SaskPower

2014 RATE APPLICATION
SIECA INTERROGATORIES ROUND ONE

Round1 – SIECA Q1:
In the course of the SaskPower 2008 Rate Application SIECA requested and received a 32 page document entitled "SaskPower 2008 Load Forecast". Given the criticality of load forecasting to a multi-year rate application, please provide a copy of the 2014 Load Forecast study used to support the current application.

Response:

SaskPower's 2014, 2015 and 2016 rate application is based on the 2013 Load Forecast. The 2013 Load Forecast book is included as part of the response to SIECA Q2.

SaskPower

2014 RATE APPLICATION
SIECA INTERROGATORIES ROUND ONE

Round1 – SIECA Q2:

In this multi-year rate application SaskPower is predicting that total 2014 electricity sales will be 21,111,400 GWh. In the 2008 Load Forecast SaskPower predicted that total electricity sales in 2014 would be 27,000,000 GWh. This disparity highlights why stakeholders must have access to SaskPower's annual load forecasts in order to perform due diligence on any rate application. Please provide a copy of the annual SaskPower Load Forecast for each year during the period 2009 through 2013.

Response:

In the 2008 Load Forecast SaskPower predicted that total energy sales would be 24,993 GWh (27, 055 GWh was the total energy requirements) vs. 21,111 GWh in the 2013 Load Forecast used for the current rate application. It is certainly true that SaskPower's load forecasts have changed since 2008. Saskatchewan fared much better than most jurisdictions, but was not immune to the 2009 recession and sluggish economic recovery. The load reduction is primarily in the Power (industrial) class. Many projects identified in 2008 were scaled back or deferred and in some cases cancelled altogether.

In addition to the impacts of the economy, SaskPower is now much more selective in how much Power class load is included in the load forecasts. Please refer to SIECA Q8 and SIECA Q9 for details on how SaskPower forecasts Power class load.

The 2009 through 2012 Load Forecasts by customer class are attached. The full reports cannot be released as there are references to individual customers. The full 2013 Q1 load forecast is attached as there are no individual customers referenced in this report.

SaskPower

2013 LOAD FORECAST

BOUNDARY DAM STATION

Load & Revenue Forecasting
Customer Services
July 2013 (Q1 Results)

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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 2013 Load Forecast was prepared for the years 2014 through 2023 using inputs from the 2013 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 is produced by Corporate Planning. The Economic Forecast 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.

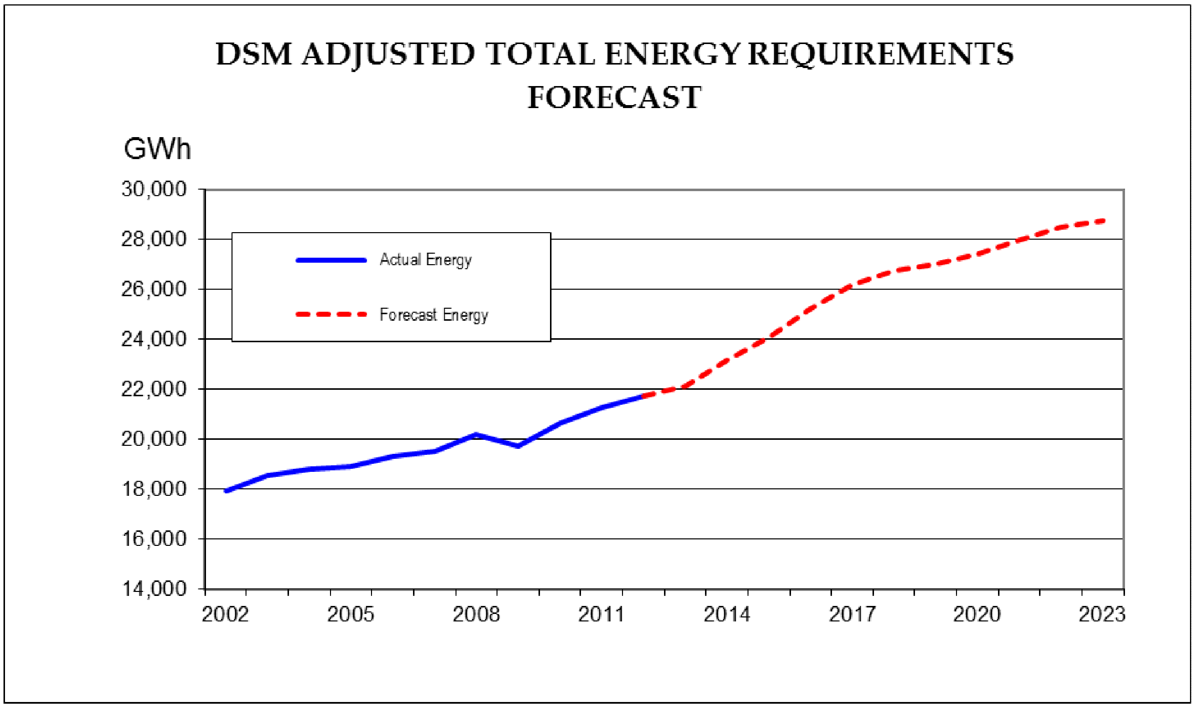
While there are many variables that can affect load forecasts, the most significant for SaskPower are the forecasts provided by large-scale industrial and commercial customers in the Power class. To ensure SaskPower is up-to-date on the load requirements for the province, SaskPower contacts these customers quarterly to obtain short and long term expansion plans. This report summarizes the results of the 2013 Q1 load forecast which is based on discussions with Power class customers in January and February, 2013. 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 2013 Base forecast is completed using the methodology outlined above, the energy and peak demand savings identified by the Customer Services Business Unit are removed. All tables in this report will reflect the DSM adjusted forecast. Table A4 at the end of this report provides a summary of the Base and DSM Adjusted Forecasts.

Introduction (cont.)

Total System Energy Requirements

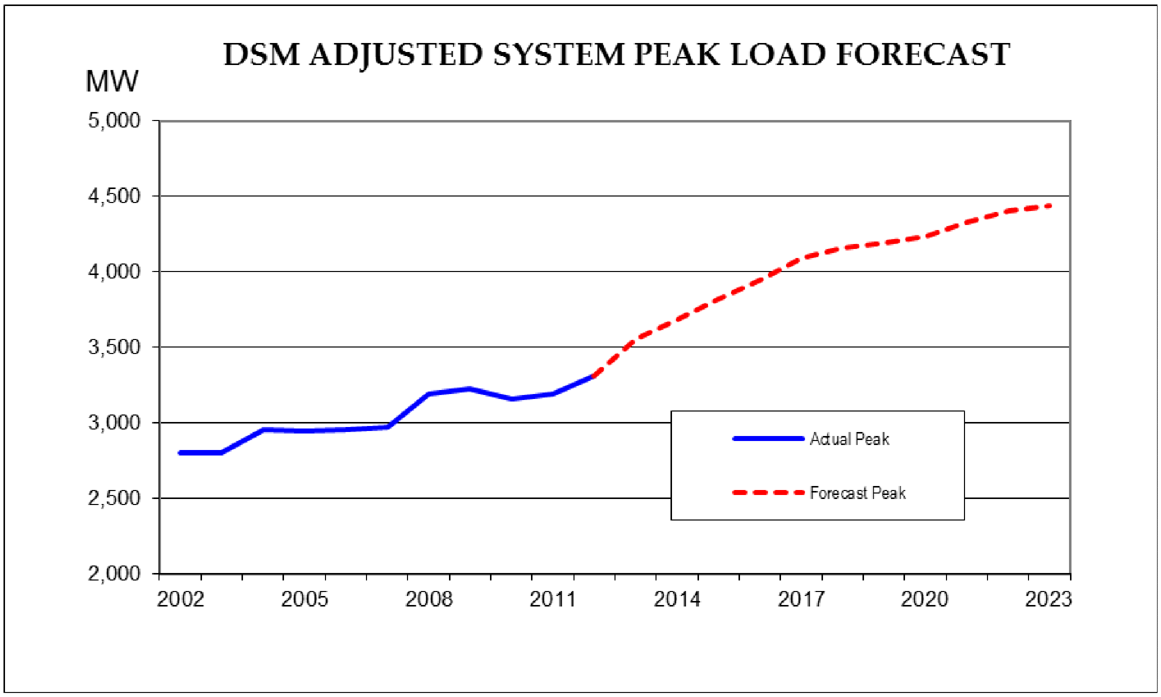
The 2013 DSM adjusted load forecast predicts an increase in the total system energy requirements of **6,605.7** GWh over the next 10 years. This increase from **22,153.8** GWh in 2013 to **28,759.5** GWh in 2023 translates into an average annual growth rate of **2.6%** (Refer to Table A1). The historical average annual growth rate was **2.0%** for the years 2002-2012. The increased growth rate in the 2013 load forecast is largely attributed to the expected growth in the Power class, combined with growth in the Oilfield, Commercial and Residential classes.



Introduction (cont.)

System Peak Load

The DSM adjusted calendar system peak load is expected to increase by **878** MW from **3,558** MW in 2013 to **4,436** MW in 2023. This equates to an average annual growth rate of **2.2%** (Refer to Table A1)**.** The system peak demand grew at an average annual rate of **1.7%** for the years 2002-2012.



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 2013-2023 timeframe.

POWER CLASS

Definition

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

The 2013 Power class 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 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 the Account Managers from Customer Development & Support, 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 Account Managers will 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. When possible, SaskPower will use electrical forecasts developed from the Ministry of the Economy's production forecasts as a check on customer forecasts.

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.

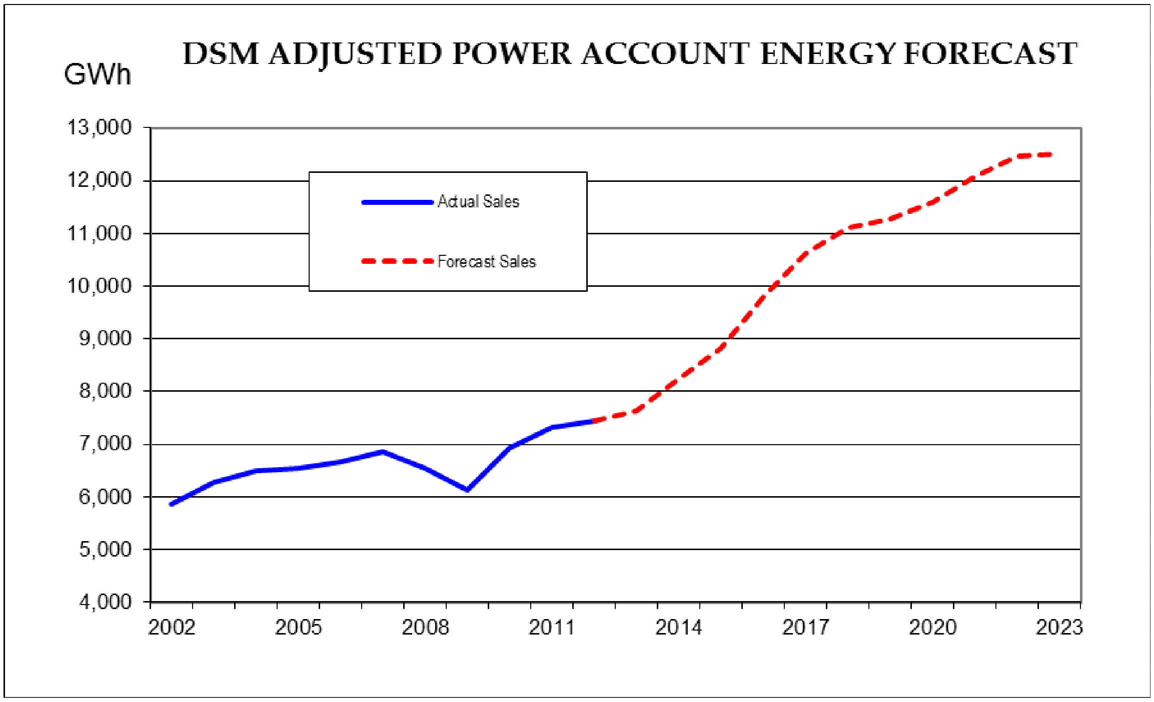
SaskPower will maintain its current customer base and market share.

Power Account Forecast Results

The total DSM adjusted Power class sales forecast (including probable load) is expected to grow from **7625.8** GWh in 2013 to **12,521.6** GWh in 2023. The total increase of **4,895.8** GWh, equates to an average annual growth rate of **5.1%** (Refer to Table A2).

Power Accounts (cont.)

Energy sales for the Power class have grown at an average rate of **2.4%** per year from 2002-2012. 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.



The major growth in the Power class is from the potash, pipeline pumping, chemical, 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 as well as two new mines. The sector load is increasing by 2,661 GWh by 2023.

Pipeline Pumping Sector

In the pipeline sector, loads are increasing as expanding Alberta oilsands production and conventional oil production in Alberta and Saskatchewan is shipped through Saskatchewan to markets in eastern Canada and the Unites States. The sector load is increasing by 1,191 GWh by 2023.

Power Accounts (cont.)

Chemical Sector
In the 2013 forecast the chemical sector is increasing by 213 GWh by 2023.

Northern Mining Sector
The northern mining sector consists of the gold and uranium mines supplied from the northern transmission system which originates at the Island Falls generating plant. In the 2013 forecast the northern mining sector has identified expansions at most sites due to market demands. The sector load is increasing by 404 GWh by 2023.

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. Currently, SaskPower has 23 Large Oilfield customers. 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

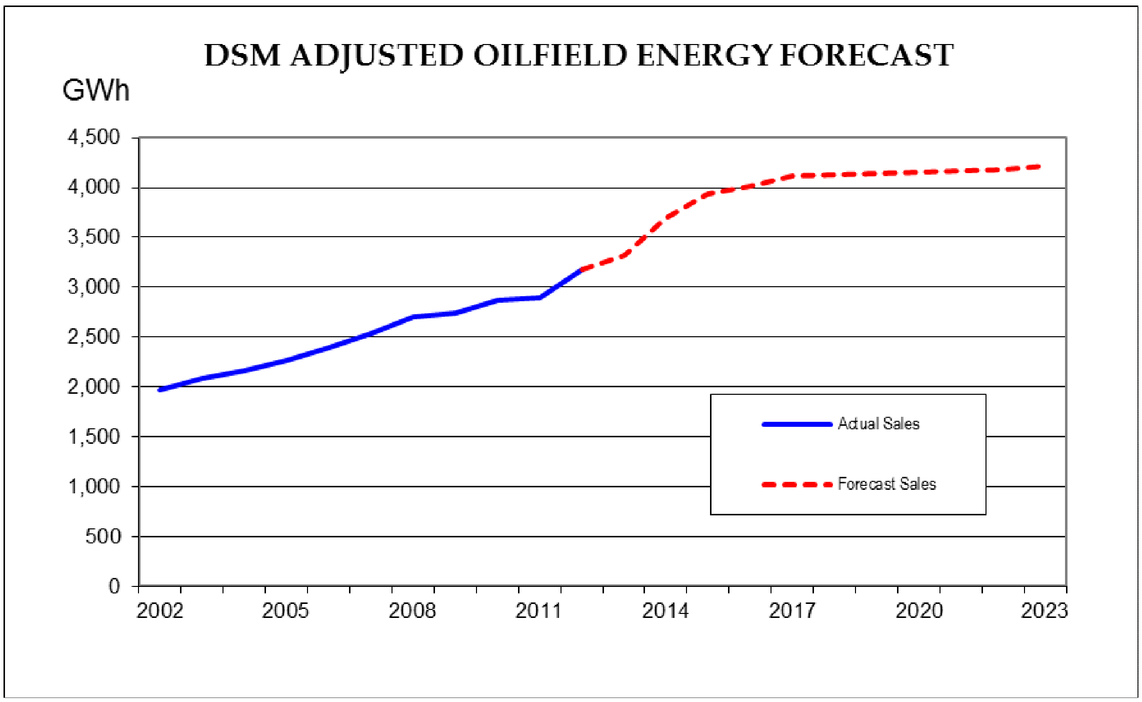
An oil production forecast for the years 2013-2023 was provided by the Ministry of Economy and by the Canadian Association of Petroleum Producers (CAPP).

Oilfield (cont.)

Oilfield Forecast Results

The DSM adjusted 2013 Oilfield forecast predicts energy sales to grow from **3,315.6** GWh in 2012 to **4,216.8** GWh in 2023. The increase of **901.2** GWh equates to an average annual growth rate of **2.4%** (Refer to Table A2). This is a result of a projected increase in oil production over the 10 year period, and an 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 2002-2012. The reduction in growth rate from historical levels is a result of lower oil production forecasts offset by higher water ratios and higher energy intensity levels.



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.

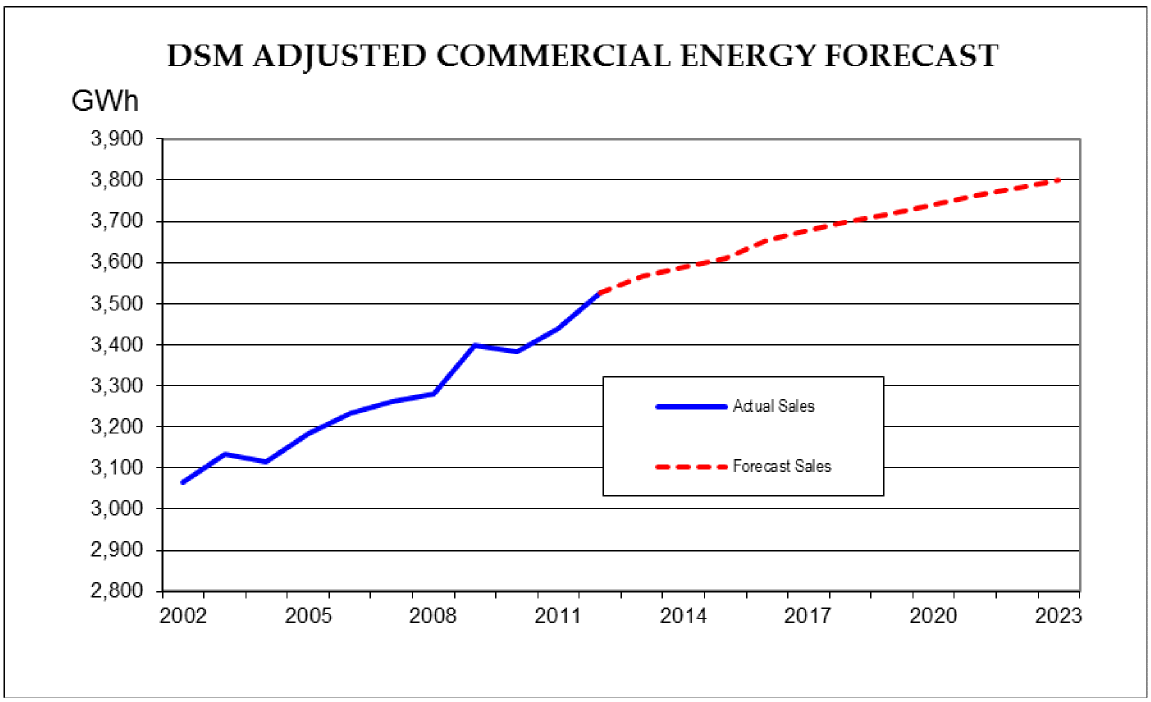
SaskPower will maintain its current customer base and market share.

Commercial (cont.)

Grid Commercial Forecast Results

The DSM adjusted Grid energy sales for the Commercial class is expected to grow from **3,580.1** GWh in 2013 to **3,814.5** GWh in 2023. This **234.4** 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 **1.4%** per year from 2002-2012. Approximately half of the reduction in growth from historic levels is due to DSM energy savings.



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.

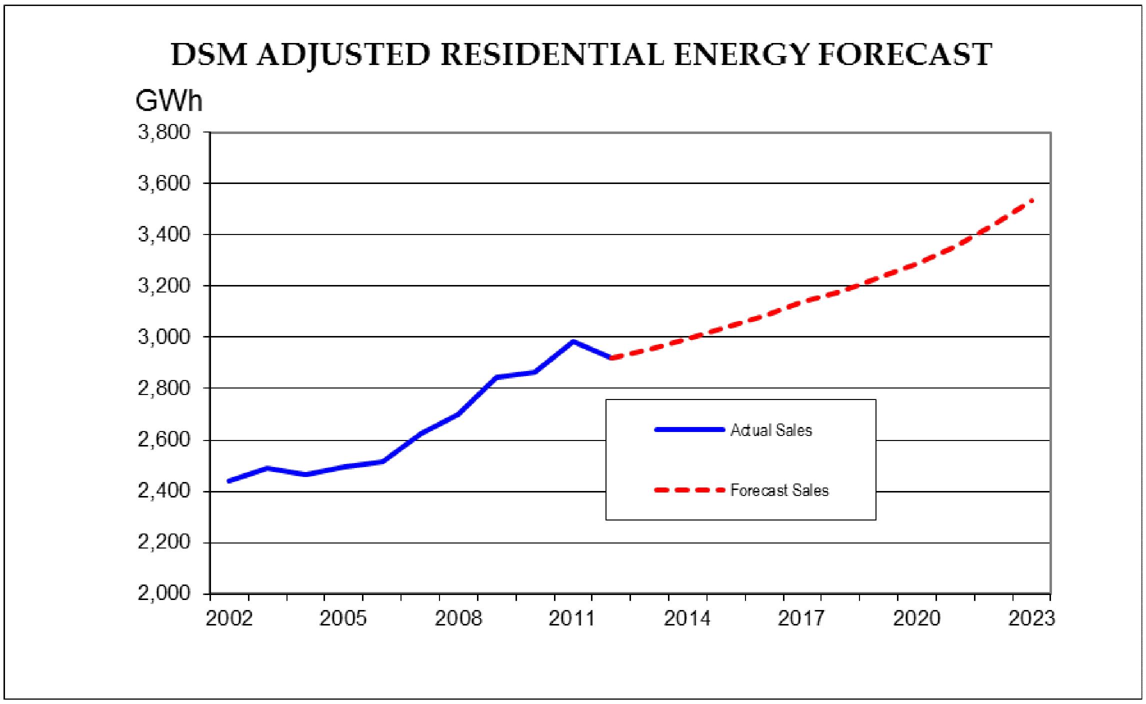
SaskPower will maintain its current customer base and market share.

Residential (cont.)

Grid Residential Forecast Results

The DSM adjusted Grid energy sales forecast for the Residential class is expected to grow from **2,952.4** GWh in 2013 to **3,535.8** GWh in 2023. This total growth of **583.4** 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 **479.3** GWh. This represents a **1.8%** average annual growth rate from 2002-2012.



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.

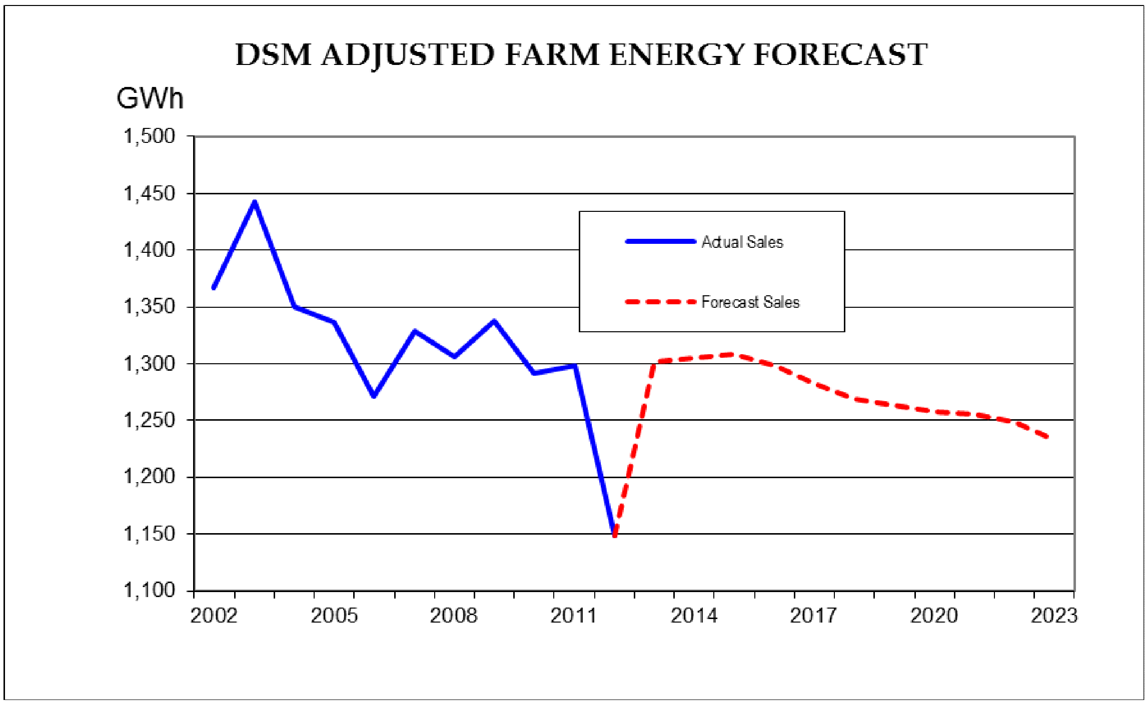
SaskPower will maintain its current customer base and market share.

Farm (cont.)

Farm Forecast Results

DSM adjusted energy sales for the Farm class are expected to decrease from **1,301.7** GWh in 2013 to **1,232.6** GWh in 2023 (Refer to Table A2). This pattern reflects the trend of fewer, more energy intensive farms.

Farm class energy sales have declined between 2002 and 2012, decreasing by 218.1 GWh over this time period.



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 Account Managers 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.

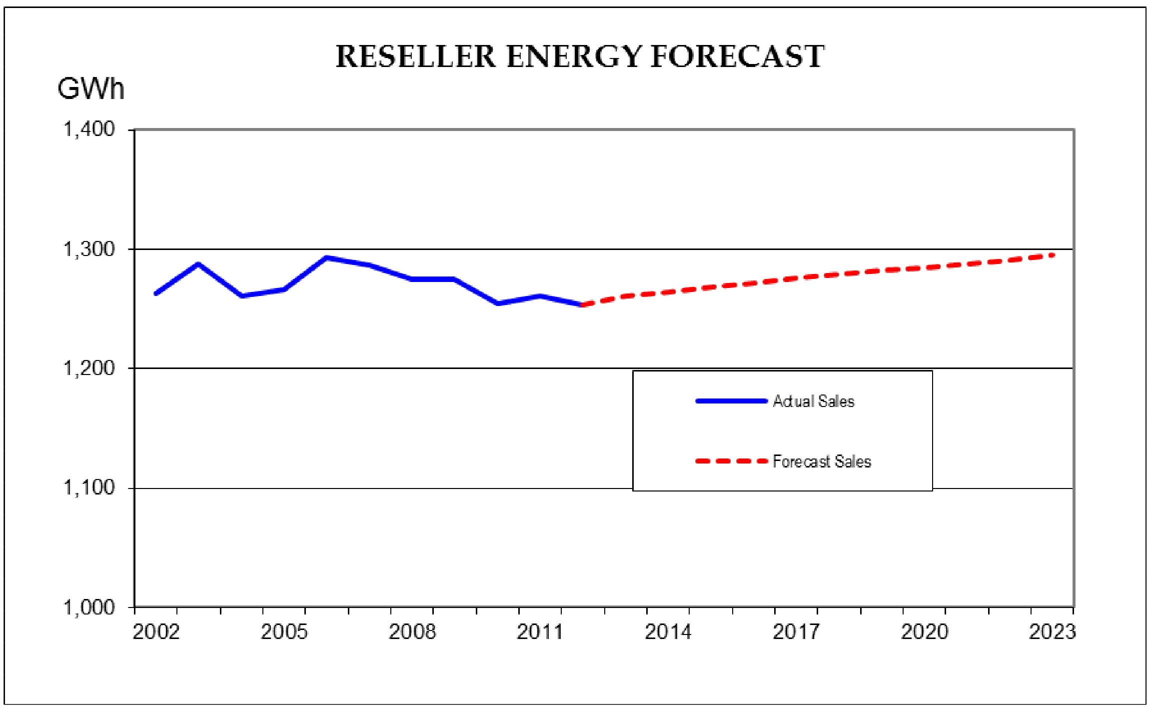
SaskPower will maintain its current customer base and market share.

Reseller (cont.)

Reseller Forecast Results

Reseller class energy sales are expected to grow from **1,260.4** GWh in 2013 to **1,294.6** GWh in 2023 (Refer to Table A2). This increase of **34.2** GWh over 10 years translates into a **0.3%** average annual growth rate.

A **9.0** GWh or **0.1%** annual decrease in Reseller class energy sales was experienced from 2002-2012.



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

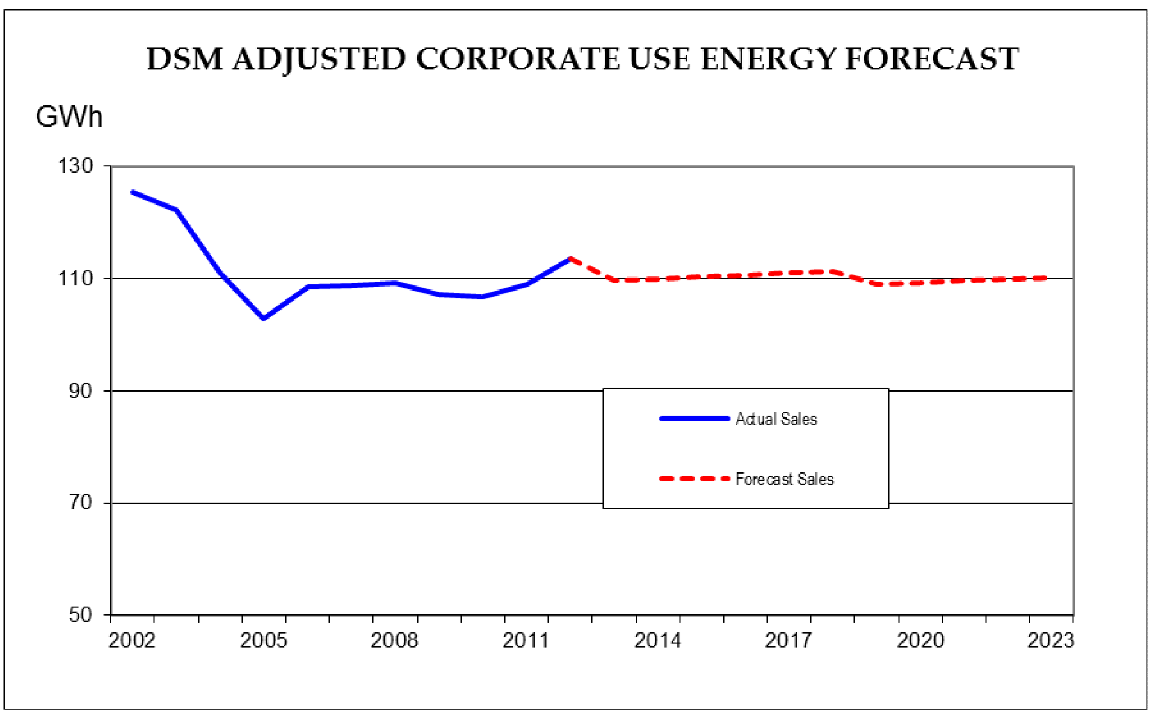
Extrapolation is used to estimate the future corporate internal energy use. The coal mine consumption is calculated from production estimates projected by Fuel Supply.

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

DSM adjusted Corporate use energy is expected to increase from **109.7** GWh in 2013 to **110.2** GWh in 2023 (Refer to Table A2).

Corporate Use had negative growth of **11.8** GWh or **1.0%** on an annual basis over the 2002-2012 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.

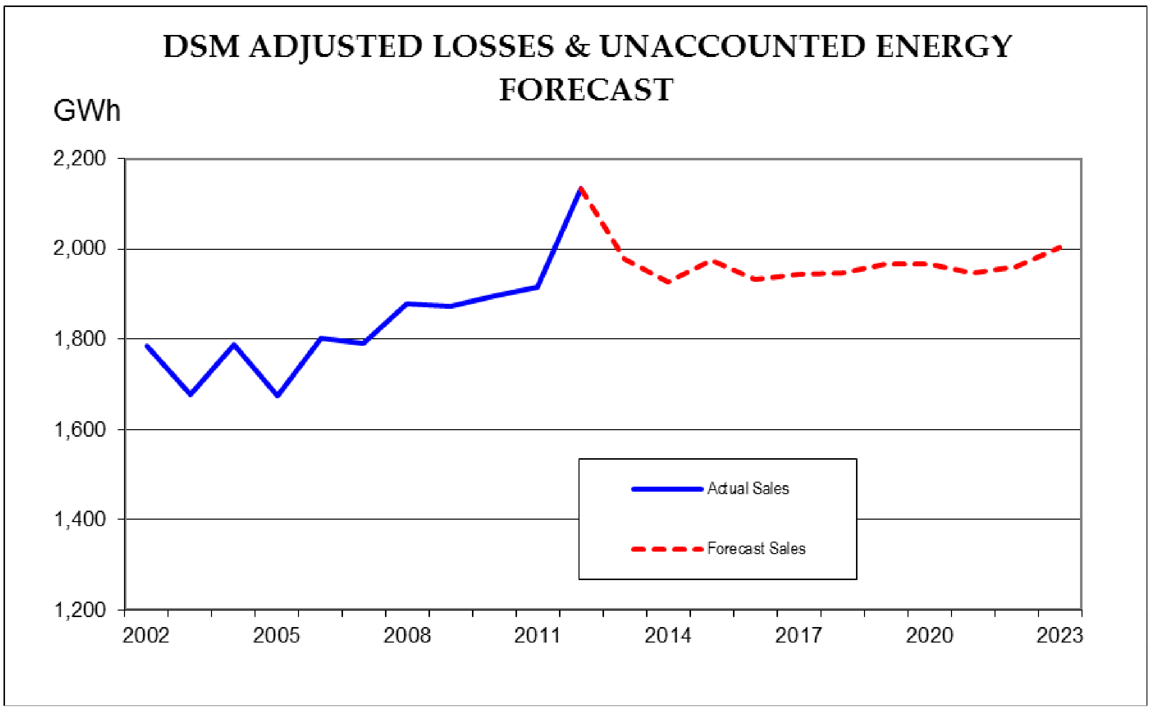
A comparison of historical actual to forecast energy consumption is used to validate the Losses and Unaccounted forecast.

Losses and Unaccounted (cont.)

Losses and Unaccounted Forecast Results

DSM adjusted losses and unaccounted are expected to increase slightly from **1,979.3** GWh in 2013 to **2,004.6** GWh in 2023 (Refer to Table A2). This **25.3** GWh increase translates into an average annual rate of **0.1%**.

Losses and unaccounted energy have increased at an average annual rate of **1.8%** in the past 10 years. The **349.2** GWh increase from 2002-2012 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.

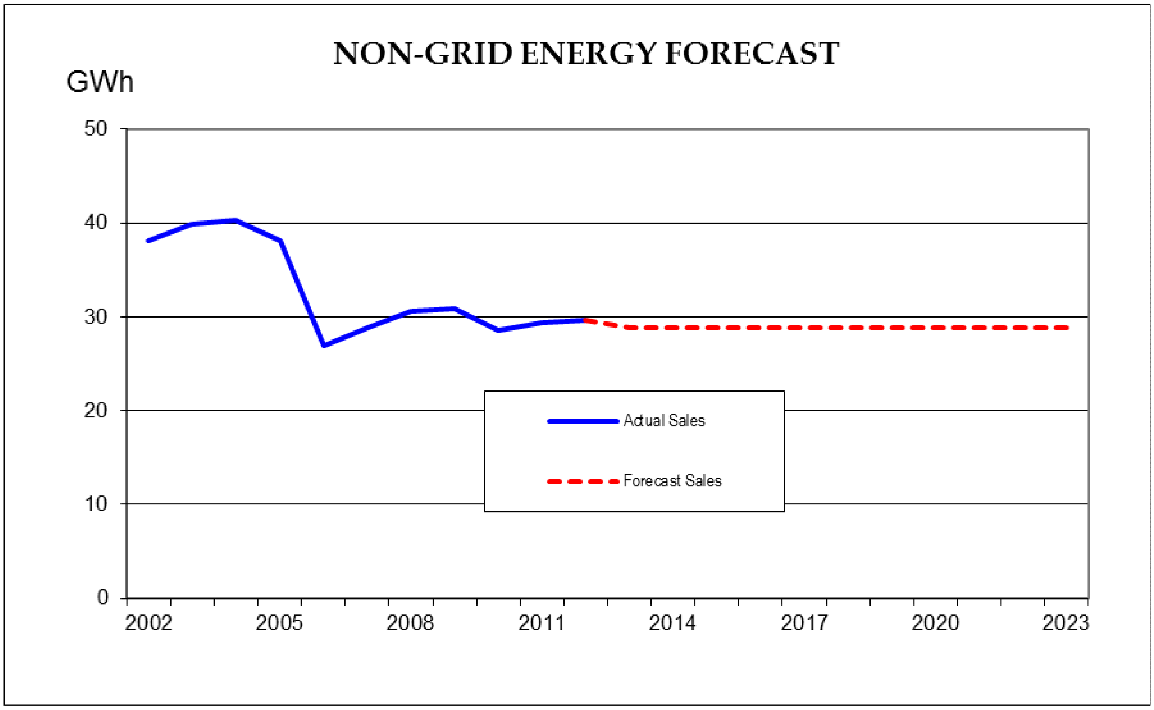
Assumption

SaskPower will maintain its current customer base and market share.

Non - Grid Forecast Results

The energy requirements for Non-Grid customers are expected to remain at **28.8** GW·h from 2013 into the future. (Refer to Table A3). The number of customers and energy requirements are forecast to remain stable in both the residential and commercial sectors.

Non-Grid (cont.)



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 Peak (cont.)

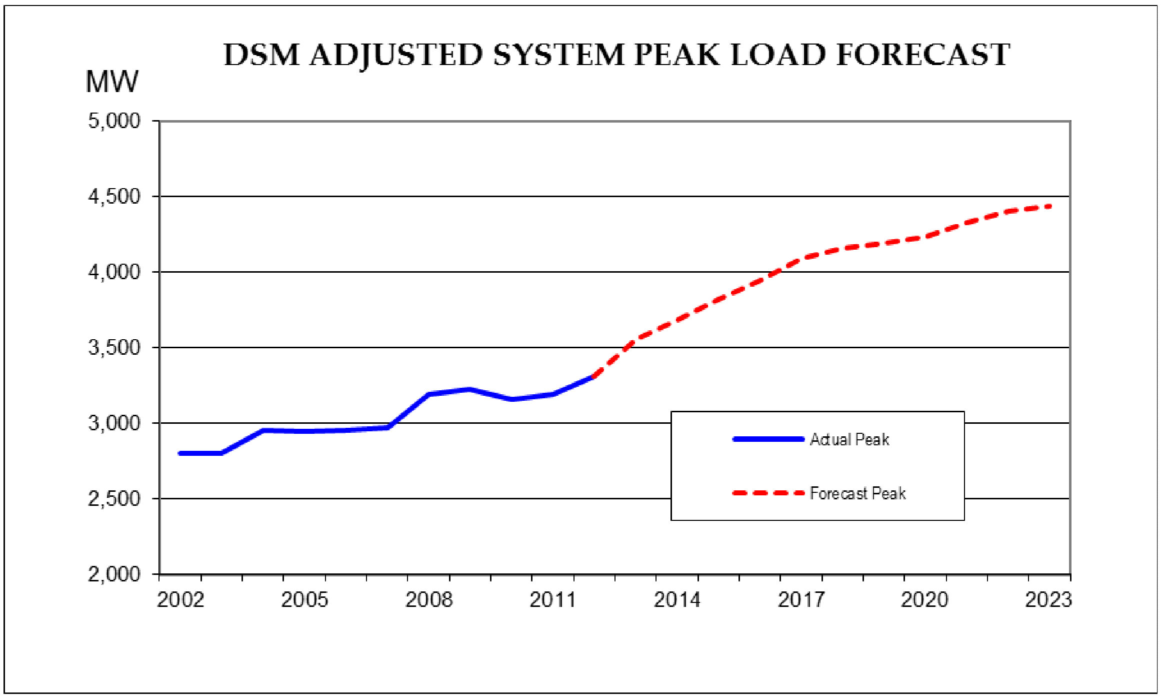
Assumptions

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 2013 DSM adjusted instantaneous system peak load is expected to reach **3,558**MW. By the 2023 a system peak load of **4,436** MW is expected (Refer to Table A1). This increase of **878** MW, or an average annual growth rate of **2.2%**, is largely attributed to the expected growth in the Power class, combined with growth in the Oilfield, Commercial and Residential classes.

The system peak load has increased at an annual rate of **1.7%** over the last 10 years.



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 2013 Economic Forecast was a major driver in the development of the 2013 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 2013 Load Forecast was also based on a thirty-year average weather pattern. Deviation from this weather pattern will also impact on energy consumption.

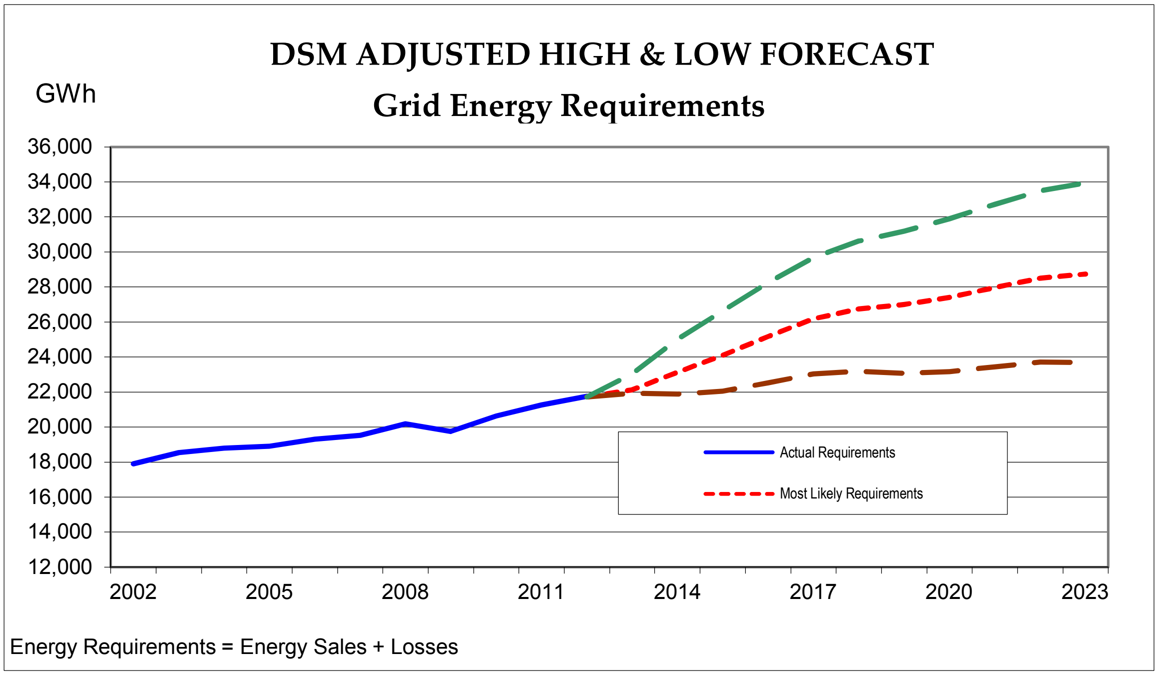
To reflect the economic and weather uncertainties, DSM adjusted grid high and low energy consumption and system peak demand forecasts are developed using a Monte Carlo simulation model. This model uses the percentage error by customer class in year 1, year 2, year 3 etc. of previous forecasts. The forecast 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 2013 most likely forecast, the DSM adjusted high forecast scenario total energy requirements and potential peak are **211 GWh** and **34 MW** higher, respectively. In 2023, the high scenario forecasts the energy to be **4,990 GWh** higher and the demand to be **770 MW** higher than the most likely forecast. (Refer to Table B).

Relative to the most likely case, the DSM adjusted low forecast scenario for 2013 total energy requirements and potential peak are **212 GWh** and **34 MW** lower, respectively. In 2023, the low scenario forecasts the energy to be 5**,032 GWh** lower and the demand to be **777 MW** lower than the most likely forecast.

Load Forecast Uncertainty (cont.)



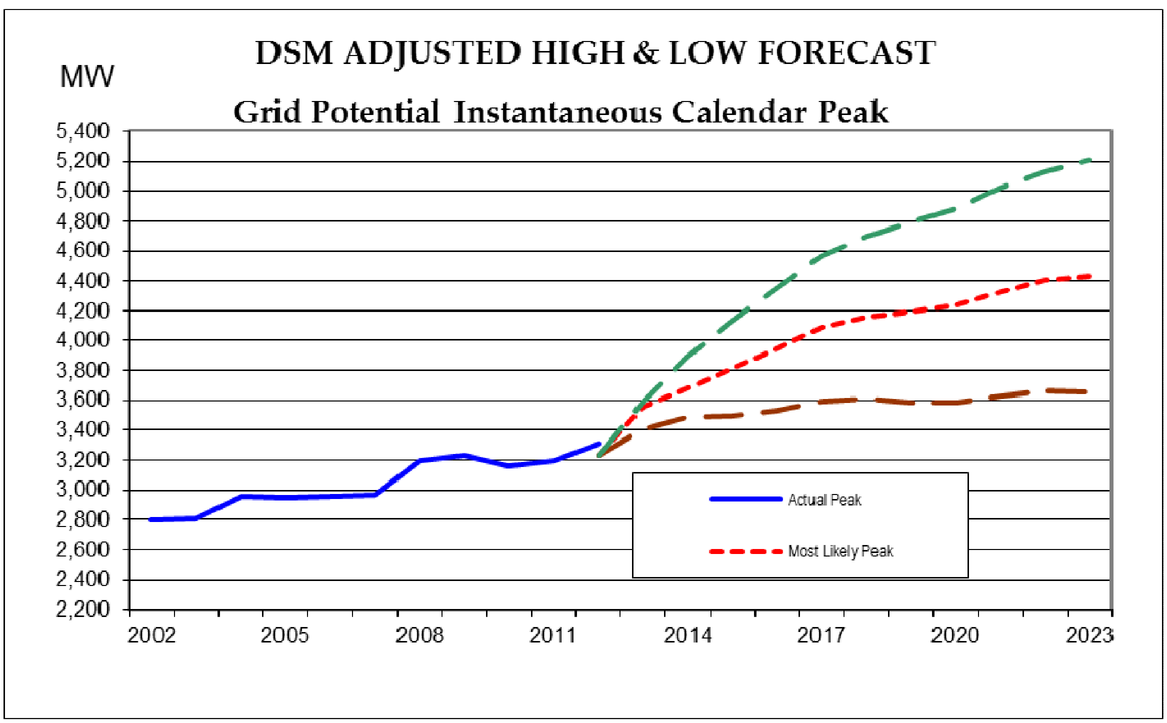


TABLE A1

2013 DSM ADJUSTED TOTAL SYSTEM LOAD FORECAST

FIRST QUARTER

ENERGY SALES, NUMBER OF CUSTOMERS AND PEAK DEMAND

	POWER		OILFIELDS		COMMERCIAL		RESIDENTIAL		FARM		RESELLER		CORPORATE USE		TOTAL SALES		LOSSES	TOTAL ENERGY REQUIREMENTS	CALENDAR PEAK DEMAND
Year	GW.h	# of Customers	GW.h	# of Customers	GW.h	# of Customers	GW.h	# of Customers	GW.h	# of Customers	GW.h	# of Customers	GW.h	# of Customers	GW.h	# of Customers	GW.h	GW.h	MW
2002	5,852.7	81	1,970.2	10,951	3,080.9	51,963	2,456.9	300,763	1,366.9	67,355	1,262.8	2	125.6	209	16,116.0	431,324	1,789.3	17,905.4	2,800
2003	6,273.9	85	2,081.8	11,058	3,150.5	52,175	2,508.9	302,897	1,441.9	67,025	1,287.3	2	122.3	209	16,866.8	433,451	1,681.8	18,548.6	2,805
2004	6,504.3	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	17,007.0	435,961	1,790.7	18,797.7	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	6,662.4	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	17,505.0	439,358	1,803.5	19,308.5	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	6,552.0	78	2,705.0	13,453	3,287.0	53,911	2,721.2	322,408	1,305.8	62,553	1,274.2	2	109.4	212	17,954.7	452,617	1,882.7	19,837.3	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	6,926.7	91	2,871.3	14,756	3,390.9	54,945	2,882.4	334,780	1,291.6	61,404	1,254.3	2	107.2	212	18,724.3	466,190	1,899.1	20,623.4	3,162
2011	7,318.7	97	2,900.8	15,015	3,447.5	55,501	3,006.0	346,312	1,298.3	60,871	1,260.6	2	109.3	212	19,341.1	478,010	1,916.2	21,257.3	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	2,137.3	21,748.4	3,314
2013	7,625.8	101	3,315.6	17,152	3,587.5	56,929	2,971.6	356,289	1,301.7	60,769	1,260.4	2	110.3	212	20,172.9	491,454	1,981.0	22,153.8	3,558
2014	8,233.6	100	3,685.7	17,992	3,609.2	57,534	3,013.5	362,882	1,305.3	60,630	1,264.1	2	110.5	212	21,221.9	499,352	1,931.3	23,153.2	3,686
2015	8,829.7	105	3,939.6	19,034	3,630.6	58,152	3,056.5	369,620	1,308.5	60,481	1,267.9	2	110.8	212	22,143.6	507,607	1,977.1	24,120.7	3,818
2016	9,796.2	107	4,016.9	19,608	3,673.7	58,779	3,102.1	376,449	1,298.3	60,341	1,271.6	2	111.2	212	23,270.0	515,499	1,934.9	25,204.8	3,945
2017	10,622.0	107	4,110.7	20,427	3,698.9	59,421	3,158.3	383,441	1,282.6	60,181	1,275.3	2	111.5	212	24,259.4	523,791	1,948.0	26,207.3	4,089
2018	11,115.3	109	4,132.3	20,752	3,721.2	60,078	3,200.6	390,594	1,269.4	60,005	1,278.5	2	111.8	212	24,829.2	531,752	1,950.0	26,779.3	4,162
2019	11,269.8	110	4,143.7	21,355	3,742.8	60,736	3,251.7	397,760	1,263.2	59,873	1,281.7	2	109.5	212	25,062.4	540,047	1,970.4	27,032.8	4,198
2020	11,600.1	110	4,149.7	21,543	3,763.8	61,402	3,307.2	405,019	1,257.5	59,752	1,284.9	2	109.9	212	25,473.2	548,040	1,968.2	27,441.4	4,241
2021	12,078.5	110	4,161.3	22,134	3,784.1	62,078	3,373.7	412,378	1,255.1	59,637	1,288.1	2	110.2	212	26,051.0	556,550	1,950.2	28,001.2	4,330
2022	12,469.0	110	4,181.1	22,725	3,803.5	62,771	3,459.0	419,927	1,249.1	59,460	1,291.4	2	110.5	212	26,563.5	565,206	1,963.0	28,526.5	4,402
2023	12,521.6	110	4,216.8	23,316	3,821.9	63,401	3,555.0	426,790	1,232.6	59,263	1,294.6	2	110.8	212	26,753.2	573,094	2,006.3	28,759.5	4,436

Growth Rates (%)

2007 - 2012	1.7%	5.1%	4.6%	5.1%	1.6%	1.2%	2.1%	2.1%	-2.9%	-0.5%	-0.5%	0.0%	0.9%	0.0%	1.7%	1.7%	3.6%	1.9%	2.2%
2002 - 2012	2.4%	2.1%	4.9%	4.2%	1.4%	0.9%	1.8%	1.5%	-1.7%	-0.8%	-0.1%	0.0%	-0.9%	0.1%	2.0%	1.2%	1.8%	2.0%	1.7%
2013 -2018	7.8%	1.5%	4.5%	3.9%	0.7%	1.1%	1.5%	1.9%	-0.5%	-0.3%	0.3%	0.0%	0.3%	0.0%	4.2%	1.6%	-0.3%	3.9%	3.2%
2013 - 2023	5.1%	0.9%	2.4%	3.1%	0.6%	1.1%	1.8%	1.8%	-0.5%	-0.3%	0.3%	0.0%	0.0%	0.0%	2.9%	1.5%	0.1%	2.6%	2.2%

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

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TABLE A2

2013 DSM ADJUSTED GRID ONLY LOAD FORECAST

FIRST QUARTER

ENERGY SALES AND NUMBER OF CUSTOMERS

Year	POWER GW.h	POWER # of Customers	OILFIELDS GW.h	OILFIELDS # of Customers	COMMERCIAL GW.h	COMMERCIAL # of Customers	RESIDENTIAL GW.h	RESIDENTIAL # of Customers	FARM GW.h	FARM # of Customers	RESELLER GW.h	RESELLER # of Customers	CORPORATE USE GW.h	CORPORATE USE # of Customers	TOTAL SALES GW.h	TOTAL SALES # of Customers	LOSSES GW.h	TOTAL ENERGY REQUIREMENTS GW.h
2002	5,852.7	81	1,970.2	10,951	3,064.6	51,768	2,439.1	299,774	1,366.9	67,355	1,262.8	2	125.4	207	16,081.7	430,138	1,785.6	17,867.3
2003	6,273.9	85	2,081.8	11,058	3,132.8	51,977	2,491.4	301,905	1,441.9	67,025	1,287.3	2	122.1	207	16,831.2	432,259	1,677.4	18,508.6
2004	6,504.3	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	16,970.9	434,769	1,786.6	18,757.4
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	6,662.4	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	17,480.5	438,123	1,801.1	19,281.6
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	6,895.0	78	2,705.0	13,453	3,280.0	53,723	2,701.5	321,367	1,305.8	62,553	1,274.2	2	109.1	210	18,270.7	451,386	1,879.0	20,149.7
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	6,926.7	91	2,871.3	14,756	3,383.7	54,745	2,863.8	333,727	1,291.6	61,404	1,254.3	2	106.8	210	18,698.1	464,935	1,896.7	20,594.8
2011	7,318.7	97	2,900.8	15,015	3,440.0	55,295	2,986.4	345,207	1,298.3	60,871	1,260.6	2	108.9	210	19,313.7	476,697	1,914.2	21,227.9
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	2,134.8	21,718.7
2013	7,625.8	101	3,315.6	17,152	3,580.1	56,716	2,952.4	355,126	1,301.7	60,769	1,260.4	2	109.7	210	20,145.7	490,076	1,979.3	22,125.0
2014	8,233.6	100	3,685.7	17,992	3,601.8	57,321	2,994.3	361,719	1,305.3	60,630	1,264.1	2	110.0	210	21,194.7	497,974	1,929.7	23,124.4
2015	8,829.7	105	3,939.6	19,034	3,623.2	57,939	3,037.3	368,457	1,308.5	60,481	1,267.9	2	110.3	210	22,116.4	506,229	1,975.4	24,091.8
2016	9,796.2	107	4,016.9	19,608	3,666.3	58,566	3,082.9	375,286	1,298.3	60,341	1,271.6	2	110.6	210	23,242.8	514,121	1,933.2	25,176.0
2017	10,622.0	107	4,110.7	20,427	3,691.5	59,208	3,139.1	382,278	1,282.6	60,181	1,275.3	2	110.9	210	24,232.2	522,413	1,946.3	26,178.5
2018	11,115.3	109	4,132.3	20,752	3,713.8	59,865	3,181.4	389,431	1,269.4	60,005	1,278.5	2	111.2	210	24,802.1	530,374	1,948.4	26,750.4
2019	11,269.8	110	4,143.7	21,355	3,735.4	60,523	3,232.5	396,597	1,263.2	59,873	1,281.7	2	108.9	210	25,035.2	538,669	1,968.8	27,004.0
2020	11,600.1	110	4,149.7	21,543	3,756.4	61,189	3,288.0	403,856	1,257.5	59,752	1,284.9	2	109.3	210	25,446.0	546,662	1,966.6	27,412.6
2021	12,078.5	110	4,161.3	22,134	3,776.7	61,865	3,354.5	411,215	1,255.1	59,637	1,288.1	2	109.6	210	26,023.8	555,172	1,948.5	27,972.4
2022	12,469.0	110	4,181.1	22,725	3,796.0	62,558	3,439.9	418,764	1,249.1	59,460	1,291.4	2	109.9	210	26,536.4	563,828	1,961.3	28,497.7
2023	12,521.6	110	4,216.8	23,316	3,814.5	63,188	3,535.8	425,627	1,232.6	59,263	1,294.6	2	110.2	210	26,726.1	571,716	2,004.6	28,730.7

Growth Rates (%)

2007 - 2012	1.7%	5.1%	4.6%	5.1%	1.6%	1.2%	2.1%	2.1%	-2.9%	-0.5%	-0.5%	0.0%	0.9%	0.0%	1.7%	1.7%	3.6%	1.9%
2002 - 2012	2.4%	2.1%	4.9%	4.2%	1.4%	0.9%	1.8%	1.5%	-1.7%	-0.8%	-0.1%	0.0%	-1.0%	0.1%	2.0%	1.2%	1.8%	2.0%
2013 -2018	7.8%	1.5%	4.5%	3.9%	0.7%	1.1%	1.5%	1.9%	-0.5%	-0.3%	0.3%	0.0%	0.3%	0.0%	4.2%	1.6%	-0.3%	3.9%
2013 - 2023	5.1%	0.9%	2.4%	3.1%	0.6%	1.1%	1.8%	1.8%	-0.5%	-0.3%	0.3%	0.0%	0.0%	0.0%	2.9%	1.6%	0.1%	2.6%

1.) All forecasted energy values are normalized to reflect 30-year average weather patterns.
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

2013 NON - GRID LOAD FORECAST

FIRST QUARTER

ENERGY SALES AND NUMBER OF CUSTOMERS

Year	COMMERCIAL GW.h	COMMERCIAL # of Customers	RESIDENTIAL GW.h	RESIDENTIAL # of Customers	CORPORATE USE GW.h	CORPORATE USE # of Customers	TOTAL SALES GW.h	TOTAL SALES # of Customers	LOSSES [1] GW.h	TOTAL ENERGY REQUIREMENTS GW.h
2002	16.3	195	17.8	989	0.2	2	34.3	1,186	3.8	38.1
2003	17.7	198	17.5	992	0.2	2	35.5	1,192	4.4	39.9
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	1027	0.4	2	25.9	1,215	3.0	28.9
2008	7.0	188	19.6	1041	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	7.4	213	19.2	1,163	0.6	2	27.2	1,378	1.6	28.8
2014	7.4	213	19.2	1,163	0.6	2	27.2	1,378	1.6	28.8
2015	7.4	213	19.2	1,163	0.6	2	27.2	1,378	1.6	28.8
2016	7.4	213	19.2	1,163	0.6	2	27.2	1,378	1.6	28.8
2017	7.4	213	19.2	1,163	0.6	2	27.2	1,378	1.6	28.8
2018	7.4	213	19.2	1,163	0.6	2	27.2	1,378	1.6	28.8
2019	7.4	213	19.2	1,163	0.6	2	27.2	1,378	1.6	28.8
2020	7.4	213	19.2	1,163	0.6	2	27.2	1,378	1.6	28.8
2021	7.4	213	19.2	1,163	0.6	2	27.2	1,378	1.6	28.8
2022	7.4	213	19.2	1,163	0.6	2	27.2	1,378	1.6	28.8
2023	7.4	213	19.2	1,163	0.6	2	27.2	1,378	1.6	28.8

Growth Rates (%)

2007 - 2012	1.1%	2.7%	0.7%	2.5%	9.9%	0.0%	1.0%	2.5%	-3.7%	0.5%
2002 - 2012	-7.6%	0.9%	0.8%	1.6%	9.4%	0.0%	-2.3%	1.5%	-4.1%	-2.5%
2013 -2018	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2013 - 2023	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

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

2013 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)
	Base Forecast	Add To-date DSM Savings	Base Forecast Plus To-date	DSM Savings	DSM Adjusted	Base Forecast	Add To-date DSM Savings	Base Forecast Plus To-date	DSM Savings	DSM Adjusted		
2013	22,154.0	111.5	22,265.5	140.5	22,125.0	3,486.6	50.0	3,536.6	58.8	3,477.9	3,558.3	85.0
2014	23,182.3	111.5	23,293.9	169.5	23,124.4	3,619.8	50.0	3,669.8	67.5	3,602.3	3,685.6	85.0
2015	24,178.8	111.5	24,290.3	198.4	24,091.8	3,757.8	50.0	3,807.8	76.2	3,731.6	3,817.9	85.0
2016	25,292.9	111.5	25,404.4	228.4	25,176.0	3,891.6	50.0	3,941.6	85.4	3,856.2	3,945.4	85.0
2017	26,324.4	111.5	26,435.9	257.4	26,178.5	4,040.4	50.0	4,090.4	93.9	3,996.5	4,088.9	85.0
2018	26,929.8	111.5	27,041.3	290.9	26,750.4	4,121.5	50.0	4,171.5	103.3	4,068.1	4,162.2	85.0
2019	27,215.3	111.5	27,326.8	322.8	27,004.0	4,165.5	50.0	4,215.5	112.8	4,102.7	4,197.6	85.0
2020	27,656.2	111.5	27,767.8	355.1	27,412.6	4,217.3	50.0	4,267.3	122.2	4,145.1	4,241.0	85.0
2021	28,248.6	111.5	28,360.1	387.8	27,972.4	4,313.7	50.0	4,363.7	131.6	4,232.1	4,330.0	85.0
2022	28,806.6	111.5	28,918.1	420.5	28,497.7	4,393.6	50.0	4,443.6	141.0	4,302.6	4,402.1	85.0
2023	29,072.3	111.5	29,183.9	453.2	28,730.7	4,436.2	50.0	4,486.2	150.4	4,335.8	4,436.1	85.0

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

TABLE B

2013 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)
2013	(960)	(154)	21,165	3,404	22,125.0	3,558	22,336	3,592	211	34
2014	(1,237)	(197)	21,888	3,488	23,124.4	3,686	24,401	3,889	1,277	204
2015	(2,050)	(325)	22,042	3,493	24,091.8	3,818	26,100	4,136	2,008	318
2016	(2,659)	(417)	22,517	3,529	25,176.0	3,945	27,756	4,350	2,580	404
2017	(3,151)	(492)	23,027	3,597	26,178.5	4,089	29,234	4,566	3,056	477
2018	(3,566)	(555)	23,184	3,607	26,750.4	4,162	30,218	4,702	3,467	539
2019	(3,926)	(610)	23,078	3,587	27,004.0	4,198	30,835	4,793	3,831	596
2020	(4,245)	(657)	23,168	3,584	27,412.6	4,241	31,572	4,884	4,159	643
2021	(4,531)	(701)	23,441	3,629	27,972.4	4,330	32,431	5,020	4,458	690
2022	(4,792)	(740)	23,706	3,662	28,497.7	4,402	33,232	5,133	4,734	731
2023	(5,032)	(777)	23,699	3,659	28,730.7	4,436	33,721	5,207	4,990	770

Growth Rates (%)

5 Year			1.8%	1.2%	3.9%	3.2%	6.2%	5.5%		
10 Year			1.1%	0.7%	2.6%	2.2%	4.2%	3.8%		

Round1 – SIECA Q3:

Please explain what the load growth drivers would be that could increase electricity sales in 2013 by 7%-8% rather than the 1.1% typical of recent years.

Response:

At the end of July, the year end load projected for 2013 was 6.2% higher than the 2012 actual load. Of this 6.2% increase approximately 0.8% is due to abnormal weather and in particular the cold weather in March and April of 2013. This still leaves very healthy 5.4% weather adjusted load growth for 2013. Load growth is higher in all classes but particularly in the following classes:

Customer Class	Growth Driver
Residential / Farm	Weather impact, number of households and usage.
Commercial	Commercial GDP drivers
Oilfields	Oil production forecast, energy intensity & water cut.
Power	Individual customer increases

Round1 – SIECA Q4:

On page 9, SaskPower states the following:

> *"Provincial load growth forecasts indicate the need for an additional 5,929 GWh over the next decade. Saskatchewan sales volumes are expected to grow by 29% over the next decade, with the bulk of that growth in the next five years."*

Please provide the underlying forecast behind this statement, the assumptions used and relevant supporting documentation.

Response:

Please refer to the 2013 Load Forecast report provided as part of SIECA Q2.

Round1 – SIECA Q5:

Please provide the most recent 10 year forecast of load and capability supplied to MRO/NERC. The load forecast must net out interruptible load to provide an adjusted demand forecast. The capability must reflect accredited capacity of the generation units and any and all purchase power agreements. Please provide this data in Excel spreadsheet format.

Response:

The LTRA (Long Term Resource Assessment) is provided to MRO/NERC on an annual basis to meet regulatory requirements. The reports for annual LTRA are available on the NERC website (http://www.nerc.com/pa/RAPA/ra/Pages/default.aspx). If required, we can forward the spreadsheet utilized and sent to NERC but it should be considered confidential.

Round1 – SIECA Q6:

Please explain what % planning reserve margin is used by SaskPower and provide reasons why this specific percentage is used?

Response:

SaskPower performs generation reliability analysis based on an unserved energy criterion. A probabilistic analysis is completed to determine the need for new generation based on every hour of the year. The deterministic planning reserve that represents this analysis is approximately equal to 13%. The analysis completed is based on industry standard practice. SaskPower is currently reviewing the reliability adequacy criterion.

2014 RATE APPLICATION
SIECA INTERROGATORIES ROUND ONE

Round1 – SIECA Q7:

Please provide quarterly demand (MW) and energy (GWh) data by customer class for the multi-year period 2004 to 2016?

Response:

The quarterly coincident peak demand by customer class is not available. The quarterly system demand is provided below along with quarterly energy consumption by class.

Round1 - SIECA Q7
Quarterly Demand - Total System (MW)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Q1	2963	2946	2838	2969	3016	3096	3051	3195	3265	3379	3,599	3,736	3,869
Q2	2591	2591	2732	2584	2762	2677	2727	2879	2963	2975	3,227	3,350	3,469
Q3	2551	2639	2736	2879	2834	2773	2750	3070	3053	3187	3,305	3,431	3,553
Q4	3015	2956	2985	2987	3194	3231	3162	3177	3314	3567	3,703	3,845	3,982

*	
	Actual
	Forecast

SaskPower

2014 RATE APPLICATION
SIECA INTERROGATORIES ROUND ONE

Quarterly Energy Consumption by Class (GWh)

	2004				2005				2006			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Power	1689.9	1632.2	1562	1620.3	1667.8	1657.7	1549	1694.6	1676.6	1587.7	1602.9	1795.3
Oilfield	571	531.9	533.5	528.1	584.9	563.8	560.2	555	614.8	612.1	589.7	582.8
Commercial	826.5	709.9	772.4	821.2	840.4	739.5	790.2	830.2	829.6	750.9	824.2	833.8
Residential	763.4	495	552.8	672.6	747.4	501	580	685.4	693.9	514.6	606.3	715.6
Farm	336.6	329.9	324.4	358.9	329.1	330.3	334.7	342.7	319.7	306.1	317	329
Reseller	330.7	294.2	311.5	324.1	327.9	298.9	317.6	321.4	322	306.9	335.3	329.2
Corporate	28.2	27.8	28.1	27.2	29.9	24.3	24.5	24.4	27.1	26.9	34.2	20.6
Losses	528.1	397.1	351.9	513.4	525.2	274.5	350	494.8	541.7	356.4	331.5	573.9

	2007				2008				2009			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Power	1786.2	1666.5	1703.8	1698.6	1796.4	1659.4	1681.8	1757.6	1610.1	1448.6	1475	1605.1
Oilfield	654.6	581.1	698.7	546.9	659.3	726.3	661.2	658.1	759	695.1	642.2	646.4
Commercial	859.5	746.4	822.5	839.6	875.2	745.5	819.7	846.8	916.5	762.5	823.2	905.2
Residential	763.3	523.9	626.6	729	815.9	546.9	611.5	746.7	886.3	565.7	623.7	789.1
Farm	326	321.3	332.4	349.2	320.8	323.2	320.7	341	321.7	321.8	333.1	361.6
Reseller	330.4	302.4	330.2	323.9	330.9	298.4	319.4	325.6	333.3	298.7	315.9	326.6
Corporate	29.7	27	25.7	26.9	30.1	28	28.4	22.8	27	27.5	24	28.9
Losses	520	360.9	291.2	622.3	601.1	337.4	356	588.2	510.3	384.9	377.5	602.5

	2010				2011				2012			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Power	1724.2	1770.6	1604.3	1827.6	1866.5	1779.2	1790.7	1882.3	1862.2	1926.6	1743.2	1902
Oilfield	786.5	722.9	678.7	683	740.1	791.9	784.5	584.4	745.7	909.8	699.1	822.3
Commercial	901.2	763	845.1	881.5	948.4	769.1	841.6	888.4	916.9	793.8	872.2	949.3
Residential	857.5	564.3	665.9	794.7	898.8	589.3	727.4	790.6	800.3	633.8	727.8	775.6
Farm	327.5	314.3	309.2	340.6	317.3	325.1	322.9	333	312.6	262.1	296.1	277.9
Reseller	321.4	298.5	312.5	322	329.9	293.3	317.8	319.8	315.8	292.8	322.6	322.8
Corporate	30.2	24.2	25.7	27.1	31.6	25.6	23.4	27.7	29.5	24	37.2	23.5
Losses	471.2	423.4	360.1	644.5	651.2	311.3	322	636.3	653.4	241.8	491.7	764.7

SaskPower

2014 RATE APPLICATION
SIECA INTERROGATORIES ROUND ONE

Quarterly Energy Consumption by Class (GWh) cont'd

	2013				2014				2015			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Power	1983.2	1928.3	1901.3	1930.7	2130.8	2039	1958.2	2105.6	2294.4	2192.7	2114.7	2228.2
Oilfield	927.9	825.7	847	837.5	916.8	915.9	922.1	931	979.9	979.1	984.9	995.8
Commercial	952.9	848.3	870.4	940.7	963.4	809.2	890.3	946.5	969.1	813.9	895.5	952
Residential	851.3	755.8	731.7	795.1	872.8	610.3	724.1	806.3	885.2	618.9	734.4	817.9
Farm	308.6	335.5	322.6	330.7	335.1	314.1	324.4	331.5	336	314.9	325.3	332.3
Reseller	323.5	294.7	320.6	313.6	331.2	296.9	321.5	314.6	332.1	297.8	322.5	315.5
Corporate	32.9	26.5	16.1	27.7	31.1	25.1	26.5	27.8	31.1	25.2	26.6	28
Losses	677.1	255.4	317.7	679.5	546.6	394.4	334	656.4	555.9	388.3	327.3	705.7

	2016			
	Q1	Q2	Q3	Q4
Power	2544.8	2421.9	2338.8	2490.7
Oilfield	1003.7	997	1000.5	1015.8
Commercial	980.6	823.6	906.1	963.4
Residential	898.4	628.2	745.4	830.1
Farm	333.4	312.5	322.8	329.8
Reseller	333.1	298.7	323.5	316.5
Corporate	31.2	25.2	26.8	28
Losses	545.3	376.8	325.2	687.6

*	
	Actual
	Forecast

Round1 - SIECA Q7

Quarterly Demand - Total System

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Q1	2930	2946	2838	2969	3016	3096	3051	3195	3265	3379	3,581	3,593	3,713
Q2	2591	2591	2706	2584	2762	2677	2727	2879	2963	2975	3,211	3,407	3,520
Q3	2551	2639	2701	2879	2834	2773	2750	3070	3053	3187	3,289	3,371	3,483
Q4	2954	2923	2960	2961	3194	3231	3162	3177	3314	3558	3,686	3,818	3,945

*	
	Actual
	Forecast

** Quarterly demand by class unavailable

Quarterly Energy Consumption by Class (GW.h)

	2004				2005				2006			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Power	1689.9	1632.2	1562.0	1620.3	1663.5	1653.385	1545	1690.2	1676.6	1587.7	1602.9	1795.3
Oilfield	571.0	531.9	533.5	528.1	584.9	563.8	560.2	555	614.8	612.1	589.7	582.8
Commercial	827.1	710.4	773.0	821.8	840.4	739.5	790.2	830.2	829.6	750.9	824.2	833.8
Residential	763.4	495.0	552.8	672.6	747.4	501	580	685.4	693.9	514.6	606.3	715.6
Farm	336.6	329.9	324.4	358.9	329.1	330.3	334.7	342.7	319.7	306.1	317	329
Reseller	330.7	294.2	311.5	324.1	327.9	298.9	317.6	321.4	322	306.9	335.3	329.2
Corporate	28.2	27.8	28.1	27.2	29.9	24.3	24.5	24.4	27.1	26.9	34.2	20.6
Losses	528.1	397.1	351.9	513.4	535.39	279.8247	356.79	504.4	541.7	356.4	331.5	573.9

6504.4	6552	6662.5
2164.5	2263.9	2399.4
3132.2	3200.3	3238.5
2483.8	2513.8	2530.4
1349.8	1336.8	1271.8
1260.5	1265.8	1293.4
111.3	103.1	108.8
1790.5	1676.4	1803.5
18797.0	18912.1	19308.3

	2007				2008				2009			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Power	1786.2	1666.5	1703.8	1698.6	1707	1576.805	1598.1	1670.1	1610.1	1448.6	1475	1605.1
Oilfield	654.6	641.1	698.7	546.9	659.3	726.3	661.2	658.1	759	695.1	642.2	646.4
Commercial	859.5	746.4	822.5	839.6	875.2	745.5	819.7	846.8	916.35	762.37	823.06	905.05
Residential	763.3	523.9	626.6	729	815.9	546.9	611.5	746.7	886.3	565.7	623.7	789.1
Farm	326	321.3	332.4	349.2	320.8	323.2	320.7	341	321.7	321.8	333.1	361.6
Reseller	330.4	302.4	330.2	323.9	330.9	298.4	319.4	325.6	333.3	298.7	315.9	326.6
Corporate	29.7	27	25.7	26.9	30.1	28	28.4	22.8	27	27.5	24	28.9
Losses	520	360.9	291.2	622.3	601.1	337.4	356	588.2	510.3	384.9	377.5	602.5

6855.1	6552	6138.8
2541.3	2704.9	2742.7
3268	3287.2	3406.836
2642.8	2721	2864.8
1328.9	1305.7	1338.2
1286.9	1274.3	1274.5
109.3	109.3	107.4
1794.4	1882.7	1875.2
19826.7	19837.1	19748.4

	2010				2011				2012			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Power	1724.2	1770.6	1604.3	1827.6	1866.5	1779.2	1790.7	1882.3	1865.6	1930.2	1746.4	1905.5
Oilfield	786.5	722.9	678.7	683	740.1	791.9	784.5	584.4	745.7	909.8	699.1	822.3
Commercial	901.2	763	845.1	881.5	948.4	769.1	841.6	888.4	916.9	793.8	872.2	949.3
Residential	857.5	564.3	665.9	794.7	898.8	589.3	727.4	790.6	800.3	633.8	727.8	775.6
Farm	327.5	314.3	309.2	340.6	317.3	325.1	322.9	333	312.6	262.1	296.1	277.9
Reseller	321.4	298.5	312.5	322	329.9	293.3	317.8	319.8	315.8	292.8	322.6	322.8
Corporate	30.2	24.2	25.7	27.1	31.897	25.84045	23.62	27.96	29.5	24	37.2	23.5
Losses	471.2	423.4	360.1	644.5	649.64	310.5545	321.23	634.78	649.06	240.19	488.43	759.62

6926.7	7318.7	7447.7
2871.1	2900.9	3176.9
3390.8	3447.5	3532.2
2882.4	3006.1	2937.5
1291.6	1298.3	1148.7
1254.4	1260.8	1254
107.2	109.3172	114.2
1899.2	1916.2	2137.3
20623.4	21257.8	21748.5

	2013				2014				2015			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Power	1983.2	1928.3	1901.3	1930.7	2130.8	2039	1958.2	2105.6	2294.4	2192.7	2114.7	2228.2
Oilfield	927.9	825.7	847	837.5	916.8	915.9	922.1	931	979.9	979.1	984.9	995.8
Commercial	952.9	848.3	870.4	940.7	963.4	809.2	890.3	946.5	969.1	813.9	895.5	952
Residential	851.3	755.8	731.7	795.1	872.8	610.3	724.1	806.3	885.2	618.9	734.4	817.9
Farm	308.6	335.5	322.6	330.7	335.1	314.1	324.4	331.5	336	314.9	325.3	332.3
Reseller	323.5	294.7	320.6	313.6	331.2	296.9	321.5	314.6	332.1	297.8	322.5	315.5
Corporate	32.9	26.5	16.1	27.7	31.1	25.1	26.5	27.8	31.1	25.2	26.6	28
Losses	677.1	255.4	317.7	679.5	546.6	394.4	334	656.4	555.9	388.3	327.3	705.7

	2016			
	Q1	Q2	Q3	Q4
Power	2544.8	2421.9	2338.8	2490.7
Oilfield	1003.7	997	1000.5	1015.8
Commercial	980.6	823.6	906.1	963.4
Residential	898.4	628.2	745.4	830.1
Farm	333.4	312.5	322.8	329.8
Reseller	333.1	298.7	323.5	316.5
Corporate	31.2	25.2	26.8	28
Losses	545.3	376.8	325.2	687.6

*	
	Actual
	Forecast

Round1 – SIECA Q8A:

Please provide narrative explanations along with references and related documentation regarding the demand (MW) and energy (MWh) growth forecast as follows:

a. What steps does SaskPower take to develop the most likely forecast for MW and MWhs? Please explain specifically what type of a statistical analysis is conducted to derive this forecast?

b. Is the weather data normalized? Please explain what methodology is used to weather normalize the load?

c. Please explain how the forecast was developed for the Power class. In addition, please address the following:

   i. Please explain the methodology, data and data sources used?

   ii. To the extent that feedback was used from customers to project expanded or new load; how was this information cross verified? Does SaskPower assign probabilities that indicate the level of confidence associated with the feedback from the customers regarding project expansion? If so, please explain in detail as to how these confidence levels are determined. If not, please explain why not?

   iii. Please explain at what point in the process do new or existing customers with expansion plans provide any type of formal commitment or dollar contribution?

Response:

Please refer to the 2013 Load Forecast report provided as part of SIECA Q2.

Statistical analysis is used to develop the high and low energy consumption and system peak demand forecasts. The high and low 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.

Round1 – SIECA Q8B:

Please provide narrative explanations along with references and related documentation regarding the demand (MW) and energy (MWh) growth forecast as follows:

d. What steps does SaskPower take to develop the most likely forecast for MW and MWhs? Please explain specifically what type of a statistical analysis is conducted to derive this forecast?

e. Is the weather data normalized? Please explain what methodology is used to weather normalize the load?

f. Please explain how the forecast was developed for the Power class. In addition, please address the following:

  iv. Please explain the methodology, data and data sources used?

  v. To the extent that feedback was used from customers to project expanded or new load; how was this information cross verified? Does SaskPower assign probabilities that indicate the level of confidence associated with the feedback from the customers regarding project expansion? If so, please explain in detail as to how these confidence levels are determined. If not, please explain why not?

  vi. Please explain at what point in the process do new or existing customers with expansion plans provide any type of formal commitment or dollar contribution?

Response:

In the rate application document the actual energy sales for 2012 are not normalized. The forecast of 2013 energy sales in the rate application is a combination of actual sales for January to July (not normalized) and forecasted sales for the remainder of the year (normalized). The forecast data for 2014 through 2016 is weather normalized.

The weather normalization process is used to determine SaskPower's historical energy requirements and system peak demand given normal weather conditions. This is important as SaskPower uses weather normalized loads to determine relationships between energy sales and the various economic drivers required for forecasting future sales.

The weather normalization process involves the quantification of weather relationships using 3 years of daily load data and a 30 year average normal weather pattern to determine daily, monthly and annual weather normalized values for energy requirements and peaks.

The dependent variable in the weather normalization models is Net Energy, which is defined as the system load less the industrial load and transmission losses, the components of the load that are assumed to be non-weather sensitive. The Net Energy variable is computed to isolate the weather sensitive load. Weather relationships are then developed between net energy and a series of weather variables (heating and cooling degree days, wind speed, humidity etc.) to estimate the weather impacts.

The result of the process is a weather adjustment and weather normalized energy requirement value for each day of the year. To compute weather normalized energy values on a monthly, and annual basis, the daily values are aggregated to monthly, and annual values.

The variables used to estimate the weather impacts for daily peaks are the same as those that estimate the weather impacts for energy requirements. The maximum of the weather normalized daily peaks is computed on a monthly and annual basis to determine the weather normalized monthly and annual peaks.

SaskPower

2014 RATE APPLICATION
SIECA INTERROGATORIES ROUND ONE

Round1 – SIECA Q8C:

Please provide narrative explanations along with references and related documentation regarding the demand (MW) and energy (MWh) growth forecast as follows:

g. What steps does SaskPower take to develop the most likely forecast for MW and MWhs? Please explain specifically what type of a statistical analysis is conducted to derive this forecast?

h. Is the weather data normalized? Please explain what methodology is used to weather normalize the load?

i. Please explain how the forecast was developed for the Power class. In addition, please address the following:

   vii. Please explain the methodology, data and data sources used?

   viii. To the extent that feedback was used from customers to project expanded or new load; how was this information cross verified? Does SaskPower assign probabilities that indicate the level of confidence associated with the feedback from the customers regarding project expansion? If so, please explain in detail as to how these confidence levels are determined. If not, please explain why not?

   ix. Please explain at what point in the process do new or existing customers with expansion plans provide any type of formal commitment or dollar contribution?

Response:

SaskPower relies heavily on interviews with Key Account customers to develop the Power class load forecast. SaskPower Account Managers meet with all of their Key Account customers in January to discuss expansion plans and future load requirements. Account Mangers will also contact customers with expansion plans on a quarterly basis, (in June, September and November) to ask if there are any changes to their plans or future requirements.

In the January meeting, customers are asked to provide an accurate forecast for the next 10 years. These customer forecasts are closely scrutinized by Account Managers and Pricing & Energy Forecasting staff and adjusted based on past performance, when warranted. SaskPower also uses contracts with take or pay provisions with new or expanding customers, to ensure the load shows up when scheduled. In order for SaskPower to release funds through the capital project authorization, a financial commitment and an executed contract must be received from the customer. This occurs early in the process.

Each customer forecast includes firm and probable load. Firm load consists of projects or expansions which are very likely to proceed. Normally these projects are 2 to 3 years out and have been announced and approved. Probable loads are longer term expansion plans or new projects which have not been approved. These loads are assigned a probability of proceeding, and are included in the forecast on that basis. The probabilities are assigned based on the timing of the project, collaborating market or industry data and whether SaskPower has the load secured by take or pay contract.

SaskPower meets with Ministry of the Economy staff on a regular basis to review potash and northern mining expansions. For the 2013 load forecast, SaskPower has also developed a potash sector energy forecast based on the Ministry of the Economy's (formerly Energy & Resources) potash production forecast. We have used this forecast to compare to, and adjust, the individual potash customer forecasts as required.

2014 RATE APPLICATION
SIECA INTERROGATORIES ROUND ONE

Round1 – SIECA Q9: Please describe the methodology used to assign confidence levels or establish probabilities of future electricity demand failing to materialize. Please explain how future loads are discounted or handicapped in the annual load forecast?

Response:

As discussed in SIECA Q8, each customer forecast includes firm and probable load. Firm load consists of projects or expansions which are very likely to proceed. Normally these projects are 2 to 3 years out and have been announced and approved. Probable loads are longer term expansion plans or new projects which have not been approved. These loads are assigned a probability of proceeding, and are included in the forecast on that basis. The probabilities are assigned based on the timing of the project, collaborating market or industry data and whether SaskPower has the load secured by take or pay contract.

The future probable loads are discounted by (multiplied by) the probability assigned to the project. These probabilities are reviewed and adjusted with each forecast update.

Round1 – SIECA Q10:

On page 9, SaskPower states the following:

> *"In addition to load growth, our generation, transmission and distribution infrastructure is aging, and will require us to rebuild, replace, or renew it in its entirety over the next forty years. Generation unit retirements will remove 200 MW of generation by 2017, including Boundary Dam units 2 and 3. New federal regulations have eliminated conventional coal-fired generation — SaskPower's primary baseload electricity source — as an option in the future."*

Please provide an explanation and relevant references for any and all of the federal and provincial environmental regulations and mandates pertaining to electrical generation that the utility has to comply with?

Response:

There are 49 directly applicable federal and provincial environmental statues; and 33 other regulations under those acts that apply to generation, transmission and distribution businesses. There are also numerous municipal bylaws, guidelines, standards, and codes that also apply.

The most significant environmental issues pertaining to power generation include:

- Air emissions
- Management of PCBs and spills
- Management of impacts to migratory birds
- Management of impacts to species at risk and critical habitat
- Compliance with regulatory requirements associated with permitting and ongoing facility operation

In terms of air emissions, SaskPower anticipates that federal regulations to limit CO_2 emissions from natural gas based electricity generation could be finalized in 2015 and discussions, between industry and Environment Canada on rules to limit emissions of other pollutants from the combustion of coal for electricity generation could resume in 2014.

Provincially, the Saskatchewan Ministry of Environment (MoE) has indicated its intensions to proceed with its proposed greenhouse gas regulations for large final emitters and to develop an equivalency agreement with the federal government to have federal GHG regulations stand down in lieu of the provincial regulations. Furthermore MoE has suggested the proposed provincial GHG regulations and an equivalency agreement could be in place by 2015, however significant progress on these two items is required for this timeline to be realized.

Round1 – SIECA Q11:

Please provide the analysis that has led to the decision to retire 200 MW of generation by 2017?

Response:

This information is confidential but the capacity in question is;

Boundary Dam Unit 1 – Retired in 2013 at end of life. Due to age and impending CO_2 regulations, the unit was retired.
Boundary Dam Unit 2 – Retires in 2015 at end of life. Due to age and impending CO_2 regulations, the unit will be retired.
Boundary Dam Unit 3 – 139 MW of conventional coal retired in 2013 and replaced with the Carbon Capture and Storage facility (110 MW) in 2014.

SaskPower

2014 RATE APPLICATION
SIECA INTERROGATORIES ROUND ONE

Round1 – SIECA Q12:

Please explain SaskPower's rationale for building wind generation?

Response:

SaskPower is committed to a diversified power supply. The addition of wind generation lowers emissions, provides environmental stewardship and social license and acts as a natural hedge to increasing fuel costs such as natural gas. From a system perspective, wind generation costs are very competitive with other sources of generation.

SaskPower

2014 RATE APPLICATION
SIECA INTERROGATORIES ROUND ONE

Round1 – SIECA Q13:

Please provide the cost benefit analysis used to ascertain the need to construct 177 MW of additional wind generation? What is the capacity factor assumption and why is this assumption used?

Response:

SaskPower is committed to a diversified power supply. The addition of wind generation lowers emissions, provides environmental stewardship and social license and acts as a natural hedge to increasing fuel costs such as natural gas. From a system perspective, wind generation costs are very competitive with other sources of generation.

Capacity factors are dependent on the area in Saskatchewan that the facility would be built. A range of 35 to 45 % would be expected from the areas where wind would be built in Saskatchewan. Current wind facilities are approximately between 38 to 40%.

The 177 MW wind farm was selected through a competitive request for proposals. The analysis completed was based on capacity factors provided by each proponent.

Round1 – SIECA Q14:

Please explain the challenges associated with integrating wind generation into the SaskPower system? Please explain the cost implications of dispatching "must run" wind generation ahead of lower cost generation alternatives.

Response:

Due to the intermittent nature, the challenges associated with wind generation are as follows:

- Capacity Benefit – how much of the wind capacity can be attributed to resource adequacy
- Cost and Operational Impact – the intermittency of the wind operation causes units to be committed to ensure proper operation of the bulk electric system
- Wind Forecasting – understanding how the wind is going to blow over the next 1 – 24 hours allows for better dispatch of system resources.
- Surplus Energy due to Wind Power – if too much must run capacity is installed, there is a requirement to curtail wind generation. This becomes very apparent in the low load times.
- Transmission Reserve Margin (TRM) – transmission availability must be reserved with neighbouring jurisdictions to ensure instantaneous power flow when systems have a sudden change in load or generation. This impacts the available transmission capability which can limit the opportunity to buy or sell with neighbouring jurisdictions.

SaskPower dispatches units based on a merit order depending on costs. SaskPower has the capability to curtail wind generation if it feels it is economic to do so.

Round1 – SIECA Q15:

Regarding the table titled “Capital Spending” on page 28 of the application; please provide a schedule on a project level basis that provides total project costs, capital invested by year and the project in-service dates. With respect to the customer connects category; please provide the annual capital costs by customer class for the 2012-2016 period and provide the number of customers in each class for the same time period. Please explain and justify the reasonableness of this forecast?

Response:

See attachment.

SaskPower
Capital Expenditures
($millions)

	Prior Years	2013 Forecast	2014 Budget	2015 Budget	2016 Budget
Transmission & Distribution					
Capacity Increase & Sustainment					
Line - I1K - 230kV - New	31.4	112.0	120.0	116.4	
Line - Aberdeen to Wolverine - 230kV - New	1.0	10.0	40.0		
Saskatoon North Reinforcement	0.0	0.0	32.0		
Key Lake Switching Station	0.0	0.0	31.5		
Switching Station - Tantallon - 230kV-138kV - Expansion	8.8	9.6	31.1		
Line - Pasqua to Swift Current - 230kV-138kV - New	0.7	8.1	26.6	56.4	13.6
Substation - Lloydminster - 138kV-25kV - New	0.2	6.8	25.2		
Vehicles & Equipment	0.0	19.6	23.0	22.0	20.0
Program - Distribution Wood Assets	0.0	16.5	23.0	26.0	29.0
Swift Current SVS	0.0	0.0	21.0		
Program - Wood Line Remediation	0.0	23.0	20.0	25.0	25.0
Substation - Halbrite East - 138kV-25kV - New	0.0	0.1	15.5		
Program - Rural Rebuild & Improvement	0.0	12.8	15.0	15.0	15.0
Substation - Kisbey - 230kV-25kV - New	0.1	3.1	14.3		
QE Expansion Interconnection	0.0	0.0	13.0	6.1	
Switching Station - Regina South - 230kV Expansion	0.0	0.6	11.5	8.9	4.5
Regina Area to Pasqua 230 kV Transmission Line - T823	0.0	0.0	9.6	36.6	28.6
Substation - Winter - 138kV-25kV - New	0.1	0.2	9.6		
Initiative - City of Regina Aging Infrastructure Replacement	1.4	3.0	8.5	10.2	10.2
T337 - Conversion of I1K to 230kV	0.0	0.0	8.4	11.5	
Scada - Distribution Control System	0.0	0.3	7.7	2.0	
D423-2 Bromhead Area Reinforcement	0.0	0.0	7.3	9.7	2.0
Switching Station - Prot Sys Beatty – 230 kV – New	0.0	0.0	7.0	7.0	7.0
Meadow Lake Tribal Council Generation Interconnection	0.0	0.0	6.7	2.3	
Program - Underground Cable Replacements	0.0	4.6	6.1	6.1	6.1
Lattice Tower Below-Ground Remediation	0.0	0.0	6.0	6.0	6.0
Program - Economic Rebuild (Rural)	0.0	4.6	6.0	6.0	6.0
Program - Distribution Defective Apparatus	0.0	6.5	5.5	5.5	5.5
BDSS Capacity Increase (138/230kV Transformers)	0.0	0.0	5.1		
Line - Beatty to Wolverine Area - 230kV - New	0.0	0.5	4.7	27.3	18.2
T309-2 - Lloydminster Area Reinforcement	0.0	0.0	4.5	14.0	19.9
T355-1 Regina Switching Station 230 kV Expansion	0.0	0.0	4.1		
Substations Rebuild - Hawarden & Tichfield	0.0	0.0	4.1	2.5	
End of Life Substation Rebuild	0.0	0.0	4.0	4.0	4.0
Program - Distribution Reliability Improvements (Rural & Urban)	0.0	4.0	4.0	4.0	4.0
Program - Power Quality Upgrades	0.0	2.2	3.7	4.7	4.7
Substation - Shaunavon - 138kV-25kV - Expansion	0.2	0.3	3.2	11.9	
Initiative - Mobile Substation	0.0	0.0	3.0		
Weathering Steel Below Ground Remediation	0.0	0.0	3.0	3.0	3.0
N013 : GOPP Riverhurst Project/Sprott Power	0.0	0.0	3.0	4.1	
Peebles 2nd 230kV Transformer	0.0	0.0	2.7		
Ermine SS Control Bldg Facilities	0.0	0.0	2.7		
Materials Management Process Improvement Program	0.0	0.0	2.5	1.1	
Line - GOPP Interconnections	0.0	0.3	2.5	2.5	
Program - Farmyard Line Relocation	0.0	2.0	2.5	2.5	2.5
Program - Urban/ Rural Hazards Mitigation	0.0	1.2	2.5	2.5	2.5
CAPACITY INCREASE - ALBERT PARK	0.0	0.0	2.4	2.5	
P2C Transmission Line Splitting and R-termination at Regina South - T321	0.0	0.0	2.3	13.1	12.8
Switching Station - Fleet Street - 230kV-138kV - Expansion	7.6	10.2	2.1	0.0	0.0
Double Circuit Line Mitigation - Mixed Voltages	0.0	0.0	2.0	2.0	2.0
Capacity Increase - Lumsden - D413	0.0	0.0	2.0		
Initiative - Regina South Reactor Switchgear Replacement	0.0	0.1	2.0		
Meter Purchases	0.0	3.8	2.0	4.2	3.2
Program - DCF & DCVF Replacements	0.0	0.2	2.0	2.0	2.0
Program - Large Power Transformer Replacement	0.0	1.0	2.0	2.0	2.0
Program - Line Program Up-rating	0.0	1.0	2.0	2.0	2.0
Program - Line Switch Replacements	0.0	1.5	2.0	2.0	2.0
Program - Protective Relay Replacements	0.0	1.2	2.0	2.0	3.0
Program - Transmission Line System Improvement	0.0	1.0	2.0	2.0	2.0
RTU Replacements	0.0	0.0	2.0	2.0	0.3
Rosewood Line Move	0.0	0.0	1.9	0.3	
NERC - CP&C - B1Q/B2Q SPS	0.0	0.0	1.9		
BD 230 kV BF Improvements - T523	0.0	0.0	1.8	2.4	
D421 - Central Butte Conversion	0.0	0.0	1.8	7.4	
BR-Saskatoon 230 kV Transmission Line-T318	0.0	0.0	1.7	27.9	26.4
Initiative - Westinghouse Jet Aire Replacements	0.0	0.8	1.7	0.7	
Switching Station - Breaker Rep	0.7	1.6	1.5	1.5	1.5
Boundary Dam Switchgear Replacement	0.0	0.0	1.5		
CP&C - Smart Grid Enterprize Service Bus	0.0	0.1	1.5	1.5	0.9
Program - Protection Upgrades	0.0	1.0	1.5	2.0	2.0
Program - Transmission Reliability Improvements	0.0	0.8	1.5	1.5	1.5
Spare Equipment Storage Sites	0.0	0.1	1.5		
Transmission Tools	0.0	2.4	1.5	1.5	1.5
Capacity Increase - Peebles 138-72 kV - T417	0.0	0.0	1.4	1.5	
PR 230 kV BF Improvements - T525	0.0	0.0	1.3	1.3	
N021: QE 230kV Bussing	0.0	0.0	1.1	1.9	
BBC, LZ96, LZ92, LIZ6	0.0	0.0	1.1	1.1	1.1
Reyrolle Distance Relay Replacements	0.0	0.0	1.1	1.1	1.1
Breaker Fail Relay Replacement Program	0.0	0.0	1.0	1.0	1.0
CP&C - Smart Grid Enterprize Data Warehouse	0.0	0.0	1.0	1.0	
D382 - Hillmond / Paradise Hill Substation	0.0	0.0	1.0	8.0	12.8
High Load Move Corridors	0.0	0.0	1.0	1.0	1.0
Network Upgrade - Yorkton Land Purchase - T304	0.0	0.0	1.0		

Steel Pole Yard Expansion	0.0	0.0	1.0		
Switching Station System Improvement Program	0.0	0.0	1.0	1.0	0.5
Paper Excellence Prince Albert Interconnection-10 MW PP (Phase I)	0.0	0.0	1.0	0.8	
D336 - Rapidview / Peerless Substation	0.0	0.0	0.5	2.7	6.9
D417 - Saskatoon West Reinforcement Phase 1	0.0	0.0	0.5	3.5	11.4
Lattice Tower Contingency Planning	0.0	0.0	0.5	2.0	2.0
Network Upgrade - W3B Rebuild	0.0	0.0	0.5	3.2	13.0
QE Re-route - Holmwood	0.0	0.0	0.5	5.0	5.0
T364 - Network Upgrade - Extend BD15 to Auburton	0.0	0.0	0.5	2.0	9.0
T365 - Network Upgrade - Martensville to Dalmeny Area 138kV Line	0.0	0.0	0.5	2.0	3.5
T368 - Lloyd to Ermine 138 kV Line	0.0	0.0	0.5	20.0	21.0
T348 – W1Y/W4B 138/72 kV Line Upgrade	0.0	0.0	0.2	10.6	10.9
String Second Circuit - Kennedy to Tantallon	0.0	0.0	0.1	2.6	13.4
Network Upgrade - String Second 230 kV Circuit - Peebles to Tantallon - T376	0.0	0.0	0.1	1.2	5.8
Switching Station - Aberdeen - 230kV - New	3.4	13.3	0.0	0.0	0.0
CP&C - GIS OT Upgrade	0.0	0.0	0.0	0.0	0.0
CP&C - P52E Powerline Carrier Rep	0.1	0.1	0.0	0.0	0.0
CP&C - W1Y - Fibre - New	3.7	1.3	0.0	0.0	0.0
Initiative - BBC, LZ96, LZ92, LIZ6	0.0	0.5	0.0	0.0	0.0
Initiative - Codette Regulator	0.0	0.2	0.0	0.0	0.0
Initiative - Cumberland House Rebuild	0.0	2.0	0.0	0.0	0.0
Initiative - Reyrolle Distance Relay Replacements	0.0	0.5	0.0	0.0	0.0
Line - Dundonald to QE14 - 138kV - New	0.0	1.3	0.0	0.0	0.0
Line - Swift Current to Coteau Creek - 230kV - Expansion	0.0	1.4	0.0	0.0	0.0
Line - Wind Interconnection - Chaplin 175 MW IPP	0.0	1.1	0.0	0.0	0.0
Program - Breaker Fail Relay Replacement	0.0	0.5	0.0	0.0	0.0
Program - Distribution Automation	0.0	1.5	0.0	0.0	0.0
Program - Economic Rebuild (Urban)	0.0	1.0	0.0	0.0	0.0
Program - Station Bus and Foundation Replacements	0.0	0.3	0.0	0.0	0.0
Program - Switching Station System Improvement	0.0	0.5	0.0	0.0	0.0
Program - Wood Substation Rebuild	0.0	0.0	0.0	0.0	0.0
Scada - EMS Lifecycle Management	3.5	1.0	0.0	0.0	0.0
Substation - Clarence - 138kV - 25kV - New	8.6	3.3	0.0	0.0	0.0
Substation - Estevan East -138kV-25kV - New	1.8	7.2	0.0	0.0	0.0
Substation - Fleet Street - 138kV-25kV - Expansion	1.2	5.0	0.0	0.0	0.0
Substation - Handsworth - 72kV-25kV - Temp	0.0	3.1	0.0	0.0	0.0
Substation - Neudorf - 138kV-25kV - New	2.1	2.7	0.0	0.0	0.0
Substation - Superb - 138kV-25kV - New	0.0	0.3	0.0	0.0	0.0
Switching Station - Boundary Dam - 230kV-138kV - Expansion	0.0	4.0	0.0	0.0	0.0
Switching Station - Ermine - 138kV-72kV - Expansion	0.0	1.3	0.0	0.0	0.0
Switching Station - Fleet Street - Land - New	0.1	2.4	0.0	0.0	0.0
Switching Station - Key Lake - 230kV-138kV - New	0.0	2.2	0.0	0.0	0.0
Switching Station - Lloydminster - 230kV-25kV - New	0.0	1.3	0.0	0.0	0.0
Switching Station - Martensville - 230kV-138kV - New	4.5	8.0	0.0	0.0	0.0
Switching Station - Points North - 25kV Capacitors	0.2	8.5	0.0	0.0	0.0
Switching Station - Queen Elizabeth - 138 kV - Exp	0.1	1.0	0.0	0.0	0.0
Switching Station - Relay System Improvement Program	0.0	1.3	0.0	0.0	0.0
Switching Station - Swift Current - 138kV - New	0.4	6.5	0.0	0.0	0.0
Switching Station - Terminal Equipment Ratings Upgrades	0.0	0.0	0.0	0.0	0.0
Switching Station - Tisdale - 138kV/72kV - Expansion	1.5	1.0	0.0	0.0	0.0
Switching Station - Under Frequency Load Shedding Prot Sys - Expansion	0.0	1.5	0.0	0.0	0.0
T&D Miscellaneous Projects Under $1,000,000	0.0	23.0	41.6	73.8	52.0
Contingency	0.0	(128.0)	(367.7)	(342.7)	(238.9)
Total Capacity Increase & Sustainment	**83.4**	**260.7**	**355.0**	**351.0**	**235.0**
Customer Connects					
Program - Distribution Customer Connects	0.0	140.0	150.0	150.0	150.0
Line - Cameco Millennium to Key Lake - 138kV - New	0.1	0.0	17.6	3.2	
Line - BHP Jansen to Wolverine - 230kV - New	0.3	2.0	17.0		
Line - Relocate - Stadium - 72/25kV - Expansion	0.0	2.1	13.0		
Line - K+S Potash to Pasqua - 230kV - New	0.3	8.3	12.9		
Line - TCP Grassy Creek to Swift Current - 138kV - New	0.6	3.2	6.4		
175 MW Wind RFP Interconnection (230 kV at Chaplin) - N002	0.0	0.0	5.6	6.0	
Line - TCP Piapot to Swift Current - 230kV - New	1.9	2.7	5.6		
Line - Western Potash to Regina - 230KV - New	0.0	0.0	5.5	21.2	
T314-3 Karnalyte - Permanent Power	0.0	0.0	4.0	5.8	5.8
BHP Melville Construction Power Interconnection	0.0	0.0	3.9	4.0	
Customer Connect - Fortune Minerals	0.0	0.0	3.7		
Elizabeth Falls Interconnection - N006	0.0	0.0	3.0	31.3	30.8
Customer Connect - BHP Melville - Construction Power	0.0	0.0	2.1		
Customer Connect - Evraz 230 kV Supply	0.0	0.0	2.1	5.7	12.4
PCS Lanigan Load Increase	0.0	0.0	1.9		
TCC East Coast Mainline (Cabri) -Load Interconnection	0.0	0.0	1.7	3.6	18.6
Customer Connect - TransCanada East Coast Line - Cabri	0.0	0.0	1.7		
T313-2 Western Potash - Interim Power	0.0	0.0	1.6	0.7	
PCS Allen 230 kV Service	0.0	0.0	1.5		
Customer Request - Dragline Walk 2014	0.0	0.0	1.5		
McArthur River Re-Termination	0.0	0.0	1.5		
Mosaic Colonsay 230 kV Service	0.0	0.0	1.3		
Vale Potash Load Interconnection - Permanent Power	0.0	0.0	1.2	7.6	3.4
Customer Connect - Belle Plaine Expansion for New Yara Supply Points	0.0	0.0	1.2	3.7	1.4
T314-1 - Karnalyte - Construction Power	0.0	0.0	1.0	2.6	
Customer Connect - BHP Billiton Melville Permanent Power - T353	0.0	0.0	0.6	1.1	3.9
Customer Connect - Rio Tinto - Sedley	0.0	0.0	0.5	1.6	8.0
New Wind Interconnection - 100MW IPP	0.0	0.0	0.0		1.0
Birtle South - Tantallon 230 kV Tie-Line (SPC costs only) - N014	0.0	0.0	0.0	0.8	4.3
T345 - Forget Switching Station	0.0	0.0	0.0	0.5	6.5
T311 - BHP Young (C2Q Tap)	0.0	0.0	0.0	0.1	0.5
Line - Cenovus to Boundary Dam - 230kV - New	21.9	12.6			
Line - CNRL to BD15 - 138kV - New	0.0	0.0			
Line - MLTC to ML3 - 138kV - New	0.0	0.2			
Line - Mosaic Colonsay Line Tap - 230kV - New	1.4	0.2			
Line - Mosaic K2 to Tantallon - 138kV - New	6.1	2.0			
Line - NBEC to Brada - 230kV - New	13.1	6.4			
Line - PCS Allan Line Tap - 230kV - New	2.0	0.7			

Line - PCS Lanigan to Wolverine – 138kV – Exp	0.0	0.0			
Line - TCP Fox Valley Line Tap - 230kV - New	2.4	3.5			
Substation - Algonquin Interconnection - 138-25 kV	0.0	1.2			
Substation - Prairie Mines - 138kV-25kV - Expansion	0.0	1.7			
Substation - Sprott Power Interconnection - 138kV-25 kV - New	0.0	0.2			
Switching Station – BD3 Clean Coal - 230kV - Expansion	4.1	1.5			
T346 - South Shaunavon Reinforcement	0.0	0.0			
D652 - Customer Connect - Areva Midwest	0.0	0.0			
T918 - Customer Connect - Shea Creek	0.0	0.0			
Switching Station - Paper Excellence - 138kV - Expansion	0.1	0.1			
Other Projects	0.0	0.0	5.7	19.1	9.6
Budget Reduction Contingency	0.0	0.0	(27.6)	(27.5)	(24.6)
Total Customer Connects	**54.3**	**188.8**	**247.7**	**241.1**	**231.6**
Total Transmission & Distribution	**137.7**	**449.4**	**602.7**	**592.1**	**466.6**

Power Production

Capacity Sustainment

B Plant Elevator Upgrades			1.0		
BD #3 Life Extension	0.0	5.6			
BD #4 Life Extension	0.0	3.5	32.2		
BD #5 Asbestos Removal	0.0	1.6			
BD #5 Plant Coated Waterwall Panels	0.0	1.6	3.5		
BD 5 Life Extension	0.0	0.0	0.0		1.6
BD A PLANT HEATING	0.0	0.0	1.0	1.0	
BD Asbestos Removal 2012 - 2020	6.5	1.1			
BD Ash Lagoon Surcharging	0.8	0.3			
BD CW Pipe Upgrades	0.0	5.4			
BD Facilities Upgrade	0.0	2.2	2.0	2.0	
BD Waste Water Mgt Phase III	0.1	0.4	1.0		
BD6 Economizer Life Extension	0.0	0.0	2.5		0.5
BD6 Plant Coated Waterwall Panels	0.0	0.0	3.5		0.9
BDPS Sewage Lagoon Expansion	0.0	0.0	3.0		
Coteau Creek Rewind	15.7	4.4			
EB Campbell Draft Tube Piers	0.0	0.1	1.0	0.9	0.9
EB Campbell N. Dyke Overflow	0.0	2.0	1.7		
EB Campbell Plant Control Monitoring System	8.9	3.1	2.6	1.2	
EB Campbell Plant Fire Suppression	0.0	0.0			
EBC 13KV SWITCHGEAR	0.0	0.0	2.0	2.0	2.0
EBC FIRE PROTECTION	0.0	0.0	1.0		
EBC GENERATOR REFURBISHMENTS	0.0	0.0	0.0	5.0	7.0
EBC Intake Gate Refurbishment	0.0	0.0	0.5	2.0	2.0
EBC LICENSE MITIGATION	0.0	0.0	10.0	15.0	20.0
ECRF-PAVAC Demonstration	0.0	1.2			
GT Capital Component Replacements	10.1	9.3			9.0
IF MAIN DAM & POWERHOUSE CONCRETE UPGRADE PH 1	0.0	0.0	4.5	4.5	4.5
Island Falls #1, 2, 3 & 7 Exciters	0.5	0.3			
Island Falls #5 Refurbishment	19.7	1.0			
Island Falls #6 Refurbishment	7.0	14.9			
Island Falls 7 Refurbishment TURB/GEN	0.0	0.0	0.0	0.5	7.0
Island Falls Concrete Rehabilitation	0.0	4.3			
Island Falls Plant Control Monitoring System	7.8	4.6	2.4	1.3	
Island Falls Roof Upgrades	0.0	1.6			
Island Falls Ventilation Improvements	0.0	0.0			
Landis Exhaust Gas Housing	0.3	0.8	1.4		
LANDIS LIFE EXTENSION	0.0	0.0	8.4		
MORRISON DAM SPILLWAY CAPACITY MAIN DAM	0.0	0.0	16.5	3.0	
Poplar River #1 Maintenance Platform	0.0	0.8	2.6		
Poplar River #1 Precipitator Mechanical Upgrades	3.3	0.2			
Poplar River #2 Ashpit and Refractory Design Improvement	0.0	1.0			
Poplar River #2B SBAC Upgrade	1.0	(0.1)			
Poplar River #3N Ash Lagoon Renewal	0.7	0.0			
Poplar River Ash Disposal Improvements	0.0	1.3			
Poplar River Controls Simulator	0.0	0.5	2.3	1.6	
Poplar River CW Discharge - Riprap	0.1	0.4			
Poplar River Facilities Improvement	1.6	0.0			
Poplar River Maint. Contractor Facility Improvements	0.0	0.4	3.5	1.3	
PR 2 Long Term Expenditures	0.0	0.0	2.0	27.0	1.0
PR ASH LAGOON 4E CONSTRUCTION	0.0	0.0	0.2	18.8	0.1
PR CW CANAL UPGRADE	0.0	0.0	2.5	2.5	
PR Dry Stack from #2 Ash Lagoon	0.0	0.0	2.0		
PR FACILITIES UPGRADE	0.0	0.0	4.5	2.5	0.8
PR MANLIFT REPLACEMENT	0.0	0.0	1.5	2.5	
PR PULVERIZER MONORAILS & LUGS	0.0	0.0	1.0	1.0	1.2
PR1 ESP ELECTRODE REPLACEMENT	0.0	0.0			3.0
QE 480V MCC Replacement	0.8	1.0			
QE Facility Upgrade	6.0	3.2			
SHAND 1 MAJOR REBUILD	0.0	0.0			
SHAND CABLE VAULT REPL	0.0	0.0	1.5		
Shand Chemical Storage Building	0.0	1.2			
SHAND LIFAC REACTOR UPGRADE	0.0	0.0	3.0		
SHAND Sorbent Delivery and Loadout	0.0	0.0	2.0		
Tazin Weir Replacement	0.0	1.0			
TAZIN WEIR REPLACEMENT	0.0	0.0	7.1	0.9	
Tazin Weir Tunnel Intake Replacement	0.5	3.3			
WELLINGTON REFURBISHMENTS	0.0	0.0	2.5	5.0	5.0
WHITESAND DAM UPGRADES	0.0	0.0	1.5		
QE A PLANT 5KV SWITCHGEAR AND RECABLE	0.0	0.0	1.1	3.1	
QE CW PUMPHOUSE BRIDGE CRANE & ENC	0.0	0.0	1.0		
Power Production Miscellaneous Projects Under $1,000,000	0.0	34.3	18.5	63.7	76
Budget Contingency	0.0	0.0	(22.0)	(28.4)	(2.5)
Total Capacity Sustainment	**91.4**	**117.6**	**140.0**	**140.0**	**140.0**

QE Repowering	25.2	94.2	225.0	117.6	25.0
Elizabeth Falls	0.0	14.4	40.0	80.0	100.0
Carbon Capture Test Facility					
BD #3 ICCS - Carbon Capture	401.4	225.6	0.0	0.0	0.0
BD #3 ICCS - Power Island	146.9	236.1	0.0	0.0	0.0
Carbon Capture Test Facility	2.1	30.0	21.0	0.0	0.0
CO2 Disposal Well	0.0	8.9	0.0	0.0	0.0
CO2 Pipeline	0.0	9.0	0.0	0.0	0.0
Total Carbon Capture Test Facility	550.4	509.6	21.0	0.0	0.0
Total Power Production	667.0	735.8	426.0	337.6	264.9
Other Capital Spending					
Operations Centre					
Buildings/Furniture/Land					
Furniture & Equipment	0.0	1.6	3.0	3.0	3.0
Head Office Elevator Refurbishment	0.0	5.0	1.0		
Head Office Refurbishment	0.0	2.9			
Lloydminster District Office/Shop	0.0	2.2	5.0		
Logistics Warehouse Complex	0.7	31.9	12.0	50.0	80.0
Regina Rural East - Purchase Land	0.0	0.0			
Saskatoon Stores	0.0	1.5	4.5		
Stony Rapids	0.0	0.3	1.1		
Swift Current Service Centre	2.7	1.6	5.4		
Tisdale Office/Shop	0.0	0.0	2.5		
TS&R Roof Replacement	2.1	1.0	1.5		
Warman - Office/Shop - Purchase Land	0.0	0.0			
Weyburn Service Center T&D	16.5	2.0			
Coronach Land Purchase	4.1	0.7			
Estevan Land Purchase	3.6	5.7			
Land for Future Gas Turbine	0.0	1.0	5.0	5.0	5.0
Schedule & Dispatch - Regina and Saskatoon	0.0	0.0	2.5		
Regina Rural East - Purchase Land	0.0	0.0	2.0		
RRSC Site Preparation	0.0	0.0	1.0	1.0	
North Battleford Service Centre	0.0	0.0	0.5	2.0	7.0
Miscellaneous Projects Under $1,000,000	0.0	4.4		24.0	20.0
Total Buildings/Furniture/Land	29.7	61.9	47.0	85.0	115.0
Service Delivery Renewal					
SDR - Advanced Metering Infrastructure	18.5	67.7	69.1	6.7	
SDR - Field Worker Technology Phase II - Schedule & Dispatch	18.0	2.7	1.2	4.2	
SDR - Field Worker Technology Phase III - Outage Mgmt System	0.0	0.0			
Miscellaneous Projects Under $1,000,000	0.0	0.0			
Total Service Delivery Renewal	36.5	70.4	70.3	10.9	0.0
Information, Technology & Security					
Business Application Rationalization (Lotus Notes) Portfolio	0.0	2.6			
BI Projects	0.5	1.3	2.0	1.5	2.0
Miscellaneous BI	0.0	0.2			
Miscellaneous Effective & Efficient Operations Portfolio Projects	0.0	0.9			
Contact Centre & Outage IVR	1.3	2.9			
Desktop Management	3.2	2.7	2.8	2.8	2.9
Enterprise Content Management	0.0	3.0			
Infrastructure Refresh and Renewal	3.0	3.5			
Perimeter Security Enhancement	0.9	2.5	2.7		
Procurement	0.0	1.0			
SAP License Purchases	0.0	1.6			
ECM Collaboration & Integration	0.8	2.2			
Enterprise Monitoring & Alerting	1.2	2.4	1.6	1.4	4.5
Electric Office	0.7	3.0			
Enterprise Apps - App Rationalization	0.0	0.0	3.1	0.3	0.3
Communications - Wireless Communications	0.0	0.0	1.7	0.9	0.9
Communications - Video Conferencing	0.0	0.0	1.0		
Enterprise Applications (projects under $1M)	0.0	0.0	0.5	1.1	1.1
Business Project - Non-Discretionary	0.0	0.0	5.0	7.2	7.3
Business Project - Discretionary	0.0	0.0	5.5	2.4	2.4
Desktop Mgmt - laptops in trucks	0.0	0.0	3.0		
Data Centre	0.0	0.0	3.5	2.2	1.0
Enterprise Services Bus - Asset Management/Smart Grid	0.0	0.0	2.0	2.3	1.1
Electric Office - Asset Management/Smart Grid	0.0	0.0	1.5	0.3	
Corporate Strategic	0.0	0.0	6.7	7.1	7.1
ECM (RIM Compliance)	0.0	0.0	2.6	1.8	2.3
Other Projects	0.0	0.0	5.2	12.5	14.1
Miscellaneous Infrastructure	0.0	1.5	3.6	3.7	3.8
Miscellaneous Proud & Productive Employees	0.0	0.7			
Miscellaneous Financial Management	0.0	0.7			
Total Information, Technology & Security	11.6	32.8	54.0	47.4	50.8
Total Other Capital Spending	77.8	165.1	171.3	143.2	165.8
Total Capital Spending	882.5	1,350.4	1,200.0	1,072.9	897.4

SaskPower
Capital Expenditures
($millions)

	2012 Actual
Transmission & Distribution	
Capacity Increase & Sustainment	
Economic Rebuild (Rural) & New Codes (Urban SI)	6.2
Economic Rebuild (Urban)	2.9
City of Regina Aging Infrastructure Replacement	1.1
Farmyard Line Relocation Program	2.6
Induction Crew Projects	0.6
Protection Upgrades	0.4
Recoordination & Protection	0.2
Regulators	0.5
Rural Distribution Reliability Improvements	1.2
Rural Rebuild & Improvement Program	9.9
Steel Street Light Replacement	0.9
Substation 4kV Sub Rebuild	0.1
Substation/Wood Substation Replacement	3.0
Transformer Replacements- Poles & Pads	6.5
Transformer Replacements- Substation	0.3
Urban Underground Cable Replacements	4.8
Urban/ Rural Hazards Mitigation	0.7
Weyburn - Steelman Distribution System Reinforcement	0.5
Wood Pole Replacement	10.5
Distribution Tools	0.3
Saskatoon Pole Storage Facility	0.3
BD#3 ICCS Interconnection	4.1
Capacity Increase - Aberfeldy 135-25 kV	0.1
Capacity Increase - Auburnton 230/72kV	3.7
Capacity Increase - Clarence	0.7
Capacity Increase - Dundonald	1.4
Capacity Increase - Fleet Street 138-25kV	1.2
Capacity Increase - Halbrite	1.4
Capacity Increase - Marengo- Hoosier	(1.6)
Capacity Increase - Shaunnavon 138-25kV	0.2
CAP-FS727,8,9 & 30 DELLE BK REP	0.4
Fibre Route Diversity (W1Y)	1.1
Fleet St 2nd 230/138kV Transformers	5.9
Husky Pike Peak Interim	0.9
Network Upgrade - 25 kV Capacitors - Points North	0.2
New Substation - Bromhead	3.6
New Substation - Kisbey	0.1
Provincial Public Safety Telecommunications Network	0.9
Paper Exc. 1 PA Interconnection - 10MW IPP (COD Jan 2014)	0.1
Pasqua to Swift Current - Transmission System Reinforcement	0.7
Peebles - Tantallon 230 kV Line	7.9
Peebles 2nd 230 -138 kV	1.3
Poplar River - Pasqua 230kV	1.8
Saskatoon East SS	2.7
Saskatoon East-Wolverine 230kV Transmission Line	0.8
Senlac Substation Capacity Increase	1.6
Stoughton Substation Capacity Increase	1.1
Substation Rebuild - Estevan #2	1.8
Substation Rebuild - Neudorf	2.1
Swift Current SVS	0.4
Yorkton 138 kV	2.3
B2R/ B3R Structure Change	1.2
EMS Lifecycle Management	0.5
GCC Facilities Upgrades	0.2
Halbrite	1.0
I1F/I2F Re-Termination	2.7
Island Falls Plant & SS TFDR Replacement	(1.5)
Line Uprating	0.5
Poplar River 230kV Breaker Replacement	1.4
QE18 138kV	0.2
Saskatoon North Reinforcement	4.2
Switching Stations Breaker Replacement	0.7
Switching Station System Improvement	0.5
Tisdale Switching Station Control Building Facilities	0.8
Transmission Line System Improvement	0.2
Transmission Reliability Improvements	0.8
Wood Pole Replacement	17.2
Regina South Land Purchase	0.8
Transmission Tools	1.8
Miscellaneous Projects	8.5
Meter Purchases	2.9
Vehicles & Equipment	20.5
Total Capacity Increase & Sustainment	**167.5**
Customer Connects	
Distribution Customer Connects	131.6
Agrium (Vanscoy) 138kV	4.2
BHP Jansen Lake 230 kV Service	0.2
Cenovus	21.7
Enbridge Steelman 138kV	0.3
Far North Reinforcement	25.8
Global Transportation Hub	5.0
K&S - Permanent	0.2
K&S Temporary Phase II	4.2

Millennium (Cameco)	0.1
Mosaic Colonsay 230 kV Service	0.8
Mosaic Esterhazy K3 Interim	1.3
Mosaic Far Field Site Load	0.7
Mosaic K2 New Site Load	3.2
NBEC Interconnection	9.4
PCS Allen 230 kV Service	0.5
PCS Rocanville Exits Site 138kV	7.4
PCS Scissors Creek 138 kV	3.7
Shore Gold Diamond Site	0.3
TCP Keystone PS6 Fox Valley	2.2
TCP Keystone PS7 Piapot Permanent	1.3
TCP Keystone PS8 Grassy Creek Permanent	0.4
TCPL Keystone Expansion Phase 2	0.7
Total Customer Connects	**225.2**
Total Transmission & Distribution	**392.7**
Power Production	
Capacity Sustainment	
Poplar River #1 Ash Controls Replacement	4.2
Poplar River #1 HP #6 FWH Replacement	3.2
Poplar River #1 Precipitator Mechanical Upgrades	1.1
Poplar River #2A SBAC Upgrade	1.0
Poplar River #2B SBAC Upgrade	1.0
Poplar River #2 Main Steam Line Piping Replacement	1.1
Poplar River #3 N Ash Lagoon Renewal	0.7
Poplar River Dry Stacking Lagoon	(0.7)
BD #4 HP Heater Replacement #4	2.4
BD #4 Waterwall Replacement	1.0
BD #6 Economizer Life Extension	0.6
BD #6 Plant Coated Waterwall Panels	0.3
BD #6 Shielding Upgrades	0.6
BD Asbestos Removal 2012 - 2020	0.8
BD East Surface Lagoon Mgmt	0.8
BD Flyash Road	0.6
BD Flyash Storage & Loadout Upgrade	9.0
BD Hydrogen Systems Upgrade	2.3
BD Plant Elevator Upgrades	0.5
BD Security Buildings Upgrade	0.7
BD Waste Water Mgt Phase III	0.1
Shand Ash Loadout Upgrade	0.1
Shand Boiler House Contractor Facility	1.7
Shand Boiler Panel Replacement	24.3
Shand Burner Upgrades	3.1
Shand Condenser Retube	2.6
Shand Lifac Reactor Upgrade	0.1
Shand Major Overhaul 2012	3.6
Shand Mercury Capture	4.1
Shand PCMS Upgrade	3.9
Shand Pulveriser Outlet Gate Upgrade	0.6
Coteau Creek Rewind	0.8
EB Campbell 8 Runner Refurbishment	3.5
EB Campbell Plant Control Monitoring System	2.2
Island Falls #4 Refurbishment	1.0
Island Falls #5 Refurbishment	13.6
Island Falls #6 Refurbishment	4.5
Island Falls Plant Control Monitoring System	3.1
Tazin Weir & Tunnel Replacement	0.5
GT Capital Component Replacements	10.1
QE 480V MCC Replacement	0.8
QE Facility Upgrade	3.2
Yellowhead - Gas Turbines	(1.0)
Generator & Gearbox Replacement - Wind Facility	0.6
Miscellaneous Projects	5.7
Total Capacity Sustainment	**124.0**
QE Repowering	**25.7**
Elizabeth Falls	**0.0**
Carbon Capture Test Facility	
BD #3 ICCS - Carbon Capture	260.5
BD #3 ICCS - Power Island	94.1
Carbon Capture Test Facility	2.1
Total Carbon Capture Test Facility	**356.7**
Total Power Production	**506.4**
Other Capital Spending	
Operations Centre	0.0
Buildings/Furniture/Land	
Furniture & Equipment	3.6
Saskatoon Service Centre Expansion	1.5
Swift Current Service Centre	2.6
Weyburn Service Center T&D	11.2
Wynyard DO - T&D	1.8
Tantallon	(1.7)
Coronach Land Purchase	3.9
Estevan Land Purchase	1.7
Miscellaneous Projects	0.9
Total Buildings/Furniture/Land	**25.5**

Service Delivery Renewal	
SDR - Automated Metering Implementation	18.5
SDR - Field Worker Technology Phase II - Schedule & Dispatch	5.9
SDR - OMS Tactical	0.5
Miscellaneous Projects	0.3
Total Service Delivery Renewal	25.2
Information, Technology & Security	
Contact Centre & Outage IVR	1.3
Refresh/Net New	3.2
Enterprise Security	0.2
Enterprise Content Management Upgrades & Enhancement	1.0
Enterprise Content Management Collaboration & Integration	0.8
Field Services Inspections - Interim Solution	0.5
Managed Print Solutions	2.4
Net New Software	1.2
Office 2010/Exchange	1.8
OS Upgrade Windows 7	1.2
Saskatoon Data Centre	1.0
Business Intelligence	0.3
Enterprise Monitoring & Alerting	1.2
Enterprise Portfolio & Project Management Tools	0.6
Fibre Routes Reliability Enhancement - South - Optical Network Upgrade	4.7
Core Infrastructure 2012	3.3
Electric Office	0.7
Hydro Modernization Release 2	0.6
Perimeter Security Enhancement	0.8
Telephony	2.2
Miscellaneous Projects	1.8
Total Information, Technology & Security	30.8
Total Other Capital Spending	81.5
Total Capital Spending	980.6

Customer Connects - Capital Expenditures

(in $ millions)	Actual 2012	Forecast 2013	Forecast 2014	Forecast 2015	Forecast 2016
Residential	$ 32.8	$ 39.7	$ 42.5	$ 42.5	$ 42.5
Farm	8.3	8.2	6.9	6.9	6.9
Commercial	34.7	41.8	34.3	34.3	34.3
Oilfield	47.0	37.8	40.5	40.5	40.5
Other *	8.8	12.5	25.8	25.8	25.8
Total Distribution	131.6	140.0	150.0	150.0	150.0
Transmission	93.9	31.8	97.7	90.6	81.6
Total Customer Connects - Capital Expenditures	**$ 225.5**	**$ 171.8**	**$ 247.7**	**$ 240.6**	**$ 231.6**

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

Number of Customers

	Actual 2012	Forecast 2013	Forecast 2014	Forecast 2015	Forecast 2016
Residential	349,336	355,126	361,719	368,457	375,286
Farm	62,063	60,769	60,630	60,481	60,341
Commercial	56,392	56,716	57,321	57,939	58,566
Oilfield	16,446	17,152	17,992	19,034	19,608
Other					
Total Distribution	484,237	489,763	497,662	505,911	513,801
Transmission	100	101	100	105	107
Total Number of Customers	**484,337**	**489,864**	**497,762**	**506,016**	**513,908**

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Q15

The capital forecast for customer connects in the years 2014 to 2016 was determined based on a combination of discussions with external customers and analysis from SaskPower's network development department. In addition, the actual capital expenditures in 2012 relating to customer connects was used as a proxy to determine the reasonability of the capital budget for the years 2014 to 2016.

Round1 – SIECA Q16:

Explain how SaskPower can add 10,345 new connects in 2012 at a cost of $226 million and have effectively no growth in residential, farm and commercial electricity sales for the period 2013 through 2016?

Response:

As discussed in SIECA Q3, at the end of July the projected load for 2013 was 6.2% higher than the 2012 actual load. Of this 6.2% increase approximately 0.8% is due to abnormal weather and in particular the very cold weather in March and April of 2013. The abnormal weather in 2013 accounts for approximately 165 GWh of additional sales in the Residential, Farm, Commercial and Reseller classes. These extra weather related sales are distorting the growth rate for these classes going forward.

It is also important to remember that a large number of new connects are in the Oilfield class.

Round1 – SIECA Q17:

What portion of the $226 million spent on new connects in 2012 was spent connecting new customers in the residential, farm and commercial customer classes?

Response:

Of the $226 million spent on new connects in 2012, the following amounts were spent connecting new customers in the residential, farm and commercial customer classes:

2012 Customer Connects Capital Expenditures	
	Actual
(in $ millions)	**2012**
Residential	$32.8
Farm	8.3
Commercial	34.7
Oilfield	47.0
Other	8.8
Distribution	131.6
Transmission	93.9
Total Customer Connects Capital Expenditures	**225.5**
Other includes customer connects shared by multiple customer classes	

SaskPower

2014 RATE APPLICATION
SIECA INTERROGATORIES ROUND ONE

Round1 – SIECA Q18: Please explain the criteria through which capital expenditures are classified as "in-service" or "used and useful" and are incorporated into the rate base?

Response:

Capital expenditures are classified as "in-service" when the asset is in the location and condition necessary for it to be capable of operating in the manner intended by management. The asset must also provide economic benefit (ex: revenue) to SaskPower before it can be classified as "in-service." Once an asset is classified as "in-service" then it is incorporated into the rate base.

Round1 – SIECA Q19:

Please provide the debt/equity ratio from 2008-2013 and projected for 2014-2016?

Response:

The following is a summary of SaskPower's actual debt ratio for the years 2008 to 2012 and SaskPower's forecasted debt ratio for the years 2013 to 2016.

	2008	2009	2010	2011	2012	2013	2014	2015	2016
% Debt	60.7%	61.4%	62.7%	62.6%	67.1%	71.4%	74.6%	76.4%	77.0%

Round1 – SIECA Q20:

Please provide the cost benefit analysis conducted for the AMI project?

Response:

The SaskPower Board of Directors has approved the development and installation of an Advanced Metering Infrastructure (AMI) system as part of the Service Delivery Renewal (SDR) program. As stated in the approved business case, the total project cost is estimated to be $190 million ($166M capital, $24M OM&A).

The investment in AMI will conservatively generate $470 million in benefits for SaskPower over a 20-year period with a Net Present Value (NPV) of $25 million, a payback period of 12 years and an IRR of 10.3%.

Meter reading, as well as the connecting or disconnecting of service to customers, is currently performed manually. With AMI, we'll save on those labour costs, as well as vehicle maintenance, fuel and travel. With the new meters, we'll also be able to do more work remotely - meter reading, connects/disconnects, and tracking and pinpointing power outage locations – which will mean additional cost savings.

Reducing the travel requirements to read meters in person will also deliver significant benefits: SaskPower will realize fuel savings worth approximately $700,000 annually and will reduce its vehicle-related costs by approximately $1 million annually.

2014 RATE APPLICATION
SIECA INTERROGATORIES ROUND ONE

Round1 – SIECA Q21:

SaskPower cites its current generating capacity at 4,302 MW. Please provide an annual listing of actual generation additions and generation retirements for the period 2004 through 2013; and provide same for the forecast period 2014 through 2026.

Response:

Year	Facility	Fuel Type	Capacity (MWH's)
2006	NRGreen Heat Recovery Facility	Waste Heat Recovery	5
2006	Centennial Wind Power Facility	Wind	149
2008	NRGreen Heat Recovery Facility	Waste Heat Recovery	15
2009	Ermine Power Station	Natural Gas	89
2010	Queen Elizabeth Plant D	Natural Gas	108
2010	Yellowhead Power Station	Natural Gas	138
2011	Red Lily Wind Power Facility	Wind	26
2011	Spy Hill Generating Station	Natural Gas	89
2012	Prince Albert Pulp Inc	Biomass	10
2012	Green Options Partners Program	Various	1
2013	North Battleford Generating Station	Natural Gas	261
2013	Green Options Partners Program	Various	1
2013	Boundary Dam Unit 1 Retired	Coal	(62)
2013	Boundary Dam Unit 3 Clean Coal Project (net reduction)	Coal	(29)
2014	Green Options Partners Program	Various	2
2015	Manitoba Hydro Import Contract	Hydro (Import)	25
2015	Meadow Lake Bioenergy Centre	Biomass	36
2015	Green Options Partners Program	Various	33
2015	BD2 Retired	Coal	(61)
2016	Chaplin Wind Enegy Project	Wind	177
2016	Green Options Partners Program	Various	20
2017	Tazi Twe (under negotiation)	Hydro	50

No decisions have been made on unit installations past 2017 at this time

Round1 – SIECA Q22:

SaskPower has stated that a new peak demand level of 3,379 MW was recorded in 2013. What was the total MW of active generation capacity and reserve generation capacity that would have been mandated by NERC at the time that the most recent peak was set?

Response:

The actual and NERC required reserves for the 2013 peak are summarized in the table below.

On-line Capacity* [MW]	Spinning Reserve [MW]	Non-Spinning Reserve [MW]	Total Operating Reserve [MW]	NERC Requirement [MW]
3732	327	99	426	281

*Note that On-line Capacity does not include imports or interruptible load.

Round1 – SIECA Q23A:

Please provide the following in Excel spreadsheet format:

a. For owned generation please provide:

i. Name plate capacity, accredited capacity and in service date by unit

ii. Actual annual MWh generation by year for the period 2010-2012, $/MWh variable cost (fuel and variable O&M) and projected for 2013-2016

b. For natural gas PPAs and imports (in aggregated data for the PPAs and imports to avoid confidentiality concerns) please provide:

i. MWh generation by year for the period 2010-2012 and $/MWh variable cost (fuel and variable O&M) and projected for 2013-2016.

ii. Please provide the capacity cost charges for the PPAs for the period 2010-2012 (actual) and 2013-2016 (forecast).

Response:

a.i.

Plant	Unit	In Service Date	Nameplate Net Capacity
COAL			
Boundary Dam	1	07/01/1959	Retired
	2	06/01/1960	61
	3	12/01/1969	139
	4	08/01/1970	139
	5	08/01/1973	139
	6	12/01/1977	288
Poplar River	1	07/15/1983	291
	2	05/31/1981	291
Shand	1	07/14/1992	276
Gas			

Queen Elizabeth	1 Turbine	11/01/1958		
	2 Turbine	1959-10-01.		
	3	11/15/1972	95	
	4 - 9	02/01/2002	227	all units including QE1 steam
	10	03/15/2010	36	
	11	03/15/2010	36	
	12	03/15/2010	36	
Ermine	1	12/01/2009	46	
	2	12/01/2009	46	
Landis	1	11/01/1975	79	
Meadow Lake	1	12/11/1984	44	
Success	1	1967-08	10	
Success	2	1967-11	10	
Success	3	1968-01	10	
Yellowhead	1	12/01/2010	46	
Yellowhead	2	12/01/2010	46	
Yellowhead	3	12/01/2010	46	
Hydro				
Coteau Creek	1	09/20/1968	62	
Coteau Creek	2	11/01/1968	62	
Coteau Creek	3	12/20/1968	62	
EB Campbell	1	04/07/1963	34	
EB Campbell	2	06/30/1963	34	
EB Campbell	3	09/05/1963	34	
EB Campbell	4	10/29/1963	34	
EB Campbell	5	03/01/1964	34	
EB Campbell	6	04/01/1964	34	

EB Campbell	7	11/01/1966	42	
EB Campbell	8	12/01/1966	42	
Island Falls	1	1930	14	
Island Falls	2	1930	14	
Island Falls	3	1930	14	
Island Falls	4	1937	18	
Island Falls	5	1939	18	
Island Falls	6	1948	18	
Island Falls	7	1959	15	
Nipawin	1	03/01/1986	85	
Nipawin	2	12/15/1985	85	
Nipawin	3	04/18/1986	85	
Charlot River	1	1980	5	
Charlot River	2	1980	5	
Waterloo	1	1961	8	
Wellington	1	1939	2.4	
Wellington	2	1959	2.4	
Wind				
Cypress	CA1-4 MC1-5 MC6-12	10/18/2002 10/18/2002 12/13/2003	10.6	Total Cypress capacity
Centennial	RC1-83	03/15/2006	149.4	Total Centennial Capacity

a.*ii.*

SaskPower

2014 RATE APPLICATION
SIECA INTERROGATORIES ROUND ONE

Volumes							
	Actual			Forecast			
(in GWh)	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
Gas	1,176	1,194	1,711	1,891	2,150	2,865	3,977
Coal							
Boundary Dam	5,862	5,433	5,740	5,100	5,192	5,230	5,207
Shand	2,068	2,064	1,495	2,122	2,300	2,316	2,306
Poplar River	4,216	4,216	4,296	4,051	4,229	4,259	4,241
Wind	478	570	541	534	552	552	554
Hydro	3,866	4,641	4,240	4,447	3,645	3,644	3,607

Variable Cost / Mwh							
	Actual			Forecast			
(in $ / Mwh's	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
Gas	$67.69	$69.27	$57.16	$59.86	N/A	N/A	N/A
Coal							
Boundary Dam	30.50	33.17	31.76	34.47	N/A	N/A	N/A
Shand	30.32	30.96	42.67	31.68	N/A	N/A	N/A
Poplar River	21.99	24.03	24.91	26.41	N/A	N/A	N/A
Wind	9.83	10.18	11.83	12.73	N/A	N/A	N/A
Hydro	7.24	7.13	7.76	7.78	N/A	N/A	N/A

2010 to 2012 figures based on actual, 2013 figures based on July 2013 forecast (January to July actual, August to December forecast), 2014 to 2016 figures based on 2014 Business Plan and estimates.

Note Variable Cost / Mwh for 2014 through 2016 have not been provided as OM&A is not available at this time.

Round1 – SIECA Q23B:

Please provide the following in Excel spreadsheet format:

a. For owned generation please provide:

   i. Name plate capacity, accredited capacity and in service date by unit

   ii. Actual annual MWh generation by year for the period 2010-2012, $/MWh variable cost (fuel and variable O&M) and projected for 2013-2016

b. For natural gas PPAs and imports (in aggregated data for the PPAs and imports to avoid confidentiality concerns) please provide:

   i. MWh generation by year for the period 2010-2012 and $/MWh variable cost (fuel and variable O&M) and projected for 2013-2016.

   ii. Please provide the capacity cost charges for the PPAs for the period 2010-2012 (actual) and 2013-2016 (forecast).

Response:

This response contains confidential information and cannot be released publicly. A response was sent to the Saskatchewan Rate Review Panel for their review.

SaskPower

2014 RATE APPLICATION
SIECA INTERROGATORIES ROUND ONE

Round1 – SIECA Q24:

Please provide the gross and net MWs generated and the total capital costs associated with the Integrated Carbon Capture Sequestration (BD3) project? How much federal funding did SaskPower receive in total for this project? Please provide a breakdown of the capital costs spent on the boiler and turbine (power island) and provide a breakdown of the carbon capture and sequestration assets?

Response:

The ICCS Project at Boundary Dam involves Unit #3. Its gross production will be 160 MW and it will provide a net 110-120 MWs to the grid.

The current capital budget for the ICCS Project is $1, 382 million.

SaskPower received $240 million from the Federal Government. This figure is included in the above budget total.

Carbon Capture	Incurred	Final Forecast	Original Budget
Commissioning	$ 5,078	$ 17,224	
Construction Services	$ 5,232	$ 5,826	
Project Management	$ 27,562	$ 29,991	
Admin	$ 4,010	$ 4,067	
Power Systems	$ 15,957	$ 19,379	
Carbon Capture	$ 611,409	$ 622,860	
Site Facilities	$ 12,536	$ 14,348	
Water and Chemical System	$ 69,961	$ 74,030	
IDC	$ 32,963	$ 44,263	
Waste Water Management	$ 473	$ 472	
Total Carbon Capture	**$ 785,181**	**$ 832,460**	**$ 848,000**

Power Island	Incurred	Final Forecast	Original Budget
Commissioning	$ 134	$ 360	
Construction Services	$ 5,337	$ 7,762	
Project Management	$ 41,696	$ 47,202	
Admin & OHD	$ 1,812	$ 1,877	
Steam Generator	$ 134,550	$ 144,626	
Power Systems	$ 34,602	$ 44,094	
Exhaust Systems	$ 401	$ 444	
Site Facilities	$ 881	$ 1,339	
Power Gen Buildings	$ 25,555	$ 28,667	
Turbine Generator	$ 159,212	$ 191,213	
IDC	$ 16,392	$ 20,392	
Misc	$ 38	$ 37	
Total Power Island	**$ 420,610**	**$ 488,013**	**$ 364,000**
Pre-Engineering and Feasibility	**$ 30,500**	**$ 30,500**	**$ 30,500**

	Incurred	Final Forecast	Original Budget
Total Actual/Budget	**$ 1,236,291**	**$ 1,350,973**	**$ 1,242,500**

Round1 – SIECA Q25:

On page 26 of the application, SaskPower states the following:

> *"In 2014, SaskPower is forecasting an increase in other revenue as the first CO2 sales from the Boundary Dam Integrated Carbon Capture and Storage project are expected to be earned"*

Please explain this sale, how the revenue was calculated and the source or basis for the assumption of the CO2 price?

Response:

SaskPower has a contract with Cenovus for all the CO2 produced by the ICCS Project. This is expected to be approximately 1,000,000 tonnes per annum. The contract with Cenovus is for a 10 year period. The price is commercially confidential.

SaskPower entered negotiations with an expectation of selling its CO2 for a similar price that existed elsewhere of between $20 – 40/tonne. This objective was achieved.

The amount of revenue expected is based on an effective date of 1 April 2014.

Round1 – SIECA Q26:

Please provide an organizational chart that details (by year from 2009 to 2013) the historical number and departmental deployment of SaskPower employees and contractor personnel.

Response:

See the corresponding schedules.

SASKPOWER
EXECUTIVE
2009 JULY 01

2009 FTEs	
President / Board	3
Power Production	913
Transmission & Distribution	1111
Corporate & Financial Services	165
Customer Services	421
Planning & Environment	611
People & Processes	87
Corporate Information & Technology	46
Clean Coal Technology	13
Coporate Relations	38
Law, Land, Regulatory Affairs	34
NorthPoint Energy Solutions	50
Total	**2947**

PRESIDENT & CHIEF EXECUTIVE OFFICER
Pat Youzwa

VICE-PRESIDENT CORPORATE RELATIONS
Kevin Doherty

VICE-PRESIDENT & CIO CORP INFORMATION & TECHNOLOGY
Tom Kindred

VICE-PRESIDENT POWER PRODUCTION
Garner Mitchell

VICE-PRESIDENT CUSTOMER SERVICES
Judy May

VICE-PRESIDENT LEGAL, LAND & REGULATORY AFFAIRS
Philip Davies

PRESIDENT & CEO NORTHPOINT ENERGY SOLUTIONS INC.
Grant Ring

VICE-PRESIDENT & CFO FINANCE & ENTERPRISE RISK MANAGEMENT
Sandeep Kalra

VICE-PRESIDENT INTEGRATED CARBON CAPTURE & SEQ PROJECT
Michael Monea

VICE-PRESIDENT TRANSMISSION & DISTRIBUTION
Mike Marsh

VICE-PRESIDENT PLANNING, ENV & REGULATORY AFFAIRS
Gary Wilkinson

VICE-PRESIDENT PEOPLE & PROCESSES (Safety, HR)
VACANT

SASKPOWER EXECUTIVE
2010 AUGUST 16

	2010	2011
President / Board	3	3
Power Production	907	860
Transmission & Distribution	1145	1185
Corporate & Financial Services	158	135
Customer Services	436	444
Planning & Environment	68	64
People & Processes	86	90
Corporate Information & Technology	87	99
Clean Coal Technology	13	14
Corporate Relations	31	33
Law, Land, Regulatory Affairs	34	33
NorthPoint Energy Solutions	50	40
Total	**3018**	**3000**

PRESIDENT & CHIEF EXECUTIVE OFFICER
Robert Watson

VICE-PRESIDENT CORPORATE RELATIONS
Kevin Doherty

PRESIDENT & CEO NORTHPOINT ENERGY SOLUTIONS INC.
Grant Ring

VICE-PRESIDENT & CIO CORP INFORMATION & TECHNOLOGY
Tom Kindred

VICE-PRESIDENT & CFO FINANCE & ENTERPRISE RISK MANAGEMENT
Sandeep Kalra

ACTING VICE-PRESIDENT POWER PRODUCTION
John Lebersback

VICE-PRESIDENT INTEGRATED CARBON CAPTURE & SEQ PROJECT
Michael Monea

SENIOR EXECUTIVE ADVISOR
Garner Mitchell

VICE-PRESIDENT CUSTOMER SERVICES
Judy May

VICE-PRESIDENT TRANSMISSION & DISTRIBUTION
Mike Marsh

VICE-PRESIDENT PEOPLE & PROCESSES
VACANT

VICE-PRESIDENT LAW, LAND & REGULATORY AFFAIRS
Philip Davies

ACTING VICE-PRESIDENT PLANNING, ENV & REGULATORY AFFAIRS
Guy Bruce

- **Robert Watson** — President & CEO
  - **Grant Ring** — Vice President Business Development
    - **Mark Peters** — VP Project Dev & Operations
    - **Lain Lovelace** — Director Energy & Risk Management
    - **Stan Saylor** — Supervisor Environmental Studies
    - **Ranjith Narayanasamy** — Sr Generation Projects Engineer
    - **Benson Thoudsanikone** — Sr Technical Advisor
  - **Steve Sousa** — Chief Commercial Officer Commercial
    - **Vacant** — Director Major Projects
    - **Keith Moen** — General Manager Service Delivery Renewal
  - **Tom Kindred** — Vice President & CIO Information Technology & Security
    - **Brian Dalby** — Manager Infrastructure Services
    - **Grant Crawford** — Manager Enterprise Architecture & Planning
    - **Sean McKim** — Manager Enterprise Security
    - **Nadine Hearn** — Manager Application Development & Support
    - **John Donhauser** — Manager Project Management Office
    - **Carla Feld** — Manager IT Business Services
    - **Gwen Fex** — Manager Enterprise Programs
  - **Sandeep Kalra** — Vice President & Chief Financial Officer Finance
    - **John Scobie** — Manager Business Analysis & Risk Management
    - **Ian Yeates** — Director Corporate Planning & Rate Design
    - **Dairen Beblow** — Treasurer
    - **Troy King** — Controller & Business Planning
    - **Jennifer Pederson** — Internal Auditor
    - **Murray Black** — Manager Business Analysis
  - **Jim Diotte** — Vice President Human Resources
    - **Glenda Barton** — Chief Safety Officer
    - **Karen Vey** — General Manager HR Operations
    - **Debbie Nielsen** — Manager Environmental Programs
    - **Judy May** — Vice President Special Projects
  - **Rachelle Verret Morphy** — Vice President Law, Land & Regulatory Affairs
    - **Michael Anderson** — Chief Electrical Inspector
    - **Syed Asif Ali** — Chief Gas Inspector
    - **John Phillips** — Associate General Counsel & Manager
    - **Michael Crosbie** — Assistant General Counsel
    - **Jonathan Kalmakoff** — Assistant General Counsel
    - **Sharon Twardy** — Corporate Paralegal
  - **Guy Bruce** — Vice President Resource Planning; President & CEO NorthPoint
    - **Iain Harry** — General Manager Clean Energy
    - **Brian Mohr** — Manager Sustainable Supply Dev
    - **John McKenzie** — Manager Strategic Development
    - **Kelly Kramer** — Manager Fuel Supply (Acting)
    - **Kory Hayko** — Director Gas Mgmt & Electricity Trading
    - **Dean Krauss** — Director Power Marketing & Contract Mgmt
  - **Michael Monea** — President, SaskPower Carbon Capture & Storage Initiatives
    - **Doug Daverne** — Manager Carbon Capture & Storage Initiatives
    - **Rhonda Smysniuk** — Sr Technical Advisor
    - Intellectual Property I.C.C.S.
    - Shand Demo C.C.T.F.
    - CO2 Sales
    - Education
  - **Mike Marsh** — Chief Operations Officer Operations
    - **John Lebersback** — Vice President Power Production
    - **Dennis Felgate** — General Mgr Transmission Services
    - **Ted Elliott** — General Mgr Distribution Services
    - **Jim Fraser** — Manager Logistics
    - **Vacant** — Business Performance & Planning
    - **Vacant** — Asset Management
  - **Diane Avery** — Vice President Customer Services
    - **Blair Debruyne** — Manager Customer Care and Billing
    - **Rhea Brown** — Manager Customer Relations
    - **Daryl Deibert** — Manager Business & Technology Support
    - **Dominic Savio** — Manager Customer Programs
    - **Kristin Linklater** — Manager Communications
  - **Donna Dressler** — General Manager Strategic Relations
    - **Wayne Rude** — Manager Aboriginal Relations
    - **Bernie Bolen** — Manager Stakeholder Engagement & Consultation
    - **Judith Fox** — Manager Stakeholder Relations
    - **Joanne Laslo** — Coordinator Board Relations

	2012 Actual	2013 Forecast	2014 F	2015 F	2016 F
President / Board	13	16	16	16	16
Operations	1995	2087	2180	2170	2174
Commercial	120	135	160	135	135
Finance	84	114	114	114	114
Customer Services	435	413	385	337	337
Resource Planning and NorthPoint	71	76	75	75	77
Human Resources	167	187	177	174	174
Information, Technology & Security	121	170	192	194	194
Clean Coal Technology	17	17	28	24	24
Law, Land & Regulatory Affairs	122	130	144	144	144
Business Development	7	7	7	7	7
Total	**3153**	**3352**	**3478**	**3390**	**3396**

SaskPower

Effective April 22, 2013

Round1 – SIECA Q27:

Please provide the forecast number and departmental deployment of planned SaskPower and contractor positions that are expected to be in place during the period 2014 through 2016.

Response:

SaskPower's targeted FTE's for the period 2013 to 2016 are as follows:

SaskPower 2013 to 2016 FTE Projection					
	2013 Target	2014	2015	2016	Change 2013-2016
President's Office	16	16	16	16	0
Power Production	850	897	869	865	15
Transmission	299	307	307	310	11
Distribution	655	663	685	690	35
Asset Management	137	144	144	144	7
Operation's Other	146	169	165	165	19
Finance	114	114	114	114	0
Customer Services	413	385	337	337	(76)
Resource Planning & NRPT	76	75	75	77	1
Law, Land & Reg. Affairs	130	144	144	144	14
Info Technology & Security	170	192	194	194	24
Human Resources	187	177	174	174	(13)
Commercial	135	160	135	135	0
Business Development	7	7	7	7	0
ICCS	17	28	24	24	7
Total	3,352	3,478	3,390	3,396	44
Annual Change		126	(88)	6	44

SaskPower does not specifically calculate the number of contractor FTE's working for the company for a number of reasons. First, many roles performed by contractors are seasonal in nature and therefore, the contracted employee is employed by SaskPower for a limited time. An example of this would be plant overhauls, which are typically conducted in the spring and autumn months. SaskPower will engage the services of contract welders, labourers, etc. to perform services until the overhaul is complete. The start and end date of each contractor will vary based on the work that is required. Second, SaskPower will hire companies, as opposed to individual contractors, to perform duties such as brush clearing or vegetation management. In these instances, SaskPower may or may not be aware of the number of contract employees that will be used to perform the work.

Round1 – SIECA Q28:

Has SaskPower conducted any peer benchmarking of OM&A costs? Please explain. If no such benchmarking is done, how does SaskPower ascertain that it is maximizing efficiency from an operational perspective?

Response:

- Yes, we have conducted benchmarking around OM&A costs but do not currently have an ongoing peer benchmarking mechanism. Utilities define OM&A differently so benchmarking against other utilities does not necessarily result in like comparisons. The other challenge in benchmarking against peers is the use of different accounting methodologies. SaskPower adopted *International Reporting Standards* (IFRS) in 2010 and are currently one of the only regulated Canadian utility using those standards. The other utilities use either *Canadian Generally Accepted Accounting Principles* (CGAPP), US GAAP or a modified version of IFRS.
- One of the main differences between SaskPower's accounting practices and those used by other regulated utilities in Canada and the United States is that the other utilities employ rate regulated accounting. The use of rate regulated accounting permits utilities to defer the recognition of certain expenses based on direction from their regulator. For example, BC Hydro has deferred approximately $4.5 billion of expense as of June 30, 2013. SaskPower is unable to use rate regulated accounting because it is not permitted by IFRS and SaskPower is not considered to a regulated utility for accounting purposes because its rates are set by Cabinet.
- Up until 2011, data was collected annual through the Committee on Performance Excellence (COPE), a sub-committee of the Canadian Electrical Association. The last annual benchmarking report was published in 2009. This benchmarking has been discontinued since the results were so difficult to interpret.
- In 2010 and 2011, external consultants KPMG and UMS Group were engaged to review our OM&A, Capital, and Fuel spending with a view to finding efficiencies and conducted benchmarking against other utilities. A number of efficiency initiatives are being implemented through our Business Renewal program based on those studies. Major initiatives include improvements to Asset Management (which includes extending the time between overhauls and shortening overhauls in a prudent way to maintain reliability), Procurement changes to improve competitive bidding and minimize lifecycle costs, and Materials Management improvements for Transmission and Distribution to reduce inventory levels.

- OM&A receives close scrutiny as part of SaskPower's budget process, but these cost control efforts must be balanced against impacts such as increased fuel costs, reduced system reliability, and the need to connect new customers in a timely way.

Round1 – SIECA Q29:

Please provide a variance analysis comparing budgeted to actual OM&A costs for the period 2010-2013. Please use the same categories as provided in the OM&A spending table on page 41 of the application. Please provide in Excel spreadsheet format.

Response:

SaskPower Operating, Maintenance & Administration											
	Actual	Budget		Actual	Budget		Actual	Budget		Forecast	Budget
(in $ millions)	**2010**	**2010**		**2011**	**2011**		**2012**	**2012**		**2013**	**2013**
Power Production	$151.8	$158.8		$158.7	$172.3		$168.7	$160.6		$154.6	$152.2
Transmission & Distribution	118.6	113.9		129.6	120.1		149.6	117.6		135.6	127.9
Asset Management	22.3	24.1		26.1	30.6		28.0	32.0		22.6	29.5
Operation Other	11.8	7.3		19.7	18.2		18.3	27.6		16.8	10.9
Subtotal Operations	**304.5**	**304.1**		**334.1**	**341.2**		**364.6**	**337.8**		**329.6**	**320.5**
President/Board	3.2	2.6		2.7	2.9		3.5	3.0		3.4	3.4
Finance	16.8	17.3		16.2	19.8		15.2	15.1		16.3	16.3
Customer Services	41.8	44.7		44.6	44.9		45.7	44.0		48.2	48.2
Resource Planning & NorthPoint	16.1	22.2		14.7	22.7		14.4	16.0		17.6	17.6
Law, Land, Regulatory Affairs	12.7	15.2		14.0	15.3		14.8	15.3		17.4	17.4
Information Technology & Security	40.9	40.1		47.8	48.3		56.5	55.4		61.5	62.0
Human Resources	20.3	25.6		22.3	27.0		25.6	24.1		27.2	27.2
Commercial	17.8	21.2		15.9	23.1		16.3	16.9		31.9	31.4
Business Development	0.0	0.0		12.5	0.0		3.9	2.8		1.1	1.1
Carbon Capture & Storage Initiatives	0.7	0.0		2.2	1.1		2.6	2.4		10.6	4.6
Total Core Costs	**474.8**	**493.0**		**527.0**	**546.3**		**563.1**	**532.8**		**564.8**	**549.7**
Demand Side Management	8.8	12.6		11.8	24.0		19.2	20.2		15.4	15.4
PPA-OMA	16.8	0.0		20.3	24.9		24.2	23.5		26.2	26.2
Other Expense	12.8	6.1		19.9	13.6		13.2	5.8		11.3	26.4
Total Other Costs	**38.4**	**18.7**		**52.0**	**62.5**		**56.6**	**49.5**		**52.9**	**68.0**
Total OMA	**$513.2**	**$511.7**		**$579.0**	**$608.8**		**$619.7**	**$582.3**		**$617.7**	**$617.7**

2010 to 2012 figures based on actual and budget, 2013 figures based on July 2013 forecast (January to July actual, August to December forecast) and budget.

Note the actual pension expense for 2010 has been included in the 2010 budget for Other Expense.

2014 RATE APPLICATION
SIECA INTERROGATORIES ROUND ONE

Round1 – SIECA Q30:

Please provide a variance analysis comparing budgeted to actual fuel costs and forecast to actual volumes for the period 2010-2013. Please use the same categories as provided on page 34. Please provide in Excel spreadsheet format.

Response:

Net Fuel and Purchased Power Expense

	2010		2011		2012		2013	
(in $ millions)	Actual	Budget	Actual	Budget	Actual	Budget	Forecast	Budget
Fuel Expense								
Gas	$183.5	$297.1	$195.6	$226.8	$213.8	$249.2	$230.5	$242.3
Coal	212.2	200.3	219.4	209.9	221.8	225.7	233.6	237.9
Wind	2.2	2.8	9.3	5.4	9.6	10.0	9.8	10.2
Hydro	15.8	13.0	20.0	14.7	19.1	14.2	21.0	15.8
Imports	20.3	53.9	24.4	24.7	31.2	20.1	25.9	14.3
Other	11.5	12.0	16.7	15.1	17.8	15.7	26.5	24.6
Total Fuel and Purchased Power Expense	**$445.5**	**$579.1**	**$485.4**	**$496.6**	**$513.3**	**$534.9**	**$547.3**	**$545.1**

2010 to 2012 figures based on actual and budget, 2013 figures based on July 2013 forecast (January to July actual, August to December forecast) and budget

Net Fuel and Purchased Power Volumes

	2010		2011		2012		2013	
(in GWh)	Actual	Budget	Actual	Budget	Actual	Budget	Forecast	Budget
Fuel Expense								
Gas	3,682	4,177	4,032	4,857	4,968	5,752	6,235	7,200
Coal	12,038	12,084	11,614	12,478	11,446	12,471	11,172	11,777
Wind	507	608	682	625	655	675	650	675
Hydro	3,866	3,302	4,641	3,324	4,240	3,319	4,447	3,327
Imports	518	1,052	502	590	656	505	496	288
Other	148	158	140	157	164	157	216	217
Gross Volumes	**20,759**	**21,381**	**21,611**	**22,031**	**22,129**	**22,879**	**23,216**	**23,484**

2010 to 2012 figures based on actual and budget, 2013 figures based on July 2013 forecast (January to July actual, August to December forecast) and budget

2014 RATE APPLICATION
SIECA INTERROGATORIES ROUND ONE

Round1 – SIECA Q31:

Regarding natural gas, please provide the $/GJ costs by year for 2012-2016 and provide a categorized breakdown of how these costs was derived. The cost categorization should include natural gas commodity cost, hedge settlement or mark-to-market costs, intra-provincial transportation costs, inter-provincial transportation costs and storage costs.

Response:

The $/GJ for the cost of gas for 2012-2016 is as follows. The intra-provincial transportation, inter-provincial transportation and storage costs are also provided below.

	2012	2013	2014	2015	2016
Storage and Transport (Millions)	$ 24.0	$ 25.4	$ 37.4	$ 45.4	$ 50.5
Cost of Gas ($/GJ)	$ 4.39	$ 3.63	$ 3.60	$ 3.94	$ 3.88

Round1 – SIECA Q32:

Please provide an annual system wide heat rate for gas-fired generation (both SaskPower owned and PPA) for the period 2004-2016.

Response:

The table below indicates the annual system wide heat rate for gas fired generation for the period 2004-2016. The 2013 to 2016 figures are forecasts.

Annual System Wide Heat Rate	
Year	MJ/MWh
2004	8,436
2005	8,427
2006	8,655
2007	8,701
2008	8,621
2009	8,278
2010	8,691
2011	8,633
2012	8,709
2013	8,797
2014	8,442
2015	8,561
2016	8,484

SaskPower

2014 RATE APPLICATION
SIECA INTERROGATORIES ROUND ONE

Round1 – SIECA Q33:

Are the current SaskPower gas price hedging strategy and the current levels of hedge coverage over the rate application period consistent with a rate application that fixes the electricity rates for a three year period? If yes explain why, and if no, what changes would SaskPower recommend to the strategy?

Response:

SaskPower's hedging program contains three objectives:

1. **Security of Supply** – Securing a portion of the natural gas supply allows for operational flexibility while stabilizing a portion of the fuel and purchased power budget.
2. **Market Access** – Managing market access by acquiring transportation service from gas markets to the gas-fired facilities.
3. **Price Stability** – The price management component allows for the protection against high natural gas prices while maintaining some upside potential, if prices should fall.

The SaskPower hedging program is designed, in part, to stabilize a portion of the natural gas component within the fuel and purchased power budget. SaskPower has hedged the price on the following percentage of forecasted natural gas consumption for the next 3 years:

- 2014 – 50%
- 2015 – 45%
- 2016 – 40%

Due to the diverse fuels mix in SaskPower's generation, it is impossible to fix all of the natural gas requirements. As operational plans unfold and change, natural gas volumes adjust accordingly thereby creating an unpredictable volume variance.

In order to fix the electricity rates for a three year period, all generation would have be concretely known and one hundred percent hedged.

Round1 – SIECA Q34:

What was the annual loss or gain on a $/GJ of actual gas consumption (including both owned and PPA) basis from natural gas hedging for the period 2009-2012?

Response:

Due to a declining market price environment over the past 5 years, the settlement value on financial transactions was negative. However, this negative value was offset by the unhedged natural gas purchased at a lower than budgeted market price. As a result, SaskPower's total cost of gas was lower than budgeted.

The settlement value on a per unit basis when compared to total gas consumption (including both owned and PPA) is as follows:

Year	Settlement Value ($/GJ)
2009	-$2.66
2010	-$1.01
2011	-$0.92
2012	-$0.79

Round1 – SIECA Q35:

Please provide a copy of the Christensen and Associates report on the evaluation of the fuel cost variance accounting?

Response:

A copy of this document has been provided to the Saskatchewan Rate Review Panel and a copy will be made available on the SRRP website.

Round1 – SIECA Q36:

Please provide an explanation of how the fixed production plant was classified as demand and energy related? Please also provide a breakdown of how the fixed production costs of the various owned units were classified? Regarding the PPAs, please provide the same breakdown and identify if the PPAs are capacity based, energy based or both?

Response:

The classification methodology currently used by SaskPower for generation rate base and 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 costs into demand and energy related.

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. 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.

SaskPower's methodology and results were reviewed by Elenchus Associates during its 2012 Cost of Service Review and determined that SaskPower's classification percentages are not out of line with other utilities and saw no compelling reason for SaskPower to change its classification methodology.

The table below details SaskPower's breakdown of its fixed production costs (Plant in Service, Accumulated Depreciation & Depreciation) based on the Equivalent Peaker Method:

Classification of SaskPower Fixed Production Costs

Generation Type	Average Demand Related (%)	Average Energy Related (%)	Total (%)

Single Cycle Gas	100%	0%	100%
Conventional Coal	52%	48%	100%
Combined Cycle Gas	83%	17%	100%
Hydro	31%	69%	100%
Wind	20%	80%	100%
Diesel	100%	0%	100%

The total (including fuel cost) purchased power breakdown to demand / energy based on fixed/variable payments to the supplier is displayed in the table below:

Classification of Total Purchased Power Expense

	Average Demand Related (%)	Average Energy Related (%)	Total (%)
Overall Weighting	34%	66%	100%

Wind and Green Power are classified as 100% energy, gas fired generation is classified both energy & demand.

Round1 – SIECA Q37:

Please explain why consumers that use energy efficiently (high load factor customers) are facing a higher than average rate increase?

Response:

The following response assumes the question is referencing Power class (industrial)) customers.

High load factor customers are actually facing a lower increase in this rate application compared to low load factor customers. This is because the last time SaskPower rebalanced rates was in August of 2010, as there were no rate increases in 2011 and 2012 and the 2013 rate increase was applied to all components of the rate (basic charge, demand charge and energy charge) because SaskPower was in the middle of an external cost of service / rate design methodology review. Since 2010 there has been a change in the demand and energy weighting of purchased power expense (higher demand and lower energy) which results in the relatively higher demand charges. For most rates, the higher demand charge increases are limited to 2014. The 2015 and 2016 demand charge increases are more in line with the class average rate increases.

If the question was why Power class (industrial) rates are increasing by more than the system average rate increase, the following response applies. As SaskPower holds the line on OM&A costs (relative to load growth) a larger portion of SaskPower's projected rate increases are driven by fuel and purchased power and generation and transmission capital expenditures. Since Power class rates consist primarily of generation and transmission costs, the Power class rate increases in the 2014 rate application are higher than the system average. SaskPower has tried to provide advanced warning of this phenomenon to customers at recent SIECA meetings. The system and the Power – Published Rate class rate increases for the 2014 rate application are as follows:

	System Increase	**Published Power Class**
2014	5.5%	7.0%
2015	5.0%	5.8%
2016	5.0%	5.8%

A rate sensitivity example may help explain the impact of higher generation costs on the Power class.

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Rate Sensitivity Example				
Impact of a $ 25 million (1.3%) increase in fuel costs on the Power class				
	Current Rate (cents/kWh)	Additional Fuel Cost (cents/kWh)	New Rate (cents/kWh)	Rate Increase (cents/kWh)
Power Class	6.19	0.12	6.31	1.9%
All Other Classes	10.61	0.12	10.73	1.1%
All Classes	8.89	0.12	9.01	1.3%
Impact of a $ 25 million (1.3%) increase in distribution costs on the Power class				
	Current Rate (cents/kWh)	Additional Distribution Cost (cents/kWh)	New Rate (cents/kWh)	Rate Increase (cents/kWh)
Power Class	6.19	-	6.19	0.0%
All Other Classes	10.61	0.23	10.84	2.2%
All Classes	8.89	0.12	9.01	1.3%
Notes:				
- For simplicity the additional fuel costs does not include the impact of line losses.				
- Fuel cost s are shared by all customers whereas distribution costs are shared by customers fed off the distribution system.				

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Round1 – SIECA Q38:

Has SaskPower taken into account that as rates rise by 20% over 3 years for the Power Class, the potential rate shock may cause demand destruction or shifting of electricity cost sensitive customer load out of Saskatchewan? Please explain why or why not?

Response:

This question has been interpreted as follows. Has SaskPower reduced its load forecast to account for the potential for the 3 year rate increase to cause industrial customers to reduce load or relocate?

There have been no reductions made to the most likely forecast (used for the rate application) to account for the possibility of industrial customers reducing load or relocating because of the 3 year rate increase. SaskPower will account for a potential industrial customer reduction or relocation in the most likely forecast, but only if there is evidence this is likely to occur.

There have been relatively few cases in Saskatchewan of industrial customers shutting down and when this has occurred there is generally some warning. SaskPower's industrial rates are currently the lowest of all Canadian thermal utilities and will still be very competitive with other Canadian thermal utilities in 2016, even if the other utilities do not increase their rates during that time. SaskPower has also been recommending customers use annual 5% rate increase for budgeting purposes for some time now.

SaskPower develops a high and low load forecast as well as the most likely forecast used in the rate application. A major Power class customer reducing load or relocating would be included in SaskPower's low load forecast.

Round1 – SIECA Q39:

For 2012, please provide the actual reserve margin by month. Please also include the supporting calculations including system peak load, adjusted demand net of interruptible resources and existing resource availability by month?

Response:

The actual reserve margin for each month of 2012 is provided in the following table.

Month	System Peak Load [MW]	Interruptible Resources [MW]	Adjusted Peak Load* [MW]	Available Generating Resources** [MW]	Operating Reserves*** [MW]
Jan	3276	97	3178	3537	359
Feb	3107	86	3021	3321	300
Mar	2947	106	2841	3220	379
Apr	2710	104	2605	3188	583
May	2748	76	2673	2948	275
Jun	2978	87	2891	3237	346
Jul	3064	95	2969	3299	330
Aug	3031	75	2956	3251	295
Sep	2868	92	2776	3182	406
Oct	2994	94	2899	3269	370
Nov	3195	88	3106	3555	449
Dec	3320	83	3236	3656	420

*Adjusted Peak Load = (System Peak Load)-(Interruptible Resources)

**Available Generating Resources includes actual Wind Generation, Imports and Non-Spinning Reserve

***Operating Reserves = (Available Generating Resources)-(Adjusted Peak Load)

Round1 – SIECA Q40:

Please provide the monthly coincident peak – MW and MWHs by class for 2012, 2014-2016?

Response:

SaskPower does not forecast a monthly coincident peak by customer class. SaskPower applies its load research results to derive an annual winter and summer coincident peak demand by customer class that is then used to allocate demand related costs within its cost of service model. The allocated coincident peak demands by customer class for the years 2012Base (actual), 2014Test, 2015Test and 2016Test are shown in the table below. Please note that 2012Base is based on 1CP (winter peak only) data while 2014-2016Test data is 2CP (average of summer and winter peak).

Class of Service	2012 Base	2014 Test 5.5% Increase	2015 Test 5.0% Increase	2016 Test 5.0% Increase
	1CP Demand (MW)	2CP Demand (MW)	2CP Demand (MW)	2CP Demand (MW)
Urban Residential	511	483	490	495
Rural Residential	141	130	132	133
Total Residential	**652**	**613**	**621**	**629**
Farms	**234**	**221**	**222**	**219**
Urban Commercial	367	417	420	424
Rural Commercial	128	146	147	148
Total Commercial	**495**	**563**	**567**	**572**
Power - Published Rates	700	797	874	972
Power - Contract Rates	220	205	202	218
Total Power	**920**	**1,003**	**1,076**	**1,190**
Oilfields	393	437	467	475
Streetlights	11	7	7	8
Reseller	198	208	209	209
Total	**2,903**	**3,051**	**3,168**	**3,300**

* Totals do not include SaskPower - Internal Use or Losses

Round1 – SIECA Q41:

Appendix C, page 27 of the Application shows the minimum, average and maximum % impact by class. Please provide the frequency distribution of percentage rate impacts by class?

Response:

The frequency distribution of percentage rate impacts by customer class is not available.

SaskPower has provided a detailed breakdown of rate impacts by consumption level for all rates codes, in pages 28 through 96 of appendix C. The detailed breakdown provides individual customers with an indication of the impact of the rate change based on their rate and typical monthly consumption.

Round1 – SIECA Q42:

Please provide the revenue to revenue requirement (dollar amounts and ratios) by class using a 1CP versus 2CP for present rates, 2014, 2015 and 2016?

Response:

SaskPower incorporated its load research results in the 2013Test cost of service for testing and impact purposes. Once the decision was made to go forward with the 2CP allocator, the cost of service model was modified to accommodate this permanent change going forward. As a result, SaskPower does not have the information requested. However, please see the table below that illustrates the results from the 2013Test cost of service under the 1CP and 2CP allocators:

2013Test 1CP Results (5.0% system average increase):

Class of Service	Allocated Revenue Requirement ($)	Revenue ($)	R/RR Ratio
Urban Residential	354,373,103	337,047,618	0.95
Rural Residential	97,341,725	92,046,256	0.95
Farms	174,213,316	155,727,285	0.89
Urban Commercial	249,334,797	262,426,470	1.05
Rural Commercial	84,463,769	93,265,353	1.10
Power Class	523,226,178	530,097,777	1.01
Oilfields	292,916,432	305,155,347	1.04
Streetlights	16,624,769	16,445,408	0.99
Resellers	81,568,974	81,851,549	1.00
Total	**1,874,063,063**	**1,874,063,063**	**1.00**

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2013Test 2CP Results (5.0% system average increase):

Class of Service	Allocated Revenue Requirement ($)	Revenue ($)	R/RR Ratio
Urban Residential	347,239,112	337,047,618	0.97
Rural Residential	96,216,343	92,046,256	0.96
Farms	156,966,096	155,727,285	0.99
Urban Commercial	267,453,222	262,426,470	0.98
Rural Commercial	92,453,762	93,265,353	1.01
Power Class	521,986,113	530,097,777	1.02
Oilfields	290,365,657	305,155,347	1.05
Streetlights	14,172,354	16,445,408	1.16
Resellers	87,210,406	81,851,549	0.94
Total	**1,874,063,063**	**1,874,063,063**	**1.00**

Round1 – SIECA Q43:

On page 47 and 48 of the application SaskPower states that:

> *"By 2017, energy efficiency programming alone will deliver over 100 MW of capacity reductions. In addition, demand response initiatives, targeting industrial customers, will provide 85 MW of capacity value.*
>
> *At the end of 2012, SaskPower has accumulated savings of 56 MW and is on track to reach the goal of 100 MW."*

Please clarify whether the identified reduction of 56 MW includes industrial demand response and provide a schedule of all demand reductions in MW by initiative or program.

Response:

This response contains confidential information and cannot be released publicly. A response was sent to the Saskatchewan Rate Review Panel for their review.

Round1 – SIECA Q44:

Please provide a listing of the type of demand response programs available to industrial customers. Please also provide the specific requirements, eligibility characteristics and compensation for each of the programs?

Response:

There are currently two Demand Response (DR) programs available to customers:

DEMAND RESPONSE				
Program	**Eligibility**	**Requirements**	**Contracts**	**Compensation**
DR1	All SaskPower customers with suitable load characteristics can submit to participate.	Must have continuous curtailable load greater than 5MW; this load must be consistently available for curtailment 24hr/7 days per week throughout the year (minimal downtime for maintenance is acceptable and must be reported), must be able to curtail demand within 12 minutes for any and all events called.	One year contracts: allow for 15 - 4 hour events to be called.	$52,000/MW per year, determined by average monthly available curtailable load - paid monthly.
DR2	All SaskPower customers with suitable load characteristics can submit to participate	Must have continuous curtailable load greater than 5MW: this load must be consistently available for curtailment 24hr/7 days per week throughout the year (minimal downtime for maintenance is acceptable and must be reported), must be able to curtail demand within 2 hours for any and all events called.	One year contract: and allow for 15 - 4 hour events to be called	There is a fixed payment and a variable payment: • Fixed- $20,000/MW per year, determined by average monthly available curtailable load, paid monthly, and; • Variable- $150/MWh when events are called.

Round1 – SIECA Q45:

On an annual basis over the 2012-2016 period; how many MW of contracted demand response does SaskPower have secured in each year at the present?

Response:

This response contains confidential information and cannot be released publicly. A response was sent to the Saskatchewan Rate Review Panel for their review.

Round1 – SIECA Q46:

Is SaskPower actively soliciting more contracted demand response in any annual forward period? If yes, quantify the targeted reductions and define the periods currently open for contracting. If no, explain why SaskPower would not be attempting to expand demand response as an alternative to building generation.

Response:

There are currently two Demand Response (DR) programs available to Industrial customers:

The DR1 program has been fully subscribed to the end of 2013 with renewable annual contracts. This program has a 2012 to 2017 mandate for up to 85MW. SaskPower Grid Control has established 85 MW as the maximum desired curtailable load as this represents ½ of their spinning reserve requirements under day to day operations. The other half of the spinning reserve is achieved through other operating measures and it is felt that to go beyond half of the required spinning reserve may enhance operating risk

The DR2 program currently has 20MW of curtailable load secured by contract and a 2012 to 2017 mandate of up to 40MW. There is room for interested organizations to subscribe. An increase to the upper limit of DR2 curtailable load will only be considered when current capacity has been filled and the DR2 is proven to be a useful tool to take advantage of trading opportunities.

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Round1 – SIECA Q47: How many MWs of demand response is SaskPower projecting to have in place for 2014-2016? What data or information are these projections based on?

Response:

There are two Demand Response (DR) programs currently in place at SaskPower.

DR1 was launched in 2010 under an original corporate mandate to offer DR programing from 2010 to 2017. The current objective is to secure up to 85MW of curtailable load. This offering is currently fully subscribed with renewable one year contracts.

DR 2 was launched 2011 under the same mandate to offer DR programing from 2010 to 2017. The current objective is to secure up to 40MW. As of November 2013 there is 20 MW of contracted curtailable load in place leaving opportunity for interested customers.

In both programs, additional uptake is being reviewed based on customer interest and potential uptake, along with internal requirements.

Round1 – SIECA Q48:

On which date(s) were the economic assumptions and load growth forecasts used in the rate application developed and finalized?

Response:

The inflation assumption of 2% is based on the Bank of Canada's long-term target of 1% to 3% and has been held constant for the last number of years.
The long-term and short-term interest rate assumptions were determined in Q1, 2013.
The natural gas price assumption was determined in August, 2013.
The load growth forecast was prepared in Q1, 2013.

Round1 – SIECA Q49:

SaskPower is predicting a return to lower export revenues in the 2014-2016 application period. What factors provided the opportunity for SaskPower to generate and transmit larger quantities of export power in 2012-2013? Does SaskPower have a strategy to maximize export sales and revenue? If yes please explain the strategy and risks.

Response:

SaskPower benefited from high hydro generation, low natural gas prices, and favourable transmission access in 2012-2013. During this time, the Alberta market offered attractive pricing for SaskPower exports.

SaskPower staffs a 24/7 electricity trading desk to take advantage of low risk opportunities to sell excess generation when revenues exceed costs.

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Round1 – SIECA Q50:

Please provide all the Tables in the Application in Excel spreadsheet format?

Response:

Tables were sent to SIECA and the SRRP in Excel format.