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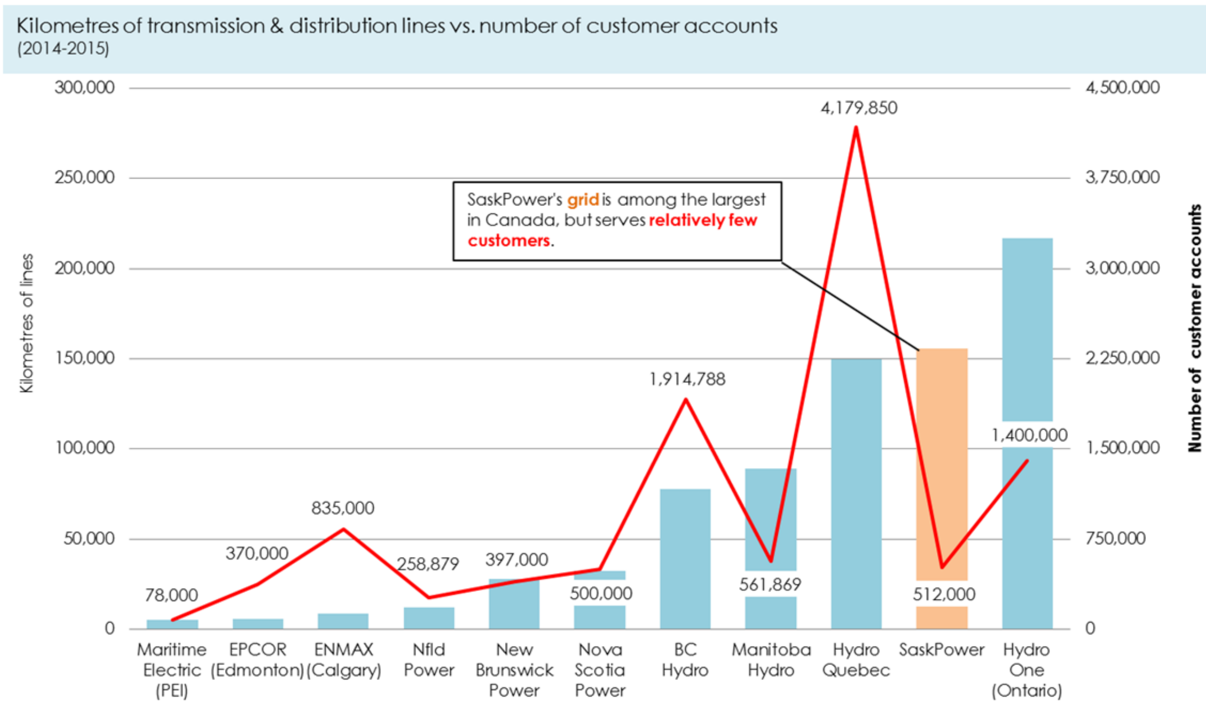
CAPP-SaskPower-1 Reference: Application page 18



Please explain why SaskPower includes two municipal-only Alberta utilities (EPCOR and ENMAX) but excludes ATCO and FortisAlberta.

CAPP-SaskPower-2 Reference: Application page 26

Other revenue

(in millions)	Twelve months December 31 2013	Twelve months December 31 2014	Twelve months December 31 2015	Twelve months March 31 2016-17	Twelve months March 31 2017-18
Gas and electrical inspections	$ 18.2	$ 22.1	$ 20.7	$ 22.0	$ 22.0
Customer contributions	45.6	46.7	92.9	50.0	50.0
CO_2 sales	-	2.8	3.1	20.3	20.7
CO_2 test facility revenue	-	-	9.1	13.4	17.0
MRM equity investment	2.6	2.0	1.3	2.1	2.1
Miscellaneous revenue	35.4	35.5	35.3	27.1	27.0
	$ 101.8	$ 109.1	$ 162.4	$ 134.9	$ 138.9

Preamble: Customer contributions are included within "Other" revenue.

a) Please provide a table showing actual and forecast data for "Customer Connects" capital expenditures and contributions by class (similar to that provided in Round1 - Consultant Q13 from the last application).

b) Please provide a table showing actual and forecast data for "Customer Connects" capital expenditures and contributions separated by distribution and transmission-connected customers (similar to that provided in Round2 - Consultant Q34 from the last application).

c) Please contrast the customer contributions as a percentage of the interconnection costs for each rate class and explain why the percentage of costs by customer class should vary to such a large degree (2014 data appeared to suggest contributions were approximately 10% of interconnection cost for the power class but 30% for other classes).

d) Please describe the basis for determining the customer contribution required. To the extent the basis varies by rate class please describe the basis for each rate class.

e) To the extent an allowable utility investment is recognized in calculating customer contribution, please describe the basis for determining the utility investment available to connect a new customer. To the extent the basis varies by rate class please describe the basis for each rate class. When was the investment level last reviewed and/or updated?

f) Is there any mechanism in place that refunds or credits customer contributions back to customers? If so, please indicate where such amounts are recorded.

CAPP-SaskPower-3 Reference: Application page 23

Energy sales volume in Saskatchewan

Energy sales volume in Saskatchewan

	Twelve months December 31	Twelve months December 31	Twelve months December 31	Twelve months March 31	Twelve months March 31
(in GWhs)	**2013**	**2014**	**2015**	**2016-17**	**2017-18**
Saskatchewan sales					
Residential	3,190.0	3,281.2	3,127.9	3,282.0	3,312.1
Farm	1,332.2	1,363.9	1,276.3	1,331.9	1,327.3
Commercial	3,663.5	3,788.2	3,795.3	3,844.9	3,875.4
Oilfields	3,448.3	3,503.1	3,493.5	3,478.9	3,551.1
Power customers	7,862.5	8,178.4	8,698.1	9,190.4	9,467.3
Reseller	1,256.8	1,273.9	1,233.8	1,290.9	1,294.7
Total Saskatchewan sales	20,753.3	21,388.7	21,624.9	22,419.0	22,827.9

Preamble:

The application suggests that residential class consumption in Fiscal 2016-17 will be at the same level as 2014.

a) Please provide the weather-adjusted consumption for the residential class from 2010 through the forecast period.

b) Please explain the year-over-year change in residential rate class consumption.

c) What percentage of sales in the Oilfield class is attributable to the “large” oilfield customers vs. “standard” oilfield customers?

d) Was the actual reduction in sales to Oilfield in 2015 resulting from the “large” oilfield customers or the “standard” oilfield customers?

e) Is the forecast reduction in sales to Oilfield in 2016-17 resulting from the “large” oilfield customers or the “standard” oilfield customers?

f) Are “large” oilfield customers generally those that are served under rates E46/E47/E48 and “standard” oilfield customers generally those served under rate E43?

CAPP-SaskPower-4 Reference: Application page 23

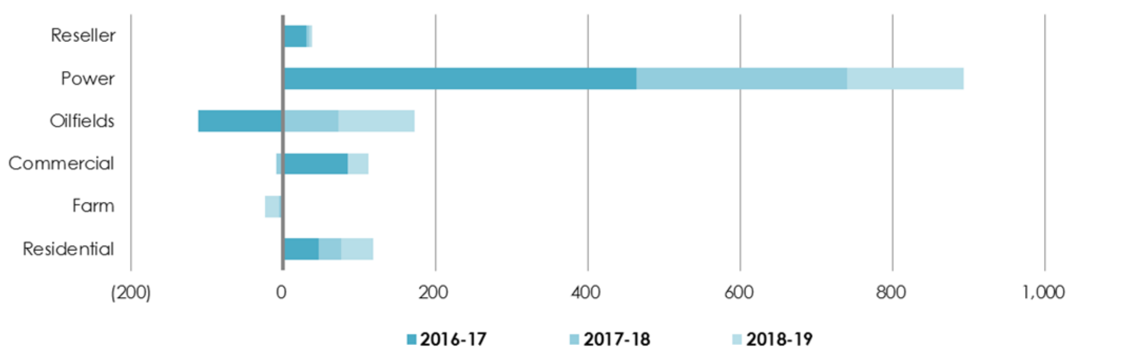
Energy sales volume in Saskatchewan

Forecasted increase in sales volume

Energy sales volume in Saskatchewan

(in GWhs)	Twelve months December 31 **2013**	Twelve months December 31 **2014**	Twelve months December 31 **2015**	Twelve months March 31 **2016-17**	Twelve months March 31 **2017-18**	Twelve months March 31 **2018-19**
Saskatchewan sales						
Residential	3,190.0	3,281.2	3,127.9	3,282.0	3,312.1	3,354.1
Farm	1,332.2	1,363.9	1,276.3	1,331.9	1,327.3	1,307.7
Commercial	3,663.5	3,788.2	3,795.3	3,844.9	3,875.4	3,903.0
Oilfields	3,448.3	3,503.1	3,493.5	3,478.9	3,551.1	3,651.1
Power customers	7,862.5	8,178.4	8,698.1	9,190.4	9,467.3	9,620.2
Reseller	1,256.8	1,273.9	1,233.8	1,290.9	1,294.7	1,298.6
Total Saskatchewan sales	20,753.3	21,388.7	21,624.9	22,419.0	22,827.9	23,134.7

Forecasted increase in sales volume
(in GWhs)



Preamble: The data in the figure/chart does not appear to be consistent with the data in the table for the oilfield class.

a) The figure/chart indicates a decrease in sales volume to Oilfields of approximately 100 GWh in 2016-17 whereas the table indicates a drop of 14 GWh. Please reconcile this apparent inconsistency.

b) The figure/chart indicates a decrease in sales volume to Commercial in 2017-18 whereas the table indicates an increase of ~30 GWh (3,875.4 – 3,844.9). Please reconcile this apparent inconsistency.

c) Do the two apparent inconsistencies in the figure/chart reflecting the Oilfield and Commercial class arise due to the figure reflecting an earlier and now updated forecast? If so, what changed between the earlier and updated forecast?

d) To SaskPower's knowledge, does the reseller class largely reflect residential and commercial customers? If not, please provide SaskPower's view as to the end-user composition of the reseller class load.

e) Please explain the low rate of growth forecast for the reseller class relative to SaskPower's residential and commercial classes.

CAPP-SaskPower-5 Reference: Application page 24

The load forecast is vital to SaskPower's budgeting and planning processes. The accuracy of the forecasts for our oilfield and large-scale industrial and commercial customers has the greatest impact on the total provincial load forecast as they are our largest customers. The demand of these customers is also the most difficult to forecast as the group is primarily made up of commodity producers and short-term plans are affected by price fluctuations and market conditions worldwide.

a) Please indicate the date the forecast of oilfield load was completed.

b) Are current economic conditions impacting the oil and gas sector consistent with the economic variables underlying the oilfield load forecast?

c) Does SaskPower anticipate updating the oilfield load and revenue forecasts prior to the Review Panel issuing its decision? If so, when will such an update be submitted?

CAPP-SaskPower-6 Reference: Application page 28

The table "Fuel and purchased power volume" provides GWh of generation by generation type.

Fuel and purchased power volume

(in GWh)	Twelve months December 31 **2013**	Twelve months December 31 **2014**	Twelve months December 31 **2015**	Twelve months March 31 **2016-17**	Twelve months March 31 **2017-18**
Fuel and purchased power					
Gas	6,460	6,883	7,976	8,927	8,672
Coal	10,846	10,219	11,011	10,916	11,016
Wind	646	636	684	772	823
Hydro	4,449	4,706	3,426	3,068	3,634
Imports	548	797	506	636	602
Other	206	183	141	179	179
	23,155	23,424	23,744	24,498	24,926

a) Please provide separately the SaskPower and IPP monthly installed capacity underlying the wind volume forecast.

b) Please provide separately the SaskPower and IPP monthly generation underlying the wind volume (GWh) forecast.

CAPP-SaskPower-7 Reference: Application page 28

Fuel and purchased power expense											
	Twelve months		Twelve months		Twelve months		Twelve months		Twelve months		Twelve months
	December 31		December 31		December 31		March 31		March 31		March 31
(in millions)	**2013**		**2014**		**2015**		**2016-17**		**2017-18**		**2018-19**
Fuel and purchased power											
Gas	$	240.6	$	286.6	$	283.5	$	281.6	$	305.3	$	308.9
Coal		223.0		246.8		285.2		272.3		279.8		283.2
Wind		10.2		10.8		16.8		21.3		21.7		25.5
Hydro		21.0		23.2		17.8		16.7		20.4		20.9
Imports		31.2		38.5		29.2		29.2		34.2		31.6
Other		23.5		31.7		17.9		25.5		25.9		36.8
	$	549.6	$	637.7	$	650.4	$	646.6	$	687.3	$	706.9

Please explain which costs for each of SaskPower-owned and IPP-owned wind facilities are included in this table under "Wind" (e.g. variable O&M).

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CAPP-SaskPower-8 Reference: Application page 28

Fuel and purchased power volume

(in GWh)	Twelve months December 31 2013	Twelve months December 31 2014	Twelve months December 31 2015	Twelve months March 31 2016-17	Twelve months March 31 2017-18	Twelve months March 31 2018-19
Fuel and purchased power						
Gas	6,460	6,883	7,976	8,927	8,672	8,232
Coal	10,846	10,219	11,011	10,916	11,016	10,880
Wind	646	636	684	772	823	1,524
Hydro	4,449	4,706	3,426	3,068	3,634	3,634
Imports	548	797	506	636	602	569
Other	206	183	141	179	179	481
	23,155	23,424	23,744	24,498	24,926	25,320

Fuel and purchased power price per generation source

(in $/MWh)	Twelve months December 31 2013	Twelve months December 31 2014	Twelve months December 31 2015	Twelve months March 31 2016-17	Twelve months March 31 2017-18	Twelve months March 31 2018-19
Fuel and purchased power						
Gas	$ 37.25	$ 41.64	$ 35.54	$ 31.55	$ 35.20	$ 37.51
Coal	20.56	24.15	25.86	24.95	25.40	26.03
Wind	86.38	88.22	95.43	96.55	98.47	101.89
Hydro	4.72	4.93	5.20	5.45	5.62	5.74
Imports	56.94	48.33	57.54	45.84	56.88	55.52
Weighted average fuel price	$ 23.74	$ 27.23	$ 27.37	$ 26.87	$ 27.58	$ 27.92

Preamble: Dividing the total fuel and purchased power cost for wind by the fuel and purchased power volume results in a unit cost much smaller than shown in the third table on page 28.

a) Please explain what volumes are reflected in the table "Fuel and purchased power volume" for wind generation.

b) Please explain what is reflected in the $/MWh value in the table "Fuel and purchased power price per generation source" for wind generation.

c) Does the $/MWh value for wind in the table "Fuel and purchased power price per generation source" include variable costs for SaskPower-owned wind generation and costs under the IPPs for IPP-owned wind generation?

d) Please explain the reason for the large jump (8.1%) in $/MWh wind costs in 2015.

e) Please explain why the unit cost for wind under the "Fuel and purchased power price per generation source" is increasing, especially in 2018-19 when new wind generation is being brought online.

f) Please describe the cost profile for wind generation IPP contracts. Are costs relatively uniform over time, with escalation provisions or are the IPPs front end loaded?

g) Given that the unit costs ($/MWh) for wind (as shown in the table) are increasing as new IPP wind generation is added in 2017-18 and 2018-19, can one conclude that the new IPP generation is more costly (or at a minimum not less costly) on a $/MWh basis that the "existing" wind generation? If not, why is this conclusion not reasonable.

h) Please describe the trend in $/MWh costs for wind generation that SaskPower has witnessed over time. Can it be expected that future wind generation will be lower cost than current generation?

CAPP-SaskPower-9 Reference: Application page 29

SaskPower's natural gas generation is supplied by nine natural gas facilities that have 1,771 MW of generation capacity; 987 MW of capacity is SaskPower-owned and our company has long-term PPAs for an additional 784 MW of natural gas-fired capacity. Natural Gas facilities

SaskPower is anticipating consuming 74.3 million gigajoules (GJ) of natural gas in 2016-17, 71.9 million GJ in 2017-18, and 67.8 million GJ in 2018-19. Our company's hedging program reduces our exposure to the volatility of natural gas prices.

a) Please provide the annual installed capacity underlying the gas volume forecast.

b) Please provide the annual generation underlying the gas volume (GWh) forecast.

c) Please provide the average annual heat rate for each of SaskPower-owned and IPP-owned gas-fired generators.

CAPP-SaskPower-10 Reference: Application page 30

Natural Gas Purchases

Natural gas is purchased on the spot market and prices are subject to significant volatility. SaskPower manages that price volatility by hedging a portion of our anticipated natural gas consumption through long-term physical and financial hedges. In addition to providing price stability, the long-term physical contracts provide some *security of supply to meet SaskPower's gas-fired facility requirements. Hedging less than our full natural gas requirements allows our company to take advantage of some upside potential if prices should fall.*

a) Please explain and quantify the cost components included in the calculation of weighted average cost of gas (e.g. commodity, transportation and storage) for each year.

b) Please provide the average cost (commodity only, in $/GJ and total $) for each of hedged and unhedged natural gas volumes, by year (actuals for 2015 and earlier, forecast for other periods).

c) Please explain which gas cost (e.g. daily market, weighted average, hedged) is used when making dispatch decisions, and explain why the cost used is the appropriate cost.

CAPP-SaskPower-11 Reference: Application page 30

Natural Gas Purchases

Natural gas is purchased on the spot market and prices are subject to significant volatility. SaskPower manages that price volatility by hedging a portion of our anticipated natural gas consumption through long-term physical and financial hedges. In addition to providing price stability, the long-term physical contracts provide some security of supply to meet SaskPower's gas-fired facility requirements. Hedging less than our full natural gas requirements allows our company to take advantage of some upside potential if prices should fall.

a) Please explain the purpose of the natural gas hedging strategy.

b) How long has the current hedging strategy been in place? Please describe any changes in hedging strategy over the last 5 years.

c) What concerns does SaskPower have in terms of security of supply? Please explain why long-term physical contracts are necessary to provide security of supply.

d) Please describe the price volatility that SaskPower is managing through its hedging activities.

e) Has the nature (i.e. magnitude and duration) of natural gas price volatility changed within the last 10 years? If so, how has the hedging strategy changed to recognize this?

f) Please explain why hedging contracts five and ten years out are required to manage price volatility.

g) Please provide a table indicating the opportunity cost/benefits in dollars and per GJ of the gas hedging program for each of the last 10 years.

CAPP-SaskPower-12 Reference: SRRP Interrogatories: Response to SRRP Q49

SaskPower plans to:

- Fully integrate the long-term hedge program into the on-going comprehensive strategic and resource planning efforts;

- Continue to improve the long-term hedge program, including addressing the recommendations in a recent third-party review of the program;

- Continue to rebalance the supply, transmission and storage service portfolio as the supply plan evolves;

- Continue to collaborate with SaskEnergy and other market participants to optimize assets;

- Continue to enhance tools, analytics and reporting; and

- Continue to evaluate the long-term people, process, technology and governance requirements associated with SaskPower's changing natural gas requirements and impending paradigm shift from fossil fuels to renewables.

a) Please explicitly identify which "program" is referred to in the second point, above.

b) Please describe the purpose of the reference third-party review of the program.

c) Please summarize the results of the third-party review.

CAPP-SaskPower-13 Reference: Application page 30

Natural gas is purchased on the spot market and prices are subject to significant volatility. SaskPower manages that price volatility by hedging a portion of our anticipated natural gas consumption through long-term physical and financial hedges. In addition to providing price stability, the long-term physical contracts provide some security of supply to meet SaskPower's gas-fired facility requirements. Hedging less than our full natural gas requirements allows our company to take advantage of some upside potential if prices should fall.

a) Please provide a schedule of all components of natural gas costs including the impacts of hedging (similar to Round 1 – Consultant Q84 in the 2014 application).

b) Please provide the annual loss or gain on a $/GJ basis from natural gas hedging for the period 2009 to 2015 (similar to Round1 – SIECA Q34 in the 2014 application).

CAPP-SaskPower-14 Reference: Application page 30

Please provide a detailed schedule of all components of fuel and purchased power costs (similar to Round 2 – Consultant Q22B in the 2014 application).

CAPP-SaskPower-15 Reference: Application page 34

Grants-in-lieu are paid to the following 13 communities across Saskatchewan: Swift Current, Estevan, Humboldt, Lloydminster, Melfort, Melville, Moose Jaw, Prince Albert, Yorkton, Regina, North Battleford, Saskatoon and Weyburn. The payments are based on the electrical revenues received from customers in those areas — as revenue increases, so do these payments.

a) Why does SaskPower pay grants-in-lieu to these 13 communities and no others?

b) Are the grants-in-lieu in place of property taxes related to SaskPower buildings/facilities?

c) Why are payments related to revenues? Is this by agreement of is there a legislated basis?

d) Are the grants-in-lieu based on the revenue from customers within the geographic boundaries of the communities?

e) Are the grants-in-lieu determined on a consistent basis in each community? If not, why not?

f) Why should all customers of SaskPower pay for grants-in-lieu that are assessed against revenues in only selected communities?

CAPP-SaskPower-16 Reference: Application page 38

SaskPower's current planned large-scale projects are listed below according to targeted completion date. All projects are subject to approval by the SaskPower Board of Directors and Crown Investments Corporation of Saskatchewan Board of Directors. Projected costs are excluded from the projects referenced below as they potentially involve IPP lease agreements.

. . .

In 2015-16, SaskPower completed an extensive site selection process for a new natural gas-fired combined cycle generating station with a capacity of up to 350 MW. The facility is required to meet growing electricity demand and to support intermittent *renewable energy generation, and will be located near Swift Current. SaskPower has issued a unique RFP for this project. In addition to IPP proposals, SaskPower has prepared a corporate-build business case that will be evaluated with the external submissions.*

a) Does the calculation of annual charges to SaskPower within an IPP contract (financial lease) result in a more front-end or back-end loaded cost stream than a traditional declining rate base cost of service approach to accounting for the capital cost of a generating asset? Please explain.

b) In evaluating an IPP vs. corporate-build does SaskPower recognize any additional equity thickness arising from the IPP (capital lease) option? If so, please explain how this impact is quantified. If no, please explain why no such recognition is made.

c) Please describe each cost category through which the costs of an IPP contract (capital leases) are passed through to customers (e.g. interest on finance leases recorded within finance charges, amortization/depreciation expense recorded within depreciation). Please provide an illustrative example.

d) Please describe each of SaskPower's "non-lease" costs that is impacted by an IPP contract (e.g. equity thickness, capital taxes etc.).

e) Are capital taxes paid by SaskPower impacted by IPP contracts? If so, please explain how the capital taxes related to an IPP are determined.

f) Please confirm that IPP contracts are recorded as leased assets under Property, Plant and Equipment on the balance sheet. If this cannot be confirmed, please explain.

g) Please confirm that the value attributed to IPP contracts as leased assets under Property, Plant and Equipment on the balance sheet is the present value of finance lease obligations. If this cannot be confirmed, please explain.

h) Please explain how the present value of finance lease obligations is calculated. How is the discount rate for the present value calculation determined? Please provide an illustrative example.

i) Please confirm that if IPP contracts are recorded as leased assets under Property, Plant and Equipment on the balance sheet, the total assets are greater with an IPP contract than without. If this cannot be confirmed, please explain.

j) Please confirm that if total assets are greater with an IPP contract than without, that for a given equity ratio, the equity return will be higher with an IPP contract than without. If this cannot be confirmed, please explain.

k) Please confirm that IPP contracts give rise to “Finance lease obligations” under liabilities on the balance sheet. If this cannot be confirmed, please explain.

l) Are “Finance lease obligations” essentially a form of debt? If not, please explain the distinction between the two.

m) Please explain how “interest on finance leases” (within finance charges) are calculated. How is the interest rate determined?

n) Please explain how amortization/depreciation of leased assets (within depreciation) is calculated.

CAPP-SaskPower-17 Reference: Application page 39

GENERATION	
TAZI TWÉ HYDROELECTRIC STATION	
IN-SERVICE	TOTAL COST (MILLIONS)
2020	$630
A proposed 50 MW power generation project in partnership with the Black Lake First Nation in northern Saskatchewan, approximately 100 kilometres south of the Northwest Territories border. Adjacent to the Fond du Lac River, the project is designed as a water diversion hydro facility that does not require a dam structure and as a result will not flood any land.	

BC Hydro Site C $8.335 billion per:

https://www.sitecproject.com/sites/default/files/Information-Sheet-Site-C-Capital-Cost-Estimate-December-2015.pdf

BC Hydro Site C 1,100 MW and 5,100 GWh/yr per:

https://www.sitecproject.com/sites/default/files/site-c-business-case-2014.pdf

a) Does the capital cost for this project include interest during construction? If so, please indicate what portion of the total cost reflects interest during construction. If not, please provide and estimate of the interest during construction.

b) Does the capital cost for this project include any required transmission upgrades? If so, what portion of the total cost reflects transmission? If not, please describe the transmission upgrades necessary and provide an estimate of the capital cost of such upgrades.

c) Can SaskPower confirm that on a $/kW basis, this project is significantly more costly than BC Hydro's Site C ($12,600/kW vs. $7,577/kW)?

d) Please indicate the median annual energy production expected from the 50 MW project.

e) Please provide an estimate of the levelized cost per MWh of generation from this project.

CAPP-SaskPower-18 Reference: Cost of Service Study Schedule 1.0: Summary of the Functionalization of Financial Account Details: 2017 Fiscal Test Embedded Cost of Service Study: Total Rate Base and Total Revenue Requirement

Return on Rate Base @ 5.92% (July 1, 2016) PDF page 35

Return on Rate Base @ 7.13% (January 1, 2017) PDF page 82

Please provide a detailed calculation each of the return on rate base values (5.92% and 7.13%), including the cost of debt and equity and debt and equity shares.

CAPP-SaskPower-19 Reference: SRRP Interrogatories: Response to SRRP Q121

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

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

a) Is the heading on this table correct?

b) Please provide the detailed derivation of the 42.5% demand/57.5% energy split, including the costs for each asset type. Please provide in a spreadsheet with all formulas intact.

c) Please confirm that the 42.5% demand/57.5% energy split is the dollar weighted average. If this cannot be confirmed, please explain.

d) Please provide the dollar amount of plant in service for each generation type.

e) Please provide and equivalent table from the 2015 Cost of Service Study submitted as part of the last application.

f) Please provide and equivalent table from the 2015 Cost of Service Study including the costs for each asset type.

g) Please describe the basis for allocating costs to each of losses, scheduling & dispatch, regulation and frequency response, spinning reserve, supplementary reserve, planning reserve and reactive supply.

h) Which asset types provide each of the services identified in g)?

i) In the table above, where are the items identified in g) recorded?

j) Please discuss the extent to which hydro generation can be dispatched to meet peak load.

k) Please discuss the ramp rate of hydro generation relative to other resources available to SaskPower.

l) Please describe the role of hydro units in meeting peak load.

m) Please provide the capacity factor of hydro generation, by month.

n) Is the role of hydro in meeting peak load consistent with a classification of 18.6% demand and 81.4% energy? Please discuss.

o) Please confirm that the classification of "clean coal" effectively classifies the costs of CCS as energy related. Please describe why this treatment is reasonable.

CAPP-SaskPower-20 Reference: Cost of Service Study Schedule 2.01: Functionalization and Classification of Financial Account Details GENERATION PLANT IN SERVICE

Asset Categories	SaskPower Total	Generation Total	Generation as a % of SaskPower Total	Load	Load
				Demand	Energy
Generation					
Power Production	**8,239.4**	8,239.4	100.0%	2,665.0	4,365.4

Preamble: The line shown above, <u>from the 2017 COSS</u>, exhibits a 37.9% demand/62.1% energy split.

Asset Categories	SaskPower Total	Generation Total	Generation as a % of SaskPower Total	Load	Load
				Demand	Energy
Generation					
Power Production	**8,239.4**	8,239.4	100.0%	2,665.0	4,365.4

The line shown above, <u>from the 2015 COSS</u>, exhibits a 47.1% demand/52.9% energy split

a) Please confirm that the current application exhibits a 37.9% demand/62.1% energy split for the load component of Power Production plant in service. If this cannot be confirmed, please explain.

b) Please confirm that the previous (2014) application exhibited a 47.1% demand/52.9% energy split for the load component of Power Production plant in service (for 2015). If this cannot be confirmed, please explain and provide the value consistent with the value in a).

c) Please describe the reasons for the change in demand/energy split between the current and prior application.

d) Please provide a breakdown of the $8,239.4 million Power Production plant in service that demonstrates all line items to which the equivalent peaker analysis is utilized to classify plant in service. Please indicate separately all line items for which the basis for classification is something other than the equivalent peaker analysis. In such cases, please identify the basis for classification.

e) Does the equivalent peaker analysis utilized for this cost of service differ from that used in the last application? If so, please provide the analysis from the previous application and describe all changes in assumptions and/or methodology.

f) Please provide the equivalent peaker analysis that forms the basis for allocating generation rate base, including the cost for both the peaker and baseload plant. Please provide a description of, and identify the source of the costs for, both the peaker and baseload plant.

g) Does SaskPower's equivalent peaker analysis index original plant costs to a current timeframe prior to apportioning costs as between demand and energy? If not, why not?

h) Please describe how IPPs are incorporated into the equivalent peaker analysis.

i) Please provide a table showing Classification of SaskPower Fixed production Costs similar to that provided in Round1 – SIECA Q36.

j) For each IPP facility, please explain how costs are classified.

k) Please provide an approximate comparison of the expected demand and energy classification percentages for a combined cycle plant owned by SaskPower and a similar plant contracted under an IPP contract. If there are differences between the classification of costs from the two plants two please explain why this should be the case.

CAPP-SaskPower-21 Reference: Cost of Service Study Schedule 4.0: Customer Data for Cost Allocation

Customer Data for Cost Allocation
2017 Fiscal Test Embedded Cost of Service Study (5%)

Customer Class	Energy Sales GWH	NCP Demand KW	CP Demand KW	NCP Load Factor [1]	CP Load Factor [2]
Urban Residential	2,545	2,399,410	522,705	12.11%	55.58%
Rural Residential	737	694,807	151,362	12.11%	55.58%
Farms	1,332	825,132	221,149	18.43%	68.75%
Urban Commercial	2,763	927,673	414,447	34.00%	76.11%
Rural Commercial	1,019	357,888	155,234	32.49%	74.91%
Power - Published Rates	6,750	1,122,756	815,879	68.63%	94.44%
Power - Contract Rates	2,441	523,605	321,364	53.21%	86.70%
Oilfields	3,479	595,762	404,976	66.66%	98.06%
Streetlights	63	15,243	7,475	47.10%	96.04%
Reseller	1,291	240,250	210,075	61.34%	70.15%
Total	**22,419**	**7,702,526**	**3,224,666**	**33.23%**	**79.36%**

a) Please confirm how many customers are reflected in the Power – Contract Rates class in both the 2015 and 2017 Cost of Service Studies.

b) Please confirm that energy sales to the Power – Contract Rates class have increased 758 GWh or 45% from the 2015 Cost of Service to the 2017 Cost of Service.

c) Please confirm that the NCP demand for the Power – Contract Rates class has increased 268 MW or 105% from the 2015 Cost of Service to the 2017 Cost of Service.

d) Please confirm that the CP demand for the Power – Contract Rates class has increased 119 MW or 59% from the 2015 Cost of Service to the 2017 Cost of Service.

e) Please confirm the above imply that the 268 MW of incremental peak load would exhibit an NCP load factor of 32% vs. 75% for the remainder of the class.

f) Please explain why the NCP load factor for the Power – Contract Rates class has decreased from 75% in 2015 to 53% in the current Cost of Service.

g) Please discuss the nature of the Power – Contract Rates load in 2015 and the nature of the load added since 2015.

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h) On what basis did SaskPower conclude that an additional 268 MW of peak load would only contribute 119 MW of coincident peak load?

CAPP-SaskPower-22 Reference: Response to SRRP Q17 (pdf page 57) - Proof of Revenue

E50	Power - Contract						
	Basic (Customers)	14	$	708,552	$	4,217.57	$
	Energy (Gwh)	2,440.7	$	139,801,727	$	0.05728	$
	Demand (kVa)	3,599,626	$	35,027,971	$	9.73	$

Response to SRRP Q122 (pdf pag 210)

SASKPOWER'S COST OF SERVICE

Class of Service	Units		
	Billing Demand (kV.a)	**Annual Sales (mW.H)**	**Number of Acccounts**
Urban Residential	-	2,545,003	330,207
Rural Residential	-	736,967	56,507
Total Residential	**-**	**3,281,969**	**386,714**
Farms	**895,020**	**1,331,884**	**60,578**
Urban Commercial	3,585,602	2,763,282	44,735
Rural Commercial	1,283,385	1,018,671	13,450
Total Commercial	**4,868,987**	**3,781,953**	**58,185**
Power - Published Rates	13,144,500	6,749,735	89
Power - Contract Rates	5,753,823	2,440,673	14
Total Power	**18,898,323**	**9,190,407**	**103**
Oilfields	2,851,174	3,478,942	19,093
Streetlights	-	62,888	2,841
Reseller	2,444,262	1,290,917	3
Total	**29,957,766**	**22,418,961**	**527,517**

a) Please explain why the annual sales and number of accounts match between these two sources but the billing demand does not. For example, billing demand for Power – Contract is shown as 3,599,626 kVA in the proof of revenue but as 5,753,823 in response to Q122. Differences are also noted for the Oilfield class where billing demand is shown as 7,597,798 kVA in the proof of revenue but as 2,851,174 in response to Q122. Please reconcile any differences by class.

b) Please explain why the number of accounts for the Power – Contract class is shown as 14 in the two references above but the response to SRRP Q126 indicates the number of customers is 2. Does the 14 refer to the number of sites served while the 2 refers to the number of corporate entities contracting for the 14 sites?

CAPP-SaskPower-23 Reference: Response to SRRP Q17 (pdf page 57) - Proof of Revenue

Rate Code	Residential	Determinant	Revenue 2015 Rates	Blended Rate
E01, E02	Basic (Customers)	330,207	$ 80,114,380	$ 20.22
	Energy (Gwh)	2,545.0	$ 321,255,712	$ 0.12623
E03, E04	Basic (Customers)	56,507	$ 19,792,886	$ 29.19
	Energy (Gwh)	737.0	$ 93,044,501	$ 0.12625
	Total Residential		$ 514,207,479	
Rate Code	Commercial			
E05, E06, E07, E08, E10, E12	Basic (Customers)	2,760	$ 2,090,928	$ 63.13
	Energy (Gwh)	2,152.7	$ 163,486,020	$ 0.07594
	Demand (kVa)	6,480,851	$ 64,869,111	$ 10.01
E15, E16, E17, E18, E35, E36, E37, E38	Basic (Customers)	2,331.00	$ 442,978	$ 15.84
	Energy (Gwh)	11.8	$ 1,282,793	$ 0.10902
E75, E76, E77, E78	Basic (Customers)	53,094	$ 19,002,951	$ 29.83
	Energy (Gwh)	1,617.4	$ 191,626,760	$ 0.11847
	Demand (kVa)	2,715,203	$ 2,860,185	$ 1.05

a) Please confirm that the demand (kVa) determinants in the proof of revenue are kVA-months.

b) Please explain why the proof of revenue reflects a per kVA rate of $1.05/mo for rates E75, E76, E77, E78 (last line of extract above) when the actual rate should be at least 10 times this amount.