1. Reference: 1st Round Information Request #1 [Delivery Service Rate Overview]

a) With reference to the response to 1st Round Information Request 1(a), please provide a list of changes to the chart of accounts and accounting practices, as well as a summary of the impact of those changes to revenue requirement categories.

As provided in the response to IR 1(a), any changes to the corporation's chart of accounts would have no impact on comparability to prior test years. The chart of accounts is the list of possible places where business units can charge costs. Operating, maintenance and administration expenses are tracked in a consistent manner each year and are included in the revenue requirement. Any organizational structure changes that impact the distribution utility's cost of service would be reflected in intercompany cost allocations.

b) Please outline the timeline and steps undertaken as part of the annual business plan budgeting process.

i. How does this timeline align with timelines required to prepare delivery or commodity rate application forecasts?

SaskEnergy's annual business plan budgeting process is as described in the response to first round IR #2(a) for the 2015 Delivery Service and Commodity Rate Application. The timelines have changed by approximately one month given the change in the corporation's fiscal year end from January 31 to March 31. The reason the timelines have moved by only one month is due to the dates for CIC review and CIC Board approvals. Prior to the change in year end, CIC required crown business plans to be board-approved by the end of October in order to allow for CIC officials to review and analyze business plans prior to Performance Management day with the CIC Board in early December. Performance Management day is now held in mid-January to better align with Cabinet Budget Finalization for the General Revenue

Fund. As a result of this change in timing, crown business plans must be Board approved by the end of November.

Anticipated rate changes are a key consideration for both crown boards and the CIC Board and, as a result, the business plan as presented includes preliminary rate change assumptions – typically expressed as a range (ex. 3% to 5%). General practice is to refine the required rate immediately prior to the development of the rate application however, unless specific details clearly need up-dating, the rate application schedules are consistent with the approved budget.

ii. What is the cut off point for updates to information for the test year forecasts included in the delivery rate application?

Due to the extensive Governance process required in order to file a Rate Application, adjustments to the Revenue Requirement for the test year need to be made four months in advance of the filing of the Application. For example, the Revenue Requirement for the 2017 Rate Application needed to be finalized in early February in order to provide sufficient time to do the Cost of Service and recommend rates for the Executive in early March. Please note that meeting documents are always due a few days to two weeks ahead of meetings in order to provide meeting participants adequate time to review the material. Following is the schedule that was followed for the 2017 Rate Application, which is typical. Due to some delays and changes to meeting agendas, the 2017 Rate Application was delayed about six weeks.

DELIVERY SERVICE RATES APPLICATION
Approval Process

TIMELINE

March 1, 2017	SaskEnergy Executive Committee Approval
March 8, 2017	SaskEnergy Audit & Finance Board Committee Approval
March 29, 2017	SaskEnergy Board of Directors Approval
Late April, 2017	CIC Board Approval to Proceed
May 2017	Cabinet Approval to Proceed
Late May 2017	Minister's Order Issued
Late May 2017	File Application with Panel and Public Announcement
September 2017	Panel Recommendations to CIC
October 2017	Cabinet Approval of Panel Recommendation
November 1, 2017	Final Rate Implementation

iii. Are there changes to timing of these activities that could improve the accuracy of information included in test year forecasts?

Historically SaskEnergy used the details consistent in the approved Business Plan to form the Revenue Requirement, updating numbers only when a material change has occurred. SaskEnergy is evaluating the implications from a governance perspective of up-dating the Revenue Requirement just prior to doing its Cost of Service.

iv. What would be required to implement these changes?

SaskEnergy may amend its internal processes prior to the next Application.

c) With reference to part (g), please confirm that the overall variance between test year forecast and actual results for the 2016/17 test year (including the period from July to October) is expected to be in the range of $5.785 million.

Confirmed, no material changes are expected for the remaining months of the test period.

d) With reference to part (g), please quantify and explain the key changes that occurred over the test period that led to the $5.785 million variance.

i. Specifically, please itemize the key expense categories where variations occurred from the test year forecast and outline the share each category has of the $5.785 million variance from forecast.

The key changes that occurred over the test period apply to operating cost reductions which are approximately $5 million of the $5.8 million variance. The key expense categories where variations occurred relative to the test year forecast are provided below.

Reduced Operating and Maintenance Expense in the following categories:

- Wages, Salaries and Benefits - $3.1 million
- Contracts and Consulting - $1.5 million
- Sustenance and Transportation - $1.0 million
- Materials and Supplies - $0.2 million

The above reductions were partially offset by increased Operating and Maintenance Expense in the following category:

- Property Costs - $0.8 million

ii. For each key expense category, to the extent known please also indicate which were due to restraint measures and which were due to other factors. Please describe the other factors.

The reduced expenses in the Wages, Salaries and Benefits category are attributable to overtime management as a result of business process changes and efficiency initiatives in addition to the restraint measures. The balance of the expense reductions listed above relate to restraint measures.

e) Please detail the specific measures that were undertaken in response to the restraint directives in 2015/16 and in 2016/17 and quantify the savings related to each measure in each year.

The following table provides the major expense categories where restraint measures were undertaken and the estimated savings related to each.

	2015/16	2016/17
Salaries and Benefits – Out of Scope Wage Freeze, Bid Lag, Reduced Vacation Liability & OT Management	2,000,000	3,000,000
Reduced Interest Expense *	1,500,000	1,400,000
Internal Gas Usage **	1,400,000	-
Training and Travel (Vehicle Mileage, Out of Province Travel, and Training)	670,000	400,000
Vehicle Fuel	500,000	400,000
Advertising	255,000	300,000
Miscellaneous Expense Reductions	682,000	200,000
Consulting/Professional Services and Professional Fees	190,000	800,000
Depreciation	100,000	500,000
Total	**7,297,000**	**7,000,000**

* The savings identified under interest expense relate to the combination of carrying more short term debt versus longer term debt (which the Corporation considered a restraint measure) and lower interest rates than assumed in the budget (which the Corporation considered market-driven expense savings).

** The reduction in Internal Gas Usage was also a market-driven expense savings as gas prices were lower than forecast.

f) Please confirm that savings related to restraint measures were not included in the 2015/16, 2016/17 or 2017/18 test year forecasts. If not confirmed, please discuss measures that were included in test year forecasts.

The restraint measures implemented in 2015/16 were not undertaken until late in the third quarter of the year and were not included in the test year forecast. The 2016/17 business plan included $4 million in planned efficiency savings/new revenue initiatives which were incorporated into the test year forecast. For 2017/18, the business plan included $7 million in planned expenditure restraint carried forward from the previous year in addition to the $4.4 million in planned efficiency savings/new revenue initiatives (see page 3 of Tab 23). These reductions were incorporated into the test year forecast for 2017/18.

g) SaskEnergy notes that for 2017/18 it is returning to normal levels of spending in several expense categories which have been subject to restraint measures in 2015/16 and 2016/17.

i. Please indicate the major expense categories subject to restraint measures in 2015/16 and 2016/17 which are returning to normal levels of spending or that will see "moderate cost increases" in 2017/18 after application of restraint measures in 2016/17.

Expense categories that are returning to more normal levels include travel, training, advertising and, to a lesser extent, sponsorships.

ii. Please confirm that for each of the above-noted expense categories where spending is returning to normal levels, the forecast level of expense is expected to be actually achieved in 2017/18.

The amounts provided in the budget for 2017/18 related to travel, training, advertising and, to a lesser extent, sponsorships formed the basis for these expenditure items included in the distribution utility's cost of service for the 2017/18 test year. That level of expenditure is expected to be achieved for 2017/18.

iii. Please also confirm whether spending is expected to be maintained at 2017/18 forecast levels going forward.

The development of the 2018/19 budget is in its very early stages. Material increases in expenses are unlikely and budget development direction to budget preparers was to endeavor to hold expenses flat wherever possible however, those decisions have not yet been finalized for 2018-19 and the forecast period.

h) Are there longer term implications arising from restraint activities over the last number of years, i.e., changes in approach to forecasting, or to undertaking activities or other efficiencies identified as part of restraint activities that will be maintained as part of ongoing operations going forward?

SaskEnergy has been very consistent in its approach to building expense budgets, conducting its business and making decisions. Safety is the top corporate priority and will not be compromised. Efficiency and productivity gains are actively pursued as are new revenue opportunities and SaskEnergy was focused on planning and achieving operating efficiencies well-before the Province began its practice of requesting restraint in Crown operating expenditures. Since 2009, SaskEnergy has realized savings of approximately $42 million through efficiency initiatives and process improvements. The corporation consistently seeks opportunities to pursue industry best practices and endeavors to maintain high levels of customer service in accordance with the Crown Sector Strategic Priorities. Some longer term implications of the restraint efforts relate to workforce diversity which suffers when the number of new hires is reduced considerably.

i) Please discuss the difference between restraint measures and productivity and efficiency measures.

Restraint measures are those things that the corporation has undertaken or quantified in response to requests from the Province for incremental earnings and are generally short term in nature. For example, the elimination of all out of province travel for a period of time would be considered “restraint”. Vacancy management opportunities that arise when positions are vacated by an incumbent and not re-bid immediately would also be considered “restraint”. Productivity and efficiency measures are those initiatives that are planned in advance in the categories of leveraging technology, crown collaboration or business processes changes that result in operating efficiencies and reduced costs.

2. Reference: 1st Round Information Request #2 [OM&A Costs]

a) With reference to part (c), please provide a further explanation regarding the “increased employee obligation costs” noted.

i. Please outline what is included in the “employee obligation costs” and explain how these items relate to the increased OM&A costs in the test years.

Employee obligation costs include wages, salaries, over time, standby pay, substitution pay, vacation pay, inconvenience pay and the premiums for employee benefit plans. Regular increases to in scope wages are mandated in the Collective Bargaining Agreement and, unless out of scope salaries are frozen by government directive, annual increases typically apply to out of scope wages as well.

ii. Do these costs relate to salaries and wages? If so, please explain and provide details of the increase.

A portion of the increase relates to salary and wage increases. Out of scope salaries were frozen in 2016 as part of the province's fiscal restraint directive which results in lower total OM&A costs for the 2016-17 forecast. This freeze did not apply to in scope wage increases that went ahead in 2016 as these increases are governed by the Collective Bargaining Agreement.

b) With the reference to 2 (g) (ii), does SaskEnergy plan to undertake the work identified regarding the Distribution Work Management system, the Records Information Management System and the Customer Information system maintenance service using internal resources? Please discuss.

Consistent with SaskEnergy's resourcing strategy, these major IT initiatives will be undertaken with an optimal combination of internal and external resources.

c) With the reference to 2(j) please describe the travel costs avoided in 2016/17 that are forecast to be restarted in 2017/18. Please outline why it is important to resume these activities in the test year. Will this level of activity be maintained going forward?

Prior to the 2015 restraint directive, SaskEnergy and TransGas personnel were active participants on important industry committees and working groups associated with the Canadian Gas Association (CGA) and the Canadian Energy Pipeline Association. Following the restraint directive, all non-essential travel was discontinued and participation on these committees was extremely difficult via teleconference. The corporation is committed to the pursuit of industry best practices and has determined that some level of active participation on these industry committees is very valuable for SaskEnergy going forward.

3. Reference: 1st Round Information Request #3 [Labour Costs]

a) With the reference to the response to 3 (a), please explain the increase in overtime in 2017/18 over 2016/17. With reference to the response to 2(e) (and SaskEnergy maintaining its "commitment to never compromise the safety of its system, its employees or the public"), does the increase relate to non-emergency or non-safety related overtime or other overtime? Please explain.

The increased over time in 2017-18 relates to potential emergency response requirements. Each year the corporation expects a certain level of non-planned over time will be incurred. The overtime amount for the 2016/17 fiscal year is well below the previous years' actual results and lower than the forecast period given the warmer than normal winter and fewer emergency responses required during the year. In addition to the mild weather, there were not any large scale emergencies during 2016/17 compared to many of the previous years (such as widespread flooding, northern fires, severe winter weather).

b) With reference to the response to 1st Round IR # 3(f), please quantify in dollars the vacant FTEs for each year.

The estimated FTE vacancy savings are as provided below:

Year	Estimated FTE Vacancies	Average Base Labour Cost/FTE	Estimated Vacancy Savings
2012	21	$86,300	$1,812,300
2013	16	$87,572	$1,401,152
2014	16	$89,472	$1,431,552
2015	22	$91,869	$2,021,118
2016/17	40	$93,165	$3,726,600
2017/18	35	$94,766	$3,316,810
2018/19	35	$96,367	$3,372,845

Please note that the statistics related to vacant FTEs as provided in question 3 (f) are actually vacant positions and not FTEs. The correct FTE vacancy numbers are provided in the above table along with the estimated savings in each year.

c) With reference to the response to 1st Round IR #3(f), please detail the positions that were filled to reduce the vacancy from 64 in 2016/17 to 52 in 2017/18. Were any positions eliminated? Please discuss.

FTE stands for full-time equivalent which is not the same as positions. For example, a summer student who works from May 1 to the end of August is one position but 0.33 of an FTE. The FTE vacancy savings are calculated based on vacant positions with wage or salary dollars attached.

At any one time there are many positions that are vacant in the organization. Vacancies are typically filled after a few weeks or in some cases a few months. There are very few positions that remain vacant the entire year as business units can "make do" during temporary vacancies but permanent vacancies require a re-organization of duties and responsibilities. A listing of vacant positions must be at a point in time and does not equate to FTEs.

Due to business process changes and the reorganization of some business units, the corporation eliminated 6 positions as part of the 2016/17 business plan.

4. Reference: 1st Round Information Request #4 [Charges to Capital]

a) With reference to the response to 4 (b), please provide details of the "established practice" referenced regarding the calculation of Charges to Capital. In particular, please explain how this applies where there is a large increase in capital expenditures in one year and large reduction in the next year.

The calculation of charges to capital is dependent on whether or not the work performed by the SaskEnergy workforce was capital in nature as defined by International Financial Reporting Standards (IFRS), which are used as the guideline for the established practice in SaskEnergy's financial reporting system.

The accounting treatment of charges to capital under IFRS is consistent, regardless of the fluctuations in capital expenditures between years.

b) With the reference to the response to 4 (c), please explain the increase in labour charged to capital in 2016/17; as well as the decrease in non-labour in that year.

Beginning in 2016-17, accounting began to eliminate inter-company construction labour and vehicle charges within the LDC from construction to the distribution area offices across the province. These costs were charged and reported within contract services and recovered in internal cost recoveries. This was not reflected in the 2017/18 and 2018/19 forecasts as the administrative decision was finalized after the forecasts were completed. The net financial impact to the corporation is zero as the decline in contract services costs is offset by the decline in internal cost recoveries.

5. Reference: 1st Round Information Request #6 [Energy Efficiency]

a) With the reference to the response to 6 (a), please explain if any cost savings related to energy efficiency programs were included in the 2017/18 revenue requirement. Please describe the programs and if possible quantify or otherwise describe any benefits.

There are no cost savings related to energy efficiency programs. Any savings from Energy Efficiency programs are to customers.

The programs are described as followed:

Residential Programs

ENERGY STAR® Loan Program - The ENERGY STAR® Loan Program promotes the efficient and safe use of high efficiency natural gas equipment and provides a valuable sales tool for SaskEnergy Network

Members who are the delivery agents of this program. In the residential market the ENERGY STAR Loan Program ($200K budget) provides 6.50% financing for ENERGY STAR furnaces, boilers, heat recovery ventilators, air conditioners, tank and tankless style water heaters. The current program is available August 1, 2017 through March 31, 2018 and is jointly funded by SaskEnergy, SaskPower and SaskEnergy Network Members.

The Tune-Up Assistance Program (TAP) is a community program designed to help low-income homeowners maintain their natural gas space heating equipment. Partipating SaskEnergy Network Members will complete a Home Heating Tune-Up on selected low-income homeowners heating equipment at no cost to the homeowner. SaskEnergy provides the homeowner with 2 furnace filters and 1 dual natural gas and carbon monoxide detector and covers the cost of the service. Late June the program piloted in Wadena and assisted 9 low-income homeowners. TAP will be rolled out to 10 communities throughout the province this fall and assist approximately 200 low-income households. The program will help to increase provincial awareness about the importance of furnace maintenance and safety benefits.

SaskEnergy has been exploring residential program options to potentially target next generation water heating, keep natural gas in new homes, and broader based options for natural gas appliance education and maintenance. Due to financial restraints the past several years, new program options have not been formalized or introduced. The remaining $325K in the residential budget would be used to promote launch, administer and fund any new programs.

Commercial Programs

The Commercial Boiler Program is designed to encourage the use of appropriately sized high-efficiency natural gas hydronic space heating systems in commercial new construction and retrofit applications. The program provides incentives based on the incremental price of high-efficiency natural gas condensing boilers over the purchase price of standard equipment. The program is offered and delivered through Commercial Network Members.

Commercial HVAC Program (Heating, Ventilation, and Air-Conditioning)

The program is designed to encourage the use of energy-efficient furnaces, smaller boilers, rooftop units, infrared heathers and condensing heaters in both commercial new construction and retrofit applications. The Commercial HVAC Program is available through participating SaskEnergy Residential and Commercial Network Members. SaskPower provides funding towards equipment that provides electrical savings in addition to natural gas savings.

SaskEnergy is selective with programs, focusing on those that can be offered with low administration costs, while offering incentives in areas that influence purchasing decisions. With Network Members interfacing directly with homeowners, business owners and home builders, and assisting with program delivery, SaskEnergy's administration costs continue to remain low. The Network Members provide a very effective delivery channel.

b) With reference to the response to 5(a) and 6(a), is Energy Efficiency Program and Awareness spending expected to increase materially going forward or remain at 2017/18 forecast levels?

The Energy Efficiency Program and Awareness spending is expected to remain near 2017/18 forecast levels going forward.

c) With reference to the response to 5(a) and 6(a), what types of costs or programs are included in the 2017/18 forecast for Energy Efficiency Program and Awareness spending that were not included in the 2016/17 actuals. Please explain.

Forecast 2017/2018 reflects the regular flat budget for this category. In 2016/2017 actual results were materially lower than budget due to restraint measures directly impacting this category.

During 2016/2017 SaskEnergy's low income program was temporarily put on hold, promotion of SaskEnergy Network Member programs was scaled back, and other programming plans were cancelled as a result of fiscal restraint and managing the FTE vacancy. Also, commercial programs uptake declined as mechanical contractors experienced an economic slow-down in both commercial and residential markets. In 2017/2018, these programs or similar ones will be reinstated.

d) Please reconcile the cost provided for Energy Efficiency and Program Awareness in response 5(a) to the costs provide for energy efficiency programs in response 6(a), and explain any differences.

$1.069 million is the cost of customer program incentives and rebates. The remainder of the $1.981 million is not dedicated to the safety program. This portion is allocated for operating, advertising and promotion of customer programs, customer technology innovation, and customer experience initiatives. One exception is the First Nations Safety calendar included in this budget. The calendar features art by students at First Nations schools highlighting natural gas safety messages. Schools are visited periodically by efficiency program team members, who provide efficiency and safety presentations to students.

The 'safety and awareness' budget is separate from the $1.981 million and is dedicated to core safety and awareness programming.

6. Reference: 1st Round Information Request #7 [External Services]

a) With reference to the response to 7(d), please explain the increase in contract services expense related to customer connections in 2017/18 compared to 2016/17.

The increase in contract services expense related to customer connections is due to the overall increase in the projected activity level in 2017-18 along with the anticipated unit cost increases. The increase in contract service expense is consistent with the overall increase in the forecast for customer connections. In 2016-17, the Distribution Utility added 4,000 new customers and in 2017-18 that number is forecast to increase to 4,500 new customers.

b) The response to 7(i), indicates that copier maintenance costs have moved to a contract services arrangement and increased costs are reflected in the External Services category.

i. Are higher costs typically expected when services are contracted externally?

Higher costs are not typically expected. Services are contracted externally to allow the corporation to leverage specific expertise not readily available internally or to more efficiently accomplish specialized tasks that are cyclical or sporadic in nature. This avoids the costs of making that service available "in house" all throughout the year. These decisions are made after careful consideration of the costs and benefits to the organization.

ii. With reference to the response to 7(b), please discuss in further detail what measures are available to manage these types cost increases going forward? Are these arrangements being applied with regard to copier maintenance? Please discuss.

Key changes in business practices that are material are typically subject to a business case review. A full analysis of the associated costs, benefits and alternatives is undertaken before a recommendation is taken forward for approval.

Long term service contracts are negotiated with vendors within the requirements of the Purchasing Department and at the most favourable rates available.

7. Reference: 1st Round Information Request #8 [Intercompany Allocations]

a) Please confirm the table provided in response to 8 (c) provides information for the 2015/16, 2016/17, 2017/18 and 2018/19 fiscal years. Please expand the table to include actuals for the 2016/17 fiscal year.

Confirmed, the table provided in response to first round IR#8 (c) provides information for the 2015/16, 2016/17, 2017/18 and 2018/19 fiscal years. Note that the 2016/17 column as provided in that response contains the actual allocation percentages.

b) With the reference to the response to 8 (c), please outline the drivers underlying the increase in allocations for the following accounts: 32 (Management), 203 (Information Systems), 222 (Payment Services), 226 (Distn Acctg, C&C Pay Servs), 1200(VP Distribution Utility), 4000 (Operations, Planning & Mtce), 4600 (Business Policy & Admin) and 5410 (Geographical Information Systems).

Explanations for the increases to the allocations from the above accounts for the 2017/18 test year are as follows:

32 – Management – increases to $1.9 million in 2017/18 test year

Executive salaries and benefits have increased in 2017-18 compared to 2016-17. The Executive allocation percentage to the LDC has increased from 56 percent as shown in the 2013 Delivery Rate Application to 56.7 percent in the 2017 Delivery Rate Application. This change is being driven by elevated growth in the distribution customer base and heightened efforts related to providing safe and reliable service to customers. At the end of the 2016-17 fiscal year, the total number of active distribution customers was 390,886 which represents a 7 per cent increase since 2012. This has required the addition of more than 1,700 kilometers of distribution pipeline during that time.

203 (Information Systems)

The increase in Information System costs relates to the increased cost for third party contractors and additional hosting service costs. As well, increased effort will be required given the planned CIS up-grade project and the Distribution Work Management project.

222 (Payment Services)

The increase in the allocation from Payment Services relates to the reorganization of this area in mid-2016/17 which saw the Collections function move to its own area. Prior to that, the Payment Services business unit employed the corporate allocation for their costs and now 100% of the costs in this business unit go to the LDC.

226 (Credit and Collections)

The increase in the allocation from Credit and Collections relates to the growth in the distribution utility customer base. More distribution customers results in increased effort related to credit and collection work.

1200 – VP Distribution utility – increases to $1.2 million

The increase in 2017-18 is attributable to the transfer of the costs for the General Managers from their service area cost centres (IE: 1100, 1700, 2500, 3300, & 4300) to the cost centre for the VP of the Distribution Utility (1200). This change was implemented as part of the operational review which was undertaken beginning in 2016.

4000 – Operations Planning & Maintenance – increases to $2.3 million

The increase in 2017-18 is attributable to cost increases related to providing liquefied natural gas service in response to peak day supply requirements in Aberdeen and St. Brieux. This service represents a much more cost effective solution than building pipeline to address supply peaks.

4600 (Distribution Information Systems)

The increase in this category reflects the elevated effort for the Distribution Work Management system and the CIS up-grade in addition to regular IT support for LDC employees.

5410 (Geographical Information Systems - LDC)

The increased allocation from GIS relates to LDC specific work being undertaken to implement the foundation for GIS.

c) Please confirm that a change in the corporate allocation does not change the overall services to be performed or costs incurred.

Confirmed, the corporate allocation is calculated based on the relative split of FTEs between the transmission utility and distribution utility. A change in the corporate allocation has no impact on the overall services to be performed or the actual costs incurred.

d) With references to the response to 1st Round IR #8(c)(i) please describe further the "elevated regulatory burden" referenced as impacting the allocation of intercompany costs.

In the last number of years, the corporation has seen a material increase in the level of effort required to respond to requests from regulatory agencies. Documentation requirements and efforts associated with communicating and meeting with these agencies has increased significantly in recent years. In order to effectively and efficiently respond to this increased work load (which is not accompanied by a commensurate increase in revenue) labour costs must be carefully managed in order to minimize rate pressure. As a result, the Corporation has expanded the roles of some existing positions to address both distribution and transmission work. Expanding the scope of some positions that have previously been exclusively dedicated to transmission services has been the corporation's solution to this elevated regulatory burden. Increases in the intercompany allocations from these departments to the Distribution Utility are far less than the labour costs that would be required if incremental resources were added to address the elevated regulatory burden.

8. Reference: 1st Round Information Request #9 [External and Internal Recoveries]

a) With the reference to the response to 1st Round IR # 9 (a), please explain the large reduction in Internal Recoveries related to labour cost [reduced from $2.5-$2.7 million for 2013-2015/16 to $1.5-$1.6 million level in 2016/17 through 2018-2019].

Beginning in 2016-17, accounting began to eliminate inter-company construction labour and vehicle charges within the LDC from construction to the distribution area offices across the province. These costs were charged and reported within contract services and recovered in internal cost recoveries. This was not reflected in the 2017/18 and 2018/19 forecasts as the administrative decision was finalized after the forecasts were completed. The net financial impact to the corporation is zero as the decline in contract services costs is offset by the decline in internal cost recoveries.

The reduction in internal recoveries related to labour costs is due to the fact that less work is being completed by internal construction crews. More work is being done by external contractors particularly in areas outside of Regina and Saskatoon.

9. Reference: 1stRound Information Request #10 [Transportation and Storage Expense]

a) With reference to the response to 1st Round IR # 10 (a) (iii), SaskEnergy states that "transportation and storage rates are based on the cost of service for TransGas". Please confirm that the TransGas cost of service assumes a 5% increase effective April 1, 2018.

The TransGas cost of service for 2018/19 as developed within the 2017/18 business plan assumed a 5% average rate increase for transmission and storage rates effective April 1, 2018. The 2018-19 business plan is in the early stages of development and that assumption will be revisited as part of the planning process. The 2018/19 plan will be presented to the SaskEnergy Board for approval in November, 2017.

b) With reference to the response to 10(d), please confirm that the dates provided in (ii) should be October 31, 2018 and (iii) should be October 31, 2019.

Yes, that is correct. Please see the corrected dates / response below.

All transportation costs from Alberta are included in the commodity rate. The transportation costs from Alberta to Saskatchewan are as follows:

- November 1, 2016 to October 31, 2017 is $19.6 million,
- November 1, 2017 to October 31, 2018 is $19.5 million, and
- November 1, 2018 to October 31, 2019 is $20.7 million.

c) With reference to the response to 10(e), please explain further how SaskEnergy use of transportation and storage contracts at slightly higher load factor will result in greater efficiencies. Please describe any risks or potential opportunities available to SaskEnergy regarding use of higher load factor.

The ability to utilize these contracts at a higher load factor is very limited and can only be leveraged in a situation such as this where the increase in the forecasted gas requirements are very modest. A portion of SaskEnergy's firm NIT to TEP transportation is reserved to enable SaskEnergy to purchase the incremental gas requirements associated with a colder than normal winter. Utilizing this transportation contract at a higher load factor means that we are using some of this transportation reserved for a colder than normal winter to meet our regular annual requirements. Therefore the risk associated with this practice is that we may not have sufficient transportation to meet the gas requirements of a colder than normal winter. Given the relatively modest increase in the forecasted requirements, SaskEnergy can manage this risk by being very proactive in purchasing any incremental winter gas requirements. There is no opportunity to leverage this transportation any further without jeopardizing the ability to meet our customers' winter gas requirements.

d) With reference to the response to 10 (g), please confirm that the 2016/17 test year forecast assumed a 3.5% rate increase effective January 1, 2017 which did not occur and that this would have both a financial and rate impact. If confirmed, please provide an amended table.

Please find the amended table below. The financial impact chart – forecast vs actual should show a variance for the 2016-17 forecast given that there was an anticipated rate increase that did not occur. (3.5% vs 0%)

Financial and Rate Impact Transportation and Storage Rates Forecast vs Actual Variance $ in millions					
	Actual 2012	Actual 2013	Actual 2014	Actual 2015	Forecast 2016-17
Rate Impact					
Transportation	0.0%	0.0%	0.0%	0.0%	3.5%
Storage	0.0%	0.0%	0.0%	0.0%	3.5%
Financial Impact					
Transportation	$0.0	$0.0	$0.0	$0.0	$0.3**
Storage	$0.0	$0.0	$0.0	$0.0	$0.2**
*The numbers shown identify that there was no rate and financial variance between the forecast and the actual from 2012 to 2015					
**The impact shown reflects three months of variance as the January 1, 2017 3.5% rate increase assumed in the 2016 Delivery Rate Application did not proceed.					

10. Reference: 1st Round Information Request #11 [Depreciation Expense]

a) With reference to the response to 11(b), please provide an update regarding the status and timing for the next depreciation study?

The next depreciation study is scheduled to be completed before March 31, 2018. The Accounting department is currently working with the consultant to get a signed contract in place and have compiled and submitted the required data for analysis.

b) The table below is prepared based on information provided in the response to 1st Round IR #19 (b) [the "average rate" is calculated as depreciation expense divided by gross plant in service]. Please explain the increase in the average depreciation rate for the forecast years.

$000	2015/16 Actual	2016/17 Forecast	2017/18 Forecast	2018/19 Forecast
Plant in-service [gross]	$1,386,701	$1,487,826	$1,620,575	$1,758,379
Depreciation Expense	$41,483	$45,169	$50,213	$53,812
"Average" rate	2.99%	3.04%	3.10%	3.06%
Difference from using 2015/16 rate		-$661	-$1,734	-$1,210

The above "average rate" was calculated using the ending plant in-service balance, and as a result does not take into account the timing of in-service dates which directly impacts depreciation expense. An average rate of depreciation expense can fluctuate annually based on the timing of additions and disposals, as well as the useful lives attributed to the additions during the period.

c) Please provide the calculation of depreciation expense for the 2017/18 and 2018/19 fiscal year forecasts, as well as forecast for 2017/18 test year showing for each account included in the most recent depreciation study mid-year balance of plant in service, depreciation rate and calculated depreciation expense.

Unfortunately, SaskEnergy does not have the resources to provide this level of detail related to the calculation of depreciation expense. The Manager of Plant Accounting is on medical leave and will not return for several months. It is also important to note that the depreciation calculations for the purposes of Financial Reporting are reviewed each year in detail by the Corporation's external auditors.

Please find below the depreciation rates as determined by the most recent depreciation study, rates are effective for all periods requested.

LDC Depreciation Rates		
December 31, 2013 - Depreciation Study		
CGA	Years	Rate
470 Land Costs	0	0.0%
471 Land Rights	60	1.7%
472 Bldg & Site Improvements	35	2.9%
473 Services	50	2.0%
474 Meter & Reg Installations	55	1.8%
474 Meter & Reg Installations - riser inspections	10	10.0%
475 Mains	65	1.5%
477 Meas & Regulating Eqpt	35	2.9%
478 Meters	32	3.1%
479 Other Distribution Eqpt	35	2.9%
479 Other Distribution Eqpt - Station Painting	10	10.0%
Total Distribution Assets		
480 Land - SEI	0	0.0%
482 Buildings & Improvements - SEI	30	3.3%
483 Office Furniture & Eqpt - SEI	20	5.0%
484 Transportation(Vehicles) - SEI	9	11.1%
485 Heavy Work Equipment	20	5.0%
486 SEI Tools	15	6.7%
489 SEI Data Related Assets	5	20.0%

Depreciation Expense per Schedule 1.3 with applicable CGA Code:

SaskEnergy Incorporated Depreciation Expense ($000's)		2017/18 Forecast	2018/19 Forecast	2017/18 Test Year*
Distribution Plant	**CGA**			
Land Costs	470 Land Costs	-	-	-
Land Rights	471 Land Rights	257	257	257
Building and Site Improvements	472 Bldg & Site Improvements	2,112	2,295	2,225
Services	473 Services	13,049	13,332	13,297
Meter and Regulator Installations	474 Meter & Reg Installations	2,001	2,192	2,114
Mains	475 Mains	11,484	12,243	12,068
Measuring and Regulating Equipment	477 Meas & Regulating Eqpt	1,531	1,585	1,563
Meters	478 Meters	3,219	3,549	3,411
Other Distribution Equipment	479 Other Distribution Eqpt	715	885	818
Distribution before Customer Contributions		34,370	36,336	35,752
Amortization of Customer Contributions		(6,182)	(6,568)	(6,417)
Sub-total		28,188	29,768	29,335
General Plant				
Land	480 Land - SEI	-	-	-
Buildings and Improvements	482 Buildings & Improvements - SEI	1,778	2,602	2,276
Office Furniture and Equipment	483 Office Furniture & Eqpt - SEI	508	498	500
Transportation Vehicles	484 Transportation(Vehicles) - SEI	2,761	2,381	2,476
Heavy Work Equipment	485 Heavy Work Equipment	1,359	1,308	1,326
Tools and Equipment	486 SEI Tools	763	800	789
Information System Assets	489 SEI Data Related Assets	8,674	9,887	9,504
Sub-total		15,844	17,475	16,872
Total Depreciation		**44,031**	**47,244**	**46,207**
***November 1, 2017 - October 31, 2018**				

d) How are customer contributions addressed in the depreciation calculation? Please discuss and describe in detail.

Depreciation expense is calculated on the total assets of the Distribution Utility, based on applicable rates per asset class. The proportion of customer contributions included within each asset class is estimated and calculated using the applicable rate for that asset class. The total amortization expense attributable to customer contributions is then removed from the calculation of depreciation expense, so the reported depreciation expense is net of amortization related to customer contributions.

11. Reference: 1st Round Information Request #12 [Interest Expense]

a) With reference to the response to 1st Round IR# 12(a), please confirm that similar information is not available for short term debt borrowings.

Confirmed, the requested information for short-term debt borrowing is not available.

b) With reference to the response to 1st Round IR# 12(a), please explain why the interest for the last two long-term debt items is different while the maturity date for the debt is the same.

The coupon rate is dependent on market interest rates when the debt is acquired. As Bond 65 was previously acquired in May 2017, and the other issuance is a forecast in the future, it is appropriate that the coupon rates differ even though the maturity dates are the same.

For greater clarity, the table provided in the response to IR 12 a) has been included below with two additional columns – Issue Date and All-In Effective Yield.

LDC Long Term Debt					
Bond I.D. #	Issue Date	Maturity Date	Coupon Rate %	Principal ($)	All In Effective Yield [4]
34	04-Dec-98	05-Mar-29	5.75	25,000,000	5.965%
35	24-Mar-99	05-Mar-29	5.60	25,000,000	5.600%
36	02-May-00	02-May-20	6.67	11,814,000	6.670%
37	02-Jun-00	02-Jun-20	6.70	13,572,000	6.700%
38	03-Jul-00	03-Jul-20	6.57	8,585,000	6.570%
40	08-Aug-01	05-Sep-31	6.40	50,000,000	6.486%
51	05-Sep-07	05-Sep-17	4.65	20,000,000	4.782%
52	14-Nov-08	01-Jun-40	5.19	75,000,000	5.190%
56	12-Mar-12	03-Feb-42	3.40	25,000,000	3.485%
57 - #1	17-Jan-14	02-Jun-45	3.90	50,000,000	4.094%
57 - #1	17-Jan-14	02-Jun-45	3.90	50,000,000	4.094%
58	28-Mar-14	03-Jun-24	3.20	50,000,000	3.272%
59	28-Mar-14	01-Mar-19	1.95	10,000,000	2.100%
60	13-Feb-15	02-Jun-45	3.90	10,000,000	2.729%
63	20-Oct-16	02-Dec-46	2.75	50,000,000	2.998%
65	16-May-17	02-Jun-48	3.30	50,000,000	3.224%
Forecast	TBD	01-Jun-48	4.39	75,000,000	
				598,971,000	

c) With reference to the response to 1st Round IR# 12 (c) and (f), please provide the financial impact if the more up to date short term debt and long term debt forecasts were used.

The financial impact if the more up to date short term debt and long term debt forecasts were used is approximately $1.3 million lower interest expense. However, it is noteworthy that the current interest rate forecasts from the five major banks for the period covered by the rate application are trending upwards and that there is speculation of a further increase in October of this year. If July 2017 actual total debt is used as the starting point, the revised interest rate assumptions result in a $0.8 million reduction to interest expense in the test period as opposed to the $1.3 million reduction referred to above which uses the original debt assumptions.

d) With reference to the response to 12 (f), please confirm when the data provided was collected.

The data provided was the most recent bank forecasts as at July 17th, 2017.

e) With reference to the response to 12(f), please provide the actual interest rates by month for short term debt and long term debt for 2016 and 2017 to date.

Please see actual interest rates from the Bank of Canada below.

Short Term Debt*	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	0.81	0.80	0.85	0.90	0.84	0.80	0.83	0.82	0.82	0.84	0.83	0.89
2017	0.91	0.89	0.88	0.88	0.81	0.97	1.20					

* Source: Bank of Canada, monthly series, Bankers' acceptances - 3 month

Long Term Debt**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	2.05	1.93	2.00	2.06	2.01	1.76	1.69	1.63	1.64	1.82	2.16	2.34
2017	2.45	2.42	2.28	2.16	2.05	2.06	2.35					

** Source: Bank of Canada, monthly series, Government of Canada benchmark bond yields - long-term

f) Please confirm the following:

i. In the 2016 Commodity and Delivery Rate Application the forecast new debt for 2016 was at $75 million with 3.46% interest rate and for 2017 was at $62.5 million with 4.14% interest rate [2016 application, Round 2 IR #7a)].

Confirmed.

ii. Please also confirm that the actual long-term debt issue for 2016 was at $50 million with interest rate of 2.75% and for 2017 was at $50 million with interest rate of 3.30%.

Confirmed.

iii. If the above is not confirmed, please provide correct numbers.

Not Applicable.

g) Please explain the increase in "Present Value of Estimated Decommissioning Liability" in 2015/16 [$104.3 million], 2016/17 [$100.1 million], 2017/18 [$109.1 million] and large increases forecast for 2018/19 [$123.3 million] compared to the forecast provided in the 2016 application [Round 1, IR #10h] which shows 2016 forecast at $82.4 million and 2017 forecast at $91.4 million.

The increase in the Present Value of the Estimated Decommissioning Liability from the 2016 application is due to the reduction in discount rates, and an increasing asset base in the Distribution Utility. The 2016 application included a forecasted discount rate of 2.9%, while the response to 12i. provided rates ranging from 2.0% to 2.4%.

As noted within the SaskEnergy Consolidated annual financial statements for the year end March 31, 2017, a 1.0% decrease in rates, assuming no changes in the amount of the liability, have the potential to increase the value of the decommissioning liability by approximately $49 million.

h) Please explain the increase in discount rate used for the calculation of accretion expense for 2017/18 and 2018/19 compared to the actual years. Please provide detailed calculations of discount rates.

Discount rates were based on the zero curve for 10 to 30 year rates as provided by the Royal Bank of Canada. The zero curve refers to the zero coupon bond rates.

For financial reporting purposes, the Accounting group prepares a quarterly calculation of decommissioning liabilities. In order to develop trend analysis for better forecasting, a historical review of the actual zero curve discount rates used was completed. This review covered the period from the first quarter of 2015-16 to the first quarter of 2017-18. It was noted through this analysis that the average discount rate used had increased on a quarterly basis since the third quarter of 2016-17. As a result, a moderate increase to the average discount rate was incorporated into the 2017-18 and 2018-19 forecasts.

12. Reference: 1st Round Information Request #13 [Tax Expense]

a) Please explain the forecast increase in tax expenses [forecast at $5.9 million in the 2017/18 test year while 2015, 2015/16 and 2016/17 actuals were at $4.6 million level].

The increase in tax expense relates to Corporate Capital Tax. The increase is primarily driven by the increase in total debt due to elevated capital expenditures projected in 2017/18 in comparison to 2015, 2015/16 and 2016/17. Total debt is a component of the paid up capital calculation which is the base upon which Corporate Capital Tax is accessed.

b) Please reconcile and explain any differences between the Net Book Value provided in response to 1st Round IR # 13 a) to the Net Book Value provided in response to 1st Round IR # 19 b).

The primary difference between the two amounts provided is the accounting framework used to calculate the net book value. The net book value provided in the calculation of corporate capital tax is reported under

International Financial Reporting Standards, while the net book value in the plant in service calculation uses accounting for rate setting purposes, which approximates what was formerly Canadian Generally Accepted Accounting Principles (GAAP). The most significant difference between the two frameworks relates to the treatment of customer contributions.

c) Please explain any relationship between Undepreciated Capital Cost shown in 1st Round IR # 13 a) and Net Book Value shown in 1st Round IR # 19 b).

As noted in the response to 13b. the calculation of net book value is different for accounting versus rate purposes.

Undepreciated Capital Costs is calculated using the capital cost allowance rates as determined by the federal government for tax purposes, which differ from the depreciation study rates used by the Corporation for accounting purposes.

d) Please reconcile information regarding Loans and Advances provided in response to 1st Round IR # 13 a) to the information provided in Tab 14 of the application.

The information provided regarding Loans and Advances cannot be reconciled to the information in Tab 14, due to the following reasons:

- Timing of the amounts provided, one is at a point in time and the other is an average over the period.
- The calculation of Loans and Advances for corporate capital tax expense is complex and has many other factors in addition to long-term debt.
- For tax purposes, the Distribution Utility is not a stand-alone taxable entity.

13. Reference: 1st Round Information Request # 15 [Planned Maintenance Program]

a) With reference to the response to 15(a)(ii), please provide the dollar values for regulator stations and mains and services each year.

It was difficult to extract the information as requested because we do not categorize information this way within our financial systems. The dollar values for planned maintenance for regulator stations and mains and services were determined based on the labour effort for activities that could be correlated to these asset groups.

The dollar amounts are as follows:

- Regulator stations = $3.3M
- Mains and Services = $2.0M

b) With reference to the response to 15(a)(ii), please indicate the other types of costs that make up total planned maintenance outside of regulator stations and mains and services (remaining balance of the approximately $17 to $18 million in expense each year).

The determination of 18% and 11% (of 2015/16 Total Planned Maintenance), on regulator stations and mains and services respectively, was based on SaskEnergy field staff labour effort directly associated with planned maintenance activities on these assets. Other costs arise from contractor costs and consumables costs related to planned maintenance activities and other planned maintenance activities not directly related to regulator stations, mains and services. These other costs are in the following categories:

- Odorization (including the cost of odorant);
- pre heating (catalytic heater and line heater maintenance);
- leak detection and repair;

- valve maintenance;
- cathodic protection;
- verification of tools and equipment;
- vegetation control; and
- sign maintenance.

c) With reference to the response to 15(a)(iii), please clarify whether the cost of line locating is included in planned maintenance costs.

Line locating costs are not included within Planned Maintenance costs. SaskEnergy classifies line locating as “customer driven” work as opposed to Planned Maintenance.

d) With reference to the response to 15(a)(iii), please indicate how the total dollars of line locating costs were determined [e.g., 10% of OM&A spending would provide double the costs for 2015/16 compared to what is provided in the response].

The total costs for line locating are determined based on the direct charges from the line locate contractor and estimated cost for line locates completed by SaskEnergy field staff. The proportion of total OM&A spend was not presented correctly as the base that was used was OM&A spending within the Distribution Operations field Areas. The corrected table is as follows:

	Proportion of Total OM&A	Dollar of Total Spend	
2015/2016	4.5%	$5.2M	Actual
2016/2017	4.2%	$4.9M	Actual
2017/2018	4.0%	$5.1M	Forecast
2018/2019	3.9%	$4.9M	Forecast

e) Please reconcile the spending on system integrity operating expenses provided in response to 15(b) to the amounts included in the figure on page 13 of the application.

The operating expenses provided in response to 15(b) are specifically non labour general administration, cathodic protection and leak survey costs only. However, there are other safety and integrity initiatives prioritized by our service technicians, instrument technicians, maintenance technicians and planning and dispatch staff across the province. In addition to labour, activities such as line locating and the use of a hydro-vac are safety and integrity costs incurred by all areas across the province. Hydrovacing is an excavation method that allows operators to safely locate and expose an underground cable or pipeline with minimal disturbance to above ground vegetation and soil. These costs along with the operating expenses provided in response to 15 (b) are included in the figure on page 13.

Below is a reconciliation of the spending on system integrity operating expenses provided in response 15 (b) to the amounts included in the figure on page 13 of the application.

	2012	2013	2014	2015	2016/17	2017-18
Service Technicians	$ 19.2	$ 17.0	$ 16.7	$ 17.2	$ 16.2	$ 19.5
Maintenance and Instrument Technicians	12.3	14.3	17.1	15.1	14.3	15.0
Planning and Dispatch	1.9	2.2	2.4	2.3	2.5	3.1
Cathodic Protection and Leak Surveys	-	2.5	2.2	3.1	3.5	3.3
	$ 33.4	$ 35.9	$ 38.4	$ 37.7	$ 36.5	$ 41.0

*Beginning in 2013 a specific cost centre was established to track cathodic protection and leak surveys which were previously expensed in the service technician category

f) With reference to the response to 15(b), please provide total spending on risk management and growth from 2017/18 to 2022/23; please break this out as follows:

i. Total spending on risk management and total spending on growth each year

ii. Spending on risk management and growth broken out by major expense category: Mains, Services, Stations, Line Heaters, Odorizers, and Measurement.

Risk Management						
	2017-2018	**2018-2019**	**2019-2020**	**2020-2021**	**2021-2022**	**2022-2023**
Mains	$4.9	$7.3	$7.6	$7.9	$8.0	$8.3
Services	$17.9	$17.9	$17.7	$16.9	$18.2	$18.3
Stations	$4.9	$5.8	$4.9	$5.2	$5.4	$5.6
Line Heaters	$2.2	$2.0	$2.0	$2.1	$2.1	$2.2
Odorization	$2.8	$2.1	$2.5	$2.3	$2.3	$2.4
Measurement	$4.5	$4.5	$4.5	$4.6	$4.6	$4.7
Risk Management TOTAL	**$37.3**	**$39.6**	**$39.2**	**$38.9**	**$40.6**	**$41.5**

Growth						
	2017-2018	**2018-2019**	**2019-2020**	**2020-2021**	**2021-2022**	**2022-2023**
Growth	$13.6	$17.5	$20.5	$16.9	$18.2	$24.4

14. Reference: 1st Round Information Request #16 [Capital Expenditure Program]

a) Please confirm that the $17 million of capital spending that was deferred in 2016/17 did not relate to restraint measures. Please explain what this deferred spending related to.

Yes, it is confirmed that the $17 million of capital spending that was deferred/and or not put into service in 2016/17 did not relate to restraint measures. The spending that was deferred/not placed into service in 2016/17 was as follows:

- Customer Connections - $6.0 million
- System Improvements - $0.9 million
- Meter Replacement - $0.8 million
- Tools and Equipment - $0.2 million
- Information Systems - $7.4 million
- Vehicles - $1.1 million
- Buildings - $0.6 million

b) With reference to the response to 16(j), please provide a more detailed explanation regarding the four identified capital expenditures areas that can result in lower O&M costs. Please explain further how these particular areas may provide lower O&M cost savings; if possible outline the extent of potential savings for each area.

Regulator / Meter Station Upgrades

- Details: Additional and improvements to station alarms, catalytic heaters, station painting program.
- Station alarms allow for remote troubleshooting of station issues, potentially saving an after-hours field trip to site to resolve. They

also provide an early indication of station issues which can sometimes escalate into a customer outage situation.

- The addition of catalytic heaters can improve the reliability of stations and reduced the number of callouts.
- The station painting program results in a complete recoating of the station and will reduce the ad hoc painting required to address localized corrosion issues.

Line Heater Upgrades

- Details: replacement of legacy equipment with new technology and new equipment.
- The replacement of legacy (conventional) line heaters with new line heaters reduces the ongoing maintenance requirements related to the line heater integrity (inspection and repair).

Service Upgrades

- Details: Replacement of services that are at a higher risk of leaks (due to a combination of materials, design and in-situ conditions).
- The upgrade of services leads directly to a reduced number of leaks which, in turn, reduces O&M costs related to leak response (whether outside odor or leak survey), and leak repair. Once the risk has been significantly reduced over a larger area (neighborhood or town), the leak survey frequency can be reduced, leading to further cost savings.

Distribution Main Replacement

- Details: Proactive replacement of mains that are nearing the end of their service life (e.g. due to materials such as first generation PE and PVC).

- Proactive main replacement reduces the operational issues (and O&M costs) associated with leak or line hit repairs on PVC and black PE mains. These repairs are typically more complex, time consuming and costly that similar repairs on modern PE mains.

SaskEnergy has not completed an analysis to determine the extent of the O&M savings related to these initiatives.

c) With reference to the response to part 16(c), (u), (w) and (x) please describe how the capital prioritization program [or other internal prioritization processes] has resulted in forecast spending on the following items:

i. Replacement of Diaphragm meters

ii. Replacement of Customer Service Center

iii. Information Systems spending

What has led to the initial prioritization of these forecast expenditures going forward and are there circumstances where spending on these items would be re-prioritized?

The capital prioritization process is in its infancy stage and was not significantly relied upon to make capital spending recommendations for the 2017/18 fiscal year. Decisions related to forecast investment on capital items such as replacement of large diaphragm meters, replacement of the Customer Service Center and Information Systems spending are guided by the core values of the corporation such as safety impacts, franchise obligations, financial return (including productivity and efficiency impacts) and regulatory requirements.

d) With reference to the response to part 16(c), (u), (w) and (x) to what extent are these expenses driven by regulatory requirements, safety and reliability or other requirements. Please describe and discuss drivers underlying each expenditure.

These capital expenditures are necessary to conduct the business of the distribution utility and are driven by regulatory requirements as well as the corporation's firm commitment to provide safe and reliable service to customers in an efficient manner. The primary drivers of these investments are the distribution utility customer base which grows steadily each year as well as the corporation's objective to keep pace with industry best practice.

e) With reference to the response to 16(d), please confirm the total actual or forecast total spending for each of the major growth projects described (including prior year spending).

Saskatoon:

TBS#5:

The actual spent to date is $12.42 million and the forecasted remaining cost to finalize this project is $4.09 million. This will result in a total project cost of $16.51 million with targeted completion in 2017/18.

TBS#2:

The projected total spend is $7.15 million staged from 2018/19 to 2022/23.

Central Avenue IP Main:

The projected total spend is $6.3 million staged from 2018/19 to 2021/22.

Regina:

East Regina:

The projected total spend is $13.5 million staged from 2017/18 to 2021/22.

Southwest Regina:

The projected total spend is $9.0 million staged from 2022/23 to 2023/24.

Northwest Regina:

The projected total spend is $17.2 million staged from 2017/18 to 2023/24.

North Battleford (NB):

NB TBS#3:

The projected total spend is $7.25 million staged from 2017/18 to 2022/23.

NB TBS#1:

The projected total spend is $4.00 million currently targeted for 2023/24.

Prince Albert (PA):

PA TBS#2:

The projected total spend is $9.5 million staged from 2017/18 to 2020/21.

Moose Jaw:

MJ TBS#2:

The projected total spend is $9.2 million staged from 2022/23 to 2023/24.

Humboldt:

Humboldt TBS#2:

The projected total spend is $1.18 million staged from 2017/18 to 2019/20.

f) With reference to the response to 16(g), please indicate how long the distribution mains replacement program is expected to remain in place; is the level of spending expected to continue at levels forecast for 2017/18 and 2018/19?

Because of the large quantity of Mains in place and the Asset Management approach of SaskEnergy, it is expected that this program will always be required. The amount of dollars required per year is being evaluated, but is estimated to peak at around $5.0M per year sometime in the next 10 years, then level off around $3.0M going forward.

g) With reference to the response to part (m) and (n) where work is completed to accommodate government highways projects or other requests how are the costs of these projects addressed (i.e., who pays the costs for re-routes and how is the share of costs paid by SaskEnergy or others determined?)

Costs associated with altering existing distribution facilities are subject to SaskEnergy's Alteration / Retirement Business Policy. SaskEnergy's investment can be applied against the cost of altering SaskEnergy facilities providing this service results in a minimum required economic return relative to increased natural gas consumption. Relative to road construction activities, costs associated to accommodate the Ministry of Highways projects are generally the responsibility of the Ministry of Highways or the party that may be performing the work on behalf of the Ministry of Highways. When alterations of SaskEnergy facilities that are located on and paralleling or crossing the road allowance are required to accommodate rural municipality road widening or reconstruction, SaskEnergy will perform the alteration at no cost to the respective Rural Municipality.

h) With reference to the response to 16(w)(i) and (ii), please provide the total actual cost or total forecast cost for each of the projects identified. Please also provided the expected ongoing O&M expense related to each of these projects.

Summary of Information System Capital and Operating Costs				
$ in millions				
	2017-18	**2017-18**	**2018-19**	**2018-19**
	Capital	**Operating**	**Capital**	**Operating**
Distribution Work Management	5.0	0.9	-	1.0
Hardware Lifecycle Initiatives	0.6	0.3	0.8	0.3
Capital Project Portfolio Management	0.5	0.3	1.0	0.5
Records Information Management	-	2.4	-	2.9
Geographical Information Systems	2.7	0.4	2.5	0.6

15. Reference: 1st Round Information Request #17 [Safety & Reliability]

a) Please reconcile the information provided in the response to 17(d) regarding total U/G leaks reported including customer and line hits from REO with the Figure provided in Tab 23, page 13 [totals for 2012 and 2016 do not appear to reconcile; the total for 2011 also appears to be too low].

Numbers have been updated. 2012 still does not align, and this is due to the fact that a review of historical incidents was done recently and additional leaks were found for that year that had not previously been reported (2012 used 3 different systems for reporting, this was consolidated into 1 system in 2013). These reviews take place annually, and this causes numbers to change sometimes from year to year, with the goal of continuous improvement.

	2012	2013	2014	2015	2016	**3 year Avg**	**5 year Avg**
No Information	1	2	13	25	0	**12.67**	**8.20**
Assiniboia	0	6	5	6	8	**6.33**	**5.00**
Canora	2	3	2	5	7	**4.67**	**3.80**
Carlyle	4	5	8	2	8	**6.00**	**5.40**
Davidson	3	3	8	7	12	**9.00**	**6.60**
Estevan	6	4	7	6	1	**4.67**	**4.80**
Fort Qu'Appelle	4	3	7	5	13	**8.33**	**6.40**
Grenfell	5	4	3	3	2	**2.67**	**3.40**
Humboldt	5	6	7	3	20	**10.00**	**8.20**
Kindersley	9	6	7	11	7	**8.33**	**8.00**
La Ronge	2	1	1	1	1	**1.00**	**1.20**
Lumsden	6	9	34	21	12	**22.33**	**16.40**
Maidstone	4	9	7	7	8	**7.33**	**7.00**
Maple Creek	5	4	1	4	5	**3.33**	**3.80**
Meadow Lake	12	4	1	3	3	**2.33**	**4.60**
Melfort	5	4	5	7	7	**6.33**	**5.60**
Melville	5	2	5	2	3	**3.33**	**3.40**
Moose Jaw	9	12	12	11	16	**13.00**	**12.00**
Moosomin	6	3	1	0	2	**1.00**	**2.40**
Nipawin	1	3	3	5	3	**3.67**	**3.00**

North Battleford	5	10	6	2	6	**4.67**	**5.80**
Prince Albert	19	17	32	17	13	**20.67**	**19.60**
Regina City	117	122	71	93	58	**74.00**	**92.20**
Rosetown	24	13	14	7	24	**15.00**	**16.40**
Rosthern	8	7	1	5	5	**3.67**	**5.20**
Saskatoon City	37	62	64	59	16	**46.33**	**47.60**
Saskatoon East	6	6	2	0	27	**9.67**	**8.20**
Saskatoon North	11	17	10	16	2	**9.33**	**11.20**
Saskatoon West	8	5	4	1	11	**5.33**	**5.80**
Shaunavon	7	4	4	5	2	**3.67**	**4.40**
Shellbrook	5	6	6	4	2	**4.00**	**4.60**
Swift Current	15	11	9	12	9	**10.00**	**11.20**
Tisdale	7	6	4	3	17	**8.00**	**7.40**
Turtleford	1	2	2	3	5	**3.33**	**2.60**
Unity	1	6	5	5	4	**4.67**	**4.20**
Wadena	3	5	2	8	6	**5.33**	**4.80**
Watrous	2	3	5	7	1	**4.33**	**3.60**
Weyburn	9	1	8	5	6	**6.33**	**5.80**
White City	7	10	14	12	5	**10.33**	**9.60**
Wynyard	8	2	2	1	4	**2.33**	**3.40**
Yorkton	2	0	9	7	9	**8.33**	**5.40**
Total	**396**	**408**	**411**	**406**	**370**	**395.67**	**398.20**

b) With reference to the response to 17(e), leaks related to equipment malfunction have continued to increase since 2013 [from 6 in 2013 to 30 in 2016]; please explain the driver for this increase and any measures being undertaken to address.

Equipment Malfunction is a newer category that was added around 2013. System Integrity has been spending more time educating Operations on when to call an incident Equipment Malfunction. It is not an increase in leaks, but a better classification of those leaks.

c) With reference to the response to 17(c)(ii) please explain how the leaks per year saved is determined for each year since 2011. Please reconcile to information regarding total leaks provided in the response to 17(d) and (e).

Leaks saved by Service Upgrade Program per year calculated by multiplying the current leak rate (3 year average in Regina, 5 year average others) by the number of upgrades completed. Note these leaks listed for each year are saved the year of the upgrade and every year going forward.

- 2012 9.3 leaks/yr
- 2013 12.5 leaks/yr
- 2014 10.3 leaks/yr
- 2015 9.8 leaks/yr
- 2016 7.1 leaks/yr

Cumulative

- 2012 9.3 leaks
- 2013 21.8 leaks
- 2014 32.1 leaks
- 2015 41.9 leaks
- 2016 49 leaks

d) With reference to the response to 17(c), please provide the leak rate for the last 5 years for each of the communities listed. How does the leak rate for these communities compare to the rest of the province.

Saskatchewan Leaks per 1000 households						
	5 year average leak rate					
	2007-2011	2008-2012	2009-2013	2010-2014	2011-2015	2012-2016
Regina	3.3	3.5	4.0	4.2	4.2	3.4
Regina Beach	1.1	1.1	1.1	5.7	7.2	7.7
Sceptre	0.0	4.5	4.5	4.5	4.5	4.5
Abbey	0.0	0.0	2.0	2.0	2.0	2.0
Sovereign	0.0	8.3	8.3	8.3	8.3	8.3
Rosetown	1.8	3.8	3.4	3.3	3.6	3.6
Elrose	1.8	1.8	2.8	2.8	2.8	3.7
Shackleton	0.0	0.0	0.0	0.0	0.0	0.0
Drinkwater	7.7	15.7	15.7	15.7	15.7	8.0
Beatty	0.0	0.0	8.7	8.7	17.8	17.8
Delisle	1.6	2.7	2.7	3.2	2.7	2.2

Shackleton was added because it had the same risk factors and we were doing work in the neighbouring community, so it was an efficiency to get it done now.

The provincial 5 year average for leaks not including External Interference is 0.56 leaks per 1000 services, these were disregarded, because the table above doesn't include these types of incidents.

e) With reference to the response to 17(d), please provide a table with the monthly leak numbers for Regina to support the figure provided.

i. Please indicate whether the figure provided in response to 17(d) includes all categories of leaks.

The table does cover all leaks, has been updated below after recent review of historical leaks.

Leak Survey stats only									Total U/G leaks reported including customer and line hits from REO							
							Planned			of Leak (other includes lightening, rodents, grease plugs, flange gaskets, li						
Year	Services	kms	Planned U	Sup U/G	Planned A	Sup A/G	U/G leaks	A/G leaks	km's of main	Pulled Service	Material Defects	Construction Defects	Corrosion	Other	Total	Leaks/1000km
2012	63784	12173	2	95	1354		0.03	21.23	68092	122		22	11	233	396	5.82
2013	95688	13586	25	82	2695		0.26	28.16	68612	134		20	10	244	408	5.95
2014	86000	11000	25	27	2074		0.29	24.12	69015	142		28	14	227	411	5.96
2015	129131	16579	34	27	758		0.26	5.87	69015	86		35	14	271	406	5.88
2016	105977	20855	81	27	1277		0.76	12.05	69015	73		33	17	247	370	5.36

The chart for Regina only includes the dresser fitting leaks, which is the current target of the service upgrade program in the City of Regina.

ii. Please indicate any changes from the version of the table provided in response to 23(d) from the 1st Round of the 2016 Delivery and Commodity Rate Application [appears to be difference of approximately 10 leaks for 2015].

This chart was changed in 2017 to better reflect the results of the service upgrade program in Regina, as it only targets dresser fitting leaks currently. Mixing in other types of leaks didn't give a true representation of the benefits of the service upgrade program and it was hard to interpret when other types of leaks are found in the City of Regina.

f) With reference to the response to 17(d), since 2011 how much of the service upgrade program activities and related spending have been targeted on Regina compared to other areas of the province (please provide portion as percentage and as dollar amount).

Number of Upgrades

- Regina – 13,297 Upgrades = 80.3%
- Rest of Saskatchewan – 3,267 Upgrades = 19.7%

These numbers include estimates until the end of 2017.

Dollars

- Regina - $62.3M – 81.6%
- Others - $14.0M – 18.4%

The cost increase for Regina is because of smaller lots (tighter working area) and more dresser valves on the mains.

g) With reference to the response to 17(f), please provide the following:

i. Please provide a version of leaks by type for community for 2016 that reconciles to the list of communities provided for 2015. Specifically, please clarify as follows for 2016:

i. Please confirm that ENTERMANUALLY refers to "unknown." Please explain what these terms refer to and how they relate to the total leak numbers provided for 2015 and 2016.

Yes, ENTERMANUALLY and unknown are the same. They are leaks entered into our reporting system without a location identified.

ii. Please indicate if the combined Saskatoon City, Saskatoon East, Saskatoon North and Saskatoon West corresponds to "Saskatoon" information as provided in the 2015 table. Please also indicate if the "Saskatoon" at the bottom of the 2016 table [third community from bottom] is to be added in to earlier Saskatoon totals or references something else.

In 2015, Saskatoon includes all of the areas as a district; they were broken out into sub districts for 2016.

iii. Moose Jaw is entered twice on the 2016 table – should these two rows be combined?

Yes, the numbers are supposed to be combined. They were spelled differently in the system, which is why the name showed up twice.

iv. What does "Reginal/ Lumsden/ Whitecity" refer to (second row from bottom of list of communities) and should these amounts be added back into individual rows for communities of Lumsden and Whitecity?

In the past this was one area, it will be broken out for future years.

ii. Please provide the annual leak rate for each of the communities listed for the last 5 years. How do these compare to the 3 year and 5 year average for the province?

	2012	2013	2014	2015	2016
No Information	1	2	13	25	0
Assiniboia	0	6	5	6	8
Canora	2	3	2	5	7
Carlyle	4	5	8	2	8
Davidson	3	3	8	7	12
Estevan	6	4	7	6	1
Fort Qu'Appelle	4	3	7	5	13
Grenfell	5	4	3	3	2
Humboldt	5	6	7	3	20
Kindersley	9	6	7	11	7
La Ronge	2	1	1	1	1
Lumsden	6	9	34	21	12
Maidstone	4	9	7	7	8
Maple Creek	5	4	1	4	5
Meadow Lake	12	4	1	3	3
Melfort	5	4	5	7	7
Melville	5	2	5	2	3
Moose Jaw	9	12	12	11	16
Moosomin	6	3	1	0	2
Nipawin	1	3	3	5	3
North Battleford	5	10	6	2	6
Prince Albert	19	17	32	17	13

Regina City	117	122	71	93	58
Rosetown	24	13	14	7	24
Rosthern	8	7	1	5	5
Saskatoon City	37	62	64	59	16
Saskatoon East	6	6	2	0	27
Saskatoon North	11	17	10	16	2
Saskatoon West	8	5	4	1	11
Shaunavon	7	4	4	5	2
Shellbrook	5	6	6	4	2
Swift Current	15	11	9	12	9
Tisdale	7	6	4	3	17
Turtleford	1	2	2	3	5
Unity	1	6	5	5	4
Wadena	3	5	2	8	6
Watrous	2	3	5	7	1
Weyburn	9	1	8	5	6
White City	7	10	14	12	5
Wynyard	8	2	2	1	4
Yorkton	2	0	9	7	9
Total	**396**	**408**	**411**	**406**	**370**

To normalize the data and compare to provincial averages, leaks per 1000 services would have to be recorded in the table, not total leaks. This is done in the service upgrade program, please reference 1st Round IR 16 d) for the communities with the highest leak rate over the past 5 years.

h) With reference to the response to (h), please explain any factors underlying the increase in preventable vehicle collisions and lost time injuries in 2016 compared to 2014 and 2015.

	2011	2012	2013	2014	2015	2016	2016/17
Lost Time Injuries (LTI)	20	13	11	10	7	12	11
Medical Aids (MA)	11	15	13	12	11	6	4
Preventable Vehicle Collisions (PVC)	23	39	30	22	20	26	22
*Total Recordable Injury Frequency Rate	3.24	2.91	2.46	2.22	1.86	1.93	1.63
**PVC Frequency Rate	1.83	2.94	2.35	1.69	1.48	2.04	1.74

It is common for lagging indicators to ebb and flow when comparing statistics over one or two years. Looking at a larger sample size (i.e. 10 year trend) will give a better sense of the overall rate of continual improvement.

The 10 year average from 2006 - 2015 is 31.5 Preventable Vehicle Collisions (PVC) annually. 26 PVCs in 2016 indicates the Corporation is continuing on a downward trend overall.

In the case of Lost Time Injuries (LTI), the 10 year average from 2006 - 2015 is 16.1 LTIs annually. 12 LTIs in 2016 indicates the Corporation is also on a downward trend in this metric.

In specific reference to the 2016 statistics, there are areas of low hanging fruit for the Corporation to address in that, a large number of the incidents in 2016 can be attributed to an overall lack of attention to the task at hand, not necessarily to abnormally hazardous work conditions or environmental factors. For example, 61% of PVCs in 2016 involved collisions with fixed objects while 58% of LTIs were the result of slips, trips and falls.

It is the Corporation's belief that there is a strong correlation between an overall focus and awareness on safety and its statistical safety performance. To this end, the Corporation continues to reinforce the importance of Hazard Near Miss Reporting to promote safety awareness, while also looking for other avenues to continually improve its safety focus. For example, a Safety Culture Work Team has been formed to identify any gaps related to safety culture and ways these gaps can be addressed.

i) With reference to the response to 17(l), please confirm that the spending information for SaskEnergy vs Industry is incorrect. If confirmed, please update the response.

Incidents – SaskEnergy vs Industry

Industry Leaks
Per 1000 Services = 1.1
Per 1000 km Mains = 8.0

SaskEnergy Leaks
per 1000 Services = 0.73
Per 1000 km Mains = 1.25

Spending– SaskEnergy vs Industry

Services
Industry - $18.1M
PE = 68%
Steel = 30%
Other = <1%

SaskEnergy - $18.0M
PE = 37%
Steel = 63%

Mains
Industry - $44.8M
PE = 70%
Steel = 30%
Other = <1%

SaskEnergy - $13.8M
PE = 90%
Steel = 10%

SaskEnergy feels this amount of spending is defendable in both cases.

Services: The spending aligns with industry, and SaskEnergy has a lower leakrate than industry.

Mains: The spending is lower than industry, but our system is relatively newer (most PE was installed in the 1980's), and SaskEnergy's leak rate is significantly lower than industry.

16. Reference: 1st Round Information Request #19 [Calculation of Ratebase]

a) Please explain why 13 months of gas storage data was used for the calculation of natural gas in storage included in rate base while the test year focuses on only 12 months.

Cost of service methodology requires that the rate base calculation be developed based on a thirteen month average to accommodate the impact of the rate base getting progressively larger over the test period. The gas in storage data used for the calculation of the rate base is also calculated over the 13 month period for consistency. The test year is a 12 month period given that the annual return target is by definition a 12 month period.

17. Reference 1st Round Information Request #21 [Cost of Service Study]

a) Please explain further the statement provided in response to 21(f), "a higher rate increase is required for the residential customer class as the majority of the integrity investment and safety related operations have been associated with this rate class."

Upon further analysis, SaskEnergy respectfully submits the following revision to its initial response to Question 21 (f) Round 1 Information request as follows:

A higher rate increase is required for residential customers compared to other rate classes while the Revenue-to-cost ratio for residential customers is forecast to be at 2016/17 cost of service study level due primarily to declining revenues within the residential rate class.

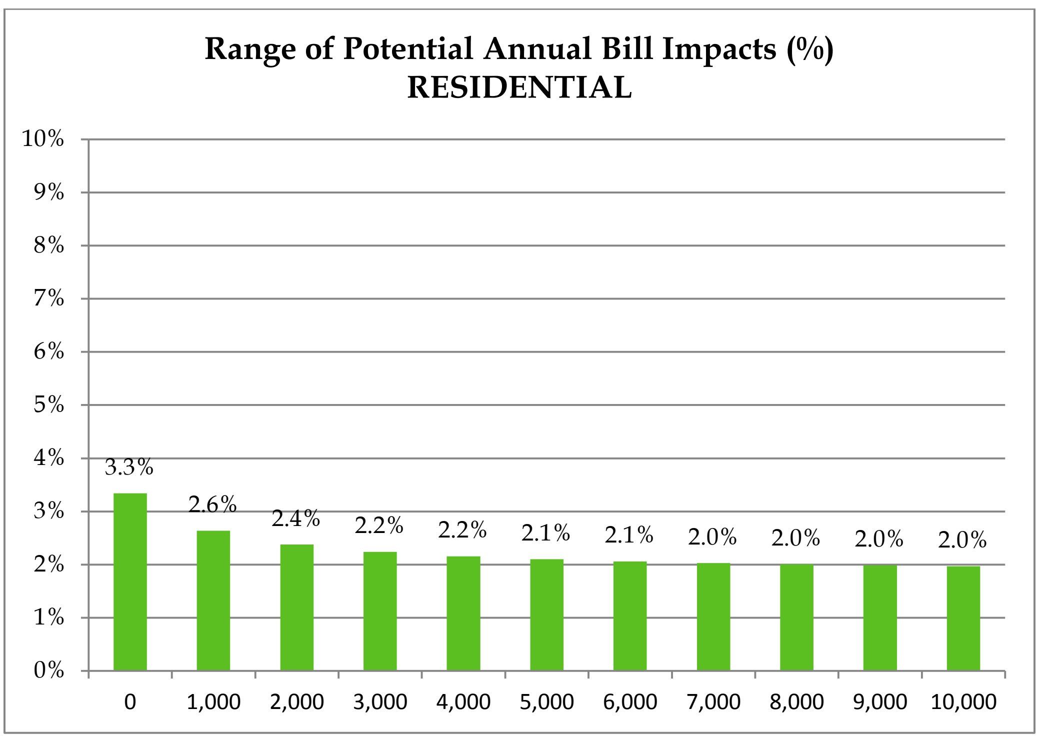
The cost of service looks at both revenues and costs to determine fair and reasonable rates for SaskEnergy customers. With the 2017/18 rate application, SaskEnergy implemented the Saskatchewan Rate Review Panels recommendation to increase the heat value from 37.50 to 38.00. This increase in heat value reduced the residential customer revenues by $2.2 million. In addition to changes in heat value, SaskEnergy updated it average use per customer which further reduced residential revenues by $0.6 million. These reductions are partially offset by new customer additions which added $2.0 million to residential revenues. The net impact is the starting point for 2017/18 residential customer revenues are lower than the 2016/17 revenues (based on new rates) by $0.8 million. This $0.8 million needs to be recovered by residential customers to minimize cross subsidization between classes. If the starting revenues for residential customer not been lower, the rate change for residential customers would have been 3.48%.

b) Please explain if the spending for "integrity investment and safety related operations" are tracked by rate class and how this was carried through in the cost of service study.

From an operating and maintenance perspective system integrity costs are tracked using cost centers. From a cost of service perspective, the rates department works with the cost center owners to understand why costs exists so the operating costs can be functionalized and classified.

18. Reference: 1st Round Information Request #22 [Customer Bill Impacts]

a) With reference to the response to 1st Round Information Request 22(b) and the information provided in response to 1st Round Information Request 25(b), please provide a version of the figure that shows the range of potential bill impacts for residential customers using a $0.75 increase in BMC and a $0.0041 increase to the volumetric delivery charge.



b) Please indicate the type of residential customers that typically use less than 2,000 m3 per year.

The most common type of residential customer that uses less than 2,000 m^3 per year primarily includes resorts and apartment style condominiums that have common walls.

19. Reference: 1st Round Information Request #24 [Load Forecast]

a) Please confirm when the load forecast is prepared as part of the annual budget process.

Yes, the load forecast is prepared as part of the annual budget process and was prepared in June 2016.

b) Please confirm how the weather normalized Use Per Customer (UPC) for the residential load forecast was calculated.

i. If trend analysis is used, please indicate the number of years used and the specific years used in such analysis.

The trend analysis uses the previous five years of actual data and therefore should have used 2011, 2012, 2013, 2014, and 2015. The formula was inadvertently not updated to include 2015 and therefore 2010, 2011, 2012, 2013 and 2014 were used.

ii. Please confirm that 2015 and 2016 data was not used in the trend analysis for the test year. Please provide the rationale for not using data for 2015 or 2016 in the trend analysis.

The 2015 year was not used in the trend analysis inadvertently. The first three months of 2016 were not used as they were not available at the time of updating the load forecast to reflect the new fiscal year end change. The last nine months of 2016 are included in the 2017/18 forecast.

c) Please quantify the impact of using data for 2006-2010 for trend analysis for 2012, 2013 and 2014. Please explain why the data used in the trend analysis was not changed, i.e., why trend for 2007-2011 was not used for 2012, 2008-2012 for 2013 and 2009-2013 for 2014 to capture most recent actuals.

Respectfully, SaskEnergy does not have the resources to complete the required analysis to answer this question within the timeframe of the Information Requests. Upon review of the spreadsheet, a formula was not accurately updated for the trend and therefore the trend analysis utilized 2006 - 2010 actuals for the 2012, 2013 and 2014 years.

The trend analysis for 2012, 2013 and 2014 does not impact the forecast for the 2017 Rate Application. The actual UPC numbers are updated every year during the budget load forecast process and actual UPC numbers are utilized.

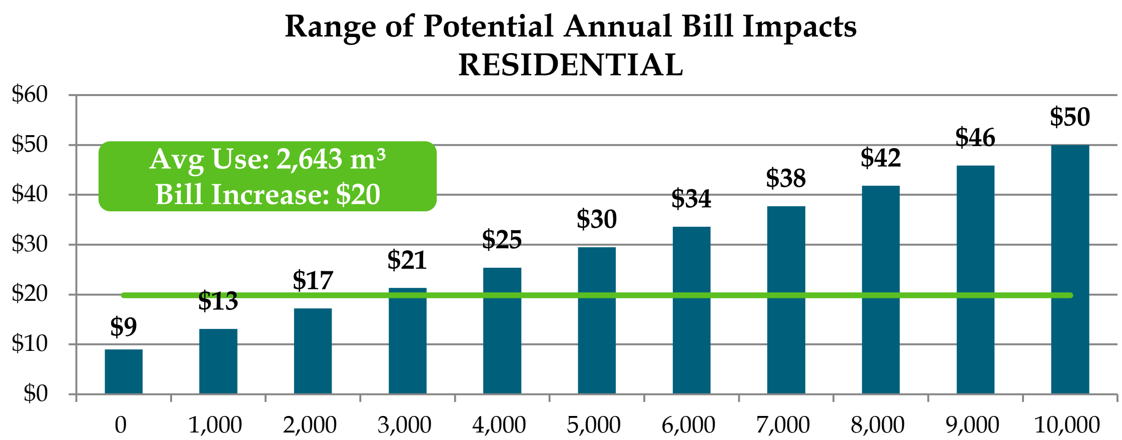
d) What would be the impact on the load forecast and forecast revenues for the test years if 2015 and 2016 actual data was used in the trend analysis including impact of using most recent five year data instead of using 2006-2010 actuals.

Respectfully, as responded in Question 20 c) above, SaskEnergy does not have the resources to complete this analysis within the timeframe of the information requests.

SaskEnergy's load forecast, as answered in 1st Round Information Request #24 b), demonstrates the tightness of SaskEnergy's forecast to weather normalized actual results. SaskEnergy believes further analysis would not materially improve the forecast.

20. Reference: 1st Round Information Request #25 [Rate Design Principles and Objectives]

a) With reference to the response to 1st Round Information Request 25(b), please provide a version of the figure in Tab 19, page 4 that shows the range of potential bill impacts for residential customers using a $0.75 increase in BMC and a $0.0041 increase to the volumetric delivery charge.



21. Reference: 1st Round Information Request #26 [Corporate Geotechnical Program]

a) Please confirm the estimated customer assistance costs outlined in response to (b)(iv) were not included in test year forecasts.

Confirmed.

b) Please provide the annual leak rate for Last Mountain Lake for the last 5 years. Please also indicate if Last Mountain Lake has had any impact on overall provincial leak rates historically.

Last Mountain Lake vs Provincial Annual Leak Rates					
	2012	**2013**	**2014**	**2015**	**2016**
Last Mountain Lake leak rate	1.3	0.63	33	15	2.5
Province-wide leak rate (with external interference leaks)	1.08	1.12	1.10	1.07	0.96
Last Mountain Lake % of total provincial leaks (with external interference leaks)	1%	0%	13%	6%	1%
Province-wide leak rate (without external interference leaks)	0.57	0.59	0.60	0.50	0.56
Last Mountain Lake % of total provincial leaks (without external interference leaks)	1%	0%	23%	13%	2%
Note1: All leak rates are in leaks per 1000 services per year.					
Note2: Province-wide and Last Mountain Lake leaks include both leaks on the main and on the service line					
Note3: Last Mountain Lake leaks only include those due to slope movement or possibly due to slope movement. Kinked services due to slope movement are not included					
Note4: The number of services in Last Mountain Lake has been kept constant at the 2016 value of 1599. The communities included are those in the Level 1 (3 week) and Level 2 (2 month) supplemental leak survey cycle for Last Mountain Lake.					

c) Did the deactivation of services at Last Mountain Lake have a material impact on leak rate or the total number of leaks in 2016? Is it expected to impact leak rate or total leaks in 2017? Please explain.

Last Mountain Lake Deactivation Zone Leaks						
	TOTAL LEAKS & KINKS			**LEAKS/1000 SERVICES**		
	2014	**2015**	**2016**	**2014**	**2015**	**2016**
2015 Last Mountain Lake Deactivations (22)	12	-	-	545	-	-
2017 Last Mountain Lake Deactivations (231)	58	22	5	251	95	22
Note: These are only kinks and leaks due to slope movement.						

In 2016, it is assumed that 3 leaks were saved due to the deactivation of 22 services at Regina Beach.

It is anticipated that very few leaks will be saved in 2017 due to the deactivation occurring late in the year. Savings of around 15 leaks per year on average are expected going forward from the 2017 planned deactivations.

In total, these deactivations will have saved an average 18 leaks per year.

d) With reference to the figure included in the response to part (a).

i. How materially do costs increase for communities being monitored as the level of risk and related risk mitigation activities increase?

As the level of risk increases, monitoring costs also increase. The typical cost of monitoring is approximately $7 dollars per service which can escalate up to $10,000 per service depending on degree of monitoring deemed appropriate.

ii. What are relative cost steps at each level of the risk pyramid?

Leak Survey costs are approximately $7 per service per leak survey visit (cycle). These can range from once per year to as often as 2 week cycles.

- Visual Inspections cost about $1,000 per service.
- Monitoring of slack loops costs approximately $486 per slack loop per visit and the frequency can be once per 6 month period to once every 2 weeks
- Satellite monitoring costs approximately $100,000/year in total for the communities of Regina Beach, Saskatchewan Beach, Kanata Valley, Rock Ridge, Kinookima, and Buena Vista
- Facility Upgrading costs approximately $5,500 per service and $30,000 per additional slack loop added

iii. How many of the 43 communities being monitored are at the lower level of the pyramid, vs the higher levels. Please discuss.

In the past 3 years, approximately 9 communities have experienced facility upgrades; 12 are currently being monitored, 12 have had visual inspections, and all 43 have had increases in the frequency of leak surveying.

iv. What level of costs were being incurred to address risk mitigation of Last Mountain Lake prior to the removal of services. How did this compare with the 43 other communities and with communities across Saskatchewan generally?

In 2016, $1,964,000 was spent monitoring and upgrading Last Mountain Lake services, while $19,000 was spent on the other sloped communities. Leak survey costs in other communities across Saskatchewan would be approximately $8/service per year.

e) Are the communities being monitored included in the 10 year service upgrade plan?

Regina Beach is being included in the Service upgrade program. A review of every community is underway to determine if any other communities across the province are not meeting the current design standards for sloped communities. All other communities around Last Mountain Lake were constructed to current design standards, so they will not be included in the service upgrade program.

f) Please provide the annual leak rate for each of the targeted communities and indicate how this compares to the 3 year and 5 year average for the province.

3-Year and 5-Year Average Leak Rates in Deactivation Communities vs Provincial Average		
	2014-2016 avg leak rates	2012-2016 avg leak rates
Regina Beach	77	79
Saskatchewan Beach	160	176
Buena Vista	12	12
Shore Acres	0	0
Craven	16	16
Sun Dale	0	0
Provincial	0.55	0.56
Note1: All leak rates are in leaks per 1000 services per year.		
Note2: Last Mountain Lake leaks only include those due to slope movement or possibly due to slope movement. Kinked services due to slope movement are not included.		
Note3: The number of services in Last Mountain Lake has been kept constant at the 2016 values.		
Note4: External Interference Leaks were removed, because they are activity based and effects of 3rd party damage, and don't relate to the ground movement issue.		

22. Reference: 1st Round Information Request #27 [Implementation of Previous Panel Recommendations]

a) With reference to the response to 27(a), please confirm that that change in heat value noted had a $1.7 million negative impact on delivery net income and a $2.7 million increase in GCVA due from customers.

Confirmed.

b) With reference to the response to 27(d)(ii), please indicate what the anticipated GCVA balance will be at the end of the test period. Please indicate if the balance will be owing to customers or from customers.

Using market prices as of August 11, 2017, the forecast GCVA at the end of the test period is $5 million owing to customers from SaskEnergy.

c) With reference to the response to 27(e), please describe further how the Customer Dialogue committee process works. How often does the committee meet; what issues are raised for discussion at the committee and what is the process for discussion and resolution of any concerns raised.

The TransGas Customer Dialogue Committee meets four times per year. The purposes of the TransGas Customer Dialogue Process are:

- To provide a forum for information exchange with TransGas Customers, which occurs on a quarterly basis.
- To seek customer input and dialogue on future TransGas service offerings, policies, capital expenditures and rate design issues. Any given topic discussed at Customer Dialogue usually follows a four step process:
    - Provide Background - Customer Dialogue members are provided with background information related to the subject being discussed to ensure everyone fully understands the issue;
    - Discussion - Customer Dialogue members have an opportunity to discuss the issue amongst themselves and ask for additional information (if required). Potential options are discussed and debated amongst the group, which typically results in either a clear path forward or the need for more discussion/background;
    - Recommendation - Based on Customer Dialogue input, TransGas will provide a recommendation for the issue which is further debated amongst the group;
    - Resolution - If Customer Dialogue is able to reach general consensus, an Issue Resolution statement is provided to the group and recorded in the meeting minutes.

- Any projected TransGas rate changes are discussed cooperatively and in advance with key customer representatives through the Customer Dialogue process.

23. Reference: 1st Round Information Request #28 [Heat Value]

a) With reference to the response to 28(c), please confirm that the reference to April 17-Mar17 at the bottom of page 161 should be April 16-March 17.

Confirmed.

b) With reference to the response to 28(c), please confirm that the forecast year referenced on page 162 is the test year forecast year.

Confirmed.

c) With reference to the response to 28(a), please clarify the following:

i. Please outline and explain the factors underlying the lower average heat value for Weyburn in 2016 compared to prior years. Is this trend expected to continue going forward? Please also discuss factors underlying changes in Melville's heat value over the period.

The lower average heat value for Weyburn in 2016 is attributed to the operation of the straddle plant that went into service in the fall of 2015. During 2016 the plant was fully operational. The heat value is not expected to trend any lower, but rather remain near 2016 levels.

The changes to Melville's heat value are due to how TransGas Limited manages the provincial natural gas supply. Melville can be supplied with natural gas from the western side of the province via the Rosetown to Regina pipeline, directly off of TCPL; or from supply in the Estevan area. While the natural gas received through Regina and directly off of TCPL has had a heat value around 38 MJ/m^3 in recent months, natural gas from the Estevan area has been over 43 MJ/m^3.

ii. Please indicate the factors driving the ongoing higher average heat values for Estevan and Yorkton. Is this expected to continue going forward?

The higher heat value of natural gas in the Estevan area is because the natural gas produced in the southeast area of the province is natural gas associated with oil production. Yorkton receives natural gas from the Estevan area, as well as off TCPL, so the heat value is not as high as Estevan, but is higher than most other regions. This same heat value is expected going forward.

iii. Please explain why the percentage bill variance for residential customers in Weyburn reduces from 7% in 2012-2014 to 1.4% in 2016; while the percentage bill variance for small commercial customers and large commercial customers remains flat over the same period (approximately 9%).

Upon further review of the Excel spreadsheet, some cells were incorrectly linked. The corrected bills are below.

	Average 2016 Residential Bill by Heat Value										
Residential	Regina	Moose Jaw	Weyburn	Estevan	Swift Current	Yorkton	Melville	Saskatoon	Prince Albert	North Battleford	System Average
BMC ($)	251	251	251	251	251	251	251	251	251	251	251
Delivery ($)	218	226	215	196	225	207	218	222	218	223	220
Commodity ($)	403	418	398	362	415	383	402	411	404	412	406
Total Bill ($)	$ 872	$ 895	$ 865	$ 809	$ 891	$ 842	$ 870	$ 884	$ 873	$ 885	$ 877
Total Bill Variance ($)	$ (5)	$ 18	$ (12)	$ (68)	$ 14	$ (35)	$ (6)	$ 7	$ (4)	$ 8	$ -
Total Bill Variance (%)	-1%	2%	-1%	-8%	2%	-4%	-1%	1%	0%	1%	0%
Weighted Average HV (MJ/m3)	38.90	37.51	39.36	43.26	37.74	40.89	38.98	38.13	38.82	38.08	38.58

	Average 2016 Commercial Small Bill by Heat Value										
Commercial Small	Regina	Moose Jaw	Weyburn	Estevan	Swift Current	Yorkton	Melville	Saskatoon	Prince Albert	North Battleford	System Average
BMC ($)	439	439	439	439	439	439	439	439	439	439	439
Delivery ($)	872	905	862	784	899	830	871	890	874	891	880
Commodity ($)	1,927	1,999	1,905	1,733	1,987	1,833	1,923	1,966	1,931	1,969	1,943
Total Bill ($)	$ 3,238	$ 3,342	$ 3,206	$ 2,956	$ 3,325	$ 3,102	$ 3,233	$ 3,295	$ 3,244	$ 3,299	$ 3,262
Total Bill Variance ($)	$ (23)	$ 81	$ (56)	$ (305)	$ 63	$ (160)	$ (29)	$ 34	$ (17)	$ 37	$ -
Total Bill Variance (%)	-1%	2%	-2%	-9%	2%	-5%	-1%	1%	-1%	1%	0%
Weighted Average HV (MJ/m3)	38.90	37.51	39.36	43.26	37.74	40.89	38.98	38.13	38.82	38.08	38.58

	Average 2016 Commercial Large Bill by Heat Value										
Commercial Large	Regina	Moose Jaw	Weyburn	Estevan	Swift Current	Yorkton	Melville	Saskatoon	Prince Albert	North Battleford	System Average
BMC ($)	1,609	1,609	1,609	1,609	1,609	1,609	1,609	1,609	1,609	1,609	1,609
Delivery ($)	11,052	11,461	10,922	9,938	11,392	10,513	11,029	11,275	11,074	11,291	11,143
Commodity ($)	27,932	28,967	27,606	25,118	28,793	26,571	27,875	28,498	27,989	28,536	28,163
Total Bill ($)	$ 40,592	$ 42,037	$ 40,137	$ 36,665	$ 41,794	$ 38,693	$ 40,513	$ 41,382	$ 40,673	$ 41,436	$ 40,914
Total Bill Variance ($)	$ (322)	$ 1,123	$ (777)	$ (4,249)	$ 880	$ (2,221)	$ (401)	$ 468	$ (242)	$ 522	$ -
Total Bill Variance (%)	-1%	3%	-2%	-10%	2%	-5%	-1%	1%	-1%	1%	0%
Weighted Average HV (MJ/m3)	38.90	37.51	39.36	43.26	37.74	40.89	38.98	38.13	38.82	38.08	38.58

iv. Please reconcile or explain the differences in average bill impact information provided for 2012 through 2016 for residential, commercial small and commercial large customers to the information for 2012 through 2015 provided in response to 2nd Round Information Request 20(h) provided in the 2016 Delivery Service and Commodity Rate Application.

Average bills were updated using the forecasted UPCs from this Rate Application:

Residential: 2,643 m^3 at HV of 38.5 MJ/m^3 - 102 GJ

Commercial Small: 12,631 m^3 at HV of 38.5 MJ/m^3 - 486 GJ

Commercial Large: 183,067 m^3 at HV of 38.5 MJ/m^3 - 7,048 GJ

v. Please also reconcile or explain the differences in weighted average heat value in 2014 in the response to 2nd Round Information Request 20(h) provided in the 2016 Delivery Service and Commodity Rate Application.

The 2014 weighted average heat values were displayed incorrectly in 20 (h) in 2016, those in 28 (a) in round 1 are correct.

24. Reference: 1st Round Information Request #29 [Productivity and Efficiency Update]

a) With regard to leveraging SaskPower Third Party Transport, have there been any operational changes regarding how the two companies work together to coordinate activities (i.e., the 2015/16 productivity and efficiency report indicates [Tab 25, page 6] indicates daily discussions at the operational level and that senior management of two companies meet twice per year; Tab 23 of the current Application notes the companies “talk frequently” at the operational level and senior management of two companies meet once per year to discuss existing business and potential new opportunities. Please discuss.

No, there have been no operational changes regarding how the two companies work together. The two companies have become more familiar with each other's gas operations, therefore the need to talk or meet as frequently as we did previously has decreased. Each company is well aware of the other's gas related assets, and when either company deems that the other's assets could be of value to them, that company initiates contact with the other to determine the asset's availability.

b) With reference to the response to 29(b), please reconcile and explain differences in the $1 million in savings noted for Crown Collaboration in the response with the $1.9 million in savings realized for the joint line servicing initiatives in 2016 (provided in Tab 23, page 4).

Page 4 of Tab 23 states that the $1.9 million is capital cost savings realized as a result of the joint service line initiative. The response to 29(b) states the crown collaboration savings relate to operating savings from several initiatives including administrative cost savings from joint line servicing.

c) With reference to the response to 29 (c), please describe in further detail the efficiency initiatives planned for 2017/18.

i. What are planned activities included under "New Revenue Initiatives"?

The new revenue initiatives identified as part of the 2017/18 Business Plan related to Facility Optimization Activity by Bayhurst Gas Limited.

ii. What additional activities are planned regarding "Crown Collaboration" and "Leveraging Technologies"?

The 2017/18 business plan anticipated crown collaboration efficiencies related to the areas of billing, employee surveys and insurance services. Leveraging technology efficiencies planned for 2017/18 include savings from the implementation of the Distribution

Work Management system and the first phase of the Communication and Collaboration infrastructure project.

iii. What activities are included under Business Process Changes"?

The 2017/18 business plan anticipated savings related to business process changes in the areas of safety and integrity patrols, procurement and auto generated timesheets in TGL operations.

d) With the reference to the response to 29 (l), please explain further how third party contractor mandatory time offs at the end of December 2016 helped to increase efficiency and reduce SaskEnergy costs.

i. Was the work planned to be undertaken by third party contractors at the end of 2016 eliminated, i.e., were the noted cost savings permanent, or were costs shifted to a later period when the work was undertaken (i.e., reduced costs in 2016 but increased costs in 2017 for work not undertaken in 2016).

The costs were shifted to a later period.

ii. If work undertaken was not eliminated in 2017 would it be more accurate to describe this as a restraint measure (rather than a productivity and efficiency measure). Please discuss.

The mandatory time off for IT contractors would most appropriately be considered a restraint measure rather than an efficiency initiative.

e) With reference to Tab 23, page 13, please reconcile the noted net savings for 2015 of $192,000 with the estimated savings noted in Tab 25 of the 2016/17 Delivery and Commodity Rate Application (of $260,000).

The estimated savings related to the service up-grade program in the 2016/17 Delivery rate application was prepared using an estimate of the number of up-graded services to be completed in 2015 and the projected reduction in gas leaks as a result of this work. The savings noted for 2015 in the 2017/18 efficiency report for up-graded services is based on the actual number of gas leaks in the high risk areas. It should be noted that other factors, such as environmental conditions, can influence leak incidence as well, so year to year variability in these results is expected.

f) Are there any ongoing savings in 2016/17 related to the following programs described in Tab 25 of the 2016 Application: Mobile Compressors; Time Reporting and On Line Pay Advice; Scanned Service Diagrams; Electronic Crew Board; Energy Efficiency Program; Reduction in Sponsorships.

The efficiency savings for new initiatives are identified in the year that the initiative is implemented because the reference point is always the previous year's budget. The expectation is that efficiency gains continue to accrue to the corporation as long as the initiative is on-going however, the reference point is lost as the following year's budget no longer includes those expenses. In the case of mobile compression, when TGL purchases new compressors the operating efficiencies from adding new mobile compressors is calculated based on the number of new mobile compressors added during the year.