014	2015	Total
P/0001159	BD Facilities Upgrade			230,703	230,703
P/0001447	SDR - AMI IT Project	730,767			730,767
P/0001448	SDR - AMI Network Communications	197,299	229,345		426,644
P/0001449	SDR - AMI Meters and Modules	293,441			293,441
P/0002325	ICCS Laboratory Equipment / Opp Support			129,009	129,009
P/0003469	LN - 138kV XMIS LINE B.D- ENCANA T716	1,057,313			1,057,313
P/0003610	SS - ABERDEEN S.S. - T805-1	376,290	458,843		835,133
P/0003939	LN-PH 1-Aberdeen To Wolverine 230kV T821		706,494	449,173	1,155,667
P/0004138	SS - SASK.N.REINF. MARTENSVILLE SS- D416	298,410	542,041		840,451
P/0004141	SUB - SASKATOON N. REINFORCEMENT-D416-1		169,698		169,698
P/0004216	LN-TCC KEYST PS6 - FOX VALLEY T915-1	205,331	240,285	164,640	610,256
P/0004217	LN - TCC KEYST PS7 - PIAPOT T915-2	120,592	506,266	320,437	947,295
P/0004218	LN - TCC KEYST PS8 - GRASSY CREEK T915-3		899,341	323,336	1,222,677
P/0004252	SS - AUBURNTON 230/72 CAP INCR. - D420-1	237,578	255,356	199,879	692,813
P/0004292	LN - K+S(Potash One)230kV SERV- D642-1			507,130	507,130
P/0004300	COTEAU CREEK REWIND	100,878			100,878
P/0004303	NH EBC EB CAMPBELL PCMS	354,287	398,174	451,526	1,203,987
P/0004304	NH TAZIN TUNNEL INTAKE REPLACEMENT			112,079	112,079
P/0004341	BD ASH LAGOON SURCHARGING			147,723	147,723
P/0004382	ISLAND FALLS 6 REFURBISHMENT	726,695	240,713		967,408
P/0004389	NH IF ISLAND FALLS PCMS (M.D.)		163,262	224,142	387,404
P/0004398	BD ICCS DEMO - Carbon Capture	24,505,049	18,743,982	794,111	44,043,142
P/0004403	2006 Capital Budget Buildings	108,387			108,387
P/0004456	2010 Swift Current Service Center	152,840	276,652		429,492
P/0004457	2010 Saskatoon Service Center Expansion	231,393			231,393
P/0004458	Logistics Warehouse Complex		1,091,747	137,541	1,229,288
P/0004459	BD FLYASH STORAGE & LOADOUT UPGRADE		141,405		141,405
P/0004571	PR 2A SBAC Upgrade	135,709	124,340	118,026	378,075
P/0004592	SS - TANTALLON 230 KV-T820-3	438,686	479,955	533,618	1,452,259
P/0004686	LN - FLEET ST. 2ND 230-138 KV- T042		100,676		100,676
P/0004688	SS- FLEET ST. 2ND 230-138 KV- T042-1	411,788	413,995		825,783
P/0004724	MORRISON DAM SPILLWAY CAPACITY MAIN DAM		143,852	663,178	807,030
P/0004746	LN - Aberdeen To Martensvil 230kV D416-1	134,358	740,600		874,958
P/0004747	LINE - SKTN N - SKTN N IND.138kV- D416-1		122,924	279,516	402,440
P/0004772	SS - NBEC BRADA UPGRADES - T924-2	159,415			159,415
P/0004775	CM - NBEC INTERCONNECTION - T924-2	113,697			113,697
P/0004829	PR1 Grinding Zone Upgrades - Mill 1A			134,903	134,903
P/0004840	BD 3 Secondary Air Heaters Upgrade		127,129		127,129
P/0005000	BD 3 ICCS - Power Island	14,348,787	8,941,861		23,290,648
P/0005002	PR 3N ASH LAGOON RENEWAL		121,427		121,427
P/0005017	BD5 Plant Coated Waterwall Panels		127,231		127,231
P/0005028	Saskatoon Pole yard	120,704			120,704
P/0005049	LN - I1K PROJECT - T817 (PDO)	2,469,782	7,366,103	5,854,220	15,690,105
P/0005067	LN - TANTALLON AREA REINFORCE T820-3			601,393	601,393
P/0005068	SS-BD#3 Clean Coal Interconn T923-1 PH1	236,757			236,757
P/0005115	BD 4 Life Extension		132,814		132,814

P/0005118	PR CW CANAL UPGRADE			104,092	104,092
P/0005178	SS - Maidstone Area Reinf(Golden)-T309		153,998		153,998
P/0005244	RE.WY - BROMHEAD AREA REINFCMNT D423-1	190,625			190,625
P/0005309	LN - Kisbey Substation 230/25kV D398		100,217		100,217
P/0005310	SUB - Kisbey Substation D398		200,537		200,537
P/0005375	SS - Points North 25kV Capacitors T335	124,334	197,579		321,913
P/0005397	SS-Swift Current SVS(Advance) N15		285,432		285,432
P/0005427	SS - Boundary Dam Capacity IncreaseT803		111,755		111,755
P/0005441	HITACHI GT COMP REPLACEMENT QE	399,686	309,290		708,976
P/0005477	PR PULVERIZER MONORAILS & LIFTING LUGS			108,643	108,643
P/0005482	PR Dry Stack from Ash Lagoon #2		152,696		152,696
P/0005500	Carbon Capture Test Facitity (CCTF)	230,130	1,503,429	610,112	2,343,671
P/0005546	BDPS CO2 STORAGE		383,921		383,921
P/0005620	LN - Superb Area Reinforcement T432			133,221	133,221
P/0005638	SS-Tran Sys Rein Pasqua-SwftCrrnt N15		130,153	147,611	277,764
P/0005657	Electric Office - Capital		202,609		202,609
P/0005661	Saskatoon Storage Facility		193,178		193,178
P/0005681	BD Roof Replacement		101,080		101,080
P/0005725	SUB - Fleet Street 138-25kV Sub D352		145,622	175,414	321,036
P/0005811	IT&S: SAP License Purchases			152,490	152,490
P/0005846	PR FACILITIES UPGRADE			177,055	177,055
P/0005891	LN - Substation - Edam Area New - T473			515,146	515,146
P/0005904	ICCS Lab Equipment		153,587		153,587
P/0005966	PRPS Diagnostics Room			115,855	115,855
P/0006036	BD5 Front WW and Corner 3 Life Extension		137,777		137,777
P/0006050	QE Repowering	2,135,693	6,425,352	8,667,268	17,228,313
P/0006054	Tazi Twe Hydroelectric	186,959	650,995	790,335	1,628,289
P/0006055	BD 3 LIFE EXTENSION	158,639	183,892		342,531
P/0006071	NH IF CAMP INFRASTRUCTURE		143,807		143,807
P/0006123	AM - Transmission Wood Line Remediation			136,481	136,481
P/0006140	Aqui Store Well		450,002	104,302	554,304
P/0006142	BD3 BOILER BUCKSTAY REINFORCEMENT		139,919		139,919
P/0006156	TR -NEW QE Expansion Interconnection N01		169,031		169,031
P/0006160	AM- Transmission System Reliability Impr			201,557	201,557
P/0006372	SS-NEW QE Expansion Intercon Upgrade N01			255,675	255,675
P/0006447	SS-Maidstone Area Reinf(Golden)-T309 PH2			142,271	142,271
P/0006479	SS-Pasqua SVS-138KV-New T808			817,068	817,068
P/0006482	SUB - Edam Area New 230-25kV T473			165,167	165,167
Misc Project with Interest < $100,000		5,042,043.73	5,186,275	5,307,976	15,536,295
Total Interest Capitalized		**56,734,343**	**61,818,644**	**31,204,022**	**149,757,009**

SRRP Q94:

Reference: **Capital Program**

For each capital project or program with projected final costs in excess of $10 million forecast to be completed in the 2016/17 or 2017/18 periods please provide:

i) The justification for the project (e.g. capacity or system growth requirements; infrastructure renewal; operating efficiencies/savings)

ii) the project or program budget

iii) estimated capitalized interest, overheads, and other charges;

iv) the depreciation, finance, corporate capital tax and other related costs in the 2016/17 and 2017/18 revenue requirement related to each project or capital program.

Response:

SaskPower is in the process of finalizing its detailed, 10-Year Capital Plan. A response to this question will be provided during the Mid-Application Update.

SRRP Q95:

Reference: **Capital Program**

Please discuss any change in SaskPower's capital budgeting process and capitalization policies since the last rate application.

Response:

All capital projects are now classified into one of the following three categories:

- Capital sustainment investment: Includes generation, transmission and distribution projects that involve renewing, refurbishing or replacing existing infrastructure, either through an annual program or one-time project.
- Growth and compliance investment: Includes new generation, transmission or distribution additions to accommodate growth in demand, customer connections and other projects.
- Strategic and other investments.

By budgeting and reporting on these categories separately, SaskPower is better able to prepare both short- and long-term plans for renewing or replacing our aging infrastructure while still ensuring that adequate budget dollars are allocated to supporting the growth of in Saskatchewan.

There were no changes to the capitalization policy since the last application.

2016 and 2017 RATE APPLICATION
SRRP INTERROGATORIES

SRRP Q96:

Reference: **Capital Program**

Please provide SaskPower's actual customer connections for 2013 through 2015 and projected for 2016/17 and 2017/18.

Response:

The following table shows SaskPower's actual customer connections for the years 2013 to 2016 and forecasted customer connections for the year's 2016/17 and 2017/18:

Customer Connects Capital Expenditures

	Actual	Actual	Actual	Actual	Budget	Budget
(in $ millions)	**2013**	**2014**	**2015**	**2016***	**2016/2017**	**2017/2018**
Residential	37.9	30.5	27.3	4.5	23.6	23.6
Farm	8.0	9.7	11.3	1.7	7.2	7.2
Commercial	37.9	46.0	34.5	8.5	29.1	29.1
Oilfield	34.6	42.3	37.0	9.6	28.0	28.0
Other	13.6	21.0	15.0	3.5	12.1	12.1
Total Distribution	132.0	149.5	125.1	27.8	100.0	100.0
Total Transmission	33.0	80.2	45.1	0.8	53.2	78.0
Total Customer Connects Capital Expenditures	165.0	229.7	170.2	28.6	153.2	178.0

** Actual 2016 reflects the first three months of 2016*

Note: Other includes customer connects shared by multiple customer classes

SRRP Q97:

Reference: Capital Program

Please provide an estimate of the average annual increase in depreciation expense, finance expense and return on equity for every $100 million in new capital spending.

Response:

SaskPower estimates that an additional $100 million in new capital spending will result in an additional $4 million in depreciation expense and $4 million in finance expense. An $8 million fluctuation in net income would result in an approximate change of 0.3% to the return on equity.

SRRP Q98:

Reference: **Capital Program**

Please provide an overview of SPC's policy with respect to tendering capital projects including whether SPC's tendering policies include preferences for Saskatchewan or Canadian companies.

Response:

SaskPower follows the New West Partnership Trade Agreement to which Saskatchewan is a signatory. The agreement states that procurements over $100,000 for construction or services, and over $25,000 for goods, be publicly posted. SaskPower publicly posts competitions on the provincial opportunity site www.SaskTenders.ca as well as on the national service Merx.com.

Furthermore, SaskPower adheres to the Crown Investments Corporation of Saskatchewan *Crown Sector Procurement - Preference Policy* which allows SaskPower to restrict competitions to the New West Partnership trading region as defined by the policy. The signatories to the New West Partnership Trade Agreement include the provinces of Saskatchewan, British Columbia, and Alberta.

SRRP Q99:

Reference: **Capital Program**

Please discuss the current state of capital planning for any future carbon capture projects including estimated timelines, key decision points and potential budgets related to such projects.

Response:

The capital budget for 2016-17 and 2017-18 does not include any provision for future carbon capture projects.

Longer-term capital budgets include notional sums for a wide range of options, but not carbon capture and storage (CCS) projects specifically. These funds can be deployed as needed, as per decisions made at the appropriate time. If the Equivalency Agreement is concluded with Canada, it is expected that additional flexibility will be afforded SaskPower in making any future conversion decision and the necessary budgets will be established at that time.

No estimate has been completed at present for a future CCS project.

The decision time frame on a potential future CCS project will, in the event that SaskPower is afforded additional flexibility in its requirements, likely be in the 2018-2019 time frame.

SRRP Q100:

Reference: **Load Forecasts**

Please provide a copy of SaskPower's most recent load forecast report.

Response:

Please note the official 2015 Load Forecast document is based on the 2015 First Quarter (Q1) Load Forecast, while the rate application is based on the 2015 Fourth Quarter (Q4) Load Forecast. Both the original load forecast based on Q1 and the changes from the Q1 to the Q4 Load Forecast have been submitted to the Rate Review Panel for review. They cannot be released publicly as they contain confidential customer information.

SRRP Q101:

Reference: Load Forecasts

For each year from 2006 through 2015, please provide a schedule showing the actual sales for each major customer group and the sales forecast from the load forecast immediately preceding the actual year. Please also include forecast and actual line losses and station service. Comment on any material variances between actuals and forecasts.

Response:

Please refer to following spreadsheet.

Electricity Sales vs Forecast by Customer Class

(GWh)

	2006			2007			2008			2009			2010		
	Sales	Forecast		Sales	Forecast		Sales	Forecast		Sales	Forecast		Sales	Forecast	
Residential	2,531	2,530	0.02%	2,643	2,590	2.05%	2,721	2,598	4.72%	2,865	2,801	2.29%	2,882	2,847	1.24%
Commercial	3,239	3,186	1.65%	3,269	3,226	1.35%	3,311	3,285	0.78%	3,407	3,338	2.07%	3,386	3,328	1.73%
Oilfields	2,399	2,341	2.49%	2,541	2,473	2.75%	2,682	2,560	4.77%	2,742	2,775	-1.20%	2,872	2,815	2.02%
Power customers	6,666	6,970	-4.36%	6,854	6,470	5.93%	6,898	7,283	-5.29%	6,139	7,750	-20.79%	6,932	7,614	-8.95%
Farm	1,272	1,362	-6.63%	1,329	1,350	-1.58%	1,306	1,327	-1.55%	1,338	1,322	1.20%	1,292	1,268	1.92%
Reseller	1,293	1,269	1.89%	1,287	1,290	-0.26%	1,274	1,355	-6.01%	1,274	1,371	-7.09%	1,254	1,283	-2.23%
TOTAL SASKATCHEWAN SALES	**17,399**	**17,658**	-1.47%	**17,923**	**17,399**	3.01%	**18,192**	**18,409**	-1.18%	**17,765**	**19,357**	-8.22%	**18,618**	**19,154**	-2.80%
Losses	1,943	1,859	4.52%	1,797	1,779	1.02%	1,879	1,851	1.53%	1,875	1,817	3.18%	1,897	1,795	5.69%
Station Service	22.9	22.7	0.88%	23.7	22.9	3.49%	24.8	24.2	2.48%	25.9	25.4	1.97%	25.4	26.5	-4.15%

	2011			2012			2013			2014			2015		
	Sales	Forecast		Sales	Forecast		Sales	Forecast		Sales	Forecast		Sales	Forecast	
Residential	3,006	2,926	2.72%	2,937	2,929	0.26%	3,190	3,011	5.94%	3,281	3,014	8.88%	3,128	3,139	-0.34%
Commercial	3,447	3,497	-1.42%	3,532	3,480	1.49%	3,663	3,514	4.24%	3,788	3,609	4.95%	3,795	3,694	2.73%
Oilfields	2,901	2,865	1.25%	3,177	3,277	-3.05%	3,448	3,546	-2.77%	3,503	3,686	-4.96%	3,494	3,793	-7.87%
Power customers	7,321	8,120	-9.84%	7,448	8,648	-13.87%	7,863	8,469	-7.16%	8,179	8,234	-0.66%	8,698	8,547	1.77%
Farm	1,298	1,297	0.09%	1,149	1,281	-10.30%	1,332	1,331	0.11%	1,364	1,305	4.50%	1,276	1,318	-3.22%
Reseller	1,253	1,277	-1.90%	1,254	1,281	-2.09%	1,257	1,275	-1.40%	1,274	1,264	0.78%	1,234	1,268	-2.64%
TOTAL SASKATCHEWAN SALES	**19,226**	**19,982**	-3.78%	**19,497**	**20,896**	-6.69%	**20,753**	**21,146**	-1.86%	**21,389**	**21,111**	1.31%	**21,625**	**21,758**	-0.61%
Losses	1,936	1,754	10.41%	2,172	1,879	15.61%	1,905	1,981	-3.83%	1,945	1,931	0.71%	2,047	1,878	9.04%
Station Service	28.6	25.9	10.42%	39.1	27.8	40.65%	38.9	29.3	32.76%	47.3	29.2	61.99%	47.3	29.5	60.34%

Notes:

*2009 - Power Customers variance is explained by the economic downturn that occurred in 2009.

*2012 - Oilfields variance is explained by project delays within the sector.

SRRP Q102:

Reference: **Load Forecasts**

Please indicate when the new load forecasting software was implemented and when SaskPower anticipates undertaking its next method review.

Response:

SaskPower implemented new load forecasting software for the 2016 Q1 forecast and will be using it on a go-forward basis. We anticipate undertaking our next methodology review in 2017 to allow time for maturation of the process.

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SRRP Q103:

Reference: **Load Forecasts**

Does SaskPower undertake a weather normalization analysis of historic sales as part of its load forecast? If so, please describe how SaskPower undertakes its weather normalization analysis.

Response:

SaskPower performs a weather normalization analysis as a part of the load forecasting process. A regression model is used in order to determine the magnitude of the effect of weather on sales. Thirty years of weather data is averaged to obtain “normal” weather. These two data streams are then combined in a simulation to determine what the weather normalization is for a given period.

SRRP Q104:

Reference: **Load Forecasts**

Please discuss how SaskPower forecasts the number of customers for each customer class.

Response:

Residential: The residential class customer forecast is based on an economic forecast of non-farm households in Saskatchewan, which is then translated into a customer count. The economic forecast is based on one provided by the Government of Saskatchewan and reviewed by our internal economist.

Commercial: The commercial class customer forecast is based on regression analysis of the historic number of commercial customers compared to residential customers. Streetlight customers are forecast separately and added to the total commercial customer forecast.

Power: The power class customer forecast is based on our existing power class customer count. Any changes to the customer count in the future are based on potential new customers in the sector, such as mines or large industrial operations. Typically our customer account representatives and planning groups know about these potential new customers years in advance and that information is incorporated into our forecast.

Oilfield: The oilfield customer forecast has two components. One is the large oilfield customer count, which is derived similarly to the power class, and the other is our standard oilfield customer count. The standard oilfield customer forecast is based on calculating the ratio of historic number of customers to the number of operating wells in the province. The ratio is then applied to the operating wells forecast provided by the Saskatchewan Ministry of Economy to calculate standard oilfield customers.

Reseller: The reseller class customer forecast is based on our existing reseller class customer count. Typically our customer account representatives and planning groups would know about any potential new reseller customers years in advance and that information would be incorporated into our forecast.

Farm: The farm class customer forecast is based on an economic forecast of farm households in Saskatchewan, which is then translated into a customer count. The economic forecast is based on one provided by the Government of Saskatchewan and reviewed by our internal economist. The farm customer forecast is broken out into “dwelling” customers and “non-dwelling” customers.

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SRRP Q105:

Reference: **Load Forecasts**

Please discuss how SaskPower forecasts the billed demand for customer classes with a demand charge.

Response:

SaskPower calculates billed demand individually for each customer in our Power, Large Oilfields and Reseller classes. Billed demand for these classes is calculated as the maximum of the forecasted on/off peak demand, where the peak demands are calculated by applying the previous year's ratio of recorded demand to energy to the forecasted monthly energy amount for that customer.

For all other classes, SaskPower forecasts billed demand monthly using the forecasted amount of energy for that class and dividing that by an average of the three most recent years historical load factor for that class, where the load factor is the ratio of energy to demand in the given period of time.

SRRP Q106:

Reference: Load Forecasts

Please discuss how frequently SaskPower updates its load forecast and indicate the date of the load forecast used to support the revenue forecasts in the application.

Response:

SaskPower updates its load forecast four times yearly, with one official forecast and three revisions. The revenue forecast in the rate application is based on the 2015 Q4 Energy Forecast, which was produced in December 2015.

SRRP Q107:

Reference: Load Forecasts

Please indicate how frequently SaskPower has discussions with its major customers on short-term and long-term anticipated energy requirements and also discuss internal processes or activities utilized by SPC to assess the validity of the load forecasts provided by Key Account customers

Response:

SaskPower has discussions with its major customers on a quarterly basis to allow them to provide updates on any anticipated changes in their energy requirements, both short and long term.

Typically, forecasts from our customers in this class do not change a tremendous amount from year to year, so the majority of the class stays static. Assessing the validity of these forecasts is as simple as comparing historic consumption to forecasted consumption.

For those customers in the potash and oil sectors, we interact the customer forecast with a production forecast from government or industry in order to give us further confidence in our estimates. In our analysis, interacting the forecasts in this manner has improved our accuracy over relying solely on customer estimates.

SRRP Q108:

Reference: **Load Forecasts**

Please provide the forecast and actual system winter and summer peaks for 2010 through 2015 and provide generation capacity by fuel types used to meet the peaks.

Response:

The forecast and actual winter system peaks for 2010 through 2015 are as follows:

Winter Peak Load (MW)			Generation by Fuel Type				
Date	**Forecast**	**Actual**	**Hydro**	**Coal**	**Gas**	**Wind & Other**	**Import**
2010-12-12	3,371	3,162	15.9%	56.5%	18.9%	5.0%	3.7%
2011-01-12	3,460	3,195	14.1%	52.8%	28.1%	5.0%	0.0%
2012-12-10	3,591	3,314	13.2%	47.1%	30.4%	6.5%	2.8%
2013-12-06	3,558	3,543	17.5%	40.8%	38.4%	3.3%	0.0%
2014-11-30	3,710	3,561	16.2%	36.2%	41.6%	4.0%	2.0%
2015-01-08	3,836	3,628	16.4%	38.6%	36.2%	5.9%	2.9%

The forecast and actual summer system peaks for 2010 through 2015 are as follows:

Summer Peak Load (MW)			Generation by Fuel Type				
Date	**Forecast**	**Actual**	**Hydro**	**Coal**	**Gas**	**Wind & Other**	**Import**
2010-07-26	3,019	2,750	28.6%	59.9%	11.4%	0.1%	0.0%
2011-07-18	3,085	3,070	26.4%	50.2%	20.7%	1.2%	1.5%
2012-07-30	3,240	3,053	26.3%	50.9%	22.0%	0.8%	0.0%
2013-09-05	3,175	3,187	21.1%	40.4%	34.4%	0.9%	3.2%
2014-08-14	3,309	3,131	21.4%	43.4%	29.9%	0.4%	4.9%
2015-07-10	3,471	3,331	19.1%	36.7%	34.9%	0.9%	8.4%

* Please note that these forecast peaks are the "potential" peak forecasts, not most likely.

SRRP Q109:

Reference: **Load Forecasts**

Please discuss SaskPower's generation planning criteria related to the amount of required available generation capacity in excess of the estimated peak load.

Response:

SaskPower uses a 13% planning reserve margin as the criteria for adding generation capacity. SaskPower plans to have 13% reserve margin at the time of estimated peak.

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SRRP Q110:

Reference: Load Forecast

Please provide the load forecast unadjusted for forecast DSM savings or indicate the amount of DSM savings included in each customer class forecast.

Response:

2015 DSM Savings by Class (GWh):

Residential	26.2
Commercial	13.5
Line losses	4.4
Total	**44.1**

SRRP Q111:

Reference: **Demand Side Management**

Please discuss how SaskPower develops its DSM programs and chooses which programs to implement.

Response:

SaskPower encourages and supports the adoption of a wide range of energy-efficient technologies in the market and provides conservation education to residential and business customers with the long-term goal of transforming Saskatchewan into a more sustainable and efficient market. SaskPower's strategy is to continually monitor the market to identify emerging trends and opportunities that may become viable and cost effective program offerings.

For DSM programs that provide financial incentives designed to accelerate the adoption of energy efficient products in the market, SaskPower is guided by the opportunities identified in the 2010 Conservation Potential Review (CPR). The CPR study helps develop a comprehensive vision of the potential electricity saving and demand reductions achievable in Saskatchewan in a given timeframe. It characterizes the "how" and "where" and identifies energy efficient measures at a technical, economic and achievable potential level. The CPR is a vision of what could be, not what will be. The potentials identified in the CPR become the inputs into the types of programming SaskPower should be focusing on and provide a target for savings that could be achieved in the market.

These recommendations are then reviewed within the context of industry economic tests, including the Utility Cost Test (UCT) and Total Resource Cost (TRC). The UCT measures the net costs of the DSM program as a resource option based on the costs incurred by the utility (including incentive costs) and excluding any net costs incurred by the participant. The TRC assists in determining the overall benefit of the energy efficiency program for all utility customers and a ratio of 1.0 or greater is considered appropriate. These tests influence the determination of whether to pursue an opportunity, how aggressive an opportunity will be pursued, the effectiveness of program design options and department budget dollar allocations.

Customer experience also continues to be a top priority for our company and for DSM program design. One specific area of focus is to deliver value to customers by developing services that provide customers with greater control over their power use and opportunities to minimize the impact of rate increases. As such programs are designed with this in mind.

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SRRP Q112:
Reference: **Demand Side Management**
Please provide the most recently completed Demand Side Management report.

Response:

SaskPower's Conservation Potential Review (CPR), conducted in 2010, helps develop a comprehensive vision of the potential electricity savings and demand reductions achievable in Saskatchewan. SaskPower is currently initiating a project to update the CPR to assess the current potential and to set new long-term targets for energy efficiency and conservation in Saskatchewan.

The Residential End Use Study (REUS) was completed in 2015. The information collected from this study is used to better understand consumers' end-use of electricity in an effort to improve customer efficiency education, forecasting of potential energy savings opportunities, and overall accuracy for forecasting electricity growth needs and requirements. A commercial lighting end use survey is currently being finalized and is projected to be complete in the fall.

The Customer Experience – Conservation Support Summary was completed in 2015. This research helps provide a comprehensive view of SaskPower's customers' overall perceptions and experience ratings and allows SaskPower to confidently identify the areas that will have the most impact on customer experience. Conservation Support is one area that drives customer experience; SaskPower continues to make efforts to help customers understand their power usage and become more energy efficient – allowing them to save power and money.

These reports are considered proprietary and cannot be released publicly. A copy of each report has been submitted to the Saskatchewan Rate Review Panel for their review.

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SRRP Q113:

Reference: Demand Side Management

Please provide a table showing annual DSM spending, MW and GWh savings, for the period 2013 to 2015 and forecast for 2016-17 and 2017-18 broken out by customer class and program area.

Response:

SaskPower strives to maintain a diversified portfolio of DSM programs across sectors to provide opportunities for all customers to participate.

SaskPower DSM focus areas are guided by the opportunities identified in the 2010 Conservation Potential Review (CPR). (Further explained in SRRP Q111).

Following the CPR review, DSM budgets are allocated to programs that provide the greatest opportunity to meet annual DSM targets while maintaining a range of programs across all sectors.

	2013			2014			2015			2016/17 (Estimated Forecasts)			2017/18 (Estimated Forecast)		
	$s	MWh	MW	$s	MWh	MW	$s	MWh	MW	$s	MWh	MW	$s	MWh	MW
Residential Programs															
Retail Discount Program*	$ 2.07	7,845	5.6	$ 2.16	17,108	8.5	$ 3.21	26,200	10.6	$ 2.75	13,240	5.66	$ 2.82	13,590	5.77
Appliance	$ 1.82	7,340	0.9	$ 1.60	5,745	0.7	$ 1.28	4,070	0.5	$ 1.20	3,630	0.43			
Plug Load	$ 0.36	14,520	11.9		1,267	1.0									
HVAC	$ 0.15	190	-		-		$ 0.04	200	0.1	$ 0.07	60	0.28	$ 0.05	40	0.20
Geothermal	$ 0.17	450	0.2												
EnerGuide	$ 0.00	180	0.1												
Home Assistance Pilot										$ 0.19	TBD		$ 0.04	TBD	
New Home										$ 0.07					
Commercial Programs															
EPC	$ 0.00	490	0.1	$ 0.11	904	0.1	$ -	-	-	$ -	-	-	$ -	-	-
Lighting	$ 1.99	12,280	1.6	$ 1.87	13,979	1.9	$ 2.52	22,410	3.0	$ 3.80	22,750	3.18	$ 2.52	14,790	2.11
HVAC		100	0.0	$ 0.13	564	0.2	$ 0.04	200	0.0	$ 0.07	140	0.02	$ 0.07	140	0.02
Municipal	$ 0.47	410	0.5	$ 0.25	203	0.3	$ 0.17	120	0.2	$ 0.23	TBD		$ 0.15	TBD	
Parking Lot	$ 0.18	2,790	-	$ 0.04	811		$ 0.04	700	-	$ 0.05	800	-	$ 0.04	800	-
Refrigeration				$ 0.05			$ 0.05	820	0.1	$ 0.12	480	0.05	$ 0.10	480	0.05
Compressed Air					90		$ 0.01	360	0.1	$ 0.04	TBD		$ 0.02	TBD	
Energy Optimisation							$ 0.07			$ 0.42	TBD		$ 0.40	TBD	
Industrial Programs															
Industrial Energy Optimization	$ 1.36	5,410	0.6	$ 2.31	1,728	0.3	$ 1.57	19,260	2.4	$ 2.91	14,000	2.00	$ 2.50	TBD	
Total EE	**$ 8.58**	**52,005**	**21.4**	**$ 8.52**	**42,399**	**12.8**	**$ 9.01**	**74,340**	**16.8**	**$ 11.90**	**55,100**	**11.6**	**$ 8.71**	**29,840**	**8.15**

Note:

- * Post Evaluation savings reported in following year (2014 and 2015 reported)
- $'s do not include salaries/benefits, office administration or projects
- Forecasts are an estimate based on expected budget dollars and customer uptake and are subject to change
- 2016-17 forecast has been updated to reflect 15-month forecast

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SRRP Q114:

Reference: **Demand Side Management**

Please discuss the program evaluation criteria or metrics (e.g, RIM test, TRC test) economic cost benefit tests) SaskPower uses to evaluate the economic benefits of its DSM programming.

Response:

Program development is assessed through various measures to ensure that overall objectives for the program will be achieved. The cost/benefit tests provide a key planning and delivery tool for measuring programs and portfolios while measuring the economics of DSM from different perspectives. When developing energy efficiency programs, the tests are reviewed as a whole since each test is designed to address different questions regarding the programs cost-effectiveness.

The Total Resource Cost (TRC) assists in determining the overall benefit of the energy efficiency program for all utility customers and a ratio of 1.0 or greater is considered appropriate. The Utility Cost Test (UCT) is also reviewed in conjunction with the program, and the overall supply value provided.

From a portfolio basis, a program mix is considered that provides a TRC of greater than 1.0. In other words, the present value of the benefits counted under the test must exceed the present value of the costs, so that the benefit-cost ratio is greater than 1.0, or the net benefits (benefits minus costs) are positive. The UCT is also reviewed to ensure there are positive benefits for the utility from a supply side perspective.

In addition to the economic measurements, customer experience (CX) also continues to be a top priority for our company and for DSM program design. One specific area of focus is to deliver value to customers by developing services that provide customers with greater control over their power use and opportunities to minimize the impact of rate increases. As such programs are designed with this in mind.

SRRP Q115:

Reference: Demand Side Management

Please discuss whether DSM savings (both MW and MWh) are considered to end or no longer provide system benefits. Alternatively, are savings assumed to continue indefinitely?

Response:

Consistent with industry evaluation standards, SaskPower's DSM savings are considered to continue indefinitely since the programs involve replacement of inefficient technologies. At future replacement time, these will be replaced with the same or perhaps a better technology which has become available.

Programs receive a technical review prior to commitment followed by an evaluation, measurement and verification process. Each step in the process can result in a change to the saving number; therefore, a reported number has often been adjusted to reflect accurately on the research. Programs with a shorter term *Expected Useful Life* are followed up with persistence research to ensure savings are being maintained, coupled with continuous education and outreach. DSM's involvement with Codes and Standards essentially replaces program savings with larger regulatory-driven savings, and in cases where the savings could be considered not permanent, they are dropped off or adjusted accordingly.

SRRP Q116:

Reference: **Demand Response Program**

For Demand Response customers, please clarify:

i) How much capacity (in MW) is available under each of SaskPower's demand response options i) 15 minute curtailment notice, and ii) 2 hour curtailment notice.

ii) Are participating customers obligated to reduce usage when requested or is the program voluntary? If voluntary, how does SaskPower account for the uncertainty of whether customers will respond when requested?

iii) Are there terms related to the maximum number or duration curtailments SaskPower can request in a given year

iv) What is the duration of the Demand Response contracts?

Response:

i) DR1 (15 min notice) works with large, high demand customers with consistent load characteristics, who are able to contribute a minimum of 5 MW. These customers are compensated based on their average use over a given month. SaskPower can rely on their loads to be consistently high and on their ability to provide a material DR load reduction at almost any time. Their contractual DR commitments combine for 84.5 MW.

DR2 (2 hour notice) arrangements are with customers that have high demand and can still contribute a minimum of 5 MW, but operate much more intermittently. Therefore, the amount of load available for curtailment at any given time is less certain. As such, they are compensated at a lower rate than the DR1 program. In 2016, the maximum contractual amounts are approximately 183 MW. These contracts identify a threshold that a customer has to reduce load to if an event is called. 183 MW is based on their anticipated or typical load should they have to reduce to their threshold when an event is called, but the actual operating load at any given time is variable and typically less than their peak. The customer is compensated for being available to reduce load and/or based on their average use over a given month.

ii) All of SaskPower DR customers are contractually obliged to reduce load when an event is called. As these are all large customers, SaskPower has live monitoring abilities for their operations. The Grid Control Operator knows what their current load is at any given time and will only call on them for an event if they are operating at loads worthy of curtailing. The contractual agreements with these customers outline the ramifications should they not respond within specified time limits.

iii) Within the contracts there are very specific terms regarding how long an event is, how many can be called adjacent to one another in a given day and how many can be called over a one year term.

iv) From 2013 to 2015, SaskPower transitioned DR1 contracts to two-year terms with alternating year end anniversaries. As a new mandate to offer DR programs is required for 2017, the contracts signed effective January 1, 2016, were for one year.

DR2 contracts are typically for one year; however, one arrangement was established in conjunction with an energy purchase agreement between SaskPower and the customer. That DR arrangement is for the extended term of the energy purchase agreement, but all other aspects of the arrangement are per the advertised DR2 program.

SRRP Q117:

Reference: **Cost of Service Study**

Please provide a list detailing any changes to methods used in SaskPower's cost of service study since the time of the last rate application.

Response:

SaskPower has made no changes in methodology in the preparation of this rate application compared to the previous rate application filed in 2013.

SRRP Q118:

Reference: **Cost of Service Study**

Please discuss when SaskPower's next external review of its cost of service study will be completed.

Response:

SaskPower plans to initiate its next Cost of Service review in April 2017, with an expected completion date by the end of March 2018.

SRRP Q119:

Reference: Cost of Service Study

Please provide a table showing the derivation of the 2CP allocator by rate class including the actual winter and summer peak information used to calculate the 2CP allocator.

Response:

Please see table below. The calculated 2CP allocators match the allocation factors found in the Cost of Service Report (Schedule 4.0).

		WINTER		SUMMER		2CP	
Class of Service	Sales Gwh	Demand KW	Load Factor %	Demand KW	Load Factor %	Demand KW	Load Factor %
Urban Residential	2,545	533,960	54.41%	511,450	56.80%	522,705	55.58%
Rural Residential	737	154,621	54.41%	148,102	56.80%	151,362	55.58%
Total Residential	**3,282**	**688,581**	**54.41%**	**659,552**	**56.80%**	**674,067**	**55.58%**
Farms	1,332	268,965	56.53%	173,333	87.72%	221,149	68.75%
Urban Commercial	2,763	380,379	82.93%	448,516	70.33%	414,447	76.11%
Rural Commercial	1,019	142,774	81.45%	167,699	69.34%	155,236	74.91%
Total Commercial	**3,782**	**523,152**	**82.52%**	**616,215**	**70.06%**	**569,684**	**75.78%**
Power - Published Rates	6,750	816,372	94.38%	815,387	94.50%	815,879	94.44%
Power - Contract Rates	2,441	298,670	93.29%	344,058	80.98%	321,364	86.70%
Total Power	**9,190**	**1,115,041**	**94.09%**	**1,159,445**	**90.49%**	**1,137,243**	**92.25%**
Oilfields	3,479	437,938	90.68%	372,014	106.75%	404,976	98.06%
Streetlights	63	14,950	48.02%	0	0.00%	7,475	96.04%
Resellers	1,291	202,398	72.81%	217,752	67.68%	210,075	70.15%
TOTAL SYSTEM	**22,419**	**3,251,024**	**78.72%**	**3,198,311**	**80.02%**	**3,224,668**	**79.36%**

Number of Hours/Year 8,760

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SRRP Q120:

Reference: **Cost of Service Study**

Please provide a table comparing the revenue requirement allocated to each class and the revenue to revenue requirement ratios for 2016 and 2017 using the 2CP method and the 1CP method.

Response:

Please see the information contained in the tables below:

SaskPower Proposed July 2016 Rate Change				
Class of Service	1CP Methodology Allocated Rev. Reqt. ($)	1CP Methodology Revenue to Rev. Reqt. Ratio	2CP Methodology Allocated Rev. Reqt. * ($)	2CP Methodology Revenue to Rev. Reqt. * Ratio
Urban Residential	$ 428,249,236	0.99	$ 423,685,247	1.00
Rural Residential	$ 126,789,141	0.94	$ 126,606,856	0.94
Farms	$ 200,175,473	0.88	$ 180,794,390	0.98
Urban Commercial	$ 317,418,304	1.07	$ 331,255,273	1.03
Rural Commercial	$ 118,285,319	1.08	$ 124,853,698	1.03
Power - Published Rates	$ 490,974,771	1.02	$ 497,008,418	1.01
Power - Contract Rates	$ 175,291,073	1.04	$ 183,474,052	0.99
Oilfields	$ 351,370,363	0.98	$ 340,547,978	1.01
Streetlights	$ 19,977,205	0.82	$ 16,939,478	0.97
Reseller	$ 98,323,614	1.01	$ 101,689,112	0.98
Total	**$ 2,326,854,500**	**1.00**	**$ 2,326,854,500**	**1.00**

* Current rate application was filed based on 2CP methodology.

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2016 and 2017 RATE APPLICATION
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SaskPower Proposed January 2017 Rate Change				
Class of Service	**1CP Methodology Allocated Rev. Reqt. ($)**	**1CP Methodology Revenue to Rev. Reqt. Ratio**	**2CP Methodology Allocated Rev. Reqt. * ($)**	**2CP Methodology Revenue to Rev. Reqt. * Ratio**
Urban Residential	$ 449,493,085	0.99	$ 444,694,296	1.00
Rural Residential	$ 133,753,366	0.93	$ 133,565,496	0.93
Farms	$ 210,526,258	0.88	$ 190,074,511	0.98
Urban Commercial	$ 333,610,142	1.07	$ 348,237,990	1.03
Rural Commercial	$ 124,854,026	1.08	$ 131,780,135	1.02
Power - Published Rates	$ 513,821,944	1.02	$ 520,170,355	1.01
Power - Contract Rates	$ 183,505,926	1.03	$ 192,128,868	0.99
Oilfields	$ 369,619,711	0.98	$ 358,206,264	1.01
Streetlights	$ 21,252,752	0.81	$ 18,045,442	0.96
Reseller	$ 102,762,790	1.02	$ 106,296,642	0.98
Total	**$ 2,443,200,000**	**1.00**	**$ 2,443,200,000**	**1.00**

* Current rate application was filed based on 2CP methodology.

SRRP Q121:

Reference: Cost of Service Study

Please provide a schedule showing the calculation of the energy/demand classification ratios based on the equivalent peaker method and illustrate how this analysis is used to classify the plant in service to demand and energy.

Response:

Please see the information in the table below.

2014 Summay of Classification of SaskPower Generating Assets			
Generating Asset Type	**Average Demand Related**	**Average Energy Related**	**Total Average Related**
Single Cycle Gas Plants a)	100.0%	0.0%	100.0%
Conventional Coal b)	51.9%	48.1%	100.0%
Clean Coal c)	19.2%	80.8%	100.0%
Combined Cycle Gas d)	81.5%	18.5%	100.0%
Hydro e)	18.6%	81.4%	100.0%
Wind	20.0%	80.0%	100.0%
Diesel	100.0%	0.0%	100.0%
Total All Units %	42.5%	57.5%	100.0%
Total All Units $	$ 3,500,082,901	$ 4,739,336,708	$ 8,239,419,609

a) Single Cycle Gas Plants - Landis, Success, Meadow Lake, Ermine, Yellowhead
b) Conventional Coal - Boundary Dam (1,2,4-6), Shand & Poplar River
c) Clean Coal - Boundary Dam #3
d) Combined Cycle Gas - All QE Units
e) Hydro - Coteau Creek, Island Falls, EB Campbell, Nipawin & Athabasca

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SRRP Q122:

Reference: **Cost of Service Study**

Please provide a schedule showing the average unit costs of energy, demand and customer by each major rate class calculated based on SaskPower's cost of service study and compare the average unit costs to the proposed rates effective January 1, 2017.

Response:

Please see the tables below detailing SaskPower's unit costs per customer class based on the January 1, 2017, increase under the cost of service and SaskPower's proposed rates:

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2016 and 2017 RATE APPLICATION
SRRP INTERROGATORIES

SASKPOWER'S COST OF SERVICE

Class of Service	Units			COS Revenue Requirement			Unit Revenue Requirement				
	Billing Demand (kV.a)	Annual Sales (mW.H)	Number of Acccounts	Demand ($)	Energy ($)	Customer ($)	Demand ($/kV.a)	Demand (c/kW.h)	Energy (c/kW.h)	Demand & Energy (c/kW.h)	Customer ($/Mo.)
Urban Residential	-	2,545,003	330,207	$ 242,061,079	$ 131,529,238	$ 71,103,979		$ 9.51	$ 5.17	$ 14.68	$ 17.94
Rural Residential	-	736,967	56,507	$ 76,199,749	$ 33,710,647	$ 23,655,100		$ 10.34	$ 4.57	$ 14.91	$ 34.89
Total Residential	**-**	**3,281,969**	**386,714**	**$ 318,260,828**	**$ 165,239,884**	**$ 94,759,080**		**$ 9.70**	**$ 5.03**	**$ 14.73**	**$ 20.42**
Farms	**895,020**	**1,331,884**	**60,578**	**$ 109,297,041**	**$ 60,889,726**	**$ 19,887,744**	**$ 122.12**	**$ 8.21**	**$ 4.57**	**$ 12.78**	**$ 27.36**
Urban Commercial	3,585,602	2,763,282	44,735	$ 183,663,494	$ 138,553,919	$ 26,020,577	$ 51.22	$ 6.65	$ 5.01	$ 11.66	$ 48.47
Rural Commercial	1,283,385	1,018,671	13,450	$ 73,380,767	$ 46,370,357	$ 12,029,011	$ 57.18	$ 7.20	$ 4.55	$ 11.76	$ 74.53
Total Commercial	**4,868,987**	**3,781,953**	**58,185**	**$ 257,044,261**	**$ 184,924,276**	**$ 38,049,588**	**$ 52.79**	**$ 6.80**	**$ 4.89**	**$ 11.69**	**$ 54.50**
Power - Published Rates	13,144,500	6,749,735	89	$ 231,398,952	$ 283,740,486	$ 5,030,918	$ 17.60	$ 3.43	$ 4.20	$ 7.63	$ 4,710.60
Power - Contract Rates	5,753,823	2,440,673	14	$ 89,191,925	$ 102,138,759	$ 798,184	$ 15.50	$ 3.65	$ 4.18	$ 7.84	$ 4,751.09
Total Power	**18,898,323**	**9,190,407**	**103**	**$ 320,590,877**	**$ 385,879,245**	**$ 5,829,102**	**$ 16.96**	**$ 3.49**	**$ 4.20**	**$ 7.69**	**$ 4,716.10**
Oilfields	2,851,174	3,478,942	19,093	$ 179,824,909	$ 156,615,772	$ 21,765,583	$ 63.07	$ 5.17	$ 4.50	$ 9.67	$ 95.00
Streetlights	-	62,888	2,841	$ 3,345,981	$ 2,898,069	$ 11,801,392		$ 5.32	$ 4.61	$ 9.93	$ 346.16
Reseller	2,444,262	1,290,917	3	$ 52,298,307	$ 53,805,637	$ 192,698	$ 21.40	$ 4.05	$ 4.17	$ 8.22	$ 5,352.71
Total	**29,957,766**	**22,418,961**	**527,517**	**$ 1,240,662,204**	**$ 1,010,252,609**	**$ 192,285,186**					
					Total Revenue	**$ 2,443,200,000**					

SASKPOWER'S PROPOSED RATES (JANUARY, 2017)

Class of Service	Units			January 1, 2017 Proposed Rates			Unit Revenue Requirement				
	Billing Demand (kV.a)	Annual Sales (mW.H)	Number of Acccounts	Demand ($)	Energy ($)	Customer ($)	Demand ($/kV.a)	Demand (c/kW.h)	Energy (c/kW.h)	Demand & Energy (c/kW.h)	Customer ($/Mo.)
Urban Residential	-	2,545,003	330,207		$ 354,849,750	$ 88,482,390		$ -	$ 13.94	$ 13.94	$ 22.33
Rural Residential	-	736,967	56,507		$ 102,762,621	$ 21,861,398		$ -	$ 13.94	$ 13.94	$ 32.24
Total Residential	**-**	**3,281,969**	**386,714**	**$ -**	**$ 457,612,371**	**$ 110,343,788**		**$ -**	**$ 13.94**	**$ 13.94**	**$ 23.78**
Farms	**895,020**	**1,331,884**	**60,578**	**$ 4,924,808**	**$ 155,726,712**	**$ 24,958,082**	**$ 5.50**	**$ 0.37**	**$ 11.69**	**$ 12.06**	**$ 34.33**
Urban Commercial	3,585,602	2,763,282	44,735	$ 49,055,999	$ 290,184,022	$ 16,352,356	$ 13.68	$ 1.78	$ 10.50	$ 12.28	$ 30.46
Rural Commercial	1,283,385	1,018,671	13,450	$ 25,754,186	$ 103,457,068	$ 7,437,300	$ 20.07	$ 2.53	$ 10.16	$ 12.68	$ 46.08
Total Commercial	**4,868,987**	**3,781,953**	**58,185**	**$ 74,810,185**	**$ 393,641,090**	**$ 23,789,656**	**$ 15.36**	**$ 1.98**	**$ 10.41**	**$ 12.39**	**$ 34.07**
Power - Published Rates	13,144,500	6,749,735	89	$ 108,615,501	$ 410,195,484	$ 6,887,796	$ 8.26	$ 1.61	$ 6.08	$ 7.69	$ 6,449.25
Power - Contract Rates	5,753,823	2,440,673	14	$ 38,688,784	$ 149,930,830	$ 782,623	$ 6.72	$ 1.59	$ 6.14	$ 7.73	$ 4,658.47
Total Power	**18,898,323**	**9,190,407**	**103**	**$ 147,304,285**	**$ 560,126,314**	**$ 7,670,419**	**$ 7.79**	**$ 1.60**	**$ 6.09**	**$ 7.70**	**$ 6,205.84**
Oilfields	2,851,174	3,478,942	19,093	$ 95,001,078	$ 249,968,466	$ 15,577,599	$ 33.32	$ 2.73	$ 7.19	$ 9.92	$ 67.99
Streetlights	-	62,888	2,841			$ 17,309,420		$ -	$ -	$ -	$ 507.73
Reseller	2,444,262	1,290,917	3	$ 45,813,355	$ 58,268,273	$ 327,032	$ 18.74	$ 3.55	$ 4.51	$ 8.06	$ 9,084.22
Total	**29,957,766**	**22,418,961**	**527,517**	**$ 367,853,711**	**$ 1,875,343,226**	**$ 199,975,996**					
					Total Revenue	**$ 2,443,172,933**					

SRRP Q123:

Reference: Cost of Service Study

Please explain how DSM costs and demand response costs are functionalized and classified in the cost of service study.

Response:

Demand Side Management (DSM) costs focus on customer programs and services relating to energy efficiency, conservation, load management and self-generation, which directly impact generation. DSM OM&A expenses are therefore functionalized 100% to the load sub-function within the generation function, and are classified equally to demand and energy within cost of service.

Demand response payments are included in fuel and purchased power expense and functionalized 100% to generation. The classification of demand response expense to demand and energy is done using the capacity and energy payments to suppliers.

SRRP Q124:

Reference: **Proposed Rates**

Please provide the revenues and revenue requirement breakdowns by class in dollars for each column in the table on page 4 of the Application.

Response:

Please see next three pages for tables.

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2016 and 2017 RATE APPLICATION
SRRP INTERROGATORIES

1) July 1, 2016, rate increase with Revenue and Revenue Requirements

Class of Service	Year 2017F Revenue at Existing Rates			Year 2017F Revenue with July 1 Adjusted Rates			
	Allocated Rev. Reqt. ($)	Revenue ($)	Revenue to Rev. Reqt. Ratio	Allocated Rev. Reqt. ($)	Revenue ($)	Revenue to Rev. Reqt. Ratio	Revenue Change (%)
Urban Residential	$ 403,677,428	$ 401,370,092	0.99	$ 423,685,416	$ 421,836,248	1.00	5.1%
Rural Residential	$ 119,979,888	$ 112,837,387	0.94	$ 126,606,934	$ 118,590,401	0.94	5.1%
Total Residential	**$ 523,657,316**	**$ 514,207,479**	**0.98**	**$ 550,292,350**	**$ 540,426,649**	**0.98**	**5.1%**
Farms	**$ 171,956,609**	**$ 168,044,865**	**0.98**	**$ 180,794,503**	**$ 176,612,633**	**0.98**	**5.1%**
Urban Commercial	$ 315,081,895	$ 323,586,964	1.03	$ 331,255,406	$ 340,085,046	1.03	5.1%
Rural Commercial	$ 118,255,570	$ 122,074,762	1.03	$ 124,852,840	$ 128,298,744	1.03	5.1%
Total Commercial	**$ 433,337,465**	**$ 445,661,726**	**1.03**	**$ 456,108,245**	**$ 468,383,789**	**1.03**	**5.1%**
Power - Published Rates	$ 474,950,173	$ 475,958,353	1.00	$ 497,008,533	$ 500,225,090	1.01	5.1%
Power - Contract Rates	$ 175,231,646	$ 175,538,250	1.00	$ 183,474,094	$ 182,303,000	0.99	3.9%
Total Power	**$ 650,181,819**	**$ 651,496,603**	**1.00**	**$ 680,482,628**	**$ 682,528,089**	**1.00**	**4.8%**
Oilfields	$ 323,731,304	$ 326,443,622	1.01	$ 340,548,156	$ 343,087,350	1.01	5.1%
Streetlights	$ 15,886,208	$ 15,675,844	0.99	$ 16,939,480	$ 16,475,077	0.97	5.1%
Reseller	$ 97,301,141	$ 94,521,722	0.97	$ 101,689,138	$ 99,340,912	0.98	5.1%
Total	**$ 2,216,051,862**	**$ 2,216,051,862**	**1.00**	**$ 2,326,854,500**	**$ 2,326,854,500**	**1.00**	**5.0%**

2016 and 2017 RATE APPLICATION
SRRP INTERROGATORIES

2) January 1, 2017, rate increase with Revenue Requirements

Class of Service	Revenue at Existing Rates from July 1 Increase			Revenue after Jan 1 Increase			
	Allocated Rev. Reqt. ($)	Revenue ($)	Revenue to Rev. Reqt. Ratio	Allocated Rev. Reqt. ($)	Revenue ($)	Revenue to Rev. Reqt. Ratio	Revenue Change (%)
Urban Residential	$ 423,685,281	$ 421,836,248	1.00	$ 444,694,151	$ 443,323,257	1.00	5.1%
Rural Residential	$ 126,606,856	$ 118,590,401	0.94	$ 133,565,413	$ 124,631,397	0.93	5.1%
Total Residential	**$ 550,292,136**	**$ 540,426,649**	**0.98**	**$ 578,259,564**	**$ 567,954,654**	**0.98**	**5.1%**
Farms	**$ 180,794,390**	**$ 176,612,633**	**0.98**	**$ 190,074,391**	**$ 185,609,280**	**0.98**	**5.1%**
Urban Commercial	$ 331,255,239	$ 340,085,046	1.03	$ 348,237,816	$ 357,408,978	1.03	5.1%
Rural Commercial	$ 124,853,698	$ 128,298,744	1.03	$ 131,781,041	$ 134,834,282	1.02	5.1%
Total Commercial	**$ 456,108,937**	**$ 468,383,789**	**1.03**	**$ 480,018,857**	**$ 492,243,260**	**1.03**	**5.1%**
Power - Published Rates	$ 497,008,418	$ 500,225,090	1.01	$ 520,170,234	$ 525,706,556	1.01	5.1%
Power - Contract Rates	$ 183,474,052	$ 182,303,000	0.99	$ 192,128,824	$ 189,406,375	0.99	3.9%
Total Power	**$ 680,482,470**	**$ 682,528,089**	**1.00**	**$ 712,299,058**	**$ 715,112,931**	**1.00**	**4.8%**
Oilfields	$ 340,547,978	$ 343,087,350	1.01	$ 358,206,076	$ 360,564,220	1.01	5.1%
Streetlights	$ 16,939,478	$ 16,475,077	0.97	$ 18,045,440	$ 17,314,318	0.96	5.1%
Reseller	$ 101,689,112	$ 99,340,912	0.98	$ 106,296,615	$ 104,401,338	0.98	5.1%
Total	**$ 2,326,854,500**	**$ 2,326,854,500**	**1.00**	**$ 2,443,200,000**	**$ 2,443,200,000**	**1.00**	**5.0%**

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2016 and 2017 RATE APPLICATION
SRRP INTERROGATORIES

3) January 1, 2017, rate increase(compounded) with Revenue Requirements

Class of Service	Year 2017F Revenue at Existing Rates			Year 2017F Revenue at Jan 1 Rates			Revenue Change
	Allocated Rev. Reqt. ($)	Revenue ($)	Revenue to Rev. Reqt. Ratio	Allocated Rev. Reqt. ($)	Revenue ($)	Revenue to Rev. Reqt. Ratio	(%)
Urban Residential	$ 403,677,428	$ 401,370,092	0.99	$ 444,694,296	$ 443,323,257	1.00	10.5%
Rural Residential	$ 119,979,888	$ 112,837,387	0.94	$ 133,565,496	$ 124,631,397	0.93	10.5%
Total Residential	**$ 523,657,316**	**$ 514,207,479**	**0.98**	**$ 578,259,792**	**$ 567,954,654**	**0.98**	**10.5%**
Farms	**$ 171,956,609**	**$ 168,044,865**	**0.98**	**$ 190,074,511**	**$ 185,609,280**	**0.98**	**10.5%**
Urban Commercial	$ 315,081,895	$ 323,586,964	1.03	$ 348,237,990	$ 357,408,978	1.03	10.5%
Rural Commercial	$ 118,255,570	$ 122,074,762	1.03	$ 131,780,135	$ 134,834,282	1.02	10.5%
Total Commercial	**$ 433,337,465**	**$ 445,661,726**	**1.03**	**$ 480,018,125**	**$ 492,243,260**	**1.03**	**10.5%**
Power - Published Rates	$ 474,950,173	$ 475,958,353	1.00	$ 520,170,355	$ 525,706,556	1.01	10.5%
Power - Contract Rates	$ 175,231,646	$ 175,538,250	1.00	$ 192,128,868	$ 189,406,375	0.99	7.9%
Total Power	**$ 650,181,819**	**$ 651,496,603**	**1.00**	**$ 712,299,223**	**$ 715,112,931**	**1.00**	**9.8%**
Oilfields	$ 323,731,304	$ 326,443,622	1.01	$ 358,206,264	$ 360,564,220	1.01	10.5%
Streetlights	$ 15,886,208	$ 15,675,844	0.99	$ 18,045,442	$ 17,314,318	0.96	10.5%
Reseller	$ 97,301,141	$ 94,521,722	0.97	$ 106,296,642	$ 104,401,338	0.98	10.5%
Total	**$ 2,216,051,862**	**$ 2,216,051,862**	**1.00**	**$ 2,443,200,000**	**$ 2,443,200,000**	**1.00**	**10.3%**

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SRRP Q125:

Reference: **Proposed Rates**

Please provide an explanation for why contract rates are only subject to a 3.9% rate increase despite their revenue to revenue requirement ratio after rate increases being less than 1.00 as shown in the table on page 4 of the application.

Response:

Contract customer increases are calculated using the escalation factors contained in their respective Electrical Service Agreement (ESA). The nature and type of these escalation factors varies by contract and can be dependent upon outlying factors beyond SaskPower's control.

Depending on the nature of the stipulated escalation, it is possible that some contract customers will not receive increases sufficient enough to recover their calculated revenue requirement. This has occurred in this application, as the contract class' R/RR ratio has dropped below its starting point of 1.00 to 0.99 after the proposed increases.

SRRP Q126:

Reference: **Proposed Rates**

Please confirm the number of customers in the power contract class.

Response:

SaskPower confirms that the number of customers in the Power-Contract class is 2.

SRRP Q127:

Reference: **Proposed Rates**

Please confirm that, outside of power contract rates, SaskPower is proposing to increase all elements of all rates (e.g. customer charges, demand charges, energy charges) by 5.1%. If the requested confirmation cannot be provided, please provide an explanation.

Response:

Please refer to the following spreadsheet.

In the case of Time of Use rates for our Power and Oilfield classes, the rate increase is established by adding a flat amount of 0.5728 cents to the standard energy rate to determine the on-peak energy charge and subtracting 1 cent from the new on-peak energy rate to determine the off-peak energy charge.

SaskPower
Rate Proposal
RESIDENTIAL

RATE CODE	DESCRIPTION	BASIC ($/month)	Energy Block 1 Size (kW.h/month)	Energy Block 1 Rate (cents/kW.h)	Energy Balance Rate (cents/kW.h)	Demand Block 1 Size (kVA)	Demand Block 1 Rate ($/kVA)	Demand Balance Rate ($/kVA)	MINIMUM BILL BASIC		
E01 Existing	City	20.22	N/A	N/A	12.623	N/A	N/A	N/A	20.22		
E01 Proposed		21.25	N/A	N/A	13.267	N/A	N/A	N/A	21.25		
Difference		**5.1%**			**5.1%**				**5.1%**		
E02 Existing	Town, Village, Urban Resort	20.22	N/A	N/A	12.623	N/A	N/A	N/A	20.22		
E02 Proposed		21.25	N/A	N/A	13.267	N/A	N/A	N/A	21.25		
Difference		**5.1%**			**5.1%**				**5.1%**		
E03 Existing	Rural, Rural Resort	29.19	N/A	N/A	12.624	N/A	N/A	N/A	29.19		
E03 Proposed		30.68	N/A	N/A	13.268	N/A	N/A	N/A	30.68		
Difference		**5.1%**			**5.1%**				**5.1%**		

SaskPower
Rate Proposal
DIESEL

RATE CODE	DESCRIPTION	BASIC ($/month)	Energy Block 1 Size (kW.h/month)	Energy Block 1 Rate (cents/kW.h)	Energy Balance Rate (cents/kW.h)	Demand Block 1 Size (kVA)	Demand Block 1 Rate ($/kVA)	Demand Balance Rate ($/kVA)	MINIMUM BILL BASIC		
E04 Existing	Residential Diesel	29.19	650	12.624	46.610	N/A	N/A	N/A	29.19		
E04 Proposed		30.68	650	13.268	48.986	N/A	N/A	N/A	30.68		
Difference		**5.1%**		**5.1%**	**5.1%**				**5.1%**		
E35 Existing	General Service	36.81	650	12.775	44.000	N/A	N/A	N/A	36.81		
E35 Proposed		38.69	650	13.426	46.243	N/A	N/A	N/A	38.69		
Difference		**5.1%**		**5.1%**	**5.1%**				**5.1%**		
E36 Existing	General Service - Federal & Provincial	36.81	N/A	N/A	89.130	N/A	N/A	N/A	36.81		
E36 Proposed		38.69	N/A	N/A	93.674	N/A	N/A	N/A	38.69		
Difference		**5.1%**			**5.1%**				**5.1%**		
E38 Existing	General Service - Local Community	36.81	N/A	N/A	81.000	N/A	N/A	N/A	36.81		
E38 Proposed		38.69	N/A	N/A	85.130	N/A	N/A	N/A	38.69		
Difference		**5.1%**			**5.1%**				**5.1%**		

SaskPower
Rate Proposal
FARM

RATE CODE	DESCRIPTION	BASIC ($/month)	Energy Block 1 Size (kW.h/month)	Energy Block 1 Rate (cents/kW.h)	Energy Balance Rate (cents/kW.h)	Demand Block 1 Size (kVA)	Demand Block 1 Rate ($/kVA)	Demand Balance Rate ($/kVA)	MINIMUM BILL * BASIC	DEMAND	NOTES
E34 Existing	Farm	31.03	16,000	11.230	4.870	50	0	11.400	31.03	4.32	/KV.A max demand over 50
E34 Proposed		32.61	16,000	11.803	5.118	50	0	11.981	32.61	4.54	/KV.A max demand over 50
Difference		**5.1%**		**5.1%**	**5.1%**			**5.1%**	**5.1%**	**5.1%**	

* Minimum Bill = Basic Monthly Charge plus the Demand Charge applicable in the preceding 11 months.

SaskPower
Rate Proposal
IRRIGATION

RATE CODE	DESCRIPTION	BASIC ($/season)	Energy Block 1 Size (kW.h/month)	Energy Block 1 Rate (cents/kW.h)	Energy Balance Rate (cents/kW.h)	Demand Block 1 Size (kVA)	Demand Block 1 Rate ($/kVA)	Demand Balance Rate ($/hp)	MINIMUM BILL BASIC	DEMAND	NOTES
E19 Existing	Farm - SaskPower Supplied Transformation	426.12	N/A	N/A	6.280	N/A	N/A	N/A	426.12		
E19 Proposed		447.85	N/A	N/A	6.600	N/A	N/A	N/A	447.85		
Difference		**5.1%**			**5.1%**				**5.1%**		
E37 Existing	General Service - SaskPower Supplied Transformation	225.34	N/A	N/A	8.550	N/A	N/A	22.670	225.34	22.670	/KV.A max demand
E37 Proposed		236.83	N/A	N/A	8.986	N/A	N/A	23.826	236.83	23.826	/KV.A max demand
Difference		**5.1%**			**5.1%**			**5.1%**	**5.1%**	**5.1%**	
E41 Existing	Mains - Interruptible - closed to new customers	803.46	N/A	N/A	5.380	N/A	N/A	N/A	803.46		
E41 Proposed		844.42	N/A	N/A	5.654	N/A	N/A	N/A	844.42		
Difference		**5.1%**			**5.1%**				**5.1%**		

E41 basic charge is a monthly charge applied in every month a customer in this rate code consumes energy. (Not a seasonal charge)

SaskPower

Rate Proposal

GENERAL SERVICE - STANDARD

RATE CODE	DESCRIPTION	BASIC ($/month)	Energy Block 1 Size (kW.h/month)	Energy Block 1 Rate (cents/kW.h)	Energy Balance Rate (cents/kW.h)	Demand Block 1 Size (kVA)	Demand Block 1 Rate ($/kVA)	Demand Balance Rate ($/kVA)	MINIMUM BILL * BASIC	MINIMUM BILL * DEMAND	MINIMUM BILL * NOTES
E05 Existing	Urban - SaskPower Supplied Transformation	51.40	16,750	10.635	6.809	50	0	13.840	51.40	4.32	/KV.A max demand over 50
E05 Proposed		54.02	16,750	11.177	7.156	50	0	14.546	54.02	4.54	/KV.A max demand over 50
Difference		**5.1%**		**5.1%**	**5.1%**			**5.1%**	**5.1%**	**5.1%**	
E06 Existing	Rural - SaskPower Supplied Transformation	57.70	15,500	10.635	6.450	50	0	13.840	57.70	4.32	/KV.A max demand over 50
E06 Proposed		60.64	15,500	11.177	6.779	50	0	14.546	60.64	4.54	/KV.A max demand over 50
Difference		**5.1%**		**5.1%**	**5.1%**			**5.1%**	**5.1%**	**5.1%**	
E07 Existing	Urban - Customer Owned Transformation	215.02	N/A	N/A	6.435	N/A	N/A	12.380	215.02	4.32	/KV.A max demand
E07 Proposed		225.98	N/A	N/A	6.763	N/A	N/A	13.011	225.98	4.54	/KV.A max demand
Difference		**5.1%**			**5.1%**			**5.1%**	**5.1%**	**5.1%**	
E08 Existing	Rural - Customer Owned Transformation	265.40	N/A	N/A	6.435	N/A	N/A	12.380	265.40	4.32	/KV.A max demand
E08 Proposed		278.93	N/A	N/A	6.763	N/A	N/A	13.011	278.93	4.54	/KV.A max demand
Difference		**5.1%**			**5.1%**			**5.1%**	**5.1%**	**5.1%**	
E10 Existing	Customer Owned Transformation	632.61	N/A	N/A	5.058	N/A	N/A	7.560	632.61	4.32	/KV.A max demand
E10 Proposed		664.86	N/A	N/A	5.316	N/A	N/A	7.945	664.86	4.54	/KV.A max demand
Difference		**5.1%**			**5.1%**			**5.1%**	**5.1%**	**5.1%**	
E12 Existing	Customer Owned Transformation	291.00	N/A	N/A	4.967	N/A	N/A	7.450	291.00	4.32	/KV.A max demand
E12 Proposed		305.84	N/A	N/A	5.220	N/A	N/A	7.830	305.84	4.54	/KV.A max demand
Difference		**5.1%**			**5.1%**			**5.1%**	**5.1%**	**5.1%**	

* Minimum Bill = Basic Monthly Charge plus the Demand Charge applicable in the preceding 11 months.

SaskPower

Rate Proposal

GENERAL SERVICE - SMALL

RATE CODE	DESCRIPTION	BASIC ($/month)	Energy Block 1 Size (kW.h/month)	Energy Block 1 Rate (cents/kW.h)	Energy Balance Rate (cents/kW.h)	Demand Block 1 Size (kVA)	Demand Block 1 Rate ($/kVA)	Demand Balance Rate ($/kVA)	MINIMUM BILL * BASIC	DEMAND	NOTES
E75 Existing	Urban - SaskPower Supplied Transformation	27.62	14,500	12.128	6.404	50	0	13.440	27.62	4.32	/KV.A max demand over 50
E75 Proposed		29.03	14,500	12.746	6.731	50	0	14.125	29.03	4.54	/KV.A max demand over 50
Difference		**5.1%**		**5.1%**	**5.1%**			**5.1%**	**5.1%**	**5.1%**	
E76 Existing	Rural - SaskPower SuppliedTransformation	36.81	13,000	12.775	6.571	50	0	13.730	36.81	4.32	/KV.A max demand over 50
E76 Proposed		38.69	13,000	13.426	6.906	50	0	14.430	38.69	4.54	/KV.A max demand over 50
Difference		**5.1%**		**5.1%**	**5.1%**			**5.1%**	**5.1%**	**5.1%**	
E77 Existing	Urban - Customer Owned Transformation	27.62	14,500	12.128	6.404	50	0	12.970	27.62	4.32	/KV.A max demand over 50
E77 Proposed		29.03	14,500	12.746	6.731	50	0	13.631	29.03	4.54	/KV.A max demand over 50
Difference		**5.1%**		**5.1%**	**5.1%**			**5.1%**	**5.1%**	**5.1%**	
E78 Existing	Rural - Customer Owned Transformation	36.81	13,000	12.775	6.571	50	0	13.240	36.81	4.32	/KV.A max demand over 50
E78 Proposed		38.69	13,000	13.426	6.906	50	0	13.915	38.69	4.54	/KV.A max demand over 50
Difference		**5.1%**		**5.1%**	**5.1%**			**5.1%**	**5.1%**	**5.1%**	

* Minimum Bill = Basic Monthly Charge plus the Demand Charge applicable in the preceding 11 months.

SaskPower

Rate Proposal

GENERAL SERVICE - UNMETERED

RATE CODE	DESCRIPTION	BASIC ($/month)	Energy Block 1 Size (kW.h/month)	Energy Block 1 Rate (cents/kW.h)	Energy Balance Rate (cents/kW.h)	Demand Block 1 Size (kVA)	Demand Block 1 Rate ($/kVA)	Demand Balance Rate ($/kVA)	MINIMUM BILL BASIC		
E15 Existing	Unmetered - Miscellaneous	N/A	N/A	N/A	3.730	/100 Watts			17.42		
E15 Proposed		N/A	N/A	N/A	3.920	/100 Watts			18.31		
Difference					**5.1%**				**5.1%**		
E16 Existing	Unmetered - Power Supply Units	64.84	/Power Supply Unit						64.84		
E16 Proposed		68.15	/Power Supply Unit						68.15		
Difference		**5.1%**									
E17 Existing	Unmetered - Cable Television Rectifiers	N/A	N/A	N/A	1.360	/10 Watts			26.97		
E17 Proposed		N/A	N/A	N/A	1.429	/10 Watts			28.35		
Difference					**5.1%**				**5.1%**		
E18 Existing	Unmetered - X-rays	N/A	N/A	N/A	N/A	3.720	/kV.A installed capacity				
E18 Proposed		N/A	N/A	N/A	N/A	3.910	/kV.A installed capacity				
Difference						**5.1%**					

SaskPower
Rate Proposal
OILFIELD

RATE CODE	DESCRIPTION	BASIC ($/month)	Energy Block 1 Size (kW.h/month)	Energy Block 1 Rate (cents/kW.h)	Energy Balance Rate (cents/kW.h)	Demand Block 1 Size (kVA)	Demand Block 1 Rate ($/kVA)	Demand Balance Rate ($/kVA)	MINIMUM BILL * BASIC	MINIMUM BILL * DEMAND	NOTES
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E43 Existing	Standard Oilfield	54.55	N/A	N/A	6.712	N/A	N/A	11.882	54.55	11.882	/KV.A max demand
E43 Proposed		57.33	N/A	N/A	7.054	N/A	N/A	12.488	57.33	12.488	/KV.A max demand
Difference		**5.1%**			**5.1%**			**5.1%**	**5.1%**	**5.1%**	

* Minimum Bill = Basic Monthly Charge plus the Demand Charge applicable to 60% of the maximum billing demand in the preceding 11 months.

SaskPower
Rate Proposal
POWER - OILFIELD

RATE CODE	DESCRIPTION	BASIC ($/month)	Energy Block 1 Size (kW.h/month)	Energy Block 1 Rate (cents/kW.h)	Energy Balance Rate (cents/kW.h)	Demand Block 1 Size (kVA)	Demand Block 1 Rate ($/kVA)	Demand Balance Rate ($/kVA)	MINIMUM BILL * BASIC	MINIMUM BILL * DEMAND	NOTES
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E46 Existing	25kV - Customer Owned Transformation	5,491.00	N/A	N/A	6.124	N/A	N/A	9.676	5,491.00	9.676	/KV.A max demand
E46 Proposed		5,770.96	N/A	N/A	6.436	N/A	N/A	10.169	5,770.96	10.169	/KV.A max demand
Difference		**5.1%**			**5.1%**			**5.1%**	**5.1%**	**5.1%**	
E47 Existing	72kV - Customer Owned Transformation	6,294.00	N/A	N/A	5.525	N/A	N/A	7.458	6,294.00	7.458	/KV.A max demand
E47 Proposed		6,614.90	N/A	N/A	5.807	N/A	N/A	7.838	6,614.90	7.838	/KV.A max demand
Difference		**5.1%**			**5.1%**			**5.1%**	**5.1%**	**5.1%**	
E48 Existing	138kV - Customer Owned Transformation	6,757.00	N/A	N/A	5.421	N/A	N/A	7.350	6,757.00	7.350	/KV.A max demand
E48 Proposed		7,101.51	N/A	N/A	5.697	N/A	N/A	7.725	7,101.51	7.725	/KV.A max demand
Difference		**5.1%**			**5.1%**			**5.1%**	**5.1%**	**5.1%**	

* Minimum Bill = Basic Monthly Charge plus the Demand Charge applicable to 75% of the maximum billing demand in the preceding 11 months.

SaskPower

Rate Proposal

POWER - OILFIELD TIME OF USE

RATE CODE	DESCRIPTION	BASIC ($/month)	Energy Block 1 Size (kW.h/month)	On-Peak Energy Rate (cents/kW.h)	Off-Peak Energy Rate (cents/kW.h)	Demand Block 1 Size (kVA)	Demand Block 1 Rate ($/kVA)	Demand Balance Rate ($/kVA)	MINIMUM BILL * BASIC	DEMAND	NOTES
E86 Existing	25kV - Customer Owned Transformation	5,491.00	N/A	6.697	5.697	N/A	N/A	9.676	5,491.00	9.676	/KV.A max demand
E86 Proposed		5,770.96	N/A	7.009	6.009	N/A	N/A	10.169	5,770.96	10.169	/KV.A max demand
		5.1%		**4.7%***	**5.5%***			**5.1%**	**5.1%**	**5.1%**	
E87 Existing	72kV - Customer Owned Transformation	6,294.00	N/A	6.098	5.098	N/A	N/A	7.458	6,294.00	7.458	/KV.A max demand
E87 Proposed		6,614.90	N/A	6.380	5.380	N/A	N/A	7.838	6,614.90	7.838	/KV.A max demand
		5.1%		**4.6%***	**5.5%***			**5.1%**	**5.1%**	**5.1%**	
E88 Existing	138kV - Customer Owned Transformation	6,757.00	N/A	5.994	4.994	N/A	N/A	7.350	6,757.00	7.350	/KV.A max demand
E88 Proposed		7,101.51	N/A	6.270	5.270	N/A	N/A	7.725	7,101.51	7.725	/KV.A max demand
		5.1%		**4.6%***	**5.5%***			**5.1%**	**5.1%**	**5.1%**	

* Minimum Bill = Basic Monthly Charge plus the Demand Charge applicable to 75% of the maximum billing demand in the preceding 11 months.

SaskPower

Rate Proposal

POWER - STANDARD

RATE CODE	DESCRIPTION	BASIC ($/month)	Energy Block 1 Size (kW.h/month)	Energy Block 1 Rate (cents/kW.h)	Energy Balance Rate (cents/kW.h)	Demand Block 1 Size (kVA)	Demand Block 1 Rate ($/kVA)	Demand Balance Rate ($/kVA)	MINIMUM BILL * BASIC	DEMAND	NOTES
E22 Existing	25kV - Customer Owned Transformation	5,491.00	N/A	N/A	6.124	N/A	N/A	9.676	5,491.00	9.676	/KV.A max demand
E22 Proposed		5,770.96	N/A	N/A	6.436	N/A	N/A	10.169	5,770.96	10.169	/KV.A max demand
Difference		**5.1%**			**5.1%**			**5.1%**	**5.1%**	**5.1%**	
E23 Existing	72kV - Customer Owned Transformation	6,294.00	N/A	N/A	5.525	N/A	N/A	7.458	6,294.00	7.458	/KV.A max demand
E23 Proposed		6,614.90	N/A	N/A	5.807	N/A	N/A	7.838	6,614.90	7.838	/KV.A max demand
Difference		**5.1%**			**5.1%**			**5.1%**	**5.1%**	**5.1%**	
E24 Existing	138kV - Customer Owned Transformation	6,757.00	N/A	N/A	5.421	N/A	N/A	7.350	6,757.00	7.350	/KV.A max demand
E24 Proposed		7,101.51	N/A	N/A	5.697	N/A	N/A	7.725	7,101.51	7.725	/KV.A max demand
Difference		**5.1%**			**5.1%**			**5.1%**	**5.1%**	**5.1%**	
E25 Existing	230kV - Customer Owned Transformation	7,081.00	N/A	N/A	5.421	N/A	N/A	7.350	7,081.00	7.350	/KV.A max demand
E25 Proposed		7,442.02	N/A	N/A	5.697	N/A	N/A	7.725	7,442.02	7.725	/KV.A max demand
Difference		**5.1%**			**5.1%**			**5.1%**	**5.1%**	**5.1%**	

* Minimum Bill = Basic Monthly Charge plus the Demand Charge applicable to 75% of the maximum billing demand in the preceding 11 months.

SaskPower
Rate Proposal
POWER - TIME OF USE

RATE CODE	DESCRIPTION	BASIC ($/month)	Energy Block 1 Size (kW.h/month)	On-Peak Energy Rate (cents/kW.h)	Off-Peak Energy Rate (cents/kW.h)	Demand Block 1 Size (kVA)	Demand Block 1 Rate ($/kVA)	Demand Balance Rate ($/kVA)	MINIMUM BILL * BASIC	DEMAND	NOTES
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E82 Existing	25kV - Customer Owned Transformation	5,491.00	N/A	6.697	5.697	N/A	N/A	9.676	5,491.00	9.676	/KV.A max demand
E82 Proposed		5,770.96	N/A	7.009	6.009	N/A	N/A	10.169	5,770.96	10.169	/KV.A max demand
Difference		**5.1%**		**4.7%***	**5.5%***			**5.1%**	**5.1%**	**5.1%**	
E83 Existing	72kV - Customer Owned Transformation	6,294.00	N/A	6.098	5.098	N/A	N/A	7.458	6,294.00	7.458	/KV.A max demand
E83 Proposed		6,614.90	N/A	6.380	5.380	N/A	N/A	7.838	6,614.90	7.838	/KV.A max demand
Difference		**5.1%**		**4.6%**	**5.5%**			**5.1%**	**5.1%**	**5.1%**	
E84 Existing	138kV - Customer Owned Transformation	6,757.00	N/A	5.994	4.994	N/A	N/A	7.350	6,757.00	7.350	/KV.A max demand
E84 Proposed		7,101.51	N/A	6.270	5.270	N/A	N/A	7.725	7,101.51	7.725	/KV.A max demand
Difference		**5.1%**		**4.6%***	**5.5%***			**5.1%**	**5.1%**	**5.1%**	
E85 Existing	230kV - Customer Owned Transformation	7,081.00	N/A	5.994	4.994	N/A	N/A	7.350	7,081.00	7.350	/KV.A max demand
E85 Proposed		7,442.02	N/A	6.270	5.270	N/A	N/A	7.725	7,442.02	7.725	/KV.A max demand
Difference		**5.1%**		**4.6%***	**5.5%***			**5.1%**	**5.1%**	**5.1%**	

* Minimum Bill = Basic Monthly Charge plus the Demand Charge applicable to 75% of the maximum billing demand in the preceding 11 months.

SaskPower
Rate Proposal
RESELLER

RATE CODE	DESCRIPTION	BASIC ($/month)	Energy Block 1 Size (kW.h/month)	Energy Block 1 Rate (cents/kW.h)	Energy Balance Rate (cents/kW.h)	Demand Block 1 Size (kVA)	Demand Block 1 Rate ($/kVA)	Demand Balance Rate ($/kVA)	MINIMUM BILL * BASIC	DEMAND	NOTES
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E31 Existing	Swift Current 25 kV (Non-Totalized)	5,444.00	N/A	N/A	4.490	N/A	N/A	16.606	5,444.00	16.606	/KV.A max demand
E31 Proposed		5,721.56	N/A	N/A	4.719	N/A	N/A	17.453	5,721.56	17.453	/KV.A max demand
Difference		**5.1%**			**5.1%**			**5.1%**	**5.1%**	**5.1%**	
E32 Existing	Swift Current 138 kV - (Non-Totalized)	6,241.00	N/A	N/A	4.349	N/A	N/A	14.842	6,241.00	14.842	/KV.A max demand
E32 Proposed		6,559.20	N/A	N/A	4.571	N/A	N/A	15.599	6,559.20	15.599	/KV.A max demand
Difference		**5.1%**			**5.1%**			**5.1%**	**5.1%**	**5.1%**	
E33 Existing	Saskatoon 138kV - (Totalized)	12,987.00	N/A	N/A	4.051	N/A	N/A	17.192	12,987.00	17.192	/KV.A max demand
E33 Proposed		13,649.14	N/A	N/A	4.258	N/A	N/A	18.069	13,649.14	18.069	/KV.A max demand
Difference		**5.1%**			**5.1%**			**5.1%**	**5.1%**	**5.1%**	

* Minimum Bill = Basic Monthly Charge plus the Demand Charge applicable to 60% of the maximum billing demand in the preceding 11 months.

SaskPower
Rate Proposal
STREETLIGHTS

RATE CODE	DESCRIPTION	Existing Monthly ($/month)	Proposed Monthly ($/month)	**Difference**
S05	Mercury Vapor - 125 W	$13.73	$14.43	**5.1%**
S06	Mercury Vapor - 175 W	$15.16	$15.93	**5.1%**
S13	Low Pressure Sodium Vapor - 90 W	$13.01	$13.67	**5.1%**
S14	Low Pressure Sodium Vapor - 90 W Continuous	$15.20	$15.97	**5.1%**
S15	Low Pressure Sodium Vapor - 135 W	$13.97	$14.68	**5.1%**
S16	Low Pressure Sodium Vapor - 180 W	$15.46	$16.25	**5.1%**
S17	High Pressure Sodium Vapor - 70 W	$10.92	$11.48	**5.1%**
S18	High Pressure Sodium Vapor - 100 W	$12.19	$12.81	**5.1%**
S19	High Pressure Sodium Vapor - 150 W	$14.18	$14.90	**5.1%**
S20	High Pressure Sodium Vapor - 150 W Continuous	$17.52	$18.41	**5.1%**
S21	High Pressure Sodium Vapor - 250 W	$18.44	$19.38	**5.1%**
S22	High Pressure Sodium Vapor - 250 W Continuous	$23.56	$24.76	**5.1%**
S23	High Pressure Sodium Vapor - 400 W	$23.91	$25.13	**5.1%**
S24	Metal Halide - 100 W	$15.01	$15.78	**5.1%**
S25	Metal Halide - 175 W	$17.87	$18.78	**5.1%**
S26	Metal Halide - 250 W	$21.00	$22.07	**5.1%**
S30	Induction - 165 W	$14.71	$15.46	**5.1%**
S31	LED - 70 W	$10.45	$10.98	**5.1%**

Load and Revenue Forecasting
Customer Services

R:\CUSTSERV\PFLR\EXCEL\RATES\2016 Rates\[2016 Summary.xls]No Ideal

SaskPower

Rate Proposal

RESIDENTIAL

RATE CODE	DESCRIPTION	BASIC ($/month)	Energy Block 1 Size (kW.h/month)	Energy Block 1 Rate (cents/kW.h)	Energy Balance Rate (cents/kW.h)	Demand Block 1 Size (kVA)	Demand Block 1 Rate ($/kVA)	Demand Balance Rate ($/kVA)	MINIMUM BILL BASIC		
E01 Existing	City	21.25	N/A	N/A	13.267	N/A	N/A	N/A	21.25		
E01 Proposed		22.33	N/A	N/A	13.943	N/A	N/A	N/A	22.33		
Difference		**5.1%**			**5.1%**				**5.1%**		
E02 Existing	Town, Village, Urban Resort	21.25	N/A	N/A	13.267	N/A	N/A	N/A	21.25		
E02 Proposed		22.33	N/A	N/A	13.943	N/A	N/A	N/A	22.33		
Difference		**5.1%**			**5.1%**				**5.1%**		
E03 Existing	Rural, Rural Resort	30.68	N/A	N/A	13.268	N/A	N/A	N/A	30.68		
E03 Proposed		32.24	N/A	N/A	13.944	N/A	N/A	N/A	32.24		
Difference		**5.1%**			**5.1%**				**5.1%**		

SaskPower

Rate Proposal

DIESEL

RATE CODE	DESCRIPTION	BASIC ($/month)	Energy Block 1 Size (kW.h/month)	Energy Block 1 Rate (cents/kW.h)	Energy Balance Rate (cents/kW.h)	Demand Block 1 Size (kVA)	Demand Block 1 Rate ($/kVA)	Demand Balance Rate ($/kVA)	MINIMUM BILL BASIC		
E04 Existing	Residential Diesel	30.68	650	13.268	48.986	N/A	N/A	N/A	30.68		
E04 Proposed		32.24	650	13.944	51.481	N/A	N/A	N/A	32.24		
Difference		**5.1%**		**5.1%**	**5.1%**				**5.1%**		
E35 Existing	General Service	38.69	650	13.426	46.243	N/A	N/A	N/A	38.69		
E35 Proposed		40.66	650	14.110	48.599	N/A	N/A	N/A	40.66		
Difference		**5.1%**		**5.1%**	**5.1%**				**5.1%**		
E36 Existing	General Service - Federal & Provincial	38.69	N/A	N/A	93.674	N/A	N/A	N/A	38.69		
E36 Proposed		40.66	N/A	N/A	98.446	N/A	N/A	N/A	40.66		
Difference		**5.1%**			**5.1%**				**5.1%**		
E38 Existing	General Service - Local Community	38.69	N/A	N/A	85.130	N/A	N/A	N/A	38.69		
E38 Proposed		40.66	N/A	N/A	89.467	N/A	N/A	N/A	40.66		
Difference		**5.1%**			**5.1%**				**5.1%**		

SaskPower
Rate Proposal
FARM

RATE CODE	DESCRIPTION	BASIC ($/month)	Energy Block 1 Size (kW.h/month)	Energy Block 1 Rate (cents/kW.h)	Energy Balance Rate (cents/kW.h)	Demand Block 1 Size (kVA)	Demand Block 1 Rate ($/kVA)	Demand Balance Rate ($/kVA)	MINIMUM BILL * BASIC	DEMAND	NOTES
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E34 Existing	Farm	32.61	16,000	11.803	5.118	50	0	11.981	32.61	4.540	/KV.A max demand over 50
E34 Proposed		34.27	16,000	12.404	5.379	50	0	12.591	34.27	4.771	/KV.A max demand over 50
Difference		**5.1%**		**5.1%**	**5.1%**			**5.1%**	**5.1%**	**5.1%**	

* Minimum Bill = Basic Monthly Charge plus the Demand Charge applicable in the preceding 11 months.

SaskPower
Rate Proposal
IRRIGATION

RATE CODE	DESCRIPTION	BASIC ($/season)	Energy Block 1 Size (kW.h/month)	Energy Block 1 Rate (cents/kW.h)	Energy Balance Rate (cents/kW.h)	Demand Block 1 Size (kVA)	Demand Block 1 Rate ($/kVA)	Demand Balance Rate ($/hp)	MINIMUM BILL BASIC	DEMAND	NOTES
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E19 Existing	Farm - SaskPower Supplied Transformation	447.85	N/A	N/A	6.600	N/A	N/A	N/A	447.85		
E19 Proposed		470.66	N/A	N/A	6.936	N/A	N/A	N/A	470.66		
Difference		**5.1%**			**5.1%**				**5.1%**		
E37 Existing	General Service - SaskPower Supplied Transformation	236.83	N/A	N/A	8.986	N/A	N/A	23.826	236.83	23.826	/KV.A max demand
E37 Proposed		248.89	N/A	N/A	9.444	N/A	N/A	25.040	248.89	25.04	/KV.A max demand
Difference		**5.1%**			**5.1%**			**5.1%**	**5.1%**	**5.1%**	
E41 Existing	Mains - Interruptible - closed to new customers	844.42	N/A	N/A	5.654	N/A	N/A	N/A	844.42		
E41 Proposed		887.43	N/A	N/A	5.942	N/A	N/A	N/A	887.43		
Difference		**5.1%**			**5.1%**				**5.1%**		

E41 basic charge is a monthly charge applied in every month a customer in this rate code consumes energy. (Not a seasonal charge)

SaskPower
Rate Proposal
GENERAL SERVICE - STANDARD

RATE CODE	DESCRIPTION	BASIC ($/month)	Energy Block 1 Size (kW.h/month)	Energy Block 1 Rate (cents/kW.h)	Energy Balance Rate (cents/kW.h)	Demand Block 1 Size (kVA)	Demand Block 1 Rate ($/kVA)	Demand Balance Rate ($/kVA)	MINIMUM BILL * BASIC	MINIMUM BILL * DEMAND	NOTES
E05 Existing	Urban - SaskPower Supplied Transformation	54.02	16,750	11.177	7.156	50	0	14.546	54.02	4.540	/KV.A max demand over 50
E05 Proposed		56.77	16,750	11.746	7.521	50	0	15.287	56.77	4.771	/KV.A max demand over 50
Difference		**5.1%**		**5.1%**	**5.1%**			**5.1%**	**5.1%**	**5.1%**	
E06 Existing	Rural - SaskPower Supplied Transformation	60.64	15,500	11.177	6.779	50	0	14.546	60.64	4.540	/KV.A max demand over 50
E06 Proposed		63.73	15,500	11.746	7.124	50	0	15.287	63.73	4.771	/KV.A max demand over 50
Difference		**5.1%**		**5.1%**	**5.1%**			**5.1%**	**5.1%**	**5.1%**	
E07 Existing	Urban - Customer Owned Transformation	225.98	N/A	N/A	6.763	N/A	N/A	13.011	225.98	4.540	/KV.A max demand
E07 Proposed		237.49	N/A	N/A	7.108	N/A	N/A	13.674	237.49	4.771	/KV.A max demand
Difference		**5.1%**			**5.1%**			**5.1%**	**5.1%**	**5.1%**	
E08 Existing	Rural - Customer Owned Transformation	278.93	N/A	N/A	6.763	N/A	N/A	13.011	278.93	4.540	/KV.A max demand
E08 Proposed		293.14	N/A	N/A	7.108	N/A	N/A	13.674	293.14	4.771	/KV.A max demand
Difference		**5.1%**			**5.1%**			**5.1%**	**5.1%**	**5.1%**	
E10 Existing	Customer Owned Transformation	664.86	N/A	N/A	5.316	N/A	N/A	7.945	664.86	4.540	/KV.A max demand
E10 Proposed		698.73	N/A	N/A	5.587	N/A	N/A	8.350	698.73	4.771	/KV.A max demand
Difference		**5.1%**			**5.1%**			**5.1%**	**5.1%**	**5.1%**	
E12 Existing	Customer Owned Transformation	305.84	N/A	N/A	5.220	N/A	N/A	7.830	305.84	4.540	/KV.A max demand
E12 Proposed		321.42	N/A	N/A	5.486	N/A	N/A	8.229	321.42	4.771	/KV.A max demand
Difference		**5.1%**			**5.1%**			**5.1%**	**5.1%**	**5.1%**	

* Minimum Bill = Basic Monthly Charge plus the Demand Charge applicable in the preceding 11 months.

SaskPower
Rate Proposal
GENERAL SERVICE - SMALL

RATE CODE	DESCRIPTION	BASIC ($/month)	Energy Block 1 Size (kW.h/month)	Energy Block 1 Rate (cents/kW.h)	Energy Balance Rate (cents/kW.h)	Demand Block 1 Size (kVA)	Demand Block 1 Rate ($/kVA)	Demand Balance Rate ($/kVA)	MINIMUM BILL * BASIC	MINIMUM BILL * DEMAND	NOTES
E75 Existing	Urban - SaskPower Supplied Transformation	29.03	14,500	12.746	6.731	50	0	14.125	29.03	4.540	/KV.A max demand over 50
E75 Proposed		30.51	14,500	13.395	7.074	50	0	14.845	30.51	4.771	/KV.A max demand over 50
Difference		**5.1%**		**5.1%**	**5.1%**			**5.1%**	**5.1%**	**5.1%**	
E76 Existing	Rural - SaskPower SuppliedTransformation	38.69	13,000	13.426	6.906	50	0	14.430	38.69	4.540	/KV.A max demand over 50
E76 Proposed		40.66	13,000	14.110	7.258	50	0	15.165	40.66	4.771	/KV.A max demand over 50
Difference		**5.1%**		**5.1%**	**5.1%**			**5.1%**	**5.1%**	**5.1%**	
E77 Existing	Urban - Customer Owned Transformation	29.03	14,500	12.746	6.731	50	0	13.631	29.03	4.540	/KV.A max demand over 50
E77 Proposed		30.51	14,500	13.395	7.074	50	0	14.325	30.51	4.771	/KV.A max demand over 50
Difference		**5.1%**		**5.1%**	**5.1%**			**5.1%**	**5.1%**	**5.1%**	
E78 Existing	Rural - Customer Owned Transformation	38.69	13,000	13.426	6.906	50	0	13.915	38.69	4.540	/KV.A max demand over 50
E78 Proposed		40.66	13,000	14.110	7.258	50	0	14.624	40.66	4.771	/KV.A max demand over 50
Difference		**5.1%**		**5.1%**	**5.1%**			**5.1%**	**5.1%**	**5.1%**	

* Minimum Bill = Basic Monthly Charge plus the Demand Charge applicable in the preceding 11 months.

SaskPower
Rate Proposal
GENERAL SERVICE - UNMETERED

RATE CODE	DESCRIPTION	BASIC ($/month)	Energy Block 1 Size (kW.h/month)	Energy Block 1 Rate (cents/kW.h)	Energy Balance Rate (cents/kW.h)	Demand Block 1 Size (kVA)	Demand Block 1 Rate ($/kVA)	Demand Balance Rate ($/kVA)	MINIMUM BILL BASIC		
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E15 Existing	Unmetered - Miscellaneous	N/A	N/A	N/A	3.920	/100 Watts			18.31		
E15 Proposed		N/A	N/A	N/A	4.120	/100 Watts			19.24		
Difference					**5.1%**				**5.1%**		
E16 Existing	Unmetered - Power Supply Units	68.15	/Power Supply Unit						68.15		
E16 Proposed		71.62	/Power Supply Unit						71.62		
Difference		**5.1%**									
E17 Existing	Unmetered - Cable Television Rectifiers	N/A	N/A	N/A	1.429	/10 Watts			28.35		
E17 Proposed		N/A	N/A	N/A	1.502	/10 Watts			29.79		
Difference					**5.1%**				**5.1%**		
E18 Existing	Unmetered - X-rays	N/A	N/A	N/A	N/A	3.910	/kV.A installed capacity				
E18 Proposed		N/A	N/A	N/A	N/A	4.109	/kV.A installed capacity				
Difference						**5.1%**					

SaskPower
Rate Proposal
OILFIELD

RATE CODE	DESCRIPTION	BASIC ($/month)	Energy Block 1 Size (kW.h/month)	Energy Block 1 Rate (cents/kW.h)	Energy Balance Rate (cents/kW.h)	Demand Block 1 Size (kVA)	Demand Block 1 Rate ($/kVA)	Demand Balance Rate ($/kVA)	MINIMUM BILL * BASIC	DEMAND	NOTES
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E43 Existing	Standard Oilfield	57.33	N/A	N/A	7.054	N/A	N/A	12.488	57.33	12.488	/KV.A max demand
E43 Proposed		60.25	N/A	N/A	7.413	N/A	N/A	13.124	60.25	13.124	/KV.A max demand
Difference		**5.1%**			**5.1%**			**5.1%**	**5.1%**	**5.1%**	

* Minimum Bill = Basic Monthly Charge plus the Demand Charge applicable to 60% of the maximum billing demand in the preceding 11 months.

SaskPower
Rate Proposal
POWER - OILFIELD

RATE CODE	DESCRIPTION	BASIC ($/month)	Energy Block 1 Size (kW.h/month)	Energy Block 1 Rate (cents/kW.h)	Energy Balance Rate (cents/kW.h)	Demand Block 1 Size (kVA)	Demand Block 1 Rate ($/kVA)	Demand Balance Rate ($/kVA)	MINIMUM BILL * BASIC	DEMAND	NOTES
E46 Existing	25kV - Customer Owned Transformation	5,770.96	N/A	N/A	6.436	N/A	N/A	10.169	5,770.96	10.169	/KV.A max demand
E46 Proposed		6,064.93	N/A	N/A	6.764	N/A	N/A	10.687	6,064.93	10.687	/KV.A max demand
Difference		**5.1%**			**5.1%**			**5.1%**	**5.1%**	**5.1%**	
E47 Existing	72kV - Customer Owned Transformation	6,614.90	N/A	N/A	5.807	N/A	N/A	7.838	6,614.90	7.838	/KV.A max demand
E47 Proposed		6,951.86	N/A	N/A	6.103	N/A	N/A	8.237	6,951.86	8.237	/KV.A max demand
Difference		**5.1%**			**5.1%**			**5.1%**	**5.1%**	**5.1%**	
E48 Existing	138kV - Customer Owned Transformation	7,101.51	N/A	N/A	5.697	N/A	N/A	7.725	7,101.51	7.725	/KV.A max demand
E48 Proposed		7,463.26	N/A	N/A	5.987	N/A	N/A	8.119	7,463.26	8.119	/KV.A max demand
Difference		**5.1%**			**5.1%**			**5.1%**	**5.1%**	**5.1%**	

* Minimum Bill = Basic Monthly Charge plus the Demand Charge applicable to 75% of the maximum billing demand in the preceding 11 months.

SaskPower
Rate Proposal
POWER - OILFIELD TIME OF USE

RATE CODE	DESCRIPTION	BASIC ($/month)	Energy Block 1 Size (kW.h/month)	On-Peak Energy Rate (cents/kW.h)	Off-Peak Energy Rate (cents/kW.h)	Demand Block 1 Size (kVA)	Demand Block 1 Rate ($/kVA)	Demand Balance Rate ($/kVA)	MINIMUM BILL * BASIC	DEMAND	NOTES
E86 Existing	25kV - Customer Owned Transformation	5,770.96	N/A	7.009	6.009	N/A	N/A	10.169	5,770.96	10.169	/KV.A max demand
E86 Proposed		6,064.93	N/A	7.337	6.337	N/A	N/A	10.687	6,064.93	10.687	/KV.A max demand
		5.1%		**4.7%***	**5.5%***			**5.1%**	**5.1%**	**5.1%**	
E87 Existing	72kV - Customer Owned Transformation	6,614.90	N/A	6.380	5.380	N/A	N/A	7.838	6,614.90	7.838	/KV.A max demand
E87 Proposed		6,951.86	N/A	6.676	5.676	N/A	N/A	8.237	6,951.86	8.237	/KV.A max demand
		5.1%		**4.6%***	**5.5%***			**5.1%**	**5.1%**	**5.1%**	
E88 Existing	138kV - Customer Owned Transformation	7,101.51	N/A	6.270	5.270	N/A	N/A	7.725	7,101.51	7.725	/KV.A max demand
E88 Proposed		7,463.26	N/A	6.560	5.560	N/A	N/A	8.119	7,463.26	8.119	/KV.A max demand
		5.1%		**4.6%***	**5.5%***			**5.1%**	**5.1%**	**5.1%**	

* Minimum Bill = Basic Monthly Charge plus the Demand Charge applicable to 75% of the maximum billing demand in the preceding 11 months.

SaskPower

Rate Proposal

POWER - STANDARD

RATE CODE	DESCRIPTION	BASIC ($/month)	Energy Block 1 Size (kW.h/month)	Energy Block 1 Rate (cents/kW.h)	Energy Balance Rate (cents/kW.h)	Demand Block 1 Size (kVA)	Demand Block 1 Rate ($/kVA)	Demand Balance Rate ($/kVA)	MINIMUM BILL * BASIC	MINIMUM BILL * DEMAND	NOTES
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E22 Existing	25kV - Customer Owned Transformation	5,770.96	N/A	N/A	6.436	N/A	N/A	10.169	5,770.96	10.169	/KV.A max demand
E22 Proposed		6,064.93	N/A	N/A	6.764	N/A	N/A	10.687	6,064.93	10.687	/KV.A max demand
Difference		**5.1%**			**5.1%**			**5.1%**	**5.1%**	**5.1%**	
E23 Existing	72kV - Customer Owned Transformation	6,614.90	N/A	N/A	5.807	N/A	N/A	7.838	6,614.90	7.838	/KV.A max demand
E23 Proposed		6,951.86	N/A	N/A	6.103	N/A	N/A	8.237	6,951.86	8.237	/KV.A max demand
Difference		**5.1%**			**5.1%**			**5.1%**	**5.1%**	**5.1%**	
E24 Existing	138kV - Customer Owned Transformation	7,101.51	N/A	N/A	5.697	N/A	N/A	7.725	7,101.51	7.725	/KV.A max demand
E24 Proposed		7,463.26	N/A	N/A	5.987	N/A	N/A	8.119	7,463.26	8.119	/KV.A max demand
Difference		**5.1%**			**5.1%**			**5.1%**	**5.1%**	**5.1%**	
E25 Existing	230kV - Customer Owned Transformation	7,442.02	N/A	N/A	5.697	N/A	N/A	7.725	7,442.02	7.725	/KV.A max demand
E25 Proposed		7,821.12	N/A	N/A	5.987	N/A	N/A	8.119	7,821.12	8.119	/KV.A max demand
Difference		**5.1%**			**5.1%**			**5.1%**	**5.1%**	**5.1%**	

* Minimum Bill = Basic Monthly Charge plus the Demand Charge applicable to 75% of the maximum billing demand in the preceding 11 months.

SaskPower

Rate Proposal

POWER - TIME OF USE

RATE CODE	DESCRIPTION	BASIC ($/month)	Energy Block 1 Size (kW.h/month)	On-Peak Energy Rate (cents/kW.h)	Off-Peak Energy Rate (cents/kW.h)	Demand Block 1 Size (kVA)	Demand Block 1 Rate ($/kVA)	Demand Balance Rate ($/kVA)	MINIMUM BILL * BASIC	MINIMUM BILL * DEMAND	NOTES
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E82 Existing	25kV - Customer Owned Transformation	5,770.96	N/A	7.009	6.009	N/A	N/A	10.169	5,770.96	10.169	/KV.A max demand
E82 Proposed		6,064.93	N/A	7.337	6.337	N/A	N/A	10.687	6,064.93	10.687	/KV.A max demand
Difference		**5.1%**		**4.7%***	**5.5%***			**5.1%**	**5.1%**	**5.1%**	
E83 Existing	72kV - Customer Owned Transformation	6,614.90	N/A	6.380	5.380	N/A	N/A	7.838	6,614.90	7.838	/KV.A max demand
E83 Proposed		6,951.86	N/A	6.676	5.676	N/A	N/A	8.237	6,951.86	8.237	/KV.A max demand
Difference		**5.1%**		**4.6%**	**5.5%**			**5.1%**	**5.1%**	**5.1%**	
E84 Existing	138kV - Customer Owned Transformation	7,101.51	N/A	6.270	5.270	N/A	N/A	7.725	7,101.51	7.725	/KV.A max demand
E84 Proposed		7,463.26	N/A	6.560	5.560	N/A	N/A	8.119	7,463.26	8.119	/KV.A max demand
Difference		**5.1%**		**4.6%***	**5.5%***			**5.1%**	**5.1%**	**5.1%**	
E85 Existing	230kV - Customer Owned Transformation	7,442.02	N/A	6.270	5.270	N/A	N/A	7.725	7,442.02	7.725	/KV.A max demand
E85 Proposed		7,821.12	N/A	6.560	5.560	N/A	N/A	8.119	7,821.12	8.119	/KV.A max demand
Difference		**5.1%**		**4.6%***	**5.5%***			**5.1%**	**5.1%**	**5.1%**	

* Minimum Bill = Basic Monthly Charge plus the Demand Charge applicable to 75% of the maximum billing demand in the preceding 11 months.

SaskPower
Rate Proposal
RESELLER

RATE CODE	DESCRIPTION	BASIC ($/month)	Energy Block 1 Size (kW.h/month)	Energy Block 1 Rate (cents/kW.h)	Energy Balance Rate (cents/kW.h)	Demand Block 1 Size (kVA)	Demand Block 1 Rate ($/kVA)	Demand Balance Rate ($/kVA)	MINIMUM BILL * BASIC	MINIMUM BILL * DEMAND	NOTES
E31 Existing	Swift Current 25 kV (Non-Totalized)	5,721.56	N/A	N/A	4.719	N/A	N/A	17.453	5,721.56	17.453	/KV.A max demand
E31 Proposed		6,013.02	N/A	N/A	4.959	N/A	N/A	18.342	6,013.02	18.342	/KV.A max demand
Difference		**5.1%**			**5.1%**			**5.1%**	**5.1%**	**5.1%**	
E32 Existing	Swift Current 138 kV - (Non-Totalized)	6,559.20	N/A	N/A	4.571	N/A	N/A	15.599	6,559.20	15.599	/KV.A max demand
E32 Proposed		6,893.33	N/A	N/A	4.804	N/A	N/A	16.394	6,893.33	16.394	/KV.A max demand
Difference		**5.1%**			**5.1%**			**5.1%**	**5.1%**	**5.1%**	
E33 Existing	Saskatoon 138kV - (Totalized)	13,649.14	N/A	N/A	4.258	N/A	N/A	18.069	13,649.14	18.069	/KV.A max demand
E33 Proposed		14,344.43	N/A	N/A	4.475	N/A	N/A	18.989	14,344.43	18.989	/KV.A max demand
Difference		**5.1%**			**5.1%**			**5.1%**	**5.1%**	**5.1%**	

* Minimum Bill = Basic Monthly Charge plus the Demand Charge applicable to 60% of the maximum billing demand in the preceding 11 months.

SaskPower
Rate Proposal
STREETLIGHTS

RATE CODE	DESCRIPTION	Existing Monthly ($/month)	Proposed Monthly ($/month)	**Difference**
S05	Mercury Vapor - 125 W	$14.43	$15.17	**5.1%**
S06	Mercury Vapor - 175 W	$15.93	$16.74	**5.1%**
S13	Low Pressure Sodium Vapor - 90 W	$13.67	$14.37	**5.1%**
S14	Low Pressure Sodium Vapor - 90 W Continuous	$15.97	$16.78	**5.0%**
S15	Low Pressure Sodium Vapor - 135 W	$14.68	$15.43	**5.1%**
S16	Low Pressure Sodium Vapor - 180 W	$16.25	$17.08	**5.1%**
S17	High Pressure Sodium Vapor - 70 W	$11.48	$12.06	**5.1%**
S18	High Pressure Sodium Vapor - 100 W	$12.81	$13.46	**5.1%**
S19	High Pressure Sodium Vapor - 150 W	$14.90	$15.66	**5.1%**
S20	High Pressure Sodium Vapor - 150 W Continuous	$18.41	$19.35	**5.1%**
S21	High Pressure Sodium Vapor - 250 W	$19.38	$20.37	**5.1%**
S22	High Pressure Sodium Vapor - 250 W Continuous	$24.76	$26.02	**5.1%**
S23	High Pressure Sodium Vapor - 400 W	$25.13	$26.41	**5.1%**
S24	Metal Halide - 100 W	$15.78	$16.58	**5.1%**
S25	Metal Halide - 175 W	$18.78	$19.74	**5.1%**
S26	Metal Halide - 250 W	$22.07	$23.19	**5.1%**
S30	Induction - 165 W	$15.46	$16.25	**5.1%**
S31	LED - 70 W	$10.98	$11.54	**5.1%**

Load and Revenue Forecasting
Customer Services

R:\CUSTSERV\PFLR\EXCEL\RATES\2014 Rates\[2016 Summary with Ideals.xls]Rates

SRRP Q128:

Reference: **Proposed Rates**

Please elaborate on the statement on page 4 of the application that SaskPower is planning to execute a rate simplification plan in its next application. Please elaborate on which rate codes SaskPower anticipates will be combined and in what fiscal year SaskPower anticipates the changes will be made.

Response:

SaskPower currently administers 61 rate codes in its billing system. In an effort to reduce the number of rates, SaskPower had initially planned to implement the first phase of its rate simplification plan in the second part of this application (January 1, 2017). Since this application now applies an equal increase to all customer classes (except the Power-Contact class), no rebalancing maintenance can be performed to those classes affected by rate simplification. As such, phase one has been deferred until SaskPower's next application for a rate increase, a date which is currently unknown.

Phase one called for combining all rural rates with their corresponding urban rates as well as combining the 138 & 230 kV Power class rate. This would result in an overall net reduction of nine rate codes from SaskPower's billing system.

SaskPower plans to initiate its rate simplification plan during its next rate application, which is unknown at this time. The table below illustrates which rates are to be combined:

RATE SIMPLIFICATION (PHASE ONE)

Customer Class	Rates Codes Combined
Residential	E01, E02, E03, E04
Commercial	E05, E06
Commercial	E07, E08
Small Commercial	E75, E76, E77, E78
Power Class	E24, E25

SRRP Q129:

Reference: Proposed Rates

a) Please provide the average percentage increase effective January 1, 2017, that would be required for the streetlights class to achieve a revenue to revenue requirement ratio of 0.98.
b) Please provide the revenue to revenue requirement ratio for the commercial group of customers if the additional revenues generated in part a) were used to lower the average rate increases for commercial customers in a manner that would facilitate the future consolidation of those customer classes.

Response:

a) The average percentage increase required for the streetlight class to achieve a R/RR of 0.98 effective January 1, 2017, would be 7.3%, which would create a revenue increase of $370,216.

b) The R/RR for the commercial class drops to1.02 from 1.03 after incorporating the streetlight revenue lift. As a result, the rate increase for the commercial class drops from 5.094% to 5.015%, effective January 1, 2017.

SRRP Q130:

Reference: **Competitiveness**

Please identify which other jurisdictions are included in the 'thermal utility average' figures provided in the chart on page 16 of the application.

Response:

The thermal rate comparison is from Hydro Quebec's *Comparison of Electricity Prices in Major North American Cities*, which is available on the Hydro Quebec website. The thermal jurisdictions involved in the comparison are:

- Calgary, Alberta
- Edmonton, Alberta
- Toronto, Ontario
- Ottawa, Ontario
- Moncton, New Brunswick
- Halifax, Nova Scotia
- Charlottetown, PEI
- St. John's, Newfoundland

SRRP Q131:

Reference: **Competitiveness**

Please provide a copy of the customer satisfaction survey referenced on page 18 of the application.

Response:

Copies of the survey and results were shared with the Saskatchewan Rate Review Panel and their consultants. However, the survey instrument and the survey results are owned by the Canadian Electricity Association and cannot be released publicly.

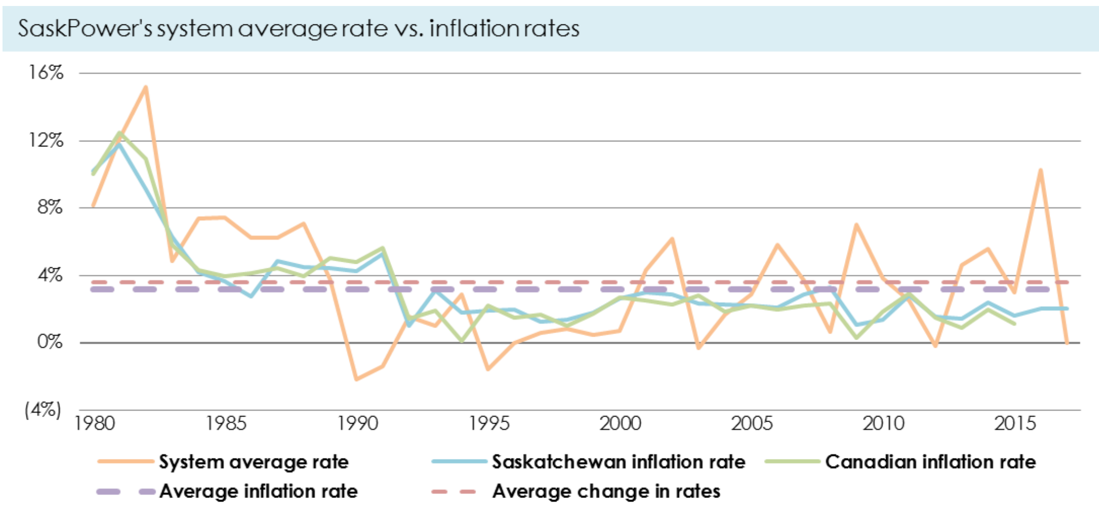
SRRP Q132:

Reference: **Competitiveness**

Please expand the rates versus inflation figure at the top of page 19 of the application to include SaskPower's proposed rate increases for 2016-17 and the inflation rates assumed in SaskPower's most recent Business Plan.

Response:

SaskPower's system average rates have increased by 3.6% annually, compared to an inflation rate that averaged 3.2%.



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SRRP Q133:

Reference: Competitiveness

Please provide the electricity spending and total household spending figures used to calculate the percentages in the figure on page 19 of the application.

Response:

Data is from Statistics Canada's website. The following table is the supporting data for the electricity spending as a percentage of household expenditures.

Table 203-0021 Survey of household spending (SHS), household spending, Canada, regions and provinces, annual (dollars)(3,4,6,7)
Survey or program details:
Survey of Household Spending - 3508

Geography	Statistic	Household expenditures, summary-level categories	2010	2011	2012	2013	2014
Canada	Average expenditure per household	Total expenditure	72,075	73,646	75,695	79,098	80,728
Canada	Average expenditure per household	Electricity for principal accommodation	1,202	1,257	1,281	1,314	1,405
Newfoundland and Labrador	Average expenditure per household	Total expenditure	62,430	66,377	70,193	75,489	77,339
Newfoundland and Labrador	Average expenditure per household	Electricity for principal accommodation	1,964	1,942	2,079	2,134	2,352
Prince Edward Island	Average expenditure per household	Total expenditure	59,534	61,328	67,346	63,348	68,358
Prince Edward Island	Average expenditure per household	Electricity for principal accommodation	1,343	1,309	1,315	1,427	1,636
Nova Scotia	Average expenditure per household	Total expenditure	61,939	67,037	68,111	68,795	70,501
Nova Scotia	Average expenditure per household	Electricity for principal accommodation	1,305	1,365	1,535	1,590	1,589
New Brunswick	Average expenditure per household	Total expenditure	60,942	62,342	64,453	65,023	68,650
New Brunswick	Average expenditure per household	Electricity for principal accommodation	2,021	2,037	2,015	2,129	2,239
Quebec	Average expenditure per household	Total expenditure	62,257	64,625	64,681	68,397	69,215
Quebec	Average expenditure per household	Electricity for principal accommodation	1,318	1,309	1,395	1,444	1,588
Ontario	Average expenditure per household	Total expenditure	75,556	77,125	78,846	82,479	84,406
Ontario	Average expenditure per household	Electricity for principal accommodation	1,156	1,252	1,184	1,228	1,336
Manitoba	Average expenditure per household	Total expenditure	67,908	68,200	71,492	73,657	76,434
Manitoba	Average expenditure per household	Electricity for principal accommodation	1,122	1,145	1,101	1,231	1,388
Saskatchewan	Average expenditure per household	Total expenditure	70,444	71,310	75,277	79,370	85,456
Saskatchewan	Average expenditure per household	Electricity for principal accommodation	1,304	1,263	1,245	1,338	1,420
Alberta	Average expenditure per household	Total expenditure	89,077	89,287	97,387	101,195	100,957
Alberta	Average expenditure per household	Electricity for principal accommodation	1,176	1,266	1,405	1,337	1,362
British Columbia	Average expenditure per household	Total expenditure	74,841	75,196	75,856	78,851	80,776
British Columbia	Average expenditure per household	Electricity for principal accommodation	864	948	1,013	1,006	989

Footnotes:

3 For more information about survey methodology, data quality, variable definitions and data products, see the Survey of Household Spending User Guide (catalogue number 62F0026MIE) available free on the Statistics Canada website: http://www5.statcan.gc.ca/bsolc/olc-cel/olc-cel?catno=62F0026M&chropg=1&lang=eng, Household expenditures research papers series.

4 For 2012, household expenditure data were also collected in the three territories. The data are available on CANSIM table 203-0030. However, caution should be used when comparing provincial and territorial data since the collection method was different in the territories.

6 The Survey of Household Spending uses survey weights which take into account population projections from the 2011 Census.

7 To ensure data quality, suppression of expenditure estimates is based on the coefficient of variation (CV). Expenditures that have a CV greater than or equal to 35% are suppressed as they are too unreliable to be published.

8 Starting in 2014, expenditure estimates for provincial health insurance premiums are included with income taxes. These estimates are calculated using information from personal income tax data (T1). Previously, provincial health insurance premiums were included with health care expenditures.

Source:
Statistics Canada. Table 203-0021 - Survey of household spending (SHS), household spending, Canada, regions and provinces, annual (dollars)
(accessed: April 19, 2016)

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The next table is the supporting data for the comparison of Saskatchewan household expenses.

Geography	Statistic	Household expenditures, summary-level categories	2014
Saskatchewan	Average expenditure per household	Total expenditure	85,456
Saskatchewan	Average expenditure per household	Total current consumption	62,287
Saskatchewan	Average expenditure per household	Food expenditures	8,708
Saskatchewan	Average expenditure per household	Shelter	16,238
Saskatchewan	Average expenditure per household	Water and sewage for principal accommodation	595
Saskatchewan	Average expenditure per household	Electricity for principal accommodation	1,420
Saskatchewan	Average expenditure per household	Natural gas for principal accommodation	809
Saskatchewan	Average expenditure per household	Other fuel for principal accommodation	122
Saskatchewan	Average expenditure per household	Household operations	4,604
Saskatchewan	Average expenditure per household	Telephone	1,694
Saskatchewan	Average expenditure per household	Cell phone and pager services	1,159
Saskatchewan	Average expenditure per household	Internet access services	447
Saskatchewan	Average expenditure per household	Household furnishings and equipment	2,112
Saskatchewan	Average expenditure per household	Clothing and accessories	3,331
Saskatchewan	Average expenditure per household	Transportation	14,126
Saskatchewan	Average expenditure per household	Health care	2,314
Saskatchewan	Average expenditure per household	Personal care	1,131
Saskatchewan	Average expenditure per household	Recreation	4,823
Saskatchewan	Average expenditure per household	Education	1,123
Saskatchewan	Average expenditure per household	Reading materials and other printed matter	164
Saskatchewan	Average expenditure per household	Tobacco products and alcoholic beverages	1,663
Saskatchewan	Average expenditure per household	Games of chance	183
Saskatchewan	Average expenditure per household	Miscellaneous expenditures	1,765
Saskatchewan	Average expenditure per household	Income taxes (8)	15,471
Saskatchewan	Average expenditure per household	Personal insurance payments and pension contributions	5,298
Saskatchewan	Average expenditure per household	Gifts of money, support payments and charitable contributions	2,400
Saskatchewan	Average expenditure per household	Charitable contributions	902

Footnotes:

3 For more information about survey methodology, data quality, variable definitions and data products, see the Survey of Household Spending User Guide (catalogue number 62F0026MIE) available free on the Statistics Canada website: http://www5.statcan.gc.ca/bsolc/olc-cel/olc-cel?catno=62F0026M&chropg=1&lang=eng, Household expenditures research papers series.

4 For 2012, household expenditure data were also collected in the three territories. The data are available on CANSIM table 203-0030. However, caution should be used when comparing provincial and territorial data since the collection method was different in the territories.

6 The Survey of Household Spending uses survey weights which take into account population projections from the 2011 Census.

7 To ensure data quality, suppression of expenditure estimates is based on the coefficient of variation (CV). Expenditures that have a CV greater than or equal to 35% are suppressed as they are too unreliable to be published.

8 Starting in 2014, expenditure estimates for provincial health insurance premiums are included with income taxes. These estimates are calculated using information from personal income tax data (T1). Previously, provincial health insurance premiums were included with health care expenditures.

Source:

Statistics Canada. Table 203-0021 - Survey of household spending (SHS), household spending, Canada, regions and provinces, annual (dollars)
(accessed: April 19, 2016)

SRRP Q134:

Reference: **System Operations**

Please describe SaskPower's dispatch policies or rules for use of the various fuel sources to meet capacity and energy requirements. Please highlight any changes to these dispatch policies or rules since the last rate application.

Response:

After meeting all transmission constraints, generation constraints, and reserve requirements, available units are dispatched in ascending order of incremental costs.

There have been no changes since the last rate application.

SRRP Q135:

Reference: **System Operations**

Please discuss how SaskPower anticipates its dispatch policies and rules will change as coal generation is phased out.

Response:

Dispatch policies will remain unchanged; the least incremental cost available unit will be dispatched on first and dispatched off last.

The implementation of a carbon tax or other penalty for CO_2 emissions could increase the incremental cost of coal and/or gas generation and potentially change their order on the stack.

SRRP Q136:

Reference: **Reliability**

Please provide a table summarizing transmission SAIDI; transmission SAIFI; distribution SAIDI and distribution SAIFI for the most recent five years of actuals available for each of:

i) SaskPower
ii) Canadian utility average

Please discuss any factors contributing to SaskPower's performance relative to the average of the other utilities such as reporting framework (e.g. including or excluding major events; different requirements for planned outages).

Response:

SaskPower (SPC) and Canadian Utility average (CAD) reliability statistics

	2015		2014		2013		2012		2011	
	SPC	CAD	SPC	CAD	SPC	CAD	SPC	CAD	SPC	CAD
Transmission SAIDI (minutes)	144	N/A	191	186	131	153	328	90	195	144
Transmission SAIFI (outages)	2.4	N/A	3.6	.89	1.89	.93	3.05	.98	2.17	.90
Distribution SAIDI (hours)	5.2	5.1	5.1	6.4	5.9	9.5	5.8	4.7	6.4	6.2
Distribution SAIFI (outages)	2.4	2.3	2.5	2.4	2.2	2.7	2.3	2.5	2.6	2.6

The transmission SAIDI and SAIFI results presented above only include forced (unplanned) outages. Approximately one third of SaskPower's total transmission outages are planned.

The electricity generated by SaskPower is used to serve relatively few customers over a substantial geographic region of approximately 652,000 square kilometres. With more than 156,000 circuit kilometres of power lines and more than 521,000 customer accounts, our company has one of the lowest customer densities relative to grid infrastructure in the country. This not only means that response times in rural areas are often longer due to repair location identification and travel time, but also that the funding of capacity increases and ongoing maintenance can be challenging due to a smaller revenue base relative to the size of the grid.

Saskatchewan's widely variable and often extreme climate causes considerable peaks in electricity demand during certain seasons and also has a fundamental effect on reliability. Provincial economic development and seasonal hot and cold temperatures contribute to increasing and fluctuating demand for generation while wind, lightning, flooding, snow and ice all contribute to outages. Weather is often joined by other factors — including equipment failure/aging infrastructure, trees/vegetation, birds, animals, operator error, and accidents — as the primary causes of interruptions.

Notably, there has been an increase in extreme weather events in recent years. This includes flooding, wildfires, ice and winds. These types of incidents are not only affecting reliability, but also the investment required to repair and harden our system. Succession planning is also a growing reliability-related issue. One third of SaskPower's entire workforce is expected to retire in the next decade, and when employees leave they will take with them a tremendous amount of experience that will be difficult to replace. Meanwhile, Saskatchewan's migration pattern from rural areas to larger urban centres involving both customers and SaskPower employees also affects reliability as it can create longer response times for outage repair.

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SRRP Q137:

Reference: **Reliability**

Please provide a schedule summarizing power outages in excess of 2 hours, indicating the cause of the outages, the type of outage (generation, transmission, distribution) and the length of time required to restore power for each of the years 2013, 2014 and 2015.

Response:

A list of transmission outages in excess of two hours from 2013 to 2015 is attached, which includes outage causes.

Due to the size of the document, a list of distribution outages in excess of two hours from 2013 to 2015 will be sent in a separate file electronically.

There were over 35,000 distribution outages in excess of two hours. The following table summarizes the reasons for all distribution outages (of any length of time) from 2013 to 2015.

Total annual outages by "reason" code

Reason	2013	2014	2015	3 year totals	
10 - Planned	4,375	5,049	5,601	15,025	20%
11 - Lightning	3,534	4,522	4,631	12,687	17%
16 - Birds / Animals	3,825	4,233	3,857	11,915	16%
00 - Unknown	3,295	3,594	3,647	10,536	14%
21 - Faulty Equipment	2,614	3,345	3,031	8,990	12%
14 - Trees	1,593	1,931	1,983	5,507	7%
13 - Other Weather	1,020	1,572	1,380	3,972	5%
18 - Accidents / External	1,202	1,021	921	3,144	4%
12 - Icing	422	576	393	1,391	2%
23 - Overload	399	545	434	1,378	2%
20 - System Failure	306	373	394	1,073	1%
22 - Contamination	264	310	287	861	1%
15 - Other Vegetation	31	70	59	160	0%
19 - Vandalism	27	51	42	120	0%
17 - Accidents / Internal (SPC)	27	44	28	99	0%
Total # of outages each year	22,934	27,236	26,688	76,858	

Generation outages rarely cause a customer outage.

2013 Transmission Line Outages in Excess of Two (2) Hours				
DD-MM-YY	Transmission Line	Customer or Delivery Point Impacted	Duration (hr:mm)	Reason for Outage
1/2/2013	P1H		16:57	Adverse weather (hoar frost)
1/2/2013		Enbridge1	2:37	Transmission customer is also out due hoar frost
1/2/2013		Enbridge3	2:37	Transmission customer is also out due hoar frost
1/8/2013	C1Q		54:04	Foreign Interference (Helicopter took out shield wire)
1/18/2013	A1R		6:21	Human Element (switching error)
1/29/2013	B5W-BD		7:48	Defective Equipment (broken shield wire)
1/29/2013		Estevan East1	6:32	Transmission customer is also out due to broken shield wire
1/29/2013		Estevan East2	6:32	Transmission customer is also out due to broken shield wire
1/29/2013		Midale1	6:47	Transmission customer is also out due to broken shield wire
1/29/2013		Midale2	6:47	Transmission customer is also out due to broken shield wire
1/29/2013		Apache Midale	7:23	Transmission customer is also out due to broken shield wire
1/29/2013		Enbridge West Midale	7:48	Transmission customer is also out due to broken shield wire
3/5/2013	BD15		6:22	Other (cause unknown)
3/5/2013		Steelman1	6:22	Transmission customer is also out due to unknown reason
3/5/2013		Steelman2	6:22	Transmission customer is also out due to unknown reason
3/14/2013	A1T-AU		2:24	Defective Equipment (switch broke)
3/14/2013		Wauchope1	2:24	Transmission customer is also out due to broken switch
3/14/2013		Wauchope2	2:24	Transmission customer is also out due to broken switch
3/25/2013	S1M		34:03	Defective Equipment
3/25/2013		TransCanadaLimited	34:03	Transmission customer is also out due to defective equipment
3/30/2013	S1M		7:27	Transmission customer is also out due to defective equipment
3/30/2013	E2B		42:34	Other (cause unknown)
4/5/2013	L2E		5:15	Adverse weather (ice)
4/5/2013		Enbridge Cactus Lake	5:15	Transmission customer is also out due to icing of the line
4/5/2013		Hearts Hill	5:15	Transmission customer is also out due to icing of the line
4/5/2013		Kinder Morgan Haytor	5:15	Transmission customer is also out due to icing of the line
4/5/2013		Macklin	5:15	Transmission customer is also out due to icing of the line
4/5/2013		Senlac2	5:15	Transmission customer is also out due to icing of the line
4/5/2013		Senlac1	5:15	Transmission customer is also out due to icing of the line
4/5/2013	C1P		8:59	Adverse weather (freezing rain)
4/5/2013		Rverhurst Pumping Station	8:59	Transmission customer is also out due to freezing rain
4/21/2013	B1W		21:56	Other (cause unknown)

2013 Transmission Line Outages in Excess of Two (2) Hours				
DD-MM-YY	**Transmission Line**	**Customer or Delivery Point Impacted**	**Duration (hr:mm)**	**Reason for Outage**
4/27/2013	ML3		2:36	Other (cause unknown)
4/27/2013		Beauval1	2:36	Transmission customer is also out due to unknown reason
4/27/2013		Beauval2	2:36	Transmission customer is also out due to unknown reason
4/27/2013		DoreLake1	2:36	Transmission customer is also out due to unknown reason
4/27/2013		Meadow Lake Saw Mill	2:36	Transmission customer is also out due to unknown reason
4/27/2013		Buffalo Narrows	2:36	Transmission customer is also out due to unknown reason
4/27/2013		Ile A Lacrosse	2:36	Transmission customer is also out due to unknown reason
4/27/2013		Turnor Lake	2:36	Transmission customer is also out due to unknown reason
4/28/2013	ML3		5:54	Other (cause unknown)
4/28/2013		Beauval1	5:54	Transmission customer is also out due to unknown reason
4/28/2013		Beauval2	5:54	Transmission customer is also out due to unknown reason
4/28/2013		DoreLake	5:54	Transmission customer is also out due to unknown reason
4/28/2013		Meadow Lake Saw Mill	5:54	Transmission customer is also out due to unknown reason
4/28/2013		Buffalo Narrows	5:54	Transmission customer is also out due to unknown reason
4/28/2013		Ile A Lacrosse	5:54	Transmission customer is also out due to unknown reason
4/28/2013		Turnor Lake	5:54	Transmission customer is also out due to unknown reason
4/28/2013		Meadow Lake Saw Mill	12:57	Transmission customer is also out due to unknown reason
5/7/2013	YN3		3:33	Adverse environment (smoke)
5/7/2013		Neudorf1	3:33	Transmission customer is also out due to smoke
5/7/2013		Neudorf2	3:33	Transmission customer is also out due to smoke
5/7/2013	ML5		2:52	Defective equipment
5/7/2013		Meadow Lake	2:52	Transmission customer is also out due to defective equipment
5/7/2013		Rapid View1	2:52	Transmission customer is also out due to defective equipment
5/7/2013		Rapid View2	2:52	Transmission customer is also out due to defective equipment
5/7/2013	ML3		3:29	Defective equipment
5/7/2013		Beauval1	3:29	Transmission customer is also out due to defective equipment
5/7/2013		Beauval2	3:29	Transmission customer is also out due to defective equipment
5/7/2013		DoreLake	3:29	Transmission customer is also out due to defective equipment
5/7/2013		Meadow Lake Saw Mill	3:29	Transmission customer is also out due to defective equipment
5/12/2013	YN3		3:33	Adverse environment (tree fell on line)
5/12/2013		Neudorf1	3:33	Transmission customer is also out due to tree on line
5/12/2013		Neudorf2	3:33	Transmission customer is also out due to tree on line
5/13/2013	YN3		15:26	Defective equipment
5/13/2013		Neudorf1	15:26	Transmission customer is also out due to defective equipment
5/13/2013		Neudorf2	15:26	Transmission customer is also out due to defective equipment

2013 Transmission Line Outages in Excess of Two (2) Hours				
DD-MM-YY	**Transmission Line**	**Customer or Delivery Point Impacted**	**Duration (hr:mm)**	**Reason for Outage**
5/15/2013	CE4		4:23	Defective equipment (pole on fire)
5/15/2013		Carrot River	4:23	Transmission customer is also out due to pole fire
5/15/2013		Nipawin	4:23	Transmission customer is also out due to pole fire
5/15/2013		Tobin	4:23	Transmission customer is also out due to pole fire
5/19/2013	YN6		1:45	Adverse environment (tree fell on line)
5/19/2013		Stenen	3:13	Transmission customer is also out due to tree on line
5/24/2013	GL7		3:04	Defective equipment (pole fire)
5/24/2013	GL8		8:08	Defective equipment (pole fire)
5/24/2013		Spiritwood	3:04	Transmission customer is also out due to pole fire
5/24/2013		Glaslyn	8:08	Transmission customer is also out due to pole fire
5/26/2013	PE8		4:15	Defective equipment (pole on fire)
5/26/2013		Kinder Morgan Creelman	4:15	Transmission customer is also out due to pole fire
5/30/2013	PE8		45:58	Defective equipment (structures down)
5/30/2013		Handsworth		Transmission customer is also out due to structures down
5/30/2013		Kinder Morgan Creelman		Transmission customer is also out due to structures down
6/14/2013	W1R		27:43	Defective equipment (structures down)
6/14/2013		NR Green Estlin	27:29	Transmission customer is also out due to structures down
6/14/2013		Enbridge Rowatt	27:29	Transmission customer is also out due to structures down
6/14/2013		Kinder Morgan Estlin	4:39	Transmission customer is also out due to structures down
6/20/2013	R1F-FS		115:11	Defective equipment (broken shield wire)
6/20/2013		Regina-Broad St.4	13:41	Transmission customer is also out due to broken sheild wire on line
6/23/2013	Y2T-TA		2:11	Other (cause unknown)
6/23/2013		K&S Potash Temp Power	2:11	Transmission customer is also out due to unknown reason
6/23/2013		Mosaic K1 Shaft	2:11	Transmission customer is also out due to unknown reason
6/27/2013	B1A-AU		6:33	Defective equipment (broken structure)
6/27/2013		Alida	6:33	Transmission customer is also out due to broken structure
6/27/2013		Carnduff	6:33	Transmission customer is also out due to broken structure
6/27/2013		Enbridge Westspur Alida	6:33	Transmission customer is also out due to broken structure
6/27/2013		Kinder Morgan Alameda	6:33	Transmission customer is also out due to broken structure
6/27/2013		N.A.L. Gas Plant	6:33	Transmission customer is also out due to broken structure
6/27/2013		NR Green Alameda	6:33	Transmission customer is also out due to broken structure
6/27/2013		Oxbow	6:33	Transmission customer is also out due to broken structure
7/1/2013	E1L		23:34	Other (cause unknown)

2013 Transmission Line Outages in Excess of Two (2) Hours				
DD-MM-YY	**Transmission Line**	**Customer or Delivery Point Impacted**	**Duration (hr:mm)**	**Reason for Outage**
7/7/2013	B2G		3:54	Foreign interference (bird nest)
7/7/2013		Bolney	4:05	Transmission customer is also out due to bird nest on line
7/7/2013		Paradise Hill	4:05	Transmission customer is also out due to bird nest on line
7/7/2013		Turtleford	4:05	Transmission customer is also out due to bird nest on line
7/7/2013		Spiritwood	4:05	Transmission customer is also out due to bird nest on line
7/7/2013		Turtleford	4:05	Transmission customer is also out due to bird nest on line
7/7/2013		Beauval1	4:23	Transmission customer is also out due to bird nest on line
7/7/2013		Beauval2	4:23	Transmission customer is also out due to bird nest on line
7/7/2013		DoreLake	4:23	Transmission customer is also out due to bird nest on line
7/7/2013		Rapid View1	4:23	Transmission customer is also out due to bird nest on line
7/7/2013		Rapid View2	4:23	Transmission customer is also out due to bird nest on line
7/7/2013		Meadow Lake Saw Mill	4:23	Transmission customer is also out due to bird nest on line
7/7/2013		Meadow Lake	4:23	Transmission customer is also out due to bird nest on line
7/11/2013	C2H-CC		7:01	Defective equipment (broken structure)
7/12/2013	B1S		0:12	Other (cause unknown)
7/12/2013		Stony Rapids3	5:19	Transmission customer is also out due to unknown reason even though line is in service
7/12/2013		Fond Du Lac	5:19	Transmission customer is also out due to unknown reason even though line is in service
7/12/2013	B1S		10:35	Other (cause unknown)
8/4/2013	I2P		0:25	Adverse weather (lightning)
8/4/2013		Points North	2:31	Transmission customer was also out due to lightning but their breaker was not closed
8/12/2013	PE802T		42:06	Other (cause unknown)
8/12/2013		Peebles3	4:32	Transmission customer is also out due to unknown reason
8/12/2013		Handsworth	4:32	Transmission customer is also out due to unknown reason
8/12/2013		Kinder Morgan Creelman	4:32	Transmission customer is also out due to unknown reason
8/15/2013	I2P		15:21	Other (cause unknown)
8/17/2013	W3B		18:41	Adverse weather (lightning)
8/23/2013	GL6		2:44	Defective equipment (breaker issue)
8/23/2013		Bolney	2:44	Transmission customer is also out due to breaker issue
8/23/2013		Paradise Hill	2:44	Transmission customer is also out due to breaker issue
8/23/2013		Turtleford	2:44	Transmission customer is also out due to breaker issue
8/28/2013	B1S		7:47	System condition
8/28/2013		Fond Du Lac	4:53	Transmission customer is also out due to system conditions
8/28/2013		Stony Rapids3	4:53	Transmission customer is also out due to system conditions

2013 Transmission Line Outages in Excess of Two (2) Hours				
DD-MM-YY	**Transmission Line**	**Customer or Delivery Point Impacted**	**Duration (hr:mm)**	**Reason for Outage**
8/30/2013	TC5		10:11	Foreign interference (car hit structure causing it to fail)
8/30/2013		La Ronge	10:11	Transmission customer is also out due to car hitting structure
8/30/2013		Montreal River	2:43	Transmission customer is also out due to car hitting structure
8/30/2013		Weyakwin	2:43	Transmission customer is also out due to car hitting structure
8/30/2013		Timbercove	2:43	Transmission customer is also out due to car hitting structure
9/4/2013	A1R		19:34	Other (cause unknown)
9/13/2013	B2P		3:59	Foreign interference (car hit structure causing it to fail)
9/23/2013	C1W		8:01	System condition
11/3/2013	PA8		2:47	Adverse weather (freezing rain & high wind)
11/3/2013		Carrier Big River Saw Mill	2:47	Transmission customer is also out due to freezing rain & high wind
11/3/2013		Debden	2:47	Transmission customer is also out due to freezing rain & high wind
11/3/2013		Shellbrook	2:47	Transmission customer is also out due to freezing rain & high wind
12/9/2013	S1C		23:07	Adverse weather (high winds)
12/9/2013		TransCanada Keystone Herbert	2:27	Transmission customer is also out due to high winds
12/18/2013	C2H-CC		5:20	Defective equipment (broken bells on tower structure)
12/18/2013		SaskWater Eastside Pump Station	5:20	Transmission customer is also out due to broken bells on tower structures
12/18/2013		SaskWater Lucky Lake	5:20	Transmission customer is also out due to broken bells on tower structures
12/18/2013		Tichfield	5:20	Transmission customer is also out due to broken bells on tower structures
12/18/2013		Tullis	5:20	Transmission customer is also out due to broken bells on tower structures
12/23/2013	QE14		4:22	Defective equipment (structure failed)
12/23/2013		Agrium Potash 72 kV (retired)	4:22	Transmission customer is also out due to failed structure
12/23/2013		Perdue	4:22	Transmission customer is also out due to failed structure
12/24/2013	P1H		7:29	Defective equipment (equipment failed)

2014 Transmission Line Outages in Excess of Two (2) Hours				
DD-MM-YY	Transmission Line	Customer or Delivery Point Impacted	Duration (hr:mm)	Reason for Outage
1/15/2014	E1L		12:20	Adverse weather (high winds)
1/15/2014	PE8		2:16	Adverse weather (high winds)
1/15/2014		Handsworth	2:16	Transmission customer is also out due to high winds
1/15/2014		Kinder Morgan Creelman	2:16	Transmission customer is also out due to high winds
1/15/2014	B1A-BD		3:10	Adverse weather (high winds)
1/15/2014		Plains Midstream Steelman Gas Plant	3:10	Transmission customer is also out due to high winds
1/15/2014		Enbridge Steelman	3:10	Transmission customer is also out due to high winds
1/26/2014	C2H-CC		9:25	Adverse weather (high winds)
1/26/2014		SaskWater Eastside Pump Station	2:46	Transmission customer is also out due to high winds
1/26/2014		SaskWater Lucky Lake	2:46	Transmission customer is also out due to high winds
1/26/2014		Tichfield	2:46	Transmission customer is also out due to high winds
1/26/2014		Tullis	9:25	Transmission customer is also out due to high winds
1/26/2014	N2L		3:10	Adverse weather (high winds)
1/26/2014		Aberfeldy	3:10	Transmission customer is also out due to high winds
1/26/2014		Battleford	3:10	Transmission customer is also out due to high winds
1/26/2014		Freemont	3:10	Transmission customer is also out due to high winds
1/26/2014		Lashburn	3:10	Transmission customer is also out due to high winds
1/26/2014		Maidstone	3:10	Transmission customer is also out due to high winds
2/3/2014	S1M		81:24	Adverse environment (birds)
2/21/2014	IF837T		5:40	Defective equipment (relay failure)
2/21/2014		Island Falls	6:06	Transmission customer is also out due to relay failure
3/30/2014	P1H		4:10	Defective equipment (broken ground wire)
3/30/2014		Enbridge1	2:35	Transmission customer is also out due to broken ground wire
3/30/2014		Enbridge3	2:35	Transmission customer is also out due to broken ground wire
3/31/2014	P2C		5:14	Defective equipment (pole fire)
4/18/2014	QE14		3:08	Adverse weather (freezing rain & snow)
4/18/2014		Agrium Potash 72 kV (retired)	3:08	Transmission customer is also out due to freezing rain & snow
4/18/2014		Perdue	8:22	Transmission customer is also out due to freezing rain & snow
4/18/2014		Dundonald1	3:08	Transmission customer is also out due to freezing rain & snow
4/18/2014		Dundonald2	3:08	Transmission customer is also out due to freezing rain & snow
4/18/2014	C1P		3:52	Adverse weather (freezing rain & snow)
4/18/2014		Riverhurst Pump Station	3:25	Transmission customer is also out due to freezing rain & snow
4/25/2014	S1M		5:37	Human element (ATCO tripped line)
4/26/2014	SW8		3:55	Defective equipment (broken equipment)
4/26/2014		Antelope	3:55	Transmission customer is also out due to broken equipment
4/26/2014		Gull Lake	3:55	Transmission customer is also out due to broken equipment
4/26/2014		Meath Park	3:55	Transmission customer is also out due to broken equipment
4/30/2014		Midale2	2:08	Transmission customer is also out due to broken equipment

2014 Transmission Line Outages in Excess of Two (2) Hours				
DD-MM-YY	Transmission Line	Customer or Delivery Point Impacted	Duration (hr:mm)	Reason for Outage
4/30/2014	BD22		2:08	Defective equipment (pole fire)
4/30/2014		Estevan East1	2:08	Transmission customer is also out due to pole fire
4/30/2014		Estevan East2	2:08	Transmission customer is also out due to pole fire
4/30/2014		Apache Midale	2:08	Transmission customer is also out due to pole fire
4/30/2014		Midale1	2:08	Transmission customer is also out due to pole fire
4/30/2014		Enbridge Westspur Midale	2:08	Transmission customer is also out due to pole fire
4/30/2014		Halbrite East	2:08	Transmission customer is also out due to pole fire
5/1/2014	QE14		1:23	Defective equipment (broken structure) & part returned to service (sectionalized)
5/1/2014		Agrium Potash 72 kV (retired)	32:56	Transmission customer is also out due to broken structure
5/1/2014		Perdue	8:26	Transmission customer is also out due to broken structure
5/1/2014	P1H		100:35	Defective equipment (fallen structures)
5/2/2014	PE3		5:12	Adverse weather (high winds)
5/2/2014		Enbridge Glenavon	5:12	Transmission customer is also out due to high winds
5/2/2014		Enbridge Odessa	5:12	Transmission customer is also out due to high winds
5/2/2014		Odessa	3:32	Transmission customer is also out due to high winds
5/8/2014	BV1		2:39	Defective equipment (broken structure)
5/8/2014		Ile A Lacrosse	2:39	Transmission customer is also out due to broken structure
5/8/2014		Buffalo Narrows	2:39	Transmission customer is also out due to broken structure
5/8/2014		Turnor Lake	2:39	Transmission customer is also out due to broken structure
5/8/2014	BV1		2:38	Defective equipment (broken structure)
5/8/2014		Ile A Lacrosse	2:38	Transmission customer is also out due to broken structure
5/8/2014		Buffalo Narrows	2:38	Transmission customer is also out due to broken structure
5/8/2014		Turnor Lake	2:38	Transmission customer is also out due to broken structure
5/9/2014	P2A		13:49	Defective equipment (broken structure)
5/12/2014	Q1H		5:10	Human element (grounds left on line)
5/28/2014	P1C		26:53	Adverse weather (high winds, lightning, suspected tornado)
5/28/2014	W1Y		2:06	Defective equipment (relay malfunction)
5/28/2014	WL2		2:10	System condition
5/28/2014		Cudworth	2:10	Transmission customer is also out due to system condition
5/28/2014		Agrium Watson	2:10	Transmission customer is also out due to system condition
5/28/2014		Watson	2:10	Transmission customer is also out due to system condition
5/28/2014	WL7		2:10	System condition
5/28/2014		Hatfield1	2:10	Transmission customer is also out due to system condition
5/28/2014		Hatfield2	2:10	Transmission customer is also out due to system condition
5/28/2014		Watrous	2:10	Transmission customer is also out due to system condition
5/28/2014	W4B-WL		2:09	System condition
5/28/2014		Lanigan	2:09	Transmission customer is also out due to system condition
5/28/2014	A1R		565:19	Adverse weather (suspected tornado)
5/28/2014	P1H		3:31	Adverse weather (suspected tornado)
5/28/2014		Enbridge1	3:31	Transmission customer is also out due to suspected tornado
5/28/2014		Enbridge2	3:31	Transmission customer is also out due to suspected tornado
5/28/2014		Enbridge3	3:31	Transmission customer is also out due to suspected tornado

2014 Transmission Line Outages in Excess of Two (2) Hours				
DD-MM-YY	Transmission Line	Customer or Delivery Point Impacted	Duration (hr:mm)	Reason for Outage
5/29/2014	C2H-HA		6:58	Adverse weather (lightning)
5/29/2014		Kinder Morgan Sovereign	6:58	Transmission customer is also out due to lightning
5/29/2014		Elrose	6:58	Transmission customer is also out due to lightning
5/29/2014		Outlook	6:58	Transmission customer is also out due to lightning
5/29/2014	B3P		134:14	Adverse weather (supsected tornado)
5/29/2014		Enbridge Steelman	3:21	Transmission customer is also out due to suspected tornado
5/29/2014		Estevan West	3:21	Transmission customer is also out due to suspected tornado
5/29/2014		Stoughton1	3:21	Transmission customer is also out due to suspected tornado
5/29/2014		Stoughton2	3:21	Transmission customer is also out due to suspected tornado
5/29/2014		Enbridge Benson	3:21	Transmission customer is also out due to suspected tornado
5/29/2014		Tecumseh	3:21	Transmission customer is also out due to suspected tornado
5/29/2014	CH1		7:29	Adverse weather (supsected tornado)
5/29/2014		Chaplin	7:29	Transmission customer is also out due to suspected tornado
5/29/2014		Central Butte	7:29	Transmission customer is also out due to suspected tornado
5/29/2014		Morse	7:29	Transmission customer is also out due to suspected tornado
5/29/2014		Plains Midstream Secretan	17:27	Transmission customer is also out due to suspected tornado
6/2/2014	I2P		0:08	Adverse weather (lightning) & line was returned to service but B1S was still out.
6/2/2014		Rabbit Lake	5:02	Transmission customer is also out due to lightning that caused high voltages
6/2/2014		Beaver Lodge	5:37	Transmission customer is also out due to lightning that caused high frequency
6/20/2014	B2P		2:14	Other (cause unknown)
6/20/2014		Senator	2:14	Transmission customer is also out due to unknown cause
6/20/2014	BE805T		2:14	System condition
6/20/2014	B4P		2:14	System condition
6/27/2014	Y2T-TA		7:31	Adverse weather (lightning)
6/27/2014		K&S Potash Temp Power	7:31	Transmission customer is also out due to lightning
6/27/2014		Mosaic K1 Shaft	7:31	Transmission customer is also out due to lightning
6/29/2014	C2H-HA		2:02	Defective equipment (structures down)
6/29/2014		Broderick	2:02	Transmission customer is also out due to downed structures
6/29/2014		Kinder Morgan Sovereign	2:02	Transmission customer is also out due to downed structures
6/29/2014		Outlook	2:02	Transmission customer is also out due to downed structures
6/29/2014		Elrose	2:02	Transmission customer is also out due to downed structures
7/5/2014	C1W		99:48	Adverse weather (high winds)
7/9/2014	I2P		8:32	Adverse weather (lightning)
7/10/2014	TD4		2:14	Adverse weather (lightning)
7/10/2014	GB1		2:14	System condition
7/10/2014		Prairie River	2:14	Transmission customer is also out due to system conditions
7/10/2014		Hudson Bay1	2:14	Transmission customer is also out due to system conditions
7/10/2014		Hudson Bay2	2:14	Transmission customer is also out due to system conditions
7/10/2014		Weyerhauser OSB	2:14	Transmission customer is also out due to system conditions

2014 Transmission Line Outages in Excess of Two (2) Hours				
DD-MM-YY	**Transmission Line**	**Customer or Delivery Point Impacted**	**Duration (hr:mm)**	**Reason for Outage**
7/10/2014	WL2		2:18	Adverse weather (lightning)
7/10/2014		Cudworth	2:18	Transmission customer is also out due to lightning
7/10/2014		Agrium Watson	12:32	Transmission customer is also out due to lightning
7/10/2014		Watson	12:32	Transmission customer is also out due to lightning
7/12/2014	ER709C		3:53	Human element (operator error)
7/12/2014		Kinder Morgan Kerrobert	3:48	Transmission customer is also out due to an operator error
7/17/2014	ER8		3:30	Adverse weather (lightning)
7/17/2014		Kerrobert	3:30	Transmission customer is also out due to lightning
7/17/2014		Luseland	3:30	Transmission customer is also out due to lightning
7/17/2014		NR Green Kerrobert	3:30	Transmission customer is also out due to lightning
7/17/2014		Unity	3:30	Transmission customer is also out due to lightning
7/17/2014	C3B		167:40	Adverse weather (plow wind)
7/21/2014	B2Q		28:58	Defective equipment (equipment failed)
7/24/2014	B1K		103:42	Adverse weather (high winds caused structures to go down)
7/24/2014	B2P		2:40	Adverse weather (lightning & high winds)
7/24/2014	B4P		8:36	system condition
7/24/2014		Senator	3:04	Transmission customer is also out due to system conditions
7/24/2014	P2C		4:44	Adverse weather (lightning & high winds)
7/25/2014	I2P		3:42	Adverse weather (lightning)
7/25/2014	P3R		3:50	System condition
7/25/2014		Wollaston Post	3:50	Transmission customer is also out due to system conditions
7/25/2014		Rabbit Lake	3:50	Transmission customer is also out due to system conditions
7/25/2014	S3P		3:46	Transmission customer is also out due to system conditions
7/25/2014	I1F		2:39	System condition
8/3/2014	C1Q		10:25	Defective equipment (broken spar)
8/3/2014		Agrium Vanscoy	5:33	Transmission customer is also out due to a broken spar
8/6/2014	I2P		17:11	Adverse weather (lightning)
8/6/2014	S3P		18:27	System condition
8/6/2014	B1S		18:42	System condition
8/6/2014		Rabbit Lake	19:01	Transmission customer is also out due to system conditions
8/6/2014		Wollaston Post	18:30	Transmission customer is also out due to system conditions
8/6/2014		McClean Lake	18:30	Transmission customer is also out due to system conditions
8/6/2014		Points North	18:25	Transmission customer is also out due to system conditions
8/6/2014		Lindsey Lake1	5:56	Transmission customer is also out due to system conditions
8/6/2014		Lindsey Lake2	5:58	Transmission customer is also out due to system conditions
8/6/2014	P3R		2:36	System condition
8/6/2014		Rabbit Lake	2:54	Transmission customer is also out due to system conditions
8/8/2014		Parkridge	4:06	Transmission customer is out due lightning

2014 Transmission Line Outages in Excess of Two (2) Hours				
DD-MM-YY	Transmission Line	Customer or Delivery Point Impacted	Duration (hr:mm)	Reason for Outage
8/8/2014	RE7		2:09	Adverse weather (lightning)
8/8/2014		Balgonie5	2:09	Transmission customer is also out due to lightning
8/8/2014		Balgonie6	2:09	Transmission customer is also out due to lightning
8/8/2014		Enbridge White City	2:09	Transmission customer is also out due to lightning
8/8/2014		Fort Qu'appelle2	10:00	Transmission customer is also out due to lightning
8/8/2014	R1F-FS		5:16	Adverse environment (tree)
8/8/2014	R1F-FS		49:59	Defective equipment (burnt pole)
8/8/2014	N1L		24:22	Adverse weather (lightning)
8/23/2014	R1P		0:06	Other (cause unknown) & line was sectionalized but customers are tapped off
8/23/2014		Mosaic Belle Plaine	13:13	Transmission customer is also out due to an unknown reason
8/23/2014		Terra Grains	11:18	Transmission customer is also out due to an unknown reason
8/23/2014	R1P		8:31	Other (cause unknown)
8/23/2014		TransCanada Keystone Belle Plaine	8:31	Transmission customer is also out due to an unknown reason
8/27/2014	I2P		0:46	Adverse weather (lightning) & line was returned to service but B1S is still out
8/27/2014		Stony Rapids	3:38	Transmission customer is also out due to lightning
9/4/2014	R1P		9:34	Defective equipment (broken spar)
9/4/2014		Mosaic Belle Plaine	9:32	Transmission customer is also out due to a broken spar
9/4/2014		TransCanada Keystone Belle Plaine	9:32	Transmission customer is also out due to a broken spar
9/4/2014		Terra Grains	9:32	Transmission customer is also out due to a broken spar
9/10/2014	BD922T		103:57	Defective equipment (switch failed)
9/10/2014	B10T		103:57	Transformer is out due to failed switch
9/16/2014	R1P		0:13	Foreign interference (grain auger contact) & line was sectionalized but customers are tapped and that's where the issue was
9/16/2014		Mosaic Belle Plaine	2:15	Transmission customer is also out due to contact with grain auger
9/16/2014		TransCanada Keystone Belle Plaine	2:15	Transmission customer is also out due to contact with grain auger
9/16/2014		Terra Grains	2:15	Transmission customer is also out due to contact with grain auger
9/24/2014	B3R		2:35	Foreign interference (grain auger contact)
10/1/2014	C1F-CD		10:01	Foreign interference (crane contact)
10/1/2014		Armour Siding6	9:59	Transmission customer is also out due crane contact
10/1/2014		Armour Siding7	9:59	Transmission customer is also out due crane contact
10/1/2014		Coronation	9:59	Transmission customer is also out due crane contact
10/1/2014		EVRAZ Plant	1:38	Transmission customer is also out due crane contact
10/1/2014		EVRAZ Rolling Mill	1:38	Transmission customer is also out due crane contact
10/1/2014		Shaw Pipe	9:59	Transmission customer is also out due crane contact
10/1/2014		Wheat City Metals	10:00	Transmission customer is also out due crane contact
10/11/2014	C2W		3:08	Other (cause unknown)
10/24/2014	C2Q		2:29	Defective equipment (relay misoperation)
11/28/2014	W1A-AS		6:10	Adverse weather (frost, high wind)
12/15/2014	RE901T		4:27	Foreign interference (rodent damage)
12/15/2014	B3R		4:27	System conditions
12/17/2014	A1R		28:40	Adverse weather (frost)

2014 Transmission Line Outages in Excess of Two (2) Hours				
DD-MM-YY	Transmission Line	Customer or Delivery Point Impacted	Duration (hr:mm)	Reason for Outage
12/17/2014	SW3		3:19	Adverse weather (frost)
12/17/2014		Battrum	3:19	Transmission customer is also out due to frost
12/17/2014		Cantuar Reg	3:19	Transmission customer is also out due to frost
12/17/2014		Crescent Point Energy	3:19	Transmission customer is also out due to frost
12/17/2014		TransCanada Keystone Stewart Valley	3:19	Transmission customer is also out due to frost
12/19/2014	TA13		2:26	Adverse environment (industrial pollution)
12/19/2014		TransCanada Keystone Moosomin	2:26	Transmission customer is also out due to pollution
12/19/2014		PCS Rocanville	2:26	Transmission customer is also out due to pollution
12/19/2014		PCS Scissors Creek	2:26	Transmission customer is also out due to pollution
12/19/2014	TA13		9:04	Adverse environment (industrial pollution)
12/19/2014		TransCanada Keystone Moosomin	9:04	Transmission customer is also out due to pollution
12/19/2014		PCS Rocanville	9:04	Transmission customer is also out due to pollution
12/19/2014		PCS Scissors Creek	9:04	Transmission customer is also out due to pollution
12/21/2014	N2L		3:12	Adverse weather (frost)
12/23/2014	C1F-CD		2:22	Foreign interference (crane contact)
12/23/2014		Armour Siding6	2:22	Transmission customer is also out due crane contact
12/23/2014		Armour Siding7	2:22	Transmission customer is also out due crane contact
12/23/2014		Coronation	2:22	Transmission customer is also out due crane contact
12/23/2014		EVRAZ Plant	2:22	Transmission customer is also out due crane contact
12/23/2014		EVRAZ Rolling Mill	2:22	Transmission customer is also out due crane contact
12/23/2014		Shaw Pipe	2:22	Transmission customer is also out due crane contact
12/23/2014		Wheat City Metals	2:22	Transmission customer is also out due crane contact
12/23/2014	WL2		0:33	Adverse weather (frost) & line was sectionalized but customers are on taps
12/23/2014		Agrium Watson	21:50	Transmission customer is also out due to frost
12/23/2014		Watson	21:50	Transmission customer is also out due to frost
12/23/2014	A1B		186:48	Adverse weather (frost bent structures)
12/24/2014	B1L		5:00	Defective equipment (shield wire down)
12/24/2014		Golden Lake	4:58	Transmission customer is also out due to shield wire down
12/24/2014	B1L		44:35	Defective equipment (shield wire down)
12/24/2014	A2B		142:33	Adverse weather (hoar frost)
12/24/2014	WL2		3:52	Adverse weather (frost bent structures)
12/24/2014		Agrium Watson	20:13	Transmission customer is also down due to frost bending structures
12/24/2014		Watson	20:13	Transmission customer is also down due to frost bending structures
12/24/2014		Cudworth	3:52	Transmission customer is also down due to frost bending structures
12/25/2014	B1W		9:19	Adverse weather (frost)
12/25/2014	WL2		7:39	Adverse weather (frost cause shield wire to break)
12/25/2014		Cudworth	7:39	Transmission customer is also out due to broken shield wire
12/30/2014	W1Y		12:28	Adverse weather (frost)
12/30/2014		BHP Jansen1	3:10	Transmission customer is also out due to frost
12/30/2014		BHP Jansen2	3:10	Transmission customer is also out due to frost
12/30/2014	BA4		8:53	System condition
12/30/2014		Bankend	8:53	Transmission customer is also out due to system condition

2014 Transmission Line Outages in Excess of Two (2) Hours				
DD-MM-YY	Transmission Line	Customer or Delivery Point Impacted	Duration (hr:mm)	Reason for Outage
12/30/2014	W4B-BA		8:53	System condition
12/30/2014		Foam Lake	8:53	Transmission customer is also out due to system condition
12/30/2014		Wadena1	8:53	Transmission customer is also out due to system condition
12/30/2014		Wadena2	8:53	Transmission customer is also out due to system condition
12/30/2014		Wynyard	3:04	Transmission customer is also out due to system condition
12/30/2014	SW7		0:38	Adverse weather (frost) & line was sectionalized but customer was on tap that was affected
12/30/2014		Eastend	2:58	Transmission customer is also out due to frost
12/30/2014	WL2		0:07	Adverse weather (frost) & line was sectionalized but customer was on tap that was affected
12/30/2014		Cudworth	0:07	Transmission customer is also out due to frost
12/30/2014		Watson	26:47	Transmission customer is also out due to frost
12/30/2014		Agrium Watson	8:40	Transmission customer is also out due to frost
12/30/2014	WL2		4:19	Adverse weather (frost)
12/30/2014		Cudworth	4:19	Transmission customer is also out due to frost
12/30/2014	WL2		0:15	Adverse weather (frost)
12/30/2014		Agrium Watson	17:54	Transmission customer is also out due to frost
12/30/2014	BR11		5:47	Adverse weather (frost)
12/30/2014		Meadow Lake Mech Pump Mill	5:47	Transmission customer is also out due to frost
12/30/2014		Meadow Lake OSB	5:47	Transmission customer is also out due to frost

2015 Transmission Line Outages in Excess of Two (2) Hours				
DD-MM-YY	Transmission Line	Customer or Delivery Point Impacted	Duration (hr:mm)	Reason for Outage
1/14/2015	Q1Q		3:19	Defective equipment (device failed)
1/18/2015	BR11		30:26	Foreign interference (farmer took down guy wire)
1/18/2015		Meadow Lake Mech Pump Mill	30:26	Transmission customer is also out due to downed guy wire
1/18/2015		Meadow Lake OSB	30:26	Transmission customer is also out due to downed guy wire
1/19/2015	PQ3		1:35	Adverse environment (fog)
1/19/2015		Buffalo Pound	6:18	Transmission customer is also out due to fog
2/3/2015	L2E		6:26	Human element (wrong relay setting)
2/9/2015	P2C		2:01	Adverse weather (freezing rain)
2/17/2015	S1M		3:10	Foreign interference (ATCO issue)
2/17/2015		TransCanadaLimited	3:10	Foreign interference (ATCO issue)
3/14/2015	S1M		8:41	Foreign interference (ATCO issue)
3/25/2015	Y2T-TA		2:20	Adverse weather (snow/ice broke crossarm)
3/25/2015		K&S Potash Temp Power	2:20	Transmission csutomer is also out due to broken crossarm
3/25/2015		Mosaic K1 Shaft	2:20	Transmission csutomer is also out due to broken crossarm
4/10/2015	TD4		7:36	Defective equipment (structure down)
4/10/2015		Prairie River	7:36	Transmission customer is also out due to structure down
4/10/2015	GB1		7:36	Defective equipment (structure down)
4/10/2015		Hudson Bay1	7:36	Transmission customer is also out due to structure down
4/10/2015		Hudson Bay2	7:36	Transmission customer is also out due to structure down
4/10/2015		Weyerhauser OSB	7:36	Transmission customer is also out due to structure down
4/11/2015	C1P		27:11	Defective equipment (broken sheild wire)
4/17/2015	A1B		191:11	Adverse environment (ice on structure caused them to fail)
4/17/2015	A2B		191:47	Adverse environment (ice on structure caused them to fail)
4/24/2015	C1F-CD		0:49	Defective equipment (cable issue) & line was sectionalized but customer still affected
4/24/2015		Armour Siding	245:32	Transmission customer is also out due to cable issue
4/28/2015	S3B		18:02	Defective equipment (relay issue)
5/1/2015		Points North	3:21	Transmission customer is also out due to relay issue
5/1/2015	R1P		10:06	Defective equipment (conductor down)
5/1/2015		Mosaic Belle Plaine	10:03	Transmission customer is also out due to conductor being down
5/1/2015		TransCanada Keystone Belle Plaine	10:03	Transmission customer is also out due to conductor being down
5/1/2015		Terra Grains	10:03	Transmission customer is also out due to conductor being down
5/9/2015	C2H-HA		2:12	Foreign interference (farmer took down line)
5/9/2015		Broderick	2:12	Transmission customer is also out due to line down
5/9/2015		Kinder Morgan Sovereign	12:47	Transmission customer is also out due to line down
5/9/2015		Elrose	12:47	Transmission customer is also out due to line down
5/9/2015		Outlook	2:12	Transmission customer is also out due to line down

2015 Transmission Line Outages in Excess of Two (2) Hours				
DD-MM-YY	Transmission Line	Customer or Delivery Point Impacted	Duration (hr:mm)	Reason for Outage
5/17/2015	S1E-SW		6:36	System condition
5/17/2015		Verlo	6:36	Transmission customer is also out due to system condition
5/17/2015		Tichfield	6:36	Transmission customer is also out due to system condition
5/17/2015		Abbey	6:36	Transmission customer is also out due to system condition
5/17/2015		Liebenhtal5	6:36	Transmission customer is also out due to system condition
5/17/2015		Liebenhtal6	6:36	Transmission customer is also out due to system condition
5/17/2015		Eston	6:36	Transmission customer is also out due to system condition
5/17/2015	SW5		6:42	System condition
5/17/2015		Swift Current City5	6:42	Transmission customer is also out due to system condition
5/17/2015		Swift Current City6	6:42	Transmission customer is also out due to system condition
5/17/2015	SW7		6:43	System condition
5/17/2015		Bone Creek	6:43	Transmission customer is also out due to system condition
5/17/2015		Shanavon	6:43	Transmission customer is also out due to system condition
5/17/2015		Eastend	6:43	Transmission customer is also out due to system condition
5/17/2015		Climax	6:43	Transmission customer is also out due to system condition
5/17/2015	SW8		6:40	System condition
5/17/2015		Antelope	6:40	Transmission customer is also out due to system condition
5/17/2015		Gull Lake	6:40	Transmission customer is also out due to system condition
5/17/2015		Maple Creek	6:40	Transmission customer is also out due to system condition
5/31/2015	B2G		13:43	Adverse weather (lightning)
5/31/2015	G1M		13:43	System condition
5/31/2015	GL6		13:43	System condition
5/31/2015		Turtleford	13:45	Transmission customer is also out due to system condition
5/31/2015		Bolney	13:45	Transmission customer is also out due to system condition
5/31/2015		Paradise Hill	13:45	Transmission customer is also out due to system condition
5/31/2015	GL7		13:46	System condition
5/31/2015		Spiritwood	13:46	Transmission customer is also out due to system condition
5/31/2015	GL8		13:46	System condition
5/31/2015		Glaslyn	13:46	Transmission customer is also out due to system condition
5/31/2015	ML3		2:27	System condition
5/31/2015		Meadow Lake Saw Mill	2:27	Transmission customer is also out due to system condition
5/31/2015		Beauval1	2:27	Transmission customer is also out due to system condition
5/31/2015		Beauval2	2:27	Transmission customer is also out due to system condition
5/31/2015	BV1		2:53	System condition
5/31/2015		Ile A Lacrosse	2:53	Transmission customer is also out due to system condition
5/31/2015		Buffalo Narrows	2:53	Transmission customer is also out due to system condition
5/31/2015		Turnor Lake	2:53	Transmission customer is also out due to system condition

2015 Transmission Line Outages in Excess of Two (2) Hours				
DD-MM-YY	Transmission Line	Customer or Delivery Point Impacted	Duration (hr:mm)	Reason for Outage
5/31/2015	ML5		4:19	System condition
5/31/2015		Meadow Lake	4:19	Transmission customer is also out due to system condition
5/31/2015		Rapid View1	4:19	Transmission customer is also out due to system condition
5/31/2015		Rapid View2	4:19	Transmission customer is also out due to system condition
6/1/2015	ML5		6:26	System condition
6/1/2015		Meadow Lake	6:26	Transmission customer is also out due to system condition
6/1/2015		Rapid View1	6:26	Transmission customer is also out due to system condition
6/1/2015		Rapid View2	6:26	Transmission customer is also out due to system condition
6/9/2015	S3P		2:39	Other (cause unknown)
6/9/2015		Beaver Lodge	2:33	Transmission customer is also out due to unknown cause
6/9/2015	B1S		2:17	System condition
6/9/2015		Fond Du Lac	2:22	Transmission customer is also out due to system condition
6/12/2015	A1T-AU		1:59	Adverse weather (lightning, high winds)
6/12/2015		Wauchope1	1:59	Transmission customer is also out due to weather issues
6/12/2015		Wauchope2	1:59	Transmission customer is also out due to weather issues
6/12/2015		Parkman	42:46	Transmission customer is also out due to weather issues
6/12/2015		Walpole	1:46	Transmission customer is also out due to weather issues
7/9/2015		Island Falls	3:10	Other (cause unknown)
7/9/2015	P2A		15:31	Defective equipment (structures)
7/14/2015		Island Falls	3:24	Adverse weather (lightning)
7/22/2015	I2P		3:06	System condition
7/22/2015		Lindsey Lake1	3:05	Transmission customer is also out due to system condition
7/22/2015		Lindsey Lake2	3:04	Transmission customer is also out due to system condition
7/22/2015		Rabbit Lake	3:31	Transmission customer is also out due to system condition
7/23/2015	I2P		0:18	Adverse weather (lightning) & line back in service but B1S still out
7/23/2015		Rabbit Lake	1:59	Transmission customer is also out due to lightning
7/23/2015		Points North	2:27	Transmission customer is also out due to lightning
7/25/2015	I2P		0:19	Adverse weather (lightning) & line back in service but P3R still out
7/25/2015		Beaver Lodge	2:38	Transmission customer is also out due to lightning
7/28/2015	WL6		17:30	Adverse weather (wind, lightning, poles down)
7/28/2015		PCS Lanigan	17:30	Transmission customer is also out due to poles down
8/11/2015	I2P		0:31	Adverse weather (lightning) & line back in service but B1S still out
8/11/2015		Rabbit Lake	7:49	Transmission customer is also out due to lightning
8/13/2015	I2P		0:36	Adverse weather (lightning) & line back in service but B1S still out
8/13/2015		Rabbit Lake	5:25	Transmission customer is also out due to lightning
8/13/2015		Points North	3:40	Transmission customer is also out due to system condition
8/13/2015	I2P		2:14	Other (removed by operator)
8/13/2015	I1K		2:14	Other (removed by operator)

2015 Transmission Line Outages in Excess of Two (2) Hours				
DD-MM-YY	**Transmission Line**	**Customer or Delivery Point Impacted**	**Duration (hr:mm)**	**Reason for Outage**
9/2/2015	W4B-BA		5:55	Defective equipment (broken spar)
9/2/2015		Foam Lake	5:55	Transmission customer is also out due to broken spar
9/2/2015		Wadena1	5:55	Transmission customer is also out due to broken spar
9/2/2015		Wadena2	5:55	Transmission customer is also out due to broken spar
9/2/2015		Wynyard	5:55	Transmission customer is also out due to broken spar
9/2/2015	BA4		2:20	System condition
9/2/2015		Bankend	2:20	Transmission customer is also out due to system condition
9/3/2015	SW7		1:31	Defective equipment (conductor broke) & line sectionalized but customer still off due to broken conductor
9/3/2015		Eastend	8:02	Transmission customer is also out due to broken conductor
9/5/2015	BD9		12:01	Adverse weather (lightning)
9/5/2015		Estevan Coal1	12:01	Transmission customer is also out due to lightning
9/5/2015		Estevan Coal2	12:01	Transmission customer is also out due to lightning
9/5/2015		Costello Mine	12:01	Transmission customer is also out due to lightning
9/5/2015		Benefait Mine	12:01	Transmission customer is also out due to lightning
9/24/2015	B3P		24:16	Human element (cut cable)
10/11/2015	CH1		1:58	Adverse weather (high winds)
10/11/2015		Morse	5:33	Transmission customer is also out due to high winds
10/11/2015	SW7		3:47	Adverse weather (high winds)
10/11/2015		Bone Creek	3:47	Transmission customer is also out due to high winds
10/11/2015		Eastend	3:47	Transmission customer is also out due to high winds
10/11/2015		Climax	3:47	Transmission customer is also out due to high winds
10/11/2015	SW8		3:03	Adverse weather (high winds)
10/11/2015		Antelope	3:03	Transmission customer is also out due to high winds
10/11/2015		Gull Lake	3:03	Transmission customer is also out due to high winds
10/11/2015		Maple Creek	3:03	Transmission customer is also out due to high winds
10/11/2015	PE8		2:10	Adverse weather (high winds)
10/11/2015		Handsworth1	2:10	Transmission customer is also out due to high winds
10/11/2015		Handsworth2	2:10	Transmission customer is also out due to high winds
10/11/2015		Kinder Morgan Creelman	2:10	Transmission customer is also out due to high winds
11/13/2015	GL6		0:12	Defective equipment (broken switch) & line sectionalized but customer is tapped and still off due to broken switch
11/13/2015		Turtleford	2:12	Transmission customer is also out due to broken switch
11/18/2015	PE8		2:27	Adverse weather (high winds)
11/18/2015		Handsworth1	2:27	Transmission customer is also out due to high winds
11/18/2015		Handsworth2	2:27	Transmission customer is also out due to high winds
11/18/2015		Kinder Morgan Creelman	2:27	Transmission customer is also out due to high winds
11/18/2015	S1M		4:26	Foreign interference (ATCO issue)
11/18/2015		TransCanadaLimited	4:26	Transmission customer is also out due ATCO issue
11/23/2015	B1A-BD		5:51	Foreign interference (excavator contact)
11/23/2015		Enbridge Steelman	5:51	Transmission customer is also out due to contact with line
11/23/2015		Plains Midstream Steelman Gas Plant	5:51	Transmission customer is also out due to contact with line

2015 Transmission Line Outages in Excess of Two (2) Hours				
DD-MM-YY	Transmission Line	Customer or Delivery Point Impacted	Duration (hr:mm)	Reason for Outage
12/1/2015	IF37		2:46	Defective equipment (broken insulator)
12/9/2015	SW8		2:56	Human element (Construction contractor issue)
12/9/2015		Antelope	2:56	Transmission customer is also out due to contractor issue
12/9/2015		Gull Lake	2:56	Transmission customer is also out due to contractor issue
12/9/2015		Maple Creek	2:56	Transmission customer is also out due to contractor issue
12/10/2015	SW8		4:04	Human element (Construction contractor issue)
12/10/2015		Antelope	4:04	Transmission customer is also out due to contractor issue
12/10/2015		Gull Lake	4:04	Transmission customer is also out due to contractor issue
12/10/2015		Maple Creek	4:04	Transmission customer is also out due to contractor issue
12/27/2015	RE7		4:23	Adverse weather (frost)
12/27/2015		Fort Qu'appelle	4:23	Transmission customer is also out due to frost on line
12/27/2015		Balgonie5	4:23	Transmission customer is also out due to frost on line
12/27/2015		Balgonie6	4:23	Transmission customer is also out due to frost on line
12/27/2015		Enbridge White City	4:23	Transmission customer is also out due to frost on line
12/27/2015	B1K		43:02	Adverse weather (frost)
12/31/2015	N1L		4:52	Defective equipment (broken shield wire)

SRRP Q138:

Reference: **Reliability**

Please discuss how the condition of SaskPower's transmission lines relative to acceptable industry standards affects transmission outages. Please also discuss any expected improvements in transmission outages as a result of SaskPower's planned transmission capital program.

Response:

For the past few years we have been creating and enhancing our asset management strategy for transmission facilities. This work defines work required for the lifecycle of this asset type. As the asset management strategy is implemented and matures, the reliability of the transmission system will improve.

SaskPower has committed to growing the capital investment for sustainment funding over the next 10 years and this investment is targeted at improved reliability for our customers.

When comparing SaskPower measures to the rest of Canadian utilities it is important to take into account that per customer we have significantly more transmission infrastructure.

SRRP Q139:

Reference: **Resource Supply Plans**

Please explain the goals or objectives for SaskPower's Resource Supply Plans. Please provide an overview of the methods used to develop the plan, including any models or decision analysis frameworks used in the plan.

Response:

The goals and objectives for SaskPower's resource supply plans are to determine when additional generating capacity is needed to meet expected load and reliability requirements. Resources additions are planned on a least-cost basis that meets regulatory requirements and considers SaskPower's corporate objectives. The supply plans are used for budgeting purposes to inform SaskPower's annual Business Plan.

SaskPower uses industry standard models to assist in the development of its Resource Supply Plans, which include PROMOD and Strategist.

SaskPower
Powering the future®

SRRP Q140:

Reference: **Resource Supply Plan**

Please discuss how SaskPower's Resource Supply Plans are used internally, how often they are reviewed, updated and approved and what opportunities are planned for public review.

Response:

Planning a reliable, sustainable, cost-effective supply of electricity is a complex and ongoing process. SaskPower's resource plans are used to inform the annual budgeting process, and to direct internal work towards securing new sources of power generation or upgrades to existing facilities as required for reliability purposes. The intention is to update these plans annually and additional updates and reviews are considered on an as-needed basis in response to special circumstances, such as significant changes in load requirements or fuel prices or availability.

SaskPower engages on a regular basis with industry, environmental and business organizations and a wide range of other stakeholders and Aboriginal groups to share our challenges and our plans to meet these challenges. Engagement takes the form of presentations, online information, project open houses and most recently our interactive customer experience tent which will appear in various locations across the province this summer. Our goal is to help our customers understand the need for significant investment in our aging system and find cleaner generation options to power our growing province.

SRRP Q141:

Reference: **Resource Supply Plan**

Please provide a table that summarizes for each year from 2016 through 2035:

i) The expected system peak demand (MW) that must be met both before and after DSM; and

ii) The contribution of each individual existing or currently planned generation resource included in SPC's preferred supply plan to meeting the system peak demand.

iii) For each generation resource, please indicate whether it is considered to be a baseload, intermediate, peaking or intermittent resource.

Response:

This response contains confidential information and cannot be released publicly. A complete response was submitted to the Saskatchewan Rate Review Panel for their review.

SRRP Q142:

Reference: Resource Supply Plan

Please provide a table that summarizes for each year from 2016 through 2035:

i) The expected annual system energy requirement (GWh) that must be met both before and after DSM; and

ii) The contribution of each individual existing or currently planned generation resource included in SPC's preferred supply plan to meeting the annual system energy requirement.

iii) For each generation resource, please indicate whether it is considered to be a baseload, intermediate, peaking or intermittent resource.

Response:

This response contains confidential information and cannot be released publicly. A complete response was submitted to the Saskatchewan Rate Review Panel for their review.

SRRP Q143:

Reference: **Resource Supply Plan**

Please provide a table that summarizes, for each year from 2016 through 2035, the annual capital spending by project or program required to implement SaskPower's preferred supply plan.

Response:

This response contains confidential information and cannot be released publicly. A complete response was submitted to the Saskatchewan Rate Review Panel for their review.

SRRP Q144:

Reference: Resource Supply Plan

a) Please provide a table that summarizes the average cost of energy per MWh (including capital costs, fuel expenses and non-fuel OM&A) (preferably in 2016 dollars) for each new generation resource planned to be added from 2016 through 2035.

b) Please provide all assumptions and rationale used to derive the estimates provided in part (a) including availability assumptions for intermittent resources such as wind or solar.

c) For comparison purposes, please provide the average levelized cost of energy per MWh (including capital costs, fuel expenses and non-fuel OM&A) for SaskPower's existing generation resources by type (e.g. hydroelectric, natural gas, wind, coal).

Response:

This response contains confidential information and cannot be released publicly. A complete response was submitted to the Saskatchewan Rate Review Panel for their review.

SRRP Q145:

Reference: **Resource Supply Plans**

Please describe the criteria SaskPower uses, in addition to average unit costs of generation, to select generation resources in its Resource Supply Plan. Where appropriate, please provide examples of how these criteria are considered, ranked and/or quantified.

Response:

SaskPower utilizes a least cost planning methodology while considering existing and potential regulatory requirements and corporate objectives to select generating resources in its Resource Supply Plan. SaskPower's decision to add wind generation is an example of this as it is a low cost option which assists SaskPower in reducing greenhouse gas emissions.

SRRP Q146:

Reference: **Resource Supply Plans**

Please describe the supporting infrastructure, including transmission and distribution upgrades, required to implement SaskPower's preferred resource supply plan.

Response:

Internal coordination is performed in the development of all of SaskPower's plans (Resource Supply, Transmission, Distribution, etc.).

Supporting infrastructure for generation projects in SaskPower's preferred resource supply plan is assessed and implemented on a project by project basis once technical details (location, size, equipment, etc.) of the resource option are finalized.

As the implementation date for generation projects identified in the preferred resource supply plan get closer and closer, the projects are assessed in further detail and planned system upgrades are refined and optimized prior to implementation.

Potential supporting infrastructure projects are budgeted and planned for to facilitate SaskPower's overall needs. As an example, transmission reinforcements between the Swift Current, Moose Jaw, and Regina areas are being developed to facilitate future generation projects as well as for other system benefit purposes, such as mitigating aging infrastructure and accommodating load growth.

SRRP Q147:

Reference: Resource Supply Plans

Please provide updates with respect to any partnership or stand-alone hydro projects envisioned within the 20 year planning horizon.

Response:

SaskPower, in partnership with the Black Lake First Nation, is working to develop an approximately 50-MW hydroelectric facility in northern Saskatchewan called the Tazi Twé Hydroelectric Project. This project is currently going through a review process before a final decision is made on whether to proceed. If a decision is made to proceed, it is anticipated that this project could go into full operation by as early as 2020.

SaskPower is also exploring a number of potential future hydroelectric facilities in Saskatchewan, however these projects are still in a very preliminary stage and no decisions have been made to begin the development of any of these projects.

SRRP Q148:

Reference: **Community Partnerships and Investment Policy**

Please explain how SaskPower ensures its community investments reflect industry best practice and are benchmarked by other professional organizations.

Response:

SaskPower is governed by the Board of Directors-approved Community Partnership & Investments Policy. The Crown Investments Corporation of Saskatchewan directs SaskPower to contribute 1% of net income to community investments based on Imagine Canada Caring Company guidelines. The 1% is calculated annually based on a five-year rolling average. The policy is included here as an appendix.

SaskPower embarked on developing a new policy in 2012, which was approved and implemented in 2014.

SaskPower hired the SiMPACT Strategy Group to lead SaskPower in developing the new policy. SiMPACT is a leading organization that provides consulting and advisory services that ensure current activity is understood in relation to best and emerging practice. It conducted a series of interviews with SaskPower leaders to determine objectives in order to create a policy that reflected community and business values.

SaskPower's current policy reflects our core strategic priorities and supports education programs that change behaviours and attitudes so customers stay safe around electricity, conserve power, and protect our environment. The policy's targeted demographics align to our business needs: Aboriginal people, youth and a broad provincial representation.

SiMPACT also facilitates LBG (London Benchmarking Group) Canada, a network of companies striving to maximize the value of corporate investment into Canadian communities. SaskPower was an active member of LBG Canada from 2010 to 2014.

SECTION: Communications
SUBJECT: Community Partnerships & Investment Policy
Effective Date: January 1, 2016

POLICY STATEMENT:

SaskPower's strategic plan requires us to gain social license and public trust as we rebuild lines, add new generation and support provincial growth. This policy outlines SaskPower's commitment to align our Community Partnerships & Investment program to the company's strategic direction while also making a real difference to our community partners.

Our Community Partnerships & Investment program encompasses community investment, employee volunteering, sponsorship, community relations, stakeholder relations, CIC provincial projects and executive support. Of these categories, community investment is the primary focus of this policy.

SaskPower seeks to ensure in all community investment:

- All Community Investment opportunities are of mutual benefit to SaskPower and Saskatchewan communities
- The company's three key messages are evident in every Community Investment program and initiative we support:
    - Investing responsibly for the future
    - Safety
    - Conservation and efficiency
- Our audiences easily make the connection from our community activities to SaskPower's business and message
- Our audiences associate SaskPower with specific sponsorships and community initiatives, unprompted
- Our program is considered industry best practice and benchmarked by other professional organizations

ELIGIBILITY for community investment:

SaskPower's Community Investment program is focused on education programming. By educating our audiences about behaviour change, we align to SaskPower's business priorities and leave a lasting mark in our communities:

- Workforce excellence — building our next generation of employees
- Safety — keeping our customers safe around electricity
- Conservation and efficiency — creating a community of customers who find ways to save power and protect our environment

Targeted demographics align to business needs:

- Aboriginal
- Youth
- Broad provincial representation

Through the broad Community Partnerships & Investment program funds are also set aside for planned activities in the following categories:

- Executive support. Visibility of SaskPower's executive team is important to SaskPower's reputation. A portion of our annual sponsorship budget will be reserved for these activities, at the discretion of the President.
- Crown alignment. Through CIC, each Crown contributes to major initiatives deemed worthy of a united Crown presence.
- Stakeholders. The purpose of our stakeholder initiatives is to build business relationships in communities across the province. We find speaking and engagement opportunities with relevant organizations aligned to our messages and designed to enhance our relationships with community leaders.
- Promotional items. In order to be present at smaller community events, we distribute promotional items at a grassroots fundraising level. Any Saskatchewan organization raising money for a Saskatchewan non-profit or charity project or event will be eligible for a promotional item to assist in their efforts once per calendar year.

CONDITIONS/PREREQUISITES:

Program Governance

- All sponsorships are reviewed annually to ensure objectives of both parties are met.
- All applications must be completed online.
- All SaskPower donations are managed out of the corporation's Community Partnerships & Investment group within Corporate Communications.
- Sponsorship opportunities are reviewed and decisions made in consultation with business units to ensure strategic corporate needs are met.

Ineligible groups/individuals include:

- Out-of-province organizations (unless approved by the President & CEO)
- Individuals
- Political organizations and political parties
- Advocacy groups
- Organizations that discriminate on the basis of ethnic origin, gender, sexuality, colour, language, national or social origin, economic status, religion, political or other contentiously held beliefs
- Religious organizations and churches (unless providing community services and activities without promoting religious or other contentiously held beliefs)
- Travel, accommodation, meal expenses, field trips or tours

- Organizations that rely upon SaskPower as the sole funder for its operations or, are seeking investment for capital projects
- Organizations without a tax-registered number or non-profit society number
- For-profit community endeavors
- Donation of electricity or electrical services

ADDITIONAL INFORMATION:

Groups that meet eligibility requirements may be denied funding due to budget constraints.

As part of major project development in communities where SaskPower is expanding operations, exceptions for significant or capital contributions may be made at the discretion of the President and CEO. These contributions are considered outside of the Community Partnerships & Investment Policy and must be budgeted as part of the project.

INQUIRIES: Verna Williamson
Manager Community Partnerships & Investment
Communications, 306-566-3575

APPENDICES: n/a

RELATED POLICIES: Code of Conduct Policy, Aboriginal Relations Policy.

REFERENCE/AUTHORITY: N/A

Approved by: SaskPower Board of Directors as the Community Engagement Policy
December 12, 2013

2016 and 2017 RATE APPLICATION
SRRP INTERROGATORIES

SRRP Q149:

Reference: **Other General**

Please provide a copy of the 2016 Corporate Balanced Scorecard: Definitions document.

Response:

A copy is attached.

2016-17 CORPORATE BALANCED SCORECARD: DEFINITIONS

SaskPower
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M1. Customer Experience Index (residential/business/industrial) (10-point scale)

DEFINITION:

The objective of the Customer Experience Index metric is to measure the value of customer experience from the customer's perspective and allow SaskPower to identify specific operational areas, practices and brand equity attributes that impact customer experience the most.

The index is comprised of the results of questions asked in SaskPower's customer experience residential, business and industrial surveys. It is the sum of weighted scores for four core areas: customer perceptions about SaskPower, contact experience, products and services and value for money. These drivers will prioritize areas for improvement based on how much impact they have on the overall experience score and capture the role other business units play in delivering to the customer.

UNIT OF MEASUREMENT:

10-point scale

FORMULA/METHODOLOGY:

Residential

(Customer perceptions score x 32%) + (contact experience score x 28%)
+ (products & services rating score x 22%) + (value score x 18%)

Where:

Customer perceptions score = (trust score x 45%) + (values my business score x 42%) + (favourability score x 13%)

Contact experience score = (easy to do business with score x 50%) + (puts the customer first score x 50%)

Products & services rating score = (I feel in control of my service score x 66%) + (overall satisfaction score x 34%)

Value score = (SaskPower provides good value for the price paid score x 100%)

Business

(Customer perceptions score x 28%) + (contact experience score x 28%)
+ (products & services rating score x 25%) + (value score x 19%)

Where:

Customer perceptions score = (trust score x 50%) + (values my business score x 50%)

Contact experience score = (goes the extra mile score x 50%) + (committed to meeting expectations score x 50%)

Products & services rating score = (I feel in control of my service score x 50%) + (overall satisfaction score x 50%)

Value score = (SaskPower provides good value for the price paid score x 100%)

Industrial

(Customer perceptions score x 20%) + (contact experience score x 25%) + (products & services rating score x 30%) + (value score x 25%)

Where:

Customer perceptions score = (trust score x 25%) + (competence score x 25%) + (transparency score x 25%) + (planning for the future score x 25%)

Contact experience score = (easy to do business with score x 50%) + (puts me in control of my service score x 50%)

Products & services rating score = (delivers what they promise score x 50%) + (overall satisfaction score x 50%)

Value score = (SaskPower provides good value for the price paid score x 100%)

TARGETS:
The targets for the residential and industrial components of the Customer Experience Index were developed using a baseline established in 2013. The target for the business component was established in 2015. The long-term target was set to show incremental improvement over the baseline.

INDUSTRY COMPARABILITY:
Unique to SaskPower.

M2. New Connect Construction Index (%)

DEFINTION:
The New Connect Construction Index is a volumetric weighted average of new connect orders based on whether or not targets were met. There are targets for three types of new connect orders included in the index:

- Prepaid notifications, whose target is completion before the later of the need date provided by the customer or the 10-day cycle time from the time a request is made for the service to the customer being connected.
- Complex orders, whose target is completion before the later of the need date provided by the customer or the 90-day cycle time from the customer quote acceptance to the customer being connected.
- Non-complex orders, whose target is completion before the later of the need date provided by the customer or the 45-day cycle time from customer quote acceptance to the customer being connected.

UNIT OF MEASUREMENT:
Percentage

FORMULA/METHODOLOGY:

$$\frac{\text{(Complex orders within target) + (non-complex orders within target) + (prepaid notifications within target)}}{\text{(Total completed complex orders) + (total completed non-complex orders) + (total completed prepaid notifications)}}$$

TARGETS:
Based on management discretion.

INDUSTRY COMPARABILITY:
Unique to SaskPower.

M3. Demand side management (DSM) peak demand/energy savings (megawatts (MW)/gigawatt hours (GWh))

DEFINITION:
The objective of this metric is to assess the progress being made in saving energy through DSM programs. It measures electricity demand reduction in MW and volume of energy saved in GWh achieved through various programs delivered at customers' sites annually. The accumulated demand reduction will be achieved through energy efficiency and conservation measures, demand response and system improvement programs.

UNIT OF MEASUREMENT:
MW/GWh

FORMULA/METHODOLOGY:

$$\frac{\text{Kilowatt hour (KWh) (per DSM program)}}{\text{Co-efficient (for specific end use)}} = \text{kilowatt (KW)} \qquad \frac{\text{KW}}{1000} = \text{MW}$$

Megawatts for each DSM project are summed to determine the overall DSM savings.

Base KWh - new unit KWh +/- adjustments = net savings

TARGETS:
Targets are set based on forecasting for the entire portfolio of DSM programs.

INDUSTRY COMPARABILITY:
Many utilities track savings attributed to DSM. Industry guidelines for the metric include the California Framework for Evaluation and the International Performance Measurement and Verification Protocol (IPMVP).

M4. Employee engagement (%)

DEFINITION:
This metric reflects the number of employees who indicate that they are highly engaged as recorded in the annual employee engagement survey.

Employee engagement is defined by specific attitudes and behaviours: say (speaking positively about SaskPower), stay (demonstrating loyalty) and strive (putting forward best efforts). The engagement survey incorporates all three drivers of engagement.

UNIT OF MEASUREMENT:
Percentage

FORMULA/METHODOLOGY:
An online employee engagement survey link is emailed to active employees and select contractors. The core measures of say, stay, and strive in the survey ultimately determine SaskPower's engagement score. Six questions comprise the overall score, and a six-point scale is used for each question. The engagement model is weighted most heavily to employees' rating of say (37% of the total engagement score), versus stay (33% of the score) or strive (30% of the score).

The three core measures are used as dependent variables in a modeling analysis called PLS (partial least squares) Path in order to determine their weighting (or relative importance) from employees' perspectives. This analysis also reveals which drivers (independent variables) impact the scores most. Ultimately, identifying the relationship between the engagement core measures and key drivers allows SaskPower to make meaningful choices about what areas to focus on in order to improve engagement among employees.

TARGETS:
Based on management discretion.

INDUSTRY COMPARABILITY:
Widely used in the utility industry and other sectors.

M5. Diversity hires (net)

DEFINITION:
This metric demonstrates the diversity of SaskPower's workforce through the change in the number of diversity employees in four designated areas: Aboriginal people; women in non-traditional roles; people with disabilities; and visible minorities. It reflects the number of diversity employees added through the hiring process minus the number of diversity employees who have departed the organization.

Only **core** employees are included within the calculation.

A **core** employee is permanent (full-time, part-time, seasonal, or reduced hours) and those on certain leaves of absence (education and training, maternity, parental, salary deferral, suspension without pay, or compassionate care).

UNIT OF MEASUREMENT:
Number

FORMULA/METHODOLOGY:

Net diversity hires[1] = new hires + rehires + changes from temporary to full-time – diversity retirements, resignations and dismissals

1. Regardless of whether diversity employees qualify for one or multiple designated areas (Aboriginal people; women in non-traditional roles; people with disabilities; and visible minorities) they are only counted in the designated area identified as their primary designation on their self-declaration form.

   The previous methodology counted diversity employees in each designated area they qualified for based on all designations made on their self-declaration form, resulting in some diversity employees being counted multiple times.

TARGETS:
Based on management discretion.

INDUSTRY COMPARABILITY:
Unique to SaskPower.

M6. Safety Index

DEFINITION:
The Safety Index measures SaskPower's performance in meeting its targeted safety objective across eight separate measures. The eight measures are made up of four leading indicators and four lagging indicators.

Leading indicators measure proactive activities that identify hazards, and assess, eliminate, minimize and control risks. They evaluate the effectiveness of safety programs and contribute to the prevention of incidents before they occur. Leading indicators include safety objectives, safety training, audit corrective/preventative actions and work observations.

Lagging indicators record safety performance related to the occurrence of safety incidents, and include lost-time injury frequency, lost-time injury severity, recordable injury frequency and motor vehicle incident frequency.

UNIT OF MEASUREMENT:
Percentage

FORMULA/METHODOLOGY:

Safety Index = (safety objectives x 12.5%) + (safety training x 12.5%) +
(audit corrective/preventative actions x 12.5%) + (work observations x12.5%) +
(lost-time injury frequency x 12.5%) + (lost-time injury severity x 12.5%) +
(recordable injury frequency x 12.5%) + (motor vehicle incident frequency x 12.5%)

Where:

Each indicator result is limited to a minimum of 0 and a maximum of 100.

Leading indicator results are calculated as:

$$\frac{\text{Indicator actual}}{\text{Indicator target}}$$

Lagging indicator results are calculated as:

$$1- \frac{\text{Indicator actual} - \text{indicator target}}{\text{Indicator target}}$$

Leading indicators

Safety objectives completed

Safety objectives are the organization's goals for safety. The objectives will be consistent with SaskPower's safety policy, including commitments to the prevention of injury and ill health, to compliance with the organization's applicable legal requirements, and to continual improvement. This measure reports the percentage of completed versus scheduled safety objectives as follows:

$$\text{Safety objectives completed (\%)} = \frac{\text{Number of completed objectives (activities)}}{\text{Number of scheduled objectives (activities)}} \times 100$$

Safety training

Safety training is essential to ensure our employees are qualified and competent to perform their jobs. This measure reports the percentage of completed versus scheduled mandatory safety training as follows:

$$\text{Mandatory safety training completed (\%)} = \frac{\text{Number of completed mandatory safety training}}{\text{Number of scheduled mandatory safety training}} \text{ X 100}$$

Safety audits corrective/preventive actions completed (%)

Safety audits measure how well the safety management system is being implemented and maintained and its effectiveness in meeting the organization's safety policy and objectives. Corrective and preventive actions are taken to eliminate the cause of a detected nonconformity or other undesirable situation found as a result of an audit. Corrective action is taken to prevent recurrence whereas preventive action is taken to prevent occurrence. This measure reports the percentage of completed versus reported corrective and preventive actions.

$$\text{Safety audit corrective/ preventive actions completed (\%)} = \frac{\text{Number of completed corrective and preventive actions}}{\text{Number of corrective and preventive actions reported}} \text{ X 100}$$

Work observations completed (%)

A work observation is a formal process where an employee is observed performing a job or task and is provided coaching on what was observed in the interest of safety. Work observations are designed to help communicate the safety responsibilities and expectations of management, supervisors and workers, and are used to identify good work practices as well as opportunities for improvement. This measure reports the percentage of completed work observations versus scheduled.

$$\text{Work observations completed (\%)} = \frac{\text{Number of completed work observations}}{\text{Number of scheduled work observations}} \text{ X 100}$$

Lagging indicators

Lost-time injury frequency rate

The lost-time injury frequency rate is a corporate-wide indicator. It calculates the number of lost-time injuries, normalized in relation to the total number of employee work hours in the injured worker's department. The normalization is done based on the formula designed by the Canadian Electricity Association (CEA) as follows:

$$\text{Lost-time injury frequency rate} = \frac{\text{Number of lost-time injuries x 200,000 hours}}{\text{Exposure hours}}$$

Lost-time injury severity rate

The lost-time injury severity rate is a corporate-wide indicator. It measures the number of calendar days lost due to lost-time injuries, normalized according to the total number of employee work hours in the injured worker's department. The normalization is done based on a standard formula designed by the CEA as follows:

$$\text{Lost-time injury severity rate} = \frac{\text{Number of calendar days lost x 200,000 hours}}{\text{Exposure hours}}$$

Recordable injury frequency rate

The recordable injury frequency rate is a corporate-wide indicator. It calculates the number of recordable injuries, normalized in relation to the total number of employee work hours in the injured worker's department. A recordable injury is any occupational injury/illness that results in an employee experiencing:

a) Fatality;
b) Lost-time injury;
c) Medical treatment injury; or
d) Other injury/illness (not captured above), which has:
    i. Restricted work; or
    ii. Significant occupational injury/illness; or
    iii. Loss of consciousness.

The normalization is done based on the formula designed by the CEA as follows:

$$\text{Recordable injury frequency rate} = \frac{\text{Number of recordable injuries x 200,000 hours}}{\text{Exposure hours}}$$

Recordable Licensed Fleet Motor Vehicle (LFMV) frequency rate

A recordable licensed fleet motor vehicle incident includes any licensed fleet motor vehicle incident involving a motor vehicle being operated by an employee that meets the recordable injury criteria or costs more than $5,000 in total property damage. The recordable licensed fleet motor vehicle incident frequency rate is done based on the formula designed by the CEA as follows:

$$\text{LMFV frequency rate} = \frac{\text{Number of recordable LFMV incidents x 1,000,000 kilometres}}{\text{LFMV kilometres driven}}$$

TARGETS:
Leading indicator targets are based on management discretion. Lagging indicator targets are based on a five-year average of the CEA Group 1 Composite.

INDUSTRY COMPARABILITY:
The Index is unique to SaskPower however some indicators included in the Index are comparable to other Canadian Utilities.

M7. Return on equity (ROE) (operating/net income) (%)

DEFINITION:
ROE is a measure of operating and net income for the year expressed as a percentage of average equity. The objective of the ROE is to measure a company's profitability.

UNIT OF MEASUREMENT:
Percentage

FORMULA/METHODOLOGY:

$$\frac{\text{Operating income}}{\text{Average equity}} \text{ x 100\%} \qquad \frac{\text{Net income}}{\text{Average equity}} \text{ x 100\%}$$

TARGETS:
The current year target is based on the current SaskPower Business Plan.

SaskPower's long-term ROE target is based on a market analysis of an appropriate ROE for Canadian electric utilities adjusted for SaskPower's specific risk profile.

INDUSTRY COMPARABILITY:
Widely used – benchmarked with other Canadian utilities.

M8. Per cent debt ratio (%)

DEFINTION:
Per cent debt ratio measures the total investment by creditors (debt) with the total investment of the owners (equity). The more debt capital a company has in it is capital structure, the more highly leveraged the company. A highly leveraged company is considered to have less financial flexibility and more risk than a lower leveraged company.

UNIT OF MEASUREMENT:
Percentage

FORMULA/METHODOLOGY:

$$\frac{\text{Debt}^{1}}{\text{Debt}^{1} + \text{equity}} \times 100\%$$

1. Debt = (long term debt + short term advances + finance lease obligations + bank indebtedness – debt retirement funds – cash and cash equivalents)

TARGETS:
The current year target is based on the current SaskPower Business Plan.

The long-term target was set with the objective of enabling SaskPower to finance its capital program while preserving our company's financial flexibility. A benchmarking of other publicly owned electric utilities was also used to validate the reasonability of the target.

INDUSTRY COMPARABILITY:
Widely used – benchmarked with other Canadian utilities; however, inclusion of finance lease obligations may vary.

M9. Operating, maintenance and administration (OM&A)/property, plant and equipment (PP&E) (%)

DEFINITION:
OM&A/PP&E provides a measure of OM&A expenses expressed as a percentage of the total PP&E. Its objective is to illustrate whether or not SaskPower's asset management program is optimally managing assets and their performance. The growth in SaskPower's asset base is considered to be a key driver of OM&A costs.

UNIT OF MEASUREMENT:
Percentage

FORMULA/METHODOLOGY:

$$\frac{OM\&A}{PP\&E^{1}} \times 100\%$$

1. PP&E = PP&E + intangible assets

TARGETS:
Based on the current SaskPower Business Plan.

INDUSTRY COMPARABILITY:
OM&A/PP&E information is collected from other utilities, however definitions of OM&A and PP&E may vary.

M10. Aboriginal procurement (%)

DEFINITION:
This metric measures the extent to which SaskPower engages in Saskatchewan Aboriginal sourced procurement relative to total Saskatchewan procurement. The Aboriginal procurement metric demonstrates SaskPower's dedication to involve Aboriginal people in economic opportunities and growth.

UNIT OF MEASUREMENT:
Percentage

FORMULA/METHODOLOGY:

$$\frac{\text{YTD direct Aboriginal procurement}^{1}\text{ purchase orders (PO) issued + YTD Aboriginal procurement non-PO spend}^{2}\text{ + YTD indirect Aboriginal procurement}^{3}}{\text{YTD Saskatchewan procurement}^{4}}$$

1. Direct Aboriginal procurement is defined as procurement from Aboriginal-owned companies. The procurement value is based on PO issued, not PO spend.
2. Non-PO spend is defined as payments issued to an Aboriginal supplier without an associated PO.
3. Indirect Aboriginal procurement is defined as Aboriginal sources employed by non-Aboriginal-owned companies; such as subcontracting to Aboriginal persons or suppliers.
4. Saskatchewan procurement is defined as procurement from vendors with a Saskatchewan presence or billing address.

TARGETS:
Based on management discretion.

INDUSTRY COMPARABILITY:
Unique to SaskPower.

M11. Competitive rates (thermal utilities) (%)

DEFINITION:
The thermal rate comparison is the comparison of the monthly revenue collected by SaskPower through rates for a typical residential, small commercial, standard commercial and power class (industrial) customer to the monthly revenue collected by other similar (thermal) utilities across Canada. The objective of the measure is to ensure that SaskPower's rates for typical customer classes are less than or equal to other Canadian thermal utilities.

UNIT OF MEASUREMENT:
Percentage

FORMULA/METHODOLOGY:
Rate information in the categories of residential, small, medium and large power customers is published annually as of April 1 by Hydro-Québec in a document called the *Comparison of Electricity Prices in Major North American Cities.* Results are generally released by Hydro-Québec in the summer.

Thermal generation refers to using coal, natural gas, oil or nuclear, as opposed to supplying most of the utility's load with low-cost hydro generation. Canadian thermal utility cities include: Calgary, AB; Edmonton, AB; Toronto, ON; Ottawa, ON; Halifax, NS; Charlottetown, PEI; St. John's, NL; and Moncton, NB.

The ratio of SaskPower's average monthly net bills (before municipal surcharges and taxes) to the average of the monthly net bills for the other Canadian thermal utilities is calculated for the four categories of residential, small, medium and large power customers. The average of these four ratios, reported as a percentage, is used.

TARGETS:
SaskPower's objective is to ensure that its rates are equal to or less than that of other thermal utilities in Canada.

INDUSTRY COMPARABILITY:
Widely used – benchmarked with other Canadian utilities.

M12. Equivalent availability factor (EAF) (%)

DEFINITION:
The EAF represents the percentage of time that a generating unit is capable of producing electricity. The EAF is adjusted for any temporary reductions in generating capability due to equipment failures, maintenance or other causes. Although higher EAF percentages are better, targets are set giving consideration to prudent maintenance requirements.

SaskPower chooses to use EAF over all other generation reliability metrics because it represents availability once all lost production has been removed (including planned outages, forced outages and derates), therefore making it suitable for establishing production targets.

UNIT OF MEASUREMENT
Percentage

FORMULA/METHODOLOGY:

$$\frac{\text{Number of hours in period - equivalent outage time}}{\text{Number of hours in the period}} \times 100 = (1 - \text{Incapability Factor}) \times 100$$

TARGETS:

The targets for EAF are based on the following components (as a result, the EAF target from year-to-year is not at static number):

- Fuel and purchased power budgets;
- A review of the previous 5-year production history and losses. Future maintenance cycles and unit conditions are factored in to provide a unit-by-unit basis forecast of performance for a 10-year outlook; and
- Annual meetings conducted with each plant to review the following year's EAF targets in detail, and to a slightly lesser extent the targets for the following nine years.

The long-term EAF target is set based upon the planned maintenance for the units. Included in the analysis are:

- Rebuilds (25-40 years apart);
- Refurbishments (20-25 years apart);
- Turbine/generator major overhauls (8-12 years apart on steam turbines and based on equivalent operating hours for gas turbines);
- Minor overhauls (24 months at Estevan, 18 months at Coronach);
- Routine overhauls (3-4 years on hydro units); and
- Unit retirements.

INDUSTRY COMPARABILITY:

Widely used – benchmarked with other Canadian utilities through reporting to the CEA. Reliability benchmarking is done annually via the CEA and the North American Electricity Reliability Corporation (NERC).

M13. Distribution system average interruption duration index (SAIDI) (hours)

DEFINITION:

The distribution SAIDI allows SaskPower to track its performance in responding to distribution outages. The index is defined as the amount of time an average customer experiences outages in a year.

The index allows SaskPower the opportunity to monitor performance and analyze where additional funding is required to improve the system.

UNIT OF MEASUREMENT:

Average number of hours per customer per year.

FORMULA/METHODOLOGY:

$$\frac{\text{Total outage hours x customers impacted}}{\text{Total customers served}}$$

TARGETS:

The targets are normally set based on a review of the:

- Level of spending for programs that support reliability;
- Condition of assets;
- Average age of assets with a link to timely asset replacement; and
- Review of the rolling 5-year average.

The long-term target is based on the average performance of the top three performing industry peers.

INDUSTRY COMPARABILITY:
Widely used – benchmarked through CEA member results.

M13. Distribution system average interruption frequency index (SAIFI) (outages)

DEFINITION:
The distribution SAIFI is defined as the number of interruptions per average customer per year. The objective of this measure is to analyze where additional funding is required to rebuild and improve the system.

UNIT OF MEASUREMENT:
Average number of interruptions per customer per year.

FORMULA/METHODOLOGY:

$$\frac{\text{Number of disruptions x customers impacted}}{\text{Total customers served}}$$

TARGETS:
Targets are normally set based on a review of the:

- Level of spending for programs that support reliability;
- Condition of assets;
- Average age of assets with a link to timely asset replacement; and
- Review of the rolling 5-year average.

The long-term target is based on the average performance of the top three performing industry peers.

INDUSTRY COMPARABILITY:
Widely used – benchmarked through CEA member results.

M14. Transmission system average interruption duration index (SAIDI) (minutes)

DEFINITION:
The objective of the transmission SAIDI is to allow SaskPower to track its performance in responding to transmission outages. The index provides a measure of the average total interruption duration that a typical Bulk Electrical Service Delivery Point (BESDP) experiences during a given period, usually one year. The index allows SaskPower the opportunity to monitor performance and take corrective action as necessary.

UNIT OF MEASUREMENT:
Minutes

FORMULA/METHODOLOGY:

$$\frac{\text{Minutes of disruption}}{\text{Number of Bulk Electrical Service Delivery Points (BESDP) monitored}}$$

TARGETS:

The targets are normally set based on a review of the:

- Level of spending for programs that support reliability;
- Condition of assets;
- Average age of assets with a link to timely asset replacement; and
- Review of the rolling 5-year average.

The long-term target is based on the average performance of the top three performing industry peers.

INDUSTRY COMPARABILITY:

Widely used – benchmarked through CEA member results.

M14. Transmission system average interruption frequency index (SAIFI) (outages)

DEFINITION:

The transmission SAIFI provides SaskPower the opportunity to monitor specific causes and frequency of outages, which may be used to take corrective action. It is defined as the average number of interruptions per Bulk Electrical Service Delivery Point (BESDP) in one year.

UNIT OF MEASUREMENT:

Average number of interruptions per customer per year.

FORMULA/METHODOLOGY:

$$\frac{\text{Number of interruptions}}{\text{Number of Bulk Electrical Service Delivery Points (BESDP) monitored}}$$

TARGETS:

The targets are normally set based on a review of the:

- Level of spending for programs that support reliability;
- Condition of assets;
- Average age of assets with a link to timely asset replacement; and
- Review of the rolling 5-year average.

The long-term target is based on the average performance of the top three performing industry peers.

INDUSTRY COMPARABILITY:

Widely used – benchmarked through CEA member results.

M15. Planned maintenance (distribution/transmission) (%)

DEFINITION:

The purpose of the planned maintenance metric is to show the proportion of distribution and transmission maintenance that is planned as opposed to reactive, as a percentage of total maintenance for both transmission and distribution.

UNIT OF MEASUREMENT:

Percentage

FORMULA/METHODOLOGY:

$$\frac{\text{Planned maintenance (operating \$)}}{\text{Total maintenance activities (operating \$)}} \times 100$$

TARGETS:

The targets for planned maintenance are based on the following:

- Maintenance spending;
- Condition of assets;
- Average age of assets linking to timely asset replacement;
- Review of the rolling 5-year average; and
- Annual adjustment to meet target.

INDUSTRY COMPARABILITY:

Unique to SaskPower.

M16. Hydro and renewable generation portfolio (%)

DEFINITION:

The objective of the metric is to show the increasing diversity in our fuel mix and is based on hydro and renewable fuel sources as a percentage of installed generation capacity (including Independent Power Producers (IPPs)), per the SaskPower Ten-Year Supply Plan. For purposes of this metric, supply sources include hydro, wind, biomass, flare gas, long-term firm capacity agreements for imports generated from hydro or renewable fuel sources, as well as Green Options Partners Program (GOPP) projects that include landfill gas, waste heat recovery and biogas.

UNIT OF MEASUREMENT:

Percentage

FORMULA/METHODOLOGY:

$$\frac{\text{Net hydro and renewable generating capacity}}{\text{Total net available generating capacity}} \times 100\%$$

TARGETS:

Based on SaskPower's Ten-Year Supply Plan.

INDUSTRY COMPARABILITY:

Unique to SaskPower.

SRRP Q150:

Reference: **Other General**

a) Please indicate how frequently NERC audits are completed.
b) Please discuss whether SaskPower has addressed all potential violations or deficiencies identified in the most recent NERC audit.

Response:

A) MRO-NERC on-site audits are conducted on a three- year cycle for SaskPower.
B) The September 2015 audit final report is still in the final stages of completion. Once completed and all possible violations are confirmed by the MRO through its review process, they will all be mitigated according to the agreed process.

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