2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

Round1 – Consultant Q1:

Please confirm that :

a. This application (P. 19 - 22) was prepared based on revenue and expenditure forecasts for 2012 as of September 2011.

Response:

No – The forecasts for 2012 were prepared as at March 31, 2012.

2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

Round1 – Consultant Q1(b):

Please confirm that:

> The economic forecasts underpinning this 2013 application was based on the business plan for the 3rd quarter economic outlook for 2011 with the inflation rate forecasted to be 2%, with short term borrowing rate forecasts of 1.7%, long term interest rates forecasted to be 4.4% and wage and salary increases of 2.0%.

Response:

All of the assumptions listed above are correct based on the 2012 Business Plan.

The economic forecasts underpinning the 2013 application however were based on revised interest rate assumptions of 1.1% on short-term debt and 4.1% on long-term debt. Inflation and salary increase assumptions remained unchanged.

SaskPower will revisit these assumptions prior to finalizing the business plan in September and make adjustments as necessary.

SaskPower

2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

Round1 – Consultant Q1(c):

Please confirm that :

The impact of this Application (if approved) would provide an overall System Average Increase of 5.0% with Urban Residential increasing $4 per customer, $10 for farms customers and commercial customers $24/29 per month, and an overall system average of $16/customer/month.

Response:

SaskPower confirms that the impact of this Application (if approved) would provide an overall System Average Increase of 5.0% with Urban Residential increasing $4 per customer, $10 for farms customers and commercial customers $24/29 per month, and an overall system average of $16/customer/month.

Round1 – Consultant Q1(d):

Please confirm that :

The last rate change provided a system average increase of 4.5% and became effective August 1, 2010.

Response:

Correct. The last rate change provided a system average increase of 4.5% and became effective August 1, 2010.

2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

Round1 – Consultant Q1(e):

Please confirm that :

SaskPower, through this 2013 Rate Application, is seeking a revenue increase of $90.8 million which equates to the 5.0% system average increase.

Response:

Correct. Based on our preliminary Business Plan, SaskPower, through this 2013 Rate Application, is seeking a revenue increase of $90.8 million which equates to the 5.0% system average increase.

Round1 – Consultant Q1(f):

Please confirm that :

If approval of this 2013 Rate Application is granted, the rate of return is forecasted to be 8.5%, the established target.

Response:

Correct. Based on our preliminary Business Plan, if approval of this 2013 Rate Application is granted, the rate of return is forecasted to be 8.5%, the established target.

2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

Round1 – Consultant Q1(g):

Please confirm that :

The interest coverage ratio for 2013 is forecasted to be 1.8%.

Response:

The interest coverage ratio for 2013 as per the 2012 Business Plan was forecast to be 1.8%. The forecasted interest coverage ratio for 2013 as per the preliminary 2013 Business Plan has dropped to 1.6%.

SaskPower

2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

> **Round1 – Consultant Q1(h):**
> Please confirm that :
>
> With the proposed increase in rates, the net income for 2013 is forecasted to be $165.9 million and without the increase in rates proposed in this application, SaskPower's net income for 2013 is forecasted to be $75.1 million.

Response:

Correct. Based on the preliminary Business Plan, with the proposed increase in rates, the net income for 2013 is forecasted to be $165.9 million and without the increase in rates proposed in this application, SaskPower's net income for 2013 is forecasted to be $75.1 million.

SaskPower

2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

Round1 – Consultant Q1(i):

Please confirm that :

The specific rate increases for all customers within the all classes except for Power- Published rates at 6.1%, are forecasted to be 4.9% if the 2013 rate application is approved.

Response:

SaskPower confirms that the specific rate increases for all customers within all classes, except for Power- Published rates at 6.1%, are forecasted to be 4.9% if the 2013 rate application is approved.

SaskPower

2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

Round1 – Consultant Q2:

Please show SaskPower's rate increase on a compounded basis during the period 1999 to 2011 and the inflation (Consumer Price Index) over that same time period.

Response:

SaskPower Historic Rate Changes
(PERCENT)

				General Service							
Year	Residential	Farm	Street Lighting	Small Commercial Up to 75 kV.A	Standard 75 - 2000 kV.A	Power	Oilfields	System Average	CPI Sask % Change		Sask. CPU
										1998	90.4
1999	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.8%	1999	92.0
2000	3.5% April	3.8%	0.0%	5.7%	0.2%	0.0%	0.0%	1.5%	2.6%	2000	94.4
2001	5.3% April	6.0% April	-10.0% April	1.0% April	0.2% April	1.0% April	-3.0% April	2.0%	3.0%	2001	97.2
2002	7.5% Jan	7.1% Jan	2.0% Jan	4.7% Jan	5.0% Jan	3.0% Jan	2.0% Jan	4.5%	2.9%	2002	100.0
2003	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.3%	2003	102.3
2004	6.3% Sept	5.5% Sept	0.0% Sept	5.4% Sept	5.5% Sept	8.4% Sept	5.5% Sept	5.7%	2.2%	2004	104.6
2005	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.2%	2005	106.9
2006	6.2% Jan	2.0% Jan	-14.1% Jan	2.1% Jan	5.0% Jan	5.7% Jan	5.2% Jan	4.9%	2.1%	2006	109.1
2007	4.8% Feb	4.0% Feb	6.5% Feb	3.5% Feb	4.2% Feb	4.7% Feb	3.4% Feb	4.2%	2.8%	2007	112.2
2008	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	3.3%	2008	115.9
2009	9.8% June	11.0% June	15.0% June	12.4% June	6.1% June	7.6% June	6.5% June	8.5%	1.0%	2009	117.1
2010	5.3% Aug	5.3% Aug	2.1% Aug	5.3% Aug	5.3% Aug	3.3% Aug	3.8% Aug	4.5%	1.4%	2010	118.7
2011	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.8%	2011	122.0
Compounded	60.3%	54.1%	-1.4%	47.2%	35.9%	38.6%	25.5%	41.8%	35.0%		

SaskPower

2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

Round1 – Consultant Q3:

Please provide similar numbers as requested in (2) above from 2005 to 2011.

(Q2 : Please show SaskPower's rate increase on a compounded basis during the period 1999 to 2011 and the inflation (Consumer Price Index) over that same time period.)

Response:

SaskPower Historic Rate Changes
(PERCENT)

Year	Residential	Farm	Street Lighting	General Service: Small Commercial Up to 75 kV.A	General Service: Standard 75 - 2000 kV.A	Power	Oilfields	System Average	CPI Sask % Change		Sask. CPU
										2004	104.6
2005	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.2%	2005	106.9
2006	6.2% Jan	2.0% Jan	-14.1% Jan	2.1% Jan	5.0% Jan	5.7% Jan	5.2% Jan	4.9%	2.1%	2006	109.1
2007	4.8% Feb	4.0% Feb	6.5% Feb	3.5% Feb	4.2% Feb	4.7% Feb	3.4% Feb	4.2%	2.8%	2007	112.2
2008	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	3.3%	2008	115.9
2009	9.8% June	11.0% June	15.0% June	12.4% June	6.1% June	7.6% June	6.5% June	8.5%	1.0%	2009	117.1
2010	5.3% Aug	5.3% Aug	2.1% Aug	5.3% Aug	5.3% Aug	3.3% Aug	3.8% Aug	4.5%	1.4%	2010	118.7
2011	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.8%	2011	122.0
Compounded	28.7%	23.9%	7.4%	25.0%	22.2%	22.9%	20.2%	24.0%	16.6%		

Round1 – Consultant Q4:

Based on 2013 forecasts, if net income was to change by $10 million, what ROE would result?

Response:

The ROE from the rate application, which was 8.5%, would change to 8.0% with a $10 million reduction in net income.

Round1 – Consultant Q5:

Please confirm what Canadian/US dollar exchange rate was in 2011, projected for in 2012 and forecast for 2013.

Response:

In 2011, 1 USD = 1.017 CAD. For 2012 and 2013, the exchange rate is assumed to be at par.

SaskPower

2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

Round1 – Consultant Q6:

Please provide copies of the reports prepared for SPC by Business Renewal Program initiatives. Also provide comments on the recommended initiatives of the Business Renewal Reports for each of the reports by KPMG, UMS and Deloitte. Please include each initiative's start date, the efficiencies expected and quantification of financial benefits with any other specific benefits accrued to date.

Response:

The full reports from the three consultancies were provided to the Panel's consultant on a confidential basis.

SaskPower

2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

Round1 – Consultant Q7:

Please provide an update on the Service Delivery Renewal Project (SDR) which illustrates the projects by functional costs to date, expected total costs relative to original budget, scheduling and timelines for each step to conclusion and the current efficiency savings experienced and expected to be generated.

Response:

SDR Program – Scope

SDR, approved in May 2009, is transforming SaskPower's service business to a performance driven organization while increasing efficiency, productivity, electrical system reliability and improving service quality to its customers. Ultimately, the work completed through SDR's projects will help employees be more productive and less frustrated, by removing barriers that create inefficiencies in the work they perform. When SDR is fully implemented, decisions about serving customers will be made from a service business perspective and a customer's point of view. Employees will be appropriately supported by having the right tools and information they need to do their jobs.

The following projects have already been completed as part of SDR:

- Telephony: a web browser-based service routes customer calls through an interactive voice response system, improving service levels.
- New Connect process: by implementing a consistent process, the average time to provide a customer quote for new service has decreased by nearly half.
- Customer relationship and billing system: the new system provides a comprehensive view of customer information, can be adapted to changing business requirements, and can manage complex billing and rate structures.
- Phase 1 of Field Worker project: 525 laptop computers were installed in field worker trucks with mobile mapping software and automatic vehicle locators.
- Business process: End to end documentation is complete for the Calculate and Collect Revenue, Deliver Products and Services, and Maintain Electrical System Reliability corporate business processes.

The following projects are part of SDR's 2012 business plan:

- Phase 2 of Field Worker project (aka Schedule and Dispatch): Using centralized scheduling and dispatch functionality in two provincial locations, connected with laptop computers in service trucks, our goal is to optimize resources for prioritizing work, minimize travel, and shorten power outage durations.

- Advanced Metering Infrastructure: the province-wide project to install 500,000 electronic meters at residential and business locations, combined with a communication network and a meter data management system.
- Outage Management System: a proactive, integrated system will identify the location of power outages and reduce the time to restore service. In 2012, a RFP will be prepared to secure a vendor for the long-term OMS solution; simultaneously, an interim solution will be implemented to streamline the existing trouble call system, allowing for the corporate mainframe computer to be taken out of service by year-end.

SDR Program – Budget

SDR was approved with a budget of $107 million. The Service Business Measurement and Benefits Realization team has been transitioned to Operations, which has resulted in an adjusted SDR budget of $106.3 million. The AMI portion of SDR was fully approved December 2010 with a budget of $189.5 million. SDR is on budget for completion mid-2015.

SDR Financials, June 2012		OM&A	Capital	Total
Actual	2009	7,972,253	9,857,158	$ 17,829,411
	2010	12,284,220	15,486,528	$ 27,770,748
	2011	10,973,536	23,215,410	$ 34,188,946
	2012	3,907,513	12,041,552	$ 15,949,066
	Total	$ 35,137,522	$ 60,600,649	$ 95,738,171
Forecast	2012	4,506,887	24,217,259	$ 28,724,145
	2013	6,703,248	69,548,025	$ 76,251,273
	2014	10,147,575	82,360,643	$ 92,508,218
	2015	1,455,711	1,130,784	$ 2,586,495
	Total	$ 22,813,421	$ 177,256,711	$ 200,070,131
Program	Total	$ 57,950,943	$ 237,857,359	$ 295,808,302

SDR Program – Benefits

As of December 2011, an annual benefit of *$22.7 million* was realized from continuous improvement and initiatives related to SDR program activities which *significantly exceeds* the SDR Business Case benefits forecast. Because SDR is measuring business processes, we have been able to capture the impact of process changes (from SDR projects) in Transmission &Distribution and Customer Services. Improvement initiatives were built on the foundation of standardized business processes and performance metrics developed in SDR.

The following table shows the current, June 2012, quarterly benefits report and forecast:

SaskPower

2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

Quantified Benefits ($000's)	Benefits Realized		Annual Forecasted Benefits				
	2010	2011	2012	2013	2014	2015	2016-20*
Hosted Contact Centre & FW1- Laptops in Trucks	$332	$391	$422	$404	$387	$420	$2,000
Deliver Products & Services (DPS) - New Connect Process	$235	$435	$490	$490	$490	$490	$2,449
Customer Relationship & Billing System (CR&B)	N/A	$0	$944	$1,582	$1,590	$1,598	$8,120
Schedule & Dispatch (S&D)	N/A	N/A	$2,566	$8,923	$22,721	$22,864	$114,566
Automated Metering Infrastructure (AMI)	N/A	N/A	$0	$7,758	$15,227	$19,340	$114,107
Outage Management System (OMS)	N/A	N/A	TBD	TBD	TBD	TBD	TBD
Continuous Improvement Initiatives - CCR	N/A	$0	$496	$2,241	$2,717	$3,219	$17,500
Continuous Improvement Initiatives - DPS	N/A	$21,285	$17,835	$17,835	$17,835	$17,835	$89,176
Totals	**$567**	**$22,112**	**$22,753**	**$39,233**	**$60,966**	**$65,766**	**$347,919**
SDR Business Case - incl AMI (2009 baselines; adjusted for timing of S&D)	$289	$999	$4,480	$22,796	$37,275	$49,191	$284,571
Variance from Business Case	$277	$21,113	$18,273	$16,437	$23,692	$16,575	$63,348
Cumulative Benefits Realized		$22,679					

* SDR Business Case timeframe extends to 2022; AMI Business Case timeframe extends to 2030.

Round1 – Consultant Q8:

Please discuss SaskPower's view of what constitutes a "large rate increase" considering the current rate of inflation and what would be its view in this regard if inflation were 5%.

Response:

SaskPower does not have a formal definition of a "large rate increase" but a large rate increase would likely lie in the range of high single digits to double digits in a single year. If expenses rose significantly in one year, requiring a large rate increase to allow SPC to achieve its financial objectives, it is likely that the resulting application would seek a smoothing effect over a longer time frame.

In general terms the suite of expenses that SPC faces tends to inflate at rates in excess of the commonly quoted CPI. Linking rate increases to the CPI is not therefore an SPC practice. Nonetheless, if the CPI were in the range of 5%, SPC would likely be facing upward cost pressures above that which would place significant financial stress on the corporation. In such a case, any necessary application would almost certainly seek to recover the necessary revenues over an extended period beyond a single year.

SaskPower

2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

Round1 – Consultant Q9:

Tab 19 - Please provide a table showing the percentage of hydro generation capacity provided by other fuel types for each of the Hydro Utilities used for Rate comparisons by SaskPower. Similarly, provide the fuel mix for each of Natural Gas, Coal, Hydro and Other for the Thermal Utilities.

Response:

Tab 19 - Fuel Mix

	BC Hydro	Hydro Quebec	Manitoba Hydro	Nova Scotia Power
Hydro	91%	95%	91%	20%
Thermal	9%	3%	8%	52%
Nuclear		2%		
Diesel			0%	
Natural Gas/Oil				28%
Wind/Other				
Total	100%	100%	100%	100%

	New Brunswick Power	Maritime Electric	Ontario (Entire Market)	Alberta (Entire Market)
Hydro	24%		37%	6%
Thermal	46%		29%	45%
Nuclear	17%		35%	
Diesel				
Natural Gas/Oil	14%	40%		39%
Wind/Other		60%		10%
Total	100%	100%	100%	100%

Round1 – Consultant Q10:

Please confirm net income for 2011 was $248.1 million with an ROE 13.2%.

Response:

As reported in SaskPower's 2011 Annual Report net income for 2011 was $248 million with a ROE of 13.2%.

SaskPower

2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

Round1 – Consultant Q11:

Please confirm that SaskPower's actual revenue received in 2011 for the revenue category "Exported Power" was $40.3 million, with forecasts for 2012 and 2013 being $27.3 million and $22.2 million. Please provide details as to the reasons for the variances in forecasted revenue for Export Power.

Response:

That is correct. Actual exported power revenue for 2011 was $40.3 million and the forecast for 2012 and 2013 is $27.3 million and $22.2 million respectively.

Exports represent the sale of SaskPower's surplus generation to other regions in Canada and the United States. The bulk of SaskPower's export sales are made to the neighbouring AESO and Midwest Independent Transmission System Operator (MISO) markets.

In 2011, exports were significantly higher than budget due to unanticipated and prolonged unit outages in Alberta. Overall, export volumes were up 153 GWh (52%) from budget and 205 GWh (84%) from the prior year. Prices in AESO also increased significantly as a result of the unit outages. In 2011, the average export price was up $38.5 / MWh (75%) from budget and $41.3 / MWh (85%) from 2010.

For 2012 and 2013, SaskPower expects export revenues to decline from 2011 as a result of increased stability in the Alberta market. The export forecast is influenced by expectations regarding the availability of surplus SaskPower generation, market conditions in Alberta and other jurisdictions, and transmission availability. As a result, exports are subject to significant variability. SaskPower's export revenues over the last 5 years are shown below:

(millions $)	**2011**	**2010**	**2009**	**2008**	**2007**
Export Revenues	$40	$12	$12	$33	$57

SaskPower

2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

Round1 – Consultant Q12:

Please provide the anticipated revenue decrease for "Revenue – Electricity Trading" from the forecast for 2012 of $15.8 million. Please explain the reasons of decrease and provide all the forecasted details.

Response:

Compared to the 2012 forecast, the electricity trading contribution is expected to decrease slightly from $16.9 million in 2012 to $11.5 million in 2013. The decline is primarily due to higher than normal contributions during 2012. In the first quarter of 2012, the AESO market experienced significant shortages resulting in higher than average contributions for SaskPower. The 2013 Business Plan assumes a return to stability in the AESO market in 2013. The following is a summary of the electricity trading contributions earned by SaskPower over the past 5 years.

(millions $)	**2011**	**2010**	**2009**	**2008**	**2007**
Electricity Trading	$14	$4	$7	$17	$11

SaskPower

2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

Round1 – Consultant Q13:

Please provide further details showing actual results for 2009, 2010, and 2011 as well as forecasts for 2012 and 2013 for ancillary "other revenue" and explain any significant variance in this and Other Revenues.

Response:

The following is a detailed breakdown of the components of other revenue. The significant variance between 2009 and 2010 relates to a transition to IFRS and the accounting treatment of customer contributions.

	IFRS	IFRS	IFRS	IFRS	CGAAP
	2013 Forecast	**2012** Forecast	**2011** Actual	**2010** Actual	**2009** Actual
Late payment charges	$ 3,948	$ 3,870	$ 4,068	$ 4,069	$ 3,750
Joint Use Charge	4,148	4,027	4,129	3,911	$ 3,748
Connect fees	1,215	1,191	1,020	1,149	1,146
Rental income	945	945	290	280	253
Meter reading	3,504	3,436	3,171	2,973	3,198
Custom work	6,510	7,021	3,221	4,055	2,954
WPPI grant	5,308	5,586	5,743	4,810	5,476
Trans tariff revenue - external	680	313	1,024	1,772	2,422
Gas & electrical inspections	14,659	14,388	14,187	12,892	10,784
Customer contributions	41,788	49,890	55,620	43,229	
Equity investment	7,382	9,081	11,100	9,370	6,351
Other revenue	2,092	2,244	3,250	1,812	1,354
Subtotal	92,179	101,992	106,823	90,322	41,436
Environmental revenue					
Green power premium	415	1,893	1,898	1,908	2,114
Flyash	8,840	8,181	7,843	7,489	7,864
Subtotal	9,255	10,074	9,741	9,397	9,978
Total SaskPower Other Revenue	**101,434**	**112,066**	**116,564**	**99,719**	**51,414**
Other revenue	-	-	-	3	34
Total NorthPoint Energy Solutions In	**-**	**-**		**3**	**34**
Total Other Revenue	**$ 101,434**	**$ 112,066**	**$ 116,564**	**$ 99,722**	**$ 51,448**

SaskPower

2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

Round1 – Consultant Q14(a):

a) **Please provide a schedule showing all revenues flowing from or expenses flowing to affiliated companies to SaskPower regulated entity, commencing in 2009 and that projected for 2012 and 2013.**

b) Please confirm that no changes (or, in the alternative, describe any changes) have been made to the cost allocation principles/policies/protocols with affiliates/subsidiaries since the 2010 Application.

Response:

See the attached schedule.

	SaskPower *					SPI					NRPT					Eliminating Entries					Consolidated SaskPower				
	IFRS	IFRS	IFRS	IFRS	CGAAP	IFRS	IFRS	IFRS	IFRS	CGAAP	IFRS	IFRS	IFRS	IFRS	CGAAP	IFRS	IFRS	IFRS	IFRS	CGAAP	IFRS	IFRS	IFRS	IFRS	CGAAP
	2013	2012	2011	2010	2009	2013	2012	2011	2010	2009	2013	2012	2011	2010	2009	2013	2012	2011	2010	2009	2013	2012	2011	2010	2009
REVENUE																									
Saskatchewan electricity sales	$ 1,914	$ 1,747	$ 1,667	$ 1,575	$ 1,447	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ 1,914	$ 1,747	$ 1,667	$ 1,575	$ 1,447
Exports	22	8	40	12	12	-	-	-	-	-	-	-	-	-	-	-	-		-	-	22	8	40	12	12
Net electricity trading **	-	-	-	-	-	-	-	-	-	-	12	6	14	4	6	-	-		-	1	12	6	14	4	7
Other	94	102	105	90	50	7	8	11	10	-	-	-	8	6	6	-	-	(8)	(6)	(4)	101	110	116	100	52
TOTAL REVENUE	2,030	1,857	1,812	1,677	1,509	7	8	11	10	-	12	6	22	10	12	-	-	(8)	(6)	(3)	2,049	1,871	1,837	1,691	1,518
EXPENSES																									
Fuel & puchased power	563	535	493	452	509	-	-	-	-	-	-	-	-	-	-	-	-	(8)	(6)	-	563	535	485	446	509
Operating, maintenance & administration	625	581	567	505	487	-	-	-	-	-	2	1	8	8	8	-	-	-	-	-	627	582	575	513	495
Depreciation	354	321	290	266	229	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	354	321	290	266	229
Finance charges	274	220	197	192	147	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	274	220	197	192	147
Taxes	56	48	43	42	39	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	56	48	43	42	39
Other losses (gains)	9	8	8	9	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	8	8	9	3
TOTAL EXPENSES	1,881	1,713	1,598	1,466	1,414	-	-	-	-	-	2	1	8	8	8	-	-	(8)	(6)	-	1,883	1,714	1,598	1,468	1,422
Operating Income	149	144	214	211	95	7	8	11	10	-	10	5	14	2	4	-	-	-	-	(3)	166	157	239	223	96
Unrealized market value adjustments		-	2	(16)	7	-	-	-	-	-	-	-	7	(3)	-	-	-	-	-	-	-	-	9	(19)	7
NET INCOME(LOSS)	$ 149	$ 144	$ 216	$ 195	$ 102	7	$ 8	$ 11	$ 10	-	$ 10	$ 5	$ 21	$ (1)	$ 4	$ -	$ -	$ -	$ -	$ (3)	$ 166	$ 157	$ 248	$ 204	$ 103

*** Shand Greenhouse is included with SaskPower.**

**** Net electricity trading is gross in NorthPoint's annual report.**

***** 2013 & 2012 based on Business Plans, 2011-2009 based on Actual**

****** SPI is included with SaskPower for 2009 and 2010.**

SaskPower

2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

Round1 – Consultant Q14(b):

c) Please provide a schedule showing all revenues flowing from or expenses flowing to affiliated companies to SaskPower regulated entity, commencing in 2009 and that projected for 2012 and 2013.

d) Please confirm that no changes (or, in the alternative, describe any changes) have been made to the cost allocation principles/policies/protocols with affiliates/subsidiaries since the 2010 Application.

Response:

Effective January 1, 2012 SaskPower and NorthPoint have terminated the transfer price agreement related to generation and load management services, electricity export and import functions related to the generation assets of SaskPower, and management of SaskPower's natural gas supplies for its natural gas-fired power plants. These activities are still being performed but all of the costs and benefits are recorded within SaskPower's financial results. This was the only change to the cost allocation policies with SaskPower's subsidiaries since 2010. This change had no impact on SaskPower's consolidated financial results (which are the basis for the 2013 Rate Application) as all inter-company transactions between SaskPower and its subsidiaries are eliminated upon consolidation.

SaskPower has three wholly-owned subsidiaries: NorthPoint Energy Solutions Inc. (NorthPoint), Power Greenhouses Inc. (SaskPower Shand Greenhouse) and SaskPower International Inc. (SaskPower International). The financial activities of SaskPower's subsidiaries are consolidated within the financial statements of SaskPower in accordance with IFRS. Separate financial statements are prepared and issued for NorthPoint and SaskPower Shand Greenhouse.

NorthPoint is a wholly-owned subsidiary of SaskPower. It was formed in late 2001 to meet requirements associated with SaskPower's OATT that mandates the separation of transmission and wholesale marketing functions.

NorthPoint acts as a principal in wholesale electricity trading transactions that do not relate to the generation assets of SaskPower.

The mandate of SaskPower Shand Greenhouse is to provide seedlings to propagate native vegetation and deliver environmental educational programs. SaskPower Shand Greenhouse has entered into an agreement with SaskPower, whereby it operates the greenhouse and in turn SaskPower funds the SaskPower Shand Greenhouse for costs incurred.

SaskPower International has no active operations beyond its joint venture interests in the Cory Cogeneration Station and the Cory Cogeneration Funding Corporation and its investment in the MRM Cogeneration Station over which it exerts significant influence.

Round1 – Consultant Q15:

Please detail the nature of the forecasts for Gas and Electric Inspections and Customer connects for 2012 and 2013 and compare these to the 2009, 2010 and 2011 actual results.

Response:

Gas and electric inspections and customer connects revenue is forecasted within Transmission & Distribution and is determined based primarily on the prior year's actual results and forecasted activities.

	2013 Forecast	2012 Forecast	2011 Actual	2010 Actual	2009 Actual
Connect fees	1,215	1,191	1,020	1,149	1,146
Gas & electrical inspections	14,659	14,388	14,187	12,892	10,784
Total	15,874	15,579	15,207	14,041	11,930

Note: assumed the requested information was for customer connects fees rather than customer contributions. Information for customer contributions is found in other responses.

SaskPower

2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

Round1 – Consultant Q16:

Please provide details of the expected revenue in 2013 of $19.2 million for CO^2 sales.

Response:

The 2013 rate application contained incorrect information relating to the composition of other revenue. While the total was correct, the allocation between the different categories contained errors. The following table should replace the one found on page 20 of the rate application. There are no CO^2 revenues forecasted for 2013.

SaskPower Consolidated Revenues			
(in millions $)	2011 Actual	2012 Forecast	2013 Forecast
Saskatchewan sales			
Residential	407.3	388.3	403.0
Farm	144.9	142.3	143.4
Commercial	355.5	351.0	352.4
Oilfields	241.6	265.6	281.6
Power customers	440.3	459.2	563.5
Reseller	77.2	77.6	79.1
Sales before rate increase	**1,666.7**	**1,684.0**	**1,823.0**
Revenue lift due to rate increases	0.0	0.0	90.8
Total Saskatchewan sales	**1,666.7**	**1,684.0**	**1,913.8**
SaskPower export	40.3	27.3	22.2
Total SaskPower sales	**1,707.0**	**1,711.3**	**1,936.0**
Net sales from trading	13.9	15.8	11.5
Other revenue			
Gas & Elect Inspection	14.2	14.4	14.7
CO^2 sales	0.0	0.0	0.0
Customer Connects	55.6	49.9	41.8
Miscellaneous revenue	35.7	38.7	37.5
Cory & MRM Equity Investment	11.1	9.1	7.4
Total other revenue	**116.6**	**112.1**	**101.4**
Total revenue	**1,837.5**	**1,839.2**	**2,048.9**

2012 figures based on March 31 forecast

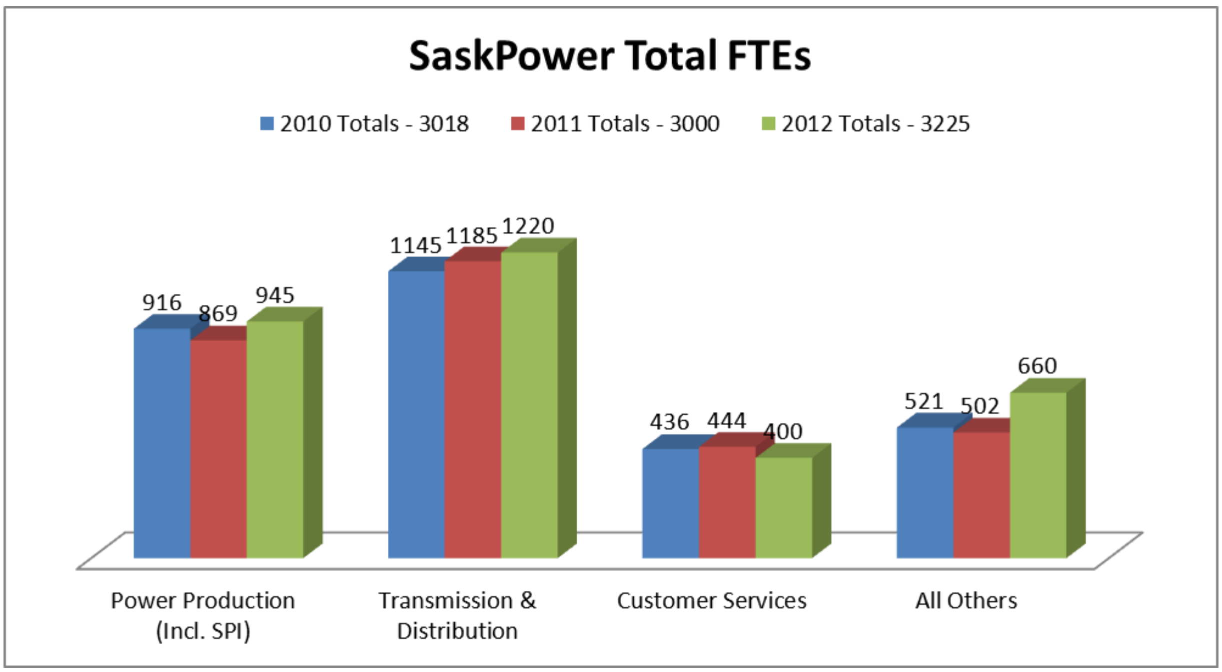
2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

Round1 – Consultant Q17:

Please update the graph for Total FTE's similar to that provided in Table 3.9 of the Consultant's Report in 2010 using actual 2010 and 2011, and forecast for 2012 and 2013.

Response:

The following graph represents actual permanent, temporary and part-time FTE's for 2010 and 2011 and budgeted FTE's for 2012. It should be noted that overtime FTE's have not been included in these totals. 2013 FTE information will be available in September.



SaskPower

2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

Round1 – Consultant Q18:

Please provide a five year historic record of SaskPower's FTE to number of customer ratio to 2011 and projected for 2012 and 2013.

Response:

	Actual					Forecast
	2007	**2008**	**2009**	**2010**	**2011**	**2012**
SaskPower FTEs	2,744	2,801	2,947	3,018	3,000	3,225
# of Customers	451,713	460,006	467,329	473,007	481,985	486,926
Customer/SP FTEs	165	164	159	157	161	151

Note: The FTE numbers for 2007 to 2011are based on year end actual FTE levels and include permanent, part-time, and temporary FTE's. For 2012, the numbers are based on our year-end target and again, are comprised of permanent, part-time and temporary FTE's.

Round1 – Consultant Q19:

Please detail and explain any changes in SaskPower organizational chart since 2010 and show 2010, 2011 & 2012 proposed FTE's per operating division.

Response:

The following is a summary material changes to SaskPower's organizational chart since 2010:

- 2 new business units were created
  - Business Development (formed by transferring employees from NorthPoint, Finance, PERA and Power Production)
  - Supply Chain (formed by transferring purchasing and Corporate Services from Finance)

- Stakeholder Relations and Aboriginal Relations were transferred from Corporate Relations to Strategic Relations-President's Office
- Fleet Services was transferred from Corporate & Financial Services to Transmission and Distribution
- Planning, Environment, & Regulatory Affairs and North Point were merged under one VP / President.
- Safety and Corporate Relations then merged with HR.
- Workplace Learning and Performance was transferred from Transmission and Distribution to Human Resources
- SDR measurement group and Pricing and Energy Forecasting were transferred from Customer Service to Finance.

SaskPower

2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

2010, 2011 Actual, & 2012 Proposed FTEs by Business Units:

	Actual		Forecast
	2010	**2011**	**2012**
President's Office	3	3	14
HR, Safety, & Corporate Comm	117	123	165
Corporate & Fin Services	158	134	97
Corporate Infor & Tech	87	99	148
Customer Services	436	444	400
PERA & NorthPoint	109	89	108
Power Production	916	869	954
T&D	1,145	1,185	1,220
Clean Coal	13	14	13
LLRA	34	33	35
Supply Chain	-	-	64
Business Development	-	7	7
	3,018	3,000	3,225

*2010 & 2011 actuals have not been restated – all changes identified earlier in this response are reflected in 2012.

Round1 – Consultant Q20:

Please discuss any proposed change in FTE from 2011 going forward in the business planning period for the business units specifically including the President's office, T & D customer service, and CI&T.

Response:

A discussion of the changes were given to the SRRP and their consultant.

Round1 – Consultant Q21:

Please provide a table illustrating OM&A cost per customer for actual costs & customers for 2009 to 2011 and forecasts for 2012 & 2013.

Response:

	Actual			Forecast	
	2009	2010	2011	2012	2013
OM&A Cost (millions)	$ 495	$ 513	$ 575	$ 603	$ 627
# of Customers	467,329	473,007	481,985	486,926	492,887
OM&A Cost per Customer	$ 1,059	$ 1,085	$ 1,193	$ 1,238	$ 1,272

Note: 2009 OM&A was based on Canadian GAAP; 2010 to 2013 is based on IFRS.

SaskPower

Round1 – Consultant Q22(a):

For transition purposes please provide:

a) a schedule as depicted on page 26 of SaskPower Application including the years 2008, 2009, and 2010 actual costs per and;

b) a break out schedule of OM & A expenses for 2010, 2011, 2012 and 2013 in the format similar to Table 3.7 on page 29 in the 2010 Consultant Report, attached including a break-out of wages/salaries (Permanent, Part Time, temporary, Apprentice and Contract positions for regular pay, premium pay, and overtime) between wages, pensions and benefit costs. Please include in this schedule specific line costs for labour credits, overhead credits, internal recoveries, charges to capital, miscellaneous corporate charges and intercompany allocations and;

c) please file a schedule detailing actual OM&A expenses capitalized for 2010, 2011 and projected for 2012 & 2013 by labour, overhead, and interest and other.

Response:

SaskPower

SaskPower OM&A			
	2008 *	2009 *	2010
(in millions $)	Actual	Actual	Actual
President' Office	$ 1.6	$ 1.9	$ 3.2
Power Production	171.3	189.2	175.5
Transmission & Distribution	106.9	114.1	140.3
Finance	8.5	11.1	16.7
Customer Services	35.9	37.3	37.4
Planning, Environment & Regulatory Affairs	8.9	9.8	10.9
Law, Land, Regulatory Affairs	4.0	4.3	3.9
Corporate Information & Technology	32.7	33.9	41.9
Human Resources	21.7	23.7	25.1
Business Development	-	-	-
Shand Greenhouse	0.7	0.6	0.6
NorthPoint Energy Solutions	7.1	7.7	7.9
Supply Chain	4.6	6.1	5.6
ICCS	-	-	0.7
Service Delivery Renewal	4.4	7.9	10.9
DIP Premium Increases	-	-	-
Total Operation Costs	**408.3**	**447.6**	**480.6**
Other			
Nuclear Initiative	-	-	-
Insurance Expense	5.4	6.3	4.8
Pension Expense	10.9	36.1	7.6
Bad Debt Expense	1.8	3.2	2.3
Human Resources Programs	1.5	2.5	1.3
Other Expense	(5.0)	(5.8)	(6.1)
PPA-OM&A	-	-	13.6
Total Other Costs	**14.6**	**42.3**	**23.5**
Demand Side Management	3.8	4.9	8.8
Total OM&A	**$ 426.7**	**$ 494.8**	**$ 512.9**
** 2008 and 2009 are presented as GAAP*			

Round1 – Consultant Q22(b):

For transition purposes please provide:

a) a schedule as depicted on page 26 of SaskPower Application including the years 2008, 2009, and 2010 actual costs per and;

b) a break out schedule of OM & A expenses for 2010, 2011, 2012 and 2013 in the format similar to Table 3.7 on page 29 in the 2010 Consultant Report, attached including a break-out of wages/salaries (Permanent, Part Time, temporary, Apprentice and Contract positions for regular pay, premium pay, and overtime) between wages, pensions and benefit costs. Please include in this schedule specific line costs for labour credits, overhead credits, internal recoveries, charges to capital, miscellaneous corporate charges and intercompany allocations and;

c) please file a schedule detailing actual OM&A expenses capitalized for 2010, 2011 and projected for 2012 & 2013 by labour, overhead, and interest and other.

Response:

As requested, see the below schedule with the exception of the 2013 forecast which will be presented at the interim update, as the detail requested is not available at this time.

SaskPower

2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

Round1 – Consultant Q22(c):

For transition purposes please provide:

a) a schedule as depicted on page 26 of SaskPower Application including the years 2008, 2009, and 2010 actual costs per and;

b) a break out schedule of OM & A expenses for 2010, 2011, 2012 and 2013 in the format similar to Table 3.7 on page 29 in the 2010 Consultant Report, attached including a break-out of wages/salaries (Permanent, Part Time, temporary, Apprentice and Contract positions for regular pay, premium pay, and overtime) between wages, pensions and benefit costs. Please include in this schedule specific line costs for labour credits, overhead credits, internal recoveries, charges to capital, miscellaneous corporate charges and intercompany allocations and;

c) please file a schedule detailing actual OM&A expenses capitalized for 2010, 2011 and projected for 2012 & 2013 by labour, overhead, and interest and other.

Response:

As requested, see the below schedule with the exception of the 2013 forecast which will be presented at the interim update, as the detail requested is not available at this time.

($ millions)	Actual 2010	Actual 2011	Budget 2012	Forecast 2013 *
Allocated Labour Costs	$ 10	$ 12	$ 13	
Labour Costs Capitalized	36	35	33	
Interest Capitalized	15	12	22	
Total	$ 61	$ 59	$ 68	$ -

** 2013 information not available*

2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

Round1 – Consultant Q23:

Please explain the DIP Premium Increase of $1.6 million forecasted for 2013 while there was no entry for 2011 actual and 2012 is forecasted at zero dollars? (Reference P. 26 Application).

Response:

Based on an actuarial valuation on both the Group Life Insurance Program and Disability Income Plan, SaskPower's contribution rates to PEBA were increased. This increase became effective in 2012 and is included in the 2012 forecast. Because it was not anticipated in last year's Business Plan, it is shown separately as a new item in the 2013 Business Plan.

Round1 – Consultant Q24:

Please provide the actuarial report detailing the change in pension expense (Reference P. 26 Application).

Response:

A copy of the confidential actuarial report was given to the SRRP and their consultant.

SaskPower

2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

Round1 – Consultant Q25:

The Please indicate when the current employee labour agreements are set to expire and provide a status report on current or anticipated negotiations with the two unions.

Response:

SaskPower has Collective Agreements with two Unions.

- International Brotherhood of Electrical Workers Local 2067 (IBEW)
  The Collective Agreement with the IBEW expires December 31, 2012
- Communications, Energy and Paperworkers Union Local 649 (CEP)
  The Collective Agreement with the CEP expires December 31, 2012

The desired outcome of negotiations is to achieve a mutually acceptable, timely negotiated settlement that:

- is consistent with SaskPower's strategic directions
- provides for efficient use of available resources including enabling and supporting management discretion and the flexible deployment of operational resources,
- provides the ability to be competitive within the changing labour market; and, is within the established financial parameters

Round1 – Consultant Q26:

Please provide the reports for the business units providing a comprehensive picture of the recommendations for reducing the OM&A cost depicted in the Table on P. 1 of Tab 7 of the Application (or as revised).

Response:

At the conclusion of the last rate application process SaskPower was directed to "*…achieve annual productivity savings of 2% in its OM&S expenses.*" In 2010 SaskPower achieved savings beyond 2% of its total OMA expenses. SaskPower's 2010 OMA budget (net of ICCS) was $553M. SaskPower was directed to save 2%, or approximately $11M. SaskPower's total OMA for 2010 was $531M, $22M under budget.

Most of the savings were in salaries and wages. Robert Watson was appointed CEO in August 2010 and immediately implemented a temporary freeze on creating new positions or filling any employee vacancies. In July 2010 SaskPower was forecasting Salaries and Wages to be $240M. At the end of 2010, Salaries and Wages were only $227M, a savings of approximately $13M from the July forecast. This also created approximately $3M in savings related to avoided employee benefit costs.

For the longer term, SPC initiated a Business Renewal process designed to achieve more significant savings from a business-as-usual perspective. This is a long-term effort with significant focus on asset management (cradle-to-grave), materials management (inventory and warehousing), and procurement. Ongoing efforts in the Service Delivery Renewal project are also delivering savings over the longer term.

SaskPower

2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

Round1 – Consultant Q27(a):

a) Please provide a description of the New OM&A Initiatives for 2012 and for 2013 together with the forecasted costs and anticipated benefits.

b) Please quantify, to the extent possible, the ultimate costs over the life of these new proposed initiatives.

c) Please provide a schedule (table) summarizing each year's current and future costs by initiative per year and in gross total for the Business Plan forecast period of 2012 to 2016.

d) Please discuss how SaskPower factors in the change in maintenance costs related to replacing of aged infrastructure as well as the installation of new generation, transmission and distribution facilities.

Response:

SaskPower's 2012 OM&A budget of $582.3 million was $7.2 million or 1.3% higher than the 2011 actual ($26.2 million or 4.6% higher if you exclude one-time payments made in 2011.)

In 2013, SaskPower's OM&A budget of $627 million is $44.7 million or 7.7% higher than the 2012 forecast ($29 million or 5.0% higher if you exclude pension expense.)

The following is a summary of four key initiatives that are budgeted for in 2012 and or 2013.

Nuclear Feasibility Study - $1.5 million in 2012; $7.1 million in 2013.
In addition to wages and salaries, also included in these totals are consulting costs for site evaluation, development of a communication strategy, legal and regulatory work and a joint venture consultant.

Asset Management - $3.0 million in 2013
Asset Management is defined as systematic and coordinated activities and practices through which an organization optimally and sustainably manages its assets and asset systems, their associated performance, risks and expenditures over their life cycles for the purpose of achieving its organizational strategic plan. The implementation of a formal Asset Management program at SaskPower is consistent with the efficiency recommendations from UMS.

ICCS Operating and Training - $2.4 million in 2012; $4.7 million in 2013
The year over year increase relates primarily to training costs associated with operating the new clean coal unit.

Enterprise Learning - $1.1 million in 2013.
This initiative relates to both Corporate Information & Technology and Human Resources with a mandate to standardize and improve the learning and training functions at SaskPower.

SaskPower

2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

Round1 – Consultant Q27(b):

a) Please provide a description of the New OM&A Initiatives for 2012 and for 2013 together with the forecasted costs and anticipated benefits.

b) Please quantify, to the extent possible, the ultimate costs over the life of these new proposed initiatives.

c) Please provide a schedule (table) summarizing each year's current and future costs by initiative per year and in gross total for the Business Plan forecast period of 2012 to 2016.

d) Please discuss how SaskPower factors in the change in maintenance costs related to replacing of aged infrastructure as well as the installation of new generation, transmission and distribution facilities.

Response:

Costs for the years 2014 to 2022 are not available at this time. A complete ten year business plan is to be finalized in September, 2012.

Round1 – Consultant Q27(c):

a) Please provide a description of the New OM&A Initiatives for 2012 and for 2013 together with the forecasted costs and anticipated benefits.

b) Please quantify, to the extent possible, the ultimate costs over the life of these new proposed initiatives.

c) Please provide a schedule (table) summarizing each year's current and future costs by initiative per year and in gross total for the Business Plan forecast period of 2012 to 2016.

d) Please discuss how SaskPower factors in the change in maintenance costs related to replacing of aged infrastructure as well as the installation of new generation, transmission and distribution facilities.

Response:

Costs for the years 2014 to 2022 are not available at this time. A complete ten year business plan is to be finalized in September, 2012.

SaskPower

2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

Round1 – Consultant Q27(d):

a) Please provide a description of the New OM&A Initiatives for 2012 and for 2013 together with the forecasted costs and anticipated benefits.

b) Please quantify, to the extent possible, the ultimate costs over the life of these new proposed initiatives.

c) Please provide a schedule (table) summarizing each year's current and future costs by initiative per year and in gross total for the Business Plan forecast period of 2012 to 2016.

d) Please discuss how SaskPower factors in the change in maintenance costs related to replacing of aged infrastructure as well as the installation of new generation, transmission and distribution facilities.

Response:

- Power Production (PPBU) performs condition assessment on aging units at intervals prior to major decision points in remaining life. The work is a collaboration of field & head office technical staff, often supplemented with industry third party expert contractors. Previous assessments lead to (1) rebuilds on the 300 MW coal units, (2) the current hydro unit refurbishments at Coteau Creek, Island Falls and EB Campbell plants AND (3) Boundary Dam Unit 3 utilization of existing infrastructure for the carbon capture project.
    - These studies often are a base for changes in maintenance budgets and work scope for remaining life of units.
- PPBU Capital Projects implemented for new generation are entered into the SaskPower Enterprise SAP system where technical master data, preventative work orders, equipment numbers are templated from existing generation units as applicable.
    - Additions of emissions control equipment, such as carbon injection for Mercury capture, are added to the plant base budgets after the Capital project is turned over for commercial service.
- Unit performance is monitored in the SPOAD (SaskPower Outage and Derate) System. Reports are generated, reviewed and acted upon where declining performance is detected.
- SaskPower and PPBU are formalizing an Asset Management Program. PPBU has many aspects of a sound Asset Management System in place. This will expand. It is predicted to take 5 plus years to reach the state of an industry best practice Asset Management program.

Examples of changes are (1) increase of Estevan coal unit overhauls from 1 year to current two year intervals and (2) Increase of coal unit turbine/generator major intervals from 6 years to an 8 plus year cycle. Performance of the unit is sustained or improved (more energy production) and maintenance budgets are reduced (longer period between expending maintenance funds).

- The Transmission and Distribution Business Unit (TDBU) has had an Asset Management department in place since 2008. This department defines maintenance practices and determines when assets have reached end of life for the TDBU through a collaborative approach with field staff and various engineering groups. Capital and maintenance related projects are justified by the asset management department and budgets are adjusted accordingly.
- Through a strong working relationship with the planning group within PERA, the TDBU will identify when assets have reached end of life or are no longer cost effective to maintain and will work with PERA to initiate new capital projects.
    - In many instances, the deferred maintenance costs are a major component of the justification for a capital project.
- The installation of new assets within TDBU may not always result in an immediate reduction in maintenance costs. For example, when constructing a new transmission line, initial vegetation clearing is performed prior to construction for the line. A year or two after line construction a follow-up application of herbicide can be applied to control woody growth and establish a grassy, accessible right of way. Vegetation control such as this is a maintenance cost, not a capital cost. This established right of way does result in a lower lifecycle cost as tree-clearing or using mechanical equipment 5-10 years into the asset life are more expensive.

Round1 – Consultant Q28(a):

a) Please provide a schedule showing lost accident days since 2009, by Business unit.

b) If available, please provide a breakdown of the $1 billion added to the Saskatchewan economy annually by various SaskPower activities.

c) Please provide details of the new metric for the 5 year FTE plan.

Response:

2009

Business Unit	Calendar Days Lost
Corporate Support Groups	13
Power Production	221
Transmission and Distribution	158
Customer Services	109
Total	**501**

2010

Business Unit	Calendar Days Lost
Corporate Support Groups	55
Power Production	520.5
Transmission and Distribution	510
Customer Services	150
Total	**1235.5**

2011

Business Unit	Calendar Days Lost
Corporate Support Groups	27
Power Production	676
Transmission and Distribution	434
Customer Services	344
Total	**1481**

2012 (Year to Date)

Business Unit	Calendar Days Lost
Corporate Support Groups	6
Power Production	42
Transmission and Distribution	264
Customer Services	1
Total	**313**

SaskPower

2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

Round1 – Consultant Q28(b):

a) Please provide a schedule showing lost accident days since 2009, by Business unit.

b) If available, please provide a breakdown of the $1 billion added to the Saskatchewan economy annually by various SaskPower activities.

c) Please provide details of the new metric for the 5 year FTE plan.

Response:

The $1 billion includes:

- $625M in capital expenditures (2011) which includes construction, information technology, and materials.
- $485M in fuel and purchased power contracts (2011). Fuel and purchased power contracts are confidential.

SaskPower

2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

Round1 – Consultant Q28(c):

a) Please provide a schedule showing lost accident days since 2009, by Business unit.

b) If available, please provide a breakdown of the $1 billion added to the Saskatchewan economy annually by various SaskPower activities.

c) Please provide details of the new metric for the 5 year FTE plan.

Response:

Under the direction of Crown Investments Corporation of Saskatchewan (CIC), SaskPower is required to be in compliance with the CIC Board and Provincial Government's direction on public service growth. The CIC total FTE target for each year to 2015 is 3379.

The cap can be adjusted upward if there is a business case for additional FTEs; SaskPower's approved FTE cap for 2012 is 3477 which enables us to address growth and continue providing quality service while we implement initiatives that will reduce our operating, maintenance and administration costs.

However, the annual cap declines again in 2013, with a long-term target of 3200 by 2016, which is well below the cap.

An FTE is defined as working 1800 hours per year and includes permanent, part-time, temporary and overtime employee hours.

Round1 – Consultant Q29:

Please provide details of the $12.3 million (or the updated amount) of savings from the Business Renewal Project and also provide details of anticipated savings for 2013. (2012 Strategic Plan P. 21).

Response:

The details have been provided to the SRRP and the consultant.

Round1 – Consultant Q30:

Please detail the $220 million in savings forecast for 2012, as mentioned in the Application.

Response:

The details have been provided to the SRRP and their consultant.

Round1 – Consultant Q31:

Please discuss the Business Renewal Office with respect to reporting relationships within SPC, current and planned FTE's, mandate and projected costs from 2011 to 2016.

Response:

The Business Renewal Office reported to Corporate Planning within the Corporate and Financial Services support function. The Business Renewal Office started with 3 FTEs redeployed from other areas for 2011 and 2012. The Business Renewal Office is now being closed down with the 3 FTE being redeployed to other tasks. Responsibility for implementation of the efficiency projects rests with the Business Units involved. Implementation costs have been prioritized and initiatives are included in the 2013 Business Plan where resources are available. Responsibility for monitoring and reporting progress is being shifted to the Performance Measurement and Benefits Realization department which has been transferred from the Service Delivery Renewal project to Finance. The mandate of the Business Renewal Office was to review all aspects of SaskPower's expenses (including Fuel, Capital, Finance Charges, and OM&A) and make recommendations on initiatives that could provide savings. The actual costs for the Business Renewal Office in 2011 were $3.4 million. The budget for 2012 is $0.6 million and it is forecast that the actual will be close to the budget. The Business Renewal Office is closing down. However, the initiatives will proceed as resources can be found to incorporate them into the 2013 and future Business Plans.

Round1 – Consultant Q32(a):

a) In the response to IR OM&A – 42 (2009) SaskPower indicated that it would be undertaking an analysis to determine if it was possible to off-set some of the costs of the credit card payment program by eliminating or reducing other functions that SaskPower had been performing prior to the program introduction. Please indicate whether that analysis been completed and if so, can you advise what, if any, actions have been taken to date and;

b) Please provide the actual costs of the credit card program for 2011 and forecast for 2012 and 2013.

Response:

The analysis has been completed. SaskPower has implemented a new billing system and reorganized the customer services operations into functional areas of responsibility. Further actions are planned for the near future that include reducing and eliminating some of the less frequently used services, such as customer walk in services.

Round1 – Consultant Q32(b):

a) In the response to IR OM&A – 42 (2009) SaskPower indicated that it would be undertaking an analysis to determine if it was possible to off-set some of the costs of the credit card payment program by eliminating or reducing other functions that SaskPower had been performing prior to the program introduction. Please indicate whether that analysis been completed and if so, can you advise what, if any, actions have been taken to date and;

b) Please provide the actual costs of the credit card program for 2011 and forecast for 2012 and 2013.

Response:

Actual and forecasted costs:

2011: $45,000
2012: $421,500
2013: $1,546,500

Round1 – Consultant Q33:

Please discuss the related transformation to SaskPower's telephony system with respect to cost, anticipated benefits and schedules.

Response:

Overview

SaskPower had an opportunity to replace its outdated mix of Centrex and PBX services with a corporate-wide IP Telephony solution that would increase service reliability, improve customer service and deliver new value-add unified communications services and capabilities (such as unified messaging and advanced conferencing services).The 3500 Centrex lines delivered through SaskTel were nearing end of life and the hosted call centre solution provided services for up to three years commencing in December 2009. In addition, there were approximately 1400 phones served by PBX and a 4-wire plant intercom system. End user research revealed a strong requirement for the advanced features and functionality of modern IP telephony solutions; current systems were not delivering such advanced capabilities.

The IP Telephony will not be a complete replacement. A number of phones are to be retained on the SaskTel-provided system:

- Phones used for electric grid management (GCC, EGCC, etc.)
- Phones at administrative sites at power plants
- Non-Administrative phones at power production and switching centre sites

Benefits

Technical

There are a number of technical benefits related to delivering the technical IP Telephony and Contact Centre projects. Some specific examples include:

Enhanced end user features

- more convenient user interface through phones with LCD screens
- more convenient user interface through IP soft phones
- LCD screen and soft phone access to personal and corporate directories with click-to-dial
- incoming and outgoing call logs with click-to-dial
- enhanced presence and instant messaging capability with integration through Microsoft Lync

Improved Access for Remote Workers

- Delivery of all desktop telephony capabilities to remote employees (home-based, connections for hotels). Users simply require secure VPN access tools plus high speed internet access.
- Supports business continuity in instances where employees are unable to access their normal offices (due to storms, fires, labour disruptions, pandemics, etc.)

Improved Service to Internal Users

- SaskPower can move a phone to another Ethernet jack in another office or conference room.

Improved Service to the Public

- More flexibility in how inbound calls are handled by pairs or clusters of users. For instance, a public relations team can readily establish a call hunt arrangement to field high volumes of inbound calls following a press release.

Improved Workforce Management

- As stated in SaskPower's Corporate Business Plan, SaskPower faces an impending workforce recruitment challenge. The highly adaptable nature of IP telephony is well-suited to complement flexible work force arrangements (work-at-home).

Foundation for Contact Centre Modernization

- IP Telephony put capabilities and network processes in place that will facilitate the reliable and cost effective deployment of contact centre capabilities.

Enhancement to Mobility Services

- IP Telephony solution delivered capabilities that facilitate a user's ability to make more efficient use of mobile phones. Call forwarding to mobile phones can be a standard feature for all users. The solution design includes an optional capability known as twin ringing, where a call to a desktop telephone number can invoke concurrent ringing on both a desktop phone and mobile phone.

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2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

Operational
Operationally SaskPower gains the ability to act and react on its own time and demands, rather than scheduling and waiting. For example, on the Centrex system hosted by SaskTel, a request was made to move a phone 1 – 2 weeks prior to the actual move attracting a $200 charge. The move would then happen only on a specific day of the week. Trying to rush an order would either result in a penalty charge or a response that it was not possible.

With the new Avaya software and hardware in place, a typical add, move or change takes less than 15 minutes (less any travel) and can be scheduled based on business need. Spare phones can be stored in remote sites and enabled in minutes with very little input from the user – simply walking them through logging in on the phone.

Currently SaskPower is using a Hosted Contact Centre (HCC) supplied by SaskTel. This system has had some challenges during peak storm times and does not integrate into our customer systems. Starting in Q1 2013, the Avaya platform will be integrated with our SAP customer information to shorten the amount of time it takes to identify and begin serving the customer. Further enhancements will more deeply integrate the technologies to provide more detailed information related to the customer on the phone; with no intervention on the part of the Customer Service Representative, the information will automatically be presented to assist them.

Process
SaskPower has streamlined its telephony and networking to one department within CI&T. Through the IP Telephony project a number of efficiencies were identified around how phone users get service, what items may be of interest to them (voice to text, specialized phones, etc.), and who they contact for all telephony support. An end user no longer has to contact SaskTel; the bulk of requests can be handled internally, largely the same day and with no charge to the requester.

Cost and Schedule
In April 2010 SaskPower Executive approved a Decision Item requesting $8.4M to procure:

1. a desktop IP telephony solution, to deliver productivity-enabling capabilities and achieve cost savings, and
2. a feature-rich enterprise contact centre solution, to upgrade customer service capabilities for the Outage Centre, Inquiries Centre and the Collections Centre.

The Decision Item identified anticipated cost savings of approximately $900K/year. Project costs are being monitored and ongoing support costs will be finalized closer to project completion.

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CONSULTANT INTERROGATORIES ROUND ONE

SaskPower will complete the telephony replacement project (IP Telephony Project) in October 2012. There is some building construction in Estevan that may have a slight impact on the project timeline.

The Contact Centre telephony solution is just finishing the planning phase. Based on the potential for customer representative disruption the implementation was delayed to ensure the technology would be implemented in a solid and sustainable manner and to ensure that all business requirements were addressed. The Contact Centre telephony solution will be implemented in 4 phases:

- Phase 1 - Basic Contact Centre with basic SAP integration - Q2 2013
- Phase 2 - Enhanced reporting and workforce management - TBD
- Phase 3 - Business reengineering, proactive outbound calling and full SAP integration - TBD
- Phase 4 - Work Management Tool implementation – TBD.

2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

Round1 – Consultant Q34:

Please discuss the Field Worker Technology (FWT) initiative, budgets, capital and implementation costs realized and anticipated benefits, indicating also when the initiative was started and completed.

Response:

The Field Worker Technology (FWT) project entails the automation and optimization of work assignments to field workers. The technologies deployed will:

1) Electronically schedule, assign and provide real-time updates of field work, and;
2) Provide planner/schedulers, dispatchers and supervisors with real-time or near real-time access to crew locations utilizing Automated Vehicle Location (AVL) functionality using cellular networks.

The initiative is comprised of two phases (FW1 & FW2).

FW1 consisted of the implementation of mounted laptop computers with mobile Geospatial Information System to 525 Transmission and Distribution operating staff. SDR initiated this work in 2009 and completed it during 2010.

FW2 (aka Schedule & Dispatch) is currently comprised of three releases:

1) Scheduling application (ClickSoftware) and basic mobile functionality;
2) Application upgrades and full mobile functionality;
3) Planning and forecasting

A pilot for FW2 began in March 2012 and is set for completion by year end 2012.

In terms of benefits, the system provides SaskPower with a set of work management tools that electronically schedule, assign, and provide real time updates of field work. Additionally, it creates optimized work schedules, resulting in more efficient resource utilization and work prioritization. It will deliver an anticipated 25 per cent productivity gain as well as a 30 per cent decrease in overtime hours.

FW2 is on schedule to be complete by June 2013, and remains on budget, per below:

1) FW1 - $7.2 MM
2) FW2 - $24.1MM
    a. $20.9 MM Capital
    b. $3.2 MM Operational

Round1 – Consultant Q35:

The 2012 Business Plan shows changes relative to the June 2011 Forecast. Please file in conjunction with the September updates, the Actual 2011 results and indicated how the results impact the 2012 and 2013 Business Plans.

Response:

The final 2013 Business Plan will be based on 2011 actuals and a 2012 forecast prepared as at June 30th.

Round1 – Consultant Q36:

Please update the schedule provided in 2010 with respect to actual Insurance costs and bad debt expenses for 2010 and 2011 and forecasted for 2012 – 2013.

Response:

The breakdown is as follows:

in $millions	Actual		Forecast	
	2010	**2011**	**2012**	**2013**
Insurance	4.8	5.0	5.3	5.6
Bad debt expense	2.3	2.5	2.7	2.3

Round1 – Consultant Q37:

Please describe what methodology changes have been instituted as a result of implementation of Ganett & Fleming 2010 deprecation study.

Response:

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

- Review of the physical plant based on site tours of typical facilities, and through conversations with management and operating staff;
- Review of the current capitalization and retirement policies;
- Review of the upcoming projects and outlooks;
- ASL estimates from previous SaskPower studies;
- ASL estimates from other peer electric generation, transmission and distribution utilities; and
- The professional judgment of Gannett Fleming.

The methodology followed by Gannett Fleming is very similar to the approach used by the Corporation when the studies were performed internally.

SaskPower

2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

Round1 – Consultant Q38:

Please provide an update to schedule for the years 2009 to 2013 (actual/forecast) confirming the actual and forecasted annual depreciation rates and amortization costs by major plant categories similar to changes shown in Table 3.39 of the 2010 Consultant's Report.

Response:

Depreciation Rates and Amortization Costs

Asset Group	Depreciation Rates	2013 Budget	2012 Budget	2011 Actual	2010 Actual IFRS	2009 Actual
Generation						
Coal	1%-20%	72,923	72,899	73,180	72,158	77,091
Natural Gas	2%-20%	28,266	30,012	28,474	19,204	10,160
Hydro	1%-4%	16,408	17,185	14,933	15,128	16,711
Cogeneration	3.3%					4,962
Wind	2%-6.67%	13,213	13,915	13,220	13,168	12,722
Leased	4.0%	38,828	21,328	16,978	15,528	
Transmission	2%-33.33%	28,065	27,165	23,246	20,377	19,198
Distribution	2.5%-33.33%	80,793	76,556	70,848	66,817	66,893
Other	1%-25%	70,389	57,918	44,551	41,050	33,255
Total		348,885	316,978	285,430	263,430	240,992
Customer Contribuition Amortization						(13,675)
Asset Retirement Expense		5,215	4,269	4,269	2,750	1,201
Total Other Dep Exp		5,215	4,269	4,269	2,750	(12,474)
Total Dep Exp		354,100	321,247	289,699	266,180	228,518

2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

Round1 – Consultant Q39(a):

Please also indicate for 2010 and 2011 the costs attributable to:
a) the new depreciation study and
b) the conversion to IFRS as applicable.

Response:

The estimated impact of the 2010 Depreciation Study on the 2011depreciation rates was as follows:

			(in millions)
Asset Group	**Estimated 2011 Dep'n Using Revised Rates**	**Estimated 2011 Dep'n At Current Rates**	**Variance**
Generation	$ 144.4	$ 136.2	$ 8.2
Transmission	21.20	21.80	(0.60)
Duistribution	68.50	68.50	-
Mining	0.90	0.90	-
Other Assets	36.80	36.20	0.60
Total	271.80	263.60	8.20

It should be noted that the Corporation would have increased its depreciation rates by approximately $9.5 million in 2011 under its existing methodology which calls for annual reviews of depreciation expense for appropriateness. This increase in depreciation expense would have occurred due to the decision to retire a significant portion of BD#3 in 2013; the decision to retire existing mechanical meters in 2014 as a result of AMI; and a decision to capitalize scheduled overhauls on new gas turbines.

The impact of the external consultant’s review was a reduction in depreciation expense of approximately $1.3 million.

Round1 – Consultant Q39(b):

Please also indicate for 2010 and 2011 the costs attributable to:
a) the new depreciation study and
b) the conversion to IFRS as applicable.

Response:

The below table shows the impact of IFRS on SaskPower's depreciation rates for 2010. The impact on 2011 is not available as the Corporation did not maintain parallel accounting records for that year.

Reconciliation of Consolidated Statement of Income for the year ended December 31, 2010

(in millions)	Canadian GAAP	IFRS Adjustments	IFRS Reclassifications	IFRS
Revenue				
Saskatchewan electricity sales	$ 1,575	$ -	$ -	**$ 1,575**
Exports	12	-	-	**12**
Net sales from electricity trading	1	-	3	**4**
Share of profit from equity accounted investees	-	4	6	**10**
Other revenue	163	43	(116)	**90**
	1,751	47	(107)	**1,691**
Expense				
Fuel and purchased power	511	(46)	(19)	**446**
Operating, maintenance and administration	641	(18)	(110)	**513**
Depreciation and amortization	258	22	(14)	**266**
Finance charges	139	45	8	**192**
Taxes	42	-	-	**42**
Other losses (gains)	-	-	9	**9**
	1,591	3	(126)	**1,468**
Income before the following	160	44	19	**223**
Unrealized market value adjustments	-	-	(19)	**(19)**
Net income	$ 160	$ 44	$ -	**$ 204**

Round1 – Consultant Q40:

Finance charges are expected to increase significantly (from $150 million in 2010) with-in the Business Plan forecast period. Please provide the schedules showing the components of this anticipated increase in actual interest charges for 2010 and 2011 and forecasted for 2012 and 2013.

Response:

The makeup of Finance Charges for the years 2010 to 2013 (based on the preliminary 2013 Business Plan) are as follows:

	2010	2011	2012	2013
Finance Charges:				
Interest on Long Term Debt	166.7	173.0	174.7	191.6
Interest on Finance Leases	50.9	54.2	67.9	122.7
Interest on ST Advances	1.1	1.4	4.6	11.9
Accretion Expense	4.8	5.0	5.2	5.5
Interest During Construction	(15.1)	(11.7)	(21.5)	(44.8)
Other Interest Charges	0.7	0.5	2.6	7.4
	209.1	222.4	233.5	294.3
Fixed Income:				
Debt Retirement Fund Earnings	(17.3)	(24.7)	(17.6)	(19.8)
Interest Income	(0.1)	(0.2)	(0.4)	(0.8)
	(17.4)	(24.9)	(18.0)	(20.6)
Total Finance Charges	191.7	197.5	215.7	273.7

The $150 million referred to in the question was based on Canadian GAAP (all numbers in table above are reported in IFRS). The major difference between the two accounting standards is the inclusion of interest on capitalized leases as part of finance charges under IFRS. The increase in finance charges is offset by a reduction in F&PP costs.

Round1 – Consultant Q41(a):

Please confirm:

a) that for 2010 forward SaskPower has, under IFRS, elected to recognize leases for exclusive production (PPA's) assets which account for the major increase in finance costs under the line item "Interest on Finance Lease" during this time period.

b) that the total finance lease obligation as at December 31, 2011 was $552 million.

Response:

As reported in SaskPower's 2011 Annual Report, under IFRS, certain take-or-pay power purchase agreements which give the Corporation the exclusive right to use specific production assets have been determined to meet the definition of a lease. These arrangements have been classified as finance leases.

Assets held under finance leases are initially recognized at the lower of their fair value at the inception of the lease or the present value of the minimum lease payments. The corresponding liability is recorded as a finance lease obligation. Each lease payment is allocated between the liability and interest so as to achieve a constant rate on the finance balance outstanding. The interest component is included in finance expense which accounts for the line item "Interest on Finance Lease".

Round1 – Consultant Q41(b):

Please confirm:

a) that for 2010 forward SaskPower has, under IFRS, elected to recognize leases for exclusive production (PPA's) assets which account for the major increase in finance costs under the line item "Interest on Finance Lease" during this time period.

b) that the total finance lease obligation as at December 31, 2011 was $552 million.

Response:

As reported in SaskPower's 2011 Annual Report (see note 21), the total finance lease obligation as at December 31, 2011 was $552 million.

Round1 – Consultant Q42:

Please confirm that the corporation had $353 million in sinking funds at December 31, 2011. Please advise the current rate of interest forecasted for these debt retirement funds.

Response:

Confirmed. With respect to the interest rate, the current rate of interest forecasted for these debt retirement funds is 5%.

Round1 – Consultant Q43:

Please confirm that currently SaskPower holds no debt or exposure for trading which would be subject to a foreign exchange cost.

Response:

SaskPower confirms it has no debt or derivatives outstanding that are subject to a foreign exchange cost.

Round1 – Consultant Q44(a):

Please provide:

a) current schedule of all outstanding long term debt including the retirement date and specific interest rate associated with each issue similar to that provided in your annual report for both long term debt and non-recourse debt.

b) a schedule for 2009, 2010 and 2011 and forecasts for 2012 & 2013 detailing, for each year, SaskPower's debt, SPI non-recourse debt, other debt and total debt less sinking funds for the total long term debt.

Response:

The following table is similar to the one found in SaskPower's 2011 annual report. There have been no changes to our long-term debt levels since December 31, 2011.

Advances from the Government of Saskatchewan's General Revenue Fund (in millions):

Date of Issue	Date of Maturity	Effective Interest Rate (%)	Coupon Rate (%)	Par Value	Unamortized Premium (Discount)	Outstanding Amount
July 20, 1993	July 15, 2013	8.63	7.81	$ 97	$ -	$ 97
December 20, 1990	December 15, 2020	11.23	9.97	129	(1)	128
February 4, 1992	February 4, 2022	9.27	9.60	240	6	246
July 21, 1992	July 15, 2022	10.06	8.94	256	(1)	255
May 30, 1995	May 30, 2025	8.82	8.75	100	(1)	99
August 8, 2001	September 5, 2031	6.49	6.40	200	(2)	198
January 15, 2003	September 5, 2031	5.91	6.40	100	6	106
May 12, 2003	September 5, 2033	5.90	5.80	100	(1)	99
January 14, 2004	September 5, 2033	5.68	5.80	200	3	203
October 5, 2004	September 5, 2035	5.50	5.60	200	3	203
February 15, 2005	March 5, 2037	5.09	5.00	150	(2)	148
May 6, 2005	March 5, 2037	5.07	5.00	150	(1)	149
February 24, 2006	March 5, 2037	4.71	5.00	100	4	104
March 6, 2007	June 1, 2040	4.49	4.75	100	4	104
April 2, 2008	June 1, 2040	4.67	4.75	250	3	253
December 19, 2008	June 1, 2040	4.71	4.71	100	-	100
September 8, 2010	June 1, 2040	4.27	4.75	200	15	215
				$ 2,672	**$ 35**	**$ 2,707**

Round1 – Consultant Q44(b):

Please provide:

a) current schedule of all outstanding long term debt including the retirement date and specific interest rate associated with each issue similar to that provided in your annual report for both long term debt and non-recourse debt.

b) a schedule for 2009, 2010 and 2011 and forecasts for 2012 & 2013 detailing, for each year, SaskPower's debt, SPI non-recourse debt, other debt and total debt less sinking funds for the total long term debt.

Response:

Date of Issue	Date of Maturity	Effective Interest	Coupon Rate	2009	2010	2011	2012	2013
July 20, 1993	July 15, 2013	8.63	7.81	97	97	97	97	-
Dec 20, 1990	Dec 20, 2020	11.23	9.97	129	129	129	129	129
Feb 04, 1992	Feb 04, 2022	9.27	9.60	240	240	240	240	240
Jul 21, 1992	Jul 15, 2022	10.06	8.94	256	256	256	256	256
May 30, 1995	May 30, 2025	8.82	8.75	100	100	100	100	100
Aug 08, 2001	Sept 5, 2031	6.49	6.40	200	200	200	200	200
Jan 15, 2003	Sept 5, 2031	5.91	6.40	100	100	100	100	100
May 12, 2003	Sept 5, 2033	5.90	5.80	100	100	100	100	100
Jan 14, 2004	Sept 5, 2033	5.68	5.80	200	200	200	200	200
Oct 5, 2004	Sept 5, 2035	5.50	5.60	200	200	200	200	200
Feb 15, 2005	Mar 05, 2037	5.09	5.00	150	150	150	150	150
May 6, 2005	Mar 05, 2037	5.07	5.00	150	150	150	150	150
Feb 24, 2006	Mar 05, 2037	4.71	5.00	100	100	100	100	100
Mar 06, 2007	Jun 01, 2040	4.49	4.75	100	100	100	100	100
Apr 02, 2008	Jun 01, 2040	4.67	4.75	250	250	250	250	250
Dec 19, 2008	Jun 01, 2040	4.71	4.71	100	100	100	100	100
Sept 08, 2010	Jun 01, 2040	4.27	4.75	-	200	200	200	200
				-	-	-	-	-
				2,472	2,672	2,672	2,672	2,575
Net Premium				21	36	35	34	33
				2,493	2,708	2,707	2,706	2,608
New Issues:								-

Nov 30, 2012	Jun 1, 2041	4.0	4.0	0	0	0	200	200
Feb 28, 2013	Jun 1, 2041	4.0	4.0	0	0	0	0	200
Other LTD in 2013		4.1	4.1	0	0	0	0	450
LTD per Schedule				2,493	2,708	2,707	2,906	3,458
Short Term Advances				272	159	251	667	883
				2,765	2,867	2,958	3,573	4,341
Lease Obligations				413	412	555	552	1,248
Remove DRFs				(246)	(291)	(353)	(389)	(406)
Total Debt				2,932	2,988	3,160	3,736	5,183

Round1 – Consultant Q45:

Please provide the actual taxes paid consisting of; corporate capital tax, municipal surcharges, grants in lieu by municipality and miscellaneous tax expense in 2010 and 2011, and the forecasted amounts for 2012 and 2013.

Response:

The following is a summary of corporate capital tax, municipal surcharges, grants in lieu by municipality and miscellaneous tax expense in 2010 and 2011, and the forecasted amounts for 2012 and 2013.

Taxes and Grant in Lieu

(in millions $)	**2010**	**2011**	**2012**	**2013**
Taxes				
Corporate capital tax	$ 22.1	$ 22.4	$ 28.2	$ 34.5
Grants in lieu	19.3	20.4	19.5	21.0
Miscellaneous tax expense	0.5	0.5	0.2	0.5
Total Taxes	**$ 41.9**	**$ 43.4**	**$ 48.0**	**$ 56.0**

SaskPower

2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

Round1 – Consultant Q46:

Please confirm that a dividend was not declared in 2010 and the declared dividend of $120 million for 2011 is to be paid in four installments in 2012.

Response:

As reported in SaskPower's 2010 and 2011 Annual Reports, SaskPower did not declare any dividends payable to CIC in 2010 and 2011. In the first quarter of 2012, it was determined that SaskPower would pay a special $120 million dividend to CIC as a result of higher than expected earnings in 2011. The special dividend is payable in equal quarterly instalments commencing on March 30, 2012.

Round1 – Consultant Q47:

Please confirm that at the time of the Application the forecast for 2012 SaskPower's net income before unrealized market value adjustments is expected to be $157 million, resulting in an approximate return on equity of 7.6%. Please provide any updates available together with the complete 2nd quarter report.

Response:

The numbers noted above are SaskPower's 2012 budgeted net income and budgeted ROE for 2012.

Our forecasted operating income (before unrealized market value adjustments) for 2012 as at March 31 was $159.8 million and the ROE was forecast to be 8.6%.

The final 10 year business plan will be based on a forecast as at June 30th, 2012. Forecasted operating income as at June 30 was $165.8 million and the ROE was forecast to be 8.8%.

SaskPower

2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

Round1 – Consultant Q48:

The 2010 debt ratio declined to 63.0% from 65.4% in 2009 and remained the same for 2011. Please provide the forecasted debt ratio for 2012 and 2013.

Response:

The forecasted debt ratio for 2012 is 66.4% and for 2013 is 71.7% as per the 2013 preliminary business plan.

SaskPower

2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

Round1 – Consultant Q49:

Please provide a schedule detailing actual working capital allowance for 2009, 2010, 2011, and projections for 2012 and 2013.

Response:

The following table indicates Actual Working Capital (for the years 2009, 2010, 2011) and Projected Working Capital (for the years 2012, 2013):

	Actuals			Forecasted	
	2009	2010	2011	2012(2010Base)	2013(2010Base)
Working Capital	$70,267,175	$85,416,800	$77,316,927	$78,843,792	$85,375,000

Working Capital is calculated by taking 12.5% of the total of OM&A and Taxes. Please note that 2009 and 2010 actuals are based on GAAP accounting and 2011 actual and 2012 and 2013 forecasted are based on IFRS accounting.

SaskPower

2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

Round1 – Consultant Q50:

Please discuss whether all data in this application for 2011 onward utilizes Weather normalized data, or actual results.

Response:

The load and revenue data in the application for 2011 is actual data. The load and revenue data for 2013 Forecast is weather normalized. The load and revenue data for 2012 Forecast (March 31) is a combination of 2 or 3 months of actual and the remaining months of normalized data. The first 3 months of 2012 were unusually warm and loads were down in some classes due to the reduction in heating loads.

Round1 – Consultant Q51:

Please provide a schedule showing the reconciliation from Canadian GAAP to IFRS on 2010 and 2011 and any future anticipated impacts.

Response:

The Corporation's consolidated financial statements were previously prepared in accordance with Canadian Generally Accepted Accounting Principles (GAAP). The 2011 consolidated financial statements have been prepared in accordance with International Financial Reporting Standards (IFRS). As these consolidated financial statements represent the Corporation's initial presentation of its financial position, income and cash flows under IFRS, they were prepared in accordance with IFRS 1, First-time Adoption of IFRS. See the below reconciliation from Canadian GAAP to IFRS on 2010. Additional details are reported in SaskPower's 2011 Annual Report (see notes 31 and 32). SaskPower did not keep dual financial records (GAAP and IFRS) in 2011(or beyond) so a reconciliation is not available for that year.

SaskPower

2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

Round1 – Consultant Q52:

Please provide a Provincial Map showing additions to all SaskPower's Generation sites, including Hydro, Natural gas, Co-Gen, wind, IPP and Diesel sites showing all transmission lines (by KV capacity) from each of the generation sites to the various load centres, indicating grid interties, as applicable since 2009.

Response:

A copy of the map was given to the SRRP and their consultant. As it contains customer information it is confidential.

Round1 – Consultant Q53:

Reference: Application - Tab 17 - Please provide schedules from 2009 to 2011 and forecasts for 2012 to 2016 showing the generation capacity added, generation capacity retired and total capacity available by fuel type.

Response:

The current total capacity available by fuel type is as follows.

Fuel Type	Percent	Net MW
Coal	41.0%	1686
Natural Gas	32.8%	1349
Hydro	20.7%	853
Purchased Power - Other	0.6%	25
Wind	4.8%	198
Total Generation	100%	4110

The following tables show the generation added since 2008 as well as any new generation that is either approved or committed to by SaskPower. The installed generation below is included in the capacity by fuel type table above.

Sustainable Supply Development
Supply Planning Database - Installed/Planned Generation Database

Table 1: Installed Generation (Excluding Net Metering/SPPP Projects)

Year	Project	Net Size (MW)	Type	Ownership SPP	Ownership IPP
2007					
2008	NRGreen Heat Recovery Facility (Alameda)	5			5
2008	NRGreen Heat Recovery Facility (Loreburn)	5			5
2008	NRGreen Heat Recovery Facility (Estlin)	5			5
2009	Ermine Power Station	92	SCGT	92	

2009	Queen Elizabeth Expansion	108	SCGT	108	
2010	Yellowhead Power Station	141	SCGT	141	
2011	Red Lily Wind Power Facility	26	Wind		26
2011	Spy Hill Generating Station	86	SSGT		86
	Subtotals	**468**		**341**	**127**

Table 2: Generation Under Development

Target in-service	Project	Net Size (MW)	Type	Ownership	
				SPP	**IPP**
2012	TransGas Rosetown Waste Heat Recovery Facility	1			1
2012	Prince Albert Pulp Inc. (Prince Albert Pulp Mill)	10			10
2013	North Battleford Energy Center	261	CCGT		261
2014	Boundary Dam Carbon Capture Project	110	Coal	110	
2015	Queen Elizabeth Expansion	205	CCGT	205	
2017	Chaplin Wind Power Project	177	Wind		177
	Subtotals	**764**		**315**	**449**

Table 3: Life Extensions

Target in-service	Project	Net Size (MW)	Type	Ownership	
				SPP	**IPP**
2014	Landis Power Station	79		**79**	
2014	Boundary Dam Unit 4	139		**139**	
2015	Meadow Lake Power Station	44		**44**	
2017	QE Unit 3	95		**95**	
	Subtotals	**357**		**357**	

Table 4: Biomass Generation (pending final PPA)

Target in-service	Project	Net Size (MW)	Type	Ownership	
				SPP	**IPP**
2014	Meadow Lake Tribal Council	36	Biomass		36

	Prince Albert/Meadow Lake Green Power Inc.	70	Biomass		70
	Subtotals	**106**			**106**

Table 5: GOPP Projects - No PPA

Target in-service	Project	Net Size (MW)	Type	Ownership SPP	Ownership IPP
	Kineticor Renewables Inc.	10	Wind		10
	Kineticor Renewables Inc.	10	Wind		10
	Confederation Power Inc./Sprott Power Corp.	10	Wind		10
	Gaia Power Inc.	9.9	Wind		9.9
	Gaia Power Inc.	9.9	Wind		9.9
	Windlectric Inc.	5	Wind		5
	Cowessess/SRC	0.96	Wind/Battery		0.96
	Subtotal	**55.76**			**55.76**
	TransGas Ltd. Hatton	0.112	Waste Heat Recovery		0.112
	TransGas Ltd. Coleville (2nd Project)	0.15	Waste Heat Recovery		0.15
	TransGas Ltd. Unity	0.26	Waste Heat Recovery		0.26
	Subtotal	**0.522**			**0.522**
	Torquay Oil Corporation & Three Point Energy Services Inc.	0.13	Flare Gas		0.13
	ARC Resources Ltd. & Three Point Energy Services Inc.	0.52	Flare Gas		0.52
	Natural Energy Partners Ltd.	3.5	Flare Gas		3.5
	Torquay Oil Corporation & Three Point Energy Services Inc.	0.26	Flare Gas		0.26
	Natural Energy Partners Ltd.	3.5	Flare Gas		3.5
	Natural Energy Partners Ltd.	3.5	Flare Gas		3.5
	Genalta Power Inc. / Talisman Energy Inc.	0.325	Flare Gas		0.325
	Creative Energy Inc	0.2	Flare Gas		0.2
	Subtotal	**11.935**			**11.935**
	City of Saskatoon Light & Power	1.6	Landfill Gas		1.6
	Saskatoon Light & Power	1	Turboexpander/Landfill Gas		1
	City of Regina	1	Landfill Gas		1
	Subtotal	**3.6**			**3.6**

Deep Earth Energy Production Corporation		5	Geothermal	5
	Subtotal	**5**		**5**
Rocky Mountain Power (2006) Inc.		2	Hydro	2
	Subtotal	**2**		**2**
WAM Investments		0.125	Biogas	0.125
	Subtotal	**0.125**		**0.125**
Keith Hesketh		2	Flare Gas/Biomass	2
	Subtotal	**2**		**2**
	GOPP TOTAL	**80.942**		**80.942**

Table 6: Demand Side Management

2008 to 2011 DSM Program Expenditures		34.2
2012 to 2017 DSM Program Budget		65.8
	Subtotal	**100**

Table7: Unit Retirements

2013	Boundary Dam Unit 1		-62
2015	Boundary Dam Unit 2		-61
2013	Boundary Dam Unit 3		-139
		Subtotal	**-262**

Round1 – Consultant Q54:

Please describe any changes, since 2009, to the specific dispatch polices and rules for use of the various fuel sources to meet daily load and the peak day load for 2009, 2010 and 2011 and projected for 2012 and 2013.

Response:

There have been no changes to dispatch policies and rules for various fuel sources to meet peak day load.

SaskPower

2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

Round1 – Consultant Q55:

Please show the fuel type used for each of the years to meet peak day load requirements as well as the annual fuel mix percentages.

Response:

The following table indicates the electrical generation by source for the 24 hour period coincident with the peak day load requirements.

Year	Peak Date	Daily Generation in MWh by Fuel Source					
		Hydro	Coal	Gas	Import	Wind & Other	System Req.
2005	2005-01-13	10,239	37,061	15,018	400	74	62,791
2006	2006-11-29	9,523	32,645	17,136	1,257	2,700	63,260
2007	2007-02-01	10,690	37,373	13,212	76	3,741	65,092
2008	2008-12-15	10,435	35,872	16,224	3,943	2,001	68,475
2009	2009-12-14	8,692	38,928	15,618	2,319	3,119	68,675
2010	2010-12-12	8,556	39,626	12,449	2,604	3,213	66,447
2011	2011-01-12	9,999	39,105	16,420	800	3,132	69,456

The following table indicates the annual fuel mix percentage.

Year	Annual Fuel Mix Percentage				
	Hydro	Coal	Gas	Import	Wind & Other
2005	22.3%	56.0%	15.8%	5.5%	0.5%
2006	20.5%	56.3%	18.0%	2.3%	2.9%
2007	21.4%	56.7%	17.2%	1.5%	3.2%
2008	19.7%	55.7%	18.6%	2.9%	3.2%
2009	14.9%	62.0%	17.3%	2.2%	3.6%
2010	18.6%	58.0%	17.7%	2.5%	3.2%
2011	21.4%	53.8%	18.7%	2.3%	3.8%

Round1 – Consultant Q56:

Please provide an update of the Feasibility Study Agreement with First Nations Partners, including SaskPower's total costs to date, as well as what SaskPower currently anticipated final total costs.

Response:

A confidential update was provided to the SRRP and their consultant.

SaskPower

2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

Round1 – Consultant Q57:

Please describe the terms of the Renewal of the British Columbia firm transmission Service and how it will ensure NorthPoint access to the Alberta Market.

Response:

In January of 2006, NorthPoint requested and was awarded 50 MW of Long Term Firm (LTF) Point To Point (PTP) transmission service from the US/BC border to the BC/Alberta border. This position allows NorthPoint to deliver physical power purchased from the US Pacific Northwest (Mid-C market) across BC and into the Alberta market. The initial term of this service was for 1 year and came with rollover rights.

In order to maintain this transmission position beyond December 31, 2010, NorthPoint had the option through rollover rights to meet the length of term of any transmission request to the British Columbia Transmission Company (BCTC) for LTF PTP service on this path or any competing path to the BC/Alberta border. At the time there were 6 competing requests with the longest duration being 10 years.

NorthPoint received Board approval to roll over this transmission position for 10 years. With the 6 competing requests, this was NorthPoint's only viable economic way to obtain transmission from the US Northwest to Alberta. Non-firm transmission could have been competed for on a daily basis, however very little of this transmission exists as long term transmission and is rarely unused. The level of firm transmission in BC to Alberta is greater than the available transfer capability posted by the Alberta Integrated Electric System. As a result, during periods of high prices in Alberta there will be no non-firm transmission available on this path to Alberta.

Round1 – Consultant Q58:

Please confirm that the material provided in Tab 17 of the Consultants MFR dated December 31, 2011 remains SaskPower's Generation Supply Plan for 2012 and 2013. If not please provide any updated materials together with the frequency and the types of changes that require SaskPower to review the 5 year and 40 year supply plans.

Response:

The SaskPower 2011 Short-term Supply Development Plan is the most current approved short-term supply plan. However, SaskPower is currently in the process of updating that plan for 2012 as a part of its annual supply plan update process.

The recently developed 40 Year Leadership Outlook, is an integrated power system planning document which will impact the supply planning development work, and ultimately the decision oriented plans that follow.

Updates to the 40 Year Leadership Outlook will be done when substantive changes to key assumptions occur. Work is underway to develop a public communication strategy for the 40 Year Outlook as well as the Short-term Supply Development Plan.

Round1 – Consultant Q59:

Please provide any updates with respect to the Contingency Plan component of the 2011 to 2015 Resource Supply Plan.

Response:

An update has been provided to the SRRP and their consultant.

2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

Round1 – Consultant Q60:

Please confirm that the material in Tab 17 (Current 40 Year Supply Plan) is considered to be confidential by SaskPower and explain the rationale for this position.

Response:

SaskPower have provided the SRRP and their consultant with a copy of the confidential document. SaskPower is developing a public communication strategy for the 40 Year Supply Plan.

Round1 – Consultant Q61:

Please discuss the status of the planning document related to the far north requirements and the integrated supply resources. If available please file the document.

Response:

The Far North report was presented to the Executive with an Information item in April of 2011. Supply Planning is currently working on an update to the Far North plan with the 2012 Q2 load forecast. This document is a confidential document but a copy has been provided to the SRRP and their consultant.

Round1 – Consultant Q62:

Please file SaskPower planned maintenance program for 2011 and the programs for 2012 & 2013. Indicate the cost savings for OM&A and fuel as a result of implementation of the recommendation of the SaskPower's consultant's report in this regard.

Response:

The planned maintenance program has been submitted to the SRRP and their consultant.

Round1 – Consultant Q63:

Please provide a schedule related to power outages in excess of 2 hours, indicating the cause of the outages, for both generation and transmission, and the length of time required to restore power for each of the years 2009, 2010 and 2011.

Response:

All the transmission outages in excess of 2 hours for the years 2009, 2010, and 2011 including the cause of the outage are included below. The duration of the outage indicates the length of time it took to place the line back in service. As with any transmission system the line outage may not result in customer outages.

Consultant Q63

Primary Causes:
DE Defective Equipment
AW Adverse Weather
AE Adverse Environment
SC System Condition
HE Human Element
FI Foreign Interference
GL Generation Losses
OT Other

Year	Major Component	Duration (hh:mm)	Primary Cause	Comments
2009	BP8	19:51	OT	Cust. Trble. Protn setting of YARA's 5000HP motor incorrect. Ext'd Otg
2009	PR#1	14:45	OT	Due to loss of both cooling water pumps following 86, 86X/505T opr.
2009	N2L	42:26	OT	PO. Sect'd. Partially I/S fr NB & LY ends up to open L3 & L4. Ext'd.
2009	GB701CAP	03:12	OT	CU. Weyerhauser OSB plant shut down. Reinsert when load >= 40A/5MW
2009	PN806	07:48	DE	Non-lockout alarms failed to clear.
2009	R2C	35:49	OT	PO. Fed from CD end L1 open and RE807LM. Extd otg. Permit to repair.
2009	C1P	21:38	OT	PO. Partially i/s fr CC end; with PQ815LM and L1 sw open. Extd otg.
2009	C1P	03:53	DE	Broken spar located btwn L1 & PQss. Ext'd Otg.
2009	W1Y	21:10	OT	PO. Partially I/S fr YN end up to Open BA 807LM.
2009	MCR1	22:01	OT	Cust trble.
2009	S1M	04:21	OT	IntrT. Mc Conv sent TX trip to SW; 85-3 Dir RX to 94-3/904L. Ext'd otg
2009	ER709C	03:59	FI	Birds in the cap bank blew 2 fuses. Ext'd otg. No TRA by GCC.
2009	R1F-FS	09:50	FI	Car hit pole on F2B-FS & pole fell into the R1F-FS SecC. Ext'd otg.
2009	F2B-FS	09:50	FI	Car hit pole on F2B-FS & pole fell into the R1F-FS RtC. Ext'd otg.
2009	Q3E-EL	03:22	AW	Lightning. Ext'd otg due to repairing downed conductor.
2009	PN10	17:46	HE	SLE; U/V due to Cust load & XL conn. to same XFMR. For DP & Cust #3
2009	W1Y	13:33	OT	PO. W1Y I/S to open 807LM switch. Ext'd otg to isl/repair broken spar.
2009	RU601C2	18:47	OT	CU. Unbl trip via harm??? Invst. prot'n dsgn.!!!! Ext'd otg;AMS miscom
2009	C1F-CD	02:04	OT	Cust Trble. Customer owned XFMR fault; 2 blown fuses. Ext'd otg.
2009	B1A-BD	05:15	OT	CU. BD701 Bkr fail opr. At same time . Ext'd Otg.
2009	BD910	88:37	DE	Bkr fails closed; due to low air pres. Inits BF oprn causing bus trip.
2009	PR#2	08:19	OT	Due to loss of station power via uexpected 86, 86X/505T ATR opr.
2009	RU601C3	03:17	OT	Loss of 602DVAR cntrlpwr; U/V. No TSht, SER or fault data. Ext'd otg.
2009	GL801	127:22	DE	Faulty mechanism. Ext'd Otg due to repairs req'd. Dur=127hr 22min.
2009	RU601C2	02:16	OT	Loss of 602DVAR cntrlpwr; U/V. No TSht, SER or fault data. Ext'd otg.
2009	RU601C1	02:09	OT	Loss of 602DVAR cntrlpwr; U/V. No TSht, SER or fault data. Ext'd otg.
2009	RU602DVAR	02:10	OT	RU Inv Ready -"NO" Alarm. Trip on Loss of CntrlPwr? No TRA. Ext'd otg.
2009	BE905	12:26	DE	Cls Cmd Failures during attempted restoration.
2009	W1Y	02:10	AE	Pole on fire; suspect from stubble fire. A/R attempt; T-C-T

Year	Major Component	Duration (hh:mm)	Primary Cause	Comments
2009	WY801T	109:22	DE	Tap changer failed. Extensive damage to transformer. Extd otg.
2009	P1S	16:56	OT	PO. P1S line sectionalized at open PQ 806LM switch. Ext'd otg.
2009	TC5	03:25	DE	Dead end clamp let go near Weyakwin resulting in downed cond. Ext'd
2009	GL700CS	04:21	DE	Several mech. failures with GL700CS prevented a close when req'd.
2009	S1M	08:17	OT	Suspect IntrT at McNeil. Ext'd Otg; waiting for ATCO's OK to re-energ.
2009	ER709C	08:10	FI	ATech suspects starlings. O/C trip as per target sheet. No TRA by GCC.
2009	ER4	04:11	AW	High Winds; conductor/shield gnd wire contact suspected. RtC. #3
2009	RU603DVAR	03:11	OT	RU Inv Ready -"NO" Alarm. Trip on Loss of CntrlPwr? Ext'd otg
2009	CD709	6212:57	DE	Cap bkr fails to close; Yph pin sheared. Parts on order. Dur=? CFwrd10
2009	SW909	73:14	DE	EMR by GCC. Air compressor failed; replaced.
2009	RU611	621:21	DE	Yph pole interruptor failure; found burnt. Ext'd otg.
2009	Q1H	03:41	OT	PO. HA/Q1H energized to open L2 sw; while permits in eff to rpr L1 sw
2009	BD810T	130:20	DE	Xfmr Aux prob; 4kV cable fault in plant. Ext'd Otg. Dur = 130hr 20min.
2009	SW3	03:51	AW	High winds; suspect galloping lines. Ext'd otg; SW7 & SW8 otgs. #2.
2009	AS705	24:59	DE	EMR due to arcing. Ext'd otg. Dur=24hr 59min.
2009	A1T-AU	03:44	DE	EMR by GCC due to fire on riser. Ext'd Otg.
2009	B2G	14:07	AE	Pole Fire located in a swamp. RtC.
2009	W1A-AS	02:41	AW	Cond. wrapped around each other. Energ'd to open L7&L8 sw. Ext'd Otg.
2009	KLM1	06:05	AE	Cust Trble; Industrial Pollution. Contaminated insl's/ RtC. Ext'd Otg.
2009	N2L	05:51	OT	PO. Sect'd. Isol'd burnt pole btwn open L1 & L2 switches. Ext'd otg.
2009	R1F-FS	124:47	AE	Salt spray build up on line that crosses Ring Road. Ext'd Otg.
2009	C1S	59:31	AW	High winds; A/R attempt. Found brkn X-arm. Ext'd otg. Dur=59hr 31min.
2009	Q1H	04:59	OT	PO. Swtg to locate & isolate flt. HA/Q1H energized up to open L1 sw.
2009	RE902	27:22	DE	EMR. Several hydraulic oil leaks caused by damaged o rings. Ext'd Otg.
2009	R1F-FS	219:16	OT	Bph of FS 546 flashed to guy wire. Ext'd Otg. Cust backfed from BR sub
2009	KLM1	03:39	DE	Cust Trble; problems with customer IMC-BP 811L switch. RtC. Ext'd Otg.
2009	R1P	03:42	OT	Dstr Flt. Cust Trble with IMC-BP 811L switch. SecC. Ext'd Otg.
2009	R1F-FS	48:29	OT	EMR. FS727 open. Arcing with FS 546. Ext'd Otg. Cust still backfed.
2009	YN802T	392:00	DE	Blue ph. lightning arrestor blew up. Ext'd Otg. Dur=392hrs 00min. RtC
2009	RU601C3	02:08	OT	CU. Unbl trip via harm??? Invst. prot'n dsgn.!!!!
2009	R1P	06:07	OT	Dstr Flt. Cust Trble; IMC Switch Yard contamination. SecC. Ext'd Otg.
2009	BVL1	05:47	AW	Wind broke tree and carried a fragment into the line. Ext'd otg.
2009	RU601C4	26:50	OT	Loss of 602DVAR cntrlpwr; U/V. No TSht, SER or fault data. Ext'd otg.
2009	P1S	02:39	AW	Lightning. A/R attempt; T-C-T. CO. Ext'd otg.
2009	B10T	08:13	HE	IntrT. Tioga Stn. tripped for fls xfmr diff. opr. Settings. Ext'd otg.

Year	Major Component	Duration (hh:mm)	Primary Cause	Comments
2009	BD810T	78:33	DE	Cable flt in the outside cable pit located on lawn. Dur=78 hr 33 min.
2009	RU601C2	21:21	OT	Normal ctrl actn of DVAR related to RU611 bkr pole failure. Ext'd otg.
2009	RU601C1	10:25	OT	Normal ctrl actn of DVAR related to RU611 bkr pole failure. Ext'd otg.
2009	RL6	09:34	OT	Cust Trble; suspect CAMECO SVC caused the trip. Ext'd otg.
2009	RL1	09:34	OT	Cust Trble; suspect CAMECO SVC caused the trip. Ext'd otg.
2009	S1M	02:01	OT	IntrT. McNeil sent TX trip to SW; 85-3 Dir RX to 94-3/904L. Ext'd otg.
2009	PE3	08:20	AW	Lightning. Bell insulators were found busted up on the bus. Ext'd otg.
2009	BD#6	03:10	DE	Unit tripped off-line due to fan vibrations. RtC.
2009	N1L	24:33	AW	High winds. Ext'd otg due to a broken pole fr NBss.
2009	PR3	03:28	OT	CU at this time. O/V trip to 94/501T & 503L. Ext'd otg. No TRA. #3
2009	FD1	07:01	DE	Burnt control fuse found by area tech. Ext'd otg.
2009	C1F-CD	06:25	OT	GCC doing switchings of loads between CD3 & C1F-CD. Ext otg.
2009	CD3	08:50	DE	Broken spar at Courtenay Ave. Ext'd otg.
2009	HA6	07:49	AW	Lightning. Ext otg. Repairs to HA6 downed line req'd.
2009	CD906T	75:50	DE	EMR by GCC for gassing investigation.
2009	PN10	05:40	HE	SLE; U/V. GCC opr error. GridV unstable; for DP & Cust. Ext'd otg. #2
2009	IF37	04:17	AW	Lightning. Ext'd otg.
2010	RE901T	15:39	OT	CU at this time. Inadvertant differential trip. Ext'd otg.
2010	SW7	05:43	AW	Suspect hoar frst caused icing. No flt found on line patrol. T-C-T-C-T
2010	PR3	33:16	OT	PR3 contacted by P2C; brkn bells east of PR plant. Ext'd otg.
2010	PR#2	23:09	OT	CU at this time.
2010	PR#1	72:18	AE	Flooded exciter. Assoc'd bkr trip caused P2A P.O. Ext'd otg.
2010	W1A-WY	02:35	AW	Storm; Caused downed shield wire. Flt isol'd by opening WY L3. RtC. #3
2010	S1M	21:42	OT	CU at this time. Ext'd otg.
2010	SW804T	71:13	OT	CU, both 801T and 804T had a N/L trip. Ext'd otg.
2010	S1M	09:29	OT	CU at this time. Ext'd otg.
2010	W1A-AS	09:42	AW	Storm; Frz rain/high winds & heavy icing. A/R attempt; T-C-T. Ext'd.
2010	B2R	16:21	AW	Hoar frost; icing caused broken shield wires on B2R.
2010	A1P	46:20	AW	Storm; Frz rain/high winds & heavy icing. Ext'd otg.
2010	C1S	20:14	AW	Hoar frost; heavy icing on lines at time of outage. Ext'd otg. #2.
2010	KLM1	02:11	AW	Hoar frost; heavy icing caused flashover at Mosaic sub. RtC.
2010	R1P	02:12	OT	Dstr Flt. Cust trble. Flashover at Mosaic sub. SecC.
2010	P1S	64:59	AW	PO at SW end. Hoar frost; heavy icing. Sw L4 open. Ext'd 4 days. #4.
2010	P1S	05:06	AW	Hoar frost; heavy icing on lines.
2010	SW7	02:27	AW	Hoar frost; heavy icing, shield wire down nrth of Climax. L6 left open

Year	Major Component	Duration (hh:mm)	Primary Cause	Comments
2010	PE802T	59:06	DE	Brkn x-arm on PE8 line causes 802T wdg fault; gas. Extd otg. Dur=???
2010	P2C	38:03	AW	Hoar frost: heavy icing caused 15 dwn'd shield wires. Ext'd otg.
2010	PQ806	02:42	DE	PQ806 would not close, impeded restoration of P1S.
2010	PE802T	08:21	DE	Faulty 87 relay on PE802T Ext'd otg. RtC.
2010	PR903T	99:99	DE	
2010	P2C	37:46	AW	Icestrm,high winds,galloping lines,shield wire fell onBph.Ext'd outg.
2010	PR#1	06:48	DE	Plant problems. 86 operation. Boiler trouble.
2010	PR#2	07:26	DE	PR#2 O/F; cross tripping malfuction. P2C did not crosstrip PR#2.
2010	L2E	03:08	AW	Hoar frost, suspect damaged pole
2010	CD907	11:09	DE	CU
2010	FS903T	81:26	DE	MR; OLTC contact defective.
2010	MOB-8-T2	09:30	AW	Low oil level on conservator due to -28 temperature. Ext'd otg.
2010	P2C	50:05	AW	Storm; Frz rain/high winds & icing. P2C fell on PR3 during otg. Ext'd.
2010	EL801T	03:12	OT	CU; Suspect moisture problem.
2010	BR902T	08:18	DE	TRO. Lack of maint. Dirty 63P oprated during XFMR tap change.
2010	PE MOBILE	02:23	OT	CU; PE8 Fault.?????????
2010	B2G	06:51	AE	Structure on fire.
2010	Q1A-QE	55:20	DE	Bad insulator. Ext'd otg. City of S'toon Cust was backfed via Q2A.
2010	Q3C	02:50	OT	Dstr. Flt. Cust. Trbl; Contaminated insls during hoar frost.
2010	PCS1	02:50	AE	Contaminated insulators; Cust Trbl.
2010	C2H-CC	02:45	AW	Storm; Frz rain; ice on lines/insl. Later disc'd bkn X-arm. Ext'd. #3
2010	KLM1	02:11	AW	Storm; Frz rain/high winds. Cust not i/s until BPG 811 closed. RtC.
2010	R1P	02:14	OT	Dstr Flt. Cust Trble; blown insulators at Mosaic Sub. SecC.
2010	BVL1	02:02	DE	Insulator failed; replaced. Ext otg.
2010	RU603DVAR	99:99	OT	Faulted Inverter TX. Ext'd Otg. DUR=??????
2010	PR3	06:40	AW	Extreme winds caused several structures down with fires.
2010	GL801T	25:26	DE	Failed insulator on 72kV bus. 87 caused 86-1/800B. RtC. Ext'd otg.
2010	q1q	93:48	DE	Plant 452PT exploded causing bus differential trip. Ext'd otg.
2010	BD405R	99:99	FI	Racoon caused flashover which caused an oil leak. Ext'd otg.
2010	N1L	22:56	AW	High wind result in brkn X-arm on N1L. Ext'd Otg.# 2 A/R attempt T-C-T
2010	TA803T	178:02	OT	Tapchanger failure. DUR = 178hr 2m
2010	BVL1	06:27	AW	High Winds led to bkn cond. Ext'd Otg. A/R attempted T-C-T-C-T-C-T. #5
2010	RL6	02:05	FI	Deliberate dmg. Cust only. Incorrect RVE status at GCC end. Ext'd Otg.
2010	C1W	24:07	OT	EMR by GCC. Structure fire. No TRA by GCC.
2010	ML706T	04:00	AW	Lightning. Ext'd Otg. DUR=4hr:0min

Year	Major Component	Duration (hh:mm)	Primary Cause	Comments
2010	WL2	08:11	OT	Broken spar 31 km from WLSS. Ext'd Otg.
2010	F2B-FS	34:45	OT	CU Suspect underground portion of wire. Cust backfed. Ext'd Otg.
2010	S3P	22:58	AE	Forest fire in area. GCC decides to leave O/S due to fire. Ext'd Otg.
2010	S3P	03:34	OT	CU at this time. Dir RX 94 S3P. Ext'd Otg.
2010	S3P	144:58	AE	Forest Fires in are. GCC decides to leave O/S. Ext'd Otg. DUR=144hr:58
2010	TD4	14:41	OT	3 poles down, 1 broken near Prairie River Reg. Ext'd Otg.
2010	S3P	03:48	AE	Forest Fire in area. Suspect smoke caused trip.
2010	KLM1	09:03	AW	Hoar frost caused contaminated insl's at Mosaic BP. Ext'd otg. RtC.
2010	R7B	13:02	DE	High resistance on 2 phases of BD906LM.
2010	BVL1	03:05	AW	Severe rain storm led to broken insulator.
2010	C3B	07:28	FI	Plane contacts shield wire. Ext'd Otg; rprs req'd. Shield ctc's 25KV.
2010	R1R-RE	03:10	AW	Lightning caused downed shield wire. Ext'd Otg.
2010	QE14	06:09	AE	Contm'd insl's from mine. Flash caused 4 poles on fire near Agrium. #3
2010	BP8	04:46	OT	CU at this time. BPG tripped at the same time. Ext'd otg.
2010	S1E-SW	02:30	OT	CU at this time. No faults found on patrol.
2010	A1P	12:20	AW	Hoar frost caused broken shield wire. Ext'd otg.
2010	PQ1	02:20	OT	Burnt pole on PQ1. T-C-T. Ext'd otg for cust. PQ701LM left open.
2010	RL6	05:06	OT	CU at this time. A/R attempt; T-C-T.
2010	R1P	21:35	DE	Broken shoe caused downed phase. No TRA by GCC. Ext'd otg.
2010	FD802T	03:37	OT	CU. Xfmr otg dur base on 801T I/S time. RtC. 802T remains o/s.
2010	BD912T	682:23	DE	2ndary cable fault in plant (station service tx).
2010	I1F	22:10	OT	CU at this time.
2010	NB801	03:36	HE	Trip during the comm. of 804T.
2010	KLM1	20:26	AE	Contm'd insl's caused pole fire/downed structure near Mosaic BP. RtC.
2010	R1P	20:34	OT	Dstr. Flt. Cust. Trbl. Mosaic BP fault. Ext'd otg. SecC.
2010	CH1	08:51	AW	Extreme winds. Ext'd otg.
2010	C1Q	11:00	AW	Extreme winds caused downed shield wire. Ext'd otg.
2010	Y2T-YN	03:46	AW	Extreme winds caused downed shield wire. Ext'd otg. #8.
2010	P1H	03:19	AW	Extreme winds caused broken shield wire. T-C-T.
2010	P1H	07:04	OT	MR by GCC to facilitate the repair of broken shield wire. Ext'd otg.
2011	W3B	02:42	AW	Lihtning
2011	Q1W	05:16	HE	Contact during live line work
2011	CD802T	20:52	FI	Owl goes Y-B phase and operates 87/802T
2011	B2G	03:07	DE	Conductor fell down.
2011	B1W	15:21	OT	CU

Year	Major Component	Duration (hh:mm)	Primary Cause	Comments
2011	PQ3	05:31	OT	CU. Lots of lightning in area.
2011	GL6	08:23	DE	2 poles down.
2011	C1F-CD	05:21	OT	Conductor down between CDSS and L8 switch.
2011	PR3	02:07	OT	CU
2011	A1R	09:27	HE	Incorrerct installation???? Of protection????
2011	I2P	10:55	AE	Fire
2011	I2P	16:56	AE	Fire
2011	I2P	02:14	AE	Fire
2011	B2G	07:43	DE	Broken spar, line on ground. Root cause.
2011	N2L	78:41	AW	Lightning, high wind. Something busted between L6 & L7.
2011	HA7	14:30	OT	CU
2011	I2P	02:17	AW	Lightning
2011	PQ3	17:25	DE	AW, Lightning broke something.
2011	Q1H	06:54	OT	CU
2011	C1W	30:15	AW	Lightning caused spar to break.
2011	SW8	06:32	FI	Tractor hit line.
2011	R5B	10:52	DE	Broken dead end. Common structure with W1R @ RE end.
2011	W1R	10:52	OT	CU; possible broken dead end. Common structure with R5B @ RE end.
2011	TD4	07:13	DE	TD715Reg blew risers off on return switching from permit.
2011	TA801T	08:01	OT	CU; Inrush? ST&R to investigate.
2011	B1W	13:56	OT	CU
2011	P2P	02:39	AW	AW; High winds + icing suspected
2011	C1F-CD	13:46	FI	72KV transformer blew up & took out understrung 25KV feeder.
2011	QE906T	11:45	AW	Lightning
2011	W1Y	99:99	DE	Two structures down
2011	W1Y	04:17	OT	CU
2011	S1M	05:56	FI	Bird caught up in the line. MC/S1M tripped O/S; MC901 tripped.
2011	BL1	14:10	OT	CU; SLE; O/V. Line was patrolled, nothing found.
2011	W1A-AS	06:14	DE	DE; Blue phase conductor fell down.
2011	W3B	18:34	OT	CU; Direct trip received from WE. CU on the generation side.
2011	C2W	04:32	OT	CU; PO; Direct trip carrier received at WE.
2011	CR#2	10:51	OT	CU;
2011	C2W	02:40	OT	CU; PO;
2011	C2W	05:17	OT	CU; PO;
2011	P2P	03:26	AW	AW; Line was patrolled - icing and galloping lines found.

Year	Major Component	Duration (hh:mm)	Primary Cause	Comments
2011	P2P	07:16	AW	AW; High winds plus icing
2011	B2G	02:20	DE	PO; GL807P burned wiring caused B2G trips at GL over and over;
2011	YN709C	13:09	CU	CU; GCC opened yn709 and yn710 tripped at the same moment.
2011	B3R	07:15	OT	CU; Possible Adverse weather conditions. Snow storm in the area.
2011	B1W	03:01	FI	Contact by trees
2011	YN3	99:99	AW	High wind, heavy snow,ice.
2011	PE6	02:17	AW	High wind, heavy snow,ice & PE8 issue downstream from L6
2011	PE8	02:17	AW	High wind, heavy snow,ice & PE8 issue downstream from L6
2011	P2K	64:20	AW	High wind, heavy snow,ice, extended outage.
2011	PE6	10:03	AW	High wind, heavy snow,ice & PE8 issue downstream from L6
2011	PE8	10:03	AW	High wind, heavy snow,ice & PE8 issue downstream from L6
2011	B10T	44:30	AW	High wind, heavy snow,ice. Y phase down. Ext Otg. 4' snow banks.
2011	BD903T	16:35	DE	L.A. on low side Y phase blew, 87/902T Y & B operated.(Metz)
2011	LL501	02:31	FI	Tree fell on line.
2011	BA4	99:99	cu	no scada, no toaster wait 4 SER & target sheets??????????
2011	W4B-BA	99:99	cu	no scada, no toaster wait 4 SER & target sheets??????????
2011	Q1W	06:22	FI	Contact by gravel truck with Q1W.
2011	TD4	08:31	OT	CU; Bells were replaced.
2011	B2R	08:15	OT	CU; Possible Adverse weather conditions. Snow storm in the area.

SaskPower

2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

Round1 – Consultant Q64:

Please provide a schedule showing all power outages related to unusual severe weather events in 2011, including cause, duration of outages, and backup supply of applicable and costs to restore power.

Response:

SaskPower does not track outages related to *unusual severe weather*. Weather related outage reporting includes all weather related outages. Outages can be broken down between transmission operations and distribution operations.

In 2011 there were 155 transmission outages related to weather with an average duration of 159 minutes. A list is attached of each outage and the duration. Transmission outages do not necessarily cause customer outages. Distribution weather related outages in 2011 totaled 6,018 with an average duration of 187 minutes. A list of each outage and the duration is attached. SaskPower does not track costs independently for weather related repairs. All emergency work is reported together and includes weather, vegetation, animals, vandalism, contamination, equipment failure, and unknown.

2011

Transmission Outages

Consultant Q64

Year	Major Component	Duration (hh:mm)	Primary Cause	Comments
2011	I2P	00:13	AW	Lightning
2011	P2P	00:04	AW	AW; Icing, galloping lines were found during patrol(see next outage)
2011	W1A-AS	00:05	AW	Lightning.
2011	A1R	01:26	AW	Lightning.
2011	I2F	00:02	AW	Lightning. Reclose cct O/S.
2011	I2P	00:19	AW	Lightning
2011	B3R	00:04	AW	Lightning. A/R was attempted. Closed in by GCC.
2011	TC5	00:02	AW	Lightning
2011	R1P	00:15	AW	Lightning.
2011	PA8	00:02	AW	Lightning; A/R not in service at time of outage.
2011	S3P	00:19	AW	Lightning
2011	B10T	44:30	AW	High wind, heavy snow,ice. Y phase down. Ext Otg. 4' snow banks.
2011	BD9	00:37	AW	High wind, heavy snow,ice.
2011	B1A-BD	00:05	AW	High wind, heavy snow,ice.
2011	PE3	01:00	AW	High wind, heavy snow,ice & PE8 issue downstream from L6
2011	PE8	10:03	AW	High wind, heavy snow,ice & PE8 issue downstream from L6
2011	PE6	10:03	AW	High wind, heavy snow,ice & PE8 issue downstream from L6
2011	PE3	00:03	AW	High wind, heavy snow,ice & PE8 issue downstream from L6
2011	W4B-WL	00:08	AW	Lightning. No A/R on line.
2011	I2P	01:23	AW	Lightning
2011	B1S	00:05	AW	Lightning
2011	I2P	00:10	AW	Lightning
2011	I2P	00:22	AW	Lightning
2011	I2P	00:23	AW	Ligtning
2011	LL2	00:02	AW	Lightning
2011	ML5	00:23	AW	Lightning, high winds and something broke. Tried to A/R.
2011	I2F	01:03	AW	Lightning
2011	C1P	00:03	AW	Lightning.
2011	P3R	01:22	AW	Lightning
2011	P2K	64:20	AW	High wind, heavy snow,ice, extended outage.
2011	P3R	00:07	AW	Lightning
2011	I2P	00:09	AW	Lightning
2011	P3R	00:06	AW	Lightning

Year	Major Component	Duration (hh:mm)	Primary Cause	Comments
2011	I2P	00:07	AW	Lightning
2011	P3R	00:12	AW	Lightning
2011	I2P	00:15	AW	Lightning
2011	ST3	00:08	AW	Lightning
2011	I1F	00:47	AW	Lightning
2011	I2P	00:13	AW	Lightning
2011	YN3	00:26	AW	High wind, heavy snow,ice.
2011	YN3	00:04	AW	High wind, heavy snow,ice.
2011	I2P	00:14	AW	Lightning
2011	G1M	00:04	AW	Lightning in area
2011	B2G	00:04	AW	Lightning; PO
2011	G1M	00:21	AW	Lightning; PO
2011	B2G	00:21	AW	Lightning in area
2011	PE8	00:59	AW	High wind, heavy snow,ice & PE8 issue downstream from L6
2011	WL7	00:04	AW	Lightning
2011	WY6A	00:03	AW	High wind, heavy snow,ice.
2011	B2G	00:06	AW	Lightning; PO
2011	G1M	00:10	AW	Lightning; PO
2011	P2P	07:16	AW	AW; High winds plus icing
2011	P2P	00:04	AW	AW; High winds plus icing
2011	P2P	02:39	AW	AW; High winds + icing suspected
2011	P2P	00:13	AW	AW; Suspect same cause as earlier in the day.
2011	P2P	03:26	AW	AW; Line was patrolled - icing and galloping lines found.
2011	W1Y	00:08	AW	High winds, 2 H frames fell into water for P-P fault (Spence).
2011	PE8	02:17	AW	High wind, heavy snow,ice & PE8 issue downstream from L6
2011	B2P	00:06	AW	Lightning
2011	PE8	00:03	AW	High wind, heavy snow,ice & PE8 issue downstream from L6
2011	PE6	00:03	AW	High wind, heavy snow,ice & PE8 issue downstream from L6
2011	PE8	00:02	AW	High wind, heavy snow,ice & PE8 issue downstream from L6
2011	PE6	00:02	AW	High wind, heavy snow,ice & PE8 issue downstream from L6
2011	PE8	00:03	AW	High wind, heavy snow,ice & PE8 issue downstream from L6
2011	PE6	00:03	AW	High wind, heavy snow,ice & PE8 issue downstream from L6
2011	YN3	99:99	AW	High wind, heavy snow,ice.
2011	PE6	00:03	AW	High wind, heavy snow,ice & PE8 issue downstream from L6

Year	Major Component	Duration (hh:mm)	Primary Cause	Comments
2011	WY6A	00:03	AW	High wind, heavy snow,ice.
2011	PE6	02:17	AW	High wind, heavy snow,ice & PE8 issue downstream from L6
2011	B3R	00:07	AW	High wind, heavy snow,ice.
2011	WY6A	00:02	AW	High wind, heavy snow,ice.
2011	WY6A	00:04	AW	High wind, heavy snow,ice.
2011	WY6A	00:05	AW	High wind, heavy snow,ice.
2011	WY6A	01:23	AW	High wind, heavy snow,ice.
2011	WY6A	00:10	AW	High wind, heavy snow,ice.
2011	PE6	00:59	AW	High wind, heavy snow,ice & PE8 issue downstream from L6
2011	PE8	00:03	AW	High wind, heavy snow,ice & PE8 issue downstream from L6
2011	R1F-FS	00:09	AW	Lightning
2011	I2P	00:13	AW	Lightning
2011	ER14	00:04	AW	Lightning
2011	PE8	00:02	AW	Lightning
2011	Q1W	00:02	AW	Lightning
2011	PA8	00:24	AW	Lightning
2011	B2G	00:04	AW	Lightning
2011	S3P	00:13	AW	Lightning
2011	R1C-CD	00:02	AW	Lightning
2011	RE9	00:02	AW	Lightning
2011	I2P	00:13	AW	Lightning
2011	C1F-CD	00:03	AW	Lightning
2011	I2P	02:17	AW	Lightning
2011	B1S	00:14	AW	Lightning
2011	I2P	00:08	AW	Lightning
2011	I2P	00:13	AW	Lightning
2011	GL7	00:02	AW	Lightning
2011	S3P	00:03	AW	Lightning
2011	I2P	00:21	AW	Lightning
2011	Y1P	00:05	AW	Lightning
2011	I2P	00:27	AW	High winds.
2011	B5W-WY	00:33	AW	Lightning broke something, line sectionalized and repired.
2011	B5W-WY	00:05	AW	Lightning
2011	PE8	00:11	AW	Lightning

Year	Major Component	Duration (hh:mm)	Primary Cause	Comments
2011	BD903T	00:30	AW	High wind, heavy snow,ice.
2011	W1A-AS	01:21	AW	Lightning broke something.
2011	A1T-TA	00:06	AW	Lightning
2011	I2P	00:17	AW	Lightning
2011	B1A-BD	00:13	AW	Lightning
2011	C1W	30:15	AW	Lightning caused spar to break.
2011	I2P	00:11	AW	Lightning
2011	B2P	00:08	AW	Lightning
2011	PA4	00:35	AW	Lightning. Could not close 72KV bkrs.
2011	QE906T	11:45	AW	Lightning
2011	I2P	00:14	AW	Lightning
2011	I2P	00:26	AW	Lightning
2011	YN6	00:03	AW	Lightning
2011	P2C	00:04	AW	Lightning
2011	I2P	00:09	AW	Lightning
2011	HA6	00:08	AW	Lightning
2011	W3B	02:42	AW	Lihtning
2011	I2P	00:12	AW	Lightning
2011	B1S	00:04	AW	Lightning.
2011	S3P	00:09	AW	Lightning.
2011	I2P	00:17	AW	Lightning
2011	I2P	00:12	AW	Lightning.
2011	I2P	00:13	AW	Lightning.
2011	I2P	00:20	AW	Lightning
2011	Q1W	00:03	AW	Lightning.
2011	N2L	78:41	AW	Lightning, high wind. Something busted between L6 & L7.
2011	Q1N	00:04	AW	Lightning
2011	Q2N	00:08	AW	Lightning
2011	I2P	00:50	AW	Lightning
2011	GB701CAP	00:12	AW	Lightning
2011	I2P	01:35	AW	Lightning
2011	LL1	00:02	AW	Lightning
2011	ER14	00:04	AW	Lightning
2011	P1H	00:02	AW	Lightning.

Year	Major Component	Duration (hh:mm)	Primary Cause	Comments
2011	P3R	00:15	AW	Lightning
2011	Y2T-YN	00:02	AW	Lightning
2011	YN3	00:08	AW	Lightning
2011	RE7	00:58	AW	Lightning, high winds. Something broke, sectionalized RE7 @ L4 switch.
2011	RE7	00:08	AW	Lightning, high winds.
2011	RE7	00:03	AW	Lightning, high winds.
2011	P1S	00:03	AW	Lightning
2011	B1S	00:16	AW	Lightning
2011	I2P	00:07	AW	Liightning
2011	S3P	00:09	AW	Lightning
2011	I2P	00:22	AW	Lightning
2011	I2P	01:09	AW	Lightning
2011	ML5	01:15	AW	Lightning, high winds. Trees on line.
2011	B1S	00:20	AW	Lightning
2011	PN10	00:28	AW	Lightning
2011	B1S	00:09	AW	Lightning
2011	S3P	00:24	AW	Lightning
2011	I2P	00:36	AW	Lightning
2011	B1P	00:05	AW	Lightning
2011	S3P	00:16	AW	Lightning

2011

Distribution Outages

Weather Related 2011 Outages

Reason	Equipment Code	Outage minutes
Icing		
	1B-117	152
	4B-79	392
	1B-111	252
	2B-155	276
	1B-115	164
	1B-115	1172
	4C-152	135
	3B-49	122
	1B-117	209
	1B-109	170
	1B-117	1234
	2B-405	311
	2B-405	72
	2B-405	10
	2B-405	40
	2B-405	247
	1B-117	76
	1B-108	82
	2B-406	132
	1B-108	105
	1B-108	1545
	1B-108	1389
	1B-108	298
	1B-108	300
	1B-111	1196
	1B-108	219
	1B-118	97
	2B-155	367
	4A-18	117

Reason	Equipment Code	Outage minutes
	1B-109	153
	1B-109	77
	1B-109	67
	1B-109	189
	1B-108	1128
	1B-281	1792
	2B-350	129
	4B-98	191
	4B-98	1799
	3B-261	101
	3B-258	52
	1B-238	40
	1B-118	122
	1B-281	1205
	1B-151	1126
	1B-93	1237
	2E-51	98
	2B-338	118
	2B-338	192
	2B-162	112
	2B-109	143
	1B-243	109
	1B-131	215
	2B-155	78
	2B-40	70
	1B-119	50
	2E-213	98
	2B-156	185
	2B-156	66
	1E-17	121
	1B-131	57
	1B-151	212
	1B-131	1218

Reason	Equipment Code	Outage minutes
	1B-131	143
	4C-114	62
	1B-131	87
	1B-143	55
	1B-151	91
	1B-118	130
	1B-131	1134
	1B-36	160
	1B-285	145
	1B-285	232
	2B-139	206
	2B-139	137
	3C-12	132
	1B-36	1190
	3C-118	172
	1B-36	122
	SHN-522	114
	3C-12	123
	2B-81	106
	1B-4	75
	3F-19	171
	1B-71	44
	2E-122	125
	4C-58	189
	2B-138	601
	2B-109	197
	2B-109	31
	3C-14	225
	2B-137	124
	2B-137	389
	2B-137	794
	1B-285	187
	3C-126	133

Reason	Equipment Code	Outage minutes
	2D-433	242
	2B-138	11
	3C-125	122
	3C-125	105
	2C-102	124
	2C-102	66
	SHN-521	69
	2D-6	23
	2D-424	108
	1A-59	34
	1A-2	24
	2B-432	1110
	1A-21	833
	4C-183	83
	4C-18	102
	2B-420	61
	3F-3	125
	1A-59	138
	2B-432	189
	4C-175	301
	1A-7	106
	2B-153	26
	2B-154	286
	2B-416	384
	1C-101	126
	2B-152	217
	2B-147	86
	2B-142	119
	2B-142	186
	2B-142	368
	2B-142	667
	3C-110	56
	2D-69	1202

Reason	Equipment Code	Outage minutes
	1A-2	117
	2B-147	101
	1A-18	135
	2B-53	51
	1A-119	128
	3C-103	94
	3C-103	65
	2B-150	157
	3C-102	98
	2E-121	9
	2B-63	188
	2B-201	119
	4B-79	227
	4B-347	81
	4B-347	89
	2B-186	487
	3A-117	147
	1C-49	78
	2B-205	160
	1C-49	358
	1C-37	88
	4B-313	181
	2B-201	105
	1C-56	126
	4B-307	90
	2B-186	1078
	2B-186	1675
	1C-49	51
	4B-400	697
	4B-407	150
	1D-77	246
	4B-405	145
	3A-107	108

Reason	Equipment Code	Outage minutes
	1D-61	71
	3B-110	343
	4B-347	59
	3D-113	71
	1C-73	148
	2B-213	1250
	2B-213	153
	2B-212	173
	2B-18	1657
	2B-183	43
	2B-183	45
	3A-110	70
	4B-209	901
	4B-20	120
	1D-108	555
	2B-189	338
	2B-189	661
	2B-189	188
	4B-255	142
	3A-79	188
	1D-112	58
	4B-266	92
	4B-209	180
	3A-22	147
	4B-235	27
	2B-193	184
	4B-226	83
	4B-223	240
	1D-227	41
	4B-276	1925
	4B-115	1330
	4B-29	108
	4B-12	233

Reason	Equipment Code	Outage minutes
	2B-187	947
	2B-187	1116
	4B-123	147
	1D-105	387
	4B-123	139
	3A-132	93
	2B-187	87
	4B-272	82
	3A-75	49
	3A-75	68
	1D-104	112
	1D-104	40
	4B-300	116
	4B-123	422
	2B-310	578
	4B-57	65
	2B-312	197
	1C-119	26
	4B-102	90
	1E-124	126
	2B-311	80
	3B-143	122
	4B-110	1007
	4B-102	34
	4B-53	92
	4B-53	921
	2B-304	236
	4B-111	600
	1E-123	60
	2B-23	68
	2F-116	26
	1F-40	47
	4B-76	166

Reason	Equipment Code	Outage minutes
	4B-73	78
	4B-73	83
	4B-72	282
	2B-236	134
	2B-24	401
	4B-57	77
	1C-107	134
	4B-58	96
	2B-314	74
	4B-10	75
	4B-100	66
	4B-100	27
	4B-101	48
	4B-603	85
	4B-46	213
	1C-106	14
	2B-163	121
	4B-408	153
	4B-408	146
	4B-408	384
	4B-114	95
	1C-137	93
	1C-137	94
	4B-112	122
	1C-137	120
	4B-409	121
	1C-19	157
	4B-408	117
	4B-407	153
	1C-19	197
	2B-172	79
	2B-432	749
	1C-137	138

Reason	Equipment Code	Outage minutes
	4B-113	1718
	4B-420	177
	4B-420	72
	2B-300	230
	4B-112	154
	3B-137	201
	3B-13	85
	4B-408	173
	4B-417	134
	4B-409	31
	4B-417	1951
	4B-113	1247
	4B-114	111
	4B-114	592
	4B-412	203
	4B-114	129
	2B-230	899
	4B-417	262
	2B-101	203
	2B-135	369
	2B-131	77
	4E-56	56
	2B-119	312
	MF-508	33
	2B-101	2781
	2C-121	152
	2B-131	2078
	2D-238	908
	3D-219	113
	4D-32	273
	PH-412	41
	2B-135	62
	4D-285	215

Reason	Equipment Code	Outage minutes
	2C-58	157
	BL-581	83
	2B-131	451
	2B-115	84
	2C-37	170
	2A-38	146
	3D-126	44
	2D-128	162
	2D-231	181
	2D-231	144
	2B-119	92
	2B-114	119
	4D-284	76
	2B-130	201
	3C-58	215
	2B-115	70
	4E-66	88
	2B-119	181
	2D-173	83
	3C-52	68
	2B-102	68
	BTR-514	61
	2B-132	137
	3D-239	134
	2C-83	223
	3D-239	90
	3D-239	98
	2B-133	892
	2B-135	144
	3D-245	104
	2C-131	225
	2B-132	170
	3D-239	140

Reason	Equipment Code	Outage minutes
	3D-239	109
	3D-239	115
	BR-565	28
	3D-239	214
	3D-239	193
	2B-132	147
	3C-232	246
	2B-130	66
	2A-104	141
	2B-135	224
	2B-117	451
	NPW-522	124
	3C-232	80
	2B-117	189
	2D-134	154
	2D-280	284
	2B-132	1744
	3C-232	213
	2B-118	71
	FS-546	439
	2B-132	607
	2B-132	1071
	2B-132	1187
	2B-117	23
	2B-117	240
	2B-110	84
	2B-135	501
	2B-135	2623
	ANT-513	235
	3C-36	77
	2B-135	579
	2B-135	114
	2C-116	163

Reason	Equipment Code	Outage minutes
	2C-223	45
	2C-118	86
	2D-216	90
	2B-121	861
	2C-127	233
	3D-81	166
	2B-111	121
	2B-432	22
	4D-105	284
	2B-109	7
	3D-124	128
	4D-106	147
	3D-8	45
	2C-200	488
	2B-121	117
	2C-24	70
	ANT-513	56
	2B-11	367
	2B-109	56
	2B-109	14
	2B-124	99
	2B-120	1144
	3C-36	153
	2B-135	520
	3E-56	8
Lightning		
	2B-119	67
	2B-242	36
	2B-123	120
	2B-118	242
	2B-118	336
	2B-127	114
	2B-240	256

Reason	Equipment Code	Outage minutes
	2B-236	57
	2B-163	73
	2B-123	302
	2B-123	117
	2B-123	167
	2B-119	59
	2B-123	198
	2B-118	69
	2B-236	136
	2B-239	359
	2B-163	160
	2B-163	499
	2B-123	216
	2B-24	286
	2B-118	149
	2B-241	59
	2B-124	280
	2B-119	109
	2B-240	184
	2B-240	25
	2B-123	321
	2B-123	61
	2B-236	62
	2B-236	146
	2B-123	234
	2B-25	82
	2B-258	170
	2B-123	160
	2B-250	114
	2B-285	42
	2B-285	61
	2B-258	99
	2B-118	154

Reason	Equipment Code	Outage minutes
	2B-173	338
	2B-280	113
	2B-28	160
	2B-250	121
	2B-120	257
	2B-250	137
	2B-120	253
	2B-258	45
	2B-258	141
	2B-120	56
	2B-120	151
	2B-121	132
	2B-262	27
	2B-258	83
	2B-258	94
	2B-258	303
	2B-268	162
	2B-163	115
	2B-242	110
	2B-119	255
	2B-119	189
	2B-244	115
	2B-25	103
	2B-280	74
	2B-163	70
	2B-119	95
	2B-119	112
	2B-250	370
	2B-163	258
	2B-119	359
	2B-119	80
	2B-119	259
	2B-119	27

Reason	Equipment Code	Outage minutes
	2B-163	36
	2B-163	92
	2B-119	188
	2B-163	45
	2B-119	63
	2B-163	122
	2B-250	410
	2B-119	4
	2B-114	61
	2B-191	66
	2B-114	156
	2B-189	81
	2B-114	312
	2B-189	11
	2B-114	219
	2B-114	149
	2B-189	172
	2B-114	49
	2B-189	60
	2B-114	270
	2B-114	258
	2B-114	208
	2B-118	81
	2B-189	270
	2B-114	24
	2B-114	298
	2B-187	48
	2B-114	348
	2B-114	474
	2B-114	403
	2B-189	242
	2B-114	168
	2B-114	344

Reason	Equipment Code	Outage minutes
	2B-189	213
	2B-189	134
	2B-189	88
	2B-189	54
	2B-189	213
	2B-114	247
	2B-114	499
	2B-193	297
	2B-114	106
	2B-193	99
	2B-193	50
	2B-114	68
	2B-114	92
	2B-193	41
	2B-193	99
	2B-193	231
	2B-193	105
	2B-193	189
	2B-113	65
	2B-193	137
	2B-193	161
	2B-193	197
	2B-193	154
	2B-191	20
	2B-191	165
	2B-114	395
	2B-191	27
	2B-191	236
	2B-191	78
	2B-193	197
	2B-114	16
	2B-115	90
	2B-191	85

Reason	Equipment Code	Outage minutes
	2B-191	79
	2B-193	38
	2B-114	150
	2B-193	137
	2B-114	39
	2B-114	272
	2B-176	115
	2B-187	26
	2B-173	192
	2B-173	72
	2B-173	150
	2B-173	323
	2B-173	119
	2B-175	149
	2B-236	166
	2B-176	95
	2B-177	86
	2B-117	155
	2B-177	22
	2B-117	144
	2B-177	55
	2B-175	56
	2B-172	114
	2B-163	31
	2B-164	51
	2B-164	161
	2B-165	59
	2B-165	87
	2B-173	98
	2B-172	131
	2B-178	155
	2B-172	124
	2B-172	153

Reason	Equipment Code	Outage minutes
	2B-172	148
	2B-173	43
	2B-173	99
	2B-173	231
	2B-172	211
	2B-115	207
	2B-116	169
	2B-186	88
	2B-116	66
	2B-116	112
	2B-116	342
	2B-177	51
	2B-186	29
	2B-182	74
	2B-115	82
	2B-115	379
	2B-115	181
	2B-115	127
	2B-115	312
	2B-118	77
	2B-116	31
	2B-116	53
	2B-115	327
	2B-117	101
	2B-178	101
	2B-178	94
	2B-178	117
	2B-178	190
	2B-183	144
	2B-116	125
	2B-182	211
	2B-178	55
	2B-178	113

Reason	Equipment Code	Outage minutes
	2B-178	69
	2B-178	109
	2B-182	0
	2B-177	78
	2B-117	143
	2B-147	186
	2B-146	116
	2B-146	66
	2B-146	109
	2B-146	104
	2B-146	70
	2B-147	102
	2B-147	70
	2B-145	66
	2B-147	195
	2B-147	70
	2B-147	116
	2B-147	59
	2B-147	65
	2B-143	231
	2B-147	134
	2B-144	70
	2B-151	63
	2B-135	70
	2B-143	147
	2B-144	113
	2B-144	228
	2B-135	47
	2B-145	134
	2B-144	207
	2B-145	110
	2B-145	157
	2B-145	140

Reason	Equipment Code	Outage minutes
	2B-145	97
	2B-145	32
	2B-145	271
	2B-147	63
	2B-135	635
	2B-151	226
	2B-15	77
	2B-15	98
	2B-150	30
	2B-150	36
	2B-150	59
	2B-147	40
	2B-151	130
	2B-149	77
	2B-134	84
	2B-134	84
	2B-134	189
	2B-134	169
	2B-221	81
	2B-161	209
	2B-151	118
	2B-135	97
	2B-135	248
	2B-148	86
	2B-148	372
	2B-148	33
	2B-149	103
	2B-149	97
	2B-15	100
	2B-149	92
	2B-15	101
	2B-149	37
	2B-149	166

Reason	Equipment Code	Outage minutes
	2B-149	64
	2B-149	131
	2B-135	174
	2B-143	43
	2B-149	35
	2B-139	131
	2B-137	79
	2B-137	223
	2B-139	232
	2B-139	308
	2B-139	143
	2B-137	221
	2B-137	66
	2B-137	206
	2B-137	195
	2B-137	300
	2B-139	19
	2B-139	112
	2B-137	253
	2B-143	170
	2B-139	170
	2B-138	54
	2B-137	475
	2B-137	10
	2B-137	306
	2B-137	94
	2B-137	497
	2B-137	317
	2B-137	76
	2B-138	408
	2B-137	231
	2B-138	110
	2B-138	137

Reason	Equipment Code	Outage minutes
	2B-137	388
	2B-138	370
	2B-138	409
	2B-137	46
	2B-138	128
	2B-142	143
	2B-142	59
	2B-142	77
	2B-142	458
	2B-142	79
	2B-142	13
	2B-137	65
	2B-142	115
	2B-141	75
	2B-142	165
	2B-142	320
	2B-135	88
	2B-135	32
	2B-135	421
	2B-135	220
	2B-142	112
	2B-140	101
	2B-139	61
	2B-14	563
	2B-137	141
	2B-136	44
	2B-136	170
	2B-136	182
	2B-142	130
	2B-140	89
	2B-142	59
	2B-140	91
	2B-140	71

Reason	Equipment Code	Outage minutes
	2B-140	101
	2B-141	101
	2B-141	126
	2B-151	71
	2B-136	193
	2B-160	210
	2B-130	36
	2B-158	49
	2B-158	76
	2B-159	214
	2B-159	58
	2B-161	283
	2B-160	61
	2B-130	229
	2B-160	227
	2B-160	52
	2B-130	188
	2B-130	5
	2B-130	309
	2B-156	106
	2B-16	77
	2B-158	148
	2B-193	138
	2B-156	53
	2B-156	53
	2B-130	102
	2B-157	58
	2B-158	159
	2B-130	331
	2B-158	722
	2B-130	55
	2B-130	169
	2B-130	169

Reason	Equipment Code	Outage minutes
	2B-130	88
	2B-130	90
	2B-130	94
	2B-161	41
	2B-158	247
	2B-13	154
	2B-162	105
	2B-13	34
	2B-162	64
	2B-162	48
	2B-162	89
	2B-130	349
	2B-162	82
	2B-130	303
	2B-13	142
	2B-162	182
	2B-13	67
	2B-162	59
	2B-13	68
	2B-236	90
	2B-162	60
	2B-130	288
	2B-161	50
	2B-161	165
	2B-161	121
	2B-161	330
	2B-161	83
	2B-161	223
	2B-162	73
	2B-161	48
	2B-13	49
	2B-130	147
	2B-161	224

Reason	Equipment Code	Outage minutes
	2B-161	106
	2B-162	71
	2B-162	147
	2B-156	207
	2B-161	107
	2B-153	97
	2B-133	57
	2B-153	84
	2B-153	116
	2B-153	149
	2B-153	61
	2B-133	88
	2B-153	48
	2B-134	90
	2B-133	249
	2B-133	96
	2B-133	37
	2B-133	73
	2B-155	345
	2B-156	38
	2B-133	61
	2B-152	1
	2B-151	160
	2B-151	32
	2B-151	58
	2B-151	106
	2B-151	225
	2B-152	122
	2B-133	58
	2B-152	207
	2B-134	71
	2B-152	120
	2B-152	11

Reason	Equipment Code	Outage minutes
	2B-134	32
	2B-134	371
	2B-152	279
	2B-155	530
	2B-152	163
	2B-156	431
	2B-156	37
	2B-156	197
	2B-132	43
	2B-132	198
	2B-132	29
	2B-155	170
	2B-156	241
	2B-132	129
	2B-132	48
	2B-132	124
	2B-131	308
	2B-131	315
	2B-131	64
	2B-156	122
	2B-132	115
	2B-155	112
	2B-155	136
	2B-155	66
	2B-155	128
	2B-155	80
	2B-155	63
	2B-155	79
	2B-132	57
	2B-132	138
	2B-132	462
	2B-132	241
	2B-132	130

Reason	Equipment Code	Outage minutes
	2B-132	269
	2B-132	257
	2B-132	235
	2B-13	36
	2B-155	95
	2C-121	98
	2C-124	53
	2C-119	156
	2C-119	20
	2C-119	44
	2C-119	67
	2C-119	54
	2C-119	162
	2C-118	282
	2C-121	169
	2C-118	61
	2C-121	76
	2C-121	96
	2C-121	241
	2C-121	123
	2C-121	246
	2C-122	93
	2C-123	443
	2C-114	192
	2C-121	125
	2C-116	366
	2B-6	284
	2C-114	252
	2C-115	186
	2C-116	46
	2C-116	23
	2C-116	82
	2C-116	82

Reason	Equipment Code	Outage minutes
	2C-118	36
	2C-116	49
	2C-124	126
	2C-116	14
	2C-116	184
	2C-116	452
	2C-117	88
	2C-118	178
	2C-118	59
	2C-118	50
	2C-118	284
	2C-116	100
	2C-132	79
	2C-124	90
	2C-131	317
	2C-132	220
	2C-132	83
	2C-132	145
	2C-132	190
	2C-132	152
	2C-131	332
	2C-132	104
	2C-131	93
	2C-133	56
	2C-133	259
	2C-133	67
	2C-133	94
	2C-133	31
	2C-133	77
	2C-139	143
	2C-14	177
	2C-132	85
	ANT-511	54

Reason	Equipment Code	Outage minutes
	2C-124	20
	2C-125	62
	2C-125	100
	2C-125	122
	2C-125	428
	2C-126	166
	2C-126	152
	2C-131	59
	2C-126	535
	2C-112	173
	2C-128	134
	700-RE7	458
	2C-129	487
	2C-130	90
	2C-130	219
	2C-130	107
	2C-130	109
	2C-131	201
	2C-126	263
	2B-81	136
	2B-81	87
	2B-750	124
	2B-76	102
	2B-79	68
	2B-79	17
	2B-79	319
	2B-8	36
	2B-720	226
	2B-81	148
	2B-720	122
	2B-81	120
	2B-81	230
	2B-81	1

Reason	Equipment Code	Outage minutes
	2B-81	354
	2B-81	89
	2B-81	102
	2B-81	74
	2C-114	177
	2B-81	5
	2B-68	104
	2B-218	55
	2B-6	62
	2B-605	73
	2B-62	338
	2B-620	125
	2B-620	156
	2B-635	240
	2B-720	149
	2B-655	142
	2B-81	77
	2B-69	157
	2B-69	123
	2B-69	155
	2B-71	46
	2B-713	156
	2B-713	105
	2B-720	140
	2B-720	460
	2B-635	311
	2C-110	62
	2B-81	187
	2C-109	296
	2C-109	182
	2C-109	360
	2C-109	10
	2C-110	107

Reason	Equipment Code	Outage minutes
	2C-110	87
	2C-109	82
	2C-110	162
	2C-109	73
	2C-110	136
	2C-110	58
	2C-110	282
	2C-110	99
	2C-111	88
	2C-111	121
	2C-111	124
	2C-112	47
	2C-110	181
	2C-104	105
	2B-850	454
	2B-855	110
	2B-87	294
	2B-87	83
	2B-98	45
	2C-101	90
	2C-101	140
	2C-109	33
	2C-102	271
	2C-141	37
	2C-104	101
	2C-104	359
	2C-104	74
	2C-104	49
	2C-104	461
	2C-104	113
	2C-106	162
	2C-109	120
	2C-101	77

Reason	Equipment Code	Outage minutes
	2D-102	191
	2D-106	229
	2D-1	79
	2D-1	82
	2D-1	36
	2D-102	90
	2D-102	50
	2D-102	161
	2C-90	59
	2D-102	180
	2C-90	37
	2D-102	100
	2D-103	644
	2D-103	161
	2D-103	133
	2D-104	285
	2D-104	183
	2D-104	166
	2C-140	229
	2D-102	291
	2C-77	55
	2C-64	144
	2C-65	129
	2C-65	205
	2C-65	111
	2C-71	527
	2C-73	541
	2C-76	58
	2C-92	8
	2C-76	151
	2D-107	157
	2C-79	140
	2C-79	84

Reason	Equipment Code	Outage minutes
	2C-79	94
	2C-85	32
	2C-85	71
	2C-87	122
	2C-87	97
	2C-87	212
	2C-76	228
	2D-120	59
	2D-105	855
	2D-116	146
	2D-116	113
	2D-117	51
	2D-117	74
	2D-118	127
	2D-12	55
	2D-115	209
	2D-120	36
	2D-115	51
	2D-121	114
	2D-121	128
	2D-121	409
	2D-121	435
	2D-121	150
	2D-121	139
	2D-121	355
	2D-122	63
	2D-120	106
	2D-114	85
	2D-107	110
	2D-107	52
	2D-107	161
	2D-113	144
	2D-113	194

Reason	Equipment Code	Outage minutes
	2D-114	93
	2D-114	156
	2D-116	130
	2D-114	100
	2C-62	151
	2D-114	165
	2D-114	941
	2D-115	74
	2D-115	145
	2D-115	78
	2D-115	316
	2D-115	134
	2D-115	198
	2D-114	157
	2C-216	389
	2C-64	1
	2C-174	95
	2C-174	75
	2C-20	33
	2C-200	90
	2C-200	403
	2C-21	64
	2C-174	218
	2C-21	235
	2C-174	495
	2C-226	70
	2C-226	212
	2C-226	63
	2C-228	161
	2C-25	465
	2C-27	82
	2C-27	167
	2C-3	124

Reason	Equipment Code	Outage minutes
	2C-21	296
	2C-151	102
	2B-6	164
	2C-141	52
	2C-142	201
	2C-142	106
	2C-142	104
	2C-142	223
	2C-142	109
	2C-174	104
	2C-144	95
	2C-310	38
	2C-151	107
	2C-151	356
	2C-16	896
	2C-16	215
	2C-161	264
	2C-174	192
	2C-174	210
	2C-174	56
	2C-142	338
	2C-54	215
	2C-45	120
	2C-45	111
	2C-46	92
	2C-47	12
	2C-47	126
	2C-48	89
	2C-50	62
	2C-308	142
	2C-54	52
	2C-38	72
	2C-55	143

Reason	Equipment Code	Outage minutes
	2C-56	210
	2C-57	63
	2C-57	34
	2C-6	109
	2C-60	82
	2C-62	141
	2C-141	160
	2C-50	105
	2C-323	111
	2C-63	165
	2C-310	266
	2C-315	138
	2C-315	341
	2C-315	130
	2C-315	109
	2C-315	105
	2C-32	172
	2C-39	38
	2C-32	80
	2C-39	467
	2C-33	67
	2C-34	118
	2C-35	43
	2C-36	106
	2C-36	205
	2C-36	144
	2C-36	78
	2C-31	140
	2C-32	207
	2B-298	118
	2B-299	46
	2B-298	183
	2B-298	343

Reason	Equipment Code	Outage minutes
	2B-298	82
	2B-298	42
	2B-298	118
	2B-298	300
	2B-290	148
	2B-298	171
	2B-235	132
	2B-298	80
	2B-298	223
	2B-298	186
	2B-298	180
	2B-298	258
	2B-298	90
	2B-298	152
	2B-225	65
	2B-298	225
	2B-230	63
	2B-6	293
	2B-227	48
	2B-227	86
	2B-228	81
	2B-228	59
	2B-228	75
	2B-228	285
	2B-298	97
	2B-230	36
	2B-299	99
	2B-230	100
	2B-231	161
	2B-231	57
	2B-231	86
	2B-232	57
	2B-234	60

Reason	Equipment Code	Outage minutes
	2B-234	135
	2B-235	80
	2B-230	76
	2B-312	236
	2B-298	110
	2B-312	250
	2B-312	346
	2B-312	89
	2B-312	197
	2B-312	73
	2B-312	336
	2B-311	43
	2B-312	74
	2B-310	225
	2B-312	807
	2B-313	165
	2B-313	152
	2B-313	438
	2B-313	91
	2B-313	48
	2B-313	319
	2B-313	146
	2B-312	209
	2B-300	120
	2B-30	75
	2B-30	86
	2B-30	18
	2B-30	44
	2B-30	85
	2B-300	155
	2B-300	97
	2B-311	126
	2B-300	250

Reason	Equipment Code	Outage minutes
	2B-225	35
	2B-304	112
	2B-304	128
	2B-304	234
	2B-304	97
	2B-307	93
	2B-310	109
	2B-310	70
	2B-310	80
	2B-300	106
	2B-2	76
	2B-201	165
	2B-198	379
	2B-198	19
	2B-198	168
	2B-199	24
	2B-199	10
	2B-199	34
	2B-198	41
	2B-199	86
	2B-198	16
	2B-2	30
	2B-2	103
	2B-2	105
	2B-201	286
	2B-201	442
	2B-201	28
	2B-201	91
	2B-225	31
	2B-199	242
	2B-194	214
	2B-193	241
	2B-193	114

Reason	Equipment Code	Outage minutes
	2B-193	147
	2B-193	43
	2B-193	29
	2B-193	129
	2B-193	49
	2B-198	22
	2B-194	125
	2B-201	279
	2B-194	308
	2B-194	77
	2B-194	60
	2B-194	239
	2B-195	107
	2B-195	51
	2B-195	68
	2B-195	176
	2B-193	386
	2B-221	110
	2B-201	64
	2B-209	80
	2B-209	59
	2B-21	101
	2B-210	75
	2B-211	107
	2B-212	497
	2B-207	41
	2B-213	532
	2B-207	105
	2A-32	116
	2B-221	382
	2B-222	129
	2B-222	80
	2B-223	124

Reason	Equipment Code	Outage minutes
	2B-223	253
	2B-223	53
	2B-223	70
	2B-212	92
	2B-201	53
	2B-201	334
	2B-201	433
	2B-201	97
	2B-201	162
	2B-201	62
	2B-201	233
	2B-201	120
	2B-207	32
	2B-201	65
	2B-314	314
	2B-201	145
	2B-201	121
	2B-201	226
	2B-201	230
	2B-201	194
	2B-202	330
	2B-203	159
	2B-206	156
	2B-201	64
	2B-430	383
	2B-44	87
	2B-43	83
	2B-43	63
	2B-43	52
	2B-430	84
	2B-430	99
	2B-430	67
	2B-43	96

Reason	Equipment Code	Outage minutes
	2B-430	116
	2B-43	38
	2B-431	15
	2B-431	140
	2B-433	44
	2B-434	28
	2B-434	86
	2B-435	46
	2B-435	97
	2B-313	337
	2B-430	80
	2B-417	478
	2B-406	141
	2B-406	135
	2B-41	94
	2B-416	239
	2B-416	131
	2B-416	129
	2B-416	137
	2B-43	602
	2B-416	211
	2B-44	70
	2B-417	54
	2B-417	119
	2B-417	90
	2B-420	95
	2B-420	118
	2B-420	70
	2B-420	245
	2B-420	34
	2B-416	75
	2B-6	101
	2B-44	77

Reason	Equipment Code	Outage minutes
	2B-53	98
	2B-53	382
	2B-53	112
	2B-53	288
	2B-53	317
	2B-53	132
	2B-53	124
	2B-6	28
	2B-53	83
	2B-6	121
	2B-6	139
	2B-6	77
	2B-6	86
	2B-6	107
	2B-6	118
	2B-6	37
	2B-6	228
	2B-6	147
	2B-506	192
	2B-5	106
	2B-501	107
	2B-501	140
	2B-502	67
	2B-502	121
	2B-502	137
	2B-506	73
	2B-53	435
	2B-506	554
	2B-406	85
	2B-506	32
	2B-53	124
	2B-53	117
	2B-53	58

Reason	Equipment Code	Outage minutes
	2B-53	458
	2B-53	28
	2B-53	132
	2B-53	152
	2B-506	41
	2B-344	74
	2B-406	168
	2B-338	25
	2B-338	279
	2B-341	41
	2B-342	73
	2B-343	92
	2B-343	96
	2B-338	71
	2B-344	132
	2B-338	395
	2B-344	202
	2B-344	116
	2B-344	98
	2B-344	81
	2B-344	51
	2B-344	134
	2B-344	55
	2B-344	125
	2B-344	0
	2B-321	65
	2B-193	85
	2B-314	295
	2B-314	277
	2B-314	305
	2B-319	355
	2B-32	95
	2B-320	292

Reason	Equipment Code	Outage minutes
	2B-338	28
	2B-320	54
	2B-344	56
	2B-322	128
	2B-322	127
	2B-324	34
	2B-325	156
	2B-325	77
	2B-332	242
	2B-337	129
	2B-338	148
	2B-320	1400
	2B-406	87
	2B-40	124
	2B-40	171
	2B-40	110
	2B-40	169
	2B-40	102
	2B-40	150
	2B-40	98
	2B-344	217
	2B-404	92
	2B-4	97
	2B-406	17
	2B-406	103
	2B-406	240
	2B-406	71
	2B-406	69
	2B-406	80
	2B-406	187
	2B-314	222
	2B-40	49
	2B-355	65

Reason	Equipment Code	Outage minutes
	2B-406	85
	2B-344	29
	2B-35	137
	2B-35	207
	2B-35	79
	2B-350	109
	2B-350	169
	2B-355	113
	2B-40	94
	2B-355	268
	2B-40	145
	2B-36	76
	2B-38	95
	2B-38	105
	2B-39	314
	2B-39	120
	2B-39	206
	2B-39	202
	2B-344	35
	2B-355	90
	1B-108	208
	1B-113	50
	1B-103	99
	1B-105	103
	1B-105	230
	1B-106	154
	1B-106	50
	1B-106	51
	1B-102	91
	1B-108	31
	1B-101	47
	1B-108	86
	1B-108	64

Reason	Equipment Code	Outage minutes
	1B-108	54
	1B-108	155
	1B-109	127
	1B-109	132
	1B-109	29
	1B-21	78
	1B-108	198
	1A-56	1187
	1A-40	68
	1A-40	148
	1A-40	174
	1A-40	109
	1A-43	140
	1A-45	79
	1A-5	87
	1B-102	83
	1A-5	192
	1B-117	105
	1A-58	87
	1A-6	311
	1A-63	189
	1A-68	76
	1A-7	93
	1A-9	92
	1B-1	41
	1B-10	133
	1A-5	32
	1B-17	112
	1B-110	130
	1B-131	212
	1B-131	141
	1B-158	79
	1B-158	58

Reason	Equipment Code	Outage minutes
	1B-158	88
	1B-158	187
	1B-121	43
	1B-16	388
	1B-121	92
	1B-171	40
	1B-171	361
	1B-171	134
	1B-19	78
	1B-2	54
	1B-2	87
	1B-2	284
	1B-87	133
	1B-158	186
	1B-119	219
	1B-117	144
	1B-118	86
	1B-118	119
	1B-118	105
	1B-118	179
	1B-118	296
	1B-118	245
	1B-121	169
	1B-119	82
	1A-36	81
	1B-119	74
	1B-12	117
	1B-12	90
	1B-120	20
	1B-120	295
	1B-121	69
	1B-121	137
	1B-121	73

Reason	Equipment Code	Outage minutes
	1B-118	256
	1A-108	134
	1A-40	223
	1A-104	94
	1A-104	69
	1A-107	62
	1A-108	91
	1A-108	91
	1A-108	129
	1A-104	172
	1A-108	222
	1A-104	225
	1A-108	68
	1A-108	396
	1A-108	119
	1A-108	132
	1A-108	50
	1A-108	276
	1A-112	92
	1A-112	54
	1A-108	92
	SWC-523	171
	1C-325	165
	SWC-521	32
	SWC-522	108
	SWC-522	73
	SWC-522	203
	SWC-522	96
	SWC-523	79
	1A-104	72
	SWC-523	69
	1A-113	82
	SWC-523	53

Reason	Equipment Code	Outage minutes
	SWC-523	160
	SWC-524	129
	1A-1	86
	1A-1	41
	1A-1	180
	1A-104	55
	1A-104	189
	SWC-523	59
	1A-14	137
	1A-121	165
	1A-122	146
	1A-122	255
	1A-122	132
	1A-122	99
	1A-13	145
	1A-13	204
	1A-113	340
	1A-13	121
	1A-12	194
	1A-16	65
	1A-16	392
	1A-2	61
	1A-21	566
	1A-22	49
	1A-22	211
	1A-26	89
	1B-22	100
	1A-13	155
	1A-116	98
	1A-40	49
	1A-114	136
	1A-114	100
	1A-114	152

Reason	Equipment Code	Outage minutes
	1A-115	119
	1A-115	5
	1A-115	55
	1A-115	75
	1A-121	103
	1A-115	161
	1A-120	212
	1A-116	62
	1A-116	78
	1A-116	90
	1A-117	87
	1A-119	81
	1A-119	80
	1A-12	61
	1A-113	50
	1A-115	114
	1C-19	142
	1E-106	145
	1C-15	33
	1C-15	119
	1C-17	116
	1C-17	26
	1C-19	51
	1C-19	135
	1C-137	83
	1C-19	45
	1C-137	197
	1E-106	167
	1E-106	69
	1E-106	75
	1E-106	14
	1E-106	120
	1E-106	196

Reason	Equipment Code	Outage minutes
	1E-106	153
	1B-20	64
	1C-19	134
	1C-137	245
	1C-137	107
	1C-137	155
	1C-137	199
	1C-137	151
	1C-137	150
	1C-137	104
	1C-137	278
	1C-15	92
	1C-137	283
	1E-106	244
	1C-137	97
	1C-137	298
	1C-137	93
	1C-137	111
	1C-137	67
	1C-137	461
	1C-137	184
	1C-137	84
	1C-137	52
	1C-27	78
	1E-106	597
	1E-121	317
	1E-121	45
	1C-2	215
	1C-20	117
	1C-21	76
	1C-215	95
	1E-117	151
	1C-27	224

Reason	Equipment Code	Outage minutes
	1E-117	98
	1C-27	156
	1C-29	19
	1C-29	101
	1C-29	67
	1C-30	99
	1C-30	96
	1C-30	81
	2A-37	101
	1C-23	318
	1E-114	249
	1E-106	164
	1E-107	491
	1E-107	334
	1E-107	107
	1E-108	80
	1E-109	111
	1E-109	102
	1E-119	166
	1E-113	128
	1C-137	66
	1E-114	1507
	1E-116	117
	1E-116	106
	1E-116	132
	1E-117	79
	1E-117	351
	1E-117	1498
	1E-117	475
	1E-112	91
	1C-103	109
	1C-137	86
	1C-101	94

Reason	Equipment Code	Outage minutes
	1C-101	69
	1C-101	56
	1C-101	66
	1C-102	138
	1C-102	36
	1C-101	37
	1C-103	23
	1C-101	110
	1C-103	43
	1C-103	108
	1C-104	33
	1C-105	290
	1C-106	47
	1C-106	37
	1C-111	172
	1C-111	119
	1C-103	37
	1B-26	581
	1B-22	159
	1B-230	134
	1B-230	361
	1B-235	71
	1B-235	76
	1B-237	154
	1B-24	97
	1C-101	48
	1B-26	282
	1C-112	137
	1B-28	124
	1B-91	26
	1B-96	314
	1C-101	55
	1C-101	270

Reason	Equipment Code	Outage minutes
	1C-101	337
	1C-101	154
	1C-101	81
	1B-247	79
	1C-135	161
	1C-121	309
	1C-121	153
	1C-121	184
	1C-124	144
	1C-124	100
	1C-129	46
	1C-130	210
	1C-112	241
	1C-131	129
	1C-12	54
	1C-135	120
	1C-135	291
	1C-135	156
	1C-135	254
	1C-135	73
	1C-135	111
	1C-136	179
	1B-87	169
	1C-131	310
	1C-119	113
	1C-137	152
	1C-116	123
	1C-116	129
	1C-117	185
	1C-117	80
	1C-117	123
	1C-117	483
	1C-117	72

Reason	Equipment Code	Outage minutes
	1C-120	632
	1C-118	522
	1C-12	80
	1C-119	196
	1C-119	103
	1C-119	360
	1C-119	133
	1C-119	84
	1C-119	666
	1C-119	84
	1C-112	142
	1C-118	141
	CN-559	435
	FQ-511	224
	CAN-514	348
	CAN-514	151
	CAN-514	167
	CAN-514	53
	CD-580	55
	CD-581	602
	CAN-513	185
	CN-559	151
	CAN-513	38
	DEW-5104	325
	DU-504	127
	DU-506	121
	EL-303	74
	EL-303	109
	EL-303	107
	FD-501	317
	MF-506	18
	CN-557	282
	CAN-511	57

Reason	Equipment Code	Outage minutes
	BY-543	204
	CAN-511	71
	CAN-511	163
	CAN-511	125
	CAN-511	178
	CAN-511	349
	CAN-511	339
	CAN-514	43
	CAN-511	24
	FQ-512	115
	CAN-511	116
	CAN-511	428
	CAN-512	94
	CAN-512	50
	CAN-512	59
	CAN-512	73
	CAN-512	23
	CAN-512	33
	CAN-511	131
	MF-504	256
	FQ-511	23
	FS-548	86
	FS-548	183
	FS-548	231
	IF-501	189
	LL-501	346
	LU-561	57
	FS-547	449
	MF-504	175
	FS-545	135
	MF-504	147
	MF-504	23
	MF-504	51

Reason	Equipment Code	Outage minutes
	MF-505	129
	MF-505	158
	MF-505	324
	MF-505	114
	SWC-521	194
	MF-504	224
	FQ-513	158
	FQ-512	74
	FQ-512	66
	FQ-513	51
	FQ-513	139
	FQ-513	277
	FQ-513	107
	FQ-513	51
	FS-548	159
	FQ-513	202
	BTR-512	132
	FQ-513	132
	FQ-513	65
	FQ-513	114
	FQ-513	35
	FQ-513	126
	FQ-513	63
	FS-544	99
	FS-544	197
	FQ-513	39
	BAT-511	74
	BY-543	325
	AR-512	51
	AT-524	224
	AT-525	78
	AT-525	173
	AT-525	59

Reason	Equipment Code	Outage minutes
	BAT-511	115
	AP-533	3570
	BAT-511	417
	ANT-513	284
	BAT-514	57
	BAT-514	114
	BC-511	297
	BC-511	19
	BC-511	98
	BC-511	38
	BC-511	101
	BC-511	103
	BAT-511	169
	ANT-513	45
	ANT-511	89
	ANT-511	67
	ANT-511	30
	ANT-513	47
	ANT-513	65
	ANT-513	71
	ANT-513	44
	AP-533	110
	ANT-513	334
	BC-512	42
	ANT-513	80
	ANT-513	75
	ANT-513	354
	ANT-513	206
	ANT-513	52
	ANT-513	75
	ANT-513	55
	ANT-513	154
	ANT-513	96

Reason	Equipment Code	Outage minutes
	BL-583	71
	BL-582	47
	BL-582	94
	BL-582	125
	BL-582	150
	BL-582	1507
	BL-583	217
	BL-583	62
	BC-512	183
	BL-583	215
	BL-581	19
	BR-564	124
	BR-564	247
	BR-568	41
	BTR-511	115
	BTR-511	117
	BTR-511	104
	BTR-511	191
	MF-508	136
	BL-583	101
	BF-504	113
	BY-543	105
	BC-512	44
	BC-512	111
	BC-512	25
	BC-512	376
	BC-512	330
	BC-512	51
	BC-513	75
	BL-582	167
	BF-503	46
	BL-582	278
	BF-504	102

Reason	Equipment Code	Outage minutes
	BF-504	198
	BF-504	80
	BF-504	203
	BF-505	98
	BL-581	249
	BL-581	34
	BC-512	78
	BF-503	83
	SHN-512	21
	SHN-514	119
	SHN-512	53
	SHN-512	73
	SHN-512	105
	SHN-512	52
	SHN-512	115
	SHN-512	80
	SHN-512	579
	SHN-512	167
	SHN-512	120
	SHN-512	28
	SHN-514	76
	SHN-514	52
	SHN-514	44
	SHN-514	97
	SHN-514	93
	SHN-514	246
	MF-506	22
	SHN-512	338
	SHN-512	150
	SHN-511	245
	SHN-511	294
	SHN-511	61
	SHN-511	130

Reason	Equipment Code	Outage minutes
	SHN-511	148
	SHN-511	163
	SHN-511	451
	SHN-512	43
	SHN-511	173
	SHN-514	268
	SHN-512	152
	SHN-512	156
	SHN-512	155
	SHN-512	37
	SHN-512	189
	SHN-512	78
	SHN-512	234
	SHN-512	71
	SHN-511	94
	1B-74	210
	SHN-514	420
	1B-4	141
	1B-43	59
	1B-49	64
	1B-56	132
	1B-60	241
	1B-66	202
	1B-4	29
	1B-73	77
	1B-37	205
	1B-74	76
	1B-74	107
	1B-74	175
	1B-81	39
	1B-81	49
	1B-82	123
	1B-82	65

Reason	Equipment Code	Outage minutes
	1B-84	34
	1B-69	48
	SHN-521	98
	SHN-514	315
	SHN-514	68
	SHN-514	32
	SHN-521	130
	SHN-521	98
	SHN-521	261
	SHN-521	36
	1B-4	159
	SHN-521	70
	SHN-511	53
	SHN-522	74
	SHN-522	361
	ST-511	253
	1B-289	96
	1B-29	97
	1B-3	79
	1B-36	359
	1B-36	28
	SHN-521	120
	MP-504	256
	SHN-511	161
	ML-505	181
	ML-506	437
	ML-506	12
	MP-503	78
	MP-503	49
	MP-504	136
	ML-505	139
	MP-504	99
	ML-505	148

Reason	Equipment Code	Outage minutes
	MP-504	11
	MP-505	86
	MP-505	81
	MP-505	1941
	MP-505	105
	MP-505	83
	MP-505	208
	MYM-512	351
	MP-504	273
	MJN-523	38
	MF-508	142
	MF-508	72
	MF-509	22
	MF-510	148
	MF-510	750
	MJA-531	137
	MJA-531	1059
	ML-505	94
	MJN-521	754
	NPW-512	54
	MJN-523	60
	MJN-523	61
	MJN-523	208
	ML-503	126
	ML-504	60
	ML-504	85
	ML-504	173
	ML-504	174
	MJA-532	1004
	PNW-512	133
	PKR-598	113
	PKR-598	130
	PKR-598	303

Reason	Equipment Code	Outage minutes
	PN-512	440
	PN-512	143
	PNW-511	1531
	PNW-511	371
	NPW-512	18
	PNW-512	77
	PKR-595	184
	RE-501	62
	RE-504	146
	RE-504	226
	RE-506	6
	RE-506	219
	RL-506	685
	SHN-511	147
	1C-37	62
	PNW-512	123
	NS-201	125
	SHN-511	179
	NPW-512	83
	NPW-512	248
	NPW-513	123
	NPW-513	128
	NPW-513	167
	NPW-513	38
	NPW-522	35
	PKR-598	110
	NPW-522	451
	PKR-596	140
	NS-201	190
	PAR-504	144
	PAS-501	197
	PAS-503	26
	PH-573	38

Reason	Equipment Code	Outage minutes
	PH-573	133
	PH-574	53
	NPW-512	53
	NPW-522	223
	2B-110	281
	2B-110	117
	2B-109	68
	2B-109	50
	2B-11	28
	2B-110	253
	2B-110	38
	2B-110	132
	2B-109	54
	2B-110	192
	2B-109	32
	2B-110	19
	2B-110	1
	2B-110	789
	2B-110	89
	2B-110	217
	2B-110	196
	2B-110	138
	2A-102	156
	2B-110	58
	2B-109	185
	2B-109	236
	2B-109	81
	2B-109	162
	2B-109	229
	2B-109	61
	2B-109	189
	2B-109	86
	2B-109	87

Reason	Equipment Code	Outage minutes
	2B-109	1
	2B-110	90
	2B-109	87
	2B-109	180
	2B-109	273
	2B-109	155
	2B-109	18
	2B-109	51
	2B-109	87
	2B-109	163
	2B-109	222
	1H-2	88
	2B-110	47
	1G-2	166
	1G-5	156
	1G-7	523
	1G-7	172
	1G-7	188
	1G-8	352
	1G-16	75
	1H-12	58
	1G-16	184
	1H-2	41
	1H-2	123
	1H-4	112
	1I-3	121
	1N-235	76
	2A-1	134
	2A-101	55
	1F-137	123
	1H-1	38
	1F-77	208
	2B-110	75

Reason	Equipment Code	Outage minutes
	2B-111	192
	2B-111	86
	2B-111	70
	1F-62	128
	1F-63	96
	1F-70	100
	1G-2	207
	1F-77	127
	2B-109	222
	1F-85	118
	1F-85	122
	1F-9	192
	1G-1	273
	1G-12	165
	1G-14	349
	1G-16	51
	1G-16	171
	1F-72	159
	1F-223	92
	2B-109	135
	1F-17	114
	1F-202	314
	1F-206	250
	1F-206	568
	1F-206	188
	1F-213	128
	1F-161	164
	1F-221	86
	1F-160	147
	1F-223	427
	1F-223	76
	1F-226	48
	1F-227	386

Reason	Equipment Code	Outage minutes
	1F-228	789
	1F-238	77
	1F-238	229
	1F-24	231
	1F-213	85
	1F-145	183
	1C-30	122
	1F-137	52
	1F-140	167
	1F-140	1141
	1F-140	22
	1F-140	125
	1F-140	172
	1F-17	462
	1F-142	96
	1F-240	555
	1F-146	151
	1F-146	196
	1F-146	904
	1F-15	87
	1F-153	88
	1F-158	85
	1F-158	125
	1F-159	81
	1F-140	450
	2B-109	85
	1F-59	70
	1F-6	142
	1F-6	412
	2B-106	57
	2B-106	86
	2B-108	384
	2B-108	165

Reason	Equipment Code	Outage minutes
	1F-24	485
	2B-109	64
	1F-57	113
	2B-109	116
	2B-109	168
	2B-109	51
	2B-109	63
	2B-109	166
	2B-109	256
	2B-109	67
	2A-103	38
	2B-109	53
	1F-26	35
	2B-109	124
	1F-240	61
	1F-247	85
	1F-247	154
	1F-248	186
	1F-249	215
	1F-249	179
	1F-252	369
	1F-58	128
	1F-254	1007
	1F-57	226
	1F-26	72
	1F-276	146
	1F-277	344
	1F-279	44
	1F-54	71
	1F-54	72
	1F-56	261
	1F-240	252
	1F-253	445

Reason	Equipment Code	Outage minutes
	2B-101	89
	2B-102	156
	2A-71	32
	2A-76	505
	2A-79	148
	2A-9	136
	2B-1	359
	2B-1	137
	2A-70	178
	2B-10	92
	2A-65	208
	2B-101	184
	2B-101	102
	2B-101	130
	2B-101	304
	2B-102	11
	2B-102	76
	2B-102	37
	2A-102	116
	2B-10	23
	2A-49	119
	2A-39	55
	2A-39	240
	2A-40	67
	2A-40	105
	2A-41	39
	2A-41	496
	2A-41	81
	2A-70	30
	2A-43	72
	2B-102	142
	2A-49	91
	2A-5	205

Reason	Equipment Code	Outage minutes
	2A-55	140
	2A-55	224
	2A-56	32
	2A-61	216
	2A-65	142
	2A-65	205
	2A-42	13
	2B-112	280
	2B-102	21
	2B-111	78
	2B-111	66
	2B-111	56
	2B-111	137
	2B-111	49
	2B-112	101
	2B-111	67
	2B-112	66
	2B-104	56
	2B-112	112
	2B-112	50
	2B-112	290
	2B-113	61
	2B-113	78
	2B-113	100
	2B-113	124
	2B-113	211
	2B-112	21
	2B-102	22
	2B-102	37
	2B-102	289
	2B-102	198
	2B-102	101
	2B-102	72

Reason	Equipment Code	Outage minutes
	2B-102	107
	2B-102	98
	2B-111	55
	2B-102	88
	2A-38	206
	2B-102	67
	2B-102	101
	2B-103	68
	2B-103	77
	2B-104	90
	2B-104	42
	2B-104	252
	2B-104	27
	2B-102	27
	2A-113	40
	2A-39	93
	2A-111	79
	2A-112	49
	2A-112	215
	2A-112	165
	2A-112	78
	2A-113	30
	2A-111	28
	2A-113	146
	2A-111	97
	2A-113	265
	2A-113	27
	2A-113	14
	2A-113	51
	2A-116	65
	2A-116	64
	2A-116	118
	2A-116	76

Reason	Equipment Code	Outage minutes
	2A-113	70
	2A-104	41
	2A-103	270
	2A-103	34
	2A-103	166
	2A-103	491
	2A-103	130
	2A-103	93
	2A-103	233
	2A-111	160
	2A-104	105
	2A-116	138
	2A-104	211
	2A-104	88
	2A-107	129
	2A-107	94
	2A-108	45
	2A-111	103
	2A-111	128
	2A-111	105
	2A-104	104
	2A-31	78
	2A-21	48
	2A-24	309
	2A-24	112
	2A-24	189
	2A-25	63
	2A-25	39
	2A-25	535
	2A-116	5
	2A-29	52
	2A-20	90
	2A-31	109

Reason	Equipment Code	Outage minutes
	2A-36	39
	2D-122	466
	2A-37	76
	2A-37	278
	2A-38	295
	2A-38	157
	1F-136	52
	2A-29	72
	2A-15	78
	2A-38	157
	2A-116	103
	2A-117	51
	2A-118	18
	2A-118	257
	2A-118	215
	2A-121	0
	2A-121	355
	2A-20	98
	2A-121	190
	2A-20	180
	2A-2	41
	2A-2	129
	2A-2	94
	2A-2	129
	2A-2	47
	2A-20	173
	2A-20	175
	2A-116	30
	2A-121	87
	1D-37	38
	1D-38	32
	1D-3	48
	1D-3	104

Reason	Equipment Code	Outage minutes
	1D-3	54
	1D-3	192
	1D-30	72
	1D-31	410
	1D-295	130
	1D-34	35
	1D-295	72
	1D-37	464
	1D-37	429
	1D-37	271
	1D-38	133
	1D-38	32
	1D-38	118
	1D-38	942
	1E-07	116
	1D-34	43
	1D-23	25
	1D-204	25
	1D-204	29
	1D-208	184
	1D-209	192
	1D-212	225
	1D-212	369
	1D-212	209
	1D-3	67
	1D-23	145
	1D-39	88
	1D-23	82
	1D-230	94
	1D-231	257
	1D-231	176
	1D-24	183
	1D-271	626

Reason	Equipment Code	Outage minutes
	1D-272	167
	1D-272	173
	1D-227	137
	1D-90	229
	1D-38	168
	1D-79	313
	1D-81	208
	1D-81	227
	1D-81	112
	1D-86	20
	1D-9	185
	1D-64	426
	1D-90	345
	1D-64	111
	1D-90	131
	1D-93	228
	1D-94	301
	1D-95	17
	1D-95	370
	1D-96	15
	1D-96	68
	1F-137	108
	1D-9	38
	1D-45	30
	1D-4	169
	1D-4	101
	1D-4	108
	1D-40	41
	1D-40	239
	1D-41	271
	1D-41	93
	1D-71	721
	1D-41	360

Reason	Equipment Code	Outage minutes
	1D-204	343
	1D-47	347
	1D-5	326
	1D-50	99
	1D-51	45
	1D-55	121
	1D-55	74
	1D-58	71
	1D-64	247
	1D-41	200
	1D-105	131
	1D-204	103
	1D-104	60
	1D-104	135
	1D-104	41
	1D-104	39
	1D-104	440
	1D-104	544
	1D-103	95
	1D-105	65
	1D-101	165
	1D-105	22
	1D-105	28
	1D-107	96
	1D-108	103
	1D-109	79
	1D-109	155
	1D-109	80
	1D-110	62
	1D-104	109
	1C-73	157
	1C-37	55
	1C-40	1099

Reason	Equipment Code	Outage minutes
	1C-45	78
	1C-48	226
	1C-48	57
	1C-50	39
	1C-50	256
	1D-103	483
	1C-67	386
	1D-114	80
	1C-73	115
	1C-76	393
	1C-91	90
	1C-91	230
	1C-91	67
	1D-1	99
	1D-101	215
	1D-101	170
	1C-57	344
	1D-2	92
	1D-139	89
	1D-139	161
	1D-15	81
	1D-15	69
	1D-16	153
	1D-16	264
	1D-16	101
	1D-110	238
	1D-2	65
	1D-134	97
	1D-2	108
	1D-2	122
	1D-2	85
	1D-2	648
	1D-2	48

Reason	Equipment Code	Outage minutes
	1D-20	185
	1D-203	43
	1E-08	233
	1D-18	56
	1D-116	122
	1D-204	147
	1D-114	299
	1D-114	56
	1D-114	50
	1D-114	172
	1D-115	110
	1D-115	44
	1D-116	47
	1D-136	17
	1D-116	88
	1D-136	53
	1D-116	75
	1D-12	169
	1D-13	554
	1D-132	101
	1D-132	291
	1D-132	215
	1D-132	68
	1D-112	89
	1D-116	95
	1E-47	80
	1E-66	134
	1E-32	83
	1E-36	1230
	1E-37	191
	1E-43	1298
	1E-44	36
	1E-44	101

Reason	Equipment Code	Outage minutes
	1E-27	356
	1E-47	39
	1E-23	26
	1E-47	186
	1E-48	91
	1E-55	213
	1E-56	70
	1E-64	155
	1E-65	1371
	1E-65	108
	1D-97	19
	1E-46	103
	1E-212	268
	1E-15	237
	1E-17	58
	1E-20	104
	1E-20	436
	1E-20	75
	1E-20	120
	1E-20	68
	1E-29	296
	1E-212	87
	1E-67	614
	1E-212	60
	1E-217	640
	1E-22	110
	1E-225	91
	1E-225	461
	1E-225	49
	1E-225	218
	1E-229	47
	1E-20	143
	1F-110	58

Reason	Equipment Code	Outage minutes
	1E-66	74
	1F-110	290
	1F-110	229
	1F-110	34
	1F-110	80
	1F-110	96
	1F-110	70
	1F-110	94
	1F-110	55
	1F-109	158
	1F-115	58
	1F-115	495
	1F-115	71
	1F-121	192
	1F-121	129
	1F-121	248
	1F-13	188
	1F-136	60
	1F-110	79
	1E-87	294
	1E-68	165
	1E-68	69
	1E-68	98
	1E-7	397
	1E-7	107
	1E-80	275
	1E-80	119
	1F-110	24
	1E-87	1
	1E-149	846
	1E-88	109
	1E-89	31
	1E-99	108

Reason	Equipment Code	Outage minutes
	1F-102	68
	1F-102	75
	1F-102	110
	1F-108	71
	1F-108	408
	1E-82	109
	1E-128	64
	1E-149	1410
	1E-124	0
	1E-124	255
	1E-124	195
	1E-124	94
	1E-124	112
	1E-124	253
	1E-124	116
	1E-128	218
	1E-124	55
	1E-13	195
	1E-130	82
	1E-130	88
	1E-131	45
	1E-131	851
	1F-282	449
	1F-288	83
	1F-291	184
	1E-128	96
	1E-103	345
	1E-08	1649
	1E-08	104
	1E-101	79
	1E-101	14
	1E-102	104
	1E-102	81

Reason	Equipment Code	Outage minutes
	1E-102	178
	1E-124	231
	1E-103	111
	1F-37	243
	1E-103	83
	1E-104	54
	1E-105	372
	1E-105	124
	1E-123	263
	1E-123	153
	1E-123	689
	1E-123	106
	1E-103	26
	1E-146	115
	1E-14	160
	1E-141	75
	1E-142	157
	1E-142	261
	1E-143	398
	1E-145	49
	1E-145	1142
	1F-31	58
	1E-145	465
	1E-133	2071
	1E-146	201
	1E-148	210
	1E-149	128
	1E-149	220
	1E-149	268
	1E-149	44
	1E-149	301
	2B-113	188
	1E-145	1587

Reason	Equipment Code	Outage minutes
	1F-51	166
	1E-149	1135
	1F-38	454
	1F-40	24
	1F-40	175
	1F-41	98
	1F-41	70
	1F-45	109
	1F-45	370
	1E-14	107
	1F-51	32
	1E-137	77
	1F-51	348
	1F-52	83
	1E-131	1576
	1E-131	116
	1E-132	76
	1E-132	17
	1E-132	88
	1F-35	330
	1F-51	194
	4A-11	80
	4A-112	223
	4A-10	79
	4A-103	63
	4A-103	59
	4A-103	38
	4A-107	394
	4A-108	71
	4A-10	97
	4A-108	73
	4A-10	126
	4A-11	37

Reason	Equipment Code	Outage minutes
	4A-111	144
	4A-111	351
	4A-111	143
	4A-111	187
	4A-111	184
	4A-111	61
	3F-7	176
	4A-108	94
	3G-1	19
	3C-219	63
	3F-71	80
	3F-71	189
	3F-71	36
	3F-71	142
	3F-72	117
	3F-8	104
	4A-10	119
	3F-9	124
	4A-112	142
	3G-1	56
	3H-1	83
	3H-2	14
	3H-2	212
	3H-4	65
	3H-4	82
	3H-4	45
	4A-1	126
	3F-9	95
	4A-119	247
	4A-111	94
	4A-118	706
	4A-118	78
	4A-119	68

Reason	Equipment Code	Outage minutes
	4A-119	93
	4A-119	236
	4A-119	109
	4A-118	141
	4A-119	158
	4A-116	81
	4A-123	114
	4A-15	82
	4A-15	93
	4A-17	27
	4A-17	35
	4A-17	57
	4A-17	245
	4A-17	34
	4A-119	126
	4A-113	91
	4A-112	163
	4A-112	265
	4A-113	126
	4A-113	281
	4A-113	14
	4A-113	37
	4A-113	55
	4A-118	69
	4A-113	201
	3F-7	426
	4A-113	82
	4A-113	302
	4A-113	146
	4A-113	74
	4A-113	217
	4A-113	76
	4A-115	253

Reason	Equipment Code	Outage minutes
	4A-115	108
	4A-113	813
	3E-87	195
	3F-110	282
	3E-56	514
	3E-58	256
	3E-67	115
	3E-68	79
	3E-69	104
	3E-7	241
	3E-54	128
	3E-74	81
	3E-5	135
	3E-91	208
	3F-11	219
	3F-11	291
	3F-11	52
	3F-11	100
	3F-11	70
	3F-11	59
	3F-70	65
	3E-7	66
	3E-36	246
	3E-32	210
	3E-33	36
	3E-33	67
	3E-34	106
	3E-34	101
	3E-34	329
	3E-36	74
	3E-56	177
	3E-36	241
	3F-110	55

Reason	Equipment Code	Outage minutes
	3E-36	307
	3E-37	43
	3E-38	110
	3E-38	429
	3E-40	1370
	3E-47	270
	3E-48	69
	3E-49	667
	3E-36	102
	3F-44	67
	3F-110	87
	3F-24	115
	3F-35	28
	3F-36	40
	3F-4	55
	3F-4	152
	3F-4	270
	3F-22	1567
	3F-42	71
	3F-22	122
	3F-5	36
	3F-5	57
	3F-57	226
	3F-59	376
	3F-59	370
	3F-59	489
	3F-59	484
	3F-7	51
	3F-42	23
	3F-13	286
	3F-111	74
	3F-112	121
	3F-112	165

Reason	Equipment Code	Outage minutes
	3F-116	314
	3F-12	414
	3F-12	131
	3F-12	95
	3F-22	80
	3F-120	232
	4A-18	64
	3F-13	321
	3F-13	121
	3F-17	280
	3F-17	94
	3F-17	109
	3F-17	63
	3F-17	192
	3F-17	260
	3F-12	71
	4B-117	151
	4B-118	144
	4B-116	205
	4B-116	92
	4B-117	56
	4B-117	91
	4B-117	120
	4B-117	217
	4B-115	594
	4B-117	114
	4B-115	362
	4B-118	33
	4B-118	187
	4B-118	269
	4B-118	156
	4B-118	95
	4B-118	252

Reason	Equipment Code	Outage minutes
	4B-118	286
	4A-17	47
	4B-117	85
	4B-114	197
	4B-112	269
	4B-112	79
	4B-112	154
	4B-112	74
	4B-112	94
	4B-112	25
	4B-112	85
	4B-115	553
	4B-113	142
	4B-118	333
	4B-114	105
	4B-115	434
	4B-115	121
	4B-115	133
	4B-115	79
	4B-115	73
	4B-115	82
	4B-115	221
	4B-112	221
	4B-221	66
	4B-118	465
	4B-216	120
	4B-216	455
	4B-217	185
	4B-219	100
	4B-219	133
	4B-22	79
	4B-214	83
	4B-221	84

Reason	Equipment Code	Outage minutes
	4B-210	93
	4B-223	325
	4B-223	158
	4B-223	66
	4B-223	49
	4B-223	143
	4B-223	159
	4B-223	228
	4B-223	79
	4B-22	81
	4B-20	931
	4B-121	23
	4B-128	107
	4B-132	722
	4B-132	151
	4B-136	0
	4B-14	105
	4B-15	53
	4B-216	48
	4B-20	103
	4B-110	283
	4B-203	934
	4B-209	212
	4B-209	331
	4B-209	340
	4B-209	336
	4B-209	99
	4B-209	108
	4B-209	954
	4B-152	169
	4A-4	184
	4B-111	105
	4A-34	73

Reason	Equipment Code	Outage minutes
	4A-35	514
	4A-36	53
	4A-36	116
	4A-36	284
	4A-38	22
	4A-3	290
	4A-4	50
	4A-3	80
	4A-4	135
	4A-4	97
	4A-40	39
	4A-40	90
	4A-43	133
	4A-43	185
	4A-43	72
	4A-44	138
	4A-4	38
	4A-28	85
	3E-25	221
	4A-2	57
	4A-20	92
	4A-20	273
	4A-20	117
	4A-24	61
	4A-26	290
	4A-3	142
	4A-28	88
	4A-48	550
	4A-28	165
	4A-28	49
	4A-28	92
	4A-28	109
	4A-28	108

Reason	Equipment Code	Outage minutes
	4A-28	63
	4A-3	47
	4A-3	90
	4A-28	178
	4B-102	74
	4B-101	98
	4B-101	438
	4B-101	139
	4B-102	59
	4B-102	234
	4B-102	166
	4B-102	205
	4A-44	506
	4B-102	554
	4A-89	155
	4B-102	165
	4B-102	301
	4B-104	164
	4B-108	84
	4B-109	201
	4B-11	148
	4B-110	47
	4A-17	98
	4B-102	64
	4A-6	72
	4B-110	82
	4A-55	87
	4A-56	18
	4A-59	230
	4A-6	258
	4A-6	117
	4A-6	151
	4A-6	177

Reason	Equipment Code	Outage minutes
	4A-96	184
	4A-6	203
	4A-96	102
	4A-60	109
	4A-60	246
	4A-60	330
	4A-60	69
	4A-64	98
	4A-72	141
	4A-72	93
	4A-48	189
	4A-6	225
	3C-503	141
	3C-512	111
	3C-450	78
	3C-450	91
	3C-451	172
	3C-451	53
	3C-452	75
	3C-47	112
	3C-450	201
	3C-49	53
	3C-43	67
	3C-51	67
	3C-511	124
	3C-511	78
	3C-511	152
	3C-511	294
	3C-511	167
	3C-511	32
	3D-114	86
	3C-48	79
	3C-402	79

Reason	Equipment Code	Outage minutes
	3C-34	174
	3C-34	201
	3C-34	256
	3C-36	144
	3C-36	94
	3C-36	37
	3C-36	144
	3C-450	172
	3C-40	112
	3C-512	47
	3C-404	56
	3C-406	67
	3C-406	87
	3C-409	199
	3C-411	27
	3C-416	118
	3C-417	274
	3C-417	653
	3C-36	82
	3D-109	262
	3C-511	73
	3D-106	203
	3D-108	99
	3D-108	200
	3D-108	389
	3D-108	158
	3D-108	157
	3D-103	62
	3D-108	98
	3D-101	135
	3D-112	106
	3D-112	178
	3D-113	218

Reason	Equipment Code	Outage minutes
	3D-113	134
	3D-113	60
	3D-113	127
	3D-114	35
	3E-3	105
	3D-108	85
	3C-67	101
	3C-512	233
	3C-512	75
	3C-55	127
	3C-56	148
	3C-58	59
	3C-6	200
	3C-6	254
	3D-104	116
	3C-63	150
	3C-318	116
	3C-67	778
	3C-76	211
	3C-78	108
	3C-8	85
	3C-85	33
	3C-86	153
	3C-9	55
	3C-9	648
	3C-62	123
	3C-229	122
	3C-319	341
	3C-225	157
	3C-225	126
	3C-226	88
	3C-226	67
	3C-226	21

Reason	Equipment Code	Outage minutes
	3C-229	107
	3C-225	109
	3C-229	119
	3C-225	208
	3C-229	142
	3C-229	187
	3C-229	36
	3C-23	162
	3C-232	81
	3C-232	62
	3C-233	240
	3C-233	98
	3C-229	57
	3C-220	33
	3C-219	70
	3C-219	552
	3C-219	80
	3C-219	89
	3C-219	130
	3C-219	65
	3C-219	91
	3C-225	87
	3C-220	141
	3C-233	55
	3C-223	39
	3C-224	83
	3C-224	84
	3C-225	57
	3C-225	105
	3C-225	117
	3C-225	75
	3C-225	221
	3C-219	77

Reason	Equipment Code	Outage minutes
	3C-306	221
	3C-302	176
	3C-302	157
	3C-302	188
	3C-302	189
	3C-302	115
	3C-302	122
	3C-302	250
	3C-233	135
	3C-302	144
	3C-302	192
	3C-308	66
	3C-31	56
	3C-31	42
	3C-31	103
	3C-31	178
	3C-31	96
	3C-311	72
	3D-114	149
	3C-302	121
	3C-29	81
	3C-319	148
	3C-233	1203
	3C-234	76
	3C-24	100
	3C-241	69
	3C-25	17
	3C-25	76
	3C-25	98
	3C-302	200
	3C-27	117
	3C-302	261
	3C-3	110

Reason	Equipment Code	Outage minutes
	3C-30	106
	3C-30	138
	3C-302	117
	3C-302	212
	3C-302	85
	3C-302	441
	3C-233	116
	3C-253	155
	3E-112	464
	3E-113	145
	3E-11	46
	3E-110	52
	3E-110	138
	3E-111	75
	3E-111	185
	3E-112	398
	3E-109	83
	3E-112	601
	3E-108	135
	3E-112	140
	3E-112	36
	3E-113	149
	3E-113	64
	3E-113	281
	3E-113	236
	3E-113	712
	3D-114	123
	3E-112	91
	3E-107	114
	3E-106	89
	3E-107	36
	3E-107	76
	3E-107	76

Reason	Equipment Code	Outage minutes
	3E-107	217
	3E-107	113
	3E-107	259
	3E-11	385
	3E-107	146
	3E-113	89
	3E-107	320
	3E-107	514
	3E-107	86
	3E-107	168
	3E-107	61
	3E-107	13
	3E-108	128
	3E-108	131
	3E-107	93
	3E-19	109
	3E-113	82
	3E-146	159
	3E-146	86
	3E-147	93
	3E-148	64
	3E-148	429
	3E-148	354
	3E-144	1451
	3E-148	200
	3E-14	83
	3E-2	95
	3E-200	92
	3E-200	289
	3E-200	38
	3E-200	67
	3E-200	121
	3E-247	60

Reason	Equipment Code	Outage minutes
	4B-224	22
	3E-148	743
	3E-117	168
	3E-114	283
	3E-114	322
	3E-114	224
	3E-114	316
	3E-114	1445
	3E-114	1820
	3E-114	163
	3E-144	321
	3E-117	33
	3E-106	77
	3E-12	114
	3E-121	367
	3E-121	70
	3E-121	72
	3E-121	67
	3E-121	504
	3E-121	197
	3E-125	152
	3E-117	113
	3D-207	96
	3E-106	205
	3D-189	86
	3D-189	57
	3D-19	186
	3D-191	30
	3D-192	129
	3D-204	223
	3D-134	260
	3D-206	63
	3D-134	227

Reason	Equipment Code	Outage minutes
	3D-213	118
	3D-223	377
	2C-128	62
	3D-225	102
	3D-225	129
	3D-226	545
	3D-230	313
	3D-239	72
	3D-206	184
	3D-124	126
	3D-114	58
	3D-12	153
	3D-121	23
	3D-123	153
	3D-124	303
	3D-124	75
	3D-124	49
	3D-15	25
	3D-124	160
	3D-25	590
	3D-125	77
	3D-126	78
	3D-128	267
	3D-129	94
	3D-129	59
	3D-133	101
	3D-133	120
	3D-134	81
	3D-124	87
	3E-1	286
	3D-62	893
	3D-64	89
	3D-64	273

Reason	Equipment Code	Outage minutes
	3D-66	185
	3D-66	102
	3D-8	122
	3D-81	59
	3D-239	74
	3D-87	735
	3D-56	129
	3E-101	68
	3E-103	21
	3E-103	32
	3E-103	47
	3E-103	78
	3E-104	81
	3E-104	117
	3E-25	115
	3D-81	87
	3D-32	115
	3E-106	96
	3D-252	73
	3D-254	152
	3D-255	742
	3D-255	474
	3D-255	140
	3D-255	115
	3D-291	118
	3D-62	68
	3D-3	109
	3D-57	134
	3D-32	302
	3D-38	145
	3D-43	99
	3D-5	89
	3D-5	269

Reason	Equipment Code	Outage minutes
	3D-54	15
	3D-56	138
	3D-245	32
	3D-291	180
	4D-113	53
	4D-121	404
	4D-108	92
	4D-108	197
	4D-108	19
	4D-109	411
	4D-110	176
	4D-110	175
	4D-106	44
	4D-111	91
	4D-105	141
	4D-113	187
	4D-113	373
	4D-113	316
	4D-113	11
	4D-113	554
	4D-121	20
	4D-121	41
	4D-31	102
	4D-111	50
	4D-102	79
	4C-98	76
	4C-99	134
	4C-99	57
	4C-99	73
	4D-10	51
	4D-10	241
	4D-102	222
	4D-108	429

Reason	Equipment Code	Outage minutes
	4D-102	307
	4D-125	169
	4D-104	105
	4D-104	219
	4D-104	102
	4D-104	149
	4D-104	102
	4D-105	125
	4D-105	97
	4D-105	126
	4D-102	310
	4D-24	53
	4D-121	274
	4D-204	227
	4D-206	435
	4D-206	152
	4D-206	546
	4D-211	100
	4D-211	587
	4D-200	195
	4D-24	437
	4D-200	335
	4D-24	163
	4D-24	66
	4D-24	89
	4D-27	120
	4D-281	65
	4D-283	278
	4D-285	177
	4C-247	50
	4D-215	144
	4D-187	325
	4D-125	463

Reason	Equipment Code	Outage minutes
	4D-13	528
	4D-13	577
	4D-14	164
	4D-14	106
	4D-14	711
	4D-186	198
	4D-203	52
	4D-186	62
	4C-98	127
	4D-189	135
	4D-192	108
	4D-192	65
	4D-193	274
	4D-193	576
	4D-194	131
	4D-197	85
	4D-200	50
	4D-186	190
	4C-47	92
	4C-98	70
	4C-34	113
	4C-40	154
	4C-41	568
	4C-47	87
	4C-47	59
	4C-47	253
	4C-310	207
	4C-47	132
	4C-310	91
	4C-49	91
	4C-49	96
	4C-49	90
	4C-49	45

Reason	Equipment Code	Outage minutes
	4C-49	111
	4C-50	36
	4C-50	65
	4C-50	149
	4C-47	71
	4C-28	109
	4B-224	132
	4C-248	113
	4C-25	20
	4C-254	72
	4C-255	85
	4C-256	75
	4C-260	15
	4C-311	306
	4C-269	79
	4C-511	80
	4C-286	91
	4C-286	143
	4C-287	486
	4C-287	140
	4C-292	82
	4C-304	113
	4C-305	105
	4C-305	125
	4C-264	99
	4C-95	372
	4C-75	168
	4C-82	97
	4C-82	129
	4C-83	178
	4C-83	66
	4C-84	199
	4C-88	59

Reason	Equipment Code	Outage minutes
	4C-511	123
	4C-90	246
	4C-66	356
	4C-96	75
	4C-96	105
	4C-96	70
	4C-96	112
	4C-97	44
	4C-98	53
	4C-98	106
	4D-36	95
	4C-88	136
	4C-52	362
	4C-98	80
	4C-511	94
	4C-512	79
	4C-513	136
	4C-513	60
	4C-513	224
	4C-513	279
	4C-513	130
	4C-72	59
	4C-513	162
	4C-72	74
	4C-56	220
	4C-56	257
	4C-56	386
	4C-61	78
	4C-61	144
	4C-62	207
	4C-66	94
	4C-511	435
	4C-513	103

Reason	Equipment Code	Outage minutes
	4E-56	234
	4E-78	53
	4E-5	53
	4E-5	23
	4E-50	86
	4E-51	849
	4E-51	673
	4E-51	303
	4E-49	125
	4E-53	1177
	4E-43	981
	4E-56	57
	4E-61	45
	4E-61	43
	4E-66	308
	4E-67	276
	4E-73	210
	4E-77	62
	4D-285	127
	4E-53	97
	4E-16	73
	4E-122	103
	4E-122	8
	4E-124	75
	4E-124	170
	4E-125	45
	4E-125	415
	4E-125	254
	4E-5	416
	4E-16	84
	4E-78	70
	4E-18	1521
	4E-31	250

Reason	Equipment Code	Outage minutes
	4E-31	202
	4E-35	80
	4E-41	71
	4E-42	71
	4E-43	90
	4E-43	62
	4E-145	73
	4G-11	165
	4E-77	421
	4F-23	238
	4F-3	456
	4F-4	37
	4G-1	390
	4G-1	300
	4G-1	48
	4F-23	65
	4G-11	66
	4F-2	594
	4G-3	35
	4G-9	57
	4G-9	61
	4G-9	134
	4G-9	76
	4H-4	50
	4J-1	444
	4J-1	180
	4G-10	184
	4F-10	211
	4E-8	61
	4E-8	79
	4E-8	89
	4E-85	62
	4E-9	190

Reason	Equipment Code	Outage minutes
	4E-9	103
	4E-9	81
	4F-23	59
	4F-10	42
	4E-122	103
	4F-102	36
	4F-102	112
	4F-102	206
	4F-103	54
	4F-106	34
	4F-11	115
	4F-123	85
	4F-2	206
	4E-9	71
	4D-49	155
	4E-122	70
	4D-42	67
	4D-45	218
	4D-45	67
	4D-46	593
	4D-47	467
	4D-48	25
	4D-414	122
	4D-48	41
	4D-410	70
	4D-52	214
	4D-52	110
	4D-52	157
	4D-52	68
	4D-52	63
	4D-53	155
	4D-54	53
	4D-54	93

Reason	Equipment Code	Outage minutes
	4D-48	114
	4D-400	118
	4D-37	51
	4D-37	62
	4D-38	405
	4D-39	650
	4D-40	279
	4D-40	31
	4D-40	83
	4D-414	161
	4D-40	598
	4D-6	130
	4D-401	346
	4D-401	157
	4D-401	147
	4D-403	296
	4D-403	279
	4D-403	385
	4D-409	159
	4D-409	145
	4D-40	95
	4E-12	71
	4D-85	210
	4D-91	16
	4D-98	458
	4E-1	276
	4E-1	164
	4E-10	120
	4E-10	80
	4D-56	570
	4E-10	241
	4D-80	101
	4E-121	46

Reason	Equipment Code	Outage minutes
	4E-121	154
	4E-121	133
	4E-121	390
	4E-122	273
	4E-122	230
	4E-122	497
	4C-247	313
	4E-10	104
	4D-73	88
	4E-122	76
	4D-6	85
	4D-620	39
	4D-64	111
	4D-65	93
	4D-69	201
	4D-69	315
	4D-69	75
	4D-85	428
	4D-73	53
	4D-82	111
	4D-73	410
	4D-75	726
	4D-77	490
	4D-77	89
	4D-77	249
	4D-77	128
	4D-77	361
	4D-56	184
	4D-72	253
	4B-408	148
	4B-420	0
	4B-408	34
	4B-408	21

Reason	Equipment Code	Outage minutes
	4B-408	342
	4B-408	78
	4B-408	46
	4B-408	917
	4B-408	95
	4B-408	39
	4B-408	45
	4B-408	170
	4B-410	143
	4B-412	117
	4B-415	191
	4B-415	824
	4B-417	34
	4B-417	99
	4B-69	767
	4B-408	47
	4B-407	89
	4B-406	197
	4B-406	380
	4B-406	456
	4B-407	170
	4B-407	64
	4B-407	250
	4B-407	135
	4B-408	105
	4B-407	159
	4B-420	216
	4B-407	299
	4B-407	95
	4B-407	217
	4B-407	595
	4B-407	262
	4B-407	70

Reason	Equipment Code	Outage minutes
	4B-408	36
	4B-408	119
	4B-407	185
	4B-64	106
	4B-420	135
	4B-54	84
	4B-57	63
	4B-57	159
	4B-57	63
	4B-60	150
	4B-601	398
	4B-54	55
	4B-602	80
	4B-54	84
	4B-64	81
	4B-66	218
	4B-66	100
	4B-66	147
	4B-66	95
	4B-68	117
	4B-68	934
	4C-248	165
	4B-602	13
	4B-48	86
	4B-420	105
	4B-420	108
	4B-420	102
	4B-44	231
	4B-46	37
	4B-46	69
	4B-46	130
	4B-54	42
	4B-47	19

Reason	Equipment Code	Outage minutes
	4B-405	100
	4B-48	146
	4B-504	149
	4B-506	47
	4B-51	173
	4B-53	91
	4B-54	22
	4B-54	516
	4B-54	216
	4B-46	135
	4B-262	160
	4B-406	261
	4B-252	374
	4B-258	81
	4B-259	87
	4B-26	259
	4B-26	94
	4B-260	115
	4B-252	369
	4B-261	344
	4B-25	159
	4B-265	146
	4B-268	20
	4B-268	410
	4B-27	63
	4B-27	104
	4B-27	132
	4B-272	559
	4B-273	197
	4B-261	67
	4B-236	103
	3D-223	59
	4B-224	271

Reason	Equipment Code	Outage minutes
	4B-225	127
	4B-229	207
	4B-23	844
	4B-23	107
	4B-233	20
	4B-252	175
	4B-236	635
	4B-276	82
	4B-237	9
	4B-237	218
	4B-24	278
	4B-24	66
	4B-24	126
	4B-25	448
	4B-25	80
	4B-25	82
	4B-233	77
	4B-403	155
	4B-357	176
	4B-357	85
	4B-39	163
	4B-39	195
	4B-40	170
	4B-40	251
	4B-40	152
	4B-273	385
	4B-400	103
	4B-346	131
	4B-403	92
	4B-403	123
	4B-403	513
	4B-403	62
	4B-403	10

Reason	Equipment Code	Outage minutes
	4B-403	195
	4B-405	75
	4B-69	157
	4B-400	177
	4B-305	129
	4B-405	82
	4B-276	211
	4B-28	294
	4B-283	203
	4B-283	86
	4B-283	92
	4B-290	106
	4B-299	457
	4B-356	98
	4B-300	139
	4B-353	44
	4B-305	104
	4B-310	76
	4B-313	125
	4B-315	322
	4B-321	53
	4B-325	997
	4B-327	183
	4B-276	16
	4B-299	401
	4C-168	124
	4C-179	31
	4C-160	463
	4C-160	45
	4C-160	80
	4C-164	167
	4C-164	345
	4C-164	163

Reason	Equipment Code	Outage minutes
	4C-160	159
	4C-168	223
	4C-160	92
	4C-168	125
	4C-168	225
	4C-171	54
	4C-171	160
	4C-175	46
	4C-175	76
	4C-175	78
	4B-69	8
	4C-164	64
	4C-159	46
	4C-157	39
	4C-157	211
	4C-157	131
	4C-157	139
	4C-159	173
	4C-159	67
	4C-159	111
	4C-160	154
	4C-159	99
	4C-18	85
	4C-159	37
	4C-159	80
	4C-159	52
	4C-160	53
	4C-160	231
	4C-160	78
	4C-160	99
	4C-160	136
	4C-159	167
	4C-24	169

Reason	Equipment Code	Outage minutes
	4C-176	125
	4C-237	85
	4C-237	1
	4C-237	62
	4C-24	5
	4C-24	105
	4C-24	115
	4C-219	56
	4C-24	142
	4C-217	260
	4C-24	188
	4C-241	92
	4C-242	70
	4C-245	365
	4C-245	178
	4C-245	181
	4C-246	244
	4C-246	54
	4C-24	112
	4C-2	79
	4C-18	191
	4C-184	175
	4C-187	220
	4C-187	115
	4C-189	94
	4C-189	74
	4C-189	56
	4C-230	166
	4C-191	46
	4C-153	102
	4C-202	115
	4C-202	163
	4C-205	96

Reason	Equipment Code	Outage minutes
	4C-206	242
	4C-206	112
	4C-209	320
	4C-214	47
	4C-216	35
	4C-190	191
	4B-94	141
	4C-156	138
	4B-87	79
	4B-89	102
	4B-89	77
	4B-9	127
	4B-91	184
	4B-91	100
	4B-84	92
	4B-92	128
	4B-84	124
	4B-94	364
	4B-98	63
	4B-98	87
	4B-98	261
	4B-98	115
	4C-104	90
	4C-104	94
	4C-109	151
	4B-92	130
	4B-77	1010
	4B-700	15
	4B-700	54
	4B-72	209
	4B-72	124
	4B-72	1021
	4B-72	1042

Reason	Equipment Code	Outage minutes
	4B-75	206
	4B-85	262
	4B-77	272
	4C-111	85
	4B-78	109
	4B-8	159
	4B-80	72
	4B-82	75
	4B-82	68
	4B-83	92
	4B-83	278
	4B-84	307
	4B-76	1003
	4C-151	552
	4C-131	58
	4C-131	84
	4C-14	48
	4C-14	151
	4C-14	85
	4C-14	417
	4C-15	97
	4C-110	113
	4C-15	144
	4C-120	262
	4C-152	364
	4C-152	154
	4C-152	100
	4C-152	83
	4C-152	141
	4C-152	98
	4C-152	253
	4B-224	101
	4C-15	65

Reason	Equipment Code	Outage minutes
	4C-119	87
	4C-156	238
	4C-114	181
	4C-114	89
	4C-114	80
	4C-117	49
	4C-117	157
	4C-117	434
	4C-117	77
	4C-130	251
	4C-118	73
	4C-120	131
	4C-119	90
	4C-119	664
	4C-119	224
	4C-119	57
	4C-119	116
	4C-119	88
	4C-120	73
	4C-110	130
	4C-118	64
	2F-101	45
	2F-43	33
	2E-76	193
	2E-91	300
	2E-91	57
	2E-91	433
	2E-91	117
	2F-1	127
	2E-74	79
	2F-10	321
	2E-73	97
	2F-101	54

Reason	Equipment Code	Outage minutes
	2F-101	195
	2F-102	154
	2F-103	36
	2F-103	898
	2F-103	32
	2F-103	75
	2F-1	84
	2E-59	51
	2E-42	203
	2E-43	119
	2E-5	66
	2E-5	72
	2E-5	48
	2E-5	544
	2E-50	71
	2E-74	115
	2E-56	306
	2F-106	295
	2E-67	227
	2E-68	50
	2E-68	142
	2E-69	61
	2E-72	105
	2E-73	150
	2E-73	135
	2E-50	147
	2F-29	80
	2F-123	129
	2F-123	41
	2F-123	123
	2F-124	204
	2F-125	69
	2F-126	54

Reason	Equipment Code	Outage minutes
	2F-126	405
	2F-103	247
	2F-126	92
	2F-116	125
	2F-29	484
	2F-32	140
	2F-34	172
	2F-35	40
	2F-35	91
	2F-40	175
	3A-79	566
	2F-126	53
	2F-111	55
	2E-330	312
	2F-106	112
	2F-107	103
	2F-107	51
	2F-107	86
	2F-109	98
	2F-110	167
	2F-121	37
	2F-110	73
	2F-121	231
	2F-111	40
	2F-111	34
	2F-111	106
	2F-112	56
	2F-112	102
	2F-112	105
	2F-114	197
	2F-106	109
	2F-110	92
	2E-122	134

Reason	Equipment Code	Outage minutes
	2E-118	466
	2E-118	35
	2E-118	42
	2E-12	72
	2E-120	153
	2E-120	36
	2E-120	92
	2E-159	449
	2E-121	187
	2E-117	61
	2E-122	80
	2E-14	110
	2E-14	136
	2E-15	100
	2E-153	131
	2E-154	76
	2E-38	129
	2E-121	605
	2E-113	96
	2E-112	455
	2E-112	1397
	2E-112	1796
	2E-112	941
	2E-112	109
	2E-112	75
	2E-112	60
	2E-118	97
	2E-113	54
	2E-118	98
	2E-113	46
	2E-113	39
	2E-113	153
	2E-113	60

Reason	Equipment Code	Outage minutes
	2E-114	250
	2E-114	106
	2E-117	104
	2E-159	307
	2E-113	292
	2E-32	131
	2E-281	38
	2E-281	89
	2E-29	205
	2E-292	182
	2E-297	153
	2E-299	270
	2E-32	43
	2E-154	107
	2E-32	50
	2E-271	430
	2E-32	358
	2E-321	763
	2E-33	124
	2E-33	124
	2E-33	113
	2E-330	216
	2F-46	35
	2E-32	167
	2E-20	1012
	2E-160	66
	2E-160	86
	2E-166	630
	2E-166	106
	2E-167	251
	2E-19	170
	2E-19	44
	2E-279	71

Reason	Equipment Code	Outage minutes
	2E-20	146
	2E-279	107
	2E-20	51
	2E-203	71
	2E-203	46
	2E-21	102
	2E-213	149
	2E-214	1448
	2E-22	156
	2E-35	79
	2E-19	65
	3A-25	48
	2F-42	210
	3A-2	111
	3A-2	177
	3A-2	117
	3A-20	45
	3A-20	98
	3A-23	101
	3A-2	22
	3A-23	141
	3A-19	292
	3A-25	906
	3A-25	280
	3A-25	193
	3A-27	209
	3A-28	160
	3A-28	94
	3A-31	818
	3A-23	97
	3A-132	184
	3A-127	416
	3A-127	117

Reason	Equipment Code	Outage minutes
	3A-127	134
	3A-127	240
	3A-128	170
	3A-128	96
	3A-128	96
	3A-2	41
	3A-132	493
	3A-33	219
	3A-133	29
	3A-133	159
	3A-133	57
	3A-134	48
	3A-15	74
	3A-15	341
	3A-16	51
	3A-132	81
	3A-75	42
	3A-54	164
	3A-62	97
	3A-62	87
	3A-67	41
	3A-69	86
	3A-72	76
	3A-73	129
	3A-32	86
	3A-73	111
	3A-50	47
	3A-79	53
	3A-79	415
	3A-79	314
	3A-79	465
	3A-79	454
	3A-79	407

Reason	Equipment Code	Outage minutes
	3A-79	71
	3A-73	74
	3A-42	83
	3A-125	148
	3A-34	191
	3A-36	348
	3A-36	69
	3A-36	121
	3A-38	52
	3A-38	152
	3A-50	96
	3A-38	77
	3A-50	46
	3A-42	159
	3A-42	63
	3A-44	105
	3A-46	36
	3A-47	793
	3A-47	312
	3A-47	809
	3A-32	225
	3A-38	108
	3A-10	61
	2H-4	145
	2H-5	40
	2H-5	121
	2H-5	125
	2J-1	193
	2J-1	272
	3A-1	81
	3A-110	336
	3A-1	238
	2H-1	4

Reason	Equipment Code	Outage minutes
	3A-10	49
	3A-102	235
	3A-102	65
	3A-102	388
	3A-107	131
	3A-108	80
	3A-125	130
	3A-1	158
	2F-84	109
	2F-46	163
	2F-59	30
	2F-68	88
	2F-81	71
	2F-81	73
	2F-84	244
	2F-84	203
	2H-4	120
	2F-84	66
	2H-2	77
	2F-84	129
	2F-84	124
	2F-87	116
	2F-93	93
	2F-94	38
	2G-1	379
	2H-1	101
	3A-110	193
	2F-84	99
	3A-120	32
	3A-117	170
	3A-117	532
	3A-117	98
	3A-117	391

Reason	Equipment Code	Outage minutes
	3A-119	106
	3A-119	35
	3A-12	76
	3A-109	92
	3A-120	72
	3A-117	158
	3A-120	29
	3A-120	66
	3A-120	103
	3A-120	195
	3A-121	260
	3A-121	98
	2E-111	76
	3A-120	39
	3A-115	1
	3A-110	340
	3A-110	200
	3A-110	305
	3A-111	162
	3A-111	60
	3A-111	95
	3A-114	178
	3A-117	86
	3A-114	108
	3A-117	24
	3A-115	160
	3A-115	75
	3A-115	38
	3A-116	15
	3A-116	333
	3A-117	205
	3A-117	304
	3A-125	176

Reason	Equipment Code	Outage minutes
	3A-114	148
	2D-222	68
	2E-112	35
	2D-216	317
	2D-216	145
	2D-218	86
	2D-218	52
	2D-22	73
	2D-220	88
	2D-216	212
	2D-220	404
	2D-213	116
	2D-222	145
	2D-223	77
	2D-223	151
	2D-224	286
	2D-23	160
	2D-23	123
	2D-23	191
	2D-220	307
	2D-205	50
	2D-177	140
	2D-19	101
	2D-19	816
	2D-19	80
	2D-19	88
	2D-19	70
	2D-200	95
	2D-216	387
	2D-205	90
	2D-23	240
	2D-206	84
	2D-206	216

Reason	Equipment Code	Outage minutes
	2D-206	174
	2D-207	148
	2D-211	13
	2D-211	157
	2D-213	98
	2D-205	76
	2D-271	208
	2D-261	93
	2D-261	232
	2D-261	96
	2D-261	108
	2D-261	100
	2D-262	124
	2D-270	192
	2D-23	198
	2D-270	732
	2D-26	47
	2D-273	157
	2D-273	62
	2D-273	121
	2D-273	290
	2D-274	45
	2D-274	67
	2D-274	85
	2D-270	359
	2D-249	306
	2D-173	135
	2D-23	118
	2D-231	49
	2D-231	63
	2D-231	185
	2D-231	192
	2D-235	112

Reason	Equipment Code	Outage minutes
	2D-26	220
	2D-237	125
	2D-26	110
	2D-25	229
	2D-25	231
	2D-25	96
	2D-258	63
	2D-258	44
	2D-258	113
	2D-258	74
	2D-23	389
	2D-237	182
	2D-128	309
	2D-128	172
	2D-128	86
	2D-128	348
	2D-128	101
	2D-128	116
	2D-128	322
	2D-128	121
	2D-131	96
	2D-128	74
	2D-127	298
	2D-128	324
	2D-128	111
	2D-129	46
	2D-129	141
	2D-129	66
	2D-131	253
	2D-177	93
	2D-128	114
	2D-123	92
	2D-123	429

Reason	Equipment Code	Outage minutes
	2D-123	207
	2D-123	248
	2D-123	131
	2D-123	42
	2D-123	220
	2D-123	96
	2D-128	147
	2D-123	72
	2D-128	191
	2D-124	71
	2D-124	52
	2D-125	184
	2D-125	72
	2D-126	68
	2D-126	190
	2D-127	250
	2D-132	30
	2D-123	126
	2D-168	102
	2D-155	101
	2D-156	67
	2D-156	149
	2D-159	212
	2D-159	144
	2D-162	211
	2D-163	187
	2D-131	80
	2D-166	63
	2D-151	445
	2D-169	78
	2D-17	109
	2D-17	162
	2D-17	27

Reason	Equipment Code	Outage minutes
	2D-172	1033
	2D-172	404
	2D-274	59
	2D-164	159
	2D-14	108
	2D-132	170
	2D-132	139
	2D-132	253
	2D-132	256
	2D-132	322
	2D-133	49
	2D-133	104
	2D-153	63
	2D-134	254
	2D-151	138
	2D-141	106
	2D-141	127
	2D-141	101
	2D-141	27
	2D-143	136
	2D-143	96
	2D-149	80
	2D-176	63
	2D-133	188
	2D-66	204
	2D-58	164
	2D-6	220
	2D-6	96
	2D-62	28
	2D-63	221
	2D-63	112
	2D-63	91
	2D-78	79

Reason	Equipment Code	Outage minutes
	2D-65	37
	2D-57	40
	2D-66	127
	2D-69	911
	2D-7	128
	2D-70	259
	2D-70	80
	2D-74	335
	2D-436	373
	2D-63	142
	2D-47	153
	2D-274	84
	2D-436	17
	2D-44	236
	2D-44	69
	2D-44	181
	2D-446	90
	2D-447	41
	2D-58	380
	2D-45	165
	2D-57	1362
	2D-47	319
	2D-47	95
	2D-47	16
	2D-50	216
	2D-51	58
	2D-53	610
	2D-53	100
	2D-79	71
	2D-45	261
	2E-11	146
	2E-105	90
	2E-105	71

Reason	Equipment Code	Outage minutes
	2E-105	161
	2E-105	240
	2E-106	206
	2E-106	108
	2E-106	49
	2D-75	97
	2E-106	285
	2E-104	74
	2E-110	118
	2E-111	297
	2E-111	45
	2E-111	73
	2E-111	138
	2E-111	188
	2F-40	91
	2E-106	558
	2E-100	84
	2D-8	112
	2D-8	73
	2D-8	182
	2D-83	262
	2D-84	333
	2D-85	238
	2D-99	117
	2E-105	91
	2E-100	130
	2E-105	53
	2E-100	121
	2E-104	85
	2E-104	178
	2E-104	254
	2E-104	80
	2E-104	49

Reason	Equipment Code	Outage minutes
	2E-104	48
	2D-436	298
	2E-10	76
	2D-401	32
	2D-30	899
	2D-308	90
	2D-308	266
	2D-308	76
	2D-310	69
	2D-311	515
	2D-311	594
	2D-403	117
	2D-400	379
	2D-30	207
	2D-401	111
	2D-401	52
	2D-402	195
	2D-402	487
	2D-402	149
	2D-403	55
	2D-436	378
	2D-40	154
	2D-28	67
	2E-111	124
	2D-274	203
	2D-274	354
	2D-274	109
	2D-274	1092
	2D-276	119
	2D-276	119
	2D-30	530
	2D-278	104
	2D-30	112

Reason	Equipment Code	Outage minutes
	2D-282	210
	2D-291	81
	2D-297	85
	2D-298	173
	2D-299	537
	2D-30	137
	2D-30	468
	2D-403	442
	2D-278	76
	2D-432	37
	2D-422	163
	2D-422	113
	2D-424	322
	2D-426	215
	2D-429	405
	2D-43	98
	2D-430	77
	2D-403	55
	2D-431	191
	2D-420	63
	2D-432	120
	2D-432	153
	2D-432	70
	2D-432	34
	2D-433	379
	2D-436	86
	2D-436	178
	2D-431	190
	2D-413	15
	2D-403	1122
	2D-403	384
	2D-403	306
	2D-404	175

Reason	Equipment Code	Outage minutes
	2D-409	140
	2D-41	40
	2D-41	406
	2D-422	254
	2D-413	182
	2D-421	42
	2D-413	52
	2D-413	895
	2D-413	355
	2D-414	263
	2D-414	145
	2D-414	415
	2D-414	87
	2D-274	77
	2D-413	164
	3B-43	88
	3C-118	76
	3C-104	30
	3C-118	21
	3C-104	141
	3C-118	61
	3B-146	216
	3C-118	82
	3C-121	84
	3C-119	36
	3B-41	90
	3B-144	104
	3C-12	920
	3B-45	55
	3B-46	140
	3C-104	236
	3B-143	40
	3C-104	79

Reason	Equipment Code	Outage minutes
	3B-201	186
	3C-119	157
	3C-118	92
	3B-54	73
	3B-200	1504
	3B-20	155
	3B-20	296
	3C-118	19
	3B-19	312
	3B-38	87
	3C-118	24
	3C-104	260
	3C-118	38
	3B-42	98
	3B-4	99
	3C-104	50
	3C-104	97
	3C-118	47
	3C-118	59
	3C-104	32
	3B-40	284
	3C-121	46
	3B-156	76
	3C-104	58
	3B-129	30
	3B-124	116
	3B-54	131
	3B-119	321
	3C-104	37
	3B-54	96
	3C-127	50
	3C-121	101
	3C-104	86

Reason	Equipment Code	Outage minutes
	3C-127	30
	3B-118	232
	3C-127	270
	3B-116	34
	3B-54	50
	3C-104	32
	3C-104	54
	3B-116	712
	3C-127	53
	3C-104	46
	3B-14	162
	3C-121	66
	3C-121	137
	3B-46	138
	3C-125	56
	3C-125	113
	3C-125	72
	3B-47	61
	3B-14	43
	3B-129	77
	3B-52	126
	3C-127	55
	3B-129	49
	3B-129	44
	3C-104	62
	3C-104	89
	3C-126	77
	3C-104	77
	3B-129	59
	3C-116	92
	3B-51	157
	3C-105	66
	3B-235	151

Reason	Equipment Code	Outage minutes
	3C-108	190
	3C-105	5
	3C-109	308
	3B-274	43
	3B-232	238
	3B-231	695
	3C-11	44
	3C-109	353
	3B-24	233
	3C-105	50
	3B-231	206
	3B-231	289
	3C-105	93
	3B-23	1804
	3B-225	52
	3B-225	63
	3B-34	42
	3C-105	10
	3B-273	59
	3B-26	89
	3B-26	62
	3B-261	71
	3B-258	38
	3B-258	30
	3B-265	69
	3B-265	85
	3B-266	171
	3B-239	94
	3B-273	125
	3B-239	107
	3B-255	191
	3B-255	274
	3B-274	48

Reason	Equipment Code	Outage minutes
	3B-249	51
	3B-245	1034
	3B-274	156
	3C-109	328
	3C-105	77
	3B-272	68
	3B-21	49
	3B-211	77
	3B-211	126
	3C-105	179
	3B-294	266
	3C-105	165
	3B-211	808
	3C-104	23
	3B-225	43
	3B-211	83
	3C-113	40
	3B-204	66
	3C-104	219
	3C-114	48
	3C-104	73
	3C-115	101
	3C-115	60
	3B-302	68
	3C-116	38
	3C-104	37
	3B-215	1266
	3B-221	119
	3C-105	177
	3B-221	174
	3B-290	514
	3B-221	4
	3B-221	342

Reason	Equipment Code	Outage minutes
	3B-95	90
	3B-62	90
	3B-211	523
	3B-22	49
	3C-105	32
	3B-213	95
	3C-105	104
	3C-105	23
	3B-213	11
	3C-112	48
	3C-113	39
	3B-212	344
	3B-143	29
	3C-112	186
	3B-108	148
	3C-20	71
	3C-103	1
	3B-110	109
	3B-112	707
	3C-103	78
	3C-182	194
	3C-103	90
	3B-102	1567
	3C-103	64
	3C-174	52
	3C-174	261
	3C-103	236
	3C-171	60
	3C-129	36
	3C-15	66
	3C-102	110
	3C-129	160
	3C-15	157

Reason	Equipment Code	Outage minutes
	3B-114	0
	3B-114	10
	3B-114	44
	3C-102	166
	3B-102	45
	3C-16	89
	3C-102	176
	3B-87	342
	3B-114	110
	3B-102	84
	3C-103	88
	3B-114	36
	3B-109	106
	3B-102	34
	3C-20	169
	3C-20	203
	3B-105	101
	3B-105	24
	3C-20	67
	3B-105	46
	3B-11	62
	3B-70	96
	3C-20	240
	3B-78	96
	3B-78	136
	3B-107	68
	3B-107	50
	3C-103	115
	3C-20	62
	3B-102	54
	3C-20	35
	3C-103	68
	3B-65	117

Reason	Equipment Code	Outage minutes
	3C-20	79
	3B-70	31
	3C-20	108
	3C-103	145
	3C-20	36
	3B-110	163
	3C-20	71
	3B-116	347
	3C-125	107
	3B-102	94
	3B-81	25
	3B-58	111
	3A-95	144
	3B-60	171
	3B-62	177
	3B-114	139
	3A-94	174
	3C-20	42
	3B-114	100
	3B-95	49
	3B-60	118
	3B-114	68
	3C-127	50
	3C-20	153
	3B-116	219
	3A-80	178
	3A-80	68
	3B-115	192
	3B-98	230
	3B-95	132
	3B-114	2
	3C-104	107
	3B-1	99

Reason	Equipment Code	Outage minutes
	3C-102	96
	3C-104	52
	3B-94	43
	3B-62	85
	3C-20	93
	3C-103	107
	3C-127	83
	3C-10	40
	3C-20	34
	3A-79	718
	3B-98	174
	3C-10	163
	3B-98	1436
	3B-116	352
	3C-219	61
	3A-9	174
Other Weather		
	4C-60	119
	4C-59	220
	2D-9	914
	2D-92	96
	2B-117	260
	4C-58	179
	1B-109	86
	1B-84	211
	2D-402	662
	1B-287	178
	2B-116	62
	SWC-522	199
	2D-413	117
	3D-128	51
	2B-117	185
	SWC-522	167

Reason	Equipment Code	Outage minutes
	SWC-521	501
	3C-452	84
	2B-104	93
	2B-145	21
	2C-112	147
	2C-112	132
	4C-60	79
	4C-157	117
	1B-117	158
	2D-403	134
	2D-403	59
	3D-124	140
	2B-56	126
	2E-104	98
	2B-53	86
	4C-152	86
	2B-115	346
	1B-70	180
	3C-5	72
	4C-511	968
	2D-406	81
	1B-44	130
	1B-64	137
	1B-44	150
	1B-44	69
	1B-44	179
	1B-117	284
	1B-50	162
	2E-102	36
	2B-53	197
	2C-116	173
	4C-5	62
	4C-5	271

Reason	Equipment Code	Outage minutes
	1B-82	77
	2D-92	433
	1B-49	211
	2D-95	35
	1B-81	120
	2C-114	269
	1B-69	230
	2D-41	231
	1B-110	142
	1B-79	40
	1B-113	102
	2C-116	91
	1B-77	79
	4C-15	72
	2C-115	95
	2C-115	92
	2C-115	105
	3C-102	111
	4C-157	88
	2B-114	207
	4C-221	74
	2B-148	165
	2B-81	389
	2D-44	85
	2B-81	59
	4C-237	110
	1B-101	220
	2B-820	63
	2B-820	131
	1B-101	97
	1B-101	61
	3C-103	118
	4D-108	185

Reason	Equipment Code	Outage minutes
	2B-114	65
	2B-144	162
	2D-65	106
	1B-102	131
	2B-66	121
	2B-147	82
	1B-104	75
	4C-161	118
	2B-147	40
	2B-113	262
	1B-105	133
	2B-114	81
	2D-424	194
	1B-102	157
	2B-81	135
	2B-725	52
	2B-740	61
	3D-108	128
	2D-60	158
	3D-108	116
	1A-63	451
	2B-713	61
	3D-109	44
	1A-7	97
	3C-104	77
	2B-114	562
	2D-52	80
	2D-630	236
	2B-69	139
	2B-149	108
	2D-51	398
	1A-30	234
	3D-105	247

Reason	Equipment Code	Outage minutes
	1A-22	39
	2D-48	136
	3D-104	974
	3D-104	372
	2B-149	56
	2B-69	163
	4C-21	126
	2B-148	102
	2B-114	407
	4C-190	149
	2D-424	206
	2C-106	175
	4C-266	100
	2D-43	65
	2B-151	87
	1B-108	36
	2B-115	182
	2B-115	215
	4C-286	184
	4C-287	95
	4C-287	141
	4C-287	246
	2B-98	71
	2D-424	201
	2B-115	626
	4C-30	88
	3D-115	221
	2B-115	96
	2B-115	63
	3D-12	133
	4C-159	68
	3C-513	97
	1A-1	79

Reason	Equipment Code	Outage minutes
	2D-416	115
	3C-104	92
	4C-159	54
	4C-42	56
	1B-108	15
	2B-62	65
	3C-7	128
	3C-67	178
	1A-117	54
	1A-117	159
	4C-245	88
	1B-106	96
	2C-102	200
	4C-246	48
	4C-246	74
	2D-432	37
	4C-160	143
	4C-160	92
	2B-112	73
	3C-64	127
	4C-261	73
	4C-248	64
	4C-25	42
	4C-25	47
	4C-25	259
	3D-113	96
	4C-250	66
	2B-6	105
	2D-75	101
	3C-58	100
	4C-259	101
	2B-6	231
	4C-43	149

Reason	Equipment Code	Outage minutes
	4C-248	66
	3C-127	24
	3C-233	48
	4D-900	257
	2C-63	79
	2B-137	54
	2B-137	407
	2D-162	20
	2C-83	101
	4D-77	119
	4D-95	367
	3C-127	101
	2D-164	96
	CD-581	293
	CN-556	1012
	CN-559	213
	2B-138	239
	4D-8	145
	2B-137	80
	3C-121	383
	2B-137	125
	2C-79	317
	BY-543	298
	CAN-511	154
	3C-232	47
	4D-92	91
	2B-132	41
	4D-92	141
	3C-233	47
	2C-68	147
	2B-132	58
	2B-137	78
	2B-137	108

Reason	Equipment Code	Outage minutes
	2D-156	288
	DU-504	206
	2D-146	629
	2B-138	60
	4D-76	23
	3C-26	83
	2B-138	140
	4D-54	134
	2B-130	79
	FQ-513	115
	3C-253	16
	4D-52	253
	2B-132	238
	FQ-513	43
	3C-126	87
	2B-138	69
	FS-544	74
	2B-130	25
	2B-130	93
	4D-105	134
	FQ-513	68
	2B-132	126
	2B-133	146
	4D-73	236
	DU-506	1
	2C-55	55
	2B-138	238
	FD-501	430
	4D-59	121
	4D-72	248
	4D-75	283
	FQ-511	56
	2D-17	20

Reason	Equipment Code	Outage minutes
	2B-132	63
	2B-132	33
	2B-132	66
	FQ-513	77
	2D-175	102
	4D-72	132
	4F-106	311
	2D-124	45
	AP-536	27
	2B-136	124
	AR-512	385
	AT-523	231
	AT-523	189
	2B-137	150
	2D-115	220
	2D-116	752
	2D-115	288
	2D-115	303
	2D-115	72
	2D-115	110
	2D-124	159
	BAT-511	103
	AT-523	550
	2D-123	57
	2D-123	12
	2B-135	52
	2B-135	148
	2B-135	93
	2B-135	267
	2B-136	17
	AP-533	377
	2D-123	170
	2D-123	114

Reason	Equipment Code	Outage minutes
	4F-7	389
	2D-118	162
	2D-117	15
	2D-117	110
	2D-123	393
	2D-123	95
	BC-511	108
	2D-12	112
	2D-131	260
	2D-124	82
	2D-128	284
	2D-128	48
	2D-128	159
	3C-225	244
	3C-226	115
	2B-134	103
	2B-134	92
	2D-106	45
	2B-133	142
	2B-133	85
	3C-226	60
	3C-226	71
	2D-132	394
	2D-132	44
	3C-229	131
	2B-134	218
	2B-134	84
	3C-121	11
	2D-114	180
	BC-511	113
	BC-512	63
	2B-137	785
	2B-135	87

Reason	Equipment Code	Outage minutes
	3C-20	65
	2D-114	60
	2B-137	127
	2B-134	21
	2B-134	56
	2B-134	101
	BF-503	114
	BF-504	145
	2D-128	84
	4E-51	355
	2B-135	58
	2B-119	24
	SHN-511	322
	2D-276	93
	SHN-512	38
	3C-112	407
	2B-119	26
	2B-119	230
	2B-120	111
	2B-119	26
	2B-119	110
	4D-102	89
	4D-102	937
	3C-419	62
	2C-124	10
	3C-43	128
	4D-102	271
	3C-417	109
	4D-108	49
	2B-139	53
	2D-274	78
	3C-113	24
	3C-404	52

Reason	Equipment Code	Outage minutes
	4D-113	67
	RE-504	170
	3C-112	231
	2B-119	67
	3C-417	141
	4D-108	84
	4D-108	193
	4D-108	192
	2B-142	56
	2D-274	915
	2C-129	206
	3C-45	117
	2B-120	45
	2B-118	88
	4D-102	171
	2B-119	38
	4C-91	346
	2B-119	16
	2B-119	115
	2D-400	85
	4C-96	72
	2D-400	168
	SHN-514	339
	2D-400	89
	2B-118	194
	2B-118	66
	SHN-523	70
	ST-511	265
	2B-118	480
	2B-118	61
	2D-400	87
	2C-122	129
	PN-512	1791

Reason	Equipment Code	Outage minutes
	4C-99	59
	2C-124	111
	2C-123	142
	2B-144	108
	2C-123	279
	4C-95	360
	SHN-514	168
	4D-102	140
	2B-119	142
	2D-305	175
	2D-305	412
	3C-451	81
	3C-108	72
	2C-121	62
	2B-119	198
	SHN-512	92
	4D-285	180
	2C-218	33
	2D-223	83
	2D-224	881
	MJS-552	417
	2D-224	1020
	2C-200	364
	2B-120	47
	4D-285	567
	MJA-542	1335
	2D-224	1115
	2C-200	115
	3C-31	135
	2B-127	119
	2B-126	70
	2B-125	40
	4D-285	89

Reason	Equipment Code	Outage minutes
	2D-220	98
	4D-41	233
	2B-14	1178
	MF-505	160
	2C-303	101
	MF-505	323
	2C-27	115
	4D-40	110
	4D-401	467
	MJN-511	1420
	4D-401	579
	2C-25	72
	4D-401	73
	MF-509	218
	2B-140	248
	2D-222	270
	2D-230	1117
	2D-220	77
	2B-121	125
	2B-125	231
	2B-123	190
	2B-121	55
	2B-121	998
	2B-121	511
	3C-36	224
	3C-115	61
	PH-576	120
	2D-259	84
	2B-121	123
	PKR-598	69
	2B-142	355
	2B-120	63
	4D-113	149

Reason	Equipment Code	Outage minutes
	4D-113	265
	2B-142	180
	4D-121	187
	2D-239	148
	2B-144	253
	4D-211	345
	2B-123	811
	2B-123	827
	3C-324	97
	MP-505	57
	3C-115	102
	4D-200	78
	2B-124	91
	2D-243	91
	2B-123	317
	2B-123	181
	2B-123	104
	2B-123	48
	2B-123	504
	3C-35	80
	MP-505	88
	2B-289	352
	2B-430	73
	1F-87	152
	1E-105	1723
	3A-10	70
	1E-105	65
	3B-144	123
	4B-113	199
	1E-123	2082
	2B-280	138
	1E-123	399
	2B-227	74

Reason	Equipment Code	Outage minutes
	2B-225	80
	1E-123	151
	3B-143	80
	4B-110	61
	2B-225	58
	1E-123	192
	2J-1	312
	3B-15	1199
	3E-17	63
	4B-115	252
	4B-115	114
	3B-146	140
	3B-146	62
	1E-104	33
	2J-1	194
	1F-72	496
	2L-2	279
	3B-146	69
	4B-115	63
	3B-146	77
	2B-230	65
	4B-113	251
	4B-113	343
	2B-230	80
	2B-110	76
	2B-110	168
	4A-95	119
	4A-89	67
	1F-40	310
	3E-36	164
	4A-8	221
	1E-124	204
	2B-110	132

Reason	Equipment Code	Outage minutes
	2B-163	212
	2B-207	67
	2B-207	336
	2B-163	60
	1E-131	61
	2B-205	86
	3B-120	164
	1E-133	116
	2B-110	41
	1E-13	1200
	4B-115	308
	2B-224	53
	1F-72	123
	1F-72	1690
	4B-104	996
	1F-72	819
	4B-102	390
	2B-111	83
	1F-72	131
	1F-37	157
	1F-72	122
	1E-131	725
	3A-111	130
	2B-111	404
	1F-31	102
	2B-213	151
	4B-110	56
	1F-72	100
	4B-123	43
	1D-295	55
	4B-14	184
	4B-14	159
	2B-298	142

Reason	Equipment Code	Outage minutes
	2B-298	201
	1I-3	191
	4B-118	962
	4B-124	176
	2B-25	40
	1H-5	59
	4B-118	97
	1D-36	148
	4B-118	1226
	4B-118	1072
	4B-118	1012
	2B-258	186
	1H-8	21
	2B-101	55
	1D-20	72
	3B-221	85
	4B-218	74
	1D-204	147
	2B-304	24
	2B-240	59
	2B-242	48
	1D-295	49
	2B-242	210
	4B-15	85
	2B-242	154
	2B-135	100
	2B-242	178
	2F-43	398
	4B-203	274
	4B-203	143
	4B-118	953
	3B-213	32
	4B-116	474

Reason	Equipment Code	Outage minutes
	2H-1	1992
	1D-64	82
	3B-16	53
	1D-65	506
	4B-116	1383
	4B-116	1007
	4B-118	969
	4B-116	696
	2H-1	108
	4B-116	407
	1D-9	297
	4B-116	284
	2B-258	78
	2B-234	794
	4B-115	87
	3A-117	91
	4B-116	975
	4B-118	390
	4B-118	944
	4B-118	899
	4B-118	888
	4B-118	853
	1D-4	157
	4B-118	886
	4B-118	475
	2H-1	248
	4B-118	412
	2H-1	454
	4B-118	1037
	2B-258	103
	1D-42	187
	1D-44	88
	1H-2	51

Reason	Equipment Code	Outage minutes
	1H-1	56
	4B-115	46
	4B-118	452
	2B-109	50
	4A-115	424
	1F-110	112
	2B-178	66
	2B-178	33
	4A-113	69
	3B-105	219
	2B-108	70
	2B-178	72
	2B-193	336
	1F-120	54
	2B-178	71
	3A-38	64
	3A-38	163
	2B-108	243
	4A-112	116
	4A-16	84
	4A-113	86
	2B-176	58
	3B-120	62
	3F-111	101
	2B-176	157
	1E-68	159
	4A-123	74
	2B-194	220
	1E-70	1788
	2B-177	87
	1E-80	392
	3B-109	78
	1E-80	101

Reason	Equipment Code	Outage minutes
	3B-110	24
	3F-114	104
	2B-193	81
	4A-119	75
	2B-193	83
	2B-106	76
	3F-111	133
	1F-221	70
	2B-189	1262
	2B-183	172
	2B-189	173
	1F-209	53
	2B-183	297
	1F-213	134
	2B-108	831
	3H-5	91
	2B-189	224
	3A-79	132
	2B-189	348
	3A-79	82
	3A-79	292
	1F-252	201
	2B-189	177
	2B-187	39
	3A-72	187
	4A-108	80
	4A-111	194
	2B-178	162
	2B-178	105
	2B-193	275
	2B-193	36
	3A-47	171
	4A-108	47

Reason	Equipment Code	Outage minutes
	3B-1	455
	1F-152	109
	1F-17	50
	4A-108	245
	3A-59	584
	3F-4	214
	4A-107	96
	2B-182	600
	2B-191	43
	1E-67	968
	1F-57	79
	1E-15	310
	2B-172	180
	2B-109	42
	2B-109	47
	1E-149	1514
	3A-125	156
	1E-15	1318
	2B-201	338
	4A-4	149
	1E-149	84
	1E-150	215
	1E-150	271
	1E-150	408
	1E-150	978
	1E-155	56
	1E-17	159
	1E-68	317
	1E-15	1954
	4A-44	184
	2A-104	260
	3B-119	47
	4A-55	121

Reason	Equipment Code	Outage minutes
	3E-47	277
	4A-55	229
	1E-143	50
	3E-47	52
	2B-11	557
	2B-201	53
	1E-149	223
	2B-172	48
	3B-118	58
	3B-116	13
	1E-149	119
	4A-42	217
	1E-149	95
	3B-116	152
	1E-143	628
	1E-57	80
	2B-173	229
	2B-174	109
	4A-20	69
	4A-18	97
	4A-17	112
	2B-198	52
	2B-109	122
	1E-57	2124
	1E-29	178
	1E-57	181
	1E-57	284
	2B-195	259
	2B-195	249
	2B-195	231
	2B-195	80
	1E-67	172
	1E-57	15

Reason	Equipment Code	Outage minutes
	1E-23	126
	2B-109	30
	4A-3	94
	2B-201	329
	2B-109	43
	1E-22	211
	3A-132	29
	2B-199	50
	2B-198	80
	3F-1	149
	4A-20	131
	1E-23	1094
	1E-23	1548
	1E-23	2264
	3A-134	272
	3F-109	77
	4A-28	95
	1E-137	491
	3F-1	65
	3D-243	115
	1C-116	896
	1C-116	117
	4B-603	157
	2E-120	88
	3D-24	448
	4B-602	230
	4B-56	891
	3D-24	498
	2B-417	224
	3D-245	24
	4B-56	1367
	4B-56	1290
	4B-56	1215

Reason	Equipment Code	Outage minutes
	4B-56	1213
	4B-56	1093
	2E-118	296
	2B-416	48
	3D-229	267
	3B-40	148
	2E-118	108
	2E-118	260
	2E-118	123
	2B-1	73
	2B-155	88
	2B-418	156
	1C-116	34
	2B-417	99
	2B-417	281
	2B-417	60
	4B-66	75
	2B-417	102
	1C-112	601
	1C-112	654
	2A-78	110
	4B-56	729
	2B-417	285
	2B-405	626
	3D-29	16
	2A-42	491
	2B-406	150
	3B-42	156
	2B-405	153
	4B-44	1180
	4B-56	989
	4B-420	161
	1C-136	75

Reason	Equipment Code	Outage minutes
	2E-19	101
	2B-405	58
	4B-417	113
	2B-405	138
	2B-404	611
	4B-417	142
	2B-305	111
	2E-168	181
	2E-159	140
	1C-120	86
	1C-120	97
	4B-56	494
	1C-120	37
	1C-120	32
	4B-55	230
	4B-55	43
	1C-137	106
	2B-406	211
	4B-47	64
	1C-135	125
	2E-159	108
	2E-159	121
	4B-503	141
	3D-29	1116
	1C-135	99
	4B-79	43
	2A-56	80
	4C-109	182
	1B-151	48
	3D-187	217
	1B-151	46
	4C-110	45
	2B-435	524

Reason	Equipment Code	Outage minutes
	2B-435	162
	4B-95	145
	2B-435	152
	1B-14	154
	4C-108	205
	4C-108	70
	3B-81	47
	4C-103	185
	4B-99	588
	2B-433	60
	1C-103	19
	4C-109	91
	3D-129	35
	2B-103	79
	2B-506	27
	1B-12	82
	2B-506	69
	4C-119	92
	2B-506	60
	2B-506	767
	3D-134	80
	2B-102	56
	1B-143	84
	3D-131	149
	2B-152	32
	2B-501	26
	2B-102	38
	2B-152	1105
	3B-93	169
	2B-432	84
	2E-105	124
	4B-84	281
	1B-87	158

Reason	Equipment Code	Outage minutes
	1D-226	137
	1B-93	24
	2B-187	263
	3D-207	350
	3D-21	113
	4B-97	217
	1C-101	174
	4B-87	1016
	2B-430	139
	2B-101	60
	2B-101	40
	4B-82	166
	2B-43	69
	4B-80	90
	2D-123	159
	1C-101	96
	1B-242	153
	3D-203	142
	1B-233	152
	3B-66	29
	2B-432	247
	1B-237	131
	1B-237	194
	1B-238	143
	2B-101	98
	3D-207	93
	4B-87	889
	2B-101	32
	1B-246	59
	4B-87	1343
	1B-247	48
	4B-87	1088
	4B-87	1054

Reason	Equipment Code	Outage minutes
	2B-40	175
	2B-431	136
	2B-162	37
	2E-78	112
	2B-325	124
	1D-101	101
	1D-102	223
	2A-117	105
	2A-117	14
	2B-314	92
	2B-161	91
	4B-29	76
	4B-27	68
	2B-162	572
	4B-268	72
	1D-104	33
	3B-253	9
	2A-113	82
	4B-39	111
	2B-161	179
	4B-316	287
	2B-404	963
	3D-91	151
	1C-35	214
	1C-35	44
	3E-101	241
	4B-356	77
	1C-38	82
	1C-98	21
	4B-325	239
	3B-258	89
	2A-123	153
	2A-121	44

Reason	Equipment Code	Outage minutes
	1C-73	108
	3B-259	132
	2E-74	176
	4B-29	118
	4B-260	74
	2B-160	59
	2A-110	47
	4B-23	92
	2B-236	97
	2A-110	52
	2F-116	24
	1D-136	69
	2A-110	53
	2B-314	202
	2B-311	222
	2B-236	104
	2B-310	102
	2B-236	116
	1D-2	81
	2B-24	68
	4B-221	142
	4B-221	99
	2B-103	241
	2B-311	211
	1D-114	147
	1D-107	59
	3B-24	150
	4B-252	129
	2B-314	582
	1D-110	84
	1D-110	56
	1D-110	192
	2A-112	63

Reason	Equipment Code	Outage minutes
	2B-313	195
	2B-312	189
	3E-109	68
	2A-112	105
	2B-235	256
	2B-235	56
	2F-109	83
	2B-236	58
	4B-39	130
	2B-314	328
	2A-36	356
	4B-407	529
	1E-106	84
	2B-39	104
	2B-38	70
	2E-287	81
	1E-106	447
	4B-406	82
	2B-36	153
	2E-281	62
	2B-355	2165
	2E-295	88
	4B-407	49
	2A-32	130
	3B-294	105
	3B-294	245
	3D-90	460
	2A-36	125
	2B-40	216
	2B-40	71
	2B-156	110
	3D-43	46
	2A-39	98

Reason	Equipment Code	Outage minutes
	2B-156	81
	2B-156	88
	2E-24	28
	2B-39	32
	3B-33	77
	4B-407	75
	3B-33	79
	3B-33	26
	4B-408	56
	1C-19	77
	3B-294	198
	2B-39	146
	2A-30	145
	2E-26	171
	4B-400	699
	1E-117	122
	1E-119	2180
	3B-288	150
	1E-119	68
	4B-402	67
	4B-402	154
	3D-67	159
	4B-401	16
	2B-344	186
	4B-400	661
	4B-400	117
	4B-400	151
	3B-283	32
	3D-81	187
	3D-81	103
	3D-81	64
	4B-402	62
	1E-116	327

Reason	Equipment Code	Outage minutes
	1E-115	131
	2B-35	176
	1E-116	113
	2A-30	283
	1E-116	449
	1E-116	2302
	1E-116	773
	1E-117	371
	1E-116	556
	1E-117	203
	4B-404	80
	3D-76	76
	2B-344	1606
	1E-117	793
	2B-344	105
	2B-344	78
	2B-305	242
	1E-116	265

Round1 – Consultant Q65:

Please confirm that the last NERC compliance audit was completed in 2009 and provide a high level summary of the Audit. If a more recent audit was preformed, please file the audit findings report, as well as any other NERC Reports regarding reliability or violations received in 2011 and 2012.

Response:

The NERC audit completed in 2009 found SaskPower to have no findings of non - compliance with the NERC standards reviewed. A follow up 2012 audit is scheduled for December of this year will, review a broader grouping of standards which have evolved since that time.

SaskPower

2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

Round1 – Consultant Q66:

Please provide further details of the Saskatchewan Electric Reliability Authority and explain how it will facilitate with compliance of NERC reliability standards (Sustainability Report P. 47).

Response:

SERA as a governance authority objective was approved by the Board of Directors in 2010, however has not been operationalized or resourced. SaskPower intends, following the 2012 NERC / MRO audit, to examine appropriate governance and managed systems options for reliability management in Saskatchewan.

SaskPower

2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

Round1 – Consultant Q67:

Please explain the follow up procedures that can be or are employed to optimize the electric system with respect to Grid Losses monitoring & explain how this reduces line losses.

Response:

For the past several years the Grid Control Centre has been minimizing the grid losses using a Supervisory Control and Date Acquisition (SCADA) tool that monitors voltages at key stations around the system. System studies have verified that closely monitoring and controlling these voltages captures most of the loss reduction on the system. Generally speaking operating the system voltages at the upper limits reduces system losses. To the end of the second quarter of 2012 we have saved approximately 3,654 MWHrs of energy due to losses for an estimated value of $183,000.

SaskPower

2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

Round1 – Consultant Q68(a):

Please describe the relationship between line losses and:
a) transmission line capacity and;
b) length and type of transmission lines.

Response:

Transmission line capacity is the amount of power that the line can handle without permanently damaging the conductor due to heat generated by losses. Transmission line capacities cannot be exceeded as protective devices will sense the overload and open the breakers preventing damage to the conductors.

In Saskatchewan we generally do not have capacity problems related to heat generation as our transmission lines are very long and we end up with low voltages.

In simplistic terms the higher the transmission line capacity the lower the losses. Transmission line capacities can be increased by either larger conductor, or by increasing the operating voltage. For example a 230kV line has less losses than a 138kV line per unit length with equivalent loads.

2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

Round1 – Consultant Q68(b):

Please describe the relationship between line losses and:
a) transmission line capacity and;
b) length and type of transmission lines.

Response:

Transmission line losses increase as the length of line increases. Each transmission line conductor has a resistance per unit length. This resistance per unit length generates losses in that length of line. The more unit lengths you have in the overall transmission line increases losses as each length produces the same amount of line losses. Therefore, a 10km transmission line will produce 10% of the losses that at 100km transmission line of the same type and load.

Transmission lines operating at higher voltages have less losses per unit length than transmission lines operating at lower voltages. Given equivalent loads a 230 kV line will have less losses than a 138 kV line. A 138 kV line will have less losses than a 72 kV line, and so on.

Round1 – Consultant Q69:

Please discuss SaskPower's expectations with respect to future line losses considering new transmission lines to accommodate expected load growth and upgrades of existing transmission infrastructure.

Response:

Line loss is a loss of electric energy due to heating of line wires by the currents that flow through the conductor. The energy lost is due to resistance and inductance of the conductor. As load grows on the system, it is expected that the line losses will increase due to the simple fact that the current flowing in the lines would have increased.

System investments such as transmitting electricity at high voltages, using larger conductors, power factor corrections, constructing parallel electric circuits and installing generation sources close to load centres will reduce the current associated with supplying loads and this inherently reduces system losses. Hence capital investments in the system can result in reducing system losses but losses on the system cannot be eliminated.

When planning and designing the future SaskPower system, line losses are considered/evaluated for investment purposes so the system is optimized. Due to the fact line losses are evaluated and play a role in decision making, the future line losses on the system will be maintained at a reasonable level. The total line losses on the SaskPower system is made up of Transmission (Bulk Electric System – 138 kV to 230 kV), sub-transmission (radial system- 72 kV to 138 kV) and distribution (25 kV and below) components. Due to new transmission lines being constructed the line losses associated with the Bulk Electric system are expected to decrease (both in GWh and as a percent of load supplied). However, losses on sub-transmission and distribution system will have a tendency to increase (in GWh) due to their radial nature even though they may remain relatively constant as a percent of load served. Distribution and sub-transmission losses make up majority of the line losses on the system.

Accounting for all subcategories, the net total impact on the SaskPower system will be incremental increase in actual line losses (measured in GWh), but the overall line losses as a percentage of system load will decrease as system is reinforced.

Round1 – Consultant Q70:

Please discuss when the net metering program was instituted, costs by year and benefits to date to SaskPower, Power produced and unit cost of purchases.

Response:

The Net Metering Program and Net Metering Rebate Program were established in 2007. SaskPower has provided approximately $1.2 million in rebates through the Net Metering Rebate Program. Approximately 3 MW of installed capacity has been assisted through the program. SaskPower purchases the energy at the full retail rate that a customer would pay for their electricity.

Round1 – Consultant Q71:

Please provide an update on the SaskPower's investigations respecting the possibility of nuclear power generation (2012 Strategic Plan P. 33).

Response:

The 40 Year leadership Outlook identifies the need to enable a diversified generation strategy which includes a Clean energy pathways encompassing (among other things) small modular reactors (SMR's) as a baseload generation option. The work examining this option is intended to bring a recommendation forward to Government (technology, regulatory requirements, site options, and business models), for next steps or to exit the strategy.

SaskPower

2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

Round1 – Consultant Q72:

Please provide schedules showing new generation added, retired and/or refurbished for 2010, 2011 and planned for 2012 & 2013. Please also indicate whether the projects were completed on budget, explaining any significant variances.

Response:

New Generation

2010:

Yellowhead Power Station – 141MW – Budget $250M, Actual $193M

This project was planned during a period of booming material prices and high demand for contract labour. During the project an economic slowdown occurred causing prices to drop and contract labour to be readily available. This along with a favourable exchange rate resulted in this project being $57M under budget.

2012 – 2015:

Queen Elizabeth Expansion – 205MW – Ongoing

This project will add 205MW at the Queen Elizabeth Power Station by adding CCGT units. This project is scheduled to be complete in 2015.

Refurbishment

2012-2014:

Boundary Dam Carbon Capture Project – 110MW – Ongoing

The power plant is expected to be in commercial operation on September of 2013 with the start-up and commissioning of the CO_2 capture plant to begin in October of 2013. Full commercial operation of the CO_2 capture plant is expected by the end of Q1 2014. Overall, the project is on time and on budget.

Retirement

2013:

Boundary Dam Unit 1 – 66MW

Retirement is scheduled for 2013.

SaskPower

2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

Round1 – Consultant Q73:

Generation and Purchased Power Volumes schedule on Page 23 of the application forecasts generation volumes. Please provide similar schedule including actual results for 2009, 2010 and 2011 with forecasts for 2012 and 2013. Please also confirm the generation forecasts for 2013 on Hydro reflect median flow conditions.

Response:

Generation and Purchased Power Volumes by Supply Source for 2009 -2013 are in the following table:

Supply Source (in GWh)	Actual			Forecast*	
	2009	2010	2011	2012	2013
SaskPower Gas	627	1,176	1,194	1,640	2,753
Gas (PPA)	2,805	2,507	2,838	3,109	5,033
Coal - Net of Internal Use	12,317	12,038	11,614	11,694	11,867
Imports	440	518	502	652	327
Hydro	2,962	3,866	4,641	4,136	3,321
Environmentally Preferred Power (EPP)	713	655	822	833	877
Other	1	1	1	1	1
Gross Volume Supplied	**19,865**	**20,759**	**21,611**	**22,063**	**24,177**
Less: Line Losses	(1,901)	(1,897)	(1,936)	(1,788)	(1,786)
Total Generation & Purchased Power	**17,964**	**18,862**	**19,675**	**20,275**	**22,391**

***2012 Forecast based on Forecast as of June 30, 2012**
***2013 Forecast based on 2013 Preliminary Business Plan**

The 2013 hydraulic generation forecast is based on median flow conditions. Hydraulic generation forecasts for the next calendar year are unlikely to change from median until the next calendar year. The reason they remain at median is the current year projections are based on returning the reservoirs to median elevation by December 31. This target is almost always attainable due to low inflows in November and December and the increased winter hydraulic generation requirements.

SaskPower

2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

Round1 – Consultant Q74:

Please update the summary of all the information provided in the 2010 response to the IR FFP-76 (2009), using the same format related to the various fuel types utilized by SaskPower.

Response:

The following table contains a breakdown of the fuel source energy for exports in 2011. By fuel type the difference in energy supplied for export and total energy generated would be the energy generated for domestic load (sales and line losses). The Power Production OM&A costs by fuel type have also been broken out by fuel source.

SaskPower 2011

Fuel Source	Energy (GWh)	(%)	Export Supply (GWh)	Domestic Sales & Line Losses(GWh)	Operating & Maintenance Costs in (millions of $)
Coal	11,614	53.7	75	11,539	130.7
Gas	4,032	18.7	354	3,678	25.9
Hydro	4,641	21.5	19	4,622	19.5
Wind	682	3.2		682	7.0
Import	502	2.3		502	
EPP & Other	140	0.6		140	
Total Generation	21,611	100	449	21,162	183.0
Line Losses	1,936			1,936	
Domestic Sales	19,226			19,226	
Exports	449		449		

Round1 – Consultant Q75:

Please provide the estimated and actual unit costs for each fuel type for each year from 2009 to 2011, and forecast unit costs for 2012 and 2013.

Response:

The following table contains the unit costs for 2009, 2010 and 2011 by fuel type and a forecast of the unit costs by fuel type for 2012 and 2013. Unit costs include the variable fuel cost only.

Unit Cost by Supply Source (in $/MWh)	Actual			Forecast*	
	2009	2010	2011	2012	2013
Gas	#77.77	49.86	48.51	41.36	32.98
Coal	15.72	17.63	18.89	19.09	20.43
Imports	57.05	39.21	48.56	44.30	58.47
Hydro	3.88	4.09	4.30	4.37	4.36
Environmentally Preferred Power (EPP)	73.88	76.25	77.78	78.93	80.86
Wind/Other	4.66	4.54	22.26	23.44	25.11

***2012 Forecast based on Forecast as of June 30, 2012**

***2013 Forecast based on 2013 Preliminary Business Plan**

#2009 Gas includes O&M and Capital costs for Gas based PPA. The 2010 change to IFRS accounting standards removed these costs.

Round1 – Consultant Q76:

Please provide a schedule and discuss SaskPower's Take or Pay obligations under its various PPA's, including energy commitments and costs (in aggregate), as well as risks that energy that must be purchased by SaskPower that cannot be fully utilized under favorable weather conditions.

Response:

The information has been provided to the SRRP and their consultant in confidence.

Round1 – Consultant Q77:

Please describe any changes to SaskPower's or NorthPoint's procedure related to procurement of Natural Gas supplies, including Storage gas since 2010.

Response:

In March 2012, SaskPower received Ministry of Finance approval to extend SaskPower's hedging program from 5 years out to a 10-year horizon. The extended program began implementation in April 2012.

Round1 – Consultant Q78:

Please provide a detailed record of SaskPower's natural gas sourced under long term, short term contracts and spot purchases including details of each contract, such as supply terms and deliverability entitlements for each contract, physical volumes and gas from storage. Please indicate the supply basin source (or Province) for all supply contracts.

Response:

Purchases (GJ Millions)				
	Saskatchewan	Alberta	Total	
2011	9.3	15.4	24.7	Actual
2012	6.9	18.8	25.7	Committed
2013	2.4	21.9	24.3	Committed
2014	2.7	18.3	21.0	Committed
2015	0.9	18.3	19.2	Committed
2016	-	15.6	15.6	Committed
2017	-	11.9	11.9	Committed
2018	-	8.2	8.2	Committed
2019	-	6.4	6.4	Committed
2020	-	4.6	4.6	Committed
2021	-	5.5	5.5	Committed
2022	-	1.8	1.8	Committed

SaskPower

2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

Round1 – Consultant Q79:

The MFR included copies of the NorthPoint Risk Management Manual and the Market Risk Management Policies and Procedure Manual. Please describe any changes to the Policies and Procedure Manual since May 21, 2009.

Response:

<u>November 2010 – Updates to the NorthPoint Risk Management Manual</u>

1. Inclusion of natural gas trading and optimization policies and procedures
2. Update NorthPoint organizational structure, committee and position title changes
3. Update references to policies, reports and governance documents, such as the Execution of Documents Resolution
4. Update references to deal capture and energy risk software systems

<u>June 2012 – Updates to the NorthPoint and SaskPower Risk Management Manuals:</u>

1. Amend the Potential Future Credit Exposure formula in Appendix 3 of the NorthPoint and SaskPower Risk Management Manuals to bring SaskPower more in line with current industry standard methodologies.
2. Amend the NorthPoint Risk Management Manual, adding in references to Liquidity Risk, in order to reflect new requirements in the U.S. ISO's (Independent System Operator) credit policies.

Round1 – Consultant Q80:

Please provide a schedule of the actual natural gas volumes used in 2010 and 2011 together with the forecasted volumes required for 2012 and 2013.

Response:

The total gas consumption by natural gas sourced by SaskPower is as follows:

Consumption Volumes by Year (GJ's)		
2010	22,453,966	GJs
2011	24,322,561	GJs
*2012	30,035,756	GJs
**2013	43,614,449	GJs

*Forecast as of June 30, 2012
**Forecast based on 2013 Preliminary Business Plan

SaskPower

2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

Round1 – Consultant Q81:

Please provide a schedule indicating the natural gas hedged actual volumes for 2011 and the 2012 and 2013 natural gas requirements that are hedged, and indicate hedges already in place for future year volumes. Please provide the financial instrument cost-volume breakdown and indicate the overall annual cost of hedged volumes.

Response:

Information has been provided to the SRRP and their consultant on a confidential basis.

SaskPower

2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

Round1 – Consultant Q82:

Please provide an update to the response provided to IR #59 (2010) using the same format.

Response:

The response to 2010 Round 1 – Q59 was as follows:

SaskPower has contracted 6 million GJs of storage capacity. Storage is an operational tool used to secure natural gas supply and meet volatile swings of both daily and peak day demand requirements.

In 2009, storage reached 97% or 5.8 million GJs full. Given the variability of gas-fired generation, care is always taken as not to incur overrun penalties from the pipeline. The peak requirement for natural gas generation is approximately 280,000 GJ per day. SaskPower gas storage as at January 1, 2010 was approximately 4.3 million GJs at a weighted average cost of gas (WACOG) of approximately $4.04/GJ. In 2009, the average monthly AECO price was $3.92/GJ, with the AECO spot price ranging from $1.90/GJ to $7.34/GJ.

The updated response using the same format is:

SaskPower has contracted 6 million GJs of storage capacity. Storage is an operational tool used to secure natural gas supply and meet volatile swings of both daily and peak day demand requirements.

In 2011, storage reached 96% or 5.7 million GJs full. Given the variability of gas-fired generation, care is always taken as not to incur overrun penalties from the pipeline. The peak requirement for natural gas generation is approximately 300,000 GJ per day. SaskPower gas storage as at January 1, 2012 was approximately 4.8 million GJs at a weighted average cost of gas (WACOG) of approximately $4.02/GJ. In 2011, the average monthly AECO price was $3.48/GJ, with the AECO spot price ranging from $2.37/GJ to $4.65/GJ.

Round1 – Consultant Q83:

Please provide schedule showing original estimates for all components of natural gas costs, second quarter estimate revisions, and final costs including the financial impacts on final costs flowing from NorthPoint's and/or SaskPower hedging activities from 2005 to 2011.

Response:

The information has been provided to the SRRP and their consultant.

Round1 – Consultant Q84:

Please provide the detailed schedule(s), similar to those provided by NorthPoint in 2010 for IR # 60 mid-application and subsequent revised forecast gas cost, that resulted in the Application forecasted AECO C natural gas costs of $2.89/GJ.

Response:

This information has been provided to the SRRP and their consultant in confidence.

Round1 – Consultant Q85:

Please discuss the Natural Gas Volume SaskPower purchases from TransGas priced at the TransGas Energy Price Pool (TEP) Price; please provide details of all costs for both source and the amount of imported volume.

Response:

In 2011, purchases at TEP from various counterparties including SaskEnergy were 9,328,300 GJs at a cost of $34,985,117.

Other purchases not at TEP (Imported from Empress and NIT) were 15,399,200 GJs at a cost of $80,489,472. This cost is only the commodity cost and does not include transportation to TEP.

2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

Round1 – Consultant Q86:

Please describe the changes, if any, in SaskPower's relationship to or contracts with NorthPoint related to natural gas procurement and daily management of required load, indicating staffing levels and changes, organization changes, and annual cost to SaskPower.

Response:

There are no natural gas contracts between SaskPower and NorthPoint. All natural gas is contracted in SaskPower's name for SaskPower's use. NorthPoint has 3 full time "SaskPower" staff, one staff member that was shared between Gas Management & Settlements and one staff member that was shared between Gas Management & Energy Trading. The total annual cost for Gas Management to manage all natural gas activities on behalf of SaskPower is approximately $700,000.

SaskPower

2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

Round1 – Consultant Q87:

Please discuss whether NorthPoint conducted any natural gas trading activity in addition to those conducted on behalf of SaskPower. If yes, please provide the financial impacts of these on NorthPoint and SaskPower.

Response:

No. Please refer to Q86. NorthPoint does all natural gas business in SaskPower's name for SaskPower's use.

SaskPower

2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

Round1 – Consultant Q88:

Please update the schedule providing the volumes of natural gas actually used compared to forecast volumes for the years 2008 through to 2011 and provide additional explanations, as necessary, for the significant variances in volumes year over year.

Response:

Note: Natural Gas is typically the marginal fuel. Thus any change in budgeted load or other fuel availability will affect natural gas generation greater than the overall impact on generation.

	Forecasted Natural Gas Consumption (GJs)	Actual Natural Gas Consumption (GJs)	Variance Natural Gas Consumption (GJs)	Explanation of Variance
2008	26,696,426	21,744,724	(4,951,702)	Electricity demand was 5% below provincial energy budget and above median hydro availability
2009	24,390,362	17,167,693	(7,222,669)	Actual provincial energy demand 10% below budget
2010	24,838,760	22,453,966	(2,384,794)	Above anticipated hydro availability
2011	30,971,131	24,322,561	(6,648,570)	Above anticipated hydro availability

Round1 – Consultant Q89:

Please re-file the document(s) filed with the Panel flowing from the Review of the Gas Supply function (Application Tab 6 - point 6).

Response:

This document will be hand-delivered as per CIC direction. It is confidential.

Round1 – Consultant Q90:

Please update SaskPower's coal supply contracts (or supply arrangements) since 2010 filing, including volumes supplied, average heat values, locations of sources, and unit costs.

Response:

The information has been provided to the SRRP and their consultant in confidence.

Round1 – Consultant Q91:

Please provide an updated schedule indicating the total coal royalties paid or forecasted to be paid in the years 2010 to 2013 as applicable.

Response:

The following table contains the coal royalties paid or forecasted to be paid in the years 2010 to 2013:

Year	Coal Royalties ($ million)
2010	$22.9
2011	$22.4
2012	$25.3
2013	$26.2

2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

Round1 – Consultant Q92:

Please discuss whether SaskPower has conducted any further analyses regarding the use of importing a higher grade coal for use in its generation.

Response:

Minimal additional analyses has been done regarding the use of higher grade imported coal for generation. This is due to the economics offered by the mine mouth operations that currently supply coal to the power stations and the relatively short term nature of the coal contracts that SaskPower is currently pursuing due to regulatory uncertainty, particularly regarding greenhouse gas emissions.

Round1 – Consultant Q93:

Please update the schedule showing the actual and forecasted water rental fees imposed by Saskatchewan Watershed Authority for 2010, 2011 and forecasted for 2012 and 2013.

Response:

The following table contains the water rental fee rate paid or forecasted to be paid in the years 2010 to 2013:

Year	Water Rental Fee ($/MWh)
2010	4.07430
2011	4.27802
2012	4.47053
2013	4.69406

SaskPower

2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

Round1 – Consultant Q94:

Please provide the actual total GWh hydraulic generation produced in 2009, 2010, 2011 and forecasted for 2012 detailing the specific flow conditions for each year.

Response:

Year	Hydraulic Generation (GWh)
2009	2,926
2010	3,866
2011	4,641
*2012	4,136

* Forecast as of June 30, 2012.

Saskatchewan River Basin:
In 2009 below average snowfall and summer precipitation resulted in below normal flows on both the North and South Saskatchewan rivers. This resulted in below median hydraulic generation at Coteau Creek, Nipawin and E.B. Campbell. 2010, 2011 and 2012 have been highly influenced by strong rains in the Saskatchewan River headwaters (Alberta Foothills) during the late spring and early summer. The result was a full supply of water at Lake Diefenbaker and spilled water and correspondingly above median generation all three years from Coteau Creek, Nipawin and E.B. Campbell. 2011 generation from these three plants contributed to an overall record hydraulic generation year.

Churchill River Basin:
In 2009 the flow conditions were above median due to carry over impacts from well above normal precipitation in 2008 and heavy rains in the summer of 2009. In 2010 and 2011there was below median flow on the Churchill River system. 2012 Churchill River flows to date have been above median.

Athabasca:
Hydrological information in the Athabasca region is very limited. Tazin Lake is the primary water supply source for these plants. Water levels on Tazin Lake have been up and down from median in all years. Current levels are slightly above median. Water was diverted as required for the Athabasca plants. Hydraulic generation was above median in 2009 and has been below median in 2010, 2011 and 2012 to date.

Round1 – Consultant Q95:

Please update the schedule showing 2010 -2013 year records for actual and forecasted export/import quantities and revenues/costs.

Response:

Exports:

The following table contains actual export revenue and actual export energy for 2010 and 2011 and forecasted export revenue and forecasted export energy for 2012 and 2013:

Year	Revenue (Millions of $)	Energy (GWh)
2010	12	244
2011	40	449
*2012	24	357
**2013	22	312

* 2012 Forecast as of June 30, 2012
** 2013 Forecast based on 2013 Preliminary Business Plan

Imports:

The following table contains actual import costs and actual import energy for 2010 and 2011 and forecasted import costs and forecasted import energy for 2012 and 2013:

Year	Costs (Millions of $)	Energy (GWh)
2010	20	518
2011	24	502
*2012	29	652
**2013	19	327

* 2012 Forecast as of June 30, 2012
** 2013 Forecast based on 2013 Preliminary Business Plan

Round1 – Consultant Q96:

Please discuss whether SaskPower's Generation Planning and future resource planning focus is on Saskatchewan's supply requirements and continues to specifically exclude provisions for export power.

Response:

SaskPower's short-term supply plan is based on serving Saskatchewan load. SaskPower will pursue export opportunities as they arise but no additional supply is specifically for export purposes.

The assumption used in developing the 40 Year Outlook was that SaskPower would continue to focus on domestic supply only and, although import opportunities would be explored, it is assumed that Saskatchewan would be self-reliant for electricity production through a combination of SaskPower owned and private sector owned generation.

Round1 – Consultant Q97:

Please define “under normal system conditions” specified on page 6 of the Application?

Response:

Normal system conditions would include expected load by switching station, expected generation by generating facility, expected transmission availability (no transmission outages).

SaskPower

2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

Round1 – Consultant Q98:

Please advise of the specific quality standards for parties utilizing the Open Access Transmission Tariff.

Response:

To receive transmission services from SaskPower, prospective transmission customers must provide evidence of creditworthiness based on SaskPower's credit review procedures. Based on the completed application, SaskPower will determine the eligibility of the applicant to receive transmission services from the Company.

Transmission Services ensures that the customer requesting transmission service meets the credit risk criteria set out by the corporation. A customer's credit risk check is done in collaboration with the BA&RM (Business Analysis and Risk Management) Department which is a part of Finance and Enterprise Risk Management.

When the customer first completes an "Application for Eligible Customer Form" BA&RM is notified. BA&RM establishes the amount of monthly and total credit available to the customer through the analysis of the company's financial situation. If the customer is approved for credit, the customer becomes an "eligible customer" and can execute an Umbrella Agreement for short-term firm or non-firm, or long-term firm transmission service depending on their request on the original application for eligible customer. Within the Umbrella Agreement, SaskPower retains the right to adjust a customer's credit limit to minimize credit risk.

<u>From our Sept 1/2011 OATT</u>

"Point-To-Point Transmission Service shall be provided by the Transmission Provider only if the following conditions are satisfied by the Transmission Customer:
(i) The Transmission Customer has pending a Completed Application for service;
(ii) The Transmission Customer meets the creditworthiness criteria set forth in Section 11;
(iii) The Transmission Customer will have arrangements in place for any other transmission service necessary to effect the delivery from the generating source to the Transmission Provider prior to the time service under Part II of the Tariff commences;
(iv) The Transmission Customer agrees to pay for any facilities constructed and chargeable to such Transmission Customer under Part II of the Tariff, whether or not the Transmission Customer takes service for the full term of its reservation; and
(v) The Transmission Customer has executed a Point-To-Point Service Agreement.

17.3 Deposit:

A Completed Application for Firm Point-To-Point Transmission Service also shall include a deposit of either one (1) month's charge for Reserved Capacity or the full charge for Reserved Capacity for service requests of less than one (1) month”

Round1 – Consultant Q99:

Please document any changes to the wind capacity factors or the Saskatchewan wind generation system planning since 2009.

Response:

Saskatchewan wind capacity factors have remained consistent since 2009 with small annual fluctuations.

Since 2009, one new wind power project has been added to the SaskPower electric system. Specifically, the 26 MW Red Lily Wind Power Project was added in 2011.

SaskPower

2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

Round1 – Consultant Q100:

Please provide a schedule showing monthly generation in GWh and wind capacity factors for the related wind facilities for 2010, 2011 and projections for 2012.

Response:

The information has been provided to the SRRP and their consultant in confidence.

Round1 – Consultant Q101:

Please discuss the maximum wind generation capacity that can be incorporated into SaskPower's grid and still be of overall benefit to the system, recognizing the need for supply backup, operational restrictions due to cold weather and any other operational constraints.

Response:

In 2009, SaskPower, through the Wind Power Integration and Development Unit, concluded that an additional 200 MW of wind could be added to SaskPower's system and with manageable operational impacts and costs. As a result, SaskPower has entered into a Power Purchase Agreement with Algonquin Power for the 175 MW Chaplin Wind Power Project. This project was selected through a public Request for Proposals process and is expected to go into service in 2017. SaskPower also selected an additional 55 MW of wind power projects from 7 different projects through its Green Options Partners Program. These projects are at various stages of development.

SaskPower is currently evaluating the implications of adding more wind power and is developing a future wind power strategy. This work is expected to be completed for the spring of 2013.

Round1 – Consultant Q102:

Please describe how SaskPower defines normal weather, and indicate any changes in the definition since 2009.

Response:

SaskPower defines normal weather as the average daily weather conditions as calculated from the most recent 30 year period. We have not changed this definition since 2009.

Please note the 30 year period was specifically addressed in the 2010 review of SaskPower's load forecasting methodology. The consultant recommended SaskPower continue with the 30 year average based on consistency with common industry practice. The weather normalization survey which was done in conjunction with the methodology review showed 47% of respondents use at least 30 years of history from which to compute normal weather.

Round1 – Consultant Q103:

Please provide a copy of the Itron Inc load forecasting methodology submitted in 2010.

Response:

Copy is included.

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SaskPower
Load Forecast Methodology Review

Itron, Inc.
Forecasting and Load Research Solutions
11236 El Camino Real
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October 7, 2010

SaskPower Load Forecast Methodology Review

SaskPower engaged Itron to perform a Load Forecasting Methodology Review. The purpose of this draft report is to summarize the combined findings from the review. The report includes an overall evaluation of SaskPower's current load forecasting process and specific recommendations regarding potential methodological enhancements. While SaskPower's final baseline forecast involves adjustment based on forward looking DSM activity, at the request of SaskPower, the scope of this report focuses on the forecasting process methodologies used to generate the unadjusted forecast. The report is organized into the following five sections.

1. Review and Assess the Current Load Forecasting Method
2. Review of the Main Methodologies implemented by Utilities in the United States and Canada.
3. Evaluation of the Consistency between SaskPower's Current Forecasting Process and Commonly Accepted Methodologies.
4. Summary of Load Forecast Methodology Enhancements
5. Load Forecast Software Packages.

1. Review and Assess the Current Load Forecasting Method

The purpose of this section is to summarize SaskPower's current Load Forecasting process methodologies. The assessment contains discussion of the economic forecast inputs, weather normalization process, class-level forecast methodologies, and the system peak forecast methodology. The focus is on how effectively SaskPower's methodologies address the following core forecasting concepts, which are known to influence electricity consumption levels.

- Weather
- Economic Drivers
- Structural Inputs

1.1. Economic Forecast

The Economic Forecast is a primary input to SaskPower's Load Forecasting models that contribute to drive the forecasted long-term electricity consumptions trends for the service territory. The Economic Forecast is generated internally by the Corporate & Financial Services department. The forecast is generated using the same econometric models used by the Ministry of Finance and the two parties work together to ensure forecast consistency.

The following economic and demographic data sources are leveraged to construct the Economic Forecast:

- Centre for Spatial Economics
- Ministry of Agriculture
- Ministry of Energy & Resources
- Ministry of Finance
- Ministry of Social Services
- Statistics Canada

The Economic Forecast is an input into SaskPower's class-level models, driving the forecasted electric consumption trends for the service territory. The table below presents a list of economic drivers used to generate the load forecast, their raw data source and the class of electric consumption which they drive.

Table 1: Economic Variable Forecast Inputs

Class	Driver	Raw Source
Commercial	Real GDP -- Finance, Insurance, Real Estate	Ministry of Finance
Commercial	Real GDP -- Public Administration	Ministry of Finance
Commercial	Real GDP -- Transportation & Warehousing	Ministry of Finance
Commercial	Real GDP -- Wholesale & Retail Trade	Ministry of Finance
Farm	Agriculture, Forestry, Fishing, and Hunting Forecast	Ministry of Energy Resources
Farm	Farm Households	Ministry of Social Services
Farm	Real GDP -- Agriculture	Ministry of Finance
Farm	Saskatchewan Crop Production Forecast	Ministry of Agriculture
Farm	Saskatchewan Livestock Receipts Forecast	Ministry of Agriculture
Oilfields	Oil Production	Ministry of Energy Resources
Power Accounts	Potash Production	Ministry of Energy Resources
Residential	Apartment Households	Calculated
Residential	Households	Ministry of Energy Resources
Residential	Non-Farm Households	Calculated
Residential	People per Houshold	Calculated
Residential	Population	Statistics Canada
Residential	Single Family Households	Calculated

The proceeding class-level forecast methodology sections of the report discuss the incorporation of the above concepts into the forecast model specifications.

1.2. Weather Normalization Process

The Weather Normalization process is used to determine SaskPower's historical energy requirements and system peak demand given normal weather conditions. The weather normalization process involves the quantification of weather relationships using 12 years of hourly data (1997 to 2008) and leveraging a 30 year average normal weather pattern to determine daily, monthly, and annual weather normalized values for energy requirements and peaks. The calculation of the annual weather normalized values is especially critical for the forecast, because they form the historical series for which the long-term economic and end use-level relationships are estimated.

Weather Normalization Model Specification

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.

Formally,

$$NetEnergy_t = SystemEnergy_t - (IndustrialLoad_t + TransmissionLosses_t)$$

Where,

t indexes the time period of the observation.

The weather normalization models are estimated based on actual weather conditions and also simulated based on a 30-year average of normal weather conditions. The weather adjustment for the specified time period is computed as the difference between the two resulting backcasts. Formally,

$$WeatherAdjustment_t = SimNorm_t - PredAct_t$$

Where,

SimNorm = the Simulated model result using normal weather conditions
PredAct = the Predicted model result using actual weather conditions
t indexes the time period of the observation.

And, the Weather Normalized Energy value is computed as the sum of the Actual Energy consumption and the Weather Adjustment. Formally,

$$WeatherNormalizedEnergy_t = ActualEnergy_t + WeatherAdjustment_t$$

All of the above calculations in this section apply for purposes of calculating the weather normalized energy requirements and peak loads.

Energy Requirement Weather Normalization

The energy requirement weather normalization models estimate Hourly Net Energy as a function of weather variables, calendar conditions, and a time trend. The following variables are used to estimate the weather impacts from these models.

- **HDD18** = HDD with a base of 18
- **HD1** = One day HDD lag
- **HD2** = Two day HDD lag
- **SQHDD** = HDD squared
- **SQHD1** = One day lag of HDD squared
- **SQHD2** = Two day lag of HDD squared
- **WCHILL** = Wind-chill equivalent temperature in Co
- **WCHILL1** = One day lag of wind-chill
- **WCHILL 2**= Two day lag of wind-chill
- **CDD18** = CDD with a base of 18.
- **CD1** = One day CDD lag
- **SQCDD** = CDD squared
- **SQCD1** = One day lag of CDD squared
- **HUMIDITY** = Humidity in %
- **HUMID1** = One day lag of humidity
- **HUMID2** = Two day lag of humidity
- **SQWIND** = Wind Squared

A separate weather impact model is used to estimate each month of the year, estimating a difference weather response slope for each variable in each month of the year and hour of the day.

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

Peak Weather Normalization

The peak weather normalization models estimate daily peaks as a function of weather variables, calendar conditions and a time trend. 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.

1.3. Residential Sales Forecast Methodology

The Residential Sales Forecast is computed as the product of the following forecasts.

- Residential Customers Forecast
- Residential Use per Customer (UPC) Forecast

Formally,

$$ResSalesFcst_t = ResCustFcst_t \times ResUPCFcst_t$$

Residential Customers Forecast

The Residential Customers forecasted growth rates are driven by the Economic Forecast of Non-Farm Households and applying a unit elasticity. To disaggregate the Residential Customers forecast to Single Family and Apartment categories, an Apartment Customers forecast is also generated. The Apartment Customers forecasted growth rates are driven by the Economic Forecast of Apartments and applying a unit elasticity. The Single Family forecast is computed by taking the Residential Customer Forecast less the Apartment forecast.

Residential UPC Forecast

The Residential UPC Forecast employs an end use model, which accounts for the type of household (single family/apartment), end use market conditions, and efficiency standards. The end use model includes saturation and efficiency information for 24 end uses. The end use saturation rates are based on the 2002 SaskPower Residential End Use Survey. The efficiency data are provided by Statistics Canada. The end use model efficiency calculation involves an abbreviated stock accounting model in which the newer vintages of equipment stock slowly replace the older vintages. The pace of equipment replacement is determined based on the appliance lifetime. The Marginal Efficiencies that are input into this algorithm are held flat throughout the forecast period for all end uses.

1.4. Commercial Sales Forecast Methodology

The Commercial Sales Forecast is modeled directly.

Commercial Customers Forecast

In addition to generating a Commercial Sales Forecast, SaskPower also generates a Commercial Customers Forecast, but each forecast is independent from the other.
The Commercial Customers forecast is driven by the Residential Customers Forecast. A regression model is used to estimate the relationship between Commercial Customers and Residential Customers.

Commercial Sales Forecast

The Commercial Sales Forecast is driven largely by a composite index of NAICS-level GDP indicators from the economic forecast that drive the commercial sector's demand. The following NAICS groupings are included in the composite index:

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

A regression model is used to estimate the relationship between Commercial Sales and the composite GDP index.

1.5. Farms Forecast Methodology

The Farm Sales Forecast is segmented into the following two components:

- Farm Households
- Farm Operations

Farm Households Forecast

The Farm Household Customers forecast is driven by the Economic Forecast of Farm Households and applying a unit elasticity. The Farm Household UPC forecast is developed using the same methodology that is used to forecast UPC for the residential class.

Farm Operations Forecast

The Farm Operations Customers forecast is driven by the number of Farm Households. A regression model estimates the relationship between Farm Operations Customers and Farm Households. The Farm Operations UPC forecast is generated using an end use model, which accounts for Farm economic indicators from the Economic Forecast.

1.6. Power Account Forecast Methodology

A Power Account is defined as any large commercial or industrial customer that is currently on a Standard Power rate and/or has negotiated an Energy Service Agreement with SaskPower. The industry sectors represented in the Power Account group include:

- Potash Mining
- Northern Mining

- Pipeline
- Refinery
- Pulp & Paper
- Steel
- Chemical
- Coal Mines
- Universities
- Other (Miscellaneous)

The Power Account forecast is generated through the aggregation of individual forecasts for each Power Account customer.

Individual Forecast Components

The Power Account Individual Customer forecasts are segmented into the following two (2) components.

- **Firm Load Forecast.** The Firm Load Forecast represents the load forecast based on the individual customer's existing facilities.
- **Probable Load Forecast.** The Probable Load Forecast represents the forecast of customer facility expansions or new projects for which the probability of proceeding is less than 100%. The annual sales impact for each probable load component is estimated and assigned a probability of occurrence based on the input from the Customer Account Managers & Customer Development & Support. The Probable Load Forecast is computed as the weighted sum across power account customer expansion projects where each expansion project's probability of occurrence defines the weights. Formally,

$$ProbableLoadFcst_t = \sum_{i}^{EX} ProbableLoadFcst_{i,t} \times ProbabilityofOccurrence_{i,t}$$

Where,

i = an individual facility expansion or new project.

EX = represents the composite of facility expansions or new projects for the selected customer.

t indexes the time period.

The individual customer forecast is then computed as the sum of its Firm Load Forecast and the Probable Load forecast components. Formally,

$$IndividualCustFcst_t = FirmLoadFcst_t + ProbableLoadFcst_t$$

The Power Account Forecast is then computed as the sum of individual customer forecasts across customers. Formally,

$$PowerAccountFcst_t = \sum_{i}^{PA} IndividualCustFcst_{i,t}$$

Where,

i = indexes the individual customers in the Power Account group.

PA = represents the composite of Power Account customers.

t indexes the time period.

Individual Customer Forecast Methodologies

The Individual Power Account Customer forecasts are developed using one of the following three (3) methodologies.

1. **External Customer Forecast.** This method involves the pass through of an Energy Forecasts provided by the customer through consultation with SaskPower's Account Managers.
2. **Economic Driven Forecast.** This method forecasts the customer's sales based on Sector-level Production Estimates and Energy Intensity Levels.
3. **Extrapolation.** This method forecasts sales based on extrapolation of historical sales.

The forecasting method chosen for each individual customer is dependent on the customer's industry and availability of information for that specific customer or industry. All methods begin by generating an annual sales forecast, which is distributed to months based on information contained in the external customer forecast where available or by assuming the same historical monthly maintenance schedule moving forward.

1.7. Oilfields Forecast Methodology

The Oilfield Sector is comprised of the following six regions.

- Lloydminster Heavy
- Kindersley Heavy
- Swift Current Medium
- Estevan Medium
- Kindersley Light
- Estevan Light

The Oilfield Forecast is comprised of the following two supporting forecasts.

- Large Oilfields (21)
- Small Oilfields

Formally,

$$OilFieldFcst_t = LargeOilFieldFcst_t + SmallOilFieldFcst_t$$

Large Oilfields

The Large Oilfield forecast is developed through the aggregation of individual forecasts of the largest 21 oilfields in Saskatchewan. The individual customer forecasts are derived by leveraging historical usage patterns, individual customer forward looking expansion and contraction information (where available), and the appropriate drivers from the Ministry of Energy Resources Oilfield Forecast.

Small Oilfields

The forecast for the smaller oilfields is developed for each of the above regions and is computed as the product of the following two forecast components.

- Number of Customers
- Use per Customer

Formally,

$$SmallOilfieldFcst_{r,t} = SO_{CustFcst\,r,t} \times SO_{UPCFcst_{r,t}}$$

Where,

r indexes the region and,
t indexes the time period of the observation.

The total Small Oilfield forecast is then calculated as the sum of its contributing regional forecasts.

$$SmallOilfieldFcst_t = \sum_{r}^{OR} SmallOilfieldFcst_{i,t}$$

Number of Customers

The Number of Customers is developed using the existing number of operating wells as a benchmark and applying future forecasts of the number of wells drilled from the Economic Forecast. Analogous growth rates are applied across regions.

<u>*Use per Customer*</u>

The forecasted oilfield use per customer involves forecasting oilfield oil and water production and their associated energy intensity. The oil production forecasts are sourced by the Ministry of Energy & Resources forecast. The water production forecast is developed by extrapolating historic water cut trends.

The Oilfield Energy Intensity is defined as the energy input (in KWh) necessary to yield a cubic meter of fluid production (oil & water). A regression model is used to forecast the intensity trend for each region.

The Small Oilfield UPC forecast is computed by region as the product of the associated fluid production and intensity.

1.8. Peak Forecast Methodology

The Peak Forecast applies annual coincident peak load factors to annual sales forecasts for the following customer categories.[1]

- Power Accounts*
- Large Oilfields*
- Small Oilfields
- Commercial
- Residential
- Farm
- Reseller

The forecasted coincident peak factors represent historical average coincident peak load factors. The result is a forecasted coincident peak load for each of the above categories. The category-level coincident peak factors are then aggregated across the classes to compute the System Peak Load Forecast.

2. Identify the Main Methodologies used by Utilities in Canada and the United States for Load Forecasting

The purpose of this section is to identify the main alternative load forecasting methodologies that are commonly implemented by utility companies throughout Canada and the United States.

[1] Coincident Peak factors are calculated and applied at the individual customer level for the classes denoted by an asterisk.

2.1. Survey Resources

This section is sourced by the following survey resources:

- Weather Normalization Survey
- Economics Survey
- SaskPower Survey

Weather Normalization Survey

In January 2008, Itron worked with Hydro One Networks, Inc. (Hydro One) to conduct a weather normalization survey. The purpose of this survey is to provide a summary of the methods used by energy companies to develop normal weather variables and methods used for weather normalizing sales and energy. The survey covered over fifty (50) energy companies in Canada and the United States.

Economics Survey

In the summer of 2010, Itron worked with PJM Interconnection staff to conduct an industry survey to identify the alternative methodologies used to incorporated economic activity into the load forecasting process. The survey covered over one hundred (100) energy companies in Canada and the United States.

SaskPower Survey

To support the SaskPower Load Forecast Methodology Review, Itron interviewed nine (9) of its Energy Forecasting Group members regarding the specifics of their load forecasting process. The following companies participated in the interview process with the Canadian companies denoted by an asterisk:

- American Electric Power
- BC Hydro*
- CPS Energy
- FirstEnergy
- Independent Electricity System Operator (IESO)*
- Minnesota Power
- New Brunswick Power*
- Nova Scotia Power*
- PacifiCorp

The survey questions focus on the following load forecasting concepts:

- Forecast Objectives

- Regulatory Influence
- Meter Read Frequency
- Weather Normalization
- Economic Inputs
- Residential Sales Forecast Methodology
- Commercial Sales Forecast Methodology
- Industrial Sales Forecast Methodology
- Peak Forecast Methodology

The proceeding nine (9) sub-sections summarize the survey findings for each of the above concepts.

2.2. Forecast Objectives

The selection of a load forecast methodology is driven by the forecast outputs required to support company business processes. The purpose of this survey section is to identify the primary forecast outputs required throughout the industry.

This section of the survey included the following questions.

- What is the focal time range of the forecast?
- What are your required primary forecast outputs?

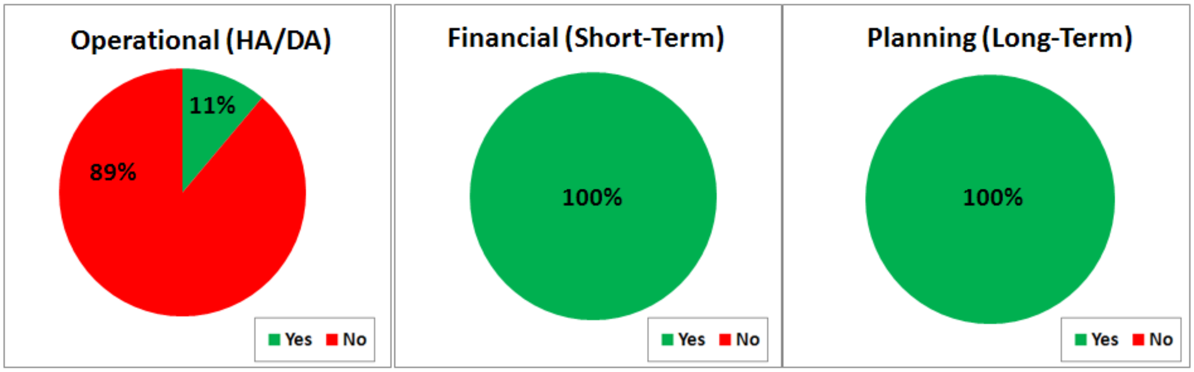
Forecast Type

In general, there are three main types of forecasting, which support different business process decisions and focus on different forecast horizons.

- **Operational (HA/DA).** Operational forecasting supports short-run system operation and is practiced by ISO's and utility system operators as well as generators, traders, and retail suppliers. This type of forecasting is usually high frequency (updates every day or every hour), it uses high frequency system load data (e.g., 5 minute, 15 minute, or hourly), and it has a relatively short focus (the rest of today, tomorrow, the next week).
- **Financial (Short-Term).** Financial forecasting is oriented around short-term budgeting, monthly reporting processes, and rate making. Activity cycles in this area are annual and monthly and the focus is short-medium term with most emphasis on the coming year.
- **Planning (Long-Term).** Planning forecasting involves longer time horizons and supports facility investment decisions, such as generation and transmission system planning and substation planning. This is typically an annual activity and time horizons are long (e.g., 10 to 15 years or more).

The purpose of this question is to assess the type of forecasting for which the survey respondent's department is responsible, as this is certain to influence their underlying forecast methodology. Figure 1 contains the survey results.

Figure 1: Forecast Type and Focal Time Range



The respondent's primary focus is on both Financial (Short-Term) and Planning (Long-Term) Forecasting[2].

Forecast Outputs

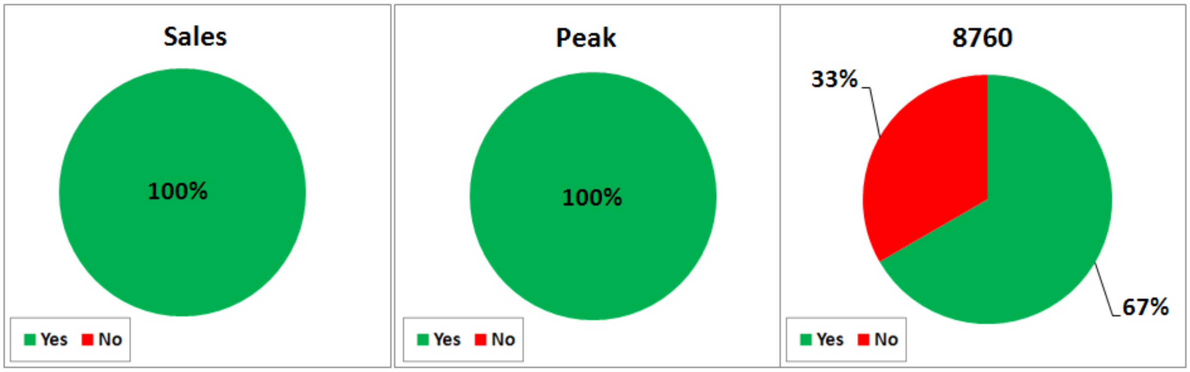
Typically, there are three main forecast outputs required to support financial and planning forecasting.

- Sales
- Peaks
- Hourly Load Shapes

The purpose of this question is to evaluate the forecast outputs required by each participating company, as this determines the load characteristics that they must forecast.

[2] Multiple companies mentioned that their company also generates Operational Forecasts, but that they are developed by another group.

Figure 2: Forecast Outputs



Of participants, 100% responded that their department is responsible for forecasting both sales and peaks and 67% respondents are also required to generate an 8760 hourly load shape forecast.

2.3. Regulatory Influence

The purpose of this survey section is to assess the level of influence that the regulatory bodies have towards determining their energy companies load forecasting methodology.

This section of the survey includes the following questions:

- Does your regulatory body have any input into deciding your load forecasting methodology?

The majority of respondents stated they are required to present their forecast to the regulatory commission and provide an adequate defense. Topics of intervention include the time period used to define normal weather, incorporation of price variables, and significance of regression model coefficients. While the regulatory body often requests that the utility substantiate certain aspects of its forecasting process, they rarely mandate a change to the core forecasting methodology.

2.4. Meter Read Frequency

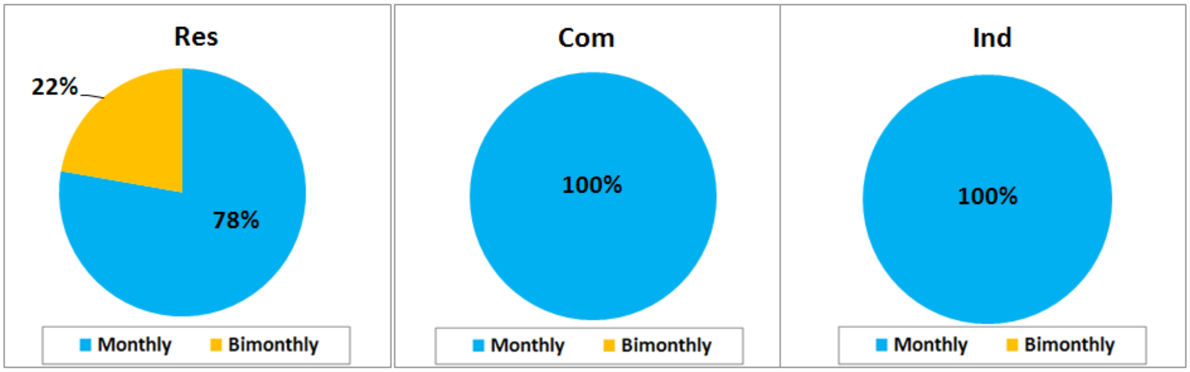
The purpose of this survey section is to identify the common billing data characteristics for the three primary sectors, Residential, Commercial, and Industrial. Of particular interest is the frequency of the meter reads in each sector.

This section of the survey included the following questions.

- How many billing cycles does your company use?
- How often are your meters read for each of the following classes, Residential, Commercial, and Industrial?

Figure 3 displays the frequency of the meter reads for each class.

Figure 3: Meter Read Frequency by Class



It is common industry practice to read the meter once a month. In certain areas where the residential sector covers a remote geography, which is more prevalent in Canada, the meters are read less frequently. The frequency of the meter reads can influence the load forecasting methodology as it determines the frequency of the actual class-level data. The industry standard meter read schedule result in actual monthly billing data. In general, most energy distribution companies model using monthly sales data, as in most cases these data reflects actual meter reads.

2.5. Weather Normalization

The purpose of this survey section is identify the main methodologies used throughout the industry to define normal weather and calculate weather normalized energy and peaks. This section is sourced by the 2008 Weather Normalization Survey Report conducted by Itron on behalf of Hydro One.

The following survey questions are relevant to SaskPower's weather normalization process:

- How many years of data do you use to define normal weather?
- What factors do you use for weather normalizing energy in the winter months?
- What factors do you use for weather normalizing energy in the summer months?
- How often do you update your weather normalization coefficients or models?

Figure 4 through Figure 7 summarize the survey results to the above questions.

Figure 4: How Many Years of Data do you use to Define Normal Weather?

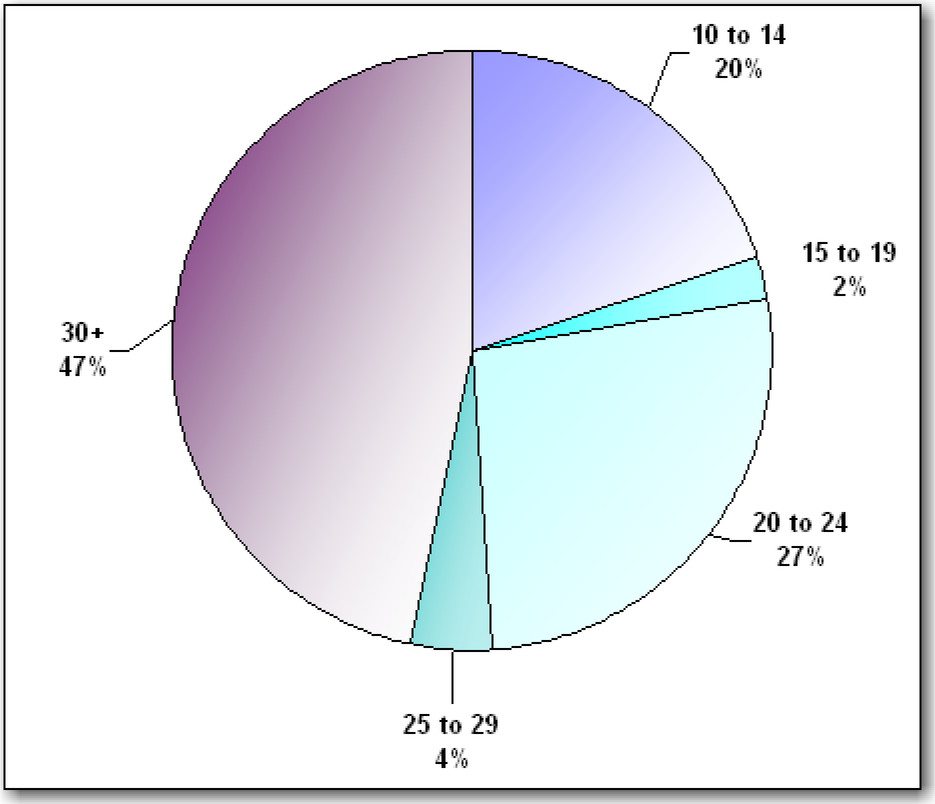


Figure 5: What Factors do you use for Weather Normalizing Energy in the Winter Months?

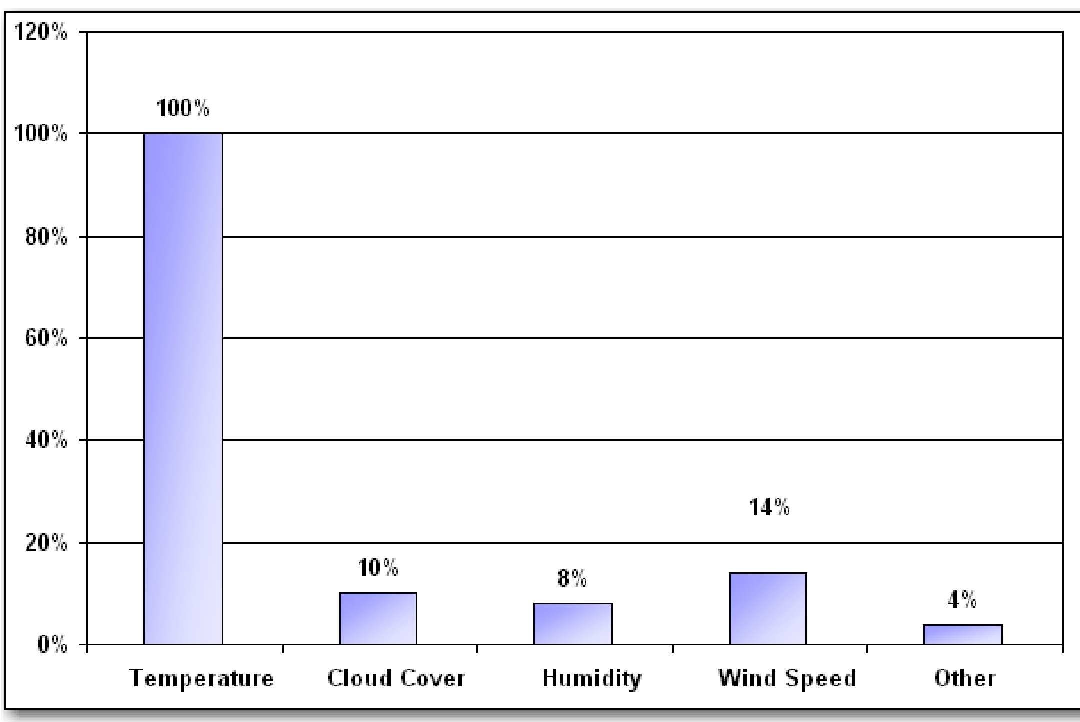


Figure 6: What Factors do you use for Weather Normalizing Energy in the Summer Months?

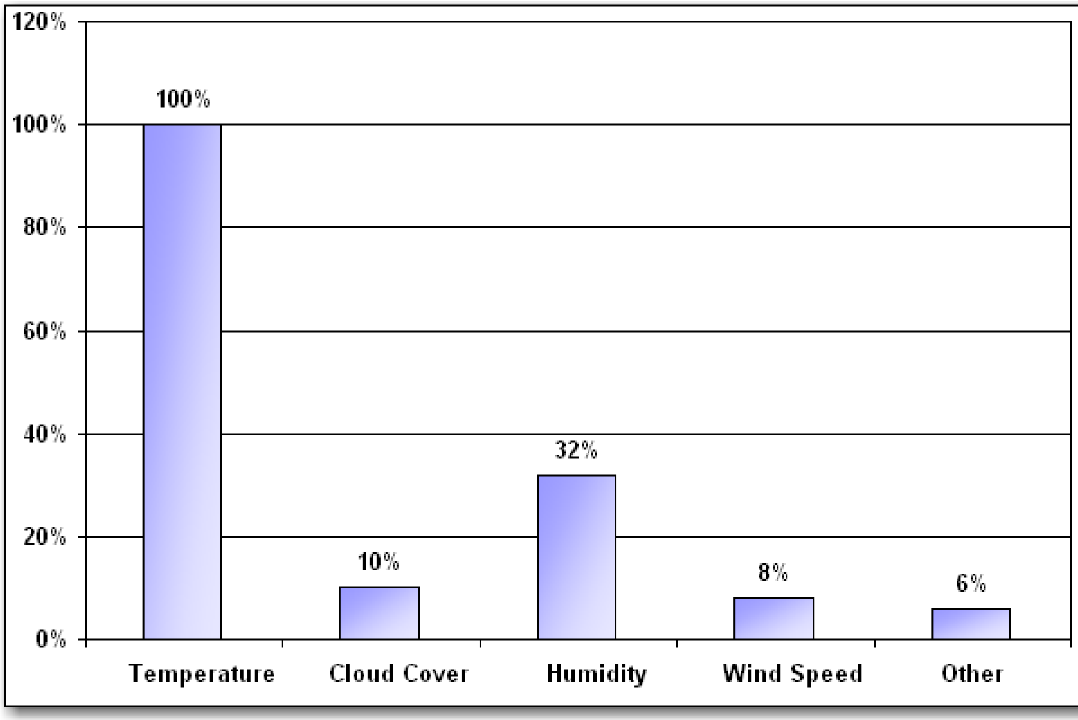
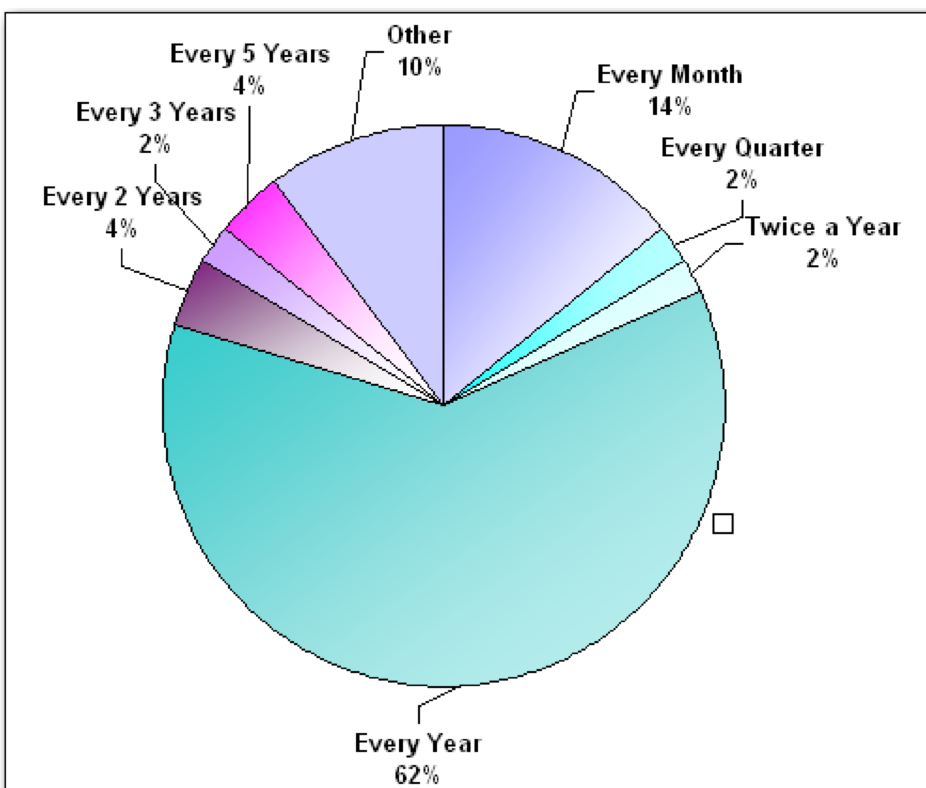


Figure 7: How Often do you Update your Weather Normalization Coefficients or Models?



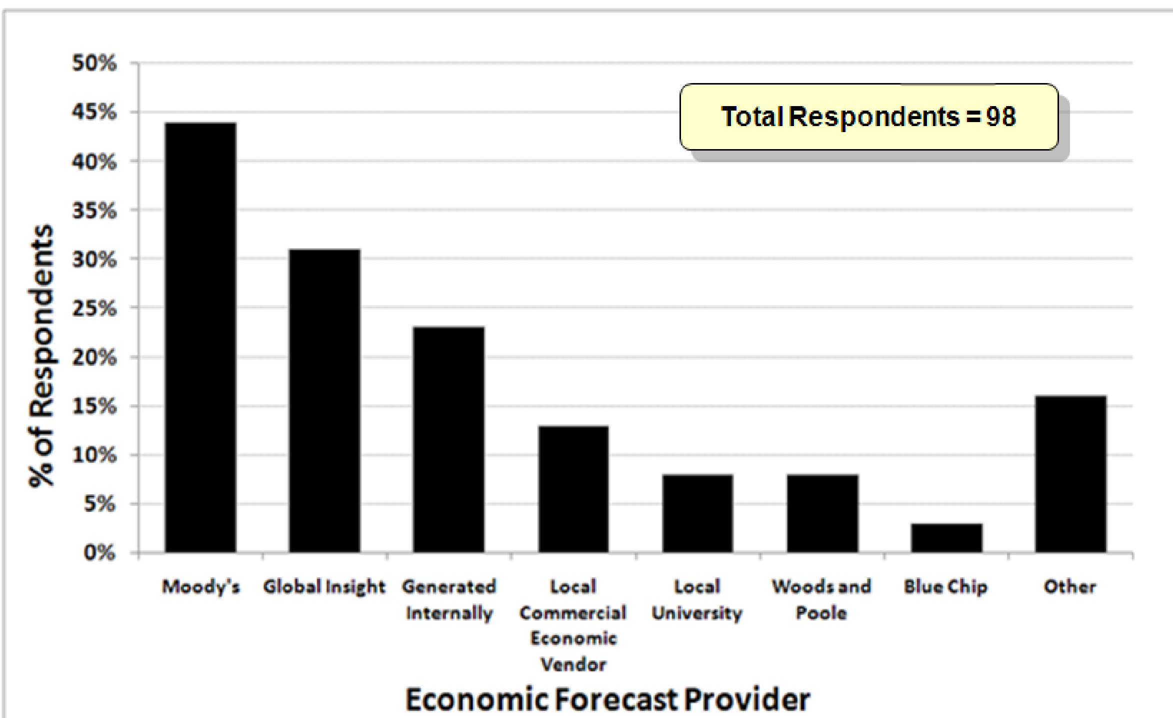
Nearly half (47%) of the respondents use a period of 30 years or more to define normal weather. The weather variables that are commonly used include temperature (CDD and HDD), Cloud Cover, Humidity, and Wind Speed. Humidity tends to be more impactful in the summer months while Wind Speed is more impactful in the winter months. The majority (62%) of respondents update their weather normalization models and corresponding coefficients on an annual basis.

2.6. Economic Inputs

The purpose of this section is to define the economic sources that are commonly used throughout the industry. Discussion of the specific economic measures that drive sector-level consumption patterns is contained in the following report sections. This section is sourced by the Economic Survey, which Itron conducted on behalf of PJM in the summer of 2010.

The Economic survey asked participants to provide the name of their economic forecast provider. The responses are presented in the figure below. The vertical axis represents the industry sourcing percentage, which represents the percentage of respondents sourced by the selected provider. The percentages do not sum to one because a collection of respondents use multiple providers.

Figure 8: Economic Forecast Providers Industry Sourcing %



2.7. Residential Sales Forecast Methodology

The purpose of this section is to identify the common industry methodologies used to develop a Residential Sales Forecast.

Alternative Modeling Methods

There are three primary modeling approaches used to forecast residential sales.

- **Econometric.** A pure econometric approach involves a regression model specification that projects residential sales as a function of weather, prices, seasonality, and economic drivers.
  - **Advantage:** The strength of the econometric model is its ability to capture the factors that drive short-term consumption patterns, such as weather, economics, and prices. The econometric models tend to perform well in the near term forecast horizon (1-3 years out).
  - **Disadvantage:** A pure econometric model does not incorporate structural changes that drive long-term usage trends. Structural changes include changes in the building shell through square footage trends and thermal shell efficiency trends, as well as changes in end use equipment in the form of saturation and efficiency trends. The econometric model does not fit as well over longer-term forecast horizons.
- **End Use.** End use models incorporate appliance-level saturation and efficiency data as well as building shell trends, which are trended out over the forecast horizon. The historical saturation/efficiency indices are refined to align with historical sales and the end use-level trends drive the forecast, which is calculated as the sum of sales across end uses.
  - **Advantage:** The strength of the end use model is its ability to capture the structural changes that drive long-term energy consumption trends. Structural changes include changes in the building shell through square footage trends and thermal shell efficiency trends, as well as changes in end use equipment in the form of saturation and efficiency trends. The end use model incorporates the necessary factors to drive energy usage over long-term forecast horizons.
  - **Disadvantage:** The weakness of a pure end use model is its relative inaccuracy in the short-term. A pure end use model is not calibrated into the historical use per customer data, but rather an aggregation of end use level estimates over time. The end use model does not properly capture the factors driving short-term energy consumption patterns, which include weather, economics, and prices. Also, a pure end use model can be laborious to maintain as it includes a multitude of inputs that must be updated each time a forecast is generated.
- **Statistically Adjusted End Use (SAE).** The SAE Model is a hybrid approach that integrates components from econometric models (weather, prices, seasonality, economics) to capture short-term changes in usage levels, as well as end use model concepts such as end use share and efficiency trends and building shell trends that

represent structural changes which occur over a longer time horizon. The above components are structured into a linear regression model that forecasts both the short and long-term forecast horizons.

Ä **Advantage:** The SAE model blends the best components from the econometric and end use approaches. It properly accounts for weather, economic activity, and prices, which influence short term consumption patterns. It also builds in structural changes for both the building shell and end use equipment, allowing the model to represent the factors driving long-term trends.

Ä **Disadvantage:** The SAE model results in a reasonably complex regression model and requires a statistical software package for a proper evaluation.

Survey Results

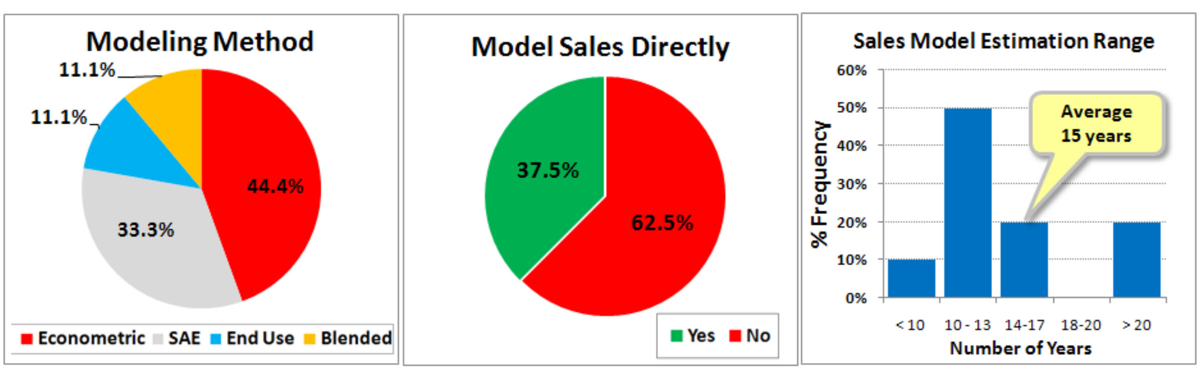
The purpose of the questions in this section is to assess the relative prevalence of each of the above methods throughout the industry, and to identify characteristics of the underlying data and model specification.

This section of the SaskPower survey contains the following questions.

- What modeling method do you currently use to generate your Residential Sales Forecast?
- How many years of data do you use for estimation?
- Do you forecast residential sales directly or forecast Residential Customers and Use per Customer (UPC) separately and compute sales as the product of the two contributing forecasts?
- If you use End Use Inputs, what is the source?

Figure 9 contains the survey results for this section.

Figure 9: Residential Modeling Approaches



The Econometric and SAE modeling approach are the most commonly implemented approaches, at 44% and 33%, respectively. It is worth noting that several of the respondents who use Econometric models either bind in end use-level concepts currently, or are looking to do so in the near future, reflecting the transition from a pure econometric approach to a pseudo SAE approach. The survey consensus is recent and anticipated changes in equipment stock have heightened the emphasis on capturing structural changes in the modeling framework. This is particularly true for the Lighting and Cooling end uses.

The majority of respondents model residential customers and use per customer (UPC) separately and compute the residential sales forecast as the product of the two contributing forecasts (62.5%).

The average estimation range for the Sales or UPC model is 15 years.[3]

Where available, respondents use historical end use saturation surveys to construct their historical share paths. In most cases, the historical share paths are extended into the forecast period using the EIA data provided by Itron via membership to its Energy Forecasting Group (EFG). Respondents most often use the EIA Efficiency data provided by Itron. Multiple Canadian utilities stated that they use the EIA end use efficiency data for the nearest US Region. Statistics Canada was also mentioned as an alternative source of efficiency data.

<u>Residential Economic Drivers</u>

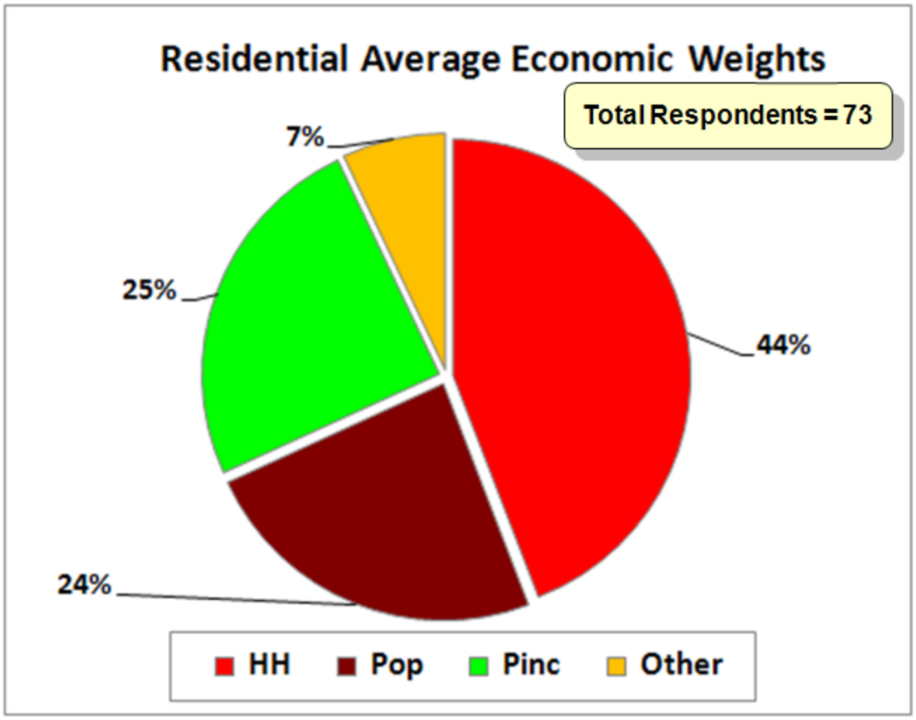
As a part of the economic survey, respondents were asked to:

- Estimate the relative weight of economic drivers on residential sales using weights that sum to 100%?

The figure below presents the results from the survey.

[3] One respondent uses a blended approach to forecast residential sales, which involves a short-term and long-term forecast that contains alternative estimation ranges. This was treated as two separate estimation ranges for purposes of computing the average.

Figure 10: Residential Economic Weights



In the residential class, a survey average weight of 68% is placed on demographic variables, households, and population, while 25% of the weight is placed on real personal income. The Other category represents the residual 7% of the weight.

2.8. Commercial Sales Forecast Methodology

The purpose of this survey section is to identify and evaluate the common industry methodologies used to develop a Commercial Sales Forecast.

Alternative Modeling Methods

Throughout the industry, there are three primary modeling approaches used to forecast commercial sales.

- **Econometric.** A pure econometric approach involves a regression model specification that projects commercial sales as a function of weather, prices, seasonality, and economic drivers.
  - **Advantage:** The strength of the econometric model is its ability to capture the factors that drive short-term consumption patterns, such as weather, economics, and prices. The econometric models tend to perform well in the near term forecast horizon (1-3 years out).
  - **Disadvantage:** A pure econometric model does not incorporate structural changes that drive long-term usage trends. Structural changes include changes in the building shell through square footage trends and thermal shell

efficiency trends, as well as changes in end use equipment in the form of fuel share and intensity (KWh/SqFt) trends.

- **End Use.** End use models incorporate end use-level fuel share and intensity (KWh/SqFt) by commercial building type data. The models also contain indices that account for building shell trends.
  - **Advantage:** The strength of the end use model is its ability to capture the structural changes that drive long-term energy consumption trends. Structural changes include changes in the building shell through square footage trends and thermal shell efficiency trends, as well as changes in end use equipment in the form of fuel share and intensity (KWh/SqFt) trends. The end use model incorporates the necessary factors to drive energy usage over long-term forecast horizons.
  - **Disadvantage:** In the commercial class, the pure end use model can be especially laborious to maintain as it includes a multitude of inputs that must be updated each time a forecast is generated. Commercial customers are spread out across multiple building types, which each contain separate fuel share and efficiency trends. Another disadvantage is relative inaccuracy in the short-term. A pure end use model is not calibrated into the historical use per customer data, but rather an aggregation of end use level estimates over time. The end use model does not properly capture the factors driving short-term energy consumption patterns, which include weather, economics, and prices.
- **Statistically Adjusted End Use (SAE).** The Commercial SAE Model is a hybrid approach that integrates components from econometric models (weather, prices, seasonality, economics) to capture short-term changes in usage levels, as well as commercial end use model concepts such as floorstock trends, and end use fuel shares and intensity trends by building type and end use, reflecting the structural changes which occur over a longer time horizon. The above components are structured into a linear regression model that forecasts both the short and long-term forecast horizons.
  - **Advantage:** The SAE model blends components from the econometric and end use approaches. It properly accounts for weather, economic activity, and prices, which influence short term consumption patterns. It also builds in structural changes for both the building shell and end use equipment, allowing the model to represent the factors driving long-term trends.
  - **Disadvantage:** The SAE model inputs are generally provided by the EIA at the Regional level. Utility service territories may contain a commercial customer portfolio that differs from the region. More specifically, they may contain a different building type mix that drives a different trend trajectory. It is difficult to determine the building type mix within a service territory, and to customize the fuel share and efficiency trends within a building type.

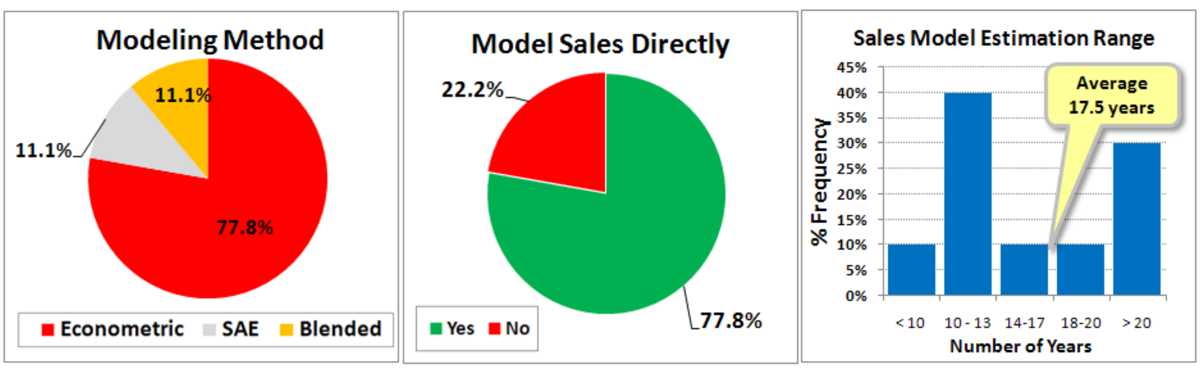
Survey Results

The Commercial Modeling Methods section of the SaskPower survey includes the following questions.

- What modeling method do you currently use to generate your Commercial Sales Forecast?
- How many years of data do you use for estimation?
- Do you forecast Commercial sales directly or forecast Commercial Customers and Use per Customer (UPC) separately and compute sales as the product of the two contributing forecasts?
- If you use End Use Inputs, what is the source?

The purpose of the survey questions in this section is to assess the prevalence of each of the above methods throughout the industry, and to identify characteristics of the model specification and supporting data. Figure 11 contains the survey results for this section.

Figure 11: Commercial Modeling Approaches



In the Commercial sector, the majority of respondents favor an Econometric based modeling approach (77.8%). One respondent uses the SAE modeling approach exclusively and another respondent uses a blend of Econometric models and SAE models to blend the short-term forecast in with the long-term forecast. The respondents who use the SAE models for the commercial sector obtain the supporting data from the EIA via Itron.

The majority of respondents forecast commercial sales directly (77.8%). The average estimation range for the models is 17.5 years.[4]

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4 One respondent uses a blended modeling approach to generate the commercial sales forecast, which involves a short-term and long-term forecast that contains alternative estimation ranges. This was treated as two separate estimation ranges for purposes of computing the average.

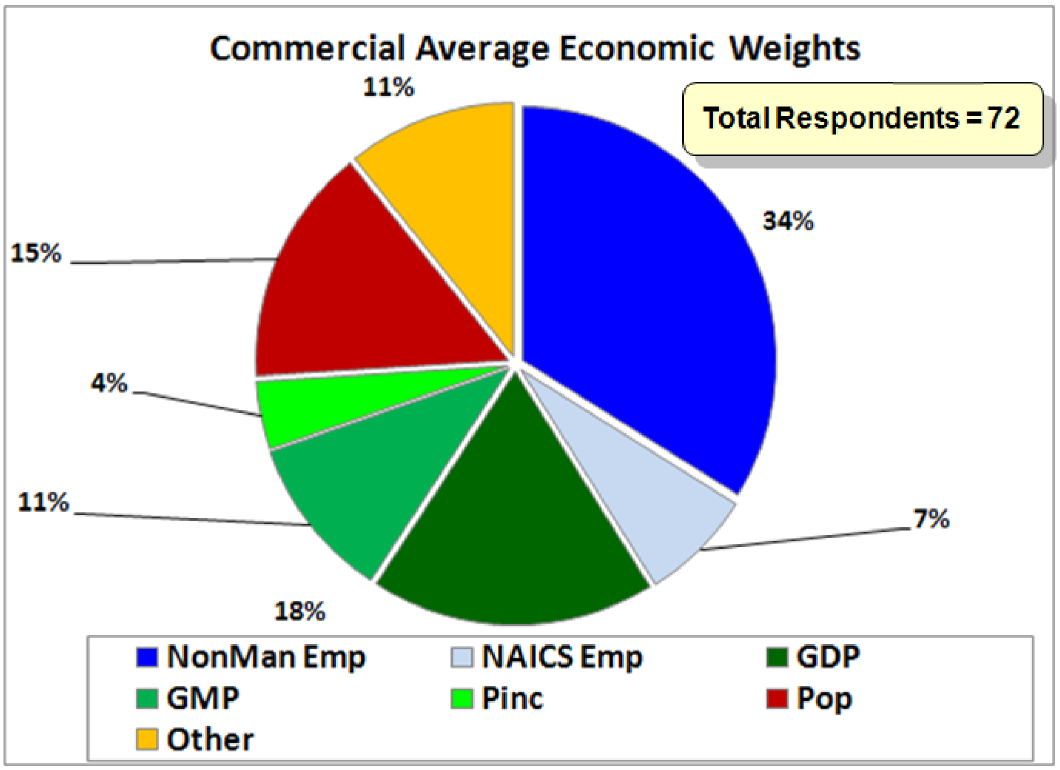
Commercial Economic Drivers

As a part of the economic survey, respondents were asked to:

- Estimate the relative weight of economic drivers on commercial sales using weights that sum to 100%?

The figure below presents the results from the economic survey.

Figure 12: Commercial Economic Weights



Commercial energy consumption levels are driven by employment, financial conditions, and demographics. A survey average weight of 41% is placed on employment variables, 33% is placed on financial variables (gross market product and personal income), and 15% on demographic variables. The Other category represents the residual 11% of the weight.

2.9. Industrial Sales Forecast Methodology

The purpose of this survey section is to identify the common industry methodologies used to develop an Industrial Sales Forecast. The industrial sales forecast methodology section resulted in close to a consensus methodology.

Survey Results

- What modeling method do you currently use to generate your Industrial Sales Forecast?
- Do you forecast Industrial sales directly or forecast Industrial Customers and Use per Customer (UPC) separately and compute sales as the product of the two contributing forecasts?
- Do you forecast the largest industrial customers individually?
- What modeling method do you use to drive the individual customer forecasts.
- Do you survey the large industrial customers regarding their forward looking expansion/contraction activity? If so, how often do you survey them?

The common industry practice is to model the largest industrial customers individually and then model the residual industrial customer grouping using an econometric model. 100% of survey participants use some derivation of the above method as their approach to forecast the industrial sector sales. The residual industrial sales (total industrial sales less large customers) are forecasted directly in all cases and the period used for estimation of this model ranges from 10 to 30 years.

The individual customer forecasts tend to be driven by information provided by Customer Account Managers (CAM), who communicate with the largest customers on a regular basis. In certain cases where there is less frequent interaction between the CAM, surveys are distributed with the frequency of surveys ranging from quarterly to every two years. Several responses mentioned that the individual customer information has been known to be a bit optimistic. The large customers are good about expressing expansion plans and increases in operational levels, but tend to be less communicative when it comes to contraction plans and decreases in operational levels.

In addition to the CAM information, respondents listed production forecasts by industry sector as an alternative resource from which to drive the forecast.

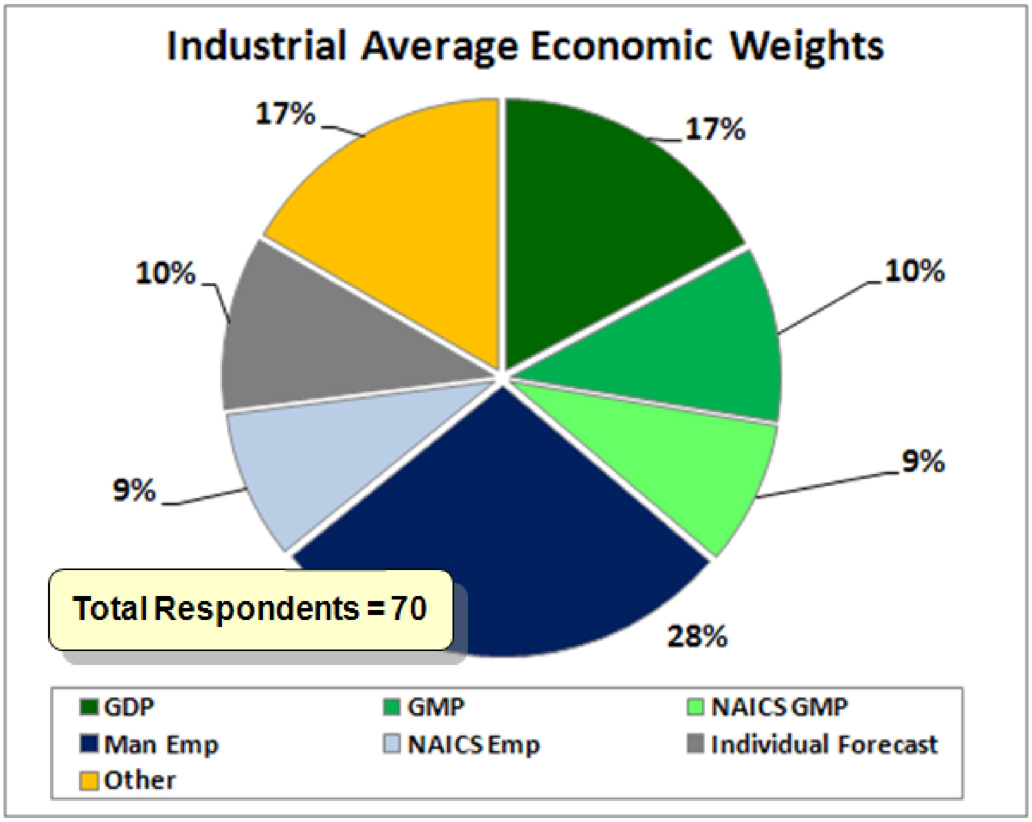
Industrial Economic Drivers

As a part of the economic survey, respondents were asked to:

- Estimate the relative weight of economic drivers on industrial sales using weights that sum to 100%?

The figure below presents the results from the economic survey.

Figure 13: Industrial Economic Weights



In the industrial class, energy consumption levels are driven by financial conditions, employment, and demographics. A survey average weight of 36% is placed on financial variables, 37% is placed on employment variables 10% on individual customer forecasts. The Other category represents the residual 17% of the weight.

2.10. Peak Forecast Methodology

The purpose of this survey section is to identify the common industry methodologies used to develop a System Peak Forecast.

Alternative Modeling Methods

There are three primary modeling approaches used to generate a peak forecast.

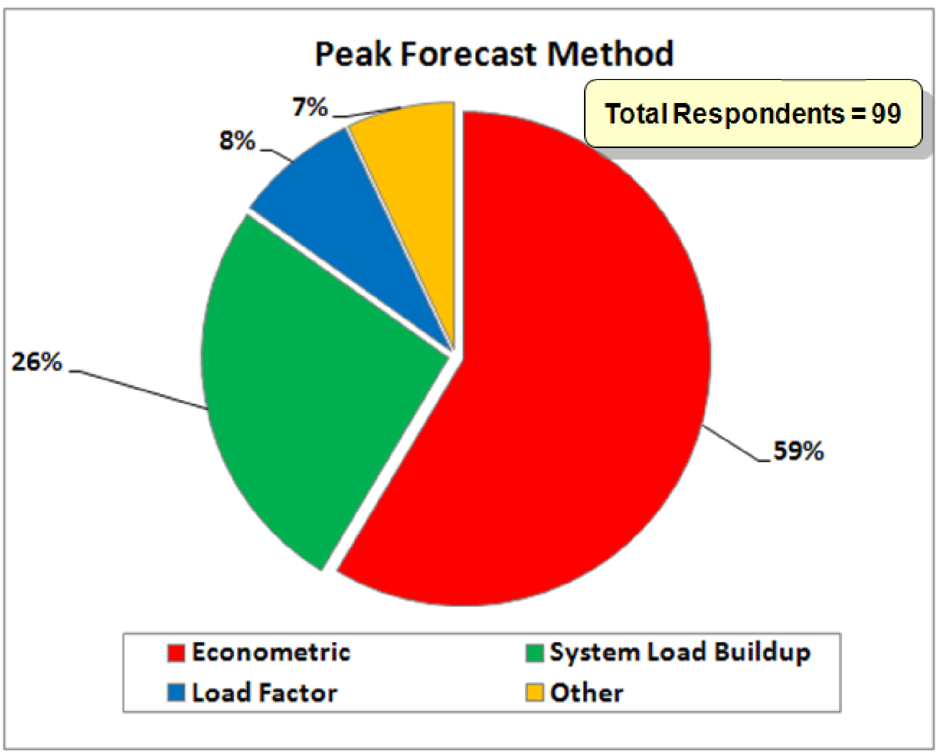
- **Load Factor.** The Load Factor approach involves the calculation of the peak forecast based on forecasted sales and the application of a historical average load factor. Different variations of this approach may apply a system-level load factor or coincident load factors by rate class.
  - **Advantage:** The strength of the load factor approach is simplicity. The peak forecast is computed as the product of the forecasted sales and a historical load factor, which can be effective for service territories with consistent characteristics in the historical and forecast period.
  - **Disadvantage:** The load factor approach fails to account for the underlying structural changes in the heating and cooling equipment stock. If a system level load factor is applied, this approach also does not account for the changing mix of customers across the rate classes which drive load factor changes over time.
- **Econometric.** The Econometric approach involves the construction of a regression model to generate the peak load forecast. The econometric models typically estimate peak loads as a function of seasonality, economic drivers, equipment stock drivers, prices, and peak producing weather conditions. It is also common to use weather normalized sales to drive peak loads, in certain cases the weather normalized sales are segmented into heating, cooling, and base load components.
  - **Advantage:** The strength of the econometric approach is its ability to capture the proper factors that drive short-term peak load levels, such as economics, prices, and weather conditions. If heating and cooling equipment indices are structured in the model, it can also account for the factors that drive long-term peak usage trends.
  - **Disadvantage:** The econometric approach does not account for the changing mix of customers across the rate classes. In a service territory with divergent growth rates across rate classes, this approach will not be able to represent the temporal factors that drive forecasted peak load levels.
- **System Load Buildup Approach.** The System Load Buildup Approach involves two sets of rate class-level inputs, a forecast of sales, and an hourly load shape forecast. The hourly load shape forecast is scaled to agree with the sales forecasts and adjusted upwards to apply losses. This approach captures the temporal interaction of the class-level loads and reflects a dynamic portfolio in which the underlying classes grow at different rates relative to one another and between the historical and forecast period.

- **Advantage:** The strength of the system load buildup approach is its ability to reflect the changing mix of customers across rate classes, driving a bottom-up class-level load shape that accounts for diverging levels of growth across the classes that drive both load factor and temporal changes to the peak load.
- **Disadvantage:** The system load buildup approach is more calculation intensive as it requires and hourly load shape forecast by rate class and proper scaling to agree with forecasted class-level energy target values. The hourly forecasting approach also has the tendency to slightly understate the annual peak forecast. The annual peak observation is an extreme observation that is usually located above the regression line derived using hourly data. Proper adjustment should be considered to account for this concept.

Survey Results

As a part of the Economics survey, participants were asked to describe their peak forecasting modeling approach. The results to this survey question are presented in the figure below.

Figure 14: Peak Forecasting Modeling Approach



The most popular modeling approach is the Econometric Approach followed by the System Load Buildup with response rates of 59% and 26%, respectively.

In addition, the SaskPower survey participants were asked to following questions.

- What modeling method do you currently use to generate your Peak Sales Forecast?
- Do you integrate the results from the sales forecast into the peak forecast?

The survey respondents represented a spectrum of methodologies including all three modeling approaches, Load Factor, Econometric, and System-Level Buildup. The common challenge they describe is to generate a peak forecast that reflects the changing mix in forecasted sales across the rate class, as well as underlying changes in the heating and cooling equipment stock, which results in a dynamic response to peak producing weather over time.

3. Evaluate the Consistency between SaskPower's Current Forecasting Process and Commonly Accepted Methodologies

The purpose of this section is to evaluate the consistency between SaskPower's current forecasting methodologies and commonly accepted methodologies throughout the industry. The comparison includes discussion of the core concepts known to influence electric consumption and also address characteristics unique to SaskPower that may drive methodological differences. The following concepts are discussed in this section.

- Meter Read Frequency
- Weather Normalization
- Economic Inputs
- Residential Sales Forecast Methodology
- Commercial Sales Forecast Methodology
- Farms Sales Forecast Methodology
- Power Accounts Sales Forecast Methodology
- Oilfields Sales Forecast Methodology
- Peak Forecast Methodology

Several of the above section concludes with recommendations for potential methodology enhancements. If no enhancement is specified, the recommendation is to proceed with the existing methodology.

3.1. Meter Read Frequency

The Meter Read Schedule influences the load forecasting process because it determines the frequency of the actual class-level data. SaskPower's residential customers are read relatively less frequently (four times a year) than is typical for energy companies throughout the industry. Based on the SaskPower survey, 78% of respondent companies read their residential customer meters once a month, and the remaining 22% read the meters bimonthly. SaskPower residential meters are read every third month or four times a year. The majority of business class customers are read roughly once a month, which is consistent with common industry practice as 100% of survey respondents read both their commercial and industrial customer s at least once a month.

It is common industry practice to construct the sales forecasting models using monthly billing data. Given the unique characteristic of the SaskPower residential data, modeling with monthly data becomes a less attractive option and a preferred approach involves the estimation of long-term trends using annual data.

3.2. Weather Normalization Process

The influence of the weather normalization process on the SaskPower Load Forecast is twofold. First, the time period used to define normal weather influences the weather pattern that drives the forecast. Second, as the annual class-level sales models use weather normalized energy as the dependent variable, proper weather normalization is required to clarify the historical usage trends assuming normal weather.

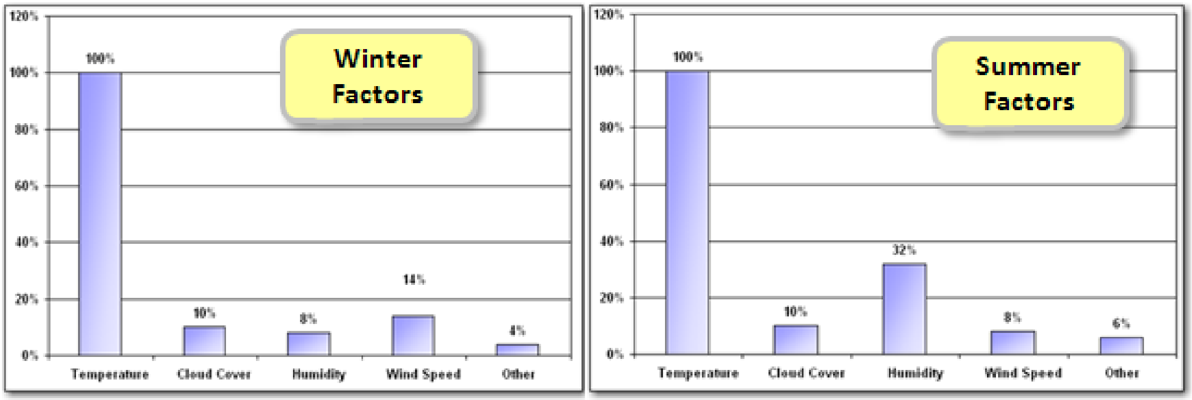
Normal Weather Calculation

SaskPower uses a 30 year time period from which to compute normals. This is consistent with common industry practice. The weather normalization survey results show 47% of respondents use at least 30 years of history from which to compute the normals.

Energy Weather Normalization Models

The SaskPower energy normalization models estimate hourly net energy as a function of weather variables, calendar conditions, and a time trend. A 12 year estimation period (1997-2008) is used to estimate the weather impacts. Separate weather impact models are estimated for each month of the year and hour of the day, resulting in 288 models, which each contain different weather slopes. To capture the heating load impacts, the models contain a composite of HDD, lagged HDD, Wind Chill, and Wind Speed variables. To capture the cooling load impacts, the models include a composite of CDD, lagged CDD, and Humidity variable.

Figure 15: Industry Weather Normalization Factors



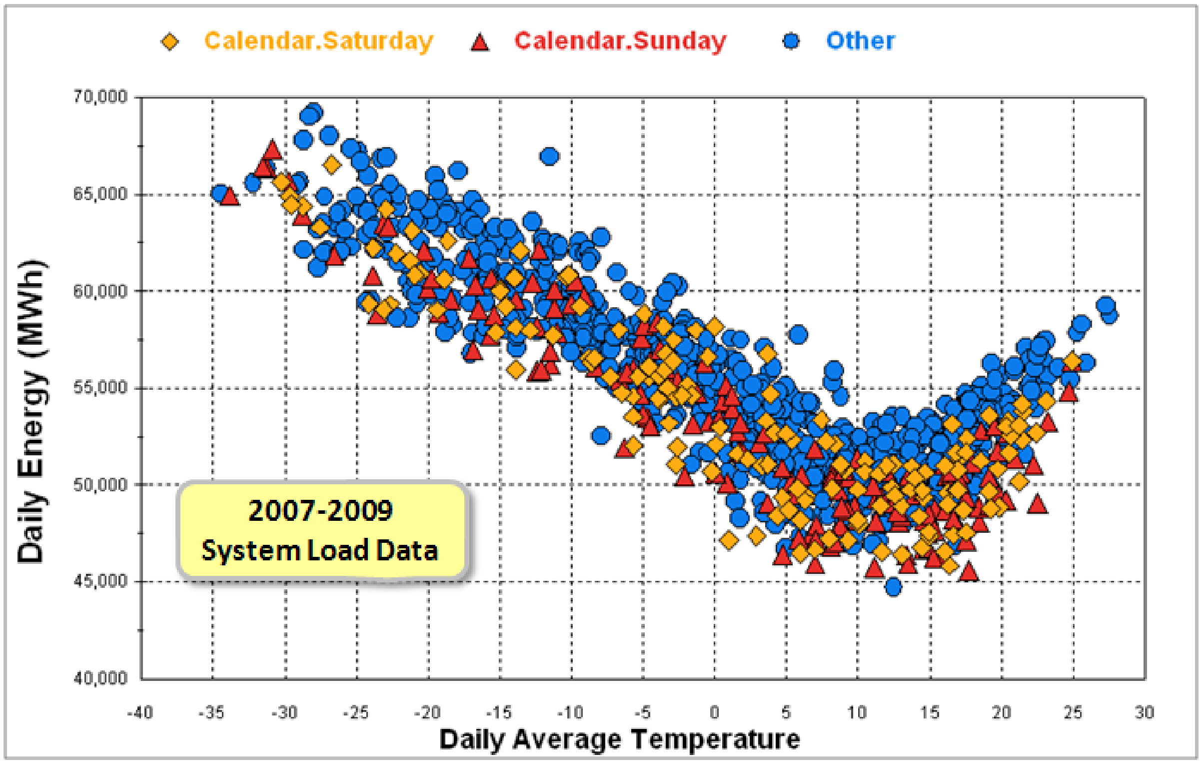
The above figure shows the majority of energy companies use exclusively temperature or temperature related variables (HDD & CDD) to calculate their weather response functions. The most commonly used supplementary variable in the winter is Wind Speed, which can be interacted with temperature to form a single wind chill variable. The most commonly used supplementary variable in the summer is Humidity, which can be interacted with temperature to construct a single THI variable.

SaskPower's weather response functions are located toward the more complex side of the industry spectrum. The combination of an hourly model, relatively complex specification, and implementation of separate models for each month can potentially lead to model instability.

Proposed Energy Normalization Model

Itron's experience suggests that daily models clarify well defined weather relationships. The figure below shows scatter plot of SaskPower Daily System Energy versus Temperature.

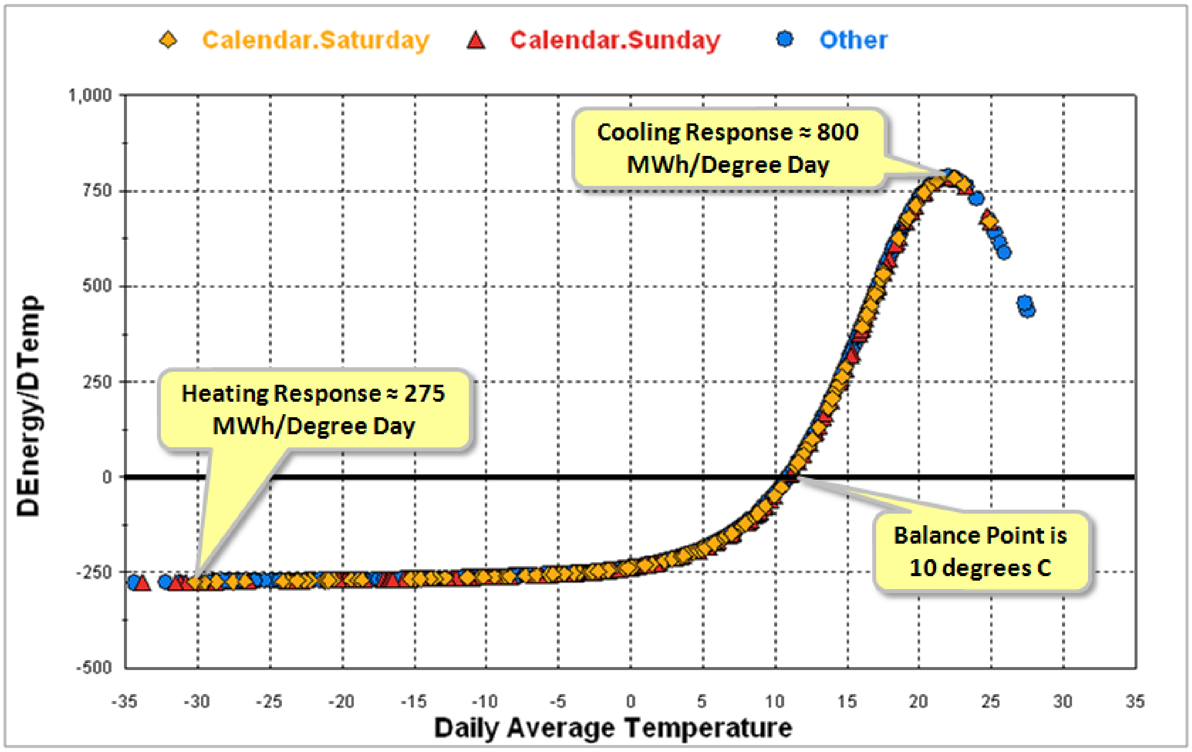
Figure 16: SaskPower Daily System Energy vs. Temperature



Daily Energy is displayed on the vertical axis and Daily Average Temperature (using a 50/50 weight for Saskatoon and Regina) is displayed on the horizontal axis. Each point represents a daily observation and is color coded by daytype. The scatter plot clarifies the weather relationships. To the left hand side of the scatter plot, increases in load are driven largely by heating loads (and increases in lighting). To the right of the balance point, increases in loads are driven largely by cooling loads.

To further clarify the relationship between daily energy and temperature, Itron estimated a daily neural network model using data from 2007-2009. The three year estimation range provides an abundant number of observations (over 1000) for estimating a well-defined daily weather response. The neural network model specification contains three nodes. The first node is linear and contains calendar condition variables in the form of day of the week variables, monthly binaries, and holiday variables. This node accounts for shifts in base load usage levels. The second and third node employ a sigmoid function with one of the nodes designed to capture the heating loads, and the other the cooling loads. The functional form of the weather nodes is nonlinear, enabling the weather slope to change at various temperature levels. The figure below displays the derivative of energy with respect to temperature (DEnergy/DTemp) plotted across temperature levels.

Figure 17: SaskPower Daily System Energy vs. Temperature



The scatter plot is first used to define the balance point, the point where the weather response is zero, for SaskPower System Loads, the balance point is 10 degrees Celsius. To the left of the balance point the absolute value of the vertical axis values represents the heating response per degree at each temperature level. To the right of the balance point, the values represent the cooling response per degree at each temperature levels. The cooling response to a maximum powered cooling degree day is approximately 800 MWh, and the heating response to a maximum powered heating degree day is approximately 275 MWh. Although, heating loads exceed cooling loads on an annual basis, the response per degree is actually stronger for cooling.

While Neural Network models are strong for performing diagnostic tests on the data, regression models are preferred for energy normalization, because they are easier to explain and therefore, easier to defend in a regulatory environment. The objective of the regression model is to define the proper HDD and CDD cutpoints that best approximate the nonlinear response to weather. Itron performed regression analysis using MetrixND to define the proper location for the HDD and CDD cutpoints. Regression models were specified to estimate Daily Energy as a function of calendar conditions and alternative composites of degree day variables. The balance point of 10 degrees Celsius, which was defined using the neural network was used as a starting point for defining the HDD and CDD composite variables. To the left of the balance point, HDD variables are constructed using alternative temperature cutpoints.

To the right of the balance point, CDD variables are constructed using alternative temperature cutpoints.

The following composite of degree-day variables properly captures the weather relationship.

- HDD 10
- CDD 10
- CDD 15

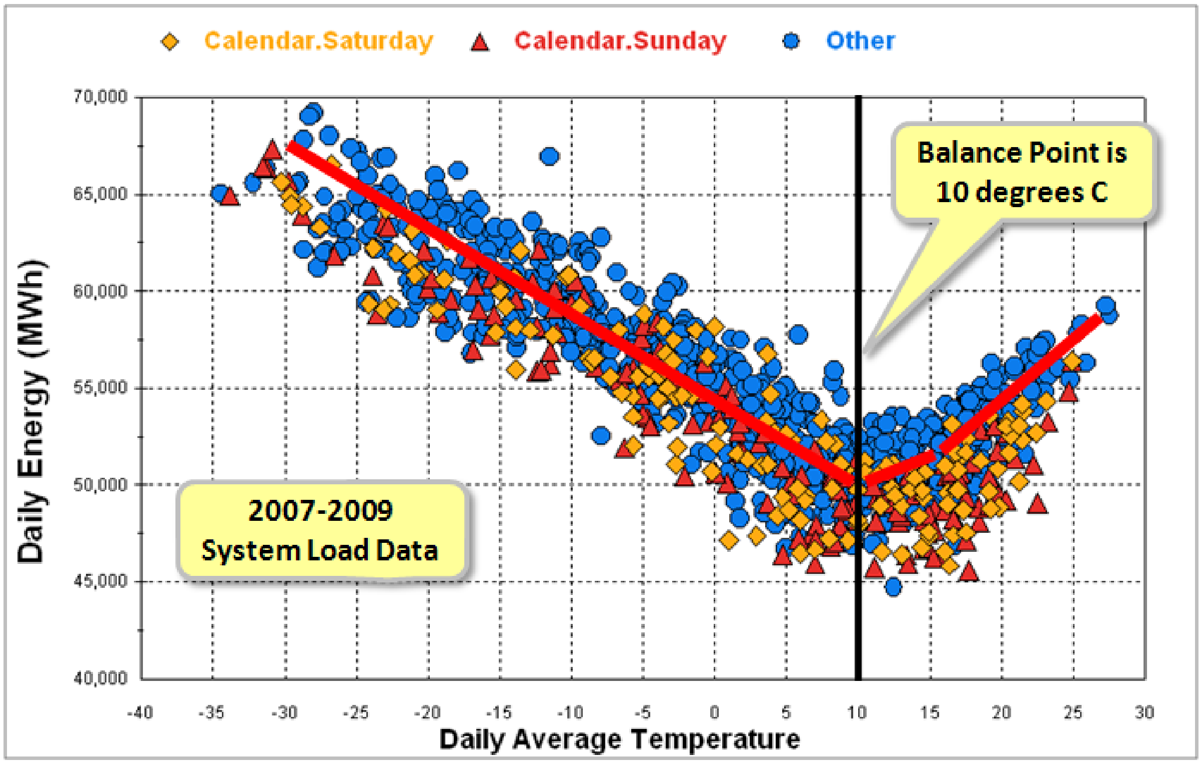
The heating response is approximately linear and thus can be captured using a single HDD variable. The cooling slope is best approximated by two CDD variables at breakpoints of 10 and 15 degrees Celsius, respectively. The table below summarizes the regression model coefficients for each of the weather variables.

Table 2: System Energy Model Weather Coefficients

Variable	Coef	T-Stat	P-Value	Units
HDD10	251.7	28.198	0.00%	Deg C
CDD10	96.9	2.311	2.10%	Deg C
CDD15	525.6	8.514	0.00%	Deg C

Figure 18 displays a graphical representation of the weather response function.

Figure 18: SaskPower Daily Energy vs Temperature Weather Response



The two CDD variables can be combined into one variable by computing their relative weights. To compute the relative weight for each cutpoint, each CDD model variable coefficient is divided by the sum of the CDD coefficients. Table 3 presents the formula for calculating the CDD Spline variable.

Table 3: Cooling Degree Day Spline Variable Construction

Variable	Coef	Weight
HDD10	251.7	100%
CDD10	96.9	16%
CDD15	525.6	84%
MaxPoweredCDD	622.5	

CDD Spline =
.16 * CDD 10 +
.84 * CDD 15

Once the multi-part cooling-degree day variable has been defined, it can be lagged, interacted with monthly or seasonal terms, and interacted with weekend variables, enabling the model to capture lagged weather impacts, seasonal offset slopes, and weekend offset slopes. This approach provides the ability to capture a flexible and dynamic weather relationship.

Itron investigated the incorporation of supplemental weather concepts at the system load level. A series of neural network models were estimated with the objective to test the incremental benefit achieved through the inclusion of additional weather variables.

The base model is analogous to the neural network model described above and represents the weather response using strictly Average Daily Temperature. All subsequent neural network models build on top of the base model to assess the incremental model fit improvement that results from the addition of supplementary weather terms. The second model adds in lagged variables for the two prior days. The third model adds in Wind Speed in the Heating Node (in addition to lags). The fourth model adds in Humidity in the Cooling Node (in addition to all terms from the prior model).

The table below displays a Mean Absolute Percentage Error (MAPE) comparison across neural network models.

Table 4: Neural Network Model Fit Comparison

Model	Adj R-Sq	MAD	MAPE
DailyNet_Tmp	0.912	1126.9	2.09%
DailyNet_Lags	0.918	1090.4	2.02%
DailyNet_Wind	0.919	1081.6	2.01%
DailyNet_Hum	0.919	1081.3	2.01%

The Model Fit Comparison shows a model fit improvement from the inclusion of lagged weather variables (MAPE reduction from 2.09% to 2.02%), but no marked improvement from the addition of wind speed and humidity (about the same MAPE). The conclusion is the addition of lagged temperature adds predictive strength to the model, but wind speed and humidity do not.

Experience also suggests this weather response varies by rate class. The residential classes tend to begin heating at higher temperatures than the business classes. There tends to be significant internal heat gain in commercial buildings, which shifts the balance point for these classes to the left. Example load research data for the Residential and Commercial classes are shown in Figure 19 and Figure 20 demonstrate the alternative weather response for each class.

Figure 19: Daily Residential Energy vs. Temperature

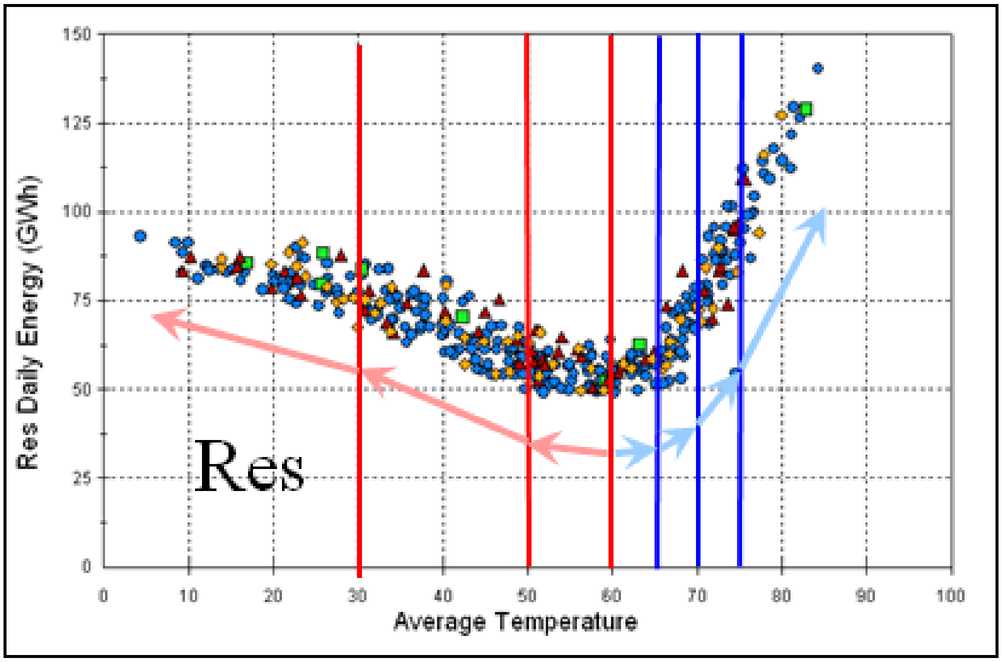
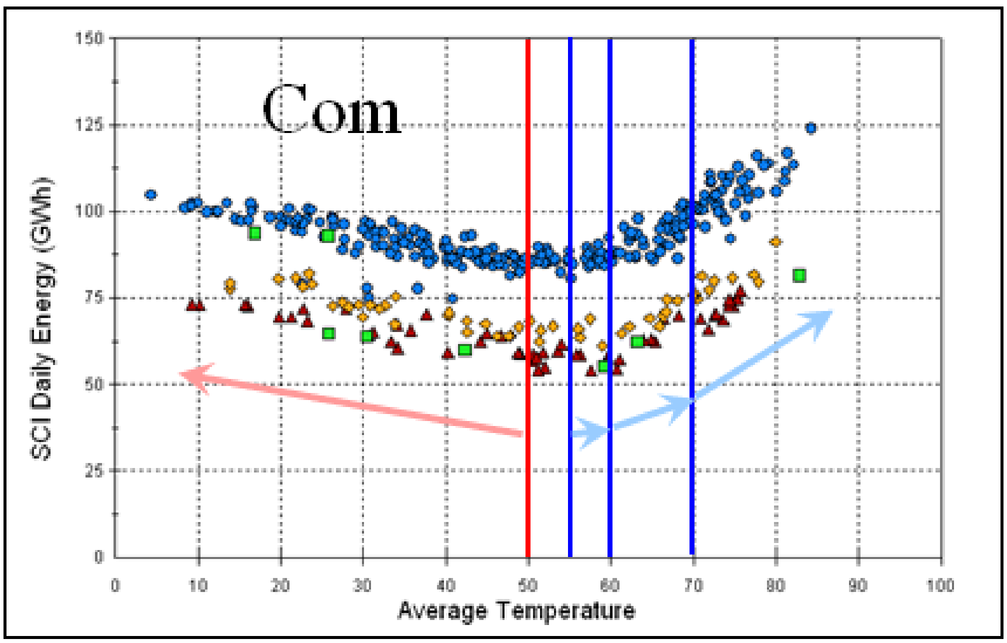


Figure 20: Daily Commercial Energy vs. Temperature



Energy Weather Normalization Recommendation

- Implement a daily system energy normalization modeling approach.
  - Ä The models should use roughly three years of recent data. Modeling with the most recent three years of data will ensure the weather relationships are computed based on the current heating and cooling equipment stock.
  - Ä The approach should evaluate the use of a multi-part degree-day weather variable to represent the heating and cooling loads, respectively. Lagged multi-part degree day variables should also be included in the models.
  - Ä With the recent addition of the Load Research sample, similar analysis can be performed for each of the weather sensitive classes.
  - Ä The System-level response functions should be used to define the weather adjustment and weather normalized energy, and the class-level models to distribute the system-level values to the appropriate classes. The weather impact models should be updated on an annual basis.

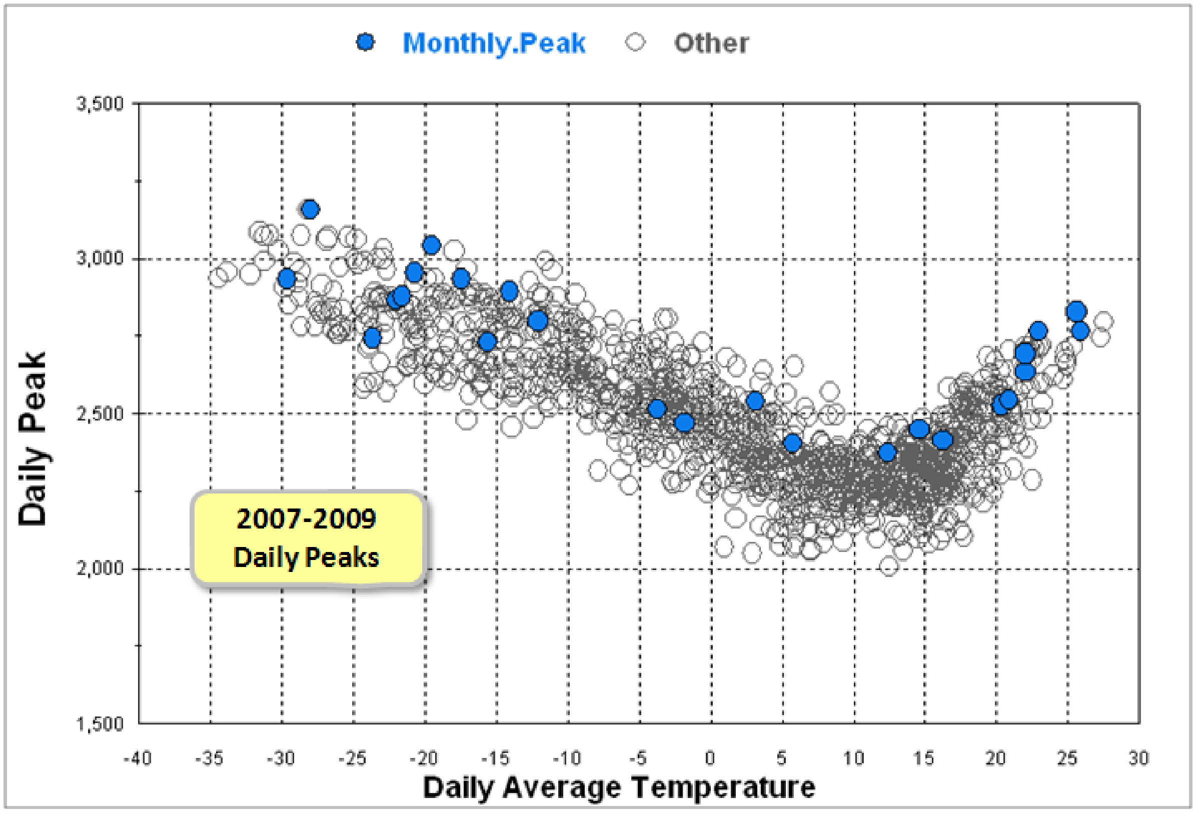
Peak Weather Normalization Models

The peak weather normalization models estimate daily peaks as a function of weather variables, calendar conditions and a time trend. 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.

Proposed Peak Normalization Model

To evaluate the weather relationship at time of peak, Itron generated a scatter plot SaskPower Daily System Energy vs Temperature.

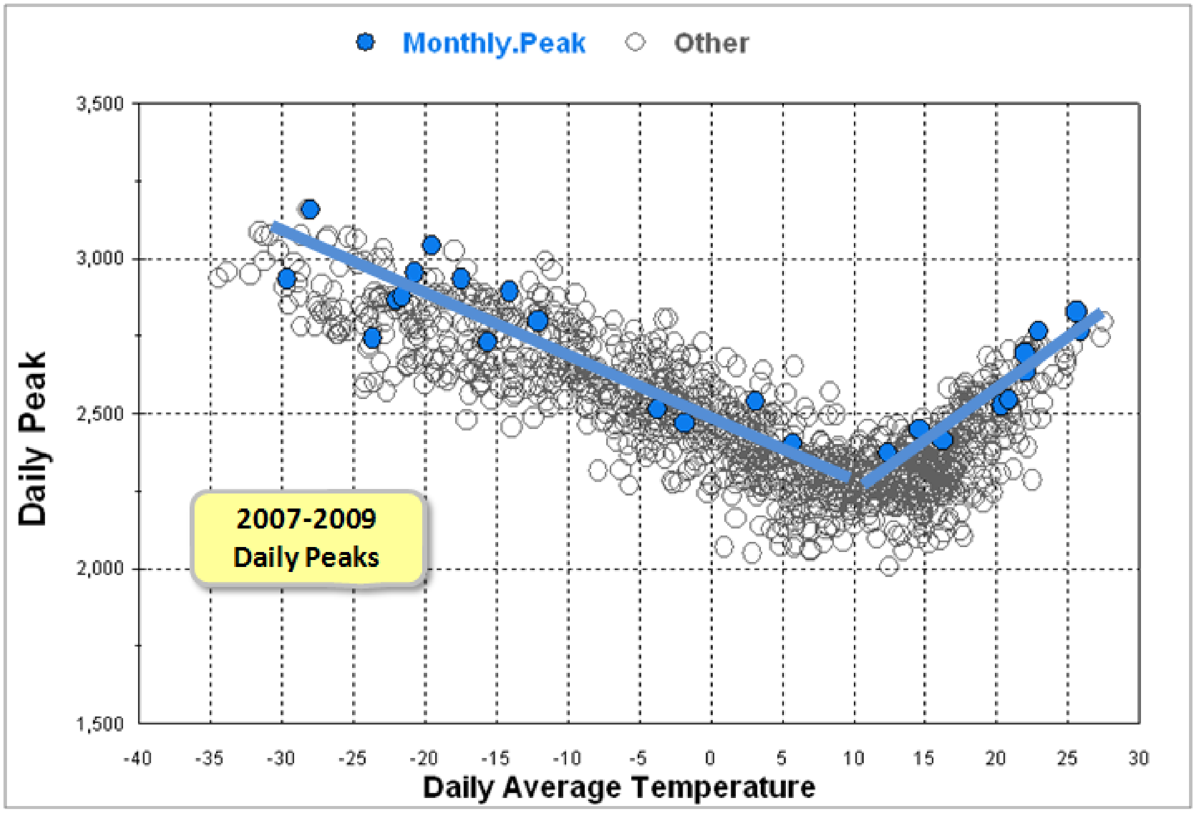
Figure 21: SaskPower Daily System Energy vs. Temperature



The scatter plot clarifies the weather relationships. Daily Peaks is displayed on the vertical axis and Daily Average Temperature (using a 50/50 weight for Saskatoon and Regina) is displayed on the horizontal axis. Each point represents a daily peak observation with the monthly peaks shown with blue circles. To the left hand side of the scatter plot, increases in daily peak load are driven largely by heating loads (and increases in lighting). To the right of the balance point, increases in loads are driven largely by cooling loads.

The peak load response is approximately linear and thus can be captured using a single HDD and CDD variable. Figure 22 displays a graphical representation of the weather response function in reference to monthly peaks.

Figure 22: SaskPower Daily Peak vs Temperature Weather Response



Itron investigated the incorporation of supplemental weather concepts to estimate system peak loads. A series of neural network models were estimated with the objective to test the incremental benefit achieved through the inclusion of additional weather variables.

The base model independent variables are analogous to those used in the base neural network model described in the energy normalization section and represents the peak weather response using strictly Average Daily Temperature. All subsequent neural network models build from the base model to assess the incremental model fit improvement that results from the addition of supplementary weather terms. The second model adds in lagged variables for the two prior days. The third model adds in Wind Speed in the Heating Node (in addition to lags). The fourth model adds in Humidity in the Cooling Node (in addition to all terms from the prior mode).

The table below displays a MAPE comparison across neural network models.

Table 5: Neural Network Daily Peak Model Fit Comparison

Model	Adj R-Sq	MAD	MAPE
DailyPkNet_Tmp	0.853	64.8	2.65%
DailyPkNet_Lags	0.856	64.1	2.62%
DailyPkNet_Wind	0.859	63.5	2.60%
DailyPkNet_Hum	0.861	63.3	2.59%

The Model Fit Comparison shows a slight model fit improvement from the inclusion of lagged weather variables (MAPE reduction from 2.65% to 2.62%), and very slight improvements from the addition of wind speed and humidity (about the same MAPE). The conclusion is the addition of lagged temperature and wind speed add minimal predictive strength to the model.

<u>Peak Weather Normalization Model Recommendation</u>

- Implement a daily peak weather normalization approach.
  - Ä The peak weather normalization models should use roughly three years of recent data. Modeling with the most recent three years of data will ensure the weather relationships are computed based on the current heating and cooling equipment stock.
  - Ä Adjust the peak weather normalization model specification to implement CDD and HDD variables with a base of 10 degrees Celsius.
  - Ä Lagged CDD and HDD variables should be included as these variables provide a slight improvement to the model fit.
  - Ä The inclusion of Wind Speed is optional. It provides only a slight model fit improvement, but also introduces the complication of quantifying normal wind speed in conjunction with temperature.

3.3. Economic Inputs

SaskPower's Economic Forecast is generated internally. Based on the Economic Survey, 23% of respondents generate their Economic Forecast internally. This is reasonably common industry practice. The SaskPower Economic Forecast leverages information from multiple, reputable sources and is managed by SaskPower staff, who have extensive experience generating the forecast and take extra care to ensure the reasonableness of the forecast and its consistency across economic concepts.

3.4. Residential Sales Forecast Methodology

The SaskPower Residential Sales Forecast is computed as the product of contributing Customers and Use per Customer forecasts. The use of separate forecasts for these concepts is common industry practice as 62.5% of survey respondents construct their residential sales forecast in this manner.

The Customers Forecast is driven by households and assumes a unit elasticity. It is common industry practice to drive the residential customers forecast with households and the unit elasticity is logical given SaskPower's provincial geography is in alignment with the representative geography of the households forecast.

The UPC model implements a pure end use approach in which 24 end uses are represented separately for single family and apartment dwellings. Of survey respondents, 11.1% use the pure end use approach.

Residential Methodology Recommendations

- Adjust the end use saturation paths to reflect the 2010 SaskPower Saturation Survey data.
- Estimate a simple UPC model using the end use model index as the primary input.
  - Ä The coefficient of the end use model index will calibrate the index into the actual UPC data.
  - Ä Add a free Time Trend variable to assess whether the end use model is capturing the appropriate historical trends.
    - If the free time trend variable is statistically significant, it suggests there are additional factors driving the residential UPC trends that are not captured through the end use index. In this case, the time trend refines the model to account for these factors. If desired, the end use inputs can be modified to the point where the time trend variable is insignificant. The statistical insignificance of the time trend variable solidifies the explanatory power of the end use index variable.

3.5. Commercial Sales Forecast Methodology

The SaskPower Commercial Sales Forecast is modeled directly. Of survey respondents, 77.5% construct their commercial sales forecast in this manner, so SaskPower's approach is well aligned with common industry practice.

The Customers Forecast is driven by residential customer and uses a regression model to estimate the associated elasticity. In Itron's experience, residential customers can be an effective driver of commercial customers.

The UPC model implements an econometric approach, which is aligned with common industry practice. Of survey respondents, 77.8% use an econometric approach to model the commercial sector. The UPC model is driven by a composite NAICS GDP index for the following sectors:

- Finance, Insurance, and Real Estate

- Manufacturing
- Public Administration
- Retail and Wholesale Trade
- Transportation & Warehousing

The response to the economics survey suggest commercial sales is driven by employment, financial and demographic conditions weighted roughly at 45%, 35%, and 20%, respectively. SaskPower's commercial sales models account for financial and demographic conditions, but do not incorporate employment factors.

Commercial Methodology Recommendations

- Evaluate the implementation of a weighted economic variable to drive the Commercial Sales model.
  - Ä In addition to the NAICS composite GDP component, the weighted economic variable should include an employment component for the relevant NAICS code groupings.
  - Ä Begin with a 50/50 weighting scheme and adjust from there.

3.6. Farms Sales Forecast Methodology

The SaskPower Farm Sales Forecast is segmented into Farm Households and Farm Operations and forecasted separately. The Farm Household Customer Forecast is driven by the Economic Forecast of Farm Households. The Farm Household UPC Forecast uses the same methodology as the Residential UPC Forecast.

The Farm Operations Customers forecast is driven by the number of Farm Households. The Farm Households variable is a logical choice with which to drive the Farm Operations Customers Forecast. A regression model estimates the relationship between Farm Operations Customers and Farm Households. The Farm Operations UPC forecast is generated using an end use model which accounts for Farm economic indicators from the Economic Forecast. The Farm Operation end use model accounts for the proper concepts.

3.7. Power Accounts Sales Forecast Methodology

SaskPower's power accounts include large individual customers from the following industries, Potash Mining, Northern Mining, Pipeline, Refinery, Pulp & Paper, Steel, Chemical, Coal Mines, Universities, Other. The Power Account forecast is constructed as the aggregation of individual customer forecasts. The Power Account Sales Forecast Methodology is compared to the Industrial Forecast Methodology employed throughout the industry. The industry standard Industrial Sales Forecast involves generating an individual customer forecast for the larger industrial customers and modeling the residual industrial customers using a regression model. SaskPower's approach is aligned with the industry standard in that they forecast the largest customers individually, which for the Power Accounts represents the entire class.

A segment of survey questions focused on the interaction between the utility and large industrial customers. It is common practice to use Customer Account Managers (CAM) communication with the large industrial customers and their corresponding forecasts to drive the load forecast for this customer grouping. However, several respondents noted the individual customer information has been known to be optimistic. The large customers are good about expressing expansion plans and increases in operational levels, but tend to be less communicative when it comes to contraction plans and decreases in operational levels. This is logical as the customers desire to ensure they have sufficient capacity to support their forward looking business processes. SaskPower's policy mitigates this bias in the short-term by mandating the large customers to guarantee their load projections starting 3-4 years away from the in-service date. However, there is still a recognized bias over longer time horizons (5 years and longer). The Power Account Forecast is the fastest growing of all classes and the forecasted growth rates exceed their historical counterparts.

Power Accounts Methodology Recommendations

- If an appropriate production index forecast can be found for the relevant industries, SaskPower could generate an alternative forecast using an econometric model that drives Power Account Energy usage with Production Indices for the respective industries. Currently, a production index forecast is only available for the Potach industry. The Production Indices should be weighted with respect to the current relative composition of Power Accounts across the representative industries.
- Track the forecast accuracy over time for both forecasts.
- Over time, explore the implementation of a weighted long-term Power Account Forecast, which weights the contributing alternative forecasts based on historical forecast accuracy.
- Blend the weighted long-term forecast in with the individual customer forecast. The individual customer forecast should be used going out 3-4 years and the growth rate from the weighted forecast should be applied in years 5 and beyond.

3.8. Oilfields Sales Forecast Methodology

The Oilfields Sales Forecast Methodology is compared to the Industrial Forecast Methodology employed throughout the industry. SaskPower's Oilfield forecast is comprised of two supporting forecasts, the Large Oilfield forecast and the Small Oilfield forecast. SaskPower forecasts the Large Oilfields individually and the Small Oilfields as a aggregate group. This is consistent with standard industry practice for the Industrial Class. In alignment with the industry standard, SaskPower uses Customer Account Managers (CAM) communication with the large industrial customers and their corresponding forecasts to drive the load forecast for this customer grouping. The small oilfield forecast is generated by first forecasting the number of oilfield customers and use per customer separately and calculating the sales forecast as the product of the two component forecasts. Given the economic data available, this is the appropriate approach. The number of customers forecast is driven by the forecast of number of wells drilled. The UPC forecast incorporates production forecasts of oil and water as well as intensity trends. This approach properly accounts for the increase in intensity that results from oilfield maturity. Overall, the oilfield forecasting approach properly incorporates the relevant factors.

Oilfields Methodology Recommendations

- Track the large oilfield forecast over time to ensure there is not a bias towards over prediction.

3.9. Peaks Sales Forecast Methodology

The SaskPower Peak Forecast applies annual coincident peak load factors to annual sales forecasts by rate class and at the individual customer level for the largest industrial customers. The result is a forecasted coincident peak load for each customer category. The category-level coincident peak factors are then aggregated across the classes to compute the System Peak Load Forecast.

This approach can be categorized as the Load Factor approach, which is implemented by 8% of the 99 Economic Survey respondents. In SaskPower's service territory, the divergent forecasted growth rates across the rate classes support a bottom-up peak load forecasting approach.

Peak Methodology Recommendation

Itron's recommends the implementation of one of two alternative approaches.

- **Approach 1. Coincident Peak Factor Approac**h. This approach involves proceeding with the existing peak forecast calculation.
  - Ä If this approach is selected, extra care should be taken to ensure the category-level CP factors are properly calculated. A regression model of CP for each class is recommended, which should account for weather. Severe peak producing weather is likely to increase the coincident peak factor for the residential class and reduce the coincident peak factor for the non-weather sensitive classes. A model should be implemented to adjust for the weather impacts.
  - Ä Compute an industry-level coincident peak factor for the Power Account category. The industries should include Potash Mining, Northern Mining, Pipeline, and Refinery. This will limit the number of necessary coincident

peak models and work well for applying the appropriate coincident peak factor to probable loads.

- Ä Compute a single coincident peak factor for the Large Oilfield category. The load shapes for this class should be consistent enough to represent in aggregate.

Approach 1 properly accounts for the changing mix of classes assuming the timing of the peak does not change moving forward.

- **Approach 2. System-Level Buildup Approach.** This approach involves the construction and aggregation of category-level hourly load shape.
  - Ä This approach will involve the construction of 10 hourly load shape forecasts for the following customer categories, Potash Mining, Northern Mining, Pipeline, Refinery, Large Oilfields, Small Oilfields, Commercial, Residential, Farm, and Reseller. These forecasts can be generated using the load research data.
  - Ä The resulting hourly load shape forecasts should be scaled to match forecasted annual energy target values. This will allow the system-level load shape to adjust with respect to the divergent forecasted growth rates for each underlying class.

  Approach 2 properly accounts for the changing mix of classes, including changes in the timing of the peak that may result from rate class load shifting. This approach also generates a Long-Term 8760 forecast that incorporates the proper class-level components and associated load shape modifications. The decision to proceed with option 1 or 2 is really driven by the need for a meaningful long-term 8760 forecast. If this is important, option 2 is preferred. If it is not, option 1 is probably sufficient.

4. Summary of Load Forecast Methodology Enhancements

The purpose of this section is to summarize the recommended enhancements from the prior section. The recommended enhancements are organized by the forecasting concept to which they pertain.

4.1. Weather Normalization

- Implement a daily system energy normalization modeling approach.
- Adjust the peak weather normalization model specification to implement CDD and HDD variables with a base of 10 degrees Celsius

4.2. Residential Methodology

- Adjust the end use saturation paths to reflect the 2010 SaskPower Saturation Survey data.

- Estimate a simple use per customer regression model using the end-use model index as the primary input.

4.3. Commercial Methodology

- Evaluate the implementation of a weighted economic variable to drive the Commercial UPC model.

4.4. Power Accounts Methodology

- If a reasonable industry-level production index forecast is available, generate an alternative forecast using an econometric model that drives Power Account Energy usage with the respective production index forecasts. The Production Indices should be weighted with respect to the current relative composition of Power Accounts across the representative industries.
- Track the forecast accuracy over time for both forecasts. In time, evaluate weighting the alternative forecasts based on historical forecast accuracy.
- Blend the weighted long-term forecast in with the individual customer forecast. The individual customer forecast should be used going out 3-4 years and the growth rate from the weighted forecast should be applied in years 5 and beyond.

4.5. Oilfields Methodology

- Track the large oilfield forecast over time to ensure there is not a bias towards over prediction.

4.6. Peak Methodology:

Itron's recommends the implementation of one of two alternative approaches.

- Approach 1. Coincident Peak Factor Approach. This approach involves proceeding the existing peak forecast calculation.
    - Ä If this approach is selected, extra care should be taken to ensure the category-level CP factors are properly calculated. A regression model of CP for each class is recommended, which should account for weather. Severe peak producing weather is likely to increase the coincident peak factor for the residential class and reduce the coincident peak factor for the non-weather sensitive classes. A model should be implemented to adjust for the weather impacts.
    - Ä Compute an industry-level coincident peak factor for the Power Account category. The industries should include Potash Mining, Northern Mining, Pipeline, and Refinery. This will limit the number of necessary coincident peak models and work well for applying the appropriate coincident peak factor to probable loads.
    - Ä Compute a single coincident peak factor for the Large Oilfield category. The load shapes for this class should be consistent enough to represent in aggregate.

Approach 1 properly accounts for the changing mix of classes assuming the timing of the peak does not change moving forward.

- Approach 2. System-Level Buildup Approach. This approach involves the construction and aggregation of category-level hourly load shape.
  - Ä This approach will involve the construction of 10 hourly load shapes for the following customer categories, Potash Mining, Northern Mining, Pipeline, Refinery, Large Oilfields, Small Oilfields, Commercial, Residential, Farm, and Reseller.
  - Ä The resulting hourly load shapes should be scaled to match forecasted energy target values. This will allow the system-level load shape to adjust with respect to the divergent forecasted growth rates for each underlying class.

Approach 2 properly accounts for the changing mix of classes, including changes in the timing of the peak that may result from rate class load shifting. This approach also generates a Long-Term 8760 forecast that incorporates the proper class-level components and associated load shape modifications. The decision to proceed with option 1 or 2 is really driven by the need for a meaningful long-term 8760 forecast. If this is important, option 2 is preferred. If it is not, option 1 is sufficient.

5. Load Forecast Software Packages

The purpose of this section is to recommend software that can assist with enhancing SaskPower's Load Forecasting process. Itron offers and supports widely used software for the development and implementation of load forecasting solutions. In addition, Itron is knowledgeable about commercially available software packages that are being used in the energy industry.

This section includes discussion of SaskPower's current load forecasting software, a list of alternative software packages that are used throughout the utility industry, and a description of Itron Software that contains the capability to enhance SaskPower's Load Forecasting process.

5.1. Existing Software

SaskPower is currently using SPSS and Microsoft Excel to generate their load forecast. Currently, SPSS is used to run sophisticated regression models and Microsoft Excel is used to run simple regression models and post-process the data. This process involves careful configuration in Excel, which given the large volume of individual customer forecasts, can potentially require several large spreadsheets to manage the process.

5.2. Statistical Software Packages and Load Forecasting Processes

The following is a list of standard software packages used to support load forecasting throughout the industry.

.

- EVIEWS
- EXCEL
- MINITAB
- SAS
- STATISTICA

All of the above packages are generalized software, which were not built with the specific utility load forecasting problem in mind. While utility industry specific calculations can be performed using a standardized software package, this requires a significant configuration effort and specialized programming skill set. In Itron's view, the software packages listed above do not provide the capability to profoundly enhance SaskPower's current process.

5.3. Itron Software Solutions

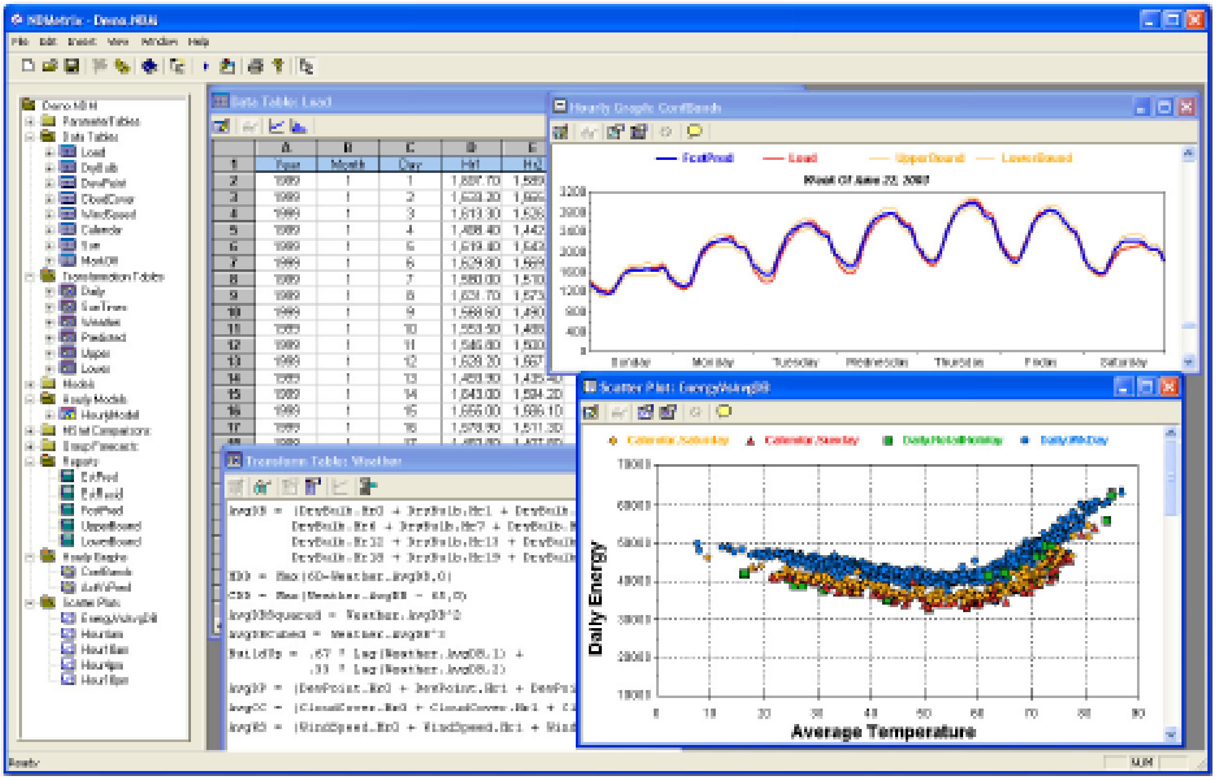
While there are several potential software alternatives available in the market, Itron offers software solutions designed specifically for supporting the load forecasting process. Each Itron product contains preconfigured objects and graphical capabilities designed specifically to support the load forecasting process, which reduces the labor associated with generating a load forecast and doesn't require programming expertise. The following two products can enhance SaskPower's Load Forecasting Process going forward.

- MetrixND
- MetrixLT

<u>MetrixND</u>

MetrixND is designed to take advantage of advanced Windows capabilities, including an intuitive graphical user interface and drag-and-drop architecture that streamlines the development of forecasting variables and models. Evaluation graphs, statistics, and reports are readily available to assist in analyzing data and forecasts. This interactive design strategy allows the user to evaluate alternative models and to select the model that works best. Over 160 utilities, ISOs, municipalities, cooperatives, retailers, wholesalers, and other energy service providers use MetrixND, making it the most widely used software in North America. There is a large and active user group, which ensures MetrixND's development priorities are driven by the needs of the electricity forecasting industry.

Figure 23: MetrixND User Interface



Given the large number of individual forecasts that SaskPower generates as a part of their load forecasting process, MetrixND will provide the ability to view this data in graphical form very quickly. The quick graph functionality enables the user to scroll across graphical representations of multiple data series quickly, enabling the user to examine each series for reasonableness.

MetrixND also supports the Daily Weather Normalization process and Class-level Hourly Modeling required to support a System-Level Peak Buildup Approach.

MetrixLT

The MetrixLT Application is designed specifically for developing hourly and sub-hourly load shape forecasts to support utility generation, transmission and distribution planning business processes. With MetrixLT, It is easy to create “bottom-up” system load forecasts that build from the end-use, rate class, or revenue class level. Built-in functionality allows the user to calibrate load shape profiles or day-type load shapes to annual or monthly energy forecasts. MetrixLT provides functionality for calibrating a long-run forecast consistent with actual system loads or with short-run load forecasts, while robust reporting capabilities allow the user to summarize hourly data or forecasts into daily, monthly, or annual tables.

Typical applications for MetrixLT include the following:

- Inspection of load shape and weather data through Graphical Views
- Creation of daily normal weather variables
- Creation of alternative daily weather patterns
- Scaling one load shape to be consistent with another
- Calibration of hourly forecasts to agree with monthly peak and energy forecasts
- Aggregation of load shape components to the System Level
- Summarize sales and peaks from an interval series in a daily, monthly, or annual table

Figure 24: MetrixLT User Interface

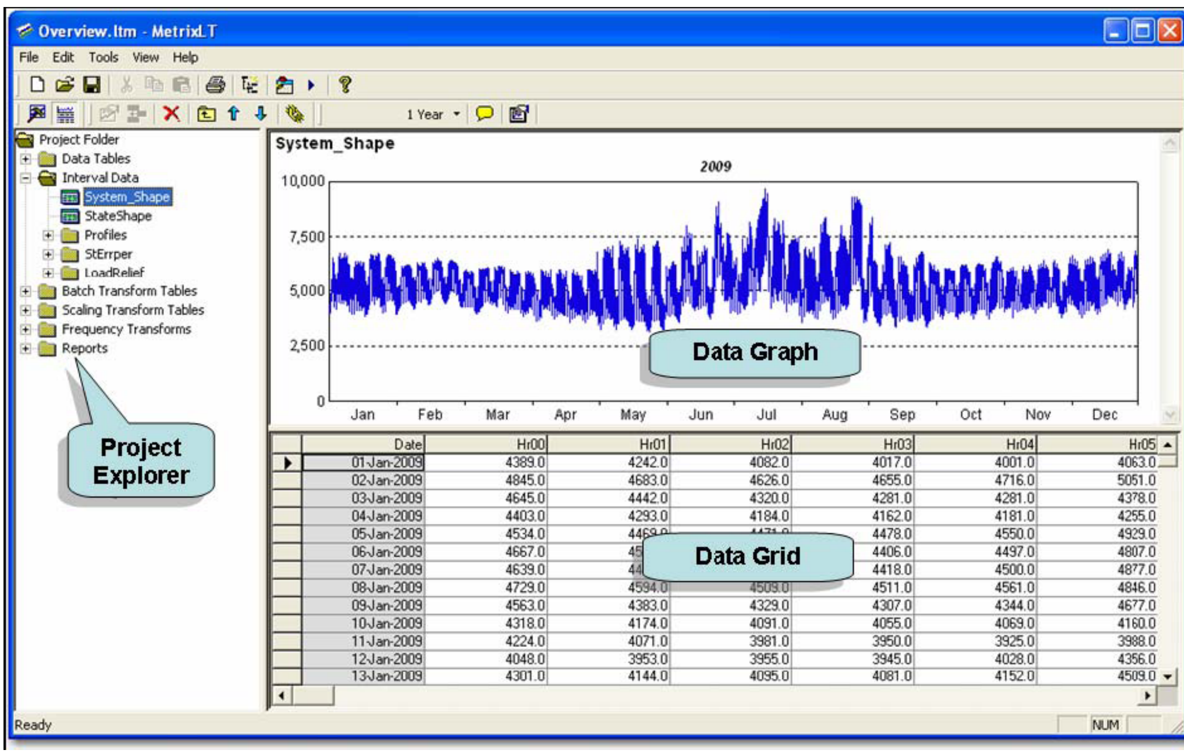
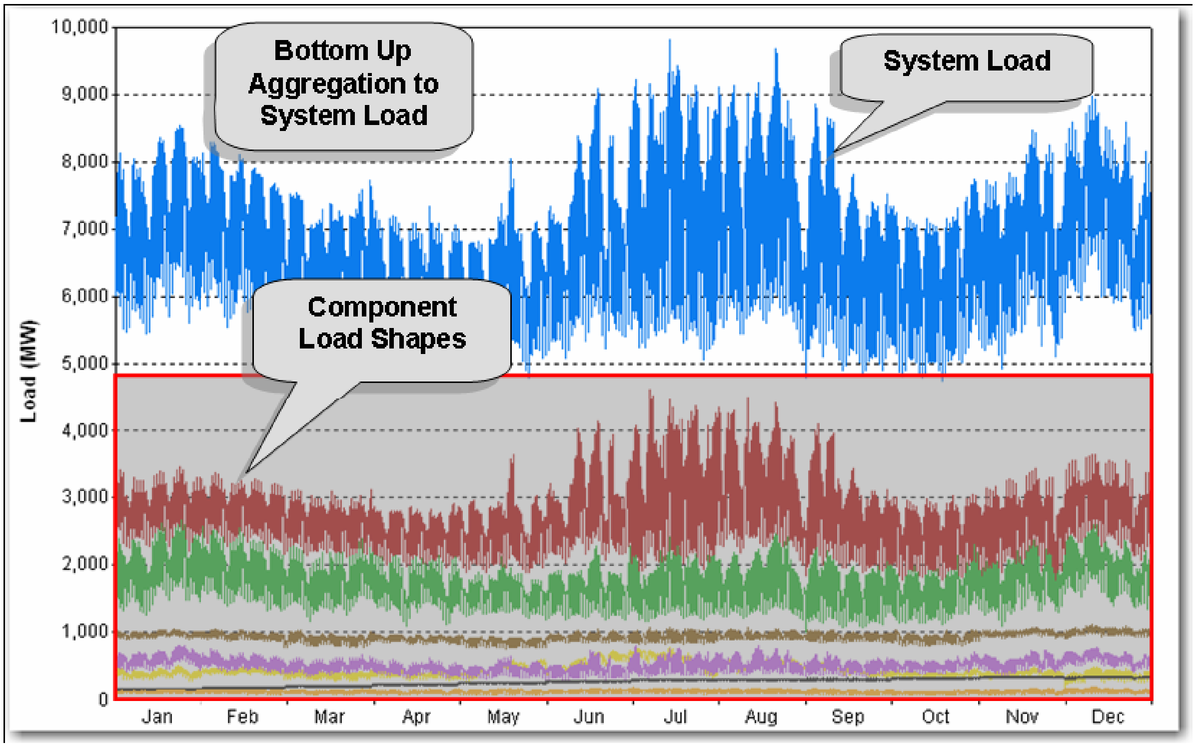


Figure 25: MetrixLT: Bottom-Up Class-Level Load Forecast Example



MetrixLT can support SaskPower's calculation of daily normal weather variables, which can be aggregated monthly and annually. In addition, if the generation of a meaningful hourly load shape forecast is of high priority to SaskPower, MetrixLT can properly integrate the class-level load shapes with associated annual sales target values to generate an 8760 and peak load forecast representative of the changing mix of customers across the rate classes.

Round1 – Consultant Q104:

Please discuss any resulting changes from that study to the 2012 and 2013 load forecasts.

Response:

Please find below a summary of the recommendations made by Itron in 2010 in their report reviewing SaskPower's load forecast methodology as well as SaskPower's actions (in bold) as a result of the report.

The review of SaskPower's load forecasting methodology was completed in October, 2010 by Itron Inc. Itron is an industry leader in load forecasting software and also provides load forecasting workshops on a regular basis. Itron did an excellent job on this review, providing verification of SaskPower's methodology using their own forecasting expertise as well as an in depth industry survey. Itron also provided recommendations for enhancements of SaskPower's methodology which are provided below. SaskPower's actions as a result of the recommendations are also included in bold.

1.) Use three years of data in SaskPower's weather normalization models and revise the heating degree day (HDD) and cooling degree day (CDD) variables to a base of 10 degrees C instead of 18 degrees C.

This work has been completed and incorporated into the 2012 and 2013 forecasts.

At the same time this change was made, SaskPower was also able to undertake weather normalization on a class by class basis using customer class loadshapes developed from Saskatchewan load research. This advancement provides a more accurate distribution of the weather normalization for the total system back to the individual customer classes.

2.) Update SaskPower's residential end use models with the 2010 residential end use survey data provided by the Demand Side Management department.

This work has been completed and incorporated into 2012 forecast.

3.) Add an employment component to the commercial GDP drivers used to determine the energy growth rate for the commercial class.

This recommendation will not be implemented. The Finance staff member who is responsible for SaskPower's economic forecasts believes the employment component

is already included in the commercial drivers used to develop the commercial load forecast.

4.) Use industry forecasts, if available, as a check on customer supplied forecasts for the Power class.

This recommendation on industry forecasts was modified somewhat. SaskPower has access to only one industry forecast applicable to the Power class – for potash production which is not suitable for SaskPower's long term planning needs. The modification to this recommendation is that SaskPower will meet with Energy & Resources staff at least once per year to review our assumptions on the in service date of expansions at existing potash mines and potential greenfield mines. At these meetings we will also review SaskPower assumptions on northern mining customers.

SaskPower

2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

Round1 – Consultant Q105:

Please discuss the impacts on SaskPower's annual energy and peak load for average weather and what these amounts would be for the warmest and coldest years on record. Please use 2011 consumptions and peak loads for this analysis.

Response:

Impacts of Warmest and Coldest Recorded Weather on 2011 Load

	2011 Actual	2011 Normal Weather	2011 with 1987 (Warmest) Weather	2011 With 1996 (Coldest) Weather
Energy (GWh)	21,120	21,048	20,892	21,365
Peak (MW)	3,195	3,179	3,114	3,236

Notes:
- All peaks are winter peaks.
- 1987 was the warmest year (highest mean temperature for the year) over the period 1982 to 2011.
- 1996 was the coldest year (lowest mean temperature for the year) over the period 1982 to 2011.
- In December, 1996 the very cold weather did not occur until the Christmas week. Had this weather arrived a week or two earlier, the peak load would have been much higher.

SaskPower

2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

Round1 – Consultant Q106:

Please provide a schedule showing the historic forecast, actual and weather normalized load and peak requirements over the last five years, by customer class and on an overall basis and explain major variances including data for 2010 and 2011.

Response:

See table below:

Variance Explanation

The Power Class typically has the largest variances each year. This is primarily due to market fluctuations (Potash & Natural Gas Prices) and individual customer planning delays/cancellations.

For part of 2008 and all of 2009 the actual energy sales to the Power class were considerably lower than forecasted due in large part to the world-wide economic slowdown. The potash, pipeline pumping and steel sectors were particularly hard hit in Saskatchewan.

In 2010 and 2011 variance in the Power class were due to reduce loads in the potash and natural gas pumping sectors due in large part to the sluggish economy.

SaskPower's forecasted system (winter) peak is a potential peak, which is based on experiencing sustained cold weather during the first two to three weeks of December. This is exactly what occurred in December of 2008 when SaskPower recorded a system peak load of 3194 MW and December of 2009 when SaskPower recorded a system peak load of 3231 MW. In 2007 and 2011 we did not experience the cold weather in December necessary to develop a good system peak which resulted in a large variance with the forecasted values for those years.

2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

Round1 – Consultant Q107:

Please discuss any specific changes or different methods used to forecast loads for the Major Customer Classes – Power, Oilfield, Commercial, Residential, Farm, Reseller and Non-Grid since the 2010 application.

Response:

The only changes that have been made to the Load Forecast methodology are explained below (same answer as Q104)

The review of SaskPower's load forecasting methodology was completed in October, 2010 by Itron Inc. Itron is an industry leader in load forecasting software and also provides load forecasting workshops on a regular basis. Itron did an excellent job on this review, providing verification of SaskPower's methodology using their own forecasting expertise as well as an in depth industry survey. Itron also provided recommendations for enhancements of SaskPower's methodology which are provided below. SaskPower's actions as a result of the recommendations are also included in bold.

2.) Use three years of data in SaskPower's weather normalization models and revise the heating degree day (HDD) and cooling degree day (CDD) variables to a base of 10 degrees C instead of 18 degrees C.

This work has been completed and incorporated into the 2012 and 2013 forecasts.

At the same time this change was made, SaskPower was also able to undertake weather normalization on a class by class basis using customer class loadshapes developed from Saskatchewan load research. This advancement provides a more accurate distribution of the weather normalization for the total system back to the individual customer classes.

2.) Update SaskPower's residential end use models with the 2010 residential end use survey data provided by the Demand Side Management department.

This work has been completed and incorporated into 2012 forecast.

3.) Add an employment component to the commercial GDP drivers used to determine the energy growth rate for the commercial class.

This recommendation will not be implemented. The Finance staff member who is responsible for SaskPower's economic forecasts believes the employment component is already included in the commercial drivers used to develop the commercial load forecast.

4.) Use industry forecasts, if available, as a check on customer supplied forecasts for the Power class.

This recommendation on industry forecasts was modified somewhat. SaskPower has access to only one industry forecast applicable to the Power class – for potash production which is not suitable for SaskPower's long term planning needs. The modification to this recommendation is that SaskPower will meet with Energy & Resources staff at least once per year to review our assumptions on the in service date of expansions at existing potash mines and potential greenfield mines. At these meetings we will also review SaskPower assumptions on northern mining customers.

SaskPower

2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

Round1 – Consultant Q108:

Please discuss how SaskPower determined load growth for its 2 Resellers and how Demand Side Management was factored into these considerations.

Response:

SaskPower requests and receives individual load forecasts from its 2 reseller customers as we feel they are in the best position to estimate load growth given their franchise constraints. These load forecasts come with a DSM component factored in from the reseller customers. SaskPower does not have the detail on their DSM component.

Round1 – Consultant Q109:

Please discuss whether SaskPower anticipates any capital programs designed to attach the current non-grid customers to the grid, within the 2012 to 2016 planning period.

Response:

SaskPower does not have any plans in place for capital programs to non-grid customers at this time.

Round1 – Consultant Q110:

Please confirm that SaskPower's second quarter load forecasts (June 2011) have been used to estimate the 2012 and 2013 revenue and/or cost estimates, and that these will be the updated in September of this year.

Response:

SaskPower confirms that it was the 2011 Q2 DSM adjusted forecast that was used for load and revenue estimates for 2012 (subject to comments below) and 2013 and in the cost of service modeling for 2013. The load and revenue estimates and the cost of service modelling for 2013 will be updated in September using SaskPower's recently completed 2012 Q2 DSM adjusted forecast.

Please note that the load and revenue estimates used for 2012 include a combination of actual and forecast data as per the response to Consultant Q50. Also include in the 2012 data are adjustments to the Power class at the end of March, 2012, which include for example, the potash market reduction in the first quarter of 2012 and delays to expansion projects.

SaskPower

2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

Round1 – Consultant Q111:

Please file schedules showing data for 2010 and 2011 total energy generated by year by fuel mix type and projections for 2012 and 2013.

Response:

The following table illustrates the total energy generated by fuel mix type for 2010 and 2011 and projections for 2012 and 2013:

Fuel Mix Type (in GWh)	Actual		Forecast*	
	2010	2011	2012	2013
Gas	3,683	4,032	4,749	7,786
Coal	12,038	11,614	11,694	11,867
Imports	518	502	652	327
Hydro	3,866	4,641	4,136	3,321
Environmentally Preferred Power (EPP)	148	139	149	149
Wind	507	682	683	728
Other	1	1	1	1
Total	20,759	21,611	22,063	24,177

***2012 Forecast based on Forecast as of June 30, 2012**
***2013 Forecast based on 2013 Preliminary Business Plan**

SaskPower

2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

Round1 – Consultant Q112:

Please provide a schedule/table using the material provided in the application on P.16/17 adding the current status of the program (ongoing, in development, or under examination) together with the estimated investment in each of the years 2012 and 2013 with the anticipated immediate projected energy savings and ultimate energy savings or other benefits.

Response:

The estimated investment includes marketing, consultants, administration and incentive costs.

DSM PORTFOLIO					
Program	**Status**	**2012 Estimate Investment (000s)**	**Estimated Annual Energy Savings MWh**	**2013 Estimated Investment (000s)**	**Estimated Annual Energy Savings MWh**
Residential Programs					
Refrigerator/Freezer Recycling Program	On Going	2,100	8,500	2,100	8,500
Retail Customer Track Program	On Going	750	3,800	750	3,800
Light Exchanges	On Going	1,500	5,000	2,000	6,300
Block Heater Timer	On Going	2,500	12,000	200	500
EnerGuide For Houses Program	On Going	50	400	50	400
HVAC Program	On Going	130	400	155	400
Geothermal & Self-Generated Renewable Power Loan & Rebate	On Going	190	600	190	600
Commercial Programs					
Lighting Incentive	On Going	800	2,300	800	2,300
Energy Efficient Lighting For Small Business	On Going	1,000	1,800	1,000	1,800
HVAC/Boiler	On Going	160	700	200	700
Energy Performance Contracting	On Going	30	2,400	50	2,400
Municipal Ice Rink	On Going	135	0	400	2,000

DSM PORTFOLIO					
Program	**Status**	**2012 Estimate Investment (000s)**	**Estimated Annual Energy Savings MWh**	**2013 Estimated Investment (000s)**	**Estimated Annual Energy Savings MWh**
Municipal Seasonal Lighting Program	On Going	135	400	200	600
Parking Lot Controller	On Going	450	3,900	450	3,900
Geothermal Rebate	On Going	25	500	25	500
Industrial					
Demand Response*	On Going	6,000	0	6,000	0
Energy Optimization	On Going	1,000	0	3,000	9,000
Renewable					
Net Metering	On Going	1,100	800	1,100	800
Small Producers	On Going	175	1,800	180	2,500

- Demand Response programs are not operated to achieve energy savings.
- Numbers are estimates and subject to change.

SaskPower

2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

Round1 – Consultant Q113:

Please provide details as to the Demand Response Program from 2009 to 2011 including the number of participants by year, actual number and extent of load reduction realized and quantify the benefits to SaskPower and to the participants.

Response:

The detail has been provided to the SRRP and their consultant.

SaskPower

2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

Round1 – Consultant Q114:

What are SaskPower's Annual Costs for 2010, 2011, 2012 & 2013 (projected) for the Refrigerator Recycle Program?

Response:

The annual estimated marketing, communication, consultant and incentive costs for Residential Refrigerator Recycle Program are outlined below.

2010 (000s)	2011 (000s)	2012 Estimate (000s)	2013 Estimate (000s)
$700	$1,700	$2,100	$2,100

2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

Round1 – Consultant Q115:

Please provide a table with the estimated annual energy savings (MWh) for 2012 and 2013.

Response:

Preliminary planning estimated energy savings for the DSM portfolio are:

MWhs	2012	2013
Estimated Energy Savings	44,000	47,000

These figures are subject to change.

SaskPower

2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

Round1 – Consultant Q116:

Please also confirm that the intent of the current programs is to deliver effective reduction in energy use, thereby providing cost savings to SaskPower's generation supply plan. Please also describe the test(s) used to determine a specific program's acceptability.

Response:

SaskPower DSM programs provide several benefits, one of which is to provide a cost effective source of generation supply by delivering low cost energy and capacity savings. These low cost demand side savings are used to partially offset current and future energy and capacity requirements that would have to be met with higher cost supply alternatives. In this way, DSM programs can yield lower short-term fuel costs and/or lower long term capital costs by deferring the need for some electric system investments.

SaskPower DSM calculates several cost-benefit tests as outlined within industry standard protocols when developing and evaluating DSM incentive programs. These tests include:

- the Total Resource Cost Test;
- the Ratepayers Impact Measure;
- the Utility Cost Test; and,
- the Participant Cost Test.

SaskPower

2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

Round1 – Consultant Q117:

Please discuss whether the Alternative Farm Energy Solar and Wind-Powered Livestock Water Pumping Program are considered a DSM Program or a cost avoidance program for both the customer and SaskPower.

Response:

The Alternative Farm Energy Solar and Wind-Powered Livestock Water Pumping Program is a cost avoidance program for both the customer and SaskPower. The Program is not a DSM Program.

At the time the Alternative Farm Energy Solar and Wind-Powered Livestock Water Pumping Program was developed, SaskPower employed an 'area coverage price' for farm services. That is to say SaskPower set a flat, fixed price for interconnecting these services. What we found was that, in the SW portion of the province for example, SaskPower had to provide lengthy service extensions to serve water wells which resulted in SaskPower also having to cover a significant portion of the service cost while receiving minimal revenue. The wind/solar water pumping program gave the customer the option to serve the well with alternative energy with SaskPower assistance. SaskPower was able to avoid the cost of installing lengthy and costly electrical services to these sites.

The program has changed again and SaskPower's policy is that it will invest the first $1,300 towards the installation of service to the site and the customer is responsible for the balance. In most cases, it is financially prudent for the customer to have the alternative energy source installed and avoid the cost of a lengthy traditional electric service extension.

Round1 – Consultant Q118:

Please describe SaskPower's capital budgeting process and capitalization policy and provide schedules showing the amount capitalized in the OM&A and other related budgets for 2010, 2011 and forecast for 2012 and 2013.

Response:

SaskPower's Capital Budgeting Process – Power Production & T&D:

The PPBU capital budgeting process for existing infrastructure projects is driven by 1) condition assessment & equipment life cycle extension 2) regulatory & safety and 3) performance improvement. During the budgeting process the PPBU management team goes over all of the projects that the plants and engineers have put forward and analyze the drivers of the project, the risks involved in doing and not doing the project and the benefits that will be received. The prioritization & selection of initiatives\projects requires business cases & managing risks to achieve optimal generating unit performance. A capital plan is then put together based on which projects were deemed to have the highest priorities and benefits. PPBU is also implementing an Asset Management System that will help with this process and, eventually, rank our capital projects based on SaskPower's priorities and risk tolerances.

Transmission capital budgeting for customer connect, capacity increases and some system improvement work is analyzed, budgeted, and authorized by the Planning, Environment & Regulatory Affairs business unit . Transmission capital budgeting for the remainder of the system improvement annual program spending as well as, all Distribution capital spending is identified, authorized and managed by the Transmission & Distribution Asset Management and Field Services department.

SaskPower's capitalization policy is attached.

SaskPower

2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

The following is a breakdown of amounts capitalized in both OM&A and finance charges for 2010 through 2012. 2013 information is not available at this time.

($ millions)	Actual 2010	Actual 2011	Budget 2012
OM&A			
Allocated Labour Costs	$ 10	$ 12	$ 13
Labour Costs Capitalized	36	35	33
Total OM&A	46	47	46
Finance Charges			
Interest Capitalized	15	12	22
Total Finance Charges	15	12	22
Total Capitalized expenses	**$ 61**	**$ 59**	**$ 68**
** 2013 information not available*			

2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

Round1 – Consultant Q119:

Please provide SaskPower's expected customer connections for 2012 and 2013, given the most recent 2010 and 2011 connections of 3,717 and 4,159 for 2012 and 2013 respectively.

Response:

SaskPower does not specifically forecast the number of customer connections in future years; however, we can provide some guidance on the expectations for 2012. In the front half of 2012, from January to May, there were 1459 customer connections. This is an increase of 469 connections over the same period in 2011. Using this information, we can assume that customer connections in 2012 will be at least equivalent to, or greater than customer connections in 2011. In 2013, customer connections are expected to follow the same trend as 2012, but are dependent on external drivers such as the Saskatchewan economy and population growth

Round1 – Consultant Q120(a):

a) Please provide a schedule showing the estimated rate increases that would be required for each year from 2013 to 2016 flowing only from the proposed capital programs (that is, all else remaining constant).

b) Please describe the nature of the negative values for the core capital projects contingency and new generation contingency 2012 Business Plan P. 32)

c) Please explain the PERA estimates under Infrastructure and capital programs for 2011, 2012 & 2013.

Response:

As a general rule of thumb, for every $100 million in capital expenditures, SaskPower will see its depreciation expense increase by $3 million and finance charges increase by $4 million. This is based on an estimated depreciation rate of 30% and a financing cost of $4 million. Based on a capital spending program of approximately $1 billion, expenses would be expected to increase by about $80 million. This increase in expense would equate to a 4.4% rate increase.

SaskPower is in the process of finalizing its 2014 to 2022 capital budgets. This information will be made available later on in September once it has been internally approved.

SaskPower

2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

Round1 – Consultant Q120(b):

a) Please provide a schedule showing the estimated rate increases that would be required for each year from 2013 to 2016 flowing only from the proposed capital programs (that is, all else remaining constant).

b) Please describe the nature of the negative values for the core capital projects contingency and new generation contingency 2012 Business Plan P. 32)

c) Please explain the PERA estimates under Infrastructure and capital programs for 2011, 2012 & 2013.

Response:

The contingencies were included in the 2012 capital budget to help offset some of the large variances between actual and budgeted capital spending over the last number of years. The contingencies were calculated by finance based on analysis of our last 5 years of actual capital spending.

SaskPower

2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

Round1 – Consultant Q120(c):

a) Please provide a schedule showing the estimated rate increases that would be required for each year from 2013 to 2016 flowing only from the proposed capital programs (that is, all else remaining constant).

b) Please describe the nature of the negative values for the core capital projects contingency and new generation contingency 2012 Business Plan P. 32)

c) Please explain the PERA estimates under Infrastructure and capital programs for 2011, 2012 & 2013.

Response:

PERA's capital budget is primarily made up of three different categories:

- New transmission projects
- New distribution projects
- New generation projects

In 2011 and 2012, PERA's new transmission and distribution projects were reported as part of T&D's capital budget. In 2013, they were reported as PERA initiatives. The reason for reporting the capital numbers in this manner is that while capital projects are in the planning phase, PERA is responsible for analyzing the projects and preparing the cost estimates. Once the project has been authorized an approved, the budget is then transferred to T&D. In the 2012 Business Plan, it was assumed that all 2011 and 2012 PERA projects were at or near the approval phase and were therefore reported as T&D initiatives. It was also assumed that all 2013 - 2021 initiatives were in the planning phase and were therefore reported as PERA capital projects.

As we finalize the 2013 to 2022 capital budget, all PERA capital projects relating to transmission and distribution will be reported as part of T&D's capital budget.

SaskPower

2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

Round1 – Consultant Q121:

Please discuss whether costs for all capital programs shown in the 2012 Business Plan are net of third party contributions from customers and/or other sources.

Response:

All capital programs shown in the 2012 Business Plan are not net of third party contributions from customers and/or other sources. Customer contributions are now recognized as revenue in SaskPower's Other Revenue

Round1 – Consultant Q122:

Recognizing the Capital Program is not within the Terms of Reference for SRRP, please provide further details of the Capital Program, similar to that provided in the 2010 Application.

Response:

Capital Expenditure ($ millions)	Actual 2010	Actual 2011	Forecast 2012	Forecast 2013
Infrastructure & Capital Programs	389.1	437.1	482.7	659.8
SaskPower New Generation	148.9	187.9	515.3	490.2
Total SaskPower Consolidated	538.0	625.0	998.0	1,150.0

SaskPower

2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

Round1 – Consultant Q123(a):

a) Please describe SaskPower's policy with respect to customer contributions related to Capital Projects and Customer attachments.

b) Please file a schedule showing all customer contributions for all capital projects for 2010 and 2011 and forecasts for 2012 and 2013 and include the calculations used to determine the amount of these contributions.

Response:

A) From a policy perspective, SaskPower pays for all costs of network upgrades. Network Upgrades are defined as: Modifications, additions or upgrades to SaskPower's existing transmission system that are required as a result of either a capacity increase request or a new service request. Network upgrades are owned and operated by SaskPower.

Customers are responsible for all Direct Assigned costs. Direct Assigned Facilities are defined as: Facilities, or portions of facilities, that are constructed by SaskPower for the sole use/benefit of a particular customer. These facilities are owned and operated by SaskPower and are attached to the existing transmission system to make possible the customer's request for a new service or a capacity increase.

Situations that involve extraordinary or unusual circumstances, e.g. remote areas or extreme conditions, may be addressed by utilizing unique or special solutions that differ from the above policy and are applied to each individual case with the prior approval of the appropriate SaskPower Vice Presidents.

The customer's contribution in aid of construction will be calculated by the Account Manager using the distance to the nearest transmission facilities with the capability to supply the load multiplied by the per kilometer unit cost of a transmission line of that voltage.

Customer transmission line costs per kilometer in 2012 are as follows:

South

	Less than 5km	Over 5km
138 kV	$335,022	$249,663
230 kV	$448,778	$332,220

North

	Less than 5km	Over 5km
138 kV	$388,600	$279,427
230 kV	$516,133	$369,436

Far North

138 kV	$909,295
230 kV	$934,926

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SaskPower

2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

Round1 – Consultant Q123(b):

a) Please describe SaskPower's policy with respect to customer contributions related to Capital Projects and Customer attachments.

b) Please file a schedule showing all customer contributions for all capital projects for 2010 and 2011 and forecasts for 2012 and 2013 and include the calculations used to determine the amount of these contributions.

Response:

The following table is a summary of customer contributions for all capital projects for 2010 and 2011 and forecasts for 2012 and 2013.

Customer Contributions			
Contributor	**2010 Actual**	**2011 Actual**	**2012 Forecast**
Distribution			
25 KV Distribution Urban	47,832	54,459	43,556
25 KV Distribution Rural	234,111	418,053	442,176
14.4 KV Distribution Urban	2,857,954	3,515,033	3,987,650
14.4 KV Distribution Rural	5,735,482	7,549,668	5,126,190
Other (Land, Streetlights) Urban	2,357,816	2,195,911	2,966,370
Other (Land, Streetlights) Urban	206,721	-	-
Residential Urban	3,558,746	3,430,988	4,118,033
Residential Rural	3,823,528	3,141,329	3,477,420
Commercial Urban	6,881,172	6,824,391	5,754,589
Farm	4,393,983	3,519,179	3,355,039
Oilfield	5,499,461	5,704,568	5,931,256
Total Distribution	*35,596,806*	*36,353,578*	*35,202,279*
Transmission			
Enbridge (Rowatt) 138kV Tap	666,000	-	-
Enbridge(Craik) 138kV Tap	418,000	-	-
Enbridge (Glenavon) 138kV Tap	10,000	-	-
Enbridge (Milden) 138kV Tap	356,000	-	-
Enbridge (Kerrobert) Tap	410,000	-	-
BHP Billiton Diamonds Inc. (Jansen Site)	3,308,240	-	-
Regina Refinery Expansion 138kV Tap	366,000	-	-
PCS Rocanville Temporary Service	617,772	-	-
Enbridge (Benson) 138kV Tap	1,088,900	-	-
Enbridge (Steelman) 72kV Tap	391,000	-	-
BHP Billiton Canada Inc.	-	849,620	-
PetroBank Energy Whitesands	-	522,855	-
Mosaic Potash	-	319,000	-
Potash Corp of Saskatchewan	-	263,925	3,049,000
Potash Corp of Saskatchewan	-	-	302,000
Potash Corp of Saskatchewan	-	-	95,000

Potash Corp of Saskatchewan	-	-	356,070
TransCanada Keystone	-	16,657,500	87,562
Potash One	-	214,500	-
Ministry of Highway	-	439,320	4,342,000
K+S Potash Canada General Partnership	-	-	2,470,000
K+S Potash Canada General Partnership	-	-	1,200,000
Total Transmission	*7,631,912*	*19,266,720*	*11,901,632*
Total Customer Connects	**43,228,718**	**55,620,298**	**47,103,911**

SaskPower

2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

Round1 – Consultant Q124:

Please provide continuity schedules for showing Gross and Net Plant, Depreciation, Plant Additions and Plant Retirements since 2009.

Response:

Plant in Service Continuity Schedule ($000)				
	Jun-12	**2011**	**2010 IFRS**	**2009**
Plant in Service Beginning of Year	9,050,608	8,518,060	8,003,126	7,361,395
Additions	244,107	572,830	568,662	543,570
Removals	(14,116)	(40,282)	(53,728)	(46,845)
Plant in Service End of Year	9,280,599	9,050,608	8,518,060	7,858,120
Accum Deprn Beginning of Year	(4,098,199)	(3,845,928)	(3,628,402)	(3,365,521)
Depreciation Provision	(152,473)	(285,430)	(263,430)	(240,992)
Accum Deprn on Retired Assets	10,567	33,159	45,904	43,081
Accum Depn End of Year	(4,240,105)	(4,098,199)	(3,845,928)	(3,563,432)
Net Plant in Service	**5,040,494**	**4,952,409**	**4,672,132**	**4,294,688**
Customer Contributions				(340,374)
*Other Property Plant & Equip	617,698	434,383	251,126	304,567
Total Property Plant & Equipment	5,658,192	5,386,792	4,923,258	4,258,881

*Other Property Plant & Equip includes: asset retirement assets and construction in progress.

2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

Round1 – Consultant Q125: Please provide details demonstrating the actual 2010, 2011 and 2012 & 2013 forecasted impacts on revenue requirements by components flowing entirely from the 2009 to 2013 Capital Programs.

Response:

Finance charges and depreciation are the largest contributors to increased revenue requirements as a result of SaskPower's capital spending programs. As a general rule of thumb, for every $100 million in capital expenditures, SaskPower will see its depreciation expense increase by $3 million and finance charges increase by $4 million.

SaskPower's actual and forecasted capital expenditures for the years 2010 to 2013 were as follows:

2010 - $565 million
2011 - $624 million
2012 - $998 million
2013 - $1,150 million

Using the methodology noted above, the impact on revenue requirements would be as follows:

2010 - $40 million
2011 - $44 million
2012 - $70 million
2013 - $80 million

2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

Round1 – Consultant Q126:

Please file a schedule showing approved and actual capital expenditures for 2010 and 2011 and explain any variances.

Response:

CAPITAL EXPENDITURE

As at December 2010

($000's)

CURRENT YEAR				PROJECT					
YTD Actual	2010 Budget	Variance		PTD Actual	Original CPA Value	Total CPR Value	% CNG	Total CPA Value	Variance
			Finance & Enterprise Risk Management						
762.1	1,680.0	(917.9)	Buildings Upgrading	762.1	1,430.0	0.0		1,430.0	(667.9)
1,318.3	1,600.0	(281.8)	Furniture & Equipment	1,318.3	1,600.0	0.0		1,600.0	(281.8)
1.8	6,000.0	(5,998.2)	North Battleford Service Center	31.1	0.0	0.0		0.0	31.1
(4.9)	1,000.0	(1,004.9)	Prince Albert Service Centre - 1 Bay Addition	(4.9)	0.0	0.0		0.0	(4.9)
117.2	6,000.0	(5,882.8)	Regina Region Service Centre	117.2	0.0	0.0		0.0	117.2
359.4	500.0	(140.6)	Regina Steel Storage Yard Rebuild	359.4	0.0	0.0		0.0	359.4
835.9	0.0	835.9	Regina - TS & R Upgrades	835.9	650.0	0.0		650.0	185.9
0.0	1,500.0	(1,500.0)	Saskatoon Service Centre Expansion	0.0	4,500.0	0.0		4,500.0	(4,500.0)
0.2	1,000.0	(999.8)	Stoney Rapids	3.2	1,010.0	0.0		1,010.0	(1,006.8)
0.0	1,000.0	(1,000.0)	Swift Current Service Centre	0.0	0.0	0.0		0.0	0.0
14,913.6	14,316.0	597.6	Vehicles & Equipment	14,913.6	14,961.0	0.0		14,961.0	(47.4)
122.8	10,000.0	(9,877.2)	Weyburn Service Center T&D	1,416.0	16,000.0	0.0		16,000.0	(14,584.0)
0.0	0.0	0.0	Miscellaneous Projects Under $500,000						
18,426.3	**44,596.0**	**(26,169.7)**	**Total Finance & Enterprise Risk Management**	**19,751.8**	**40,151.0**	**0.0**		**40,151.0**	**(20,399.2)**
			Planning, Environment & Regulatory Affairs						
0.0	798.0	(798.0)	110 MW IPP Peaking at Tantallon Interconnection	0.0	0.0	0.0		0.0	0.0
0.0	4,466.0	(4,466.0)	141 MW Yellowhead Peaking Interconnection	0.0	0.0	0.0		0.0	0.0
0.0	5,220.0	(5,220.0)	300 MW IPP Base Load (Meridian as proxy) Interconnnection (2012)	0.0	0.0	0.0		0.0	0.0
0.0	700.0	(700.0)	Meterological Towers for Wind Forecasting	0.0	0.0	0.0		0.0	0.0
0.0	31,500.0	(31,500.0)	Shand Coal Drying	0.0	0.0	0.0		0.0	0.0
389.9	622.0	(232.1)	Shand Greenhouse	610.2	716.0	0.0		716.0	(105.8)
18,440.8	0.0	18,440.8	Tantallon Peaking Station Natural Gas Pipe Line	18,440.8	17,801.9	0.0		17,801.9	639.0
18,830.8	**43,306.0**	**(24,475.2)**	**Total Planning, Environment & Regulatory Affairs**	**19,051.1**	**18,517.9**	**0.0**		**18,517.9**	**533.2**
			Corporate Information and Technology						
1,667.6	960.0	707.6	Backup & Storage	3,425.1	2,992.0	1,495.0	50.0	4,487.0	(1,061.9)
512.3	0.0	512.3	Automated Test Tools	512.3	610.1	0.0		610.1	(97.9)
619.5	0.0	619.5	DeskTop Modernization	619.5	2,009.0	0.0		2,009.0	(1,389.5)
2,773.7	1,850.0	923.7	Infrastructure Refresh & Renewal -2010	2,773.7	2,920.6	0.0		2,920.6	(146.9)
0.0	1,290.0	(1,290.0)	Enterprise Applications	0.0	0.0	0.0		0.0	0.0
4,771.8	0.0	4,771.8	Microsoft Enterprise Agreement	4,771.8	4,400.0	580.0	13.2	4,980.0	(208.2)
884.8	250.0	634.8	Identity & Access Management	4,229.8	4,120.0	127.4	3.1	4,247.4	(17.6)
1,112.6	1,800.0	(687.4)	IP Telephony	1,112.6	9,271.8	0.0		9,271.8	(8,159.2)
0.0	600.0	(600.0)	Security Infrastructure	0.0	0.0	0.0		0.0	0.0
0.0	750.0	(750.0)	Information Management Portfolio	0.0	0.0	0.0		0.0	0.0
1,921.0	2,500.0	(579.0)	PC Refresh Program & New Requests	1,921.0	2,408.1	0.0		2,408.1	(487.1)
0.0	412.0	(412.0)	SAP Archiving	0.0	0.0	0.0		0.0	0.0
0.0	1,406.0	(1,406.0)	Prudent Financial Management Portfolio	0.0	0.0	0.0		0.0	0.0
795.7	0.0	795.7	EPPM Tools	795.7	1,861.7	463.8	24.9	2,325.5	(1,529.7)
0.0	3,157.0	(3,157.0)	Dependable & Secure Infrastructure Porfolio	0.0	0.0	0.0		0.0	0.0
620.1	0.0	620.1	Overhaul Scope Management	1,502.3	1,775.0	(295.0)	(16.6)	1,480.0	22.3
1,362.8	0.0	1,362.8	Properties Management	2,391.2	1,613.0	813.0	50.4	2,426.0	(34.8)
0.0	550.0	(550.0)	Loyal & Satisfied Customers Portfolio	0.0	0.0	0.0		0.0	0.0
503.4	0.0	503.4	Law Practice Management	858.3	325.0	697.9	214.7	1,022.9	(164.6)
122.6	300.0	(177.4)	Small Business Projects	174.6	0.0	0.0		0.0	174.6
0.0	587.0	(587.0)	Proud & Productive Employees Portfolio	0.0	0.0	0.0		0.0	0.0
2,447.7	0.0	2,447.7	Miscellaneous Projects Under $500,000	0.0	0.0	0.0		0.0	0.0
20,115.4	**16,412.0**	**3,703.4**	**Total Corporate Information and Technology**	**25,088.0**	**34,306.4**	**3,882.0**	**11.3**	**38,188.4**	**(13,100.4)**

CAPITAL EXPENDITURE (CONTINUED)

CURRENT YEAR				PROJECT					
YTD Actual	2010 Budget	Variance		PTD Actual	Original CPA Value	Total CPR Value	% CNG	Total CPA Value	Variance
			Customer Services						
2,945.7	5,688.0	(2,742.3)	Meter Purchases	2,945.7	5,688.0	0.0		5,688.0	(2,742.3)
0.0	1,000.0	(1,000.0)	Handheld Meter Replacements	0.0	0.0	0.0		0.0	0.0
0.0	1,917.0	(1,917.0)	SDR - Automated Metering Implementation	0.0	0.0	0.0		0.0	0.0
11,898.0	11,113.0	785.0	SDR - CIS/CRM System Implementation	13,503.0	20,421.3	0.0		20,421.3	(6,918.3)
0.0	4,783.0	(4,783.0)	SDR - Telephony	0.0	0.0	0.0		0.0	0.0
			Service Delivery Renewal - CI&T Delivered						
810.4	4,602.0	(3,791.6)	SDR - Business Intelligence	810.4	0.0	0.0		0.0	810.4
285.7	0.0	285.7	SDR - Field Worker Technolgy Phase I - Ruggedized Laptops	6,551.8	6,102.0	684.3	11.2	6,786.3	(234.5)
0.0	881.0	(881.0)	SDR - Field Worker Technolgy Phase III - Outage Mgmt System	0.0	0.0	0.0		0.0	0.0
2,492.3	1,747.0	745.3	SDR - Field Worker Technology Phase II - Schedule & Dispatch	4,478.4	1,524.6	461.5	30.3	1,986.1	2,492.3
0.0	0.0	0.0	Miscellaneous Projects Under $500,000						
18,432.2	**31,731.0**	**(13,298.8)**	**Total Customer Services**	**28,289.3**	**33,735.9**	**1,145.8**	**3.4**	**34,881.7**	**(6,592.4)**
			Power Production						
			Poplar River						
80.1	504.0	(423.9)	Poplar River #1 Ash Controls Replacement	133.0	4,434.0	0.0		4,434.0	(4,301.0)
26.3	916.0	(889.7)	Poplar River #1 HP #6 Feedwater Heater Replacement	26.3	0.0	0.0		0.0	26.3
13.5	1,375.0	(1,361.5)	Poplar River #1 Precipitator Improvements	16.2	0.0	0.0		0.0	16.2
148.5	548.0	(399.5)	Poplar River #1 Sootblower Controls Upgrade	394.5	950.0	0.0		950.0	(555.5)
1,582.6	2,000.0	(417.4)	Poplar River #1 Waterwall Refurbishment	1,582.6	0.0	0.0		0.0	1,582.6
727.6	900.0	(172.4)	Poplar River #2 A SBAC Upgrade	1,141.5	1,200.0	600.0	50.0	1,800.0	(658.5)
1,658.7	3,367.0	(1,708.3)	Poplar River #2 Ash Controls Replacement	1,824.7	5,551.0	0.0		5,551.0	(3,726.3)
1,329.4	400.0	929.4	Poplar River #2 FDF Stall Remediation	1,859.5	1,400.0	600.0	42.9	2,000.0	(140.5)
0.0	900.0	(900.0)	Poplar River #2 Flue Gas Heat Mass Balance	0.0	0.0	0.0		0.0	0.0
1,636.6	3,000.0	(1,363.4)	Poplar River #2 Ignitor & Flame Scanner Upgrade	2,216.4	3,665.0	866.0	23.6	4,531.0	(2,314.6)
56.0	1,395.0	(1,339.0)	Poplar River #2 Main Steam Line Piping Replacement	159.5	1,540.0	535.0	34.7	2,075.0	(1,915.5)
198.0	548.0	(350.0)	Poplar River #2 Sootblower Controls Upgrade	396.5	950.0	(207.0)	(21.8)	743.0	(346.5)
0.0	813.0	(813.0)	Poplar River #2 Switchgear Replacement	0.0	0.0	0.0		0.0	0.0
3,334.7	2,646.0	688.7	Poplar River Ash Lagoon #4 Construction	11,373.7	7,703.0	6,375.0	82.8	14,078.0	(2,704.3)
1,747.6	0.0	1,747.6	Poplar River Ash Line Perm Structures	1,747.6	2,640.0	0.0		2,640.0	(892.4)
2,514.6	4,000.0	(1,485.4)	Poplar River Coal Crusher Replacement	3,880.6	4,250.0	0.0		4,250.0	(369.4)
1,306.3	0.0	1,306.3	Poplar River Facilities Improvement	1,643.4	2,500.0	661.2	26.4	3,161.2	(1,517.8)
810.6	0.0	810.6	Poplar River Hydrogen Facilities Improvement	1,488.0	1,876.7	0.0		1,876.7	(388.7)
0.0	800.0	(800.0)	Poplar River Salinity & Dewatering Wells	0.0	0.0	0.0		0.0	0.0
17,171.0	24,112.0	(6,941.0)	**Total Poplar River Projects**	29,884.0	38,659.7	9,430.2	24.4	48,089.9	(18,205.9)
			Boundary Dam						
0.0	810.0	(810.0)	BD #4 Burner Uprades	0.0	0.0	0.0		0.0	0.0
1,244.1	804.0	440.1	BD #4 HP Heater Replacement #4	1,469.8	3,285.0	0.0		3,285.0	(1,815.2)
1,028.4	1,500.0	(471.6)	BD #4 Waterwall Replacement	1,028.4	2,500.0	0.0		2,500.0	(1,471.6)
1,401.2	861.0	540.2	BD #5 & #6 WTP HMI Replacement	1,614.9	2,366.0	472.0	19.9	2,838.0	(1,223.1)
85.9	1,200.0	(1,114.1)	BD #5 Cabling & Switchgear	346.1	3,800.0	0.0		3,800.0	(3,453.9)
0.0	1,500.0	(1,500.0)	BD #5 HP Major Overhaul	0.0	4,266.0	0.0		4,266.0	(4,266.0)
680.2	750.0	(69.8)	BD #6 Boiler Seal Trough	680.2	750.0	354.0	47.2	1,104.0	(423.8)
2,961.6	3,207.0	(245.4)	BD #6 Economizer Life Extension	2,961.6	4,886.9	1,991.1	40.7	6,878.0	(3,916.5)
3,056.7	5,928.0	(2,871.3)	BD #6 Generator Rotor Upgrade	5,619.7	6,516.8	100.4	1.5	6,617.2	(997.5)
2,992.4	2,885.0	107.4	BD #6 HP Replacement #6	3,600.9	2,885.0	1,015.0	35.2	3,900.0	(299.1)
8,265.7	12,367.0	(4,101.3)	BD #6 LP Turbine Upgrade	20,402.7	19,861.0	1,977.0	10.0	21,838.0	(1,435.3)
716.4	2,000.0	(1,283.6)	BD #6 Power Distribution/Cabling	726.3	2,700.0	0.0		2,700.0	(1,973.7)
0.1	650.0	(649.9)	BD #6 Secondary Air Upgrades	0.1	0.0	0.0		0.0	0.1
994.5	1,435.0	(440.5)	BD #6 Turbine Supervisory	1,015.2	1,680.0	0.0		1,680.0	(664.8)
863.1	1,152.0	(288.9)	BD Asbestos Removal	2,068.1	9,075.9	478.0	5.3	9,553.9	(7,485.8)
404.9	500.0	(95.1)	BD Ash Lagoon Surcharging	837.8	500.0	0.0		500.0	337.8
945.7	1,100.0	(154.3)	BD Coated Waterwall Panel (KE)	4,149.6	7,226.1	527.8	7.3	7,753.9	(3,604.3)
383.9	1,894.0	(1,510.1)	BD Fire System Upgrade	383.9	1,650.0	0.0		1,650.0	(1,266.1)
1,046.6	7,500.0	(6,453.4)	BD FLYASH Collection & Storage Expansion	1,056.7	6,000.0	0.0		6,000.0	(4,943.3)
40.7	1,000.0	(959.3)	BD Hydrogen Systems Upgrade	40.7	3,169.5	0.0		3,169.5	(3,128.8)
868.2	0.0	868.2	BD Powerhouse Ventilation	3,349.7	3,000.0	380.0	12.7	3,380.0	(30.3)
1,393.6	300.0	1,093.6	BD Roof Replacement	2,827.0	420.0	3,524.0	839.0	3,944.0	(1,117.0)
2,139.7	2,153.0	(13.3)	BD Shielding Upgrades	2,139.7	7,901.6	0.0		7,901.6	(5,761.9)
435.6	500.0	(64.4)	BD 'B' Pulveriser Upgrade	973.2	642.0	0.0		642.0	331.2
8,500.5	572.0	7,928.5	BDPS Spillway Upgrade	56,621.8	30,000.0	26,000.0	86.7	56,000.0	621.8
40,449.4	52,568.0	(12,118.6)	**Total Boundary Dam Projects**	113,914.0	125,081.8	36,819.3	29.4	161,901.1	(47,987.1)

CAPITAL EXPENDITURE (CONTINUED)

CURRENT YEAR				PROJECT					
YTD Actual	2010 Budget	Variance		PTD Actual	Original CPA Value	Total CPR Value	% CNG	Total CPA Value	Variance
			Shand						
0.0	4,100.0	(4,100.0)	Shand Additional FLYASH Storage Capacity	1.1	0.0	0.0		0.0	1.1
278.7	583.0	(304.3)	Shand Analytical Panel	302.4	600.0	0.0		600.0	(297.6)
0.0	5,800.0	(5,800.0)	Shand Major Overhaul 2012	0.0	0.0	0.0		0.0	0.0
652.3	0.0	652.3	Shand Shower Room Upgrade	707.0	964.2	237.3	24.6	1,201.5	(494.5)
603.6	997.0	(393.4)	Shand Water Treatment Plant Upgrades	607.4	2,350.0	0.0		2,350.0	(1,742.6)
1,534.6	11,480.0	(9,945.4)	**Total Shand Projects**	1,617.8	3,914.2	237.3	6.1	4,151.5	(2,533.7)
			Northern Hydro						
5,065.4	8,000.0	(2,934.6)	Coteau Creek Rewind	8,983.1	20,100.0	0.0		20,100.0	(11,116.9)
6,903.8	7,914.0	(1,010.2)	EB Campbell 7 Runner Refurbishment	8,856.9	15,000.0	0.0		15,000.0	(6,143.1)
3,382.6	1,082.0	2,300.6	EB Campbell 8 Runner Refurbishment	5,173.5	15,000.0	0.0		15,000.0	(9,826.5)
4,576.7	2,400.0	2,176.7	EB Campbell PCMS	5,150.0	11,000.0	0.0		11,000.0	(5,850.0)
5,293.3	6,556.0	(1,262.7)	Island Falls #4 Refurbishment	8,948.5	28,000.0	4,200.0	15.0	32,200.0	(23,251.5)
1,025.0	1,938.0	(913.0)	Island Falls #5 Refurbishment	1,757.8	21,000.0	2,520.0	12.0	23,520.0	(21,762.2)
658.5	337.0	321.5	Island Falls #6 Refurbishment	1,267.3	21,000.0	2,150.0	10.2	23,150.0	(21,882.7)
2,725.4	2,641.0	84.4	Island Falls Dam Safety Upgrades	2,854.6	5,242.2	0.0		5,242.2	(2,387.6)
620.9	788.0	(167.1)	Island Falls Generator Breaker Upgrade	1,786.3	2,100.0	309.0	14.7	2,409.0	(622.7)
1,791.0	1,300.0	491.0	Island Falls PCMS	1,962.9	11,000.0	0.0		11,000.0	(9,037.1)
32,042.5	32,956.0	(913.5)	**Total Northern Hydro**	46,740.9	149,442.2	9,179.0	6.1	158,621.2	(111,880.3)
			Western Plants						
0.0	1,500.0	(1,500.0)	Ermine Maintenance Facility	0.0	0.0	0.0		0.0	0.0
676.4	0.0	676.4	QE #2 Governor Upgrades	2,425.6	2,000.0	0.0		2,000.0	425.6
767.4	0.0	767.4	QE #2 Turbine Overhaul	4,840.2	4,750.0	(77.6)	(1.6)	4,672.4	167.8
3,019.3	3,202.0	(182.7)	QE #3 Controls	3,281.5	3,781.0	788.0	20.8	4,569.0	(1,287.5)
648.9	3,235.0	(2,586.1)	QE Facility Upgrade	1,115.4	9,127.0	0.0		9,127.0	(8,011.6)
5,112.0	7,937.0	(2,825.0)	**Total Western Plants**	11,662.6	19,658.0	710.4	3.6	20,368.4	(8,705.8)
			Fuel Supply						
0.0	2,000.0	(2,000.0)	Cookson Reservoir Supplementary Water	0.0	2,000.0	0.0		2,000.0	(2,000.0)
0.0	868.0	(868.0)	Coronach Land Purchase	0.0	2,075.0	0.0		2,075.0	(2,075.0)
69.1	1,330.0	(1,260.9)	Estevan Land Purchase	69.1	2,990.0	0.0		2,990.0	(2,920.9)
69.1	4,198.0	(4,128.9)	**Total Fuel Supply**	69.1	7,065.0	0.0		7,065.0	(6,995.9)
			Other						
2,418.9	1,900.0	518.9	On-Line Performance Monitoring & Anomoly Detection Systems	5,324.8	5,000.0	80.0	1.6	5,080.0	244.8
563.8	0.0	563.8	NERC CIP 002-009 Cyber Security	1,182.6	1,500.0	120.0	8.0	1,620.0	(437.4)
862.7	585.0	277.7	Emissions Control Research Facility Phase IV	2,458.7	2,712.0	1,235.0	45.5	3,947.0	(1,488.3)
750.2	674.0	76.2	Power Production Capital Tools	750.2	0.0	0.0		0.0	750.2
4,595.6	3,159.0	1,436.6	**Total Other**	9,716.3	9,212.0	1,435.0	15.6	10,647.0	(930.7)
6,207.9	6,338.0	(130.1)	Miscellaneous Projects Under $500,000						
107,182.2	**142,748.0**	**(35,565.8)**	**Total Power Production - Infrastructure Renewal**	**213,604.7**	**353,032.9**	**57,811.2**	**16.4**	**410,844.1**	**(197,239.4)**
			New Generation						
5,773.1	0.0	5,773.1	BD #3 ICCS - Power Island	5,773.1	354,000.0	0.0		354,000.0	(348,226.9)
1,221.3	3,853.0	(2,631.7)	Ermine SC Gas Turbine Project	131,880.3	150,000.0	0.0		150,000.0	(18,119.7)
113,430.4	136,559.0	(23,128.6)	Yellowhead Gas Turbine SCGT #2	186,890.2	250,000.0	0.0		250,000.0	(63,109.8)
5,522.4	8,447.0	(2,924.6)	Queen Elizabeth Gas Turbines	157,200.0	240,000.0	0.0		240,000.0	(82,800.0)
125,947.1	148,859.0	(22,911.9)	**Total New Generation**	481,743.5	994,000.0	0.0		994,000.0	(512,256.5)
278.7	575.0	(296.3)	Cory Cogeneration Station Improvements	278.7	0.0	0.0		0.0	278.7
233,408.0	**292,182.0**	**(58,774.0)**	**Total Power Production**	**695,626.9**	**1,347,032.9**	**57,811.2**	**4.3**	**1,404,844.1**	**(709,217.2)**

CAPITAL EXPENDITURE (CONTINUED)

CURRENT YEAR				PROJECT					
YTD Actual	2010 Budget	Variance		PTD Actual	Original CPA Value	Total CPR Value	% CNG	Total CPA Value	Variance
			Transmission and Distribution						
			Customer Connects by Region						
24,664.6	16,000.0	8,664.6	Prince Albert Region	24,664.6	16,000.0	8,000.0	50.0	24,000.0	664.6
21,346.5	16,500.0	4,846.5	Regina Region	21,346.5	16,500.0	4,000.0	24.2	20,500.0	846.5
26,994.0	29,000.0	(2,006.0)	Saskatoon Region	26,994.0	29,000.0	(3,000.0)	(10.3)	26,000.0	994.0
28,189.8	35,000.0	(6,810.2)	Weyburn Region	28,189.8	35,000.0	(7,000.0)	(20.0)	28,000.0	189.8
101,194.9	96,500.0	4,694.9	**Total Customer Connects by Region**	101,194.9	96,500.0	2,000.0	2.1	98,500.0	2,694.9
			Annual Capital Programs						
4,095.9	2,500.0	1,595.9	Farmyard Line Relocation Program	4,095.9	2,500.0	1,500.0	60.0	4,000.0	95.9
1,560.8	2,000.0	(439.2)	Induction Crew Projects	1,560.8	2,000.0	0.0		2,000.0	(439.2)
577.2	2,000.0	(1,422.8)	Miscellaneous Apparatus Improvements	577.2	2,000.0	0.0		2,000.0	(1,422.8)
1,744.4	1,000.0	744.4	New Codes (Urban SI)	1,744.4	1,000.0	1,000.0	100.0	2,000.0	(255.6)
2,869.7	3,000.0	(130.3)	Power Quality Projects/25kV Rebuilds	2,869.7	3,000.0	0.0		3,000.0	(130.3)
499.5	1,060.0	(560.5)	Regulators	499.5	1,060.0	0.0		1,060.0	(560.5)
4,448.0	12,500.0	(8,052.0)	Rural Rebuild & Improvement Program	4,448.0	12,500.0	0.0		12,500.0	(8,052.0)
477.8	600.0	(122.2)	Steel Street Light Replacements	477.8	600.0	0.0		600.0	(122.2)
561.1	750.0	(188.9)	T & D Tools	561.1	650.0	0.0		650.0	(88.9)
7,633.6	5,500.0	2,133.6	Transformer Replacements	7,633.6	5,500.0	1,905.0	34.6	7,405.0	228.6
980.6	1,300.0	(319.4)	Urban Underground Cable Replacements	980.6	1,300.0	0.0		1,300.0	(319.4)
1,606.9	2,500.0	(893.1)	Urban/Rural Hazards Mitigation	1,606.9	2,500.0	0.0		2,500.0	(893.1)
8,920.8	15,000.0	(6,079.2)	Wood Pole Replacement	8,920.8	15,000.0	0.0		15,000.0	(6,079.2)
35,976.1	49,710.0	(13,733.9)	**Total Annual Capital Programs**	35,976.1	49,610.0	4,405.0	8.9	54,015.0	(18,038.9)
			Network Development						
			Communication, Protection and Control Projects						
0.0	500.0	(500.0)	72kV BF Protection Installations	0.0	0.0	0.0		0.0	0.0
0.0	550.0	(550.0)	A1R & R1S Protection Upgrade	0.0	0.0	0.0		0.0	0.0
0.0	750.0	(750.0)	Ermine Switching Station Control Building Facilities	0.0	0.0	0.0		0.0	0.0
0.0	4,600.0	(4,600.0)	Fibre Route Diversity	0.0	0.0	0.0		0.0	0.0
2,234.5	0.0	2,234.5	Fibre Optic Terminal Loop	2,234.5	2,385.0	0.0		2,385.0	(150.5)
353.3	900.0	(546.7)	Fleetnet - P25 Radios	34,620.9	23,899.0	14,211.6	59.5	38,110.6	(3,489.7)
38.1	800.0	(761.9)	GCC Grid Control Room Rehabilitation	38.1	305.0	0.0		305.0	(266.9)
0.0	610.0	(610.0)	NERC - B1K Redundant Protection Communications	0.0	0.0	0.0		0.0	0.0
2.3	930.0	(927.7)	NERC - B1L Redundant Protection Communications	2.3	77.0	0.0		77.0	(74.7)
0.0	1,340.0	(1,340.0)	NERC - Special Protection System Loss of B2R/B3R	0.0	0.0	0.0		0.0	0.0
0.0	500.0	(500.0)	Operational WAN Access	0.0	0.0	0.0		0.0	0.0
0.0	750.0	(750.0)	Protection Development Facility	0.0	0.0	0.0		0.0	0.0
0.0	650.0	(650.0)	Regina South 72kV Breaker Fail Protection & Relay Replacement	0.0	827.7	0.0		827.7	(827.7)
412.8	945.0	(532.2)	Replace BBC, LZ96, LZ92 & LIZ6-13 Distance Relays	2,162.2	3,027.2	0.0		3,027.2	(865.0)
324.7	675.0	(350.3)	Replace Reyrolle Distance Relays	1,858.6	2,342.4	0.0		2,342.4	(483.8)
0.0	700.0	(700.0)	RTU Data Communications Speed Increase	0.0	0.0	0.0		0.0	0.0
338.6	0.0	338.6	RTU / SER Replacement	5,989.5	3,785.0	0.0		3,785.0	2,204.5
1,085.1	1,000.0	85.1	SCADA EMS Lifecycle (XA/21 Replacement)	1,708.5	7,604.0	0.0		7,604.0	(5,895.5)
4,789.5	16,200.0	(11,410.5)	**Total Communication, Protection and Control Projects**	48,614.8	44,252.3	14,211.6	32.1	58,463.9	(9,849.2)
			Subtransmission System Projects						
0.4	1,010.0	(1,009.6)	Aberfeldy Capacity Increase	0.4	100.0	0.0		100.0	(99.6)
0.0	960.0	(960.0)	Agrium Tritin Construction Power	0.0	0.0	0.0		0.0	0.0
3,264.1	3,840.0	(575.9)	Agrium Vanscoy 138kV Service	3,504.0	7,759.0	0.0		7,759.0	(4,255.0)
668.5	515.0	153.5	Assiniboia Substation Rebuild	678.7	2,160.9	0.0		2,160.9	(1,482.2)
0.0	6,010.0	(6,010.0)	Athabasca Burr Construction Power	0.0	0.0	0.0		0.0	0.0
5.2	4,600.0	(4,594.8)	Auburnton 230/72kV Capacity Increase	5.2	200.0	0.0		200.0	(194.8)
2,424.8	4,275.0	(1,850.2)	Auburnton Substation	3,264.3	5,450.8	0.0		5,450.8	(2,186.5)
4,754.9	3,750.0	1,004.9	BHP Construction Power	4,787.8	8,000.0	0.0		8,000.0	(3,212.2)
2,441.0	4,872.0	(2,431.0)	Clarence & Engen Substation Rebuild	6,968.0	9,603.0	0.0		9,603.0	(2,635.0)
909.1	2,400.0	(1,490.9)	Dundonald Capacity Increase	915.1	4,967.0	0.0		4,967.0	(4,051.9)
1,616.2	1,325.0	291.2	Enbridge - Benson	1,616.2	1,778.5	0.0		1,778.5	(162.3)
0.0	2,800.0	(2,800.0)	Enbridge - Redvers	0.0	0.0	0.0		0.0	0.0
0.0	1,000.0	(1,000.0)	Fleet Street Capacity Increase	0.0	0.0	0.0		0.0	0.0
2,664.2	5,200.0	(2,535.8)	GAIA Power - Red Jacket	2,664.2	4,411.7	(391.0)	(8.9)	4,020.7	(1,356.5)
667.4	2,050.0	(1,382.6)	Halbrite West 138/25kV Substation	1,288.3	4,489.1	0.0		4,489.1	(3,200.8)
60.5	800.0	(739.5)	Hoosier Substation	1,519.1	0.0	0.0		0.0	1,519.1
1,611.5	2,000.0	(388.5)	Insulator Upgrade	2,941.4	700.0	0.0		700.0	2,241.4
2,783.5	664.0	2,119.5	Kindersley - Coleville 138kV Line	5,492.5	0.0	0.0		0.0	5,492.5

CAPITAL EXPENDITURE (CONTINUED)

CURRENT YEAR				PROJECT					
YTD Actual	2010 Budget	Variance		PTD Actual	Original CPA Value	Total CPR Value	% CNG	Total CPA Value	Variance
379.4	555.0	(175.6)	Marengo - Hoosier 138kV Line	1,368.7	0.0	0.0		0.0	1,368.7
59.2	3,000.0	(2,940.8)	Mobile Transformers	65.6	5,000.0	0.0		5,000.0	(4,934.4)
307.6	741.0	(433.4)	Mosaic K2 New Site Load Interconnection	2,828.9	5,530.5	(1,009.0)	(18.2)	4,521.5	(1,692.6)
961.3	2,645.0	(1,683.7)	North Battleford Substation	6,119.5	9,889.0	0.0		9,889.0	(3,769.5)
1,767.6	5,892.0	(4,124.4)	PCS Rocanville 138kV Service	1,801.4	7,761.4	2,161.1	27.8	9,922.5	(8,121.1)
3.0	1,289.0	(1,286.0)	PCS Scissor Creek 138kV Service	3.0	6,592.7	(2,701.7)	(41.0)	3,891.0	(3,888.0)
6.9	1,500.0	(1,493.1)	Potash One Construction Power	6.9	211.3	0.0		211.3	(204.4)
0.0	1,500.0	(1,500.0)	QE3 River Crossing	2,500.4	0.0	0.0		0.0	2,500.4
4,768.1	1,261.0	3,507.1	S1E - ER Conversion & Hoosier Substation	12,418.7	14,888.7	0.0		14,888.7	(2,470.0)
26.8	4,000.0	(3,973.2)	Saskatoon North Reinforcement	27.9	355.0	0.0		355.0	(327.1)
8.2	1,500.0	(1,491.8)	Saskatoon West Reinforcement	14.1	0.0	0.0		0.0	14.1
5.4	1,400.0	(1,394.6)	SNI Capacity Increase	8.7	100.0	0.0		100.0	(91.3)
42.1	1,490.0	(1,447.9)	Spiritwood Capacity Increase	57.7	2,391.9	0.0		2,391.9	(2,334.2)
10,964.0	9,998.0	966.0	Steelman Capacity Increase	12,224.3	14,400.0	(1,677.0)	(11.6)	12,723.0	(498.7)
2,894.3	4,176.0	(1,281.7)	Weyburn Substation Rebuild	6,994.1	8,250.7	0.0		8,250.7	(1,256.6)
576.6	0.0	576.6	Wildwood 11/15 MVA Transformer Replacement	576.6	683.0	0.0		683.0	(106.4)
5,001.7	4,850.0	151.7	Wollaston Lake Substation	5,058.0	8,188.6	(116.0)	(1.4)	8,072.6	(3,014.6)
124.5	1,075.0	(950.5)	Yorkton #2 Capacity Increase	124.5	7,434.0	0.0		7,434.0	(7,309.5)
51,767.9	94,943.0	(43,175.1)	**Total Subtransmission System Projects**	87,844.3	141,296.8	(3,733.6)	(2.6)	137,563.2	(49,718.8)
			Transmission Projects						
0.0	1,500.0	(1,500.0)	Apparatus Test Support for Power Production	0.0	0.0	0.0		0.0	0.0
0.0	2,800.0	(2,800.0)	Assiniboia SVS	0.0	0.0	0.0		0.0	0.0
0.0	1,232.0	(1,232.0)	Beatty - Wolverine 230kV Line	0.0	0.0	0.0		0.0	0.0
0.0	1,300.0	(1,300.0)	Boundary Dam Breaker Fail Improvement	0.0	0.0	0.0		0.0	0.0
0.0	620.0	(620.0)	CCILS SPS Redundancy	0.0	0.0	0.0		0.0	0.0
0.0	2,800.0	(2,800.0)	Chaplin Switching Station	0.0	0.0	0.0		0.0	0.0
0.0	2,827.0	(2,827.0)	Cluff Lake Interconnection Transmission Line	0.0	0.0	0.0		0.0	0.0
0.0	2,600.0	(2,600.0)	Codette 230/72kV Capacity Increase	0.0	0.0	0.0		0.0	0.0
1,607.4	4,340.0	(2,732.6)	Ermine SCGT #1 & #2 Interconnection	7,847.2	9,559.0	494.0	5.2	10,053.0	(2,205.8)
0.7	5,370.0	(5,369.3)	Fleet Street 230/138kV Transformer	0.7	17,920.4	0.0		17,920.4	(17,919.7)
5.5	1,500.0	(1,494.5)	Fleet Street Breaker Position	222.7	0.0	0.0		0.0	222.7
0.3	678.0	(677.7)	FS 727-730 Delle Breaker Replacements	6.1	0.0	0.0		0.0	6.1
38.9	6,315.0	(6,276.1)	Halbrite Area Reinforcement	90.5	500.0	0.0		500.0	(409.5)
579.5	1,000.0	(420.5)	Independent Power Producer (IPP) - Tantallon SCGT Unit #1 & 2	579.5	2,012.0	0.0		2,012.0	(1,432.5)
763.7	22,421.0	(21,657.3)	Island Falls - Far North 138kV Transmission Line	1,102.5	1,394.3	0.0		1,394.3	(291.8)
0.0	2,801.0	(2,801.0)	Millenium Interconnection Transmission Line	0.0	0.0	0.0		0.0	0.0
0.0	1,150.0	(1,150.0)	NERC - QESS Breaker Fail	0.0	0.0	0.0		0.0	0.0
0.0	13,030.0	(13,030.0)	Pasqua Static VAR Compensation System (SVS)	0.0	0.0	0.0		0.0	0.0
1,020.7	2,237.0	(1,216.3)	PCS Allan 230kV Service	1,020.7	3,436.5	0.0		3,436.5	(2,415.8)
0.0	1,634.0	(1,634.0)	Peebles Switching Station 230/138kV Second Transformer	0.0	0.0	0.0		0.0	0.0
0.0	2,305.0	(2,305.0)	Poplar River Breaker Fail Improvement	0.0	0.0	0.0		0.0	0.0
0.0	1,386.0	(1,386.0)	Poplar River CB Replacements	0.0	0.0	0.0		0.0	0.0
29,058.2	5,000.0	24,058.2	Poplar River to Pasqua 230kV Transmission Line & SS (NERC)	62,423.1	59,779.5	1,872.0	3.1	61,651.5	771.6
0.0	2,000.0	(2,000.0)	QESS Breaker Fail Improvement	0.0	0.0	0.0		0.0	0.0
696.3	0.0	696.3	QE SCGT Generator Interconnection	4,185.3	6,203.7	(903.3)	(14.6)	5,300.4	(1,115.1)
2,165.2	7,863.0	(5,697.8)	Rabbit Lake SVS Replacement	2,165.2	9,900.0	0.0		9,900.0	(7,734.8)
434.7	0.0	434.7	Reconstruct Trans Line Global Trans Hub Authority	434.7	200.0	0.0		200.0	234.7
0.0	5,209.0	(5,209.0)	Regina - Pasqua 230kV Transmission Line	0.0	0.0	0.0		0.0	0.0
0.0	500.0	(500.0)	Reliability Improvements	0.0	0.0	0.0		0.0	0.0
15.9	800.0	(784.1)	Saskatoon East - Wolverine 230kV Line	15.9	38,286.0	0.0		38,286.0	(38,270.1)
27.9	7,694.0	(7,666.1)	Saskatoon East Switching Station	107.1	17,811.0	0.0		17,811.0	(17,703.9)
0.0	3,000.0	(3,000.0)	Swift Current SVS	0.0	0.0	0.0		0.0	0.0
19.7	0.0	19.7	TC5 Line Reinforcement	15,424.4	10,768.0	4,973.7	46.2	15,741.7	(317.3)
670.5	0.0	670.5	TCPL Keystone Projects	10,543.1	8,940.9	3,411.8	38.2	12,352.7	(1,809.6)
12,617.8	12,708.0	(90.2)	TCPL Keystone Expansion Interconnection	12,738.1	20,154.6	106.5	0.5	20,261.1	(7,523.0)
13.5	1,786.0	(1,772.5)	TCPL Keystone Expansion Phases 3 & 4	13.5	3,000.0	0.0		3,000.0	(2,986.5)
694.1	688.0	6.1	WL 701,3,6,7 Delle Breaker Replacements	699.7	3,352.0	0.0		3,352.0	(2,652.3)
4,474.7	866.0	3,608.7	Yellowhead SCGT Units #1-3	4,548.1	6,380.0	150.0	2.4	6,530.0	(1,981.9)
0.0	1,400.0	(1,400.0)	Yorkton Reinforcement	0.0	0.0	0.0		0.0	0.0
54,905.3	131,360.0	(76,454.7)	**Total Transmission Projects**	124,168.1	219,597.9	10,104.7	4.6	229,702.6	(105,534.6)
7,509.1	15,158.0	(7,648.9)	Miscellaneous Projects Under $500,000	0.0	0.0	0.0		0.0	0.0
118,971.8	257,661.0	(138,689.2)	**Total Network Development**	260,627.2	405,147.0	20,582.7	5.1	425,729.7	(165,102.5)
256,142.8	**403,871.0**	**(147,728.2)**	**Total Transmission & Distribution**	**397,798.2**	**551,257.0**	**26,987.7**	**4.9**	**578,244.7**	**(180,446.5)**
565,355.4	**832,098.0**	**(266,742.6)**	**Total SaskPower Capital Expenditures**	**1,185,605.3**	**2,025,001.0**	**89,826.7**	**4.4**	**2,114,827.7**	**(929,222.5)**

CAPITAL EXPENDITURE (CONTINUED)

Total capital budget for 2010 is $832.1 million. Expenditures were $266.7 million under budget, primarily due to deferrals in various projects.

Finance & Enterprise Risk Management

- Total Finance & Enterprise Risk Management capital budget is $44.6 million. Expenditures were $26.2 million under budget.
- North Battleford Service Centre project budget is $6.0 million; expenditures were minimal due to deferral of construction to 2011-2012.
- Prince Albert Service Center 1 Bay Addition budget is $1.0 million; expenditures were zero due to deferral of construction to 2013.
- Regina Region Service Centre project budget is $6.0 million; expenditures were minimal due to deferral of construction to 2011-2012.
- Saskatoon Service Centre Expansion project budget is $1.5 million; expenditures were zero due to deferral of construction to 2011-2012.
- Stoney Rapids budget is $1.0 million; expenditures were minimal due to deferral of construction to 2011.
- Swift Current Service Centre project budget is $1.0 million; expenditures were zero due to deferral of construction to 2011-2012.
- Weyburn Service Centre T&D project budget is $10.0 million; expenditures were $9.9 million under budget due to limited work approved for 2010.

Planning, Environment & Regulatory Affairs

- Total Planning, Environment & Regulatory Affairs capital budget is $43.3 million. Expenditures were $24.5 million under budget.
- 141 MW Yellowhead Peaking Interconnection project budget is $4.5 million; expenditures were zero due to a duplication of budget.
- 300 MW IPP Base Load Interconnection project budget is $5.2 million; expenditures were zero due to project delays.
- Shand Coal Drying project budget is $31.5 million; expenditures were zero due to project deferrals to 2011.
- Tantallon Peaking Station Natural Gas Pipe Line project was not identified until after the 2010 capital budget was set; expenditures were to install the natural gas pipeline for the IPP Project at Tantallon. Expenditures were $18.4 million.

CAPITAL EXPENDITURE (CONTINUED)

Corporate Information & Technology

- Total Corporate Information & Technology capital budget is $16.4 million. Expenditures were $3.7 million over budget.
- Enterprise Applications project budget is $1.3 million; expenditures were zero due to deferrals.
- Microsoft Enterprise Agreement project was not budgeted in 2010. Expenditures were $4.8 million to cover the cost of licenses required to support desktop refresh.
- Prudent Financial Management Portfolio budget is $1.4 million; expenditures were zero due to allocation of funds from portfolio level to specific projects.
- Dependable & Secure Infrastructure Portfolio budget is $3.2 million; expenditures were zero due to allocation of funds from portfolio level to specific projects including Overhaul Scope Management project and Properties Management project. Expenditures were $2.0 million.

Customer Services

- Total Customer Services capital budget is $31.7 million. Expenditures were $13.3 million under budget.
- Meter Purchases budget is $5.7 million. Expenditures were $2.7 million under budget due to the lower Itron purchase agreement.
- Handheld Meter Replacement project budget is $1.0 million; expenditures were zero due to project deferrals.
- Service Delivery Renewal – Automated Metering Implementation project budget is $1.9 million; expenditures were zero due to project schedule delays.
- Service Delivery Renewal - Telephony project budget is $4.8 million; expenditures were zero due to a duplication of budget.
- Service Delivery Renewal – Business Intelligence budget is $4.6 million. Expenditures were $3.8 million under budget due to project delays.

Power Production

- Total Power Production capital budget is $292.2 million – $142.7 million for Infrastructure Renewal Projects; $148.9 million for New Generation projects and $0.6 million for Cory Cogeneration. Expenditures were $58.8 million under budget.

CAPITAL EXPENDITURE (CONTINUED)

- The Poplar River #1 Life Precipitator Improvements projects budget is $1.4 million; expenditures were minimal due to the deferral of work to 2011.
- Poplar River #2 Ash Controls Replacement project budget is $3.4 million. Expenditures were $1.7 million under budget due to deferrals to future years.
- The Poplar River #2 Ignitor & Flame Scanner Upgrade project budget is $3.0 million. Expenditures were $1.4 million under budget due to a change in scope of work.
- The Poplar River #2 Main Stream Line Piping Replacement project budget is $1.4 million. Expenditures were minimal due to deferrals.
- The Poplar River Ash Line Perm Structures project had no budget in 2010; expenditures were $1.7 million.
- The Poplar River Coal Crusher Replacement project budget is $4.0 million. Expenditures were $1.5 million under budget due to advanced procurement in 2009.
- The Poplar River Facilities Improvement project had no budget in 2010. Expenditures were $1.3 million due to carryovers from 2009.
- The BD #5 Cabling & Switchgear project budget is $1.2 million. Expenditures were $1.1 million under budget due to cable supply being less than anticipated.
- The BD #5 HP Major Overhaul project budget is $1.5 million. Expenditures were zero due to a portion of the work being transferred from capital to operating, and the remainder being deferred to 2011.
- The BD #6 Generator Rotor Upgrade project budget is $5.9 million. Expenditures were $2.9 million under budget due to advanced procurement in 2009.
- The BD #6 LP Turbine Upgrade project budget is $12.4 million. Expenditures were $4.1 million under budget due to advanced procurement in 2009 and reduced costs.
- The BD#6 Power Distribution/Cabling project budget is $2.0 million. Expenditures were $1.3 million under budget due to advance work in 2009 and reduced costs.
- The BD Fire System Upgrade budget is $1.9 million. Expenditures were $1.5 million under budget due to deferrals.
- The BD Flyash Collection & Storage Expansion project budget is $7.5 million. Expenditures were $6.5 million under budget due to deferrals.

CAPITAL EXPENDITURE (CONTINUED)

- The BD Roof Replacement project budget is $0.3 million. Expenditures were $1.1 million over budget due to carryover of work from 2009.
- The BD Spillway Upgrade project budget is $0.6 million. Expenditures were $7.9 million over budget primarily due to carryovers from 2009.
- Shand Additional Flyash Storage Capacity project budget is $4.1 million; expenditures were zero due to the deletion of the project.
- Shand Major Overhaul 2012 project budget is $5.8 million; expenditures were zero due to a portion of the work transferred from capital to operating and the balance deferred to 2011.
- Coteau Creek Rewind project budget is $8.0 million. Expenditures were $2.9 million under budget due to advanced procurement in 2009 and deferral of work to 2011.
- EB Campbell 7 Runner Refurbishment project budget is $7.9 million. Expenditures were $1.0 million under budget due to deferrals.
- EB Campbell 8 Runner Refurbishment project budget is $1.1 million. Expenditures were $2.3 million over budget due to carryovers from 2009.
- EB Campbell PCMS project budget is $2.4 million. Expenditures were $2.2 million over budget due to 2011 work being advanced.
- Island Falls #4 Refurbishment project budget is $6.6 million. Expenditures were $1.3 million under budget due to deferrals.
- Ermine Maintenance Facility project budget is $1.5 million. Expenditures were zero since the project scope is included in the Ermine Gas Turbine Project.
- QE Facility Upgrade project budget is $3.2 million. Expenditures were $2.6 million under budget due to deferrals.
- Cookson Reservoir Supplementary Water project budget is $2.0 million. Expenditures were zero due to deferrals.
- Estevan Land Purchase budget is $1.3 million. Expenditures were minimal due to deferrals to 2011.
- BD #3 ICCS – Power Island project had no budget in 2010. Expenditures were $5.8 million due to advanced procurement and engineering costs.
- New Generation – Gas Turbine projects budget is $148.9 million. Expenditures were $28.7 million under budget primarily due to decreased Yellowhead Gas Turbine SCGT #2 project costs.

CAPITAL EXPENDITURE (CONTINUED)

Transmission and Distribution

- Total Transmission & Distribution capital budget is $403.9 million – $146.2 million for Customer Connect and Annual Program spending and $257.7 million for Network Development projects. Expenditures were $147.7 million under budget.
- Customer Connects budget is $96.5 million. Expenditures were $4.7 million over budget due to increased activity.
- Annual Capital Programs budget is $49.7 million. Expenditures were $13.7 million under budget primarily due to construction delays.
- Communications, Protection & Control projects budget is $16.2 million. Expenditures were $11.4 million under budget primarily due to deferral of Fibre Route Diversity and NERC projects.
- Subtransmission System projects had a total budget of $94.9 million. Expenditures were $43.2 million under budget due to deferrals.
- Transmission projects had a total budget of $131.4 million. Expenditures were $76.5 million under budget due to deferrals.

CAPITAL EXPENDITURE

As at December 2011

($000's)

CURRENT YEAR YTD Actual	2011 Budget	Variance		PROJECT PTD Actual	Original CPA Value	Total CPR Value	% CNG	Total CPA Value	Variance
			Finance & Enterprise Risk Management						
481.2	200.0	281.2	Buildings Upgrading	481.2	0.0	0.0		0.0	481.2
4,069.7	1,600.0	2,469.7	Furniture & Equipment	4,069.7	1,600.0	0.0		1,600.0	2,469.7
6.8	1,000.0	(993.2)	North Battleford Service Center	37.8	0.0	0.0		0.0	37.8
68.4	1,000.0	(931.6)	Regina Multi-Purpose Complex	185.6	0.0	0.0		0.0	185.6
2,979.0	2,000.0	979.0	Saskatoon Service Centre Expansion	2,979.0	4,500.0	0.0		4,500.0	(1,521.0)
8.1	1,000.0	(991.9)	Stoney Rapids	11.3	1,040.0	0.0		1,040.0	(1,028.7)
5.0	1,000.0	(995.0)	Swift Current Service Centre	5.0	0.0	0.0		0.0	5.0
0.0	0.0	0.0	Tisdale Office/Shop	0.0	1,000.0	0.0		1,000.0	(1,000.0)
758.6	0.0	758.6	TS&R Roof Replacement	2,104.4	2,500.0	0.0		2,500.0	(395.6)
1,507.4	7,500.0	(5,992.6)	Weyburn Service Center T&D	2,923.4	16,000.0	0.0		16,000.0	(13,076.6)
556.0	1,500.0	(944.0)	Wynyard District Office	577.4	1,500.0	0.0		1,500.0	(922.6)
78.0	0.0	78.0	Miscellaneous Projects Under $500,000						
10,518.3	**16,800.0**	**(6,281.7)**	**Total Finance & Enterprise Risk Management**	**13,374.8**	**28,140.0**	**0.0**		**28,140.0**	**(14,765.2)**
			Planning, Environment & Regulatory Affairs						
10.3	20.0	(9.7)	Shand Greenhouse	10.3	0.0	0.0		0.0	10.3
836.3	2,942.0	(2,105.7)	Tantallon Peaking Station Natural Gas Pipe Line	19,277.1	17,801.9	0.0		17,801.9	1,475.3
846.6	**2,962.0**	**(2,115.4)**	**Total Planning, Environment & Regulatory Affairs**	**19,287.4**	**17,801.9**	**0.0**		**17,801.9**	**1,485.6**
			Corporate Information and Technology						
0.0	1,000.0	(1,000.0)	Dependable & Secure Infrastructure Portfolio	0.0	0.0	0.0		0.0	0.0
2,586.8	0.0	2,586.8	Desktop Modernization	3,206.3	2,009.0	2,065.0	102.8	4,074.0	(867.7)
0.0	2,777.0	(2,777.0)	Effective & Efficient Operations Portfolio	0.0	0.0	0.0		0.0	0.0
0.0	1,653.0	(1,653.0)	Enterprise Applications	0.0	0.0	0.0		0.0	0.0
845.6	0.0	845.6	Enterprise Portfolio & Project Management Tools	1,641.3	1,861.7	463.8	24.9	2,325.5	(684.2)
0.0	1,350.0	(1,350.0)	Information Management	0.0	0.0	0.0		0.0	0.0
3,689.7	1,818.0	1,871.7	Infrastructure Refresh & Renewal -2011	3,689.7	3,008.0	1,577.9	52.5	4,585.9	(896.2)
1,567.5	2,500.0	(932.5)	PC Refresh Program & New Requests	1,567.5	2,498.7	0.0		2,498.7	(931.2)
135.3	1,500.0	(1,364.7)	Perimeter Security Enhancement	135.3	3,356.5	0.0		3,356.5	(3,221.2)
0.0	1,476.0	(1,476.0)	Proud & Productive Employees Portfolio	0.0	0.0	0.0		0.0	0.0
4,973.7	0.0	4,973.7	SAP Licence Purchase	4,973.7	4,974.0	0.0		4,974.0	(0.3)
3,050.3	0.0	3,050.3	Saskatoon Data Centre	3,170.9	1,762.5	1,988.3	112.8	3,750.8	(579.9)
1,847.9	4,500.0	(2,652.1)	Unified Communications	2,960.5	9,271.8	0.0		9,271.8	(6,311.3)
4,158.8	827.0	3,331.8	Miscellaneous Projects Under $500,000	0.0	0.0	0.0		0.0	0.0
22,855.6	**19,401.0**	**3,454.6**	**Total Corporate Information and Technology**	**21,345.2**	**28,742.2**	**6,095.0**	**21.2**	**34,837.2**	**(13,492.0)**

CAPITAL EXPENDITURE (CONTINUED)

CURRENT YEAR				PROJECT					
YTD Actual	2011 Budget	Variance		PTD Actual	Original CPA Value	Total CPR Value	% CNG	Total CPA Value	Variance
			Customer Services						
3,851.1	8,416.0	(4,564.9)	Meter Purchases	3,851.1	8,416.0	0.0		8,416.0	(4,564.9)
0.0	500.0	(500.0)	Miscellaneous Capital	0.0	0.0	0.0		0.0	0.0
0.0	9,965.0	(9,965.0)	SDR - Automated Metering Implementation	0.0	0.0	0.0		0.0	0.0
13,149.2	7,868.0	5,281.2	SDR - CIS/CRM System Implementation	26,652.3	21,421.3	5,347.6	25.0	26,768.9	(116.6)
			Service Delivery Renewal - CI&T Delivered						
1,044.6	1,094.0	(49.4)	SDR - Business Intelligence	1,855.0	2,536.6	0.0		2,536.6	(681.6)
7,596.8	8,871.0	(1,274.2)	SDR - Field Worker Technology Phase II - Schedule & Dispatch	12,075.2	15,781.8	792.7	5.0	16,574.5	(4,499.4)
0.0	1,131.0	(1,131.0)	SDR - Field Worker Technology Phase III - Outage Mgmt System	0.0	0.0	0.0		0.0	0.0
1,455.9	0.0	1,455.9	SDR - Service Business Metrics 2011	1,455.9	830.0	0.0		830.0	625.9
(31.1)	122.0	(153.1)	Miscellaneous Projects Under $500,000						
27,066.5	**37,967.0**	**(10,900.5)**	**Total Customer Services**	**45,889.4**	**48,985.7**	**6,140.3**	**12.5**	**55,126.0**	**(9,236.6)**
			Power Production						
			Poplar River						
722.1	1,982.0	(1,259.9)	Poplar River #1 Ash Controls Replacement	855.1	4,434.0	1,823.0	41.1	6,257.0	(5,401.9)
845.5	0.0	845.5	Poplar River #1 HP #6 FWH Replacement	871.8	2,723.0	0.0		2,723.0	(1,851.2)
1,324.0	540.0	784.0	Poplar River #1 Mill Gearcase Upgrade	3,307.7	2,746.2	179.8	6.5	2,926.0	381.7
2,170.9	3,400.0	(1,229.1)	Poplar River #1 Precipitator Improvements	2,187.0	2,816.0	0.0		2,816.0	(629.0)
37.7	3,250.0	(3,212.3)	Poplar River #1 Waterwall Refurbishment	1,620.3	2,000.0	0.0		2,000.0	(379.7)
563.4	511.0	52.4	Poplar River #2 A SBAC Upgrade	1,704.9	1,200.0	1,318.0	109.8	2,518.0	(813.1)
4,625.6	2,413.0	2,212.6	Poplar River #2 Ash Controls Replacement	6,450.3	5,551.0	1,687.0	30.4	7,238.0	(787.7)
1,137.6	0.0	1,137.6	Poplar River #2 Main Diesel Generator	1,162.0	1,000.0	0.0		1,000.0	162.0
367.3	1,927.0	(1,559.7)	Poplar River #2 Main Steam Line Piping Replacement	526.3	1,540.0	535.0	34.7	2,075.0	(1,548.7)
1,891.6	145.0	1,746.6	Poplar River Ash Lagoon #4 Construction	13,265.3	7,703.0	5,803.0	75.3	13,506.0	(240.7)
5,887.5	0.0	5,887.5	Poplar River Dry Stacking Lagoon 3S	5,887.5	5,986.3	0.0		5,986.3	(98.8)
0.0	1,000.0	(1,000.0)	Poplar River Plant HVAC	0.0	0.0	0.0		0.0	0.0
19,573.1	15,168.0	4,405.1	**Total Poplar River Projects**	37,838.2	37,699.5	11,345.8	30.1	49,045.3	(11,207.1)
			Boundary Dam						
397.4	500.0	(102.6)	BD "C" Plant Coated Waterwall Panel (KE)	4,547.0	7,753.9	(3,063.9)	(39.5)	4,690.0	(143.0)
177.3	599.0	(421.7)	BD #2 Station Transformer Cable Replacement	186.5	1,609.0	0.0		1,609.0	(1,422.5)
129.7	676.0	(546.3)	BD #3 Secondary Air Heaters Upgrades	135.0	990.0	448.0	45.3	1,438.0	(1,303.0)
802.8	800.0	2.8	BD #3 Waterwall Replacement	1,774.7	1,900.0	(128.0)	(6.7)	1,772.0	2.7
356.7	794.0	(437.3)	BD #4 HP Heater Replacement #4	1,826.5	3,285.0	91.0	2.8	3,376.0	(1,549.5)
915.8	825.0	90.8	BD #5 & #6 WTP HMI Replacement	2,530.7	2,366.0	472.0	19.9	2,838.0	(307.3)
2,463.4	2,792.0	(328.6)	BD #5 Cabling & Switchgear	2,809.5	3,800.0	0.0		3,800.0	(990.5)
2,280.3	4,066.0	(1,785.7)	BD #5 HP Major Overhaul	2,280.3	4,266.0	0.0		4,266.0	(1,985.7)
1,058.5	1,581.0	(522.5)	BD Asbestos Removal 2010 - 2015	1,921.6	9,075.9	999.1	11.0	10,075.0	(8,153.4)
413.5	500.0	(86.5)	BD Boiler Cameras	413.5	550.0	0.0		550.0	(136.5)
1,469.1	1,597.0	(127.9)	BD East Surface Lagoon Management	1,472.9	1,985.0	0.0		1,985.0	(512.1)
2,065.2	975.0	1,090.2	BD Fire System Upgrade	2,449.2	1,650.0	1,020.0	61.8	2,670.0	(220.9)
6,668.6	4,395.0	2,273.6	BD FLYASH Collection & Storage Expansion	7,725.3	6,000.0	2,250.0	37.5	8,250.0	(524.7)
12,061.9	14,350.0	(2,288.1)	BD Flyash Storage & Loadout Upgrade	12,290.4	21,500.0	0.0		21,500.0	(9,209.6)
624.9	2,814.0	(2,189.1)	BD Hydrogen Systems Upgrade	665.5	3,169.5	(415.6)	(13.1)	2,753.9	(2,088.3)
799.0	772.0	27.0	BD Roof Replacement	3,626.0	420.0	3,633.0	865.0	4,053.0	(427.0)
473.0	625.0	(152.0)	BD Security Buildings Upgrade	473.0	1,300.0	0.0		1,300.0	(827.0)
329.6	750.0	(420.4)	BD Shielding Upgrades	2,469.3	7,901.6	(5,336.9)	(67.5)	2,564.7	(95.4)
892.9	0.0	892.9	BD Spillway Upgrades	57,514.7	30,000.0	28,100.0	93.7	58,100.0	(585.3)
34,379.7	39,411.0	(5,031.3)	**Total Boundary Dam Projects**	107,111.8	109,521.9	28,068.7	25.6	137,590.6	(30,478.8)

CAPITAL EXPENDITURE (CONTINUED)

CURRENT YEAR				PROJECT					
YTD Actual	2011 Budget	Variance		PTD Actual	Original CPA Value	Total CPR Value	% CNG	Total CPA Value	Variance
			Shand						
788.4	0.0	788.4	Shand Ash Belt Conveyor Gallery	801.7	1,271.3	0.0		1,271.3	(469.6)
4,076.8	0.0	4,076.8	Shand Boiler Panel Replacement	4,076.8	31,000.0	0.0		31,000.0	(26,923.2)
613.1	710.0	(96.9)	Shand Low NOX Burners	613.1	4,286.0	0.0		4,286.0	(3,672.9)
506.0	1,085.0	(579.0)	Shand Major Overhaul 2012	506.0	3,651.9	0.0		3,651.9	(3,145.9)
416.6	552.0	(135.4)	Shand PCMS Upgrade	416.6	6,085.0	0.0		6,085.0	(5,668.4)
798.6	578.0	220.6	Shand Primary Air Heater Basket Replacement	1,020.4	1,500.0	(497.0)	(33.1)	1,003.0	17.4
789.7	0.0	789.7	Shand Shower Room Upgrades	1,496.7	1,904.8	62.0	3.3	1,966.8	(470.1)
0.0	768.0	(768.0)	Shand Turbine Supervisory	0.0	0.0	0.0		0.0	0.0
579.2	1,350.0	(770.8)	Shand Water Treatment Plant Upgrades	1,186.6	2,350.0	(1,070.0)	(45.5)	1,280.0	(93.4)
8,568.3	5,043.0	3,525.3	**Total Shand Projects**	10,117.9	52,049.0	(1,505.0)	(2.9)	50,544.0	(40,426.1)
			Northern Hydro						
5,915.9	271.0	5,644.9	Coteau Creek Rewind	14,899.0	20,100.0	0.0		20,100.0	(5,201.0)
2,678.6	3,001.0	(322.4)	EB Campbell 7 Runner Refurbishment	11,535.5	15,000.0	(2,990.0)	(19.9)	12,010.0	(474.5)
4,634.3	11,218.0	(6,583.7)	EB Campbell 8 Runner Refurbishment	9,807.8	15,000.0	0.0		15,000.0	(5,192.2)
1,487.4	2,931.0	(1,443.6)	EB Campbell Plant Control Monitoring System	6,637.5	11,000.0	0.0		11,000.0	(4,362.5)
466.6	0.0	466.6	Island Falls 1,2,3 & 7 Exciter Upgrade	466.6	2,080.0	0.0		2,080.0	(1,613.4)
20,160.0	19,173.0	987.0	Island Falls #4 Refurbishment	29,108.6	28,000.0	2,585.0	9.2	30,585.0	(1,476.4)
4,349.8	9,857.0	(5,507.2)	Island Falls #5 Refurbishment	6,107.6	21,000.0	3,500.0	16.7	24,500.0	(18,392.4)
1,227.6	3,003.0	(1,775.4)	Island Falls #6 Refurbishment	2,494.9	21,000.0	1,100.0	5.2	22,100.0	(19,605.1)
1,283.1	1,000.0	283.1	Island Falls Dam Safety Upgrades	4,137.7	5,242.2	3.8	0.1	5,246.0	(1,108.3)
195.3	653.0	(457.8)	Island Falls Generator Breaker Upgrade	1,981.6	2,100.0	170.0	8.1	2,270.0	(288.4)
2,726.2	2,394.0	332.2	Island Falls Plant Control Monitoring System	4,689.1	11,000.0	0.0		11,000.0	(6,310.9)
45,124.8	53,501.0	(8,376.2)	**Total Northern Hydro**	91,865.7	151,522.2	4,368.8	2.9	155,891.0	(64,025.3)
			Western Plants						
939.6	0.0	939.6	Ermine SC Gas Turbines	132,819.9	150,000.0	(17,310.0)	(11.5)	132,690.0	129.9
1,534.7	1,334.0	200.7	QE #3 Controls	4,816.2	3,781.0	1,194.0	31.6	4,975.0	(158.8)
1,644.5	3,602.0	(1,957.5)	QE Facility Upgrade	2,759.9	9,127.0	0.0		9,127.0	(6,367.1)
(449.6)	3,500.0	(3,949.6)	Yellowhead SC Gas Turbines	186,440.5	250,000.0	(61,265.0)	(24.5)	188,735.0	(2,294.5)
3,669.1	8,436.0	(4,766.9)	**Total Western Plants**	326,836.5	412,908.0	(77,381.0)	(18.7)	335,527.0	(8,690.5)
			Fuel Supply						
223.7	3,450.0	(3,226.3)	Coronach Land Purchase 2010 - 2011	223.7	5,525.0	0.0		5,525.0	(5,301.3)
1,862.1	3,765.0	(1,902.9)	Estevan Land Purchase 2010 - 2011	1,933.3	6,755.0	0.0		6,755.0	(4,821.7)
0.0	1,250.0	(1,250.0)	Mine Service Building - Purchase & Rebuild	0.0	0.0	0.0		0.0	0.0
2,085.8	8,465.0	(6,379.2)	**Total Fuel Supply**	2,157.0	12,280.0	0.0		12,280.0	(10,123.0)
			Other						
85.0	792.0	(707.0)	Climb Assists - Wind Facilities	85.0	110.0	0.0		110.0	(25.0)
481.0	1,351.0	(870.0)	Emissions Control Research Facility Phase IV	2,939.6	2,712.0	1,235.0	45.5	3,947.0	(1,007.4)
864.4	640.0	224.4	Gas Turbine & Wind Performance Monitor	1,172.4	2,200.0	(200.0)	(9.1)	2,000.0	(827.6)
712.9	1,620.0	(907.1)	Generator & Gearbox Replacement - Wind Facility	712.9	625.0	375.0	60.0	1,000.0	(287.1)
59.2	568.0	(508.8)	NERC - Generation Testing Standards - Def & Upgrades	927.2	1,635.0	0.0		1,635.0	(707.8)
897.0	0.0	897.0	Operations Support - Waterfall Security	897.0	0.0	0.0		0.0	897.0
769.7	945.0	(175.3)	Power Production Capital Tools	769.7	0.0	0.0		0.0	769.7
3,869.2	5,916.0	(2,046.8)	**Total Other**	7,503.7	7,282.0	1,410.0	19.4	8,692.0	(1,188.3)
5,560.8	(1,763.0)	7,323.8	Miscellaneous Projects Under $500,000						
122,830.9	**134,177.0**	**(11,346.1)**	**Total Power Production**	**583,430.8**	**783,262.5**	**(33,692.7)**	**(4.3)**	**749,569.8**	**(166,139.1)**
			ICCS						
257,222.3	381,000.0	(123,777.7)	BD #3 ICCS - Carbon Capture	262,996.3	1,002,000.0	0.0		1,002,000.0	(739,003.7)
(69,290.5)	0.0	(69,290.5)	BD #3 ICCS - Grants	(69,290.5)	0.0	0.0		0.0	(69,290.5)
187,931.8	**381,000.0**	**(193,068.2)**	**Total ICCS**	**193,705.8**	**1,002,000.0**	**0.0**		**1,002,000.0**	**(808,294.2)**

CAPITAL EXPENDITURE (CONTINUED)

CURRENT YEAR YTD Actual	2011 Budget	Variance		PROJECT PTD Actual	Original CPA Value	Total CPR Value	% CNG	Total CPA Value	Variance
			Transmission and Distribution						
			Customer Connects by Region						
16,569.9	16,000.0	569.9	Prince Albert Region	16,569.9	16,000.0	813.0	5.1	16,813.0	(243.1)
30,101.2	16,500.0	13,601.2	Regina Region	30,101.2	16,500.0	13,601.0	82.4	30,101.0	0.2
32,018.7	29,000.0	3,018.7	Saskatoon Region	32,018.7	29,000.0	3,042.0	10.5	32,042.0	(23.3)
28,525.0	35,000.0	(6,475.0)	Weyburn Region	28,525.0	35,000.0	(5,878.0)	(16.8)	29,122.0	(597.0)
107,214.9	96,500.0	10,714.9	**Total Customer Connects by Region**	107,214.9	96,500.0	11,578.0	12.0	108,078.0	(863.1)
			Annual Capital Programs						
2,492.2	2,500.0	(7.8)	Farmyard Line Relocation Program	2,492.2	2,500.0	0.0		2,500.0	(7.8)
1,161.9	2,000.0	(838.1)	Induction Crew Projects	1,161.9	2,000.0	0.0		2,000.0	(838.1)
571.1	2,000.0	(1,428.9)	Miscellaneous Apparatus Improvements	571.1	2,000.0	0.0		2,000.0	(1,428.9)
1,549.5	1,000.0	549.5	New Codes (Urban SI)	1,549.5	1,000.0	550.0	55.0	1,550.0	(0.5)
1,981.8	3,000.0	(1,018.2)	Economic Rebuilds	1,981.8	3,000.0	0.0		3,000.0	(1,018.2)
536.7	1,060.0	(523.3)	Regulators	536.7	1,260.0	0.0		1,260.0	(723.3)
5,256.5	12,500.0	(7,243.5)	Rural Rebuild & Improvement Program	5,256.5	12,500.0	(7,075.0)	(56.6)	5,425.0	(168.5)
695.8	600.0	95.8	Steel Street Light Replacements	695.8	600.0	96.0	16.0	696.0	(0.2)
1,958.5	1,420.0	538.5	T & D Tools	1,958.5	2,447.1	538.0	22.0	2,985.1	(1,026.7)
5,540.9	5,500.0	40.9	Transformer Replacements	5,540.9	6,083.6	11.0	0.2	6,094.6	(553.7)
1,422.7	1,300.0	122.7	Urban Underground Cable Replacements	1,422.7	1,300.0	123.0	9.5	1,423.0	(0.3)
736.8	2,500.0	(1,763.2)	Urban/Rural Hazards Mitigation	736.8	2,500.0	0.0		2,500.0	(1,763.2)
15,696.3	18,700.0	(3,003.7)	Vehicles & Equipment	15,696.3	19,119.0	0.0		19,119.0	(3,422.7)
10,910.4	20,000.0	(9,089.6)	Wood Pole Replacement	10,910.4	20,000.0	(5,821.0)	(29.1)	14,179.0	(3,268.6)
50,511.2	74,080.0	(23,568.8)	**Total Annual Capital Programs**	50,511.2	76,309.7	(11,578.0)	(15.2)	64,731.7	(14,220.6)
			Network Development						
			Communication, Protection and Control Projects						
0.0	500.0	(500.0)	72kV BF Protection Installations	0.0	0.0	0.0		0.0	0.0
0.0	800.0	(800.0)	A1R & R1S Protection Upgrade	0.0	0.0	0.0		0.0	0.0
365.6	500.0	(134.4)	C2W (52/56 & 96/921) SSPLC Replacement	489.3	602.8	0.0		602.8	(113.5)
0.0	850.0	(850.0)	Ermine Switching Station Control Building Facilities	0.0	0.0	0.0		0.0	0.0
2,694.4	5,600.0	(2,905.6)	Fibre Route Diversity	2,694.4	5,102.0	0.0		5,102.0	(2,407.6)
84.8	500.0	(415.2)	Regina South 72kV Breaker Fail Protection & R1C Relay Replacement	384.6	827.7	0.0		827.7	(443.1)
18.0	530.0	(512.0)	Replace AEI & DTa2 Differential Relays	18.0	1,506.1	0.0		1,506.1	(1,488.1)
261.4	900.0	(638.6)	Replace BBC, LZ96, LZ92 & LIZ6-13 Distance Relays	2,423.6	3,027.2	0.0		3,027.2	(603.6)
212.6	750.0	(537.4)	Replace Reyrolle Distance Relays	2,072.6	2,342.4	0.0		2,342.4	(269.8)
1,092.0	1,249.0	(157.0)	RTU/SER Replacement	7,980.4	3,785.0	0.0		3,785.0	4,195.4
1,273.7	820.0	453.7	SCADA EMS Lifecycle (XA/21 Replacement)	2,982.2	7,604.0	0.0		7,604.0	(4,621.8)
0.0	1,400.0	(1,400.0)	Special Protection System - B1Q/B2Q	0.0	0.0	0.0		0.0	0.0
0.0	1,400.0	(1,400.0)	Special Protection System - B2R/B3R	0.0	0.0	0.0		0.0	0.0
0.0	1,400.0	(1,400.0)	Special Protection System - E2B/E2C	0.0	0.0	0.0		0.0	0.0
789.5	550.0	239.5	VSAT Upgrade	789.5	1,244.8	0.0		1,244.8	(455.3)
6,792.0	17,749.0	(10,957.0)	**Total Communication, Protection and Control Projects**	19,834.5	26,042.0	0.0		26,042.0	(6,207.5)

CAPITAL EXPENDITURE (CONTINUED)

CURRENT YEAR				PROJECT					
YTD Actual	2011 Budget	Variance		PTD Actual	Original CPA Value	Total CPR Value	% CNG	Total CPA Value	Variance
			Subtransmission System Projects						
0.0	1,000.0	(1,000.0)	138/72kV Transformer Rewind	0.0	0.0	0.0		0.0	0.0
0.0	500.0	(500.0)	4kV Substation Rebuild	0.0	0.0	0.0		0.0	0.0
668.2	2,000.0	(1,331.8)	72 kV Line Upgrades - Insulators/Arms	3,609.6	3,975.0	0.0		3,975.0	(365.4)
70.5	1,510.0	(1,439.5)	Aberfeldy Capacity Increase	70.9	100.0	0.0		100.0	(29.1)
2,829.0	1,000.0	1,829.0	Agrium Vanscoy 138kV Service	6,333.0	7,759.0	0.0		7,759.0	(1,426.0)
1,612.0	1,350.0	262.0	Assiniboia 72/25kV Substation Rebuild	2,290.6	2,160.9	0.0		2,160.9	129.7
610.6	6,100.0	(5,489.4)	Auburnton 230/72kV Capacity Increase	615.8	7,463.9	0.0		7,463.9	(6,848.1)
2,325.2	408.0	1,917.2	Auburnton Sub	5,589.6	5,450.8	0.0		5,450.8	138.8
3,756.2	3.0	3,753.2	BHP Construction Power	8,544.0	8,000.0	0.0		8,000.0	544.0
0.0	1,000.0	(1,000.0)	Biopure Oil - Belle Plaine	0.0	0.0	0.0		0.0	0.0
656.3	500.0	156.3	Deschambeault 25kV Line Upgrades	686.5	500.0	0.0		500.0	186.5
4.6	500.0	(495.4)	Distribution Automation	4.6	500.0	0.0		500.0	(495.4)
470.2	1,250.0	(779.8)	Distribution Reliability Improvements	470.2	1,250.0	0.0		1,250.0	(779.8)
1,547.9	2,230.0	(682.2)	Dundonald Capacity Increase	2,471.1	5,067.0	0.0		5,067.0	(2,595.9)
0.0	500.0	(500.0)	Enbridge - Redvers	0.0	0.0	0.0		0.0	0.0
8.1	500.0	(491.9)	Estevan #2 Substation Rebuild	8.1	365.0	0.0		365.0	(356.9)
0.0	1,200.0	(1,200.0)	EXT - Belle Plaine	0.0	0.0	0.0		0.0	0.0
0.0	1,000.0	(1,000.0)	Fortune Minerals	0.0	0.0	0.0		0.0	0.0
2,652.7	1,360.0	1,292.7	Halbrite West Substation Capacity Increase	3,940.9	4,489.1	0.0		4,489.1	(548.2)
443.3	750.0	(306.7)	High Load Move Corridors	446.6	300.0	0.0		300.0	146.6
1.5	1,000.0	(998.5)	Kisbey New Substation	1.5	500.0	0.0		500.0	(498.5)
114.7	2,200.0	(2,085.3)	Line Uprating	114.7	2,200.0	0.0		2,200.0	(2,085.3)
4,286.9	4,750.0	(463.1)	Mobile Transformers	4,352.5	5,000.0	0.0		5,000.0	(647.5)
611.7	950.0	(338.3)	Mosaic - Colonsay 230kV Service	611.7	1,719.7	0.0		1,719.7	(1,108.0)
0.0	5,600.0	(5,600.0)	Mosaic Esterhazy K3	0.0	0.0	0.0		0.0	0.0
466.5	1,000.0	(533.5)	PCS Allen 138kV Service	1,487.3	3,436.5	450.2	13.1	3,886.7	(2,399.4)
1,385.5	3,270.0	(1,884.5)	PCS Rocanville 138kV Service	3,186.9	7,761.4	2,161.1	27.8	9,922.5	(6,735.6)
240.7	5,130.0	(4,889.3)	PCS Scissor Creek 138kV Service	243.8	6,592.7	(2,701.7)	(41.0)	3,891.0	(3,647.2)
125.2	3,610.0	(3,484.8)	Potash One Construction Power	132.1	3,990.3	0.0		3,990.3	(3,858.2)
20.5	1,500.0	(1,479.5)	Potash One New Service	24.2	250.0	0.0		250.0	(225.8)
0.0	1,500.0	(1,500.0)	Power Transformer Replacement	0.0	0.0	0.0		0.0	0.0
27.9	800.0	(772.1)	Protection Upgrades	95.5	400.0	0.0		400.0	(304.5)
372.9	1,000.0	(627.1)	QE18 138kV Reroute - Evergreen	498.8	1,504.0	0.0		1,504.0	(1,005.2)
1,120.2	2,040.0	(919.8)	Rabbit Lake Substation	6,178.2	8,188.6	(116.0)	(1.4)	8,072.6	(1,894.4)
944.6	0.0	944.6	Relocate R1C Lewvan Drive & Highway #1	2,174.8	0.0	0.0		0.0	2,174.8
2,209.3	0.0	2,209.3	Red Lilly Wind @ Red Jacket	4,873.4	4,411.7	(391.0)	(8.9)	4,020.7	852.7
(2,481.2)	1,081.0	(3,562.2)	S1E - ER Conversion & Hoosier Substation	16,859.2	14,888.7	(5,875.1)	(39.5)	9,013.6	7,845.6
229.4	8,000.0	(7,770.6)	Saskatoon North Reinforcement	257.2	48,873.0	0.0		48,873.0	(48,615.8)
2,488.6	0.0	2,488.6	Saskatoon Pole Yard	2,488.6	2,480.0	0.0		2,480.0	8.6
1,928.9	2,500.0	(571.1)	Senlac Capacity Increase	1,928.9	3,993.1	0.0		3,993.1	(2,064.2)
0.0	1,000.0	(1,000.0)	Shaunavon Capacity Increase	0.0	4,397.4	0.0		4,397.4	(4,397.4)
2,188.2	0.0	2,188.2	Spiritwood Sub Capacity Increase	2,241.9	2,391.9	0.0		2,391.9	(150.0)
1,096.8	0.0	1,096.8	Steelman Distribution System Reinforcement	1,096.8	1,201.5	0.0		1,201.5	(104.7)
(358.3)	211.0	(569.3)	Steelman Sub Capacity Increase	11,866.0	12,723.0	0.0		12,723.0	(857.0)
2,171.2	1,100.0	1,071.2	Stoughton 801T Capacity Increase	2,186.0	2,446.0	0.0		2,446.0	(260.0)
0.0	750.0	(750.0)	Treated Wood Pole Storage	0.0	0.0	0.0		0.0	0.0
0.0	600.0	(600.0)	Uranium City 25kV Line Rebuild	0.0	0.0	0.0		0.0	0.0
2,283.5	0.0	2,283.5	Weyburn Substation	9,281.4	8,250.7	0.0		8,250.7	1,030.7
0.0	4,000.0	(4,000.0)	Wood Substation Replacements	0.0	0.0	0.0		0.0	0.0
6,267.7	1,793.0	4,474.7	Yorkton #2 Capacity Increase	6,392.2	7,434.0	0.0		7,434.0	(1,041.8)
45,397.7	80,046.0	(34,648.3)	**Total Subtransmission System Projects**	113,655.3	202,414.9	(6,472.5)	(3.2)	195,942.4	(82,287.1)

CAPITAL EXPENDITURE (CONTINUED)

CURRENT YEAR				PROJECT					
YTD Actual	2011 Budget	Variance		PTD Actual	Original CPA Value	Total CPR Value	% CNG	Total CPA Value	Variance
			Transmission Projects						
0.0	500.0	(500.0)	175 MW IPP Wind Farm Interconnection (2013)	0.0	0.0	0.0		0.0	0.0
3.1	600.0	(596.9)	Battery Replacement	3.1	778.5	0.0		778.5	(775.4)
827.2	0.0	827.2	Boundary Dam #3 Clean Coal Equipment Move Line Uprating	827.2	497.7	439.8	88.4	937.5	(110.3)
35.2	3,000.0	(2,964.8)	Boundary Dam #3 Clean Coal Interconnection Project	35.2	6,770.0	0.0		6,770.0	(6,734.8)
0.0	2,500.0	(2,500.0)	Boundary Dam Breaker Fail Improvement	0.0	0.0	0.0		0.0	0.0
0.0	500.0	(500.0)	Breaker Maintenance/ Rebuild	0.0	0.0	0.0		0.0	0.0
0.0	3,500.0	(3,500.0)	Breaker Replacement	0.0	3,496.0	0.0		3,496.0	(3,496.0)
8.2	684.0	(675.8)	C1S Clearance Increase	226.2	900.0	0.0		900.0	(673.8)
0.0	500.0	(500.0)	CCILS SPS Redundancy	0.0	0.0	0.0		0.0	0.0
0.0	750.0	(750.0)	CVT Replacement	0.0	0.0	0.0		0.0	0.0
1,669.0	6,000.0	(4,331.0)	Fleet Street 230/138kV Transformer	1,669.7	17,920.4	0.0		17,920.4	(16,250.7)
56.0	1,035.0	(979.0)	FS 727-730 Delle Breaker Replacements - SS Capacity	2,538.3	3,855.0	(503.0)	(13.0)	3,352.0	(813.7)
0.0	2,500.0	(2,500.0)	GOPP (EPP Grid) Interconnection	0.0	0.0	0.0		0.0	0.0
38.8	3,900.0	(3,861.2)	Halbrite Area Reinforcement	129.3	28,655.0	0.0		28,655.0	(28,525.7)
2,975.9	3,750.0	(774.1)	I1F/I2F Re-Termination	3,080.6	6,320.0	36.8	0.6	6,356.8	(3,276.2)
4,438.1	30,000.0	(25,561.9)	Island Falls - Far North 138kV Transmission Line	5,540.6	9,300.0	0.0		9,300.0	(3,759.4)
1,713.1	0.0	1,713.1	Island Falls & SS TFDR Replacement	1,715.7	230.0	0.0		230.0	1,485.7
0.0	1,000.0	(1,000.0)	Millennium Interconnection Transmission Line	0.0	0.0	0.0		0.0	0.0
570.0	0.0	570.0	Mosaic Esterhazy K3 Interim	570.0	1,714.0	0.0		1,714.0	(1,144.0)
3,634.1	3,000.0	634.1	NBEC Interconnection	3,686.6	12,924.0	6,960.0	53.9	19,884.0	(16,197.4)
0.0	2,500.0	(2,500.0)	NERC - QESS Breaker Fail Improvement	0.0	0.0	0.0		0.0	0.0
0.0	500.0	(500.0)	NERC - Special Protection System - P3C - R4C	0.0	0.0	0.0		0.0	0.0
0.0	600.0	(600.0)	NERC - UVLS N-2 Contingencies	0.0	0.0	0.0		0.0	0.0
1,786.3	884.0	902.3	Pasqua 230kV Switching Station	64,209.4	59,779.5	1,872.0	3.1	61,651.5	2,557.9
0.0	15,000.0	(15,000.0)	Pasqua Static VAR Compensation System (SVS)	0.0	0.0	0.0		0.0	0.0
852.8	8,000.0	(7,147.2)	Peebles - Tantallon 230kV Line	852.8	62,686.0	0.0		62,686.0	(61,833.2)
6.8	4,000.0	(3,993.2)	Peebles Switching Station 230/138kV Second Transformer	6.8	4,272.1	0.0		4,272.1	(4,265.3)
0.0	2,500.0	(2,500.0)	Poplar River Breaker Fail Improvement	0.0	0.0	0.0		0.0	0.0
728.0	1,400.0	(672.0)	Poplar River CB Replacements	728.0	2,146.0	0.0		2,146.0	(1,418.0)
742.4	0.0	742.4	R1C Tap Relocate	742.4	996.0	0.0		996.0	(253.6)
5,618.4	4,000.0	1,618.4	Rabbit Lake SVC Replacement	7,783.6	9,900.0	0.0		9,900.0	(2,116.4)
2,084.2	6,000.0	(3,915.8)	Reconstruct Trans Line Global Trans Hub Authority	2,518.9	5,925.0	0.0		5,925.0	(3,406.1)
0.0	7,000.0	(7,000.0)	Regina to Pasqua 230kV Transmission Line	0.0	0.0	0.0		0.0	0.0
153.2	13,000.0	(12,846.9)	Saskatoon East - Wolverine 230kV Line	169.0	38,286.0	(821.6)	(2.1)	37,464.4	(37,295.4)
621.7	5,000.0	(4,378.3)	Saskatoon East Switching Station	728.8	17,811.0	0.0		17,811.0	(17,082.2)
0.0	500.0	(500.0)	Shand Breaker Failure Improvement	0.0	0.0	0.0		0.0	0.0
236.7	2,500.0	(2,263.3)	Shore Gold Diamond Project End Use Load Interconnection	378.7	11,846.0	0.0		11,846.0	(11,467.3)
0.0	500.0	(500.0)	Steel Pole Yard for Central Stores	0.0	0.0	0.0		0.0	0.0
0.0	10,000.0	(10,000.0)	Swift Current SVS	0.0	0.0	0.0		0.0	0.0
1,180.7	0.0	1,180.7	Tantallon Generation	1,760.2	2,012.0	0.0		2,012.0	(251.8)
2,819.6	3,076.0	(256.4)	TCPL Keystone Expansion Phase 2	15,557.7	20,154.6	106.5	0.5	20,261.1	(4,703.4)
201.5	2,000.0	(1,798.5)	TCPL Keystone Expansion Phases 3 & 4 - PS6 Fox Valley Site	202.2	5,688.0	0.0		5,688.0	(5,485.8)
579.9	11,000.0	(10,420.1)	TCPL Keystone Expansion Phases 3 & 4 - PS7 Piapot Site	590.3	20,917.6	0.0		20,917.6	(20,327.3)
293.3	10,000.0	(9,706.7)	TCPL Keystone Expansion Phases 3 & 4 - PS8 Grassy Creek Site	295.6	24,856.6	0.0		24,856.6	(24,561.0)
0.0	500.0	(500.0)	Third Regina South 230/138kV Transformer	254.6	243.0	0.0		243.0	11.6
0.0	1,800.0	(1,800.0)	Tisdale Switching Station	0.0	0.0	0.0		0.0	0.0
0.0	1,500.0	(1,500.0)	Transmission Reliability Improvements	0.0	0.0	0.0		0.0	0.0
33,874.1	177,479.0	(143,604.9)	**Total Transmission Projects**	116,801.5	380,880.0	8,090.5	2.1	388,970.5	(272,169.0)
8,621.5	17,316.0	(8,694.5)	Miscellaneous Projects Under $500,000	0.0	0.0	0.0		0.0	0.0
94,685.2	292,590.0	(197,904.8)	**Total Network Development**	250,291.3	609,336.9	1,618.0	0.3	610,954.9	(360,663.6)
252,411.3	**463,170.0**	**(210,758.7)**	**Total Transmission & Distribution**	**408,017.4**	**782,146.7**	**1,618.0**	**0.2**	**783,764.7**	**(375,747.3)**
624,461.0	**1,055,477.0**	**(431,016.0)**	**Total SaskPower Capital Expenditures**	**1,285,050.7**	**2,691,078.8**	**(19,839.3)**	**(0.7)**	**2,671,239.5**	**(1,386,188.8)**

CAPITAL EXPENDITURE (CONTINUED)

Total SaskPower capital budget for 2011 is $1,055.4 million. Expenditures were $431 million under budget, primarily due to construction delays in the BD ICCS – Carbon Capture project and Transmission project deferrals.

Finance & Enterprise Risk Management

- Total Finance & Enterprise Risk Management capital budget is $16.8 million. Expenditures were $6.3 million under budget.
- Furniture and Equipment capital budget is $1.6 million. Expenditures were $2.5 million over budget due to an increase in renovations.
- Weyburn Service Centre T&D capital budget is $7.5 million. Expenditures were $6.0 million under budget due to start delays.

Planning, Environment & Regulatory Affairs

- Total Planning, Environment & Regulatory Affairs capital budget is $3.0 million. Expenditures were $2.1 million under budget.
- The Tantallon Peaking Station Natural Gas Pipe Line project capital budget is $2.9 million. Expenditures were $2.1 million under budget due to the 2010 payment of $2.8 million to SaskEnergy.

Corporate Information & Technology

- Total Corporate Information & Technology capital budget is $19.4 million. Expenditures were $3.5 million over budget.
- Dependable & Secure Infrastructure Portfolio budget is $1.0 million; expenditures were zero due to the reallocation reallocation to support new business and technology priorities..
- Desktop Modernization project budget is zero. Expenditures were $2.6 million due to changes in infrastructure priorities and increased associated costs.
- Effective & Efficient Operations portfolio capital budget is $2.8 million; expenditures were zero due to the reallocation to support new business and technology priorities.
- Enterprise Applications projects capital budget is $1.7 million; expenditures were zero due to the reallocation to support new business and technology priorities.
- Information Management portfolio capital budget is $1.4 million; expenditures were zero due to the reallocation to support new business and technology priorities.

CAPITAL EXPENDITURE (CONTINUED)

- Infrastructure Refresh & Renew projects capital budget is $1.8 million. Expenditures were $1.9 million over budget due to unforeseen demand for technology to support new business needs.
- Perimeter Security Enhancement capital budget is $1.5 million. Expenditures were $1.4 million under budget due to the deferral of costs to 2012.
- Proud & Productive Employees portfolio capital budget is $1.5 million; expenditures were zero due to the reallocation to support new business and technology priorities.
- SAP Licence Purchase capital budget is zero; expenditures were $5.0 million due to the purchase of a mobile technology solution to support the initiative around business object licences.
- Saskatoon Data Centre capital budget is zero; expenditures were $3.1 million due to changes in infrastructure priorities and increased associated costs.
- Unified Communications projects capital budget is $4.5 million. Expenditures were $2.7 million under budget due to unforeseen delays in project deliverables, which will defer costs to future years.

Customer Services

- Total Customer Services capital budget is $38.0 million. Expenditures were under budget by $10.9 million.
- Meter Purchases capital budget is $8.4 million. Expenditures were under budget by $4.6 million due to lower than anticipated purchases.
- Service Delivery Renewal – Automated Metering Implementation capital budget is $10.0 million; expenditures were zero due to deferral of the project to 2012.
- Service Delivery Renewal – CIS/CRM System Implementation capital budget is $7.9 million. Expenditures were $5.3 million over budget primarily due to the delayed implementation date.
- Service Delivery Renewal – Field Worker Technology Phase II – Schedule & Dispatch capital budget is $8.9 million. Expenditures were $1.3 million under budget due to costs moved from capital to OMA.
- Service Delivery Renewal – Field Worker Technology Phase III – Outage Management System capital budget is $1.1 million; expenditures were zero due to deferral of the project to 2012.
- Service Delivery Renewal – Service Business Metrics 2011 project capital budget was zero; expenditures were $1.5 million due to the addition of the project to facilitate benefit measurement.

CAPITAL EXPENDITURE (CONTINUED)

Power Production

- Total Power Production capital budget is $134.2 million. Expenditures were $11.3 million under budget.
- Poplar River #1 Ash Controls Replacement capital budget is $2.0 million. Expenditures were $1.3 million under budget due to deferrals to future years.
- Poplar River #1 Precipitator Improvements project capital budget is $3.4 million. Expenditures were $1.2 million under budget due to major supply contract costs that were less than expected.
- The Poplar River #1 Waterwall Refurbishment capital project budget is $3.3 million. Expenditures were $3.2 million under budget due to deferral to future years
- Poplar River #2 Ash Controls Replacement project capital budget is $2.4 million. Expenditures were $2.2 million over budget due to carry over from 2010 to complete procurement and installation.
- The Poplar River #2 Main Diesel Generator capital budget is zero; expenditures were $1.1 million due to the project being added in late 2010.
- The Poplar River #2 Main Stream Line Piping Replacement project capital budget is $1.9 million. Expenditures were $1.6 million under budget due to deferral to future years.
- The Poplar River Ash Lagoon #4 Construction project capital budget is $0.1 million. Expenditures were $1.7 million over budget due to carry over from 2010 to complete piping and shelterbelt installation.
- The Poplar River Dry Stacking Lagoon 3S project capital budget is zero; expenditures were $5.9 million due to work advanced from future years.
- The Poplar River Plant HVAC project budget is $1.0 million; expenditures were zero due to deferrals to 2012.
- The BD #5 HP Major Overhaul capital budget is $4.1 million. Expenditures were $1.8 million under budget due to deferrals to 2012.
- The BD Fire System Upgrade capital budget is $1.0 million. Expenditures were $1.1 million over budget due to carry over from 2010.
- The BD Flyash Collection & Storage Expansion project capital budget is $4.4 million. Expenditures were $2.3 million over budget due to carry over from 2010 and final cost increase of $1.0 million.

CAPITAL EXPENDITURE (CONTINUED)

- BD Flyash Storage & Loadout Upgrade project capital budget is 14.4 million. Expenditures were $2.3 million under budget due to deferrals to 2012.
- The BD Hydrogen Systems Upgrade project capital budget is $2.8 million. Expenditures were $2.2 million under budget due to deferral to 2012.
- Shand Boiler Panel Replacement project capital budget is zero: expenditures were $4.1 million due to procurement advanced from future years.
- Coteau Creek Rewind project capital budget is $0.3 million. Expenditures were $5.6 million over budget due to carry over from 2010.
- EB Campbell #8 Runner Refurbishment project capital budget is $11.2 million. Expenditures were $6.6 million under budget due to deferral to 2012.
- EB Campbell Plant Control Monitoring System capital budget is $2.9 million. Expenditures were $1.4 million under budget due to advanced purchases in 2010.
- Island Falls #5 Refurbishment project capital budget is $9.9 million. Expenditures were $5.5 million under budget due to deferral to 2012.
- Island Falls #6 Refurbishment project capital budget is $3.0 million. Expenditures were $1.8 million under budget due to deferral to 2013.
- QE Facility Upgrade project capital budget is $3.6 million. Expenditures were $2.0 million under budget due primarily to a major contract that was awarded for less than anticipated.
- Yellowhead SC Gas Turbines capital budget is $3.5 million. Expenditures were $3.9 million under budget due to cost estimate reductions.
- Coronach & Estevan Land Purchase projects capital budget are $3.5 million and $3.8 million respectively. Expenditures were $3.2 million and $1.9 million under budget respectively due to the current pace of negotiations with land owners.
- The Mine Service Building – Purchase & Rebuild project capital budget is $1.3 million. Expenditures were zero due to the decline of the current proposal for procurement.

CAPITAL EXPENDITURE (CONTINUED)

ICCS

- BD #3 - ICCS Carbon Capture project budget is $381.0 million. Expenditures were $193 million under budget due to construction delays and deferral of part of the project to 2012.

Transmission and Distribution

- Total Transmission & Distribution capital budget is $463.2 million – $170.6 million for Customer Connect and Annual Program spending and $292.6 million for Network Development projects. Expenditures were under budget by $210.8 million.
- Customer Connects budget is $96.5 million. Expenditures were $10.7 million over budget due to increased connects in new city subdivisions and oilfields.
- Annual Capital Programs budget is $74.1 million. Expenditures were $23.6 million under budget due primarily to resource constraints.
- Communications, Protection & Control projects budget is $17.7 million. Expenditures were $11 million under budget due to deferrals of the Fibre Route Diversity project and the Special Protection System projects to 2012.
- Subtransmission System projects had a total budget of $80.0 million. Expenditures were $34.6 million under budget due to deferral of some projects to 2012, partially offset by carry overs from 2010.
- Transmission projects had a total budget of $177.5 million. Expenditures were $143.6 million under budget due primarily to deferrals of projects to 2012.

Round1 – Consultant Q127:

Please confirm that the September update will include actual capital expenditures for 2011 and revisions to planned capital programs for 2012 to 2016, as necessary.

Response:

That is correct.

SaskPower

2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

Round1 – Consultant Q128:

Please discuss the "shift in the timing of Capital Expenditures" and explain how this timing shift impacts on future capital programs contemplated for 2012 and 2013.

Response:

A shift in the timing of Capital Expenditures relates to capital projects that were either budgeted for and not completed in a particular year or not budgeted for but started in the same year.

Using the years 2011 to 2013 as an example, the following explains how the timing of capital expenditures impacts budgets.

The 2013 capital budgeting process begins early in the 2nd quarter of 2012. During this time, each business unit will assess the status of projects that are currently underway and/or were budgeted for in 2012 as well as new projects that are to be done in 2013. If project ‘X’, was with an original capital budget of $10 million in 2012, is now being forecast at $5 million in 2012, the remaining $5 million would have to be included in the 2013 capital budget.

Based on this example, it’s important to note that capital budgets to not carry over from year to year. If a project is not completed in year 1, the budget is not carried forward and added to the Board approved capital budget in the Business Plan. Rather, the unfinished portion of the project should be included in the year 2 capital budget.

SaskPower

2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

Round1 – Consultant Q129:

Please discuss SaskPower's analysis of the capability of Saskatchewan Construction Industry to install SaskPower's capital program projects for 2012, and 2013, and indicate the experience in 2010 and 2011.

Response:

SaskPower’s actual capital expenditures were significantly below budget in both 2010 and 2011. In addition to competitive labor markets, a number of factors, such as wet weather conditions, changing customer requests, timing of projects, etc. contributed to this variance. In 2012, SaskPower dealt with these variances by building in contingencies to its capital budgets. The contingencies were determined by analyzing the previous 5 year’s actual capital expenditures to assess what SaskPower’s workforce is able to do vs. what is being requested.

Management will continue to monitor our actual capital spending vs. budget in 2012 and take into consideration, amongst other things, the demands of the Saskatchewan Construction Industry, when finalizing its 2013 to 2022 capital spending budgets.

SaskPower

2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

Round1 – Consultant Q130:

Please provide a list by year for 2012 and 2013 and discuss the amount of Capital Programs that SaskPower considers could be done within the Province and what portion must be "imported". Please also indicate what portion of the 2011 capital program was constructed by Saskatchewan based industry.

Response:

In 2011, SaskPower spent a total of $891 million on capital and goods and services expenditures. Of this total, $392 million (or 44%) was provided by a Saskatchewan establishment and $499 million (or 56%) was provided by an out-of-province establishment.

This information is based on an annual information request from CIC (guidelines established in March of 2012). Information relating to 2012 and 2013 will only be available at the end of each calendar year. In addition, the numbers referred to above include monies spent on both capital and OM&A activities as there is no way to differentiate between the two when preparing this report.

Round1 – Consultant Q131:

Please discuss the potential upgrades to transmission interties with Manitoba, Alberta, and North Dakota; including nature of the upgrades, increased import/export capacity projected costs and tentative schedules.

Response:

Currently there are no firm SaskPower plans to upgrade transmission interties with Manitoba, Alberta, or North Dakota as no SaskPower business case has been identified to require upgrading.

Under its open access transmission tariff (OATT) process, SaskPower has ongoing transmission service and interconnection requests that may initiate upgrades to the interties. Since these projects would be market driven, no projected costs or schedules can be provided without customer commitment to proceed with such reinforcements. As part of the OATT process, SaskPower has studied potential upgrades to transmission interties for the purpose of increasing import/export capacities with Manitoba and Alberta at specific customer requests. At present, there are no committed plans for upgrading transmission interties.

Round1 – Consultant Q132:

Please either confirm that there have been no changes to the Cost of Service methodology, classification/allocation factors from the 2010 application, or alternatively, describe fully the changes made.

Response:

SaskPower confirms that there have been no changes to the Cost of Service methodology, classification/allocation factors from the 2010 application.

Round1 – Consultant Q133:

Please confirm that there have been no changes in rate design for any classes, including intra class rate differentials.

Response:

SaskPower confirms that there have been no changes in rate design for any classes, including intra class rate differentials.

SaskPower

2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

Round1 – Consultant Q134:

Please explain why the forecasted revenue for Residential, Farm and Commercial customers is greater in 2011 than is expected for 2012.

Response:

During the first quarter of 2012, Saskatchewan had one of the warmest winters on record. This caused a dramatic fluctuation from normal weather related energy usage for the above mentioned classes, enough to alter the entire year revenue profile. The table below illustrates the amount of energy (and % of budget) that had to be removed (in 2011) and added (in 2012) to the actual loads, in order to weather normalize to the 30 year average.

2011	Normalized Energy Adj.	% of Budget
Jan	3,465	0.02%
Feb	(20,320)	-0.09%
Mar	(46,000)	-0.21%
April	(13,381)	-0.06%

2012	Normalized Energy Adj.	% of Budget
Jan	71,624	0.53%
Feb	62,375	0.46%
Mar	81,740	0.60%
April	(3,183)	-0.02%

Round1 – Consultant Q135:

Please provide schedules showing the revenues and costs for each customer class for each of the energy, demand and basic monthly charge components for 2010, 2011 and that projected for 2012 & 2013, as well as the average class unit revenues (in cents/KWh).

Response:

See table below:

Please note that SaskPower's billing system can only provide a breakdown of revenue to the demand charge and the combination of basic and energy charge. This applies to the 2010 and 2011 actual billing data. Also, the 2013 revenue breakdown provided in the table is before the rate increase.

There are 2 factors which impact how the basic, energy and demand revenue aligns with costs. The first is that the energy charge for small residential, farm and commercial customers includes both the energy and demand costs. The second is that SaskPower's demand metered rates are designed to collect the appropriate revenue for customers of all load factors. To do this, it is necessary to collect some of the demand costs in the energy charge.

Revenue

	2010		2011		2012		2013	
Residential	**Revenue**	**Costs**	**Revenue**	**Costs**	**Revenue**	**Costs**	**Revenue**	**Costs**
Basic		78,951,856		85,145,146	84,944,331	79,816,033	86,213,727	89,008,055
Energy	381,533,381	347,782,998	407,263,748	332,352,428	312,238,643	325,367,532	316,789,697	329,870,121
Total	381,533,381	426,734,854	407,263,748	417,497,574	397,182,974	405,183,565	403,003,424	418,878,176
Farm								
Basic		16,580,672		17,776,038	21,265,196	18,215,747	21,247,638	20,076,158
Energy	137,779,024	95,720,034	141,839,126	42,937,904	118,800,515	45,416,461	119,346,416	44,422,754
Demand	3,069,272	44,254,484	3,081,780	103,285,646	2,768,567	83,226,242	2,774,902	84,236,877
Total	140,848,296	156,555,190	144,920,906	163,999,588	142,834,277	146,858,450	143,368,956	148,735,789
Commercial								
Basic		30,696,935		33,693,027	18,061,957	35,172,666	18,199,658	38,017,515
Energy	288,211,789	140,005,029	302,787,006	123,501,539	285,915,448	132,315,734	286,719,856	130,260,068
Demand	51,190,375	125,300,905	52,742,300	183,531,965	47,507,319	187,665,288	47,483,618	189,237,338
Total	339,402,164	296,002,869	355,529,306	340,726,531	351,484,724	355,153,688	352,403,132	357,514,921
Oilfields								
Basic		13,579,375		14,130,552	10,793,305	14,519,170	11,365,753	15,814,415
Energy	167,842,492	120,039,312	173,767,526	94,743,724	184,638,681	114,774,259	193,059,735	116,987,128
Demand	65,549,475	97,280,377	67,854,127	133,649,660	74,455,415	129,683,634	77,191,735	135,678,292
Total	233,391,967	230,899,064	241,621,653	242,523,936	269,887,400	258,977,063	281,617,223	268,479,835
Power Customers								
Basic		4,491,036		4,858,454	6,216,072	5,471,855	6,252,072	6,838,453
Energy	334,674,250	219,982,287	361,692,879	224,439,599	414,352,988	285,586,083	459,261,571	309,364,099
Demand	69,433,967	166,177,298	78,609,296	195,074,925	86,725,964	211,808,902	98,021,003	235,774,538
Total	404,108,217	390,650,621	440,302,175	424,372,978	507,295,024	502,866,840	563,534,647	551,977,090
Reseller								
Basic		196,893		202,664	282,240	262,115	282,240	325,594
Energy	40,062,029	34,269,724	41,418,474	38,157,532	41,768,941	41,906,205	42,149,568	41,229,116
Demand	35,410,212	39,447,051	35,730,709	39,306,168	36,378,599	35,906,254	36,710,222	35,928,890
Total	75,472,241	73,913,668	77,149,183	77,666,364	78,429,780	78,074,574	79,142,030	77,483,600
Grand Total	1,574,756,266	1,574,756,266	1,666,786,971	1,666,786,971	1,747,114,180	1,747,114,180	1,823,069,411	1,823,069,411

Consumption (GW.h)

	2010	2011	2012	2013
Residential	2,882.4	3,006.0	2,929.4	2,972.1
Farm	1,291.6	1,298.3	1,280.9	1,286.7
Commercial	3,386.5	3,447.5	3,480.2	3,488.3
Oilfields	2,871.6	2,900.8	3,277.0	3,431.7
Power Customers	6,932.4	7,320.9	8,647.5	9,608.8
Reseller	1,254.3	1,252.8	1,280.8	1,292.5
Total	18,618.8	19,226.3	20,895.8	22,080.1

Cents/KWh

	2010	2011	2012	2013
Residential	0.1324	0.1355	0.1356	0.1356
Farm	0.1090	0.1116	0.1115	0.1114
Commercial	0.1002	0.1031	0.1010	0.1010
Oilfields	0.0813	0.0833	0.0824	0.0821
Power Customers	0.0583	0.0601	0.0587	0.0586
Reseller	0.0602	0.0616	0.0612	0.0612
Total	0.0846	0.0867	0.0836	0.0826

Round1 – Consultant Q136:

Please file the 2011 COSS and the 2012 & 2013 Prospective COSS.

Response:

Work continues on the 2011Base COSS report and will be submitted as soon as it is completed. The 2013Test COSS report has been previously filed and there is no 2012Test COSS report since there was no rate application tabled in 2012.

SaskPower

2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

Round1 – Consultant Q137:

Please provide an update respecting SaskPower industry partnership including the government of Canada in examining Carbon Capture and Storage, economic, technical & environmental needs including costs, cost sharing and proposed schedules. (Sustainability Report P. 22).

Response:

SaskPower is proceeding with implementing the BD3 ICCS project. The overall cost of the project is $1.242 billion. A part of this cost has been off-set of approximately $240 million in Government of Canada funding. This funding was allocated to the Province of Saskatchewan for the general purpose of developing full scale carbon capture from coal fired power in Saskatchewan. The government of Saskatchewan, in turn allocated this funding to the BD3 project resulting in a net cost to SaskPower of $1.002 billion.

The project consists of two components: a rebuild of the power plant to modernize it and allow for an additional 30 years of reliable operation; and the construction of a sulphur dioxide (SO2) and CO2 capture and compression facility to capture all of the SO2 from BD3 and 90% of the CO2.

The project will produce four products of value: electricity, CO2, fly ash, and sulphuric acid. The revenue from these products offsets the capital cost to make the project financial competitive with other potential new sources of electricity generation.

The project is currently in the construction stage with the CO2 capture plant approximately 50% complete. The power plant rebuild work will take place in 2013 during a six month outage starting in March of 2013.

Project procurement is approaching the 95% complete point. Negotiations of a CO2 sale are well advanced.

The power plant is expected to be in commercial operation on September of 2013 with the start-up and commissioning of the CO2 capture plant to begin in October of 2013. Full commercial operation of the CO2 capture plant is expected by the end of Q1 2014

Overall, the project is on time and on budget.

2013 RATE APPLICATION
CONSULTANT INTERROGATORIES ROUND ONE

Round1 – Consultant Q138:

Please provide an update on the Green Power Initiative including the ability of parties to currently access this program.

Response:

SaskPower implemented the Green Options (GO) Partners Program in 2010 and 2011 to procure up to 50 MW, per year, of small to medium-sized renewable energy projects. Technologies eligible for the GO Partners Program included biomass/biogas, flare gas, heat recovery, low-impact hydro, solar, turbo expander and wind power. A total of eight projects were selected in 2010 and nineteen projects in 2011 bringing the total to:

- 54.8 MW Wind
- 1.4 MW Heat Recovery
- 14.7 MW Flare Gas
- 14.3 MW Other

The Green Options (GO) Partners Program lottery will not be held in 2012.

SaskPower is reviewing the program to ensure it continues to meet SaskPower’s goal of supporting emerging power generation technologies while providing opportunities for Independent Power Producers (IPPs). SaskPower expects to have the review complete in the spring of 2013 and will provide more information on the program at that time.