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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. 18-057-03** **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 16, 2018

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 an 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.

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 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 746-440-1 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 does not agree with the Company's conclusion.

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

A: The Division is not convinced that approval is warranted because DEU has failed to show that the proposed LNG facility is in the public interest. The analysis that has been provided does not demonstrate that the proposed facility is the lowest reasonable cost alternative or that construction of this facility is in the public interest. As will be demonstrated in this testimony and in the testimony of Mr. Allen Neale, several questions remain concerning the quality of the analysis, the ongoing operational cost, and the necessity of the large increase in the rate base. The limited set of alternatives selected for comparison by DEU is insufficient to conclude that the LNG facility is the lowest reasonable cost option available to meet the claimed need.

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

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, cyber-attacks, third party damages, and force majeure 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.

Q: The Commission has a specific set of guidelines to follow in order to approve the addition of a significant utility resource. Is the proposed LNG facility the best choice and will it provide customers with the lowest reasonable cost alternative assuming the need for supply resource DEU claims?

A: Not necessarily. The Division is not convinced that the proposed facility is the best alternative. As outlined by the Division consultant, Mr. Neale, DEU's analysis does not provide a thorough evaluation of the alternatives to the proposed LNG facility. The Division agrees with Mr. Neale's assessment. The Commission should require DEU to issue a request for proposals (RFP) seeking resources to satisfy the purported need. Such an RFP should be agnostic about technology assuming capabilities are met. This will allow evaluation of all options, not just a few chosen by DEU in advance of its filing.

Q: Has DEU adequately addressed the long term impacts of the LNG facility on customer rates?

A: No. As will be demonstrated later in my testimony, the DEU analysis does not include gas cost in evaluating the impact on customer rates and has not included some of the initial and

[3] DEU Exhibit 2.12

ongoing cost for this facility. The cost to fill the facility and the working gas charge to customers has not been included in the analysis for comparable alternatives.

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 is always helpful to meet unexpected conditions, the risk of an event and the size and impact of the disruption should 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 restrictions.

As part of the justification for the proposed LNG facility, DEU has identified a number of natural disaster scenarios that could disrupt service. If there is a significant earthquake concentrated along the Wasatch front, there could be damage to DEU's infrastructure, rupturing high pressure or intermediate high pressure lines. There are many variables regarding the severity of a natural disaster and amount of time that pipelines could be out of service or supplies disrupted. Some of the factors include the length of the affected line, the location, weather conditions, and the availability of materials. In response to DPU Data request 4.16, DEU estimated that a disruption in the pipeline could take several weeks to several months to repair.[4]

Depending on the location and severity of an earthquake, the time of year and the demand on the system, the LNG facility may 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 or Dominion Energy Questar Pipeline 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 included to justify the need for an LNG facility, it is unlikely that this facility would be capable of meeting the demand under these conditions. A

[4] DPU Data Request 4.16, Attachment DPU Exhibit 1.1

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. Since is it unlikely that the utility has the ability or resources to sustain the system in the event of a major catastrophe, the Division's primary focus has been on supply cuts that could occur, particularly during cold weather conditions. A focus on possible cuts due to cold weather conditions is also supported in the testimony provided by DEU witness, Mr. Michael Platt.[5]

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

A: Yes. As part of the technical conference held on June 19, 2018, DEU presented information to show the number of supply shortfalls that have occurred from 2011 through 2017. In response to DPU Data request 4.01, DEU provided the source data used to prepare the exhibit and provided additional detail concerning the nature and duration of the supply cuts. The information provided by DEU was limited to cuts in excess of 20,000 Dth.[6]

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 when the mean temperature was below 30 degrees. In order to put the volume of the recent cuts into perspective, I have prepared a summary of the information by year.

[5] Direct Testimony of Michael L. Platt, p. 2, line 30.

[6] DPU Data Request 5.03. 20,000 Dth was used in order to simplify the data and chart. Small reductions occur on a regular basis due to scheduling mismatches, rounding, etc. The goal was to limit the data to significant events.

Year	Number of Cuts	Duration of Cuts (Days)	Average Amount Cut (Dth)	Max Amount Cut (Dth)	Mean Temp @ Max Cut
2011	8	2	24,315	40,112	17°
2012	1	1	33,711	33,711	28°
2013	14	2	34,653	78,623	15°
2014	8	2	54,425	139,793	23°
2015	0	0	0	0	
2016	5	1	101,415	389,435	23°
2017	4	1	88,698	114,821	13°

A review of the number of cuts that have occurred in recent years does not indicate that the frequency or severity[7] of the supply cuts during the heating season has increased, contrary to what DEU has represented in its filing.

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 2013 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 in recent years.
2. The cuts have historically lasted for one day and at the most have extended to two days. The LNG plant has been designed to provide gas for eight consecutive days, which is much greater than the historical experience would indicate. Since the duration of the cuts does not appear to be a primary concern, the priority should be placed on the products or services that can deliver the greatest volume of gas to the system and the duration should be a secondary issue.
3. With the exception of one large event that occurred in 2016, the average and maximum amount of the cuts in any given year have been much lower than the 150,000 Dth per day

[7] Though cuts in 2014, 2016, and 2017 involved higher volumes, there is not a clear trend and no evidence that a trend should be expected. Rather, these supply cuts appear to be unpredictable and variable events. Furthermore, additional context for the large 2016 cut suggests it is an anomaly with minimal relation to the supply issue.

volume that could potentially be provided from the LNG facility. One particularly large supply cut was of particular concern. In response to DPU Data Request 5.02, DEU indicated that the 389,435 Dth cut on Feb 4, 2016 was likely a scheduling error and the issue was resolved prior to the evening cycle, which did not affect the flow of gas on February 4, 2016. If that one event is excluded, the average cut in 2016 is 29,410 Dth and the maximum cut is 46,898 Dth.

4. The cuts that occurred on January 6, 2017 were due to cold weather conditions at the well head as well as problems at the gas processing facilities. 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 customer's use was burned by transportation customers.[8] Transportation customers that burned excess gas on that day were charged penalties. Some of the penalty charges from that event are still under dispute.[9]

Q: Are there other things that the Commission should consider when evaluating the proposed LNG facility?

A: Yes. There are several additional items that should be considered by the Commission and may not have been included in the initial application. The remaining portion of my testimony will discuss other issues and items that have not been included but should be discussed to determine if the proposed LNG facility is reasonable and in the public interest.

Q: What specific issues should be included in the analysis and review process?

A: The support and justification for the proposed facility has been based on the need for additional supply during cold weather conditions. As demonstrated previously, these events are infrequent in nature and historically have been short in duration. Historically these events have been managed without the need of an LNG facility and have been managed by purchasing additional supply or withdrawals from other storage facilities. Since this is a

[8] Docket No. 17-057-04, 17-057-13, 18-057-10
[9] Docket No. 18-057-10

large addition to the rate base and an ongoing cost, one item that has not been discussed is how the facility would be used by the utility under normal or warmer than normal operating conditions. Furthermore, it appears the need has been defined by the capacity of the Company's preferred resource, rather than being independently identified and a facility being sought to meet the need.

DEU explained during the technical conference that the proposed LNG facility will have an operational requirement to use or cycle through approximately 30% of the storage capacity on an annual basis.[10] It is likely that some years will have warmer than the normal weather conditions and that the facility will not be needed to meet winter supply shortage conditions. The bleed off or the required use of 30% of the gas held in the LNG facility 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.[11]

In response to DPU 4.02U, DEU provided a breakdown of the cost per Dth for gas that would be provided from the LNG facility assuming that the tanks were filled with Wexpro gas and held for one year. During the time of year the facility is likely to be filled, a significant portion of system gas is from Wexpro production. The projected O&M expense for the facility is $5.2 million and includes both variable and fixed cost. The carrying cost assumes the 9.33% return on the gas held in storage for one year and the vaporization rate assumes the maximum rate of 150,000 Dth per day. All of the expenses have been calculated on a per Dth basis to estimate the price of gas coming out of the proposed facility.

Wexpro cost-of-service gas used to fill the tank	$4.23
Cost to liquefy and Vaporize natural gas	$4.08
Carrying cost (Working gas cost)	$0.39
Total Cost of LNG Gas per Dth	$8.70[12]

[10] Supply Reliability Technical Conference, June 19, 2018, p. 18.
[11] Supply Reliability Technical Conference, June 19, 2018, p. 18.
[12] DPU Data Request 4.02U, DPU Exhibit 1.2

Due to the additional cost to liquefy, hold, and vaporize the gas at the LNG facility, this resource would almost certainly be significantly more expensive than purchasing gas at the prevailing market price. Because the LNG facility requires the 30% withdrawal each year, DEU would be forced to use more expensive gas than it otherwise could acquire and that more expensive gas cost would then be passed on to customers. The LNG facility would then need to be refilled, likely with cost-of-service Wexpro gas at a time when DEU could purchase gas on the open market at more favorable rates, again to the detriment of customers.

All of these conditions may not be applicable for every Dth that comes out of the LNG facility. However, the cost per Dth is significantly higher than the market price of gas. Whether Utah customers experienced colder than normal or warmer than normal conditions, a portion of the gas supply would be provided from the LNG facility at a price that would be significantly more expensive than market purchases. After a review of the specific cost estimate, it is difficult to say that the LNG facility represents the lowest reasonable cost for Utah customers, especially with such a limited review of alternatives.

Q: DEU stated that the LNG facility would be located on its distribution system and would be under the control of DEU. If the gas control function is operated under the joint operating agreement between DEU and DEQP, would DEQP have access to the LNG facility that would be paid for by DEU customers?

A: That is unknown and the DEU has not addressed how the LNG facility would be isolated from the gas control function. It is the Division's understanding that the joint operating agreement between DEU and DEQP strives to maintain adequate pressures on the distribution system. It is likely that an on system LNG facility would be included in the analysis of system pressures and could be utilized to support shortages in delivery from DEQP, thus, becoming an asset at the disposal of DEQP through the joint operating agreement.

Q: What other issues do you believe are important when evaluating the proposed facility?

A: As part of the evaluation it is important to look at some of the costs that have not been included in the application. DEU stated during the technical conference that if the LNG facility were to be approved and built, the natural gas used to fill the facility would likely come from Wexpro production. In response to DPU Data Request 1.03U, DEU stated that the Send out model would be used to determine if Wexpro or market purchased gas would be used to fill the facility. The Send out model would consider, among other things, the cost of Wexpro gas at the time, the cost of market supplies at the time, the other costs that may be incurred, including the cost of shutting in supplies.[13] Since we do not know the market price or the Wexpro price in the future, the Division has calculated the cost to fill the facility using the current prices that are available.

The proposed facility will hold approximately 1,250,000 Dth in the storage tank. Using the gas prices that were approved in the most recent pass-through (Docket 18-057-04), DEU estimated the cost to fill the tank with Wexpro Gas at $4.23/Dth would be $5,287,500. The cost to fill the tank with market purchased gas at $2.41/Dth (also from the pass-through) would be $3,012,500 or a difference of $2,275,000. This difference in price represents a 75% increase to Utah customers for the commodity. The initial cost to fill the facility with either Wexpro gas or market purchase gas has not been included in the DEU comparative cost analysis since the actual gas cost will flow through the 191 account and would not be charged to customers until the gas is used. The bleed off costs have not been addressed and present similar concerns.

In addition to the cost of gas to fill the new LNG facility, DEU is allowed to earn a rate of return on the working gas that is held in the various storage facilities. If we assume that the tank is full for the entire year, using its current rate of return, DEU would be allowed to earn 9.33% annually on the $5.3 million cost or an estimated $493,323. The working gas charge is an ongoing expense that would be added to the 191 account's pass-through cost and passed on to customers as additional gas cost. The working gas cost and this ongoing expense has

[13] DPU Data Request 1.03U, DPU Exhibit 1.3

not been included in the DEU analysis or cost comparison. Under the current market price conditions, it would be to DEU's advantage to fill the LNG facility and all storage facilities with the more expensive Wexpro gas. If the Commission is inclined to support the LNG facility it may want to require that the natural gas used to fill the facility be priced at the lower of cost or market, regardless of its source. Since natural gas prices are usually lower during the summer months when demand is low, using market purchases to fill all of the storage facilities should be carefully reviewed by DEU. Filling storage facilities with more expensive gas along with additional working gas cost is not in the best interest of Utah customers. The Division has not evaluated this recommendation against the existing Wexpro agreements. However, if the facility is approved with this cost-or-market condition, the Commission will not be compelling action, rather imposing a condition that DEU is free to take or leave.

Q: Do you have any concerns with DEU's projected time line for completion of the proposed facility?

A: Yes. DEU has 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 analysis presented or short term solution identified to satisfy a potential supply short fall prior to the completion of the proposed LNG facility.

DEU provided a Supply Reliability Risk Report as DEU Exhibit 2.12. 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.[14]

If the potential supply shortfall is a priority and is critical to maintain system pressures, DEU does not appear to be concerned with exposure to this risk for the next few years. There has

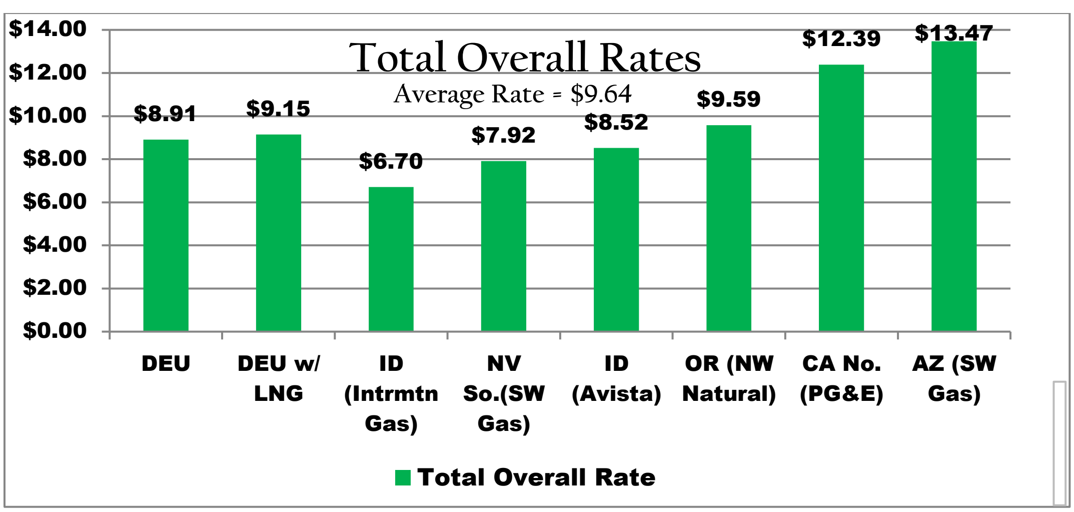
[14] Supply Reliability Risk, DEU Exhibit 2.12, p. 3

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 seem to belie its stated concerns.

Q: Do you agree with the statement that Dominion has some of the lowest gas rates in the nation?

A: No. The testimony and exhibits on this issue has been carefully worded and refers only to the non-gas portion of rates. Any comparison of gas rates with those of other local distribution companies (LDCs) should look at the total overall rate for customers and not just the non-gas cost. DEU Exhibit 1.06 shows only the non-gas portion of rates for DEU compared to some of the other LDCs in the West. DEU's analysis compares DEU's non-gas rate to the non-gas rate for NW Natural (Oregon), PG&E (California), Southwest Gas (Nevada), Avista (Idaho) and Intermountain Gas (Idaho). As will be shown later, Oregon, California, and Arizona have some of the most expensive rates in the country which makes their comparison to DEU look more favorable than a comparison of the surrounding states or a comparison of total gas cost with these same utilities. When the weighted average price of gas is included, DEU has some of the more expensive rates compared to the companies identified. The chart below uses the same companies that were included in DEU 1.06 but includes the gas cost for a total overall rate comparison. This does not include the additional cost that would come from filling the proposed facility.

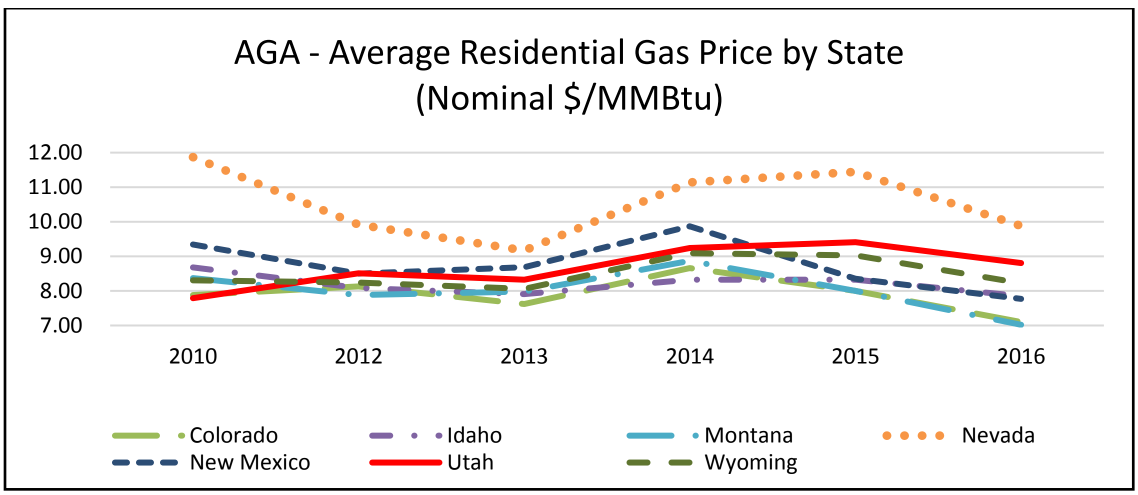
Chart 1



The overall rate comparison shows DEU does not have favorable gas prices as represented in Mr. Mendenhall's testimony.[15] Intermountain Gas, Southwest Gas, and Avista have lower overall gas rates than DEU which is the opposite of what was represented by DEU. Adding additional cost for an LNG facility to the current rate is not in the best interest of the rate payers and does not support future economic development.

Since the DEU analysis looked at only a few companies for comparison, the Division evaluated how the price of gas in Utah compares to the price in the surrounding states. Information was readily available from The American Gas Association (AGA) through 2016 and provides a comparison of the average residential gas price for each state.[16] Chart 2 provides a comparison of the average residential gas price for Utah and the surrounding states.

Chart 2



Since 2012, the average price of gas in Utah has been one of the highest compared to the neighboring states. In 2015 and 2016 the price of gas in Utah is higher than all of the surrounding states except Nevada,

[15] Kelly B. Mendenhall, DEU Exhibit 1.0, p. 6, line 138.
[16] www.AGA.org/research/data/prices, Table 9-4, Average Residential Gas Prices by State.

Q: Do you have an opinion as to why the price for gas in Utah is higher than the surrounding states?

A: Yes. I believe this is directly related to the cost-of-service gas produced by Wexpro. When comparing the average residential rate for each state it is clear to see how the above market price for Wexpro gas has had an adverse impact on Utah customers, contrasting with the benefit it provided in former years.

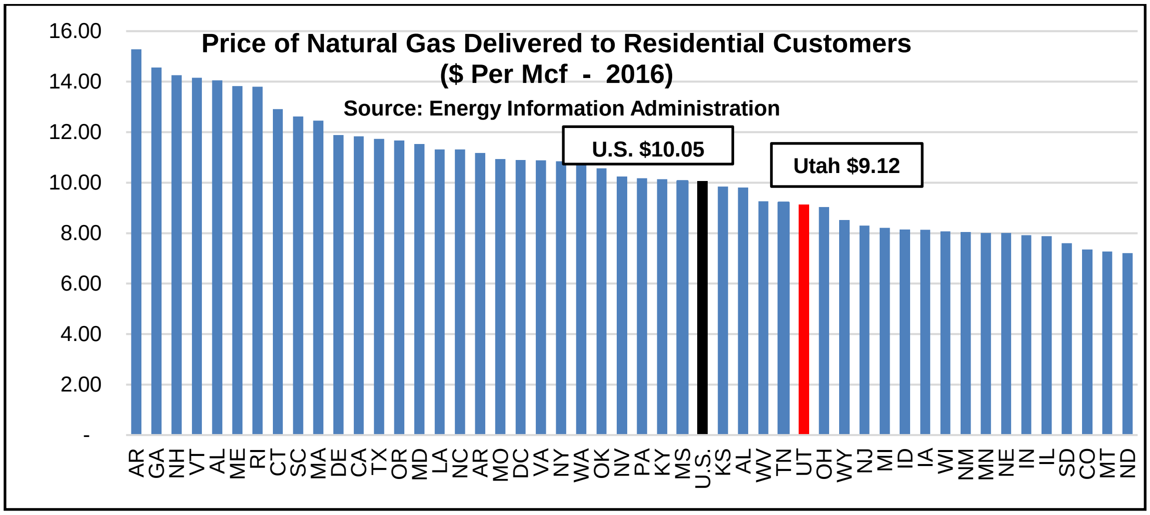
As the market price of gas has moved lower, surrounding states have been able to purchase gas at the lower market price. Since the production from Wexpro represents a large percentage of the total gas supply, DEU is not able to take full advantage of the current low market price. In the last 191 account filing for example, the cost-of-service price was estimated to be $4.23 per Dth compared to market purchases estimated at $2.41. The difference between the market price of natural gas and the cost of service gas from Wexpro continues to have an impact on customers in Utah as more large use customers continue to move to transportation service through third party marketing companies.

The Wexpro agreements have provided large volumes of gas to Utah customers for decades. On balance, they have been in the public interest and continue to be. However, given their relative upward influence on rates in recent years, the Commission should approach increases to those rates with great caution. It is not in the public interest for Utah's natural gas rates to become less competitive with nearby states, if it can be helped.

Q: You have talked about how the price of gas in Utah compares to the surrounding states, but how does the Utah gas price compare to the national average?

A: The U.S. Energy Information Administration (EIA) provides an annual cost comparison of the average price of natural gas delivered to residential customers for each state. The most recent information was published for year end 2016 and shows Utah below the nation average but well above the low ranking in previous years.

Chart 3



DEU can no longer claim to have some of the lowest gas prices in the country and is quickly approaching the national average. The same EIA information was used previously by the Company to support its claim of having some of the lowest priced gas in the country. In a Questar Gas report, this same information ranked Utah with the second lowest gas price in the nation as of 2014.[17] In just two years, the state has moved from the second lowest to the 17th lowest and is approaching the national average.

Q: Why do you believe that it is important to include the gas price comparison in the analysis of the LNG application?

A: Including a comparison of the gas prices in the surrounding states is important in order for the Commission to consider the short-term and the long-term impacts of a major resource decision. The proposed increase is only one portion of customer rates and only one of several proposed increases that will be presented for consideration in the near future.

In the Report and Order in Docket No. 13-057-05, the Commission directed Questar Gas (DEU's predecessor) to file a general rate case no later than July 2016. On July 1, 2016, Questar Gas filed for a 5.84% increase in customer rates citing an increase in its capital

[17] DPU Exhibit 1.4

investment as the primary driver of the requested increase. As part of the stipulation agreement relating to the merger of Dominion Energy with Questar Corporation, Questar Gas agreed to withdraw the 2016 general rate increase and agreed to file a new general rate case in July 2019.[18] The capital expenditures that were the driving force for the 2016 case have not been included in current rates and additional capital spending has occurred since that time. DEU does not have an estimate of the amount of the increase that may be requested in the 2019 case, however, additional capital spending has occurred since the 2016 case and will likely be included in the next general rate case. If the 2016 requested increase was any indication of the future request, the 2019 general rate case could conceivably seek a 10 – 12% increase in customer rates due to capital spending.

Prior to the effective date of the 2019 general rate case, DEU will also be filing for rate increases in its infrastructure tracker due to capital spending that has occurred under that program. All of these potential increases should be considered as part of the short-term and long-term impact to customer rates. With gas prices that are already higher than the surrounding states, it is even more important to select the resource decision that has the lowest reasonable cost impact to customers.

Q: Do you have any reason to believe that the decision to construct the LNG facility was not based on a fair comparison of the choices and alternatives that were available to the utility?

A: Yes. It appears that the decision to construct an on-system LNG facility may have been decided before all of the information had been received from the various parties.

In highly confidential Exhibit 2.11, the narrative identifies the dates that Magnum Energy provided various proposals. Option 3A was proposed in [redacted] and Option 3D was

[18] Docket No. 16-057-01, Settlement Stipulation

proposed in [redacted]. These dates were prior to the filing of this case but were after DEU notified the investment community of its intentions to move forward with an LNG facility.[19]

In its 2017 Integrated Resource Plan (IRP), DEU identified that it had been evaluating the benefits of on-system LNG for a number of years. In 2014, the Company contracted with CH-IV International, to perform a conceptual cost study of an on-system facility and on February 26, 2016, the Company sent out an RFP for on-system storage. DEU selected HDR, Inc. to complete the front end engineering design study and site selection.[20] It appears that the Company had already decided to move forward with the LNG facility before properly evaluating the alternative storage options and may have decided to move forward as early as 2014.

In its September 2017 Investor Presentation, Dominion Energy, DEU's parent, represented that new investments in reliability and capacity had been planned with an on-system LNG facility scheduled to be built in Northern Utah.[21] A copy of the applicable pages have been included as DPU Exhibit 1.5 for reference. The document does include a footnote that the LNG facility is subject to regulatory approval, however, the decision to move forward with the LNG facility had already been determined and has been presented to investors.

From a related but slightly different perspective, in its recent May 2018 Investor Presentation, Dominion Energy identifies the specific items that it expects will be the drivers to increase the earnings per share for 2017 – 2020. The first item listed is projected net plant growth of 6-7% per year.[22] While this growth projection for Dominion Energy is for the entire national asset base including electrical generation and distribution, it is likely that the emphasis to increase the rate base applies to each of the individual operating units. A copy of the applicable pages have been included as DPU Exhibit 1.6 for reference.

[19] DPU Exhibit 1.5
[20] Docket No. 17-057-12, 2017 IRP, Section 8, p. 5.
[21] Dominion Energy Investor Meetings, September 2017, p. 26. DPU Exhibit 1.5
[22] Dominion Energy Investor Meetings, May 2018, p. 33. DPU Exhibit 1.6

The Division has little faith that the self-selected set of alternatives addressed in the DEU application represent a whole-hearted attempt by the Company to seek the lowest reasonable cost manner of meeting the purported need. Rather, it appears that a limited set of selected alternatives were sought after the decision to proceed with the proposed LNG facility was made. The Commission should be skeptical of the validity of any process where a favored outcome that benefits the utility shareholders is compared by the utility against limited alternatives. Clearly identifying the needed capabilities and issuing a broad RFP to meet those demands is the appropriate method to determine the least reasonable cost option. Such an RFP would better inform DEU and the Commission of options and prices. The Commission should order such an undertaking.

Q: Has the reason for pursuing the LNG facility remained consistent during this lengthy process?

A: No. In the 2017 IRP, DEU stated the driving reason for LNG storage was to meet the peak hour needs.

> The Company's engineering analysis concluded that owning and operating an on-system storage facility is a critical component of the long-term solution to the peak-hour demand issue.[23]

The 2018 IRP changed the focus from peak hour to system reliability.

> An on-system LNG facility was originally considered to also be used to meet peak-hour demand requirements. The evaluation of alternatives of this purpose resulted in the conclusion that Firm Peaking Services were the best alternative to meet that need because they could reliably meet peak-hour needs at a considerably lower cost. As a result, the design of the facility was changed to reduce the size including storage, liquefaction, and vaporization. The current design still has the capability to provide some peak-hour system support.
>
> Based on the Company's analysis and evaluations, the construction of a new on-system LNG storage facility is recommended to meet the Company's supply reliability needs.[24]

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

[23] Docket No. 17-057-12, IRP, Section 8, p.5.
[24] Docket No. 18-057-01, IRP, Section 11, p. 5.

A: DEU has not shown its proposed LNG facility to be in the public interest. The analysis does not demonstrate that the proposed facility is the lowest reasonable cost alternative or that construction of this facility is in the public interest. As demonstrated in my testimony and will also be demonstrated in the testimony of Mr. Allen Neale, several questions remain concerning the quality of the analysis, the ongoing operational cost, and the necessity of the large increase in the rate base. The Commission should order DEU to define the needed capabilities and issue an RFP to meet those needs if DEU wishes to proceed.

Q: Does this conclude your testimony?

A: Yes.