Comments

To: Public Service Commission of Utah

From: Utah Division of Public Utilities

Chris Parker, Director
Brenda Salter, Assistant Director
Doug Wheelwright, Utility Technical Consultant Supervisor
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Date: August 22, 2024

Re: **Docket No. 24-057-04, Enbridge Gas** Utah's Integrated Resource Plan (IRP) for Plan Year: June 1, 2024, to May 31, 2025.

Recommendation (Acknowledge)

The Division of Public Utilities (Division) has reviewed Enbridge Gas Utah's (Enbridge or Company) Integrated Resource Plan (IRP) and has determined that it contains the necessary information and complies with the 2009 Standards and Guidelines as ordered. The Division recommends that the Public Service Commission of Utah (Commission) acknowledge this most recent IRP. No further action is required at this time.

Issue

The purpose of the IRP filing is to provide regulators with an update of the "process in which known resources are evaluated on a uniform basis, such that customers are provided quality natural gas services at the lowest cost to QGC and its customers consistent with safe and reliable service."[1]

While the Commission has made it clear that "Acknowledgement of an acceptable [IRP] Plan will not guarantee favorable rate-making treatment of future resource acquisitions" (Docket No. 91-57-09), the Division uses the IRP as one tool among many to help evaluate the reasonableness of the Company's business and regulatory plans for the coming year

[1] Proposed IRP Guidelines for Questar Gas Company, Docket No. 97-057-06, p. 1.

and beyond. Therefore, it is important that the IRP not simply adhere to the Standards and Guidelines set forth by the Commission but also provide regulators some measure of comfort that Enbridge is making reasoned forward-looking choices.

Background

The Company prepares an IRP every year; however, the details and content have evolved over time. The Commission's initial IRP guidance came with the December 14, 2007, Report and Order.[2] Just over a year later, the Commission issued its Standards and Guidelines and on March 31, 2009, ordered future IRPs to be filed in compliance with the new guidelines. On March 22, 2010, the Commission issued a Clarification Order[3] and made several findings to clarify expectations of the 2009 IRP Standards.

Nearly ten years later, on November 19, 2018, the Commission found that future IRPs should provide complete information rather than incorporating information by reference and provided guidance on confidential information. More recently, on January 16, 2020, the Commission adopted the Company's additional commitments and ordered the Company to convene stakeholder meetings to discuss concerns regarding the sufficiency of information. During stakeholder meetings and subsequent discussions, the parties were able to reach a mutual understanding, and the Division's recommendations were generally adopted. The IRP has been a beneficial and productive collaborative process between regulators and the Company for many years.

On February 2, 2024, Enbridge filed its Notice of Intent to File IRP and Request for Scheduling Order and Notice of Technical Conferences. The specified Technical Conferences were held on February 15, 2024, March 19, 2024, April 23, 2024, and May 1, 2024. The Company filed the current IRP on June 14, 2024, and on June 18, 2024, the Commission issued its Notice of Virtual Scheduling Conference. On June 27, 2024, the

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[2] In the Matter of the Revision of Questar Gas Company's Integrated Resource Planning Standards and Guidelines, Report and Order on Standards and Guidelines for Questar Gas Company, Docket No. 08-057-02, March 31, 2009. It is assumed that the order referenced on page 20 as the "December 17, 2007, Report and Order" is in fact the "December 14, 2007, Report and Order."

[3] In the Matter of Questar Gas Company's Integrated Resource Plan for Plan Year: May 1, 2009, to April 30, 2010, Report and Order, Docket No. 09-057-07, Issued: March 22, 2010.

Commission issued its Scheduling Order with comments due by August 22, 2024, and reply comments due September 26, 2024. This memorandum represents the Division's comments.

Discussion

The IRP has been submitted each year since the early 1990s. The IRP is a planning document that is used as a guide to show regulators that the utility is making reasonable plans to meet its customers natural gas requirements for the upcoming year and the foreseeable future. As its customer base continues to grow, Enbridge needs to ensure that its system can continue to meet customer needs. The IRP states that the distribution system will be capable of meeting the demands with adequate supplies and pressures. Gate stations have adequate capacity, supply contracts are adequate, and system pressures are sufficient to meet the needs of its customers.

Current IRP Summary

Among other things, in this IRP (for the 2024-2025 heating season) Enbridge has provided the following conclusions:

1. Natural gas sales are estimated to be 124.6 MMDth, up from 121.2 MMDth in last year's IRP (on a temperature-adjusted basis).

2. Design Day firm sales demand is estimated to be 1.28 MMDth.

3. Wexpro-produced gas is projected to be approximately 58.9 MMDth or 47.3% of the forecasted annual demand assuming the completion of new development drilling projects.

4. Purchased gas is projected to be approximately 66.7 MMDth.

5. The Company "may purchase additional contracts for fixed-price baseload supply for December 2024 through February 2025 to protect against high-pricing events similar to

those that occurred during the past few heating seasons"[4] as it expects price volatility to continue.

6. The Company is projected to add just over 21,000 new customers and expects to end the IRP year with 1.22 million GS customers.

7. Annual GS usage per customer is anticipated to be around 99.6 Dth.

8. An average residential usage per customer of 78 Dth.

9. Total system throughput is projected to be 242 MMDth. Temperature-adjusted system throughput (sales and transportation) is estimated at 225.4 MMDth.

10. The forecasted level of sales demand is 124.6 MMDth, an increase of approximately 0.4%, based mainly on continued growth in the GS customer base in both residential and commercial customers.

Additional Points

On an overall basis, the contents and details that have been requested by regulators over the years are included in the current IRP. In addition, the Division provides some clarifying information in the following five areas obtained in response to data requests.

1. Sections 3.6, 6.2, and 12.1 mention that damage to pipes is caused by "third parties". The Division again intends to clarify that damage to pipes can also be caused by First (Company employees) and Second Parties (Company contractors) as well as Third Parties (All others). The Second Quarter Line Damage Report filed on 07/22/2024 demonstrates that First Party damages do occur, although to a much lesser degree.

2. Table 6.2 showed the Anomalies Repaired in the Company's pipes. The Division asked about the change from four Anomalies Repaired in 2022 compared with 17 in 2023. In response the Company stated that the figures in table 6.2 was inaccurate

[4] Dominion Energy Utah Integrated Resource Plan Docket No. 23-057-02 (Plan Year: June 1, 2023, to May 31, 2024) Page 1-1

stating: “The Company identified four additional anomalies while verifying the anomalies repaired count for this data request. Table 6.2 for 2023 did not include these four anomalies. The correct number of anomalies repaired in 2023 is 21. During Integrity Management direct assessments, the Company records information relating to the pipeline and its environment, including information on anomalies, in a Direct Examination Dig Report. One such report contained information related to the four anomalies in an incorrect section of the report. As a result, the four anomalies found in that dig were erroneously omitted from Table 6.2.” Following this response from the Company an updated response was received, which provided more information, stating that “A second report for a separate dig location having one repaired anomaly was completed prior to the count of the repaired anomalies being completed.” As a result, these five repaired anomalies were erroneously omitted from Table 6.2. It is intriguing that in 2022 there were 4 repairs and 2023 there were 22. The Division has not ascertained whether this represents a new trend or is an outlier. The Division recommends that Enbridge file a corrected Table 6.2 with the Commission so that an accurate document is on file.

3. The Division sought a more definitive definition of “liquid supply locations” mentioned in Section 10-4. MountainWest Overthrust Pipeline. The Company’s reply clarified that: “In this reference, the term “liquidity” is meant to explain the amount of trading availability of natural gas at the location. A more “liquid” location is a location with more trading, and therefore likely has higher availability and lower pricing than locations with less “liquidity.” It is not referring to natural gas liquids.

4. In Section 10-10. Aquifer Storage. The statement is made: “Following the end of the withdrawal season, the inventories in the Leroy and Coalville facilities have maintained a working gas inventory of approximately 30–50% of maximum capacity through the summer months. Previous practice was to completely deplete the facilities each year at the end of the withdrawal season.” The advantages to this new practice are then listed. The Division asked three questions pertaining to this new practice. Namely:

1) Does the Utility earn a return on working gas inventory?

2) Does the pipeline company earn a return on working gas inventory? and

3) Will this new practice increase costs to customers (everything else being equal) and if so, please quantify.

The Company responded stating:

"(1) Yes, the Company earns it's allowed overall return on gas inventory. Currently this return is 8.46%.

(2) The pipeline company would earn a return on cushion gas and any working gas that it owns, but it would not earn a return on gas that the utility holds in its storage facility.

(3) To clarify, the practice to carry an inventory in the aquifers has been in effect for more than ten years, so it is not a new practice. DPU 1.03 attachment 1 provides a comparison of the carrying charge assuming an inventory balance of 45% during summer months, compared with an empty inventory balance. The difference in cost to customers is $67,298."

The Company's referred attachment (except the reference should be to DPU 2.03, not 1.03) is inserted here.

Docket No. 24-057-04
DPU Data Request No. 2.03
Requested by the Division of Public Utilities
Date of EGU Response: August 13, 2024

Month	Storage Inventory Average $/Dth	1/	Aquifer Summer No Balance (Dth)		Aquifer Summer Balance (Dth)		Aquifer Summer No Balance $	Aquifer Summer Balance $	Carrying Charge Difference
Apr-24	$2.31798		1,928,368	2/	1,928,368	2/	$4,469,918.95	$4,469,918.95	
May24	$2.40333		0		867,766	3/	$0.00	$2,085,526.24	
Jun24	$2.68474		-		867,766	3/	$0.00	$2,329,728.54	
Jul24	$2.88570		-		867,766	3/	$0.00	$2,504,110.78	
Aug24	$3.02668		-		867,766	3/	$0.00	$2,626,447.61	
Sep24	$3.12187		1,928,368	2/	1,928,368	2/	$6,020,114.10	$6,020,114.10	
Oct24	$3.12419		1,928,368	2/	1,928,368	2/	$6,024,593.16	$6,024,593.16	
Nov24	$3.14732		1,928,368	2/	1,928,368	2/	$6,069,200.64	$6,069,200.64	
Dec24	$3.16139		1,928,368	2/	1,928,368	2/	$6,096,318.32	$6,096,318.32	
Jan25	$3.16139		1,928,368	2/	1,928,368	2/	$6,096,318.32	$6,096,318.32	
Feb25	$3.24867		1,928,368	2/	1,928,368	2/	$6,264,637.93	$6,264,637.93	
Mar25	$3.40105		1,928,368	2/	1,928,368	2/	$6,558,481.90	$6,558,481.90	
Apr-25	$3.40108		1,928,368	2/	1,928,368	2/	$6,558,542.76	$6,558,542.76	
							$4,053,658	$4,849,142	
Return							8.46%	8.46%	
							$342,939.46	$410,237.44	$67,297.98

1/ Storage monthly Inventory prices based on Pass Through UT Storage tab column G
2/ Balance based on assumption that aquifer is full during this period.
3/ Balance based on assumption that aquifer is 45% full during this period.

5. In Section 10-15. Transportation Planning. The statement is made: "In order to obtain supply in other areas, the Company is exploring the availability of additional transportation capacity options to access other market areas." The Division asked in DPU DR 2.05 how pipeline pancaking rates may affect or may not affect access to other market areas and the Utility's customer's rates.

   The Company responded: "In order to obtain access to supply in other areas, the Company may need to obtain capacity on pipelines that extend outside of the region. Some examples the Company has explored and are currently exploring include Northwest Pipeline (Williams), Ruby Pipeline (Tallgrass) and Rockies Express Pipeline (Tallgrass). Unless these pipelines have a direct connect to the existing distribution system, this will require the use of other existing capacity to transport supply to the EGU city gates. This would result in "stacking" or "pancaking" rates in order to transport the supply to the city gate.

   Unfortunately, supply in the region has not been growing to match demand. As demand continues to grow, the Company will need to source supply from other areas. This will require the use of additional pipeline capacity."

Given the clarifications noted above, the Company has been forthright in its responses and the current IRP appears to be the most complete and beneficial to regulators to-date.

The Division anticipates obtaining additional detailed information on the numerous subjects contained in the IRP, which are to be filed in the IRP Variance Reports. This information will be filed as updates and changes occur.

Conclusion

Following a careful examination of the current IRP, the Division has determined that the Company has included the required information and has filed a complete IRP. The Division has also determined that the assumptions used, and the information presented, represent a reasonable forecast of the conditions that are likely to occur during the IPR forecast period. The Division recommends the current IRP be acknowledged by the Commission as compliant. This filing does not request any change in the Company’s current rates and requires no further action by the Commission.

cc: Kelly B. Mendenhall, Enbridge Gas Utah
Michele Beck, Office of Consumer Services