BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

IN THE MATTER OF THE APPLICATION OF QUESTAR GAS COMPANY TO INCREASE DISTRIBUTION NON-GAS RATES AND CHARGES AND MAKE TARIFF MODIFICATIONS	)))))	DOCKET NO. 07-057-13 DPU EXHIBIT 6.0

PRE-FILED DIRECT TESTIMONY

OF

MARLIN BARROW

ON BEHALF OF THE

UTAH DIVISION OF PUBLIC UTILITIES

PHASE 2-COST OF SERVICE

August 18, 2008

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PURPOSE OF TESTIMONY

Q: Please state your name, business address, employer, and current position or title for the record.

A: My name is Marlin Barrow, and my business address is 160 E 300 S, Salt Lake City, 84114. My employer is the Division of Public Utilities in the Utah Department of Commerce. My current position is a Technical Consultant.

Q: Have you testified before in this proceeding?

A: Yes, I testified in the Revenue Requirement phase of this Docket.

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

A: There are seven main points I want to present in my testimony. First, I want to introduce the Division's Witness, Mr. Glen Gregory. Mr. Gregory will present the Division's overall position with respect to the Company's Cost of Service and Rate Design proposals in this second phase of this Docket. Second, I will recommend changing the interest rate used to calculate the Extension Area Charge (EAC) to certain customers on their gas bills.[1] Third, I want to discuss the GSS rate schedule and the communities currently being served under this schedule.[2] Fourth, I want to make a recommendation concerning the current Natural Gas Vehicle (NGV) rates of Questar Gas Company's Tariff found in

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[1] This affects customers living in the communities of Brian Head, Fayette, Joseph & Sevier, New Harmony, Newton & Clarkston, Oak City, Panguitch, Wales.

[2] This includes the communities of Delta, Lynndyl, Leamington, Scipio, Holden, Fillmore, Meadow, Kanosh, Milford, Minersville, Beaver, Newcastle, Enterprise, Central, Veyo, Cleveland and Elmo.

Section 2.07. Fifth, I will recommend a change in Basic Service Fees from those proposed by the Company in this case. That recommended change is incorporated in Mr. Gregory's proposed rate design. Sixth, I will comment on the Tariff changes recommended by Company witness Brent Bakker. The seventh and final purpose is to make some recommended format changes to Questar Gas Company's tariff and how the Company presents information in the tariff filings.

EAC RECOMMENDATON

Q: What is the EAC Recommendation?

A: The Division recommends applying a 6% financing rate to the original schedules used to calculate the expiration dates of the EAC tariffs.

Q: What is the result of following such a recommendation?

A: DPU Exhibit 6.1 presents the results to the estimated expiration dates of using different interest rates. Column K, lines 16 – 24 shows the results for the EAC communities at the current approved rates and column K, lines 28-36 at the recommended rate of 6%.

Q: Why is the Division proposing this recommendation?

A: Without going into the long history on this issue, in the summer of 2007, in preparation for this rate case, the Division requested from Questar Gas a calculation of the EAC charges currently in place using different interest rates. The Division made this request after the Commission issued its April 2007 order in Docket No. 06-057-T04, denying approval of a stipulation that would have rolled the current GSS rates and EAC charges into the GS-1 rate schedule.

In the Order denying the Stipulation, the Commission suggested several alternative solutions, which would

> "neither violate the preferences statute nor offend rate-making principles."[3]

One of those solutions was

> "re-financing the unpaid balances of the estimated extension costs on a community by community basis."[4]

Questar, in responding to the Division request, provided information that showed four different interest rate scenarios. Those interest rate scenarios included 13.86%, the original rate used when the EAC rates were first established, 9.64%, [5] the current rate, 6%, and 0%. This information is presented in DPU Exhibit 6.1. As shown in the exhibit, the estimated expiration date for most communities under the 9.64% interest rate option, (Column K, lines 16-24), goes beyond the original expiration date noting that the community of Brian Head will never pay

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[3] Commission Order on Stipulation, Docket No. 06-057-T04, page 25.

[4] Ibid.

[5] The interest rate was changed from 13.86% to 9.64% in Docket No. 05-057-13.

off. The 6% interest rate option, (Column K, lines 28-36), shows all of the communities, with the exception of Brian Head, with an accelerated payoff date when compared to the current rate. New Harmony would have paid off in January 2008. Brian Head will never payoff unless 0% is the interest rate and then it may take until 2017 to payoff.

Q: Why use 6% as an interest rate?

A: 6% is the rate Questar Gas is authorized to charge as a carrying charge in their Account 191 balance accrual. It also is the interest rate Questar pays to customers if those customers are required to provide a cash deposit in order to receive service. It is a rate readily used by Questar in their daily operations dealing with customers.

Q: If the Commission adopts this recommendation, New Harmony would have paid off in January 2008. Would New Harmony customers be entitled to a refund?

A: No. Assuming the Commission approves this change in interest rates, the Division intends this rate change to be effective on a going-forward basis. New Harmony customers would cease to be billed their monthly EAC charge after the Commission issues its order in this phase of the proceeding.

Q: You mentioned previously that Brian Head will never payoff. What is the Division recommendation concerning this situation?

A: The Division recommends that customers currently paying a monthly EAC charge should not pay any longer than originally estimated, irrespective of whether or not QGC has earned its target ROR. Under the current paradigm, a customer who first signed up for the service as originally agreed is dependent on other customers doing likewise. In the event that other customers do not sign up as originally planned, the entire area falls behind and, as is the case with Brian Head, the payoff date may never be reached. In the Division's opinion, this is unfair and needs to be corrected by setting firm expiration dates for those areas currently paying EAC charges. The Division recommends those firm expiration dates as the original expiration dates indicated Column J in Exhibit 6.1.

Q: What is the revenue impact of doing this now?

A: The only revenue impact of doing this now is the loss of New Harmony's annual EAC revenue of $2, 061.48 which would be absorbed in the rate design of the GSR and GSC rate schedules.

GSS RATE SCHEDULE

Q: What is the Division recommendation regarding the GSS rate schedule?

A: The Division recommends eliminating the GSS rate schedule and putting those customers living in those communities served under the GSS rate schedule into their respective GSR and GSC rate schedules.

Q: Why is the Division making this recommendation at this time?

A: Customers who currently receive natural gas service under this schedule will do so until the years 2012 and 2013.[6] These rates were set to be effective for 20 years. In the original applications (Docket No. 91-057-13 and Docket No. 93-057-03) the actual rates used to determine the 20 year time period were set at double the then current GS-1 rate of $1.70716/Dth and held constant for the twenty-year period. However, in practice, whenever the GS DNG rates have changed, the GSS rates have been percentage increased or decreased by the same percentage as the change in the GS rates. As a result of this, based on the rates approved with an effective date of August 15, 2008, the current GSS summer rate is 3 times the GS summer rate and 2.5 times the winter GS rate. The Division believes this was not the intent of the original rate design. If the intent of using a fixed double margin rate was to recover the cost of the additional rate base required to serve those areas, at best the incremental portion of that rate or $1.70716/Dth should have been held constant while adjusting the base rate by the same percentage amount as the GS rate.

Q: Does that fact alone justify the elimination of the GSS rate?

A: No, I think the Company recognized the flaws in the GSS rate design and hence established the Extension Area Charge (EAC) in 1995 to provide service to

[6] Application to Remove GSS and EAC Rates From Questar Gas Company's Tariff, Docket No. 06-057-T04, page 3.

Ogden Valley and the other communities now paying the EAC monthly charge. Using the same 6% ROR as used in the EAC recommendation produces some interesting results when applied to the original GSS applications.

Q: What is the effect of using a 6% average ROR to those areas currently receiving service under the GSS rate schedule?

A: DPU Exhibits 6.2 and 6.3 are a duplication of the original exhibits filed in Docket No. 91 -057-13, the GSS Southwestern Utah System and Docket No. 93-057-03, the Cleveland Elmo area. By using a target rate of 6% for an average ROR, the GSS Southwestern Utah System would achieve its target average ROR in 10 years or by 2003. Likewise, the Cleveland Elmo area would achieve its target 6% average ROR between 11 and 12 years or sometime in 2005. The original filing required a time-period of twenty years in order to achieve an average ROR of 11%. The Division believes it is appropriate to apply the same 6% rate to the GSS exhibits as recommended for the EAC charges. In doing so, a ten to twelve year payoff would have been required. The counties currently receiving natural gas service under the GSS rate schedule have been doing so for better than fifteen years. Now is the time to eliminate the GSS rate schedule, not only because of the proposed changes by the Company regarding the split of the GS-1 rate schedule into the GSR and GSC rate classes and the consolidation of other rate schedules, but because the current GSS rates do not follow assumptions used to establish a twenty-year time frame. Applying the same refinancing rate suggested for the EAC areas to the same exhibits originally used to establish the twenty-year GSS rate shows a payoff of ten to twelve years. The Division recommends that the Commission approve the elimination of the GSS rate schedule.

Q: If the Commission were to approve this recommendation, what would happen to those customers currently receiving service under the GSS schedule?

A: They would receive service under the proposed new GSR and GSC rate schedules with the elimination of the proposed GSE rate schedule. Also, those customers currently receiving service under the IS-4 and ITS schedules are to move to the proposed ISE and TSE rate schedules. The Division recommends moving those customers to the proposed IS and TS rate schedules and eliminate the newly proposed ISE and TSE rate schedules. There are currently five customers receiving service under the IS-4/ISE schedule and one receiving service under the ITS/TSE schedule.

Q: What would the rate impact be to the GSR and GSC class of customers if the GSS rate schedule were eliminated?

A: The Division estimates, using Mr. Gregory's class cost of service and rate design model, that the rate impact to the GSR rate class would be an increase in cost of service revenue of $1.8 million, a 1.02% increase from the current recommended increase of 4.66%. The GSC rate class would increase by $0.7 million, a 1.76% increase from the current recommended increase of 4.66%.

Q: There are areas in the State that currently do not have natural gas service available to them. What can they expect?

A: Future customers living in areas of the State that currently do not have natural gas service available to them will be offered the opportunity to receive service from QGC using 6% as a target ROR calculated on a NPV basis similar to the current EAC customers. Exactly what that monthly EAC charge will be is dependent on the total cost necessary to provide the infrastructure to serve those customers. In order for those monthly charges to be reasonable, some areas may need to find additional funding sources to reduce the total cost of the project that is financed at a 6% interest rate.

NGV RECOMMENDATON

Q: What is the Division's recommendation regarding the Natural Gas Vehicle (NGV) tariff rate?

A: The Division recommends gradually increasing the NGV rate to a full Cost of Service (COS) rate.

Q: Is the current rate not a full COS rate?

A: The current NGV rate, as found in QGC's Natural Gas Tariff PSCU 400, Section 2.07 is not a full COS rate. The NGV rate was first established in 1990 through Docket No. 89-057-15. At that time, the rate design was based on using a levelized rate to better match NGV pricing with gasoline. A levelized rate is designed to under-collect on a regulatory basis in the early years and over collect in the latter years.[7] However, subsequent to that time, mainly due to very little interest or demand by customers, the rate has only been percentage increased by Commission Order in each subsequent general rate case.[8]

Q: What is the Company's proposal regarding the NGV rate in this docket?

A: The Company is only proposing to eliminate Section 6.01 in their current tariff that deals with the leasing of NGV equipment for the reason stated in Mr. Brent Bakker's testimony.[9] They are not proposing to eliminate the NGV rate used for fueling NGV vehicles. The Division does not dispute the reason given by Mr. Bakker and supports the elimination of the section of the tariff that deals with the leasing of the NGV equipment. In today's environment, it is very difficult to find the required equipment to lease. The Company currently has eight customers that lease NGV equipment. The annual revenue from these leases is about $42,400. The Company will continue to honor the current leases with the elimination of

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[7] Testimony of J.L. Balthaser, Mountain Fuel Supply Co.,Docket No. 89-057-15, Page 14, lines 13-16.

[8] Answer to DPU Data Request 32.02.

[9] QGC Exhibit 9.0, Docket No. 07-057-13, Page 12, lines 294-299.

this section of the tariff.[10] However, in this rate case, the Company does not discuss the NGV rate as found in Section 2.07.

Q: Why did the Company not address the current NGV tariff rate in this rate case filing?

A: Company representatives verbally stated that at the time the rate case was being prepared, the NGV rate was not an issue. It has become more of an issue due to the recent rapid increase in the price of a gallon of gasoline and the resulting increase in demand for natural gas for transportation uses.

Q: What is the current NGV rate?

A: The total current NGV rate is $9.93600/Dth. This compares to a current annualized residential rate of $9.23223/Dth.[11] However, when converted to a gasoline gallon equivalent (GGE) it is approximately $0.87/ gallon for compressed natural gas (CNG)[12] compared to $4.00 plus for regular gasoline. Because of this price differential, the demand for CNG in Utah has doubled

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[10] Response to DUP data request 32.01.

[11] The GS-1 1st block rate, effective 08/15/2008, was adjusted for the summer winter differential. ($9.72866 x 5 /12 + 8.87764 x 7/12)

[12] Assumes a conversion factor of 8.33 gals per Dth. The CNG price includes a Federal tax credit of $0.32 / gallon passed on to consumers at the pump. DPU data request 32.05 & 32.19.

during the first 5 months of 2008 compared to the first 5 months of 2007.[13] As shown in the Company's Tariff, Section 2.07, there are three components that make up this rate, a Distribution Non-Gas Cost (DNG) component, a Supplier Non-Gas Cost (SNG) component and a Commodity Cost component. As previously mentioned the DNG component of this rate has historically been adjusted as a percentage increase or decrease. The SNG and the Commodity Cost rates adjust when the Company files the 191-pass through filings. The Commodity rate is the same rate charged residential customers. Currently, the DNG component is 26% of the total NGV rate.

Q: What would the GGE NGV rate be if this is rate were based on a full COS?

A: The Company has provided information that shows the full cost of service, based on the current book value of existing stations, to be $14.61/Dth. On a GGE basis, the rate is $1.75.[14] This can be broken into $0.88 for the DNG component, $0.08 for SNG and $0.79 for the Commodity component. At current rates, the DNG component of the NGV rate is $0.32. The difference between the current DNG GGE rate and the full cost of service GGE rate is $0.56 which is 275% below the full cost of service rate. The Division recommends increasing the DNG rate to

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[13] DPU data request 32.09.

[14] Response to DPU data request 32.05, Docket No. 07-057-13

50% of the full cost of service or approximately by $0.28. When added to the SNG and Commodity components that equates to $1.47/gallon. After applying the Federal Tax Credit of $.32, the GGE price for NGV should be around $1.15/gallon.[15] Compared to the current price for a gallon of gasoline this is still a great value for those customers who have NGV vehicles. Because of this disparity between the price for a gallon of regular gasoline compared to a gallon of NGV, the demand for NGV vehicles and improvements to the current NGV distribution infrastructure has increased. The Division believes now is the time to begin eliminating any inter-class subsidy that may exist by recommending moving the NGV rate to 50% of the full cost of service with the intention of moving to a full cost of service rate in the next rate case. The Division is aware of the current supply versus demand issues confronting owners of natural gas vehicles. However, the Division feels that discussions regarding what role natural gas will play in the future as a fuel source to vehicles and how best to balance the supply demand paradigm needs to be deferred to a much broader policy discussion held outside the context of this rate case docket. It should be noted that the current $1.75 per GGE cost of service is only for the cost of current stations in existence. Adding additional facilities to help alleviate current

[15] The cent per gallon figure is an approximation. Actual amount will be determined by QGC if the Commission accepts this recommendation.

distribution shortcomings will only increase the cost. How much of an increase is something that needs additional investigation and study.

BSF RECOMMENDATON

Q: What is the Division's recommendation regarding the Basic Service Fees proposed by the Company in this rate case?

A: The Division strongly opposes the Company's proposed Basic Service Fee (BSF) structure and recommends keeping the same monthly charges for BSF for all customers in all the proposed rate classes.

Q: Why is the Division making this recommendation?

A: The newly proposed GSR and GSC rate classes both will be under the CET pilot program. During this CET pilot period, in order to evaluate fully the effect of the CET program at the end of the pilot period, there should be no changes to the BSF from the current rates charged. A more appropriate time to consider changes to the current BSF structure should be in the context of a general rate case when the permanent status of the CET is determined. The pilot period for the CET program ends in October 2009. The Company will need to file a rate case no later than the end of January 2009 if the Company wants the possibility of continuing with a CET type mechanism beyond the pilot period. If a CET type decoupling mechanism, based on customer usage, becomes permanent, one can argue there is no need for any type of fixed fees for rate schedules that have such a decoupling mechanism in place. An alternative to decoupling mechanisms based on customer usage is to increase the monthly BSF. The Company reported to a task force in 2004 that a monthly BSF of $23.45 to all the GS-1 customers would eliminate the need for a DNG rate component based on usage.[16] More importantly, in today's environment where conservation and energy efficiency are major public policy concerns, it may make more sense, given the CET, to put the onus on individual customers to conserve and become more energy efficient by increasing the DNG volumetric rate while reducing or completing eliminating the monthly customer charge. This lends itself to moving to flatter block rates and even inclining block rates rather than declining block rates for those schedules that currently have volumetric usage blocks. For large volume industrial customers, flatter or an inclining block rate design may encourage those customers to pursue DSM projects because of the increased paybacks for the DSM projects.

Q: **Can you please explain what type of costs the BSF covers?**

A: The BSF is intended to recover a portion of the Company's total costs attributed directly to a class of customers that are caused every month.[17] An example of

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[16] Cost of Service/Rate Design Task Force, Minutes of Meeting held on February 11, 2004, page 2.

[17] Commission Order, Docket No. 82-057-15, page 27

these costs would include a customer's service line, meter sets and regulators, which includes a calculation for return and taxes, meter reading and billing costs, customer records and collection expense. The volumetric rate recovers the other costs not attributed directly to customer causation every month.

Q: **How does that differ from what the CET recovers?**

A: The CET is a decoupling mechanism that decouples the collection of revenues from the volumetric sales of natural gas. Under the current Pilot Program for the GS-1 rate class, a fixed annual amount per customer is calculated and spread monthly. This monthly number is multiplied by the number customers to determine an allowed amount of revenue per month. Comparing the allowed monthly amount to the actual revenues collected through the volumetric sales determines the deferral entry into the 191 account. The accumulated balance in the 191 account from these entries is either refunded or collected from customers through a bi-annual amortization rate. The allowed revenue includes revenues collected from the BSF. The allowed revenues collected under the CET not only cover the costs included in the BSF but also the other costs attributed to the GS-1 class that previously were collected strictly through the volumes of gas sold. It's analogous to moving an individual from a commission based compensation system to a salaried based compensation system.

Q: Other proposed rate schedules besides the GSR and GSC also have increased BSF. Is the Division position the same with those proposed rate schedules?

A: Yes, the Company is proposing consolidating some rate schedules, which by its nature will cause some customers to move from one schedule to another. The Division believes is it better policy to keep all BSF status quo in order to better isolate and understand the impact of schedule consolidation on customer classes. If the Commission approves the Company's proposed rate schedule consolidation, it is much easier to understand and evaluate the effect on customers who change schedules by keeping the current BSF structure. For this reason, the Division currently takes no position on the Company's recommendation to revise the BSF cost structure and expansion of the meter classifications. The Division does not necessarily dispute the meter classification or cost analysis presented by the Company, but feels it is better to complete the rate schedule consolidation first, with the current BSF intact, and then in the next rate case address a change in BSF in the context of determining the permanent status of the CET program.

Q: With the Company consolidating some rate schedules, what BSF should the new rate schedules have assigned to them?

A: The Division believes the new rate schedules should retain the BSF structure contained in the primary rate schedule that created the consolidation. For example, the GSR and GSC rate schedules have the same BSF as the current GS-

1 rate schedule. The newly created FS schedule's primary customers come from the current F-1 schedule and therefore should retain the current F-1 schedule's BSF. The FT schedule is the same as the current FT-1 BSF. The new IS schedule is made up from the customers in the current I4 schedule. The new TS schedule is a combination of the current IT and FT2 customers which currently have different BSF rates for categories 2-4 but because 70% of the customers come from the current IT schedule the Division believes the TS schedule should retain the BSF of the current IT schedule. DPU Exhibit 6.4 is a summary table showing the Division's recommended BSF for the new proposed rate schedules.

Q: Has the Division performed any analysis on the potential impact to customer classes if the Commission were to approve the Company's proposed BSF?

A: Yes, DPU Exhibit 6.5 shows an estimate of the potential impact to current customers should the Company's proposed BSF be implemented. The only caveat is to note that the assumptions on the Exhibit, while also realizing this is a calculated approximation. With that caveat in mind, this exhibit shows the disproportional burden placed on those customers who currently have meters rated at 0-700 cu. ft./hr, which is 98% of the total estimated customer count. This most certainly covers the GS class that is currently under the CET pilot program. Increasing the monthly BSF to this class is counter to the purpose of the CET program, which is designed as an incentive for QGC to offer and promote DSM programs to conserve natural gas usage, thereby helping customers directly save on the component that is 70 plus percent of their monthly bill.

TARIFF CHANGES

Q: What are the changes the Company is proposing to their Utah Natural Gas Tariff PSCU 400?

A: In Mr. Brent Bakker's testimony, the Company is proposing changes to the residential security deposits that include reducing the amount that triggers a collection process from $75 to $25 dollars, reducing the days in arrears from 75 to 60 days and requiring a security deposit from customers with no credit history. The Company is also proposing to increase the required security deposit from customers with a poor credit history as well as adding an after-hours reconnection fee of $100. Changes in the required volumes of gas purchases for interruptible transportation customers and changes in the monthly imbalance cash-outs are also proposed. The Company wants to add five additional weather zones to the existing three and proposes to calculate heating degree days specific to each weather zone. The Company also is clarifying the right-of-way and environmental obligations of the Company and customers by adding language to Section 7.04. Lastly, as I mentioned early in my testimony, the Company is proposing to eliminate Section 6.01 that pertains to the leasing of NGV equipment.

Q: What is the Division's recommendations regarding the proposed changes to the Tariff?

A: For the most part, the Division recommends adoption of the changes as discussed by Mr. Bakker. However, there are a couple of changes the Division is recommending to those proposed by Mr. Bakker.

Q: What is the first recommend change?

A: The Division recommends that the amount of security deposit required by customers with a poor credit history stay at the current amount (that is equal to their highest monthly bill). There are a couple of reasons for making this recommendation. The first reason is that the majority of people who find themselves in these circumstances are already struggling with strained financial resources. With the recent increase in gas costs and with the prospect of those costs going even higher during the winter heating season, it seems unreasonable to impose an even greater financial burden on these customers by requiring an increase in security deposit that is greater than currently expected. Secondly, it seems discriminatory to require only a security deposit equal to one times the highest bill for new customers with no credit history versus two times for customers with poor credit history. Some of these new customers may very well be in the same circumstances as customers who may be required to pay a double security deposit.

Q: What is the second recommended change?

A: The second recommended change concerns the after-hours reconnection charge. The Company is proposing to collect an after hours reconnection charge of $100. The Company presents evidence showing that the actual cost to perform such a service is closer to $150.00 (Company's actual figure was $156.93[18]). The Division believes the cost for this service should be closer to the actual cost and therefore recommends a fee of $150.00. The Company expects that there may be only 15 to 20 requests annually for this service. Those customers who desire such emergency service can choose to pay the actual cost for the service or wait until the next regular business day and save the fee.[19] The Division also suggests that additional language needs to be added to the tariff clarifying what hours constitute an after-hours connection. As an example, after hours reconnection will be performed only between the hours of 5:00 PM to 10:00 PM. Also, the Company should explain whether there are any restrictions on how much notice customers need to provide before a request for an after-hours reconnection fee is even considered.

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[18] QGC Exhibit 9.0, Docket No. 07-057-13, Direct Testimony of Brent Bakker, Page 5, Line 124

[19] Ibid, Page 6, line 132.

Q: Are there any other recommendations regarding the proposed tariff changes?

A: No, the Division recommends the Commission accept the other tariff changes as proposed by Mr. Bakker.

TARIFF FILINGS

Q: What is the Division recommending regarding tariff filings?

A: The Division has two recommendations regarding tariff filings that it wishes the Company to adopt. The first recommendation pertains to the presentation of the components of rate information (as shown in the Company's tariff under each rate schedule) for firm sales customers. Currently the Company shows the rate information broken into a Distribution Non-Gas Cost component (DNG), a Supplier Non-Gas Cost component (SNG) and a Commodity Cost component. For example, for the GS class of customers, there are three sub-components of the DNG rate; a base rate sub-component (established in general rate cases), a CET sub-component (established through amortization requests no less frequently than semi-annual), and a DSM sub-component, the sum of which totals the DNG rate shown in the tariff. The Division recommends that each of these sub-components of the DNG are reflected in their respective GS tariff sheets.

Likewise, the SNG rate and the Commodity Cost rate has two sub-components, a base rate component and a 191 balance amortization rate, both of which usually change when the Company files their semi-annual pass-through filings. The Division recommends showing the two respective sub-components of the SNG and Commodity rates in their respective firm sales schedules. DPU Exhibit 6.6 shows an example of this recommended presentation.

The second recommendation's genesis comes from the first recommendation and pertains to how QGC presents information in filings when making requests to adjust rates. As an example, I will use information from the most recent requests to amortize CET and DSM balances filed in Docket No. 07-057-16 and Docket No. 07-057-17. DPU Exhibit 6.7, pages 1-7 shows examples of recommended formats. Pages 1 and 2 show an example from the filing in Docket No. 08-057-16, the most recent request to amortize the amount in the CET balance in the 191.9 account. Pages 3 and 4 show an example from the filing in Docket No. 08-057-17, the request to amortize the balance in the DSM deferred account. Pages 1 and 3 provide the detail behind the calculation of the new CET and DSM amortization rate requests which includes the current rate structure as proposed in DPU Exhibit 6.6 for the proposed current tariff presentation. Page 5 shows the combined effect of pages 2 and 4. Pages 6 and 7 show the effects these filings have on a typical customer using the information from pages 2 and 4.

Q: Why is the Division making this request?

A: The Division is making this request for a couple of reasons. The first reason is to provide summary documentation of the history of rate changes in filings so that parties are better able to track how rates are changing and in which dockets these rate changes are made. The second reason is to provide a complete record in the Company filings of exactly how the new rates are derived and the impact those new rates will have in relation to current rates and on customers. By incorporating these recommended changes into the Company's filings, the application, review, and approval processes will be more straightforward, allowing all parties to analyze the process equally as well as provide an historical tracking record for tariff changes.

SUMMARY

Q: Would you please provide a summary of the main points of you testimony?

A: In summary, the Division recommends the following:

1). Adopt the recommendations made by Division witness Mr. Glen Gregory.

2). Accelerate the payoff of the Extension Area Charges by applying a 6% rate of return to the original financing applications and limiting the maximum payoff date to the original estimated date. Future expansion areas will also use a 6% rate of return in determining the incremental cost to those areas for expansion of natural gas services.

3). Eliminate the GSS, ISE and TSE rate schedules by applying a 6% rate of return to the GSS original financing assumptions. This shows a payoff of between 10 to 12 years. They currently have been paying for 15 years.

4) Gradually move the NGV rate to a full cost of service rate. The Division recommends a 50% to full cost-of-service in this case and moving to a full cost-of service in the next rate case.

5) Keep the Basic Service Fees at current amounts for all rate schedules.

6) Keep security deposits at current levels for customers with a poor credit history and increase the Company recommended after-hours connection fee of $100 to $150.

7) Provide more detail to the current rates in both the Company's filed tariffs by adding the various rate components that make up the current DNG, SNG and Commodity Rates. Provide more detail to future tariff filings in order to better track the historical changes and facilitate a better understanding of the rate changing process.

Q: Does this conclude your prepared testimony?

A: Yes it does.