MEMORANDUM

TO: Missouri Public Service Commission Official Case File
Case No. GR-2008-0368, The Empire District Gas Company

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/s/ David M. Sommerer 12/29/2009	/s/ Bob Berlin 12/29/2009
Project Coordinator, Date	General Counsel's Office, Date

SUBJECT: Staff Recommendation in Empire's 2007/2008 Actual Cost Adjustment Filing.

DATE: December 29, 2009

The Procurement Analysis Department (Staff) has reviewed the 2007/2008 Actual Cost Adjustment (ACA) filing of Empire District Gas Company (EDG). The 2007/2008 ACA filing became effective on November 12, 2008, and was docketed as Case No. GR-2008-0368. Staff's review consisted of an analysis of the billed revenues and actual gas costs for the period of September 2007 to August 2008. Staff performed an examination of the Company's gas purchasing practices to evaluate the prudence of the Company's purchasing decisions. The Company's recovery balances include the PGA, ACA, Take-or-Pay (TOP), Transition Cost (TC), and Refund balances. In the Company's filed rate case, GR-2009-0434, there is a proposal that all TOP and TC language be removed from the Company's tariffs. Staff conducted a reliability analysis to determine if the Company had reasonable plans to meet its customer's needs on the coldest days. Staff's analysis included a review of estimated peak day requirements and the capacity levels needed to meet those requirements. Staff also conducted a review of the Company's hedging policy and implementation for the 2007/2008 ACA.

Empire separates its gas operations into a Southern System, a Northern System, and a Northwest System (formerly L&P). The larger communities served on the Southern System include Sedalia, Marshall, Higginsville, Lexington and Richmond in west-central Missouri and Platte City near Kansas City. On the Northern System, the larger communities include Chillicothe, Marceline and Trenton in north-central Missouri. The Northwest System includes Maryville, which is located in the northwestern part of the state. Southern Star Central Gas Pipeline (SSCGP) serves customers on the Southern System. Panhandle Eastern Pipeline Company (PEPL) serves customers on the Northern System while ANR Pipeline (ANR) serves customers on the Northwest System. For the 2007/2008 ACA review period, there was an average of 29,590 sales customers on the Southern System, 9,550 on the Northern System, and 5,598 on the Northwest (NW) System.

** **Denotes Highly Confidential Information** **

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**** __________________ ** SETTLEMENT AGREEMENT**

Empire District Gas has contracted capacity on the Cheyenne Plains Gas Pipeline, which experienced a large fire at their compression station on September 16, 2007, affecting its operability. As a result, gas flows were under 50% of normal. Cheyenne Plains declared a force majeure (reduction in flow) during this time as full service was not available until November 7, 2007. One of Empire's suppliers, ** ___________ _**, did not acknowledge the force majeure and litigation with **___________ ** ensued. Empire indicated that they were having difficulties obtaining gas deliveries from ** ___________ ** at this time. ** ___________________________ ____ ____________________ **. This settlement agreement ** ________________________ _____ **.

Empire has treated this settlement amount as a purchased gas expense. These costs more closely resemble litigation expenses, not purchased gas expenses, and therefore should be subject to review and potential recovery in the context of a rate case. Staff proposes that the cost of gas on the Southern System be reduced by ** _____ **. The removal of this cost further impacted certain allocation factors that divide the cost of Cheyenne Plains gas between the Company's three systems. This reallocation is discussed in the next section.

CHEYENNE PLAINS ALLOCATION ADJUSTMENT

As was the case in the 2006-2007 ACA, natural gas was purchased for delivery on Cheyenne Plains during the 2007-2008 ACA to benefit all three systems, and thus, all systems should share equally in the cost of gas delivered over Cheyenne Plains. The allocation adjustment was developed by Empire during this ACA to accomplish that. Basically, the Company's accounting process distributed individual Cheyenne Plain's gas supply packages to the specific systems (South, North, Northwest) based upon how the gas was originally nominated on each individual pipeline. Since the Cheyenne Plains supply sometimes contained multiple supply packages, the Company developed a Weighted Average Cost of Gas (WACOG) approach to allocate the Cheyenne Plains gas as a generic pool of supply. Included in the Company's original Cheyenne Plains WACOG allocation adjustment were costs associated with the ** ___________ ** settlement (see settlement agreement above). As a result of Staff's proposed disallowance, the ** ___________ ** settlement costs of **_____ _** should be excluded from the filed allocation adjustment. Under the **___________ ** adjustment proposed by Staff (above), 100% of the adjustment is credited to the Southern System and the Northern and Northwest Systems are not affected. In other words, the Company originally allocated the entire ** _____ ** to the Southern System and therefore (as discussed in the preceding section) the Staff removed those costs from the Southern System. However, an additional recalculation of the Cheyenne Plains supply costs is necessary since the **___________ _** settlement costs impacted the Cheyenne Plains supply allocation process. Under the WACOG allocation method, all three systems are influenced by the ** ___________ _** settlement's impact on the allocation factors. Only **______________________________ ** is credited to the Southern System, thus reducing the credit due to the Southern System customers (from the ** ___________ ** adjustment) by (**______________________ **). This is because a lower WACOG is created by the ** _______ ** disallowance. The difference, (** ____________________ **), is then

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credited to the Northern and Northwest Systems based on their monthly delivery volumes, reducing the cost of gas by ** _______ ** and ** _______ ** respectively, for each system. Staff proposes the following adjustments: Southern System $10,529; Northern System ($7,897); and NW System ($2,632).

PROPERTY TAXES

During March 2008, Empire included property taxes of $8,075 as storage injections in its Southern System storage inventory balance. The property taxes were assessed by Grant County in Oklahoma for gas in storage. The property taxes should not be included in storage inventory as these costs do not qualify as purchased gas expenses. (In Empire's current rate case, GR-2009-0434, Empire sought an Accounting Authority Order to include Kansas property taxes as a deferral in Account 186). Staff recommends that these costs should be removed from the Southern System storage inventory costs.

During January 2008, Empire included property taxes of $6,355 as storage injections in its Northern System storage inventory balance. These property taxes are assessed on gas held in PEPL storage. As indicated on the Southern System, the property taxes should not be included in storage inventory. Staff recommends that these costs should be removed from the Northern System storage inventory costs.

No adjustment is required in the current ACA case as these inventory costs (for both Northern and Southern Systems) were included as storage injections and will not be included as a cost of gas until the gas is withdrawn.

NORTHERN AND SOUTHERN SYSTEM - CASH-OUTS

During the months of December 2007, February 2008 and July 2008 errors were found with Empire's posting of cash-out totals to the Company's ACA filing. The cash-out totals posted to the filing during those months was based on preliminary data that did not include updated pipeline pricing or volume information. Two primary reasons exist for the preliminary posting of the cash-out volumes (and dollars). First, the ANR natural gas price index is not published until the 8th day following the month being reconciled. Second, the SSCGP invoice is the last invoice to be posted to the Company, typically 5 days after the end of the month. As a result, a Southern Star index rate of $6.92 was prematurely included in the July 2008 cash-out total posted to the Company's filing ($11.20 is the proper rate). The Company desires to change its index pricing mechanism for the ANR region, and has requested that change in its current rate case (GR-2009-0434). The Company continues to encourage Southern Star to issue more timely postings.

Regarding the Company's books and records, the Company's cash-out report properly summarizes all of the updated pipeline information that is generated from the customer billings. In summary, Staff proposes a $661 increase to the Northern System, a $35,655 increase to the Southern System and a $3,169 decrease to the NW System to correct the errors from the preliminary postings.

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SOUTHERN SYSTEM – FINANCE CHARGES

During the month of October 2007, Empire was billed a total of $675 ($190+ $485) for finance charges. The charges reflect interest assessed by Southern Star on transportation charges that were not paid by the due date. These charges were not prudently incurred and therefore should not be included in the PGA as a cost of gas. Staff proposes to reduce the cost of gas on the Southern System by $675.

SOUTHERN SYSTEM – PRIOR PERIOD ADJUSTMENT

Empire included a charge allegedly billed by ** ______________ ** for $1,449 to reconcile September and October 2007 activity that was trued up in October 2007. The Company was not able to determine how this charge was determined by ** ______________ ** nor did the charge accompany any invoice or billing statement to support the amount billed. $1,449 should be removed from the cost of gas for customers on the Southern System.

CUSTOMER BILLINGS

Staff discovered that Empire's firm sales customer billings do not include the usage and PGA rate used to develop the PGA charge. This applies to all three districts that Empire serves. All customers should be kept informed of the PGA rate that is applied to their billing so that any disputes or questions on the billing can be addressed on a more timely basis. After discussion with the Company, action is underway to include this information on its customer billings by the summer of 2010.

HEDGING

During the heating season under review, weather was mild overall so actual delivered volumes to customers were less than expected in normal weather. The Company has individual gas supply portfolios for each of its three systems. Staff's comments are provided for each service area.

For the Southern System, EDG hedged about 99% of the normal requirements through a combination of storage, financial instruments, and fixed price contracts. For the Northern and Northwest Systems, EDG depended mostly on storage for its hedging strategies. For the Northern System, EDG hedged about 85% of the normal requirements by using storage and fixed price contracts, while about 76% of the Northwest System's normal requirements came from storage and fixed price hedges.

EDG's overall hedging planned target was at 92% while actual coverage was 93% based on normal volumes for the 2007/2008 ACA heating season. Nevertheless, Staff noted there is a significant difference in the hedging level for the Southern System compared to the Northern and the Northwest Systems. Although it may have been economically efficient for the Company to purchase a relatively large portion of the hedged volumes for the Southern System for the winter months when the market prices were relatively low, Staff is concerned the high level of hedging for the Southern System using storage, financial instruments, and fixed price supply contracts may have negative operational impacts in warm weather. The 2007/2008 winter experienced near normal weather. The Staff recommends the Company consider warmer weather in its determination of volumes to be hedged for the upcoming winters.

The Staff recommends the Company continue to assess and document the effectiveness of its hedges for the 2008-2009 ACA and beyond. The analysis should include, but not be limited to, whether the hedging implementation was consistent with the hedging plan, identifying the benefits/costs based on the outcomes from the hedging strategy, and thus evaluating any potential improvements on the future hedging plan and its implementation. EDG should also consider longer term horizons in its hedging strategy, given the increased impact of natural gas summer market price volatility. Consideration should be given to dollar cost averaging concepts when hedging. In addition, Staff recommends the Company evaluate whether the hedging plan for each of the three systems has operational implications for warm and cold weather conditions.

RELIABILITY ANALYSIS AND GAS SUPPLY PLANNING

As a gas corporation providing natural gas service to Missouri customers, EDG is responsible for conducting reasonable long-range supply planning to meet its customer needs. EDG must make prudent decisions based on that planning. One purpose of the ACA process is to examine the reliability of the Local Distribution Company's (LDC) gas supply, transportation, and storage capabilities. For this analysis, Staff reviews the LDC's plans and decisions regarding estimated peak-day requirements, LDC's pipeline capacity levels to meet those requirements, peak day reserve margin, rationale for this reserve margin, and natural gas supply plans for various weather conditions. Staff proposes no dollar adjustments related to its reliability analysis. Staff has the following comments and concerns regarding the reliability analysis:

Customer growth/decline and projected peak day estimation

Empire continues to see a decline in customer numbers for its Northwest, North, and Southern Systems. This is most evident in its Residential customer class. Because EDG's capacity planning must consider future period estimates, Staff recommends Empire provide an estimate of each system's peak day at least 3 years beyond an ACA period. Thus, for the 2008/2009 ACA, not only would the Company provide a peak day estimate for that ACA period, but also for the winters through 2011/2012. This estimated peak day should include factors such as customer growth and decline.

Peak Day Model Development and Usage

Empire uses regression analysis to estimate peak day. Staff recommends Empire expand its usage of its regression models to estimate monthly, seasonal, and baseload usage for the Company's 3 systems to aid in its gas supply planning.

Southern System Reserve Margin

The following table shows the reserve margins for the Southern System for the 2006/2007 and 2007/2008 ACA periods:

Southern System Reserve Margins			
ACA Period	Contracted Capacity	Peak Day	Reserve Margin
2006/2007	50,109	48,719[1]	2.85%
2007/2008	53,109	45,001[2]	18.02%

The reserve margin increased for this ACA review for two primary reasons. First, the capacity was increased by 3,000 dth/day for the Tracy, Weston, and Platte City area in May 2007. Empire's analysis shows this additional capacity was needed primarily because there was not enough capacity to serve the area for cold days without risk of incurring pipeline penalties. The previous capacity of 2,758dth/day, could serve the area for temperatures down to +8°Farenheit, but the EDG peak day for the Southern System is minus 16°Farenheit. Secondly, the peak day estimate for the Southern System has declined. The combination of the two has caused the reserve margin to increase from 2.9% for the 2006/2007 ACA period to 18% for the 2007/2008 period.

The overall 18% reserve margin is high, considering that this capacity is reserved with Southern Star through November 1, 2018 and the system is experiencing a decline in customer numbers. The Company has provided an analysis that supports that at the time the decision was made the additional capacity was needed to serve this portion of the Southern System. Staff accepts the Company explanation for the additional capacity.

For future ACA periods, Staff recommends the Company re-evaluate it peak day estimations for the Southern System. Since the Southern System is served by four different line segments on Southern Star Central Pipeline, four separate regressions need to be evaluated for the Southern district with reserve margin calculations for each segment; unless EDG can show that the capacity can be moved from one line segment to another, such as done for a central delivery area. The four segments to which these regressions need to be broken out are for: 1) Segment 95, Nevada; 2) Segment 235, consisting of Sedalia, Clinton, and Leeton; 3) Segment 250, consisting of Tracy, Weston, and Platte City and 4) Segment 425, consisting of Marshall, Lexington, Richmond, and Henrietta.

Staff also evaluated the Company's peak day estimation provided in the 2008 and 2009 hedging presentations and on a forward-looking basis, the reserve margins become greater, up to 30% for the winter of 2009/2010. Staff recommends the Company pursue capacity releases, as appropriate, to reduce the cost burden associated with excess capacity on Southern Star Central Pipeline.

1 Peak day estimate considers the Company's Upper 95% C.I.
2 Peak day estimate considers the Company's Upper 95% C.I.

Cheyenne Plains Supply

The Rockies gas, leading up to and including 2007/2008 ACA period, has typically been cheaper than the mid-continent priced natural gas, thus creating a basis differential between the two geographic regions. Empire's estimate of added transportation costs to get gas from the Rockies to the Greensburg hub is $0.38/dth. This is in addition to the commodity price of gas. With the commencement of service for the Rockies Express Pipeline, the basis differential is diminishing. If the basis spread exceeds the $0.38/dth., then the gas delivered into the Empire system will be at a discount. If the basis spread is lower, then the gas delivered into the Empire system will be at a premium.

Transportation capacity was obtained by Empire through a capacity release deal with Encana Marketing-US (EMUS) for 10,000 Dth./day on the Cheyenne Plains Gas Pipeline. ** __________

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_____ **. From a reliability perspective, if EMUS does call on the capacity, there should be no impact because Empire has access to supply through its Mid-Continent transportation agreements. Staff recommends the Company continue to evaluate the reliability and economic decisions surrounding its Cheyenne Plains capacity and pursue capacity releases, as appropriate, in future ACA periods.

Cheyenne Plains Compressor Fire

The Cheyenne Plains Natural Gas Pipeline experienced a large fire at their compression station on September 16, 2007 resulting in gas flows that were under 50% of normally flowed volumes. Cheyenne Plains declared a force majeure during this time as full service was not available until November 7, 2007. Empire's natural gas supply was impacted by this event. Collectively, Empire utilized 80% of its total capacity on Cheyenne Plains from September through November of 2007. If the months of September and October are considered, since these were the primary months to which the Cheyenne Plains compressor was inoperable, 70% of the total capacity was utilized from Cheyenne Plains. Unused capacity was credited back to the Cheyenne Plains invoice per the tariff provisions. In this event, Empire simply reverted back to using its supplier agreements in the Mid-continent region. From a reliability perspective, there was no impact for this ACA period because the Mid-continent transportation and supply contracts have been and will be in place to accommodate this additional supply basin.

SUMMARY

The Staff has addressed the following concerns regarding Case No. GR-2008-0368 for Empire:

1. Details of EDG's hedging activity are described in the "Hedging" section of this recommendation. Staff recommends that EDG should continue to pursue longer term horizons given the impact of summer market price volatility. Consideration should be given to dollar cost averaging concepts. In addition, Staff recommends the Company evaluate

whether the hedging plan for each of the three systems has operational implications for warm and cold weather conditions.

2. There is no financial adjustment related to the section, Reliability Analysis and Gas Supply Planning, but Staff has provided comments and concerns.

3. ** ______________________________ ** as part of a settlement agreement. This fee should not be included as a purchased gas expense, but rather should be considered for potential recovery in the context of a rate case.

4. Staff recalculated the Cheyenne Plains allocation adjustment without the ** __________________________ **. Staff proposes adjustments as follows: Southern System $10,529; Northern System ($7,897); and Northwest System ($2,632). The combined cost of gas for all three systems remains the same under these adjustments.

5. Property taxes were assessed on Empire's Northern and Southern System storage inventory, ($6,355) and ($8,075) respectively, and included as storage injection costs in Empire's storage inventory balances. These costs should be excluded from storage inventory as they do not qualify as purchased gas expenses.

6. Cash-out amounts posted to the Company's filing (North, South and NW) during the months of December 2007, February 2008 and July 2008 were found to be in error. Staff proposes a $661 increase to the Northern System, a $35,655 increase to the Southern System and a $3,169 decrease to the NW System.

7. Finance charges of $675 were billed to Empire during October 2007. These charges were imprudently incurred and therefore should not be included in the PGA as a cost of gas.

8. A charge of $1,449 was allegedly billed by ** ____________ ** for September and October 2007 activity that was trued up in October 2007. These charges were not substantiated and therefore should not be included in the Company's filing.

9. Firm sales customer billings do not include the usage and PGA rate used to develop the PGA charge. All customers should be kept informed of the PGA rate that is applied to their billing so that any disputes or questions on their billing can be addressed on a timelier basis.

RECOMMENDATIONS

The Staff recommends that the Commission issue an order requiring EDG to:

1. Adjust the balances in its 2007/2008 ACA filing to reflect the ending (over)/under recovery balances for the ACA, TOP, TC, and Refund accounts per the following table:

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TABLE 1

Description (+) Under-recovery (-) Over-recovery	**8-31-08 Ending Balances Per Filing**	**Commission Approved Adjustments Prior to 2007-2008 ACA**	**Staff Adjustments For 2007-2008 ACA**	**Staff Recommended 8-31-08 Ending Balances**
Southern System: Firm ACA	$1,286,283	$38,936 (1A)	($4,440) (B)	$1,320,779
Interruptible ACA	$47,099	$0	$0	$47,099
Take-or-Pay	$0	$0	$0	$0
Transition Cost	$0	$0	$0	$0
Refund	$0	$0	$0	$0
Northern System: Firm ACA	$293,668	($46,172) (2A)	($7,236) (C)	$240,260
Interruptible ACA	$56,098	$0	$0	$56,098
Take-or-Pay	$0	$0	$0	$0
Transition Cost	$0	$0	$0	$0
Refund	$0	$0	$0	$0
Northwest System: Firm ACA	$395,903	($11,231) (3A)	($5,801) (D)	$378,871
Interruptible ACA	$0	$0	$0	$0
Take-or-Pay	$0	$0	$0	$0
Transition Cost	($2,586)	$0	$0	($2,586)
Refund	$0	$0	$0	$0

1A-3A) - Prior period adjustments (all adjustments in GR-2008-0123)
1A) $55,853 + ($11,039) + ($5,878)
2A) ($43,226) + ($2,946)
3A) ($12,627) + $1,396.
B) **____________________ ** + Cheyenne Plains allocation $10,529 + cash-out $35,655 + finance charge ($675) + prior period adj. ($1,449)
C) Cheyenne Plains allocation ($7,897) + cash-out $661
D) Cheyenne Plains allocation ($2,632) + cash-out ($3,169)

2. Address the Staff recommendations in the summary section related to hedging.

3. Respond to the Staff recommendations in the section, Reliability Analysis and Gas Supply Planning.

4. Respond to recommendations included herein within 30 days.

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