SASKATCHEWAN RATE REVIEW PANEL ROUND ONE INTERROGATORY RESPONSES

[2018 Rate Application]

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2018 RATE APPLICATION
SRRP INTERROGATORIES

SRRP Q1 Reference: Application

A) When were the revenue and expenditure forecasts used in the application prepared? Please provide the date of the business plan that forms the basis of the application and identify the date of any updates to that business plan included in the application.

B) Please summarize any changes to SaskPower's chart of accounts or accounting treatments since the last rate application and advise of any resulting issues in comparability of figures from the last rate application and the current rate application.

Response:

A. The fuel and revenue numbers were based on the 2017 Q2 Fiscal Load Forecast, which was prepared in October 2016. All other expense categories were based on the five-year 2018 Rate Application Business Plan update, dated July 26, 2017. This update follows the original 2018 Business Plan, finalized on April 15, 2017.

B. No significant changes have been made to SaskPower's chart of accounts or accounting treatments since the last rate application, with the exception of the adoption of IFRS 9, *Financial Instruments,* effective April 1, 2017. Upon adoption of IFRS 9, SaskPower elected to apply hedge accounting to its outstanding natural gas hedges. As a result, any future changes in market value related to these natural gas hedges will be recognized in other comprehensive income.

   Previously, these changes in market value were recognized in net income as unrealized market value adjustments. Any realized gain/loss upon settlement of the hedges will be recognized in fuel and purchased power, which is consistent with prior years.

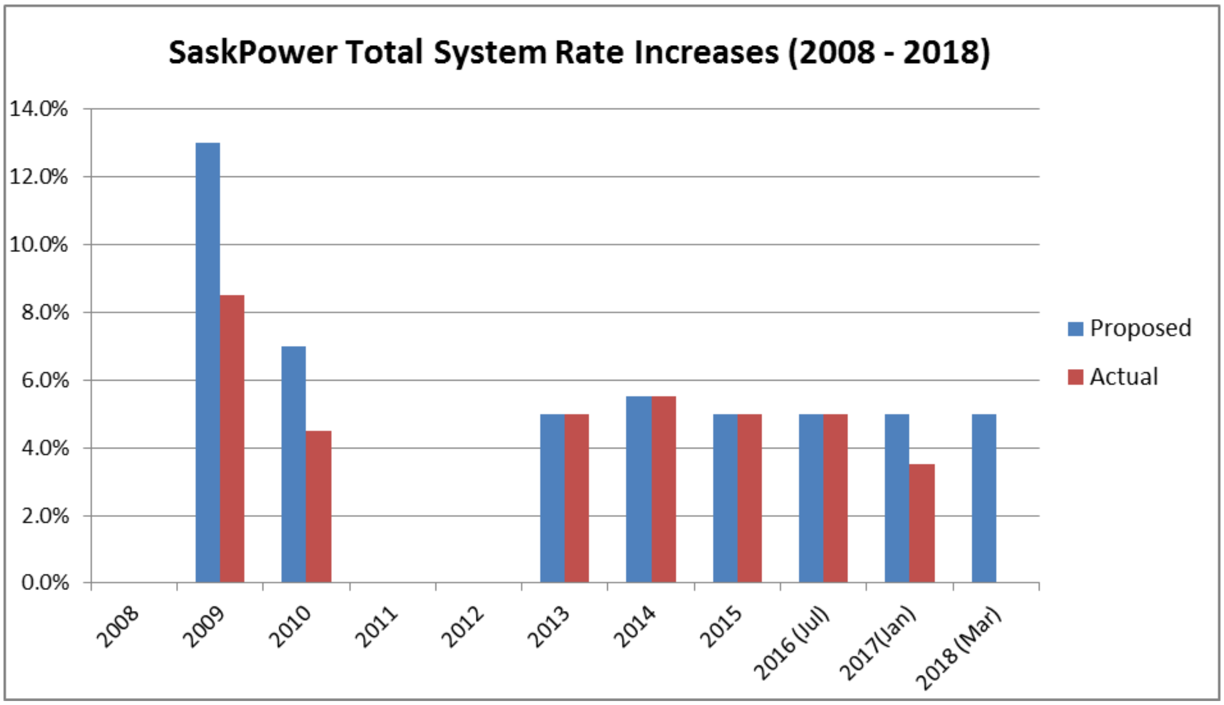
   In addition, under IFRS 9, changes in market value related to SaskPower's debt retirement funds (sinking funds) will also be recognized in other comprehensive income rather than unrealized market value adjustments in net income.

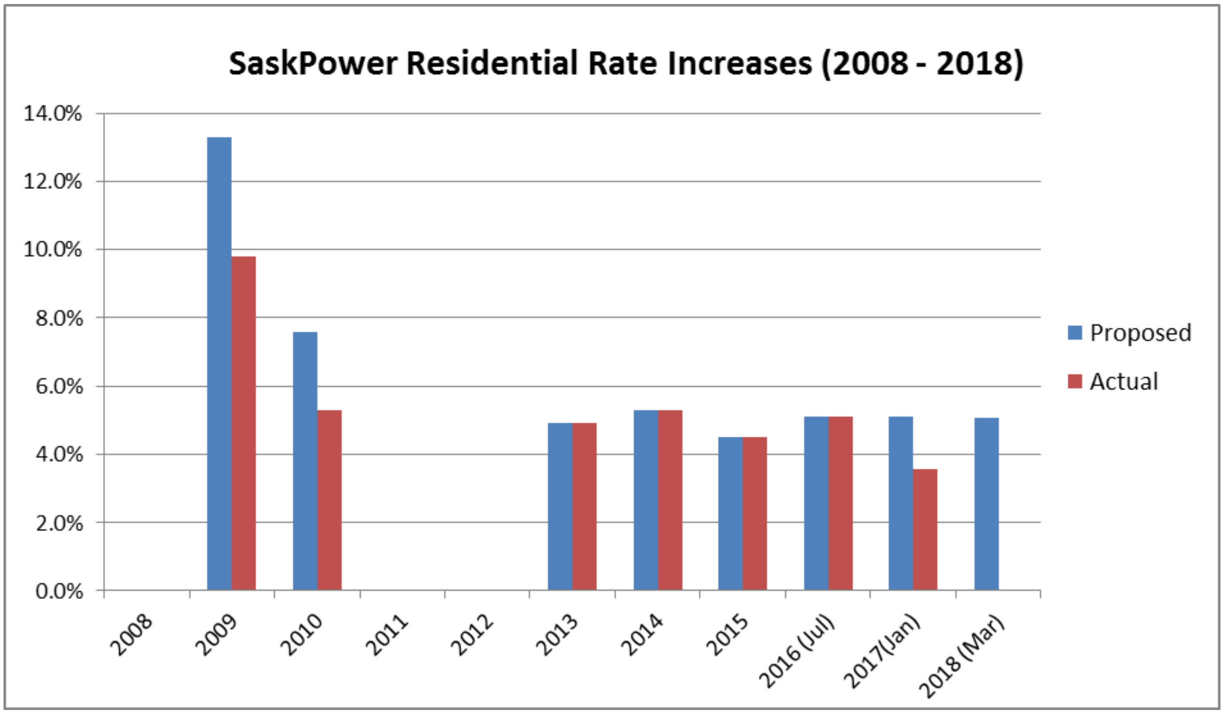
SRRP Q2	**Reference:**	**Application**

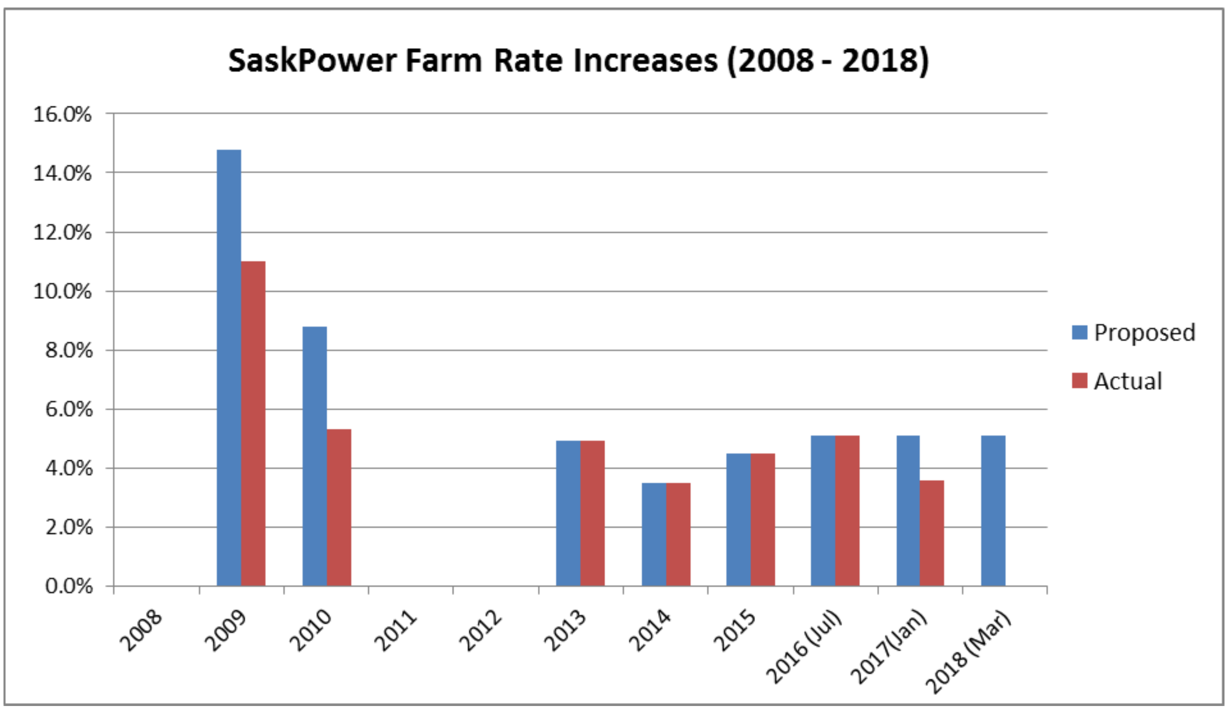
Please provide a graph which illustrates the actual and proposed percentage increases for each major customer group from 2008 through 2018-19.

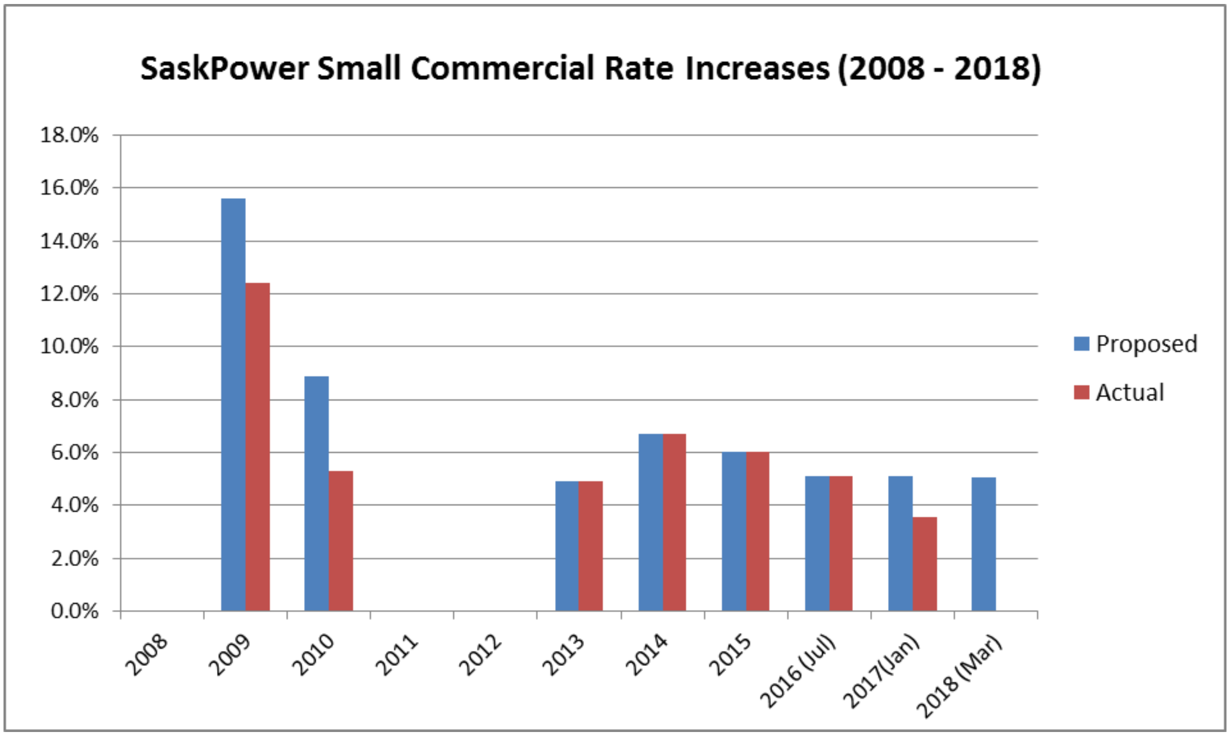
Response:

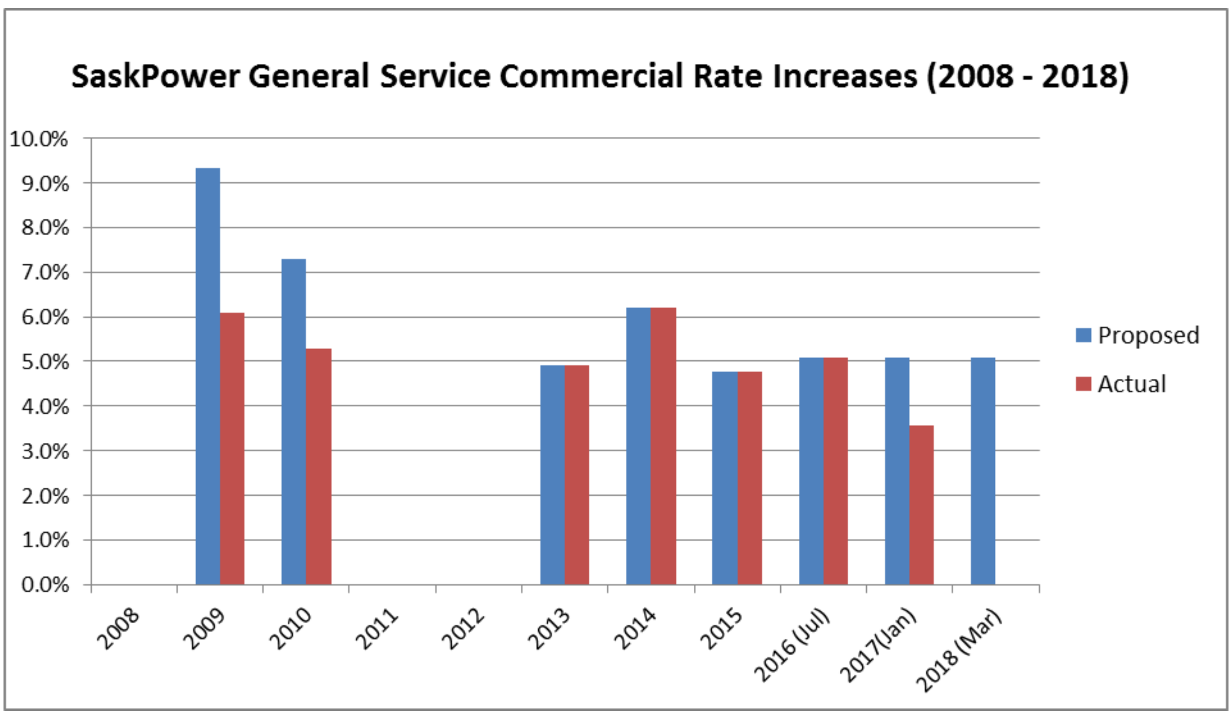
SaskPower's rate increases by each major customer group from 2008 to 2018 are as follows (the absence of data in 2008, 2011, and 2012 indicates no rate increases were implemented in those years):

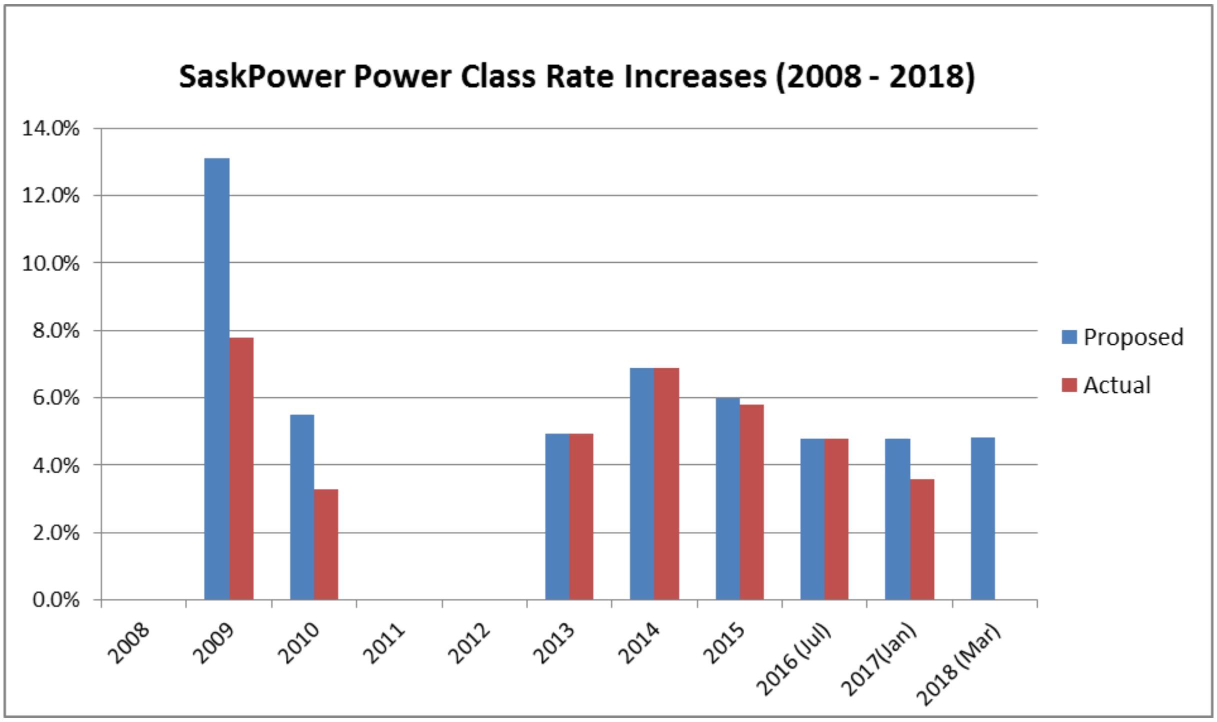


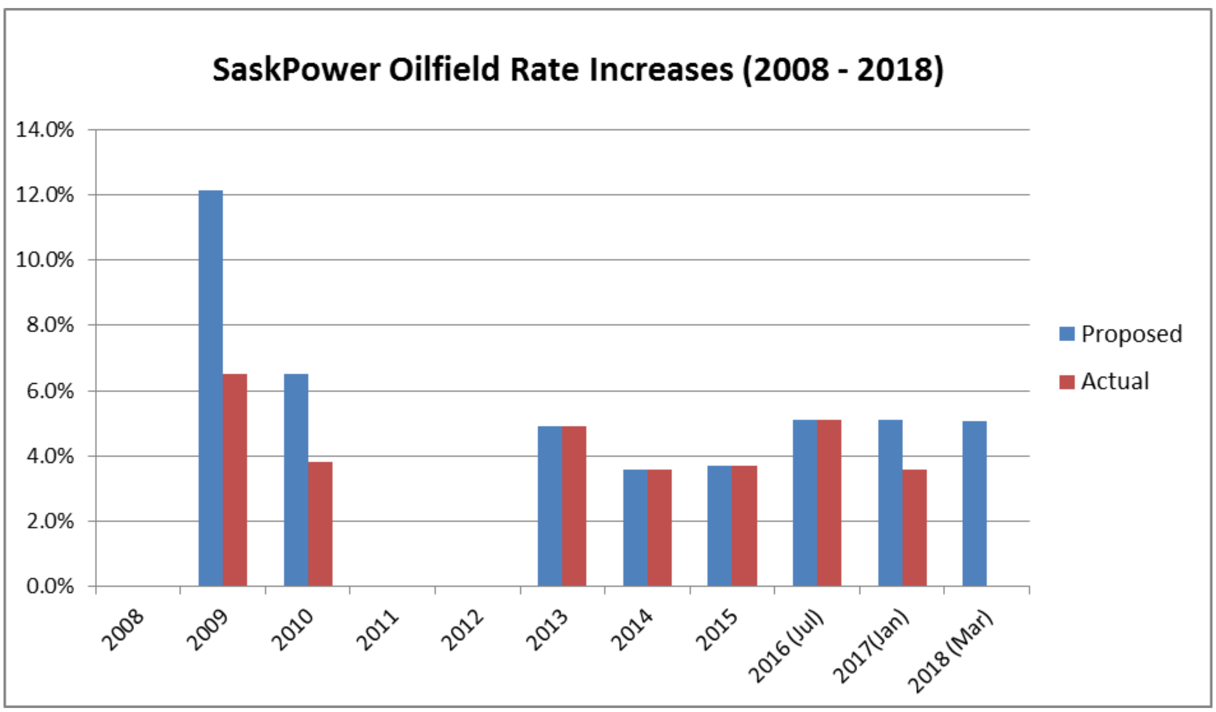

SaskPower Residential Rate Increases (2008 - 2018)
14.0%
12.0%
10.0%
8.0%
6.0%
4.0%
2.0%
0.0%
2008
2009
2010
2011
2012
2013
2014
2015
2016 (Jul)
2017(Jan)
2018 (Mar)
Proposed
Actual

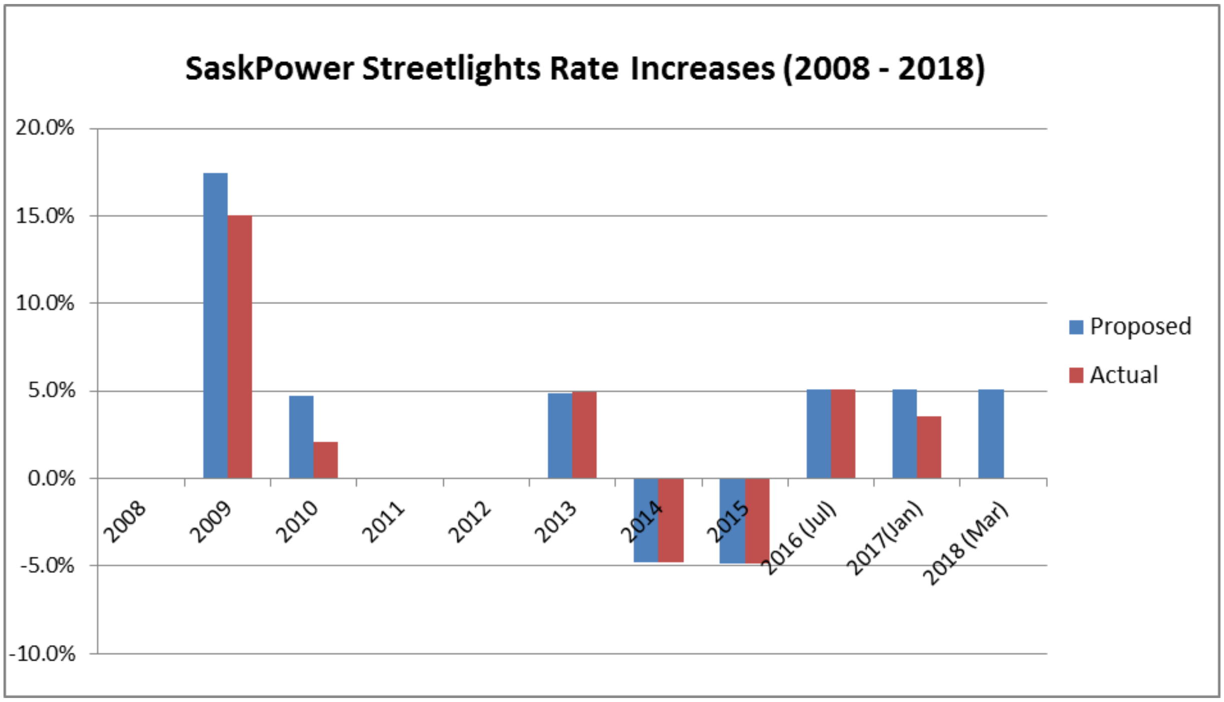

SaskPower Farm Rate Increases (2008 - 2018)
16.0%
14.0%
12.0%
10.0%
8.0%
6.0%
4.0%
2.0%
0.0%
2008
2009
2010
2011
2012
2013
2014
2015
2016 (Jul)
2017(Jan)
2018 (Mar)
Proposed
Actual

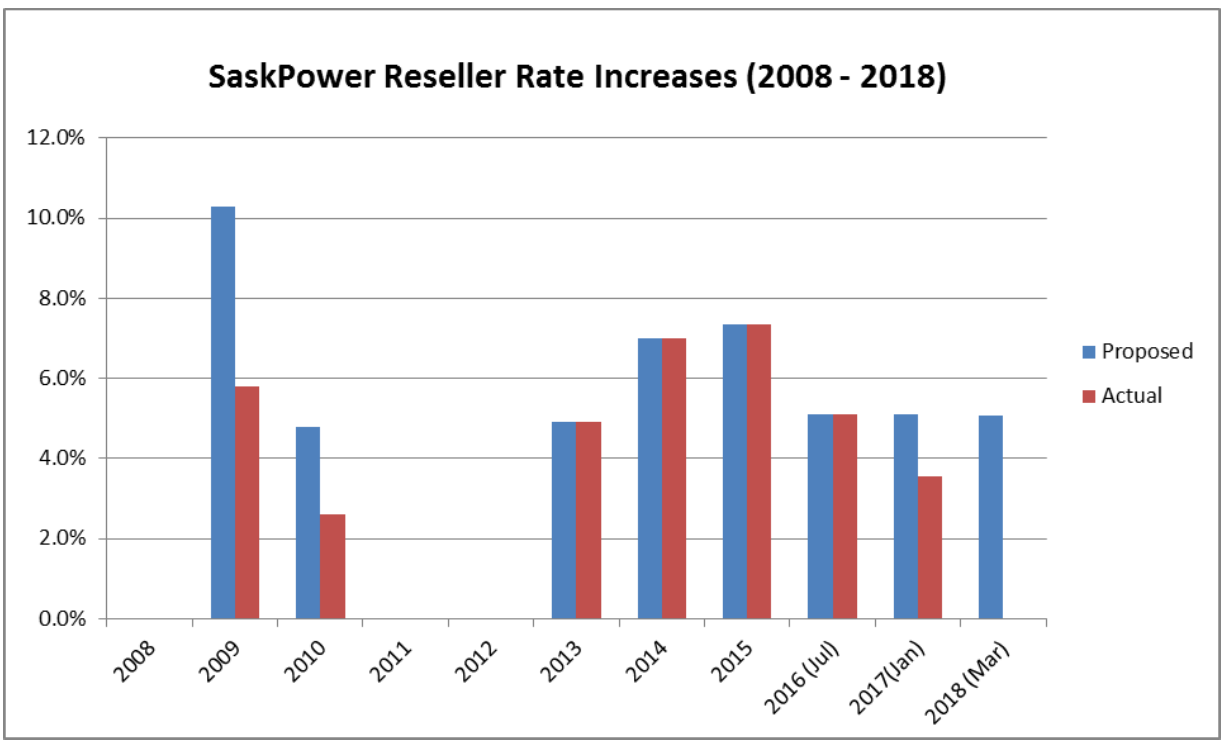

SaskPower Small Commercial Rate Increases (2008 - 2018)
18.0%
16.0%
14.0%
12.0%
10.0%
8.0%
6.0%
4.0%
2.0%
0.0%
2008
2009
2010
2011
2012
2013
2014
2015
2016 (Jul)
2017(Jan)
2018 (Mar)
Proposed
Actual


SaskPower General Service Commercial Rate Increases (2008 - 2018)
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)
2018 (Mar)
Proposed
Actual


SaskPower Power Class Rate Increases (2008 - 2018)
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)
2018 (Mar)
Proposed
Actual


SaskPower Oilfield Rate Increases (2008 - 2018)
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)
2018 (Mar)
Proposed
Actual


SaskPower Streetlights Rate Increases (2008 - 2018)
20.0%
15.0%
10.0%
5.0%
0.0%
-5.0%
-10.0%
2008
2009
2010
2011
2012
2013
2014
2015
2016 (Jul)
2017(Jan)
2018 (Mar)
Proposed
Actual


SaskPower Reseller Rate Increases (2008 - 2018)
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)
2018 (Mar)
Proposed
Actual

SRRP Q3 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 2017/18 and 2018/19 assuming each of the following potential rate scenarios:

A) Confirmation of a 5% average rate increase effective March 1, 2018 as applied for;
B) Confirmation of a 4% average rate increase effective March 1, 2018;
C) Confirmation of a 2.5% average rate increase effective March 1, 2018;
D) Confirmation of a 1% average rate increase effective March 1, 2018; and
E) No rate increase in the 2018/19 fiscal year.

Response:

The following table is a breakdown of the impact of the five rate increase scenarios noted above:

	A		B		C		D		E	
	2017/18	2018/19	2017/18	2018/19	2017/18	2018/19	2017/18	2018/19	2017/18	2018/19
Rate Increase	5.0%	0.0%	4.0%	0.0%	2.5%	0.0%	1.0%	0.0%	0.0%	0.0%
Revenue Lift	10.1	121.7	8.2	98.5	5.1	61.5	2.0	24.6	-	-
Sales revenue	2,428.7	2,566.6	2,423.9	2,543.3	2,420.8	2,506.4	2,417.8	2,469.5	2,415.7	2,444.9
Operating Income	159.9	209.7	157.8	186.4	154.8	149.5	151.7	112.6	149.7	88.0
Return on Equity	6.9%	8.5%	6.8%	7.6%	6.7%	6.1%	6.6%	4.7%	6.5%	3.7%
% Debt	75.8%	75.3%	75.9%	75.6%	75.9%	76.0%	75.9%	76.3%	75.9%	76.5%

SRRP Q4 Reference: Application

Please provide a continuity schedule of Plant in Service and Total Property, Plant and Equipment by function (generation, transmission, distribution, general) for the three most recent actual years and forecasts for 2017/18 and 2018/19.

Response:

The following table provides a continuity schedule of Plant in Service and Total Property Plant and Equipment by function for the years 2013 to 2016/17 and the forecasted amounts for 2017/18 and 2018/19:

Property, plant and equipment

(in millions)	Generation	Leased assets	Transmission	Distribution	Other	Construction in progress	Total
Cost or deemed cost							
Balance, January 1, 2014	$ 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	28	-	39	53	17	247	**384**
Disposals and/or retirements	(3)	-	(1)	(3)	(13)	-	**(20)**
Transfers	-	-	-	-	-	(142)	**(142)**
Balance, March 31, 2015	**$ 5,634**	**$ 1,233**	**$ 1,354**	**$ 3,350**	**$ 726**	**$ 1,158**	**$ 13,455**
Additions	757	-	547	264	69	931	**2,568**
Disposals and/or retirements	(35)	-	(12)	(25)	(26)	-	**(98)**
Transfers	-	-	-	-	-	(1,646)	**(1,646)**
Balance, March 31, 2016	**$ 6,356**	**$ 1,233**	**$ 1,889**	**$ 3,589**	**$ 769**	**$ 443**	**$ 14,279**
Additions	228	-	246	233	72	875	**1,654**
Disposals and/or retirements	(36)	-	(16)	(28)	(25)	-	**(105)**
Transfers	-	-	-	-		(778)	**(778)**
Balance, March 31, 2017	**$ 6,548**	**$ 1,233**	**$ 2,119**	**$ 3,794**	**$ 816**	**$ 540**	**$ 15,050**
Additions	132	-	306	212	471	220	**1,341**
Balance, March 31, 2018	**$ 6,680**	**$ 1,233**	**$ 2,425**	**$ 4,006**	**$ 1,287**	**$ 760**	**$ 16,391**
Additions	139	35	294	232	277	96	**1,073**
Balance, March 31, 2019	**$ 6,819**	**$ 1,268**	**$ 2,719**	**$ 4,238**	**$ 1,564**	**$ 856**	**$ 17,464**

Accumulated depreciation							
Balance, January 1, 2014	$ 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	42	14	8	24	10	-	**98**
Disposals and/or retirements	(2)	-	(1)	(2)	(3)	-	**(8)**
Transfers	-	-	-	-	-	-	**-**
Balance, March 31, 2015	**$ 2,327**	**$ 293**	**$ 496**	**$ 1,367**	**$ 292**	**$ -**	**$ 4,775**
Depreciation expense	196	57	38	103	44		**438**
Disposals and/or retirements	(31)	-	(3)	(21)	(19)	-	**(74)**
Transfers	-	-	-	-		-	**-**
Balance, March 31, 2016	**$ 2,492**	**$ 350**	**$ 531**	**$ 1,449**	**$ 317**	**$ -**	**$ 5,139**
Depreciation expense	217	56	45	105	46		**469**
Disposals and/or retirements	(32)	-	(5)	(22)	(17)	-	**(76)**
Transfers	-	-	-	-		-	**-**
Balance, March 31, 2017	**$ 2,677**	**$ 406**	**$ 571**	**$ 1,532**	**$ 346**	**$ -**	**$ 5,532**
Depreciation expense	**249**	**56**	57	**112**	68	214	**756**
Disposals and/or retirements	(4)				(40)	-	**(44)**
Transfers						-	**-**
Balance, March 31, 2018	**$ 2,921**	**$ 462**	**$ 628**	**$ 1,644**	**$ 374**	**$ 214**	**$ 6,244**
Depreciation expense	**257**	58	68.0	122	67	-	**572**
Disposals and/or retirements	(5)			(17)	(40)	-	**(62)**
Transfers						-	**-**
Balance, March 31, 2019	**$ 3,174**	**$ 520**	**$ 696**	**$ 1,749**	**$ 401**	**$ 214**	**$ 6,754**

Net book value							
Balance, January 1, 2014	**$ 2,115**	**$ 1,010**	**$ 682**	**$ 1,808**	**$ 361**	**$ 1,665**	**$ 7,641**
Balance, December 31, 2014	**$ 3,322**	**$ 954**	**$ 827**	**$ 1,955**	**$ 437**	**$ 1,053**	**$ 8,548**
Balance, March 31, 2015	**$ 3,307**	**$ 940**	**$ 858**	**$ 1,983**	**$ 434**	**$ 1,158**	**$ 8,680**
Balance, March 31, 2016	**$ 3,864**	**$ 883**	**$ 1,358**	**$ 2,140**	**$ 452**	**$ 443**	**$ 9,140**
Balance, March 31, 2017	**$ 3,871**	**$ 827**	**$ 1,548**	**$ 2,262**	**$ 470**	**$ 540**	**$ 9,518**
Balance, March 31, 2018	**$ 3,759**	**$ 771**	**$ 1,797**	**$ 2,362**	**$ 913**	**$ 546**	**$ 10,147**
Balance, March 31, 2019	**$ 3,645**	**$ 748**	**$ 2,023**	**$ 2,488**	**$ 1,164**	**$ 642**	**$ 10,710**

SRRP Q5 Reference: Application

For the period 2013 – 2018/19 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 actual payments made to the Province of Saskatchewan for the period 2013 – 2016/17 and forecasted amounts for 2017/18 and 2018/19:

Payments to the Province of Saskatchewan
(millions)

	2013	2014	2015-16	2016-17	2017-18	2018-19
Water Rentals	$ 21	$ 23	$ 17	$ 19	$ 26	$ 21
Corporate Capital Tax	32	35	39	46	46	50
Coal Royalties	24	28	40	32	35	35
Dividends	-	-	-	-	-	21
Total	**$ 77**	**$ 86**	**$ 96**	**$ 97**	**$ 107**	**$ 127**

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SRRP Q6 Reference: Future Rate Directions

A) Please confirm the average annual rate increase in 2018/19 through 2022/23 that would be required solely to fund the current capital plan (depreciation, finance expense, corporate capital tax and any other direct capital costs).
B) Please provide an estimate of the annual average rate increases that would be required in 2018/19 through 2022/23 that would be required to maintain SaskPower's debt ratio at 75% or lower, given the current capital plan.
C) Please discuss whether SaskPower plans to file for rate increases on an annual basis going forward.
D) Please indicate the rate increases assumed each year for the next 5 years in SaskPower's current business plan.

Response:

A) As a general rule of thumb, SaskPower assumes that for every $1 billion spent on capital, the company incurs a $70 million increase in expense. This increase in expense would result in a rate increase of approximately 3%.

B) SaskPower's current Business Plan calls for annual rate increases of 5% or less, which will enable the Corporation to bring its debt ratio below 75% by 2022/23.

C) SaskPower's most recent Business Plan does call for regular but not necessarily annual rate increases. Our company's increased capital investments are significantly pressuring rates, however SaskPower has prioritized efficiency.

Since 2015, SaskPower has reduced its OM&A costs from budget by $73 million, and the 2018 Rate Application calls for a further $143 million in reductions over the next three years. SaskPower has also realized significant cost reductions in capital. Since 2015, SaskPower has saved $484 million in capital. The 2018 Rate Application calls for a further $1.9 billion in capital savings over the next three years. These efficiencies will reduce but not eliminate the pressure to raise rates.

SaskPower is working hard to become as efficient as possible, but there are too many variables that can affect SaskPower's need for a rate increase to conclude whether or not annual increases will be required.

D) SaskPower's Business Plan currently calls for annual rate increases of 5% or less over the next five years.

SRRP Q7 Reference: Corporate Risks

A) Please indicate what SaskPower considers to be the largest business or 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 2017/18 and 2018/19.

B) In addition to the risks identified above, please provide an estimate of the potential impact of the following risks on SaskPower's operating income and return on equity in 2017/18 and 2018/19 for the following (if not addressed in part (a)):

i) 0% domestic load growth.
ii) 2% decrease in domestic sales.
iii) 1% increase in short-term interest rates

Response:

As part of SaskPower's strategic planning process, we have identified major challenges to our business which introduce a variety of risks and uncertainties that could impact the achievement of our financial, operational, and public safety objectives. The following risk factors represent challenges SaskPower considers the most significant in the short to medium term:

- Fossil fuel generation
- Financial constraints
- Infrastructure & reliability
- Reputation
- Security
- Safety
- Project delivery
- Industry disruption
- Workforce management
- Fuel supply

The business or financial risks that could have a significant impact on operating income and/or return on equity in the short term, including 2017/18 and 2018/19, are discussed below with alignment to our top corporate risk profile identified.

Capital expenditures | Project Delivery / Financial Constraints / Fossil Fuel Generation
SaskPower has identified the need to invest significant amounts of capital in long-term projects to ensure continuing reliability; maintain, upgrade and expand infrastructure; and meet environmental requirements. New regulations, stakeholder expectations, and financial constraints are placing increasing demands on SaskPower and are all competing for operating and capital resources.

SaskPower's Business Plan assumes capital expenditures of over $1.1 billion in both 2017/18 and 2018/19. A $100 million change in the capital budget is estimated to have a $7 million impact on net income.

Rate increase | Financial Constraints / Reputation
SaskPower's Business Plan assumes a rate increase of 5% effective March 1, 2018. The rate increase is subject to review by the Saskatchewan Rate Review Panel with final approval by Cabinet.

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Each 1% change in the recommended rate increase is estimated to have a $25 million impact in 2018/19 on SaskPower's net income.

Saskatchewan electricity sales volumes | Financial Constraints / Industry Disruption
SaskPower is forecasting Saskatchewan electricity sales growth of 1.9% in 2017-18, resulting in total annual electricity sales of 22,683 GWh. In 2018-19, the Corporation is forecasting 1.2% growth, resulting in a total annual sales volume of 23,023 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 $14 million impact on SaskPower's bottom line. A 100 GWh change in Power customer class sales is estimated to have a $5 million impact on SaskPower's financial results. These estimates were calculated before applying the impact of the proposed rate increases.

Natural gas prices | Financial Constraints / Fuel Supply / Fossil Fuel Generation
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 32% of the Corporation's electrical needs in 2017-18 and 2018-19, which is second only to coal generation in terms of percentage of electricity supplied. SaskPower is forecasting to consume 64.8 million GJ of natural gas in 2017-18 and 70.8 million GJ in 2018-19.

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 $24 million change in SaskPower's fuel and purchased power costs in 2017-18 and $32 million in 2018-19.

Hydro volumes | Financial Constraints / Fuel Supply
Hydro generation is forecast to provide approximately 15% - 18% of SaskPower's generation needs in 2017-18 and 2018-19. 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 in both 2017/18 and 2018/19.

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

Business Plan Sensitivity Analysis					
	Assumptions			NI Impact	NI Impact
Item	2017-18	2018-19	Sensitivity Analysis (in $millions)	17/18	18/19
Revenue					
Rate Increase (%)	5.0%	0.0%	1% change in the rate increase assumption	$ 24	$ 25
Sask Sales Growth (%)	1.9%	1.2%	100 GWh change in power customer consumption	$ 5	$ 5
			100 GWh change in residential power consumption	$ 14	$ 14
			0% Load Growth	$ 31	$ 20
			2% Reduction in domestic sales	$ 33	$ 34
Exports & Trading Margin (Millions $)	$ 5	$ 7	$10 million change in export sales	$ 5	$ 5
Fuel & Purchased Power					
Natural Gas Price ($/GJ)	$ 4.14	$ 3.88	$1 / GJ change in the natural gas price assumption	$ 24	$ 32
Hydro Generation (GWh)	4,530	3,634	10% change in the hydro assumption	$ 13	$ 13
Coal Generation (GWh)	10,918	11,138	10% change in the coal generation assumption	$ 14	$ 14
Capital					
Capital Spending (Millions $)	$1,121	$ 1,112	$100 million change in capital budget	$ 7	$ 7
Short-Term Interest Rates	0.5%	0.8%	1% change in short-term interest rates	$ 11	$ 12
Long-Term Interest Rates	3.1%	3.3%	1% change in interest rate assumption	$ 4	$ 4

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CONFIDENTIAL SRRP Q8 Reference: Corporate Risks – Carbon Pricing

A) Please provide an analysis of the implications of a carbon tax of $10/tonne on revenue requirement and future rate increases.
B) Please provide a schedule that shows the impact of a $10/tonne carbon tax beginning in 2018 and increasing by $10/tonne for each of the next five years on revenue requirement and future rate increases.
C) Please discuss what actions SaskPower is taking to mitigate the potential rate impacts of a carbon tax on ratepayers.
D) Please provide a summary of how SaskPower understands carbon taxes in British Columbia and Alberta have impacted utility costs and customer electricity rates.
E) Please provide an estimate of the average annual rate increases that would be required in order to implement capital projects to reduce SaskPower's greenhouse gas emissions by 40% by 2030.
F) Please discuss how the impacts of a carbon tax on revenue requirement would be shared with different customer classes? What principles and methods would SaskPower use to pass these costs on to residential, commercial, industrial and other customers?

Response:

A response has been submitted to the Saskatchewan Rate Review Panel for its review. However, the response contains confidential information that is not for public release.

SRRP Q9 Reference: Financial Indicators

Please discuss the financial/productivity indicators provided on page 45 of the application including:

A) How does SaskPower select its financial and productivity indicators?
   i. Provide a rationale for why SaskPower considers each of these indicators to be important.
   ii. How does SaskPower use these indicators in developing its business plan?

B) Please discuss why SaskPower believes return on equity and percent debt ratio are useful financial indicators for a crown-owned utility.

C) Please discuss whether SaskPower uses any form of financial indicators related to cash flows?

D) Please discuss whether SaskPower has investigated or considered other financial indicators or targets including:
   i. A risk-based reserve account.
   ii. An interest coverage target.

Response:

A) SaskPower selects its financial and productivity indicators based on a number of factors, including those that focus on specific financial and/or productivity aspects the Corporation considers important for measuring performance against targets and historical performance; allow for benchmarking against other Canadian electric utilities and Saskatchewan Crown corporations; and are required and assessed by counterparties with which SaskPower transacts.

   i. Operating income provides a measure of income generated from SaskPower's regular day-to-day operations. This indicator will no longer be used in 2018-19 due to the adoption of IFRS 9 and hedge accounting, upon which the difference between operating income and net income, if any, will be immaterial.

   Net income provides a measure of the performance of the company's risk management activities related to natural gas prices, electricity prices and long-term debt, in addition to income generated from regular operations.

   Return on equity (operating) demonstrates financial sustainability and profitability, assisting SaskPower to evaluate its ability to continue to reinvest in its aging infrastructure. This indicator will be revised to return on equity based on net income in 2018-19 due to the adoption of IFRS 9 and hedge accounting.

Debt ratio (including capital leases) illustrates SaskPower's financial structure and assists with managing our company's credit risk, which is considered by the counterparties we transact with and can impact the credit risk associated with our shareholder and ultimately the provincial government.

OM&A/PP&E illustrates how efficiently SaskPower is managing its OM&A in terms of our company's growth, as the Corporation considers growth in its asset base to be a key driver of OM&A costs. This indicator, which is SaskPower-specific, will be replaced in 2018-19. The Corporation will move to an OM&A/customer account indicator, which is more commonly used in the electric utility industry. In addition to the size of our company's asset base, customer accounts are considered to be a key driver of OM&A costs.

Dividend declared measures the amount from SaskPower's profits required to be remitted to our shareholder, Crown Investments Corporation (CIC) of Saskatchewan, as opposed to being available for reinvestment into our aging electrical infrastructure or repayment of debt.

ii. These indicators are considered in decisions regarding how to balance the costs to operate, maintain, and renew or replace our aging infrastructure with the need to impose constraints on expenses and capital investments and how best to finance capital investments.

B) Return on equity and per cent debt ratio are commonly used by other Canadian electric utilities, both private and government-owned, and allow SaskPower to benchmark its profitability and long-term solvency against these utilities. They are also considered by counterparties with which SaskPower transacts. Furthermore, these indicators are a reporting requirement of CIC.

C) SaskPower currently uses an interest coverage ratio based on EBIT (earnings before interest and taxes) as a financial performance measure. Calculated monthly, results are measured against targets established for both the current fiscal year (1.4 for 2017-18) and the long term (2.0). Results are taken before the Executive, and are available to staff as part of SaskPower's internal monthly Key Indicator Report and Financial Summary.

SaskPower also measures its interest coverage ratio against other electric utilities across Canada in the company's annual *System Reliability & Financial Metrics Comparison* white paper, which is provided to SaskPower's Executive and Board of Directors, as well as CIC.

This indicator is being replaced in the 2018-19 Business Plan with an interest coverage ratio based on EBITDA, which SaskPower feels provides a better indicator of the Corporation's ability to cover interest obligations.

D) SaskPower has considered other financial and productivity indicators, and will be adding two additional indicators for 2018-19, in addition to modifying some of the existing indicators as noted in the response to A) i. above.

The 2018-19 Business Plan will include a free cash flow indicator, which will measure operating cash flows against capital expenditures, and the 2018-19 Corporate Balanced Scorecard will include an Earned Value Management portfolio indicator to measure actual capital investment project progress against planned schedules and costs, identifying performance that is over or under budget and ahead or behind schedule.

i. SaskPower has not investigated or considered a risk-based reserve account.

ii. See response to B) above.

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SRRP Q10 Reference: Financial Indicators

Please provide a schedule that shows the calculation of SaskPower's actual and forecast debt ratio and return on equity for the three most recent actual years and forecasts for 2017/18 and 2018/19.

Response:

The following tables show the calculation of SaskPower's debt ratio and return on equity for the years 2014 – 2016/17 and forecasted amounts for 2017/18 and 2018/19:

Debt and Equity
(millions)

	2014	2015/16	2016/17	2017/18	2018/19
Gross long-term debt	$ 4,355	$ 5,130	$ 5,559	$ 5,881	$ 6,224
Finance lease obligation	1,138	1,133	1,126	1,113	1,131
Short-term advances	890	981	900	1,136	1,213
Debt retirement funds	(457)	(533)	(590)	(668)	(739)
Cash and cash equivalent:	2	(28)	(13)	(5)	(5)
Total net debt	5,928	6,683	6,982	7,457	7,824
Equity advances	660	660	660	660	660
Retained earnings	1,521	1,547	1,603	1,772	1,962
Accumulated OCI	(3)	(61)	(22)	(50)	(50)
Total capital	$ 8,106	$ 8,829	$ 9,223	$ 9,839	$ 10,396
Percent debt ratio	73.1%	75.7%	75.7%	75.8%	75.3%

Return on Equity
(millions)

	2014	2015/16	2016/17	2017/18	2018/19
Net Income (Loss)	$ 60	$ (19)	$ 56	$ 160	$ 210
Equity advances	660	660	660	$660	660
Retained earnings	1,521	1,546	1,603	1,772	1,962
Accumulated OCI	(3)	(61)	(22)	(50)	(50)
Average Equity	$ 2,201	$ 2,162	$ 2,193	$ 2,312	$ 2,477
Return on Equity	2.7%	-0.9%	2.6%	6.9%	8.5%

SRRP Q11 Reference: Financial Indicators

Please provide a statement of cash flows for the three most recent actual years and forecasts through 2019/20 that separately shows interest paid, investing activities and financing activities.

Response:

The following table shows a statement of cash flows for the years 2014 – 2016/17 and forecasted amounts for 2017/18 and 2018/19:

(in millions)	2014	2015/16	2016/17	2017/18	2018/19
Net Income	$ 60	$ (19)	$ 56	$ 160	$ 210
Non-cash adjustments to income	721	955	919	976	991
Change in working capital	(3)	(151)	12	(38)	(6)
Interest paid	(387)	(409)	(423)	(442)	(456)
Net cash provided by operating activities	**391**	**376**	**564**	**655**	**738**
Capital expenditures	(1,279)	(931)	(886)	(1,105)	(1,113)
Other	61	27	24	8	12
Cash used in investing activities	**(1,218)**	**(904)**	**(862)**	**(1,097)**	**(1,101)**
Net proceeds from short-term advances	86	65	(81)	237	76
Proceeds from long-term debt	792	535	535	425	350
Repayment of long-term debt	(4)	(5)	(105)	(105)	(5)
Total	788	530	430	320	345
Debt retirement fund installments	(36)	(43)	(48)	(54)	(54)
Realized gains (losses) on derivatives designated as cash flow hedges	(12)	(17)	(11)	-	-
Other	1	(3)	(7)	(69)	(4)
Cash provided by financing activities	**827**	**532**	**283**	**433**	**363**
Change in cash position	**$ -**	**$ 4**	**$ (15)**	**$ (8)**	**$ (0)**

SRRP Q12 Reference: Finance Expense

Please describe SaskPower's debt strategy with respect to how much short-term versus long-term debt SaskPower takes on. In particular, what mixture of floating rate debt versus fixed rate debt does SaskPower consider to be optimal?

Response:

SaskPower continues to target up to 15% in ongoing floating rate debt as a percentage of total debt equivalent obligations, which includes capital leases. SaskPower does not have a minimum requirement.

In addition to targeting up to 15% in ongoing floating rate debt, SaskPower may carry up to $800 million in temporary floating rate debt for the purposes of bridge financing, credit support financing and to cover cash requirements in an emergency.

SRRP Q13 Reference: Finance Expense

A. 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.

B. Please provide a schedule showing SaskPower's debt in relation to the total debt of the Province of Saskatchewan for each of the last three years.

Response:

A. 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, 2017 (in millions):

Date of issue	Date of maturity	Effective interest rate (%)	Coupon rate (%)	Par value	Unamortized premiums (discounts)	Outstanding amount
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	3	243
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	2	202
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	(4)	196
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	17	217
February 5, 2015	June 2, 2045	2.73	3.90	200	46	246
May 26, 2015	December 2, 2046	3.15	2.75	200	(15)	185
October 15, 2015	December 2, 2046	3.43	2.75	200	(25)	175
January 19, 2016	December 2, 2046	3.34	2.75	200	(22)	178
July 12, 2016	December 2, 2046	2.85	2.75	150	(3)	147
October 13, 2016	December 2, 2046	3.00	2.75	200	(10)	190
January 19, 2017	June 2, 2048	3.35	3.30	200	(2)	198
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
				$ 5,500	**$ 12**	**$ 5,512**

Subsequent to year-end, the Corporation repaid $100 million of floating rate debt on June 5, 2017. In addition, on August 17, 2017, the Corporation borrowed $150 million of long-term debt at a premium of $18 million. The debt issue has a coupon rate of 3.75%, an effective interest rate of 3.19%, and matures March 5, 2054.

Please refer to the table below for details on SaskPower' non-recourse debt as at March 31, 2017 (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, 2017 to December 31, 2025	7.87	7.59	$ 25	$ (1)	$ 24
April 26, 2001	June 30, 2017 to June 30, 2026	7.88	7.60	23	-	23
				$ 48	**$ (1)**	**$ 47**

Please refer to the table below for details on SaskPower's long-term lease obligations as at March 31, 2017 (in millions):

(in millions)	**March 31 2017**
Total future minimum lease payments	**$ 2,983**
Less: future finance charges on finance leases	**(1,857)**
Present value of finance lease obligations	**$ 1,126**
Less: current portion of finance lease obligations	**(14)**
	$ 1,112

B. The following table provides a comparison of SaskPower's gross debt in comparison to the Province of Saskatchewan:

	March 31 2017	March 31 2016	March 31 2015
General Revenue Fund	**$ 6,308**	$ 4,972	$ 4,661
SaskPower	**6,448**	6,084	5,423
Other	**5,039**	4,031	3,215
Total Public Debt	**$ 17,795**	$ 15,087	$ 13,299

Note: the above table includes both recourse and non-recourse debt and short-term advances, but does not include finance lease obligations or debt premiums/ discounts.

SRRP Q14 Reference: Finance Expense

For each year of the ten most recent actual years please provide a schedule showing the forecast short-term and long-term interest rates for new debt from the prior year's business plan (i.e. the last business plan prepared before the start of each fiscal year) and the actual short-term and long-term interest rates for new debt.

Response:

The following table shows the budgeted vs. actual rates for each of SaskPower's long-term debt issues going back to 2008, as well as the budgeted vs. actual interest rates for short-term borrowings.

Year	Budgeted L/T Rate	Budgeted S/T Rate	L/T Issues:	Actual Effective Rate	Actual Coupon Rate	Actual S/T Interest Rates (%)
2008	5.5%	N/A	250.0	4.7%	4.8%	
			100.0	4.7%	4.7%	
2009	5.5%	N/A	-			
2010	5.7%	N/A	200.0	4.3%	4.8%	
2011	4.6%	1.6%	-	-	-	.91 to 1.0
2012	5.1%	2.6%	200.0	3.2%	3.4%	.97 to 1.0
2013	3.4%	1.2%	200.0	3.5%	3.4%	.97 to 1.0
			400.0	4.0%	3.9%	
2014	3.7%	1.1%	200.0	4.0%	3.9%	.97 to 1.0
			100.0	3.8%	3.8%	
			175.0	3.7%	3.8%	
			200.0	3.4%	3.9%	
2015	4.2%	1.2%	200.0	2.7%	3.9%	.97 to 1.0
2015-16	3.1%	0.8%	200.0	3.2%	2.8%	.55 to .67
			200.0	3.4%	2.8%	
			200.0	3.3%	2.8%	
2016-17	3.1%	0.8%	150.0	2.9%	2.8%	.55 to .64
			200.0	3.0%	2.8%	
			200.0	3.4%	3.3%	

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SRRP Q15 Reference: Finance Expense

Please provide a schedule showing details of the total finance charges for the three most recent actual years and forecasts for 2017/18 and 2018/19 including interest on long-term debt; interest on short-term debt; leases; interest capitalized; debt retirement fund earnings and other finance charges.

Response:

The following table summarized actual finance charges for the years 2014 to 2016-17, and forecasted finance charges for the years 2017-18 and 2018-19.

Finance Charges
(millions)

	2014	2015-16	2016-17	2017-18	2018-19
Interest on long-term debt	$ 218	$ 243	$ 257	$ 268	$ 286
Interest on finance lease	165	167	166	163	164
Interest on short-term debt	7	5	6	7	9
Accretion	6	4	5	5	5
Interest capitalized	(62)	(25)	(15)	(23)	(34)
Amortization of debt premiums/discounts	(1)	(2)	(1)	1	(1)
Amortization of bond forward agreements net g	(1)	-	-		
Interest on Employee Benefits	11	9	11	9	9
Other interest and charges	1	1	-	(1)	4
Finance expense	**344**	**402**	**429**	**430**	**442**
Debt retirement fund earnings	(18)	(17)	(13)	(12)	(17)
Interest income	-	(1)	-	(1)	(1)
Finance income	**(18)**	**(18)**	**(13)**	**(13)**	**(18)**
TOTAL FINANCE CHARGES	**$ 326**	**$ 384**	**$ 416**	**$ 417**	**$ 424**

SRRP Q16 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:

Once a long-term borrowing is made, each year thereafter by the 1st of the month of the anniversary month of a borrowing's eventual maturity a payment of at least 1% of the outstanding principal amount of that borrowing must be made into a sinking fund up to and including the year and month of that borrowing's maturity.

There have been no changes to sinking fund requirements for new debt.

SRRP Q17 Reference: Finance Expense

Please provide details of the actual and forecast sinking fund balances, earnings, contributions and average returns for the three most recent actual years and forecasts for 2017/18 and 2018/19.

Response:

The following is a continuity schedule relating to annual sinking fund balances for the years 2014 to 2016/17, and forecasted amounts for 2017/18 and 2018/19:

Sinking Funds
(millions)

	2014	2015*	2015/16	2016/17	2017/18	2018/19
DRF Opening Balance	368	457	491	533	590	656
DRF Installments	36	13	43	48	54	54
DRF earnings	18	15	18	13	12	17
DRF redemptions	-	-	-	-	-	
DRF market value gain (loss)	35	6	(19)	(4)		
Debt retirement funds	457	491	533	590	656	728
Return	**3.9%**	**3.1%**	**3.4%**	**2.2%**	**1.8%**	**2.3%**

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

SRRP Q18 Reference: Finance Expense

Please elaborate on the statement on page 39 of the application that "Using market forecasts, SaskPower is also anticipating an increase in interest rates over the next three years that will contribute to higher finance charges", specifically:

A. Please identify the 'market forecasts' SaskPower is using as the basis for this statement.
B. Please indicate the magnitude of the impact on the 2018/19 business plan finance expense of these higher interest rate forecasts compared to assuming interest rates remain unchanged from current rates. Please separate the impact between short-term and long-term rates if possible.

Response:

A) The market forecasts refer to forward implied interest rates, which are based on market interest rates at a point in time and are obtained from Bloomberg.

B) The impact on 2018/19 finance expense of rising interest rates (current rates assumed to be the 2016/17 interest rates):

Short-term rates:

Borrowing year	Avg outstanding	Current rate	Forecasted rate	Finance expense
2018/19	$1.18 billion	0.5%	0.8%	$3.5 million
Total increase				$3.5 million

Long-term rates:

Borrowing year	Borrowing amount	Current rate	Forecasted rate	Finance expense
2017/18	$200	3.1%	3.3%	$400,000
2018/19	$450	3.1%	3.3%	$450,000 (1/2 year)
Total increase				$850,000

Note:
Rising short-term rates are assumed to impact the entire balance of short-term debt for the entire year given that their rates float. Rising long-term rates are assumed to only impact planned new borrowings during 2017/18 and 2018/19 as once a long-term borrowing is made, its cost is fixed and not impacted by interest rate changes.

SRRP Q19 Reference: Depreciation

Please provide the date of SaskPower's last external depreciation study and the proposed timing of the next external depreciation study.

Response:

The last external depreciation study was completed in 2010 by Gannett Fleming. External depreciation studies were scheduled to be performed every five years. However, due to restraint measures, management decided to defer the next external depreciation study.

Management has continued reviewing depreciation rates annually with internal personnel. In 2017-18, management will focus efforts on reviewing generation, transmission and distribution asset components' estimated service lives and depreciation rates to determine whether or not any changes need to be made.

SRRP Q20 **Reference:** **Depreciation**

Please describe SaskPower's process for reviewing and revising its depreciation rates between external depreciation studies. Please include in the discussion the degree to which SaskPower reviews depreciation studies approved by regulators in other jurisdictions.

Response:

On an annual basis, SaskPower's Finance Department reviews its depreciation rates with internal personnel from various operating areas to determine whether any changes to the estimated useful lives are required based on manufacturers' guidance, past experience and future expectations regarding the potential for technical obsolescence. In addition, depreciation rates are adjusted each year for coal facility assets based on the Corporation's most recent supply plan and expected federal government requirements to phase out conventional coal-fired generation in Canada by 2030.

While SaskPower does not review annual depreciation studies approved by regulators in other jurisdictions, SaskPower 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 discussions with topics that include depreciation.

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

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SRRP Q21 **Reference:** **Depreciation**

A) Please provide a qualitative description of any major changes to SaskPower's depreciation rates since the last rate application and the total impact of these proposed changes on revenue requirement. Please provide a break-out to the extent possible without disclosing any information SaskPower considers to be confidential.

B) Please confirm if SaskPower's auditor has reviewed and accepted these changes for financial reporting purposes.

Response:

A) As per SaskPower's policy, a depreciation rate review was performed in 2016-17. The incremental depreciation expense that would be recorded in SaskPower's 2017-18 financial statements is estimated at $34.2 million.

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.

Results from the 2016-17 depreciation rate review include:

Coal generation unit retirement date scenarios
SaskPower has signed an Agreement in Principle with the Ministry of Environment and Environment and Climate Change Canada which sets out the broad terms of an Equivalency Agreement (EA). Due to the uncertainty with regards to this EA, the retirement dates for the coal facilities have been determined through discussions with Asset Management and are based on the most recent supply plan, which is subject to change.

Gas turbine overhauls
Recently the costs incurred to replace internal gas turbine components during the Hot Gas Path and Major overhauls have been capitalized rather than charged to OM&A as maintenance. As a result, management is recommending that the estimated average service lives of these components be updated to align with the timing of the overhauls (between 5 – 10 years).

Steel and wood pole testing
Over the past few years, annual capital programs have been initiated to perform coating and anode protection on the Corporation's lattice and weathering steel structures as well as testing and treating on our wood poles. As a result, management is recommending that a new asset category be created to depreciate these costs over a shorter 15-year period rather than the estimated average service life of the original structures (35-50 years).

Transformer, station and grid automation
The life expectancy of the transformer, switching station control systems and distribution SMART line devices electronic components have decreased due to design life and technology obsolescence. Therefore, management is recommending reducing the average service life of these components to 15 years from 20-50 years to reflect that fact that this transmission and distribution equipment is being replaced more frequently.

Surface stone and fencing
Management is recommending creating a new asset category called Surface Stone and Fencing. This new category will have an average service life of 20 years to depreciate the crushed rock, gravel and fences which are not lasting as long as the foundations.

Shand Carbon Capture Test Facility
Management is recommending accelerating the depreciation rate on this research and development asset from 5 to 4 years to represent its remaining economic life.

B) Yes. SaskPower s external auditors — Deloitte and the Office of the Provincial Auditor — have reviewed and accepted all changes to deprecation rates and estimated service lives based on the 2016-17 Depreciation Study.

SRRP Q22 **Reference:** **Forecast Saskatchewan Sales Revenues**

A) Please confirm whether the revenues for 2017/18 and 2018/19 in the table on page 26 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 each customer class for the existing rates and SaskPower's proposed rates effective March 1, 2018.

Response:

A) The revenues in the table on page 26 of the application include the proposed system average 5% rate increase as of March 1, 2018, and a full year of the rate increase for fiscal 2018/2019.

B) Please see the following tables. Note that the proof of revenue calculations are annualized (i.e. calculated over 12 months) in order to reflect the correct percentages.

Proof of Revenue
2017/2018 - Fiscal Basis

Rate Code	Residential	Determinant	Revenue 2017 Rates	Blended Rate	Revenue 2018 Jan 1 Rates	Blended Rate	Difference	Blended Rate Pct Diff	Revenue Pct Difference
E01, E02	Basic (Customers)	332,725	$ 87,879,206	$ 22.01	$ 92,351,025	$ 23.13	$ 4,471,819	5.1%	5.1%
	Energy (Gwh)	2,560.3	$ 351,783,284	$ 0.13740	$ 369,654,082	$ 0.14438	$ 17,870,797	5.1%	5.1%
E03, E04	Basic (Customers)	61,698	$ 23,521,859	$ 31.77	$ 24,713,866	$ 33.38	$ 1,192,008	5.1%	5.1%
	Energy (Gwh)	763.6	$ 104,926,835	$ 0.13741	$ 110,256,795	$ 0.14439	$ 5,329,960	5.1%	5.1%
	Total Residential		$ 568,111,185		$ 596,975,768		$ 28,864,584		5.1%
Rate Code	Commercial								
E05, E06, E07, E08, E10, E12	Basic (Customers)	3,002	$ 2,463,233	$ 68.38	$ 2,588,302	$ 71.85	$ 125,070	5.1%	5.1%
	Energy (Gwh)	2,204.3	$ 176,974,468	$ 0.08029	$ 185,962,013	$ 0.08436	$ 8,987,544	5.1%	5.1%
	Demand (kVa)	6,581,019	$ 76,198,285	$ 11.58	$ 80,067,514	$ 12.17	$ 3,869,229	5.1%	5.1%
	Demand Block 1	1,727,370	$ -	$ -	$ -	$ -	$ -		
	Demand Block 2	4,853,649	$ 76,198,285	$ 15.70	$ 80,067,514	$ 16.50	$ 3,869,229	5.1%	5.1%
E15, E16, E17, E18, E35, E36, E37, E38	Basic (Customers)	2,584	$ 666,604	$ 21.50	$ 700,476	$ 22.59	$ 33,872	5.1%	5.1%
	Energy (Gwh)	11.5	$ 1,436,816	$ 0.12511	$ 1,509,762	$ 0.13146	$ 72,946	5.1%	5.1%
E75, E76, E77, E78	Basic (Customers)	56,614	$ 22,108,389	$ 32.54	$ 23,233,491	$ 34.20	$ 1,125,102	5.1%	5.1%
	Energy (Gwh)	1,637.1	$ 203,668,365	$ 0.12441	$ 214,007,063	$ 0.13072	$ 10,338,698	5.1%	5.1%
	Demand (kVa)	2,864,993	$ 7,361,104	$ 2.57	$ 7,734,967	$ 2.70	$ 373,862	5.1%	5.1%
	Demand Block 1	2,363,939	$ -	$ -	$ -	$ -	$ -		
	Demand Block 2	501,054	$ 7,361,104	$ 14.69	$ 7,734,967	$ 15.44	$ 373,862	5.1%	5.1%
Streetlights	Basic (Customers)	2,886	$ 17,007,014	$ 491.09	$ 17,877,185	$ 516.22	$ 870,170	5.1%	5.1%
	Energy (Gwh)	61.6		$ -		$ -			
	Total Commercial		$ 507,884,278		$ 533,680,772		$ 25,796,494		5.1%

Rate Code									
E34, E19, E41	Farm								
	Basic (Customers)	58,987	$ 24,271,298.71	$ 34.29	$ 25,507,453.29	$ 36.04	$ 1,236,155	5.1%	5.1%
	Energy (Gwh)	1,308.4	$ 148,391,553.74	$ 0.11342	$ 155,929,628.42	$ 0.11918	$ 7,538,075	5.1%	5.1%
	Demand (kVa)	953,281	$ 4,612,984.00	$ 4.84	$ 4,847,202.00	$ 5.08	$ 234,218	5.1%	5.1%
	Demand Block 1	581,506	$ -	$ -	$ -	$ -	$ -		
	Demand Block 2	371,775	$ 4,612,984.00	$ 12.41	$ 4,847,202.00	$ 13.04	$ 234,218	5.1%	5.1%
	Total Farm		$ 177,275,836		$ 186,284,284		$ 9,008,447		5.1%
Rate Code									
E43	Oilfield								
	Basic (Customers)	18,979	$ 14,028,656	$ 61.60	$ 14,744,621	$ 64.74	$ 715,965	5.1%	5.1%
	Energy (Gwh)	2,513.3	$ 183,696,223	$ 0.07309	$ 193,018,125	$ 0.07680	$ 9,321,902	5.1%	5.1%
	Demand (kVa)	6,290,253	$ 81,351,842	$ 12.93	$ 85,484,538	$ 13.59	$ 4,132,696	5.1%	5.1%
E46, E47, E48, E86, E87, E88									
	Basic (Customers)	36	$ 2,625,512	$ 6,077.57	$ 2,758,871	$ 6,386.28	$ 133,359	5.1%	5.1%
	Energy (Gwh)	932.0	$ 59,259,627	$ 0.06358	$ 62,272,980	$ 0.07	$ 3,013,353	5.1%	5.1%
	Demand (kVa)	1,652,079	$ 15,938,842	$ 9.65	$ 16,748,279	$ 10.14	$ 809,438	5.1%	5.1%
	Total Oilfield		$ 356,900,701		$ 375,027,415		$ 18,126,714		5.1%
Rate Code									
E31, E32, E33	Reseller								
	Basic (Customers)	2	$ 322,254	$ 13,427.24	$ 338,622	$ 14,109.27	$ 16,369	5.1%	5.1%
	Energy (Gwh)	1,285.8	$ 57,177,829	$ 0.04447	$ 60,081,562	$ 0.04673	$ 2,903,734	5.1%	5.1%
	Demand (kVa)	2,510,113	$ 46,378,143	$ 18.48	$ 48,735,052	$ 19.42	$ 2,356,909	5.1%	5.1%
	Total Reseller		$ 103,878,226		$ 109,155,237		$ 5,277,011		5.1%
Rate Code									
E22, E23, E24, E25, E82, E83, E84, E85, E50	Power								
	Basic (Customers)	103	$ 8,029,654	$ 6,496.48	$ 8,440,013	$ 6,828.49	$ 410,360	5.1%	5.1%
	Energy (Gwh)	9,217.7	$ 558,652,811	$ 0.06061	$ 585,012,955	$ 0.06347	$ 26,360,143	4.7%	4.7%
	Demand (kVa)	16,752,327	$ 137,769,026	$ 8.22	$ 144,867,058	$ 8.65	$ 7,098,032	5.2%	5.2%
	Total Power	704,451,491	$ 704,451,491		$ 738,320,026		$ 33,868,535		4.8%
Total	Basic (Customers)	537,615	$ 202,923,678	$ 31.45	$ 213,253,927	$ 33.06	$ 10,330,248	5.1%	5.1%
	Energy (Gwh)	22,495.5	$ 1,845,967,812	$ 0.08206	$ 1,937,704,965	$ 0.09	$ 91,737,153	5.0%	5.0%
	Demand (kVa)	37,604,065	$ 369,610,226	$ 9.83	$ 388,484,610	$ 10.33	$ 18,874,384	5.1%	5.1%
	Total		2,418,501,716		2,539,443,501		120,941,785		5.0%

SRRP Q23 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):

ISOs
Alberta Electric System Operator (AESO) – Alberta

RTOs
Southwest Power Pool (SPP)
Midwestern US, including North and South Dakota

Midcontinent Independent System Operator (MISO)
Midwestern states and provinces, including Manitoba and Minnesota

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

SaskPower's export sales are almost always spot-market transactions, but the Corporation has occasionally entered into single-month export transactions. As at September 2017, SaskPower has not entered into any short-term or long-term export contracts.

SaskPower has firm transmission rights on export paths within Saskatchewan:

1. 15 MW to AESO, which is scheduled to increase to 153 MW in 2018
2. 150 MW to the US, which has been limited to 125 MW in 2017

SRRP Q24 Reference: Export Revenues

Please elaborate on the factors described on page 31 of the application that are contributing to SaskPower's higher forecast export volumes and prices in 2018/19 relative to 2015/16 and 2016/17.

Response:

SaskPower is forecasting modest increases to export volumes in 2018/19 relative to 2015/16 and 2016/17. The increases are based on an expected recovery in the Alberta Electric System market price and growth in the US markets.

Factors contributing to an expected recovery in the Alberta market price include increased Alberta load growth, the retirement/mothballing of coal-fired generation units, and the evolution of Alberta's carbon tax and renewable energy policy.

Growth in the US markets is a result of higher expected load growth, improved economic opportunity, and greater expected market participation.

SRRP Q25 Reference: Export Revenues

Please provide SaskPower's actual export sales for the last 10 years compared to forecasts from the prior year's business plan (i.e. the last business plan prepared prior to the start of the fiscal year).

Response:

SaskPower export revenue as at
fiscal year ending (in thousands)

Fiscal	Revenue	Budget
2017	$ 5,368	$ 17,000
*2016**	$ 9,230	$ 20,655
2014	$ 7,338	$ 27,490
2013	$ 61,755	$ 27,472
2012	$ 49,057	$ 8,200
2011	$ 40,328	$ 15,184
2010	$ 11,847	$ 28,041
2009	$ 12,480	$ 54,952
2008	$ 33,455	$ 115,600
2007	$ 57,551	$ 50,119

*With the change to an off calendar year end the 2016 results show 15 months.

SRRP Q26 Reference: Export Revenues

Please discuss how SaskPower believes adding additional wind generation in the near future will affect its export sales, both in terms of volume of export sales and also volatility in export sales forecasts.

Response:

SaskPower believes that the additional wind generation will increase export sales volume. The annual export sales forecast volatility will be a function of the timing of new wind project commissioning dates. The annual export sales forecast volatility will be minimal when no new wind installments occur.

However, as the resolution of the time horizon studied is increased the volatility will also increase. Monthly export sale volatility will be greater than annual export sale volatility, daily export sale volatility will be greater than monthly export sale volatility, and intra-day export sale volatility will be greater than daily export sale volatility.

SRRP Q27 Reference: Net Sales from Trading

A) Please provide a table showing the three most recent actual years and forecasts for 2017/18 and 2018/19 of net sales from electricity trading.

B) Please indicate if there are any fixed costs associated with pursuing net trading activity and if so quantify any fixed amounts.

Response:

A)

Year	Actual (000's)	Forecast (000's)
2014	-$1,656	
2015 (Jan 2015-Mar 2016)	-$1,920	
2016/17	-$2,843	
2017/18		$1,358
2018/19		$500

B) The fixed costs associated with pursuing trading activity are approximately $3.8M per year. Spot trading can have zero fixed costs. NorthPoint does have a long-term transmission position with an annual fixed cost of approximately $3.8M. To date this position provided a 70% ROI. Profitable trades on this transmission position continue to be made, but due to market conditions over the last few years, there hasn't been enough opportunity to cover the fixed transmission costs.

SRRP Q28 Reference: Net Sales from Trading

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

Response:

SaskPower uses various modeling software that help determine probabilistic future market prices and margins. The historic relationship between market price, margins, and net sales is applied to the forecasted market prices and margins to form the projected forecast of net sales from trading.

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SRRP Q29 Reference: Net Sales from Trading

Please provide an illustrative sample of a trading transaction that shows how SaskPower calculates the revenue from the transaction (showing both volumes and prices); the costs of the transaction (including both direct costs and the share of any fixed costs related to trading); the net revenues from the transaction.

Response:

Net sales from trading

SaskPower sells 50 MWh to the buyer at a price of $50 per MWh. The delivery point is the Saskatchewan border.

Assuming transmission losses are 2%, SaskPower needs to generate 51 MWh to deliver 50 MWh to the border.

Costs

Energy: 50 MWh x $20 per MWh (incremental cost of supply unit) = $1,000

Transmission: No charge within the Saskatchewan system and no external transmission charges because the buyer took delivery at the Saskatchewan border

Transmission losses: 1 MWh x $20 per MWh (incremental cost of supply unit) = $20

Total cost: $1,000 + $0 + $20 = $1,020

Revenue

50 MWh x $50 per MWh = $2,500

Net profit margin on the trading transaction

$2,500 - $1,020 = **$1,480**

Fixed costs are not allocated to individual transactions.

SRRP Q30 Reference: Net Sales from Trading

Please elaborate on why SaskPower believes electricity trading activities can be a revenue positive endeavor after trading costs based on the recent annual losses.

Response:

Historically, the Alberta market has been our highest volume market for trading activities. Market prices in Alberta dropped 45% in 2016 ($33/MWh in 2015, $18/MWh in 2016). The Alberta market price has averaged approximately $19/MWh in the first quarter of 2017-18.

Alberta market price forecasters are predicting a rebound in 2018 to $47/MWh. This is due to the retirement of some generation and the coal generation that is currently being offered into the market at marginal cost by the Balancing Pool returning to the hands of the previous owners, which should result in a return to more strategic offer behaviour.

NorthPoint has estimated a net trading profit of approximately $1.5 million over the next three year period (2018 – 2020) based on forecasted prices for the Alberta market.

SRRP Q31 Reference: Other Revenue

Please provide an explanation for the materially higher customer contribution revenue in 2015/16 compared to 2016/17 and the 2018/19 forecasts.

Response:

Customer contributions are funds received related to 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. The following table shows the customer contribution breakdown of revenue:

(in millions)	2015/16	2016/17	2017/18	2018/19
Customer connects - Distribution	$ 48.6	$ 30.5	$ 39.1	$ 39.0
Customer connects - Transmission	42.5	22.2	15.0	16.0
	$ 91.1	$ 52.7	$ 54.1	$ 55.0

The higher customer contributions in 2015/16 were due to the completion of various large transmission and distribution projects.

SRRP Q32 Reference: Other Revenue

Please explain how SaskPower forecasts customer contribution revenues in the test years.

Response:

Customer contribution revenues are forecast based on historic averages of actual customer contribution revenues received by SaskPower. Since 2010, the average annual customer contribution revenue is approximately $55 million.

It should be noted that this average includes the $93 million received in 2015, as major contributions from potash, pipeline and wind interconnections were received. If 2015 was excluded from the calculation, the average would be $49 million.

SaskPower allocates the total budgeted amount by using three years of actuals to allocate it to the individual customer classes.

SRRP Q33 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 inspections 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 2016/17, the net income for Gas and Electrical Inspections was $2.3 million.

Gas and Electrical Inspections (millions)	
Permits	$ 16.9
Plan & Code Review	0.1
Field Approvals	0.3
Inspections	0.1
Revenue	$ 17.4
Expenses	$ 15.1
Net Income	$ 2.3

SRRP Q34 Reference: Other Revenue

A) Please discuss how the CO2 sales revenue forecasts are prepared, do the forecasts assume SaskPower captures and sells the maximum amount of CO2?

B) Please explain if the forecast increases in CO2 sales revenues in 2017/18 and 2018/19 reflect escalation in the selling price of the CO2 or an increase in volume of CO2 sales or both.

Response:

A) CO_2 sales revenue forecasts are prepared in accordance with contractual obligations of the offtaker. The forecast does not assume SaskPower captures and sells the maximum amount of CO_2.

B) The selling price of CO_2 is escalated in accordance with the agreement with the offtaker. Volumes of CO_2 may either increase or decrease depending upon operating days in a year as a result of maintenance schedules.

SRRP Q35 Reference: Other Revenue

A) Please confirm if there are any costs included in 2017/18 and 2018/19 associated with the CO_2 test facility and if so please quantify these amounts.

B) Is SaskPower seeking to identify new sources of revenue related to the CO_2 test facility? If so please describe any such activities.

Response:

A. The 2017/18 OM&A budget includes approximately $2.4 million for the operation of the Carbon Capture Test Facility (CCTF). While operating budgets have not been finalized for 2018/19, management will review the actual costs incurred in 2017/18 and determine the required OM&A budget for 2018/19 later in the year.

B. Yes, SaskPower has been touring prospective clients who could use the CCTF. In addition, the International CCS Knowledge Centre has arranged for several prospective clients to tour both the CCTF and the carbon capture and storage facility at Boundary Dam Power Station. The CCTF currently has a client.

SRRP Q36 Reference: Other Revenue

Please provide a detailed breakout for Miscellaneous Revenue for the three most recent actual years and forecasts for 2017/18 and 2018/19. Please provide an explanation for the decreased revenue from 2015/16 to 2016/17.

Response:

The following table provides a detailed schedule for Miscellaneous Revenue for the years 2014 – 2016/17 and forecasted amounts for 2017/18 and 2018/19. The decrease in revenue from 2015/16 to 2016/17 was mainly due to the completion of the 10-year Wind Production Incentive (WPPI) Program that was offered by the Government of Canada when the Centennial Wind Power and Cypress Wind Power Facilities were commissioned.

Miscellaneous Revenue Summary
(millions)

	2014	2015/16	2016/17	2017/18	2018/19
Late payment charges	$ 5.1	$ 5.7	$ 5.0	$ 5.7	$ 5.8
Joint Use Charges	4.6	5.8	4.6	4.5	4.7
Connect fees	1.2	1.2	1.3	1.2	1.3
Rental income	0.2	0.5	0.3	0.3	0.3
Meter reading	3.6	2.9	2.5	2.5	2.6
Custom work	4.5	4.3	3.8	4.2	4.2
Trans tariff revenue - External	0.4	0.7	-	0.1	0.1
Green power premiums	0.2	0.2	0.2	0.2	0.2
WPPI	4.8	4.4	-	-	-
Flyash	7.2	6.7	5.9	6.4	7.0
Miscellaneous	3.6	2.6	2.3	2.4	0.9
Total	$ 35.4	$ 35.0	$ 25.9	$ 27.5	$ 27.1

2018 RATE APPLICATION
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SRRP Q37 Reference: Business Plan (Tab 4)

A) Please provide a description of SaskPower's annual business planning cycle, including inputs required, review and approval processes and the typical timing of mid-year updates.

B) Please confirm if dates labelled March reflect fiscal year end forecasts (i.e. March 31st) or March 1st in each year.

Response:

A. 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 a preliminary Business Plan.
- SaskPower's Audit & 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 – 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 & 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 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.

B. Dates labelled March reflect the fiscal year end of March 31.

SRRP Q38 Reference: Business Plan (Tab 4)

With respect to the Key Indicators and Assumptions table in the July 2017 Business Plan (tab 4) please explain:

i. How does SaskPower determine the dividend amount forecast in 2019 through 2023?

Response:

i. The dividend amount is based on 10% of SaskPower's annual net income, as recommended by the Crown Investments Corporation of Saskatchewan.

SRRP Q39 Reference: Fuel and Purchased Power (F&PP)
Please describe how SaskPower prepares its forecast fuel and purchase 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:

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

In each hour the units to be dispatched are determined as follows:

1) The projected must-run hydro generation (generation from run-of-river plants or for environmentally required flow), the projected wind generation, the must-run (take or pay) portion of PPA-contracted generation, contracted imports, and the minimum generation 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. The order of unit dispatch is: dispatchable hydro generation, dispatchable coal generation, and dispatchable gas generation.
3) The remaining 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 (the marginal cost unit) is compared to the projected spot import costs from SaskPower's neighbouring jurisdictions for the hour. If the import costs are less than the marginal cost, and if there is tie line availability, then spot imports will replace dispatchable generation up to the corresponding import transfer capability. This creates a new marginal cost.
5) The new marginal cost is then compared to the projected spot export prices from SaskPower's neighbouring jurisdictions for the hour. If the export prices are greater than the marginal cost, and if there is tie line availability, then generation is committed to facilitate the spot export. This results in a final System Marginal Cost for the hour.

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

SRRP Q40 Reference: Fuel and Purchased Power (F&PP)

Please confirm if the volumes in the table on page 33 of the application are measured at each generation source or at some common delivery point on SaskPower's system.

Response:

The volumes indicated in the table on page 33 of the application are measured at each generation source.

SRRP Q41 Reference: Fuel and Purchased Power (F&PP)

For each of the last ten actual years, please provide a schedule that compares actuals and the forecasts from the previous business plan (i.e., the last business plan prepared prior to the start of the fiscal year) that shows:

A) Forecast and actual fuel and purchased power expense by generation type.
B) Forecast and actual fuel and purchased power volumes (in GWh) by generation type.
C) Forecast and actual average unit costs ($/MWh) by generation type.

Response:

Please refer to the following tables.

FUEL AND PURCHASED POWER - BY GENERATION CLASS
For the Twelve Month Period Ending December 2007

CURRENT MONTH						YEAR-TO-DATE				
2007			2006			2007			2006	
ACTUAL	BUDGET	VAR	ACTUAL	VAR	DESCRIPTION	ACTUAL	BUDGET	VAR	ACTUAL	VAR
					FUEL AND PURCHASED POWER EXPENSE ($000'S)					
$ 8,828	$ 8,586	$ 242	$ 8,375	$ 453	Boundary	$ 86,696	$ 95,851	$ (9,155)	$ 90,214	$ (3,518)
3,427	3,133	294	3,073	354	Shand	32,116	34,098	(1,982)	30,827	1,289
5,743	4,457	1,286	6,594	(851)	Poplar River	57,104	51,246	5,858	51,828	5,276
(625)	(557)	(68)	(483)	(142)	Less: Interdepartmental usage	(6,440)	(6,686)	246	(6,180)	(260)
17,373	**15,619**	**1,754**	**17,559**	**(186)**	**Coal**	**169,476**	**174,509**	**(5,033)**	**166,689**	**2,787**
7,554	4,677	2,877	11,634	(4,080)	Queen Elizabeth	74,727	52,555	22,172	85,459	(10,732)
640	223	417	876	(236)	Landis/Meadow Lake/Success	4,350	2,660	1,690	5,725	(1,375)
8,194	**4,900**	**3,294**	**12,510**	**(4,316)**	**Gas**	**79,077**	**55,215**	**23,862**	**91,184**	**(12,107)**
1,035	1,120	(85)	1,075	(40)	**Hydro**	15,191	12,496	2,695	13,754	1,437
17,632	**20,817**	**(3,185)**	**18,151**	**(519)**	**Purchased Power - Gas**	**176,217**	**198,176**	**(21,959)**	**197,422**	**(21,205)** -
302	363	(61)	-	302	**Purchased Power - EPP**	2,869	3,502	(633)	-	2,869
1,470	2,200	(730)	3,178	(1,708)	**Imports**	17,643	28,796	(11,153)	26,219	(8,576)
391	287	104	349	11	**Other**	3,105	3,064	(165)	2,871	(51)
46,397	**45,306**	**1,091**	**52,822**	**(6,425)**	**Gross Fuel & Purchased Power**	**463,578**	**475,758**	**(12,386)**	**498,139**	**(34,846)**
1,298	-	1,298	-	1,298	Add: Realized costs of NG settlements	17,789	-	17,789	-	17,789
$ 47,695	**$ 45,306**	**$ 2,389**	**$ 52,822**	**$ (5,127)**	**NET FUEL & PURCHASED POWER**	**$ 481,367**	**$ 475,758**	**$ 5,403**	**$ 498,139**	**$(17,057)**

FUEL AND PURCHASED POWER - BY GENERATION CLASS (CONTINUED)
For the Twelve Month Period Ending December 2007

CURRENT MONTH						YEAR-TO-DATE				
2007			2006			2007			2006	
ACTUAL	BUDGET	VAR	ACTUAL	VAR	DESCRIPTION	ACTUAL	BUDGET	VAR	ACTUAL	VAR
					GENERATION AND PURCHASED POWER VOLUMES (GWh's)					
532.3	558.5	(26.2)	482.2	50.1	Boundary	5,669.4	6,023.9	(354.5)	6,053.1	(383.7)
191.1	178.7	12.4	161.9	29.2	Shand	1,985.8	1,844.9	140.9	1,977.0	8.8
399.3	392.5	6.8	404.3	(5.0)	Poplar River	4,114.7	4,211.8	(97.1)	3,180.5	934.2
(10.3)	(9.6)	(0.7)	(8.6)	(1.7)	Less: Interdepartmental usage	(109.2)	(114.7)	5.5	(108.8)	(0.4)
1,112.4	**1,120.1**	**(7.7)**	**1,039.8**	**72.6**	**Coal**	**11,660.7**	**11,965.9**	**(305.2)**	**11,101.8**	**558.9**
108.5	50.7	57.8	136.4	(27.9)	Queen Elizabeth	906.7	539.1	367.5	948.9	(42.2)
5.4	0.9	4.5	6.4	(1.0)	Landis/Meadow Lake/Success	25.2	10.9	14.3	31.4	(6.2)
113.9	**51.6**	**62.3**	**142.8**	**(28.9)**	**Gas**	**931.9**	**550.0**	**381.9**	**980.3**	**(48.4)**
297.8	323.6	(25.8)	316.0	(18.2)	**Hydro**	4,393.0	3,611.0	782.0	4,031.9	361.1
58.3	**56.4**	**1.9**	**80.0**	**(21.7)**	**Wind**	**579.5**	**552.2**	**27.3**	**534.5**	**45.0**
282.0	**265.1**	**16.9**	**238.1**	**43.9**	**Purchased Power -Gas**	**2,613.3**	**2,547.4**	**65.9**	**2,576.5**	**36.8**
3.8	4.8	(1.0)	-	3.8	**Purchased Power - EPP**	35.5	46.8	(11.3)	-	35.5
34.6	49.6	(15.0)	39.0	(4.4)	**Imports**	316.0	627.8	(311.8)	451.0	(135.0)
4.9	3.6	1.3	4.6	0.3	**Other**	41.1	38.4	2.7	38.2	2.9
1,907.7	**1,874.8**	**32.9**	**1,860.3**	**47.4**	**NET GENERATION & PURCHASED POWER**	**20,571.0**	**19,939.5**	**631.5**	**19,714.2**	**856.8**
					GENERATION AND PURCHASED POWER STATISTICS ($/MWh)					
$ 15.62	$ 13.94	$ 1.67	$ 16.89	$ (1.27)	Coal	$ 14.53	$ 14.58	$ (0.05)	$ 15.01	$ (0.48)
71.94	94.96	(23.02)	87.61	(15.66)	Gas	84.86	100.39	(15.54)	93.02	(8.16)
3.48	3.46	0.01	3.40	0.07	Hydro	3.46	3.46	(0.00)	3.41	0.05
62.52	78.53	(16.00)	76.23	(11.81)	Purchased Power - Gas	67.43	77.80	(10.36)	76.62	(9.19)
79.47	75.63	3.85	-	79.47	Purchased Power - EPP	80.82	74.83	5.99	-	80.82
42.49	44.35	(1.87)	81.49	(39.00)	Imports	55.83	45.87	9.96	58.14	(2.30)
$ 24.32	**$ 24.17**	**$ 0.16**	**$ 28.39**	**$ (4.07)**	**GENERATION & PURCHASED POWER (W/A)**	**$ 22.54**	**$ 23.86**	**$ (1.32)**	**$ 25.27**	**$ (2.73)**

FUEL AND PURCHASED POWER - BY GENERATION CLASS
For the Twelve Month Period Ending December 2008
(000's)

FUEL AND PURCHASED POWER EXPENSE

CURRENT MONTH						YEAR-TO-DATE				
2008			2007			2008			2007	
ACTUAL	BUDGET	VAR	ACTUAL	VAR		ACTUAL	BUDGET	VAR	ACTUAL	VAR
33,875	**33,666**	**209**	**25,827**	**8,048**	**Gas**	**308,764**	**350,397**	**(41,633)**	**255,294**	**53,470**
8,966	8,600	366	8,828	138	Boundary Dam	98,630	98,599	31	86,696	11,934
3,418	2,830	588	3,426	(8)	Shand	37,490	32,453	5,037	32,116	5,374
6,378	5,288	1,090	5,743	635	Poplar River	60,333	57,588	2,745	57,104	3,229
(441)	(558)	117	(625)	184	Less: Interdepartmental usage	(6,455)	(6,695)	240	(6,440)	(15)
18,321	**16,160**	**2,161**	**17,372**	**949**	**Coal**	**189,998**	**181,945**	**8,053**	**169,476**	**20,522**
5,315	4,265	1,050	1,470	3,845	**Imports**	33,143	61,744	(28,601)	17,643	15,500
955	1,221	(266)	1,035	(80)	**Hydro**	14,378	12,766	1,612	15,191	(813)
887	1,629	(742)	693	194	**Other**	8,352	10,538	(2,186)	5,974	2,378
547	-	547	1,298	(751)	Add: Realized costs of NG settlements	(8,839)	-	(8,839)	17,789	(26,628)
$ 59,900	**$ 56,941**	**$ 2,959**	**$ 47,695**	**$ 12,205**	**Fuel & Purchased Power**	**$ 545,796**	**$ 617,390**	**$ (71,594)**	**$ 481,367**	**$ 64,429**

FUEL AND PURCHASED POWER - BY GENERATION CLASS (CONTINUED)
For the Twelve Month Period Ending December 2008
(GWh's)

CURRENT MONTH						YEAR-TO-DATE				
2008			2007			2008			2007	
ACTUAL	BUDGET	VAR	ACTUAL	VAR		ACTUAL	BUDGET	VAR	ACTUAL	VAR
					GENERATION AND PURCHASED POWER VOLUMES					
453.3	**435.2**	**18.1**	**395.8**	**57.5**	**Gas**	**3,812.5**	**4,494.9**	**(682.4)**	**3,545.2**	**267.3**
516.2	554.0	(37.8)	532.3	(16.1)	Boundary Dam	6,019.1	6,204.5	(185.4)	5,669.4	349.7
193.4	178.6	14.8	191.1	2.3	Shand	1,994.5	1,989.9	4.6	1,985.8	8.7
382.2	381.1	1.1	399.3	(17.1)	Poplar River	3,500.9	3,648.3	(147.4)	4,114.7	(613.8)
(7.8)	(9.2)	1.4	(10.3)	2.5	Less: Interdepartmental usage	(110.0)	(109.9)	(0.1)	(109.2)	(0.8)
1,084.0	**1,104.5**	**(20.5)**	**1,112.4**	**(28.4)**	**Coal**	**11,404.5**	**11,732.8**	**(328.3)**	**11,660.7**	**(256.2)**
62.3	**56.4**	**5.9**	**58.3**	**4.0**	**Wind**	**537.4**	**554.0**	**(16.6)**	**579.5**	**(42.1)**
76.8	60.2	16.6	34.7	42.1	**Imports**	586.9	980.1	(393.2)	316.0	270.9
266.4	346.1	(79.7)	297.8	(31.4)	**Hydro**	4,029.9	3,619.7	410.2	4,393.0	(363.1)
11.9	20.6	(8.7)	8.7	3.2	**Other**	108.7	126.7	(18.0)	76.6	32.1
1,954.7	**2,023.0**	**(68.3)**	**1,907.7**	**47.0**	**NET GENERATION & PURCHASED POWER**	**20,479.9**	**21,508.2**	**(1,028.3)**	**20,571.0**	**(91.1)**
					GENERATION AND PURCHASED POWER STATISTICS ($/MWh)					
$ 74.73	$ 77.36	$ (2.63)	$ 65.25	$ 9.48	Gas	$ 80.99	$ 77.95	$ 3.03	$ 72.01	$ 8.98
16.90	14.63	2.27	15.62	1.28	Coal	16.66	15.51	1.15	14.53	2.13
69.21	70.85	(1.64)	42.36	26.84	Imports	56.47	63.00	(6.53)	55.83	0.64
3.58	3.53	0.06	3.48	0.11	Hydro	3.57	3.53	0.04	3.46	0.11
74.54	79.08	(4.54)	79.66	(5.12)	Other	76.84	83.17	(6.34)	77.99	(1.15)
$ 30.36	**$ 28.15**	**$ 2.22**	**$ 24.32**	**$ 6.04**	**GENERATION & PURCHASED POWER (W/A)**	**$ 27.08**	**$ 28.70**	**$ (1.62)**	**$ 22.54**	**$ 4.55**

FUEL AND PURCHASED POWER - BY GENERATION CLASS
For the Twelve Month Period Ending December 2009
(000's)

FUEL AND PURCHASED POWER EXPENSE

CURRENT MONTH						YEAR-TO-DATE				
2009			2008			2009			2008	
ACTUAL	BUDGET	VAR	ACTUAL	VAR		ACTUAL	BUDGET	VAR	ACTUAL	VAR
$ 17,574	$ 37,818	$ (20,244)	$ 33,875	$ (16,301)	**Gas**	$ 191,015	$ 360,597	$ (169,582)	$ 308,764	$ (117,749)
19,644	17,255	2,389	18,321	1,323	**Coal**	193,560	188,212	5,348	189,998	3,562
1,949	5,662	(3,713)	5,315	(3,366)	**Imports**	18,930	77,688	(58,758)	33,143	(14,213)
1,103	1,218	(115)	955	148	**Hydro**	11,465	12,862	(1,397)	14,378	(2,913)
2,889	1,486	1,403	887	2,002	**Other**	18,770	15,386	3,384	5,603	13,167
43,159	63,439	(20,280)	59,353	(16,194)	**Fuel & Purchased Power**	433,740	654,745	(221,005)	551,886	(118,146)
5,561	-	5,561	547	5,014	**Realized NG mgnt activities**	75,380	-	75,380	(8,839)	84,219
$ 48,720	$ 63,439	$ (14,719)	$ 59,900	$ (11,180)	**Net Fuel & Purchased Power**	$ 509,120	$ 654,745	$ (145,625)	$ 545,796	$ (36,676)

FUEL AND PURCHASED POWER - BY GENERATION CLASS (CONTINUED)
For the Twelve Month Period Ending December 2009
(GWh's)

CURRENT MONTH						YEAR-TO-DATE				
2009			2008			2009			2008	
ACTUAL	BUDGET	VAR	ACTUAL	VAR		ACTUAL	BUDGET	VAR	ACTUAL	VAR
					GENERATION AND PURCHASED POWER VOLUMES					
372.1	**434.0**	**(61.9)**	**453.3**	**(81.2)**	**Gas**	**3,432.3**	**4,017.9**	**(585.6)**	**3,812.5**	**(380.2)**
1,172.7	**1,086.2**	**86.5**	**1,084.1**	**88.6**	**Coal**	**12,316.9**	**11,820.9**	**496.0**	**11,404.5**	**912.4**
45.3	**60.3**	**(15.0)**	**66.1**	**(20.8)**	**Wind**	**578.6**	**590.2**	**(11.6)**	**574.4**	**4.2**
35.7	118.2	(82.5)	76.8	(41.1)	**Imports**	439.9	1,666.0	(1,226.1)	586.9	(147.0)
284.7	343.3	(58.6)	266.4	18.3	**Hydro**	2,961.9	3,625.3	(663.4)	4,029.9	(1,068.0)
59.2	76.1	(16.9)	74.1	(14.9)	**Other**	713.2	755.6	(42.4)	646.1	67.1
1,924.4	**2,057.8**	**(133.4)**	**1,954.7**	**(30.3)**	**NET GENERATION & PURCHASED POWER**	**19,864.2**	**21,885.7**	**(2,021.5)**	**20,479.9**	**(615.7)**
					GENERATION AND PURCHASED POWER STATISTICS ($/MWh)					
$ 47.23	$ 87.14	$ (39.91)	$ 74.73	$ (27.50)	Gas	$ 55.65	$ 89.75	$ (34.10)	$ 80.99	$ (25.34)
16.75	15.89	0.87	16.90	(0.15)	Coal	15.71	15.92	(0.21)	16.66	(0.94)
73.00	72.05	0.95	75.26	(2.26)	PP Wind	75.24	72.68	2.56	74.30	0.95
54.59	47.90	6.69	69.21	(14.61)	Imports	43.03	46.63	(3.60)	56.47	(13.44)
3.87	3.55	0.33	3.58	0.29	Hydro	3.87	3.55	0.32	3.57	0.30
$ 22.43	**$ 30.83**	**$ (8.40)**	**$ 30.36**	**$ (7.94)**	**GENERATION & PURCHASED POWER (W/A)**	**$ 21.84**	**$ 29.92**	**$ (8.08)**	**$ 27.08**	**$ (5.25)**

FUEL AND PURCHASED POWER - BY GENERATION CLASS
For the Twelve Month Period Ending December 2010
(000's)

CURRENT MONTH						YEAR-TO-DATE				
2010			2009			2010			2009	
Actual	Budget	Variance	Actual	Variance		Actual	Budget	Variance	Actual	Variance
					FUEL AND PURCHASED POWER EXPENSE					
24,797	**29,755**	**(4,958)**	**23,134**	**1,663**	**Gas**	**229,712**	**277,038**	**(47,326)**	**266,395**	**(36,683)**
21,357	**18,720**	**2,637**	**19,644**	**1,713**	**Coal**	**212,213**	**200,313**	**11,900**	**193,560**	**18,653**
205	277	(72)	147	58	**PP Wind**	2,209	2,761	(552)	2,626	(417)
2,239	5,936	(3,697)	1,948	291	**Imports**	20,291	53,907	(33,616)	18,929	1,362
1,276	1,239	37	1,104	172	**Hydro**	15,845	12,972	2,873	11,466	4,379
1,057	1,135	(78)	2,743	(1,686)	**Other**	11,455	12,020	(565)	16,144	(4,689)
$ 50,931	**$ 57,062**	**$ (6,131)**	**$ 48,720**	**$ 2,211**	**Net Fuel & Purchased Power**	**$ 491,725**	**$ 559,011**	**$ (67,286)**	**$ 509,120**	**$ (17,395)**

FUEL AND PURCHASED POWER - BY GENERATION CLASS (CONTINUED)
For the Twelve Month Period Ending December 2010
(GWh's)

CURRENT MONTH						YEAR-TO-DATE				
2010			2009			2010			2009	
Actual	Budget	Variance	Actual	Variance		Actual	Budget	Variance	Actual	Variance
					GENERATION AND PURCHASED POWER VOLUMES					
438.4	**419.4**	**19.0**	**372.1**	**66.3**	**Gas**	**3,682.5**	**4,177.0**	**(494.5)**	**3,432.3**	**250.2**
1,158.9	**1,126.5**	**32.4**	**1,172.7**	**(13.8)**	**Coal**	**12,037.9**	**12,083.8**	**(45.9)**	**12,316.9**	**(279.0)**
50.3	**62.0**	**(11.7)**	**45.3**	**5.0**	**Wind**	**506.6**	**608.3**	**(101.7)**	**578.6**	**(72.0)**
48.3	95.1	(46.8)	35.7	12.6	**Imports**	517.7	1,052.4	(534.7)	439.9	77.8
307.6	315.2	(7.6)	284.7	22.9	**Hydro**	3,866.0	3,302.1	563.9	2,961.9	904.1
13.8	14.9	(1.1)	13.9	(0.1)	**Other**	148.7	157.6	(8.9)	134.6	14.1
2,017.3	**2,033.1**	**(15.8)**	**1,924.4**	**92.9**	**NET GENERATION & PURCHASED POWER**	**20,759.4**	**21,381.2**	**(621.8)**	**19,864.2**	**895.2**
					GENERATION AND PURCHASED POWER STATISTICS ($/MWh)					
$ 56.56	$ 70.95	$ (14.38)	$ 62.17	$ (5.61)	Gas	$ 62.38	$ 66.32	$ (3.95)	$ 77.61	$ (15.23)
18.43	16.62	1.81	16.75	1.68	Coal	17.63	16.58	1.05	15.71	1.91
75.93	72.89	3.03	73.50	2.43	PP Wind	76.44	72.85	3.59	75.24	1.19
46.36	62.42	(16.06)	54.57	(8.21)	Imports	39.19	51.22	(12.03)	43.03	(3.84)
4.15	3.93	0.22	3.88	0.27	Hydro	4.10	3.93	0.17	3.87	0.23
76.59	76.17	0.42	197.34	(120.74)	Other	77.03	76.27	0.77	119.94	(42.91)
$ 25.25	**$ 28.07**	**$ (2.82)**	**$ 25.32**	**$ (0.07)**	**GENERATION & PURCHASED POWER (W/A)**	**$ 23.69**	**$ 26.14**	**$ (2.46)**	**$ 25.63**	**$ (1.94)**

NET FUEL AND PURCHASED POWER - BY GENERATION CLASS

For the Twelve Month Period Ending December 2011
(000's)

CURRENT MONTH						YEAR-TO-DATE				
2011			2010			2011			2010	
Actual	Budget	Variance	Actual	Variance	NET FUEL AND PURCHASED POWER EXPENSE	Actual	Budget	Variance	Actual	Variance
$ 17,541	$ 26,345	$ (8,804)	$ 20,293	$ (2,752)	Gas	$ 195,645	$ 226,805	$ (31,160)	$ 183,506	$ 12,139
17,956	19,102	(1,146)	21,359	(3,403)	Coal	219,438	209,917	9,521	212,214	7,224
1,224	726	498	205	1,019	Wind	9,273	5,445	3,828	2,209	7,064
2,658	2,471	187	2,239	419	Imports	24,366	24,662	(296)	20,291	4,075
1,300	1,205	95	1,275	25	Hydro	19,979	14,697	5,282	15,845	4,134
1,483	1,426	57	1,058	425	Other	16,708	15,055	1,653	11,455	5,253
$ 42,162	$ 51,275	$ (9,113)	$ 46,429	$ (4,267)	Net Fuel & Purchased Power	$ 485,409	$ 496,581	$ (11,172)	$ 445,520	$ 39,889

NET FUEL AND PURCHASED POWER - BY GENERATION CLASS (CONTINUED)
For the Twelve Month Period Ending December 2011
(GWh's)

GENERATION AND PURCHASED POWER VOLUMES

CURRENT MONTH						YEAR-TO-DATE				
2011			2010			2011			2010	
Actual	Budget	Variance	Actual	Variance		Actual	Budget	Variance	Actual	Variance
422.8	**552.3**	**(129.5)**	**438.4**	**(15.6)**	**Gas**	**4,031.7**	**4,856.5**	**(824.8)**	**3,682.5**	**349.2**
1,124.0	**1,152.6**	**(28.6)**	**1,158.8**	**(34.8)**	**Coal**	**11,614.0**	**12,477.6**	**(863.6)**	**12,037.9**	**(423.9)**
91.4	**67.7**	**23.7**	**50.3**	**41.1**	**Wind**	**682.3**	**625.2**	**57.1**	**506.6**	**175.7**
68.2	57.4	10.8	48.3	19.9	**Imports**	501.8	589.7	(87.9)	517.7	(15.9)
303.5	272.6	30.9	307.6	(4.1)	**Hydro**	4,641.2	3,324.2	1,317.0	3,866.0	775.2
14.0	15.0	(1.0)	13.8	0.2	**Other**	139.7	157.4	(17.7)	148.7	(9.0)
2,023.9	**2,117.6**	**(93.7)**	**2,017.2**	**6.7**	**NET GENERATION & PURCHASED POWER**	**21,610.7**	**22,030.6**	**(419.9)**	**20,759.4**	**851.3**

GENERATION AND PURCHASED POWER STATISTICS ($/MWh)

CURRENT MONTH						YEAR-TO-DATE				
2011			2010			2011			2010	
Actual	Budget	Variance	Actual	Variance		Actual	Budget	Variance	Actual	Variance
$ 41.49	$ 47.70	$ (6.21)	$ 46.29	$ (4.80)	Gas	$ 48.53	$ 46.70	$ 1.83	$ 49.83	$ (1.31)
15.98	16.57	(0.60)	18.43	(2.46)	Coal	18.89	16.82	2.07	17.63	1.27
83.27	63.68	19.58	75.93	7.34	PP Wind	82.72	74.39	8.34	76.44	6.28
38.97	43.05	(4.08)	46.36	(7.38)	Imports	48.56	41.82	6.74	39.19	9.36
4.28	4.42	(0.14)	4.14	0.14	Hydro	4.30	4.42	(0.12)	4.10	0.21
105.93	95.07	10.86	76.67	29.26	Other	119.60	95.65	23.95	77.03	42.56
$ 20.83	**$ 24.21**	**$ (3.38)**	**$ 23.02**	**$ (2.18)**	**GENERATION & PURCHASED POWER (W/A)**	**$ 22.46**	**$ 22.54**	**$ (0.08)**	**$ 21.46**	**$ 1.00**

NET FUEL AND PURCHASED POWER - BY GENERATION CLASS

For the Twelve Month Period Ending December 2012
(000's)

NET FUEL AND PURCHASED POWER EXPENSE

CURRENT MONTH						YEAR-TO-DATE				
2012			2011			2012			2011	
Actual	Budget	Variance	Actual	Variance		Actual	Budget	Variance	Actual	Variance
$ 23,577	$ 27,230	$ (3,653)	$ 17,541	$ 6,036	**Gas**	$ 213,820	$ 249,220	$ (35,400)	$ 195,645	$ 18,175
23,434	20,815	2,619	17,956	5,478	**Coal**	221,824	225,701	(3,877)	219,438	2,386
561	941	(380)	1,224	(663)	**Wind**	9,624	9,965	(341)	9,273	351
4,191	2,421	1,770	2,659	1,532	**Imports**	31,136	20,124	11,012	24,366	6,770
1,380	1,365	15	1,299	81	**Hydro**	19,062	14,198	4,864	19,979	(917)
2,153	1,560	593	1,483	670	**Other**	17,806	15,642	2,164	16,708	1,098
$ 55,296	$ 54,332	$ 964	$ 42,162	$ 13,134	**Net Fuel & Purchased Power**	$ 513,272	$ 534,850	$ (21,578)	$ 485,409	$ 27,863

NET FUEL AND PURCHASED POWER - BY GENERATION CLASS (CONTINUED)
For the Twelve Month Period Ending December 2012
(GWh's)

CURRENT MONTH						YEAR-TO-DATE				
2012			2011			2012			2011	
Actual	Budget	Variance	Actual	Variance		Actual	Budget	Variance	Actual	Variance
					GENERATION AND PURCHASED POWER VOLUMES					
576.4	**611.8**	**(35.4)**	**422.7**	**153.7**	**Gas**	**4,966.7**	**5,752.4**	**(785.7)**	**4,031.7**	**935.0**
1,109.6	**1,150.4**	**(40.8)**	**1,124.0**	**(14.4)**	**Coal**	**11,446.3**	**12,470.6**	**(1,024.3)**	**11,614.0**	**(167.7)**
49.8	**67.8**	**(18.0)**	**91.3**	**(41.5)**	**Wind**	**655.4**	**674.9**	**(19.5)**	**682.3**	**(26.9)**
84.7	58.1	26.6	68.2	16.5	**Imports**	656.0	505.1	150.9	501.8	154.2
306.0	319.2	(13.2)	303.5	2.5	**Hydro**	4,240.4	3,318.9	921.5	4,641.2	(400.8)
19.8	14.9	4.9	14.1	5.7	**Other**	163.8	157.3	6.5	139.7	24.1
2,146.3	**2,222.2**	**(75.9)**	**2,023.8**	**122.5**	**NET GENERATION & PURCHASED POWER**	**22,128.6**	**22,879.2**	**(750.6)**	**21,610.7**	**517.9**
					GENERATION AND PURCHASED POWER STATISTICS ($/MWh)					
$ 40.90	$ 44.51	$ (3.60)	$ 41.50	$ (0.59)	Gas	$ 43.05	$ 43.32	$ (0.27)	$ 48.53	$ (5.48)
21.12	18.09	3.03	15.98	5.14	Coal	19.38	18.10	1.28	18.89	0.49
83.73	81.83	1.91	83.27	0.47	PP Wind	84.57	81.08	3.49	82.72	1.85
49.48	41.67	7.81	38.99	10.49	Imports	47.46	39.84	7.62	48.56	(1.09)
4.51	4.28	0.23	4.28	0.23	Hydro	4.50	4.28	0.22	4.30	0.19
108.74	104.70	4.04	105.18	3.56	Other	108.71	99.44	9.27	119.60	(10.89)
$ 25.76	**$ 24.45**	**$ 1.31**	**$ 20.83**	**$ 4.93**	**GENERATION & PURCHASED POWER (W/A)**	**$ 23.19**	**$ 23.38**	**$ (0.18)**	**$ 22.46**	**$ 0.73**

NET FUEL AND PURCHASED POWER - BY GENERATION CLASS
For the Twelve Month Period Ending December 2013
(000's)

NET FUEL AND PURCHASED POWER EXPENSE

	CURRENT MONTH						YEAR-TO-DATE				
	2013			2012			2013			2012	
	Actual	Budget	Variance	Actual	Variance		Actual	Budget	Variance	Actual	Variance
Gas	**$ 28,412**	**$ 26,340**	**$ 2,072**	**$ 21,758**	**$ 6,654**		**$ 240,611**	**$ 242,272**	**$ (1,661)**	**$ 213,820**	**$ 26,791**
Coal	**21,901**	**21,969**	**(68)**	**19,816**	**2,085**		**223,037**	**237,869**	**(14,832)**	**221,824**	**1,213**
Wind	**964**	**973**	**(9)**	**908**	**56**		**10,227**	**10,215**	**12**	**9,624**	**603**
Imports	3,286	990	2,296	3,669	(383)		31,217	14,358	16,859	31,136	81
				-							
Hydro	1,584	1,512	72	1,229	355		20,982	15,765	5,217	19,062	1,920
		-									
Other	1,905	2,381	(476)	1,955	(50)		23,517	24,605	(1,088)	17,806	5,711
Net Fuel & Purchased Power	**$ 58,052**	**$ 54,165**	**$ 3,887**	**$ 49,335**	**$ 8,717**		**$ 549,591**	**$ 545,084**	**$ 4,507**	**$ 513,272**	**$ 36,319**

NET FUEL AND PURCHASED POWER - BY GENERATION CLASS (CONTINUED)

For the Twelve Month Period Ending December 2013

(GWh's)

CURRENT MONTH						YEAR-TO-DATE				
2013			2012			2013			2012	
Actual	Budget	Variance	Actual	Variance		Actual	Budget	Variance	Actual	Variance
GENERATION AND PURCHASED POWER VOLUMES										
775.4	**773.1**	**2.3**	**541.6**	**233.8**	**Gas**	**6,459.6**	**7,199.9**	**(740.3)**	**4,966.7**	**1,492.9**
971.0	**1,094.2**	**(123.2)**	**1,007.5**	**(36.5)**	**Coal**	**10,845.9**	**11,776.9**	**(931.0)**	**11,446.4**	**(600.5)**
71.4	**68.1**	**3.3**	**62.7**	**8.7**	**Wind**	**646.3**	**674.8**	**(28.5)**	**655.4**	**(9.1)**
62.2	15.5	46.7	75.8	(13.6)	**Imports**	548.2	288.4	259.8	656.0	(107.8)
334.2	319.5	14.7	271.9	62.3	**Hydro**	4,448.8	3,326.6	1,122.2	4,240.4	208.4
16.8	21.3	(4.5)	17.2	(0.4)	**Other**	206.2	217.0	(10.8)	163.8	42.4
2,231.0	**2,291.7**	**(60.7)**	**1,976.7**	**254.3**	**NET GENERATION & PURCHASED POWER**	**23,155.0**	**23,483.6**	**(328.6)**	**22,128.7**	**1,026.3**
GENERATION AND PURCHASED POWER STATISTICS ($/MWh)										
$ 36.64	$ 34.07	$ 2.57	$ 40.17	$ (3.53)	Gas	$ 37.25	$ 33.65	$ 3.60	$ 43.05	$ (5.80)
22.56	20.08	2.48	19.67	2.89	Coal	20.56	20.20	0.37	19.38	1.18
87.64	83.16	4.47	84.86	2.78	PP Wind	86.38	83.25	3.12	84.57	1.81
52.83	63.87	(11.04)	48.40	4.43	Imports	56.94	49.79	7.16	47.46	9.48
4.74	4.73	0.01	4.52	0.22	Hydro	4.72	4.74	(0.02)	4.50	0.22
113.39	111.78	1.61	113.66	(0.27)	Other	114.05	113.39	0.66	108.71	5.34
$ 26.02	**$ 23.64**	**$ 2.39**	**$ 24.96**	**$ 1.06**	**GENERATION & PURCHASED POWER (W/A)**	**$ 23.74**	**$ 23.21**	**$ 0.52**	**$ 23.19**	**$ 0.54**

NET FUEL AND PURCHASED POWER - BY GENERATION CLASS

For the Twelve Month Period Ending December 2014

(000's)

CURRENT MONTH						YEAR-TO-DATE				
2014			2013			2014			2013	
Actual	Budget	Variance	Actual	Variance	NET FUEL AND PURCHASED POWER EXPENSE	Actual	Budget	Variance	Actual	Variance
$ 32,246	**$ 28,136**	**$ 4,110**	**$ 28,412**	**$ 3,834**	**Gas**	**$ 286,645**	**$ 255,199**	**$ 31,446**	**$ 240,610**	**$ 46,035**
26,906	**24,496**	**2,410**	**21,900**	**5,006**	**Coal**	**246,828**	**264,881**	**(18,053)**	**223,038**	**23,790**
841	**1,010**	**(169)**	**964**	**(123)**	**Wind**	**10,816**	**10,559**	**257**	**10,227**	**589**
3,510	1,290	2,220	3,286	224	**Imports**	38,516	8,915	29,601	31,217	7,299
1,602	1,378	224	1,584	18	**Hydro**	23,212	17,986	5,226	20,981	2,231
990	1,474	(484)	1,227	(237)	**Waste Heat**	12,735	15,250	(2,515)	11,712	1,023
2,159	1,241	918	679	1,480	**Other**	18,969	5,499	13,470	11,806	7,163
$ 68,254	**$ 59,025**	**$ 9,229**	**$ 58,052**	**$ 10,202**	**Net Fuel & Purchased Power**	**$ 637,721**	**$ 578,289**	**$ 59,432**	**$ 549,591**	**$ 88,130**

NET FUEL AND PURCHASED POWER - BY GENERATION CLASS (CONTINUED)

For the Twelve Month Period Ending December 2014

(GWh's)

CURRENT MONTH						YEAR-TO-DATE				
2014			2013			2014			2013	
Actual	Budget	Variance	Actual	Variance		Actual	Budget	Variance	Actual	Variance
					GENERATION AND PURCHASED POWER VOLUMES					
795.8	**771.6**	**24.2**	**775.4**	**20.4**	**Gas**	**6,883.3**	**7,163.8**	**(280.5)**	**6,459.6**	**423.7**
854.0	**1,071.7**	**(217.7)**	**971.0**	**(117.0)**	**Coal**	**10,218.7**	**11,610.6**	**(1,391.9)**	**10,845.9**	**(627.2)**
62.0	**68.2**	**(6.2)**	**71.4**	**(9.4)**	**Wind**	**636.4**	**676.0**	**(39.6)**	**646.3**	**(9.9)**
74.3	22.0	52.3	62.2	12.1	**Imports**	796.7	156.7	640.0	548.2	248.5
354.5	279.0	75.5	334.2	20.3	**Hydro**	4,706.1	3,644.9	1,061.2	4,448.8	257.3
11.6	17.2	(5.6)	14.5	(2.9)	**Waste Heat**	153.2	177.9	(24.7)	145.4	7.8
0.1	7.2	(7.1)	2.3	(2)	**Other**	29.4	84.2	(54.8)	29.9	(0.5)
2,152.3	**2,236.9**	**(84.6)**	**2,231.0**	**(78.7)**	**NET GENERATION & PURCHASED POWER**	**23,423.8**	**23,514.1**	**(90.3)**	**23,124.1**	**299.7**
					GENERATION AND PURCHASED POWER STATISTICS ($/MWh)					
$ 40.52	$ 36.46	$ 4.06	$ 36.64	$ 3.88	Gas	$ 41.64	$ 35.62	$ 6.02	$ 37.25	$ 4.40
31.51	22.86	8.65	22.55	8.95	Coal	24.15	22.81	1.34	20.56	3.59
89.47	86.32	3.14	87.64	1.83	PP Wind	88.22	85.15	3.07	87.63	0.59
47.24	58.64	(11.40)	52.83	(5.59)	Imports	48.34	56.89	(8.55)	56.94	(8.60)
4.52	4.94	(0.42)	4.74	(0.22)	Hydro	4.93	4.93	(0.00)	4.72	0.22
85.34	85.70	(0.35)	84.62	0.72	Waste Heat	83.13	85.72	(2.60)	80.55	2.58
$ 31.71	**$ 26.39**	**$ 5.33**	**$ 26.02**	**$ 5.69**	**GENERATION & PURCHASED POWER (W/A)**	**$ 27.23**	**$ 24.98**	**$ 2.25**	**$ 23.74**	**$ 3.49**

FUEL AND PURCHASED POWER - BY GENERATION CLASS
For the Period Ending December 2015
(000's)

CURRENT MONTH						YEAR-TO-DATE				
2015			2014			2015			2014	
Actual	Budget	Variance	Actual	Variance		Actual	Budget	Variance	Actual	Variance
					FUEL AND PURCHASED POWER EXPENSE					
$ 26,168	**$ 29,115**	**$ (2,947)**	**$ 32,246**	**$ (6,078)**	**Gas**	**$ 283,475**	**$ 270,183**	**$ 13,292**	**$ 286,645**	**$ (3,170)**
28,642	**22,884**	**5,758**	**26,906**	**1,736**	**Coal**	**285,217**	**250,797**	**34,420**	**246,828**	**38,389**
1,436	**1,841**	**(405)**	**841**	**595**	**Wind**	**16,792**	**18,382**	**(1,590)**	**10,816**	**5,976**
1,873	2,340	(467)	3,510	(1,637)	**Imports**	29,144	26,738	2,406	38,516	(9,372)
1,880	1,568	312	1,602	278	**Hydro**	17,803	18,008	(205)	23,212	(5,409)
1,149	1,385	(236)	990	159	**Waste heat**	11,947	14,108	(2,161)	12,735	(788)
762	1,344	(582)	2,159	(1,397)	**Other**	5,989	8,931	(2,942)	18,969	(12,980)
$ 61,910	**$ 60,477**	**$ 1,433**	**$ 68,254**	**$ (6,344)**	**Fuel and Purchased Power**	**$ 650,367**	**$ 607,147**	**$ 43,220**	**$ 637,721**	**$ 12,646**

FUEL AND PURCHASED POWER - BY GENERATION CLASS (CONTINUED)

For the Period Ending December 2015

(GWh's)

CURRENT MONTH						YEAR-TO-DATE				
2015			2014			2015			2014	
Actual	Budget	Variance	Actual	Variance		Actual	Budget	Variance	Actual	Variance
					GENERATION AND PURCHASED POWER VOLUMES					
825.3	**845.5**	**(20.2)**	**795.9**	**29.4**	**Gas**	**7,976.2**	**7,608.6**	**367.6**	**6,883.3**	**1,092.9**
1,012.8	**1,023.5**	**(10.7)**	**854.0**	**158.8**	**Coal**	**11,010.8**	**11,090.7**	**(79.9)**	**10,218.7**	**792.1**
65.1	**76.0**	**(10.9)**	**62.0**	**3.1**	**Wind**	**684.1**	**764.0**	**(79.9)**	**636.4**	**47.7**
21.9	63.0	(41.1)	74.3	(52.4)	**Imports**	505.7	744.0	(238.3)	796.7	(291.0)
292.8	304.8	(12.0)	354.5	(61.7)	**Hydro**	3,425.6	3,499.6	(74.0)	4,706.1	(1,280.5)
13.6	16.0	(2.4)	11.6	2.0	**Waste heat**	139.9	163.6	(23.7)	153.2	(13.3)
1.0	5.8	(4.8)	0.1	0.9	**Other**	1.4	12.9	(11.5)	29.4	(28.0)
2,232.5	**2,334.6**	**(102.1)**	**2,152.4**	**80.1**	**Generation and Purchased Power**	**23,743.7**	**23,883.4**	**(139.7)**	**23,423.8**	**319.9**
					GENERATION AND PURCHASED POWER STATISTICS ($ / MWh)					
$ 31.71	$ 34.44	$ (2.73)	$ 40.52	$ (8.81)	Gas	$ 35.54	$ 35.51	$ 0.03	$ 41.64	$ (6.10)
28.28	22.36	5.92	31.51	(3.23)	Coal	25.90	22.61	3.29	24.15	1.75
100.42	93.45	6.97	88.53	11.89	PP Wind	95.79	93.22	2.58	88.22	7.57
85.53	37.14	48.38	47.24	38.28	Imports	57.63	35.94	21.69	48.34	9.29
6.42	5.14	1.28	4.52	1.90	Hydro	5.20	5.15	0.05	4.93	0.26
84.49	86.56	(2.08)	85.34	(0.86)	Waste Heat	85.40	86.23	(0.84)	83.13	2.27
$ 27.73	**$ 25.90**	**$ 1.83**	**$ 31.71**	**$ (3.98)**	**Generation and Purchased Power (W / A)**	**$ 27.39**	**$ 25.42**	**$ 1.97**	**$ 27.23**	**$ 0.17**

FUEL AND PURCHASED POWER - BY GENERATION CLASS

For The Twelve Month Period Ending March 2017

(000's)

CURRENT MONTH						YEAR-TO-DATE				
2016/2017			2015/2016			2016/2017			2015/2016	
Actual	Budget	Variance	Actual	Variance		Actual	Budget	Variance	Actual	Variance
					FUEL AND PURCHASED POWER EXPENSE					
$ 29,104	**$ 25,310**	**$ 3,794**	**$ 25,539**	**$ 3,565**	**Gas**	**$ 298,858**	**$ 280,118**	**$ 18,740**	**$ 290,000**	**$ 8,858**
21,739	**23,053**	**(1,314)**	**23,449**	**(1,710)**	**Coal**	**274,984**	**275,931**	**(947)**	**286,360**	**(11,376)**
2,009	**1,873**	**136**	**1,833**	**176**	**Wind**	**21,518**	**21,277**	**241**	**18,629**	**2,889**
2,447	**2,402**	**45**	**1,542**	**905**	**Imports**	**27,993**	**29,156**	**(1,163)**	**22,377**	**5,616**
2,141	2,195	(54)	1,428	713	**Hydro**	19,225	16,714	2,511	16,826	2,399
1,078	1,512	(434)	1,127	(49)	**Waste heat**	11,882	15,439	(3,557)	11,878	4
543	1,245	(702)	1,176	(633)	**Other**	6,983	7,962	(979)	6,106	877
$ 59,061	**$ 57,590**	**$ 1,471**	**$ 56,094**	**$ 2,967**	**Fuel and Purchased Power**	**$ 661,443**	**$ 646,597**	**$ 14,846**	**$ 652,176**	**$ 9,267**

FUEL AND PURCHASED POWER - BY GENERATION CLASS (CONTINUED)
For The Twelve Month Period Ending March 2017
(GWh's)

	CURRENT MONTH 2016/2017 Actual	CURRENT MONTH 2016/2017 Budget	CURRENT MONTH 2016/2017 Variance	CURRENT MONTH 2015/2016 Actual	CURRENT MONTH 2015/2016 Variance	YEAR-TO-DATE 2016/2017 Actual	YEAR-TO-DATE 2016/2017 Budget	YEAR-TO-DATE 2016/2017 Variance	YEAR-TO-DATE 2015/2016 Actual	YEAR-TO-DATE 2015/2016 Variance
GENERATION AND PURCHASED POWER VOLUMES										
Gas	**853.1**	**751.5**	**101.6**	**757.3**	**95.8**	**8,728.9**	**8,927.1**	**(198.2)**	**8,379.0**	**349.9**
Coal	**843.1**	**916.8**	**(73.7)**	**976.8**	**(133.7)**	**10,758.7**	**10,916.0**	**(157.3)**	**10,966.8**	**(208.1)**
Wind	**68.6**	**70.1**	**(1.5)**	**69.4**	**(0.8)**	**740.2**	**772.4**	**(32.2)**	**681.7**	**58.5**
Imports	**46.3**	**54.6**	**(8.3)**	**16.2**	**30.1**	**478.5**	**637.2**	**(158.7)**	**374.8**	**103.7**
Hydro	383.9	393.5	(9.6)	266.7	117.2	3,524.7	3,067.5	457.2	3,212.7	312.0
Waste heat	11.9	16.7	(4.8)	12.9	(1.0)	135.0	173.2	(38.2)	138.4	(3.4)
Other	0.7	1.8	(1.1)	0.7	(0.0)	7.6	6.3	1.3	2.0	5.6
Generation and Purchased Power	**2,207.6**	**2,205.0**	**2.6**	**2,100.0**	**107.6**	**24,373.6**	**24,499.7**	**(126.1)**	**23,755.4**	**618.2**
GENERATION AND PURCHASED POWER STATISTICS ($ / MWh)										
Gas	$ 34.12	$ 33.68	$ 0.44	$ 33.72	$ 0.39	$ 34.24	$ 31.38	$ 2.86	$ 34.61	$ (0.37)
Coal	25.78	25.15	0.64	24.01	1.78	25.56	25.28	0.28	26.11	(0.55)
PP Wind	100.45	97.55	2.90	89.85	10.60	98.71	96.54	2.17	96.93	1.78
Imports	52.85	43.99	8.86	95.19	(42.33)	58.50	45.76	12.75	59.70	(1.20)
Hydro	5.58	5.58	(0.00)	5.35	0.22	5.45	5.45	0.01	5.24	0.22
Waste Heat	90.59	90.54	0.05	87.36	3.22	88.01	89.14	(1.12)	85.82	2.19
Other	-	-	-	-	-	-	-	-	-	-
Generation and Purchased Power (W / A)	**$ 26.75**	**$ 26.12**	**$ 0.64**	**$ 26.71**	**$ 0.04**	**$ 27.14**	**$ 26.39**	**$ 0.75**	**$ 27.45**	**$ (0.32)**

SRRP Q42 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 of the three most recent actual years and forecasts for 2017/18 and 2018/19.

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 2017/18 or 2018/19.

Response:

a) Table Q42a

Year	Take or Pay Energy (MWh)
2014	107,000
2015	186,000
Jan – Mar 2016	83,000
2016/17	350,000
2017/18	353,000
2018/19	376,000

b) No costs related to Take or Pay provisions were incurred in fiscal year 2016/17 and no costs are forecast to be incurred in 2017/18 or 2018/19.

SRRP Q43 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 2015/16 and 2016/17 and forecasts for 2017/18 and 2018/19.

Response:

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

Hydro unit costs ($/MWh) increase in accordance with the *Water Power Rental Regulations*.

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.
- The impact of acquiring increasing amounts of firm gas transmission capacity/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.

SRRP Q44 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 (IPP) 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 use a 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 facilities. SaskPower does not own any facilities that we import from nor do we import power from any IPPs.

The IPP "Other" category includes green technologies, such as heat recovery, flare gas, and 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	$6	$27	$35	$0	N/A	N/A
IPP	N/A	N/A	$30	$102	N/A	$93

SRRP Q45 Reference: Fuel and Purchased Power (F&PP)
Please discuss how SaskPower chooses when to enter into purchase power agreements versus constructing its own generation resources? What factors does SaskPower consider and how does SaskPower ensure purchase power agreements represent the best value for customers.

Response:

The decision to enter into a Power Purchase Agreement (PPA) versus constructing our own generating resources is driven by economics and access to the fuel source.

SaskPower may choose to enter into a PPA when the Corporation identifies an opportunity for an economic source of generation but our company does not have control of the site or the fuel.

Examples of such scenarios would be hydro generation, flare gas generation, landfill gas generation, biomass generation, heat recovery generation, cogeneration, and wind generation in cases where the Independent Power Producers have already secured the land rights to the preferred sites.

When there is flexibility in the site and access to fuel can be managed (for example, natural gas delivery may be arranged to any location), SaskPower will review the economics of self-generating versus entering into a PPA. In 2016, SaskPower completed a RFP for a combined cycle facility and compared the proposals received to the cost of SaskPower completing the project. Crown Investments Corporation of Saskatchewan determined that the best value for customers was achieved by having SaskPower construct the project. This project, referred to as the Chinook Power Station, is currently under construction near Swift Current.

SRRP Q46 Reference: Fuel and Purchased Power (F&PP)
Please provide the calculations that support the fuel and purchased power variances in the figure on page 34 of the application.

Response:

SaskPower breaks out the fuel expense variance into three categories: Volume variance, mix variance and price variance. The calculations are as follows:

Volume variance =
(Actual generation X budgeted price) – (Budgeted generation X budgeted price)

Mix variance =
(Actual generation X standard price) – (Actual generation X budgeted price)

Price variance =
(Actual generation X actual price) – (Actual generation X standard price)

* “Standard price” is the budgeted price weighted by the actual fuel mix.

Variance Analysis
FUEL AND PURCHASED POWER VARIANCE ANALYSIS
2016-17 Actual vs 2017-18 Business Plan

Fuel/Source	2016-17 Actual	Price Variance *	Volume Variance *	Mix Variance *	Total Variance *	2017-18 BP	2016-17 Actual Price/GWh	2017-18 BP Price/GWh	2016-17 Actual Generation GWh	2017-18 BP Generation GWh	2016-17 Actual % of Total GWh	2017-18 BP % of Total GWh	Standard Price/GWh ($000's)
Gas	$ 298,900	$ (11,349) F	$ (20,054) F	$ (7,097) F	$ (38,500) F	$ 260,400	$ 34.24	$ 32.81	8,728.9	7,936.0	35.81%	31.81%	10.89
Coal	275,000	3,628 U	3,923 U	148 U	7,700 U	282,700	25.56	25.89	10,758.7	10,918.0	44.14%	43.76%	11.19
Wind - SaskPower	-	-	-	-	-	-	-	-	623.1	627.0	2.56%	2.51%	-
Wind - IPP	21,500	(767) F	619.03 U	648 U	500 U	22,000	183.60	177.42	117.1	124.0	0.48%	0.50%	0.91
Imports	28,000	(9,075) F	4,655 U	4,620 U	200 U	28,200	58.52	44.27	478.5	637.0	1.96%	2.55%	1.49
Hydro	19,200	1,024 U	25,478 U	(20,002) F	6,500 U	25,700	5.45	5.67	3,524.7	4,530.0	14.46%	18.16%	0.99
Other	18,800	3,097 U	1,258 U	3,145 U	7,500 U	26,300	131.84	149.43	142.6	176.0	0.59%	0.71%	0.93
Net Fuel & Purchase Power	661,400	(13,442) F	15,880 U	(18,537) F	(16,100) F	645,300	27.14	25.87	24,373.6	24,948.0	100.00%	100.00%	$ 26.40

Standard Price/GWh ($000's) = $ 26.40

*** Note: U=Unfavourable Variance; F=Favourable Variance**

SRRP Q47 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 2017/18 and 2018/19.

Response:

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

SaskPower contracts enough market access and storage to ensure it can meet the supply of natural gas during an abnormally low 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.

The market access for all transmission and storage service is contracted with TransGas Ltd. In 2017, SaskPower has 155,000 GJ/day of firm receipt border service to transport gas from Alberta into Saskatchewan; 227,900 GJ/day of firm delivery service to transport gas in Saskatchewan to the gas generation facilities; 150,000 GJ/day of firm storage withdrawal capability; and 6 million GJ of firm storage capacity.

The following table outlines the 2014 – 2020 fiscal periods for service:

Summary of Transmission & Storage Service				
Period	Receipt GJ/Day	Delivery GJ/Day	Storage Withdrawal GJ/Day	Storage Capacity GJ
2014	120,000	185,900	150,000	6,000,000
2015	145,000	227,900	150,000	6,000,000
Jan-Mar 2016	170,000	227,900	150,000	6,000,000
Fiscal 2016/17	170,000	227,900	150,000	6,000,000
Fiscal 2017/18	155,000	227,900	150,000	6,000,000
Fiscal 2018/19	155,000	227,900	150,000	6,000,000
Fiscal 2019/20	205,000	277,900	150,000	6,000,000

Please note that service is as of the last day of the period.

As SaskPower has added gas generation, incremental receipt and delivery service has been contracted. This includes the Chinook Power Station, scheduled for commissioning in 2019.

SaskPower is also in the queue for:

1. Incremental firm storage withdrawal service; and
2. Incremental firm receipt border service at Empress.

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 Q48:
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:

Since the last application, there has been an update to the Long-Term Natural Gas Exposure Management Policy.

The Long-Term Natural Gas Exposure Management Policy was updated in December 2016. 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 change to the program was intended to provide the most up-do-date forecasted natural gas volumes, which are used in the hedge schedule. The hedge schedule is now based on the most recent iteration of the Business Plan, (which may be preliminary Business Plan values), rather than the most recent Board-approved Business Plan. All other guidelines and targets remain the same as the 2015 approval of the Policy.

A full update of the Risk Management Manual, which has been effective since June 18, 2012, is currently in progress.

Additionally, SaskPower has adopted International Financial Reporting Standards (IFRS 9) *Financial Instruments* effective April 1, 2017 and has elected to apply hedge accounting to the eligible portion of its natural gas financial hedges to reduce the impact of any movements in the forward price of natural gas on the Corporation's net income.

SRRP Q49 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 of the three most recent actual years and forecasts for 2017/18 and 2018/19.

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
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	5	13	$ 2.38	40	136	$ 3.38
2017/18*	5	10	$ 2.14	35	125	$ 3.58
2018/19*	5	12	$ 2.55	43	154	$ 3.56

*** Forecasted volume and cost**

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 Q50 Reference: Natural Gas

Please provide a schedule showing actual natural gas hedged volumes for the ten most recent actual years and currently hedged volumes for 2017/18 and 2018/19. 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 with some collars in the years 2007-2009.

	GJ (Millions)	Notional Value (Millions)	$/GJ
2007	10	$ 89	$ 9.05
2008	15	$ 112	$ 7.34
2009	16	$ 140	$ 8.60
2010	19	$ 121	$ 6.27
2011	21	$ 137	$ 6.46
2012	25	$ 148	$ 5.85
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	$ 182	$ 3.93
2018/19	40	$ 167	$ 4.21

SRRP Q51 Reference: Natural Gas

Please provide an estimate of the impact of SaskPower's hedging activities on natural gas costs for each of the ten most recent actual years. Please also provide a discussion on the net cost or benefit to ratepayers of the hedging program over the past ten years.

Response:

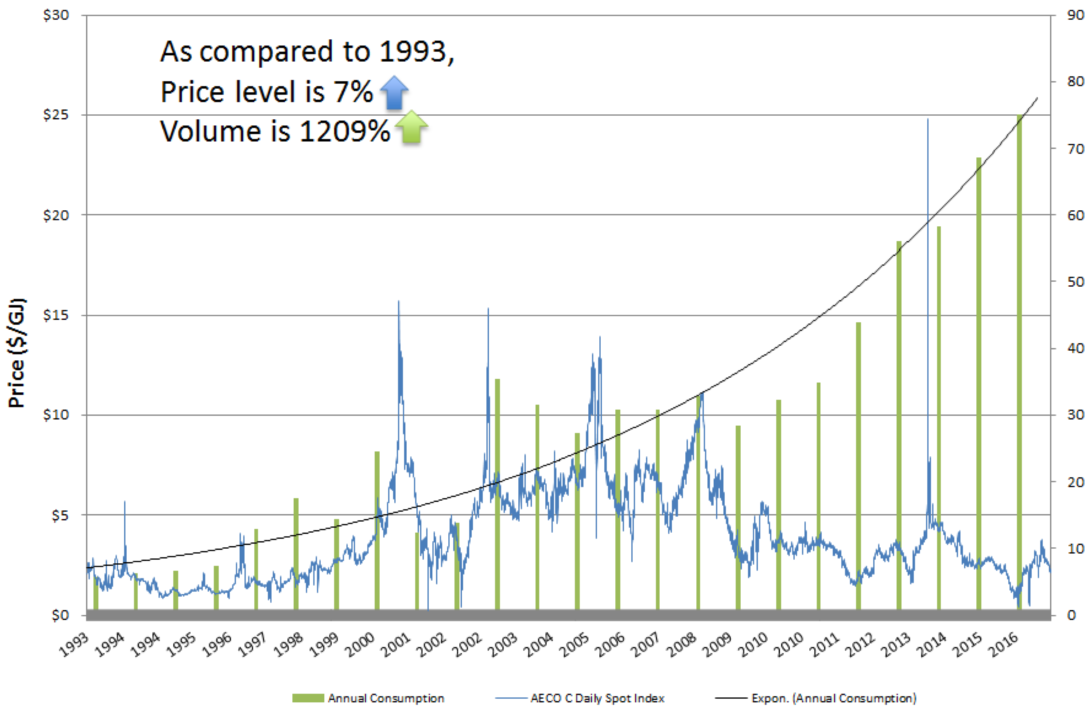
	2007	2008	2009	2010	2011
Gas Portfolio Variance from Budget ($millions)	13	(59)	(96)	(42)	(22)
Variance from Market	18	(9)	76	45	61
Market Price ($/GJ)	6.10	7.73	3.76	3.79	3.44
WACOG ($/GJ)	5.87	7.09	4.04	4.17	4.02
Volatility Reduction Percentage	79%	78%	89%	85%	78%

	2012	2013	2014	2015	2016
Gas Portfolio Variance from Budget ($millions)	(42)	(4)	50	36	22
Variance from Market	90	40	2	58	92
Market Price ($/GJ)	2.27	3.01	4.24	2.56	2.06
WACOG ($/GJ)	3.62	3.70	3.80	3.12	3.46
Volatility Reduction Percentage	84%	88%	70%	86%	88%

Table Notes:

- Gas portfolio variance from budget year contains actual values, including all hedge transactions, physical purchases, transportation & storage costs. A negative value indicates net savings compared to budget, with a positive value as higher value than budgeted.
- Variance from market includes the settlement from financial transactions and the difference between the notional value and market value of physical hedge transactions. A negative value indicates the amount received by SaskPower. A positive value indicates the amount paid out by SaskPower.
- Market price is the average AECO spot market price.
- WACOG is the year end weighted average cost of physical gas.
- Volatility reduction is the percent change between spot price volatility and SaskPower's cost of gas volatility.
- SaskPower's gas variance from budget is influenced by deviations in the combinations of expected hydro, gas generation variance and overall system generation changes. Each year is unique.

At times, there is an incremental cost for certainty of supply and price, which leads to the stability of the fuel budget. When long-term transactions are layered into the gas portfolio in a declining market price environment, then SaskPower pays an incremental cost of the mark-to-market settlement value. However, the net effect typically results in lower than budgeted gas portfolio costs. Alternatively, in a rising market price environment, SaskPower receives funds on the mark-to-market settlement value; however, the net effect typically results in higher than budgeted gas portfolio costs. There has been significant gas generation growth at SaskPower over the years. With projections for over 50% growth in the next 20 years, the impact on net income and rates continues to be significant.



Even though there have been incremental settlement costs for hedge gas transactions over the past few years due to transaction timing and structural market changes, SaskPower has greatly benefitted from a diversified generation portfolio. Over the past 10 years, the net effect has resulted in lower than budgeted gas fuel expenses for SaskPower and Power Purchase Agreement generation. The total net savings to budget, including hedge activities from 2007 to 2016, is estimated to be close to $150 million, with an average volatility reduction of 82% per year.

The Long-Term Natural Gas Exposure Management Policy objectives include:

1. **Security of supply**: Securing a portion of the natural gas supply allows for operational flexibility while stabilizing a portion of the fuel & purchased power budget. It ensures a long-term focus is given to natural gas requirements by aligning with and executing the long-term supply plan.

2. **Market access**: Entails proactively securing and managing market access by acquiring transportation service from gas markets to the gas-fired facilities. Since Saskatchewan is a small natural gas market in terms of users and production, SaskPower relies on Alberta production for supply. With the recent gas generation growth, SaskPower has become the Province's largest natural gas consumer.

3. **Price management**: Managing natural gas prices using physical and financial tools to stabilize a portion of business plan fuel costs, directly impacting net income and any rate change considerations.

SaskPower's long-term hedging program is in place to stabilize the natural gas market price impact on the fuel budget. It protects against fuel spikes and resulting rate increase spikes for external unforeseen market events. Feedback from SaskPower's key and major customers indicates that electricity rates are a concern, with stability preferred over fluctuations. The ability to smooth the fuel budget volatility leads to stabilizing the fuel impact on SaskPower's net income and thereby, customer rates.

SRRP Q52 Reference: Natural Gas

A) Please provide a schedule that shows SaskPower's natural gas fuel efficiency ratio (i.e. the kW.h generated per unit of natural gas) for each of the three most recent actual years and forecasts for 2017/18 and 2018/19. Please comment on any material variances between years.

B) Please describe how SaskPower prepares its forecasts of natural gas fuel efficiencies.

Response:

A)

	SaskPower Natural Gas Fuel Efficiency Ratio (KWh/GJ)
2015	102
2015/16	103
2016/17	103
2017/18	116
2018/19	111

In historic years, the fuel efficiency ratio was impacted by operating conditions that required gas units to run for short periods of time at lower optimal efficiency in order to meet system requirements. The forecasted years contain a higher percentage of dispatches at optimal efficiency points.

B) SaskPower natural gas unit efficiencies are periodically tested; where applicable, new efficiency equations are developed and updated within the fuel hourly dispatch model. Recent natural gas fleet addition fuel efficiencies are based on design fuel efficiencies.

SRRP Q53 Reference: Natural Gas

Please provide a schedule showing the average cost of transmission and storage per GJ for the three most recent actual years and forecasts for 2017/18 and 2018/19.

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 2018/19.

	Average Transportation Cost ($/GJ)	Average Storage Cost ($/GJ)
2014	$ 0.70	$ 0.17
2015	$ 0.68	$ 0.13
Jan-Mar '16	$ 0.69	$ 0.11
2016/17	$ 0.78	$ 0.12
2017/18	$ 0.82	$ 0.14
2018/19	$ 0.84	$ 0.15

SRRP Q54 Reference: Natural Gas

A) Please discuss what strategies SaskPower intends to pursue to mitigate risks associated with increasing reliance on natural gas as currently contemplated in the integrated resource plan.

B) Please discuss whether SaskPower has contemplated implementing a fuel price stabilization account to address differences between forecast natural gas prices assumed in a rate application and actual natural gas prices.

Response:

A) 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 ongoing comprehensive strategic and resource planning efforts;
- Continue to improve the long-term hedge 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 the 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.

B) The concept of a fuel price stabilization account was studied thoroughly earlier in the decade. In 2010, the Saskatchewan Rate Review Panel recommended that, "SaskPower undertake an immediate dialogue with stakeholders to resolve the need for a fuel cost variance account so a decision can be made before the next general rate application, but no later than the end of 2010."

A consultant, Christensen Associates Energy Consulting LLC, was selected to provide an assessment of a Fuel Cost Variance Account (FCVA) for SaskPower. The consultant recommended that if Saskatchewan adopts an FCVA for SaskPower, it should create a quasi-judicial regulatory agency.

The consultant noted that the agency should be fully funded, supported by expert staff, relatively independent from the provincial government and responsible for reviewing both the annual FCVA application and base rate case applications. Christensen Associates continued that if Saskatchewan adopts an FCVA without creating a fully functioning, independent, quasi-judicial regulatory agency, the government should increase the Panel's budget so that it can hire full-time expert staff to review both FCVA applications and base rate case applications.

The consultant added, "We emphasize that adoption of an FCVA without independent regulatory governance mechanism is fraught with regulatory risks that could detrimentally affect SaskPower's financial and operational situation, with concomitant effects on the province's economic prosperity."

As a result of the consultant's review and SaskPower's own analysis, the Corporation did not proceed with adoption of a FCVA.

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2018 RATE APPLICATION
SRRP INTERROGATORIES

SRRP Q55 Reference: Coal

A) Please provide the average heat values for coal generation for each of the past three actual years and forecasts for 2017/18 and 2018/19.

B) Please discuss how SaskPower forecasts heat values for coal

Response:

A) Average heat values

i) Coronach area

Year		2015	2016	2017	2018	2019
Heat value	MJ/Mg	13,163	13,216	13,554	13,695	13,423

ii) Estevan area

Year		2015	2016	2017	2018	2019
Heat value	MJ/Mg	16,031	15,806	15,668	15,844	15,837

B) Heat value forecast methodology

SaskPower utilizes internal geoscience and mine engineering expertise dedicated to fuel resource management. The coal supply contracts have specific clauses that deal directly with obtaining the necessary information needed for security of supply and related coal quality parameters. This is performed by having all of the future mining areas drilled and cored five years in advance of mining. SaskPower takes this information, confirms the geological validity, inputs this into a database, and then proceeds to model the information with a mining industry standard software platform. The model then is utilized to pick the appropriate mining area where SaskPower is able to derive the associated heating values for the year to be mined.

2018 RATE APPLICATION
SRRP INTERROGATORIES

SRRP Q56 Reference: Coal

Please discuss whether SaskPower has any current plans to build additional carbon capture technology. If so, please identify any planning or capital costs related to these plans included in the 2017/18 and 2018/19 forecasts.

Response:

Current federal regulations require that all traditional coal generating facilities must be retired by the earlier of 50 years of age and 2030. SaskPower is currently studying its options with respect to the future of its existing coal generating fleet.

The next facilities that are due to reach 50 years of age are Units #4 and #5 at Boundary Dam Power Station. SaskPower is expected to make a formal decision on the future of Units #4 and #5 in early 2018. There are no capital costs included in this rate application that relate to the conversion of these or any other units to carbon capture and storage.

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2018 RATE APPLICATION
SRRP INTERROGATORIES

SRRP Q57 Reference: Coal

Please provide an update on negotiations with the federal government on an emissions equivalency agreement. Please discuss how progress on an equivalency agreement affects SaskPower's planned retirement dates for its coal facilities.

Response:

On November 22, 2016, Saskatchewan and Canada signed an agreement in principle to complete an Equivalency Agreement (EA). The EA would enable the Government of Saskatchewan to assume regulatory oversight on greenhouse gas emissions from coal and natural gas facilities generating electricity for SaskPower, and requires the regulatory oversight from Saskatchewan to provide equivalent, or lower, emission rates to those that would be achieved under current federal regulations.

SaskPower has provided technical information to the provincial government and Environment and Climate Change Canada (ECCC) for the purposes of calculating carbon dioxide equivalent (CO_{2e}) emission limits for provincial regulations. SaskPower anticipates provincial regulations to come into force by January 1, 2018.

A formal signing of the EA (between ECCC and Saskatchewan's Ministry of Environment (MOE)) is anticipated for July 2018. Full federal approval of the EA is expected to be completed near the end of 2018. SaskPower believes progress towards completing an EA is on track and remains strongly supported by ECCC and MOE.

Under an EA, end-of-life dates currently defined or proposed under federal regulations would no longer be in effect in Saskatchewan. Instead, SaskPower would be required to meet specific emission limits that are deemed to be equivalent to what the federal regulation would have achieved. This would enable SaskPower to have some flexibility on the end-of-life dates for conventional coal units, and allow a more cost-effective transition to a lower emissions electricity generating system.

SRRP Q58 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 2017/18 and 2018/19 forecasts.

Response:

Options to earn revenue from the implementation of carbon capture technology in other jurisdictions continue to be explored. However, to-date no significant revenue streams have been identified. In the meantime, SaskPower continues to focus on optimizing carbon capture technology here in Saskatchewan to ensure we maintain a diverse, reliable, and economical source of electric power for the residents of this province.

SRRP Q59 Reference: Hydro

Please provide an update on the status of the Tazi Twé project, including any changes to project costs and in-service date since the last rate application.

Response:

SaskPower is nearing completion of its review of the economic viability of proceeding with the Tazi Twé Hydroelectric Project as a result of reduced demand for power in the North.

Demand for electricity in this region has not materialized as expected, which will significantly impair the economics of the project. A final decision on the future of the project is expected before the end of 2017.

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2018 RATE APPLICATION
SRRP INTERROGATORIES

SRRP Q60 Reference: Hydro
Please provide a schedule showing the actual and forecast water rental rates for the three most recent years of actuals and forecasts for 2017/18 and 2018/19.

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)
2014	4.89
2015	5.10
2016 Q1	5.32
Fiscal 2016/17	5.45
Fiscal 2017/18	5.66
Fiscal 2018/19	5.86

SRRP Q61 Reference: Hydro

A) Please discuss the basis of the specific flow conditions forecast for 2017/18 and 2018/19 with reference to the generation volumes on page 33 of the application.

B) Please provide any updates to the expected flow conditions in 2017/18 and 2018/19 that were not available at the time the business plan and the current application were prepared.

Response:

A) The basis of the specific flow conditions forecast in June 2017 for 2017/18 was as follows:

- High storage levels in the reservoirs, above average snowfall in the mountains, and an early spring and mountain runoff lead to a 2017/18 flow projection for between median flow and upper quartile flow on the South Saskatchewan River system.

- 2016 fall rains, above average snowfall, and strong 2017 spring rains lead to a 2017/18 flow projection for between upper quartile and upper decile flow on the North Saskatchewan River system.

- Strong 2016 fall rains, strong snowfall, and strong 2017 spring rains lead to a 2017/18 flow projection for above upper decile flow on the Churchill River system.

B) The long-term bases of specific flow conditions forecast past the current year reflect a return to median conditions. Thus, for the 2018/19 fiscal year the projection is for median flow conditions on all three river systems.

SRRP Q62 Reference: Hydro

A) Please confirm which 40 years of data are used for forecasting hydro availability.

B) Please confirm how long a time series SaskPower has for hydro availability data and indicate why SaskPower has elected to use 40 years of data.

Response:

A) The current data set being used is 1970-2009, adjusted for the current level of Alberta development.

B) SaskPower expanded the 40-year data set in 2016 to now include 1965 thru 2015, adjusted for the current level of Alberta development. The updated median flow did not lead to a change in median hydro generation for two reasons.

First, the median flow values were not significantly different than the current data set. Second, a larger data set dating back to 1928 adjusted for the current level of Alberta development is being developed. When the larger data set is complete, each historic year will be input into the hydro generation model and an updated median hydro generation value will be calculated.

SRRP Q63 Reference: Wind

Please provide a schedule showing actual and forecast monthly wind generation in GWh and wind capacity factors for wind facilities for the last year actual years available and forecasts for 2017/18 and 2018/19.

Response:

The following table contains actual data thru May 2017. The values after May 2017 are forecasted.

Generation (GWh)	Apr '17	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan '18	Feb	Mar
2016/17	66.2	55.3	53.7	35.2	48.5	47.8	64.1	72.6	92.3	77.9	58	68.6
2017/18	59.4	58.7	49.7	50.8	52.5	59.1	67.9	66.8	75.1	75.2	65.8	69.6
2018/19	65.8	68.4	55.6	51	52.7	58.7	67.7	66.8	75.3	85.1	75.2	80.4

Capacity Factor	Apr '17	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan '18	Feb	Mar
2016/17	30%	25%	24%	16%	22%	22%	29%	33%	42%	35%	26%	31%
2017/18	27%	27%	22%	23%	24%	27%	31%	30%	34%	34%	30%	31%
2018/19	30%	31%	25%	23%	24%	27%	31%	30%	34%	34%	30%	32%

SRRP Q64 Reference: Wind

Please indicate if SaskPower is considering developing more of its own wind generation or if future wind generation is contemplated to be exclusively through power purchase agreements?

Response:

A decision regarding the ownership of future wind power generation has not been made.

SRRP Q65 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 of the last three actual years and forecasts for 2017/18 and 2018/19.

Response:

Firm contracts are comprised of a single firm contract and have thus been included with spot market or short-term contracts to preserve counterparty confidentiality.

	Actual			Forecast		
	Volume (GWh)	Cost ($ Million)	Average Price ($/Mwh)	Volume (GWh)	Cost ($ Million)	Average Price ($/Mwh)
2015	506	$29.1	$57.57			
2015/16	375	$22.4	$59.71			
2016/17	479	$28.0	$58.50			
2017/18				637	$28.2	$44.27
2018/19				565	$31.0	$54.87

SRRP Q66 Reference: Imports

Please provide an explanation for the forecast decrease in import unit prices shown in the table on page 34 of the application from $58.27/MWh in 2016/17 to $44.16/MWh in 2017/18.

Response:

The 2017/18 import forecast developed in June 2017 included almost three months of actual data. In this actual data there were large volumes of imports at pricing significantly less than previous projections.

The key drivers behind the reduced import pricing are declining natural gas prices and above-average hydro generation from Manitoba. This trend was projected for the balance of the 2017/18 fuel forecast and creates the $44.16/MWh import unit price.

SRRP Q67 Reference: Imports

Please discuss any current plans SaskPower has to increase import capabilities from other jurisdictions.

Response:

SaskPower-Manitoba Hydro interface

SaskPower is currently increasing import capability to its main southern system from Manitoba by 100 MW for the 2020 timeframe. This involves the addition of a new 230-kV tie-line between SaskPower and Manitoba Hydro at the Tantallon and Birtle transmission stations – including associated system reinforcements.

SaskPower-Alberta interface

SaskPower is currently adding a 230-kV transmission line between Swift Current, Moose Jaw and Regina. The main drivers for this project were to facilitate generation additions (Chinook Power Station and wind) and firm 153-MW export capability to Alberta. The total transfer capability on the SK-AB interface is limited to 153 MW due to the capability of the McNeill Convertor Station. Based on past Transmission Service Request assessments, it was concluded that a 230 kV line between Swift Current- Moose Jaw-Regina can also facilitate increased import capability from Alberta. There are currently no active attempts to secure/firm up the import capability under SaskPower's Open Access Transmission Tariff provisions.

SaskPower-US interface

SaskPower is currently planning to upgrade the transformer ended tie-line with North Dakota by installing a larger phase shifting transformer at its Boundary Dam station. The main driver for this project is to facilitate larger unit size (Chinook Power Station). Based on engineering judgement it can be stated that by increasing the size of the phase shifting transformer, there is incremental increase in import capability. Further studies need to be conducted to determine the specifics on quality and quantity of the increase, while being coordinated with selected transformer size. There are currently no active attempts to secure/firm up any increased import capability under SaskPower's Open Access Transmission Tariff provisions.

2018 RATE APPLICATION
SRRP INTERROGATORIES

SRRP Q68 Reference: Operating, Maintenance and Administration (OM&A)

A) Please provide a table for each of the ten most recent fiscal years that shows:
   i. Actual OM&A spending.
   ii. Actual customer counts.
   iii. Average OM&A per customer.
   iv. Forecast OM&A spending from the prior year's business plan (i.e. the last business plan prepared before the start of each fiscal year).
   v. Forecast customer counts from the prior year's business plan.
   vi. Forecast OM&A per customer from the prior year's business plan.

B) Please provide an explanation for any material variances between forecasts and actuals in the information provided in the response to part (a).

Response:

A. The following table shows both the actual and forecasted OM&A spend, customer counts and the average OM&A per customer for the years 2007 – 2016/17.

OM&A/Customer

	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual
	2007	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015/16**	**2016/17**
OM&A (millions)	416	427	495	512	577	616	618	656	637	675
Total of Saskatchewan customer accounts	451,713	460,006	467,329	473,007	481,985	490,611	500,879	511,941	521,745	528,059
OM&A per Saskatchewan customer account	920.9	928.2	1,059.2	1,082.4	1,197.1	1,255.6	1,233.8	1,281.4	1,220.9	1,278.3

	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast
	2007	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015/16**	**2016/17**
OM&A (millions)	386	441	493	611	609	582	615	647	672	702
Total of Saskatchewan customer accounts	441,907	446,214	458,951	469,351	481,185	478,753	496,895	503,951	518,879	523,351
OM&A per Saskatchewan customer account	872.8	989.2	1,074.2	1,302.0	1,266.5	1,216.3	1,238.1	1,284.1	1,295.1	1,341.4

B. The variance between actual and forecasted OM&A in 2010 is due to the reclassification of ICCS grant funding as a reduction to OM&A.

SRRP Q69 Reference: Operating, Maintenance and Administration (OM&A)
Please provide a version of the Operating, Maintenance & Administration table included in the business plan dated July 26, 2017 (section 4 of the MFRs) that includes the three most recent years of actuals.

Response:

The following table provides OM&A actuals by Business Unit for the years 2014 – 2016/17:

Operating, Maintenance and Administration - Business Unit
(millions)

	2014	2015/16	2016/17
President /Board	$ 10	$ 6	$ 7
Power Production	203	196	205
Transmission	74	72	86
Distribution	107	94	93
Finance	15	16	15
Customer Services	34	29	30
Planning, Envi. & Sustainable Dev.	15	19	17
Law, Land, Regulatory Affairs	19	24	25
Information, Technology & Security	68	73	76
Human Resources	24	23	22
Commercial & Industrial Operations	8	10	10
Procurement & Supply Chain	32	32	34
Total core costs	**609**	**594**	**620**
Demand Side Management	12	15	17
Insurance expense	5	5	5
Bad debt expense	3	6	6
Return to work program	3	3	2
Other expense	(2)	(7)	(2)
Purchased power agreements (OM&A)	26	21	27
Total other costs	**47**	**43**	**55**
TOTAL OM&A	**$ 656**	**$ 637**	**$ 675**

SRRP Q70 Reference: Operating, Maintenance and Administration (OM&A)

Please discuss how SaskPower forecasts and manages its overtime and vacation costs.

Response:

Overtime is managed at the Business Unit level and is a component of each area's overall OM&A budget. Variances between actual and budgeted overtime costs are driven primarily by emergency maintenance that results from storm activity and unplanned outages. While SaskPower makes every effort to do this work during regular working hours, we also attempt to restore power as quickly as possible, regardless of when the outage occurs.

Overtime costs are reviewed on a monthly basis at the Business Unit level and forecasts are updated as required to reflect year-to-date activity and projections for the remainder of the year.

Vacation costs are also managed at the Business Unit level, but are done so in accordance with SaskPower's corporate Vacation Policy. Vacation is typically scheduled/approved one month in advance to ensure that there is sufficient coverage. All employees are required to take a minimum of three week's leave annually.

Employees are entitled to carry a maximum of 20 days plus current year's vacation. While any accumulation over the 20 days will automatically be paid out, employees are strongly encouraged to make every effort to schedule vacation in order to limit the payout of unused vacation.

On an annual basis, the Executive and Human Resources/Compensation Committee are provided a listing of employees with carryover vacation and/or vacation payouts.

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2018 RATE APPLICATION
SRRP INTERROGATORIES

SRRP Q71 Reference: Operating, Maintenance and Administration (OM&A)
Please provide a schedule that breaks out actual and forecast total OM&A costs for the three most recent actual fiscal years and forecasts for 2017/18 and 2018/19 in a format similar to the response to SRRP Q69 from the 2016 and 2017 Rate Application. Please include any necessary adjustments as required to reconcile to the OM&A figures provided on page 37 of the current application.

Response:

The following table summarizes SaskPower's actual OM&A expenses by cost category for the years 2014 to 2016/17. It also contains the forecast for the years 2017/18 and 2018/19:

Operating, Maintenance and Administration by Category
(millions)

	2014	2015/16	2016/17	2017/18	2018/19
Salaries and wages	$ 304	$ 302	$ 317	$ 329	$ 336
Premium pay	53	39	37	35	36
Benefits	66	70	66	73	74
Wages and salaries	423	411	420	436	445
Labour credits	(81)	(79)	(66)	(72)	(73)
Subtotal wages & salaries	342	332	354	364	372
Materials and supplies	30	30	37	35	36
Contract services	185	183	195	202	206
Consulting services	24	20	19	17	17
Advertising expenses	5	3	2	3	3
External services	214	206	216	222	227
Training expenses	4	2	3	3	3
Travel expenses	14	12	11	12	12
Administrative expenses	21	23	21	19	20
Insurance expenses	5	5	5	5	5
Bad debt expense	3	6	6	6	6
Tools and equipment expens	3	3	3	2	3
Vehicle expenses	12	9	9	9	9
Property expenses	8	9	10	12	12
Other	70	69	68	67	69
TOTAL OM&A	**$ 656**	**$ 637**	**$ 675**	**$ 689**	**$ 703**

SRRP Q72 Reference: Operating, Maintenance and Administration (OM&A)
Please provide the actual overhaul spending for the three most recent years and forecasts for 2017/18 and 2018/19.

Response:

2014	$34,559,472 Actual
2015	$30,670,345 Actual
2016/17	$42,902,503 Actual
2017/18	$45,324,547 Forecast
2018/19	$44,095,282 Forecast

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2018 RATE APPLICATION
SRRP INTERROGATORIES

SRRP Q73 Reference: Operating, Maintenance and Administration (OM&A)
Please provide the actual vacancy rates for the three most recent years and forecasts for 2017/18 and 2018/19.

Response:

The following is a breakdown of actual vs. budgeted permanent FTEs for the three most recent years ending March 31, 2017, as well as the actual FTE count for the current year as at July 31, 2017.

SaskPower - Permanent FTE's

	2014	2015	2016/17	2017/18*
Actual FTE's	3,091.0	3,125.0	3,162.0	3,137.0
Budgeted FTE's	3,282.0	3,268.0	3,347.0	3,366.0
Variance	(191.0)	(143.0)	(185.0)	(229.0)
Vacancy Rate	5.8%	4.4%	5.5%	6.8%

*** 2017/18 figures are based on actuals as at July 31, 2017**

It should be noted that FTE targets and forecasts have not yet been established for 2018/19. While SaskPower does not anticipate the target changing significantly, one factor that does impact FTE targets is the repatriation of contract employees back as SaskPower employees. Repatriation initiatives typically result in higher wage and salary costs but are more than offset by reductions to contract services costs.

CONFIDENTIAL SRRP Q74 Reference: Operating, Maintenance and Administration (OM&A)

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

Response:

A response has been submitted to the Saskatchewan Rate Review Panel for its review. However, the response contains confidential information that is not for public release.

SRRP Q75 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:

The SaskPower and IBEW Local 2067 collective agreement expired December 31, 2016. The parties have signed a tentative agreement that is subject to ratification by the union membership. The ratification process is targeted to be completed by the end of September 2017.

The SaskPower and UNIFOR Local 649 collective agreement expired December 31, 2016. The parties are in negotiations but have not reached a tentative agreement as at September 8, 2017.

SRRP Q76 Reference: Operating, Maintenance and Administration (OM&A)

Please discuss how SaskPower has incorporated the spending controls outlined at page 11 in the province's 2017 budget (http://www.finance.gov.sk.ca/budget17-18/2017-18Budget.pdf) into its OM&A forecasts in the current application.

Response:

SaskPower is currently in negotiations with its two unions (IBEW Local 2067 and Unifor Local 649). Included in these negotiations are discussions based on the spending controls identified in the provincial budget. The OM&A forecasts included in the application do not include the financial impact of any potential salary rollbacks.

SRRP Q77 Reference: Other Expenses

Please provide a break-out of SaskPower's Other expense category including Asset Disposals, Asset Retirements, Foreign exchange (if any) and Environmental Expense for each of the three most recent actual years and forecasts for 2017/18 and 2018/19.

Response:

The following table shows the actual breakdown of other expense for the years 2014 to 2016/17 and the forecasted amounts for the years 2017/18 and 2018/19.

Other Expenses
(millions)

	2014	2015/16	2016/17	2017/18	2018/19
Gain/Loss on asset retirements	$ 12	$ 24	$ 26	$ 8	$ 8
Gain/Loss on asset disposal	3	3	6	5	5
Inventory adjustments	7	3	1	3	3
Loss on impairment of assets	17	-	-		
Foreign exchange	-	-	-		
Environmental expense	7	7	5	14	14
TOTAL OTHER	**$ 46**	**$ 37**	**$ 38**	**$ 30**	**$ 30**

SRRP Q78 Reference: Debt and Equity

A) Please confirm that SaskPower's credit rating is essentially 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 most recent actual year and forecasts for 2017-18 and 2018-19.

Response:

A) Confirmed.

B) SaskPower's total borrowing authority provided by the *Power Corporation Act* is $10 billion.

C) Current (2016-17) – $3.5 billion
2017-18 – $3.2 billion
2018-19 – $2.7 billion

SRRP Q79 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 the three most recent years of actuals and forecasts for 2017/18 and 2018/19.

Response:

The following table shows the calculation of SaskPower's capital structure for the years 2014 – 2016/17 and the forecasted amounts for 2017/18 and 2018/19:

Debt and Equity
(millions)

	2014	2015/16	2016/17	2017/18	2018/19
Gross long-term debt	4,355	5,130	$5,559	$5,881	$6,224
Finance lease obligation	1,138	1,133	1,126	1,113	1,131
Short-term advances	890	981	900	1,136	1,213
Debt retirement funds	(457)	(533)	(590)	(668)	(739)
Cash and cash equivalents	2	(28)	(13)	(5)	(5)
Total net debt	$5,928	$6,683	$6,982	$ 7,457	$ 7,823
Equity advances	$660	$660	$660	$660	$660
Retained earnings	1,521	1,547	1,603	1,772	1,962
Accumulated OCI	(3)	(61)	(22)	(50)	(50)
Total capital	$8,106	$8,829	$9,223	$ 9,839	$ 10,395
Percent debt ratio	73.1%	75.7%	75.7%	75.8%	75.3%

SRRP Q80 Reference: Debt and Equity

Please provide the calculation of the operating return on equity percentage for each the three most recent years of actuals and forecasts for 2017/18 and 2018/19 showing;

i. the calculation of the operating income
ii. the calculation of the equity component of SaskPower's total capital structure and the equity component of ratebase.

Response:

The following table shows the calculation of the operating return on equity for the years 2014 to 2016/17 and the forecasted amounts for 2017/18 and 2018/19:

Return on Equity (Operating)
(millions)

	2014	2015/16	2016/17	2017/18	2018/19
Operating Income	$43	$64	$46		
Equity advances	660	660	660	660	660
Retained earnings	1,521	1,547	1,603	1,885	1,885
Accumulated OCI	(3)	(61)	-22	0	0
Average Equity	$2,201	$2,154	$2,194	$2,393	$ 2,545
Operating Return on Equity	2.0%	2.9%	2.1%	0.0%	0.0%

SRRP Q81 Reference: Debt and Equity

Please confirm that SaskPower's long-term debt is guaranteed by the provincial government and that the provincial government does not charge SaskPower a guarantee fee.

Response:

SaskPower's long-term debt is not guaranteed by the provincial government and therefore SaskPower is not charged a guarantee fee.

2018 RATE APPLICATION
SRRP INTERROGATORIES

SRRP Q82 Reference: Debt and Equity

Please provide a table showing the actual and budgeted Return on Equity in dollars and in percentage terms for the five most recent actual years. Please discuss any reasons for material variances between actuals and forecasts, including the potential impact of weather.

Response:

The following table shows the actual and budgeted Return on Equity for the years 2012 – 2016/17:

Return on Equity
(millions)

	2012		2013		2014		2015/16		2016/17	
(in $millions)	**Actual**	**Budget**	**Actual**	**Budget**	**Actual**	**Budget**	**Actual**	**Budget**	**Actual**	**Budget**
Net Income (Loss)	135	157	114	126	60	27	(19)	82	56	156
Equity advances	660	660	660	660	660	660	660	660	660	660
Retained earnings	1,347	1,492	1,461	1,388	1,521	1,363	1,547	1,599	1,603	1,673
Accumulated OCI	(149)		102		(3)		(61)		(22)	
Average Equity	1,861	2,005	2,041	2,100	2,201	2,036	2,162	2,141	2,194	2,296
Return on Equity	7.3%	7.8%	5.6%	6.0%	2.7%	1.3%	-0.9%	3.8%	2.6%	8.0%

	2012		2013		2014		2015/16		2016/17	
(in $millions)	**Actual**	**Budget**	**Actual**	**Budget**	**Actual**	**Budget**	**Actual**	**Budget**	**Actual**	**Budget**
Gross long-term debt	2,979	3082	3,568	3309.1	4,355	4,169	5,130	4,999	$5,559	$5,372
Finance lease obligation	435	553	1,137	1253.4	1,138	1,139	1,133	1,138	1,126	1,130
Short-term advances	762	553	804	972.1	890	1,052	981	953	900	1,066
Debt retirement funds	(390)	-377	(368)	(418)	(457)	(418)	(533)	(517)	(590)	(599)
Cash and cash equivalents	-1	-13	2	-16.5	2	-13	(28)	(5)	(13)	(28)
Total net debt	$3,785	$3,798	$5,143	$5,100	$5,928	$5,929	$6,683	$6,568	$6,982	$6,941
Equity advances	$660	660	$660	660	$660	660	$660	660	$660	660
Retained earnings	1,347	1,492	1,461	1,388	1,521	1,363	1,547	1,599	1,603	1,673
Accumulated OCI	(149)		102		(3)		(61)		(22)	
Total capital	$5,643	$5,950	$7,366	$7,148	$8,106	$7,952	$8,829	$8,827	$9,223	$9,274
Percent debt ratio	67.1%	63.8%	69.8%	71.3%	73.1%	74.6%	75.7%	74.4%	75.7%	74.8%

SRRP Q83 Reference: Debt and Equity

Please provide a table showing the actual and forecast from the prior year's business plan for the five most recent actual years.

Response:

The following table outlines SaskPower's actual vs. budgeted debt, equity and the applicable ratios for the years 2012 to 2016/17 and incorporates the information requested in SRRP Q82.

Return on Equity
(millions)

(in $millions)	2012 Actual	2012 Budget	2013 Actual	2013 Budget	2014 Actual	2014 Budget	2015/16 Actual	2015/16 Budget	2016/17 Actual	2016/17 Budget
Net Income (Loss)	135	157	114	126	60	27	(19)	82	56	156
Equity advances	660	660	660	660	660	660	660	660	660	660
Retained earnings	1,347	1,492	1,461	1,388	1,521	1,363	1,547	1,599	1,603	1,673
Accumulated OCI	(149)		102		(3)		(61)		(22)	
Average Equity	1,861	2,005	2,041	2,100	2,201	2,036	2,162	2,141	2,194	2,296
Return on Equity	7.3%	7.8%	5.6%	6.0%	2.7%	1.3%	-0.9%	3.8%	2.6%	8.0%

(in $millions)	2012 Actual	2012 Budget	2013 Actual	2013 Budget	2014 Actual	2014 Budget	2015/16 Actual	2015/16 Budget	2016/17 Actual	2016/17 Budget
Gross long-term debt	2,979	3082	3,568	3309.1	4,355	4,169	5,130	4,999	$5,559	$5,372
Finance lease obligation	435	553	1,137	1253.4	1,138	1,139	1,133	1,138	1,126	1,130
Short-term advances	762	553	804	972.1	890	1,052	981	953	900	1,066
Debt retirement funds	(390)	-377	(368)	(418)	(457)	(418)	(533)	(517)	(590)	(599)
Cash and cash equivalents	-1	-13	2	-16.5	2	-13	(28)	(5)	(13)	(28)
Total net debt	$3,785	$3,798	$5,143	$5,100	$5,928	$5,929	$6,683	$6,568	$6,982	$6,941
Equity advances	$660	660	$660	660	$660	660	$660	660	$660	660
Retained earnings	1,347	1,492	1,461	1,388	1,521	1,363	1,547	1,599	1,603	1,673
Accumulated OCI	(149)		102		(3)		(61)		(22)	
Total capital	$5,643	$5,950	$7,366	$7,148	$8,106	$7,952	$8,829	$8,827	$9,223	$9,274
Percent debt ratio	67.1%	63.8%	69.8%	71.3%	73.1%	74.6%	75.7%	74.4%	75.7%	74.8%

2018 RATE APPLICATION
SRRP INTERROGATORIES

SRRP Q84 Reference: Tax Expense

A) Please provide a table showing the detailed calculation of SaskPower's corporate capital tax obligation for the three most recent actual years and forecasts for 2017/18 and 2018/19.

B) Please confirm grants in lieu are now paid to the provincial government.

Response:

A)

(in millions)		Actual			Forecast	
Computation of Taxable Paid-Up Capital		**2015**	**2016**	**2017**	**2017/2018**	**2018/2019**
Surpluses - Earned		1,463	1,404	1,494	1,625	1,814
- Contributed		660	660	660	660	660
Loans and Advances from shareholders, related persons and related corporations		967	997	908	1,127	1,186
Reserves deducted from income and not allowed as a deduction for income tax		278	291	424	421	427
Indebtedness		4,448	4,613	4,995	5,278	5,609
Subtotal		7,816	7,965	8,481	9,111	9,696
purposes in excess of amounts recorded in books.						
Excess of Net Book Value(NBV) over Undepreciated Capital Cost (UCC)		(1,271)	(1,274)	(1,345)	(1,320)	(1,361)
Total Paid- Up Capital		6,545	6,691	7,136	7,791	8,335
Deduct Allowances						
Standard Exemption		10	10	10	10	10
Additional Exemption		4	4	4	4	4
Investment Allowance		21	21	13	24	24
Total Deductions		35	35	27	38	38
Taxable Paid-Up Capital		6,510	6,656	7,109	7,753	8,297
Tax Rate		0.6%	0.6%	0.6%	0.6%	0.6%
Corporation Capital Tax Payable		39	40	43	47	50
			90/365			
			10			
*Short fiscal period to accommidate fiscal yearend change.						

B) Based on the proposed regulation, our understanding is that SaskPower will be required to pay Grants in Lieu to the Government of Saskatchewan Ministry of Finance effective April 1, 2017. The amount paid to the Government of Saskatchewan Ministry of Finance will be capped at an amount that ensures no municipality incurs a reduction in municipal revenue sharing of greater than 30%. Therefore, if the maximum payment to the Government of Saskatchewan Ministry of Finance is reached, SaskPower may be required to make a Grants in Lieu payment to the municipalities.

SRRP Q85 Reference: Business Renewal and Business Optimization

A) Please elaborate on the new Business Optimization Initiative and provide copies of any program plans including program objectives, targets or other documentation.

B) Please confirm if the Business Optimization initiative replaces the previous Business Renewal Program. If so, discuss any similarities and differences between the two.

Response:

A) During 2016-17, SaskPower introduced the new Business Optimization Initiative. Attached are the Terms of Reference that outline the goals, benefits, governance and approach.

The business reality of today requires us to challenge how we currently deliver services – effectively meet the expectations of our stakeholders and most importantly, our customers. This will mean committing to the top priorities needed to execute our strategy and challenging the current programs and services we offer to our customers.

This initiative will review our company from top to bottom, challenging the way we currently do business. It is focused on streamlining, refining and prioritizing our high-value work, as well as improving our company's ability to evolve along with the ever-changing regulatory requirements, technological standards, environmental demands and service expectations inherent in our industry.

These improvements will come in the form of operational savings, reinvesting in stakeholder priorities and challenging how, why and what is being delivered for service to customers. Through a combination of restraint measures and optimization activities, SaskPower has realized $73 million in operating, maintenance and administration reductions from the budget over the past two years.

SaskPower's leadership is committed and accountable for driving optimization for the long term. The Business Optimization Initiative is led by SaskPower and is designed to engage and support SaskPower leaders to review our top priorities and identify opportunities for optimization.

People will remain SaskPower's highest valued assets. As we collaboratively progress through this initiative we will ensure we balance our people needs with the needs of the business.

B) The Business Optimization Initiative did not replace the Business Renewal Program.

SaskPower Business Optimization Initiative

Terms of Reference

Prepared by: [redacted]
November 24, 2016

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Contents

Background:

The economic downturn worldwide is having a significant impact on two important revenue sources for the Province of Saskatchewan; mining and the oil & gas sectors. As a result the Province is facing a billion dollar budget shortfall for fiscal 2016/17 and has asked all of the government sector (including the Crowns) to deliver cost reductions on four separate occasions since January 2015. Saskpower has contributed over $66.5M of OM&A reductions in the last 22 month period alone. Although the Corporation has made these reductions being mindful of our customer, regulatory and statutory requirements, while not compromising employee and/or public safety, we are at our limit of cutting back without having to change the way we provide and deliver services to the people of Saskatchewan.

The Business Optimization Initiative is designed to engage and support SaskPower leaders to review our top priorities. The business reality of today requires us to challenge all facets of how we currently deliver services, and effectively meet the expectations of our stakeholders and most importantly, our customers. The initiative will effectively optimize work flow, organizational structure and internal resource capacity to ensure maximum capability to deliver on high priority and high value work.

People will remain SaskPower's highest valued assets; as we collaboratively progress through this initiative we will ensure we balance our people needs with the needs of the business. The ultimate goal of this collaborative approach is to enhance our focus on optimization and embed it into how we plan and manage our business.

Additionally, it will allow us to demonstrate to our shareholder a methodology and process to evaluate and measure the efficiency of operations at Saskpower.

Definition:

Optimization: Identifying and measuring the most cost effective or highest achievable performance, by maximizing desired priorities and minimizing low-priority ones.

Goals:

Short-term – by March 31, 2017:

- Leaders will be engaged to identify opportunities to improve the business resulting in a 5-10% quantifiable savings or optimization with consideration of associated risks. This will be done by shifting to meet high value priorities or gains in efficiencies of operations.

Longer-term – Beyond March 31, 2017:

- Roadmap: a detailed plan with an owner, deliverables and a timeline for each recommendation will be in place by June 30, 2017
- Execute identified optimization strategies that focus on efficiency gains, cost reductions and organizational health at both the divisional and enterprise levels
- Accountability for status reporting and benefit realization
- Enhance an organizational culture change that embraces continuous improvement

Benefits:

- Ability to position the organization for future success
- Ability to demonstrate prudent and responsible cost management
- Ability to measure performance against baseline
- Ability to answer the question – "Is SaskPower an efficient organization?"
- Ability to identify risks and impacts to our shareholder and customers

Guiding Principles:

Accountability:

- Engage Directors and Managers to help SaskPower build ownership of continuous improvement
- Focus on the right level of detail to capitalize on the value of optimization
- Work with Directors and Managers to effectively balance and deliver high value priorities
- Sustain ongoing optimization efforts
- Focus on the tension between cost, delivery, quality, safety and morale

Openness:

- Create visibility of optimization efforts at all levels
- Be open and transparent
- Create opportunity for success

Safety:

- Never lose sight of, or compromise on safety

Collaboration:

- Engage leaders and all staff throughout the initiative

Members:

Executive Sponsor: Mike Marsh
Role: Champion of the initiative and ultimately accountable to ensure the intended outcomes and benefits are achieved

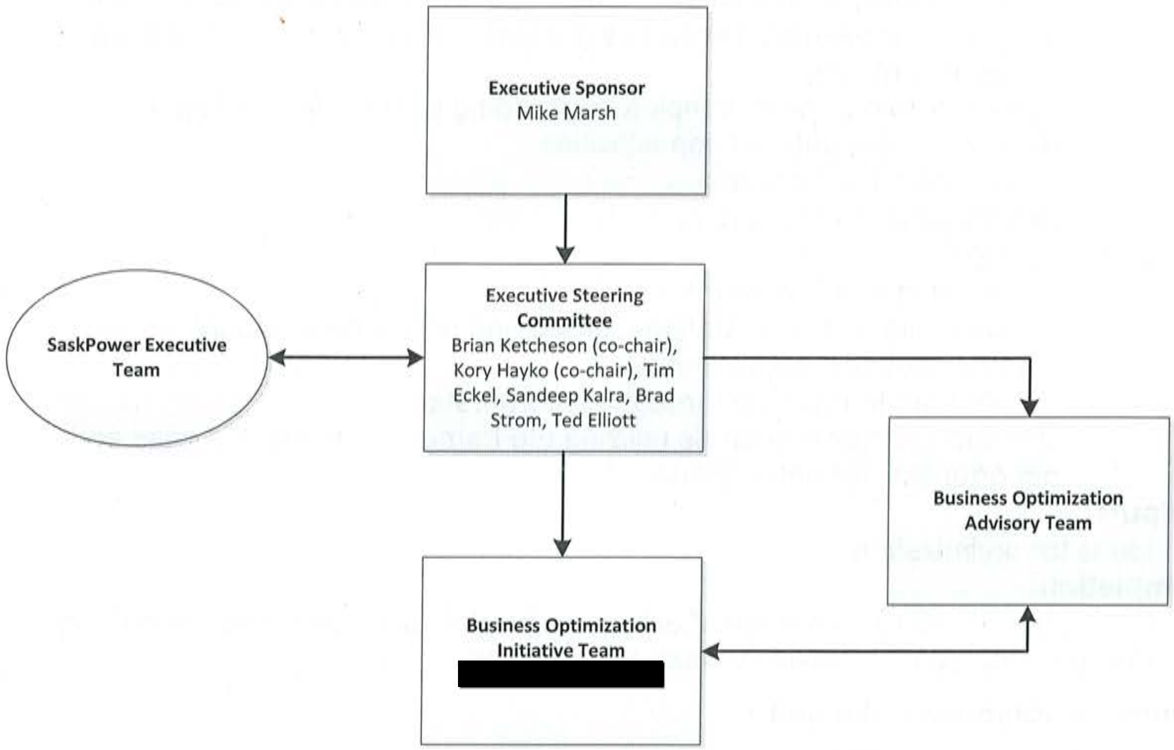
Executive Steering Committee: Brian Ketcheson (co-chair), Kory Hayko (co-chair), Tim Eckel, Sandeep Kalra, Brad Strom, Ted Elliott
Roles:

- Visible sponsorship
- Set goals and expectations
- Remove barriers to initiative success
- Balance and align decisions with corporate strategic direction and priorities
- Approve recommendations

Business Optimization Advisory Team: Directors to be determined
Roles:

- Visible leadership
- Guide and provide insight on the viability of optimization ideas
- Develop and prioritize recommendations

Governance:



Approach:

The initiative will create leadership inclusion and visibility of the work to identify gaps and opportunities in two different ways:

1. **Enterprise (horizontal) view:** Understand and evaluate the effectiveness of our business, including processes, measures, resources (budget and people) and technology. This will focus on a strategic view and identifying optimization opportunities that impact the organization across more than one division.
2. **Divisional (vertical) view:** Understand and evaluate the effectiveness of functional core processes, hand-offs, measures, resources (budget and people) and technology. Create a framework to pilot in an operational group and a support group. The framework on how to optimize will be replicated in all divisions in SaskPower.

Initiative Phases:

Initiation

- Initiative Planning – Terms of Reference, Schedule, Resource Plan, Budget, Communication Plan
- Best Practice Research

Outputs:

- Terms of Reference
- Communication Plan

Completion: November 30, 2016

Enterprise & Divisional Analysis

- Enterprise View
  - Create visibility to evaluate the effectiveness of our business, including processes, measures, resources (budget and people) and technology (enterprise model)
  - Review previous work completed (including past consultant reports)
  - Review current optimization activities
  - Obtain input from leaders
  - Identify gaps and opportunities for optimization
- Divisional View:
  - Create plan and framework for pilots
  - Conduct pilots (one operational group and one support group)
  - Identify gaps and opportunities
  - Create plan to replicate throughout corporation
  - Conduct divisional analysis utilizing the framework to identify gaps and opportunities for optimization

Outputs:

- Ideas for optimization

Completion:

- December 31, 2016 – creation of enterprise model, pilots complete, plan to replicate
- February 28, 2017 – divisional analysis complete

Alignment & Recommendations

- Identify areas to optimize
- Quantify benefits and risks
- Internal and external communication

Outputs:

- Recommendations presented and approved by Executive Sponsor and Executive Steering Committee

Completion:

- March 31, 2017

Implementation Roadmap

- Create an Implementation Roadmap which details a rigorous and systematic approach, including:
  - Detailed plan with an owner, deliverables and a timeline identified for each recommendation
  - Accountability for status reporting and benefit realization
  - Integrated change management approach
- Aligns to longer-term goal stated in Goals section above
- Completion: June 30, 2017

Approvals:

Dec 13/2016

Mike Marsh
Executive Sponsor, President & Chief Executive Officer

Date

Nov 30/16

Kory Hayko
Co-Chair Executive Steering Committee, Vice President, Commercial and Industrial Operations and President and CEO NorthPoint Energy Solutions

Date

Nov 30/16

Brian Ketcheson
Co-Chair Executive Steering Committee, Vice President, HR, Safety & Stakeholder Relations

Date

1/12/16

Sandeep Kalra
Executive Steering Committee Member, Vice President, Finance and Chief Financial Officer

Date

Dec 12/2016

Ted Elliott
Executive Steering Committee Member, Vice President, Distribution Services

Date

Dec 2, 2016

Tim Eckel
Executive Steering Committee Member, Vice President, Transmission Services

Date

1/12/16

Brad Strom
Executive Steering Committee Member, Vice President, Information Technology and Security, and Chief Information Officer

Date

SRRP Q86 Reference: Business Renewal (BR) Program

Please elaborate on the reasons for the delay in the rollout plan for distribution services schedule and dispatch program. Does SaskPower anticipate proceeding with this initiative in the future?

Response:

Phase one of the dispatch program was successfully rolled out to the Powerline Technicians (formerly known as District Operators). In phase two of the rollout, crews were to begin utilizing the tool as well. However, based on the project's initial scope, crew functionality was minimal. Added crew functionality will be provided by a software upgrade, which is scheduled to go live in November.

SRRP Q87 Reference: Business Renewal (BR) Program
Please comment on whether SaskPower has observed any performance issues as a result of the overhauls maintenance management program.

Response:

SaskPower's overhaul maintenance program is continually evolving to respond to funding within operating and capital budgets. As units reach end of life, funding is optimized and the unit performance adjusted. Units are retired in a safe and reliable condition while providing what is evaluated as reasonable performance to avoid stranded investments.

The overhaul maintenance program will then follow the investment strategy, which may include a reduction in performance (with funding reductions), or an increase in performance (with increased funding).

The performance of the generation fleet has been steady, as evidenced by the following metrics:

Based on boiler tube leak lost unit production:
- On the conventional thermal fleet, the losses have remained flat and within target, with the exception of one year, for the past several years.

Based on fleet Equivalent Availability Factor (EAF)
- EAF has been slightly below target for the past few years.
- In the few years prior to this, EAF performance was below target.
    - *EAF = equivalent time of year, in percent, the fleet of units were capable of full production. Forced and planned outage time is subtracted from 100%.*

SaskPower
Powering the future®

2018 RATE APPLICATION
SRRP INTERROGATORIES

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SRRP Q88 Reference: Business Renewal (BR) Program

Please provide a breakdown of the OM&A budget reductions provided in the application on page 17. Where possible, please cross-reference these savings to the applicable business renewal or business optimization program.

Response:

In 2015, SaskPower implemented a number of restraint measures at the request of the Crown Investments Corporation (CIC) of Saskatchewan. For the year, SaskPower's OM&A expense came in $38 million under budget.

One of the restraint measures implemented was a temporary hiring freeze. This hiring freeze played a significant role in the overall OM&A reduction in 2015, contributing to the $17 million in savings that were achieved from lower wages and salaries. SaskPower also put restrictions on training and travel, which resulted in an additional savings of $6 million.

In 2016/17 SaskPower introduced its own internal Business Optimization Initiative. The objective of the program was to not only build off of the efficiencies gained or implemented in 2015, but to also re-examine how SaskPower does business and continue to find ways to streamline, refine and maximize the efficiency of the organization.

The majority of the $27 million in OM&A savings in 2016/17 continued to come from reduced wages and salaries costs and were achieved by extending the amount of bid lag (the period between when a position is vacated and when it is filled) and where possible, leaving the position permanently vacant. At the end of 2016/17, SaskPower had 185 unfilled, permanent, full-time positions.

SRRP Q89 Reference: Business Renewal (BR) Program

Please discuss how the business optimization initiative aligns with the Government of Saskatchewan's Transformational Change Initiative and the Saskatchewan Plan for Growth.

Response:

The Business Optimization Initiative at SaskPower is not a result of the Government of Saskatchewan's Transformation Change Initiative or the Saskatchewan Plan for Growth; however, the intent around streamlining and prioritizing work is similar.

The Corporation's focus remains on providing services to customers in the most effective and optimal way.

SRRP Q90 Reference: Capital Program

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

Response:

The most recent capital plan was included in our 2018 Business Plan (see attached). Over the next few months, SaskPower will be updating the detailed capital plan to reflect the revised capital targets assumed in this rate application.

SaskPower
Capital Expenditures Budget Submission
2016 Actual and March 2017 to 2027 Forecast

	Dec 2015	Mar 2017	Mar 2018	Mar 2019	Mar 2020	Mar 2021	Mar 2022	Mar 2023	Mar 2024	Mar 2025	Mar 2026	Mar 2027	2018-2027 Total
Capital Sustainment Investment													
Transmission	$ 79.8	$ 87.9	$ 88.0	$ 89.8	$ 91.6	$ 93.4	$ 95.3	$ 97.2	$ 99.1	$ 101.1	$ 103.1	$ 105.2	**$ 963.6**
Distribution	50.0	72.9	80.0	81.6	83.2	84.9	86.6	88.3	90.1	91.9	93.7	95.6	**876.0**
Generation	126.2	145.0	132.1	139.1	139.1	139.1	139.1	139.1	139.1	139.1	139.1	139.1	**1,384.0**
IT&S	37.5	35.4	17.0	17.3	21.5	27.4	18.7	19.1	19.5	19.9	20.3	20.7	**201.3**
Buildings & Furniture	10.9	20.6	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	**200.0**
Mining Land	1.5	2.6	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	**25.0**
Meter Purchases	22.5	11.7	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	**75.0**
Vehicles	22.7	20.0	20.0	18.2	16.5	15.0	15.3	15.6	15.9	16.3	16.6	16.9	**166.4**
ICCS	44.8	28.0	37.0	-	-	-	-	-	-	-	-	-	**37.0**
Total Sustainment Investment	**395.9**	**424.1**	**404.1**	**376.0**	**381.9**	**389.8**	**385.0**	**389.3**	**393.7**	**398.2**	**402.8**	**407.5**	**3,928.3**
Growth & Compliance Investment													
Transmission	$ 163.8	$ 124.2	170.0	173.4	176.9	180.4	184.0	187.7	191.4	$ 195.3	$ 199.2	$ 203.2	**$ 1,861.5**
Distribution	80.3	23.7	24.2	24.7	25.2	25.7	26.2	26.7	27.2	27.8	28.3	28.9	**264.7**
	244.1	147.9	194.2	198.1	202.0	206.1	210.2	214.4	218.7	223.0	227.5	232.1	**2,126.2**
Transmission Connects	45.1	20.6	30.0	30.6	31.2	31.8	32.5	33.1	33.8	34.5	35.1	35.9	**$ 328.5**
Distribution Connects	125.1	119.4	100.0	102.0	104.0	106.1	108.2	110.4	112.6	114.9	117.2	119.5	**1,095.0**
	170.2	140.0	130.0	132.6	135.3	138.0	140.7	143.5	146.4	149.3	152.3	155.4	**1,423.5**
New Generation & Carbon Capture													
- QE Expansion	167.5	5.0											**-**
- Tazi Twe	4.9	7.0	11.7	218.4	290.4	63.9	-	-	-	-	-		**584.4**
- Chinook Gas Plant		140.0	306.0	186.6	47.9								**540.5**
- XCG2							142.1	364.2	205.2	36.9			**748.4**
	172.4	152.0	317.7	405.0	338.3	63.9	142.1	364.2	205.2	36.9	-	-	**1,873.3**
Total Growth & Compliance	**586.7**	**439.9**	**641.9**	**735.7**	**675.6**	**407.9**	**493.0**	**722.1**	**570.3**	**409.3**	**379.8**	**387.4**	**5,422.9**
Strategic & Other Investments	**7.7**	**25.2**	**74.7**	**149.0**	**171.3**	**86.6**	**65.9**	**53.4**	**53.1**	**48.8**	**34.5**	**25.6**	**763.0**
Total Capital Budget	**$ 990.3**	**$ 889.2**	**$ 1,120.7**	**$ 1,260.6**	**$ 1,228.8**	**$ 884.3**	**$ 943.9**	**$ 1,164.8**	**$ 1,017.1**	**$ 856.2**	**$ 817.2**	**$ 820.5**	**$ 10,114.2**

2018 to 2027 Capital Expenditures
(Millions $)

Capital Sustainment Investment

Transmission	Mar 2018	Mar 2019	Mar 2020	Mar 2021	Mar 2022	Mar 2023	Mar 2024	Mar 2025	Mar 2026	Mar 2027	2018-2027 Total
LN - Line Switch Replacements	1.5	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	$ 19.5
LN - Transmission Lattice Steel Remediation	9.0	10.0	10.0	10.0	10.0	-	-	-	-	-	49.0
LN - Wood Line Remediation (Incl Gulfport)	47.5	58.0	62.3	75.0	77.0	90.0	95.0	95.0	95.0	95.0	789.8
LN - Weathering Steel Below Ground Remediation	7.0	7.5	7.5	7.5	8.0	9.0	9.0	9.0	9.0	9.0	82.5
LN - Transmission Reliability Improvements	5.5	6.0	6.0	6.0	6.5	6.5	7.0	7.0	7.0	7.0	64.5
LN - I1F/I2F Capital Sustainment	6.0	6.0	6.0	1.0	-	-	-	-	-	-	19.0
LN - I2P Capital Sustainment	3.0	3.0	3.0	-	-	-	-	-	-	-	9.0
LN - Transmission Line Uprating	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	22.5
Stn - Circuit Breaker Replacements	10.0	8.0	7.5	7.5	5.0	5.0	2.0	2.0	2.0	2.0	51.0
Stn - Boundary Dam Switchgear Replacements	1.0										1.0
Stn - Station Bus and Foundation Replacements	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	10.0
Stn - Current Transformers and Potential Transformers	1.0	0.3	0.3	0.8	0.8						3.0
Stn - Transmission Apparatus Accessories	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	10.0
Stn - Relay Replacements	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	50.0
Stn - Transmission Ground Grid & Fencing Upgrades	4.5	2.0	1.5	1.5	1.5	0.5	0.5	0.5	0.5	0.5	13.5
Stn - RTU Replacements	2.0	2.0	1.5								5.5
Projects under $1M	2.8	2.9	2.6	3.0	2.7	2.5	2.5	2.7	2.5	2.5	26.4
Contingency	(22.1)	(27.1)	(27.8)	(30.1)	(27.4)	(27.5)	(28.1)	(26.3)	(24.1)	(22.0)	(262.6)
Sub Total	**$ 88.0**	**$ 89.8**	**$ 91.6**	**$ 93.4**	**$ 95.3**	**$ 97.2**	**$ 99.1**	**$ 101.1**	**$ 103.1**	**$ 105.2**	**$ 963.6**

Distribution	Mar 2018	Mar 2019	Mar 2020	Mar 2021	Mar 2022	Mar 2023	Mar 2024	Mar 2025	Mar 2026	Mar 2027	2018-2027 Total
Sub - Station Ground Grid & Fencing Upgrades	3.6	3.6	3.6	2.5	2.5	0.5	0.5	0.5	0.5	-	17.8
Sub - Protection Upgrades	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	-	9.0
Program - City of Regina Aging Infrastructure Replacement	9.0	9.0	8.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	61.0
Program - Rural Rebuild & Improvement	20.5	20.5	20.5	21.0	21.0	21.0	21.0	21.0	21.0	21.0	208.5
Strategic & Other Investments	15.0	17.5	20.0	25.0	30.0	35.0	40.0	45.0	45.0	45.0	317.5
Program - Steel Street Light Replacement	1.1	1.2	1.3	1.4	1.5	1.5	1.5	1.5	1.5	1.5	14.0
Program - HPSV Streetlight Luminair Conversion to LED	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	81.0
Program - Power Quality Upgrades	6.0	7.0	8.0	8.0	9.0	9.0	9.0	9.0	9.0	9.0	83.0
Program - Distribution Reliability Improvements	6.0	6.0	7.0	7.0	8.0	8.0	8.0	8.0	8.0	8.0	74.0
Program - High Load Move Corridors	1.0	-	-	-	-	-	-	-	-	-	1.0
Program - Wood/Steel Substation Rebuild	4.0	4.0	4.0	4.0	4.0	-	-	-	-	-	20.0
Program - Recoordination & Protection	1.0	1.0	1.0	1.2	1.2	1.2	1.2	1.2	1.2	1.2	11.4
Program - Distribution Automation	2.0	2.0	3.0	3.0	4.0	4.0	4.0	4.0	4.0	4.0	34.0
Distribution Line - Protection Upgrades	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	10.5
Initiative - Distribution Transformer Wildlife Protection	1.0	1.0	1.0	-	-	-	-	-	-	-	3.0
Initiative - Planned Appartaus Replacement Program	3.5	3.5	3.5	3.5	4.5	3.3	-	-	-	-	21.8
Sub - Power Transformer Replacement	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	-	45.0
Projects under $1M	4.8	4.9	5.1	5.3	5.5	5.7	5.5	5.6	5.6	2.6	50.6
Contingency	(55.8)	(58.7)	(64.3)	(65.1)	(74.7)	(72.9)	(72.7)	(76.0)	(74.1)	(62.8)	(677.1)
											-
Sub Total	**$ 80.0**	**$ 81.6**	**$ 83.2**	**$ 84.9**	**$ 86.6**	**$ 88.3**	**$ 90.1**	**$ 91.9**	**$ 93.7**	**$ 95.6**	**$ 876.0**

Generation	Mar 2018	Mar 2019	Mar 2020	Mar 2021	Mar 2022	Mar 2023	Mar 2024	Mar 2025	Mar 2026	Mar 2027	2018-2027 Total
IF MAIN DAM POWERHOUSE CONCRETE	14.3	12.8	2.7	1.7	-	-	-	-	-	-	31.5
BD CEM	1.5	-	-	-	-	-	-	-	-	-	1.5
BD6 ECONOMIZER LIFE EXTENSION	1.0	-	-	0.5	-	-	-	-	-	-	1.5
PR0 CEM SYSTEM	2.3	-	-	-	-	-	-	-	-	-	2.3
PR ASH LAGOON 4E CONSTRUCTION	4.7	-	-	-	-	-	-	-	-	-	4.7
SHAND ASH BELT CONVEYOR GALLERY	2.3	6.0	-	-	-	-	-	-	-	-	8.3
PR2 GRINDING ZONE UPGRADES	1.0	-	-	-	-	-	-	-	-	-	1.0
PR CONTROLS SIMULATOR	1.6	-	-	-	-	-	-	-	-	-	1.6
IF7 REFURBUSHMENT TURB/GEN	-	-	0.7	0.8	0.7	0.3	3.3	6.8	31.8	-	44.5
SHAND 1 MAJOR REBUILD	-	-	-	5.0	16.0	60.0	-	-	-	-	81.0
PR1 LONG TERM EXPENDITURES	1.0	-	-	-	-	-	-	-	-	-	1.0
PR2 LONG TERM EXPENDITURES	2.9	-	-	-	-	-	-	-	-	-	2.9
EBC 7 & 8 REFURBISHMENT	-	0.8	-	-	0.8	0.7	0.1	1.1	2.0	13.0	18.6
BD6 PLANT COATED WATERWALL PANELS	1.0	-	-	-	-	-	-	-	-	-	1.0
WATERLOO REFURBISHMENTS	0.7	3.9	10.3	14.8	28.0	-	-	-	-	-	57.7
IF PLANT FIRE SUPPRESSION	1.4	-	-	-	-	-	-	-	-	-	1.4
BD5 LIFE EXTENSION	11.2	-	-	-	-	-	-	-	-	-	11.2
PR MANLIFT REPLACEMENT	2.5	-	-	-	-	-	-	-	-	-	2.5
GE GT CAPITAL COMP REPLACEMENT	3.4	-	8.5	8.9	5.0	-	-	-	-	-	25.7
SHAND MANLIFT REPLACEMENT	4.2	-	-	-	-	-	-	-	-	-	4.2
QE A PLANT 5KV SWITCHGEAR	6.2	-	-	-	-	-	-	-	-	-	6.2
BD4 ASBESTOS REMOVAL	1.2	-	-	-	-	-	-	-	-	-	1.2
BD5 ASBESTOS REMOVAL	1.5	0.2	-	-	-	-	-	-	-	-	1.7
BDPS MANLIFT REPLACEMENT	3.4	0.4	-	-	-	-	-	-	-	-	3.8
HITACHI GT COMP REPLACEMENT U4-9	4.1	1.4			7.9	7.9	3.2	-	-	-	24.3
HITACHI GT COMP REPLACEMENT U10-12	4.1					9.5	-	-	-	-	13.5
HITACHI GT COMP REPLACEMENT U13-15	-	-	-	4.5	-	-	-	10.5	-	-	15.0
PR FACILITIES UPGRADE	2.2	-	-	-	-	-	-	-	-	-	2.2
NIPAWIN LIFE EXTENSION	-	-	-	-	-	-	0.8	1.5	2.1	9.0	13.4
CC LIFE EXTENSION	0.5	5.4	15.1	13.4	40.0	37.6	27.8	2.9	-	-	142.9
SHAND SBAC LIFE EXTENSION	2.0	-	-	-	-	-	-	-	-	-	2.0
MEADOW LAKE LIFE EXTENSION	6.4	-	-	-	-	-	-	-	-	-	6.4
QE1 LIFE EXTENSION	6.1	5.4	13.9	7.8	-	-	-	-	-	-	33.0
QE 'C' PLANT GOVERNOR CONTROLS UPGRADE	2.8	1.1	-	-	-	-	-	-	-	-	3.9
ATHABASCA INFRASTRUCTURE UPGRADES	2.3	-	-	-	-	-	-	-	-	-	2.3
WHITESAND DAM CONCRETE REHAB	1.5	-	-	-	-	-	-	-	-	-	1.5
SHAND KE SYSTEM IMPROVEMENT	0.5	0.2	1.4	0.4	3.8	11.7	1.8	-	-	-	19.7
SHAND MERCURY MONITOR	1.4	-	-	-	-	-	-	-	-	-	1.4
IF GANTRY CRANE AND A DAM STOPLOG REPLACEMENT	1.4	0.2	0.2	0.2	0.2	-	-	-	-	-	2.2
NH PUBLIC SAFETY AND SITE SECURITY	1.1	0.9	-	-	-	-	-	-	-	-	2.0
EBC SEWAGE HANDLING UPGRADES	1.1								-	-	1.1
EBC UNIT 1 TO 6 LIFE EXTENSION	16.2	39.1	45.4	44.1	39.1	40.6	38.9	36.5	-	-	300.1
WELLINGTON UNIT 1 AND 2 LIFE EXTENSION	-	-	0.5	0.6	3.3	2.7	28.3	67.3	1.6	-	104.2
QE2 MAJOR O/H	-	-	-	-	-	-	10.0	-	-	-	10.0
PR SBAC REFURBISHMENT	1.6				-	-	-	-	-	-	1.6
IF 1-3 LIFE EXTENSION	-	-	-	0.9	2.1	1.9	4.9	15.9	12.4	37.3	75.5
BDPS CHEMICAL STORAGE	2.1	-	-	-	-	-	-	-	-	-	2.1
HR WHITESAND DAM REMEDIATION	-	-	-	0.3	0.4	7.0	3.0	-	-	-	10.7
HR IF STATION SERVICE MODERNIZATION	1.8		-	-	-	-	-	-	-	-	1.8
BD MAIN SECURITY COMPLEX	1.2	-	-	-	-	-	-	-	-	-	1.2
HR CHARLOT RIVER BRIDGE	1.4	-	-	-	-	-	-	-	-	-	1.4
GE GT MAJOR COMPONENT REPLACEMENT	-	-	-	-	-	-	-	10.3	0.0	0.0	10.4
Projects under $1M	30.2	73.5	48.2	38.6	25.0	33.9	11.9	7.4	5.0	8.7	282.4
Contingency	(29.0)	(12.1)	(8.0)	(3.2)	(33.2)	(74.7)	5.1	(21.2)	84.3	71.0	(21.1)
Sub Total Generation	**$ 132.1**	**$ 139.1**	**$ 139.1**	**$ 139.1**	**$ 139.1**	**$ 139.1**	**$ 139.1**	**$ 139.1**	**$ 139.1**	**$ 139.1**	**$ 1,384.0**

IT&S	Mar 2018	Mar 2019	Mar 2020	Mar 2021	Mar 2022	Mar 2023	Mar 2024	Mar 2025	Mar 2026	Mar 2027	2018-2027 Total
Desktop Mgmt	3.0	3.0	3.1	3.2	3.2	3.3	3.4	3.4	3.5	3.6	$ 32.7
Toughbooks	1.0	1.1	1.1	1.1	1.1	1.1	1.2	1.2	1.2	1.2	11.4
Net New Hardware	1.0	1.0	1.1	1.1	1.1	1.1	1.1	1.2	1.2	1.2	11.2
Core Infrastructure	3.5	3.6	3.7	3.7	3.8	3.9	4.4	4.5	4.5	4.5	40.2
SAP Upgrade	-	-	3.5	9.0	-	-	-	-	-	-	12.5
Business Intelligence	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	10.0
Projects under $1M	1.5	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	7.0
Contingency	6.0	7.0	7.5	7.7	7.9	8.0	7.7	7.9	8.2	8.5	76.4
Sub Total IT&S	**$ 17.0**	**$ 17.3**	**$ 21.5**	**$ 27.4**	**$ 18.7**	**$ 19.1**	**$ 19.5**	**$ 19.9**	**$ 20.3**	**$ 20.7**	**$ 201.3**

Buildings & Furniture	**$ 20.0**	**$ 20.0**	**$ 20.0**	**$ 20.0**	**$ 20.0**	**$ 20.0**	**$ 20.0**	**$ 20.0**	**$ 20.0**	**$ 20.0**	**$ 200.0**

	Mar 2018	Mar 2019	Mar 2020	Mar 2021	Mar 2022	Mar 2023	Mar 2024	Mar 2025	Mar 2026	Mar 2027	2018-2027 Total
Mining Land	$ 2.5	$ 2.5	$ 2.5	$ 2.5	$ 2.5	$ 2.5	$ 2.5	$ 2.5	$ 2.5	$ 2.5	$ 25.0
Meter Purchases	$ 7.5	$ 7.5	$ 7.5	$ 7.5	$ 7.5	$ 7.5	$ 7.5	$ 7.5	$ 7.5	$ 7.5	$ 75.0
Vehicles & Tools	$ 20.0	$ 18.2	$ 16.5	$ 15.0	$ 15.3	$ 15.6	$ 15.9	$ 16.3	$ 16.6	$ 16.9	$ 166.4
Carbon Capture Projects	$ 37.0	$ -	$ -					$ -	$ -		$ 37.0
Total Sustainment Investment	**$ 404.1**	**$ 376.0**	**$ 381.9**	**$ 389.8**	**$ 385.0**	**$ 389.3**	**$ 393.7**	**$ 398.2**	**$ 402.8**	**$ 407.5**	**$ 3,928.3**

Growth & Compliance Investment

Transmission	Mar 2018	Mar 2019	Mar 2020	Mar 2021	Mar 2022	Mar 2023	Mar 2024	Mar 2025	Mar 2026	Mar 2027	2018-2027 Total
LN-Turnor Lake to Laloche-138 kV -Exp	-	-	-	0.5	4.5	5.0	-	-	-	-	$ 10.0
LN - ML3 Rebuild / MLBC Int - 72kV - New	1.5	8.8	3.0	-	-	-	-	-	-	-	13.3
LN - Martensville to Dalmeny - 138kV - New	0.2	1.5	7.9	8.6	-	-	-	-	-	-	18.1
LN - Golden Lake to Ermine 138kV - New	-	-	4.5	8.0	31.2	42.6	-	-	-	-	86.3
T355 - Rowatt 230 kV Station Development	0.8	15.5	16.8	0.2	-	-	-	-	-	-	33.3
STN - Oxbow Substation Capacity Increase - Exp	2.9	0.1	-	-	-	-	-	-	-	-	3.1
STN-Beauval-138-72 kV - New	5.0	15.0	-	-	-	-	-	-	-	-	20.0
Sub - Harbour Landing - 138-25 kV - New	0.1	0.5	5.9	3.7	-	-	-	-	-	-	10.2
LN - TC5 - 138 kV - Exp	8.9	14.6	25.9	-	-	-	-	-	-	-	49.4
STN - Halbrite - 138-25kV	2.3	5.6	4.3	-	-	-	-	-	-	-	12.2
STN - BD Phase Shifting Transformer Upgrade - 230kV - Exp	16.7	4.2	0.1	-	-	-	-	-	-	-	20.9
STN - Pasqua Transformer Position - 230kV - Exp	1.0	1.0	-	-	-	-	-	-	-	-	2.0
LN - Auburnton to Kennedy - 230 kV - New	1.0	13.0	22.8	23.3	-	-	-	-	-	-	60.1
LN - Aberdeen to Martensville - 230kV - EXP	3.0	6.7	6.7	-	-	-	-	-	-	-	16.4
STN - Belle Plaine Area Station – 230 kV - New	-	-	0.8	1.3	9.5	8.5	-	-	-	-	20.0
STN - QE Transf Replacement - 230kV - Exp	8.8	10.4	9.3	5.8	-	-	-	-	-	-	34.2
STN - ML Reinf - 138-72 kV - Exp	9.3	0.2	-	-	-	-	-	-	-	-	9.5
LN - PQ-SW - 230/138kV - New	80.2	106.4	7.0	-	-	-	-	-	-	-	193.7
LN - Condie to Belle Plaine Area - 230 kV - New	7.5	24.8	0.2	-	-	-	-	-	-	-	32.5
STN - Pasqua SVS - 138 kV -New	1.0	-	-	-	-	-	-	-	-	-	1.0
STN - Bankend - 138kV - Exp	4.8	-	-	-	-	-	-	-	-	-	4.8
STN - A1B/A2B RAS - New	1.1	-	-	-	-	-	-	-	-	-	1.1
STN - System Spare Transformer - 230-138 kV - Exp	2.6	2.3	-	-	-	-	-	-	-	-	4.9
LN – B4P and PA4 – 138kV - Exp	13.4	19.0	-	-	-	-	-	-	-	-	32.5
STN - BD19 Re-Termination	2.2	-	-	-	-	-	-	-	-	-	2.2
STN - Chaplin - 138 kV - Exp	1.6	5.6	-	-	-	-	-	-	-	-	7.2
LN - Beaval to Ile A La Crosse - 138 kV - New	0.7	2.1	8.2	8.1	-	-	-	-	-	-	19.1
STN - Central Butte - 72 kV - Exp	1.6	5.6	-	-	-	-	-	-	-	-	7.2
LN - R1P Rebuild -230 kV - New	1.7	10.9	24.9	0.1	-	-	-	-	-	-	37.5
LN - C1S River Crossing - 230kV - Exp	5.6	1.1	-	-	-	-	-	-	-	-	6.7
STN - Kennedy - 230-138kV - Exp	3.0	-	-	-	-	-	-	-	-	-	3.0
LN - Kennedy to Tantallon - 230kV - Exp	16.2	-	-	-	-	-	-	-	-	-	16.2
Tazi Twe Connection		17.0	18.0								35.0
New Gas Interconnections	7.2	6.0			2.3	7.9	6.6				30.1
Projects under $1M	4.6	20.1	17.3	0.8	2.6	3.4	-	-	-	-	48.8
Contingency	(67.2)	(144.5)	(74.9)	(65.5)	(2.2)	75.9	116.4	82.4	40.8	47.3	8.6
Unassigned Capital Project	20.9	(0.1)	68.4	185.6	136.1	44.3	68.4	112.9	158.3	155.8	950.7
Sub Total	**$ 170.0**	**$ 173.4**	**$ 176.9**	**$ 180.4**	**$ 184.0**	**$ 187.7**	**$ 191.4**	**$ 195.3**	**$ 199.2**	**$ 203.2**	**$ 1,861.5**

Distribution	Mar 2018	Mar 2019	Mar 2020	Mar 2021	Mar 2022	Mar 2023	Mar 2024	Mar 2025	Mar 2026	Mar 2027	2018-2027 Total
STN-Bluebell PODS-72/25 kV -New	$ 5.1	$ 2.6	$ 0.0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	7.7
SUB - White City - 138-25kV - New	$ 4.0	$ 0.5	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	4.5
SUB - Spare transformer 25 MVA - 138-25 kV - New	$ 2.0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	2.0
SUB – Hawarden – 72-25 kV – New	$ 2.8	$ 5.7	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	8.5
SUB - Wadena - 72-25kV - Exp	$ 3.1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	3.1
STN - Outlook -72-25 kV - Exp	$ 1.3	$ 4.1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	5.4
Program - Economic Rebuild (Rural)	$ 6.0	$ 7.0	$ 7.0	$ 8.0	$ 9.0	$ 10.0	$ 10.0	$ 10.0	$ 10.0	$ 10.0	87.0
Program - Economic Rebuild (Urban)	$ 3.0	$ 3.0	$ 4.0	$ 4.0	$ 5.0	$ 5.0	$ 5.0	$ 5.0	$ 5.0	5.0	44.0
Projects under $1M	$ 1.8	$ 10.4	$ 13.6	$ 6.8	$ 5.2	$ 2.9	$ 2.1	$ 3.1	$ -	$ -	45.9
Unassigned Capital Project	$ (4.9)	$ (8.7)	$ 0.6	$ 6.9	$ 6.9	$ 8.8	$ 10.1	$ 9.6	$ 13.3	$ 13.9	56.6
Sub Total Distribution	**$ 24.2**	**$ 24.7**	**$ 25.2**	**$ 25.7**	**$ 26.2**	**$ 26.7**	**$ 27.2**	**$ 27.8**	**$ 28.3**	**$ 28.9**	**$ 264.7**
											-
Sub Total T&D	**$ 194.2**	**$ 198.1**	**$ 202.0**	**$ 206.1**	**$ 210.2**	**$ 214.4**	**$ 218.7**	**$ 223.0**	**$ 227.5**	**$ 232.1**	**$ 2,126.2**

Customer Connects	Mar 2018	Mar 2019	Mar 2020	Mar 2021	Mar 2022	Mar 2023	Mar 2024	Mar 2025	Mar 2026	Mar 2027	2018-2027 Total
Customer Connects - Transmission	$ 30.0	$ 30.6	$ 31.2	$ 31.8	$ 32.5	$ 33.1	$ 33.8	$ 34.5	$ 35.1	$ 35.9	328.5
Customer Connects - Distribution	$ 100.0	$ 102.0	$ 104.0	$ 106.1	$ 108.2	$ 110.4	$ 112.6	$ 114.9	$ 117.2	$ 119.5	$ 1,095.0
Approved Capital Budget - All Customer Connects	**$ 130.0**	**$ 132.6**	**$ 135.3**	**$ 138.0**	**$ 140.7**	**$ 143.5**	**$ 146.4**	**$ 149.3**	**$ 152.3**	**$ 155.4**	**$ 1,423.5**

New Generation and Carbon Capture Projects

(Millions $)

	Mar 2018	Mar 2019	Mar 2020	Mar 2021	Mar 2022	Mar 2023	Mar 2024	Mar 2025	Mar 2026	Mar 2027	2018-2027 Total
Tazi Twe	11.7	218.4	290.4	63.9	-	-	-	-	-		584.4
Chinook Gas Plant	306.0	186.6	47.9								540.5
XCG2					142.1	364.2	205.2	36.9			748.4
TOTAL NEW GEN & CARBON CAPTURE	**$ 317.7**	**$ 405.0**	**$ 338.3**	**$ 63.9**	**$ 142.1**	**$ 364.2**	**$ 205.2**	**$ 36.9**	**$ -**	**$ -**	**$ 1,873.3**
Total Growth & Compliance	**$ 641.9**	**$ 735.7**	**$ 675.6**	**$ 407.9**	**$ 493.0**	**$ 722.1**	**$ 570.3**	**$ 409.3**	**$ 379.8**	**$ 387.4**	**$ 5,422.9**

Strategic & Other Investments

Total Strategic & Other Investments	**$ 74.7**	**$ 149.0**	**$ 171.3**	**$ 86.6**	**$ 65.9**	**$ 53.4**	**$ 53.1**	**$ 48.8**	**$ 34.5**	**$ 25.6**	**$ 763.0**
TOTAL CAPITAL BUDGET	**$ 1,120.7**	**$ 1,260.6**	**$ 1,228.8**	**$ 884.3**	**$ 943.9**	**$ 1,164.8**	**$ 1,017.1**	**$ 856.2**	**$ 817.2**	**$ 820.5**	**$ 10,114.2**

SRRP Q91 Reference: Capital Program
Please provide an explanation or definition for the types of capital projects that SaskPower considers to be capital sustainment, growth & compliance and strategic & other investments.

Response:

SaskPower groups its capital investments as follows:

1) Growth and compliance
2) Core sustainment; and
3) Strategic and other.

1. Growth and compliance investments

Definition:
These are investments with a primary purpose of assisting SaskPower in meeting electricity load growth in the Province of Saskatchewan or those which are required to meet environmental, safety or other regulatory requirements. These projects cannot be deferred to future years without causing undue risk to SaskPower, including an inability to serve new load growth or meet regulatory compliance obligations.

SaskPower's load forecast is prepared annually, with semi-annual updates of the long-term electricity requirements for SaskPower's customers. SaskPower's load forecast not only forms the basis for capacity additions, but is also used to develop maintenance schedules, power plant operations, fuel and operating budgets, and revenue forecasts.

Regulatory requirements and targets drive the compliance portion of this investment category. The regulatory requirements that currently have the biggest impact on SaskPower's capital plan relate to greenhouse gas emissions. The Federal Government currently has regulations in place that require the retirement of all conventional coal generation in Canada by 2030. In addition, SaskPower has a target of a 40% reduction in GHG emissions relative to 2005 levels by 2030.

Both the load forecast and regulatory compliance requirements are key inputs into the development of SaskPower's Integrated Resource Plan (IRP). The IRP identifies how SaskPower will meet the electricity needs of the Province of Saskatchewan, including both generation and transmission requirements. The IRP forms the basis of SaskPower's growth and compliance capital budget.

Funding justification:
Growth and compliance investments require independent business cases to enable support. While the IRP provides general guidance in the long-term strategy for meeting SaskPower's obligation to meet the electrical demands of the Province of Saskatchewan, each investment decision requires the preparation of an independent business case to support the investment decision. There are certain exceptions, such as distribution customer connects; these are approved on a program basis.

Growth investments represent approximately 65% - 70% of SaskPower's capital budget. These investments are not considered discretionary as a result of the Corporation's obligation to serve. The focus of SaskPower's business case will be on the following elements:

a) Appropriate timing of the investment. SaskPower's objective is to ensure that customer needs are met while not unnecessarily over building the grid; and

b) Ensuring the investment selected to meet the growth requirements is the most appropriate considering a variety of factors, including: total cost of ownership (capital, operating, fuel and decommissioning), regulatory requirements, environmental impacts, stakeholders concerns, public policy, capacity value, future growth, existing resource mix and fuel availability.

Examples:
Examples of growth investments include new generation, T&D capacity upgrades, customer connects, and new buildings.

2. Core sustainment investments

Definition:
These are investments with a primary purpose of replacing or refurbishing existing assets in order to maintain or improve asset performance and capabilities.

Funding justification:
Core sustainment investments are prioritized through long-term risk based asset strategies in which the highest priority is assigned to the most critical equipment and facilities with the greatest risks associated with failure, obsolescence, safety or other factors. SaskPower's asset management group is responsible for prioritizing the capital investment needs for the orporation s core assets — generation, transmission and distribution. An envelope of dollars is initially allocated to each asset group. The asset management team is responsible for the quarterly review of this allocation, and reallocating dollars as circumstances change. SaskPower also allocates a separate envelope of dollars to the other asset groups (buildings, vehicles, information technology) which are subject to their own prioritization and ranking system.

SaskPower's 10-year capital plan allocates 25-30% of the capital budget to sustainment activities. This is an amount that management feels will enable the Corporation to meet its long-term financial goals while enabling improvements in our asset reliability over the long-term.

Examples:
Some examples of sustainment investments include transmission and distribution annual programs (wood pole replacement, rural rebuild), plant overhauls and refurbishments, vehicle purchases, and emergency infrastructure replacements.

3. Strategic and other investments

Definition:
These are investments with a primary purpose of furthering a strategic priority of the Corporation.

Funding justification:
Strategic investments require independent business cases to enable support. This category represents around 5% of SaskPower's total capital budget.

Examples:
Some examples of strategic investments include grid modernization, the customer relations and billing module, outage management, and the Carbon Capture Test Facility.

SRRP Q92 Reference: Capital Program

A) Please describe the process by which SaskPower prepares its capital plan.

B) Please provide a description of how SaskPower paces and prioritizes its capital plans. For example, does SaskPower develop a high level capital spending envelope and then prioritize projects within that envelope?

C) Does SaskPower prepare a business case or similar document for major capital projects? If so, please provide a business case sample document and explain how it is developed and approved as part of SaskPower's capital planning process.

Response:

A) SaskPower's capital plan is formally prepared on an annual basis and is updated quarterly. All capital investments need to be justified either through inclusion in an asset management plan or through a specific business case. Emergency capital investments to replace assets that fail are not subject to the above criteria.

B) The Corporation prioritizes its capital investments based on the following groupings:
   a. Growth and compliance investments;
   b. Core sustainment investments; and
   c. Strategic and other investments

   The initial allocation of the capital projects into the above three envelopes takes place through a peer evaluation process that includes representatives from various business areas. The size of the capital budget and the envelopes assigned to each category are developed through a process that examines a number of factors, including historical capital spending, operational requirements, risk analysis and financial targets and objectives.

   The final capital allocation is approved by the SaskPower Board of Directors and the Crown Investments Corporation of Saskatchewan Board of Directors.

C) All capital investments need to be justified either through inclusion in an asset management plan or through a specific business case. A sample business case follows.

SaskPower

System Planning & Asset Management
Asset Management, Planning & Sustainability

Capital Project Authorization

TLA16-038 B1W 138KV WPR STR REPL

[redacted]

[redacted]

SUBJECT: *TLA16-038 B1W 138KV WPR STR REPL*

Executive Summary

The B1W – Beatty to Wolverine 138 kV transmission line has been identified with 23 structures, which have reached end of life, and present a significant risk to the safety of the public and workers and the reliability of SaskPower's radial system. Because such structures are dispersed throughout the line and due to span lengths and terrain conditions, the replacement of 21 additional structures is required in order to meet current design criteria without the need to install conductor weights or violate clearances. Therefore, this initiative covers the replacement of 44 structures.

The program's success will restore the quality of the structures to a satisfactory state, improve safety for the public and the worker, and improve the quality and dependability of the infrastructure.

This CPA authorizes construction phase funds for the TLA16-038 B1W 138KV WPR STR REPL Project.

The estimated total project cost is $1,123,025 with an in-service date of March 31, 2018.

Governance

APPROVALS REQUIRED:

The total cost of this project is expected to be below the limit required for Board Approval.

TYPE OF AUTHORIZATION:

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

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 Total Cost: **$1,123,025**

Table 1: Funds included in the Updated Business Plan

	Prior	2018	2019	2020	Total
Capital	$6,605	$1,116,420			$1,123,025
OM&A					
Total	$6,605	$1,116,420			$1,123,025

Funds included in the Approved Business Plan (refer to Table 2): ☒ Full ☐ Partial

Table 2: Funds included in the Approved Business Plan

	Prior	2018	2019	2020	Total
Capital	$6,605	$1,116,420			$1,123,025
OM&A					
Total	$6,605	$1,116,420			$1,123,025

Recommendation

It is recommended that the funds be authorized for the following construction phase high level scope of work:

- Replace 44 existing structures on the B1W 138 kV transmission line.
- Identify all project delivery risks and mitigation options and associated costs.
- Complete all other work required to execute required service agreements, engineering, procurement, installation and construction and management of this project.
- Complete all work required for construction readiness.
- Any other associated work.

The total authorized amount is $1,123,025 and the construction phase completion date is March 31, 2018.

Key Issues / Major Risks / Key Benefits / Implications

Major Project Risks	Analysis / Implications
Safety risks	Due to the present condition of the line, the work may be completed using Live Line methods. There are additional risks when working under live line conditions that need to be taken into account during the planning stage and mitigations incorporated into the construction work procedures. Prior to the Service Provider commencing construction activities, live line work procedures should be thoroughly reviewed and approved by SaskPower.
Schedule delays	Should this project be delayed and the milestone schedule not achieved, the structures will likely fail as the condition of the existing structures is substandard. It is crucial that this program is initiated as soon as possible to avoid potential outages.
Design risks	Risks are low for design requirements provided that the assets are being replaced with standard designs. An Engineering IFC package has been completed for these replacements.

Budget risks	No budgetary concerns have been identified at this time.
Land risks	All structures identified in this document have a registered legal easement. The SaskPower Land Dep't can be contacted to pull these easements if any special circumstances or registered agreements exist. This program may affect land owners. The SaskPower Land department must contact the owner's previously for courtesy calls advising them when SaskPower (or our contractors) will be on their land performing this work. Documentation of any land damage must be recorded and land owners must be fairly compensated for such damages.
Environmental risks	Environmental pre-screening/secondary screenings are not complete. PDO should complete this at its earliest convenience to avoid delays and environmental issued. Consultation with SaskPower's EA&A department and the MoE is required. The consultation process well in advance of the construction schedule to ensure no delays.

Background and Analysis

Utilizing aerial photos and a consistent rating system in combination with field reports, an appropriate assessment has been made to determine the condition of the assets in order to support this initiative.

Originally, 23 structures were identified to be in substandard condition, resulting in the need of structural replacement; however, because such structures are dispersed throughout the line and due to span lengths and terrain conditions, the replacement of 21 additional structures is required in order to meet current design criteria without the need to install conductor weights or violate clearances. Therefore, this initiative covers the replacement of 44 structures.

The structures that will be replaced will utilize the D14-901 structure design in alignment with previous structure replacements.

Consequences of Deferment

If this initiative is not pursued, SaskPower will be at risk of system interruption, as failure is highly probable due to the condition of the structures. This could lead to emergency repairs and high costs of restoration.

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

Alternatives

Alternatives for this project are unwarranted for the replacement of these assets since they are presently in substandard condition and at the end of their physical life. Life extending maintenance and repair for such structures is not a practicable solution and replacement options are limited to a single design (D14-901 Tangent H-Frame) to match the existing structure design for the line and ensure continuity with the rest of the electrical system.

Advance Consultation

[redacted]

Project Baseline Change

Changes in the schedule or cost of the project identified by the Project Team (or PM) must be submitted to SP&AM for approval in the form of a Change Request. If required, a CPR will be issued by SP&AM.

Any scope additions/modifications are to be brought to the attention of SP&D for review. If required, a CPA will be issued by SP&AM.

Project Contact

The formal contact for project comments or concerns is as follows:

[redacted]

Subject: TLA16-038 B1W 138 KV WPR STR REPL

Appendices

Appendix A: Cost Estimates

Appendix B: Statement of Work (SoW)

Appendix C – Risk Profile

Appendix D: Line Rating Analysis

Appendix E: Project Plan

Appendix F: Asset Management Data Requirements Standard

Appendix D: Line Rating Analysis

Present Health Index

A health index based on the assets' physical condition has been obtained for the line. Based on the latest line inspections, it currently presents a grade of 71.7%. This grade is categorized based on the following:

Description	Grade	Colour
Excellent	80%	
Good	70-80%	
Acceptable	60-70%	
Poor	50-60%	
Substandard	< 50%	

Table 2: Scoring Summary

To produce such grade, an assessment of the individual component's health was obtained, yielding the following results:

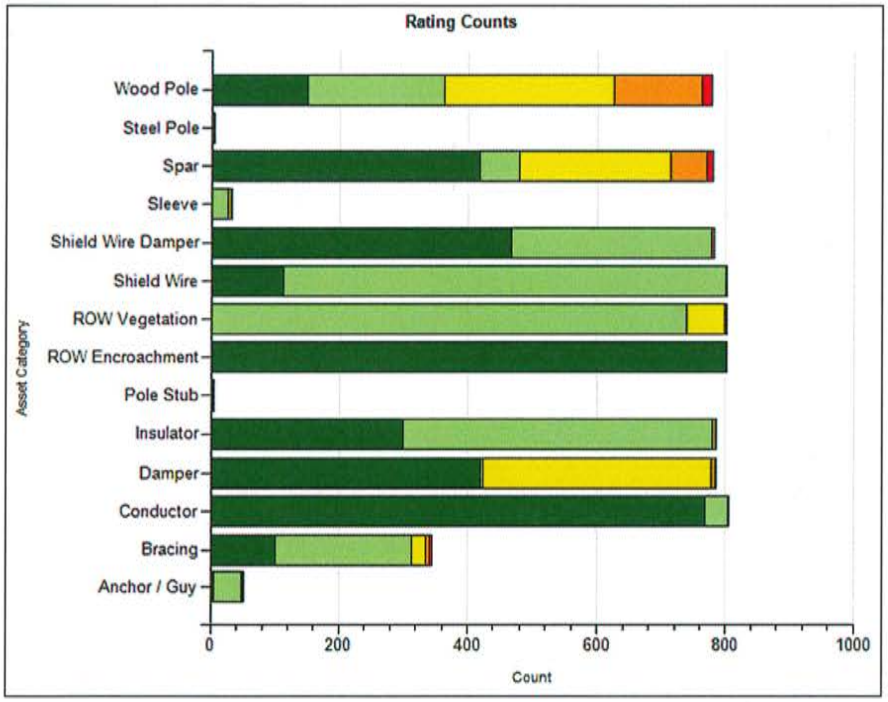


Figure 2: Component Scoring

It can be observed tha the overall condition of the line is acceptable; however, the 23 structures included in this project were identified as sub-standard and deemed high-risk to the reliability of the line.

Post-Project Health Index

An analysis to obtain the component grade and overall line health index upon the completion of the project has been made. The results are shown by Figure 3.

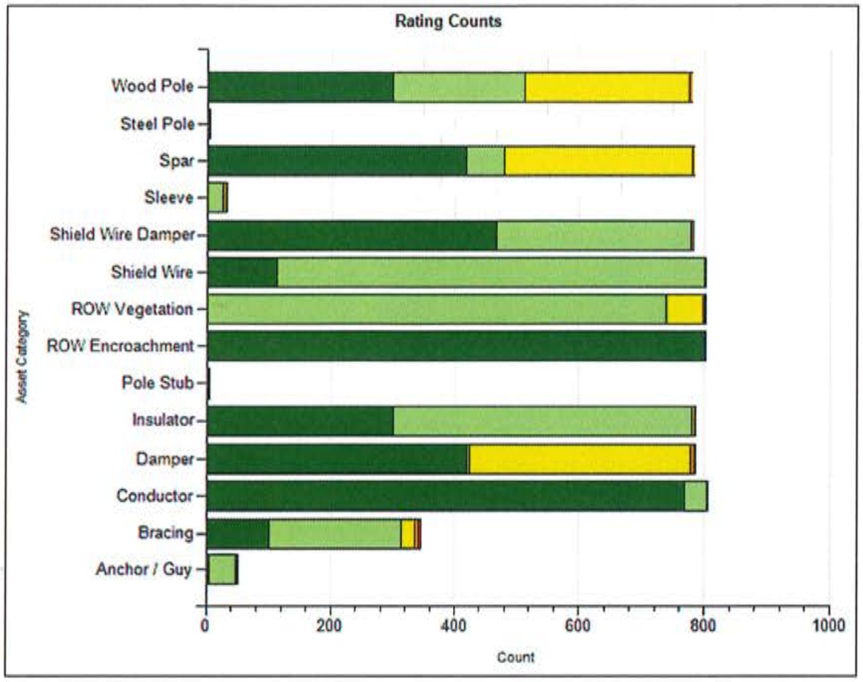


Figure 3: Post-Project Component Scoring

It can be seen that upon the replacement of the high-risk components, the overall health index is improved. Even though there is not a substantial difference in rating, the high-risk assets as the additional structures that will be replaced will increase the reliability of the circuit and decrease the risk of service interruption.

SRRP Q93 Reference: Capital Program

For each capital project or program with final costs in excess of $10 million for each of the last three actual years 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

Response:

All detail is reported as follows: the calendar-years 2014 and 2015, the three-month reporting period for 2016, and the fiscal year for 2016/17.

<u>i,ii, iii & v</u>
See attached Capital Expenditure documents.

<u>iv</u>
See Capital Expenditure documents for interest by project. SaskPower capital projects do not include overhead costs.

CAPITAL EXPENDITURES
As at December 2014
($000's)

CURRENT YEAR				PROJECT						
YTD Actual	2014 Budget	Variance		PTD Actual	Original CPA Value	Total CPR Value	% CNG	Total CPA Value	Variance	Interest
			Poplar River Power Station							
11,332.2	13,250.0	(1,917.8)	Poplar River Morrison Dam Spillway Capacity	11,848.1	26,500.0	0.0		26,500.0	(14,651.9)	143.9
			Boundary Dam Power Station							
37,907.5	39,406.0	(1,498.5)	BD #4 Life Extension	39,888.7	34,975.0	6,413.0	18.3	41,388.0	(1,499.3)	132.8
			Queen Elizabeth Power Station							
216,094.1	225,000.0	(8,905.9)	QE Repowering	322,628.4	531,970.0	0.0		531,970.0	(209,341.6)	6,425.4
			Distribution Customer Connects							
149,504.0	100,000.0	49,504.0	Program - Distribution Customer Connects	149,504.0	150,000.0	0.0		150,000.0	(496.0)	0.0
			Distribution Infrastructure Capacity Increase							
21,627.3	20,427.9	1,199.4	Substation - Kisbey - 230kV-25kV - New	27,199.6	20,296.4	6,549.6	32.3	26,846.0	353.6	434.4
			Transmission Customer Connects							
20,842.2	10,000.0	10,842.2	Line - K+S Potash to Pasqua - 230kV - New	21,762.2	37,500.0	0.0		37,500.0	(15,737.8)	105.2
27,033.0	17,000.0	10,033.0	Line - TCP Grassy Creek to Swift Current - 138kV - New	30,605.5	38,000.0	0.0		38,000.0	(7,394.5)	913.2
10,220.1	10,000.0	220.1	Substation - Morse Creek - 138-25 kV New	10,573.6	13,037.0	1,395.0	10.7	14,432.0	(3,858.4)	145.6
10,534.8	12,084.8	(1,550.0)	Switching Station – Queen Elizabeth - 138kV - Expansion	10,882.0	18,609.8	0.0		18,609.8	(7,727.8)	173.5
			Transmission Infrastructure Capacity Increase							
135,446.9	100,000.0	35,446.9	Line - I1K - 230kV - New	234,802.3	363,292.0	0.0		363,292.0	(128,489.7)	7,379.1
18,498.2	10,085.1	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)	261.1
34,571.9	45,492.6	(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)	1,639.0
10,381.5	6,800.0	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)	285.4
			Transmission Infrastructure Sustainment							
10,948.9	10,000.0	948.9	Program - Wood Line Remediation	10,948.9	18,400.0	0.0		18,400.0	(7,451.1)	138.6
			Operations - Other							
13,976.5	19,265.0	(5,288.5)	Vehicles & Equipment	13,976.5	22,564.5	0.0		22,564.5	(8,588.0)	0.0
			Integrated Carbon Capture Sequestration							
83,584.9	70,000.0	13,584.9	BD #3 ICCS - Carbon Capture	685,839.9	648,000.0	38,000.0	5.9	686,000.0	(160.1)	18,737.9
87,669.5	100,000.0	(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)	8,941.9
16,613.3	0.0	16,613.3	BD #3 Boiler Buckstay Reinforcement	16,613.3	17,025.7	0.0		17,025.7	(412.4)	139.9
35,344.5	17,500.0	17,844.5	Carbon Capture Test Facility	55,144.5	51,821.4	18,178.6	35.1	70,000.0	(14,855.5)	1,503.4
			Service Delivery Renewal							
7,598.0	40,663.0	(33,065.0)	AMI Replacement Project	29,290.6	108,023.4	0.0		108,023.4	(78,732.8)	0.2

2014 Capital Variance Explanations:

- 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 project capital budget is $39.4 million. Year to date expenditures were $1.5 million under budget due to updated cost estimates.
- Queen Elizabeth Repowering project capital budget is $225.0 million. Year to date expenditures were $8.9 million under budget due to deferrals to 2015.
- Distribution Customer Connects Program capital budget is $100.0 million. Year to date expenditures were $49.6 million over budget due to higher project activity and increased costs.
- Distribution Kisbey Substation project capital budget is $20.4 million. Year to date expenditures were $1.2 million over budget due to higher than anticipated costs in the construction phase.
- Transmission K+S Potash to Pasqua 230kV project capital budget is $10.0 million. Year to date expenditures were $10.8 million over budget mainly due to higher material costs than originally estimated.
- Transmission TCP Grassy Creek to Swift Current project capital budget is $17.0 million. Year to date expenditures were $10.0 million over budget mainly due to higher construction costs.
- Transmission Queen Elizabeth Switching Station project capital budget is $12.1 million. Year to date expenditures were $1.6 million under budget mainly due to project deferral to 2015.
- Transmission I1K 230kV project capital budget is $100.0 million. Year to date expenditures were $35.4 million over budget mainly due to construction of the North section progressing further than anticipated.
- Transmission Maidstone Area Switching Station project capital budget is $10.1 million. Year to date expenditures were $8.4 million over budget mainly due to higher construction costs than anticipated.
- Transmission Martensville Switching Station project capital budget is $45.5 million. Year to date expenditures were $10.9 million under budget mainly due to project deferral.
- Transmission Swift Current Switching Station project capital budget is $6.8 million. Year to date expenditures were $3.6 million over budget mainly due to higher construction costs than anticipated.
- Vehicles & Equipment capital budget is $19.3 million. Year to date expenditures were $5.3 million under budget due to delays in equipment delivery.

- 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.
- 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.
- AMI Meter Replacement capital budget is $40.7 million. Year to date expenditures were $33.1 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.

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	Interest
			Poplar River Power Station							
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)	87.1
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)	663.2
			Western Plants							
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)	1.0
			Queen Elizabeth Power Station							
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)	8,667.3
			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)	
			Distribution Infrastructure Capacity Increase							
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)	154.2
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)	735.1
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)	164.3
			Distribution Infrastructure Sustainment							
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	0.0
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	0.0
			Transmission Customer Connects							
13,011.8	19,080.1	(6,068.3)	LN - K+S Potash to Pasqua - 230kV - New	34,774.0	37,500.0	0.0		37,500.0	(2,726.0)	544.7
			Transmission 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)	550.0
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)	5,950.7
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)	819.7
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)	1,147.0
			Transmission Infrastructure Sustainment							
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	19.7
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	154.9
			Operations - Other							
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)	0.0
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	
			Integrated Carbon Capture Sequestration							
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)	71.3
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)	610.1

2015 Capital Variance Explanations:

- Poplar River #2 Long Term 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 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.
- 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.
- Queen Elizabeth 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 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 Bromhead 138kV-25kV Expansion project capital budget is $12.8 million. Year to date expenditures were $2.6 million under budget mainly due to the second phase issued for the project.
- Distribution Edam Area project capital budget is $33.2 million. Year to date expenditures were $4.6 million under budget mainly due to the delay of the project.
- Distribution Superb 138kV-25kV project capital budget is $15.3 million. Year to date expenditures were $4.4 million under budget mainly due to the delay of the project due to environmental concerns.
- Distribution Wood Assets Program capital budget is $9.2 million. Year to date expenditures were $1.5 million over budget mainly due to the reallocation of funding to focus on system improvement.
- Distribution Rural Rebuild & Improvement Program capital budget is $8.4 million. Year to date expenditures were $5.8 million over budget mainly due to the reallocation of funding to focus on system improvement.
- Transmission K+S Potash to Pasqua 230kV project capital budget is $19.1 million. Year to date expenditures were $6.1 million under budget mainly due to environmental mitigations costs less than originally estimated.
- Transmission Aberdeen to Wolverine 230kV project capital budget is $3.4 million. Year to date expenditures were $13.6 million over budget mainly due to project reactivation from deferral status.
- Transmission I1K 230kV project capital budget is $129.0 million. Year to date expenditures were $47.4 million under budget mainly due to project in service date 2016.

- Transmission Pasqua SVS 138kV project capital budget is $17.1 million. Year to date expenditures were $3.0 million over budget mainly due to scope and costs moved from another capital project to this capital project.
- Transmission Pasqua Tantallon 230kV-138kV project capital budget is $40.0 million. Year to date expenditures were $13.4 million under budget mainly due to 2017 in-service date.
- Transmission Lattice Steel Remediation Program capital budget is $4.5 million. Year to date expenditures were $5.6 million over budget mainly due to the reallocation of funding to focus on system improvement.
- Transmission Wood Line Remediation Program capital budget is $9.0 million. Year to date expenditures were $12.4 million over budget mainly due to the reallocation of funding to focus on system improvement.
- Meter Purchases capital budget is $19.2 million. Year to date expenditures were $3.3 million over budget due to increased meter exchanges.
- 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
- 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.
- 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.

CAPITAL EXPENDITURES
As at March 2016
($000's)

CURRENT YEAR			PROJECT						
YTD Actual	2016 Budget		PTD Actual	Original CPA Value	Total CPR Value	% CNG	Total CPA Value	Variance	Interest
		Distribution Customer Connects							
27,841.1	33,750.0	Program - Distribution Customer Connects	27,841.1	32,500.0	0.0		32,500.0	(4,658.9)	0.0
		Transmission Infrastructure Capacity Increase							
13,657.3	19,956.4	LN - Aberdeen to Wolverine - 230kV - New	41,617.0	73,350.0	0.0		73,350.0	(31,733.0)	374.0
10,579.0	8,000.0	LN - I1K - 230kV - New	326,955.7	380,000.0	(16,708.0)	(4.4)	363,292.0	(36,336.3)	67.0
		Transmission Infrastructure Sustainment							
29,806.8	17,000.0	Program - Wood Line Remediation	29,806.8	17,000.0	0.0		17,000.0	12,806.8	127.7

As at March 2017

($000's)

CURRENT YEAR				PROJECT						
YTD Actual	2017 Budget	Variance		PTD Actual	Original CPA Value	Total CPR Value	% CNG	Total CPA Value	Variance	Interest
			Poplar River Power Station							
13,860.2	14,000.0	(139.8)	Poplar River Ash Lagoon 4E Construction	14,373.4	28,000.0	0.0		28,000.0	(13,626.6)	194.4
			Chinook CCGT Project							
165,735.2	0.0	165,735.2	Chinook CCGT Project	165,735.2	680,500.0	0.0		680,500.0	(514,764.8)	720.9
			Integrated Carbon Capture Sequestration							
24,014.2	37,500.0	(13,485.8)	BD Mechanical Modifications	24,583.6	37,500.0	0.0		37,500.0	(12,916.4)	365.1
			Distribution Customer Connects							
104,832.5	100,000.0	4,832.5	Program - Distribution Customer Connects	104,832.5	135,000.0	0.0		135,000.0	(30,167.5)	0.0
			Distribution Sustainment Investment							
15,008.5	13,500.0	1,508.5	Program - Rural Rebuild & Improvement	15,008.5	13,500.0	150.0	1.1	13,650.0	1,358.5	6.4
			Transmission Growth & Compliance							
22,214.0	22,379.0	(165.0)	LN - Aberdeen to Wolverine - 230kV - New	63,831.0	73,350.0	0.0		73,350.0	(9,519.0)	702.0
11,472.5	8,067.6	3,404.9	LN - I1K - 230kV - New	338,428.1	380,000.0	(16,708.0)	(4.4)	363,292.0	(24,863.9)	70.6
31,831.8	50,400.0	(18,568.2)	LN - Kennedy to Tantallon - 230kV - Expansion	80,702.7	113,000.0	28.0	0.0	113,028.0	(32,325.3)	1,781.8
22,902.7	45,036.6	(22,133.9)	LN - Pasqua - Swift Current - 230kV -New	35,367.3	223,409.3	0.0		223,409.3	(188,042.0)	581.6
			Transmission Sustainment Investment							
14,817.8	7,000.0	7,817.8	Program - Transmission Lattice Steel Remediation	14,817.8	7,000.0	0.0		7,000.0	7,817.8	142.3
30,403.5	32,000.0	(1,596.5)	Program - Wood Line Remediation	30,403.5	32,000.0	0.0		32,000.0	(1,596.5)	912.4
			Operations - Other							
19,461.8	20,000.0	(538.2)	Vehicles & Equipment	19,461.8	20,000.0	0.0		20,000.0	(538.2)	0.0

2017 Capital Variance Explanations:

- Chinook CCGT project has no capital budget. Year to date expenditures were $165.7 million over budget due to the decision that SaskPower would build the facility.
- BD #3 Mechanical Modifications project capital budget is $37.5 million. Year to date expenditures were $13.5 million under budget due to deferred project management and engineering costs.
- Distribution Customer Connects Program capital budget is $100.0 million. Year to date expenditures were $4.8 million over budget due to more customer connects than planned.
- Distribution Rural Rebuild and Improvement Program capital budget is $13.5 million. Year to date expenditures were $1.5 million over budget due to increased customer demand.
- Transmission I1K 230kV Line project capital budget is $8.1 million. Year to date expenditures were $3.4 million over budget due to SaskPower deciding to pay the contractor the amount held back for liquidated damages in lieu of paying for warranty work.
- Transmission Kennedy to Tantallon 230kV Line project capital budget is $50.4 million. Year to date expenditures were $18.6 million under budget due to costs coming in well below budget.
- Transmission Pasqua to Swift Current 230kV Line project capital budget is $45.0 million. Year to date expenditures were $22.1 million under budget due to the project being deferred to future years.
- Transmission Lattice Steel Remediation Program capital budget is $7.0 million. Year to date expenditures were $7.8 million over budget due to more work planned than budgeted.
- Transmission Wood Line Remediation Program capital budget is $32.0 million. Year to date expenditures were $1.6 million under budget due to a combination of factors including extended periods of warm weather, inability to build and maintain ice of adequate strength, and poor contractor performance, several water remediation projects remained incomplete at the end of FY2017, resulting in unspent or underspent budgets on these projects.

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 2017/18 or 2018/19 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;

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 describe how SaskPower prepares budgets for each capital project. Please include in the discussion:

i. How project scopes and costing are developed.

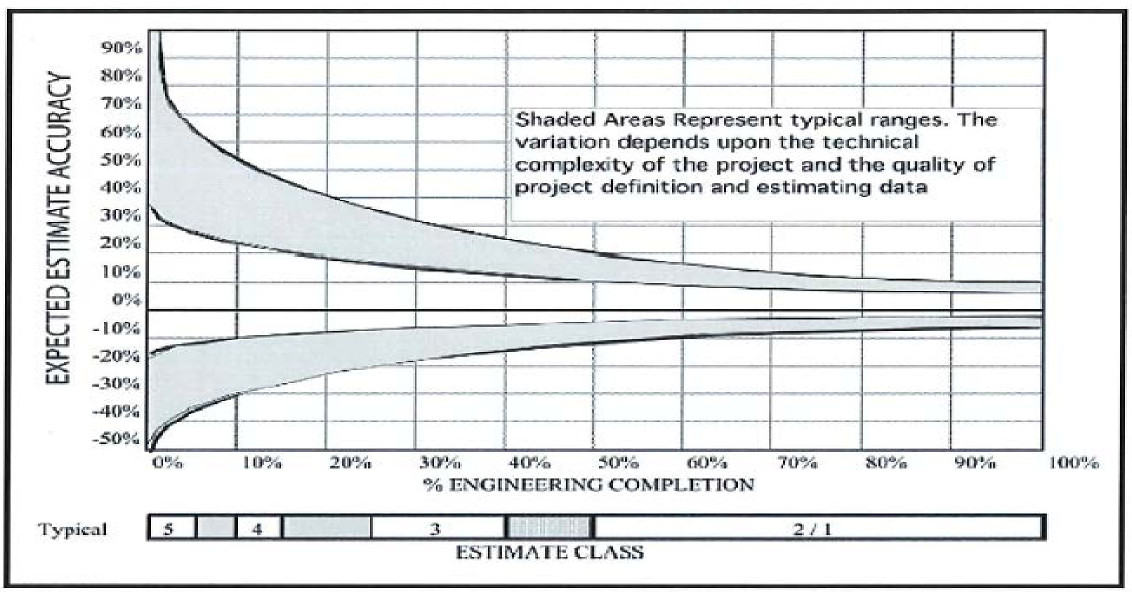
ii. Whether SaskPower uses costing benchmarks either from its own experience or from other jurisdictions.

iii. How SaskPower determines any contingency amounts included in the budget. Do contingencies include consideration of different risk profiles or uncertainty related to certain projects?

Response:

i) There are many ways a project can be initiated at SaskPower. However, for the project to be capital, infrastructure/assets in the organization are either added or modified to meet the intent of the project. The primary scope of the project is based on facilitating the intent/type of project. Common to all is the process for confirming the need for the project, evaluating options and selecting a solution based on technical and economic benefits — coordinated with corporate values/strategic objectives in mind.

At the project initiation stage, the expected estimation accuracy is -50% to +100%, however funds are only released to complete the initial engineering or study. After this initial analysis is completed, a construction CPA will be prepared and approved through our governance process with an estimated accuracy of -30% to +30%.



ii) SaskPower primarily uses costing benchmarks from its own experience in project delivery. We have utilized external benchmarks from engineering/material vendors and are currently involved with the CUCE (Canadian Utility Cost Engineering Working Group) to fully incorporate project cost benchmarking data from a number of Canadian Utilities.

iii) Project contingency is determined based on the risk profile of individual projects. Through the course of project definition, the project manager works with the project team to identify potential risks to project delivery and potential mitigation actions that could be pursued. This may include risks related to material delivery, construction issues, environmental, stakeholder concerns, etc. Individual risks are evaluated, based on potential impact to the project and probability of occurrence and assigned appropriate contingency in the project budget. The risk management plan and associated contingency budget is reviewed and subject to the approval of the Asset Manager/Project Sponsor prior to being included in whole or in part in the project budget.

SRRP Q96 Reference: Capital Program

Please discuss how SaskPower manages and monitors the delivery of its capital projects. Please include in the discussion an overview of responsibility, project reporting, variance analysis and quality assurance in the delivery of each capital project.

Response:

SaskPower's corporate governance defines the overall practices and controls that direct and manage the business affairs of SaskPower. The delivery of capital projects occurs within this broader organizational context; all capital projects must therefore conform to the requirements of SaskPower's overall corporate governance structure.

All capital projects shall be managed in line with applicable SaskPower corporate policies, procedures, and standards, including but not limited to:

- Financial reporting;
- Human resource management;
- Occupational health and safety;
- Procurement standards;
- Environmental sustainability;
- Quality assurance (including adherence to engineering and other technical standards).

All major projects are required to be managed in compliance with applicable regulatory and legislative requirements.

The Executive Project Owner, VP Asset Management, Planning and Sustainability, is the sponsor of the project and ultimately accountable for ensuring the intended outcomes and benefits for projects and the portfolio are achieved. The Executive Project Owner is the primary link between SaskPower's senior Executive body and the project.

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The Project Owner / Asset Manager has ultimate accountability for the realization of project outcomes (ensuring the ongoing fit of project outputs to SaskPower's strategic goals and business needs). The Project Owner`s authority is delegated by the Executive Owner and, in partnership with the Capital Projects Group, represents the primary link between SaskPower's senior Executive body and the project.

The Capital Projects Group carries the primary responsibility for management and control of capital projects at SaskPower. Delivery services are tailored to the scope and complexity of the projects and include all aspects of project planning, execution, oversight, and control. This includes analysis, documentation, and reporting to support the successful management and delivery of capital projects.

The following are the primary responsibilities and deliverables of capital project delivery at SaskPower:

Project planning

- Develop project delivery strategy and plan with input from subject matter experts across SaskPower.
- Develop, monitor, and execute the project risk management plan in collaboration with subject matter experts.
- Lead project team to complete the project plan including project milestones, budget and schedule.

Project monitoring & control

- Monitor and resolve project issues to ensure adherence to scope, schedule and budget.
- Analyze, monitor, and proactively manage project risks.
- Monitor and manage project performance and ensures timely and accurate reporting.
- Issue reports and respond to queries related to projects.
- Inform key stakeholders regarding project progress, issue management and risk mitigation.
- Ensure responsible project oversight through project and corporate governance policy and processes.

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Project analysis
- Conduct variance analysis (cost, schedule and scope), proactively identify risks and understand and manage issues in collaboration with project team members and functional managers.
- Review changes and ensure change control requirements are met.

Project Close
- Ensure project and required documentation are complete.
- Ensure smooth hand-off to Operations.

Portfolio monitoring & control
- Produce monthly dashboards and portfolio reports.
- Provide portfolio level analysis, reporting, and governance support to ensure consistent and effective project delivery.
- Provide specialized subject matter support to delivery teams for highly complex projects and programs (scheduling, forecasting, risk management).
- Support project delivery teams with project control systems and tools.
- Administer and support project governance system.

Project delivery maturity and continuous improvement
- Support the adoption, proficiency and consistent delivery of projects across SaskPower.
- Conduct root cause assessments and consult with delivery teams and functional areas to determine issues.
- Identify and make recommendations regarding systemic project delivery issues.
- Develop collaborative and effective solutions to delivery issues.
- Investigate and implement best practices across SaskPower and with other utilities and external bodies.

SRRP Q97 Reference: Capital Program

Please provide SaskPower's actual customer connections for the three most recent years of actuals and forecasts for 2017/18 and 2018/19.

Response:

The following table shows actual customer connections for the years 2014 to 2016/17 and the forecasted amounts for the years 2017/18 and 2018/19.

Customer Connects Capital Expenditures

	Actual	Actual	Actual	Budget	Budget
(in $ millions)	**2014**	**2015/16**	**2016/2017**	**2017/2018**	**2018/2019**
Residential	30.5	27.8	25.8	23.0	23.5
Farm	9.7	11.4	13.0	11.6	11.8
Commercial	46.0	36.8	41.4	36.9	37.7
Oilfield	42.3	35.7	17.3	15.5	15.7
Other	21.0	15.5	14.6	13.0	13.3
Total Distribution	149.5	127.2	112.1	100.0	102.0
Total Transmission	80.2	22.1	18.0	33.6	30.6
Total Customer Connects Capital Expenditures	**229.7**	**149.3**	**130.1**	**133.6**	**132.6**

**Other includes customer connects shared by multiple customer classes*

SRRP Q98 Reference: Capital Program

Please provide an update on the Chinook generation project including projected in-service date and whether the project is proceeding on budget.

Response:

- Project is on schedule for an in-service date of Oct 1, 2019. The overall project is approximately 37% complete to date.
- The project is on/within the original approved budget of $680.5 million.
- Project engineering design is approximately 80% complete to date.
- 98% engineered equipment has been procured and fabrication/delivery are underway.
- Construction is progressing well. Foundation and underground infrastructure construction is in progress and are expected to be substantially complete by the end of September.
- The Phase 1 Mechanical Installation Contractor has mobilized and erection of the Heat Recovery Steam Generator (HRSG) has begun.
- Installation of water storage tanks and the administration/water treatment building are in progress.
- Water and natural gas interconnections are progressing as scheduled.

SRRP Q99 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:

A $100 million change in the capital budget is assumed to have a $7 million impact on depreciation expense and finance charges. The breakdown between the two expense categories is as follows:

a) Depreciation expense: $100 million capital expenditure / 25 year amortization period = $4 million annual expense

b) Finance charges: $100 million borrowed at 3.0% = $3 million annual expense

In terms of the impact on SaskPower's return on equity (ROE), a $7 million increase in expense would result in SaskPower's ROE dropping by approximately 0.3%.

SRRP Q100 Reference: Customer connects

Please provide SaskPower's financial policy/policies for customer system connections. Please discuss how SaskPower determines any customer contribution amounts that may be required.

Response:

SaskPower will make an investment into the provision of all new service installations on the distribution system. SaskPower's investment levels into new distribution connected customers are determined using a net present value calculation based on the difference between the incremental revenues and costs associated with adding new customers over a five year period.

Once the level of investment is determined using this methodology, it is then converted into the appropriate investment in terms of either a fixed dollar amount for residential and standard farm services, or a fixed number of months of anticipated revenue from that customer for a general service, oilfield, streetlight or large farm service. The current investment levels for distribution connected customers are:

- $1,300 investment into new residential and standard farm services
- 18 months of anticipated revenue into new large farm services
- 24 months of anticipated revenue into new general service, oilfield and street light services
- An investment based upon an individual discounted cash flow analysis for each new large (greater than 2000 kVA) general service

The new customer pays all estimated construction costs in excess of SaskPower's calculated investment amount.

There is no investment based upon expected revenue into transmission connected services. New transmission connected customers are assessed a construction charge based on the number of kilometres to the nearest transmission line of a voltage capable of serving the customer's anticipated load times the per kilometre cost of constructing a line of that voltage. SaskPower has a network upgrade policy for transmission connected customers which allows for all costs associated with any network upgrade or reinforcement to be completed at SaskPower costs.

SRRP Q101 Reference: Load Forecasts

Please confirm that the 2018 Rate Application is based on the 2017 Q1 Load Forecast. If not confirmed, please provide the Load Forecast documents the Application is based on.

Response:

The 2018 Rate Application is not based on the 2017 Q1 Load Forecast. It is based on the 2017 Q2 Fiscal Load Forecast which can be found in the following table (highlighted cells).

TABLE A1

2016-2017 DSM ADJUSTED TOTAL SYSTEM LOAD FORECAST

Fiscal Second Quarter

ENERGY SALES, NUMBER OF ACCOUNTS AND PEAK DEMAND

	POWER		OILFIELDS		COMMERCIAL		RESIDENTIAL		FARM		RESELLER		CORPORATE USE		TOTAL SALES		LOSSES	TOTAL ENERGY REQUIREMENTS	FISCAL YR PEAK DEMAND
Year	GWh	# of Accounts	GWh	# of Accounts	GWh	# of Accounts	GWh	# of Accounts	GWh	# of Accounts	GWh	# of Accounts	GWh	# of Accounts	GWh	# of Accounts	GWh	GWh	MW
2005-2006	6,555.6	78	2,293.9	11,599	3,189.3	50,388	2,460.4	294,830	1,327.6	29,319	1,259.9	2	100.4	212	17,187.1	386,494	1,681.4	18,868.4	2,954
2006-2007	6,772.3	78	2,438.9	12,248	3,268.6	50,831	2,600.0	297,424	1,277.9	28,894	1,301.8	2	110.5	212	17,770.0	389,738	1,781.9	19,551.9	2,923
2007-2008	6,866.5	78	2,545.4	13,092	3,285.1	51,341	2,695.6	304,157	1,323.6	28,504	1,287.3	2	109.7	212	18,113.2	397,451	1,875.5	19,988.6	2,969
2008-2009	6,710.6	78	2,780.9	13,639	3,351.9	51,819	2,791.6	310,060	1,306.6	28,429	1,276.6	2	106.3	212	18,324.5	404,329	1,791.9	20,116.4	3,016
2009-2010	6,252.1	82	2,769.8	14,314	3,392.1	52,431	2,835.9	316,123	1,344.1	28,327	1,262.6	2	110.7	212	17,967.3	411,609	1,836.2	19,803.5	3,194
2010-2011	7,076.0	91	2,824.9	14,756	3,433.6	53,983	2,923.6	321,755	1,281.2	28,236	1,262.7	2	108.6	212	18,910.6	419,173	2,079.2	20,989.8	3,231
2011-2012	7,293.9	97	2,906.6	15,133	3,416.1	53,863	2,907.6	329,286	1,293.6	36,754	1,238.8	2	106.3	212	19,162.9	435,523	1,923.0	21,085.8	3,195
2012-2013	7,583.3	100	3,359.2	16,728	3,568.0	55,812	2,988.5	352,748	1,144.6	61,914	1,261.4	2	117.7	212	20,022.7	487,789	2,175.1	22,197.8	3,265
2013-2014	7,903.1	101	3,393.3	17,621	3,731.3	57,247	3,276.0	363,040	1,377.6	60,805	1,279.2	2	99.6	212	21,060.1	498,850	1,902.0	22,962.0	3,379
2014-2015	8,393.4	101	3,578.9	18,485	3,771.9	59,580	3,240.7	371,652	1,348.3	59,228	1,248.6	2	100.3	212	21,682.1	399,058	1,852.9	23,535.1	3,543
2015-2016	8,876.5	101	3,453.3	19,126	3,768.1	60,239	3,066.6	379,079	1,255.4	59,397	1,222.8	2	99.3	212	21,742.0	519,420	1,888.4	23,630.4	3,640
2016-2017	8,887.3	101	3,370.2	18,602	3,865.7	64,538	3,273.9	386,819	1,310.9	59,151	1,282.1	2	96.4	212	22,086.4	529,425	1,892.6	23,979.0	3,832
2017-2018	9,217.7	101	3,445.3	19,015	3,914.5	65,086	3,323.9	394,423	1,308.4	58,987	1,285.8	2	104.0	212	22,599.5	537,825	1,920.9	24,520.4	3,917
2018-2019	9,339.1	102	3,538.4	19,531	3,939.2	65,606	3,372.2	401,747	1,287.7	58,926	1,289.4	2	109.0	212	22,875.0	546,126	1,951.1	24,826.1	3,962
2019-2020	9,716.7	103	3,601.6	19,879	3,962.8	66,114	3,422.9	408,826	1,279.9	58,825	1,293.0	2	109.3	212	23,386.1	553,959	2,035.5	25,421.6	4,050
2020-2021	9,850.1	103	3,655.8	20,181	3,984.3	66,622	3,491.1	415,749	1,273.0	58,698	1,296.5	2	109.6	212	23,660.4	561,567	2,049.6	25,710.0	4,082
2021-2022	9,947.8	104	3,659.2	20,199	4,003.8	67,120	3,556.9	422,689	1,269.2	58,577	1,299.7	2	109.9	212	23,846.5	568,903	2,073.5	25,920.0	4,119
2022-2023	10,142.2	104	3,666.8	20,241	4,019.4	67,578	3,620.9	429,614	1,265.8	58,465	1,302.9	2	110.2	212	24,128.2	576,217	2,090.4	26,218.6	4,162
2023-2024	10,307.1	104	3,661.5	20,213	4,031.8	68,019	3,703.6	436,477	1,263.9	58,376	1,306.2	2	110.5	212	24,384.6	583,404	2,097.1	26,481.7	4,207
2024-2025	10,395.0	105	3,635.5	20,069	4,045.6	68,518	3,797.6	443,245	1,259.6	58,313	1,309.5	2	110.8	212	24,553.5	590,463	2,078.4	26,631.9	4,225
2025-2026	10,557.7	105	3,633.3	20,057	4,061.6	69,035	3,877.5	450,028	1,254.5	58,239	1,312.8	2	88.5	212	24,785.8	597,678	2,083.3	26,869.0	4,275
2026-2027	10,666.7	105	3,603.6	19,894	4,078.4	69,559	3,952.5	456,748	1,250.2	58,172	1,316.0	2	88.8	212	24,956.2	604,691	2,110.3	27,066.5	4,299

Growth Rates (%)

10/11-15/16	4.6%	2.1%	4.1%	5.3%	1.9%	2.2%	1.0%	3.3%	-0.4%	16.0%	-0.6%	0.0%	-1.8%	0.0%	2.8%	4.4%	-1.9%	2.4%	2.4%
5/6-15/16	3.1%	2.6%	4.2%	5.1%	1.7%	1.8%	2.2%	2.5%	-0.6%	7.3%	-0.3%	0.0%	-0.1%	0.0%	2.4%	3.0%	1.2%	2.3%	2.1%
16/17-21/22	2.3%	0.7%	1.7%	1.7%	0.7%	0.8%	1.7%	1.8%	-0.6%	-0.2%	0.3%	0.0%	2.7%	0.0%	1.5%	1.4%	1.8%	1.6%	1.5%
16/17-26/27	1.8%	0.4%	0.7%	0.7%	0.5%	0.8%	1.9%	1.7%	-0.5%	-0.2%	0.3%	0.0%	-0.8%	0.0%	1.2%	1.3%	1.1%	1.2%	1.2%

1.) All forecasted energy values are normalized to reflect 30-year average weather patterns.
2.) All forecasted peak values are potential; peak shavings are not included. All historical peaks are actuals with peak shavings and interruptibles included.
3.) The demand side management (DSM) energy and peak demand saving as identified by SaskPower's DSM department are reflected in the forecast above.
4.) The number of accounts is the average for the year as required for rate design and revenue forecasting.

SRRP Q102 Reference: Load Forecasts

A) Please discuss any methodology changes for the Load Forecast since the previous rate application, including any changes affecting input data.

B) Please confirm that the 2017 Q1 Load Forecast uses the new load forecasting software.

C) In testing the new load forecast software, did SaskPower prepare concurrent load forecasts using the previous approach and the new forecasting software? If so, please provide a summary of any differences in the outcomes between the two approaches.

D) Please explain how SaskPower prepares its forecasts of customer counts.

Response:

A) Residential:

- Customer forecast – The only change to the methodology is that rather than separating households into single detached and apartment dwellings, a weighted average of these is applied to the end-use data and then the Residential class customer count is forecasted as a whole.

Commercial:

- Customer forecast – The Residential customer forecast is no longer used as an input to the forecast. Rather, population estimates as well as gross domestic product for finance, insurance, real estate, public administration, wholesale and retail trade, transportation and warehousing are used in conjunction with regression analysis to derive the customer forecast.

Streetlights:

- Energy forecast – Bulb counts are no longer used to produce a streetlight forecast. Instead historical streetlight energy is input into a regression analysis using economic household counts as well as past trends in streetlights carrying forward into the future.

Farm:

- Customer forecast - Farm customer forecasts are no longer derived by differentiating between farm households and operations. Instead, they are now obtained by using a variable which integrates household size and farm households.

- Energy forecast – Energy is no longer calculated separately between analysis on household, operations, and irrigation. All farm energy is now input into a regression analysis that factors in end-use assumptions as well as past trends carrying forward into the future. Irrigation is forecast separately as before.

Oilfield:
- Customer forecast – Oilfield customers are determined by extrapolating historical customer counts based on historic trends. Previously, this was done using existing numbers of operating wells and adding on future forecasts of number of wells drilled.

Reseller – The methodology has not changed for this class.

Corporate Use – The methodology has not changed for this class.

System Losses and Unaccounted Energy – The methodology has not changed for this class.

Non-Grid – The methodology has not changed for this class.

Power Class - The methodology has not changed for this class.

B) Both the 2017 Q1 (Fiscal) as well as the 2017 Q2 (Fiscal) Load forecasts use the new load forecasting software. The 2017 Q2 (Fiscal) Load forecast is what the rate application is based on.

C) Testing of the new load forecast software included creating forecasts concurrently with the Excel-based models up to and including 2015Q4. Comparisons were done to ensure that the forecasts created in the new software were reasonable. The most recent "mirror" comparison that is available prior to the cutover to the new forecasting software is summarized in the table below. Note that the Power and Reseller classes didn't experience methodology changes and are therefore the same between the two forecasts. The table summarizes the mirrors' performance, including APE (Absolute Percent Error):

2016-2017 Forecast vs Actual							
Gwh	**Res**	**Com**	**Power**	**Oilfield**	**Reseller**	**Farm**	**Total**
New Methodology Forecast	3,327.3	3,798.2	9,190.5	3,619.5	1,290.8	1,256.3	**22,482.6**
Old Methodology Forecast	3,281.9	3,844.8	9,190.5	3,478.9	1,290.8	1,331.9	**22,418.8**
Actual	3,068.6	3,776.9	9,206.7	3,620.8	1,218.7	1,188.8	**22,080.5**
New Methodology Variance	**(258.7)**	**(21.3)**	**16.2**	**1.3**	**(72.1)**	**(67.5)**	**(402.1)**
Old Methodology Variance	**(213.3)**	**(67.9)**	**16.2**	**141.9**	**(72.1)**	**(143.1)**	**(338.3)**
APE - New Methodology	**7.77%**	**0.56%**	**0.18%**	**0.03%**	**5.59%**	**5.37%**	**1.79%**
APE - Old Methodology	**6.50%**	**1.77%**	**0.18%**	**4.08%**	**5.59%**	**10.74%**	**1.51%**

Average APE	
New Methodology	**3.25%**
Old Methodology	**4.81%**

D) Residential – Customer counts are obtained by using historical trends and the non-farm households economic data.

Commercial – Inputs are population in the province as well as gross domestic product for finance, insurance, real estate, public administration, wholesale and retail trade, transportation and warehousing in conjunction with regression analysis to determine forecasted customers.

To obtain Streetlight customers, household economic data is used in a regression analysis against the historical streetlight customer count.

Farm - Farm customer forecasts are no longer derived by differentiating between farm households and operations. Instead they are now obtained by using a variable which integrates household size and farm households.

Oilfield – Oilfield customers are determined by taking historical customer counts and extrapolating them based on historic trends.

Reseller – We do not anticipate any change in customer count for this class.

Corporate Use – We do not anticipate any change in customer count for this class.

Non-Grid – Customer forecast is held constant at historic actuals; no growth is assumed.

Power Class – Power customer counts are forecast through consultation with Senior Business Advisors (SaskPower customer service representatives) and the Ministry of the Economy as well as the analysis of historic trends.

SRRP Q103 Reference: Load Forecasts

For Table A5, please provide high, low and most likely sensitivity analysis for energy and peak (and corresponding growth rate) for forecast years with no DSM and DSM adjusted (i.e. a version of Table B from the 2015 Load Forecast).

Response:

The most recent readily available Table B with and without DSM is from the first calendar quarter of 2016, and is not available fiscally (fiscal historic forecasts are only available from 2016 forward – the Monte Carlo simulation upon which the High/Low is based requires 21 previous forecasts).

No DSM:

TABLE B

2016 HIGH & LOW GRID LOAD FORECAST (WITHOUT DSM INITIATIVES)

FIRST QUARTER

ENERGY REQUIREMENTS AND POTENTIAL INSTANTANEOUS CALENDAR PEAK

Based On:
- Percentage error by Customer Class in year 1, year 2, year 3 etc. of previous forecasts.
- 90% Confidence Interval

	Lower Bound				Most Likely		Upper Bound			
	Difference from Most Likely		Energy Rqmt's	Potential Peak	Energy Rqmt's	Potential Peak	Energy Rqmt's	Potential Peak	Difference from Most Likely	
Year	(GWh)	(MW)	(GWh)	(MW)	(GWh)	(MW)	(GWh)	(MW)	(GWh)	(MW)
2016	(248)	(40)	24,004	3,821	24,251.9	3,861	24,811	3,950	559	89
2017	(1,224)	(196)	23,546	3,765	24,770.1	3,962	26,129	4,179	1,359	218
2018	(1,831)	(293)	23,310	3,721	25,141.4	4,014	27,023	4,315	1,881	301
2019	(2,278)	(365)	23,463	3,754	25,741.1	4,119	28,019	4,484	2,278	365
2020	(2,635)	(419)	23,515	3,734	26,150.2	4,153	28,752	4,567	2,602	414
2021	(2,933)	(468)	23,355	3,725	26,287.8	4,193	29,165	4,652	2,877	459
2022	(3,189)	(508)	23,607	3,757	26,796.3	4,265	29,914	4,761	3,118	496
2023	(3,415)	(544)	23,742	3,782	27,156.7	4,326	30,488	4,856	3,332	531
2024	(3,616)	(574)	23,957	3,805	27,572.9	4,380	31,098	4,939	3,525	560
2025	(3,799)	(604)	24,203	3,851	28,001.5	4,456	31,703	5,044	3,702	589
2026	(3,966)	(630)	24,459	3,885	28,424.8	4,515	32,289	5,128	3,864	613
Growth Rates (%)										
5 Year			-0.5%	-0.5%	1.6%	1.7%	3.3%	3.3%		
10 Year			0.2%	0.2%	1.6%	1.6%	2.7%	2.6%		

SaskPower
Powering the future®

2018 RATE APPLICATION
SRRP INTERROGATORIES

With DSM:

TABLE B

2016 DSM ADJUSTED HIGH & LOW GRID LOAD FORECAST

FIRST QUARTER

ENERGY REQUIREMENTS AND POTENTIAL INSTANTANEOUS CALENDAR PEAK

Based On:
- Percentage error by Customer Class in year 1, year 2, year 3 etc. of previous forecasts.
- 90% Confidence Interval

	Lower Bound				Most Likely		Upper Bound			
	Difference from Most Likely		Energy Rqmt's	Potential Peak	Energy Rqmt's	Potential Peak	Energy Rqmt's	Potential Peak	Difference from Most Likely	
Year	(GWh)	(MW)	(GWh)	(MW)	(GWh)	(MW)	(GWh)	(MW)	(GWh)	(MW)
2016	(351)	(56)	23,871	3,811	24,222.0	3,867	24,287	3,877	65	10
2017	(1,281)	(206)	23,429	3,754	24,710.4	3,960	25,951	4,159	1,240	199
2018	(1,857)	(297)	23,139	3,701	24,996.0	3,998	27,060	4,329	2,064	331
2019	(2,280)	(363)	23,267	3,730	25,546.5	4,093	28,241	4,523	2,694	430
2020	(2,616)	(414)	23,289	3,704	25,905.0	4,118	29,116	4,626	3,211	508
2021	(2,897)	(458)	23,094	3,690	25,990.9	4,148	29,644	4,726	3,653	578
2022	(3,139)	(496)	23,308	3,714	26,446.8	4,210	30,486	4,848	4,039	638
2023	(3,351)	(529)	23,402	3,732	26,753.1	4,261	31,138	4,953	4,385	692
2024	(3,541)	(556)	23,573	3,749	27,113.4	4,305	31,811	5,043	4,698	738
2025	(3,712)	(584)	23,776	3,788	27,488.1	4,372	32,472	5,156	4,984	784
2026	(3,869)	(608)	23,990	3,814	27,858.7	4,422	33,108	5,247	5,249	825
Growth Rates (%)										
5 Year			-0.7%	-0.6%	1.4%	1.4%	4.1%	4.0%		
10 Year			0.0%	0.0%	1.4%	1.4%	3.1%	3.1%		

SRRP Q104 Reference: Load Forecast

Please comment on the reason for the reduction to GWh after 2016 DSM savings compared to the 2015 Load Forecast.

Response:

The reduction is due mainly to a drop in anticipated Power class energy sales as a result of lower anticipated sales to the potash and pipeline sectors. To a lesser extent, oilfield sales were also expected to be lower between these forecasts due to the lower price of oil.

SRRP Q105 Reference: Load Forecast

A) For each of the ten most recent actual years, 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.

B) Please comment on the factors leading to SaskPower's increase of customer accounts of 9,577 in 2017/18 and 8,301 in 2018/19 as shown on page 38 of the application.

Response:

A) Please see the following table.

B) The increase in customer accounts is nearly all (over 90%) in the Residential and Commercial classes. The increases are primarily as a result of the provincial population forecast that assumes the Government of Saskatchewan's goal of 1.2 million by 2020 is realized (most recent data shows population is 1.16 Million as of June 2017).

Electricity Sales vs Forecast by Customer Class
(GWh)

	2007			2008			2009			2010			2011		
	Sales	Forecast		Sales	Forecast		Sales	Forecast		Sales	Forecast		Sales	Forecast	
Residential	2,643	2,590	**2.01%**	2,721	2,598	**4.51%**	2,865	2,801	**2.24%**	2,882	2,847	**1.23%**	3,006	2,926	**2.65%**
Commercial	3,269	3,226	**1.33%**	3,311	3,285	**0.78%**	3,407	3,338	**2.03%**	3,386	3,328	**1.70%**	3,447	3,497	**-1.44%**
Oilfields	2,541	2,473	**2.68%**	2,682	2,560	**4.56%**	2,742	2,775	**-1.21%**	2,872	2,815	**1.98%**	2,901	2,865	**1.23%**
Power customers	6,854	6,470	**5.60%**	6,898	7,283	**-5.58%**	6,139	7,750	**-26.24%**	6,932	7,614	**-9.83%**	7,321	8,120	**-10.91%**
Farm	1,329	1,350	**-1.60%**	1,306	1,327	**-1.57%**	1,338	1,322	**1.19%**	1,292	1,268	**1.88%**	1,298	1,297	**0.09%**
Reseller	1,287	1,290	**-0.26%**	1,274	1,355	**-6.39%**	1,274	1,371	**-7.63%**	1,254	1,283	**-2.28%**	1,253	1,277	**-1.94%**
TOTAL SASKATCHEWAN SALES	**17,923**	**17,399**	2.92%	**18,192**	**18,409**	-1.19%	**17,765**	**19,357**	-8.96%	**18,618**	**19,154**	-2.88%	**19,226**	**19,982**	-3.93%
Losses	1,797	1,779	**1.01%**	1,879	1,851	**1.51%**	1,875	1,817	**3.08%**	1,897	1,795	**5.39%**	1,936	1,754	**9.43%**
Station Service	23.7	22.9	**3.38%**	24.8	24.2	**2.42%**	25.9	25.4	**1.93%**	25.4	26.5	**-4.33%**	28.6	25.9	**9.44%**

Notes:

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

*2012 - Potash and pipeline energy lower than forecast

*2012 and 2017F - Farm energy is volatile due to widely varying customer use patterns

*2015 - Oilfield energy is lower than forecast due to the reduction in price

Electricity Sales vs Forecast
(GWh)

	2012			2013			2014			2015			2017F		
	Sales	Forecast		Sales	Forecast		Sales	Forecast		Sales	Forecast		Sales	Forecast	
Residential	2,937	2,929	**0.26%**	3,190	3,011	**5.61%**	3,281	3,014	**8.15%**	3,128	3,139	**-0.34%**	3,069	3,282	**-6.95%**
Commercial	3,532	3,480	**1.47%**	3,663	3,514	**4.07%**	3,788	3,609	**4.72%**	3,795	3,694	**2.65%**	3,777	3,845	**-1.80%**
Oilfields	3,177	3,277	**-3.15%**	3,448	3,546	**-2.85%**	3,503	3,686	**-5.22%**	3,494	3,793	**-8.55%**	3,621	3,503	**3.27%**
Power customers	7,448	8,648	**-16.10%**	7,863	8,469	**-7.71%**	8,179	8,234	**-0.67%**	8,698	8,522	**2.03%**	9,207	9,221	**-0.16%**
Farm	1,149	1,281	**-11.48%**	1,332	1,331	**0.11%**	1,364	1,305	**4.30%**	1,276	1,318	**-3.32%**	1,189	1,332	**-12.04%**
Reseller	1,254	1,281	**-2.14%**	1,257	1,275	**-1.42%**	1,274	1,264	**0.78%**	1,234	1,268	**-2.71%**	1,219	1,291	**-5.92%**
TOTAL SASKATCHEWAN SALES	**19,497**	**20,896**	**-7.17%**	**20,753**	**21,146**	**-1.89%**	**21,389**	**21,111**	**1.30%**	**21,625**	**21,758**	**-0.62%**	**22,081**	**22,473**	**-1.78%**
Losses	2,172	1,879	**13.50%**	1,905	1,981	**-3.98%**	1,945	1,931	**0.70%**	2,047	1,878	**8.29%**	2,117	1,874	**11.50%**
Station Service	39.1	27.8	**28.90%**	38.9	29.3	**24.68%**	47.3	29.2	**38.27%**	31.0	29.5	**4.84%**	32	30	**5.31%**

Notes:
*2009 - Power Customers variance is explai
*2012 - Potash and pipeline energy lower th
*2012 and 2017F - Farm energy is volatile du
*2015 - Oilfield energy is lower than forecas

SRRP Q106 Reference: Load Forecasts

For each of the ten most recent actual years, please provide a schedule showing the actual customer counts for each major customer group and the customer count forecast from the load forecast immediately preceding the actual year. Comment on any material variances between actuals and forecasts.

Response:

Please see the following table.

Customer Actuals vs Forecast by Class

	2007			2008			2009			2010			2011		
	Customers	Forecast		Customers	Forecast		Customers	Forecast		Customers	Forecast		Customers	Forecast	
Residential	321,183	315,174	**1.87%**	328,719	317,265	**3.48%**	334,684	328,033	**1.99%**	340,518	338,445	**0.61%**	345,854	348,663	**-0.81%**
Commercial	53,917	52,858	**1.96%**	54,563	52,379	**4.00%**	55,853	53,918	**3.46%**	55,714	54,757	**1.72%**	58,118	55,808	**3.97%**
Oilfields	13,147	12,423	**5.51%**	13,932	12,906	**7.36%**	14,461	14,157	**2.10%**	15,098	15,094	**0.03%**	15,437	14,755	**4.42%**
Power customers	80	96	**-20.00%**	78	98	**-25.64%**	84	80	**4.76%**	98	81	**17.35%**	99	95	**4.04%**
Farm	63,384	61,354	**3.20%**	62,712	63,564	**-1.36%**	62,245	62,761	**-0.83%**	61,577	60,972	**0.98%**	62,475	61,862	**0.98%**
Reseller	2	2	**0.00%**	2	2	**0.00%**	2	2	**0.00%**	2	2	**0.00%**	2	2	**0.00%**
TOTAL SASKATCHEWAN CUSTOMERS	**451,713**	**441,907**	**2.17%**	**460,006**	**446,214**	**3.00%**	**467,329**	**458,951**	**1.79%**	**473,007**	**469,351**	**0.77%**	**481,985**	**481,185**	**0.17%**

Notes:

*2012: Oilfield customer growth higher than expected.

Customer Actuals vs Forecast by C

	2012			2013			2014			2015			2017F		
	Customers	Forecast		Customers	Forecast		Customers	Forecast		Customers	Forecast		Customers	Forecast	
Residential	353,435	346,310	**2.02%**	362,738	360,636	**0.58%**	373,109	366,488	**1.77%**	380,392	378,201	**0.58%**	388,006	382,961	**1.30%**
Commercial	58,435	55,162	**5.60%**	59,402	56,386	**5.08%**	60,274	57,712	**4.25%**	61,231	60,204	**1.68%**	61,918	60,600	**2.13%**
Oilfields	16,894	15,281	**9.55%**	17,560	17,524	**0.21%**	18,662	18,562	**0.54%**	19,307	18,433	**4.53%**	19,234	18,805	**2.23%**
Power customers	108	101	**6.48%**	101	100	**0.99%**	102	100	**1.96%**	121	100	**17.36%**	124	99	**20.16%**
Farm	61,737	61,897	**-0.26%**	61,076	62,247	**-1.92%**	59,792	61,087	**-2.17%**	59,262	61,939	**-4.52%**	58,775	60,884	**-3.59%**
Reseller	2	2	**0.00%**	2	2	**0.00%**	2	2	**0.00%**	2	2	**0.00%**	2	2	**0.00%**
TOTAL SASKATCHEWAN CUSTOMERS	**490,611**	**478,753**	**2.42%**	**500,879**	**496,895**	**0.80%**	**511,941**	**503,951**	**1.56%**	**520,315**	**518,879**	**0.28%**	**528,059**	**523,351**	**0.89%**

Notes:
*2012: Oilfield customer growth higher than expect

2018 RATE APPLICATION
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SRRP Q107 Reference: Load Forecast

For Table A1, please identify if the 2016/17 fiscal year as reported is actual or forecast. If forecast, please compare forecast to actual values for Table A1 if available.

Response:

The 2016/2017 fiscal year in Table A1 is forecast, assuming that the table in question comes from the 2017F Q1 Load Forecast Report.

Comparison:

	POWER		OILFIELDS		COMMERCIAL		RESIDENTIAL		FARM	
	GWh	# of Accounts	GWh	# of Accounts	GWh	# of Accounts	GWh	# of Accounts	GWh	# of Accounts
2016-2017 FORECAST	9,114.4	101	3,475.1	19,293	3,865.7	64,538	3,273.9	386,819	1,310.9	59,151
2016-2017 ACTUAL	9,206.7	101	3,620.8	19,234	3,776.9	61,918	3,068.6	388,006	1,188.8	58,775
DIFFERENCE	92.3	0	145.7	(59)	(88.8)	(2,620)	(205.3)	1,187	(122.1)	(376)

	RESELLER		CORPORATE USE		TOTAL SALES		LOSSES	TOTAL ENERGY REQUIREMENTS
	GWh	# of Accounts	GWh	# of Accounts	GWh	# of Accounts	GWh	GWh
2016-2017 FORECAST	1,282.1	2	111.7	212	22,433.7	530,449	1,903.1	**24,336.8**
2016-2017 ACTUAL	1,218.7	2	96.8	212	22,177.3	528,248	2,195.0	**24,372.3**
DIFFERENCE	(63.4)	0	(14.9)	-	(256.4)	(2,201)	291.9	**35.5**

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2018 RATE APPLICATION
SRRP INTERROGATORIES

SRRP Q108 Reference: Load Forecast

A) Please comment on the steps SaskPower takes to verify large-scale industrial and commercial customer load forecasts and any changes SaskPower makes to these self-reported customer forecasts to reduce variability.

B) Please discuss how the recent BHP decision will affect load forecasts in future years?

Response:

A) SaskPower has discussions with its major customers on a semi-annual basis to allow them to provide updates on any anticipated changes in their short- and long-term energy requirements. This includes expansions or speculative load.

Typically, large-scale industrial class loads are the most difficult to forecast due to the volatility in certain industries, notably the potash, oilfield, pipeline, and northern mining sectors.

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

Other large-scale industrial customer forecasts are compared with actuals to determine if adjustments are needed to firm or speculative load forecasts going forward.

B) We are engaging in ongoing discussions with the respective SaskPower account manager for BHP to facilitate an update to our forecast planned for early October. We will make changes to our forecast at that time based on those discussions.

SRRP Q109 Reference: Load Forecasts

A) Please provide the forecast and top three actual system winter and summer peaks for each of the five most recent actual years.

B) Please provide the generation capacity by fuel types used to meet the top actual system winter and summer peaks.

Response:

A)

	Winter				Summer			
	Interval Peak (MW)			Forecast (MW)	Interval Peak (MW)			Forecast (MW)
Year	1	2	3		1	2	3	
2012	3,227	3,224	3,224	3,502	3,000	2,978	2,948	3,134
2013	3,477	3,467	3,441	3,614	3,179	3,117	3,109	3,280
2014	3,488	3,472	3,467	3,602	3,093	3,081	3,071	3,236
2015	3,536	3,532	3,525	3,712	3,273	3,262	3,226	3,347
2016	3,648	3,645	3,626	3,809	3,224	3,210	3,207	3,482

*Note – The forecast peaks are "potential," meaning that average 30-year weather temperatures are achieved (cold weather is assumed in winter, and warm weather in summer) with no load disruptions. Interval peak refers to the average of all readings across an hourly interval, rather than the instantaneous maximum.

B)

Winter Peak Load (MW)		Generation by Fuel Type				
Year	Peak	Hydro	Coal	Gas	Wind & Other	Import
2012	3227	13.2%	47.0%	30.4%	6.5%	2.8%
2013	3477	17.5%	40.8%	38.4%	3.3%	0.0%
2014	3488	16.2%	36.2%	41.5%	4.0%	2.0%
2015	3536	16.4%	38.6%	36.2%	5.9%	2.9%
2016	3648	14.5%	43.8%	39.2%	2.5%	0.0%

Summer Peak Load (MW)		Generation by Fuel Type				
Year	Peak	Hydro	Coal	Gas	Wind & Other	Import
2012	3000	13.2%	47.0%	30.4%	6.5%	2.8%
2013	3179	17.5%	40.8%	38.4%	3.3%	0.0%
2014	3093	16.2%	36.2%	41.5%	4.0%	2.0%
2015	3273	16.4%	38.6%	36.2%	5.9%	2.9%
2016	3224	14.2%	40.2%	35.3%	2.8%	7.5%

SRRP Q110 Reference: Load Forecast

A) Please provide the load forecast unadjusted for forecast DSM savings or indicate the amount of DSM savings (GWh and MW) included in each customer class forecast.

B) If there are no forecast savings for any customer classes please explain why.

Response:

A) 2017/2018 DSM Savings by Class (GWh):

Residential	12.6
Commercial	14.3
Line Losses	2.9
Total	29.8

B) For all other customer classes, there are no official DSM programs in place for 2017/2018.

SRRP Q111 Reference: Demand Side Management

A) Please provide any updated studies or reports on DSM since the 2010 Conservation Potential Review.

B) Identify and explain any steps SaskPower has taken to increase its Demand Side Management offerings and results since the last rate application.

Response:

A) A Residential End Use Study was completed in 2015. The information collected is used to better understand consumers' end-use of electricity in an effort to identify savings opportunities, while also improving customer efficiency education, the forecasting of potential energy savings opportunities, and the overall accuracy for forecasting electricity growth needs and requirements.

A Commercial Lighting End Use Study was completed in 2016. The information collected in this study is used to better understand how lighting is currently used by SaskPower's business customers, informing savings opportunities for customer programming and improving the forecasting of potential energy savings.

A Customer Experience – Conservation Support Summary was completed in 2015. This research helps provide a comprehensive view of our 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.

Additionally in 2017, SaskPower initiated a new Conservation Potential Review (CPR). The CPR helps develop a comprehensive vision of the potential electricity savings and demand reductions achievable in Saskatchewan in a given timeframe. The study will provide an updated view of potential electricity savings and establish new long-term energy savings and demand reduction targets for energy efficiency in Saskatchewan. These new long-term targets will be used in SaskPower's integrated resource planning process. The CPR is scheduled to be complete by the end of 2017.

B) SaskPower strives to maintain a diversified portfolio of DSM programs across sectors to provide opportunities for all customers to participate. In recognizing the unique needs of our small and medium business customers, SaskPower introduced the Walk-Through Assessment Program in the latter part of 2016. Based on annual consumption and square-footage, qualifying customers get an in-person facility audit that helps customers understand their power usage and provides recommendations on measures that can help them save power and money on their bills. To-date, 22 customers have participated.

2018 RATE APPLICATION
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To complement the Walk-Through Assessment Program, a Commercial Energy Optimization Program (CEOP) was launched this July. The CEOP is designed to help SaskPower's large commercial customers identify, develop and implement energy efficiency projects.

Meanwhile, in addition to our energy efficiency and conservation programs SaskPower continues to dedicate resources to outreach and customer education. The Efficiency Partners Program launched in 2016 as a network of small and medium business organizations that work with SaskPower to help customers make energy efficiency choices. It includes a membership of 58 partners to date. The network features semi-annual workshops open to all program partners and provides insights on current and future program offerings.

In the residential sector, within the Retail Discount Program select smart home products were added in the fall of 2016 to complement the successful instant discounts on energy efficient lighting products. Over 1,100 smart home products have been incented, and include smart power bars, smart plugs, smart lighting controls and smart thermostats. Additionally, this provided a platform to begin the conversation with customers about savings opportunities throughout their home that go beyond just lighting.

A direct install, residential demand response pilot was launched in May 2017 to explore the load reduction capabilities of residential demand response in Saskatchewan. Demand response events occurred between May and September of 2017 on high temperature days in order to target residential air conditioning load.

In May of 2017, SaskPower also launched a residential and a commercial Online Energy Assessment Tool. Hosted on SaskPower.com, these tools provide customers with recommendations that will help them reduce their power consumption based on physical building and equipment information. Over 1,600 residential and commercial customers have accessed this tool.

As noted above, SaskPower is working to complete an updated CPR by the end of 2017 to provide updated energy and capacity savings potentials, as well as provide direction on the types of programming upon which SaskPower should focus. The CPR will also update savings potentials used in the integrated resource planning process to establish an optimal mix of resources, including Demand Side Management.

SRRP Q112 Reference: Demand Side Management

Please provide forecast costs, annual DSM savings and cost/benefit test metrics used by DSM program available and being developed.

Response:

The following are incremental savings targets for the 2017/18 fiscal year, including forecasted costs and cost/benefit test metrics.

	2017/18 (Forecast)				
	$s	GWh	MW	TRC (ratio)	UCT ($/kWh)
Residential Programs					
Retail Discount Program	$ 3,400,000	24.0	9.8	3.20	0.01
HVAC	$ 60,000	0.3	0.1	1.22	0.02
Commerical Programs					
Commercial Lighting Program	$ 1,600,000	10.0	1.3	1.64	0.02
Municipal Ice Rink Program	$ 120,000	0.4	0.1	0.12	0.04
Commercial HVAC	$ 100,000	0.3	0.0	0.24	0.04
Parking Lot Controller	$ 30,000	0.2	-	3.25	0.01
Refrigeration Program	$ 150,000	2.4	0.3	0.83	0.01
Compressed Air Program	$ 40,000	0.1	0.0	1.70	0.04
Commercial Optimization	$ 150,000	0.8	0.1	2.40	0.03
Industrial Programs					
Energy Optimization Program	$ 2,400,000	14.0	2.0	3.12	0.01
Portfolio Results - Weighted by Program Energy Savings (GWh)		**52.4**	**13.7**	**2.71**	**0.01**

Note:

- $s do not include salaries/benefits, office administration or projects.
- Forecasts are an estimate based on expected customer uptake and are subject to change.

Legend:

$s – Annual incremental budget dollars.

GWh – The energy savings attributed to the energy efficiency program.

MW – Peak reduction attributed to the energy efficiency program.

Total Resource Cost Test (TRC) – Measures total costs and benefits of implementing energy efficiency programs from the combined perspective of all utility customers (whether they are participants or not) and the utility itself. When a program/portfolio passes the TRC, it indicates that the energy efficient program(s) are cost effective overall for the utility and both participant and nonparticipant, and indicates total resource costs will decrease and energy costs for the average customer will fall.

Utility Cost Test (UCT) – Measures costs and benefits of implementing energy efficient programs from the perspective of the utility. UCT provides a comparison of how the energy efficient program compares with supply side investments. When the program/portfolio passes the UCT, it indicates that the total costs to save energy are less than the costs of the utility delivering the same power. When this happens, average bills will be reduced.

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SRRP Q113 Reference: Demand Response Program

Please comment on any changes that have occurred to the Demand Response program since the last rate application.

Response:

Changes that have occurred with DR1 are as follows:

- Contracts were renegotiated in September for the approaching winter peak season, and then renegotiated according to the fiscal or calendar year end. Accordingly, a 21-month contract was signed with both active customers to accommodate the change.

- There were two definite sub terms identified for these 21-month contracts. The first was for a nine-month term from January 1, 2017, to September 30, 2017, in order to establish a September anniversary date. During the nine- month contract, the number of events permitted under the contract was prorated to 11. The second sub term was established for the full-year period from October 1, 2017, to September 31, 2018. A full complement of 15 events is available in this second sub term.

- SaskPower also negotiated a 20% reduction in the compensation provided to the customers for being available to curtail load. The price was reduced from $70,000/MWyr to $56,000/MWyr. However, as incentive for SaskPower to continue to use DR as an emergency contingency, it was agree that if more than four of the available 15 events per year were called, the price would increase to the pre-reduction compensation of $70,000/MWyr. For the nine-month term, the number of events until an increase in compensation occurs was prorated to three.

All other aspects of the DR1 program remained the same as in 2016.

Other DR offerings remain exactly as in 2016.

SRRP Q114 Reference: Cost of Service Study

A) Please provide a timeline of events for SaskPower's external review of the cost of service study, starting with release of the Request for Proposal and ending with the current rate application. Please include in the timeline all opportunities for public participation and feedback.

B) Please identify any further steps SaskPower is anticipating as part of the external review of its cost of service study including the timing of SaskPower's anticipated response.

C) Please provide a weblink to where materials and supporting files used in the Elenchus study and public review can be publicly accessed.

Response:

A) 2017 Cost of Service Methodology Review Schedule of Events:

Item No.	Milestone	Completion Date
1	Issue of RFP	Dec 8, 2016
2	Selection of the technical consultant.	Jan 30, 2017
3	Technical consultant conducts a kick-off meeting with SaskPower and interested stakeholders to discuss issues and scope of review. Interested stakeholders had the opportunity to provide input into what they would like to see from the review.	Feb 8, 2017
4	Technical consultant conducts review of SaskPower's cost of service methodology, including surveying Canadian electric utilities on their cost of service methodologies.	Feb 28, 2017
5	Technical consultant presents preliminary update of review of SaskPower's cost of service methodology to SaskPower, the Saskatchewan Rate Review Panel and stakeholders. All interested stakeholders were encouraged to provide feedback and submit written questions/submissions to SaskPower & Elenchus.	Mar 15, 2017
6	Technical consultant prepares and files draft report with SaskPower.	Apr 30, 2017
7	Technical consultant presents draft report and its findings to stakeholders and the Saskatchewan Rate Review Panel. All interested stakeholders were encouraged to provide feedback and submit written questions/submissions to SaskPower & Elenchus.	May 15, 2017

8	Technical consultant and SaskPower provide written responses to all stakeholder questions/submissions.	May 30, 2017
9	Stakeholders prepare and file written submissions on the draft report.	Jun 15, 2017
10	Technical consultant prepares and files a final report which includes responses to all written stakeholder questions and submissions.	Jun 30, 2017
11	Technical consultant provides written responses to all stakeholder submissions that were submitted after the final report was issued.	Jul 5, 2017
12	SaskPower prepares a final response to the Saskatchewan Rate Review Panel regarding the technical consultant's report indicating proposed actions resulting from the review.	Sept. 19, 2017

B) SaskPower has recently completed its analysis of the core recommendations from the technical consultant's final report and has included them in this response. Please refer to the attached document titled with the subject, *SaskPower's Response to the Review of SaskPower's Cost Allocation and Rate Design Methodologies final report of June 30, 2017, Prepared by Elenchus Research Associates Inc.* for full details.

C) The weblink to the materials and supporting files used in the Elenchus study and public review can be found on SaskPower's website at the following address:

http://www.saskpower.com/accounts-and-services/power-rates/2017-cost-of-service-methodology-review/

SUBJECT: **SaskPower's Response to the *Review of SaskPower's Cost Allocation and Rate Design Methodologies* final report of June 30, 2017, Prepared by Elenchus Research Associates Inc.**

DATE: **September 19, 2017**

Purpose

The purpose of this communication is to summarize the recommendations in the final report prepared by Elenchus Research Associates of its 2017 review of SaskPower's cost of service and rate design methodologies, indicate which of the recommendations will be implemented, and communicate the approximate impact of those changes.

The project scope, Elenchus' recommendations and SaskPower's responses are summarized in Appendix A.

Background

SaskPower's current cost of service model was developed in 1985 and previously reviewed in 1998, 2002, 2008 and 2012. The model was updated in 1998, 2002, 2009 and 2014 based on the recommendations made from those reviews.

At the present time, the Saskatchewan government oversees utility cost of service and rate changes with the aid of the Saskatchewan Rate Review Panel (SRRP). The SRRP has mandated that SaskPower's cost of service methodology be reviewed every 5 years by an independent technical consultant, with input from interested stakeholders, to verify whether the current methodology is consistent with accepted electric power utility practices and is appropriate for SaskPower's system characteristics. The SRRP was an active stakeholder in this review, but will not submit a final report at the review's conclusion.

During the Request for Proposals stage, stakeholders were encouraged to offer feedback on the proposed scope of the review, as well as provide input into the evaluation process used to select the independent technical consultant. In January 2017, SaskPower engaged the services of Elenchus Research Associates, from Toronto, Ontario, to review its cost of service methodology. Elenchus promptly began reviewing SaskPower's methodologies and models and presented its preliminary findings and draft recommendations during two public meetings held in Regina on March 30 and May 15, 2017.

At each meeting, Elenchus presented its findings to date, outlined its opinions, made recommendations for enhancements, and showed the potential impacts of its recommendations on customers, where applicable. At both events, Elenchus responded to inquiries and/or concerns from interested stakeholders and invited them to submit written questions and submissions. These are included, along with Elenchus' responses, in the final report. Elenchus' services were made available to respond to any interrogatories from interested stakeholders at any time during the review process, either directly through their SaskPower account representative or via the 2017 Cost of Service Methodology Review webpage located on SaskPower's corporate website.

Various representatives from the SRRP, the cities of Saskatoon and Swift Current, the Canadian Association of Petroleum Producers (CAPP), the Saskatchewan Industrial Energy Consumers Association (SIECA), and members of the general public were in attendance or listening via conference call to the proceedings. All correspondence, including the audio recordings of the events, has been posted to SaskPower's website.

Elenchus' Recommendations

Elenchus filed its final report on June 30, 2017. It states the view that SaskPower's current cost allocation methodology is consistent with accepted rate-making principles and practices, as well as the methodologies commonly used by other electric utilities, and is consistent with, and reflective of, SaskPower's operational circumstances, with some recommendations for enhancements:

1) Implement the "**Average and Excess**" method to classify SaskPower's generating assets between energy and demand.

2) Implement the "**Minimum System**" method to classify distribution transformers and urban and rural distribution line costs between demand and customer.

3) Replace the existing Non-Coincident Peak (NCP) data used for allocation purposes with the **Class Maximum Diversified Demand (MDD)**.

SaskPower's Response

SaskPower has reviewed Elenchus' recommendations and has made the following comments:

1) **<u>Implement the "Average and Excess" method to classify SaskPower's generating assets between energy and demand.</u>**

   SaskPower currently uses the **Equivalent Peaker Method (EPM)** to classify its generation assets between energy and demand. The premises of this methodology are that (1) increases in peak demand require the addition of peaking capacity only; and (2) that utilities incur the costs of more expensive baseload units because of the additional energy loads they must serve (NARUC, 1992, pg.53). Therefore, peaking plants, such as a Simple Cycle Gas Turbine (SCGT) are classified 100% to demand under the EPM. The difference between the total cost for a new generation plant and the cost of a peaking plant is caused by the energy loads to be served and is therefore classified as energy related in COS.

   There are several emerging issues with this methodology:

   i. Standard costing data for conventional coal plants is no longer available, therefore historical, inflation-adjusted data must be used.

ii. Required coal retrofitting regulations required significant capital investments, impacting the results.
iii. Generation assets are no longer typically dispatched for their original purpose (e.g., gas units are no longer dispatched exclusively for peaking).

Elenchus believes that the resulting changes in the calculated demand-energy split under the EPM due to the above factors does not result in a reasonable reflection of cost drivers for SaskPower's generation assets and expenses.

The **Average and Excess Demand (AED) Method** classifies generation assets and expenses using factors that combine each class's average demands over the period with its non-coincident peak demands. The average component in this methodology is based on the ratio of each class's average demand to its peak demand. The excess demand is the difference between the class non-coincident peak and the average demand.

The methodology essentially mirrors a utility's system load factor --- a measure of the energy consumed compared to the energy that would have been consumed at its maximum rate established during the designated time period. A high load factor means power usage is relatively constant; a low load factor means that power usage is relatively inconsistent; with occasional high demands being set.

The rationale behind AED is that a utility's average annual demand is required to meet its energy requirements, and any demand in excess of that average is required to meet its peaking requirements. This is illustrated below:

SaskPower's 2015 Average Demand	= Total Energy Requirements / Annual # of hours = 23,775,308 MWH / 8760 Hours = 2,714 MW
SaskPower's 2015 Maximum Demand	= 3,465 MW
SaskPower's Average to Max Demand ratio	= 2,714 MW / 3,465 MW = **78.3%**

Based on 2015 actuals, using the AED methodology, 78.3% of SaskPower's generating assets and associated expenses would be classified to energy, and 21.7% to demand. This is a substantial shift from the current energy to demand split currently being used within SaskPower's COS under the EPM, as detailed in the table below:

Methodology	Energy (%)	Demand (%)	Total (%)
EPM	54.3%	45.7%	100.0%
AED	78.3%	21.7%	100.0%
Change (%)	**24.0%**	**(24.0%)**	**0.0%**

The customer class impacts of changing from the EPM to AED are detailed in the tables below (based on 2015 actuals):

Customer Class (2015Base)	Original - EPM		AED		Variance	
	Rev Req ($M)	R/RR	Rev Req ($M)	R/RR	Rev Req ($M)	R/RR
Residential	509.2	0.96	502.1	0.98	(7.1)	0.02
Farms	164.9	0.96	163.6	0.97	(1.3)	0.01
Commercial	420.9	1.03	420.4	1.03	(0.5)	0.00
Power	593.9	1.03	600.7	1.01	6.9	(0.02)
Oilfields	324.6	1.02	327.5	1.02	2.9	0.00
Streetlights	17.5	0.86	17.5	0.85	0.1	(0.01)
Reseller	96.8	0.93	95.8	0.94	(1.0)	0.01
Total	**2,127.7**	**1.00**	**2,127.7**	**1.00**	**0.0**	**1.00**

Note – Some columns may not sum to indicated totals due to rounding

A higher R/RR ratio indicates that those customer classes' revenue requirements have decreased under the proposed AED methodology, indicating that these customers would likely experience lower increases than they would have received under the EPM. Conversely, those customer classes with lower R/RR ratios would likely experience higher increases than they would have received under the existing EPM, as their revenue requirements have increased under the proposed AED methodology.

Conclusion:
SaskPower agrees with Elenchus' opinion that the current use of the Equivalent Peaker Method (EPM) is not providing a reasonable, consistent or accurate reflection of SaskPower's cost drivers as they relate to its generation assets and expenses and endorses the use the Average and Excess Demand (AED) Method. To illustrate, the table below shows the impact of the capitalization of the Boundary Dam Carbon Capture and Storage plant in 2014 on the demand/ energy classification ratios produced under the EPM:

	2013	2014	Variance
Demand Related	52.2%	42.5%	9.8%
Energy Related	47.8%	57.5%	9.8%
Total	**100.0%**	**100.0%**	**0.0%**

The addition of one generation asset in 2014 resulted in a nearly 10% change in the Demand/ Energy ratio. If SaskPower continues to use the EPM to calculate the Demand/Energy ratio, the same volatility can be expected every time a major generation asset is capitalized.

SaskPower believes the AED methodology is a superior alternative to the EPM method for the following reasons:

a) It reduces volatility in the demand to energy classification ratio due to additional capitalized generation assets by:
    i. Eliminating estimated cost factors that may no longer be relevant (or accurate) that can vastly affect the outcome; and,
    ii. Disregarding the type of generation technology utilized.
b) It accurately reflects the actual operational circumstances of the utility on a system-wide basis.
c) The impacts to stakeholders are reasonable and manageable.
d) It is relatively simple to understand and easily verified by stakeholders.

SaskPower will implement the AED methodology during the next scheduled rate application by utilizing a 3-year average of SaskPower's system load factor to classify generation assets and expenses. This results in the average value below:

	2013	2014	2015	Average
System Load Factor (2CP)	71.8%	74.2%	78.3%	74.8%

Based on these results, SaskPower will use an energy to demand classification ratio for generation costs of 75% energy and 25% demand during the next scheduled rate application.

2) <u>Implement the "Minimum System" method to classify distribution transformers and urban and rural distribution line costs between demand and customer.</u>

Distribution assets connect transmission assets to customers. Assets that are close to the transmission system tend to be classified in a manner similar to the transmission assets (i.e., demand). Distribution assets that are closer to the customer connections tend to be classified in a manner that is more reflective of other customer-related costs. For example, meter assets and costs are classified as 100% customer related, since they must be incurred regardless of how much power the customer consumes. SaskPower currently uses industry **survey data** to classify its distribution transformers and urban and rural distribution line costs between customer and demand.

The **Minimum System Method (MSM)** calculates the proportion of distribution asset costs that are customer related by taking the ratio of the costs of the smallest distribution assets being used by the utility (e.g., shortest poles) to the costs of all similar assets (e.g., all poles). This process is used to determine the customer components for transformers and line conductors. A common critique of this method is that the customer related portion of the distribution system is able to carry some electricity, therefore some demand related costs would be included in the customer component. To address this concern, an adjustment is made to take into consideration the demand that can be supplied through the minimum system. The adjustment is called the **Peak Load Carrying Capacity (PLCC)**.

The PLCC adjustment determines the theoretical capacity of the minimum system, that is, the capacity of the smallest distribution asset. The capacity of the smallest distribution asset is divided by the number of customers served by the distribution system and an average minimum system capacity per customer is calculated. This average minimum capacity is multiplied by the number of customers in each rate class and the corresponding amount is deducted from the peak demand for that rate class to derive the adjusted peak demand. The adjusted peak demand is used to allocate demand related distribution assets and costs.

At the conclusion of the 2012 Cost of Service Review it was recommended that SaskPower study the potential to implement the MSM for classifying its distribution transformers and lines. SaskPower did examine this option, but was reluctant to implement the methodology until the results could be verified by an external third party. Elenchus Research Associates reviewed and verified SaskPower's calculations of the MSM, the results of which are shown in the table below:

Methodology	Transformers		Lines	
	Customer	Demand	Customer	Demand
Survey Data	30.0%	70.0%	35.0%	65.0%
MSM	35.5%	64.5%	68.5%	31.5%
Change	**5.5%**	**(5.5%)**	**33.5%**	**(33.5%)**

The results show that the customer related portion of distribution lines under the MSM is significantly higher than what SaskPower is currently using. This is not uncommon for low-density utilities such as SaskPower, which serves approximately 3 customers per kilometer of line.

As a result, customer related portions are expected to be higher, as assets are being utilized by fewer customers and the distribution assets are required regardless of how much electricity customers consume.

The customer class impacts of changing from survey data to the MSM are detailed in the tables below (based on 2015 actuals):

Customer Class (2015Base)	Original – Surveys		Minimum System Method		Variance	
	Rev Req ($M)	R/RR	Rev Req ($M)	R/RR	Rev Req ($M)	R/RR
Residential	509.2	0.96	519.0	0.94	9.9	(0.02)
Farms	164.9	0.96	166.4	0.96	1.5	0.00
Commercial	420.9	1.03	415.5	1.04	(5.4)	0.01
Power	593.9	1.03	593.9	1.03	0.0	0.00
Oilfields	324.6	1.02	317.0	1.05	(7.5)	0.03
Streetlights	17.5	0.86	19.0	0.79	1.5	(0.07)
Reseller	96.8	0.93	96.8	0.93	0.0	0.00
Total	**2,127.7**	**1.00**	**2127.7**	**1.00**	**0.0**	**1.00**

Note – Some columns may not sum to indicated totals due to rounding

A higher R/RR ratio indicates that those customer classes' revenue requirements have decreased under the proposed MSM methodology, indicating that these customers would likely experience lower increases than they would have received under the existing methodology. Conversely, those customer classes with lower R/RR ratios would likely experience higher increases than they would have received under the existing methodology, as their revenue requirements have increased under the proposed MSM methodology.

Conclusion:
SaskPower is in agreement with Elenchus' recommendation and endorses the use of the MSM to classify distribution transformers and lateral lines. SaskPower believes the results of its MSM study more accurately reflects SaskPower's circumstances as it pertains to its distribution system and will implement the results during the next scheduled rate application.

For consistency, SaskPower will hold the MSM classification factors to the following levels and examine them again during the next Cost of Service review, scheduled for 2022.

Methodology	Transformers		Lines	
	Customer	Demand	Customer	Demand
MSM	35.0%	65.0%	70.0%	30.0%

3) **<u>Replace the existing Non-Coincident Peak (NCP) data used for allocation purposes with the Class Maximum Diversified Demand (MDD).</u>**

SaskPower currently uses **Non-Coincident Peak (NCP)** demands to allocate the demand related portion of classified costs for distribution transformers within its cost of service. All other demand related costs are allocated based on **Coincident Peak** demand. SaskPower defines these terms as follows:

i. **Coincident Peak Demand (CP)**
This is the demand of a customer or rate class at the time of a specified system peak hour(s). SaskPower's load research includes the coincident peak demands for winter, summer and an average of the two (2CP).

ii. **Non-Coincident Peak Demand (NCP)**
For an individual customer, this is the maximum demand during a specified period for that customer. For the rate class, it is the aggregate of each individual customer's maximum demand regardless of when it occurs.

SaskPower currently aggregates each customer's individual maximum demand, regardless of when it occurs, within a class to calculate their non-coincident peak load factors. Elenchus reviewed the calculations of SaskPower's NCP load factors and their use in the cost allocation study and determined that the **Class Maximum Diversified Demand (MDD)** should be used, as the load factors should be based on the maximum demand of the rate class, as defined below:

iii. Class Non-Coincident Peak Demand (Class NCP)

This is the maximum demand of a rate class, regardless of when it occurs, during a specified period. Also known as the **Class Maximum Diversified Demand (MDD)**, it represents the totalized demand of all customers residing within a particular class at the time of the class peak, not the aggregate of their individual maximum demands.

A comparison of SaskPower's NCP values currently used in its cost allocation study and the recommended MDD values are shown in the table below:

Customer Class	NCP			MDD		
	Load Factor %	MW	% of Total	Load Factor %	MW	% of Total
Residential	11.86%	3,009.7	40%	48.89%	730.4	20%
Farms	18.67%	780.2	10%	54.50%	267.3	7%
Commercial	33.45%	1,274.5	17%	63.25%	674.1	19%
Power	63.69%	1,689.0	22%	83.01%	1,295.9	36%
Oilfield	55.99%	564.5	7%	81.57%	387.5	11%
Streetlights	47.12%	14.6	0%	47.12%	14.6	0%
Resellers	58.79%	239.6	3%	58.79%	239.6	7%

Under SaskPower's current definition and usage of NCP, the demand values are excessive and do not reflect Elenchus' experience in other jurisdictions of how NCP load factors are calculated for customer classes. The existing methodology gives too much weighting to the Residential and Farm classes, as these are traditionally low load factor customers whose individual maximum demands, when aggregated, inadvertently allocate more costs to their class (see above table).

The customer class impacts of changing from NCP to MDD are detailed in the tables below (based on 2015 actuals):

Customer Class (2015Base)	Original – NCP		MDD		Variance	
	Rev Req ($M)	R/RR	Rev Req ($M)	R/RR	Rev Req ($M)	R/RR
Residential	509.2	0.96	502.6	0.97	(6.6)	0.01
Farms	164.9	0.96	164.4	0.97	(0.4)	0.01
Commercial	420.9	1.03	424.4	1.02	3.5	(0.01)
Power	593.9	1.03	593.9	1.03	0.0	0.00
Oilfields	324.6	1.02	327.9	1.01	3.4	(0.01)
Streetlights	17.5	0.86	17.7	0.85	0.2	(0.01)
Reseller	96.8	0.93	96.8	0.93	0.0	0.00
Total	**2,127.7**	**1.00**	**2127.7**	**1.00**	**0.0**	**1.00**

The Power and Reseller classes are unaffected by this change, as the MDD is used only to allocate distribution transformers costs which, as transmission customers, neither class would incur at a material level. Therefore, even though their adjusted weightings increase under the MDD, there is no corresponding shift in their revenue requirement.

A higher R/RR ratio indicates that those customer classes' revenue requirements have decreased under the proposed MDD methodology, indicating that these customers would likely experience lower increases than they would have received under the existing methodology. Conversely, those customer classes with lower R/RR ratios would likely experience higher increases than they would have received under the existing methodology, as their revenue requirements have increased under the proposed MDD methodology.

Conclusion:
SaskPower agrees with Elenchus' recommendation and endorses the use of the MDD (Class NCP) methodology to allocate the demand classified portion of distribution transformer costs. SaskPower will implement this change during the next scheduled rate application.

Summary of Impacts

It is important to note that the COS methodology is a zero-sum process, resulting in winners and losers whenever the allocation principles change. The cumulative effect of Elenchus' final recommendations appears in the table below (based on 2015 Actuals):

Customer Class	Revenue Requirement (Existing) ($M)	R/RR Ratio (Existing)	Revenue Requirement (Revised) ($M)	R/RR Ratio (Revised)	Revenue Requirement Change ($M)	R/RR Ratio Change
Residential	509.2	0.96	505.4	0.97	(3.8)	0.01
Farm	164.9	0.96	164.7	0.97	(0.2)	0.01
Commercial	420.9	1.03	418.6	1.03	(2.3)	0.00
Power	593.9	1.03	600.7	1.01	6.9	(0.02)
Oilfields	324.6	1.02	323.3	1.03	(1.2)	0.01
Streetlights	17.5	0.86	19.2	0.78	1.7	(0.08)
Reseller	96.8	0.93	95.8	0.94	(1.0)	0.01
Total	**2127.7**	**1.00**	**2127.7**	**1.00**	**0.0**	**0.00**

The implication of the higher R/RR ratios for the Residential, Farm, Oilfield and Reseller classes is that they will likely experience lower increases than they would have under the original methodology. The implication of the lower R/RR ratio for the Power and Streetlight classes is that they will likely experience higher increases than they would have under the original methodology.

A breakdown of each methodology's impact to the revenue requirement by customer class is summarized in the table below:

Customer Class (2015Base)	Original	AED	MDD	MSM	Revised	Total Variance
	Rev Req ($M)	Rev. Impact	Rev. Impact	Rev. Impact	Rev Req ($M)	Rev Req ($M)
Residential	509.2	(7.1)	(6.6)	9.9	505.4	(3.8)
Farms	164.9	(1.3)	(0.4)	1.5	164.7	(0.2)
Commercial	420.9	(0.5)	3.5	(5.4)	418.6	(2.3)
Power	593.9	6.9	0.0	0.0	600.7	6.9
Oilfields	324.6	2.9	3.4	(7.5)	323.3	(1.2)
Streetlights	17.5	0.1	0.2	1.5	19.2	1.7
Reseller	96.8	(1.0)	0.0	0.0	95.8	(1.0)
Total	**2,127.7**	**0.0**	**0.0**	**0.0**	**2,127.7**	**0.0**

A breakdown of each methodology's impact to the Revenue to Revenue Requirement ratios (R/RR) by customer class is summarized in the table below:

Customer Class (2015Base)	Original	AED	MDD	MSM	Total Revised
	R/RR	R/RR	R/RR	R/RR	R/RR
Residential	0.96	0.98	0.97	0.94	0.97
Farms	0.96	0.97	0.97	0.96	0.97
Commercial	1.03	1.03	1.02	1.04	1.03
Power	1.03	1.01	1.03	1.03	1.01
Oilfields	1.02	1.02	1.01	1.05	1.03
Streetlights	0.86	0.85	0.85	0.79	0.78
Reseller	0.93	0.94	0.93	0.96	0.94
Total	**1.00**	**1.00**	**1.00**	**1.00**	**1.00**

Any changes in R/RR ratios resulting from the methodology review need not be completely rebalanced in the next rate application. Future rate increases will weigh the desire to rebalance rates against the need to limit the maximum rate increases to any one class of customers to avoid rate shock.

Supplemental Items

As a result of issues brought forward by stakeholders, or via the natural course of the review, subsequent items for SaskPower to potentially examine were suggested by Elenchus. Although the issues raised fell outside of the contracted scope of this review, SaskPower would like to thank Elenchus Research Associates for providing insights on these issues:

1) Evaluate the potential to decrease the existing 230kV rate for Power class customers.

2) Assess the potential to increase the Time-of-Use (TOU) energy differential from its current level of 1 cent/kwh.

3) Using forecasted versus historic capacity and energy payments for the classification of Power Purchase Agreement expenses between energy and demand.

SaskPower's Response

SaskPower continues to examine these items and will provide a separate response to stakeholders when completed.

Appendix A – 2017 Cost of Service Review Requirements, Recommendations and Potential Impacts

Requirement	**Elenchus' Recommendation**	**SaskPower's Position**	**Impact Description**
Review current Equivalent Peaker Method	Change to Average and Excess methodology	Agree – will implement at next scheduled rate application	Will shift more generation asset costs to energy, impacts high load factor customers
Review Minimum System Method	Implement Minimum System Method	Agree – will implement at next scheduled rate application	Will shift more distribution costs to the basic monthly charge; improves SaskPower's fixed cost recovery, negatively impacts low energy users and streetlights
Examine current Winter & Summer allocation (2CP) factors	No changes recommended	NA	None
Identify main classification and allocation methodologies (surveys)	SaskPower is in compliance with industry standards	NA	None
Examine current functionalization of overhead costs	No changes recommended	NA	None
Examine current coincident and non-coincident peak allocators (load research program)	Replace existing NCP demand with MDD for allocation purposes	Agree – will implement at next scheduled rate application	Affects allocation of distribution transformer costs only; Farms and Residentials slightly gain, Commercial and Oilfields slightly lose ground
Review current existing rate design methodology	No changes recommended	NA	None
Compare existing methodologies with other jurisdictions (surveys)	SaskPower is in compliance with industry standards	NA	None
Examine proposed customer class consolidation strategy (rate simplification)	No changes recommended	NA	None
Examine current treatment of Demand Response program in COS	No changes recommended	NA	None

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SRRP Q115 Reference: Cost of Service Study

Please provide a table that individually shows the impact of implementing each of Elenchus' proposed method changes on each class revenue requirement and revenue to revenue requirement ratio.

Response:

2015 Base	Original		Average & Excess Demand		Maximum Diversified Demand		Minimum System Method		Cummulative Impact	
Class of Service	**Allocated Rev. Reqt. ($)**	**Revenue to Rev. Reqt. Ratio**	**Allocated Rev. Reqt. ($)**	**Revenue to Rev. Reqt. Ratio**	**Allocated Rev. Reqt. ($)**	**Revenue to Rev. Reqt. Ratio**	**Allocated Rev. Reqt. ($)**	**Revenue to Rev. Reqt. Ratio**	**Allocated Rev. Reqt. ($)**	**Revenue to Rev. Reqt. Ratio**
Residential	509,170,656	0.96	502,104,445	0.98	502,551,446	0.97	519,046,040	0.94	505,360,620	0.97
Farms	164,871,905	0.96	163,588,295	0.97	164,432,301	0.97	166,419,457	0.96	164,696,243	0.97
Commercial	420,907,213	1.03	420,441,098	1.03	424,435,677	1.02	415,519,534	1.04	418,581,883	1.03
Power	593,892,909	1.03	600,749,614	1.01	593,892,909	1.03	593,892,909	1.03	600,749,614	1.01
Oilfields	324,560,522	1.02	327,504,913	1.02	327,918,979	1.01	317,028,602	1.05	323,331,450	1.03
Streetlights	17,494,801	0.86	17,545,634	0.85	17,666,694	0.85	18,991,463	0.79	19,214,189	0.78
Reseller	96,845,105	0.93	95,809,112	0.94	96,845,105	0.93	96,845,105	0.93	95,809,112	0.94
Total	**2,127,743,111**	**1.00**	**2,127,743,111**	**1.00**	**2,127,743,111**	**1.00**	**2,127,743,111**	**1.00**	**2,127,743,111**	**1.00**

SRRP Q116 Reference: Cost of Service Study

A) Please confirm that Elenchus recommended SaskPower retain the existing methodology for calculating demand-related allocation (2 CP)?

B) Did Elenchus review how many Coincident Peaks and/or how many years data go into each CP value for the utilities surveyed? If yes, please provide a summary of findings by utility.

C) Please provide the analysis done of the last 10 years and last 3 years of system data (2006 – 2015) showing the ratio of summer to winter maximum demand is 91%.

D) Please provide the Coincident Peaks and resulting CP allocator percentages as reviewed in the sensitivity study conducted by SaskPower staff for a) the highest winter and summer peak, b) based on the 5 year average of the 3 highest hours of winter and summer peaks, and c) based on the 5 year average of the winter and summer maximum peaks (pg. 52 of MFR-24).

Response:

A. SaskPower confirms that Elenchus recommended the continued use of 2CP methodology for calculating demand-related allocation. Please see section 6.5.4 Winter/Summer Allocation (2 CP) of Elenchus's final report on the 2017 Cost of Service Methodology Review for more details, which can be found on SaskPower's corporate website at the following location:

http://www.saskpower.com/wp-content/uploads/Final_Elenchus_report.pdf

B. Elenchus did examine how many Coincident Peaks go into each CP value for the utilities surveyed. The results of their findings are as follows:

Utility	Method used to allocate generation demand costs	Method used to allocate transmission demand costs	Method used to allocate sub-transmission demand costs	Method used to allocate distribution stations demand costs
BC Hydro	4CP	4CP	4CP	Class NCP
ATCO	NA	Allocated POD Capacity Demand and AEIS CP Summary Demand	An EDLA study (Energy, Demand Loss Analysis) is used to allocate costs to rate classes (Annual POD NCP Demand)	An EDLA study (Energy, Demand Loss Analysis) is used to allocate costs to rate classes (Annual POD NCP Demand)
Manitoba Hydro	1 CP on top 50 winter hours	1 CP on top 50 winter hours	1 CP on top 50 winter hours	Class NCP

Hydro One	NA	Highest 12 CP or 85% 12 NCP during peak hours for Networks	12 CP	CP and NCP
Hydro Quebec	Highest 300 hours	1CP	1CP	1NCP
NL Power	1 CP	1 CP	1 CP	NCP
NB Power	3 CP	1 CP	1 CP	12 NCP
NS Power	3 winter CP	3 winter CP	3 winter CP	1 NCP
Georgia Power	12 CP	Bulk power transmission: Step-up substations - 12 MCP 115 kV to 500 kV lines and subs - 80% 4-CP & 20% 12-CP (4-CP is June - Sept) Sub-transmission Levels (69 kV to 46 kV) - 4-CP Primary and Secondary - NCP (Non-coincident peak)	4 CP	69 kV to 46 kV - 4-CP (4-CP is June - Sept) Primary and Secondary - NCP
Consumers Energy	4 Coincident Peak 75% Demand/25% Energy	12 CP	CP	CP

The above table can be found in the *Appendix B: Utilities Surveyed* section of Elenchus's final report on the 2017 Cost of Service Methodology Review.

Elenchus also examined the number of years that the utilities surveyed included in their CP values. Elenchus indicated that based on the survey of utilities, the number of years of historical data used included 1, 3, 5, 8, 10, and 22 years, however Elenchus did not indicate which utility used how many years of data. Elenchus did support SaskPower's continued use of a minimum of 3 years and a maximum of 5 years of historical data in its CP calculation. Please see section *6.5.5 Coincident and Non-Coincident Peak Allocators* section of Elenchus's final report of the 2017 Cost of Service Methodology Review for more details.

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C. The calculation of SaskPower's summer to winter maximum for 10 and 3 years of system data are as follows:

SaskPower Winter/Summer Peak Comparison - 10 Years			
	Winter Peak (MW)	Summer Peak (MW)	Summer/Winter Ratio
2006	2,895	2,671	92.3%
2007	2,934	2,827	96.4%
2008	3,156	2,764	87.6%
2009	3,156	2,709	85.8%
2010	3,085	2,765	89.6%
2011	3,133	2,988	95.4%
2012	3,227	3,012	93.3%
2013	3,477	3,179	91.4%
2014	3,488	3,093	88.7%
2015	3,536	3,273	92.6%
Total	32,087	29,281	**91.3%**

SaskPower Winter/Summer Peak Comparison - 3 Years			
	Winter Peak (MW)	Summer Peak (MW)	Summer/Winter Ratio
2013	3,477	3,179	91.4%
2014	3,488	3,093	88.7%
2015	3,536	3,273	92.6%
Total	10,501	9,545	**90.9%**

D. 2015 Coincident Peaks per customer class are as follows:

SaskPower 2015 Coincident Peak Demand			
Customer class	**Single year, winter and summer peaks (KW)**	**5 year average, 3 highest hours winter and summer peaks (KW)**	**5 year average, winter and summer peaks (KW)**
Residential	666,650	659,984	644,891
Farms	224,233	213,724	219,421
Commercial	558,762	563,699	564,366
Power	1,123,943	1,138,316	1,173,349
Oilfields	333,126	324,395	332,267
Streetlights	7,306	7,127	7,252
Reseller	213,321	204,047	200,688
Total	3,127,342	3,111,291	3,142,234

2015 Coincident Peak load factor allocator percentages per customer class are as follows:

SaskPower 2015 Coincident Peak Load Factor Percentages			
Customer class	**Single year, winter and summer peaks**	**5 year average, 3 highest hours winter and summer peaks**	**5 year average, winter and summer peaks**
Residential	53.6%	54.1%	55.4%
Farms	65.0%	68.2%	66.4%
Commercial	76.3%	75.6%	75.5%
Power	95.7%	94.5%	91.7%
Oilfields	94.9%	97.4%	95.1%
Streetlights	94.2%	96.6%	95.0%
Reseller	66.0%	69.0%	70.2%
Total	78.9%	79.3%	78.5%

SRRP Q117 Reference: Proposed Rates

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

B) Please confirm whether the revenue requirement breakdown in part (a) is measured using SaskPower's current cost of service method; or a cost of service method that implements the recommendations from the Elenchus review of SaskPower's cost of service methods.

Response:

A. The revenues and revenue requirement breakdowns by class in dollars for the rate increase found on page 4 of the Application are as follows:

	Year 2018 Revenue at Existing Rates			Year 2018 Revenue at Adjusted Rates		
Class of Service	**Allocated Rev. Reqt. ($)**	**Revenue ($)**	**Revenue to Rev. Reqt. Ratio**	**Allocated Rev. Reqt. ($)**	**Revenue ($)**	**Revenue to Rev. Reqt. Ratio**
Urban Residential	$ 447,745,118	$ 439,662,491	0.98	$ 470,582,930	$ 461,994,392	0.98
Rural Residential	$ 138,775,400	$ 128,448,694	0.93	$ 146,636,925	$ 134,973,153	0.92
Total Residential	**$ 586,520,518**	**$ 568,111,185**	**0.97**	**$ 617,219,855**	**$ 596,967,546**	**0.97**
Farms	**$ 182,908,567**	**$ 177,275,836**	**0.97**	**$ 192,407,948**	**$ 186,280,436**	**0.97**
Urban Commercial	$ 346,051,480	$ 354,421,923	1.02	$ 363,985,640	$ 372,424,531	1.02
Rural Commercial	$ 135,556,387	$ 136,455,340	1.01	$ 143,182,032	$ 143,386,491	1.00
Total Commercial	**$ 481,607,868**	**$ 490,877,264**	**1.02**	**$ 507,167,672**	**$ 515,811,023**	**1.02**
Power - Published Rates	$ 502,363,500	$ 513,735,378	1.02	$ 524,950,522	$ 539,830,198	1.03
Power - Contract Rates	$ 191,612,804	$ 190,716,113	1.00	$ 200,311,490	$ 198,481,062	0.99
Total Power	**$ 693,976,304**	**$ 704,451,491**	**1.02**	**$ 725,262,011**	**$ 738,311,260**	**1.02**
Oilfields	$ 347,545,158	$ 356,900,701	1.03	$ 365,527,901	$ 375,029,217	1.03
Streetlights	$ 19,906,763	$ 17,007,014	0.85	$ 21,141,536	$ 17,870,873	0.85
Reseller	$ 106,036,538	$ 103,878,226	0.98	$ 110,698,077	$ 109,154,646	0.99
Total	**$ 2,418,501,716**	**$ 2,418,501,716**	**1.00**	**$ 2,539,425,000**	**$ 2,539,425,000**	**1.00**

B. The revenue requirement breakdown in part (a) was produced using SaskPower's current cost of service methodology. No recommendations resulting from the 2017 Cost of Service Methodology Review conducted by Elenchus have been implemented in the results.

SRRP Q118 Reference: Proposed Rates

A) Please elaborate on the statement on page 47 of the application that SaskPower has delayed plans to rebalance rates and implement a rate simplification strategy to a future rate application. Can SaskPower provide details on when it anticipates filing a rate application that includes rate simplification and rate rebalancing?

B) Please indicate when SaskPower last adjusted rates that included a degree of rate rebalancing.

Response:

A. SaskPower has delayed implementing the recommendations that came out of the recently completed 2017 Cost of Service Methodology Review in order to fully evaluate the impacts to customers. Rebalancing the rates for this application under the existing methodology may result in customers experiencing even larger rebalancing impacts in subsequent rate applications than what would have otherwise occurred once the recommendations are fully implemented.

Unless directed otherwise, it is SaskPower's intention to rebalance rates and undertake rate simplification at the time of the next rate application. This will allow for sufficient time to evaluate the impacts from implementing the recommendations and effectively manage the outcomes.

B. SaskPower last rebalanced its rates as part of the 2015 Rate Application.

SRRP Q119 Reference: Proposed Rates

A) Please provide an explanation for why contract rates are only subject to a 4.1% 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.
B) Please confirm the number of customer in the power contract class.
C) Please indicate whether the contracts have expiration dates and if so, does SaskPower intend to renew the existing contracts or convert contract customers to the general tariff rate?

Response:

A) The Contract class is subject to an average rate increase of 4.1% and has a R/RR ratio of less than 1.00 due to an underperforming contract in that class.

B) The Contract class consists of two customers spread over 14 metered sites.

C) All contracts within the Contract class will expire by December 31, 2019.

The decision to convert existing Contract customers to published rates will be dependent upon negotiations with customers.

2018 RATE APPLICATION
SRRP INTERROGATORIES

SRRP Q120 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:

SaskPower confirms that, outside of the Power – Contract class, SaskPower is proposing to increase all elements of all rates by 5.1%.

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 0.573 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
Powering the future®

2018 RATE APPLICATION
SRRP INTERROGATORIES

SRRP Q121 Reference: Proposed Rates
Please provide a summary of municipal surcharges applied by community and confirm if SaskPower collects these amounts and remits them to the municipality.

Response:

Cities can request a municipal surcharge of up to 10%, while towns and villages can request a maximum municipal surcharge of 5%. The municipal surcharge is calculated as a percentage of the customer's total electrical charges, before taxes. In 2016/17, SaskPower collected and remitted $66.6 million to 397 municipalities (please see the attached summary of municipal surcharges collected and remitted to the municipalities).

SaskPower
2016/17 Municipal Surcharges collected and remitted to municipalities

Town	Total
ABBEY	8,021.13
ABERDEEN	31,899.74
ABERNETHY	9,578.51
ALAMEDA	17,465.61
ALBERTVILLE	5,454.18
ALIDA	12,877.15
ALLAN	27,578.54
ALVENA	3,932.86
ARBORFIELD	17,363.88
ARCHERWILL	13,315.25
ARCOLA	38,202.54
ARRAN	2,478.03
ASQUITH	23,244.54
ASSINIBOIA	137,775.78
AVONLEA	37,140.30
AYLSHAM	5,120.51
B SAY TAH	13,163.27
BALCARRES	34,237.56
BALGONIE	65,221.46
BANGOR	1,889.71
BATTLEFORD	181,070.33
BEATTY	2,447.94
BEAUVAL	43,184.41
BEECHY	17,326.42
BENGOUGH	22,311.01
BETHUNE	20,319.14
BIENFAIT	33,525.64
BIG RIVER	43,272.10
BIGGAR	250,263.24
BIRCH HILLS	45,669.22
BLADWORTH	2,960.09
BLAINE LAKE	29,001.18
BORDEN	13,619.60
BRADWELL	7,896.56
BREDENBURY	17,670.60
BRIERCREST	7,924.79
BROADVIEW	34,975.05
BROCK	7,702.66
BRODERICK	4,107.62
BROWNLEE	3,184.02
BRUNO	25,487.76
BUCHANAN	10,896.80
BUFFALO NARROWS	85,274.99
BURSTALL	15,976.77
CABRI	28,069.94
CADILLAC	5,955.38
CALDER	6,649.69
CANORA	108,884.14
CANWOOD	20,473.85
CARIEVALE	13,940.72
CARLYLE	95,753.28
CARMICHAEL	2,591.61
CARNDUFF	67,313.03
CARROT RIVER	58,522.18
CENTRAL BUTTE	33,412.73
CEYLON	9,402.91
CHAMBERLAIN	8,404.72
CHAPLIN	14,362.48
CHITEK LAKE	17,259.34
CHOICELAND	21,768.83
CHRISTOPHER LAKE	17,083.56
CHURCHBRIDGE	40,876.03
CLAVET	17,550.69
CLIMAX	10,130.49
COCHIN	23,790.31
CODERRE	2,099.55
CODETTE	8,417.03
COLEVILLE	18,623.14
COLONSAY	22,583.96
CONQUEST	7,778.15
CORONACH	41,680.05
CRAIK	28,440.81
CREELMAN	8,149.75
CUDWORTH	33,155.25
CUPAR	28,655.99
CUT KNIFE	34,455.48
DAFOE	1,118.24
DALMENY	59,599.67
DAVIDSON	69,700.23
DEBDEN	19,649.43
DELISLE	49,601.13
DENHOLM	4,496.28
DENZIL	7,525.11
DINSMORE	18,851.11
DISLEY	2,313.60
DODSLAND	13,103.41
DRAKE	19,771.77
DUBUC	3,778.82
DUCK LAKE	40,205.54
DUFF	1,558.58
DUNDURN	23,528.61
DUVAL	4,451.67
DYSART	9,391.38
EARL GREY	10,472.86
EASTEND	34,543.48
EATONIA	27,759.60
EBENEZER	7,274.64
EDAM	31,131.19
EDENWOLD	9,257.62
ELBOW	22,431.36
ELFROS	5,336.15
ELROSE	28,688.65
ENDEAVOUR	6,294.87
ENGLEFELD	26,894.52
ESTERHAZY	144,124.11
ESTON	60,912.06
EYEBROW	9,385.26
FAIRLIGHT	2,895.59
FENWOOD	1,934.68
FILLMORE	20,231.77
FLAXCOMBE	5,295.06
FLEMING	4,146.01
FOAM LAKE	88,814.57
FORGET	2,695.17
FORT QU'APPELLE	130,635.98
FOX VALLEY	14,358.99
FRANCIS	7,569.71
FROBISHER	7,881.98
FRONTIER	22,196.65
GAINSBOROUGH	15,158.98
GLASLYN	45,854.88
GLEN EWEN	7,107.73
GLENAVON	10,865.93
GLENSIDE	2,324.67
GOLDEN PRAIRIE	2,659.20
GOODEVE	2,500.51
GOODSOIL	17,415.78
GOVAN	10,736.54
GRAND COULEE	17,588.07
GRANDVIEW BEACH	5,067.12
GRAVELBOURG	71,162.57
GRAYSON	13,338.62
GREEN LAKE	26,344.70
GRENFELL	54,461.41
GULL LAKE	54,302.96
HAFFORD	19,861.25
HAGUE	37,305.61
HANLEY	24,295.13
HARRIS	10,092.23
HAWARDEN	2,963.37
HAZENMORE	3,461.58
HAZLET	6,872.75
HEPBURN	24,468.14
HERBERT	37,598.45
HEWARD	2,285.97
HODGEVILLE	12,107.57
HOLDFAST	9,154.20
HUBBARD	2,083.23
HUDSON BAY	298,340.44
HYAS	4,907.53
IMPERIAL	25,000.40
INDIAN HEAD	94,931.79
INVERMAY	12,604.07
ISLE A LA CROSSE	73,916.16
ITUNA	35,826.90
JANSEN	6,408.35
KAMSACK	103,671.63
KATEPWA BEACH	41,657.83
KELLIHER	14,886.69
KELVINGTON	48,461.18
KENASTON	19,468.21
KENDAL	3,488.62
KENNEDY	11,090.75
KENOSEE LAKE	17,300.65
KERROBERT	59,404.30
KINCAID	9,924.92
KINDERSLEY	332,559.61
KINISTINO	33,389.16
KINLEY	2,505.46
KIPLING	60,593.80
KISBEY	10,152.26
KRYDOR	1,378.75
KYLE	28,234.00
LA LOCHE	126,936.30
LA RONGE	186,667.15
LAFLECHE	23,115.13
LAIRD	11,533.73
LAKE ALMA	2,538.37
LAKE LENORE	14,030.00
LAMPMAN	44,856.76
LANCER	3,283.57
LANDIS	10,322.93
LANG	8,338.50
LANGENBURG	66,832.35
LANGHAM	53,848.87
LANIGAN	69,364.25
LASHBURN	42,914.34
LEADER	52,458.22
LEASK	22,214.95
LEBRET	9,276.05
LEMBERG	18,177.88
LEOVILLE	18,241.93
LEROY	24,847.35
LESTOCK	7,904.84
LIBERTY	5,027.11
LIMERICK	7,603.14
LINTLAW	8,419.45
LIPTON	15,012.87
LOON LAKE	16,734.55
LOREBURN	7,506.60
LOVE	3,310.18
LUCKY LAKE	21,046.12
LUMSDEN	79,863.11
LUSELAND	33,919.80

Town	Total
MACKLIN	81,013.50
MACNUTT	4,337.94
MACRORIE	4,799.48
MAIDSTONE	67,243.29
MANITOU BEACH	34,918.59
MANKOTA	16,717.21
MANOR	14,427.67
MAPLE CREEK	130,887.18
MARCELIN	7,919.69
MARENGO	13,311.68
MARGO	4,938.47
MARKINCH	3,351.95
MARSDEN	14,439.48
MARSHALL	19,308.83
MARYFIELD	21,050.18
MAYMONT	8,317.43
MCTAGGART	3,744.65
MEACHAM	5,233.39
MEATH PARK	8,984.60
MEDSTEAD	9,179.46
MENDHAM	1,428.87
MEOTA	18,955.24
MERVIN	8,169.43
MIDALE	30,780.57
MIDDLE LAKE	11,742.35
MILDEN	9,465.43
MILESTONE	29,154.27
MINTON	4,139.15
MISTATIM	3,903.19
MONTMARTRE	28,389.05
MOOSOMIN	175,879.04
MORSE	14,428.90
MOSSBANK	20,502.51
MUENSTER	17,475.10
NAICAM	36,865.50
NEILBURG	24,469.37
NETHERHILL	1,104.48
NEUDORF	12,330.09
NEVILLE	3,424.00
NIPAWIN	234,393.10
NOKOMIS	20,989.05
NORQUAY	25,572.19
NORTH PORTAL	11,840.60
ODESSA	10,367.15
OGEMA	21,406.67
OSAGE	1,711.98
OSLER	41,891.95
OUTLOOK	115,663.81
OXBOW	75,983.29
PADDOCKWOOD	7,401.06
PANGMAN	12,450.19
PARADISE HILL	27,823.85
PARKSIDE	5,254.22
PAYNTON	6,751.07
PELLY	14,400.19

Town	Total
PENNANT	5,685.57
PERDUE	17,989.33
PIERCELAND	25,365.22
PILGER	4,327.01
PILOT BUTTE	88,107.15
PINEHOUSE	45,476.84
PLENTY	9,741.00
PLUNKETT	3,689.83
PONTEIX	29,031.06
PORCUPINE PLAIN	43,103.81
PREECEVILLE	58,156.24
PRELATE	6,437.19
PRUDHOMME	7,250.39
PUNNICHY	12,412.17
QU'APPELLE	27,882.74
QUILL LAKE	20,957.37
QUINTON	3,659.52
RADISSON	23,486.72
RADVILLE	46,358.82
RAMA	4,796.32
RAYMORE	38,687.86
REDVERS	64,139.09
REGINA BEACH	63,333.15
RHEIN	7,267.53
RICHARD	819.94
RICHMOUND	7,761.40
RIDGEDALE	3,539.33
RIVERHURST	8,683.67
ROCANVILLE	50,951.25
ROCHE PERCEE	4,533.23
ROCKGLEN	27,238.26
ROSE VALLEY	17,904.71
ROSETOWN	158,364.50
ROSTHERN	82,530.73
ROULEAU	22,071.77
RUDDELL	1,644.34
RUSH LAKE	2,837.01
SALTCOATS	22,214.90
SANDY BAY	45,557.83
SCEPTRE	6,051.32
SCOTT	4,409.82
SEDLEY	14,140.82
SEMANS	11,421.61
SENLAC	3,026.11
SHAMROCK	1,557.26
SHAUNAVON	109,576.52
SHEHO	7,463.53
SHELL LAKE	13,616.56
SHELLBROOK	83,383.55
SIMPSON	8,138.20
SINTALUTA	5,825.58
SMEATON	9,967.37
SMILEY	3,334.14
SOUTH LAKE	8,403.07
SOUTH MAKWA	4,225.48

Town	Total
SOUTHEY	39,353.86
SPALDING	11,880.37
SPEERS	3,253.18
SPIRITWOOD	58,274.56
SPRINGSIDE	19,447.13
SPY HILL	10,936.45
ST BRIEUX	110,189.83
ST LOUIS	20,365.05
ST WALBURG	38,391.54
STAR CITY	16,854.99
STENEN	4,969.05
STEWART VALLEY	5,341.76
STOCKHOLM	15,621.20
STORTHOAKS	4,983.49
STOUGHTON	46,311.49
STRASBOURG	40,903.63
STRONGFIELD	2,372.52
STURGIS	28,764.56
TANTALLON	5,426.83
TESSIER	1,274.26
THEODORE	18,717.15
TISDALE	198,259.34
TOBIN LAKE	14,071.86
TOGO	6,452.57
TOMPKINS	9,905.71
TORQUAY	11,803.20
TRAMPING LAKE	2,961.26
TUGASKE	6,210.48
TURTLEFORD	35,337.89
UNITY	123,073.07
VAL MARIE	9,116.17
VALPARAISO	866.73
VANGUARD	11,938.30
VIBANK	17,075.42
VISCOUNT	14,310.08
VONDA	26,892.51
WADENA	75,126.79
WAKAW	47,475.40
WALDECK	9,753.65
WALDHEIM	43,232.02
WALDRON	1,276.84
WAPELLA	15,138.24
WASECA	6,667.64
WATROUS	109,499.54
WATSON	42,007.54
WAWOTA	31,627.18
WEBB	3,166.63
WEEKS	4,108.51
WEIRDALE	2,844.71
WELDON	6,018.82
WELWYN	5,857.96
WHITEFOX	16,922.20
WHITEWOOD	52,895.05
WILCOX	22,290.44
WILKIE	75,604.61

Town	Total
WILLOWBUNCH	18,199.41
WINDTHORST	12,256.55
WISETON	4,940.21
WOLSELEY	45,452.32
WOOD MOUNTAIN	1,927.78
WYNYARD	131,172.02
YARBO	3,556.51
YELLOW GRASS	18,688.46
YOUNG	12,089.93
ZEALANDIA	6,602.36
ZELMA	1,498.41
ZENON PARK	8,872.66
Totals	**11,083,604.88**

City	
SWIFT CURRENT	178,521.55
ESTEVAN	1,400,510.99
HUMBOLDT	677,073.72
LLOYDMINSTER	510,248.13
MARTENSVILLE	686,259.44
MEADOW LAKE	567,813.29
MELFORT	644,578.08
MELVILLE	516,026.26
MOOSE JAW	3,681,808.55
WARMAN	812,000.13
PRINCE ALBERT	3,539,671.08
YORKTON	2,273,194.44
REGINA	25,737,847.82
NORTH BATTLEFORD	1,647,175.07
SASKATOON	11,379,104.27
WEYBURN	1,234,498.05
City Totals	**55,486,330.87**
Provincial Totals	**66,569,935.75**

SRRP Q122 Reference: Proposed Rates

A) Please provide the average percentage rate increases for each class (excluding the Power-contract rate class) effective March 1, 2018 for each of the following rate scenarios, using a revenue requirement allocation that reflects the recommendations of the Elenchus cost of service review:
   i. Moving all customer classes within a R/RR range of 0.98 to 1.02.
   ii. Moving all customer classes with a R/RR range of 0.95 to 1.05.
   iii. Moving all customer classes within a R/RR range of 0.98 to 1.02 and eliminating the distinction between rural and urban rates.

B) Please comment on the technical feasibility of implementing rates related to the scenarios described in part (a). Would there be any data availability issues, time constraints or other impediments to SaskPower's ability to implement any of those rate scenarios effective March 1, 2018?

Response:

A) Please see the tables below that summarize the 3 rate scenarios requested and reflect the recommendations of the Elenchus cost of service review (including the Existing Rates):

i. Moving all customer classes within a R/RR range of 0.98 to 1.02:

Year 2018F Rate Change & R/RR Ratios
5.0% General Rate Increase With Rebalancing Maintenance

Class of Service	2018F R/RR Ratio (Existing Rates)	2018F Rate Change	2018F R/RR Ratio (Revised Rates)
Urban Residential	1.01	1.4%	0.98
Rural Residential	0.92	13.0%	0.98
Total Residential	**0.99**	**4.0%**	**0.98**
Farms	0.96	7.2%	0.98
Urban Commercial	1.02	4.4%	1.01
Rural Commercial	1.02	5.5%	1.01
Total Commercial	**1.02**	**4.7%**	**1.01**
Power - Published Rates	1.01	5.2%	1.01
Power - Contract Rates	0.99	4.2%	0.98
Total Power	**1.00**	**4.9%**	**1.01**
Oilfields	1.02	4.6%	1.01
Streetlights	0.81	29.7%	0.98
Reseller	0.99	6.0%	1.00
Total (System)	**1.00**	**5.0%**	**1.00**

Under this scenario, Residential and Farm customers are set to 0.98, Resellers are set to 1.00 and all other classes (with the exception of Streetlights) are set to 1.01. Streetlights are set to 0.98, the lowest level of the R/RR range under the request.

While this option meets the parameters of the request, it results in the Streetlight class' proposed increase exceeding the current customer/class maximum of 15% and would not be recommended by SaskPower to the SRRP.

ii. Moving all customer classes with a R/RR range of 0.95 to 1.05:

Year 2018F Rate Change & R/RR Ratios
5.0% General Rate Increase With Rebalancing Maintenance

Class of Service	2018F R/RR Ratio (Existing Rates)	2018F Rate Change	2018F R/RR Ratio (Revised Rates)
Urban Residential	1.01	1.5%	0.98
Rural Residential	0.92	13.0%	0.98
Total Residential	**0.99**	**4.1%**	**0.98**
Farms	0.96	7.2%	0.98
Urban Commercial	1.02	4.4%	1.01
Rural Commercial	1.02	5.5%	1.01
Total Commercial	**1.02**	**4.7%**	**1.01**
Power - Published Rates	1.01	5.2%	1.01
Power - Contract Rates	0.99	4.2%	0.98
Total Power	**1.00**	**4.9%**	**1.01**
Oilfields	1.02	4.6%	1.01
Streetlights	0.81	25.7%	0.95
Reseller	0.99	6.0%	1.00
Total (System)	**1.00**	**5.0%**	**1.00**

Under this scenario, the only change was to move the Streetlights to 0.95 (the lowest level of the R/RR range under the request) and slightly increase the Urban Residential class proposed increase from 1.4% to 1.5% (to adjust for the remaining revenue not collected under Streetlights). Since the Streetlight class is small relative to the Urban Residential, the increase has no impact on the class' R/RR ratio, which remains at 0.98.

This option, while meeting the parameters of the request, still results in the Streetlight's proposed increase to exceed the current customer/class maximum of 15% and would not be recommended by SaskPower to the SRRP.

iii. **Moving all customer classes within a R/RR range of 0.98 to 1.02 and eliminating the distinction between rural and urban rates:**

Year 2018F Rate Change & R/RR Ratios
5.0% General Rate Increase With Rebalancing Maintenance

Class of Service	2018F R/RR Ratio (Existing Rates)	2018F Rate Change	2018F R/RR Ratio (Revised Rates)
Residential	0.99	4.0%	0.98
Farms	0.96	7.2%	0.98
Small Commercial	1.01	5.9%	1.01
General Service	1.03	3.7%	1.01
Total Commercial	**1.02**	**4.7%**	**1.01**
Power - Published Rates	1.01	5.2%	1.01
Power - Contract Rates	0.99	4.2%	0.98
Total Power	**1.00**	**4.9%**	**1.01**
Oilfields	1.02	4.6%	1.01
Streetlights	0.81	29.7%	0.98
Reseller	0.99	6.0%	1.00
Total (System)	**1.00**	**5.0%**	**1.00**

The table above has eliminated the distinction between urban and rural rates for Residential and Commercial customers. Under this scenario, Residential and Farm customers are set to 0.98, Resellers are set to 1.00 and all other classes (with the exception of Streetlights) are set to 1.01. Streetlights are set to 0.98, the lowest level of the R/RR range under the request.

While this option meets the parameters of the request, it results in the Streetlight class' proposed increase exceeding the current customer/class maximum of 15% and would not be recommended by SaskPower to the SRRP.

B) While there would be no technical impediments or data availability issues related to implementing the rates related to the scenarios described in part (a) effective March 1, 2018, SaskPower considers the proposed single year increase to the Streetlight class excessive in all the above scenarios, and doubts such a request would be supported by the SRRP, affected municipalities or SaskPower's shareholder.

Due to their relatively small size, the Streetlight class is very sensitive to fluctuations in their costs, which vastly affects their R/RR ratio. SaskPower is currently in the process of converting many of its existing light standards to more energy efficient LED technologies.

While it is expected that the Streetlight's R/RR ratio will further decrease as the costs of the project are added to their rate base (i.e., increased revenue requirement), it is also expected that their energy consumption and contribution to system peak will be lower (i.e., reduced revenue requirement), thereby raising their R/RR ratio. The impact to the Streetlight's R/RR ratio will not be fully known until the costs of the conversion project begin to be reflected in subsequent cost of service studies.

Given the inherent uncertainty in the Streetlight class, while recognizing the need to rebalance the rates and implement simplification, SaskPower would recommend the following scenario:

Year 2018F Rate Change & R/RR Ratios
5.0% General Rate Increase With Rebalancing Maintenance

Class of Service	2018F R/RR Ratio (Existing Rates)	2018F Rate Change	2018F R/RR Ratio (Revised Rates)
Residential	0.99	5.2%	0.99
Farms	0.96	5.2%	0.96
Small Commercial	1.01	5.9%	1.01
General Service	1.03	3.7%	1.01
Total Commercial	**1.02**	**4.7%**	**1.01**
Power - Published Rates	1.01	5.2%	1.01
Power - Contract Rates	0.99	4.2%	0.98
Total Power	**1.00**	**4.9%**	**1.01**
Oilfields	1.02	4.6%	1.01
Streetlights	0.81	8.1%	0.82
Reseller	0.99	6.0%	1.00
Total (System)	**1.00**	**5.0%**	**1.00**

The above scenario would:

- Fully implement all of Elenchus' core recommendations from the 2017 Cost of Service Review
- Amalgamate the urban and rural rates for all residential and commercial customers (rate simplification)
- Ensure all customer classes' R/RR ratios (with the exception of Streetlights) is within the industry standard of 0.95-1.05
- Fully rebalance the Reseller class due to changes in the cost of service methodology from the 2012 review
- Hold the Streetlight R/RR ratio constant until the impacts of the LED conversion program are known

SRRP Q123 Reference: Rate Design

A) Please confirm if the proposed change in maximum demand billing from 80-85% affects only customers with time-of-day metering and indicate which rate codes are affected by this change.

B) Please provide an estimate of the number customers who will be affected by this change and the reasons for the proposed change.

C) What is the range of bill impacts SaskPower expects (and resulting revenue impacts) from the proposed rate design change from 80% maximum registered demand to 85%.

Response:

A) SaskPower confirms that the proposed change in the maximum registered demand (k.VA) from 80%-85% (off-peak) affects only customers with time-of-day metering. Only Commercial (small and medium) customers with approved time-of-day metering in rate codes E05, E06, E07, E10, E12, E75, E76, and E78 are affected.

B) The following table is a list of Commercial (small and medium) customers which are currently billed utilizing approved time-of-day metering:

Rate Code	Number of Time-of Day Metering Customers
E05	2
E06	5
E07	2
E10	10
E12	3
E75	1
E76	1
E78	3
Total	**27**

The reason for SaskPower's proposed change is to shift the time-of-day incentive from demand-related to energy-related parameters of service.

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C) The following is a table that demonstrates the impact from changing the maximum registered demand (off-peak) from 80% to 85% only. The average rate increase of 5.1% is not included in this table.

Rate Code	Number of Customers on Time-of-Day Billing	Number of Customers Impacted	Average kW.H/Month of Impacted Customers (kW.H)	80% OffPeak Demand Average Monthly Bill ($)	85% OffPeak Demand Average Monthly Bill ($)	Impact Average Revenue Increase (%)
E05	2	1	14,583	$2,107	$2,123	0.8%
E06	5	2	267,202	$29,833	$29,867	0.1%
E07	2	1	25,574	$5,144	$5,214	1.4%
E10	10	2	386,217	$33,442	$33,497	0.2%
E12	3	1	274,420	$25,615	$25,671	0.2%
E75	1	0	0	$0	$0	0.0%
E76	1	0	0	$0	$0	0.0%
E78	3	0	0	$0	$0	0.0%

SRRP Q124 Reference: Competitiveness

Please identify which other utilities are included in the 'range of rates at Canadian utilities' and 'thermal average' figures provided in the chart on page 21 of the application.

Response:

The utilities included in the Hydro Quebec survey include:

Predominantly hydro utilities:
BC Hydro
Manitoba Hydro
Hydro-Québec

Thermal utilities:
ENMAX
EPCOR
Toronto Hydro
Hydro Ottawa
Nova Scotia Power
NB Power
Newfoundland and Labrador Hydro (customers with a power demand of 30,000 kW or more)
Newfoundland Power (all other customer categories)
Maritime Electric

SRRP Q125 Reference: Competitiveness

Please provide a table showing the calculation of bills before applicable taxes and after applicable taxes for each of the following types of customers located in Regina at rates effective April 1, 2017, and proposed for March 1, 2018. Please also confirm which rate code would apply to each customer:

i. A residential customer using 625 kWh in a month.
ii. A small commercial customer with demand of 14 kW and using 2,000 kWh in a month.
iii. A large power customer using 5,000 kW of demand and 3,060,000 kWh in a month.

Response:

Note that the kW are converted to kVa as per our billing structure, and the table uses the power factors as prescribed by the Hydro Quebec *Comparison of Electricity Prices in Major North American Cities*.

	Current Rates			Proposed Rates		
Rate Code	**E01**	**E75**	**E22**	**E01**	**E75**	**E22**
Customer Class	**Residential**	**Commercial**	**Power**	**Residential**	**Commercial**	**Power**
Consumption (kwh)	625	2,000	3,060,000	625	2,000	3,060,000
Demand (kVa)	-	15.5	5,263	-	15.5	5,263
Basic Rate	$ 22.01	$ 30.07	$ 5,976.74	$ 23.13	$ 31.6	$ 6,280.32
Energy Rate	$ 0.1374	$ 0.1320	$ 0.06665	$ 0.1444	$ 0.1387	$ 0.07004
Demand Rate	$ -	$ -	$ 10.5320	$ -	$ -	$ 11.0670
Total Before Taxes	$ 107.89	$ 294.07	$ 265,355.66	$ 113.37	$ 309.00	$ 278,848.34
Taxes (Incl. Municipal Surcharges)	$ 16.18	$ 44.11	$ 39,803.35	$ 17.01	$ 46.35	$ 41,827.25
Total	**$ 124.07**	**$ 338.18**	**$ 305,159.00**	**$ 130.37**	**$ 355.35**	**$ 320,675.59**

For E75, the kVa amount falls below the threshold of 50 kVa. As a result, the customer incurs no demand charge.

SRRP Q126 Reference: Competitiveness

Can SaskPower provide an explanation for what characteristics of its system (population density, generation mix, etc) result in it having twice as many metres of line per customer compared to Manitoba Hydro?

Response:

Manitoba Hydro delivers electricity to its customers using over 18,000 kilometres of transmission lines and 68,000 kilometres of distribution lines. SaskPower delivers electricity over 14,000 kilometres of transmission lines and more than 144,000 kilometres of distribution lines — more than double the distribution lines that Manitoba Hydro requires.

Manitoba has a significant portion of its 1.3 million population in two major centres. Saskatchewan has significantly more small towns and farms and the populated region is much larger (compared to Manitoba's large geographic area of Canadian Shield and lakes). This results in many of our towns being picked up by an extensive distribution grid, with long distribution feeders going much further from the transmission fed substations.

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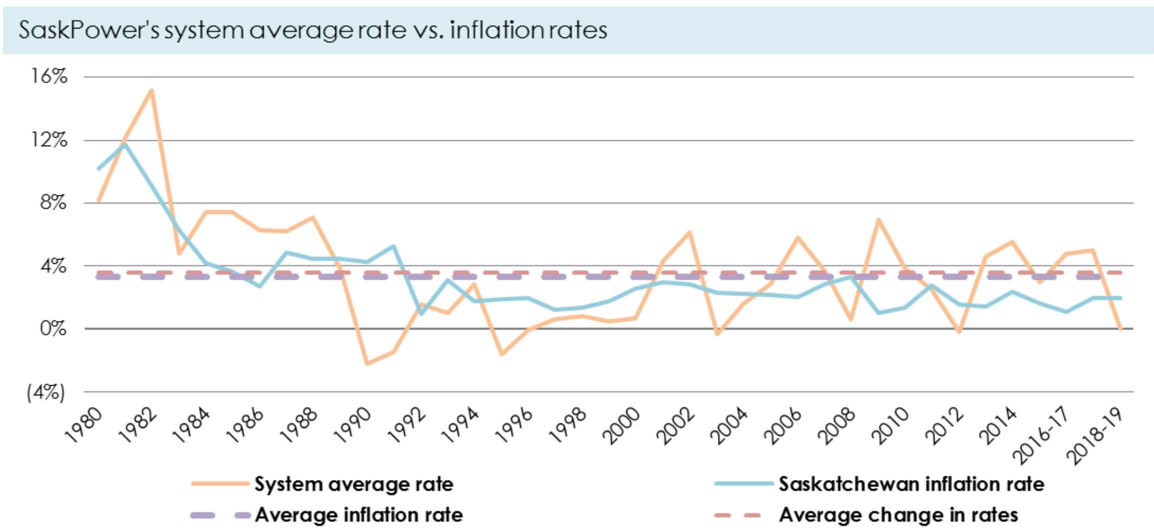
SRRP Q127 Reference: Competitiveness

Please expand the rates versus inflation figure on page 24 of the application to include SaskPower's proposed rate increases for 2018/19 and the inflation rates assumed in SaskPower's most recent business plan.

Response:

Overall, SaskPower's system average rates will have increased at slightly more than the rate of inflation from 1980 through 2018-19 (3.6% vs 3.3% respectively).



SRRP Q128 Reference: Competitiveness

Please confirm the electricity spending as a percentage of total household spending of 1.74% cited on page 24 of the application is from 2015 and will not include rate increases from 2016, 2017 or proposed for 2018.

Response:

Confirmed. The data is from Stats Canada and is dated 2015.

SRRP Q129 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.

SRRP Q130 Reference: Reliability

Please provide a table summarizing transmission SAIDI; transmission SAIFI; distribution SAIDI and distribution SAIFI for the most recent three 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, etc.).

Response:

	2013	**2014**	**2015**
Transmission			
SaskPower SAIDI (minutes)	131	191	144
Canadian SAIDI avg. (minutes)	194	187	154
SaskPower SAIFI (interruptions)	1.89	3.60	2.39
Canadian SAIFI avg. (interruptions)	0.93	0.89	0.86
Distribution			
SaskPower SAIDI (hours)	5.94	5.08	5.19
Canadian SAIDI avg. (hours)	9.49	6.38	3.88
SaskPower SAIFI (interruptions)	2.18	2.49	2.36
Canadian SAIFI avg. (interruptions)	2.72	2.39	2.21

The Canadian averages are reported by the Canadian Electricity Association (CEA). The methodology used by the CEA to calculate these averages weight the results from each included utility by the size of that utility's customer base. The CEA considers individual utility information confidential. The 2016/17 Canadian averages were not available when the response was written.

Also, please note that transmission data only include forced (unplanned) outages. Approximately one third of SaskPower's total transmission outages are planned.

Transmission SAIDI and SAIFI tend to vary to a much greater extent than distribution results, as one major transmission event during a year can have a significant impact.

SaskPower has remained at or near the Canadian average for the most part, with the exception of transmission SAIFI. SaskPower's transmission interruptions are significantly higher than the Canadian average.

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SRRP Q131 Reference: Reliability

Please provide the data for both duration of outages by cause and frequency of outages by cause for each of the past five years.

Response:

Transmission:

Component Outages								
	Adverse Environment	Adverse Weather	Defective Equipment	Foreign Interference	Human Element	Unknown	System Conditions	Grand Total
2012	5	148	55	16	22	100	76	422
2013	8	62	34	15	21	61	22	223
2014	6	202	39	17	28	52	43	387
2015	8	119	29	12	34	44	98	344
2016-17	5	123	47	8	39	82	9	313

Number of Interruptions								
	Adverse Environment	Adverse Weather	Defective Equipment	Foreign Interference	Human Element	Unknown	System Condition	Grand Total
2012	16	486	156	84	35	255	4	1,036
2013	18	184	94	47	81	196	-	620
2014	19	513	78	31	57	98	252	1,048
2015	17	272	60	29	44	112	243	777
2016-17	14	367	105	26	33	227	152	924

Duration of Interruptions (minutes)								
	Adverse Environment	Adverse Weather	Defective Equipment	Foreign Interference	Human Element	Unknown	System Condition	Grand Total
2012	204	83,810	21,767	2,677	537	9,270	42	118,307
2013	983	4,745	24,003	5,476	1,125	10,119	-	46,451
2014	2,438	31,769	8,970	5,209	1,295	3,029	11,091	63,801
2015	794	12,507	7,169	6,677	2,672	573	15,444	45,836
2016-17	3,987	6,188	19,759	2,223	1,398	822	7,551	41,928

Distribution:

		2016-17		2015		2014		2013		2012		5-Year	
Reason		Hours	Interruptions	Hours	Interruptions	Hours	Interruptions	Hours	Interruptions	Hours	Interruptions	Hours	Interruptions
Unknown	00	203,772	105,069	176,931	96,144	179,066	121,887	271,970	125,236	150,416	92,037	982,154	540,373
Planned	10	642,266	307,048	554,210	295,507	422,242	253,201	625,650	298,761	513,870	237,146	2,758,238	1,391,663
Lightning	11	263,495	83,676	275,950	78,848	415,125	158,216	255,247	68,249	302,048	109,964	1,511,865	498,953
Icing	12	54,933	17,750	65,287	18,798	72,559	23,882	72,554	34,642	104,642	40,572	369,976	135,644
Other Weather	13	157,300	54,741	167,534	60,117	247,167	105,854	146,542	41,959	258,363	71,654	976,905	334,325
Trees	14	268,575	103,162	230,024	92,596	299,264	97,558	337,209	81,956	467,267	111,418	1,602,340	486,690
Other Vegetation	15	2,913	1,787	3,144	1,117	2,834	2,000	2,108	1,072	5,104	1,407	16,104	7,383
Birds/Animals	16	174,003	114,731	230,167	142,780	118,720	78,154	169,886	81,992	202,612	105,926	895,389	523,583
Accident Internal	17	4,570	4,129	14,028	8,598	3,106	2,592	4,776	2,790	29,872	15,400	56,351	33,509
Accident External	18	176,975	76,485	223,448	105,247	183,649	86,733	373,240	107,216	211,739	100,862	1,169,051	476,543
Vandalism	19	7,479	4,078	6,951	5,966	16,186	5,032	12,609	4,116	1,486	391	44,711	19,583
System Failure	20	103,484	57,072	142,562	40,835	91,140	43,540	127,436	41,178	31,883	7,124	496,506	189,749
Faulty Equipment	21	515,761	194,030	463,840	213,596	424,130	225,894	467,249	163,175	454,815	172,140	2,325,795	968,835
Contamination	22	57,890	11,293	15,752	7,494	21,749	18,618	14,584	5,283	60,913	15,197	170,888	57,885
Overload	23	16,744	11,043	63,020	29,645	29,991	15,104	35,413	10,448	19,448	11,356	164,616	77,596
		2,650,161	**1,146,094**	**2,632,849**	**1,197,288**	**2,526,929**	**1,238,265**	**2,916,471**	**1,068,073**	**2,814,478**	**1,092,594**	**13,540,887**	**5,742,314**

Reason		Hours	Interruptions	Hours	Interruptions	Hours	Interruptions	Hours	Interruptions	Hours	Interruptions	Hours	Interruptions
Unknown	00	7.69%	9.17%	6.72%	8.03%	7.09%	9.84%	9.33%	11.73%	5.34%	8.42%	7.25%	9.41%
Planned	10	24.23%	26.79%	21.05%	24.68%	16.71%	20.45%	21.45%	27.97%	18.26%	21.70%	20.37%	24.24%
Lightning	11	9.94%	7.30%	10.48%	6.59%	16.43%	12.78%	8.75%	6.39%	10.73%	10.06%	11.17%	8.69%
Icing	12	2.07%	1.55%	2.48%	1.57%	2.87%	1.93%	2.49%	3.24%	3.72%	3.71%	2.73%	2.36%
Other Weather	13	5.94%	4.78%	6.36%	5.02%	9.78%	8.55%	5.02%	3.93%	9.18%	6.56%	7.21%	5.82%
Trees	14	10.13%	9.00%	8.74%	7.73%	11.84%	7.88%	11.56%	7.67%	16.60%	10.20%	11.83%	8.48%
Other Vegetation	15	0.11%	0.16%	0.12%	0.09%	0.11%	0.16%	0.07%	0.10%	0.18%	0.13%	0.12%	0.13%
Birds/Animals	16	6.57%	10.01%	8.74%	11.93%	4.70%	6.31%	5.83%	7.68%	7.20%	9.69%	6.61%	9.12%
Accident Internal	17	0.17%	0.36%	0.53%	0.72%	0.12%	0.21%	0.16%	0.26%	1.06%	1.41%	0.42%	0.58%
Accident External	18	6.68%	6.67%	8.49%	8.79%	7.27%	7.00%	12.80%	10.04%	7.52%	9.23%	8.63%	8.30%
Vandalism	19	0.28%	0.36%	0.26%	0.50%	0.64%	0.41%	0.43%	0.39%	0.05%	0.04%	0.33%	0.34%
System Failure	20	3.90%	4.98%	5.41%	3.41%	3.61%	3.52%	4.37%	3.86%	1.13%	0.65%	3.67%	3.30%
Faulty Equipment	21	19.46%	16.93%	17.62%	17.84%	16.78%	18.24%	16.02%	15.28%	16.16%	15.76%	17.18%	16.87%
Contamination	22	2.18%	0.99%	0.60%	0.63%	0.86%	1.50%	0.50%	0.49%	2.16%	1.39%	1.26%	1.01%
Overload	23	0.63%	0.96%	2.39%	2.48%	1.19%	1.22%	1.21%	0.98%	0.69%	1.04%	1.22%	1.35%
		100%	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**

SRRP Q132 Reference: Reliability

A) Please discuss how SaskPower develops generation, transmission and distribution reliability targets.

B) Please describe how these reliability targets are considered when prioritizing SaskPower's capital plan.

C) Please discuss how SaskPower investigates and responds to situations where it fails to achieve its generation, transmission and distribution reliability targets

Response:

A) Development of targets:

i. Generation: SaskPower uses the Equivalent Availability Factor (EAF) to measure generation reliability. The System Average EAF target is a weighted average, based on capacity, of individual EAF targets for each generation unit. Individual targets are determined using five years of historical data, anticipated equipment problems, plans for capital and/or OM&A spending to resolve historical problems, and the scheduled unit outages from the Generation Maintenance Schedule.

ii. Transmission: SaskPower uses the System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) (average total interruption duration and average number of interruptions, respectively, that a Bulk Electric Service Delivery Point experiences during one year.) Short-term targets are determined using five-year historical data, factoring in a downward trend resulting from infrastructure renewal initiatives, improved technology, and improved maintenance programs. The long-term target is determined as the five-year historical average adjusted to improve the performance of components currently underperforming on design to today's design criteria.

iii. Distribution: SaskPower uses SAIDI and SAIFI (average total interruption duration and average number of interruptions, respectively, that a customer experiences during one year). The short-term targets are based on historical data, factoring in a downward trend to reflect infrastructure renewal and sustainment initiatives. The long-term target is based on industry averages.

B) SaskPower considers reliability results, not targets, in the prioritization process for our company's capital plan. SaskPower's strategic priorities and business values, which include reliability and performance of the Business Unit, are used to score and rank business risks associated with a capital project. Our reliability targets are based on historical data adjusted to factor in capital and maintenance plans.

C) SaskPower's customers rely heavily on the service our company provides, requiring immediate investigation and emergency maintenance or replacement in the event of an unexpected outage or shutdown. Assets that underperform or for which a future outage is anticipated are included in the planned maintenance schedule to proactively address future issues.

i. Generation: If a generation unit falls short of its EAF target, SaskPower would investigate and repair the unit as necessary.

ii. Transmission: Transmission staff review if assets perform as designed and perform root cause analysis where there is a variance.

iii. Distribution: Distribution staff review equipment and maintenance-related outages and modify equipment specifications and maintenance practices accordingly.

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SRRP Q133 Reference: Reliability

Please discuss how SaskPower evaluates the health of its transmission lines. Provide details on the calculation of the transmission health index by voltage to the extent possible without needing to provide confidential or commercially sensitive information.

Response:

In general terms, SaskPower evaluates the health of its transmission lines based on condition assessments. Composite health indices are developed utilizing findings from preventative maintenance activities and condition assessment surveys for individual components to develop an overall picture of the health of the asset.

Details on process and sample calculation:

Transmission lines are inspected on a prescribed schedule using three asset classes — structure, span, and right of way. Based on electrical utility best practices, a scoring system was developed by which a rating is assigned on individual components using a scale of 0-4 (0 being critical and a 4 being perfect condition).

Below is a template of how the scoring for a structure is calculated. The rating assigned to individual components is multiplied by a weighting factor (multiplier) to come up with a weighted score. The weighted score, divided by the maximum possible score (Max Score), is the health index on a percentage scale.

Structure (Rating)

Component	Multiplier	Max Score
Wood Pole	10	40
Steel Pole	10	40
Spar	20	80
Bracing	2	8
Anchor / Guy	1.5	6
Grounding	2	8
Cathodic	1	4
U-Bolt	1	4
Bonding	2	8
Shield Wire Insulator	2	8
Steel Pole Coating	2	8
Cross Member	2	8
Coating	1	4
Foundation	5	20
Keys & Pins	5	20
Pole Stub	3	12

Structure (Example)

Component	Rating	Multiplier	Weighted Score	Max Score
Wood Pole	3	10	30	40
Spar	2	20	40	80
Bracing	4	2	8	8
Anchor / Guy	2	1.5	3	6
Grounding	3	2	6	8
U-Bolt	3	1	3	4
Bonding	4	2	8	8
Shield Wire Insulator	2	2	4	8
Foundation	4	5	20	20
Keys & Pins	3	5	15	20
Pole Stub	4	3	12	12
Total :			**149**	**214**

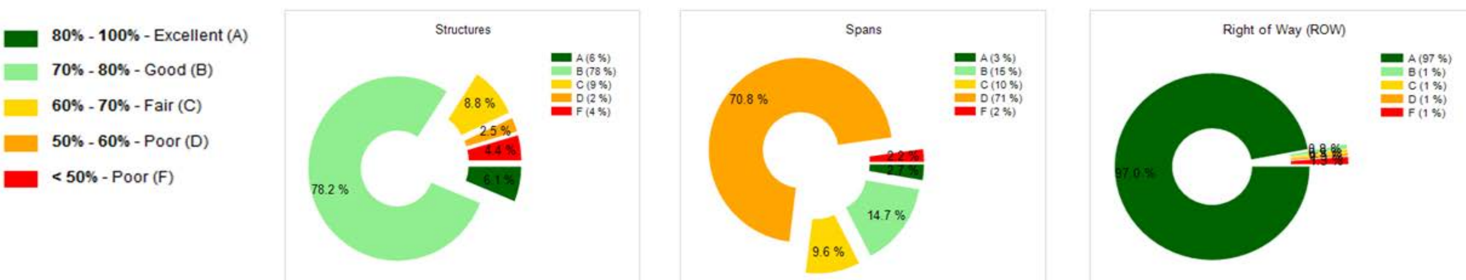
Structure Score : 149 / 214 = 69.6%

The above calculation is for an individual structure. For a line score, every structure's total weighted score is summed and divided by the sum of the total possible score. As an example, lets assume the line has four structures. The line score would be determined as follows:

Structure Number	Weighted Score	Max Score
1	149	215
2	135	220
3	148	235
4	118	215
Total	**550**	**885**

Line Score : 550 / 885 = 62.1%

Similar analytics can be carried out to determine the scores for spans and right of ways. The componenets are typicaly assessed as Excellent, Good, Fair, Poor or Fail based on scores.



The process can be carried on to determine the voltage class score by summing the weighted score of indvidual lines over the maximum possible score. As an example, let's assume a voltage class had four lines. The health index for the voltage class would be as follows:

Line	Weighted Score	Max Score
1	1200	1800
2	1300	1900
3	1400	2000
4	1500	2100
Total	**5400**	**7800**

Voltage Class Score : 5400 / 7800 = 69.2%

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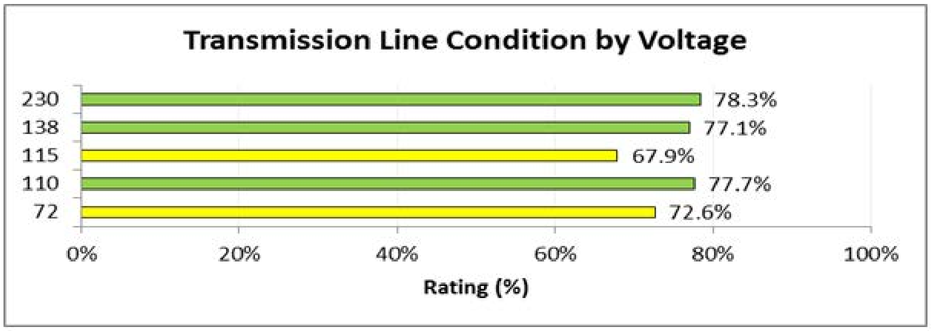
On the transmisison system, the health index is determined for 72 kV, 110 kV, 115 kV, 138 kV and 230 kV transmission lines.



SRRP Q134 Reference: Integrated Resource Plan

Please provide a summary that can be made public of:

i. the goals and objectives of SaskPower's Integrated Resource Plan.

ii. an overview of the methods used to develop the plan, including models or decision analysis frameworks used in the plan.

Response:

Integrated Resource Plans (IRPs) are a common planning tool employed in the utility industry to develop a long-term strategy in consideration of today's uncertainties. Electric utilities are very capital intensive, with significant investments recovered over long time horizons.

The industry is also going through rapid change making forecasting very difficult when it comes to key factors, such as future market conditions, regulatory changes, technological advancements, and customer expectations. SaskPower's IRP is a 20-year look ahead that evaluates reliable, cost-effective resource options (supply-side, demand-side and transmission/distribution resources) for meeting future demand for electricity under a range of potential future conditions.

The 2017 IRP strives to accomplish the following:

- Ensure reliability for all stakeholders
- Evaluate all options in a fair and consistent manner
- Minimize costs to all stakeholders
- Create a flexible plan that allows for uncertainty and permits adjustment in response to changed circumstances
- Reduce CO_2 emissions from power generation
- Consider stakeholder preferences regarding investment decisions

IRP objective statement

To meet system demand, customer expectations and environmental objectives in a reliable, sustainable, and cost-effective manner across a reasonable range of foreseeable futures. The planning approach considers reliability, sustainable development and cost effectiveness.

Process overview

The IRP is intended to respond to two core resource planning questions: In consideration of long term costs, what quantity of resources does SaskPower need and what are the timing of those needs? Both existing resources and potential future resources are considered using the methodology described below.

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The 2017 IRP is the culmination of a comprehensive decision-making process aimed at meeting future customer needs, achieving regulatory requirements and managing environmental impacts during the 20-year planning period. Many different disciplines and areas of expertise from SaskPower and external industry experts were incorporated in this planning process. This process provided a framework through which both supply-side and demand-side options were compared to develop a plan that provides reliable, sustainable and cost-effective electricity for Saskatchewan.

Creating SaskPower's 2017 IRP was an iterative process, using both internal and external resources to accomplish the tasks necessary to complete the plan, which included:

STEP 1 – SCOPING

Identified resource options, strategies and future conditions to evaluate as part of the IRP process. Sessions were held with employees representing various departments and levels of seniority and experience. The comments received helped to identify important issues and lay the foundation for the process.

STEP 2 –DEVELOP PLANNING FRAMEWORK

Developed scenarios through a collaborative approach to identify the range of plausible futures that are outside of SaskPower's control and a set of potential portfolio strategies which SaskPower can choose to employ.

STEP 3 – ASSESS NEEDS

Evaluated forecasts of load growth, plant conditions, contract terms and operational constraints to define the needed resources over the 20-year planning horizon.

STEP 4 – CONSIDER RESOURCE OPTIONS

Evaluated potential energy resources, including conventional, renewable, and customer-side solutions and identified the role each may play in meeting customer needs. Peak contributions from existing resources were compared to the forecasted load and reserve requirements.

STEP 5 – PERFORM SCENARIO ANALYSIS

Ran the combinations of strategies and scenarios through a simulation model that filtered each through a series of pre-defined variables to produce key decision metrics for further evaluation and comparison. This phase of the IRP used industry-standard capacity expansion planning and production cost modelling software including PROMOD and Strategist.

STEP 6 - SELECT PLAN

Select a portfolio from the scenario analysis process based on the one that provided the best mix of benefits to SaskPower and customers on the defined metrics versus all others considered.

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SRRP Q135 Reference: Integrated Resource Plan

Please itemize the planning criteria used by SaskPower in developing its Integrated Resource Plans. Please include any policy objectives such as reducing greenhouse gas emissions or installing a particular capacity of renewable generation.

Response:

The Integrated Resource Plan (IRP) is intended to respond to two core resource planning questions: 1) In consideration of long term costs, what quantity of resources does SaskPower need to meet expected load requirements and what are the timing of those needs; and 2) What existing resources and potential future resources are available to meet these resource needs at the time they are required.

Additionally, the following policy objectives were also considered in developing the IRP:

- SaskPower's target of having up to 50% renewable capacity by 2030; and
- SaskPower's target of reducing carbon emissions by 40% from 2005 levels by 2030.

SRRP Q136 Reference: Integrated Resource Plan

Please provide an update on SaskPower's engagement plan for the Integrated Resource Plan. Has SaskPower provided an engagement plan to its executive? Does SaskPower have a timeline for implementing an engagement plan?

Response:

SaskPower publicly shares information about Saskatchewan's power future, including major generation projects as identified within the Integrated Resource Plan, on an ongoing basis. This includes sharing information on saskpower.com, announcements as projects are approved, and presentations to key stakeholder audiences, including the Saskatchewan Industrial Energy Consumers Association, business organizations and other interested organizations.

We also host open houses to provide detailed information and seek input on major projects, with a recent example being the Let's Talk Solar consultations in the spring of 2017, which will help to shape future solar programs in Saskatchewan.

SRRP Q137 Reference: Integrated Resource Plans

A) At page 36 of the Application, SaskPower states it has a goal of up to 50% renewable capacity by 2030. Please explain if this capacity target reflects nameplate capacity, firm winter capacity or some other capacity definition.

B) Please discuss whether the 50% renewable capacity target would also result in 50% of total energy (GW.h) being suppled from renewable sources. If not, please indicate the approximate percentage of total energy that is expected from renewable sources once the 50% of total capacity target is met.

Response:

A) This target reflects winter capacity rating.

B) The 50% renewable capacity target likely will not result in 50% of total energy being supplied from renewable sources. Wind generation is projected as the largest renewable source to be added, and it has an annual capacity factor of 40-45% (depending on location). Given the work performed in the 2017 Integrated Resource Plan, SaskPower estimates that while the Corporation will meet the 50% capacity target, approximately 41% of the energy produced will be from renewable sources.

SRRP Q138 Reference: Integrated Resource Plan

Please provide an update on SaskPower's renewable integration study including when the study is anticipated to be completed and any initial or preliminary findings or recommendations to date.

Response:

SaskPower's renewables integration study is progressing as per schedule. We have recently completed the scenario modeling and benchmarking phase. Model runs are now starting, with preliminary results are expected at the end of September 2017. The final study report is expected to be completed by the end of November 2017.

SRRP Q139 Reference: Integrated Resource Plan

Please provide a discussion on how SaskPower views the future potential for energy storage (including batteries or other forms of energy storage) in the current Integrated Resource Plan.

Response:

Battery storage was considered in the Integrated Resource Plan. However, given cost estimates at the time it was not included in the detailed analysis. SaskPower continues to monitor developments in the energy storage space (not just batteries) and is also investigating the potential for SaskPower-specific applications that may be feasible.

2018 RATE APPLICATION
SRRP INTERROGATORIES

SRRP Q140 Reference: Integrated Resource Plan

Please discuss SaskPower's perspectives on distributed generation development in the Integrated Resource Plans, including any studies, pilot projects or rate options SaskPower is planning related to distributed generation.

Response:

With appropriate testing, there would appear to be an opportunity to leverage customer investments in Distributed Energy Resources (DER). This would primarily be related to solar and battery storage, and would create decentralized generation sources (i.e. virtual power plants) that can be included as a strategic electricity supply option in the Integrated Resource Plan.

In December 2016, SaskPower established a cross-functional Solar Task Force to evaluate and make recommendations on how SaskPower can most effectively support future development of residential, small business and community-based solar power generation. The Task Force conducted comprehensive stakeholder engagement as part of an assessment process that also included: (1) a review of current customer self-generation programs in Saskatchewan and in other North American jurisdictions; (2) an analysis of emerging program, technology and regulatory trends in North America; (3) a survey of industry rate strategies; and 4) SaskPower's current approach to serving self-generation customers.

The findings revealed that customers and stakeholders were intrigued by and supportive of solar. Specifically, the following key feedback themes emerged:

- Community participation – Stakeholders felt that SaskPower should create equitable opportunities to allow customers and communities to participate in solar power generation in Saskatchewan;
- Environmentally sustainability – Stakeholders felt that environmental sustainability should be an important consideration in the development of future solar programs;
- Quality – SaskPower heard there is opportunity to collaborate with reputable and reliable vendors;
- Innovation – There is a potential investment role for SaskPower in demonstrating emerging solar technology (e.g. battery storage); and
- Continued Stakeholder Engagement – Stakeholders expressed strong support for ongoing engagement with SaskPower in the development of solar generation and customer generation programs in Saskatchewan.

SaskPower is now reviewing the findings. The information, along with jurisdictional program reviews and analysis of emerging trends, will be used to inform a set of solar program recommendations. This will include program updates and potential pilot projects that are anticipated to be brought forward in 2018.

SRRP Q141 Reference: Integrated Resource Plan

Please provide a table that summarizes for each year from 2017 through 2036:
The expected system peak demand (MW) and system energy (GWh) that must be met both before and after DSM; and
The total nameplate capacity, total winter capacity and the contribution in each year of each of the following generation types in SPC's preferred supply plan to meeting the system peak demand and system energy requirements:

- Coal
- Natural Gas
- Wind
- Hydro
- Imports
- Other renewable (solar, geothermal, biomass etc.)
- Other non-renewable

Response:

i) Below is a table showing the expected system peak demand and system energy that must be met both before and after DSM.

	Instantaneous Peak (MW)				Total Energy (Gwh)		
Fiscal Year	**Non-DSM**	**DSM Adjusted**	**Net DSM**		**Non-DSM**	**DSM Adjusted**	**Net DSM**
2018F	3,932	3,917	14		24,580	24,520	60
2019F	3,991	3,962	29		24,972	24,826	145
2020F	4,088	4,050	38		25,616	25,422	195
2021F	4,130	4,082	48		25,955	25,710	245
2022F	4,176	4,119	57		26,217	25,920	297
2023F	4,229	4,162	67		26,568	26,219	350
2024F	4,283	4,207	77		26,885	26,482	404
2025F	4,311	4,225	86		27,092	26,632	460
2026F	4,370	4,275	95		27,383	26,869	514
2027F	4,403	4,299	104		27,633	27,067	566
2028F	4,455	4,343	112		28,027	27,411	616
2029F	4,520	4,401	119		28,428	27,767	662
2030F	4,583	4,457	126		28,792	28,088	704
2031F	4,651	4,518	133		29,223	28,479	744
2032F	4,696	4,557	139		29,599	28,819	780
2033F	4,767	4,624	144		30,029	29,213	816
2034F	4,831	4,684	148		30,369	29,524	845
2035F	4,881	4,730	151		30,695	29,825	870
2036F	4,934	4,780	154		31,105	30,214	891

ii) Please see the attached “SRRP Q141 – Appendix A rev2.xls” for a listing of the total nameplate capacity and total winter capacity. The total winter capacity is equal to the contribution from each generation type to meeting the system peak demand.

Capacity

Fiscal Year	01 Apr'17-31 Mar'18 2017		01 Apr'18-31 Mar'19 2018		01 Apr'19-31 Mar'20 2019		01 Apr'20-31 Mar'21 2020		01 Apr'21-31 Mar'22 2021		01 Apr'22-31 Mar'23 2022	
	Installed Capacity	Winter Capacity	Installed Capacity	Winter Capacity	Installed Capacity	Winter Capacity	Installed Capacity	Winter Capacity	Installed Capacity	Winter Capacity	Installed Capacity	Winter Capacity
Coal	1530.6	1530.6	1530.6	1530.6	1530.6	1530.6	1530.6	1530.6	1391.6	1391.6	1391.6	1391.6
Natural Gas	1823.5	1815.2	1823.5	1815.2	2173.5	2165.2	2173.5	2165.2	2094.6	2086.3	2094.6	2086.3
Wind	221.7	44.34	221.7	44.34	241.7	48.34	428.7	85.74	817.5	163.5	817.5	163.5
Hydro	864	856.8	864	856.8	864	856.8	864	856.8	864	856.8	864	856.8
Imports	25	25	25	25	25	25	125	125	125	125	100	100
Other Renewable	27.264	25.264	47.264	45.264	67.264	65.264	132.264	130.264	132.264	130.264	212.264	210.264
Other Non-Renewable												
Total	4492	4297	4512	4317	4902	4691	5254	4894	5425	4753	5480	4808

ENERGY

Calendar Year (Jan 1 to Dec 31)	Coal	Gas	Wind	Hydro	Imports	other renewable	renewable	non renewa	total
2018	42.3%	39.7%	2.9%	13.8%	0.6%	0.7%	17.9%	82.1%	100.0%
2019	40.7%	41.3%	3.0%	13.3%	0.5%	1.1%	18.0%	82.0%	100.0%
2020	38.5%	42.3%	3.3%	13.1%	1.4%	1.3%	19.2%	80.8%	100.0%
2021	38.6%	36.5%	7.9%	12.7%	2.3%	2.0%	24.9%	75.1%	100.0%
2022	33.1%	40.7%	9.8%	12.4%	1.9%	2.0%	26.2%	73.8%	100.0%
2023	32.4%	39.9%	10.4%	12.3%	1.7%	3.3%	27.7%	72.3%	100.0%
2024	30.4%	38.3%	12.4%	12.2%	1.7%	5.0%	31.2%	68.8%	100.0%
2025	26.9%	39.9%	14.3%	12.2%	1.7%	5.1%	33.2%	66.8%	100.0%
2026	26.1%	38.9%	16.1%	12.1%	1.7%	5.2%	35.1%	64.9%	100.0%
2027	27.9%	35.3%	18.1%	12.0%	1.7%	5.1%	36.9%	63.1%	100.0%
2028	22.0%	39.2%	20.4%	12.0%	1.7%	4.7%	38.8%	61.2%	100.0%
2029	21.9%	37.8%	22.0%	12.0%	1.6%	4.6%	40.2%	59.8%	100.0%
2030	2.6%	53.6%	22.5%	15.1%	1.6%	4.6%	43.8%	56.2%	100.0%
2031	2.4%	53.9%	22.4%	14.9%	1.6%	4.8%	43.7%	56.3%	100.0%
2032	2.6%	53.1%	22.9%	14.9%	1.6%	4.9%	44.3%	55.7%	100.0%
2033	2.4%	52.5%	23.9%	14.8%	1.6%	4.8%	45.1%	54.9%	100.0%
2034	2.6%	52.7%	23.7%	14.7%	1.6%	4.8%	44.7%	55.3%	100.0%
2035	2.2%	52.7%	24.2%	14.6%	1.6%	4.8%	45.1%	54.9%	100.0%
2036	2.5%	51.7%	25.1%	14.4%	1.6%	4.7%	45.8%	54.2%	100.0%
2037	2.3%	52.3%	24.9%	14.3%	1.5%	4.7%	45.4%	54.6%	100.0%

01 Apr'23-31 Mar'24 2023		01 Apr'24-31 Mar'25 2024		01 Apr'25-31 Mar'26 2025		01 Apr'26-31 Mar'27 2026	
Installed Capacity	Winter Capacity	Installed Capacity	Winter Capacity	Installed Capacity	Winter Capacity	Installed Capacity	Winter Capacity
1391.6	1391.6	1252.6	1252.6	1252.6	1252.6	1252.6	1252.6
1999.6	1991.3	2349.6	2341.3	2349.6	2341.3	2349.6	2341.3
1017.5	203.5	1217.5	243.5	1417.5	283.5	1617.5	323.5
864	856.8	864	856.8	864	856.8	864	856.8
100	100	100	100	100	100	100	100
282.264	280.264	282.264	280.264	342.264	340.264	336.564	335.064
5655	4823	6066	5074	6326	5174	6520	5209

01 Apr'27-31 Mar'28 2027		01 Apr'28-31 Mar'29 2028		01 Apr'29-31 Mar'30 2029		01 Apr'30-31 Mar'31 2030
Installed Capacity	Winter Capacity	Installed Capacity	Winter Capacity	Installed Capacity	Winter Capacity	Installed Capacity
968.3	968.3	968.3	968.3	110	110	110
2349.6	2341.3	2699.6	2691.3	3049.6	3041.3	3355.7
1817.5	363.5	2017.5	403.5	2117.5	423.5	2117.5
864	856.8	864	856.8	1114	1106.8	1114
100	100	100	100	100	100	100
336.564	335.064	319.464	319.464	319.464	319.464	319.464
6436	4965	6969	5339	6811	5101	7117

	01 Apr'31-31 Mar'32 2031		01 Apr'32-31 Mar'33 2032		01 Apr'33-31 Mar'34 2033		01 Apr'34-31 Mar'35 2034		01 Apr'35-31 Mar'36 2035		01 Apr'36-31 Mar'37 2036	
Winter Capacity	Installed Capacity	Winter Capacity	Installed Capacity	Winter Capacity	Installed Capacity	Winter Capacity	Installed Capacity	Winter Capacity	Installed Capacity	Winter Capacity	Installed Capacity	Winter Capacity
110	110	110	110	110	110	110	110	110	110	110	110	110
3347.4	3355.7	3347.4	3355.7	3347.4	3434.7	3426.4	3206.7	3198.4	3556.7	3548.4	3556.7	3548.4
423.5	2117.5	423.5	2317.5	463.5	2317.5	463.5	2317.5	463.5	2517.5	503.5	2517.5	503.5
1106.8	1114	1106.8	1114	1106.8	1114	1106.8	1114	1106.8	1114	1106.8	1114	1106.8
100	100	100	100	100	100	100	100	100	100	100	100	100
319.464	379.464	379.464	379.464	379.464	379.464	379.464	379.464	379.464	379.464	379.464	379.464	379.464
5407	7177	5467	7377	5507	7456	5586	7228	5358	7778	5748	7778	5748

SRRP Q142 Reference: Integrated Resource 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:

The following table shows the approximate capital cost by year by technology for the past two fiscal years and an estimate for fiscal year 2018.

Table 1 – Actual/Forecast Capital Cost of Preferred Supply Plan (in millions)

	Technology						
Fiscal Year	**Biomass**	**Solar**	**Wind**	**Hydro**	**Natural Gas**	**Other**	**Total**
2016	-	-	-	-	525	-	525
2017	-	-	-	-	-	-	-
2018	-	-	-	-	-	-	-

The following table shows an approximate capital cost by year by technology for the 10-year Business Plan window. Forecasting beyond 2027 is not available.

Table 2 – Business Plan Capital Cost of Preferred Supply Plan (in millions)

	Technology						
Fiscal Year	**Biomass**	**Solar**	**Wind**	**Hydro**	**Natural Gas**	**Other**	**Total**
2019	-	48	-	-	-	-	48
2020	174	48	-	-	680	-	902
2021	-	49	896	-	-	-	946
2022	-	-	486	680	-	-	1,166
2023	-	-	-	-	-	-	-
2024	-	-	505	-	-	-	505
2025	-	-	516	-	751	-	1,266
2026	-	164	526	-	-	-	690
2027	-	-	536	-	-	-	536
2028	-	-	547	-	-	-	547
Total	174	309	4,012	680	1,431	-	6,606

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2018 RATE APPLICATION
SRRP INTERROGATORIES

SRRP Q143 Reference: Integrated Resource Plan
Please describe the supporting infrastructure, including transmission and distribution upgrades, required to implement SaskPower's preferred resource supply plan.

Response:

When load or generation is added to the system, a certain amount of data (size location, configuration, schedule, equipment data, etc.) is required to carry out a system impact study. The system impact study is a technical/economical assessment of options and recommends infrastructure required to facilitate the new service point. The infrastructure required to provide new service is mostly classified as:

1. Physical interconnection – The infrastructure required for service is typically optimized to the local project.
2. System reinforcement - The infrastructure required to facilitate service is optimized considering other opportunities or strategic initiatives as well.

At any given time, the preferred resource plan may not have all of the required information to specifically identify required supporting infrastructure. Typically, there is adequate information available for projects in the short time horizon and it is less likely that information will be available for conceptual plans in the long time horizon.

The following infrastructure has been identified for specific projects in the short time horizon:

- To facilitate planned (*Chinook Power Station*) and potential future gas and/or wind supply options in southwestern Saskatchewan, SaskPower is adding a 230-kV transmission line between Swift Current, Moose Jaw, and Regina;
- To facilitate larger unit sizes of up to 350 MW, SaskPower is upgrading the transformer ended tie-line with North Dakota;
- To facilitate the addition of two small wind farms in the Riverhurst and Grenfell areas, SaskPower is adding two new 138-25 kV distribution substations; and
- To facilitate the planned Manitoba Hydro supply option, SaskPower is adding a new 230 kV tie-line between the Tantallon (SK) and Birtle (MB) transmission stations.

Additional facilities will be needed/ identified once the potential supply options in the medium- to long-term become more defined. The supply plan is a high level document that may not contain definitive plans for size, location, and date for all individual projects.

SRRP Q144 Reference: Integrated Resource Plan

Please provide updates with respect to any hydro projects envisioned within the 20 year planning horizon, including any potential independent power projects or project partnerships.

Response:

SaskPower has identified a number of potential hydroelectric projects that could meet the electrical needs of Saskatchewan in the future. However, with current environmental targets and the information developed to date on various generation costs, these potential projects are not expected to form part of the most economically optimal supply portfolio for the 20-year planning horizon. The relative feasibility and optimal timing for development of these projects will continue to be evaluated as energy supply decisions are influenced by emerging market and regulatory conditions.

SRRP Q145 Reference: Integrated Resource Plan

Please provide a high level discussion of how SaskPower's resource plan addresses the different asset life cycles for different types of resource options – for example, how does SaskPower address differences in asset lives of hydro resources compared to natural gas resources and wind resources.

Response:

Comparing projects with significantly different asset lives can be challenging because including the entire lifetime of amortized capital costs of a resource, while only including its operating costs and benefits for a portion of its lifetime, is an obvious bias against a high capital cost resource; a hydro or nuclear plant would be a good example. To deal with this issue, SaskPower utilizes an industry-standard production cost and capacity expansion optimization software called *Strategist* to help develop its optimal capacity expansion plan.

Strategist calculates the Economic Carrying Charge (ECC) function to represent the capital cost "hit" for each resource commissioned within the planning period. This approach charges the economic carrying charge for each year of the alternative's operating life. A single year's economic carrying charge is the cost avoided by delaying an alternative one year. This approach has been referred to as a value of deferral calculation and can be thought of as applying an appropriate "rental" payment for the option being considered. This method is commonly used throughout the industry. This approach avoids the bias against high capital projects and the Strategist program will determine the best plan based on the present value of utility costs in a fair and consistent manner while considering alternatives with differing lifespans.

Key inputs to the economic carrying charge calculation include: (1) the utility's discount rate, (2) the expected inflation rate for that type of plant, net of technical progress, and (3) the average service life for that type of plant.

The operating costs are calculated directly from the planning period production cost modelling. Thus, if the resource has lower operating costs than the other alternatives, this difference is captured even if the resource in question is commissioned in the final year of the planning period. The trade-off between higher capital & lower operating costs vs. lower capital & higher operating costs is captured using this method. Resources with different lifespans are thus treated equally.

SRRP Q146 Reference: Integrated Resource Plan

Please provide a high level discussion of how potential carbon pricing or carbon taxes affect SaskPower's preferred plan. What approximate level of carbon price or carbon tax would be required before SaskPower would need to adapt its current preferred plan?

Response:

Carbon pricing or carbon taxes will impact SaskPower's preferred plan by increasing its operating cost due to the additional expense incurred due to the carbon penalty.

Given that SaskPower has announced a target of up to 50% renewable capacity by 2030 — through which it plans to add what it currently feels is the maximum amount of intermittent renewable generation onto its syste — a carbon tax would not cause SaskPower to adapt its current preferred plan.

SRRP Q147 Reference: Other General

Please provide a copy of the most recent Corporate Balanced Scorecard: Definitions document.

Response:

A copy of the 2017-18 definitions document follows.

2017-18 CORPORATE BALANCED SCORECARD: DEFINITIONS

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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 surveys for residential, business and industrial customers. Each survey result 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:

<u>Residential</u>

(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%)

<u>Business</u>

(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%)

<u>Industrial</u>

(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:
Residential and industrial targets were developed using a baseline established in 2013. A baseline was established for business targets in 2015. Annual and long-term targets are determined with the goal of continuous improvement over baselines.

INDUSTRY COMPARABILITY:
Unique to SaskPower.

M2. New Connect Construction Index (%)

DEFINTION:
The New Connect Construction Index measures our completed new connect order performance against established completion standards. There are three types of new connect orders which are measured by the Index:

- Prepaid notifications, whose standard is completion before the later of a 10 day cycle time from the time a request is made for the service to the customer being connected or the need date provided by the customer.
- Complex orders, whose standard is completion before the later of a 90 day cycle time from the customer quote acceptance to the customer being connected or the need date provided by the customer.
- Non-complex orders, whose standard is completion before the later of a 45 day cycle time from customer quote acceptance to the customer being connected or the need date provided by the customer.

UNIT OF MEASUREMENT:
Percentage

FORMULA/METHODOLOGY:
A 12-month rolling average of:

$$\frac{\text{(Complex orders within target) + (non-complex orders within target) + (prepaid notifications within target)}}{\text{(Total completed complex orders) + (total completed non-complex orders) + (total completed prepaid notifications)}} \times 100\%$$

TARGETS:
Targets are determined at the discretion of management, with efforts to improve annually until the long-term target is achieved. The long-term target has been capped at 80%, as diminishing returns are expected beyond this level of performance due to the amount of investment required to meet a more aggressive performance level.

INDUSTRY COMPARABILITY:
Unique to SaskPower.

M3. Demand side management (DSM) peak demand/energy savings (megawatts (MW)/gigawatt hours (GWh))

DEFINITION:
The DSM peak demand/energy savings metric assesses the progress being made in developing and delivering DSM programs, which promote electric energy efficiency or conservation. It records demand reduction in MW and energy savings in GWh at the customer site expected to be achieved by end of year. The demand reduction will be achieved through energy efficiency and system improvement programs that are designed to achieve demand or energy savings.

UNIT OF MEASUREMENT:
MW/GWh

FORMULA/METHODOLOGY:

Demand

$$\sum\left(\frac{\text{kWh (per DSM program)}}{\text{Co-efficient (for specific end use)}}\right) \div 1{,}000\Big) = \text{MW}$$

Energy savings

$$\sum\Big(\left(\text{Base kWh - new unit kWh +/- adjustments}\right) \div 1{,}000\Big) = \text{GWh}$$

TARGETS:
Targets are 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:
The employee engagement metric reflects the number of employees who indicate 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). All three of these drivers of engagement are incorporated into the annual survey.

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 were 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' perspective. This analysis also reveals which drivers (independent variables) impact the scores most. Ultimately, identifying the relationship between the engagement core measures and key drivers (including learning, wellness/work-life balance, pay/benefits, recognition, direct OOS director/manager, performance management, work environment, and leadership) allows SaskPower to make meaningful choices about what areas to focus on in order to improve engagement among employees.

TARGETS:
Targets are determined at the discretion of management, with an aim to improve employee engagement scores on an annual basis.

INDUSTRY COMPARABILITY:
Widely used in the utility industry and other sectors, although survey questions and methodologies used may vary.

M5. Diversity hires (net)

DEFINITION:
The diversity hires (net) 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.

UNIT OF MEASUREMENT:
Number

FORMULA/METHODOLOGY:

New hires + rehires + changes from temporary to full-time – diversity retirements, resignations and dismissals

Where:

Diversity employees are only counted in the designated area (Aboriginal people; women in non-traditional roles; people with disabilities; and visible minorities) identified as their primary designation on their self-declaration form, regardless of whether they qualify for multiple designated areas.

Only core employees, who are permanent (full-time, part-time, seasonal, or reduced hours), including those on certain leaves of absence (education and training, maternity, parental, salary deferral, suspension without pay, or compassionate care), are included within the calculation.

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. They include lost-time injury frequency; lost-time injury severity; recordable injury frequency; and motor vehicle incident frequency.

UNIT OF MEASUREMENT:

Percentage

FORMULA/METHODOLOGY:

(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 (prior to 12.5% weighting).

Indicator results are calculated as:

$$\frac{\text{Indicator actual}}{\text{Indicator target}} \times 100\%$$

<u>Leading indicators</u>

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:

$$\left(\text{\% complete reported for Director}_n \times \frac{\text{number of employees under Director}_n}{\text{number of SaskPower employees}}\right) \times 100\%$$

Safety training

Safety training includes the mandatory safety training activities and courses required to be completed by employees each year. It 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:

$$\frac{\text{Number of completed mandatory safety training}}{\text{Number of scheduled mandatory safety training}} \times 100\%$$

Safety audits corrective/preventive actions completed (%)

Safety audits measure how well the safety management system (SMS) is being implemented and maintained, as well as the effectiveness of the SMS 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 corrective and preventive actions versus corrective and preventive actions due.

$$\frac{\text{Number of completed corrective and preventive actions}}{\text{Number of corrective and preventive actions due}} \times 100\%$$

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 work observations.

$$\frac{\text{Number of completed scheduled work observations}}{\text{Number of scheduled work observations}} \times 100\%$$

Lagging indicators

Lost-time injury frequency rate

The lost-time injury frequency rate refers to the rate of occurrence of workplace incidents that result in an employee's inability to work the next full work day. 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:

$$\frac{\text{Number of lost-time injuries x 200,000 hours}}{\text{Exposure hours}} \times 100\%$$

Lost-time injury severity rate

The lost-time injury severity rate shows the extent of safety anomalies by revealing how critical the injuries and illnesses are. The theory is that an employee who takes time to return to work after injury had a more severe problem than one who can return immediately. 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:

$$\frac{\text{Number of calendar days lost x 200,000 hours}}{\text{Exposure hours}} \times 100\%$$

Recordable injury frequency rate

The recordable injury frequency rate 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; lost-time injury; medical treatment injury; or restricted work, as well as a significant occupational injury/illness or loss of consciousness. The normalization is done based on the formula designed by the CEA as follows:

$$\frac{\text{Number of recordable injuries x 200,000 hours}}{\text{Exposure hours}} \times 100\%$$

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:

$$\frac{\text{Number of recordable LFMV incidents x 1,000,000 kilometres}}{\text{LFMV kilometres driven}} \text{ x 100\%}$$

TARGETS:

Targets are determined at the discretion of management, based on previous performance with expectations of improvement each year.

INDUSTRY COMPARABILITY:

The Safety Index is unique to SaskPower however some indicators included are comparable to safety measures used by other Canadian Utilities.

M7. Return on equity (ROE) (operating/net income) (%)

DEFINITION:

ROE is a measure of operating or net income for the year expressed as a percentage of average equity. The objective of 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:

$$\frac{\text{Debt}}{\text{Debt + equity}} \times 100\%$$

Where:

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 total PP&E. This metric illustrates how efficiently SaskPower is managing its OM&A in terms of our company's growth, as SaskPower's asset base is considered to be a key driver of OM&A costs. A lower ratio is indicative of more efficient operations.

UNIT OF MEASUREMENT:

Percentage

FORMULA/METHODOLOGY:

$$\frac{\text{OM\&A}}{\text{PP\&E}} \times 100\%$$

Where:

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:

The Aboriginal procurement metric measures the extent to which SaskPower makes business decisions that engage in Saskatchewan Aboriginal sourced procurement relative to total Saskatchewan procurement (purchase orders issued during a year). SaskPower is committed to promoting and pursuing viable business development opportunities through long-term relationships with Aboriginal people, communities and companies in the Province of Saskatchewan. The purpose of the metric is to demonstrate SaskPower's dedication to involve Aboriginal people in economic opportunities and growth.

UNIT OF MEASUREMENT:

Percentage

FORMULA/METHODOLOGY:

$$\frac{\text{YTD direct Aboriginal procurement}^{1}\text{ purchase orders (PO) issued + YTD Aboriginal procurement non-PO spend}^{2}\text{ + YTD indirect Aboriginal procurement}^{3}}{\text{YTD Saskatchewan procurement PO issued}^{4}} \times 100\%$$

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 PO issued is defined as procurement from vendors with a Saskatchewan presence or billing address with the value based on PO issued, not PO spend.

TARGETS:

Targets are determined at the discretion of management, with a focus on year-over-year growth.

INDUSTRY COMPARABILITY:

Unique to SaskPower.

M11. Competitive rates (thermal utilities) (%)

DEFINITION:

The competitive rate (thermal utilities) 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.

UNIT OF MEASUREMENT:

Percentage

FORMULA/METHODOLOGY:

Hydro Québec annually publishes *Comparison of Electricity Prices in Major North American Cities*, which reports annual rate data as of April 1 in the categories of residential, small, medium and large power customers is published by Hydro Québec in its annual *Comparison of Electricity Prices in Major North American Cities.* Results are generally released by Hydro Québec towards the end of 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, PE; 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 less than or equal to 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. It is adjusted for any temporary reductions in generating capability due to equipment failures, maintenance or other causes.

UNIT OF MEASUREMENT
Percentage

FORMULA/METHODOLOGY:

The system average EAF is an average of the individual unit EAFs, weighted by unit capacity:

(individual unit EAF x Maximum Continuous Rating (MCR) for the unit

Where an individual unit's EAF is calculated as:

$$\frac{\text{Number of hours in period - equivalent outage time}}{\text{Number of hours in the period}} \times 100 = (1 - \text{incapability factor}) \times 100$$

The System Average EAF is an average of the individual unit EAF targets, weighted by unit capacity.

TARGETS:
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. Although higher EAF percentages are better, targets are set giving consideration to prudent maintenance requirements.

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 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 is defined as the amount of time an average customer experiences outages in a year. It allows SaskPower to track its performance responding to distribution outages and analyze where additional funding is required to improve the system.

UNIT OF MEASUREMENT:
Number of outage hours per average 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 industry averages.

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 outage interruptions an average customer experiences in a year. It allows SaskPower to analyze where additional funding is required to rebuild and improve the system.

UNIT OF MEASUREMENT:
Number of outage interruptions per average customer per year.

FORMULA/METHODOLOGY:

$$\frac{\text{Number of disruptions x customers impacted}}{\text{Total customers served}}$$

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 industry averages.

INDUSTRY COMPARABILITY:
Widely used – benchmarked through CEA member results.

M14. Transmission system average interruption duration index (SAIDI) (minutes)

DEFINITION:
The transmission SAIDI is defined as the total interruption duration that an average Bulk Electrical Service Delivery Point (BESDP) experiences during a given period, usually one year. It allows SaskPower to track its performance responding to transmission outages and take corrective action as necessary.

UNIT OF MEASUREMENT:
Number of outage minutes per typical BESDP per year.

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 industry averages.

INDUSTRY COMPARABILITY:
Widely used – benchmarked through CEA member results.

M16. Transmission system average interruption frequency index (SAIFI) (outages)

DEFINITION:

The transmission SAIFI is defined as the average number of outage interruptions the average Bulk Electrical Service Delivery Point (BESDP) experiences per year. It provides SaskPower the opportunity to monitor specific outage causes and their frequency, which can be used to take corrective action.

UNIT OF MEASUREMENT:

Average number of interruptions per average BESDP 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 industry averages.

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 each transmission and distribution.

UNIT OF MEASUREMENT:

Percentage

FORMULA/METHODOLOGY:

$$\frac{\text{Planned maintenance (operating \$)}}{\text{Total maintenance activities (operating \$)}} \times 100\%$$

TARGETS:

Targets are based on moving current results toward the UMS Group recommended long-term target of 80%.

INDUSTRY COMPARABILITY:

Unique to SaskPower.

M16. Renewable generation portfolio (%)

DEFINITION:

The objective of the renewable generation portfolio metric is to show the increasing diversity in SaskPower fuel mix, and is based on renewable fuel sources as a percentage of installed generation capacity (including Independent Power Producers (IPPs)), per the SaskPower 10-Year Supply Plan. For purposes of this metric, renewable 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:

$$\frac{\text{Net renewable generating capacity}}{\text{Total net generating capacity}} \times 100\%$$

TARGETS:

Based on SaskPower's 10-Year Supply Plan.

INDUSTRY COMPARABILITY:

Unique to SaskPower.

SRRP Q148 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) Midwest Reliability Organization (MRO) conducts on-site audits of NERC reliability standards every three years.

B) The most recent audit (September 2015) resulted in five findings of noncompliance. Mitigation plans have been completed and certified by MRO for three findings.

The two remaining findings are currently in mitigation, with completion scheduled for December 2017.

NOTE:
MRO audit reports and information about mitigating activities are confidential and non-public until a public audit report is issued. A public audit report is not issued until MRO has certified mitigation of all outstanding issues from the audit. As a result, information from SaskPower's 2012 and 2015 audits is confidential.

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