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State of Utah
DEPARTMENT OF COMMERCE
Office of Consumer Services

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To: The Public Service Commission of Utah

From: The Office of Consumer Services

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Date: August 13, 2014

Subject: Questar Gas Company's 2014 IRP, Docket No. 14-057-15

INTRODUCTION

On June 11, 2014, Questar Gas Company ("QGC" or "Company") filed its 2014 Integrated Resource Plan ("IRP") for the planning period June 1, 2014 to May 31, 2015. On June 25, 2014, the Utah Public Service Commission ("Commission") issued a scheduling order which set a deadline of August 13, 2014 for parties to file initial comments on the IRP in this proceeding.

The Office of Consumer Services ("Office") submits these comments to the Commission regarding the Company's 2014 IRP.

COMMENTS

<u>Demand Side Management (DSM) Impact on Peak Demand and Infrastructure</u>

In its Order on the Company's 2013 IRP, the Commission ordered the following:

> "The Office recommends future IRPs should report on the effect of EE programs on peak demand and the need for new infrastructure and how EE programs could reduce or offset the need for future capital projects such as some of the reinforcement projects described in the DNG action plan. Absent input from other parties on this issue, we find the Office's request should be first addressed by Questar Gas at the next Demand-

> Side Management ("DSM") Advisory Committee meeting and future meetings, if necessary. Following input from the DSM Advisory Committee, we direct the Company to schedule a discussion of this topic at an IRP public input meeting."

The Company states in the IRP that meetings were held with the DSM Advisory Group and during IRP workshops relating to DSM. The Company asserts in the IRP that DSM programs are designed to reduce overall gas usage, not to affect the peak hour during the peak day.[1] However later in the IRP, the Company states, "In both meetings, the attendees discussed the ThermWise® programs, the fact that they are designed to reduce over-all energy consumption, and *they do not, necessarily, impact peak day usage."* (Italics added).[2] The phrase "and they do not, necessarily, impact peak day usage" creates inconsistency between these statements and requires clarification by the Company.

The Office acknowledges that the Company presented scenarios during the ordered DSM Advisory Group meeting and during the IRP workshop showing how DSM programs could affect the peak demand and other scenarios where DSM programs would not affect the peak day. Also, the Company indicated that the system peak day design is not affected by DSM programs and thus would not have an effect on capital expenditure decisions. However, the Office asserts that the Company should state its conclusions from these discussions within in the IRP. Specifically, the phrase "do not, necessarily, impact" is imprecise and inappropriate for inclusion in a planning document.

The Office does not dispute the Company's assertion that its DSM programs are designed for gas usage reduction. However, the Company should articulate specifically how its DSM programs do or do not impact peak day usage and the extent to which DSM programs impact peak day design in the IRP. This information is pertinent to the IRP and should be included and well explained in each IRP.

Office Recommendation

The Office recommends that the Commission require the Company to indicate the impact, if any, of DSM programs on peak day usage in future IRPs. The nature of the DSM programs could change and evolve and should be reported on.

[1] See Questar 2014 IRP, page 2-11
[2] See Questar 2014 IRP, page 8-4

Transmission Integrity Management Plans ("TIMP") & Distribution Integrity Management Plans ("DIMP")

The 2010 IRP showed costs at $3.9 million per year (2011 & 2012) and the 2014 IRP shows costs at $6.3 to $6.8 per year (2014 to 2016). See Table 1 below.

Table 1 – Integrity Management Costs ($ Thousands)

	2010 IRP				2014 IRP		
	2010	2011	2012		2014	2015	2016
Transmission	3,807	3,366	3,344		5,281	5,296	5,002
Distribution	590	565	565		1,462	1,486	1,255
Total	4,397	3,931	3,909		6,743	6,782	6,257

The budget for these costs has increased about 60% since the 2010 IRP. According to the Company, these costs will most likely continue to increase and continue into the future indefinitely due to federal and state pipeline safety regulations.[3] Given these expenditures, the Office has identified two concerns.

First, inspection results are not included in the IRP. The Company files a TIMP activities report with the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration in an annual report titled, "Annual Report for Calendar Year 2011 Natural or other Gas Transmission and Gathering Systems." The DIMP has no such report. Inspection results should be at least summarized in the IRP to justify TIMP and DIMP annual expenditures. The Office recommends that inspection results from TIMP and DIMP activities should be included either as an appendix, or as part of the System Capabilities and Constraints section of the IRP. If these reports reside in other Commission filings, the Company should cite the location where these reports can be found.

Second, actual annual TIMP and DIMP expenditures are not included in the IRP. Since TIMP and DIMP expenditures are forecast for the IRP year, comparing actual expenditures with forecast expenditures from the past IRP year allows parties to evaluate variances. IRP Variance Reports currently do not include TIMP and DIMP forecast or actual expenditures. The Office recommends that the Commission require the Company to provide actual annual expenditures for transmission and distribution

[3] Questar Gas Company response to data request OCS 1.02, July 31, 2014.

integrity management plans in upcoming IRP filings or to be included with IRP Variance Reports.

Office Recommendation

The Office recommends that inspection results from TIMP and DIMP activities should be included either as an appendix, as part of the System Capabilities and Constraints section of the IRP, or cited to where the information can be found. The Office also recommends that the Commission order the Company to provide actual annual expenditures for the Transmission and Distribution Integrity Management Plans from the past year either in the IRP or in the IRP Variance Reports.

Level of Cost of Service (COS) Gas Production under Wexpro II

The Office has two concerns with the IRP as it relates to the level of COS gas production in the 2014 IRP. First, the Company does not expressly calculate the COS gas production within the Cost of Service Gas section of the IRP. According to the Trail Unit Stipulation in Docket No. 13-057-13, the Company will begin managing COS production under Wexpro II up to 65% of the annual forecasted demand from the IRP, beginning with the next IRP in 2015 (plan year June 2015 to May 2016).[4] This information will be essential for determining if the Company is complying with managing its COS gas production to the agreed upon 65% level. The calculation should be explicitly shown in the COS section of the IRP to make clear the Company's compliance with the 13-057-13 Stipulation.

Second, the COS gas production calculation appears to be inconsistent with the 13-057-13 stipulation. On page 10-1 of the IRP, the Company indicates that 72 million Dth of COS gas will be produced with a balance of 43.2 million Dth of purchased gas for a total annual demand of 115.2 million Dth. Dividing 72 million Dth by the total annual demand of 115.2 million Dth produces a COS percent of 62.5%. However, the Company indicates on page 1-1 that COS production of 72 million Dth will be 64% of forecast annual demand. Company representatives indicated to the Office that they computed the annual demand for the IRP year from Exhibit 9.89 and 9.90 by summing total sales of 111.7 million Dth, off system gas of .996 million Dth and LAUF gas of .555 million Dth for a total of 112.7 million Dth. The Office notes that this is (perhaps coincidentally) very similar to the temperature-adjusted sales for 2014 on page 3-1 of 112.2 million Dth and

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[4] See Corrected Settlement Stipulation, Docket 13-057-13, page 4 at paragraph 12.

produces a COS percentage of 64.2%. This potential inconsistency does not pose any problem in the current IRP. However, forecast annual demand becomes extremely important starting with next year's IRP. The Office recommends that the Company, the Office, and the Division (the parties to the Trail Unit stipulation) confer prior to the filing of the next IRP to seek a shared understanding of the calculation of annual demand to avoid unnecessary controversy regarding the gas management agreement that was contained in the Trail Unit stipulation.

Office Recommendation

The Office recommends that in future IRPs the Company explicitly shows the COS gas production percentage calculation in the COS Gas Production section of the IRP and show clearly how the annual forecasted demand is derived to comply with the stipulated 65% level of COS gas from Docket No. 13-057-13.

COS Production Shut-Ins

Page 6-6 of the IRP has a new section discussing the COS production that the IRP model has forecasted to be shut-in during the low demand (summer) period of the IRP plan year. The amount of shut-ins from Table 6.2 of the IRP is reproduced below.

Table 2 – 2014 IRP Forecasted COS Gas Shut-Ins (Dth/day)

	June	July	August	September
Shut-ins	10,263	28,525	31,787	7,001

The Office finds this section very informative and useful in light of the Trail Unit Stipulation in Docket No. 13-057-13. However, in the future, the Office would like to see the Company provide additional information. For example, in a meeting with the Company, we learned that the forecasted shut-ins in Table 6.2 are cumulative which means that approximately an additional 3,200 Dth/day was forecast to be shut in between July and August and that approximately 24,700 Dth/day was to be re-opened to production between August and September. In addition, the Office learned that some wells require two weeks notice to be shut in due to shared interest in the wells. In the future, a more expansive discussion on shut-ins would be helpful in promoting the reader's understanding of this issue.

The Office would also find it informative if future IRPs would include a review of shut-ins from the previous year – actual amount, comparison with previous year's IRP forecast, reasons for deviations, factors for determining which wells were shut in, etc. The review should also discuss the amount of excess production that was sold and a description of the factors (cost, location, etc) explaining why or why not COS gas was sold.

Office Recommendation

The Office recommends that in future IRPs the Company expand upon the section on COS gas shut-ins as described in our comments above.

Office Recommendations

In summary, the Office commends the Company on the information provided in the IRP and recommends the Commission acknowledge the Company's 2014 IRP.

The Office recommends that the following be required for future IRPs:

- The Company should be required to indicate the impact, if any, of DSM programs on peak day usage.

- Inspection results from TIMP and DIMP activities should be included either as an appendix, as part of the System Capabilities and Constraints section of the IRP, or cited to where the information can be found.

- The Company should provide actual annual expenditures for the Transmission and Distribution Integrity Management Plans.

- The Company should explicitly show the COS gas production percentage calculation in the COS Gas Production section of the IRP and show clearly how the annual forecasted demand is derived to comply with the stipulated 65% level of COS gas from Docket No. 13-057-13

- The Company should expand upon the section on COS gas shut-ins as described in our comments above.

In addition, the Office recommends that the Company, the Division, and the Office should confer prior to the filing of the next IRP to seek a shared understanding of the correct calculation to be used in determining the annual demand forecast, which is key to the gas management plan agreed to in the Trail Unit stipulation.