SASKATCHEWAN RATE REVIEW PANEL ROUND TWO INTERROGATORY RESPONSES

[2016 and 2017 Rate Application]

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2016 and 2017 RATE APPLICATION
SRRP ROUND TWO INTERROGATORIES

SRRP R2Q1:

Reference: Application, page 3

Please provide a table showing the calculation of the rate change per month for the July 1, 2016 and Jan 1 2017 rate changes. Please include all relevant billing determinants for the applicable energy, demand and customer charges.

Response:

Please see the tables below showing the calculation of the rate change per month:

Revenue Change / Customer / Month - Proposed July 1, 2016 Increase

	A	B	C	D	E	F	G
Class of Service	**Number of Accounts**	**Sales (MW.h)**	**Billing Demand (kV.a)**	**Sales Revenue (Existing Rates) ($)**	**1-Jul-16 Proposed Increase (%)**	**1-Jul-16 Revenue Change ($)**	**1-Jul-16 Revenue Change $/cust/month**
Urban Residential	330,207	2,545,003	0	$ 401,370,092	5.1%	$ 20,466,156	$ 5
Rural Residential	56,507	736,967	0	$ 112,837,387	5.1%	$ 5,753,014	$ 8
Total Residential	**386,714**	**3,281,969**	**0**	**514,207,479**	**5.1%**	**26,219,170**	**$ 6**
Farms	**60,578**	**1,331,884**	**895,020**	**$ 168,044,865**	**5.1%**	**$ 8,567,767**	**$ 12**
Urban Commercial	44,735	2,763,282	3,585,602	$ 323,586,964	5.1%	$ 16,498,081	$ 31
Rural Commercial	13,450	1,018,671	1,283,385	$ 122,074,762	5.1%	$ 6,223,982	$ 39
Total Commercial	**58,185**	**3,781,953**	**4,868,987**	**445,661,726**	**5.1%**	**22,722,063**	**$ 33**
Power - Published Rates	89	6,749,735	13,144,500	$ 475,958,353	5.1%	$ 24,266,737	$ 22,722
Power - Contract Rates	14	2,440,673	5,753,823	$ 175,538,250	3.9%	$ 6,764,750	$ 40,266
Total Power	**103**	**9,190,407**	**18,898,323**	**651,496,603**	**4.8%**	**31,031,486**	**$ 25,106**
Oilfields	19,093	3,478,942	2,851,174	$ 326,443,622	5.1%	$ 16,643,728	$ 73
Streetlights	2,841	62,888	0	$ 15,675,844	5.1%	$ 799,233	$ 23
Reseller	3	1,290,917	2,444,262	$ 94,521,722	5.1%	$ 4,819,190	$ 133,866
Total	**527,517**	**22,418,961**	**29,957,766**	**$ 2,216,051,862**	**5.0%**	**$ 110,802,638**	**$ 18**

Revenue Change / Customer / Month - Proposed January 1, 2017 Increase

	A	B	C	D	E	F	G
Class of Service	**Number of Accounts**	**Sales (MW.h)**	**Billing Demand (kV.a)**	**Sales Revenue (Adjusted Rates) ($)**	**1-Jan-17 Proposed Increase (%)**	**1-Jan-17 Revenue Change ($)**	**1-Jan-17 Revenue Change $/cust/month**
Urban Residential	330,207	2,545,003	0	$ 421,836,248	5.1%	$ 21,487,010	$ 5
Rural Residential	56,507	736,967	0	$ 118,590,401	5.1%	$ 6,040,995	$ 9
Total Residential	**386,714**	**3,281,969**	**0**	**540,426,649**	**5.1%**	**27,528,005**	**$ 6**
Farms	**60,578**	**1,331,884**	**895,020**	**$ 176,612,633**	**5.1%**	**$ 8,996,648**	**$ 12**
Urban Commercial	44,735	2,763,282	3,585,602	$ 340,085,046	5.1%	$ 17,323,932	$ 32
Rural Commercial	13,450	1,018,671	1,283,385	$ 128,298,744	5.1%	$ 6,535,538	$ 40
Total Commercial	**58,185**	**3,781,953**	**4,868,987**	**468,383,789**	**5.1%**	**23,859,470**	**$ 34**
Power - Published Rates	89	6,749,735	13,144,500	$ 500,225,090	5.1%	$ 25,481,466	$ 23,859
Power - Contract Rates	14	2,440,673	5,753,823	$ 182,303,000	3.9%	$ 7,103,375	$ 42,282
Total Power	**103**	**9,190,407**	**18,898,323**	**682,528,089**	**4.8%**	**32,584,841**	**$ 26,363**
Oilfields	19,093	3,478,942	2,851,174	$ 343,087,350	5.1%	$ 17,476,870	$ 76
Streetlights	2,841	62,888	0	$ 16,475,077	5.1%	$ 839,240	$ 25
Reseller	3	1,290,917	2,444,262	$ 99,340,912	5.1%	$ 5,060,426	$ 140,567
Total	**527,517**	**22,418,961**	**29,957,766**	**$ 2,326,854,500**	**5.0%**	**$ 116,345,500**	**$ 18**

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Revenue Change / Customer / Month - Proposed July 1, 2016 & January 1, 2017 Increase (Compounded)

	A	B	C	D	E	F	G
Class of Service	Number of Accounts	Sales (MW.h)	Billing Demand (kV.a)	Sales Revenue (Existing Rates) ($)	Compounded Proposed Increase (%)	Compounded Revenue Change ($)	Compounded Revenue Change $/cust/month
Urban Residential	330,207	2,545,003	0	$ 401,370,092	10.5%	$ 41,953,166	$ 11
Rural Residential	56,507	736,967	0	$ 112,837,387	10.5%	$ 11,794,009	$ 17
Total Residential	**386,714**	**3,281,969**	**0**	**514,207,479**	**10.5%**	**53,747,175**	**$ 12**
Farms	**60,578**	**1,331,884**	**895,020**	**$ 168,044,865**	**10.5%**	**$ 17,564,415**	**$ 24**
Urban Commercial	44,735	2,763,282	3,585,602	$ 323,586,964	10.5%	$ 33,822,014	$ 63
Rural Commercial	13,450	1,018,671	1,283,385	$ 122,074,762	10.5%	$ 12,759,520	$ 79
Total Commercial	**58,185**	**3,781,953**	**4,868,987**	**445,661,726**	**10.5%**	**46,581,533**	**$ 67**
Power - Published Rates	89	6,749,735	13,144,500	$ 475,958,353	10.5%	$ 49,748,203	$ 46,581
Power - Contract Rates	14	2,440,673	5,753,823	$ 175,538,250	7.9%	$ 13,868,125	$ 82,548
Total Power	**103**	**9,190,407**	**18,898,323**	**651,496,603**	**9.8%**	**63,616,328**	**$ 51,470**
Oilfields	19,093	3,478,942	2,851,174	$ 326,443,622	10.5%	$ 34,120,598	$ 149
Streetlights	2,841	62,888	0	$ 15,675,844	10.5%	$ 1,638,473	$ 48
Reseller	3	1,290,917	2,444,262	$ 94,521,722	10.5%	$ 9,879,616	$ 274,434
Total	**527,517**	**22,418,961**	**29,957,766**	**$ 2,216,051,862**	**10.3%**	**$ 227,148,138**	**$ 36**

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SRRP R2Q2:

Reference: Competitiveness

Please provide a table showing the calculation of bills before applicable taxes for each of the following types of customers located in Regina at rates effective April 1, 2016, July 1, 2016 and proposed for January 1, 2017. 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:

	Residential (Urban)			Small Commercial (Urban)			Power (138kv - Urban)		
	1-Apr-16	1-Jul-16	1-Jan-17	1-Apr-16	1-Jul-16	1-Jan-17	1-Apr-16	1-Jul-16	1-Jan-17
Rate Code	E01	E01	E01	E75	E75	E75	E24	E24	E24
Energy (kwh)	625	625	625	2,000	2,000	2,000	3,060,000	3,060,000	3,060,000
Energy Rate	$ 0.12623	$ 0.13267	$ 0.13943	$ 0.12128	$ 0.12746	$ 0.13395	$ 0.05421	$ 0.05697	$ 0.05987
Energy Revenue	$ 78.89	$ 82.92	$ 87.14	$ 242.56	$ 254.92	$ 267.90	$ 165,882.60	$ 174,328.20	$ 183,202.20
Demand (kw)	0	0	0	14	14	14	5000	5000	5000
Demand Rate	$ -	$ -	$ -	$ -	$ -	$ -	$ 7.350	$ 7.725	$ 8.119
Demand Revenue	$ -	$ -	$ -	$ -	$ -	$ -	$ 36,750.00	$ 38,625.00	$ 40,595.00
Basic Monthly Rate	$ 20.22	$ 21.25	$ 22.33	$ 27.62	$ 29.03	$ 30.51	$ 6,757.00	$ 7,101.51	$ 7,463.26
Basic Monthly Revenue	$ 20.22	$ 21.25	$ 22.33	$ 27.62	$ 29.03	$ 30.51	$ 6,757.00	$ 7,101.51	$ 7,463.26
Total Energy Charges	$ 99.11	$ 104.17	$ 109.47	$ 270.18	$ 283.95	$ 298.41	$ 209,389.60	$ 220,054.71	$ 231,260.46
Municipal Surcharge	$ 9.91	$ 10.42	$ 10.95	$ 27.02	$ 28.40	$ 29.84	$ 20,938.96	$ 22,005.47	$ 23,126.05
Total Charges	$ 109.03	$ 114.59	$ 120.42	$ 297.20	$ 312.35	$ 328.25	$ 230,328.56	$ 242,060.18	$ 254,386.51

SRRP R2Q3:

Reference: **First Round Q2: Application:**
Please quantify how much of the $7 million change in net income resulting from a $100 million change in capital spending relates to depreciation expense versus interest expense or return on equity.

Response:

The calculation to determine the $7 million change noted above is as follows:

Depreciation expense
$100 million / 30 year amortization = $3.3 million / year

Interest expense
$100 million @ 3.5% = $3.5 million / year

SRRP R2Q4:

Reference: **First Round Q3: Application:**
For each chart provided in the response, please provide a table summarizing the calculation of each bill in each year showing both the rates and the billing determinants (units of demand and energy).

Response:

Please see the attached Excel file titled, "SRRP R2Q4-tables."

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SRRP R2Q5:

Reference: **First Round Q4: Application Rate Scenarios**

Please provide a version of the tables in the response to first round question 4 for the following additional scenarios:

i) Confirmation of a 5% average rate increase effective July 1, 2016 and an additional 2.5% average rate increase effective April 1, 2017.

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

Response:

The following tables provide the analysis for the rate increase scenarios requested above:

5% Jul 1, 2016; 2.5% rate increase Apr 1, 2017

Financial/Productivity Indicators	December 2014	December 2015	2016/17	2017/18
Avg customer rate increase (%) *	5.5	5.0	5.0	2.5
Operating income (millions $)	43.2	103.6	126.9	147.2
Net Income (millions $)	59.6	39.7	152.3	147.2
Total Domestic electricity sales reve	2,042.7	2,127.7	2,299.2	2,418.7
Finance Charges	325.5	361.6	418.7	414.7
Return on equity (%)	2.0	4.7	5.6	6.1
Debt ratio incl. capital leases (%)	73.1	74.8	75.0	74.6

5% Jul 1, 2016; 2.5% rate increase Apr 1, 2017; 2.5% January 1, 2018

Financial/Productivity Indicators	December 2014	December 2015	2016/17	2017/18
Avg customer rate increase (%) *	5.5	5.0	5.0	5.1
Operating income (millions $)	43.2	103.6	126.9	162.3
Net Income (millions $)	59.6	39.7	152.3	162.3
Total Domestic electricity sales reve	2,042.7	2,127.7	2,299.2	2,433.8
Finance Charges	325.5	361.6	418.7	414.6
Return on equity (%)	2.0	4.7	5.6	6.8
Debt ratio incl. capital leases (%)	73.1	74.8	75.0	74.4

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SRRP R2Q6:

Reference: **First Round Q31: Other Revenue**

Please provide an explanation for the decrease in miscellaneous revenue from $2.5 million in 2015/16 to $389,000 in 2016/17.

Response:

The two primary contributors to the drop in miscellaneous revenue were:

1. Approximately $0.6 million from stale dated cheques
2. Approximately $0.6 million in lease revenue from a third party.

These items were not included in the 2016/17 budget.

Miscellaneous revenue for 2016-17 is under review and may be adjusted for the Mid-Application Update.

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SRRP R2Q7:

Reference: **First Round Q31: Other Revenue**

Please elaborate on the adjustments to the load forecast described in this response. Please indicate which customer classes the reduced sales forecasts related to and explain the reasons for the adjustments.

Response:

The table below outlines the specific customer classes that were impacted by the updated load forecast.

The reductions are largely related to two customer classes (oilfield and power customers) and are due primarily to a slowdown in the oil and gas sector.

	2016-17			2017-18			2018-19		
Customer Class	Original Business Plan	Business Plan Update	Variance	Original Business Plan	Business Plan Update	Variance	Original Business Plan	Business Plan Update	Variance
Residential	3,282.1	3,282.0	(0.1)	3,312.2	3,312.1	(0.1)	3,354.3	3,354.1	(0.2)
Farm	1,331.9	1,331.9	-	1,327.3	1,327.3	-	1,307.7	1,307.7	-
Commercial	3,844.9	3,844.9	-	3,875.5	3,875.4	(0.1)	3,903.1	3,903.0	(0.1)
Oilfields	3,502.5	3,478.9	(23.6)	3,642.9	3,551.1	(91.8)	3,746.0	3,651.1	(94.9)
Power customers	9,221.0	9,190.4	(30.6)	9,555.5	9,467.3	(88.2)	10,011.8	9,620.2	(391.6)
Reseller	1,290.9	1,290.9	-	1,294.7	1,294.7	-	1,298.5	1,298.6	0.1
Total	22,473.3	22,419.0	(54.3)	23,008.1	22,827.9	(180.2)	23,621.4	23,134.7	(486.7)

SRRP R2Q8:

Reference: **First Round Q63: Renewable Integration**

Please provide additional information on the scope of the study and when the study is expected to be completed.

Response:

SaskPower is proposing to undertake a Renewables Integration Study (RIS) that is specific to Saskatchewan and will help address the challenges posed by the large increase in renewable generation that is planned to be added between now and 2030. The concern over renewable generation is due in part to the following:

- Renewables are intermittent resources (sources of energy that are not continuously available due to factors outside the direct control of the operator);
- Not being able to directly control the fuel source corresponds to not being able to directly control the output (dispatch level); and
- Renewables add another factor that system operators need to account for in balancing the system (on top of variations already cause by load, generation, and transmission).

The RIS will focus on wind integration (as the majority of the planned new renewables are wind) however the study will also consider the impacts from other renewables (such as solar, hydro, etc.). The RIS will be used by SaskPower to enhance our skill sets in order to better understand, quantify and manage the operational impacts that come with a large percentage of renewables in our system.

SaskPower currently has a Request for Proposals issued that will close in August 2016. The RIS is anticipated to be completed by the end of 2017. However, this schedule may be adjusted once a consultant is selected.

SRRP R2Q9:

Reference: **First Round Q69: OM&A**

Please provide the following information to assist with understanding the information provided in the first round response:

i. Please describe what types of costs are included in "premium pay" (e.g. overtime).
ii. Please describe the nature of the "labour credits". Are these primarily salaries and wages that are capitalized?
iii. Please provide an explanation for why bad debt expense has increased from approximately $3 million in 2013 and 2014 to $6 million in 2015 and the test years and elaborate on any measures SaskPower is taking to address this issue.

Response:

i. Premium pay includes costs such as: overtime pay, stand-by pay, stat holiday pay, insufficient notice pay, substitution pay, shift differential pay and temp instructor premium pay.

ii. Labour credits are internal salary and benefit costs of employees that are capitalized.

iii. The bad debt increase in 2015 was the result of more residential customers defaulting on bill payments, or not paying bills in a timely manner, which resulted in an increase in the allowance for doubtful accounts.

Customer Care & Billing is undertaking a number of initiatives in 2016 to manage bad debts including:

1. Reviewing key processes to identify improvements that will increase the timeliness of collection activities;
2. Cross training of Customer Care & Billing staff in collection activity to maximize the utilization of staff and collection efforts;
3. Automation of some collection steps, namely the sending of final outstanding bill notices to customers, which was completed in May 2016;
4. Reviewing technology solutions, such as auto dialing and auto text message reminders to customers for past due accounts; and
5. Reviewing the potential to utilize multiple collection agencies to enhance our collection efforts.

SRRP R2Q10:

Reference: **First Round Q73: OM&A**

For each year summarized in the response to question 73, please provide a breakdown of the total overhaul costs by category including salaries and wages, materials and supplies, external services and other expenses.

Response:

The following is a summary of actual and forecasted overhaul costs for the years 2013 to 2018 (in $millions).

GAS PLANTS:

All of these costs are contracted services.

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

COAL PLANTS:

2013	**$10.8 million**
Contract services	$9,421,509.90
Labour-premium – IBEW	576,193.01
Labour-premium – MGMT	12,525.17
Labour-regular – IBEW	618,342.13
Labour-regular – MGMT	18,312.50
Materials	240,855.03
2014	**$31.8 million**
Contract services	$21,975,040.81
Labour-premium – IBEW	2,586,896.94
Labour-premium – MGMT	112,495.66
Labour-regular – IBEW	2,477,242.47
Labour-regular – MGMT	41,481.36
Materials	4,566,242.83

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2015	**$23.5 million**
Contract services	$16,895,888.18
Labour-premium – IBEW	1,677,160.38
Labour-premium – MGMT	97,807.19
Labour-regular – IBEW	1,644,484.69
Labour-regular – MGMT	52,558.70
Materials	3,102,872.65
2016/17	**$45.1 million**
Contract services	$32,908,158.36
Labour-premium – IBEW	4,234,890.25
Labour-regular – IBEW	388,768.00
Materials	7,635,405.28
2017/18	**$50.7 million**
Contract Services	$37,698,526.00
Labour-premium – IBEW	2,756,480.00
Labour-regular – IBEW	254,768.00
Materials	9,947,380.00

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SRRP R2Q11:

Reference: **First Round Q76: OM&A**

Please indicate the approximate breakdown in employee complement between those employees subject to collective agreements and those who are excluded from collective agreements.

Response:

As of August 2, 2016, approximately 64% of SaskPower's permanent workforce was unionized and subject to collective agreements, with the remaining 36% being out-of-scope.

SRRP R2Q12:

Reference: **First Round Q85 and Q86: Tax Expense**

a) Please clarify whether the total paid up capital figure in the response to Q85 includes other comprehensive income or not. If OCI is included, please provide a version of the table that breaks out the impact of OCI on a separate row.

b) Please confirm whether the $10 million exemption applies to each Crown utility or if the $10 million exemption is a total for all Crown utilities.

Response:

a) Other comprehensive income was included in the total paid up capital figure. The table has been updated to reflect the OCI as a separate item.

Computation of Taxable Paid-Up Capital	2015	2016/2017	2017/2018
Surpluses - Earned	1,690	1,526	1,538
- AOCI	(8)	(8)	(8)
- Contributed	660	660	660
Loans and Advances from shareholders, related persons and related corporations	1,105	1,087	1,177
Reserves deducted from income and not allowed as a deduction for income tax purposes	248	252	261
Indebtedness	4,387	5,094	5,520
Subtotal	8,082	8,611	9,148
Subtract: Amounts deducted for income tax purposes in excess of amounts recorded in books. Excess of Net Book Value(NBV) over Undepreciated Capital Cost (UCC)	(1,438)	(1,620)	(1,757)
Total Paid- Up Capital	6,644	6,991	7,391
Deduct Allowances			
Standard Exemption	10	10	10
Additional Exemption	4	4	4
Investment Allowance	51	37	38
Total Deductions	65	51	52
Taxable Paid-Up Capital	6,579	6,940	7,339
Tax Rate	0.6%	0.6%	0.6%
Corporation Capital Tax Payable	39	42	44

b) Each commercial Crown corporation is entitled to a standard exemption of $10 million. There is an additional $10 million exemption available that is shared by the Crown corporations.

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SRRP R2Q13:

Reference: **First Round Q100: Load Forecast**

Please provide versions of the Q1 and Q4 2015 Load Forecast documents with any confidential information removed or redacted that can be made public.

Response:

The 2015 Load Forecast follows, as well as an Information Item in which any confidential references to customers have been removed.

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2015 LOAD FORECAST

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Load & Revenue Forecasting
2015 August 6

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LOAD FORECAST UNCERTAINTY

TABLES

INTRODUCTION

The Load Forecast is developed annually to determine the long term energy requirements and system peak demand for SaskPower's customers in the province of Saskatchewan. The 2015 Load Forecast was prepared for the years 2016 through 2025 using inputs from the 2015 SaskPower Economic Forecast, historical energy sales, and individual customer forecasts. The forecast is a compilation of energy sales forecasts for Power Accounts, Oilfield, Commercial, Residential, Farm, and Reseller customers and also includes projections for internal corporate use, system losses, peak demand, unaccounted energy use, and non-grid energy use. SaskPower’s load forecast forms the basis for capacity additions, maintenance schedules, power plant operations, fuel budgets, operation budgets and the corporate revenue forecast.

A major input to the Load Forecast is the SaskPower Economic Forecast which provides information on population and household growth and GDP growth rates for commercial and farm categories. It is important to note that SaskPower and the Ministry of Finance use the same econometric model for forecasting and work closely together to ensure consistency. Since weather can have a significant impact on the amount of electricity used by Residential, Commercial, Farm and Reseller customers, average daily weather conditions for the last thirty years are assumed throughout the forecast horizon.

SaskPower’s load forecast methodology is reviewed by outside industry experts every 5 years. The purpose of this review is to determine if the methodology is appropriate for SaskPower and is consistent with accepted electric power utility practices. The last methodology review was completed in 2010 by Itron Inc. Itron provided verification of SaskPower’s methodology using their own forecasting expertise as well as an in depth industry survey.

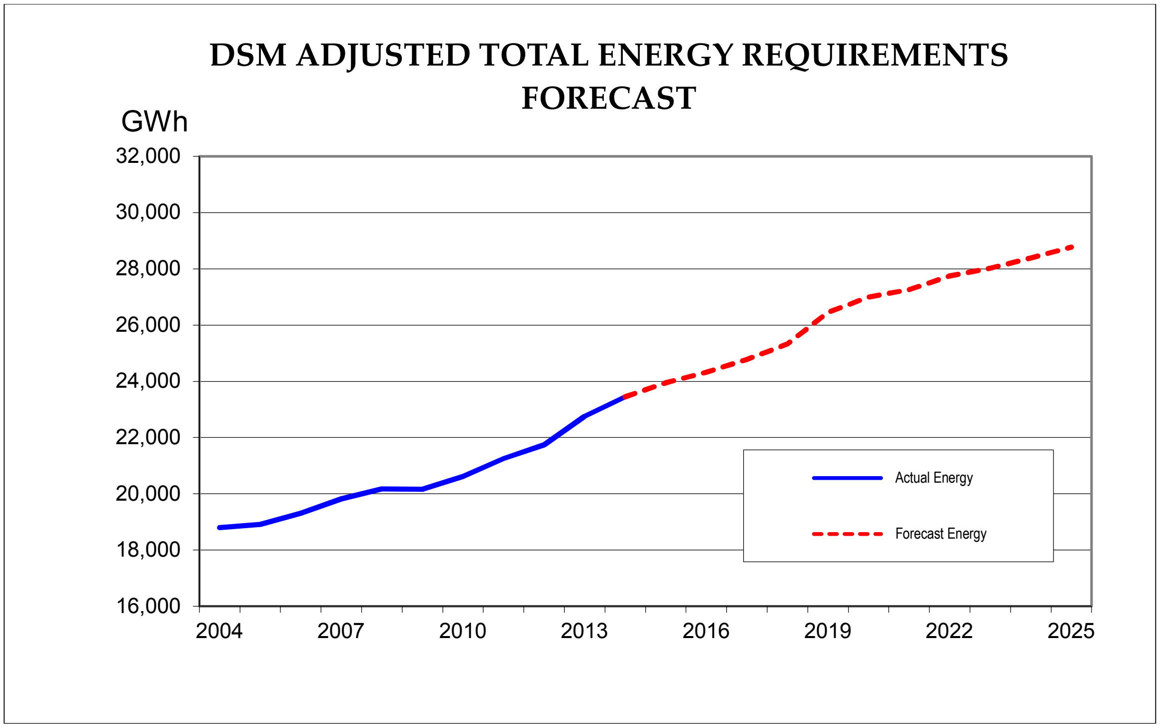
While there are many variables that can affect load forecasts, the most significant for SaskPower are the forecasts provided by large-scale industrial and commercial customers in the Power class. SaskPower contacts these customers quarterly to obtain short and long term expansion plans. This report summarizes the results of the 2015 Q1 load forecast which is based on discussions with Power class customers in the first trimester of 2015. Quarterly forecast updates will be prepared using data provided by Power class customers in June, September and November.

Load & Revenue Forecasting develops a “Base” and “DSM Adjusted” load forecast. Once the 2015 Base forecast is completed using the methodology outlined above, the energy and peak demand savings identified by Customer Services are removed. All tables in this report will reflect the DSM adjusted forecast. Table A5 at the end of this report provides a summary of the Base and DSM Adjusted Forecasts.

Introduction (cont.)

Total System Energy Requirements

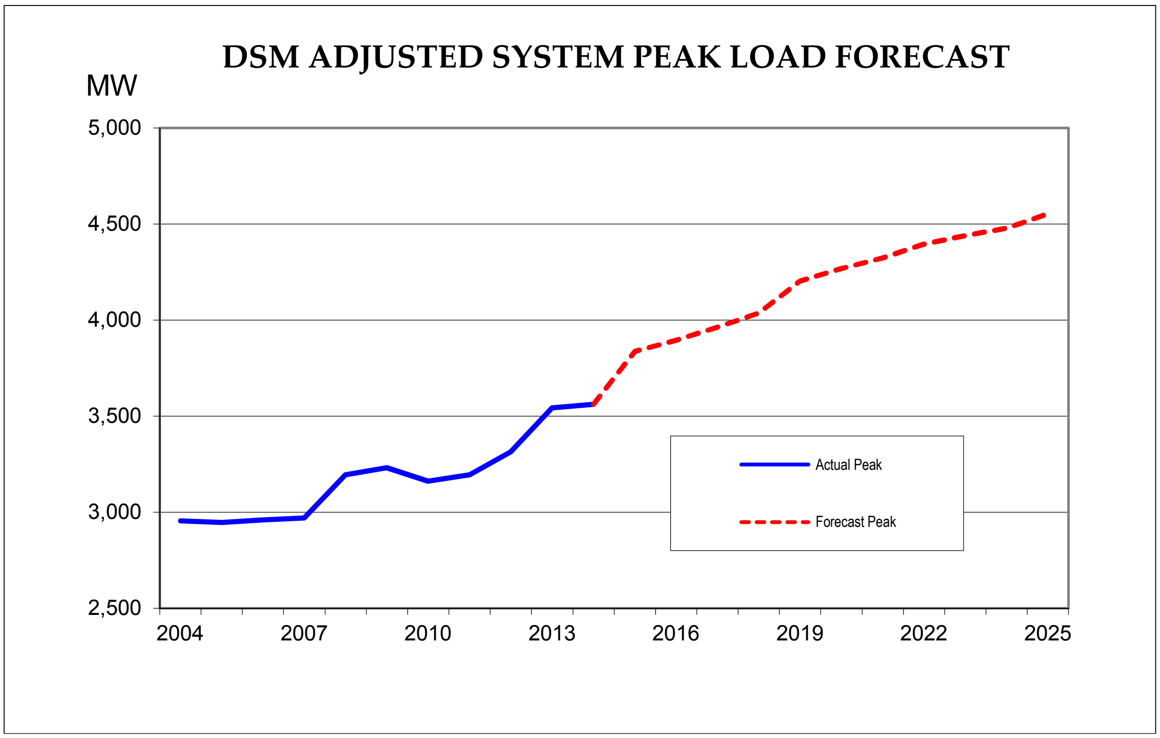
The 2015 DSM adjusted load forecast predicts an increase in the total system energy requirements of **4,815.5** GWh over the next 10 years. This increase from **23,950.5** GWh in 2015 to **28,766.0** GWh in 2025 translates into an average annual growth rate of **1.8%** (Refer to Table A1). The historical average annual growth rate was **2.2%** for the years 2004-2014. The consistent growth rate in the 2015 load forecast is largely attributed to the expected growth in the Power, Oilfield, Commercial and Residential classes.



Introduction (cont.)

System Peak Load

The DSM adjusted calendar system peak load is expected to increase by **717** MW from **3,836** MW in 2015 to **4,553** MW in 2025. This equates to an average annual growth rate of **1.7%** (Refer to Table A1)**.** The system peak demand grew at an average annual rate of **1.9%** for the years 2004-2014.
Table A4 at the back of this report provides additional information on SaskPower's system peak demand. In addition to the (winter) potential peak forecast, table A4 also provides the summer potential peak forecast, which assumes sustained hot weather occurring in July. A most likely winter and summer peak forecast, based on the actual weather experienced at the time of the system peaks over the last 5 years, is also provided.



This report documents the definition of each customer class, the methodology behind the derivation of the forecast data, the assumptions and the forecast results for the 2015-2025 timeframe.

POWER ACCOUNTS

Definition

A Power customer is defined as any large commercial or industrial customer who is currently on Standard Power rates or who has negotiated an Energy Service Agreement with SaskPower.

The 2015 Power Account load forecast is a compilation of individual forecasts for each Power customer. Each customer forecast includes firm load and probable load when applicable. Firm load consists of projects or expansions which are very likely to proceed. Normally these are projects that are 2 to 3 years out, and the project has been announced and approved. Probable loads are longer term expansion plans or new projects which have not been approved. With input from SaskPower Senior Business Advisors, Key Accounts, these loads are assigned a probability of proceeding, and are included in the forecast on that basis.

Methodology

The primary method used to forecast load for the Power class is through individual customer forecasts. SaskPower's Senior Business Advisors, Key Accounts meet with each customer and record their future load growth plans. SaskPower will also consult with the Ministry of the Economy to review mine expansion plans in the province. SaskPower also develops a potash sector energy forecast based on the Ministry of the Economy's potash production forecast. This forecast is used to compare to, and adjust, the individual potash customer forecasts if required.

After the Base Power class forecast has been completed, the DSM energy savings are removed; resulting in the DSM adjusted Power class forecast.

Assumptions

Monthly maintenance schedules for individual Power customers are determined either by the customer's forecast or by assuming the same historical maintenance cycle.

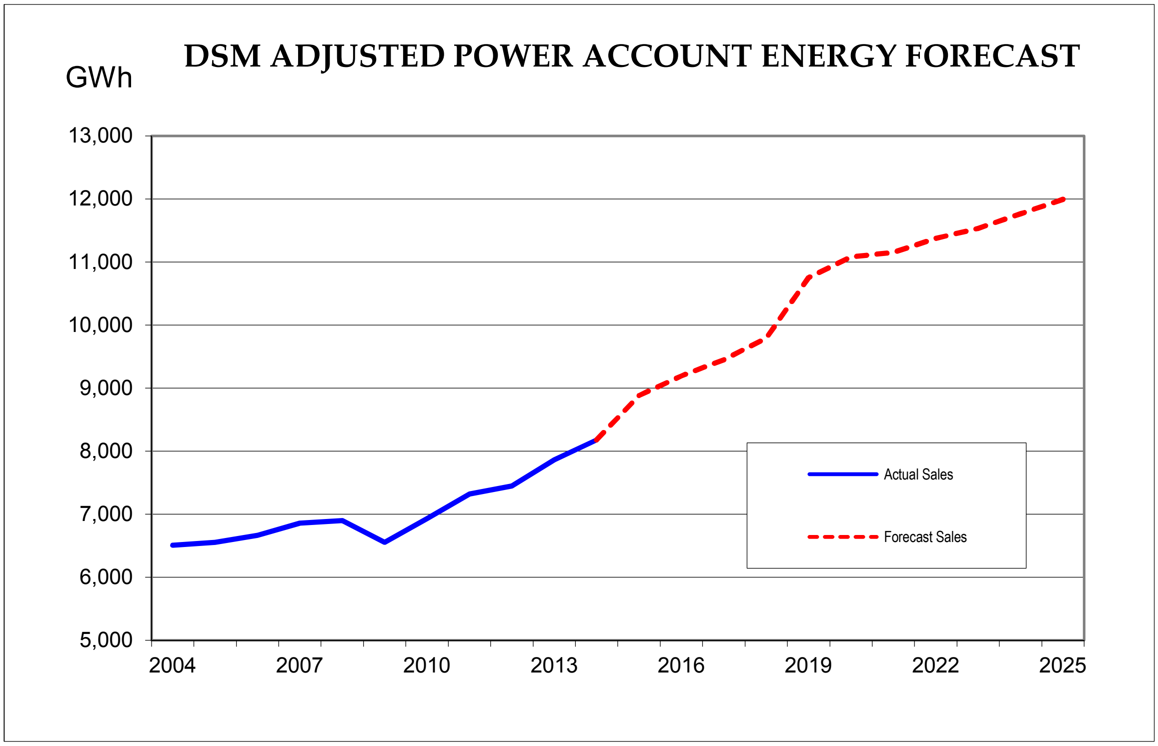
SaskPower will maintain its current customer base and market share.

Power Account Forecast Results

The total DSM adjusted Power class sales forecast (including probable load) is expected to grow from **8,882.9** GWh in 2015 to **11,992.7** GWh in 2025. The total increase of **3,109.8** GWh equates to an average annual growth rate of **3.0%** (Refer to Table A2).

Power Accounts (cont.)

Energy sales for the Power class have grown at an average rate of **2.3%** per year from 2004-2014. In 2009, energy sales dropped substantially due to the global economic downturn. The potash, pipeline pumping and steel sectors were particularly hard hit in Saskatchewan. In 2010 the Power class load returned to levels exceeding those before the economic downturn.



Power Account Major Growth Increases

The major growth in the Power class is from the potash, pipeline pumping, and northern mining sectors.

Potash Sector

There was a reduction in potash sales and the energy supplied to Saskatchewan potash mines in 2009, however energy sales returned to normal levels in 2010. Expansions are planned or underway at most existing mine sites, and two new mines are in the planning or construction stages. By 2025, the annual sector load is forecast to increase by **1,469** GWh.

Pipeline Pumping Sector

In the pipeline sector, loads are increasing as expanding Alberta oilsands production and conventional oil production in Alberta and Saskatchewan are shipped through Saskatchewan to markets in eastern Canada and the United States. By 2025, the annual sector load is forecast to increase by **1,080** GWh.

Power Accounts (cont.)

Northern Mining Sector
The northern mining sector consists of the gold and uranium mines supplied through the northern transmission system originating from the Island Falls generating plant. Load increases are expected at most sites in the northern mining sector due to market demands. The annual sector load is expected to be **315** GWh higher by 2025.

OILFIELD

Definition

Oilfield customers are those involved in individual oil and gas production and 'in-field' oil pumping and processing services. The Oilfield class is comprised of wells pumping oil from underground patches throughout Saskatchewan. These wells are separated into six regions: **Lloydminster Heavy, Kindersley Heavy, Swift Current Medium, Estevan Medium, Kindersley Light and Estevan Light.**

Due to the global nature of the oil and gas market, oil production in Saskatchewan is heavily influenced by the world market. It is greatly affected by the demand for and price of oil and gas and by provincial royalty structures.

Methodology

Econometric, extrapolation and statistical regression methods are used to determine the future energy requirements of the Oilfield class. The number of customer accounts is estimated using the existing number of operating wells and future forecasts of the number of wells drilled, provided by the Ministry of Economy. To determine the forecast for the Oilfield class energy, a regression analysis is developed for energy intensity in kWh per cubic meter of oil or fluid (oil and water) production by year for each region. The forecasted energy requirements are then calculated using the regression analysis results and the forecasted oil or fluid (oil and water) production. The forecasted oil production is provided by the Ministry of Economy and the Canadian Association of Petroleum Producers and the forecasted water production is based on historic water cut trends.

Large Oilfield customer forecasts are prepared on an individual basis. The methodology for the preparation of this forecast is based on historical usage patterns, individual customer information (if available), along with the appropriate Ministry of Economy growth drivers.

After the Base Oilfield class forecast has been completed, the DSM energy savings are removed; resulting in the DSM adjusted Oilfield class forecast.

Assumptions

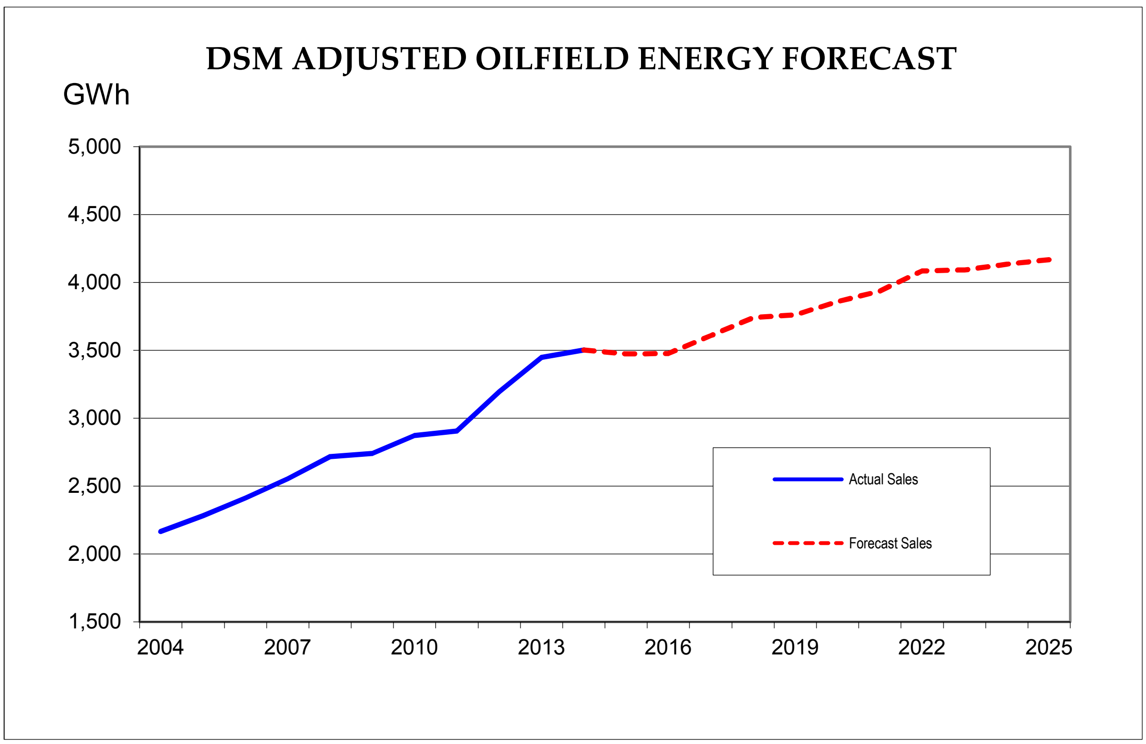
An oil production forecast for the years 2015-2025 was provided by the Ministry of Economy and by the Canadian Association of Petroleum Producers (CAPP).

Oilfield (cont.)

Oilfield Forecast Results

The DSM adjusted 2015 Oilfield forecast predicts energy sales to grow from **3,474.3** GWh in 2015 to **4,168.2** GWh in 2025. The increase of **693.9** GWh equates to an average annual growth rate of **1.8%** (Refer to Table A2). This is a result of the oil production forecast which peaks and then drops off over the 10 year period, and increased water production. Aging Saskatchewan oilfields also require more energy to extract oil from reserves including the use of CO2 injection to enhance oil recovery.

Energy sales for the Oilfield sector have grown at an average rate of **4.9%** per year from 2004-2014. The reduction in growth rate from historical levels is a result of lower oil production forecast offset by increased water production and higher energy intensity levels. Low oil prices have impacted oil production and the Oilfield load forecast in the short term.



COMMERCIAL

Definition

Commercial customers are defined as non-residential and non-farm customers not included in any other category. This customer class consists of customers involved in a wide range of activities, varying from small and large business establishments to streetlights.

Methodology

Econometric, extrapolation and statistical regression methods are used to develop the energy forecast for the Commercial class. The forecasted number of commercial customers forecast is determined by first developing a regression analysis with the number of residential customers. This regression is then combined with the forecasted number of residential customers (from the Economic Forecast) to determine the future number of commercial customers.

Forecasted Commercial class energy sales are determined by first removing the streetlight load from the commercial class. The Streetlight energy forecast is determined by lamp count and usage for different lamp technologies with future lamp counts escalated to the number of Residential customers. The remainder of the Commercial class load is forecasted using a regression analysis of commercial energy sales to GDP indicators from the SaskPower Economic Forecast for the following commercial categories.

Finance, Insurance and Real Estate
Public Administration
Retail and Wholesale Trade
Transportation & Warehousing

The forecasted GDP indicators for these categories from the Economic Forecast and the regression analysis results are used to forecast future Commercial class energy sales.

After the Base Commercial class forecast has been completed, the DSM energy savings as identified by SaskPower's DSM department are removed; resulting in the DSM adjusted Commercial class forecast.

Assumptions

The electrical usage for commercial customers assumes weather conditions equivalent to the average weather conditions over the last thirty years.

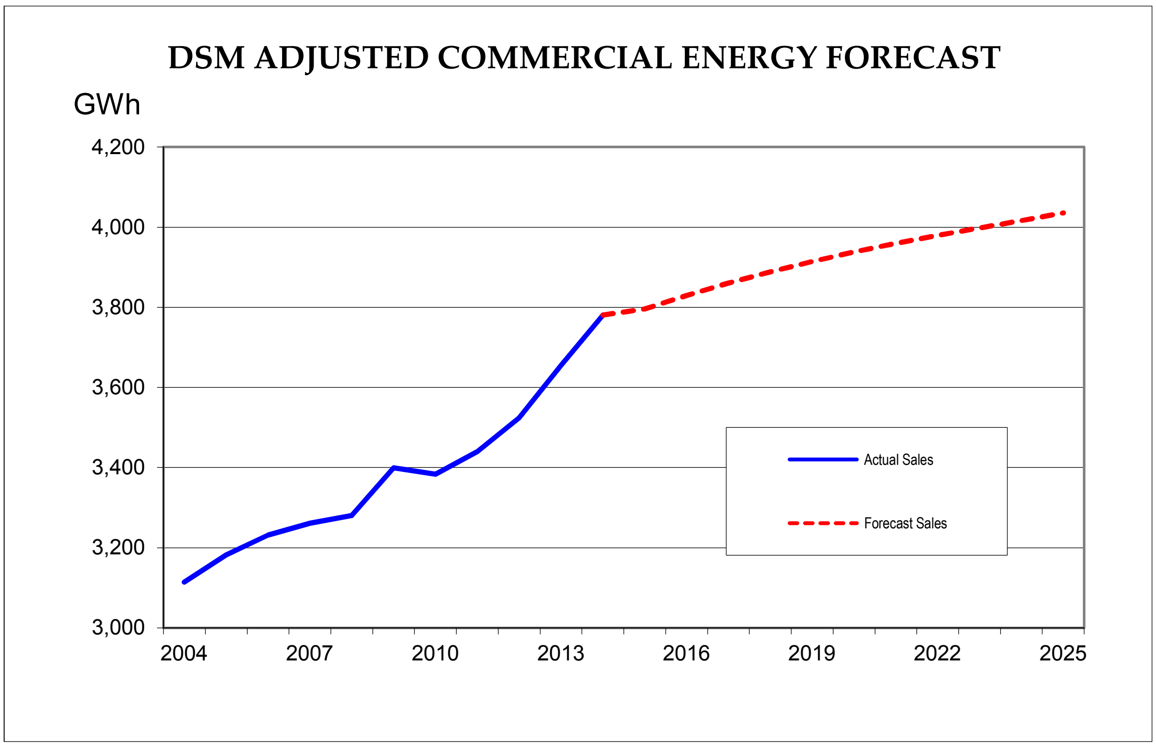
SaskPower will maintain its current customer base and market share.

Commercial (cont.)

Grid Commercial Forecast Results

The DSM adjusted Grid energy sales for the Commercial class is expected to grow from **3,795.8** GWh in 2015 to **4,035.6** GWh in 2025. This **239.8** GWh increase translates into an average annual growth rate of **0.6%** (Refer to Table A2).

Energy sales for the Commercial class have grown at an average rate of **2.0%** per year from 2004-2014. This growth reflects the exceptional level of economic activity in Saskatchewan between 2009 and 2014 and unusually cold winters in 2013 and 2014. The reduction in load growth in the forecast reflects a more typical level of economic activity in the province, the return to normal weather and SaskPower's aggressive demand side management (DSM) energy savings targets for the Commercial class.



RESIDENTIAL

Definition

The Residential class includes customers occupying residential premises, including apartment units, resort cottages and domestic outbuildings. Residential customers served by municipal utilities in Swift Current and Saskatoon are excluded from this customer class.

Methodology

Econometric, end use, extrapolation and statistical regression methods are used to predict future residential customers' energy requirements. Energy sales to the Residential class are forecasted based on the number of residential customers and the average use per residential customer.

The number of residential customers is determined using the population and number of persons per household as provided in the SaskPower Economic Forecast. The households are separated into two categories: apartments and single family dwellings.

The average use per residential customer is calculated based on the type of household, end use market conditions and efficiency standards. This methodology includes twenty-four end uses. The use per appliance calculation considers market saturation and penetration rates, average load of appliances, hours of use, life expectancy and efficiency standards. Saturation rates are based on data from the 2010 Residential End Use Survey. Efficiency standards are based on information from Statistics Canada.

After the Base Residential class forecast has been completed, the DSM energy savings are removed; resulting in the DSM adjusted Residential class forecast.

The Residential forecast is validated through a comparison of weather-normalized actual energy sales to forecast energy sales.

Assumptions

The electrical usage for Residential customers assumes normal daily weather conditions based on a thirty-year average.

The energy efficiency standards used in the forecast are a criterion set by regulatory boards, which must be met by all electrical appliance manufacturers.

SaskPower will maintain its current customer base and market share.

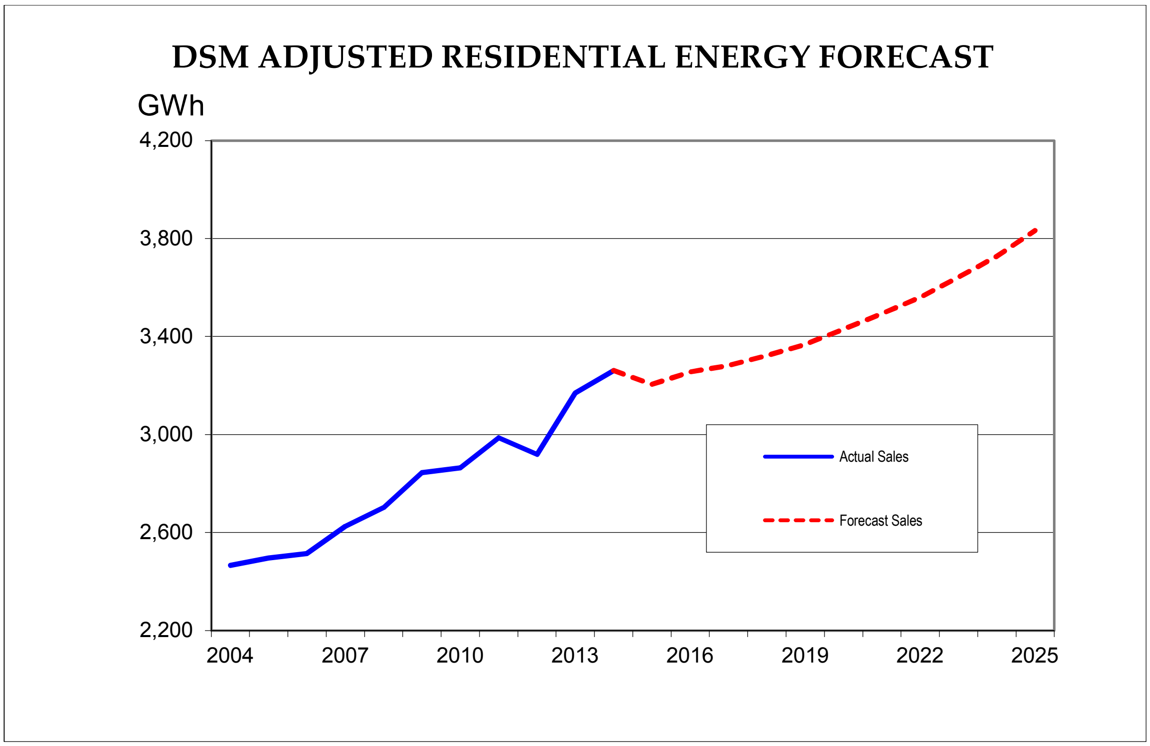
Residential (cont.)

Grid Residential Forecast Results

The annual DSM adjusted Grid energy sales forecast for the Residential class is expected to grow from **3,204.7** GWh in 2015 to **3,832.1** GWh in 2025. This total growth of **627.4** GWh equates to an average annual growth rate of **1.8%** (Refer to Table A2). This growth is due to an increase in the number of customers as well as an increasing use per customer over time.

In the past 10 years, sales for the Grid Residential class have increased by **794.5** GWh. This represents a **2.8%** average annual growth rate from 2004-2014. As was the case for the Commercial class, this growth reflects the exceptional level of economic activity in Saskatchewan between 2009 and 2014 and unusually cold winters in 2013 and 2014.

The reduction in load growth in the forecast reflects a more typical level of economic activity in the province, the return to normal weather and SaskPower's aggressive demand side management (DSM) energy savings targets for the Residential class.



FARM

Definition

A Farm customer is one with normal farm household and agricultural use, and irrigation loads.

Methodology

The forecasted number of Farm customers is developed by first dividing the total number of Farm class customers to households and operations. The future number of farm households is obtained from the Economic Forecast. The future number of farm operations is forecasted using a regression analysis with the number of farm households. The methodology used to predict the future Farm class household energy sales is the same as that used to forecast the Residential class energy sales described above. The energy use for the operations component of the Farm class is also derived from an end use model combined with Farm economic indicators from the Economic Forecast. Energy consumption for irrigation is calculated based on the number of services and the average use per service.

After the Base Farm class forecast has been completed, the DSM energy savings are removed; resulting in the DSM adjusted Farm forecast.

The Farm forecast is validated through a comparison of weather-normalized actual energy sales to forecast energy sales. The growth in the economic variables is also analyzed.

Assumptions

The electrical usage for farm customers assumes thirty-year average weather conditions.

SaskPower will maintain its current customer base and market share.

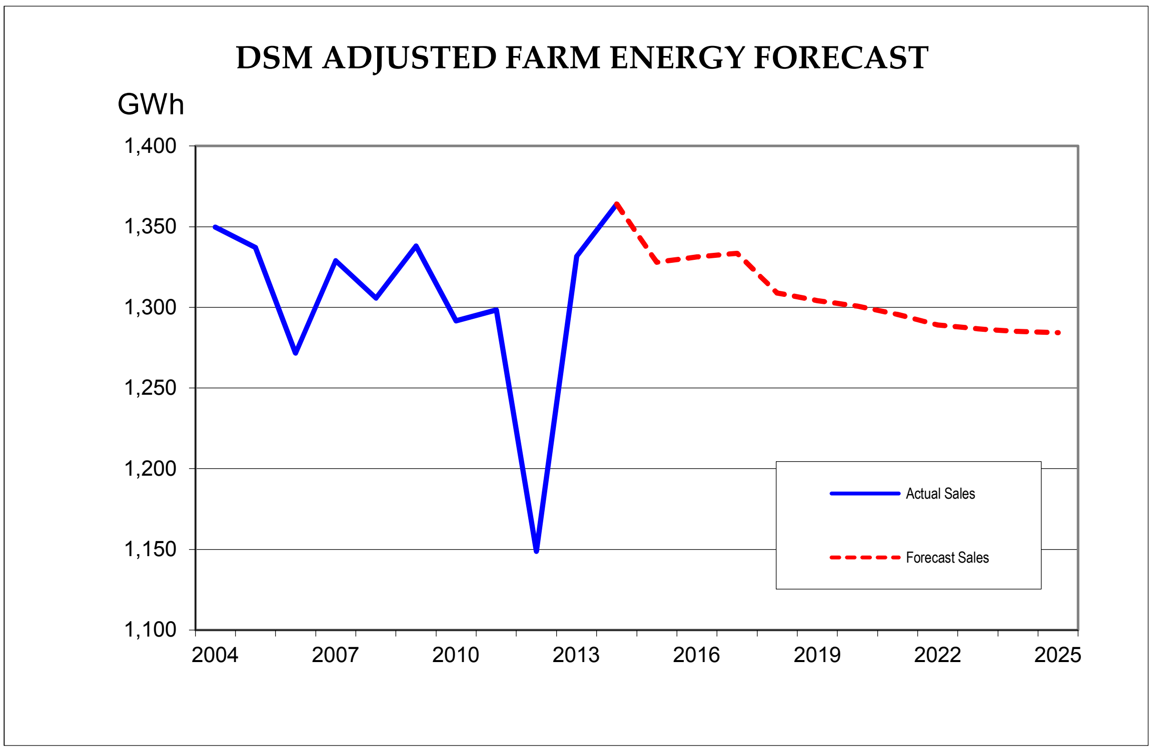
Farm (cont.)

Farm Forecast Results

DSM adjusted energy sales for the Farm class are expected to decrease from **1,327.9** GWh annually in 2015 to **1,284.4** GWh in 2025 (Refer to Table A2). This pattern reflects the trend of fewer, more energy intensive farms.

Annual Farm class energy sales have risen very slightly between 2004 and 2014, increasing by **14.2** GWh or **0.1%** over this time period.

Energy sales in the Farm class were also impacted by the unusually cold weather during the years 2013 and 2014. In 2015 energy sales are forecasted to decrease, with the expected return to normal weather conditions.



RESELLER

Definition

The Reseller class includes customers who purchase bulk power from SaskPower and distribute to residential and commercial customers within their jurisdictions. SaskPower serves two Reseller customers, the City of Saskatoon and the City of Swift Current.

Methodology

Since the Reseller class customers have a fixed franchise area which limits their expansion, SaskPower's Senior Business Advisors, Key Accounts will meet with each customer and record their estimate of future load growth. An individual forecast is developed for each customer, which are then combined into a total Reseller class forecast.

To validate the Reseller class forecast, the forecasted energy sales are compared to historical sales trends.

Assumptions

Normal daily weather conditions are based on a thirty-year average.

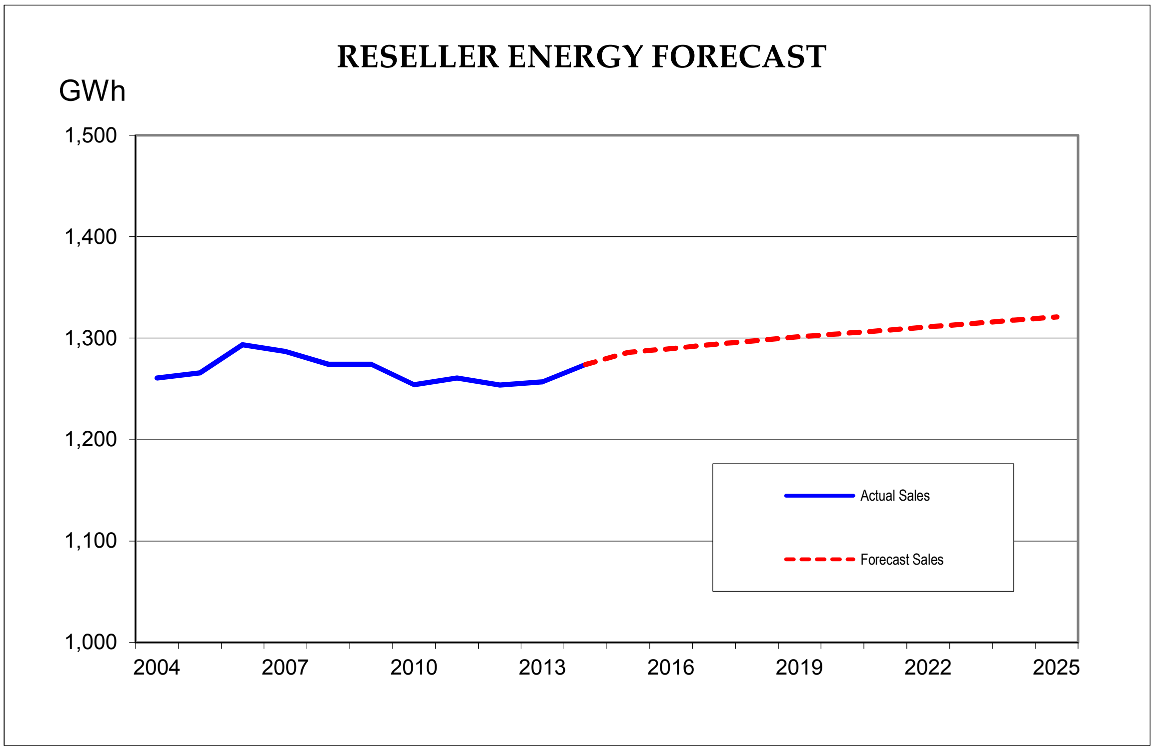
SaskPower will maintain its current customer base and market share.

Reseller (cont.)

Reseller Forecast Results

Annual Reseller class energy sales are expected to grow from **1,286.1** GWh in 2015 to **1,321.0** GWh in 2025 (Refer to Table A2). This increase of **34.9** GWh over 10 years translates into a **0.3%** average annual growth rate.

A **13.2** GWh or **0.1%** annual increase in Reseller class energy sales was experienced from 2004-2014.



CORPORATE USE

Definition

Corporate use includes electrical energy used by SaskPower for fuel supply and all other electric system internal use. Station service usage at the corporate generating plants is excluded from Corporate use.

Methodology

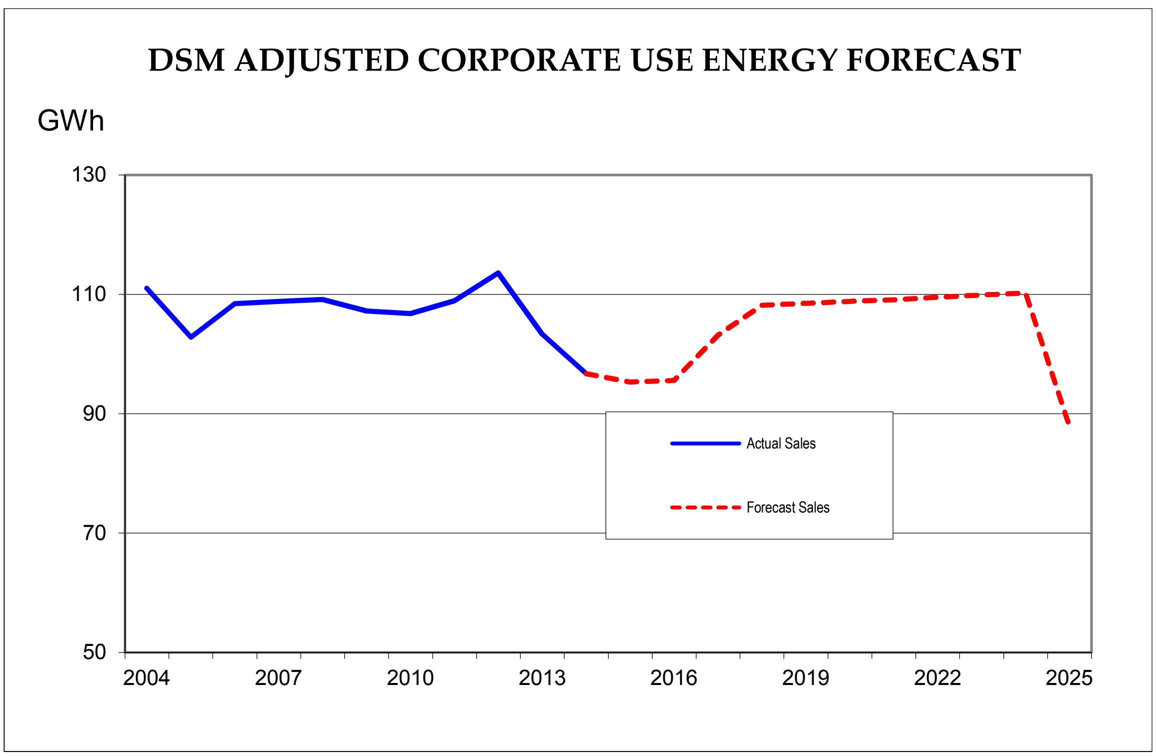
Extrapolation is used to estimate the future corporate internal energy use. The coal mine consumption is calculated from production estimates projected by Fuel Supply.

After the Base Corporate use forecast has been completed, the DSM energy savings are removed; resulting in the DSM adjusted Corporate use forecast.

Corporate Use Forecast Results

Annual DSM adjusted Corporate use energy is expected to decrease from **95.3** GWh or **-0.8%** in 2015 to **87.8** GWh in 2025 (Refer to Table A2).

Corporate use had negative growth of **14.9** GWh or **-1.4%** on an annual basis over the 2004-2014 timeframe.



SYSTEM LOSSES and UNACCOUNTED ENERGY

Definition

This category is comprised of transmission and distribution losses and unmetered corporate and customer electric energy use.

Transmission losses are incurred in transmitting power from generating stations to the distribution system – typically the high voltage side of 138kV to 25kV or 72kV to 25kV substations. Distribution losses are the losses incurred in distributing power to the customers. Unaccounted use is the unmetered corporate energy use including the energy use at all switching stations and distribution substations.

Methodology

Extrapolation techniques as well as the SPLoss program are used to predict the future energy losses due to transmission, distribution system losses and unmetered use.

Transmission losses are determined by Network Development using the SPLoss program. Distribution losses are estimated using a 5-year historical average percent of distribution sales applied to future distribution sales. The method used to estimate unaccounted energy usage is the same as used for estimating distribution losses.

After the base loss forecast has been completed, the DSM energy savings are removed; resulting in the DSM adjusted loss forecast.

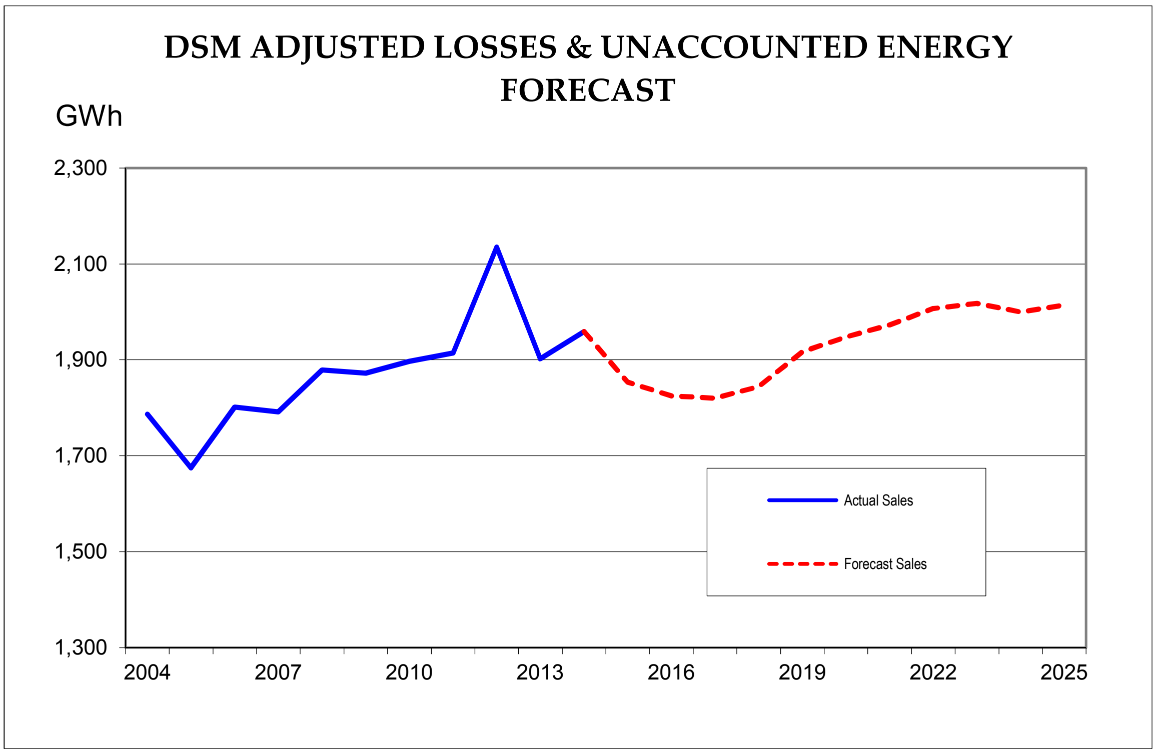
A comparison of historical actual to forecast energy consumption is used to validate the Losses and Unaccounted forecast.

System Losses and Unaccounted Energy (cont.)

Grid Losses and Unaccounted Forecast Results

DSM adjusted losses and unaccounted energy are expected to increase from **1,853.4** GWh in 2015 to **2,014.1** GWh in 2025 (Refer to Table A2). This **160.7** GWh increase translates into an average annual rate of **0.8%**.

Losses and unaccounted energy have increased at an average annual rate of **0.9%** in the past 10 years. The **172.2** GWh increase from 2004-2014 is correlated to the growth in energy sales for each year, partially offset by system improvements.



NON-GRID

Definition

The Non-Grid forecast represents energy sold to customers in communities which do not have access to the SaskPower electrical grid. These communities include Kinoosao, Creighton, Sturgeon Landing and Denare Beach. The energy sold to these communities comes from the Kinoosao diesel plant and power purchases from Manitoba Hydro. The customers in these communities are classified as residential, commercial or corporate. The Non-Grid forecast also includes distribution system losses incurred serving these communities.

Methodology

Extrapolation is used for predicting the future use per customer and the number of customers.

To validate the Non-Grid forecast a comparison of historical to forecast consumption is made.

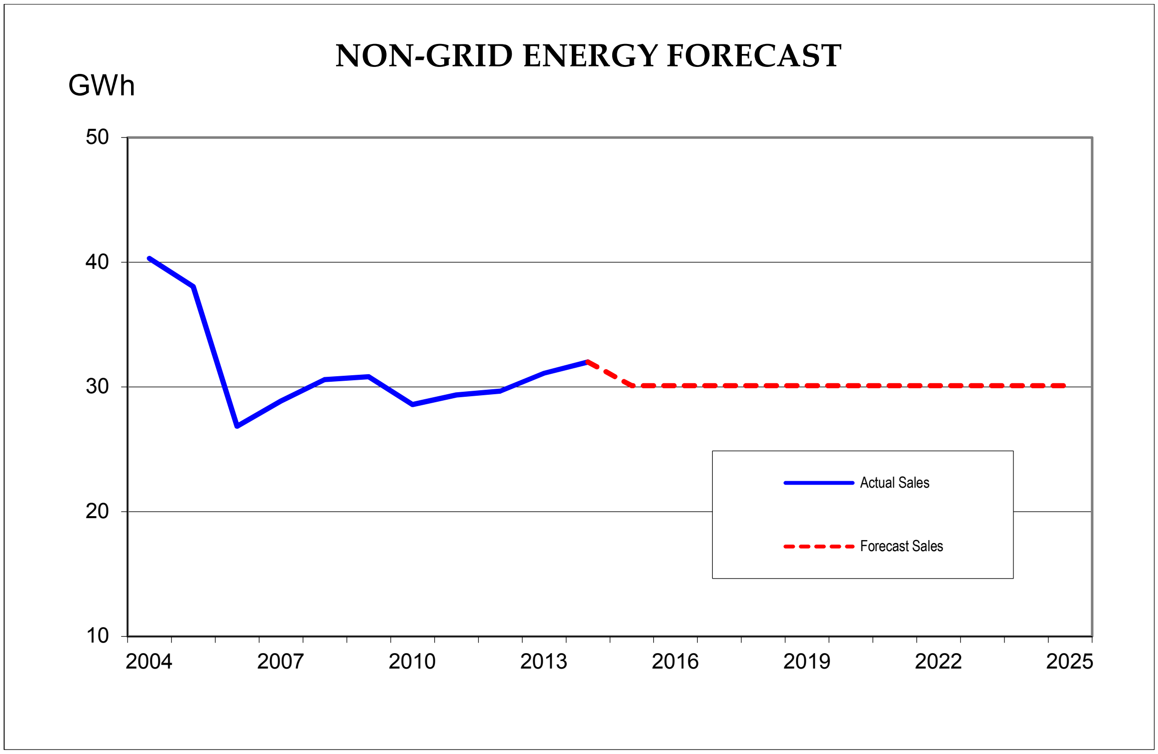
Assumption

SaskPower will maintain its current customer base and market share.

Non-Grid (cont.)

Non-Grid Forecast Results

The energy requirements for Non-Grid customers are expected to remain at **30.1** GW·h from 2015 into the future. (Refer to Table A3). The number of customers and energy requirements are forecast to remain stable in the residential, commercial and corporate sectors.



POTENTIAL SYSTEM PEAK DEMAND

Definition

The system peak demand represents the highest level of demand placed on the supply system at any time during the year. The system peak has historically occurred in the winter months and is important for planning purposes because SaskPower must have adequate generation and transmission capacity available to supply the system peak demand.

Methodology

SaskPower forecasts an instantaneous as well as hourly interval system peak demand. The factors that contribute to the peak load include time of day, seasonal variations, industrial load and weather conditions. Seasonal variations include Christmas lighting, increased lighting load due to shorter daylight hours and increased shopping hours. Historically, the peak load has occurred during the heating season months of November, December, January and February. SaskPower forecasts a potential system peak demand which requires sustained cold weather during the month of December prior to the Christmas vacation period.

Historical and current sales forecast data is used to develop an hourly interval coincident peak load factor for each Power class and Large Oilfield customer. This information, along with that obtained during discussions with each Account Manager regarding anticipated changes in operations, is used to develop an hourly interval peak demand forecast for each Power class and Large Oilfield customer. The hourly interval peak forecast for all other customer classes is estimated using coincident peak load factors developed from SaskPower's interval meter load research. This load research relates customer class historic contribution to the system peak demand to annual energy sales. The hourly interval system peak load forecast is determined by adding the hourly interval peak load for each class and the instantaneous system peak load is calculated using the historic relationship between the hourly interval and instantaneous peak demand.

After the Base system peak demand forecast has been completed, the DSM peak demand savings are removed; resulting in the DSM adjusted system peak demand forecast.

Three approaches are used to validate the system peak demand forecast. Historical peak load is compared to forecast peak load, forecasted peak load is compared to historical system peak loads normalized for weather conditions, and historical load factor is compared to forecasted future system load factor.

Potential System Peak Demand (cont.)

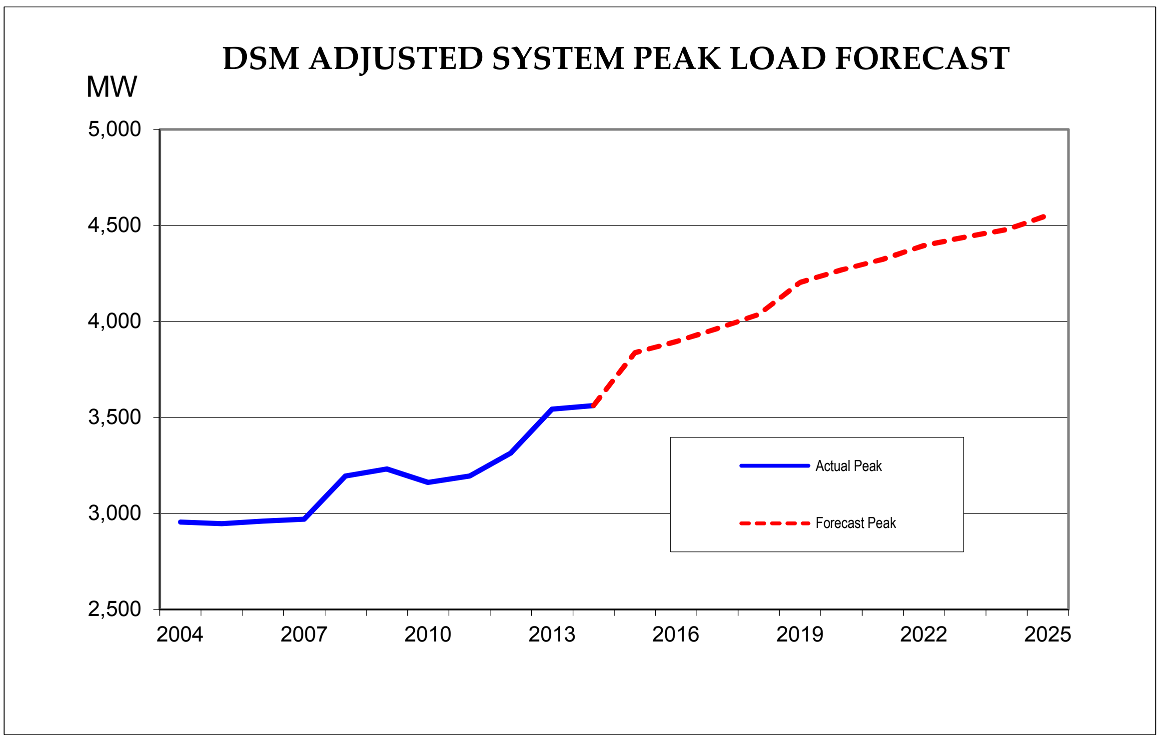
Assumptions

All customer classes, with the exception of Power Accounts and Large Oilfield customers, use hourly interval coincident peak load factors from SaskPower load research. Each Power Account and Large Oilfield customer uses a five-year historical average where applicable to determine its hourly interval coincident peak load factor. For those customers who have not been in existence for this period of time, the most recent history is used, or a coincidence factor from a similar customer is assumed.

Potential Peak Forecast Results

The 2015 DSM adjusted instantaneous system peak load is expected to reach **3,836** MW. By 2025, a system peak load of **4,553** MW is expected (Refer to Table A1). This increase of **717** MW, or an average annual growth rate of **1.7%**, is largely attributed to the expected growth in the Power, Oilfield, Commercial and Residential classes.

The system peak load has increased at an annual rate of **1.9%** over the last 10 years.



Note:

Table A4 provides additional information on SaskPower's system peak demand. In addition to the (winter) potential peak forecast, table A4 also provides the summer potential peak forecast, which assumes sustained hot weather occurring in July. A most likely winter and summer peak forecast, based on the actual weather experienced at the time of the system peaks over the last 5 years, is also provided.

LOAD FORECAST UNCERTAINTY

(High and Low Forecasts)

Definition

The energy and system peak load forecasts developed above are considered to reflect a most likely scenario of economic and weather conditions. A degree of uncertainty is inherent in most long-term forecasts due to the fact that they are based on many assumptions and input variables. For this reason, a high and a low scenario forecast is developed for both Energy and Peak Demand. These scenarios cover possible ranges in economic variations and other uncertainties.

Methodology

The 2015 Economic Forecast was a major driver in the development of the 2015 most likely Load Forecast. An actual course of economic development for Saskatchewan that deviates from the forecast would have an impact on energy consumption. The 2015 Load Forecast was also based on a thirty-year average weather pattern. Deviation from this weather pattern will also impact energy consumption.

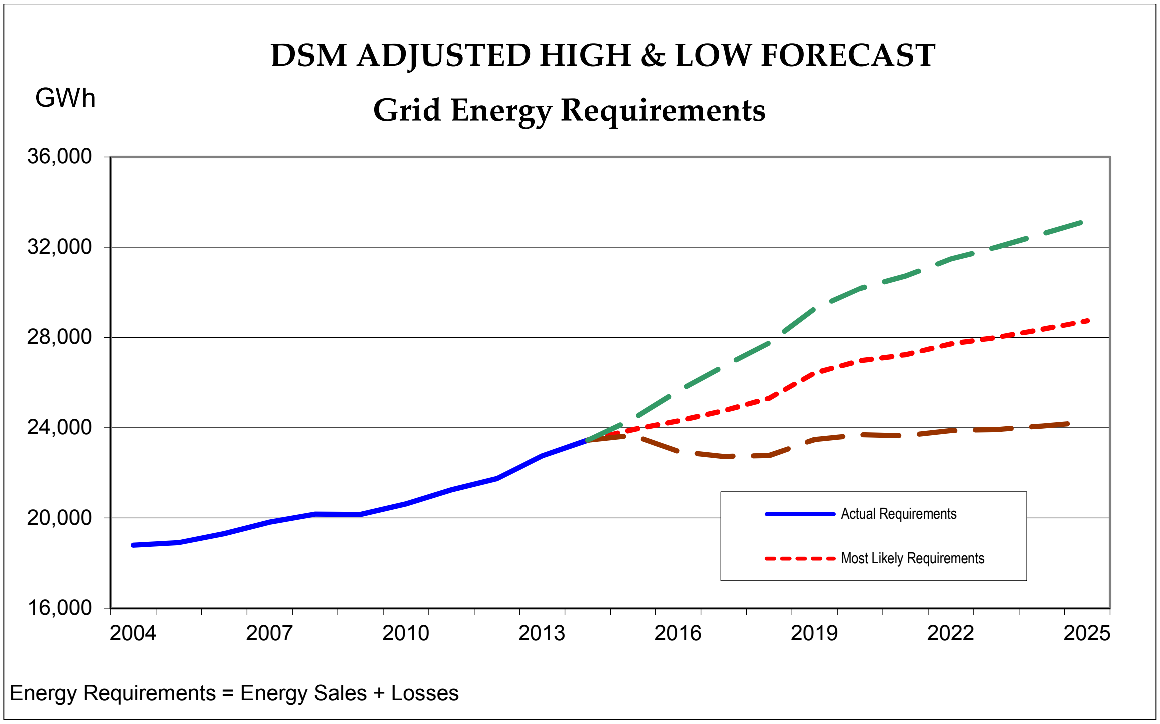
To reflect the economic and weather uncertainties, DSM adjusted grid high and low energy consumption and system peak demand forecasts are developed using a Monte Carlo simulation model. This model uses the percentage error by customer class in year 1, year 2, year 3 etc. of previous forecasts. The forecast error for each class is considered to have a normal distribution and to be independent from the forecast error of other classes. The high / low forecast results are developed using a 90 percent confidence interval. This means that there is 90% probability that future energy and peak demand loads will fall within the bounds created by the high and low load forecasts.

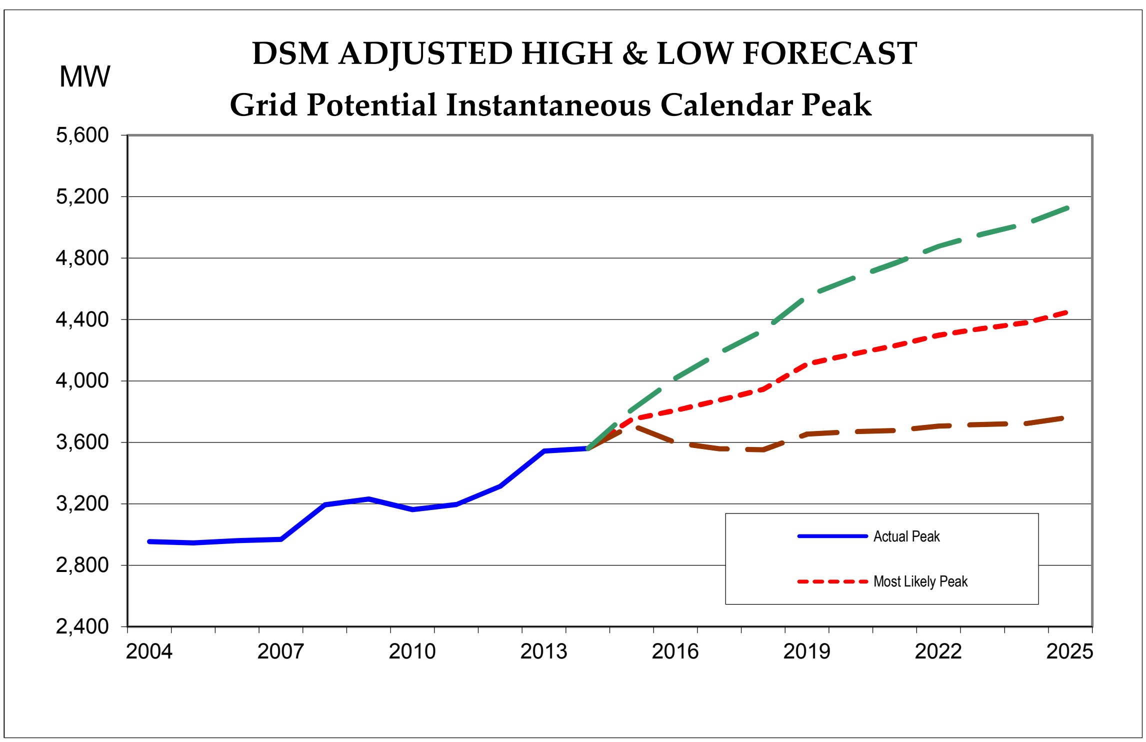
High - Low Forecast Results (Total)

In relation to the 2015 most likely forecast, the DSM adjusted high forecast scenario total energy requirements and potential peak are **467 GWh** and **75 MW** higher, respectively. In 2025, the high scenario forecasts the energy to be **4,434 GWh** higher and the demand to be **697 MW** higher than the most likely forecast (refer to Table B).

Relative to the most likely case, the DSM adjusted low forecast scenario for 2015 total energy requirements and potential peak are **255 GWh** and **41 MW** lower, respectively. In 2025, the low scenario forecasts the energy to be **4,475 GWh** lower and the peak demand to be **703 MW** lower than the most likely forecast (refer to Table B).

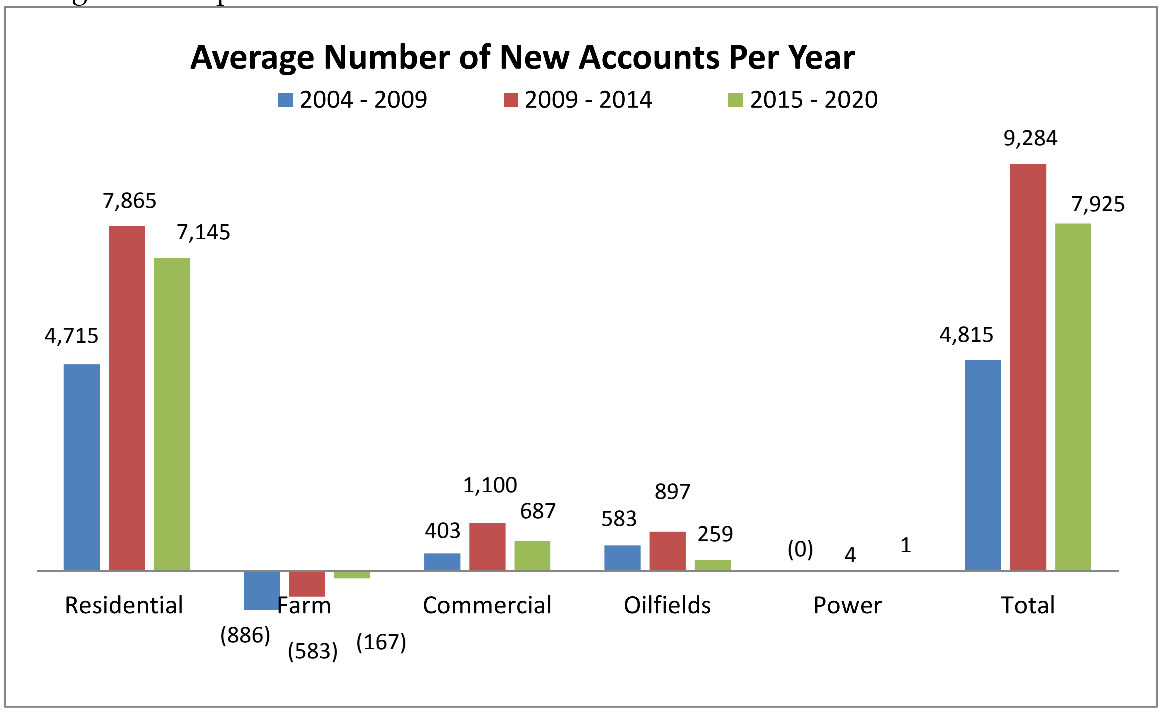
Load Forecast Uncertainty (cont.)

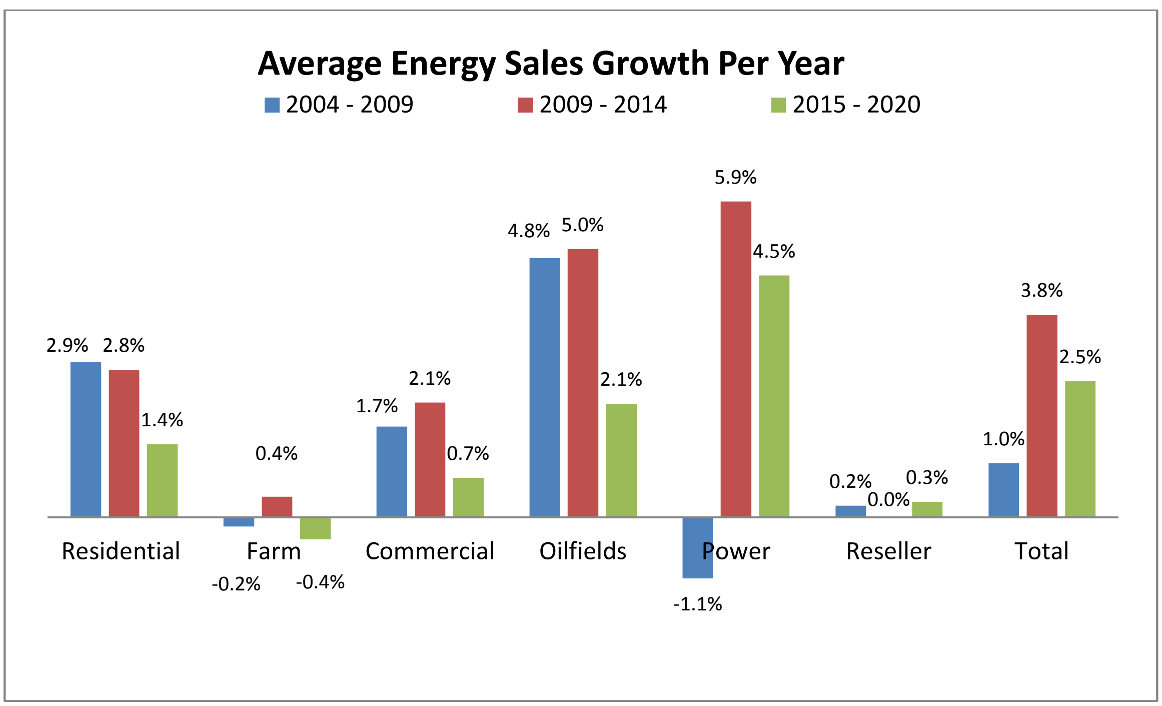




Growth in Number of Accounts and Energy Sales

The tables below provide the average number of new accounts/year and the average energy sales growth/year over 3 time periods – actual loads for 2004 to 2009 and 2009 to 2014 and forecasted loads for 2015 to 2020. The average number of accounts and energy sales growth in the 2004 to 2009 period was typical, with the exception of the Power class which was affected by the 2008 – 2009 recession. Oilfield energy growth was very strong over this period.





Growth in Number of Accounts and Energy Sales (cont)

The exceptional level of economic activity in Saskatchewan between 2009 and 2014 led to an increased number of accounts, and combined with the unusually cold winters in 2013 and 2014, led to a substantial increase in energy sales growth. Oilfield energy sales continued to be strong and the Power class growth recovered from the recession to provide strong gains, particularly in the pipeline pumping, potash and northern mine sectors.

The average number of accounts and average energy sales growth for the 2015 to 2020 period reflect a return to a more typical level of economic activity in the province. The reduction in growth rate in the Residential and Commercial classes also reflects the return to normal weather and SaskPower's aggressive demand side management (DSM) energy savings targets for these classes. The oilfield forecast is significantly lower than in recent years, due to the impact of low oil price on production in the province. Power class load growth continues to be strong, led by the pipeline pumping, potash and northern mine sectors.

TABLE A1

2015 DSM ADJUSTED TOTAL SYSTEM LOAD FORECAST

First Quarter

ENERGY SALES, NUMBER OF ACCOUNTS AND PEAK DEMAND

	POWER		OILFIELDS		COMMERCIAL		RESIDENTIAL		FARM		RESELLER		CORPORATE USE		TOTAL SALES		LOSSES	TOTAL ENERGY REQUIREMENTS	CALENDAR 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
2004	6,502.0	84	2,164.8	11,259	3,132.2	52,508	2,483.8	305,472	1,349.8	66,424	1,260.7	2	111.3	212	17,004.8	435,961	1,790.7	18,795.4	2,954
2005	6,552.0	78	2,263.9	11,508	3,200.1	52,604	2,513.8	308,221	1,337.0	64,985	1,265.8	2	103.1	212	17,235.7	437,610	1,676.4	18,912.1	2,946
2006	6,666.0	78	2,399.3	12,045	3,238.8	52,869	2,530.5	309,551	1,271.7	64,601	1,293.5	2	108.8	212	17,508.6	439,358	1,803.5	19,312.1	2,960
2007	6,854.9	78	2,541.4	12,805	3,268.1	53,421	2,642.9	315,507	1,329.0	63,751	1,286.8	2	109.2	212	18,032.3	445,776	1,794.4	19,826.7	2,969
2008	6,898.0	78	2,682.0	13,453	3,311.0	53,911	2,721.2	322,408	1,305.8	62,553	1,274.2	2	109.4	212	18,301.7	452,617	1,882.7	20,184.3	3,194
2009	6,138.7	82	2,742.5	14,174	3,406.8	54,525	2,864.8	329,046	1,338.1	61,993	1,274.4	2	107.6	212	17,873.0	460,034	1,875.2	19,748.2	3,231
2010	6,932.0	91	2,871.3	14,756	3,386.3	54,945	2,882.4	334,780	1,291.6	61,404	1,254.3	2	107.2	212	18,725.0	466,190	1,897.0	20,622.0	3,162
2011	7,321.0	97	2,900.8	15,015	3,447.0	55,501	3,006.0	346,312	1,298.3	60,871	1,253.0	2	109.3	212	19,335.4	478,010	1,936.0	21,271.4	3,195
2012	7,447.7	100	3,177.2	16,446	3,532.0	56,605	2,937.6	350,499	1,148.8	62,063	1,253.8	2	114.2	212	19,611.1	485,927	2,172.0	21,783.1	3,314
2013	7,863.0	101	3,448.0	17,476	3,663.0	59,390	3,190.0	360,431	1,331.6	61,449	1,257.0	2	103.9	212	20,856.5	499,061	1,905.0	22,761.5	3,543
2014	8,178.4	101	3,503.1	18,659	3,788.2	60,026	3,281.2	368,373	1,364.0	59,079	1,273.9	2	96.7	212	21,485.5	506,452	1,945.0	23,430.5	3,561
2015	8,882.9	99	3,474.3	18,701	3,803.4	60,178	3,223.9	377,858	1,327.9	60,459	1,286.1	2	96.1	212	22,094.6	517,509	1,855.8	23,950.5	3,836
2016	9,190.4	99	3,475.9	18,948	3,836.6	60,883	3,274.8	385,189	1,331.3	60,292	1,289.9	2	96.4	212	22,495.3	525,625	1,827.4	24,322.7	3,895
2017	9,451.5	102	3,608.0	19,442	3,867.9	61,473	3,301.0	391,324	1,333.5	60,125	1,293.7	2	104.0	212	22,959.7	532,680	1,822.5	24,782.3	3,964
2018	9,789.4	104	3,740.0	19,523	3,896.4	62,173	3,341.4	398,618	1,308.9	59,958	1,297.5	2	109.1	212	23,482.8	540,590	1,846.4	25,329.2	4,036
2019	10,748.5	104	3,763.0	19,938	3,921.5	62,892	3,387.6	406,096	1,304.2	59,791	1,301.3	2	109.4	212	24,535.5	549,036	1,919.7	26,455.2	4,204
2020	11,081.4	106	3,858.0	19,997	3,945.3	63,612	3,450.0	413,583	1,300.8	59,624	1,304.6	2	109.7	212	25,049.7	557,135	1,950.1	26,999.8	4,268
2021	11,152.5	106	3,936.5	20,405	3,967.5	64,339	3,512.9	421,149	1,295.6	59,457	1,307.8	2	110.0	212	25,282.7	565,669	1,975.6	27,258.3	4,324
2022	11,373.9	106	4,085.6	20,442	3,987.2	65,065	3,579.0	428,707	1,289.0	59,289	1,311.1	2	110.4	212	25,736.3	573,823	2,009.3	27,745.6	4,395
2023	11,532.4	106	4,091.8	20,843	4,005.8	65,794	3,661.0	436,293	1,286.6	59,122	1,314.4	2	110.7	212	26,002.7	582,371	2,020.1	28,022.8	4,440
2024	11,764.4	106	4,134.6	21,244	4,023.8	66,523	3,747.1	443,874	1,285.1	58,955	1,317.7	2	111.0	212	26,383.7	590,916	2,001.9	28,385.6	4,478
2025	11,992.7	106	4,168.2	21,645	4,043.1	67,264	3,851.4	451,594	1,284.4	58,788	1,321.0	2	88.7	212	26,749.4	599,611	2,016.6	28,766.0	4,553

Growth Rates (%)

2009 - 2014	5.9%	4.3%	5.0%	5.7%	2.1%	1.9%	2.8%	2.3%	0.4%	-1.0%	0.0%	0.0%	-2.1%	0.0%	3.8%	1.9%	0.7%	3.5%	2.0%
2004 - 2014	2.3%	1.9%	4.9%	5.2%	1.9%	1.3%	2.8%	1.9%	0.1%	-1.2%	0.1%	0.0%	-1.4%	0.0%	2.4%	1.5%	0.8%	2.2%	1.9%
2015 -2020	4.5%	1.4%	2.1%	1.3%	0.7%	1.1%	1.4%	1.8%	-0.4%	-0.3%	0.3%	0.0%	2.7%	0.0%	2.5%	1.5%	1.0%	2.4%	2.2%
2015 - 2025	3.0%	0.7%	1.8%	1.5%	0.6%	1.1%	1.8%	1.8%	-0.3%	-0.3%	0.3%	0.0%	-0.8%	0.0%	1.9%	1.5%	0.8%	1.8%	1.7%

1.) All forecasted energy values are normalized to reflect 30-year average weather patterns.
2.) All forecasted Calendar Peak values are potential.
3.) The demand side management (DSM) energy and peak demand savings as identified by SaskPower's Customer Services Division 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.

TABLE A2

2015 DSM ADJUSTED GRID ONLY LOAD FORECAST

First Quarter

ENERGY SALES AND NUMBER OF ACCOUNTS

	POWER		OILFIELDS		COMMERCIAL		RESIDENTIAL		FARM		RESELLER		CORPORATE USE		TOTAL SALES		LOSSES	TOTAL ENERGY REQUIREMENTS
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
2004	6,502.0	84	2,164.8	11,259	3,114.4	52,314	2,465.8	304,476	1,349.8	66,424	1,260.7	2	111.0	210	16,968.6	434,769	1,786.6	18,755.1
2005	6,552.0	78	2,263.9	11,508	3,182.4	52,410	2,495.6	307,212	1,337.0	64,985	1,265.8	2	102.8	210	17,199.5	436,405	1,674.6	18,874.1
2006	6,666.0	78	2,399.3	12,045	3,231.7	52,668	2,513.4	308,519	1,271.7	64,601	1,293.5	2	108.4	210	17,484.1	438,123	1,801.1	19,285.2
2007	6,854.9	78	2,541.4	12,805	3,261.1	53,235	2,624.4	314,480	1,329.0	63,751	1,286.8	2	108.8	210	18,006.4	444,561	1,791.4	19,797.8
2008	6,898.0	78	2,682.0	13,453	3,304.0	53,723	2,701.5	321,367	1,305.8	62,553	1,274.2	2	109.1	210	18,274.7	451,386	1,879.0	20,153.7
2009	6,138.7	82	2,742.5	14,174	3,399.3	54,331	2,844.8	328,003	1,338.1	61,993	1,274.4	2	107.2	210	17,845.0	458,795	1,872.3	19,717.4
2010	6,932.0	91	2,871.3	14,756	3,379.0	54,745	2,863.8	333,727	1,291.6	61,404	1,254.3	2	106.8	210	18,698.8	464,935	1,894.6	20,593.4
2011	7,321.0	97	2,900.8	15,015	3,439.5	55,295	2,986.4	345,207	1,298.3	60,871	1,253.0	2	108.9	210	19,308.0	476,697	1,934.0	21,242.0
2012	7,447.7	100	3,177.2	16,446	3,524.5	56,392	2,918.4	349,336	1,148.8	62,063	1,253.8	2	113.6	210	19,583.9	484,549	2,169.5	21,753.4
2013	7,863.0	101	3,448.0	17,476	3,655.4	59,177	3,170.0	359,268	1,331.6	61,449	1,257.0	2	103.3	210	20,828.3	497,683	1,902.1	22,730.4
2014	8,178.4	107	3,503.1	18,659	3,780.6	59,813	3,260.3	367,210	1,364.0	59,079	1,273.9	2	96.1	210	21,456.4	501,071	1,942.1	23,398.5
2015	8,882.9	107	3,474.3	18,701	3,795.8	59,965	3,204.7	376,695	1,327.9	60,459	1,286.1	2	95.3	210	22,067.0	516,139	1,853.4	23,920.4
2016	9,190.4	107	3,475.9	18,948	3,829.1	60,670	3,255.5	384,026	1,331.3	60,292	1,289.9	2	95.6	210	22,467.7	524,255	1,825.0	24,292.7
2017	9,451.5	107	3,608.0	19,442	3,860.3	61,260	3,281.8	390,161	1,333.5	60,125	1,293.7	2	103.2	210	22,932.1	531,307	1,820.1	24,752.2
2018	9,789.4	108	3,740.0	19,523	3,888.9	61,960	3,322.2	397,455	1,308.9	59,958	1,297.5	2	108.2	210	23,455.2	539,216	1,843.9	25,299.1
2019	10,748.5	111	3,763.0	19,938	3,913.9	62,679	3,368.4	404,933	1,304.2	59,791	1,301.3	2	108.5	210	24,507.9	547,665	1,917.2	26,425.1
2020	11,081.4	111	3,858.0	19,997	3,937.8	63,399	3,430.7	412,420	1,300.8	59,624	1,304.6	2	108.8	210	25,022.1	555,762	1,947.7	26,969.8
2021	11,152.5	111	3,936.5	20,405	3,959.9	64,126	3,493.7	419,986	1,295.6	59,457	1,307.8	2	109.1	210	25,255.1	564,296	1,973.1	27,228.2
2022	11,373.9	111	4,085.6	20,442	3,979.7	64,852	3,559.8	427,544	1,289.0	59,289	1,311.1	2	109.5	210	25,708.7	572,450	2,006.9	27,715.5
2023	11,532.4	111	4,091.8	20,843	3,998.3	65,581	3,641.8	435,130	1,286.6	59,122	1,314.4	2	109.9	210	25,975.1	580,998	2,017.7	27,992.8
2024	11,764.4	112	4,134.6	21,244	4,016.3	66,310	3,727.8	442,711	1,285.1	58,955	1,317.7	2	110.2	210	26,356.1	589,544	1,999.5	28,355.6
2025	11,992.7	113	4,168.2	21,645	4,035.6	67,051	3,832.1	450,431	1,284.4	58,788	1,321.0	2	87.8	210	26,721.8	598,240	2,014.1	28,735.9

Growth Rates (%)

2009 - 2014	5.9%	5.5%	5.0%	5.7%	2.1%	1.9%	2.8%	2.3%	0.4%	-1.0%	0.0%	0.0%	-2.2%	0.0%	3.8%	1.8%	0.7%	3.5%
2004 - 2014	2.3%	2.4%	4.9%	5.2%	2.0%	1.3%	2.8%	1.9%	0.1%	-1.2%	0.1%	0.0%	-1.4%	0.0%	2.4%	1.4%	0.8%	2.2%
2015 -2020	4.5%	0.7%	2.1%	1.3%	0.7%	1.1%	1.4%	1.8%	-0.4%	-0.3%	0.3%	0.0%	2.7%	0.0%	2.5%	1.5%	1.0%	2.4%
2015 - 2025	3.0%	0.5%	1.8%	1.5%	0.6%	1.1%	1.8%	1.8%	-0.3%	-0.3%	0.3%	0.0%	-0.8%	0.0%	1.9%	1.5%	0.8%	1.9%

2.) The demand side management (DSM) energy and peak demand saving as identified by SaskPower's DSM department are reflected in the forecast above.
3.) The number of accounts is the average for the year as required for rate design and revenue forecasting.

TABLE A3

2015 NON - GRID LOAD FORECAST

First Quarter

ENERGY SALES AND NUMBER OF ACCOUNTS

	COMMERCIAL		RESIDENTIAL		CORPORATE USE		TOTAL SALES		LOSSES [1)]	TOTAL ENERGY REQUIREMENTS
Year	GWh	# of Accounts	GWh	# of Accounts	GWh	# of Accounts	GWh	# of Accounts	GWh	GWh
2004	17.8	194	18.1	996	0.3	2	36.2	1,192	4.1	40.3
2005	17.7	194	18.2	1009	0.3	2	36.2	1,205	1.8	38.0
2006	7.1	201	17.1	1032	0.4	2	24.5	1,235	2.4	26.8
2007	7.0	186	18.5	1,027	0.4	2	25.9	1,215	3.0	28.9
2008	7.0	188	19.6	1,041	0.3	2	26.9	1,231	3.7	30.6
2009	7.5	194	20.0	1,043	0.4	2	27.9	1,239	2.9	30.8
2010	7.3	200	18.6	1,053	0.4	2	26.2	1,255	2.4	28.6
2011	7.5	206	19.5	1,105	0.4	2	27.4	1,313	2.0	29.4
2012	7.4	213	19.2	1,163	0.6	2	27.2	1,378	2.5	29.7
2013	7.6	213	20.0	1,163	0.6	2	28.2	1,378	2.9	31.1
2014	7.6	213	20.9	1,163	0.6	2	29.1	1,378	2.9	32.0
2015	7.5	213	19.3	1,163	0.8	2	27.6	1,378	2.4	30.1
2016	7.5	213	19.3	1,163	0.8	2	27.6	1,378	2.4	30.1
2017	7.5	213	19.3	1,163	0.8	2	27.6	1,378	2.4	30.1
2018	7.5	213	19.3	1,163	0.8	2	27.6	1,378	2.4	30.1
2019	7.5	213	19.3	1,163	0.8	2	27.6	1,378	2.4	30.1
2020	7.5	213	19.3	1,163	0.8	2	27.6	1,378	2.4	30.1
2021	7.5	213	19.3	1,163	0.8	2	27.6	1,378	2.4	30.1
2022	7.5	213	19.3	1,163	0.8	2	27.6	1,378	2.4	30.1
2023	7.5	213	19.3	1,163	0.8	2	27.6	1,378	2.4	30.1
2024	7.5	213	19.3	1,163	0.8	2	27.6	1,378	2.4	30.1
2025	7.5	213	19.3	1,163	0.8	2	27.6	1,378	2.4	30.1

Growth Rates (%)

2009 - 2014	0.2%	1.9%	0.9%	2.2%	8.6%	0.0%	0.8%	2.1%	0.0%	0.7%
2004 - 2014	-8.2%	0.9%	1.5%	1.6%	6.5%	0.0%	-2.2%	1.5%	-3.3%	-2.3%
2015 -2020	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2015 - 2025	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

Notes:

1) Losses are calculated by taking the difference between Total Energy Requirements and Total Sales. The Total Sales and Total Energy Requirements are forecasted numbers.

TABLE A4

2015 LOAD FORECAST

First Quarter

INSTANTANEOUS SYSTEM PEAK DEMAND FORECAST

Year	Historical Winter MW	Historical Summer MW	Most Likely Calendar Peaks Winter MW	Most Likely Calendar Peaks Summer MW	Potential Calendar Peaks Winter MW	Potential Calendar Peaks Summer MW
2004	2,805	2,591				
2005	2,954	2,639				
2006	2,946	2,706				
2007	2,960	2,879				
2008	2,969	2,834				
2009	3,194	2,773				
2010	3,231	2,750				
2011	3,162	3,070				
2012	3,195	3,053				
2013	3,314	3,187				
2014	3,543	3,161				
2015			3,675	3,325	3,836	3,471
2016			3,727	3,372	3,895	3,524
2017			3,810	3,447	3,964	3,586
2018			3,872	3,504	4,036	3,652
2019			4,017	3,634	4,204	3,804
2020			4,103	3,713	4,268	3,862
2021			4,152	3,756	4,324	3,913
2022			4,219	3,817	4,395	3,976
2023			4,264	3,858	4,440	4,017
2024			4,311	3,901	4,478	4,051
2025			4,371	3,955	4,553	4,120

Growth Rates (%)

	Historical Winter	Historical Summer	Most Likely Winter	Most Likely Summer	Potential Winter	Potential Summer
2009 - 2014	2.1%	2.7%				
2004 - 2014	2.4%	2.0%				
2015 - 2020			2.2%	2.2%	2.2%	2.2%
2015 - 2025			1.7%	1.7%	1.7%	1.7%

Notes:

- Most Likely Peaks are based on the actual weather experienced at the time of the system peaks over the last 5 years.
- The Potential Winter peak is based on sustained cold weather occurring in the first 3 weeks of December.
- The Potential Summer Peak is based on sustained hot weather occurring in July.
- The Demand Side Management (DSM) system peak demand savings as identified by SaskPower’s Customer Services Division are reflected in the forecast above.

TABLE A5

2015 GRID ONLY LOAD FORECAST

First Quarter

Summary of Base and DSM Adjusted Forecasts

Year	Grid Only Energy Requirements (GWh)					Interval Calender Peak (MW)					Instantaneous Calender Peak (MW)	Demand Response Available (MW)
	No DSM	DSM Savings			DSM Adjusted	No DSM	DSM Savings			DSM Adjusted		
		Prior to 2015	After 2015	Total			Prior to 2015	After 2015	Total			
2015	24,192.5	228.2	43.9	272.1	23,920.4	3,848.8	89.8	8.3	98.1	3,750.7	3,835.8	85.0
2016	24,608.9	228.2	88.1	316.3	24,292.7	3,915.3	89.8	16.6	106.4	3,808.9	3,895.4	85.0
2017	25,136.8	228.2	156.4	384.6	24,752.2	3,993.4	89.8	27.8	117.6	3,875.8	3,963.8	85.0
2018	25,738.1	228.2	210.8	438.9	25,299.1	4,073.5	89.8	37.1	126.9	3,946.6	4,036.2	85.0
2019	26,919.9	228.2	266.6	494.8	26,425.1	4,246.9	89.8	46.4	136.2	4,110.7	4,204.1	85.0
2020	27,521.5	228.2	323.5	551.7	26,969.8	4,318.9	89.8	55.8	145.6	4,173.3	4,268.1	85.0
2021	27,837.3	228.2	380.9	609.0	27,228.2	4,383.3	89.8	65.1	154.9	4,228.5	4,324.5	85.0
2022	28,383.0	228.2	439.3	667.5	27,715.5	4,461.1	89.8	74.4	164.2	4,296.9	4,394.5	85.0
2023	28,719.3	228.2	498.4	726.5	27,992.8	4,514.9	89.8	83.7	173.5	4,341.4	4,440.0	85.0
2024	29,141.6	228.2	557.9	786.0	28,355.6	4,561.0	89.8	92.9	182.8	4,378.3	4,477.7	85.0
2025	29,578.4	228.2	614.3	842.5	28,735.9	4,643.6	89.8	101.7	191.5	4,452.1	4,553.2	85.0

Notes:
- DSM savings includes distribution loss savings.
- DSM savings do not include savings associated with the Internal Line Program.

SaskPower

TABLE B

2015 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)
2015	(255)	(41)	23,665	3,795	23,920.4	3,836	24,387	3,911	467	75
2016	(1,344)	(215)	22,949	3,680	24,292.7	3,895	25,636	4,110	1,343	215
2017	(2,028)	(325)	22,724	3,639	24,752.2	3,964	26,725	4,280	1,973	316
2018	(2,536)	(404)	22,764	3,632	25,299.1	4,036	27,756	4,428	2,457	392
2019	(2,942)	(467)	23,483	3,737	26,425.1	4,204	29,280	4,657	2,855	453
2020	(3,283)	(518)	23,687	3,750	26,969.8	4,268	30,166	4,772	3,196	504
2021	(3,578)	(565)	23,651	3,759	27,228.2	4,324	30,723	4,877	3,495	552
2022	(3,837)	(605)	23,878	3,789	27,715.5	4,395	31,478	4,988	3,763	594
2023	(4,070)	(641)	23,923	3,799	27,992.8	4,440	31,998	5,071	4,006	631
2024	(4,281)	(672)	24,074	3,806	28,355.6	4,478	32,584	5,141	4,228	663
2025	(4,475)	(703)	24,261	3,850	28,735.9	4,553	33,170	5,250	4,434	697

Growth Rates (%)

5 Year			0.0%	-0.2%	2.4%	2.2%	4.3%	4.1%		
10 Year			0.2%	0.1%	1.9%	1.7%	3.1%	3.0%		

PRESENTED TO: **SaskPower Executive**

SUBJECT: **2015 Q4 Load Forecast**

MEETING DATE: **January 26, 2016**

Review Process

SaskPower Executive: January 26, 2016
SaskPower Audit & Finance Committee: March 2, 2016

Issue

Pricing & Energy Forecasting has recently completed the 2015 Q4 Load Forecast which reflects changes identified by Senior Business Advisors in the Key Accounts department, as well as updated potash and oil production forecasts provided by the Ministry of the Economy. The 2015 Q4 forecast also reflects the changes identified in the 2015 Q2 and 2013 Q3 forecasts prepared earlier in 2015. The 2015 Q4 forecast is significantly lower than the 2015 Q1 forecast from 2018 onwards.

Please refer to the attached graphs which depicts SaskPower's system peak loads and energy requirements in the 2015 Q4, 2015 Q1 (2016 business plan) and the 2014 Q1 (2015 business plan) forecasts.

Background

The 2015 Q1 load forecast was completed in March, 2015. The 2015 Q2 forecast update was completed in July based on updated customer expansion plans identified by Senior Business Advisors in the Key Accounts department. Pricing & Energy Forecasting also obtained an updated oil production forecast from the Ministry of the Economy. The 2015 Q3 forecast update completed in October reflected a reduced load forecast for [redacted] and a revised forecast for distribution losses reflecting a recent trend of higher losses as a percentage of distribution loads. All of these changes are summarized below.

Action

Senior Business Advisors in the Key Accounts department surveyed their customers in November for an update on customer expansion plans and forecasted loads. In the [redacted] segment, the probability of the [redacted] has been reduced and the in service date delayed to [redacted], and the [redacted] has been removed from the forecast. Pricing & Energy Forecasting has also revised the forecast for the oilfield class and the potash segment of the Power class based on updated production forecasts from the Ministry of the Economy. The following table summarizes the peak load changes between the 2015 Q4 forecast (including the changes identified in the 2015 Q2 and Q3 forecasts) and the 2015 Q1 load forecast used for the 2016 business plan.

2015 Q4 vs. 2015 Q1 Load Forecast - Peak Load Changes (MW)

Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Oilfield Class	(1)	(11)	(16)	(3)	(1)	(1)	(21)	(21)	(31)	(34)
Distribution Losses	11	9	8	11	11	11	8	8	7	7
Power Class Sectors										
[redacted]										
Total Power	**(4)**	**(4)**	**(36)**	**(108)**	**(105)**	**(123)**	**(113)**	**(112)**	**(113)**	**(112)**
Total	**6**	**(6)**	**(44)**	**(100)**	**(95)**	**(113)**	**(125)**	**(125)**	**(137)**	**(140)**

- The decrease in peak demands for the Oilfield class is based on an updated oilfield production forecast provided by the Ministry of the Economy.
- The increase in peak demand in distribution losses reflects a recent trend of higher losses as a percentage of distribution load.
- The decrease in peak demand for the potash sector of the Power class reflects a recent updated potash production forecast provided by the Ministry of the Economy. The peak reduction starting in 2019 is due to new potash production capacity in Russia.
- The decrease in peak demands for the [redacted] sector of the power class reflects the delay and decreased loads for the [redacted], the delay and reduced probability for the [redacted] and the removal of [redacted].
- The changes in the [redacted] sector peak demands are based on an updated forecast received from [redacted] and a substantially reduced forecast received from [redacted].
- The changes in peak demand for the remaining Power class customers are primarily attributed to the new [redacted] in-service date and slightly larger loads for the [redacted]

Implications

It is expected the load reductions identified above will help with the tight supply / demand situation in the 2018 – 2019 time period. The 2015 Q4 load forecast will be forwarded to NorthPoint and Supply Planning for use in developing a revised fuel and purchased power estimates for the 2016 rate application. The 2015 Q1 load forecast will continue to be used for the 2016 business plan.

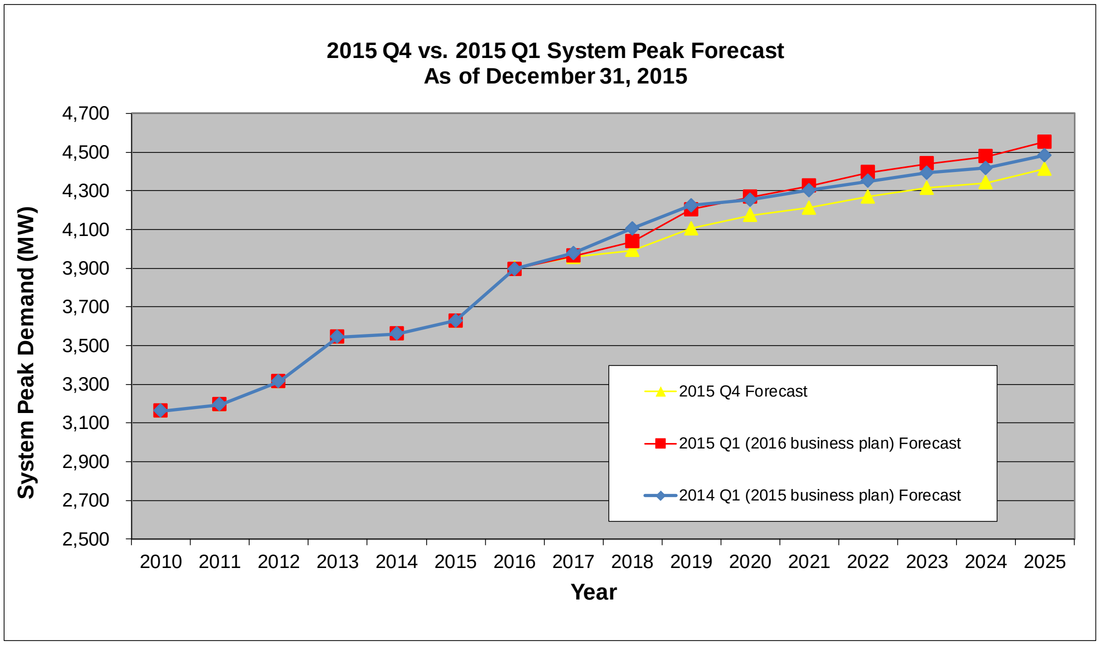
Submitted by:

____

Sandeep Kalra, Vice President & Chief Financial Officer

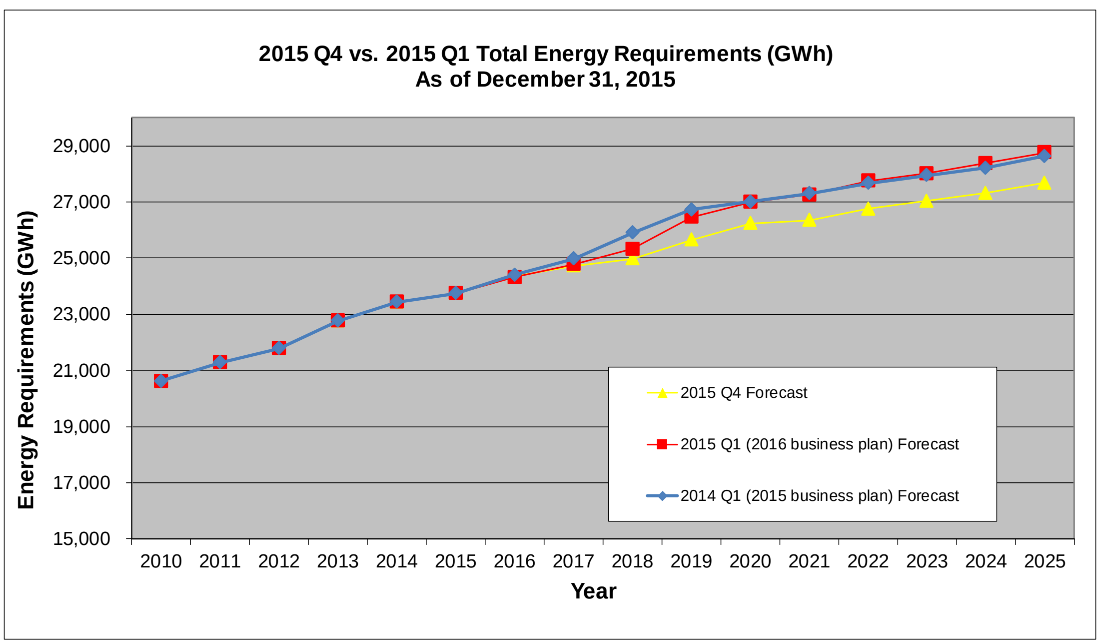
Prepared by: [redacted], Director, Pricing & Energy Forecasting

Appendix A - 2015 Q4 Load Forecast Tables



2015 Q4 Less 2015 Q1 Forecast (MW)

2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
6	(6)	(44)	(100)	(95)	(113)	(125)	(125)	(137)	(140)

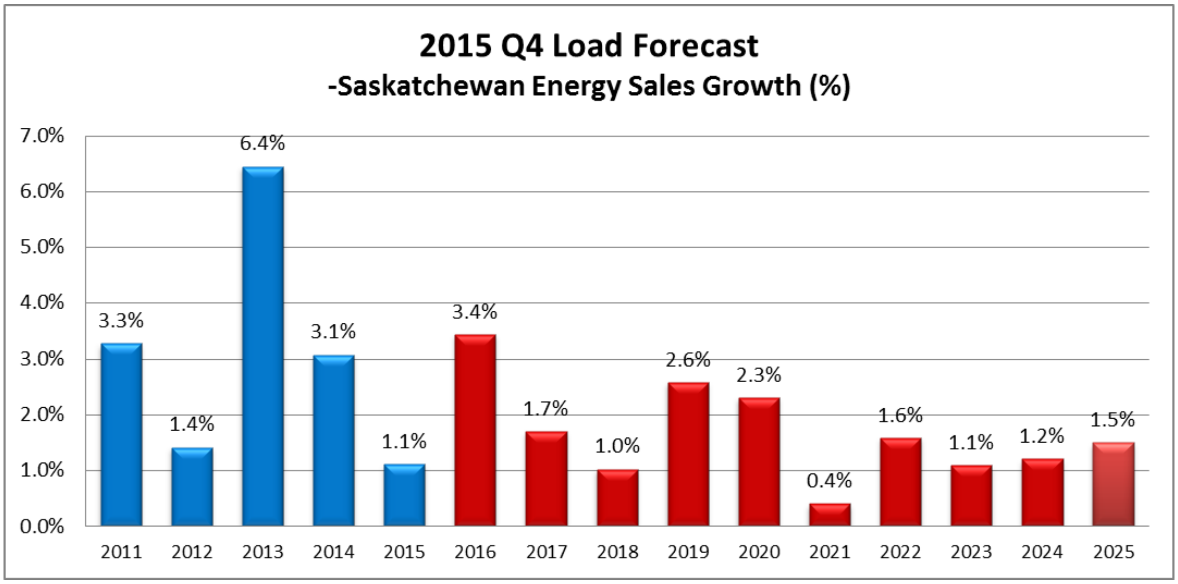


2015 Q4 Less 2015 Q1 Forecast (GWh)

2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
25	(61)	(351)	(800)	(769)	(903)	(989)	(987)	(1,076)	(1,091)

Appendix A - 2015 Q4 Load Forecast Tables

The following table provides the historical and forecasted annual growth rate in Saskatchewan sales in the 2015 Q4 load forecast.



- The 2013 growth rate reflects additional sales due to unusually cold weather.

The following tables summarize the energy sales by customer class and energy sales by power class sector for the 2015 Q4 load forecast.

2015 Q4 Load Forecast - Customer Class Energy (GWh)

Year	Power	Oilfield	Commercial	Residential	Farm	Reseller	Corp & Losses	Total Energy
2015	8,698	3,494	3,795	3,128	1,276	1,234	2,125	23,749
2016	9,162	3,472	3,837	3,275	1,331	1,290	1,982	24,348
2017	9,424	3,525	3,868	3,301	1,334	1,294	1,976	24,721
2018	9,512	3,621	3,896	3,341	1,309	1,298	2,001	24,978
2019	9,912	3,742	3,921	3,388	1,304	1,301	2,086	25,655
2020	10,263	3,848	3,945	3,450	1,301	1,305	2,119	26,231
2021	10,193	3,932	3,967	3,513	1,296	1,308	2,147	26,355
2022	10,495	3,930	3,987	3,579	1,289	1,311	2,165	26,756
2023	10,657	3,934	4,006	3,661	1,287	1,314	2,177	27,036
2024	10,879	3,905	4,024	3,747	1,285	1,318	2,152	27,309
2025	11,117	3,916	4,043	3,851	1,284	1,321	2,142	27,675
Annual Growth Rate	**2.5%**	**1.1%**	**0.6%**	**2.1%**	**0.1%**	**0.7%**	**0.1%**	**1.5%**

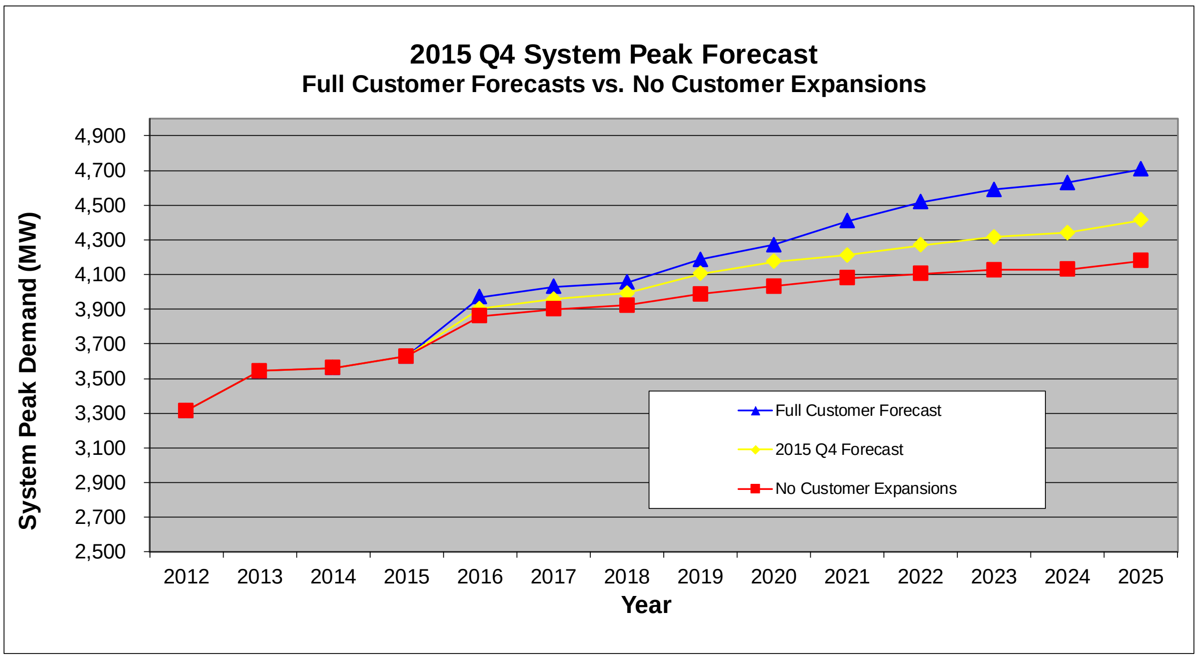
2015 Q4 Load Forecast - Power Class Energy by Sector (GWh)

Year	Potash	Pipeline	Pulp & Paper	Steel	Chemical	Refineries	Northern Mines	Misc.	Total
2015	2,614	1,850	748	683	551	811	446	995	8,698
2016	2,560	2,158	802	705	605	834	497	1,000	9,162
2017	2,695	2,147	800	804	603	833	535	1,007	9,424
2018	2,787	2,149	800	762	586	834	567	1,026	9,512
2019	2,919	2,312	800	804	603	836	581	1,057	9,912
2020	3,032	2,441	802	806	605	842	657	1,079	10,263
2021	2,874	2,538	800	804	587	840	676	1,074	10,193
2022	3,069	2,599	800	804	603	844	704	1,073	10,495
2023	3,245	2,599	800	804	603	846	702	1,059	10,657
2024	3,428	2,601	802	806	605	871	717	1,049	10,879
2025	3,623	2,593	800	804	603	882	780	1,032	11,117
Annual Growth Rate	**3.3%**	**3.4%**	**0.7%**	**1.6%**	**0.9%**	**0.8%**	**5.7%**	**0.4%**	**2.5%**

The Power (industrial) class continues to drive load growth over the next 10 years. In the [redacted] sector, expansions are underway [redacted]. In the [redacted] sector, loads are increasing on the [redacted] Projects include the [redacted]. Other sector growth is attributed to a proposed expansion for [redacted] and [redacted]

Customer Forecasts

The following graph compares the 2015 Q4 System peak forecast to the peak load if all major customer expansion projects proceed. Also included is the peak load if none of the major customer expansion projects proceed.



Comparison to 2015 Q4 Forecast

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Full Customer Forecasts	68	71	61	82	98	195	248	275	290	295
No Customer Expansions	(43)	(59)	(71)	(116)	(142)	(132)	(165)	(187)	(210)	(236)

SRRP R2Q14:

Reference: **First Round Q100: Load Forecast**

a) Please confirm which version of the economic forecast was used as the basis for the Q4 2015 load forecast.
b) Please summarize any key changes between the 2015 economic forecast the 2016 economic forecast that might influence the load forecast.

Response:

a) The economic forecast used for the 2015 Q4 forecast was finalized on 12/1/2015.

b) SaskPower used the same economic forecast for the 2016 Q1 forecast, as it is only completed once per year.

SRRP R2Q15:

Reference: **First Round Q101: Load Forecast**

Does SaskPower have a target range for variances in its load forecast at the corporate level and for each rate class? If so please describe what variance ranges SaskPower considers acceptable and provide explanations for any variances from SaskPower's accepted variance ranges in the table provided in the response to question 101.

Response:

SaskPower has a target range of plus or minus 3% at the corporate level. There is no established variance target for any of the contributing classes.

Major variances resulted in 2009 as a result of the economic recession of 2008-2009. In 2012, the variances were due to project delays in the potash sector as well as lower sales than expected in the potash and pipeline sectors.

SRRP R2Q16:

Reference: **First Round Q102: Load Forecast**

Please confirm that SaskPower's new load forecast software was not used for the basis of the 2015 Load Forecast and this Rate Application

Response:

SaskPower confirms it did not use the new forecast software for the 2015 Q4 forecast used in this rate application.

2016 and 2017 RATE APPLICATION
SRRP ROUND TWO INTERROGATORIES

SRRP R2Q17:

Reference: **Demand Side Management**

Please discuss how SaskPower develops its DSM programs to ensure broad access and availability to different types of consumers, particularly low income residential customers.

Response:

SaskPower strives to maintain a diversified portfolio of DSM programs across sectors to provide opportunities for all customers to participate and is guided by the opportunities identified in the 2010 Conservation Potential Review (CPR). The CPR study helps develop a comprehensive vision of the potential electricity saving and demand reductions achievable in Saskatchewan in a given timeframe.

Following the CPR review, DSM budgets are allocated to programs that provide the greatest opportunity to meet annual DSM targets while maintaining a range of programs across all sectors. SaskPower encourages and supports the adoption of a wide range of energy-efficient technologies in all market segments, and provides targeted conservation education to residential and business customers with the long-term goal of transforming Saskatchewan into a more sustainable and efficient market.

All CPR recommendations are reviewed within the context of industry economic tests, including the Utility Cost Test (UCT) and Total Resource Cost (TRC). These tests influence the determination of whether to pursue an opportunity, how aggressive an opportunity will be pursued, the effectiveness of program design options and department budget allocations.

However, customer experience also continues to be a top priority for our company and for DSM program design. One specific area of focus is to deliver value to customers by developing services that provide customers with greater control over their power use and with opportunities to minimize the impact of rate increases.

For residential low income customers, it is estimated that utility bills make up approximately 6.5% of a household's expenditures[1] and in 2015 SaskPower estimated that there are approximately 80,000 low income households in Saskatchewan. Furthermore, Statistics Canada estimated that, in 2012, 10.6% of the population in Saskatchewan had incomes below the Market Basket Measure.[2] As such, rate changes can have more significant impact on this customer segment.

---

[1] Based on Statistics Canada 2013 report for Saskatchewan

[2] The **Market Basket Measure** (MBM) is a **measure** of low income based on the cost of a specified **basket** of goods and services representing a modest, basic standard of living.

In an effort to minimize this impact, SaskPower has launched a Home Assistance Pilot to:

1. Assist low income households in reducing their electricity needs and save money on their power bills;
2. Develop relationships and partnerships with local organizations to build the capacity of the current pilot and future programs;
3. Increase awareness and effectiveness of efficiency and conservation education messaging among low income households; and
4. Deliver cost-effective demand and energy savings.

The Home Assistance Pilot includes the assembly of simple energy efficient products (see below) and information into kits, which are then distributed to low income households in designated areas through the assistance of local organizations. Kit content can vary based on the needs of each specific location and are assembled by the Saskatchewan Abilities Council.

Item #	Possible Energy Kit Content
1	Fridge/Freezer Thermostat Card
2	Door Weather/Window Closed Cell Foam Weather Stripping (Constructed of 100% PVC foam. Self-sticking adhesive.)
3	A19 A-LED Indoor Bulbs
4	A19 A-LED Outdoor Bulb
5	Outlet and Switch Gaskets
6	Polyethylene Pipe Insulation
7	Teflon Tape for around Shower Heads
8	LED Nightlight (with photocell sensor.)
9	Hot Water Card for Water Tank,
10	Faucet Aerator (1.5 gpm max – Kitchen)
11	Faucet Aerators (1.5 gpm max – Bathroom)
12	Low Flow Showerhead (1.5 gpm)
13	Information packages that identify energy savings associated with each product, information on SaskPower's residential energy efficiency programs, and no-cost energy saving tips and tricks.

The pilot is designed to test customer interest and participation in this type of program. It is also an opportunity to identify if current and future programs of this nature would meet the needs of customers while also achieving the goal of delivering cost-effective energy efficiency savings opportunities.

The first phase of the pilot was executed in early 2015 in collaboration with the Saskatchewan Housing Corporation, which assisted with the coordination of the delivery and/or installation of energy efficiency kits for seven northern communities: Beaver River, Buffalo Narrows, Cumberland House, Creighton, Il a la Crosse, La Loche, and La Ronge. In total, 1,500 kits were delivered as part of the first phase of the pilot.

The second phase of this pilot began in May 2016, with a total of 527 kits installed in three communities: Meadow Lake, Melville and Melfort. Three additional communities are schedule for participation this year, including North Battleford, Weyburn and Humboldt. The pilot program is expected to continue into 2017-18.

During the course of these pilot phases, SaskPower will leverage the lessons learned, as well as ongoing research (including information from other utility programs across Canada) to design and deliver future programs for the low income customer sector.

SRRP R2Q18:

Reference: **Demand Side Management**

Does SaskPower have annual DSM program reduction targets (in GWh or MW or both)? Please discuss how these targets relate to the 2010 CPR scenarios (e.g. upper and lower achievable, reference case, economic potential).

Response:

SaskPower energy efficiency targets are guided by the opportunities identified in the 2010 Conservation Potential Review (CPR). The CPR study helps develop a comprehensive vision of the potential electricity saving and demand reductions achievable in Saskatchewan in a given timeframe.

Prior to the most recent Conservation Potential Review (CPR), in 2008 a goal was set for SaskPower to deliver 100 megawatts (MW) of capacity reductions by the end of 2017.

The 2010 CPR validated the 100 MW target within the context of SaskPower's business plan and available operating budget at the time. The CPR also provided direction in terms of the types of programs on which SaskPower should focus.

Within the 10-year goal horizon, annual DSM targets continue to be updated as market and technology information is available and resources and budget evolve. As part of this, the lower and upper achievable potential ranges in the CPR are referenced as part of annual DSM target setting.

In 2015, SaskPower achieved incremental demand savings of 16.7 MW through a portfolio of energy efficiency and conservation programs, exceeding the goal of reaching a 10-year accumulated target of 100 MW two years early.

In 2016, SaskPower will also be commencing a new Conservation Potential Review (CPR) to provide an updated view of the electricity savings potential and to set new long-term GWh and MW targets for energy efficiency and conservation in Saskatchewan.

Additionally in 2016, SaskPower has commenced the development of an Integrated Resource Plan to meet future system demand, customer expectations and environmental objectives in a reliable, sustainable, and cost-effective manner. The 20-year Integrated Resource Plan will establish an optimal mix of resources, including Demand Side Management, to meet electrical demands of customers across Saskatchewan. The CPR will provide updated energy and capacity savings potentials to be used in the integrated resource planning process.

2016 and 2017 RATE APPLICATION
SRRP ROUND TWO INTERROGATORIES

SRRP R2Q19:

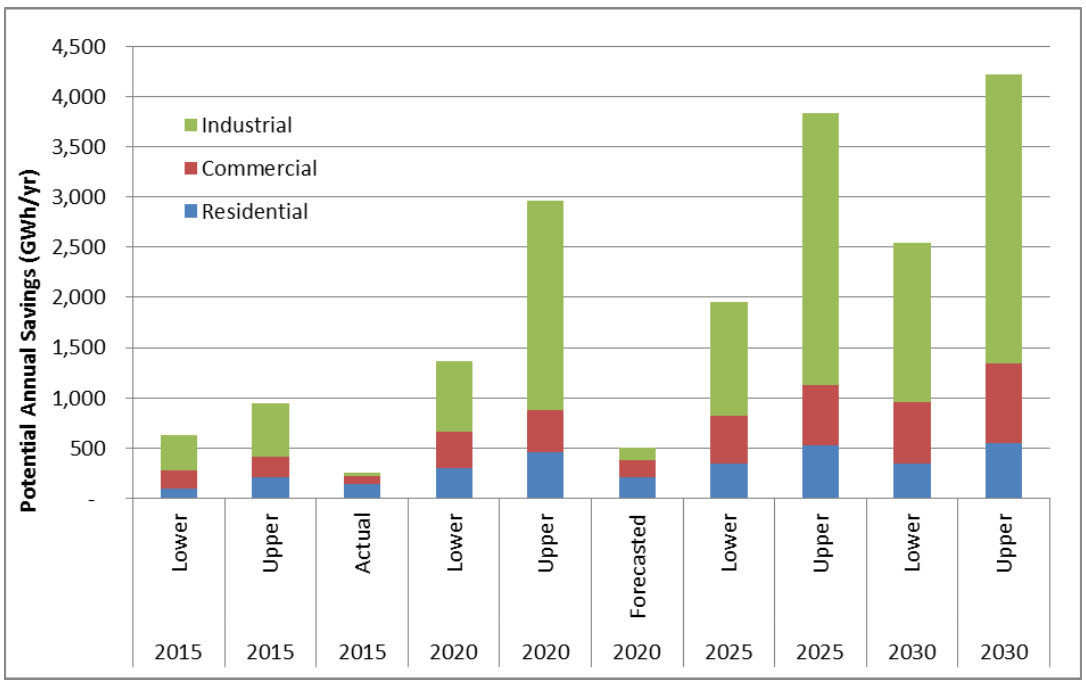
Reference: Demand Side Management

Please provide an updated Exhibit 4 from page 11 (for GW.h) and Exhibit 6 from page 13 (for MW) of the 2010 CPR (provided in SRRP Q112) comparing 2015 actual and 2020 forecast DSM electricity and peak period savings with upper and lower achievable savings by customer class. Please roll up the data to the extent necessary to provide a public version of the requested exhibits.

Response:

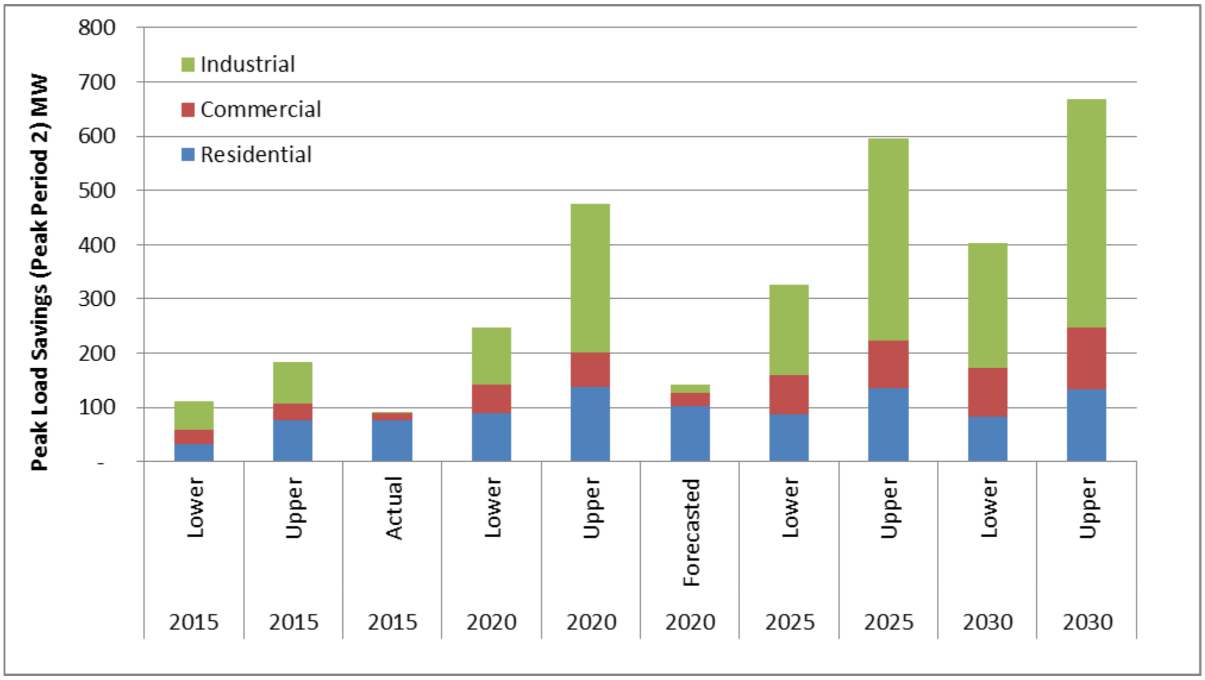
The following exhibits compare 2015 actual savings and forecasted 2020 savings with the upper and lower savings potentials found in the 2010 CPR. Savings potential is allocated by sector, with the largest potential identified in the industrial sector.

Upper and Lower Achievable Electric Energy Savings by Sector
Including Actual Results to the End of 2015 and Forecasted Savings to 2020



Note:
The actual savings reported in 2015 reflect cumulative results from 2010 to the end of 2015 to align with CPR reporting.

Upper and Lower Achievable Peak 2 Savings by Sector
Including Actual Results to the End of 2015 and Forecasted Savings to 2020



Note:
The CPR Summary Report reflects results of Peak Period 4. SaskPower DSM reports peak savings on Peak Period 2, which is reflected in the above exhibit. The actual savings reported in 2015 reflect cumulative results from 2010 to the end of 2015 to align with CPR reporting.

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SRRP ROUND TWO INTERROGATORIES

SRRP R2Q20:

Reference: First Round Q113: Demand Side Management

Please clarify whether values provided in SRRP Q113 are incremental or cumulative per year? If they are incremental, please provide the cumulative savings since program inception for each program area.

Response:

The values provided in SRRP Q113 are incremental. Below are the cumulative savings of programs since inception for the period 2013 to 2015 and forecasted for 2016-17 and 2017-18.

	2013		2014		2015		2016/17		2017/18	
	MWh	MW	MWh	MW	MWh	MW	MWh	MW	MWh	MW
Residential Programs										
Retail Discount Program	32,967	27.2	50,075	35.7	76,275	46.3	89,515	51.96	103,105	57.73
Appliance	29,009	3.5	34,754	4.1	38,824	4.6	42,454	5.03	42,454	5.03
Plug Load	33,568	26.9	34,835	27.9	34,835	27.9	34,835	27.92	34,835	27.92
HVAC	2,054	0.7	2,054	0.7	2,254	0.8	2,314	1.03	2,353.90	0.20
Geothermal	1,284	0.6	1,284	0.6	1,284	0.6				
EnerGuide	1,692	0.6	1,692	0.6	1,692	0.6				
Home Assistance Pilot							TBD		TBD	
New Home										
Commercial Programs										
EPC	44,697	11.7	45,601	11.8	45,601	11.8	45,601	11.82	45,601	12
Lighting	23,907	3.8	37,886	5.7	60,296	8.6	83,046	11.81	97,836	13.92
HVAC	676	0.1	1,240	0.3	1,440	0.3	1,580	0.31	1,720	0.33
Municipal	1,130	1.5	1,333	1.7	1,453	1.9	TBD		TBD	
Parking Lot	6,355	-	7,166		7,866	-	8,666	-	9,466	-
Refrigeration					820	0.1	1,300	0.15	1,780	0.20
Compressed Air			90		360	0.1	TBD		TBD	
Energy Optimiation							TBD		TBD	
Industrial Programs										
Industrial Energy Optimization	5,410	0.6	7,138	0.9	26,398	3.3	40,398	5.25	TBD	
TOTAL EE	182,749	77	225,148	90	299,398	107	349,709	115	339,151	117

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SRRP ROUND TWO INTERROGATORIES

SRRP R2Q21:

Reference: First Round Q113: Demand Side Management

Please provide 2016/17 forecast values for the 12 month fiscal year only (not the 15-month forecast).

Response:

Following are the incremental saving targets for the 2016-17 fiscal year. The residential portfolio of programs is seasonal in nature and doesn't realize savings until the beginning of spring with the launch of the lighting and appliance programs. The remaining programs have been adjusted to reflect the fiscal year forecasted values.

	2016-17 (estimated forecast)	
	MWh	**MW**
Residential programs		
Retail discount program	13,240	5.7
Appliance	3,630	0.4
Plug load		
HVAC	60	0.3
Geothermal		
Energuide		
Home Assistance pilot	TBD	
New home		
Commercial programs		
EPC		
Lighting	15,720	2.3
HVAC	140	0.0
Municipal	TBD	
Parking lot	690	
Refrigeration	480	0.1
Compressed air	TBD	
Energy optimization	TBD	
Industrial programs		
Industrial energy optimization	13,370	1.9
Total EE	**47,330**	**10.6**

Note:
Forecasted savings are estimated, based on expected customer uptake and program funding, and are subject to change.

SRRP R2Q22:

Reference: **First Round Q114: Demand Side Management**

Please provide the UTC and TRC metrics for each program and at the portfolio level and the figures and assumptions that support the calculations.

Response:

The following chart outlines both UCT and TRC metrics for each program and for the portfolio as a whole:

Programs	Utility Test - Benefit/Cost Ratio	Utility Test - Levelized Unit Cost	TRC Test - Benefit/Cost Ratio	TRC Test - Levelized Unit Cost
Commercial Lighting Program	5.55	0.01	1.60	0.02
Commercial Refrigeration Program	2.74	0.01	0.23	0.16
Commercial MSLED Program	3.06	0.02	3.09	0.01
Intelligent Parking Lot Controller Program	4.27	0.01	1.84	0.02
Industrial Energy Optimization Program	2.17	0.02	0.82	0.05
Appliance Recycling Program	1.15	0.03	1.30	0.03
Residential Lighting Program	3.45	0.01	3.19	0.01
Energy Star Loan Program	1.52	0.03	0.73	0.06
Portfolio Level Measures weighted by Energy Savings (KWh)	**3.63**	**0.01**	**1.87**	**0.03**

Ratio

The UCT measures the net costs of a DSM program as a resource option based on the costs incurred by the utility (including incentive costs) and excluding any net costs incurred by the participant. The TRC assists in determining the overall benefit of the energy efficiency program for all utility customers and a ratio of 1.0 or greater is considered appropriate.

These tests influence the determination of whether to pursue an opportunity, how aggressive an opportunity will be pursued, the effectiveness of program design options and department budget allocations.

The benefit/cost ratios are calculated using the following formula:

$$\frac{\text{Present Value (PV) of Program \$ Benefits}}{\text{Present Value (PV) of Program \$ Costs}}$$

The benefits (numerator) calculation for both the UCT and TRC metrics include the following:

- Avoided power supply costs (marginal energy cost)
- Avoided capacity costs (generation)

The costs (denominator) calculation differs slightly between the two measures:

TRC
- Direct utility DSM costs (consulting and contract fees, incentives)
- Direct customer DSM costs
- Utility program administration (salaries)

UCT
- Direct utility DSM costs
- Utility program administration

The discount factor or discount rate used in the above PV calculation is SaskPower's weighted average cost of capital, which is updated annually by Finance.

The time in years used in the above PV calculation reflects the estimated useful life (EUL) of the energy conservation measure (ECM) being reviewed.

Further, energy savings are fine-tuned up (+) or down (-) in SaskPower's models to reflect a variety of adjustment factors, including:

- **(-) Free ridership rate** - savings that occur but cannot be attributed to SaskPower's programs.
- **(+) Line loss rate** - transmission and distribution losses that must be added in so that energy savings are at generation vs. at the meter.
- **(-) Persistence factor** – factors in declining savings over time.
- **(-) Removal/non-install rate** - ECMs that are never installed or installed and then removed.

SRRP R2Q23:

Reference: **Cost of Service Study**

a) Please provide a copy of the 2013 SaskPower Cost Allocation Review completed in 2013.
b) Please discuss the review process for the 2013 study including timing of the review and opportunities for the public and stakeholders to participate in the process.

Response:

a) The 2013 Cost of Service Review by Elenchus Research Associates Inc follows this response.

b) Please see the schedule of events below describing the 2013 Cost of Service review:

Schedule of Events
2012/2013 Cost of Service Review

1.	**Preparation of RFP**	**April 2012**
2.	**Issued RFP & selected Technical Consultant**	**May – June 2012**
3.	**Technical Consultant conducted review of SaskPower's COS Methodology**	**June – July 2012**

a) Review, in consultation with SaskPower's staff, SaskPower's existing cost of service methodology. This review included the following items:

- The classification of power production rate base and expense to demand and energy related.
- The classification of distribution rate base and expense to demand and customer related.
- The allocation of generation, transmission and distribution demand related rate base and expense to customer classes in consultation with SaskPower's Supply & Network Development staff.
- The potential for rate simplification with SaskPower's new Customer Relations & Billing (CR&B) system.
- Verification of the use of Saskatchewan's cold winter coincident peak allocators for demand related rate base and expenses.
- The functionalization and classification of overhead costs.
- The recommendation and development of a study plan to examine the potential for time-of-use rates.

b) Review, in cooperation with SaskPower staff, SaskPower's existing rate design methodology, including the development of ideal cost-based demand, energy, and customer rates and minimum charges for each rate code.

4. Technical Consultant conducted surveys of Canadian utilities' COS methodologies: July – August 2012

a) Identified the main classification and allocation methodologies used by utilities in Canada and the United States for cost of service modeling. A written summary of the relative advantages and disadvantages was prepared for each method.

b) Prepared and implemented a survey of the classification and allocation methodologies currently in use by Canadian electric utilities. The survey included the classification and allocation results in percentages.

5. Technical Consultant prepared draft report August 2012

a) Prepared a draft report for SaskPower by August 31, 2012, which included an overall assessment of SaskPower's cost of service and rate design methodology and specific recommendations on how the Corporation can improve its methodologies. The consultant's report included:

- A review and assessment of SaskPower's existing cost of service and rate design methodology.
- A review and assessment of common and accepted cost of service methodology in the electrical utility industry in Canada and the United States.
- A survey of the classification and allocation methodologies currently in use by Canadian electric utilities as well as the classification and allocation results in percentages.
- A verification of whether or not the current methodology is consistent with accepted electric power utility practices and is appropriate for SaskPower's system characteristics.
- A proposal for the enhancement of SaskPower's cost of service and rate design methodology including the reasons for the changes.

6. Technical Consultant presented draft report to SRRP and SaskPower September 2012

a) Presented the recommendations from the draft report to the Saskatchewan Rate Review Panel and SaskPower in Regina by September 30, 2012.

7. Stakeholder meeting & request for written questions **October 2012**

a) SaskPower conducted a stakeholder meeting in Regina on October 16, 2012. The meeting was attended by members of the SRRP as well as representatives from Saskatchewan's industrial, commercial and oilfield sectors. Members of the general public were also in attendance, as well as representatives from the cities of Saskatoon and Swift Current. At the meeting, the vendor explained the review process and described SaskPower's basic system and current cost of service and rate design methodologies. The vendor then presented the recommendations from the draft report and responded to questions directly, as well as invited stakeholders to submit written questions.

8. Technical Consultant responds to stakeholder questions **November 2012**

a) The Technical Consultant responded to all submitted stakeholder questions in writing by November 2012. Questions were submitted by the cities of Saskatoon and Swift Current, the Saskatoon Chamber of Commerce and the Canadian Association of Petroleum Producers (CAPP).

9. Stakeholders filed written submissions on the draft report **December 2012**

a) Stakeholders were invited to prepare written submissions to the Technical Consultant on the results of the draft report. Submissions were received from the cities of Saskatoon and Swift Current, the Saskatoon Chamber of Commerce and CAPP.

10. Technical Consultant prepared final report **January 2013**

a) The Technical Consultant finalized the report and provided an electronic copy of the final report to SaskPower by January 31, 2013. The Technical Consultant's final report included responses to the written questions and submissions provided by stakeholders.

11. SaskPower filed its response to final report, including proposed actions resulting from the review **February 2013**

a) SaskPower filed its response to the Consultant's final report. SaskPower was in agreement with the recommendations and proposed the following actions:

i. Incorporate SaskPower's load research results into its cost of service methodology before the next rate application (completed).

ii. Use the customer classes' contribution to SaskPower's most likely winter peak as opposed to potential (i.e. worst case – very cold weather in December) peak when SaskPower switches from Alberta to Saskatchewan based load research (completed).

iii. Change the demand allocator used to allocate generation, transmission and most of the distribution demand-related costs from the contribution to SaskPower's winter peak to a combination of SaskPower's winter and summer peaks (completed).

iv. Continue with rate simplification (ongoing).

v. Classify distribution lines and transformers to demand and customer using the minimum system method (ongoing).

Review of Cost Allocation and Rate Design Methodologies

A Report Prepared by
Elenchus Research Associates Inc.
John Todd, Michael Roger

On Behalf of
SaskPower

January 25, 2013

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Table of Contents

1 OVERVIEW

SaskPower retained Elenchus Research Associates (Elenchus) to:

1. review its cost allocation methodology,
2. compare the SaskPower methodology with practices in Canada and the US with particular emphasis on Canadian electric utilities,
3. make recommendations to SaskPower on possible improvements to the cost allocation methodology
4. review SaskPower's current rate design approach, and
5. make recommendations for possible changes to its approach to rate design for SaskPower's consideration.

This report consists of 5 additional sections.

Section 2 provides a very brief overview of the standard approach to cost allocation that is widely accepted by regulators across Canada and internationally. Section 3 extends the discussion of the principles on which the Elenchus review is based by summarizing generally accepted rate making (Bonbright) principles, as the tailored version of those general principles that guide SaskPower approach to rate making.

Section 4 provides an overview of SaskPower's cost allocation methodology, recognizing that this methodology is fully documented in "2010 Base IFRS Embedded Cost of Service Results" which has been prepared by SaskPower. Elenchus has reviewed this documentation to confirm that the SaskPower model is consistent with the documentation of the methodology.

Section 5 presents the results of Elenchus survey of the cost allocation methodologies currently used by selected (major) Canadian and U.S. electric utilities.

Section 6 contains Elenchus comments and recommendations based on our review of the SaskPower cost allocation model and its approach to rate design in light of generally accepted regulatory principles, current standard practices across jurisdictions and the specific operational circumstances of SaskPower.

Section 7 includes the comments received from stakeholders on Elenchus' recommendations in this report and provides Elenchus' responses to the comments.

Appendix A includes the documentation of SaskPower's Cost Allocation Methodology.

Appendix B provides a list of the utilities surveyed and the responses to the cost allocation survey.

Appendix C includes the qualifications of the Elenchus' team that conducted the study and prepared this report.

2 COST ALLOCATION

It is standard practice in Canada in many jurisdictions internationally to rely on cost allocation studies to apportion utility assets and expenses to a utility's customer classes.[1] Because most of the assets and expenses of an electrical power system are used jointly by multiple customer classes, cost allocation studies are used to apportion a utility's revenue requirement among customer classes on a fair and equitable basis as guided by the principle of cost causality.

Traditionally there are three steps that are followed in a cost allocation study: Functionalization, Categorization or Classification, and Allocation.

Functionalization of assets and expenses is the process of grouping assets and expenses of a similar nature, for example, generation, transmission, distribution, customer service, meter reading, etc. Hence, as a first step in a cost allocation study, each account in the utility's system of accounts is functionalized. That is, the function(s)

[1] A standard reference document for cost allocation methodologies continues to be the "Electric Utility Cost Allocation Manual" published by the National Association of Regulatory Utility Commissioners (NARUC) in 1992. A subsequent NARUC publication, "Cost Allocation for Electric Utility Conservation and Load Management Programs" (1993) extends the application of the basic principles to conservation and demand side management (DSM) programs.

served by the assets or expenses contained in each account is identified so that the costs can be attributed appropriately to the identified functions.

Categorization or Classification is the process by which the functionalized assets and expenses are classified as demand, energy and/or customer related. Hence, the costs associated with each function are attributed to these categories based on the principle that the quantum of costs is reflective of the quantum of system demand, energy throughput or the number of customers.

Allocation, which is the final step, is the process of attributing the demand, energy and customer related assets and expenses to the customer classes being served by the utility. This allocation is accomplished by identifying allocators related to demand, energy, or customer counts that are reflective of the relationship between different measures of these cost drivers and the costs that are deemed to be caused by each customer class. For example, if the necessary investment in a particular class of asset (e.g., certain transmission lines) is caused strictly by the single peak in annual demand, then the relevant costs would be allocated using the 1-coincident peak (1-CP) method. The actual application of these broad principles in the context of SaskPower is explained in section 4.

In some instances assets and/or costs can be related directly to a particular customer class and are then directly assigned to the customer class, for example streetlight assets and expenses, by-passing the categorization step.

Cost allocation studies can be done using historical actual data or using future test year data. The information needed is the utilities' financial data related to assets and expenses as well as sales data. The financial data is usually based on the accounting system used by the utility. The sales data used is by customer class and includes for example number of customers, energy (kWh) and demand (kW) consumption.

Cost allocation studies are conducted periodically by utilities to compare the costs attributable to the various customer classes with the revenues being collected from the customer classes. The comparison of costs and revenues is done to determine to what extent the customer class is paying their fair share of the costs imposed on the utility.

The ratio of revenue to cost illustrates to what extent the class is paying for their share of costs. A revenue to cost ratio of 1 or above 1 means that the class is paying their fair share of cost or even more than their fair share. A revenue to cost ratio below 1 means that the class is not paying for their fair share of costs.

Since the allocation of shared costs amongst various customer classes can't be done in an accurate way and parameters or allocators are used to split shared costs, in many jurisdictions, a range of revenue to cost ratio is accepted as reflecting the fair allocation of costs to customer classes instead of thriving to achieve a revenue to cost ratio of 1 for all customer classes. Many jurisdiction use a range of 0.95 to 1.05 as acceptable revenue to cost ratios when establishing revenue responsibilities by customer class.

3 GENERALLY ACCEPTED RATE MAKING PRINCIPLES

It is generally accepted by regulators and regulated utilities that any utility's cost allocation methodology and approach to rate design should be based on a set of clearly enunciated principles. These principles then guide the work that is undertaken to allocate assets and expenses to customer groups appropriately and establish rates that recover those costs from customers in a manner that is consistent with the principles.

The most commonly used reference for defining the objectives in utilities' cost allocation and rate design is the seminal work of James Bonbright.[2] Chapter 16 of the Second Edition sets out ten "attributes of a sound rate structure":

Revenue-related Attributes:

> • *Effectiveness in yielding the utility's total revenue requirement, under the fair return standard, without socially undesirable expansion of rate base or socially undesirable level of product quality or safety.*
>
> • *Revenue stability and predictability with a minimum of unexpected changes seriously adverse to utility companies.*

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[2] *The Principles of Public Utility Rates*, James C. Bonbright, Albert L. Danielsen, David R. Kamerschen (Second Edition, 1988) Public Utilities Reports, pages 383-4.

• Stability and predictability of the rates themselves, with a minimum of unexpected changes seriously adverse to the ratepayers, and with a sense of historical continuity.

Cost-related Attributes:

• Static efficiency of the use of rate classes and rate blocks in discouraging wasteful use of the service, while promoting all justified types and amounts of use.

• Reflections of all of the present and future private and social costs and benefits occasioned by the service's provision.

• Fairness of the specific rates in the apportionment of total cost of service among the different ratepayers, so as to avoid arbitrariness and capriciousness, and to attain equity.

• Avoidance of undue discrimination in rate relationships.

• Dynamic efficiency in promoting innovation and responding economically to changing demand and supply patterns.

Practical-related Attributes

• The related, practical attributes of simplicity, certainty, convenience of payment, economy in collection, understandability, public acceptability, and feasibility of application.

• Freedom from controversies as to proper interpretation.

It is inevitable that in applying these principles, conflicts arise in trying to apply all of the principles simultaneously. An allocation that is more equitable may well compromise economic efficiency or simplicity. Determining the optimal trade-offs between the principles in developing rates therefore requires judgment. For this reason, cost allocation and rate design are often referred to as being as much art as science.

SaskPower's six stated key objectives[3] for its cost of service study and resulting rate design are consistent with the Bonbright principles and appear to encompass all ten of the principles set out by Bonbright in 1988. The SaskPower objectives are:

1. Meeting revenue requirement
2. Fairness and equity
3. Economic efficiency
4. Conservation of resources

[3] 2010 Base IFRS Embedded Cost of Service Results Document

5. Simplicity and administrative ease
6. Stability and gradualism

The flowing sub-sections set out our interpretation of SaskPower's objectives.

3.1 Meeting Revenue Requirement

Meeting SaskPower's revenue requirement implies that customer rates should be set so as to yield sufficient revenues for the utility to recover its approved costs. The recoverable costs that make up the company's revenue requirement include all operating, maintenance and administration expenses, including amortization, as well as the cost of capital. The cost of capital includes both the interest on outstanding debt and a return on equity (or interest coverage) that enables the utility to be financially sound.

3.2 Fairness and Equity

Fairness and equity are understood to mean that the utility's assets and expenses have been apportioned to the customer classes in a manner that has cost causality as the main criteria. The methodologies used to apportion costs follow criteria that can be measured in a fair way and can be understood and accepted by stakeholders. Most of the utilities assets and expenses are shared by all or most of the utility's customers and cost causality parameters are developed to assign the assets and expenses to customer groups.

3.3 Economic Efficiency

Economic efficiency means that the utility's assets and expenses are being utilized effectively (operational efficiency) and, to the extent practical, the rates charged customers provide reasonable price signals that allow the utility to develop the power system in a manner that is efficient through time (dynamic efficiency).

3.4 Conservation of Resources

Conservation of resources is further dimension of economic efficiency in that the design of rates should result in price signals that encourage consumers the use power in a manner that maintains a reasonable balance between cost of supplying power to consumers and the value of that power to consumers.

3.5 Simplicity and Administrative Ease

Simplicity and administrative ease are criteria that address the need to use cost allocation and rate design methods that are understandable by stakeholders and customers and are implementable by the utility given its available capabilities and resources.

3.6 Stability and Gradualism

Stability and gradualism are criteria that deal with the need to use cost allocation and rate design approaches that produce stable results over time and manageable/gradual changes as a result of changing circumstances. The purpose of the criteria is to avoid as much as possible approaches that produce sudden and significant changes in cost allocation and rate design as a result of changing circumstances. This is not intended as an impediment to appropriate changes, but rather a recognition that significant changes in the level of charges can be difficult for consumers to absorb in their daily lives. Hence, when circumstances justify changes that may have a significant impact on customer bills, it is desirable to phase in the changes in a manner that mitigates bill impacts without unduly compromising the other objectives of SaskPower's cost allocation and rate design.

4 SASKPOWER COST ALLOCATION METHODOLOGY

SaskPower cost allocation methodology[4] follows the standard industry approach of Functionalization, Classification and Allocation of assets and costs to customer classes.

4.1 *FUNCTIONALIZATION*

The asset and expense functions utilized by SaskPower to group assets and costs of a similar nature include the following:

1. Generation:
    i. Load
    ii. Losses
    iii. Scheduling and Dispatch
    iv. Regulation and Frequency Response
    v. Spinning Reserve
    vi. Supplementary Reserve
    vii. Planning Reserve
    viii. Reactive Power
    ix. Grants in Lieu of Taxes
    x. Interruptible Adjustment
2. Transmission
    i. Main Grid
    ii. 138 kV Lines Radials
    iii. 138/72 kV Substations
    iv. 72 kV Lines Radials
3. Distribution
    i. Area Substations

[4] ibid

- ii. Distribution Mains
- iii. Urban Laterals
- iv. Rural Laterals
- v. Transformers
- vi. Service Customer
- vii. Meters
- viii. Streetlights

4. Customer Service
   - i. Metering Services
   - ii. Meter Reading
   - iii. Billing and Customer Service
   - iv. Customer Collecting
   - v. Customer service
   - vi. Marketing

The functions used by SaskPower provide enough differentiation of assets and costs by grouping assets and costs of a similar nature in the cost allocation methodology to enable the classification and allocation of assets and costs to customer classes using cost causality principles. The extent of the breakdown onto functions is consistent with other Canadian power utilities.

Additional details on the functionalization step followed by SaskPower in its cost allocation methodology are provided in Appendix A, which excerpts the details of the methodology from SaskPower's "2010 Base IFRS Embedded Cost of Service Results Document".

4.2 CLASSIFICATION

SaskPower classifies assets and costs into demand related, energy related and customer related as it is the standard practice of other Canadian power utilities. Classifying assets and costs into these three categories allow for the subsequent proper allocation of these assets and costs to customer groups.

The classification methodology currently used by SaskPower for generation rate base and depreciation expenses is the Equivalent Peaker method. This method is based on the ratio of the unit cost of new peaking capacity to the new cost of base load capacity by generation types to classify rate base and depreciation into demand and energy related.

The fuel expense for SaskPower units is classified as 100% energy-related as is common practice in the cost allocation studies of other Canadian power utilities with rate regulated generation functions.

Transmission facilities are classified by SaskPower as 100% demand-related. This also is the usual approach for these types of assets and costs.

Distribution substations and three phase feeders are classified 100% demand-related. Urban and rural single-phase primary lines are classified 65% demand-related and 35% customer-related. Line transformers are classified 70% demand-related and 30% to customer-related.

All secondary lines, services, and meters are classified 100% customer-related.

Customer related assets and costs are classified 100% to customer.

More details on the classification of assets and costs in SaskPower's cost allocation methodology are provided in Appendix A, which excerpts the details of the methodology from SaskPower's "2010 Base IFRS Embedded Cost of Service Results Document".

4.3 ALLOCATION

The last step in SaskPower's cost allocation study allocates the demand, energy and customer related assets and costs to SaskPower's customer classes. Having classified assets and costs into demand, energy and customer related, allows for the allocation of these assets and costs using the appropriate parameters (i.e., allocators) that reflect cost causality. For example, it allows for energy consumed by customer class to be used to allocate energy related assets and costs, and for using the number of customers to allocate customer related assets and costs that are driven by the number of customers.

Demand related generation assets and costs and transmission assets and costs are allocated to customer classes using the one coincident peak (1-CP) method based on demand adjusted for the estimated associated transmission and distribution losses. Energy related generation assets and costs are allocated to customer classes based on the energy consumed by customer classes, adjusted to include estimated losses.

Distribution demand related assets and costs are allocated to customer classes based on a combination of one coincident peak method or one class non-coincident peak method.

Customer related assets and costs are allocated to customer classes based on a combination of methods based on the number of customer by customer class or weighted number of customer by customer class, depending on the assets or costs being allocated.

4.3.1 CUSTOMER CLASSES

The following is a list of the customer classes currently served by SaskPower, to which the functionally classified rate base and expenses are allocated. Each rate class may have multiple rate codes.

- *Urban Residential*
- *Rural Residential*
- *Farms*
- *Urban Commercial*
- *Rural Commercial*
- *Power - Published Rates*
- *Power - Contract Rates*
- *Oilfields*
- *Streetlights*
- *Reseller*

More details on the allocation of assets and costs in SaskPower's cost allocation methodology are provided in Appendix A, which excerpts the details of the methodology from SaskPower's "2010 Base IFRS Embedded Cost of Service Results Document".

SaskPower also conducted studies to develop appropriate customer class load profiles based on valid sampling of customers and SaskPower also utilizes a study of losses to determine the losses incurred in providing electricity to its various customer groups.

More details on the customer load profiles and loss study conducted by SaskPower are provided in Appendix A, which excerpts the details of the methodology from SaskPower's "2010 Base IFRS Embedded Cost of Service Results Document".

5 SURVEY OF COST ALLOCATION METHODOLOGIES

Elenchus conducted a survey of Canadian and US utilities with respect to the Cost Allocation methodologies currently being used in the industry. Special emphasis was placed on obtaining information from Canadian utilities.

Classification of assets and expenses and allocation methodologies were surveyed and the results of the survey are included in this report and more details of the survey responses are provided in Appendix B.

As a result of deregulation in the electricity sector, some generators no longer follow a cost allocation approach to determine how to allocate their assets and costs to customer classes and to develop appropriate rates. Instead generators bid their supply to electricity system market operators, or have bi-lateral agreements that have specified prices. Revenues are based on market prices for electricity.

5.1 GENERATION CLASSIFICATION

There are a variety of methodologies used in the utility industry to classify generation between demand and energy related. The methodologies range from classifying all generation as energy related to classifying all generation as demand related. The choice of methodology would usually reflect the utility's circumstances. Some utilities may consider also a 50/50 split as a compromise method.

In the Average and Excess method of classifying generation, assets and costs are allocated using factors that combine each class's average demands over the test period with its non-coincident peak demands. The average demand is the ratio of each class average demand to total average demand. The excess demand is the difference between the class non-coincident peak and the average demand.

In the Equivalent Peaker method, generation assets and costs are separated into those deemed to serve peak demands and those that are deemed to be incurred to provide energy. The peaker assets and costs are allocated on a demand basis and the remaining assets and costs, deemed to be energy related, are allocated on an energy basis. The peaker assets and costs are the generation assets and costs of the units used to satisfy all demands.

In the Peak and Average method a combination of the class contribution to 12 CP and class contribution to average energy usage is used to allocate generation.

SaskPower uses the Equivalent Peaker method outlined in the NARUC Electric Utility Cost Allocation manual by taking the ratio of the unit costs of new peaking capacity to the unit cost of new base load capacity in order to determine the demand related portion of generation by fuel type.

5.1.1 HYDROELECTRIC

Based on the survey results, Canadian utilities appear to favour the load factor approach to classify hydroelectric generation.

Other methodologies for classifying some hydroelectric generation assets and expenses to energy are based on the:

- purpose of hydroelectric generation, base or peaking
- ratio of energy produced in an average year compared to extreme year
- ratio between hydroelectric capacity factor and total system capacity factor

Based on the responses to the survey the percentages of demand related classification of hydroelectric generation costs are summarized in the following Table.

Classification of Hydroelectric generation costs to demand		
Percent Classified as demand	Number of respondents	Percent of Respondents
90 - 100	2	17
70 - 90	0	0
50 - 70	1	8
35 - 50	3	25
Below 35	1	8
NA	5	42
Totals	12	

5.1.2 BASE LOAD STEAM

Based on the responses to the survey the percentages of demand related classification of base load steam generation (coal, oil, or gas) costs are summarized in the following Table.

Classification of Base Load Steam generation costs to demand		
Percent Classified as demand	Number of respondents	Percent of Respondents
90 - 100	3	25
70 - 90	0	0
50 - 70	0	0
35 - 50	2	17
Below 35	1	8
NA	6	50
Totals	12	

5.1.3 Base Load Combined Cycle

Based on the responses to the survey the percentages of demand related classification of base load combined cycle generation costs are summarized in the following Table.

Classification of Base Load combined cycle generation costs to demand		
Percent Classified as demand	Number of respondents	Percent of Respondents
90 - 100	3	25
70 - 90	0	0
50 - 70	0	0
35 - 50	1	8
Below 35	1	8
NA	7	58
Totals	12	

5.1.4 Combustion Turbine

Based on the responses to the survey the percentages of demand related classification of combustion turbine generation costs are summarized in the following Table.

Classification of combustion turbine generation costs to demand		
Percent Classified as demand	Number of respondents	Percent of Respondents
90 - 100	4	33
70 - 90	0	0
50 - 70	0	0
35 - 50	2	17
Below 35	1	8
NA	5	42
Totals	12	

5.2 Transmission Classification

Based on the responses to the survey the percentages of demand related transmission costs are summarized in the following Table.

Classification of transmission costs to demand		
Percent Classified as demand	Number of respondents	Percent of Respondents
90 - 100	7	58
70 - 90	0	0
50 - 70	0	0
35 - 50	3	25
Below 35	0	0
NA	2	17
Totals	12	

Transmission costs are usually classified as 100% demand related since transmission is planned in order to transport electricity at the time of maximum demand in the system. Transmission includes the operation of the grid at different voltages as a single function that transports power from generating stations to the distribution system. Transmission also provides reliability to the electricity system by connecting multiple generation sources.

In some cases transmission is considered and extension of generation, when it is connecting remote generators, and is therefore, classified into demand and energy in the same proportion as the generation it is connecting.

5.3 Sub-Transmission Classification

Some utilities may have an additional asset and expense function, sub-transmission system, which connects the transmission system to the distribution system. The definition of sub-transmission depends on the definition of Transmission. If Transmission assets are defined as 115kV and above, then 69 kV assets would be defined as Sub-transmission. In Ontario where Transmission is defined as assets above 50 kV, Sub-transmission is usually defined as 27.6 kV and 44 kV, or as in the case of one distributor it includes voltages between 13.8 kV and below 50 kV.

The sub-transmission assets and expenses are usually classified in the same proportion as the transmission system is classified. Based on the responses to the survey the percentage of demand related costs for sub-transmission costs are summarized in the following Table.

Classification of Sub-transmission costs to demand		
Percent Classified as demand	Number of respondents	Percent of Respondents
90 - 100	8	67
70 - 90	0	0
50 - 70	0	0
35 - 50	1	8
Below 35	2	17
NA	1	8
Totals	12	

5.4 DISTRIBUTION CLASSIFICATION

Distribution assets connect the transmission assets to the customer. The closer the distribution assets are to the transmission system and further away from the customers, the classification of these assets will be similar to the classification of the transmission assets.

The closer the distribution assets are to the customer connections, then these costs are more and more classified as customer related. For example meter assets and costs are classified as 100% customer related, since these assets and costs have to be incurred by the utility regardless of how much power the customer consumes.

In order to determine what proportion of distribution costs are customer related and what proportion are demand related, there are two generally accepted methodologies being used by utilities: Minimum System method and Zero Intercept method.

The Minimum System method calculates the proportion of distribution asset costs that are customer related by taking the ratio of the costs of the smallest distribution assets, 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.

The Zero Intercept method calculates the customer related component of a distribution asset type by plotting a graph of the unit costs of different size similar assets and using the value at the zero intercept in the graph to represent to customer component of the asset costs. A common critique of this method is that a utility may not have enough data to plot a proper graph, or in some instances may result in a negative value at zero intercept. Based on the responses to the survey the classification methods used for line and transformers are shown in the following Table.

Classification Method for Distribution Lines and Transformers		
Method	Number of respondents	Percent of Respondents
Minimum System	2	17
Zero Intercept	1	8
Both Minimum and Zero Intercept	3	25
Other	5	42
NA	1	8
Totals	12	

Based on the responses to the survey the proportion of distribution stations costs classified as demand related is shown in the Table below.

Classification of Distribution Substation costs to demand		
Percent Classified as demand	Number of respondents	Percent of Respondents
90 - 100	11	92
NA	1	8
Totals	12	

Based on the responses to the survey the proportion of Primary Lines costs classified as demand related is shown in the Table below.

Classification of Primary Lines costs to demand		
Percent Classified as demand	Number of respondents	Percent of Respondents
90 - 100	5	42
70 - 90	2	17
50 - 70	3	25
35 - 50	1	8
NA	1	8
Totals	12	

Based on the responses to the survey the proportion of Distribution Transformer costs classified as demand related is shown in the Table below.

Classification of Distribution Transformers costs to demand		
Percent Classified as demand	Number of respondents	Percent of Respondents
90 - 100	7	58
70 - 90	2	17
50 - 70	1	8
35 - 50	1	8
NA	1	8
Totals	12	

Based on the responses to the survey the proportion of Line Transformer costs classified as demand related is shown in the Table below.

Classification of Line Transformers costs to demand		
Percent Classified as demand	Number of respondents	Percent of Respondents
90 - 100	4	33
70 - 90	4	33
50 - 70	1	8
35 - 50	1	8
NA	2	17
Totals	12	

Based on the responses to the survey the proportion of Secondary Line costs classified as demand related is shown in the Table below.

Classification of Secondary Line costs to demand		
Percent Classified as demand	Number of respondents	Percent of Respondents
90 - 100	2	17
70 - 90	2	17
50 - 70	4	33
35 - 50	1	8
Below 35	2	17
NA	1	8
Totals	12	

Based on the responses to the survey the proportion of Services costs classified as customer related is shown in the Table below.

Classification of Services costs to customer		
Percent Classified as customer	Number of respondents	Percent of Respondents
90 - 100	11	92
NA	1	8
Totals	12	

Based on the responses to the survey the proportion of Meter costs classified as customer related is shown in the Table below.

Classification of Meter costs to customer		
Percent Classified as customer	Number of respondents	Percent of Respondents
90 - 100	11	92
NA	1	8
Totals	12	

5.5 ALLOCATION

5.5.1 GENERATION AND TRANSMISSION ALLOCATORS

1 COINCIDENT PEAK METHOD

The 1 CP allocation method allocates demand related costs to a customer class in proportion to the contribution of that customer class to the utility's maximum system peak. This method is based on the assumption that system capacity requirements are determined by the maximum demand imposed by customers on the system.

The advantage of this method is that it reflects cost causality and customers that impose costs on the system are responsible for those costs.

The disadvantage of this method is that customers that do not use the system at the time of the system peak, or can reduce their consumption during the peak could end up using the system for free, or not paying their fair share of costs. Another disadvantage is that if there are major system changes and the peak shifts to a different time, it could result in changes to class allocation factors.

12 COINCIDENT PEAK METHOD

The 12 CP method is similar to the 1 CP method but instead of using only one value for the year, it is based on each months maximum peak times. This method assumes that each monthly peak is important and not just the single annual peak.

The advantage of this method is that it addresses the disadvantage of the 1 CP method by reducing or eliminating entirely the possibility of using the system for free. The disadvantage of this method is that if the system had seasonal characteristics, using only one value for each month may not track costs properly.

VARIOUS COINCIDENT PEAK VARIATIONS

A variation on the 1 CP and 12 CP methods is that more than 1 and less than 12 values are used in the derivation of the coincident peak allocator.

Another variation is that the coincident peak value may not necessarily be one per month, but could be for example, the higher 5 coincident peak values regardless of when they occur in the year.

1 CLASS-NON-COINCIDENT PEAK METHOD

The 1 Non-Coincident peak method is based on the maximum demand by customer class, regardless of when they occur. It is very likely that the maximum demands occur at different times and may not all be at the time of the system maximum demand. A ratio is developed by customer class based on the class maximum demand compared to the sum of all classes' maximum demands.

The advantage of this method is that it reflects cost causality for assets that are the closest to the customer, or serve only similar type of customers.

The disadvantage of this method is that it does not take into account the benefits derived though diversity and that not all customers' maximum demand occur at the same time, allowing for the assets to be built to serve less than the sum of all customers maximum demand.

Another disadvantage of this method is that a customer class can increase consumption up to its maximum demand and not be charged more costs.

12-NON-COINCIDENT PEAK

The 12 NCP allocation method is similar to the 1 NCP method, but instead of using just one maximum demand for the year, 12 monthly values are used. The ratios of class maximum demand to the sum of each class maximum demands are calculated for each month.

The advantage of this method over the 1 NCP is that if a class increases consumption, it would be allocated more costs.

AVERAGE AND EXCESS METHOD

This method develops allocation factors taking into account average and excess demand. Average demand factors are the ratio of the average demand by customer class to the total system average demand. The excess demand is the difference between the maximum demand by class to the average demand. The excess demand factor is the ratio of each class excess demand to the total system excess demand.

The allocation factors for each class are determined by weighting the average demand factor for each class by the system average load factor. The excess demand factor is weighted by one minus the load factor. The two ratios are added together to determine the average and excess allocation factor.

The advantage of this method is that takes into account load factors, how the system is being utilized and also addresses allocation of costs at times other than the maximum system demand.

The disadvantage of this method is that it allocates costs equally to classes, regardless if the consumption is during the peak of the system or not.

Other disadvantages of this method are that it assumes a linear relationship between load factor and coincidence factor and that it does not reflect diversity between customer classes.

EQUIVALENT PEAKER METHOD

This method is based on charging the marginal energy cost in each hour plus the annual cost of peaking capacity equal to the peak kW. The assumption is that all peak demand costs should equal the cost of peaking capacity and the excess of cost of base load generation over peaking capacity should be energy related costs.

The advantage of this method is that it reflects marginal costs, so from economic theory perspective it is efficient.

The disadvantage of this method is that it is complex and uses marginal costs which may introduce variability over time to the results.

Based on the responses to the survey the allocation method for generation demand related costs is shown in the Table below.

Allocation Method for Generation Demand Costs		
Method	Number of respondents	Percent of Respondents
1 CP	2	17
4 CP	2	17
12 CP	2	17
Highest 300 Hours	1	8
3 Winter CP	1	8
NA	4	33
Totals	12	

Based on the responses to the survey the allocation method for transmission demand related costs is shown in the Table below.

Allocation Method for Transmission Demand Costs		
Method	Number of respondents	Percent of Respondents
1 CP	4	33
2 CP	1	8
4 CP	1	8
12 CP	2	17
Other	3	25
NA	1	8
Totals	12	

Based on the responses to the survey the allocation method for sub-transmission demand related costs is shown in the Table below.

Allocation Method for Sub-transmission Demand Costs		
Method	Number of respondents	Percent of Respondents
1 CP	2	17
4 CP	2	17
12 CP	3	25
NCP	2	17
Other	2	17
NA	1	8
Totals	12	

5.5.2 Interruptible Load

Interruptible load reflects a type of service that is curtailed at time of system maximum demand or other emergencies. Because of the possibility of curtailment, customers served under this condition pay less for electricity than customers supplied on a firm basis. Usually the amount of the discount customer receives is tied to the savings to the utility of not building peak capacity to serve the customer. Having this type of service allows for better utilization of the electricity system.

SaskPower has implemented a demand response program[5] that is based on the same principle as interruptible rates, better utilization of the electricity system in return for a discount. In the program, at times of capacity constraints customers participating in the program that shift load, receive financial compensation.

SaskPower accounts for the costs of the demand response program as Fuel expenses. This treatment is acceptable since in the absence of the program, the utility would have to supply the shifted demand by utilizing marginal plants burning marginal fuel and these avoided expenses would have been included as Fuel expenses.

5.5.3 DISTRIBUTION COSTS ALLOCATORS

DEMAND

The demand allocation methods for distribution costs are related to the proximity of the distribution asset to the end-use customer. Distribution assets that are further away from the customer and closer to the sub-transmission or transmission system are allocated to customer classes based on coincident demand allocators. The closer the distribution assets are to the customers, then the demand allocation method would reflect the customer class' maximum demand, that is, non-coincident maximum demand.

CUSTOMER

Distribution costs that do not vary with customer consumption are classified as customer related and are allocated to customer classes based on number of customers by class or based on weighted number of customers. The weights are related to the type of assets or costs being considered and reflect cost causality. For example meter reading assets and costs would be weighted by the number of times the meter is read by customer class, e.g. monthly, by-monthly.

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[5] http://www.saskpower.com/save_power/business/programs_offers/demand_response/

Based on the responses to the survey the allocation method for distribution station demand related costs is shown in the Table below.

Allocation Method for Distribution Station Demand Costs		
Method	Number of respondents	Percent of Respondents
1 NCP	5	42
4 NCP	1	8
12 NCP	2	17
Other	3	25
NA	1	8
Totals	12	

Based on the responses to the survey the allocation method for distribution Primary Lines demand related costs is shown in the Table below.

Allocation Method for Distribution Primary Lines Demand Costs		
Method	Number of respondents	Percent of Respondents
1 NCP	6	50
4 NCP	1	8
12 NCP	2	17
Other	2	17
NA	1	8
Totals	12	

Based on the responses to the survey the allocation method for distribution transformers demand related costs is shown in the Table below.

Allocation Method for Distribution Transformers Demand Costs		
Method	Number of respondents	Percent of Respondents
1 NCP	6	50
4 NCP	1	8
12 NCP	2	17
Other	2	17
NA	1	8
Totals	12	

Based on the responses to the survey the allocation method for distribution secondary lines demand related costs is shown in the Table below.

Allocation Method for Distribution Secondary Lines Demand Costs		
Method	Number of respondents	Percent of Respondents
1 NCP	5	42
4 NCP	1	8
12 NCP	2	17
Other	3	25
NA	1	8
Totals	12	

Based on the responses to the survey the allocation method for distribution station customer costs is shown in the Table below.

Allocation Method for Distribution Station Customer Costs		
Method	Number of respondents	Percent of Respondents
# of Customers	3	25
NA	9	75
Totals	12	

Based on the responses to the survey the allocation method for distribution primary lines customer costs is shown in the Table below.

Allocation Method for Distribution Primary Lines Customer Costs		
Method	Number of respondents	Percent of Respondents
# of customers	7	58
Other	2	17
NA	3	25
Totals	12	

Based on the responses to the survey the allocation method for distribution transformer customer costs is shown in the Table below.

Allocation Method for Distribution Transformers Customer Costs		
Method	Number of respondents	Percent of Respondents
# of customers	5	42
Other	4	33
NA	3	25
Totals	12	

Based on the responses to the survey the allocation method for distribution secondary line customer costs is shown in the Table below.

Allocation Method for Distribution Secondary Lines Customer Costs		
Method	Number of respondents	Percent of Respondents
# of customers	7	58
Other	3	25
NA	2	17
Totals	12	

Based on the responses to the survey the allocation method for services customer costs is shown in the Table below.

Allocation Method for Services Customer Costs		
Method	Number of respondents	Percent of Respondents
# of customers	3	25
Weighted # of customers	4	33
Other	4	33
NA	1	8
Totals	12	

Based on the responses to the survey the allocation method for meter costs is shown in the Table below.

Allocation Method for Meter Customer Costs		
Method	Number of respondents	Percent of Respondents
# of customers	2	17
Weighted # of customers	5	42
Other	4	33
NA	1	8
Totals	12	

5.6 Rate Design

There are various alternatives for rate design being used for different customer classes in the industry. They include:

- End use – Purpose of electricity use, for example residential, commercial, pumping load
- Energy or demand billed – How the customer is being billed: based on energy (kilowatt hours) or demand (kilowatts)
- Density – Where the customer is located: in an urban (high density) area or a rural (low density) area
- Seasonal – When the customer consumes power: year-round or only during a specific season (e.g. summer cottages)
- Voltage of supply – Voltage that the customer is supplied electricity: transmission or high voltage, sub-transmission, primary, secondary or low voltage
- Size – Amount of demand (kilowatts) or capacity that the customer consumes: e.g. above 50 kW, above 5 MW
- Load factor – Consumption pattern of electricity over time reflecting the costs that this pattern of consumption imposes on the utility, e.g. high load factor customers consume almost the same amount of electricity in all hours
- Quality of supply – Assurances of electricity supply, e.g. firm, interruptible
- Time-of-use – How electricity is charged to the customer, prices may vary by season, (e.g. winter summer), and by period (e.g. peak, off-peak)
- Unmetered – If electricity consumption is uniform then it does not need to be metered e.g. streetlight, cable TV

More than one rate design is usually used by utilities in order to properly reflect the differences across customer classes and the individual utility's operations.

6 ELENCHUS COMMENTS AND RECOMMENDATIONS

Based on our review of SaskPower's cost allocation methodology, our knowledge of standard practices in other jurisdictions across Canada and our survey of the cost allocation practices of other electric utilities undertaken for this report, we are of the view that the methodology currently used by SaskPower in its cost allocation methodology is generally consistent with generally accepted rate making principles and practices as well as the methodologies commonly used by other electric utilities. Furthermore, SaskPower's cost allocation methodology is consistent with, and reflective of, SaskPower's operational circumstances.

The following sub-sections outline observations on notable issues and recommended refinements that in our view merit consideration. As noted earlier, cost allocation is more of an art than a science; hence, adoption of any recommended changes to SaskPower's methodology should be dependent on the cost and/or availability of the required data, as well as the potential impact on the complexity of rates and the impact on customers. No changes should be implemented without due consideration and balancing of all of the Bonbright principles of rate making and SaskPower's objectives and operational circumstances.

6.1 CLASSIFICATION OF GENERATION COSTS

Based on the results of the survey, six out of seven utilities classify hydroelectric generation as at least 35% demand related. The seventh utility classifies hydroelectric generation as 100% energy related. In SaskPower case, using the peaker method results in 31% of hydroelectric generation being classified as demand related. Elenchus therefore notes that the proportion of demand-related costs used by SaskPower is at the lower end of the range compared to other utilities that classify a portion of hydroelectric generation as demand related, but Elenchus does not recommend a change in the classification methodology used by SaskPower. SaskPower's classification results reflect the way hydroelectric generation is being used by the utility.

For baseload steam generation, combined cycle generation, and combustion turbine generation five out of six utilities surveyed classify at least 35% as demand related, compared to SaskPower's baseload steam generation value of 52% demand related, combined cycle value of 83% demand related and peaking generation of 100% demand related. SaskPower result's for these types of generation are within the range for other utilities surveyed.

Given the mix of type of generation used by SaskPower to meet electricity demand in its territory, the use of the peaker method to classify generation costs is appropriate in Elenchus' opinion.

Elenchus understands that SaskPower is having difficulties in obtaining the data needed in order to update the Equivalent Peaker method of classifying generation assets and costs between demand and energy related. Standard costing data for fossil plants is no longer available and historical data are being used. Even when using historical data, the results for SaskPower are not out of line with the results for other utilities.

Elenchus suggests that as long as the results of the survey of other electric utilities shows that SaskPower's classification percentages are not out of line, the current percentages should continue to be used by SaskPower. If SaskPower results start to deviate from other utilities, SaskPower should consider changing the classification methodology, or updating the values used to reflect the results of the survey. Another alternative would be to use inflation indices to update the historical costs that SaskPower has available.

Elenchus does not see a compelling reason to suggest changing the SaskPower classification methodology. The survey results and Elenchus experience do not suggest that there is a consensus in the industry of what is considered a right or wrong methodology. The various classification methodologies used in the industry are the result of utilities' past practices, utilities' circumstances and are determined through the regulatory process as providing appropriate results that reflect local circumstances.

6.2 Classification of Distribution Costs

Lines and transformers are the largest cost items in the distribution of electricity to customers. Five of the twelve utilities surveyed use the minimum system to classify some component of the distribution system as customer related.

Currently SaskPower uses survey results to classify distribution costs between demand and customer related for lines and transformers. SaskPower tried to use the Zero Intercept method, but was unable to obtain the necessary supporting data.

An alternative for SaskPower's consideration is to use the Minimum System method to classify lines and transformer assets and costs between demand and energy. The data required for the Minimum System method reflects the current minimum size transformers and lines used by the utility in serving customers and uses replacement assets and costs to estimate the value of this the minimum system. The ratio of the cost of the minimum system to the cost of replacing all transformers and lines would represent the customer component percentage. The data needed for the minimum system method may be easier to obtain since it is based on current values of assets.

6.3 Classification and Allocation of Overhead Costs

SaskPower requested that Elenchus review its classification and allocation of overhead assets and costs.

In general, other utilities classify overhead assets and costs in the same proportion as other assets and costs. Using this approach ensures that the effect of the classification of overhead costs is neutral and it does not alter the overall classification of assets and costs. Similarly, the allocation of overhead assets and costs is based on the allocation of other assets and costs to customer classes. It is Elenchus' understanding that SaskPower's classification and allocation of overhead costs follows the same approach, it is classified and allocated in the same manner as other assets and costs.

Elenchus endorses this approach. There is a very loose causal relationship to support the allocation of overhead costs to customer classes. There is significant merit in allocating these costs in direct proportion to all other costs, where there is a more directly discernible causal relationship.

6.4 ALLOCATION OF COSTS

6.4.1 LOAD FORECAST DATA

SaskPower currently uses a forecast of the potential maximum demand in its sales forecast when estimating the peak system demand. This demand only occurs under extreme weather conditions. The rationale for this approach is that the system is designed to handle extreme weather conditions. Hence, from an engineering perspective, the costs incurred in ensuring that the system has sufficient capacity under extreme weather conditions are based on the forecast demand under those extreme conditions.

Elenchus notes, however, that other utilities commonly use a forecast of system demand based on the class load profiles under normal weather conditions and not on design (i.e., most extreme) weather; hence, the peak demands can be characterized as the “typical” rather than “extreme”. The concept underlying this approach is that it is more equitable to allocate capacity costs based on the typical usage of the system, rather than design considerations.

Since this approach allocates cost to classes based on peak demands in a normal year, it results in a lower allocation of costs to classes with weather sensitive load. Over time, deviations from normal weather patterns even out. Using a normal forecast based on the last 30 years (or the last 10 years) of observations is an alternative that many utilities consider to be consistent with the fairness principle since it reflects actual typical usage rather than extreme demands that are rarely experienced.

The determination of the normal peak demands of the classes is typically determined by calculating the average annual (or monthly) maximum degree-days and then forecasting the peak demands using that average maximum degree-day value. The time period used to determine the average maximum degree-days is most commonly 10 years, although some utilities use as much as a 30-year average and other use as little as a five-year average. Given the apparent warming trend in recent years, the rationale for using a shorter time frame for calculating the average is that recent experience is probably the best indicator of current "normal" weather and therefore the best forecast of the "most likely" weather and demand peaks in the test year.

Elenchus recommends that SaskPower consider basing the demand allocators on peak demand under "normal", rather than extreme, weather conditions.

6.4.2 Coincident Peak

In jurisdictions where electricity markets have been opened up to competition, such as Ontario and Alberta, generation costs are bid to the system market operator by generators and are not classified and allocated to customers using a traditional cost allocation methodology. Transmission companies in these competitive markets are also usually not allowed to own generation assets. This is the situation in which four of the utilities surveyed operate.

The survey results show that the method used to allocated demand-related generation assets and costs by five out of seven utilities involves using more than one coincident peak as allocator: three, four or twelve coincident peak values are used.

For transmission demand related assets and costs four out of eleven utilities use the one coincident peak method as allocator and seven out of eleven utilities use more than one coincident peak as an allocator: two, three, four or twelve peaks are used.

SaskPower uses the 1 CP allocation method to allocate both generation and transmission demand related assets and costs to customer classes in order to reflect cost causality. For Distribution demand related assets and costs SaskPower uses a combination of one coincident peak method or one class non-coincident peak method.

Although SaskPower's methodology is consistent with the approach taken by several other electric utilities included in the survey, Elenchus considers it important to consider the extent to which SaskPower's cost are actually caused by the single annual coincident demand peak.

Based on information from SaskPower staff it was determined that it is not only the maximum demand for the year that is of importance to system planners, but also the maximum demand in the spring and fall when most of the maintenance of equipment is scheduled, reducing available capacity. From this perspective, it may be that the spring and fall peaks are critical causal drivers of certain system costs.

In addition the capacity of network equipment in the summer can be reduced by as much as 25% of the winter capacity due to the effect of higher summer temperatures on the actual loads that the facilities can handle. As a result, for some facilities, even though SaskPower is a winter peaking utility, it is the summer capacity that determines the required installed capacity of certain facilities.

An analysis of the last 10 years of system data (2002-2011) in SaskPower's service territory shows that the ratio of summer to winter maximum demand is 91%. The same data for the last 3 year shows a ratio of 90% between summer and winter maximum demand. It is therefore evident that SaskPower is a winter peaking utility. Nevertheless, it is also evident that if the seasonal peak is assessed as a percentage of seasonal capacity, it is the summer peaks that place the greatest demands on the network relative to the actual operating capacity during those peak periods. On this basis, it may be more appropriate to view the summer peaks as the prime driver that causes capacity costs to be incurred, at least for those facilities that are most affected by the higher summer temperatures.

In Ontario, which used to be a winter peaking system, but is now a summer peaking system, the ratio of winter to summer maximum demand, using 2010 and 2011 data, was 89%[6]. In Ontario, the allocation factor used by Hydro One Networks (Hydro One Networks has over 95% of transmission capacity in Ontario) to allocate a large portion

[6] Ontario maximum demand: December 2010, 22,114 MW, July 2010, 25,075 MW, January 2011, 22,733 MW July 2011, 25,450 MW. IESO Market Summaries
http://www.ieso.ca/imoweb/marketdata/marketSummary.asp

of its transmission costs, (network costs represent over 60% of Hydro One's Transmission Revenue Requirement), is based on the higher of the monthly coincident demand during the peak period or 85% of the monthly maximum customer demand, also during the peak period.

Based on the results of the survey where the majority of applicable utilities use more than one peak as allocator, taking into consideration the information from SaskPower's system planners, Elenchus recommends that SaskPower explore the implications of using as demand allocation methodology for generation and transmission a coincident peak method that incorporates more months. This change would allow for seasonal capacity and seasonal demand to also be taken into consideration in the allocation factors.

Elenchus would recommend using two or four CP as an allocation method for demand related generation and transmission assets and costs to take into account system planning considerations and as a first step of moving away from using the 1 CP allocation method. While it is conceivable that through detailed analysis it would be possible to determine which facilities experience peak demand, relative to their seasonal capacity, in summer (reduced capacity), winter (highest demand) and the spring/fall (maintenance outages), with different peak allocators being used for each category of assets, it may be more straightforward to simply transition over time to a 4-CP allocator and possibly eventually to a 12-CP allocator.

In order to capture SaskPower circumstances, Elenchus recommends that the coincident peak allocators be split in equal numbers between winter and summer. For example if SaskPower implements 2 CP as an allocator, one should be for the winter months and the other should be for the summer months.

For Distribution demand related costs, Elenchus recommends that if SaskPower changes the 1 CP allocation for Generation and Transmission and uses more than one CP, a similar change should be done for those distribution related demand assets and costs that are currently allocated to customer classes using 1 CP. This would result in consistent change for the allocators and would reflect SaskPower's circumstances. For the distribution assets and costs that SaskPower currently uses 1 NCP, Elenchus is not recommending changes.

6.4.3 Customer Classes

The number of customer classes in a utility is usually determined by regulation or past utility history. The number of customer classes reflects a balancing act between trying to group customers with similar cost causality characteristics and maintaining a manageable level of different customer classes. The larger the number of customer classes, the better the cost allocation will reflect cost causality characteristics for individual customers, but the more expensive it is to maintain by the utility and the more complicated the regime is for customers. It is inevitable that any grouping of customers results in winners and losers within the group. The trade-off is that the fewer the number of customer classes, the less expensive it is to maintain by the utility and also it is easier to understand by customers and stakeholders.

SaskPower customer classes consist of 10 groups, but each customer class has multiple rate codes, making the administration of the multiple rate codes a challenge for SaskPower staff. Elenchus recommends that a review of the rates code should be undertaken by SaskPower and rates codes that are found to contain no customers should be eliminated, unless the rate code is required to support Government or SaskPower initiatives (for example encouraging time-of-use rates). Also, there may be circumstances where a rate code contains customers, but in order to simplify customer classification, these customers could be combined with another rate code that exhibits similar cost causality characteristics and would not result in undue customer impact from the elimination of the rate code.

As an example, small farm customers that are energy billed and that show similar cost causality characteristics as residential customers could be merged with the Residential rate code. Larger farms that are demand billed and show similar costs causality characteristics as commercial customers could be moved to the applicable commercial rate code.

6.4.4 Rate Design Time-of-use rates

SaskPower requested that Elenchus comment on the implications of establishing time-of-use rates.

Time-of-use rates are implemented by utilities in order to send a more refined price signal to customers on the costs of consuming electricity at different times of the day. Generation costs are normally the largest component of electricity supply costs and reducing generation costs could provide benefits to the utility and consumers in the form of lower utility costs and therefore lower customer bills. The intent of time-of-use rates is that if customers have the proper price signals with enough incentives to modify behaviour, customers would change consumption patterns and reduce or eliminate consumption during high cost periods and increase consumption during low cost periods. Reducing consumption in high cost periods would allow the utility to reduce its total costs by reducing the requirement for peak capacity or for purchasing expensive imported power at times of high electricity demand.

Implementing time-of-use rates (TOU rates) requires that the proper infrastructure be in place in the form of “smart” meters that are capable of recording, for example, hourly consumption. Implementing TOU rates also requires meter reading and billing systems capabilities that enable the processing of the required data. The assets and software required in order to implement time-of-use rates are such that it may be justifiable in locations with very high electricity supply costs during peak periods. TOU rates may also provide some benefits to larger electricity consumers, but it may not be a financially sound investments in instances of low electricity consumption, for example seasonal customers or where the capacity and fuel cost savings are not large enough to offset the infrastructure costs required to implement time-of-use rates. As with any other investment, a decision on implementation should be based on a sound business case. The business case for TOU rates can be approached either by considering only the utility’s generation and network costs and savings, or by also building into it external costs, such as environmental and health benefits. The goal of TOU rates should not be to benefit “free-riders” who are not on-peak users of power in any case, but to shift demand and reduce the average cost of power.

In order for time-of-use to achieve the goal of changing consumption patterns, the differential in prices between high and low cost periods should provide incentive for customers to modify behaviour without resulting in undue sacrifices. Is also should reflect the utility’s characteristics that would result in savings as a result of lower consumption during high cost periods. For example, if the period of high costs lasts for many hours, it would be difficult for consumers to reduce or shift load away from the high costs period and into lower costs periods.

In SaskPower’s case, it is Elenchus’ understanding that reduction in customers’ electricity consumption during high cost periods would not result in cost savings to SaskPower. Currently gas is the fuel used at the margin in order to supply capacity at times of high electricity demands and if consumption is shifted to periods of low electricity consumption, gas is still the fuel at the margin that is used to supply power at the margin during periods of low electricity consumption.

Time-of-use for transmission costs may make sense in instances when there is capacity constraint in the transmission system, but transmission costs are not a large component of customers’ electricity bill. Time differentiated transmission rates may be implemented to complement time differentiated generation rates and thus provide a consistent price signal to customers.

Distribution costs are for the most part fixed for a utility and are not dependent on customer’s electricity consumption, therefore time differentiated distribution rates may not be appropriate from a cost causality perspective, although they may be implemented to provide a consistent price signal to customers in support of time differentiated generation rates.

If SaskPower is to consider implementing time differentiated rates that could provide benefits to SaskPower in the form of reducing the need to build new capacity, or achieve fuel cost savings during peak demand periods, or in order to foster a culture of conservation in consumers, Elenchus recommends that pilot studies be conducted by

SaskPower in order to evaluate the potential results in consumption shift by customers in response to time differentiated price signals. Analyzing the load shifting and quantifying the related system benefits compared to the costs of implementing time differentiated rates would provide SaskPower with the information necessary to make a decision if implementing time differentiated rates makes financial sense for SaskPower. Different levels of differentials between high price and low price periods should be tested as well as different length of high price periods in order to evaluate customers' response to time differentiated prices.

It is Elenchus' understanding that SaskPower operates an electricity system that is already high load factor and is projected to become even higher by the addition of new load that is for the most part flat consumption load. Operating a system with high load factor limits the expected benefits of implementing time differentiated rates and the benefits of the potential load shifting. Under this circumstance Elenchus recommends that pilot time-of-use studies should be undertaken only if there is a reasonable expectation of implementing time differentiated rates in Saskatchewan. If circumstances change in Saskatchewan, for example marginal costs change, or what fuel type is at the margin providing peak capacity, consideration should be given to implementing time-of-use rates as one possible demand management tool available to the utility to be considered, instead of building new capacity to meet increased demand for electricity.

6.4.5 CP Allocation Method

SaskPower applies an adjustment in its rate design to take into consideration the relationship between load factor and coincidence factors. High load factor customers tend to have higher coincidence factors. That is, the higher the load factor for a customer the higher the chances are that it will consume electricity at the time of the utility's maximum system demand. In order to better reflect cost causality, energy rates are increased and demand rates are decreased by applying this adjustment. At a class level the revenue collected from customers before and after the rate design adjustment remains unchanged. This adjustment, which is referred to as the coincident peak allocation method by SaskPower, results in customers within a class with different load profiles having a revenue to cost ratio that is closer to the customer class average revenue to cost ratio than if no adjustment is made to the rates.

Based on Elenchus' experience the adjustment made by SaskPower is not widely applied in utilities, but it makes theoretical sense.

7 STAKEHOLDERS COMMENTS

Stakeholders provided the following comments on Elenchus' report.

7.1 GREATER SASKATOON CHAMBER OF COMMERCE

The Chamber of Commerce is of the view that the Reseller revenue to revenue requirement ratio be set at a value of 1.00. The Chamber of Commerce suggests that a value higher than 1.0 would deter alternate suppliers and a rate lower than 1.0 could result in cross-subsidization between SaskPower's customers and resellers' customers.

Elenchus' Response

Conducting a cost allocation study involves utilizing the best available, yet nevertheless imprecise, information with respect to how shared assets are used by various customer groups. For example:

- The allocators used to apportion assets and expenses to customer groups based on cost causality principles reflect the key drivers of costs;
- Sample load data is used in order to determine customer class consumptions for smaller customers;
- Simplifying assumptions are used in order to classify some distribution-related assets and expenses as demand and customer related.

A range of values around a revenue to revenue requirement ratio value of 1.0 is therefore analogous to adding statistical significance (standard deviation) to a statistical analysis. That is, ratios close to 1.0 are deemed not to represent cross-subsidization, just as small statistical variances are not considered to be "statistically significant". A range of acceptable revenue to revenue requirement ratios of 0.95 to 1.05 is used in many jurisdictions as being acceptable for cost allocation studies and is considered to reflect that the customer group is paying their fair share of costs. Hence, a revenue to revenue requirement ratio that is slightly above or below unity does not demonstrate that one customer class subsidizes or receives subsidy from other customer classes.

Rather, if the ratios are within the acceptable range given the uncertainty that is inherent in a cost allocation study, the results are deemed to be reasonable in that there is no demonstrable cross-subsidy.

A cost allocation study is a "zero-sum" exercise. The utility's revenue requirements and assets are apportioned amongst its customer groups in a fair and reasonable manner using cost causality principles. Any changes to the methodology in order to improve it will result in winner and losers when compared to the results of the previous methodology. Hence, rate stability is an important principle in setting rates and relative rates are typically not altered on the basis of deviations from a ratio of 1.0 that is not significant. The proposed changes, in Elenchus views, improve the cost causality and fairness of SaskPowers' cost allocation methodology.

7.2 CITY OF SWIFT CURRENT

The City of Swift Current questions the results of the proposed changes to the demand allocators from using a winter peak to using a combination of winter and summer peaks. The City of Swift Current requests that Elenchus review the results of the proposed changes. The City of Swift Current draws the following conclusions from the results:

> *"1. The peak loads for the Urban Residential and Urban Commercial customer classes are under estimated.*
>
> *2. The Reseller customer class has been specifically targeted for a larger rate increase by design*."

Elenchus' Response

Elenchus' has no reason to believe that SaskPower is specifically targeting the Reseller customer class for large rate increases or that the peak loads used by SaskPower for Urban Residential and Commercial customer classes are not a fair representation of their consumption characteristics. Elenchus understands that SaskPower is now using their own load research in order to determine the consumption characteristics of the mass market customers, (residential, farm, commercial and oilfield), as opposed to the previous methodology of using ATCO's load research.

Elenchus' review and recommendations are based on best industry practices and are not biased in favour or against any particular customer group. Cost causality is the main criteria used by Elenchus in its recommendation to include more values in the demand allocators. It is also a reflection on how the electricity system built by SaskPower is being operated.

7.3 CITY OF SASKATOON

The City of Saskatoon opposes changing the demand allocators from winter peak to a combination of winter and summer peaks because in its view the change impacts only the Reseller customer class and the change would impact the City of Saskatoon financially.

The City of Saskatoon mentions, in its comments on Elenchus' recommendations, that City Council made the decision to have electricity retail rates in the City of Saskatoon equal to the SaskPower's rates and asked if Elenchus has encountered a similar situation like the one described for the City of Saskatoon.

Elenchus' Response

Elenchus recommendation with respect to demand allocation method is based on cost causality principles and SaskPower system operations.

As stated in Section 6.4.2 of this report, SaskPower staff described to Elenchus that it is not only the maximum demand for the year that is of importance to SaskPower's system planners, but also the maximum demand in the spring and fall when most of the maintenance of equipment is scheduled, reducing available capacity. This means that the spring and fall peaks are critical causal drivers of certain system costs and should be considered when selecting the proper allocation methodology in order to reflect cost causality principles.

Additionally the capacity of network equipment in the summer can be reduced by as much as 25% of the winter capacity due to the effect of higher summer temperatures on the actual loads that the facilities can handle. As a result, even though SaskPower is a winter peaking utility, it is the summer capacity that determines the required installed capacity of certain facilities.

In its submission, the City of Saskatoon mentions that Saskatoon Light and Power annual peak generally occurs in July or August. In this case, the City's load profile is such that its contribution to SaskPower's winter peak is not as critical and has less of an impact in cost allocation than its contribution to SaskPower's summer peak. Using an allocation method that includes more values than just the winter peak will still reflect the lower winter than summer consumption of Saskatoon Light and Power and provide some benefit to Saskatoon Light and Power. As mentioned above, summer available capacity reductions due to temperature and summer loads are taken into account by system planners in building and maintaining the SaskPower electricity system. It is Elenchus' opinion that the choice of an appropriate allocation method should be reflective of cost causality and how the electricity system is designed and operated.

The issue raised by the City of Saskatoon on the setting of rates in other jurisdiction is not directly related to the work undertaken by Elenchus in this report for SaskPower.

Nevertheless, with respect to Elenchus' experience in other jurisdiction where companies purchase electricity for distribution inside their territories, the rate approach followed by the City of Saskatoon is unique. In other jurisdiction with similar arrangements as exist between SaskPower and the City of Saskatoon, the distributors establish the rates they charge their customers reflecting the cost they incur in purchasing electricity and adding their own distribution costs. The distributors' rates are commonly reviewed and approved by regulators and allow the distributors to earn an approved return on their investments. The regulatory review level can be at a high level or can also be very detailed. Distributors' rates are not set equal to other distributors' rates in jurisdictions that Elenchus is familiar with.

As an example, in Ontario there are over 70 distributors that serve mostly urban centers and each distributor has its rates reviewed and approved by the Ontario Energy Board, reflecting their own costs. There are situations in Ontario where one side of the street is served by one distributor and the other side of the street is served by another distributor. Customers on each side of the street pay different rates depending on which distributor is serving them and the rates reflect the costs incurred by the serving utility distributor. Similarly, the rates for municipal electric utilities are based on their costs and not the rates charged by the primary integrated electric utilities in other Canadian jurisdictions that have municipal electric distributors, namely, Nova Scotia, New Brunswick, Quebec and British Columbia.

7.4 CANADIAN ASSOCIATION OF PETROLEUM PRODUCERS

The Canadian Association of Petroleum Producers agrees with Elenchus' proposed changes to SaskPower's Cost Allocation and Rate Design methodologies but is concerned with the level of cross-subsidization that may occur if the ratio of revenue to revenue requirement is not set at 1.0 and encourages SaskPower to move all customer classes to a ratio of 1.0.

Elenchus Response

As explained above in our response to the Grater Saskatoon Chamber of Commerce comments, a revenue to revenue requirement ratio that is slightly above or below unity does not demonstrate that one customer class subsidizes or receives subsidy from other customer classes. Rather, if the ratios are within the acceptable range given the uncertainty that is inherent in a cost allocation study, the results are deemed to be reasonable in that there is no demonstrable cross-subsidy.

A range of acceptable revenue to revenue requirement ratios of 0.95 to 1.05 is used in many jurisdictions as being acceptable for cost allocation studies and is considered to reflect that the customer group is paying their fair share of costs.

APPENDIX A: SASKPOWER COST ALLOCATION METHODOLOGY DOCUMENTATION

The information below was extracted from a document titled: "2010 Base IFRS Embedded Cost of Service Results" prepared by SaskPower.

Functionalization

1. Rate Base Items
1.01 - Plant in Service & Accumulated Depreciation

SaskPower Generation, Transmission, and Distribution:

All of the rate base accounts are functionalized on the basis of the plant designation; generation plant is functionalized entirely to the generation function, transmission plant is functionalized to transmission and distribution plant is functionalized entirely to distribution. The plant in service and accumulated depreciation for the Centennial Wind Project are included with SaskPower generation. The sub-functionalization is relatively straightforward using SaskPower's detailed accounting records. The sub-functionalization of generation assets to ancillary service which is required for SaskPower's OATT tariffs is more complicated. It is important to note, however, that the generation load and losses sub-functions and all ancillary services sub-functions are allocated to all full-service customers.

Coal Reserves:

SaskPower coal reserves are functionalized to the load and losses sub-functions within the generation function.

Shand Greenhouse:

The Shand Greenhouse assets are functionalized to generation. The subfunctionalization is the same as the total for all SaskPower generation.

Cory Cogeneration Project:

The SaskPower International assets associated with the Cory Cogeneration Station are functionalized to generation.

Meters:

Meters are included in the meters sub-function within distribution.

General Plant - Unused Land:

The functionalization and sub-functionalization of Unused land is done using operations, maintenance and administration expense.

General Plant – Buildings:

The functionalization of the SaskPower head office building is based on floor space analysis. All other buildings are functionalized using cost center charge backs. The asset values for buildings are then prorated to sub-functions within each function using operations, maintenance and administration expense.

General Plant - Office Furniture & Equipment:

The functionalization and sub-functionalization is the same as for buildings.

General Plant - Vehicles & Equipment:

The functionalization of the Vehicles and Equipment is based on the vehicles and equipment asset summary report by profit center. The asset values for vehicles and equipment are then prorated to sub-functions within each function using operations, maintenance and administration expense.

General Plant - Computer Development & Equipment:

The functionalization of the computer development and equipment is done in two steps. In the first step the asset value for computer development and equipment is divided into mainframe systems and desktop. In the second step the main frame assets (software and hardware) is functionalized on an application by application basis and desktop assets (hardware and software) are functionalized using the number of employees. The asset values for computer development and equipment are then prorated to sub-functions within each function using operations, maintenance and administration expense.

General Plant - Communication, Protection & Control Equipment:

Communication, protection & control equipment is functionalized to generation, transmission, distribution and customer services based on an evaluation of each type of asset and using advice from SaskPower's Transmission Services staff.

General Plant - Tools & Equipment:

The functionalization of the Tools and Equipment is based on the asset history by function report. The asset values for tools and equipment are then prorated to sub-functions within each function using operations, maintenance and administration expense.

1.02 - Allowance for Working Capital

The allowance for working capital is consistent with Cost of Service methodology that a utility should sustain a suitable level of working capital to meet its current obligations such as payroll, taxes etc. The allowance for working is calculated as 12.5% of the sum of operations, maintenance and administration expense, corporate capital tax, grants in lieu of taxes and miscellaneous tax expense and is prorated to functions and sub-functions using the sum of these expense items.

1.03 - Inventories

SaskPower accounting records summarizes inventory cost by Power Production and Transmission and Distribution. The inventories are then prorated to sub-

functions within the generation, transmission and distribution functions using operations, maintenance and administration expense.

1.04 - Other Assets

Other assets (deferred assets and prepaid expenses) are grouped into 4 categories as follows:

· Natural gas / coal related:

Functionalized to generation.

· Employee related:

Functionalized using head count by Business Unit / Support Group.

· Insurance expense related:

Functionalized using advice from SaskPower Risk management staff.

· Miscellaneous:

Prorated to sub-functions within each function using operations, maintenance and administration expense.

2. Revenue Requirement Items

A summary of the functionalization methodology for expense plus the return on rate base items is provided below.

2.01 - Fuel Expense SaskPower Units

The fuel expense for SaskPower units is functionalized 100% to generation.

2.02 - Purchased Power and Import

The purchased power expense is functionalized 100% to generation.

2.03 - Export & Net Electricity Trading Revenue

Export revenue is treated as an offset to fuel expense and as such is functionalized 100% to generation.

2.04 - Operating, Maintenance & Administration (O M & A) Expense

Power Production Business Unit:

The O M & A expense for the Power Production Business Unit is functionalized to generation. The O M & A expense for the Cory Cogeneration Station, flyash sales and the Centennial Wind Power Facility (credit) is functionalized to Generation.

Shand Greenhouse:

The O M & A expense for the Shand Greenhouse is functionalized to Generation.

NorthPoint:

The O M & A expense for NorthPoint is functionalized to Generation.

Transmission & Distribution Business Unit:

A small amount of the Transmission and Distribution Business Unit's O M & A expense relating to the transmission planning, scheduling & dispatch and generation regulation and frequency response are functionalized to generation.

The remainder of the O M & A expense for the Business Unit is split to transmission and distribution using cost centre reports. The transmission O M & A is sub-functionalized by separating transmission O M & A expense into line and station related. The line related O M & A is sub-functionalized to main grid,138 & 72 kV radials using line lengths by sub-function. The station related O M & A expense is sub-functionalized using station assets plant in service by subfunction.

Distribution O M & A is functionalized to distribution and customer services using a combination of staff advice and detailed cost centre O M & A reports.

The same analysis provides the sub-functionalization within the distribution and customer services functions. The Electrical and Gas inspections O M & A is functionalized to customer services.

Customer Services Business Unit:

The O M & A for the Customer Services Business Unit is functionalized to customer services. The sub-functionalization is provided directly from cost centre operation, maintenance and administration reports.

Customer Services - Bad Debt Expense:

The bad debt expense is assigned to the customer collections sub-function with the Customer Services function.

President / Board:

Assigned to functions and sub-functions based on the functionalization and subfunctionalization of the sum of the O M & A expense for the three Business Units and Support Groups.

Corporate & Financial Services:

Functionalized based on employee head count by Business Unit and Support Group.

Corporate & Financial Services - Insurance Premiums & Insurable Losses:

Functionalized based on Breakdown from SaskPower Risk Management & Insurance department staff.

Planning, Environment & Regulatory Affairs:

There are two major cost centres: Planning and Regulatory Affairs, and Environment. The Planning cost center is assigned to functions and sub-functions based on the functionalization and sub-functionalization of the sum of the O M & A expense for the three Business Units and Support Groups. The Environment cost center is allocated based on an employee analysis which was done by SaskPower Environment department staff. Sub-functionalization is completed using O M & A sub-functionalization within each function.

People & Processes - General Council / Land:

Assigned to functions and sub-functions based on the functionalization and subfunctionalization of the sum of the O M & A expense for the three Business Units and Support Groups.

People & Processes - Communication & Public Affairs:

Assigned to functions and sub-functions based on the functionalization and subfunctionalization of the sum of the O M & A expense for the three Business Units and Support Groups.

People & Processes – Safety:

Functionalized based on the safety department staff assignments to the Business Units and Support Groups and then sub-functionalized using the O M & A subfunctionalization within each function.

People & Processes - Corporate Information & Technology (CI & T):

C I & T operations, maintenance and administration expense is separated into personal computer related and Business Unit related. The personal computer related is functionalized using employee headcount. The Business Unit related is functionalized using information from the cost centre report. Subfunctionalization is completed using O M & A within each function.

People & Processes - Human Resources:

Functionalized based on the employee head count by Business Unit and then subfunctionalized using the O M & A sub-functionalization within each function.

Service Delivery Renewal:

Functionalized based on costs being evenly allocated between T&D and Customer Services and then sub-functionalized using the O M & A sub-functionalization within each function.

2.05 - Depreciation & Depletion

The functionalization of depreciation and depletion is the same as for plant in service and accumulated depreciation above.

2.06 - Corporate Capital Tax

Corporate capital tax is prorated to functions and sub-functions using resultant rate base functionalization.

2.07 - Grants in Lieu of Taxes

Grants in lieu of taxes are assigned to the grants in lieu of taxes sub-function within the generation function.

2.08 - Miscellaneous Tax

The miscellaneous tax expenses have been grouped into the following categories using cost center reports:

- *Power production related:*

  Functionalized to generation.

- *Fuel supply related:*

  Functionalized to generation.

- *Gas & electric inspections related:*

  Functionalized to customer services.

- *Vehicles and equipment related:*

  Functionalized using the vehicles and equipment plant functionalization above.

- *Buildings related:*

  Functionalized using the buildings plant functionalization above.

- *Corporate related:*

  Functionalized using total O M & A expense.

2.09 - Other Income

Other income is treated as an offset to expenses in the cost of service model. Other income has been grouped into the following categories using accounting records.

- *Customer services payment income:*

  Assigned to the billing and customer accounts and customer collections subfunctions within customer services.

- *Meter reading income:*

  Assigned to the meter reading sub-function within the customer services function.

- *Gas & electric inspections income:*

  Assigned to the meter reading sub-function within the customer services function.

- *Transmission related income:*

  Assigned to sub-function within the transmission function using transmission OM & A expense.

- *Distribution related income:*

  Assigned to sub-function within the distribution function using distribution O M& A expense.

- *Clean Coal Project Credits:*

  Assigned to sub-function within the generation function using power production OM&A expense

- *Customer Contribution Revenue*

    As per adoption of IFRS, contributions in aid of construction and reconstruction are now recognized immediately as Other Income when the related fixed asset is available for use and is functionalized to transmission and distribution.

- *Green power premium:*

    Functionalized to generation.

- *NorthPoint:*

    Functionalized to generation.

- *Flyash Sales:*

    Functionalized to generation.

2.10 - Return on Rate Base

The functionalization and sub-functionalization of return on rate base is determined by the functionalization of rate base above as the RORB is the simple calculation of rate base multiplied by the return on rate base in percent.

Classification

SaskPower generation rate base and expense is classified as either demand or energy related. The classification methodology currently used by SaskPower for generation rate base and depreciation expenses is the Equivalent Peaker method, based on the NARUC Electric Utility Cost Allocation manual. This approach uses the ratio of the unit cost of new peaking capacity to the new cost of base load capacity for different generation types to classify rate base and depreciation to demand and energy.

The fuel expense for SaskPower units is classified 100% to energy. The classification of purchased power and import expense to demand and energy is done using the capacity and energy payments to suppliers. The classification of export and net electricity trading revenue is classified 100% to energy. Generation operating, maintenance and administrative (OM&A) expenses are classified using an analysis of fixed and variable OM&A by type of generating plant.

The assets and expenses associated with the Cory Cogeneration Station are classified to demand and energy using the purchased power capacity / energy payments for this plant.

The expenses and income associated with fly-ash sales are classified as energy related.

The classification of all wind power rate base and expense are classified 80% to energy based on the results of SaskPower's most recent planning study regarding the capacity value of wind generation. This is a change from previous years, when SaskPower planning staff did not attach any capacity value to wind generation.

Coal Reserves:

SaskPower coal reserves are classified energy related.

Shand Greenhouse:

The Shand Greenhouse assets, O M & A and depreciation expenses are classified using the classification of all SaskPower generation.

NorthPoint:

The O M & A expense and other revenue associated with NorthPoint are classified 100% to energy related.

Transmission:

Transmission facilities are built to meet the maximum system coincident demand requirements of customers and are classified 100% to demand.

Distribution:

Substations are classified 100% to demand-related cost. Three phase feeders are classified 100% to demand-related cost. Both urban and rural single-phase primary lines are classified 65% to demand-related and 35% to customer-related cost. Line transformers are classified 70% to demand-related and 30% to customer-related cost based upon industry data. All secondary lines, services, and meters are classified 100% as customer-related cost. Streetlighting is directly assigned as customer-related.

Customer:

Customer related costs are classified 100% to customer.

Allocation

Generation:

The energy related rate base and expenses such as fuel and cost of coal are allocated to the customer classes by the energy consumed by each class plus an estimate of losses.

The demand related rate base and expenses are allocated by the single coincident peak (1CP) method, plus an estimate of losses. The 1CP method allocates costs to customer classes based upon the contribution which the respective customer class makes to the system peak. The system peak load is SaskPower's largest demand calculated on an hourly interval basis. Allocation factors are developed as the ratio of the class load at the time of the system peak to the total load.

Interruptible Credit:

This interruptible credit (benefit) is allocated to the interruptible customer's class using the 1CP method. The cost of the interruptible credit is allocated to all other (non-interruptible) customers using the 1CP allocator.

Transmission:

All of the transmission functions are classified as demand and are allocated using the single coincident peak (1CP) method as aforementioned.

Distribution:

The demand functions within distribution use a combination of the 1CP method and the Non Coincident Peak (NCP) method. The NCP method allocates rate base and expense responsibilities based on the ratio of the sum of the maximum demands of all customers within a class whenever they occur, to the sum of all the class peaks, similarly determined. Only the transformers function uses the NCP methodology, all other functions use the 1CP methodology.

The customer functions within distribution use a combination of methodologies depending on the sub-function. Urban and rural laterals are allocated to customer classes based on the number of urban and rural customers supplied through laterals. Customer related transformers are allocated using the number of customers supplied through transformers. Distribution services are allocated directly to customer classes. Meters are allocated by the number of metered customers weighted by the installed cost of a meter.

Streetlight related rate base and expenses are allocated directly to streetlights.

Customer Services:

The customer services functions are allocated to customer classes based on the weighted number of customers in the class. This weighting is based on annual surveys of how much time departments spend working with each customer class.

Customer Contributions:

These contributions are allocated back directly to the customer classes which made the contribution.

Load Data

Customer load patterns were obtained for each class from the best available sources.

Hourly Residential, Farm, Commercial, and Oilfield load data were obtained from a statistically valid sample size of meter readings from actual customer's interval metered sites. The typical load shapes for the customer types in each of these classes was then extrapolated to the entire class in proportion to the classes' billing determinants. Typical load shapes for the Streetlight class were gathered from a neighbouring utility.

Power and Reseller loads were analyzed based on hourly meter readings from actual customer's interval metered sites.

Loss Study

The purpose of a loss study is to properly quantify and assign to the appropriate customer class the electrical energy and demand losses in the various segments of the system. The starting point is the total energy loss in GWH, calculated as the *difference between input to the system measured at the generator and output measured at the customer's meter.*

The loss analysis relies, to a significant extent, upon the loss analysis prepared by the Network Planning department, which includes a load-flow analysis of the transmission system. The load-flow analysis provides both energy and demand losses.

Distribution system losses are apportioned to the various components in proportion to loss percentages generally associated with those elements of the distribution system.

A spreadsheet program is used to apportion the energy losses to the various class loads, recognizing that losses at one level of the system increase losses at another level.

APPENDIX B UTILITIES SURVEYED

Canadian

BC Hydro

ATCO

Manitoba Hydro

Hydro One Networks Inc.[7]

Ontario Power Generation (OPG)

Hydro Quebec

Newfoundland Power

New Brunswick Power

Nova Scotia Power

US Utilities

AVISTA Corp.

Georgia Power

PECO

Many more utilities were contacted, but did not respond.

[7] In Ontario the electricity market was deregulated in April 1999. OPG generates electricity and Hydro One transmits and distributes electricity

	Hydroelectric	Baseload Steam	Combined Cycle	CTU	Transmission	Sub-transmission
BC Hydro	50% demand/50% energy	100% demand	100% demand	100% demand	100% demand	100% demand
ATCO	NA	NA	NA	NA	AESO bill into demand/customer	30% to 35%
Manitoba Hydro	100% weighted energy/0% demand	100% weighted energy/0% demand	100% weighted energy/0% demand	100% weighted energy/0% demand	100% demand	100% demand
Hydro One	NA	NA	NA	NA	100% demand	100% demand
OPG	NA	NA	NA	NA	NA	NA
Hydro Quebec	NA	NA	NA	NA	42.7% demand	100% demand
NL Power	System load factor 45.6% demand	NA	NA	NA	100% demand	100% demand
NB Power	40% demand	40% demand	NA	40% demand	100% demand	Same as TX
NS Power	Not easily available	Not tracked for all costs by type	As Baseload Steam	100% demand	Currently 43% demand	Currently 43% demand
Avista	34.2% demand	34.2% demand	34.2% demand	34.2% demand	34.2% Wash. 100% Idaho	34.2% Wash. 100% Idaho
Georgia Power	100% demand	100% demand	100% demand	100% demand	100% demand	100% demand
PECO	95% demand+ Excl Fuel	95% demand+ Excl Fuel	95% demand+ Excl Fuel	95% demand+ Excl Fuel	100% demand	100% demand

	Distribution Substations	Primary Lines	Distribution Transformers	Line Transformers	Secondary Lines	Services Fixed costs
BC Hydro	100% demand	100% demand	38% demand/62% customer	NA	3% demand/97% customer	100% customer
ATCO	100% demand	100% demand	40% to 60% demand	40% to 60% demand	30% to 35% demand	100% customer
Manitoba Hydro	100% demand	60% demand	100% demand	100% demand	60% demand	100% customer
Hydro One	100% demand	45% demand related	100% demand	38% demand related	45% demand related	100% customer
OPG	NA	NA	NA	NA	NA	NA
Hydro Quebec	100% demand	100% demand	100% demand	77% demand	77% demand	100% customer
NL Power	100% demand	64%	73%	73%	64%	100% customer
NB Power	100% demand	50% demand	75% demand	75% demand	50% demand	100% customer
NS power	100% demand	73% demand	100% demand	100% demand	50% demand	100% customer
Avista	100% demand	100% demand	100% demand	100% demand	100% demand	100% customer
Georgia Power	100% demand	84% demand	100% demand	85% demand	77% demand	100% customer
PECO	100% demand	100% demand	100% demand	100% demand	100% demand	100% customer

	Meters	Method used to determine distribution customer related	Method used to allocate generation demand costs	Method used to allocated transmission demand costs	Method used to allocated sub-transmission demand costs	Method used to allocated distribution stations demand costs
BC Hydro	100% customer	Zero Intercept for transformers. Minimum System for secondary system	4CP	4CP	4CP	Class NCP
ATCO	100% customer	Average of Zero intercept and Minimum system	NA	Allocated POD Capacity Demand and AEIS 1 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	100% customer	Fixed 60% demand/40% customer	NA	2 CP (average of Summer and Winter)	Class NCP	Class NCP
Hydro One	100% customer	Minimum System	NA	Highest 12 CP or 85% 12 NCP during peak hours for Networks	12 CP	4NCP
OPG	NA	NA	NA	NA	NA	NA
Hydro Quebec	100% customer	Minimum System	Highest 300 hours	1CP	1CP	1NCP
NL Power	100% customer	Minimum System Analysis or Zero Intercept Method	1 CP	1 CP	1 CP	NCP
NB Power	100% customer	Historical	1 CP	12 CP	12 CP	12 CP

NS Power	100% customer	Judgement 50/50	3 winter CP	3 winter CP	3 winter CP	1 NCP
Avista	100% customer	Basic Customer Only Services and Meters (and directly assigned Street Lighting apparatus) is Customer-Related, all other Distribution plant is Demand-Related.	12 CP	12 CP	12 CP	12 NCP
Georgia Power	100% customer	most frequently used and smaller, Zero intercept	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
PECO	100% customer	Assumed secondary plant is customer related and primary is demand related	4 CP Average of 4 summer peaks	1 CP	NCP	NCP

	Method used to allocated distribution primary lines demand costs	Method used to allocated distribution transformers demand costs	Method used to allocated distribution secondary lines demand costs	Method used to allocated distribution stations customer costs	Method used to allocated distribution primary lines customer costs	Method used to allocated distribution transformers customer costs
BC Hydro	NCP class	NCP class	NCP class	# of customers	# of customers	# of customers
ATCO	An EDLA study (Energy, Demand Loss Analysis) is used to allocate costs to rate classes (Annual POD NCP Demand)	Weighted Property Plant & Equipment (Transformers)	Weighted Property Plant & Equipment (Poles & Conductor)	NA	NA	Property Plant & Equipment (Transformers) weightings depending on customer counts
Manitoba Hydro	Class NCP	Class NCP	Class NCP	NA	Customer count	NA
Hydro One	4NCP	4NCP	4NCP	NA	Customer count Primary	Customer count
OPG	NA	NA	NA	NA	NA	NA
Hydro Quebec	1NCP	1NCP	1NCP	# of customers	# of customers	# of customers
NL Power	NCP	NCP	NCP	N/A	Equal Weighting	Equal Weighting
NB Power	12 NCP	12 NCP	12 NCP	N/A	# of customers	# of customers
NS Power	1 NCP	1 NCP	1 NCP	N/A	Weighted # of customer	NA
Avista	12 NCP	12 NCP	12 NCP	NA	NA	NA
Georgia Power	NCP	NCP	Average # of Customers	NA	Average # of Customers	NA
PECO	NCP	NCP	NCP	# of customers	# of customers	# of customers

	Method used to allocated distribution secondary lines customer costs	Method used to allocated services customer costs	Method used to allocated Meter customer costs
BC Hydro	# of customers	# of customers	# of customers
ATCO	Property Plant & Equipment (Transformers) weightings depending on customer counts	Weighted Customer Count	Weighted Customer Count
Manitoba Hydro	Customer Count	Weighted Customer Count	Weighted Customer Count
Hydro One	Customer Count Secondary	Weighted Customer Count	Weighted Customer Count
OPG	NA	NA	NA
Hydro Quebec	# of customers	Weighted # of customers	Weighted # of customers
NL Power	Equal Weighting	Based on typical costs to provide drops to customers within each class	Based on typical costs to provide drops to customers within each class
NB Power	# of customers	Overhead allocation study	Direct Assignment
NS power	Weighted number of customers	# of customers	Weighted # of customers
Avista	NA	Unweighted # of customers	Weighted # of customers
Georgia Power	Average # of customers	Average # of customers	Average # of customers
PECO	# of customers	Direct Assignment	Direct Assignment

APPENDIX C ELENCHUS TEAM QUALIFICATIONS

JOHN D. TODD

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PRESIDENT

John Todd has specialized in government regulation for over 35 years, addressing issues related to price regulation and deregulation, market restructuring to facilitate effective competition, and regulatory methodology. Sectors of primary interest in recent years have included electricity, natural gas and the telecommunications industry. John has assisted counsel in over 200 regulatory proceedings and provided expert evidence in over 100 hearings. His clients include regulated companies, producers and generators, competitors, customers groups, regulators and government.

PROFESSIONAL OVERVIEW

Founder of Elenchus Research Associates Inc. (ERAI) **2003**

- ERAI was spun off from ECS (see below) as an independent consulting firm in 2003. There are presently twenty-five ERAI Consultants and Associates. Web address: www.elenchus.ca

Founded the Canadian Energy Regulation Information Service (CERISE) **2002**

- CERISE is a web-based service providing a decision database, regulatory monitoring and analysis of current issues on a subscription basis. Staff are Keith Bryan, Rachel Chua and rotating co-op students. Web address: www.cerise.info

Founded Econalysis Consulting Services, Inc., (ECS) **1980**

- ECS was divested as a separate company in 2003.
- There are presently four ECS consultants: Bill Harper, Roger Higgin and James Wightman. Web address: www.econalysis.ca

PRIOR EMPLOYMENT

Ontario Economic Council **1978 - 1980**
Research Officer (Government Regulation)

Research Assistant **1973 - 1978**
Univ. of Toronto, Faculty of Management Studies

Bell Canada **1972 - 1973**
Western Area Engineering

REGULATORY/LEGAL PROCEEDINGS

Provided expert evidence and/or assistance to the applicant or another participant for:

Before the Ontario Energy Board

2011
- Cost Allocation evidence for several Ontario electricity distributors (2012 Cost of Service)

2010
- Natural Resource Gas Rate Case
(Evidence: Proposed Incentive Regulation Mechanism
- Cost Allocation evidence for several Ontario electricity distributors (2011 Cost of Service)

2009
- Hydro One Distribution Rate Case
(Evidence: Principles for Density Based Rates)
- Cost Allocation evidence for several Ontario electricity distributors (2010 Cost of Service)

2008
- Provided technical and strategic assistance to eight second tranche electricity distribution companies in preparing their rebasing applications for rates for 2009.
(Evidence: Cost allocation model updates (for two LDCs))

2007
- Third generation Incentive Regulation
(Evidence: Inclusion of a capital expenditure factor)
- Provided technical and strategic assistance to six first tranche electricity distribution companies in preparing their rebasing applications for rates for 2008.

2006
- Cost Allocation Review (EB-2005-0252)
- Transmission Revenue Requirement Adjustment Mechanism (EB-2005-0501)
- Second Generation Incentive Regulation Mechanism (EB-2006-0088-0089)
(Evidence: Capital Investment Factor)
Sub-metering Review (EB-2005-0317)
(Evidence: Comments on Staff Discussion Paper on Sub-metering)

2005
- Union Gas Rate Hearing
(Evidence: Evaluation of Avoided Cost Methodology)

2004
- Enbridge Gas Distribution 2005 Rates (RP-2003-0203)

(Evidence: Determining the Fair Rate of Return for a 15-Month Period)
(Evidence: Stand-alone System Supply Costs)

2003
- Generic Proceeding on Electricity Distributor Boundary Changes (RP-2003-0044)
  (Evidence: The Benefits of Competition in the Electrical Distribution Sector)
- Union Gas Limited, 2004 Rates (RP-2003-0063)
  (Evidence: Monthly Demand Charge for Brighton Beach Power Station (with Paula Zarnett))

2002
- Union Gas Limited, 2003 Rates (RP-2002-0130/EB-2002-0363)
  (Evidence: Review of Union's Delivery Commitment Credit (with Joyce Poon))

2001
- Union Gas, Further Unbundling of Rates (RP-2000-0078)
  (Evidence: Regulatory Framework and Cost Responsibility)
- Hydro One Networks, Cost Allocation and Rate Design for RP-2000-0023
  (Evidence: Cost Allocation Model (with Bruce Bacon))

1999
- Propose Electric Distribution Rate Handbook
  (Evidence: Comments on Staff Proposals)
- Standard Supply Service Code, (RP-1999-0040)
- (Evidence: Comments and Alternate Proposal)
- Enbridge, Year 2000 Rate Application (RP 1999-0001)
- Enbridge, Performance Based Regulation Application (EBRO 497-01)
- Enbridge, Ancillary Service Separation & Rental Wind Down (EBO 179-14/15)

1998
- Consumers Gas, 1999 Test Year Rates Application (EBRO 497)
- Union Gas, Separation of Ancillary Services (EBO 177-17)
- Town of Aurora, Franchise Renewal (EBA 795)
- Union Gas, Customer Information System (EBO 177-15)
- Legislative Change (EBO 202)
- System Expansion Generic Hearing (EBO 188)

1997
- Consumers Gas, 1998 Test Year Rates Application (EBRO 495)

1997
- Ten Year Market Review Working Group
- Union Gas/Centra Gas Amalgamation Application

1996
- Union Gas/Centra Gas, 1997 Rates Application (EBRO 493/494)
- Consumers Gas, 1997 Test Year Rates Application (EBRO 492)
- Ontario Hydro, Review of 1997 Rates (HR-24)

1995
- Ontario Hydro, Review of 1996 Rates (HR-23)
- Consumers Gas, 1996 Test Year Rates Application (EBRO 490)
- Union Gas, 1996 Test Year Rates Application (EBRO 486)
- Union Gas/Centra Gas, Shared Services Hearing (EBRO 486/489)

1994
- Centra Gas, 1995 Test Year Rates Application (EBRO 489)
- Ontario Hydro International Hearing (EBRLG - 36)
- Ontario Hydro Corporate Restructuring and 1995 Rates (HR-22)
- Consumers' Gas, 1995 Test Year Rate Case (EBRO 487)

1993
- Joint Hearing on Direct Purchase Issues (EBRO 474-B/476/483/484/485)
- (Evidence: Return-to-System Policies for Ontario LDCs)
- Centra Gas, 1994 Test Year Rates Application (EBRO 483/484)
- Consumers' Gas, 1994 Test Year Rate Case (EBRO 485)

- Union Gas, 1994 Test Year Rate Case (EBRO 476-03)
- (Evidence: Equity Effects of Union's Depreciation Study)

1992
- Consumers' Gas, 1993 Test Year Rate Case (EBRO 479)
- Union Gas, 1993 Test Year Interim Rate Increase (EBRO 476)

1991
- Consumers' Gas, 1992 Test Year Rate Case (EBRO 473)
  (Evidence: Direct Purchase Issues)
- Union Gas, Application for Rates and Cost of Gas (EBRO 462)
- Centra Gas, 1992 Test Year Rates Application (EBRO 474)
  (Evidence: Direct Purchase Issues)

Before the Public Utilities Board of Manitoba

2005
- Manitoba Public Insurance, 2006 General Rates Application
  (Evidence: Rate Stabilization Reserve and Related Issues)

2003
- Centra Gas Manitoba, 2003/04 General Rate Application,
  (Evidence: Comments on the Future Regulatory Methodology)
- Manitoba Hydro, Rate Status Update
  (Evidence: Manitoba Hydro's Financial Requirements and Proposed

2002
  Curtailable Rate Program, with William Harper)
- Manitoba Hydro, Integration Proceeding
  (Evidence: Assessment of Manitoba Hydro/Centra Manitoba Integration, with William Harper)

2001
- Manitoba Public Insurance, 2002 General Rate Application
  (Evidence: Rate Stabilization Issues)
- Centra Gas Manitoba, Primary Gas Rates
  (Evidence: Centra Gas Manitoba's Rate Setting Methodology)

2000
- Centra Gas Manitoba, Rate Management
- Manitoba Public Insurance, 2001 General Rate Application
  (Evidence: MPI's Rate Stabilization Reserve Surplus)
- Manitoba Hydro, Surplus Energy Program

1999
- Centra Gas Manitoba, Western T-Service and Agency Billing and Collection Service
  (Evidence: Assessment of the Proposals of the Company)
- Manitoba Public Insurance, 2000 General Rate Application
  (Evidence: Rate Stabilization Reserve Risk Analysis)

1999
- Manitoba Hydro Purchase of Centra Manitoba
  (Evidence: Implications for Rates and the Regulatory Regime)

1998
- Centra Gas Manitoba, Rates Flowing from Board Order 79/98
- Manitoba Public Insurance, 1999 General Rate Application
  (Evidence: Rate Stabilization Reserve, Allocation of Costs and IT Expenditures)
- Centra Gas Manitoba, Feasibility Cost Assumptions Application
  (Evidence: Comments on Centra's Proposed Changes to the Feasibility Test)
- Centra Gas Manitoba, 1998 Test Year General Rate Application
  (Evidence: Comments on Centra's Proposed Customer Information System)

1997	• Centra Gas Manitoba, Ste. Agathe Franchise Application
	• Manitoba Hydro, Review of ISE/DFH/SESS Programs
	• Manitoba Public Insurance, 1998 General Rate Application
	• Centra Gas Manitoba, Continuation of Shared Services Application
1996	• Centra Gas Manitoba, 1997 General Rate Application
	• Centra Gas Manitoba, Cost of Service and Rate Design Review
	• Generic Hearing on the Role of the LDC in Manitoba (Evidence: The Future Role of Centra Manitoba in the Supply of Natural Gas)
	• Manitoba Hydro, General Rate Application, 1996 and 1997
	• Centra Gas Manitoba, Price Management and Direct Purchase Issues
1995	• Application of the Gladstone, Austin Natural Gas Co-op Ltd.
	• Manitoba Hydro, Review of Prospective Cost of Service Study (GRA) (Evidence: Comments on the Prospective COSS Methodology)
	• Manitoba Hydro, Dual Fuel Heating and Industrial Surplus Energy Rates
	• Centra Gas Manitoba, Rural Expansion/Brandon Facilities Upgrade Hearings
	• Centra Gas Manitoba, 1995 General Rate Application (Evidence: Review of Centra's Weather Normalization Methodology)
	• Centra Gas Manitoba, Rural Expansion Hearing (Evidence: Rural Mains Expansion Feasibility Test)
1994	• Centra Gas Manitoba, Future Test Year Application (Evidence: Comparison of the Future and Historic Test Year methods of RB-ROR regulation)
	• Manitoba Hydro, General Rate Application, 1994 and 1995
1993	• Centra Gas Manitoba, Inc. 1994 General Rate Application
	• Manitoba Telephone System, Interconnect Hearing
	• Manitoba Telephone System, 1993 General Rate Application
1992	• Manitoba Telephone System, 1992 General Rate Application (Evidence: The appropriate debt ratio for a crown corporation)
	• Manitoba Hydro, General Rate Application, 1992
	• Centra Gas Manitoba, Inc. General Rate Application
1991	• Manitoba Telephone System, General Rate Application, 1991
	• Centra Gas Manitoba, Inc. Application for Interim Refundable Rate Increase
1990	• Manitoba Hydro, Major Capital Projects (Evidence: Hydro's 1000MW Ontario Sale and system planning risks)
	• ICG Utilities (Manitoba) Ltd., Generic Hearing on Rate Setting (Evidence: Implications of using a future versus historic test year)

Before the British Columbia Utilities Commission

2006	• British Columbia Transmission Corporation, 2006 Transmission Revenue Requirement
2005	• Insurance Corporation of British Columbia, Financial Allocation Workshop
	• FortisBC, General Rates Application (Evidence: Review of FortisBC Performance under PBR, 1996 to 2004) w. S. Motluk

2004	• Insurance Corporation of British Columbia, Financial Allocation Methodology (Evidence: Review of ICBC's Financial Allocation Methodology, with ICBC)
2002	• Pacific Northern Gas West and Northeast, General Rate Application
2001	• Utilicorp Networks Canada (formerly West Kootenay Power), Annual Review, 2001
2000	• Pacific Northern Gas, 2000-01 General Rate Application (negotiated) • West Kootenay Power, Annual Review, 2000
1999	• Centra Gas BC, 2000-02 Rates Application (negotiated) • BC Gas, Market Unbundling Group (Report to the BCUC) • West Kootenay Power, 2000-02 Rate Application (negotiated) • Pacific Northern Gas, 1999-00 General Rate Application (negotiated) • Annual Reviews of WKP and BC Gas • West Kootenay Power, Transmission Access Application
1998	• BC Gas, Southern Crossing Pipeline Application (Revised) • Pacific Northern Gas, 1998-99 Revenue Requirement/Rate Design (Evidence on PNG's Cost of Service Methodology)
1997	• BC Gas, Southern Crossing Pipeline Application (Evidence on the impact of ratepayer risks related to the SCP due to developments in the competitive environment in the natural gas sector) • Annual Reviews of WKP and BC Gas. • West Kootenay Power, Cost of Service and Rate Design (negotiated settlement)
1997	• Pacific Northern Gas Shared Services • Retail Access and Unbundling Tariff Hearing (suspended) (Evidence on the impact of market restructuring on costs and rates)
1996	• BC Gas - 1996 Rate Design (negotiated settlement) (Evidence: Alternative Methods for Allocating Distribution Mains Costs to Customer Classes) • BC Gas - 1996-1997, Revenue Requirement & IRP (negotiated settlement) • West Kootenay Power - Brilliant Generating Station Transactions • West Kootenay Power - General Rate Application/IRP (negotiated settlement)
1995	• Generic System Expansion Hearing • BC Gas - General Rate Application (negotiated settlement)
1994	• BC Hydro, 1994 Rate Increase Application • West Kootenay Power, 1994/95 Rates and Integrated Resource Plan (Evidence: Review of WKP's Integrated Resource Plan)
1993	• BC Hydro, 1993 Rate Increase Application • BC Gas, Rate Design Hearing (Evidence: Analysis of BC Gas' cost studies and their use in setting rates) • BC Gas - General Rate Application (settled and withdrawn prior to hearing) • Generic Hearing into the New Provincial Domestic Natural Gas Supply Policy

Before the Régie de l'énergie

2001
- Hydro Québec, Transmission Rates (R-3401-98)
  (Evidence: HQT's Transmission Tariff Rate Design Methodology, with B. Bacon)
- Inclusion of Operating Costs in the Gasoline Price Floor Set By the Régie
  (Evidence: Review of Principles) (Régie File R-3457-2000)

2000
- SCGM Unbundling of Tariffs (R-3443-2000)
  (Evidence: SCGM's Unbundling Tariff Proposal, with R. Higgin)
- Gazifère, Rates (R-3446-2000)
  (Evidence: Cash Working Capital and Other Issues, with G. Morrison)

1999
- Operating Costs Borne by Gasoline or Diesel Fuel Retailers (R-3399-98)
  (Evidence: Methodology for Determining Operating Costs)
- Small Hydro Within Hydro Quebec's Resource Plan (R-3410-98)
  (Evidence: Determining the Purchase Price for Small Hydro)

1999
- Gazifère, Year 2000 Rate Case
  (Evidence: Assessment of Cost Allocation and Revenue Sharing Proposals)

1998
- Hydro Québec, Rate-Setting Methodology Under s. 167 of the Régie de l'énergie Act.
  (Evidence: Recommendations on Regulatory Framework)
- Hydro Québec,The Role of Wind Power in the Quebec Energy Portfolio
  (Evidence: Issues Related to Establishing a Set-Aside)

Before the Alberta Energy and Utilities Board

2001
- Generic, Gas Rate Unbundling (2001-093)
  (Evidence: Canadian Experience and Approaches)
- Generic, Gas Cost Recovery Rate Methodology (2001-040)

Before the Newfoundland & Labrador Board of Commissioners of Public Utilities

2009
- Newfoundland Power, 2010 General Rate Application
  (Evidence: Assessment of five hearing issues)

2007
- Newfoundland Power, 2008 General Rate Application
  (Evidence: Regulatory instruments and other issues)

2006
- Newfoundland Power, 2007 Amortization and Cost Deferrals Application

2005
- Newfoundland Power, 2006 Accounting Policy Application
  (Evidence: Assessment of Newfoundland Power's Proposals)

Before the New Brunswick Energy and Utilities Board

2010
- New Brunswick Power Distribution Corp, 2010 Rate Review

2009
- EGNB, Development Period hearing
- New Brunswick Power Distribution Corp, 2009 Rate Review

2008
- New Brunswick Power Distribution Corporation, PDVSA Deferral Account

2007
- New Brunswick Power Distribution Corporation, PDVSA Deferral Account

(Evidence: Treatment of the Petroleos De Venezuela, S.A. (PDVSA) Settlement in Setting Rates)

Before the Nova Scotia Utility and Review Board

2011	•	Nova Scotia Power, 2011 Annual Capital Expenditure Plan
	•	Nova Scotia Power, Load Retention Tariff (Evidence: Load Retention Tariff Methodology)
	•	Heritage Gas, 2012 General Tariff Application
	•	Efficiency Nova Scotia, Compliance Filing (Cost Allocation Methodology Report)
2008	•	Town of Antigonish Electric Utility rate process (Evidence: Comments on the Town of Antigonish Electric Utility Revised Cost of Service Study)

Before the National Energy Board

1999	•	BC Gas, Southern Crossing Project

Before the Canadian Radio television and Telecommunications Commission

2010	•	Obligation to Serve and Other Matters (NC 2010-43) (Evidence: Analysis of Issues Related to Local Service Subsidy)
2006	•	Review of Price Cap Framework (PN 06-5)
2001	•	Implementation of Price Cap Regulation for Québec-Téléphone & Télébec (PN 01-36) (Evidence: Designing a Consistent Price Cap Regime)
	•	Price Cap Review (PN 01-37) (Evidence: The Second Generation Price Cap Regime)
	•	Recovery of 2000 and 2001 Income Tax Expense (PN 00-108) (Evidence: Appropriate Recovery of MTS Income Tax Expense)
2000	•	Scope of Price Cap Review (PN 00-99)
	•	Sunset Rule for Near-Essential Facilities (PN 00-96)
	•	Access to Municipal Property in the City of Vancouver (PN 99-25)
	•	Review of Contribution Collection Mechanism (PN 99-6) (Evidence: Review of Contribution Collection Mechanism)
	•	Review of Direct Connection Charges
1999	•	Review of Frozen Contribution Rate Policy (PN 99-5) (Evidence: Comments on the Frozen Contribution Rates Policy)
	•	High Cost of Serving Areas (PN 97-42)
1998	•	Local Number Portability Start-up Costs (PN 98-10)
	•	Competition in the Provision of International Telecommunications Services (PN 97-34)
1997	•	Implementation of Price Caps (PN 97-11)

	• Review of Joint Marketing Restrictions (PN 97-14/97-21) • Forbearance from Regulation of Toll Services Provided by Dominant Carriers (96-26) • Regulation of Telecom Services Offered by Broadcast Carriers (PN 96-36)
1996	• Scope of Contribution (PN 96-19) • Bell Canada, Business Rate Restructuring (PN 96-13) • Price Cap Regulation and Related Issues (PN 96-8) (Evidence: Evidence addressing the design of the price cap system) • Interconnection and Network Component Unbundling (PN 95-36) (Evidence: Mechanisms for Collecting Contribution) • AGT, General Rate Application • Local Services Pricing Options (PN 95-49/95-56) (Evidence: Mechanisms for Pursuing the Goal of Universally Available Basic • Telephone Service in Low-Penetration Exchanges) • Review of Phase II (PN 95-19) • Regulatory Framework for Ontario Independent Telephone Cos. (PN 95-15) • Split Rate Base Hearing (PN 94-52, 94-56 and 94-58) (Evidence: Applicability of the Decision 94-19 Regulatory Framework to MTS)
1995	• Review of the Regulatory Framework of Teleglobe Canada Inc. (PN 95-11) • Review of the Quality of Service Indicators (PN 94-50) • Bell SYGMA Hearing (PN 94-53)
1994	• Regulatory Framework (Evidence: A Proposed Regulatory/Structural Alternative) • Maritime Tel, General Rate Increase • Island Tel, General Rate Increase • BC Tel, General Rate Increase • AGT, General Rate Increase • Northwestel, General Rate Increase (paper hearing) • Bell Canada, General Rate Increase • Teleglobe, Annual Construction Program Review (paper hearing) • New Brunswick Tel, Annual Construction Program Review (paper hearing)
1992	• Bell Canada - 1992 Annual Construction Program Review • AGT - 1992 Annual Construction Program Review
1991	• Bell Canada - 1991 Construction Program Review
1990	• Maritime Telegraph & Telephone, Review of Revenue Requirement 1990-91 • (Evidence on the impact of modernization) • Island Telephone Company, Review of Revenue Requirement 1990-91 (Evidence on the impact of modernization) • Review of Cable Television Regulations (Evidence on alternative forms of regulation)

Before the Ontario Telephone Services Commission

1992 • Review of Rate-of-Return Regulation for Public Utility Telephone Companies.
(Evidence: The need for OTSC regulation of municipal public utility telcos)

Before the Ontario Securities Commission

1985 • Securities Industry Review
(Evidence: Industry structure and the form of regulation)

1983 • Role of Financial Institutions in the Securities Industry
(Evidence: Discount Brokerage and the Role of Financial Institutions)

1982 • Institutional Ownership of, and Diversification by, Securities Dealers
(Evidence: The impact of foreign and institutional entry)

1981 • The Unfixing of Brokerage Commission Rates
(Evidence: The impact of price competition on the securities industry)

Before the Ontario Municipal Board

1995 • Appeal of Boundary Expansion by Lincoln Hydro Electric Commission
(Affidavit prepared on the tests for boundary expansions)

1992 • Evidence dealing with the *Rental Housing Protection Act, 1989*

Before the Supreme Court of Ontario

1990 • Challenge of the Residential Rent Regulation Act (1986) under the *Canadian Charter of Rights and Freedoms*
(Evidence: The impact of rent regulation on Ontario's rental housing market)

Before the Saskatchewan Court of Queen's Bench

1993 • Evidence regarding market dynamics and competition policy.

Non-Hearing Processes (Task Forces, Lawsuits and Arbitrations)

2011 • Developing a regulatory training course for Ontario electricity distributors

2010 • Expert Advisor to the Ontario Energy Board for the Cost Allocation Review

2009 • Expert Advisor to New Brunswick Department of Energy on regulatory matters related to the proposed purchase of NB Power assets by Hydro Quebec
• Benchmarking for Regulatory Purposes (CAMPUT)

2008 • Expert Advisor to Ontario Energy Board for the Rate Design Review

2007	• Workshop on Electricity Market Design for the Electricity Regulatory Authority of Vietnam
2006	• Workshop on Regulatory Methodology for the Government of Vietnam (electricity regulator, Ministry of Energy and state-owned enterprises) with Marie Rounding
2004	• Vitamin Price Fixing
	• Allocation of debt related to separation of electric utilities
2001	• BC Gas, Second Generation Performance Based Regulation Negotiation
	• Telecommunications Industry, Price Cap Review Negotiation
1999	• PBR Task Force (Electricity), Ontario Energy Board
	• Market Unbundling Group (BC Gas), British Columbia Utilities Commission
	• Western Supply Transportation Service (Centra Gas Manitoba), Manitoba PUB
1998	• Market Design Task Force, Ontario Energy Board
1997	• Ten Year Market Review, Ontario Energy Board

Commercial Arbitrations

Current: Two arbitrations in Alberta

2006	• Disputed Power Purchase Agreement (PPA)
2004	• Evidence on the interpretation of a Gas Purchase Agreement (GPA)

Facilitation Activities

2010	• Three Strategic Planning Process for the Boards of Directors of an Ontario electricity distributor
2008	• Three Strategic Planning Processes for the Boards of Directors of electricity distributors
2007	• Stakeholder facilitation for Ontario Power Generation in relation to its Regulated Payment Amounts
2004	• Ontario Energy Board, Review of Further Efficiencies in the Electricity Distribution Sector (RP-2004-0020) (with IBM Consulting)
	• Visioning Session: Structural Review of an association of Ontario electric LDCs
	• Business Plan Visioning Session with the Board of Directors of an Ontario electric LDC
2000	• Ontario Energy Board, Distribution Access Rule Task Force

Other Regulatory Issues Researched for Clients

- “Benchmarking for Regulatory Purposes” (with First Quartile Consulting) for the Canadian Association of members of Regulatory Tribunals (CAMPUT)
- “Review of Potential Regulatory Cost Measures” (a Report for the OEB)
- “Survey of Regulatory Cost Measures” (a Report for the Ontario Energy Board)
- OEA Working Dialogue on OEB Regulating Efficiency and Effectiveness (2007)
- Regulatory Cost Measures for the Ontario Energy Industry (2007)
- “Designing an Appropriate Lost Revenue Adjustment Mechanism (LRAM) for Electricity CDM Programs In Ontario”
- Small Hydro PPA Terms and Conditions
- Ontario Electricity Supply Mix
- Mitigation of Regulatory Risk for Utilities
- Regulatory Benchmarking
- Cross-jurisdictional Survey of Regulatory Efficiency
- Renegotiation of Municipal Franchise Agreement

Regulated Industries:
Papers and Research Projects

- *Report on the Effects of Separating Hydro One’s Transmission and Distribution Functions.*
- *Report on Hydro One Privatization Options.*
- *The Impact of Complete Deregulation on Market Efficiency of the Gas and Electric Industry in Alberta Post-2005 Assuming Current Market Dominance.*
- *Analysis of a Possible Equity Infusion for Ontario Hydro: Potential Implications for Financing Costs.*
- *Volatility in the Ontario Electricity Market, by ECS with Snelson International Energy.*
- *An Assessment of Price Volatility in the Ontario Electricity Market.*
- *Analysis of MTS Privatization Plan.*
- *Comments on the Issues Identified in the December 1995 Working Paper of the Advisory Committee on Competition in Ontario’s Electricity System, A submission on behalf of The Power Workers’Union.*
- *Telecommunications Municipal/Franchise Tax Design Options (with Dr. E. Slack).*
- The Implications of Phase III Costing for the Rates and Toll Settlements of Independent Telephone Companies (with Andrew Roman).
- Submission to the Department of Communications (Canada) (August 1990): *Towards Competition in Telecommunication and Cable TV Services: A Single Switched Broadband Distribution Facility* (Comments of the Public Interest Advocacy Centre, with Robert E. Horwood and Gaylord Watkins).

- Submission to the Department of Communications (Canada) (May 1990): *Fibre Optic Networks: Facilitating Competition in Telecommunication and Television Services for the Benefit of All Users* (Comments of the Public Interest Advocacy Centre, with Robert E. Horwood and Gaylord Watkins).
- Submission to the CRTC concerning cable television regulation on behalf of the Public Interest Advocacy Centre (with Carmen Baggaley).
- Analysis of financing alternatives for Toronto Hydro's 13.8 kV conversion program for the City of Toronto Parks and Recreation Department.
- Analysis of the MacEachen White Paper on "Inflation and the Taxation of Personal Investment Income" for the Ontario Economic Council.
- Submission to the Parliamentary Committee commenting on the April 1985 Finance Green Paper, "The Regulation of Financial Institutions: Proposals for Discussion" prepared on behalf of the Public Interest Research Centre.

Financial Markets:
Papers and Research Projects

- Analysis of the potential consumer benefits from insurance retailing by financial institutions in Canada for the Public Interest Research Centre.
- Development of a financial model for projecting the financial implications of alternative corporate structures.
- Developed model for projecting cash flows for a major land development project.
- Analysis of the impact on the capital markets of changes to the investment rules for public sector pension funds for the Task Force on the Investment of Public Sector Pension Funds (with Prof. John Bossons).
- Review of the OSC proposals and alternatives for relaxing ownership restrictions in the securities industry prepared for the Ontario Securities Commission for submission to the Premier's Office (with Prof. Tom Courchene).
- Analysis of the Impact of Opening the Ontario Securities Market on the Economy of Toronto for a major Canadian securities dealer.
- Response to the December 1984 "Interim Report of the Ontario Task Force on Financial Institutions" for Consumer and Corporate Affairs (Canada).
- Report on functional integration in the Canadian financial services sector for the Australian Merchant Bankers' Association.
- Analysis of the Canadian and American Experience with Partially Negotiable Brokerage Commission Rates for the Australian Merchant Bankers Assoc.
- Served as a North American contact for the Office of Fair Trading (United Kingdom) providing information on developments in the debate over unfixing of brokerage fees, entry of banks into securities dealing and related matters.

- Development of a computerized package for analyzing the effects of alternative tax systems on business investment. Prepared for the Ontario Government reference to the Ontario Economic Council to study a separate personal income tax for Ontario.
- "An Analysis of the Use of Component Internal Rates of Return for Fund Performance Measurement" for Canadian National Investments.
- Analysis of Canadian Stock Market Data (development of a computer package for evaluating investment portfolio efficiency).
- Redesign and periodic updating of the financial, analysis methodology for Alfred Bunting and Co.
- Developed an APL computer package for teaching Business Finance concepts.

Housing:
Papers and Research Projects

- Potential Impact of Rent De-Control on Selected Markets in Ontario
- Review of the Ontario Auditors analysis of the cost of social housing.
- *Future Social Housing Delivery Opportunities in Metro Toronto*.
- Development of a model for projecting core need households to 2011.
- Analysis of the City of Toronto's approach to the valuation of certain properties developed under the *Rental Housing Protection Act, 1989*.
- *Security of Tenure Issues Pertaining to Co-operative Housing*.
- *Rent Regulation in Ontario*, a report prepared as expert Evidence for a Charter of Rights challenge of Ontario's system of rent regulation (with W.T. Stanbury).
- Feasibility study of enhancements to long term housing forecasting models (demographic factors) with David Foot.
- Feasibility study of enhancements to long term housing forecasting models (economic factors).
- Review of the housing situation in the Greater (Toronto) Metropolitan Region in 1988 and the next decade for the Ontario Ministry of Housing.
- Treatment of the Assisted Rental Program under rent regulation for the Ontario Ministry of Housing.
- Alternatives for implementing of the chronically depressed rent provision of the Residential Rent Regulation Act, 1986.
- Projected rental housing requirements to 1996, by unit rent level for Ontario Ministry of Housing.
- Analysis of the effects of the Canadian Home Ownership Stimulation Program on housing starts for Canada Mortgage and Housing Corporation.
- Energy Efficiency of New Housing (with Peat, Marwick and Partners and Scanada Consultants Limited) for Canada Mortgage and Housing Corporation.
- A Model of Supply and Demand in the Market for Housing for the Ontario Ministry of Housing.
- Several publications and presentations shown in the Academic Profile (see below).

Other Areas:
Papers and Research Projects

- Economic analysis of the market impact of the merger of two Canadian trucking companies in the context of the Competition Act.
- Assisted a Joint Task Force of the Ontario Ministries of Social Services and Health to develop a cost project model of alternative long term health care delivery systems.
- Study of Tax Incentives for Film and Television (joint project with Dr. E. Slack) for the Canadian Film and Television Association.
- Economic Analysis of Tax Incentives for the Film Industry (joint project with Dr. E. Slack) for the Department of Communications.
- Economic Impact of Cultural Institutions for Ontario Association of Art Galleries with the Ontario Federation of Symphony Orchestras and the Toronto Theatre Alliance.
- Economic Impact of Art Galleries' Expenditures on their Local Communities for the Ontario Association of Art Galleries.
- Developed a case study of the potash pro-rationing scheme invoked by the Saskatchewan government for the Faculty of Management Studies, Univ. of Toronto.
- Analysis of Regional Municipality of Niagara financial information for the Niagara Region Review Commission.
- Analysis of Ottawa/Carleton regional government's financial information, and comparison with other regional governments, using the MARS database (with Dr. E. Slack).
- A Dynamic Simulation Model of the North York Secondary School System for Planning for Declining Enrolment for the Ontario Institute for Studies in Education, Department of Educational Planning (with Dr. S. Padro).
- Development of an extension to the Limits to Growth World III Model incorporating commodity prices, technology, disaggregated regions and energy resources into the model.
- Development of a computer program for solving the Dynamic Transportation Problem (with Professors Sethi and Bookbinder at the Faculty of Management Studies, University of Toronto).

PRESENTATIONS

- “Innovations in Rate Design”, 2010 CAMPUT Training Session
- “Cost of Service Filing Requirements” (2010) 2nd Annual Applications Training for Electricity Distributors, Society of Ontario Adjudicators and Regulators in cooperation with the Ontario Energy Board
- “Green Energy Act” (2010) 2nd Annual Applications Training for Electricity Distributors, Society of Ontario Adjudicators and Regulators in cooperation with Ontario Energy Board
- “Rate Design”, 2009 CAMPUT Training Session
- “How To Build Transmission and Distribution to Enable FiT: The Role of Distributors”, EUCI Conference on Feed in Tariffs, Toronto, Sept. 2009

- “Distributor Mergers and Acquisitions: Potential Savings”, 2007 Electricity Distributors Ass
- “Beyond Borders” Regulating the Transition to Competition in Energy Markets (with Fred Hassan), EnerCom Conference March 2006.
- “Low-Income Energy Plan for Peterborough City & County”, 2006 LIEN-AHAC Conference
- “The “Deregulated Retail Energy Sector in Ontario”, Toronto Association of Business Economists, Oct. 2003.
- “Other Approaches to Rate Regulation”, CAMPUT Annual Meeting, Sept. 2003.
- “Price Projection: Will the Rate Freeze be Revenue Neutral?” at Canadian Institute Conf., The Impact of Ontario’s New Electricity Market on Large Power Consumers Jan. 2003.
- “Managing Energy Price Risk: Impact of Market & Regulatory Developments on Price Risk Management”, Canadian institute Conference, Toronto, October 21, 2002.
- “Location Based Marginal Pricing: Will it Happen?” Ontario Energy Contracts, Insight Conference, Toronto, October 1, 2002.
- “The Evolution of the North American Energy Market” Canadian Gas Association Executive Conference, Vancouver, June 2002.
- “Alternate Dispute Resolution: Can Everyone Win?” Canadian Gas Association Breakfast, Whistler, British Columbia, May 7, 2002.
- “Incentive Regulation and Commodity Competition Impacts on Quality of Service & Rates”, CAMPUT Regulatory Educational Conference, Whistler, BC, May 7, 2002.
- “Energy Deregulation Developments and Impacts on the HVACR Industry”, HRAI’s 33rd Annual Meeting, August 23-25, 2001 Huntsville, Ontario.
- “Natural Gas Delivery Regulation in Canada”, HRAC Conference on Natural Gas in Nova Scotia, Halifax, Nova Scotia, August 25, 1999.
- “Licensing as a Regulatory Approach” Thirteenth Annual CAMPUT Regulatory Educational Conference, Saint John, New Brunswick, May 4, 1999.
- “The Impact of Restructuring Electricity Markets on Customers”, West Kootenay Power 1998 Annual Conference, The Dawn of Customer Choice, Kelowna, B.C., Dec. 2, 1998.
- “Gaining Access to the Retail Customer”, *Electricity Competition in Ontario, New Rule, New Opportunities, New Players* (Canadian Institute Conference), Toronto, Oct. 1998.
- “The Future: Mega-BTU Inc.?” (Plenary session) Twelfth Annual CAMPUT Regulatory Educational Conference, Banff, Alberta, April 27, 1998.
- “Protecting Low Income Consumers’ Access: Lessons Learned From Other Countries,” Twelfth Annual Energy Affordability Conference, National Consumers Law Center, Washington, D.C, February 26-27, 1998.
- “Competition: What happens downstream of the meter?” (Plenary) Eleventh Annual CAMPUT Regulatory Educ. Conference, Whistler, B.C., May 6, 1997.
- “Brokers, Marketers and the Public Interest” Eleventh Annual CAMPUT Regulatory Educational Conference, Whistler, B.C., May 6, 1997.
- “Separation of Gas Supply, Merchant Functions & Other Alternatives,” Tenth Annual CAMPUT Regulatory Educ. Conf., Niagara-on-the Lake, May 1, 1996.

- “The Impact of Deregulation on the Public Interest,” Tenth Annual CAMPUT Regulatory Educational Conference, Niagara-on-the Lake, April 30, 1996.
- “Marketing to Low and Moderate Income Consumers in the New Competitive Market: Lessons Learned From Other Industries,” Tenth Annual Energy Affordability Conference, National Consumers Law Center, Washington, D.C, February 22, 1996.
- “Where Should We be Going?” OEB Ten Year Market Review Workshop, Jan. 31, 1996.
- “Restructuring the Electrical Power Industry in Ontario” for the Board of Directors of Ontario Hydro on behalf of the Power Workers’ Union, August, 1995.
- "A New Vision for Ontario's Electric Demand/Supply Future" panel presentation, Opening Plenary Session of the Canadian Independent Power Conference, Toronto, Dec. 1993.
- "Trends in Rental Housing Affordability by Income Level in Ontario" presented at the 1992 meetings of the Canadian Economics Assoc., Charlottetown, PEI.
- "An Evaluation of Rent Regulation as an Instrument for Meeting the Housing Needs of Renters in Ontario," presented to the Ontario Standing Committee on General Government, August, 1991.
- with S.W. Hamilton (Sept 1990) "Housing and the Regulatory Environment", a paper presented at the Housing Young Families Affordability Symposium, (Vancouver: Canadian Housing and Renewal Association/Canada Mortgage and Housing Corp.)
- "New Telecommunications Technologies: Who Pays? Who Benefits?" presented at the 1990 (June) meetings of the Canadian Economics Assoc., Victoria, B.C.
- with W.T. Stanbury, (1989) "Rent Controls as a Prisoner of War Game", Canadian Real Estate Research Bureau, Faculty of Commerce and Business Administration, University of British Columbia, #89-ULE-019.
- "The Implications of Rent Regulation for Housing Market Models" presented at 1989 (June) meetings of the Canadian Economics Association, Quebec City.
- "Price Caps - An Alternative to Rate of Return Regulation?" at the Canadian Association of Members of Public Utility Tribunals/Centre for the Study of Regulated Industries, Annual Regulatory Studies Training Programme, McGill University, May 14-18, 1989.
- "Living with Rent Regulation in Ontario" at the 35th North American meetings of the Regional Sciences Association, Toronto, November 1988.
- "A Survey of the Research of the Thom Commission," at *Rent Control: The International Experience*, John Deutsch Institute Roundtable, Queen's University, September, 1987.
- Invited address on "Forecasting the Regulatory Environment of Financial Institutions" sponsored by the University of Michigan - Flint as the 1985 paper for their annual *Lectures on the American Economy and the Business Community* series.
- "Collapsing Barriers Between Banking and Other Financial Institutions" at the 1984 Canadian MBA Conference, McMaster University.
- The economic impact of cultural activities for conferences of National Museums of Canada, Canadian Conference on Heritage Resources, Canadian Museums Association, Ontario Association of Art Galleries, and Ontario Federation of Symphony Orchestras.

PUBLICATIONS

Refereed Books and Monographs:

- with W.T. Stanbury (February 1990) *Rent Regulation: The Ontario Experience*, (Vancouver: The Canadian Real Estate Research Bureau).
- with W.T. Stanbury (January 1990) *The Housing Crisis: The Effects of Local Government Regulation*, (Vancouver: The Laurier Institute).
- with T. Courchene and L. Schwartz (October 1986) *Ontario's Proposals for the Canadian Securities Industry*, Observation No. 29, (Toronto: C.D. Howe Inst.).
- (1983) *Price Competition in the Canadian Securities Industry: A Test Case of Deregulation*, (Toronto: Ontario Economic Council).
- with G.F. Mathewson (1982) *Information Entry and Regulation in Markets for Life Insurance - Part II Overview and Policy Implications*, (Toronto: Ontario Economic Council).

Refereed Articles:

- with W.T.Stanbury (1990) "Landlords as Economic Prisoners of War", *Canadian Public Policy*, XVI no.4.
- with G.D. Quirin and S.P. Sethi (1977) "Market Feedbacks and the Limits to Growth", *INFOR*, Vol. 15, No. 1.

Other Publications:

- (1992) *Technology, Competition and Cross-subsidization in the Canadian Telecommunications Industry*, (Ottawa: Public Interest Advocacy Centre).
- (April 1990) *Paying for What You Need: Technological Advances and Competition in Telecommunications*, (Ottawa: Public Interest Advocacy Centre).
- with Andrew Roman and Robert Horwood, (1989) *Insurance Retailing by Financial Institutions in Canada*, (Ottawa: Public Interest Research Centre).
- with Douglas G. Hartle (1983) "The TAX-2 Model and Results" in *A Separate Personal Income Tax for Ontario: An Economic Analysis*, Special Research Report, (Toronto: Ontario Economic Council).
- (1982) "Commentary" in *Inflation and the Taxation of Personal Investment Income: An Analysis and Evaluation of the Canadian 1982 Reform Proposals* (edit. D.W. Conklin), Special Research Report (Toronto: Ontario Economic Council).

TEACHING

1989	Economics of Housing, Scarborough College, University of Toronto
1979 – 1985	Engineering Economy, Faculty of Engineering, University of Toronto

1982 – 1985	Computerized Business Systems (B.A. Program), and Management Information Systems (M.B.A.), Canadian School of Management
1979	Introductory Economics at St. George Campus, University of Toronto
1977 – 1979	Economic Principles at Erindale College, University of Toronto
1980 – 1985	Scuba diving instruction for Basic Diver, Sport Diver, Assistant Instructor and Instructor courses (National Association of Underwater Instructors).

RESEARCH MANAGEMENT

1983 –1987

- Research Director: Commission of Inquiry Into Residential Tenancies.
- Directing a staff of four in house researchers on various background studies on Ontario's housing market and the literature related to rent regulation. Managed thirty external projects on topics related to the housing market and rent regulation.

1978 –1980

- Research Officer: Ontario Economic Council.
- Research was conducted in the areas of regulation of the securities industry, mineral resource taxation policy, and Federal Provincial energy policy.
- Other duties included managing ten external research contracts on topics in regulation and directing the work of research assistants.

OTHER ACTIVITIES

- Organizing Committee for the Concert for Inclusion in support of ParaSport Ontario
- Chairman of the Board of Directors of the Ontario Energy Marketers Association (formerly the Direct Purchase Industry Committee) and Executive Director of the Association.
- Invited participant in the Ontario Energy Board's External Advisory Committee.
- Panelist for "Administrative Tribunals and ADR", Osgoode Hall Law School, Professional Development Program, Continuing Legal Education, April 1997.
- Participation on behalf of OCAP in consultative processes related to direct purchase and integrated resource planning in the Ontario natural gas industry.
- Former Member of the Board of Directors of East Toronto Community Legal Services.
- Former Chairman of the Board of Directors of the Festival of Canadian Theatre.
- Articles in the editorial section of the Financial Times of Canada on policies for reforming Ontario's system of rent regulation (June 1990) and federal proposals regarding bank directorships (February 1991).
- Numerous appearances on CBC radio and television commenting on energy industry issues, competition, regulation and mergers in the Canadian economy.
- Refereed articles and research studies for *Canadian Public Policy*, *Queen's Quarterly* and Consumer and Corporate Affairs, Canada.

- Several organizations have been assisted in developing their research agendas, writing submissions to government on economic issue, or in other advisory capacities. Clients include the Public Interest Research Centre (topics include airline deregulation, Via Rail, telephone solicitation, Bell Canada's rate structure, frequent flyer programs, price cap regulation, and home equity conversion), Ontario Association of Art Galleries (arts funding and economic impact), Public Affairs Management, Inc., City of Toronto, Parks and Recreation Department, and Goldfarb Consultants.

CLIENTS

Private Sector Companies

Alfred Bunting & Co.
BC Gas Utilities Limited
Buttcon Ltd.
Canadian National Investments
Comdisco Canada Inc.
Devon Canada
EnCana
Enbridge Gas Distribution
Enron Trade and Capital Canada
Fine Line Communications Ltd.
Fuji Electric (Tokyo)
Great West Life Assurance Co.
Hydro One Networks Inc.
Insurance Corp. of British Columbia
New Brunswick Power (Disco)
Ontario Power Generation
Sithe Canada
Terasen Gas
Union Gas Limited
Over 30 Ontario electricity distributors
Auto Haulaway Inc.
BC Rail
Canavest House Ltd.
Entergrus (Chatham-Kent Energy)
Coral Energy
Direct Energy
ENERconnect
EnCana Corporation
Financial Times of Canada
FortisBC
Goldfarb Consultants
Highmark Properties
Hydro Québec
McLeod Young Weir
Ontario Hydro Services
Shulman Communications Inc.
Star Produce
The Morassutti Group
Wirebury Connections Inc.

Industry and Other Associations

Association for Furthering Ontario's Rental Development
Australian Merchant Bankers' Association
Canadian Association of Members of Public Utilities Tribunals (CAMPUT)
Canadian Business Telecommunications Alliance
Canadian Film and Television Association
Canadian Independent Telephone Association
Canadian Museums Association
Cornerstone Hydro Electric Concepts
Electricity Distributors Association

Manitoba Keewatinowi Okimakanak
Ontario Association of Art Galleries
Ontario Energy Association
Ontario Federation of Symphony Orchestras
Power Workers' Union (CUPE 1000)
Toronto Theatre Alliance

Consumers' Associations

Alberta Council on Aging
Alert on Welfare
British Columbia Old Age Pensioners' Association
Canadian Pensioners Concerned
(Nova Scotia Division)
Consumers Association Of Canada
(National)
(Manitoba Branch)
(Alberta Branch)
(Northwest Territories Branch)
Consumers Fight Back Association
Council of Senior Citizens' Organizations
Co-operative Housing Association of Ontario
Federated Anti-Poverty Groups of British Columbia
Action réseau consommateurs (formerly La Fédération
Nationale des Associations de Consommateurs du Québec)
Manitoba Society for Seniors
The National Anti-Poverty Organization
Nova Scotia League for Equal Opportunities
Ontario Coalition Against Poverty
Option Consommateurs
PEI Council for the Disabled
PEI Senior Citizens Federation
People on Welfare for Equal Rights
Public Interest Research Centre
Rural Dignity of Canada
Rural Dignity, PEI Chapter
Senior Citizen' Association
Social Action Commission

Counsel for Consumers' Associations

British Columbia Public Interest Advocacy Centre
Legal Aid Manitoba, Public Interest Law Centre
Newfoundland Consumer Advocate
Public Interest Advocacy Centre (Ottawa)

Government

Federal
Canada Mortgage and Housing Corporation
Canadian Conference on Heritage Resources
Consumer and Corporate Affairs (Canada)
Department of Communications (Canada)
Director of Investigation and Research, Combines Investigation Act
St. Lawrence Seaway Authority

Provincial
Alberta Department of Energy
Commission of Inquiry into Residential Tenancies
New Brunswick, Department of Energy
Niagara Region Review Commission
Ontario Economic Council
Ontario Energy Board
Ontario Institute for Studies in Education, Department of Educational Planning
Ontario Ministry of Community and Social Services
Ontario Ministry of Health
Ontario Ministry of Housing (Corporate Policy and Planning; Rent Review Policy, Housing Field Operations)
Ontario Securities Commission
Ontario Task Force on the Investment of Public Sector Pension Funds
Ottawa/Carleton Region Review Commission
University of Toronto

Other
City of Calgary Electrical System
City of Peterborough
City of Toronto, (Telecom; Housing; Parks and Recreation)
Halifax Regional Municipality
Manitoba NDP Caucus
Office of Fair Trading (United Kingdom)

St. Francis Xavier University

Toronto Harbour Commissioners

Four municipally operated public utility telephone system

ACADEMIC ACHIEVEMENTS

1975	Masters in Business Administration in Economics and Management Science, University of Toronto
1972	Bachelors of Science in Electrical Engineering, University of Toronto

MICHAEL J. ROGER

34 King Street East, Suite 600 | Toronto, ON M5C 2X8 | 905 731 9322 | mroger@elenchus.ca

ASSOCIATE CONSULTANT, RATES AND REGULATION

Michael has over 33 years experience in the electricity industry dealing in areas of finance, cost allocation, rate design and regulatory environment. Michael has been an expert witness at numerous Ontario Energy Board proceedings and has participated in task forces dealing with his areas of expertise. Michael is a leader and team player that gets things done and gets along well with colleagues.

PROFESSIONAL OVERVIEW

Elenchus **2010 - Present**
Associate Consultant, Rates & Regulation

- Provide guidance on the Regulatory environment in Ontario for distributors, with particular emphasis in electricity rates in Ontario and the regulatory review and approval process for cost allocation and rate design. Some of the clients that Michael provides advice include: Hydro Quebec Energy Marketing Inc., GTAA, Ontario Energy Board, City of Hamilton, Hydro One Transmission, Powerstream, Hydro Ottawa, and Hydro 2000.

Hydro One Networks Inc. **2002 - 2010**
Manager, Pricing, Regulatory Affairs, Corporate and Regulatory Affairs

- In charge of Distribution and Transmission pricing for directly connected customers to Hydro One's Distribution system, embedded distributors and customers connected to Hydro One's Transmission system. Determine prices charged to customers that conform to guidelines and principles established by the Ontario Energy Board, (OEB). Provide expert testimony at OEB Hearings on behalf of Hydro One in the areas of Cost Allocation and Rate Design. Keep up to date on Cost Allocation and Rate Design issues in the industry. Ensure deliverables are of high quality, defensible and meet all deadlines. Keep staff focused and motivated and work as a team member of the Regulatory Affairs function. Provide support to other units as necessary.

Ontario Power Generation Inc. **1999 - 2002**
Manager, Management Reporting and Decision Support, Corporate Finance

- In charge of producing weekly, monthly, quarterly and annual internal financial reporting products. Input to and coordination of senior management reporting and performance assessment activities. Expert line of business knowledge in support of financial and business planning processes. Coordination, execution of review, and assessment of business plans, business cases and proposals of an operational nature. Provide support to other units as necessary. Work as a team member of the Corporate Finance function.

Ontario Hydro **1998 - 1999**
Acting Director, Financial Planning and Reporting, Corporate Finance

- In charge of the day to day operation of the division supporting the requirements of Ontario Hydro's Board of Directors, Chairman, President and CEO, and the Chief Financial Officer, to enable them to perform their due diligence role in running the company. Interact with business units to exchange financial information.

Financial Advisor, Financial Planning and Reporting , Corporate Finance **1997**

- Responsible for co-ordinating Retail, Transmission, and Central Market Operation divisions' support of Corporate Finance function of Ontario Hydro to ensure financial information consistency between business units and Corporate Office, review business units compliance with corporate strategy. Provide advice to Chief Financial Officer and Vice President of Finance on business unit issues subject to review by Corporate Officers.
- Participate or lead task team dealing with issues being evaluated in the company. Supervise professional staff supporting the function. Co-ordinate efforts with advisors for GENCO and Corporate Function divisions to ensure consistent treatment throughout the company.

Section Head, Pricing Implementation, Pricing **1986 - 1997**

- In charge of pricing experiments, evaluation of marginal costs based prices, cost-of-service studies for municipal utilities, analysis and comparison of prices in the electric industry, rate structure reform evaluation, analysis of cost of servicing individual customers and support the cost allocation process used to determine prices to end users.
- The section was also responsible for the derivation of wholesale prices charged to Municipal Electric Utilities and retail prices for Direct Industrial customers, preparation of Board Memos presented to Ontario Hydro's Board of Directors and support the department's involvement at the Ontario Energy Board Hearings by providing expert witness testimony.

Section Head, (acting), Power Costing, Financial Planning & Reporting, Corporate Finance **1994 - 1995**

- Responsible for the allocation of Ontario Hydro's costs among its customer groups and ensure that costs are tracked properly and are used to bill customers. Maintain the computer models used for cost allocation and update the models to reflect the structural changes at Ontario Hydro. Participate at the Ontario Energy Board Hearings providing support and expert testimony on the proposed cost allocation and rates. Provide cost allocation expertise to other functions in the company.

Additional Duties **1991**

- Manager (acting) Rate Structures Department.
- Review of utilities' rates and finances for regulatory approval.
- Consultant.
- Sent by Ontario Hydro International to Estonia to provide consulting services on cost allocation and rate design issues to the country's electric company.

Analyst, Rates **1983 - 1986**

- In charge of evaluating different marketing strategies to provide alternatives to customers for the efficient use of electricity. Co-ordinate and supervise efforts of a work group set up to develop a cost of service study methodology recommended for implementation by Municipal Electric Utilities and Ontario Hydro's Rural Retail System. Provide support data to Ontario Hydro's annual Rate Submission to the Ontario Energy Board. Participate in various studies analysing cost allocation areas and financial aspects of the company.

Forecasting Analyst, Financial Forecasts **1980 - 1983**

- Evaluating cost data related to electricity production by nuclear plants and preparing short term forecasts of costs used by the company. Maintain and improve computer models used to analyse the data.
- Review Ontario Hydro's forecast of customer revenues, report actual monthly, quarterly and yearly results and explain variances from budget. Support the development of new computerized models to assist in the short-term forecast of revenues.

Project Development Analyst, Financial Forecasts **1979 - 1980**

- In charge of developing computerized financial models used by forecasting analysts planning Ontario Hydro's short term revenue and cost forecasts and also in the preparation of Statement of Operations and Balance Sheet for the Corporation.

Assistant Engineer – Reliability Statics, Hydroelectric Generations Services **1978 - 1979**

- In charge of analysing statistical data related to hydroelectric generating stations and producing periodic report on plants' performance.

ACADEMIC ACHIEVEMENTS

1977	Master of Business Administration, University of Toronto. Specialized in Management Science, Data Processing and Finance. Teaching Assistant in Statistics.
1975	Bachelor of Science in Industrial and Management Engineering, Technion, Israel Institute of Technology, Haifa, Israel.

SRRP R2Q24:

Reference: First Round Q119: Cost of Service Study

a) For the 2CP allocators provided in the response to Q119, are the peaks calculated based on a single 15 minute or hourly peak or on some other metric such as an average of the top 50 hours?

b) What year(s) of peak information is used to calculate the Winter and Summer Coincident Peaks?

c) Please provide a table with the dates, time period, and peak demand by customer class for each peak period used to calculate the Winter and Summer Coincident Peaks.

Response:

a) 2CP Peaks are calculated based on the average of SaskPower's top three winter and summer hourly peaks.

b) For this rate application, SaskPower utilized information from 2010-2014 to calculate the Winter and Summer Coincident Peaks.

c) Please see the table below that shows the dates, time period, and peak demand by customer class for each peak period used to calculate the Winter and Summer Coincident Peaks. Please note that the mass market classes' (Residential, Farm, Oilfield and Commercial) peaks are the results from SaskPower's EIS sample meter data only. The Tri-Average results are extrapolated to SaskPower's annual billing data by class to derive a coincident peak load factor that is then applied to the forecasted energy within cost of service. MV90 results are used to determine each individual customer's average coincident peak load factor over a five-year period and then directly applied to their forecasted energy. Since all of SaskPower's streetlights are unmetered, SaskPower relies on a streetlight load profile provided by ATCO electric to determine the class' coincident peak.

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				EIS (KW)								MV-90 (KW)				ATCO Profile (KW)	
		Date/Time		Residential		Commercial		Oilfield		Farm		Power Class		Resellers		Streetlights	
Year	CP	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer
2010	1 CP	12/12/10 18:00	7/30/10 17:00	509	398	2,516	3,510	3,783	3,212	896	391	915,970	859,942	191,312	170,283	14,027	-
	2 CP	12/8/10 18:00	7/29/10 14:00	441	339	3,207	3,732	3,569	3,170	843	412	963,692	793,749	198,493	211,696	13,774	-
	3CP	12/16/10 18:00	7/29/10 17:00	407	416	3,252	3,721	3,460	3,259	816	443	964,948	807,571	193,459	205,355	13,872	-
			Tri-Average	**452**	**384**	**2,992**	**3,654**	**3,604**	**3,213**	**852**	**415**	**948,203**	**820,421**	**194,421**	**195,778**	**13,891**	**-**
2011	1 CP	2/1/11 19:00	7/18/11 17:00	304	472	3,256	4,483	3,330	2,745	7,343	7,067	977,433	902,194	195,386	221,767	13,644	-
	2 CP	1/12/11 18:00	7/18/11 16:00	401	431	3,416	4,533	3,246	2,777	7,475	6,911	977,305	921,829	187,175	218,237	11,598	-
	3CP	1/20/11 19:00	7/18/11 18:00	391	498	3,233	3,624	3,145	2,774	7,187	6,824	938,622	857,148	189,767	239,322	13,644	-
			Tri-Average	**365**	**467**	**3,302**	**4,213**	**3,240**	**2,765**	**7,335**	**6,934**	**964,453**	**893,724**	**190,776**	**226,442**	**12,962**	**-**
2012	1 CP	12/10/12 18:00	9/8/12 19:00	409	236	3,489	2,236	5,453	4,615	7,066	5,807	1,007,179	857,388	196,370	145,160	13,023	-
	2 CP	1/18/12 19:00	7/30/12 18:00	438	493	3,532	3,678	5,631	4,299	7,133	6,649	952,132	904,222	196,580	221,725	13,262	-
	3CP	12/17/12 18:00	7/30/12 17:00	424	425	3,473	4,400	5,293	4,269	7,156	6,874	971,690	887,966	197,143	221,683	13,262	-
			Tri-Average	**424**	**385**	**3,498**	**3,438**	**5,459**	**4,394**	**7,118**	**6,443**	**977,000**	**883,192**	**196,698**	**196,189**	**13,182**	**-**
2013	1 CP	12/6/13 18:00	9/5/13 17:00	394	368	3,773	4,660	4,738	4,201	7,132	6,813	1,060,140	1,024,256	201,813	241,424	14,071	-
	2 CP	12/7/13 18:00	8/29/13 17:00	417	374	3,240	4,637	4,682	4,208	7,036	6,994	1,093,592	981,724	197,093	231,733	13,873	-
	3CP	12/9/13 18:00	7/2/13 18:00	415	434	3,976	4,416	4,736	3,754	7,282	6,599	1,052,372	958,941	206,092	233,390	14,085	-
			Tri-Average	**409**	**392**	**3,663**	**4,571**	**4,718**	**4,054**	**7,150**	**6,802**	**1,068,702**	**988,307**	**201,666**	**235,516**	**14,010**	**-**
2014	1 CP	11/30/14 18:00	8/14/14 18:00	362	295	6,622	9,479	5,173	4,232	6,769	5,968	1,101,014	928,017	189,781	227,996	13,958	-
	2 CP	12/29/14 18:00	8/14/14 17:00	347	296	7,270	10,143	4,748	4,200	6,997	6,191	1,080,556	901,494	192,272	234,073	13,490	-
	3CP	12/29/14 19:00	7/31/14 17:00	352	283	7,059	9,329	4,790	4,251	6,750	6,151	1,077,038	993,228	190,992	221,183	14,170	-
			Tri-Average	**354**	**291**	**6,984**	**9,650**	**4,904**	**4,228**	**6,839**	**6,103**	**1,086,203**	**940,913**	**191,015**	**227,751**	**13,873**	**-**
			Average	**401**	**384**	**4,088**	**5,105**	**4,385**	**3,731**	**5,859**	**5,340**	**1,008,912**	**905,311**	**194,915**	**216,335**	**13,584**	**-**

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Note:

While answering this interrogatory, SaskPower realized a reporting inaccuracy in its initial response to question “SRRP Q119” (round one) when it compiled the winter and summer coincident peak demands for its Power, Reseller and Large Oilfield customers. The corrected information is highlighted in the table below. The correction has no impact on this application, as the 2CP results used for allocation purposes in cost of service are the same in both tables. SaskPower apologizes for any inconvenience this may have caused.

		WINTER		SUMMER		2CP	
Class of Service	Sales Gwh	Demand KW	Load Factor %	Demand KW	Load Factor %	Demand KW	Load Factor %
Urban Residential	2,545	533,960	54.41%	511,450	56.80%	522,705	55.58%
Rural Residential	737	154,621	54.41%	148,102	56.80%	151,362	55.58%
Total Residential	**3,282**	**688,581**	**54.41%**	**659,552**	**56.80%**	**674,067**	**55.58%**
Farms	1,332	268,965	56.53%	173,333	87.72%	221,149	68.75%
Urban Commercial	2,763	380,379	82.93%	448,516	70.33%	414,447	76.11%
Rural Commercial	1,019	142,796	81.44%	167,673	69.35%	155,234	74.91%
Total Commercial	**3,782**	**523,175**	**82.52%**	**616,188**	**70.06%**	**569,681**	**75.78%**
Power - Published Rates	6,750	845,164	91.17%	786,594	97.96%	815,879	94.44%
Power - Contract Rates	2,441	320,764	86.86%	321,964	86.54%	321,364	86.70%
Total Power	**9,190**	**1,165,929**	**89.98%**	**1,108,558**	**94.64%**	**1,137,243**	**92.25%**
Oilfields	3,479	437,868	90.70%	372,084	106.73%	404,976	98.06%
Streetlights	63	14,950	48.02%	0	0.00%	7,475	96.04%
Resellers	1,291	200,939	73.34%	219,211	67.23%	210,075	70.15%
TOTAL SYSTEM	**22,419**	**3,300,405**	**77.54%**	**3,148,926**	**81.27%**	**3,224,666**	**79.36%**

Number of Hours/Year 8,760

SRRP R2Q25:

Reference: **First Round Q 120: Cost of Service Study**

Please confirm that there are no changes to the revenue from each rate class when comparing the 1CP and 2CP methods and that all revenue to revenue requirement ratio changes are a result of revenue requirement changes related to the CP method change.

Response:

SaskPower confirms that there are no changes to the revenue from each rate class when comparing the 1CP and 2CP methods and that all revenue to revenue requirement ratio changes are a result of revenue requirement changes related to the CP method change.

SRRP R2Q26:

Reference: **First Round Q 121: Cost of Service Study**

For the calculation of energy/demand classification using the Equivalent Peaker Method provided in Q121, are the data used to calculate the ratios based on embedded costs or estimated costs of new construction for each type of generation? Please discuss and provide examples of the calculations if feasible without disclosing any confidential information.

Response:

The data used to calculate the ratios is based on a mixture of embedded costs indexed to inflation, designated inputs directly from SaskPower's Supply Planning department, and estimated new costs of construction for each type of generation.

For example, it is no longer possible for SaskPower to obtain capital costs estimates for conventional coal plants. SaskPower mitigates this by indexing the last available costs to inflation (approximately 2% per year).

According to SaskPower's Supply Planning group, wind power provides approximately 20% capacity to the system and is therefore classified 80% to energy.

Diesel has an extremely high fuel cost and is therefore classified 100% to demand.

All other types of generation are classified based on the estimated costs of new construction to that of a simple cycle gas (peaking) plant. New costs are used so that any potential savings from efficiency gains, economies of scale, etc., for new construction will provide the maximum benefit to those customers affected by changes to the energy/demand ratio as a result of the new generation mix.

SaskPower's capital costs by generation type are considered confidential and cannot be released.

SRRP R2Q27:

Reference: **First Round Q130: Competitiveness**

Please confirm whether or not SaskPower is included in the calculation of the Thermal Utility Average and Canadian Utility Average calculations?

Response:

No, SaskPower is not included in the calculation of the thermal utility average value in the graph on page 16 of the rate application document. If SaskPower is included in the calculation of the thermal utility average, only the Residential average changes – from 14.1 cents per kWh to 14.2 cents per kWh. All other averages per kWh stay the same.

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SRRP R2Q28:

Reference: First Round Q132: Competitiveness

Please provide the data supporting the chart in tabular form for each year.

Response:

SaskPower's Historical Average System Rates

		Historical (cents/Kwh)			CPI		
Year		Average Rate (cents/kWh)	Year over Year (%)	Compounded (%)	Sask CPI	Year over Year (%)	Compounded (%)
1	1979	2.74			40.2		
2	1980	2.96	8.2%	8.2%	44.3	10.2%	10.2%
3	1981	3.32	12.1%	21.2%	49.5	11.7%	23.1%
4	1982	3.83	15.2%	39.7%	54.0	9.1%	34.3%
5	1983	4.01	4.8%	46.4%	57.4	6.3%	42.8%
6	1984	4.31	7.4%	57.3%	59.8	4.2%	48.8%
7	1985	4.63	7.4%	68.9%	62.0	3.7%	54.2%
8	1986	4.92	6.3%	79.5%	63.7	2.7%	58.5%
9	1987	5.23	6.2%	90.7%	66.8	4.9%	66.2%
10	1988	5.60	7.1%	104.2%	69.8	4.5%	73.6%
11	1989	5.81	3.8%	112.0%	72.9	4.4%	81.3%
12	1990	5.68	-2.2%	107.4%	76.0	4.3%	89.1%
13	1991	5.60	-1.4%	104.4%	80.0	5.3%	99.0%
14	1992	5.69	1.5%	107.6%	80.8	1.0%	101.0%
15	1993	5.75	1.0%	109.7%	83.3	3.1%	107.2%
16	1994	5.91	2.9%	115.7%	84.8	1.8%	110.9%
17	1995	5.82	-1.6%	112.3%	86.4	1.9%	114.9%
18	1996	5.82	0.0%	112.3%	88.1	2.0%	119.2%
19	1997	5.85	0.6%	113.6%	89.2	1.2%	121.9%
20	1998	5.90	0.8%	115.4%	90.4	1.3%	124.9%
21	1999	5.93	0.5%	116.4%	92.0	1.8%	128.9%
22	2000	5.97	0.7%	117.9%	94.4	2.6%	134.8%
23	2001	6.23	4.3%	127.3%	97.2	3.0%	141.8%
24	2002	6.61	6.1%	141.3%	100.0	2.9%	148.8%
25	2003	6.59	-0.3%	140.5%	102.3	2.3%	154.5%
26	2004	6.70	1.7%	144.5%	104.6	2.2%	160.2%
27	2005	6.89	2.9%	151.5%	106.9	2.2%	165.9%
28	2006	7.29	5.8%	166.1%	109.1	2.1%	171.4%
29	2007	7.57	3.7%	176.0%	112.2	2.8%	179.1%
30	2008	7.61	0.6%	177.8%	115.9	3.3%	188.3%
31	2009	8.15	7.0%	197.2%	117.1	1.0%	191.3%
32	2010	8.46	3.9%	208.7%	118.7	1.4%	195.3%
33	2011	8.67	2.5%	216.4%	122.0	2.8%	203.5%
34	2012	8.65	-0.2%	215.7%	123.9	1.6%	208.2%
35	2013	9.05	4.6%	230.2%	125.7	1.5%	212.7%
36	2014	9.55	5.6%	248.5%	128.7	2.4%	220.1%
37	2015	9.84	3.0%	259.0%	130.8	1.6%	225.4%
38	2016-17	10.85	10.3%	295.8%	133.4	2.0%	231.9%
39	2017-18	10.85	0.0%	295.8%	136.1	2.0%	238.5%

	SaskPower average rate (c/kWh)			Saskatchewan CPI		
	Compounded (%)		Avg Annual (%)	Compounded (%)		Avg Annual (%)
All	295.8%		3.6%	238.5%		3.2%

SRRP R2Q29:

Reference: First Round Q137: Reliability

a) Please expand the table provided in Q137 to show the duration of distribution outages by each of the reason codes.

b) Please provide a table similar to the table provided Q137 for transmission outages showing both the number of outages and the total duration of outages by reason code.

Response:

a)

Total distribution outages

	2013		2014		2015		3-yr totals	
	Outages	Duration*	Outages	Duration*	Outages	Duration*	Outages	Duration*
Planned	4,375	619,473	5,049	420,712	5,601	549,241	15,025	1,589,426
Lightning	3,534	460,259	4,522	418,223	4,631	463,793	12,687	1,342,276
Birds / Animals	3,825	255,287	4,233	415,049	3,857	273,848	11,915	944,184
Unknown	3,295	336,801	3,594	298,392	3,647	229,998	10,536	865,191
Faulty Equipment	2,614	372,553	3,345	183,411	3,031	223,221	8,990	779,185
Trees	1,593	267,289	1,931	178,639	1,983	175,488	5,507	621,417
Other Weather	1,020	148,308	1,572	244,439	1,380	166,797	3,972	559,543
Accidents / External	1,202	169,886	1,021	118,718	921	230,167	3,144	518,771
Icing	422	127,297	576	97,045	393	142,622	1,391	366,963
Overload	399	72,505	545	72,566	434	65,286	1,378	210,358
System Failure	306	35,429	373	29,936	394	63,020	1,073	128,386
Contamination	264	14,562	310	21,749	287	15,752	861	52,064
Other Vegetation	31	12,609	70	16,186	59	6,951	160	35,746
Vandalism	27	4,776	51	3,106	42	14,028	120	21,910
Accidents / Internal (SPC)	27	2,071	44	2,834	28	3,144	99	8,049
Total	22,934	2,899,105	27,236	2,521,006	26,688	2,623,357	76,858	8,043,468

* 'duration' equals customer hours (outage length X number of affected customers)

b)

Transmission outages over two hours

	2013		2014		2015		Total	
	Count	Duration	Count	Duration	Count	Duration	Count	Duration
Adverse weather	22	139:48	115	2469:30	49	296:08	186	2905:26
Adverse environment	3	8:51	4	98:10	3	384:33	10	491:34
Defective equipment	67	691:53	61	343:25	35	500:54	163	1536:12
Foreign interference	23	151:53	22	115:50	18	155:56	63	423:39
Human element	1	6:21	5	12:20	4	37:42	10	56:23
System condition	4	25:34	43	315:18	53	340:23	100	681:15
Other	36	306:42	8	45:34	5	12:50	49	365:06
Total	156	1331:02	258	3400:07	167	1728:26	581	6459:35

- 'duration' is in hours: mins

SRRP R2Q30:

Reference: **Reliability**

a) For what reasons does SaskPower plan distribution and transmission outages?
b) How does SaskPower notify affected customers of planned distribution and transmission outages?

Response:

a) SaskPower's Transmission and Distribution Services divisions will take planned outages on the system for a number of reasons. The most common include connecting new customers, performing system upgrades or repairing damage to facilities. Other situations include escorting over-dimension loads along roadways, completing oil sampling of oil-filled apparatus, trimming vegetation along right-of-ways, and other preventative maintenance activities. In all cases, service personnel will determine if work on the system can be performed in an energized state in a safe manner. If there are no safety concerns, work is performed in an energized state to reduce disruptions to customers. However, outages are often required to reduce risks associated with working on or near energized high voltage facilities as the safety of employees and the public is always SaskPower's first priority.

b) SaskPower uses a number of methods to contact customers that will be affected by a planned outage based on the duration of the outage, number of customers affected and demographics of these customers. Saskatchewan residents rely on different and multiple media for information and SaskPower is adapting accordingly. Research has demonstrated the need for a comprehensive media mix to notify residential customers about planned power outages.

i. **Radio**: There's growth in this market, with more use from 2013 to 2015. Radio has the advantage of well-targeted demographics, good listener loyalty, and immediacy. That said, listeners are sometimes not actively engaged.
ii. **Digital**: This includes display, online banners, mobile and social media. The rise of mobile technology means customers are looking for digital information. This is a budget-friendly tool that is flexible and has strong targeting capabilities. However, digital targeting can't zero in on a specific urban neighborhood. This media requires continual maintenance and monitoring since all conversations started (from an ad or otherwise) need to be captured and documented. (Even Facebook digital ads can be commented on and therefore need to be monitored, tracked and documented.) In the case of digital ads, if there is a re-scheduled outage there's no way to ensure people who saw the first ad will see the second (corrected) ad.

iii. **Newspaper**: This is a credible and familiar medium that is good at targeting the 50+ age markets. Circulation is declining in urban markets as readers move to online issues. Weekly newspapers reach specific small rural communities; however, your ad must stand out in all of the "clutter" and you must be willing to pay a high cost considering the short shelf life of each paper. Minimum notice to place ads in newspapers is quite long: 21 days for rural papers and the Monday the week before an outage for urban papers (to ensure the ad is placed on the highest readership days, Friday and/or Saturday). Newspaper is typically used in rural areas only so long as the timelines can be met and there's no chance of the work being rescheduled or cancelled as it is impossible to pull a newspaper ad after it is sent.

iv. **Out-of-Home**: Otherwise known as outdoor advertising, this medium is good for geo-targeting and directional advertising. Prime locations are expensive and in high demand, therefore more than five days are needed in lead time to secure spots. There is a short exposure time (6-8 seconds) by the audience so the message needs to be brief. There is broad reach and 24/7 exposure, but the audience is disengaged. Out-of-home is not recommended. However, consideration is being given to investing in company-owned mobile signs that can be used for larger projects in specific locations.

v. **Door Hangers**: Anecdotal experiences in Regina have validated that traditional communications activities such as face-to-face, CSR interactions and targeted print pieces like door hangers continue to form the foundation of how many audiences connect with SaskPower. From May until June of 2016, the transformer replacement and cable injection projects ensured a site crew member delivered a door hanger to all impacted houses. Regina and Saskatoon cable injection projects used this approach and have realized positive experiences for customers.

vi. **App**: SaskPower is actively pursuing a new application which will provide more detail information for customers related to planned outages affecting their area including an interactive mapping solution.

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2016 and 2017 RATE APPLICATION
SRRP ROUND TWO INTERROGATORIES

SRRP R2Q31:

Reference: Safety

Does SaskPower track year over year corporate performance on safety metrics such as lost time incidents and vehicle collisions? If so please provide a discussion of how SaskPower monitors its corporate safety performance or provide references to where such discussion may be found in the MFRs.

Response:

SaskPower tracks safety performance in a variety of areas and reports on a Safety Index within its Corporate Balanced Scorecard. A discussion on the SaskPower Corporate Balanced Scorecard can be found within the Performance Management Plan contained in the Minimum Filing Requirements.

SaskPower's Safety Index measures how well SaskPower achieves its safety targets. It uses both leading and lagging indicators to measure how well our company is promoting proactive safety behaviours.

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. The leading indicators include safety objectives, safety audits, work observations and health and safety training.

Lagging indicators record safety performance related to the occurrence of safety incidents, including lost-time injury frequency, lost-time injury severity, recordable injury frequency and recordable licensed fleet motor vehicle frequency.

The Safety Index is a weighted average of leading and lagging indicator results. The targets have been set by SaskPower's Health and Safety Department. Each indicator is calculated as a percentage, with 100% being the best possible result. The index is a weighted average of all the percentages.

Each of the components is outlined below.

LEADING INDICATORS:

Safety Objectives Completed (%)

Safety objectives are the organization's goals for safety and are managed in the Learning and Goals System (LMS). 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.

The measure reports the percentage of completed safety objectives as follows:

$$\text{Safety Objectives Completed (\%)} = \frac{\text{No. of Completed Objectives}}{\text{No. of Scheduled Objectives}} \times 100$$

Safety Audits Corrective/Preventive Actions Completed (%)
Safety audits are conducted to measure how well the Safety Management System (SMS) is being implemented and maintained and its effectiveness in meeting the organization's safety policy and objectives. Corrective and preventive actions are taken to eliminate the cause of a detected nonconformity or other undesirable situation found as a result of an audit. Corrective action is taken to prevent recurrence whereas preventive action is taken to prevent occurrence. The measure reports the percentage of completed versus corrective and preventive actions due.

$$\text{Safety Audit Corrective/Preventive Actions Completed (\%)} = \frac{\text{No. of Completed Corrective/Preventive Actions}}{\text{No. of Corrective/Preventive Actions Due}} \times 100$$

Scheduled 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. The measure reports the percentage of completed scheduled work observations versus scheduled.

$$\text{Scheduled Work Observations Completed(\%)} = \frac{\text{No. of Completed Scheduled Work Observations}}{\text{No. of Scheduled Work Observations}} \times 100$$

Safety Training Completed (%)
SaskPower training is managed in the Learning and Goals System (LMS) and courses are identified as Safety Related when they are created. The measure reports the percentage of assigned safety training due in the quarter (including overdue assigned courses) versus the number complete.

$$\text{Safety Training Completed(\%)} = \frac{\text{No. of Completed Safety Training}}{\text{No. Assigned and Due or Overdue Safety Training}} \times 100$$

LAGGING INDICATORS:

Lost-Time Injury Frequency Rate

The lost time injury frequency rate is a corporate-wide indicator. It calculates the number of lost-time injuries, normalized in relation to the total number of employee work hours. The normalization is done based on the formula designed by the Canadian Electricity Association as follows:

$$\text{Lost-Time Injury Frequency Rate} = \frac{\text{(Number of lost-time injuries) x 200,000 hours}}{\text{Exposure hours}}$$

Lost-Time Injury Severity Rate

The lost-time injury severity rate is a corporate wide indicator. It measures the number of calendar days lost due to lost time injuries, normalized according to the total number of employee work hours. The normalization is done based on a standard formula designed by the Canadian Electricity Association as follows:

$$\text{Lost-Time Injury Severity Rate} = \frac{\text{(Number of calendar days lost) x 200,000 hours}}{\text{Exposure hours}}$$

Recordable Injury Frequency Rate

The recordable injury frequency rate is a corporate-wide indicator. It calculates the number of recordable injuries, normalized in relation to the total number of employee work hours. A recordable injury is any occupational; injury/illness that results in an employee experiencing:

a) Fatality;
b) Lost-Time Injury;
c) Medical Treatment Injury; or
d) Other Injury/Illness (not captured above), which has:
    i. Restricted Work; or
    ii. Significant Occupational Injury/Illness; or
    iii. Loss of Consciousness.

The normalization is done based on the formula designed by the Canadian Electricity Association as follows:

$$\text{Recordable Injury Frequency Rate} = \frac{\text{(Number of recordable injuries) x 200,000 hours}}{\text{Exposure hours}}$$

Recordable Licensed Fleet Motor Vehicle Frequency Rate (LFMV)
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 Canadian Electricity Association as follows:

$$\text{LMFV Frequency Rate} = \frac{\text{(Number of recordable LFMV Incidents x 1,000,000 km)}}{\text{LFMV Kilometres Driven}}$$

SRRP R2Q32:

Reference: **First Round Q140: Resource Supply Plan**

Please discuss whether SaskPower has reviewed the integrated resource planning processes undertaken in other jurisdictions such as British Columbia. If so, please discuss whether in SaskPower's view there may be merit in undertaking a more public integrated resource planning process and what elements of the BC approach may be valuable in Saskatchewan.

Response:

There are many examples of well-developed integrated resource plans. SaskPower has reviewed, at a high level, the integrated resource planning processes and documents of BC Hydro in British Columbia as well as other power companies in Canada and the United States.

Common to most IRP processes is a broader approach to public engagement than is typically carried out in generation planning. SaskPower recognizes the need to help our customers and stakeholders understand the corporation's challenges and plans for the future of electricity in Saskatchewan as we face a changing operating environment that involves a need for significant investment and continued rate increases.

To address this need, a comprehensive stakeholder engagement strategy will be developed to accompany SaskPower's IRP. Both documents will be presented to the SaskPower Board of Directors for review and comment by year-end 2016.

SRRP R2Q33:

Reference: **First Round Q141: Resource Supply Plan**

Please discuss if SaskPower's resource planning is primarily driven by the need to meet a capacity planning criterion. In the response, please discuss if SaskPower plans its system to include a reserve margin over and above the forecast total system peak.

Response:

SaskPower's resource planning is primarily driven by the need to meet capacity planning criteria. SaskPower plans new generation capacity in years when the reserve margin falls below approximately 13%.

SRRP R2Q34:

Reference: First Round Q141: Resource Supply Plan

a) If possible, please provide a table showing the forecast peak that SaskPower is planning to be required to meet for each of the next 10 years that does not disclose any information SaskPower considers to be confidential.

b) If possible, without disclosing any information SaskPower considers to be confidential, please include in the table the gap between the forecast system peaks provided in part a) and SaskPower's existing generation resources.

Response:

Year	Forecast Peak - DSM and demand response reduced (MW)	Gap between peak and existing resources (MW)
2016	3,705	583
2017	3,796	491
2018	3,834	454
2019	3,926	710
2020	3,951	826
2021	3,980	758
2022	4,041	531
2023	4,091	426
2024	4,134	822
2025	4,200	658

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