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BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

IN THE MATTER OF THE REQUEST OF DOMINION ENERGY UTAH FOR APPROVAL OF A VOLUNTARY RESOURCE DECISION TO CONSTRUCT AN LNG FACILITY	))))))))))	**DOCKET NO. 19-057-13** **Exhibit No. DPU 1.0 DIR** **Direct Testimony** **Douglas D. Wheelwright**

FOR THE DIVISION OF PUBLIC UTILITIES
DEPARTMENT OF COMMERCE
STATE OF UTAH

Direct Testimony of

Douglas D. Wheelwright

August 15, 2019

Docket No. 19-057-13
DPU Exhibit 1.0 DIR
Douglas D. Wheelwright
August 15, 2019

Q: Please state your name, business address and title.

A: My name is Douglas D. Wheelwright; my business address is 160 East 300 South, Salt Lake City, Utah 84114. I am a Technical Consultant with the Division of Public Utilities (Division).

Q: On whose behalf are you testifying?

A: The Division.

Q: Please describe your position and duties with the Division.

A: As a technical consultant, I examine public utility financial data and review filings for compliance with existing programs as well as applications for rate increases. I research, analyze, document, and establish regulatory positions on a variety of regulatory matters. I review operations reports and evaluate the compliance with the laws and regulations. I provide written and sworn testimony in hearings before the Utah Public Service Commission (Commission) and assist in the case preparation and analysis of testimony.

Q: Please identify the Division's witnesses for this docket.

A: Mr. Allen R. Neale from Daymark Energy Advisors (Daymark) and I are the Division's witnesses. Daymark was hired by the Division to provide an independent evaluation of the analysis and conclusions that have been prepared by DEU concerning the construction of a liquefied natural gas (LNG) facility. Mr. Neale has over 25 years of experience in the natural gas distribution business and has a broad range of experience including the design, procurement, operation and review of LNG facilities. Mr. Neale also provided testimony for the Division in the previous LNG filing under Docket No. 18-057-03.

Q. Pursuant to what statute did Dominion Energy Utah (Dominion or DEU) file its application for a voluntary resource decision for its LNG plant?

A. DEU filed its application pursuant to Utah Code § 54-1-401 et seq.

Q: What is your understanding of the requirements for a voluntary resource decision?

A: The request for review of this resource decision is governed by Utah Code §54-17-402. In reviewing the application, the Commission is to determine if the request is in the public interest taking into consideration a number of specific factors identified as follows:

> (i) whether it will most likely result in the acquisition, production, and delivery of utility services at the lowest reasonable cost to the retail customers of an energy utility located in the state;
> (ii) long-term and short-term impacts;
> (iii) risk;
> (iv) reliability;
> (v) financial impacts on the energy utility; and
> (vi) other factors determined by the commission to be relevant.[1]

In addition, Public Service Commission Rule R746-440-1 outlines the filing requirements for approval of a resource decision. The rule requires the utility to provide "sufficient data, information, spreadsheets, and models to permit an analysis and verification of the conclusions reached and the models used by the energy utility."[2]

While DEU has addressed each of these points to some degree in the filing, the Division finds deficiencies in DEU's application.

Q: What is the Division's position and recommendation?

A: The Division is not convinced that approval is warranted as proposed since DEU has failed to show that the cost is appropriate for the level of risk identified and has not supported the position that the entire cost should be allocated only to sales customers. The proposed LNG facility is similar to purchasing a very expensive insurance policy to cover events that may never occur. While this may be appropriate in many circumstances, the Division is not yet convinced that it is appropriate here. This is due, in part, to DEU's use of fear about catastrophes that the proposed LNG facility would be unable to mitigate. DEU should bolster its analysis with a more balanced assessment of risks and a projection of most likely uses of the facility from year-to-year.

[1] Utah Code § 54-17-402(3)(b).
[2] Utah Code § R746-440-1(f).

The proposed LNG facility is very expensive for the amount of risk and uncertainty of a potential cut to the gas supply during an extremely cold weather condition. The proposed LNG facility will not be available for the 2022/2023 heating season and is not required to meet the same in-service requirements as outlined in the RFP for the other bidders. The Division is not convinced the proposed facility will result in the delivery of utility services at the lowest reasonable cost to retail customers, and whether the Company has determined the appropriate level of risk as required for approval under Utah Code § 54-1-401. However, the facility would provide a physical gas supply close to the bulk of DEU's distribution customers, which could be a significant benefit. As will be demonstrated in this testimony and in the testimony of Mr. Neale, several questions remain concerning the cost benefit analysis and the ongoing operational cost given the large increase in the rate base.

Q: Please summarize what Dominion has identified as the primary reason or need for the proposed LNG facility?

A: DEU is seeking approval to construct an LNG facility that would be located on its own distribution system in order to offset possible disruptions in the gas supply. Disruptions in the gas supply to the utility have been identified as cold weather events, earthquakes, landslides, upstream maintenance issues, human error, systemic failure due to age and corrosion, third party damages, and other unanticipated events.[3] Should a supply disruption occur, DEU would be able to withdraw gas from the LNG facility to satisfy the supply shortfall without relying on nominations from third parties or requiring DEU to make nominations under the NAESB cycle limitation.[4]

Q: Do you agree with DEU that the proposed facility would be able to satisfy the risk of supply shortfall that has been identified?

A: While an LNG facility or any other type of storage would be helpful to meet unexpected conditions, the risk of an unforeseen event and the size and impact of the disruption should

[3] DEU witness Tina M. Faust, page 3, line 57.
[4] DEU Exhibit 3.02, page 3.

also be considered. The key to the analysis of this issue is an assessment of the risk to customers and the ability of DEU and the pipeline system to meet the unexpected supply disruption. Hardening a system against all eventualities is very expensive. Even when the costs of an outage might be extremely high, it does not follow that a very expensive solution is warranted. That is especially so when the facility will not be adequate to effectively guard against all of those outages. The key elements of a major resource decision should be to identify the need, the associated risk, and cost of each of the possible solutions to meet the need.

As part of the justification for the proposed LNG facility, DEU has identified a number of natural disaster scenarios that could disrupt service and continues to highlight earthquake risk. A significant earthquake along the Wasatch Front could damage DEU's infrastructure, potentially rupturing high pressure or intermediate high-pressure lines.[5] There are many variables when a natural disaster affects service or disrupts supplies. Depending on the severity of the occurrence, the location and length of the affected line, weather conditions, and the availability of materials, a disruption in the pipeline could take several weeks to several months to repair.[6]

Depending on the location and severity of an earthquake, the time of year and the demand on the system, the proposed LNG facility would most likely not be able to provide enough supply to the distribution system to maintain adequate system pressure. In a similar way, if a landslide were to disrupt or destroy a portion of the Kern River Gas Transmission Company (Kern River) or Dominion Energy Questar Pipeline (DEQP) interstate pipeline systems during high demand periods, DEU would likely experience a supply shortage that could not be completely satisfied from the proposed LNG facility. While these events have been

[5] FEMA and the Utah Office of Emergency Management estimate that there could be 197 pipeline breaks and 310 leaks in natural gas pipelines under a magnitude 7.0 earthquake simulation. Energy Lifeline Components, Hazus Results for Wasatch Fault Planning, FEMA Slide Presentation, August 7, 2019, DPU Exhibit 1.1.
[6] Docket No. 18-057-03, DPU Data Request 4.16.

included to justify the need for an LNG facility, it is unlikely that the proposed facility would be capable of meeting the supply shortfall under these conditions. The Commission should not rely too heavily on DEU's fear-based argument concerning large natural disasters because the proposed LNG facility will not be an effective tool to significantly mitigate disaster-related outages.

A more reasonable and likely reason for using an LNG facility would be in the event of short term supply cuts due to a cold weather event, well freeze off, or short term system maintenance condition. The Division agrees with DEU witnesses, Mr. Platt and Ms. Faust that the most likely reason for a supply disruption event would be weather related due to very cold conditions.[7] Since is it unlikely the proposed LNG facility would have the ability to sustain the system in the event of a major catastrophe, the Division's primary focus has been on supply cuts that are more likely to occur, particularly during cold weather conditions.

Q: The Company has stated that the proposed facility will be used to cover supply cuts that could occur on a peak design day. What is the amount of the peak design day compared to the actual usage amount?

A: The design day demand for firm sales customers for the 2019-2020 heating season is forecast to be 1,220,000 Dth[8] as identified in the current IRP forecast. The highest firm sales demand day occurred on December 30, 2014 at 996,189 Dth[9] or 17% below the peak design day. The mean temperature on that day was 12 degrees.

Q: Do you have any concerns with DEU's assessment of the risk and reliability of the system without the proposed LNG facility?

A: Yes. DEU indicated that system reliability is a critical concern along with system integrity and the possible loss of service. While DEU has identified its concern, there has been no

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[7] DEU witness Michael L. Platt, Page 2, Line 34 and Tina M. Faust, page 1, line 22.
[8] Docket No. 19-057-01, Dominion Energy Utah, Integrated Resource Plan, June 1, 2019 to May 31, 2020, page 1-1.
[9] Email from DEU's William Schwarzenbach, Max Flow Questions, August 7, 2019.

analysis presented or short term solution identified to satisfy a potential supply shortfall prior to the completion of the proposed LNG facility.

DEU provided a Supply Reliability Risk Report as DEU Exhibit 2.04. The report states:

> Based on historical evidence, there is a high probability of a supply shortfall. … In fact, in recent years, such shortfall on cold (but warmer than Design-Peak Day temperatures) have reached shortfall volumes in excess of 100,000 Dth/day. Therefore, the Company believes it is prudent to plan its gas supply and design system function reliability on a Design-Peak Day that coincides with a supply shortfall of at least that magnitude.[10]

If the potential supply shortfall is a priority and is critical to maintain system integrity and pressures, DEU does not appear to be concerned and has not offered any discussion regarding current mitigation efforts for exposure to this risk for the next few years. There has been no indication that DEU proposes to look for short term storage options or other alternatives to satisfy the need in the near future. Its actions, or lack thereof, seem to belie its stated concerns.

Q: Doesn't DEU's Supply Reliability Risk Report provide a fair assessment of the risk to the Dominion Energy Questar Gas distribution system?

A: No. The Supply Reliability Report was prepared by Mike Platt, Will Schwarzenbach, Mike Gill, and Tina Faust in preparation for filing Docket No. 18-057-03 (the previous LNG Docket) and updated for this Docket.[11] The Supply Reliability Report was prepared in February 2018 prior to filling the first LNG Docket but was completed well after the land had been secured and investors had been notified of the intent to build the LNG facility. It appears the Supply Reliability Report may have been prepared as a justification for the LNG facility and not as a candid assessment of risk giving rise to solution-finding efforts.

Q: Has DEU provided an analysis of the size and duration of the supply cuts that have occurred on the distribution system in recent years?

[10] Supply Reliability Risk, DEU Exhibit 2.04, page 3.
[11] DPU Data Request 1.21, DPU Exhibit 1.2 DIR.

A: Yes. Exhibit 2.05 identifies the amount of the supply cuts from 2011 through 2017 at various temperatures. The supply cut data was updated through March 2019 in response to DPU Data Request 1.2 and was included in the June 19, 2019 technical conference. After a review of this information it was determined that the supply cut information used to support the need for the proposed LNG facility included only supply cuts to sales customers that had occurred on Dominion Energy Questar Pipeline (DEQP), an interstate natural gas transmission pipeline that delivers gas to DEU, and was not representative of the entire system.

In response to DPU Data Request 3.04 and 3.06, the Company provided additional information to include supply cut information for Kern River Gas Transmission Company (Kern River), another interstate natural gas transmission pipeline that delivers gas to DEU, and cuts on DEQP for transportation customers. The Company has not been able to provide information on supply cuts that have occurred for transportation customers on the Kern River pipeline. This additional information should have been included in the initial filing and is necessary to review the potential for supply cuts that could occur simultaneously on both pipelines.

Since the greatest concern with cuts to the gas supply would be during the winter heating season, the Division's analysis focused on the supply cuts that have occurred during cold weather conditions and looked only at the cuts greater than 20,000 Dth when the mean temperature was below 30 degrees. In order to put the volume of the recent cuts into perspective, the Division has prepared a summary of the information by year and has focused on the cuts that have occurred in cycle 2 or later since many of the cycle 1 cuts are due to scheduling errors. This same information has been included in graphic form as DPU Exhibit 1.3 DIR (cuts on DEQP) and DPU Exhibit 1.4 DIR (cuts on Kern River) but is sorted by the mean temperature on the date of the cut.

Table 1

Year	Number of Cuts	Max Duration of Cuts (Days)	DEPQ Average Amount Cut (Dth)	Kern River Average Amount Cut (Dth)	Max Amount Cut (Dth)	Mean Temp @ Max Cut
2011	21	1	11,367	8,520	39,403	13°
2012	1	1	13,759	-	13,759	28°
2013	18	1	17,012	34,427	87,974	15°
2014	11	3	24,856	16,669	50,336	29°
2015	11	2	17,000	26,361	137,390	26°
2016	6	1	6,312	26,227	51,001	24°
2017	5	2	112,236	43,368	114,821	6°
2018	6	2	26,548	1,990	42,965	28°
2019	4	2	37,770	9,995	80,847	18°

A review of the number of cuts that have occurred in recent years does not indicate that the frequency or severity of the supply cuts during the heating season has increased. Part of the justification for the proposed LNG facility identifies a single day event that occurred in January 2017 and the last sustained cold weather event that occurred 29 years ago in December 1990.[12] These conditions do not indicate an immediate need for a large capital expenditure.

Q: Has the Company indicated if cuts on the Kern River pipeline are similar in size and timing to the cuts that have been experienced on the Dominion Energy Questar Pipeline?

A: In response to DPU Data Request 3.02, the Company indicated there are fewer cuts on Kern River due to a number of factors "including that DEU transports less gas on Kern River's pipeline, the supply sources are different, and the pipeline is operated differently." From a risk management perspective, obtaining additional supply from Kern River could help to reduce the risk of supply cuts since some of the supply is sourced from different locations and may not be subject to the same weather conditions.

[12] DEU witness Tina M. Faust, Page 4, line 110.

Q: What else have you been able to conclude from the information related to the historical supply cuts during the winter heating seasons?

A: There are several things that stood out to the Division after its review of this information.

1. The greatest number of cuts occurred in 2011 during cold weather conditions. This supports DEU's position that there could be supply cuts during cold weather events. The data does not support the claim that the frequency of supply cuts during cold weather conditions has increased. DPU Exhibit 1.3 DIR and 1.4 DIR does not show an increase in the number or the size of the cuts as the temperature gets colder.
2. The cuts have historically lasted for one day and at the most have extended to two days. The proposed LNG plant is designed to provide 150,000 Dth of natural gas per day for eight days, which is much greater than the historical experience would indicate is needed. The duration of the cuts does not appear to be a primary concern and the facility would be available for multiple cuts of short duration.
3. The average and maximum amount of the cuts in any given year have been much lower than the 150,000 Dth per day volume that could potentially be provided from the proposed LNG facility.
4. The cuts that occurred on January 6, 2017 were due to cold weather conditions or freeze-offs at the well head in addition to problems that occurred at the gas processing facilities.[13] On this particular day, some interruptible transportation customers continued to use gas in excess of their nomination amount and some system gas that was purchased by DEU for firm sales customer's was apparently burned by transportation customers.[14] Transportation customers that burned gas in excess of the volume of gas delivered to DEU for their use on that day were charged penalties in the next billing cycle, however the gas purchased for firm sales customers had already been consumed.

Q: Do you believe it is appropriate to allocate the full cost of the LNG facility to only GS customers as proposed?

[13] DEU witness Tina M. Faust, page 4, line 83.
[14] Docket No. 17-057-04, 17-057-13, 18-057-10.

A: No. As mentioned above and discussed by the Division's witness Mr. Neale, if the facility were to be approved, the cost should be allocated to both GS and transportation customers. The Company does not have the ability to limit the gas usage to only GS customers, despite post hoc mechanisms for charging other customers for using GS customers' gas.

Q: Are there other things the Commission should consider when evaluating the proposed LNG facility and the accompanying proposed large increase in rate base?

A: Yes, there are additional items that should be considered by the Commission.

1. Construction of an LNG facility will significantly add to the Company's rate base and will create a long term asset. The Company has explained the optimal location for an LNG facility is in a relatively small geographic area primarily due to different pressures within the distribution system. There has been no explanation for why the Company operates the system at different pressures for these two regions or what the long-term solution to the current situation might be to equalize the pressures. During the June 19, 2019 Technical Conference the Company indicated that the goal is to have the entire system function at the higher pressure but no information has been provided to explain what would be required, the cost or estimated time period to accomplish the desired goal. An understanding of this issue could help determine if the location of the LNG facility will best meet the long-term needs of the utility and what additional capital expenditures will be needed in the future.

2. The proposed LNG facility has been presented as the solution for possible supply disruptions due to extremely cold weather conditions. While this is a risk, there are other risks that have not been addressed or considered in the analysis. During the coldest and high usage winter months of December, January and February, approximately 36% of the supply is provided by Wexpro as cost-of-service production and 64% is provided from purchased gas.[15] Even though there is diversification in the supply source, approximately

[15] DPU Data Request 3.08, DPU Exhibit 1.5.

80% of the total gas volume is transported on the DEQP system and only 20% on the Kern River system during the high demand winter months.[16] Having 80% of the supply transported through DEQP creates additional risk of loss of service if there is a maintenance issue or pipeline disruption on the DEQP system. Dominion Energy has indicated supplies on the Kern River pipeline have experienced fewer cuts but no analysis has been completed to examine or compare the cost of additional access points on the Kern River system compared to the cost of the LNG facility. Additional access to the Kern River system could help with long-term growth as the population and the customer count continues to grow within the Dominion service area. Additional access points to the Kern River Pipeline could potentially reduce the risk and exposure to cold weather events, earthquakes, landslides, human error, and third party damages to the system more efficiently than the proposed LNG facility.

A review of the FERC Form 2 financial information from DEQP indicates capital expenditures have dropped from $69.4 million in 2013 to $32.5 million in 2018. Reduced capital investment by the entity that provides 80% of the transportation needs during the critical heating season could affect DEQP's ability to meet Dominion Energy's future growth needs. The historical financial information for DEQP is included as DPU Exhibit 1.7 DIR.

3. One item that should be addressed and understood by all parties is how the LNG facility would be used by DEU under normal or warmer than normal operating conditions or when there are no significant supply disruptions. As explained in the technical conference and as outlined in the testimony of DEU witness Michael Gill, no matter what usage the LNG facility experiences during the winter months, the proposed LNG facility will be required to use or cycle through approximately 30% of the storage capacity on an annual basis.[17] The bleed-off or required use of 30% of the gas held in the LNG facility

[16] DPU Data Request 3.09,DPU Exhibit 1.6.
[17] DEU witness Michael L. Gill, page 13, line 357.

would likely occur in the spring after the winter heating season has concluded. The required 30% withdrawal would flow into the distribution system from the LNG facility and would offset or reduce the need for market gas supply purchases.[18] This required gas withdrawal will likely be more expensive than gas purchased on the market and gas produced by Wexpro. Due to the additional cost to liquefy, hold, and vaporize the gas in the LNG facility, natural gas from this supply source would almost certainly be significantly more expensive than purchasing gas at the prevailing market price during the spring and summer months.

4. The need for the proposed LNG facility should be evaluated on the basis the risk and cost of an outage that may affect current customers. The Company has included the delivery of liquefied natural gas to possible satellite locations as an additional benefit and justification for the proposed facility. The cost estimates provided are very preliminary and should not be included in the evaluation. This issue is addressed in more detail by Mr. Neale.

Q: The Company presented an estimate of the cost of the gas coming out of the LNG facility during the technical conference. Does the Company still support the estimated price that was presented?

A: The Company has presented several different ways to look at the estimated cost of gas from the LNG facility. During the June 19, 2019 technical conference, the Company estimated the cost of gas from the LNG facility at [redacted]. This price assumed the facility would be completely filled and then completely emptied during the year. Since these conditions are not likely to occur, DPU Data Request 3.19 asked the Company to revise the calculation assuming the facility is filled to capacity in year 1 and then 30% is withdrawn each year as would be expected under normal operating conditions.

[18] Supply Reliability Technical Conference, June 19, 2018, page 18.

The calculations used in the revised estimate changed the assumptions and included only the variable cost to liquefy, hold and vaporize the gas on a per Dth basis. For this calculation, the majority of the capital costs for this facility are considered distribution non-gas costs and would be included in base rates.[19] The response to DPU Data Request 3.19 estimated the variable cost per Dth as follows:

Liquefaction	$1.42
Carrying Cost @ 9.33%	$0.37
Vaporization	$0.12
Total	$1.92[20]

These costs would most likely be added to the cost of gas and recovered through the 191 pass-through balancing account.[21]

Q: How does the cost per Dth for storage in the proposed LNG facility compare to the cost per Dth for storage in other facilities?

A: While there is not a true apples to apples comparison of the cost for storage, the Division asked the Company to provide an estimate of the per Dth price for storage in the existing storage facilities. The Company calculated the price for storage but included the total Transportation Demand cost for the entire system instead of allocating only a portion of the $62 million demand charge to storage. Excluding the total transportation demand charge results in the following:

Transportation Commodity	$0.00476
Storage Demand	$0.14544
Storage Commodity	$0.00427
Return on Working Gas	$0.02860
Total	$0.18307[22]

Storage cost of $0.18 per Dth for existing storage facilities is significantly lower than the estimated $1.92 per Dth for the LNG facility.

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[19] DPU Data Request 3.11, DPU Exhibit 1.8
[20] DPU Data Request 3.19, DPU Exhibit 1.9
[21] DPU Data Request 3.14, DPU Exhibit 1.10
[22] DPU Data Request 3.13, DPU Exhibit 1.11

Q: Did you find other relevant information in your review of the estimated cost per Dth calculations?

A: Yes. In the response to DPU Data Request 3.14, the Company included an estimate of the annual price impact to typical GS customers over the first five years of operation. The estimate shows that the LNG facility will not be filled and ready for the 2022 heating season. (The heating season begins in November of each year) The actual filling of the facility does not begin until December 2022 and will not be completely filled until approximately July 2023. According to Mr. Gill's testimony the proposed facility will take approximately 100 days to fill.[23] Beginning to fill the facility during the winter months when natural gas prices are historically higher than during the summer months could create additional cost for ratepayers. The Company provided a forecast of the Gas Supply Management Plan which also indicates the in-service date and liquefaction beginning December 2022.[24]

It should be noted that the identified schedule for completion of the LNG facility does not meet the stated in-service requirement as outlined in the RFP. Requirement number 5 of the RFP reads as follows:

> <u>In-Service Date:</u> In addition to the foregoing requirements, the supply reliability resource **must be online and able to provide supply by no later than November of 2022**.[25]

Based on the response to DPU 3.14 and 3.17, it appears the proposed LNG facility will not be available for the 2022/2023 heating season and fails to meet the same RFP guidelines outlined for the other bidders.[26] The proposed LNG facility could not provide supply by November 2022 when liquefaction is not scheduled to begin until December 2022.

Q: Has the Company calculated the impact to a typical customer's bill if the proposed LNG facility is approved?

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[23] DEU witness Michael L. Gill, page 4, line 92.
[24] DPU Data Request 3.17, DPU Exhibit 1.12.
[25] DEU Exhibit 3.02, page 3.
[26] DPU Data Request 3.14, DPU Exhibit 1.10, page 2.

A: Yes. DEU Highly Confidential Exhibit 1.07 calculates the annual dollar impact to the typical GS customer's bill for each of the options discussed in the filing. Line 7 estimates the annual bill impact for the proposed LNG facility at [redacted] increase. While the majority of the increase in cost would be included in base rates, a portion of the increase will be passed on to rate payers through the 191 account. The proposed facility is estimated to add [redacted] in O & M cost each year for the life of the facility.

The Company provided a separate estimate of the variable cost that would be passed on to rate payers in response to DPU Data Request 3.14. This analysis assumes the facility would be completed at the end of year 1 and filled in year 2. The normalized cost of using 30% of the storage capacity and then refilling each year would begin in year 3. The Company has calculated the impact to customer bills for the variable cost to be $0.67 per year for the typical GS customer.[27]

Q: Can you explain why you feel that the cost of the proposed facility does not match the level of risk of a possible supply cut due to a cold weather event?

A: Yes. It is important to have some comparison and perspective as part of the evaluation process. The proposed LNG facility has an estimated capital cost of [redacted][28] for a facility that will likely have limited use for much of the year. For comparison, the total expenditure for all capital projects for calendar year 2018 was $212.2 million[29] and included the cost of the intermediate and high pressure feeder line replacement programs, the transponder replacement program, as well as customer growth and improvements for the entire service area. The capital costs of the proposed LNG facility is [redacted] At the end of 2018, the Company had $2,433.7

[27] DPU Data Request 3.14, DPU Exhibit 1.9, page 2.
[28] DEU witness Kelly B. Mendenhall, page 10, line 244.
[29] Docket No. 19-057-02, Exhibit 1.02, page 68.

million[30] in net plant assets on which it is allowed to earn a rate of return. The proposed LNG facility would increase the net plant assets by approximately [redacted].[31]

The total O & M expense for calendar year 2018 was $146.7 million.[32] An additional [redacted] in annual expense for the proposed LNG facility would increase the total O & M cost by approximately [redacted].[33] The [redacted] in additional O & M cost each year is a very expensive price to pay for the risk of a possible cold weather supply cut of unknown size and short duration.

Q: Can you summarize the Division's position and recommendation?

A: Yes. The Division is not convinced that approval is warranted as proposed. The Division and its consultant have identified several questions that remain.

1. The Company has not demonstrated that the cost of the proposed facility is commensurate with the level of risk identified or that the large increase in the rate base and ultimately customer rates is the best choice alternative. The proposed LNG facility is very expensive relative to the risk of a potential cut to the gas supply during an extremely cold weather condition.

2. The Company stated the facility is being built and will be used for the sole benefit of sales customers.[34] However, because there is no mechanism in place to stop transportation customers from using gas on the system and receiving the benefit of the proposed facility, it is likely they will do so.

3. The proposed LNG facility will not be available for the 2022/2023 heating season and is not required to meet the same in-service requirements as outlined in the RFP.

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[30] Questar Gas Financial Statements, Fiscal Year Ended December 31, 2018, page 6.

[31] [redacted]

[32] Docket No. 19-057-02, Exhibit 3.10, page 1, column A, line 53.

[33] [redacted]

[34] Division witness Kelly B. Mendenhall, page 18, line 449.

4. The Division is not convinced the proposed facility will result in the delivery of utility services at the lowest reasonable cost to retail customers or that the Company has determined the appropriate level of risk as required for approval under Utah Code § 54-1-401.

5. The need for and partial justification for this resource is based on the possible addition of satellite LNG distribution locations sometime in the future. These projections and estimates should not be considered since the forecast is very preliminary and no specific period or actual cost estimate has been provided. The proposed facility should be evaluated on the basis of risk and cost of an outage that would affect current on-system customers, rather than justified with the potential to support satellite locations at some point in the future. While the proposed facility may have significant supply benefits, the Division is not convinced those benefits are worth the high cost. Evaluation is made more difficult by DEU's reliance on purported benefits that are highly unlikely to occur.

Q: Does this conclude your testimony?

A: Yes.