DIRECT TESTIMONY
OF STEVEN W. WISHART
ON BEHALF OF NORTHWESTERN ENERGY

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Exhibits

Witness Information

Q. Please identify yourself, your employer, and your job title.

A. My name is Steven W. Wishart. I am an Assistant Vice President at Concentric Energy Advisors, Inc. ("Concentric"). Concentric is a management consulting firm that provides regulatory, financial, and economic advisory and litigation support services to energy and utility clients across North America. My business address is 293 Boston Post Road West, Suite 500, Marlborough, Massachusetts 01752.

Q. On whose behalf are you submitting this Direct Testimony?

A. I am submitting this Direct Testimony on behalf of NorthWestern Corporation d/b/a NorthWestern Energy ("NorthWestern" or "Company").

Q. Please provide a description of your relevant employment experience and other professional qualifications.

A. I have worked in the energy industry for more than 20 years. Before joining Concentric in the fall of 2023, I worked at Xcel Energy for 18 years. At Xcel Energy I served as Director of Pricing and Regulatory Analytics for the Colorado jurisdiction. In that role I performed rate design, cost allocation, long term rate forecasting, and numerous other analyses in support of regulatory filings. At Xcel Energy I also served as Director of Resource Planning and Bidding for the Minnesota jurisdiction. In that role I oversaw the long-range planning for the electric generation portfolio and conducted competitive resource acquisition processes. I hold a Bachelor of Science in Finance and a Master of Science in Resource Economics from the University of Arizona and have completed all of the coursework for a Ph.D. in Applied Economics from the University of Minnesota.

Q. Have you testified before any regulatory authorities?

A. Yes, I have been a witness in 35 regulatory proceedings in four jurisdictions.

Purpose of Testimony

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to present the Company's proposal for a new Standby Electric Service tariff ("SESS-1") and associated modifications to other tariff sheets to provide cost-based service to customers with large on-site generation. In doing so I address Montana Administrative Rule 38.5.1204, which specifies several requirements for utilities that are proposing new standby charges. I provide information on the number and type of customer that will be impacted by the proposed change, the impact on the expected payback period for on-site generation, and the cost to serve customers with on-site generation.

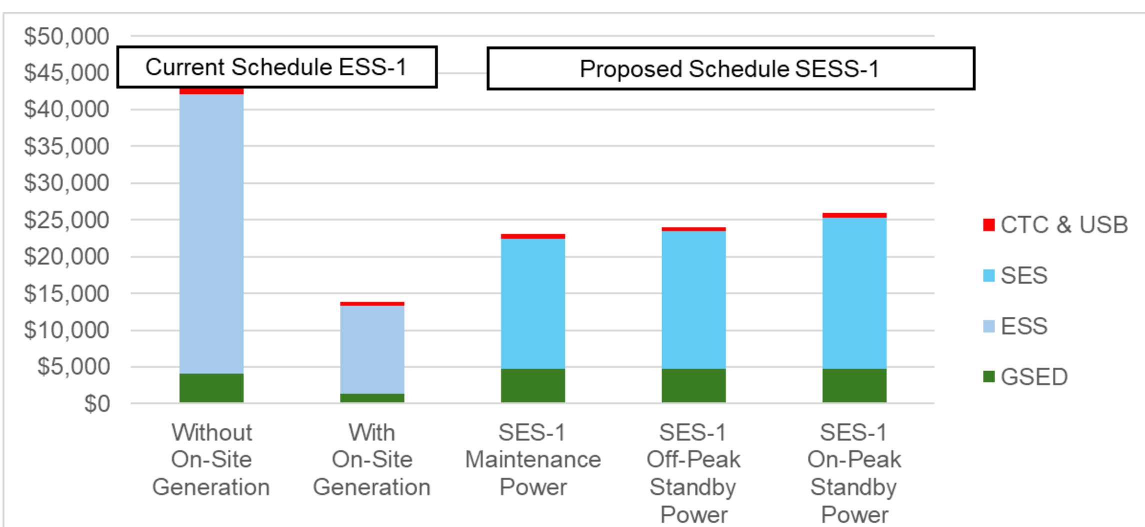
The Company's proposal is intended to address the growing number of customers that are installing natural gas, or similar generators, to encourage those customers to operate their systems efficiently, and ensure that they are paying the appropriate amount for energy provided by the Company. The Company is proposing that the proposed standby service not be applicable to energy storage systems because such systems do not reduce the total consumption by customers. Rather energy storage shifts the timing of energy consumed from the grid Schedule SESS-1 would not apply to Net Energy Customers.

Q. Please summarize your testimony.

A. My testimony provides a detailed description of the Company's proposed standby rate design and includes a draft of the tariff as Exhibit SWW-1. I explain that under the Company's current rate structure, customers with on-site generation are paying less than the appropriate cost of service and the rest of the Company's customers are subsidizing them. Although some customers supply much of their own energy needs, the Company must still construct or purchase generation, transmission, and distribution assets to serve those customers. Because the Company's Electric Service tariff relies heavily on energy-based (kilowatt-hour ("kWh")) charges, customers with on-site generation can potentially reduce their monthly bills to the point where they are no longer paying their fair share of the system resources they use and costs they cause the system.

The proposed standby rate structure will encourage customers to operate their generators in an efficient manner and only take those resources offline during periods of low demand. This will minimize overall system costs and rates for all customers. Customers taking service through the proposed standby rate Schedule SESS-1 will still realize large bill savings through the installation of on-site generation, but NorthWestern proposess to restructure the energy service charges to ensure that these customers are being appropriately charged for the system resources that serve them. The following chart summarizes the bill impact analysis I discuss later in my testimony. It illustrates that bill reductions will still be of a similar magnitude but will vary depending on the performance of the customer's generator. The two columns to the left illustrate the bill reductions under the current rate structure and the three to the right illustrate the magnitude of the bill reductions under the proposed standby rates assuming three different scenarios; maintenance power, off-peak standby, and on-peak standby, which I will explain later in my testimony

Figure 1: Proposed Standby Rate Bill Impact Analysis



On-Site Generation and Current Rate Structure

Q. How does on-site generation impact customers' bills under the Company's current rate structure?

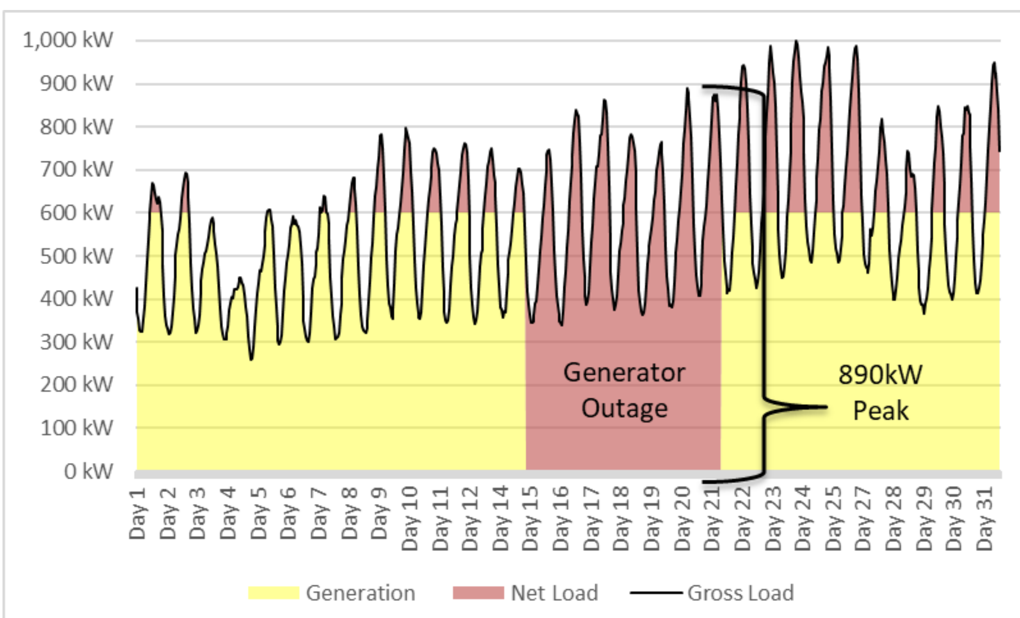
A. As discussed in the direct testimony of Cynthia S. Fang, because NorthWestern's current rate structure relies heavily on energy charges, when customers install their own on-site generation, they can greatly reduce their monthly bills and potentially pay less than their appropriately allocated share of system costs. The following table provides the Company's proposed final rates in this case for a customer taking service on the GS-1 Primary Voltage Energy rate option. It shows that except for the small monthly customer charge, the rest of the monthly bill is assessed through kWh-based energy charges and not peak kW demand charges.

Table 1: Current GS-1 Primary Non-Demand Rates

	GSED-1 Primary Non-Demand
Customer Charge	$235.30 / month
Energy Charge	$0.008854/kWh
	ESS-1
Generation Supply	$0.073948/kWh
Transmission Energy	$0.014943/kWh
	CTC & USB
CTC & USB Energy Charge	$0.004319/kWh

When a customer installs on-site generation, their bills will be dramatically reduced even if they use the Company's distribution, transmission, and generation resources during periods when their generator is offline. To illustrate this issue, I developed an example of a hypothetical customer with a peak demand of 1,000 kW who installs a 600-kW generator. To reflect the reality that generators occasionally go offline for either planned maintenance or unplanned outages, I simulated the generator going offline for one week in the month. The following figure illustrates how the customer's generator does a good job of serving most of the customer's energy needs during the month. But during the outage the customer puts a peak demand of 890 kW on the Company's system. While this is not as high as the customer's gross peak demand of 1,000 kW, it is still a large strain on the Company's system in which the Company must still be prepared to provide.

Figure 2: On-site Generation Simulation



Next, I calculated what the customer's monthly bill would have been under the GS-1 Primary Voltage Energy rates, both with and without the on-site generation. The results show that even though the hypothetical customer places 890 kW of peak demand on the system when their generator is offline, the monthly bill is 68 percent lower than it would have been without on-site generation.

Table 2: On-Site Generation Bill Comparison

	Gross Load GSED-1 Primary Non-Demand		**Net Load With On-site Generation** GSED-1 Primary Non-Demand	
Customer Charge	1 Month	$235.30	1 Month	$235.30
Energy Charge	428,619 kWh	$3,795.00	133,523 kWh	$1,182.21
	ESS-1		ESS-1	
Generation Supply	428,619 kWh	$31,695.55	133,523 kWh	$9,873.73
Transmission Energy	428,619 kWh	$6,404.86	133,523 kWh	$1,995.23
	CTC & USB		CTC & USB	
CTC&USB Energy Charge	428,619 kWh	$1,851.21	133,523 kWh	$576.68
	Total Bill	$43,981.91	Total Bill	$13,863.15
			Bill Decrease	-$30,118.77 -68%

Q. Are such large bill reductions for on-site generation justified?

A. No. A majority of utility system costs are fixed, meaning that they do not vary in relation to the monthly amount of kWh sold. Rather, most utility assets are designed and built to meet the peak demands of customers. For customers with on-site generation, this means that distribution is sized such that the Company can deliver the maximum peak demand that the customer usess at any time over the course of a year, and transmission and generation are sized to meet the customer’s expected demand during the aggregate system peak.

Therefore, to ensure that customers are paying their share of the system resources they use, distribution charges should be based on the peak demand that the customer places on the system, and transmission and generation charges should be based on the actual or expected load during the Company's total system peak.

Standby Tariff and Associated Tariff Modifications

Q. What is the Company's proposal for a new standby tariff?

A. The Company is proposing to create a new Standby Electric Service tariff, Schedule SESS-1. Customers with on-site generation larger than 100 would take service through the Schedule SESS-1 instead of the Schedule ESS-1.

The existing Schedule ESS-1 specifies the cost of electric supply including the fixed cost of generation and transmission capacity and the variable cost of fuel and purchased energy. Schedule SESS-1 will also specify the cost of electric supply but disaggregates the costs for power supplied by the Company into three contract quantities and three power supply components.

The three contract quantities are:

1) Standby Contract Capacity: Equal to the net dependable capability of the customer's generator and the amount of capacity that the

Company must be ready to serve in the event that the customer's generator is offline for any reason.

2) Supplemental Contract Capacity: Equal to the customer's peak demand in excess of what is served by the customer's on-site generation.

3) Total Contract Capacity: The sum of Standby Contract Capacity and Supplemental Contract Capacity.

The three power supply components are:

1) Maintenance Power: Additional demand supplied by the Company when the customer's generation is offline for planned maintenance during periods of low system demand.

2) Standby Power: Additional demand supplied by the Company when the customer's generation is offline for an unplanned outage.

3) Energy: The variable cost of energy, typically fuel and purchased power, which the Company supplies at any time.

Q. Is the Company proposing any other tariff changes associated with the new standby power tariff?

A. Yes, accompanying the Schedule SESS-1, the Company is also recommending a change to the applicability section of the General Service Electric Delivery Service tariffs, Schedules GSEDS-1 and GSEDS-2. Those tariffs specify the cost of power delivery through the Company's distribution system and a portion of generation capacity costs. First, the Company is proposing to modify Schedule GSEDS-1 to specify that customers utilizing standby service are required to take service through one of the demand-metered options. Second, for both Schedules GSEDS-1 and GSEDS-2, the Company is proposing to modify the demand billing quantity from the measured 15-minute maximum demand to the Total Contract Capacity specified in the customer's service agreement. These changes will ensure that standby customers are paying the full cost of the system distribution assets that NorthWestern has constructed to serve them.

Q. How does the Schedule SESS-1 compare to the current Schedule ESS-1?

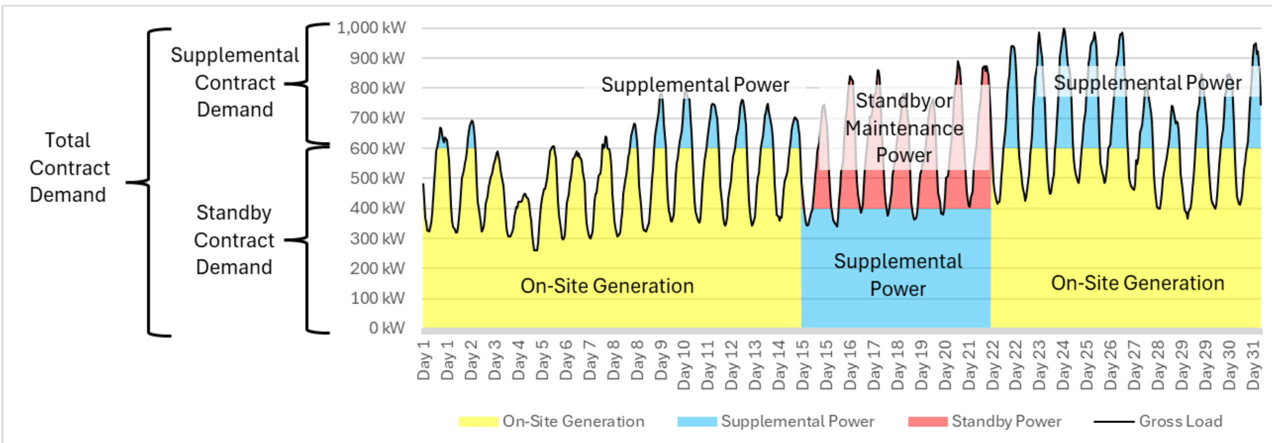
A. I have calculated the rates for Schedule SESS-1 such that an average customer, without on-site generation, would have the same monthly bill as they would under Schedule ESS-1. The Schedule SESS-1 replaces the energy charges in ESS-1 with a demand charge and introduces discounted charges for standby services. The following table provides a comparison between all the charge items for customers taking service through Schedule ESS-1 and the proposed charges for Schedule SESS-1. This example is based on delivery service through GSEDS-1 at the primary voltage level. The comparison demonstrates how the generation supply and transmission charges in Schedule ESS-1 are replaced by six different charges in the Schedule SESS-1.

Table 3: ESS-1 Versus SESS-1 Rate Comparison

	GSEDS-1 Primary Energy	GSEDS-1 Primary Demand	GSEDS-1 Primary Demand
Customer Charge	$235.30 / month	$740.60 / month	$740.60 / month
Energy Charge	$0.008854/kWh	$0.004020/kWh	$0.004020/kWh
Demand Charge		$3.44/kW-mo	$3.44/kW-mo
	ESS-1 Primary Energy	**ESS-1 Primary Demand**	**SESS-1 Primary**
Generation Supply	$0.073948/kWh	$0.073948/kWh	
Transmission Energy	$0.014943/kWh		
Transmission Demand		$6.24/kW-mo	
Supplemental Contract Capacity			$29.41/kW-mo
Standby Contract Capacity			$5.88/kW-mo
Standby Power - Peak Months			$0.97/kW-day
Standby Power - Off-Peak Months			$0.32/kW-day
Schedule Maintenance Power			$0.00/kW-day
Energy Charge			$0.018424/kWh
	CTC & USB	**CTC & USB**	**CTC & USB**
CTC&USB Energy Charge	$0.004319/kWh	$0.004319/kWh	$0.004319/kWh

To illustrate the various charge types I have developed Figure SWW-3. The figure illustrates how the hypothetical customer with a 1,000 kW peak demand and 600 kW of on-site generation would be billed over a representative month. First, the Supplemental Contract Capacity and Standby Contract Capacity are set based on the customer-expected net peak demand and the net dependable capability of the on-site generation, respectively. Next, the monthly quantity charged for Supplemental Power, and either Standby or Maintenance Power, are measured by the actual levels of demand over the course of the month. Figure 3 illustrates how during an outage the customer’s first increment of demand is defined to be Supplemental Demand and only after that amount is exhausted is the remaining demand charged as either Standby Power or Maintenance Power, depending on if the customer had scheduled the outage with the Company during off-peak months.

Figure 3: Schedule SESS-1 Charge Types



Q. How was the Supplemental Contract Capacity charge calculated?

A. The Supplemental Contract Capacity charge, which is applied to the customer's demand not regularly served by on-site generation, is equivalent to the generation and transmission charges found in ESS-1. The demand charge of $29.41/kW month and the energy charge of $0.018424/kWh in Schedule SESS-1 for a customer with an average load factor of 57.2% is equal to the generation and transmission charges under either of the ESS-1 Primary Voltage rate options. The following table illustrates how ESS-1 and SESS-1 would result in identical total monthly bills for a 53.6% load factor customer.

Table 4: On-Site Generation Bill Comparison

	Demand	Energy	Load Factor
Average Customer	1,000 kW	417,345 kWh	57.2%
ESS-1 Primary Energy	**Rate**	**Volume**	**Total Charge**
Generation Supply	$0.073948/kWh	417,345 kWh	$30,861.86
Transmission Energy	$0.014943/kWh	417,345 kWh	$6,236.39
		Total Monthly Charge	$37,098.25
ESS-1 Primary Demand	**Rate**	**Volume**	**Total Charge**
Generation Supply	$0.073948/kWh	417,345 kWh	$30,861.86
Transmission Demand	$6.24/kW-mo	1,000 kW	$6,236.39
		Total Monthly Charge	$37,098.25
SESS-1 Primary	**Rate**	**Volume**	**Total Charge**
Supplemental Contract Capacity	$29.41/kW-mo	1,000 kW	$29,409.08
Energy Charge	$0.018424/kWh	417,345 kWh	$7,689.17
		Total Monthly Charge	$37,098.25

Q. How was the Standby Contract Capacity charge calculated?

A. The Standby Contract Capacity charge, which is applied to the maximum generating capacity of the customer's on-site generation, is 20 percent of the Supplemental Contract Capacity rate. The 80 percent discount on standard generation and transmission charges is a large benefit to self-generating customers. The 20 percent charge represents a reasonable estimate of the generation and transmission capacity that the Company must hold on the customer's behalf to ensure that they can reliably provide standby power in the event that the on-site generation experiences an outage during a time of system peak demand. I recommend the 20 percent charge as a conservative reflection of the 19.9 percent Western Resource Adequacy Program winter planning reserve margin rate that the Company used in its 2023 Montana

Integrated Resource Plan, Docket No. 2022.11.102. 19.9 percent represents the extra capacity that the Company holds to ensure system reliability in the event of generator outages or other unusual events.

Q. How were the charges for Standby Power and Maintenance Power calculated?

A. The Standby Power charge for on-peak months, which are defined as December, January, February, July, and August[1], is calculated as the daily equivalent of the Supplemental Contract Capacity. This implies that if a customer experiences a generator outage during the peak months, they will be charged the full average cost of generation and transmission capacity. However, by utilizing a daily charge instead of a monthly charge, the rate provides an incentive to the customer to bring their generation back online as quickly as possible.

The Standby Power charge for off-peak months is calculated such that the price ratio between on-peak and off-peak months is 3 to 1. This reduces the charge for unplanned outages during the off-peak months but still provides incentive to customer to avoid such outages. The ratio of 3 to 1 was selected because it is equal to the on-peak to off-peak price ratio that had been previously approved by the Commission for use in the Company's Residential Time-of-Use Demonstration rate, Schedule RSGTOUD-1.

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[1] In the Montana Integrated Resource Plan these months were identified as the months when the NWE system was most likely to experience annual peak demands.

If a customer schedules maintenance for their generator with the Company during the off-peak months, Schedule SESS-1 specifies a charge of zero for Maintenance Power. During the off-peak months if the Company is aware of a planned outage for a customer's on-site generator, it should be able to adequately plan for the increased customer load without any material incremental generation or transmission costs.

Q. How was the energy charge for Schedule SESS-1 calculated?

A. The Company does not have a standalone fuel and energy charge like most utilities. However, the testimony of Joseph M. Stimatz details the costs included in the Power Costs and Credits Adjustment Mechanism ("PCCAM"). This mechanism accounts for the cost of fuel, purchased energy, purchased capacity cost, Qualifying Facilities ("QF") contracts, and Demand Side Management costs. I have isolated just the cost of fuel, purchased energy, and QF contracts to use as the energy charge in Schedule SESS-1. Due to line lossess, the energy rate varies slightly depending on the voltage level at which the customer receives service.

Table 5: Schedule SESS-1 Energy Charges

Voltage Level	SESS-1 Energy Rate
Secondary	$0.018781/kWh
Primary	$0.018424/kWh
Substation	$0.018224/kWh

Transmission	$0.018101/kWh

Q. How will the Supplemental Capacity and Standby Contract Capacity quantities in Schedule SESS-1 be established?

A. The customer will enter into a Service Agreement with the Company, which specifies the customer's gross peak demand and net dependable capacity of the on-site generation. The maximum capacity of the generator is defined as the Standby Contract Capacity; the difference between the gross peak demand and the Standby Contract Capacity is defined as the Supplemental Contract Capacity, and the sum of the two is the Total Contract Capacity. Continuing the example, I presented previously, the following table illustrates the various contact capacity values for a customer with 1,000 kW of peak demand and a 600-kW generator.

Table 6: Contract Capacity Values

Customer Loads	
Gross Peak Demand	1,000 kW
- Net Dependable Capacity of Generator	600 kW
= Net Load Served by the Company	400 kW
Contract Capacity	
Standby Contract Capacity	600 kW
+ Supplemental Contract Capacity	400 kW
= Total Contract Capacity	1,000 kW

Q. How will Standby or Maintenance Power be measured?

A. The charges for Standby Power are measured on a daily basis. The customer's peak demand is recorded for each day in a billing period, and daily demand over the customer's Supplemental Contract Capacity is counted as Standby Power. The exception is if the customer has scheduled the outage with the Company in advance during an off-peak month, in which case the outage is considered Maintenance Power and there is no charge. In the example previously presented in this section, the customer generator was offline for one week in the month. During that period, the customer's peak demand exceeded their Supplemental Contract Capacity on each day resulting in Standby Power charges, unless the outage had been previously scheduled with the Company. The following table illustrates the calculation of the daily charges for Standby Power.

Table 7: Contract Capacity Values

	Gross Peak Demand	Generation	Net Peak Demand	Supplemental Power	Standby or Maintenance Power
Day 15	746 kW	0 kW	746 kW	400 kW	346 kW
Day 16	840 kW	0 kW	840 kW	400 kW	440 kW
Day 17	862 kW	0 kW	862 kW	400 kW	462 kW
Day 18	781 kW	0 kW	781 kW	400 kW	381 kW
Day 19	764 kW	0 kW	764 kW	400 kW	364 kW
Day 20	890 kW	0 kW	890 kW	400 kW	490 kW
Day 21	875 kW	0 kW	875 kW	400 kW	475 kW
				Total Standby or Maintenance Power	2,959 kW-days

Impact of Schedule SESS-1 on Customer Bills

Q. Have you prepared an analysis of how the proposed Schedule SESS-1 would impact customer bills?

A. Yes. Using the example of a customer with 1,000 kW of peak demand and 600 kW of on-site generation, I developed several scenarios to illustrate how Schedule SESS-1 would impact customer bills. The impacts will vary depending on if a customer's generator experiences an outage and whether that outage was scheduled maintenance or an unplanned event.

Q. What scenarios did you model for the bill impact analysis?

A. The first set of scenarios are the baseline that I presented earlier in my testimony where the customer is taking service through Schedule GSEDS-1 Primary Non-Demand and Schedule ESS-1 Primary Energy. I show the customer's representative monthly bill both with and without the on-site generation. I also show the impact of a one-week outage for that generator. With the current rate structure of Schedule ESS-1 it does not matter if the outage is planned or unplanned nor does it matter if the outage occurs during peak demand or not.

Next, I modeled four scenarios for customers taking service through the proposed SESS-1 rates. First, I modeled a scenario assuming the customer's generator operated for the entire month. Then, I modeled the average bills assuming a one-week outage as Scheduled Maintenance Power, Off-Peak Standby Power, and On-Peak Standby Power.

Q. What were the results of the bill impact analysis?

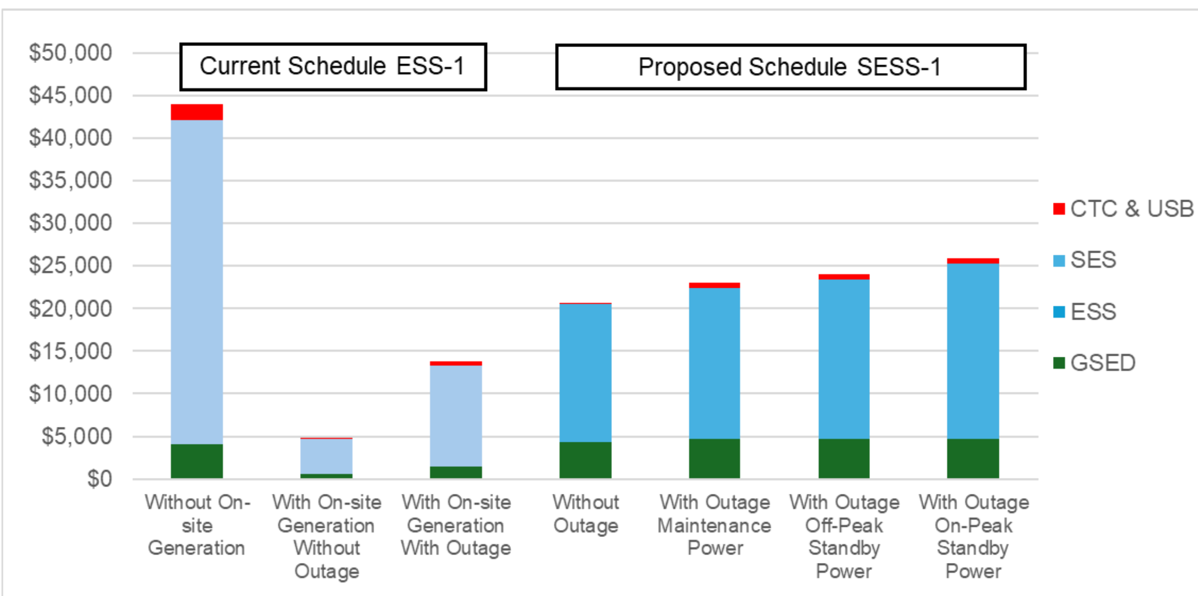
A. The bill impact analysis is included as Exhibit SWW-2. I have summarized the results of the analysis in the table and figure below. The analysis showed that without on-site generation, a 1,000-kWh industrial or commercial customer would have a monthly bill of $48,840. With the addition of a 600-kW on-site generator and without Schedule SESSS, the customer's bills would fall to $5,179 assuming no outage and $15,221 with a one-week outage. The proposed Schedule SESSS would appropriately align charges to the customer with the cost to serve them and increase the average monthly bills to a range between $16,719 and $24,708.

Table 8: Bill Impact Scenarios

Scenario	Monthly Peak Demand	Monthly Energy	Average Monthly Bil

ESS-1 Without On-site Generation	1,000 kW	428,619 kWh	$43,982
ESS-1 With On-site Generation Without Outage	400 kW	45,386 kWh	$4,868
ESS-1 With On-site Generation With Outage	890 kW	133,523 kWh	$13,863
SESS-1 Without Outage	400 kW	45,386 kWh	$20,685
SESS-1 With Outage Maintenance Power	890 kW	133,523 kWh	$23,044
SESS-1 With Outage Off-Peak Standby Power	890 kW	133,523 kWh	$23,997
SESS-1 With Outage On-Peak Standby Power	890 kW	133,523 kWh	$25,904

Figure 4: Bill Impact Scenarios



Montana Administrative Rule 38.5.1204

Q. What are the requirements for utilities proposing to implement standby charges for customers with on-site generation?

A. Montana Administrative Rule 38.5.1204 requires the following data for utilities proposing new standby rate charges:

(a) number of customers equipped with alternative, renewable energy sources who would be affected by such charges;

(b) current costs and payback periods of the major alternative energy systems with no standby charge; current costs and payback periods of the major alternative energy systems if the standby charge as requested is authorized;

(c) for proposed standby charges for electric utility service, time-of-day and load information for the various classess of customers; and for the various energy source systems employed by them;

(d) cost of service information, including incremental cost of service information broken down by cost of service to the class of customers with unlimited use backup systems and the class of customers with backup service restricted to off-peak replenishment of energy storage systems.

Q. How many customers would be impacted by the Company's proposed Schedule SESS-1?

A. As I stated earlier, the proposed Schedule SESS-1 would not apply to customers with net metered renewable energy systems nor would it apply to customers with energy storage systems such as battery storage. The draft tariff states that the rate is applicable to customers with on-site generation of 100 kW or greater and explicitly excludes photovoltaic generation, wind generation, or energy storage systems.

Based on information provided by the Company, there are currently seven customers with on-site generation that would be required to take service through Schedule SESS-1.

Q. How would the proposed standby Schedule SESS-1 impact the cost and payback periods for major alternative energy systems?

A. The proposed tariff would not impact the upfront cost of on-site generation systems. However, the change in rate structure would impact the estimated payback period of those systems. Neither the Company nor I have insight into the actual cost that customers have incurred to install on-site generation. Therefore, to conduct the required analysis I utilized publicly available information on generator cost and performance data from the U.S. Energy Information Administration's ("EIA") Annual Energy Outlook. This is a study that the EIA performs regularly to forecast future energy usage and prices. The EIA provides documentation for the underlying assumptions used.[2] The following table provides the types of energy systems that I evaluated and the cost and performance data that I collected from the EIA. I believe that customers subject to Schedule SESS-1 would most likely install combustion

[2] Assumptions to the Annual Energy Outlook 2023: Electricity Market Module (eia.gov).

turbines. But in order to comply with the Montana rule requirements I have provided information on a variety of generation technologies even though some are not realistic options for customers. The table presents two critical line items. The first line is the EIA's reported upfront construction costs. In my analysis, this is the amount that must be recovered throughout the payback period. The rest of the information is used to derive the last line item, which is the total average cost per kWh for each generator type.

Table 9: Cost and Performance Data for Alternative Energy Systems

	Internal Combustion Engine	Combustion Turbine Industrial Frame	Combustion Turbine Aeroderivative	Fuel Cells	Biomass	Geothermal	Nuclear Small Modular Reactor
Construction Costs	$2,240/kW	$867/kW	$1,428/kW	$7,291/kW	$4,998/kW	$3,403/kW	$8,349/kW
Annual Fixed O&M	$40/kW-yr	$8/kW-yr	$18/kW-yr	$35/kW-yr	$142/kW-yr	$154/kW-yr	$107/kW-yr
Variable O&M	$6.40/MWh	$5.06/MWh	$5.29/MWh	$0.66/MWh	$5.44/MWh	$1.31/MWh	$3.38/MWh
Heat Rate	8,295Btu/kWh	9,905Btu/kWh	9,124Btu/kWh	6,469Btu/kWh	13,500Btu/kWh	NA	10,447Btu/kWh
Fuel Cost	$32.80/MMBtu	$10.33/MMBtu	$10.33/MMBtu	$8.50/MMBtu	$3.72/MMBtu	$0.00/MMBtu	$0.71/MMBtu
Total Variable Cost	$0.2785/kWh	$0.1073/kWh	$0.0995/kWh	$0.0556/kWh	$0.0557/kWh	$0.0013/kWh	$0.0034/kWh
Assumed Capacity Factor	75%	75%	75%	75%	75%	75%	75%
Total Annual Cost	$1,869/kW	$713/kW	$672/kW	$400/kW	$507/kW	$163/kW	$129/kW
Total Average Cost Per kWh	$0.28454/kWh	$0.10853/kWh	$0.10229/kWh	$0.06092/kWh	$0.07720/kWh	$0.02475/kWh	$0.01965/kWh

Q. What is your assessment of the total average cost per kWh for alternative energy systems based on the EIA data?

A. I believe that the average cost per kWh for the internal combustion engine and the two combustion turbine alternatives are reasonable. I am familiar with the fuel cost and performance of similar units, and based on my experience the final calculated cost per kWh is within the range of what I would expect for a new unit. However, I do not have a strong basis for comparison for the other options. The four other options are either rarely deployed or not yet commercially available. As such, I have used the EIA assumptions as reported but cannot testify as to the accuracy of those assumptions.

Q. What is the average avoided electric bill per kWh for the current Schedule ESS-1 and the proposed Schedule SESS-1?

A. Based on the example of a customer with a 1,000-kW peak and 600 kW of on-site generation, I derived the average savings for both the existing Schedule ESS-1 and the proposed Schedule SESS-1. I calculated that the average bill reduction for Schedule ESS-1 is about 11 cents and about 8 cents for Schedule SESS-1.

Table 10: Average Savings Rates for On-Site Generation

	ESS-1 With Outage	SESS-1 With Outage Off-Peak Supplemental
Without On-Site Generation	$586,082	$586,082
With On-Site Generation	$182,648	$292,655
Total Savings	$403,434	$293,426
Annual Generation	3,541,162 kWh	3,541,162 kWh
Average Savings Rate	$0.11393/kWh	$0.08286/kWh

Q. What were the results of the payback analysis?

A. Based on an assumed 75 percent capacity factor for the on-site generation, I calculated how much it would cost to operate the on-site generation annually and compared that to how much the customer would save annually on their electric bill. For some technologies, such as the internal combustion engine, the operating costs were higher than the bill savings meaning that the upfront construction cost could never be paid back, these results are marked as "NA" in the results table. For the geothermal plant alternative, the payback period was relatively short. But for geothermal, my understanding is that the economics of that technology is very site specific, and most areas will not have the appropriate geology to support that type of generation. As expected, with a restructured standby tariff that assesssess more costs for distribution, transmission, generation capacity used by the customer, the payback periods increase in each of the scenarios evaluated. It is important to note that this analysis is based on the simple payback for the upfront construction cost of on-site generation and does not consider the financing cost that will likely be needed for these large capital projects.

Table 11: Payback Analysis Results

	Internal Combustion Engine	Combustion Turbine Industrial Frame	Combustion Turbine Aeroderivative	Fuel Cells	Biomass	Geothermal	Nuclear Small Modular Reactor
Construction Costs	$2,240/kW	$867/kW	$1,428/kW	$7,291/kW	$4,998/kW	$3,403/kW	$8,349/kW
Total Average Cost Per kWh	$0.28454/kWh	$0.10853/kWh	$0.10229/kWh	$0.06092/kWh	$0.07720/kWh	$0.02475/kWh	$0.01965/kWh
Average Savings ESS-1	$0.11393/kWh	$0.11393/kWh	$0.11393/kWh	$0.11393/kWh	$0.11393/kWh	$0.11393/kWh	$0.11393/kWh
Average Savings SESS-1	$0.08286/kWh	$0.08286/kWh	$0.08286/kWh	$0.08286/kWh	$0.08286/kWh	$0.08286/kWh	$0.08286/kWh
Simple Payback							
Current ESS-1	NA	24.5 years	18.7 years	20.9 years	20.7 years	5.8 years	13.5 years
Proposed SESS-1	NA	NA	NA	50.6 years	134.3 years	8.9 years	20.1 years

Q. Have you provided time of time-of-day and load information for the customers expected to be impacted by the proposed Schedule SESS-1 and the various energy systems that they employ?

A. Yes. The seven customers that the Company has identified as having on-site generation had a combined total load of 56,643 MWh in 2023. Of the seven customers there are four with interval meters that record hourly data. Based on 2023 load data I developed the following figure to illustrate the time-of-day patterns of those four customers. The figure and supporting data is also included in Exhibit SWW-3.

Figure 5: Time-of-Day Load Information

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
12:00 AM	5,729 kW	5,714 kW	5,696 kW	5,879 kW	5,683 kW	5,749 kW	5,847 kW	6,014 kW	6,016 kW	5,938 kW	5,975 kW	5,852 kW
1:00 AM	5,655 kW	5,575 kW	5,570 kW	5,697 kW	5,503 kW	5,610 kW	5,698 kW	5,842 kW	5,815 kW	5,787 kW	5,851 kW	5,734 kW
2:00 AM	5,625 kW	5,564 kW	5,344 kW	5,610 kW	5,421 kW	5,537 kW	5,616 kW	5,788 kW	5,757 kW	5,692 kW	5,751 kW	5,674 kW
3:00 AM	5,578 kW	5,518 kW	5,484 kW	5,597 kW	5,388 kW	5,500 kW	5,567 kW	5,778 kW	5,730 kW	5,655 kW	5,740 kW	5,632 kW
4:00 AM	5,554 kW	5,479 kW	5,463 kW	5,563 kW	5,355 kW	5,456 kW	5,517 kW	5,744 kW	5,668 kW	5,643 kW	5,727 kW	5,631 kW
5:00 AM	5,668 kW	5,629 kW	5,626 kW	5,735 kW	5,500 kW	5,605 kW	5,643 kW	5,901 kW	5,804 kW	5,766 kW	5,873 kW	5,744 kW
6:00 AM	5,914 kW	5,917 kW	5,911 kW	6,015 kW	5,734 kW	5,826 kW	5,842 kW	6,083 kW	6,064 kW	6,065 kW	6,152 kW	5,971 kW
7:00 AM	6,222 kW	6,273 kW	6,273 kW	6,332 kW	6,023 kW	6,096 kW	6,130 kW	6,363 kW	6,354 kW	6,397 kW	6,490 kW	6,270 kW
8:00 AM	6,511 kW	6,646 kW	6,623 kW	6,611 kW	6,293 kW	6,344 kW	6,394 kW	6,672 kW	6,705 kW	6,767 kW	6,841 kW	6,544 kW
9:00 AM	6,659 kW	6,847 kW	6,844 kW	6,760 kW	6,512 kW	6,539 kW	6,490 kW	6,812 kW	6,846 kW	6,872 kW	6,915 kW	6,617 kW
10:00 AM	6,745 kW	6,935 kW	6,873 kW	6,732 kW	6,574 kW	6,569 kW	6,477 kW	6,915 kW	7,080 kW	7,016 kW	7,059 kW	6,702 kW
11:00 AM	6,790 kW	7,011 kW	6,914 kW	6,768 kW	6,610 kW	6,639 kW	6,571 kW	7,007 kW	7,238 kW	7,110 kW	7,154 kW	6,758 kW
12:00 PM	6,836 kW	7,044 kW	6,954 kW	6,950 kW	6,771 kW	6,830 kW	6,789 kW	7,182 kW	7,292 kW	7,202 kW	7,175 kW	6,756 kW
1:00 PM	6,814 kW	7,063 kW	6,959 kW	6,981 kW	6,816 kW	6,910 kW	6,905 kW	7,341 kW	7,350 kW	7,217 kW	7,164 kW	6,760 kW
2:00 PM	6,819 kW	7,038 kW	6,962 kW	7,017 kW	6,836 kW	6,992 kW	6,984 kW	7,365 kW	7,404 kW	7,299 kW	7,240 kW	6,788 kW
3:00 PM	6,772 kW	6,988 kW	6,913 kW	6,988 kW	6,835 kW	6,920 kW	7,002 kW	7,379 kW	7,424 kW	7,332 kW	7,233 kW	6,816 kW
4:00 PM	6,690 kW	6,853 kW	6,782 kW	6,923 kW	6,816 kW	6,872 kW	6,994 kW	7,387 kW	7,386 kW	7,306 kW	7,258 kW	6,854 kW
5:00 PM	6,546 kW	6,689 kW	6,553 kW	6,707 kW	6,609 kW	6,710 kW	6,826 kW	7,154 kW	7,201 kW	7,136 kW	7,121 kW	6,754 kW
6:00 PM	6,428 kW	6,583 kW	6,452 kW	6,605 kW	6,494 kW	6,528 kW	6,707 kW	6,963 kW	7,060 kW	7,080 kW	6,935 kW	6,629 kW
7:00 PM	6,367 kW	6,488 kW	6,435 kW	6,626 kW	6,421 kW	6,433 kW	6,660 kW	6,907 kW	6,977 kW	6,975 kW	6,832 kW	6,530 kW
8:00 PM	6,336 kW	6,474 kW	6,409 kW	6,624 kW	6,369 kW	6,387 kW	6,608 kW	6,883 kW	6,915 kW	6,914 kW	6,749 kW	6,532 kW
9:00 PM	6,142 kW	6,250 kW	6,256 kW	6,450 kW	6,246 kW	6,298 kW	6,482 kW	6,760 kW	6,734 kW	6,684 kW	6,559 kW	6,373 kW
10:00 PM	5,941 kW	5,966 kW	5,953 kW	6,125 kW	5,890 kW	5,926 kW	6,035 kW	6,279 kW	6,362 kW	6,305 kW	6,239 kW	6,066 kW
11:00 PM	5,828 kW	5,847 kW	5,801 kW	5,975 kW	5,739 kW	5,781 kW	5,901 kW	6,114 kW	6,134 kW	6,101 kW	6,131 kW	5,956 kW

Q. Have you developed cost of service information, including incremental cost of service information for customers with unlimited use of backup services and for those customers who only use backup service to replenish energy storage systems during off-peak periods?

A. Yes. Although the Company is not proposing that Schedule SESS-1 be applied to customers with energy storage systems, comparing the cost to serve customers who may utilize standby service at any time to those who limit themselves to off-peak periods highlights the importance of efficient management of on-site generation.

For this analysis I modeled four scenarios. First was a 1,000 kW customer without on-site generation. Next was a customer with a conventional 600 kW generator that is has an outage during an off-peak month (October). Third was also a customer with a 600 kW generator, but the generator was off-line in a peak month (February). Finally, I modeled a 600MW battery storage system that can store 2,400kWh of energy and has an 80 percent round trip efficiency. I modeled this system to be available all year with no outages.

Q. How did you determine the incremental cost of service?

A. First, I separated the incremental cost of service into three different categories: generation, transmission, distribution, and energy. I did not include customer-related costs such as service drops, metering, and customer accounting because those costs would be the same for any customer regardless of whether they used backup service or standard service. I based the incremental cost for production, transmission, and distribution on the plant in-service values and O&M expensess the Company reported in the annual FERC Form 1. To convert the plant in-service values to annual revenue requirements I used a revenue requirements factor of twelve percent. This value approximates the cost of return of, return on, and taxes associated with capital investments. I then divide the estimated total annual cost by 2,646,000 kW which was the 2023 peak demand reported in FERC Form 1. The following table illustrates the incremental cost of service that I developed.

Table 12: Derivation of Incremental Costs

Functional Category	Plant In-Service	Approximate Revenue Requirements	O&M	Total Annual Cost	Average Annual Cost
Production Steam	$414,180,998	$49,701,720	$20,544,677	$70,246,397	$27/kW
Production Hydro	$639,442,491	$76,733,099	$15,348,910	$92,082,009	$35/kW
Production Other	$561,560,413	$67,387,250	$13,451,195	$80,838,445	$31/kW
Total Production	$1,615,183,902	$193,822,068	$49,344,782	$243,166,850	$92/kW
Transmission	$1,415,582,914	$169,869,950	$42,215,219	$212,085,169	$80/kW
Distribution	$1,545,965,284	$185,515,834	$31,874,194	$217,390,028	$82/kW

For incremental energy costs I utilized hourly prices from the Miles City node in the MISO market. The Company does not participate in an organized energy market like MISO or PJM. As such, hourly energy prices for the Company's specific service territory are not publicly available. However, the Miles City node in MISO is on the eastern side of Montana and should be a reasonable estimate of the energy prices in the Company's service territory.

Q. How did you model the dispatch of the conventional generation?

A. First, I developed the appropriate customer load shape that matched the 1,000 kW peak demand and the average capacity factor of 57.3% for the GS-1 Primary Voltage class of customers. Then I specified that the generator dispatched up to its maximum capacity but no more than the customer's hourly demand. This ensured that the generator was not sending excess demand into the grid. Finally, I specified that the generator had a maximum capacity of zero during the simulated outages.

Q. How did you model the dispatch of the energy storage system?

A. The energy storage system was much more complicated. I used the assumption of perfect foresight for the simulation, meaning that the model knew in advance in which hours the customer's load would be lowest and highest. The model then charged the energy storage system during the lowest four hour demand period and then discharged during the highest four hour demand period. The 80 percent round trip efficiency implies that the amount of energy discharged from the system is only 80 percent of the energy injected into the system. The result is that the customer's total annual load is increased.

Q. How did you measure each customer's system peak demand that drives generation and transmission cost of service?

A. In order to capture the range of customer loads during critical system peaks I used the average customer demand during the system's highest 100 load hours. This approach allows the measurement of customer demand and generator performance over a wide range of critical system conditions that can drive the need for generation and transmission resources. However, many planning studies focus on the single annual coincident peak demands, so I also tracked and reported those results as well.

Q. How did on-site generation impact customers' total annual energy and peak demands?

A. The conventional on-site generation systems dramatically reduced the customers' annual energy needs. That type of system also reduced the customer demand during the top 100 hours of system peak demand. However, the generator that was off-line during the peak month of February failed to reduce customer load during the coincident peak. The energy storage system increased the customer's annual energy consumption by about 5 percent. The energy storage system also increased the customer's individual peak demand by a large amount. This situation occurs when the energy storage system is recharging at a time when the customer's load is still relatively high, but the system needs to be refilled to be ready for the next day's peak. The following table summarizes the results of the on-site generation simulations.

Table 13: On-Site Generation Simulation Results

	No On-Site Generation	Conventional On-Site Off-Peak Outage	Conventional On-Site On-Peak Outage	Energy Storage System
Individual Peak Demand	1,000kW	746kW	1,000kW	1,404 kWh
Average Demand During Top 100 System Load Hours	904kW	304kW	520kW	400 kW
Demand During Single System Coincident Peak	1,000kW	400kW	1,000kW	550 kW
Total Annual Energy	4,695,360kWh	574,680kWh	618,930kWh	4,909,605 kWh

Q. **What were the final incremental cost of service results?**

A. The results show that the cost to serve customers with conventional on-site generation is lower than a customer without on-site generation. For on-site generation that is off-line during the system peak the cost of service is 39 percent higher. The cost of service for a customer with an energy storage system is only a 10 percent reduction from the baseline. This is because there are only minor savings associated with total annual energy and the costs for distribution is higher due to the incremental load created when the system is charging.

Table 14: Incremental Cost of Service Results

Net Load Data	**No On-Site Generation**	**Conventional On-Site Storage Off-Peak Outage**	**Conventional On-Site Storage On-Peak Outage**	**Energy Storage System**
Individual Peak Demand	1,000kW	746kW	1,000kW	1,404kW
Average Demand During Top 100 System Load Hours	904kW	304kW	520kW	550kW
Total Annual Energy	4,695,360kWh	574,680kWh	618,930kWh	4,909,605kWh
Incremental Costs				
Distribution	$92/kW	$92/kW	$92/kW	$92/kW
Transmission	$80/kW	$80/kW	$80/kW	$80/kW
Production	$82/kW	$82/kW	$82/kW	$82/kW
Energy	$0.0318/kWh	$0.0377/kWh	$0.0283/kWh	$0.0270/kWh
Total Cost of Service				
Distribution	$91,900	$68,552	$91,900	$128,985
Transmission	$72,428	$24,337	$41,650	$44,047
Production	$74,240	$24,945	$42,691	$45,148
Energy	$149,463	$21,673	$17,537	$132,760
Total Cost of Service	$388,032	$139,506	$193,777	$350,941

Q. What conclusions do you draw from your cost of service analysis?

A. While it is impractical to evaluate every permutation of generation type and performance, the analysis does provide valuable information regarding how on-site generation impacts the cost to serve customers. The analysis show that while reductions in customers bills are justified based on the cost to serve the bill reductions should not be as large as those available under the Company's current rate structure.

Q. Does this conclude your direct testimony?

A. Yes.

<u>Verification</u>

This Direct Testimony of Steven W. Wishart is true and accurate to the best of my knowledge, information, and belief.

/s/ Steven W.Wishart
Steven W.Wishart