RAILROAD COMMISSION OF TEXAS

HEARINGS DIVISION

GUD No. 10190

STATEMENT OF INTENT OF HUGHES NATURAL GAS, INC.

APPEARANCES:

APPLICANT:

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PROCEDURAL HISTORY:

Docket Established:	July 6, 2012
Suspension Order Issued:	July 17, 2012
Hearing:	February 6 – 8, 2013
Heard By:	Gene Montes, Hearings Examiner Rose Ruiz, Technical Examiner
Unanimous Settlement Agreement:	February 19, 2013
Record Closed:	March 12, 2013
PFD Circulation:	March 12, 2013
Statutory Deadline:	April 23, 2013

STATEMENT OF THE CASE

HNG filed this proceeding to increase rates in the unincorporated areas served by HNG. HNG initially filed a *Statement of Intent* that sought an increase in revenues totaling $902,974. The *Settlement Agreement* contemplates an increase of $436,076. This represented a decrease from the initial request of $466,898. The Settlement Agreement also contemplates recovery of rate case expenses for HNG totaling $650,000. This is less than the total actual and estimated rate cases expenses incurred by HNG of $1,156,819. The Examiners recommend approval of a Final Order consistent with the terms of the *Settlement Agreement*.

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PROPOSAL FOR DECISION

1. Procedural History

On June 2, 2011, Hughes Natural Gas, Inc. ("HNG") filed a *Statement of Intent* to increase rates with the City of Magnolia and the Railroad Commission of Texas ("Commission"). The City of Magnolia denied the proposed rate increase and HNG appealed. That case was docketed as GUD No. 10093. The case filed at the Commission was docketed as GUD No. 10083. The cases were consolidated. A hearing was conducted in that case, the Examiners issued a *Proposal for Decision* and the Commission ultimately issued a *Final Order* rejecting the proposed increase on January 10, 2012.

Six months later, on July 6, 2012, HNG filed the current proceeding. This case was docketed as GUD No. 10190. The company is not requesting a change in its rates within the City of Magnolia.[1] In this proceeding, HNG seeks to implement rates within the environs. As initially filed, the Statement of Intent in this docket was based upon a test year for the twelve-month period ending December 31, 2011. HNG agreed to amend the proposed effective date and provided data for a test year that included the twelve-month period ending September 30, 2012.

Staff of the Railroad Commission and the City of Magnolia intervened in this proceeding. Additionally, Michael Kelley and Henry Oncken also intervened. Mr. Kelley and Mr. Oncken are customers of HNG. Additionally, Mr. Oncken is President of the Powder Milles Estates Owners Associations. Members of the Powder Mills Estates Owners Association are served by HNG.

A hearing was held from February 6, 2013 through February 8, 2013. HNG provided testimony and evidence through the following witnesses: Real Provencher, President of HNG; Charles E. Loy, Principal with GDS Associates, Inc.; Ellen Blumenthal, Principal with GDS Associates, Inc.; Joe K. Wells, Jr., engineer for WWD Engineering; Alan R. Lovinger, Joe Wells; Gregory Sheig, ValueScope, Inc.; Morey Villareal, consultant with Villareal & Associates; and, Amelija J. Hodgins, attorney. Staff of the Railroad Commission presented testimony through, Mark Brock, Brock Utility Consultants, LLC and Frank M. Tomicek, Utility Specialist, Market Oversight Section of the Gas Services Division. The City of Magnolia also offered testimony through Karl J. Nalepa. The proffered testimony, however, was not admitted as it was found to be in violation of the Commission's determination regarding the scope of the standing of the City of Magnolia. HNG provided testimony from the following witnesses on rebuttal. Mr. Provencher, Mr. Loy, Ms. Blumenthal, Mr. Schieg, Mr. Lovinger, Mr. Villareal, and Donald Clayton, a consultant with Tangibl, LLC

At the conclusion of the hearing, the parties announced that a settlement was reached and a Settlement Agreement was filed on February 19, 2013 that resolved all issues related to this proceeding. HNG, Staff, and the City of Magnolia are signatories to the Settlement Agreement. Although the intervenors Michael Kelley and Henry Oncken are not signatories, neither has objected to the Settlement Agreement.

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[1] HNG Ex. 8, Provencher Direct, p. 7, lns. 13 – 14.

2. Jurisdiction

The Commission has jurisdiction over the applicant, associated affiliates and over the matters at issue in this proceeding pursuant to Tex. Util. Code Ann. §§ 102.001, 103.003, 103.051, 104.001, 121.051, 121.052, and 121.151 (Vernon 2007 and Supp. 2012). The statutes and rules involved in this proceeding include, but are not limited to Tex. Util. Code Ann. §§104.101, 104.102, 104.103, 104.105, 104.106, 104.107, 104.110, 104.301, and 16 Tex. Admin. Code Chapter 7.

3. Overview of the Company

HNG provides natural gas service to customers within the City of Magnolia and in the unincorporated and rural areas of Austin, Colorado, Grimes, Harris, Montgomery and Waller Counties. HNG provides service to approximately 3,336 customers in the unincorporated and rural areas and HNG serves approximately 210 customers in the incorporated City of Magnolia in Montgomery County. HNG was formed in 1996 and began serving its first development in 1997. At that time HNG filed initial rates with the Commission.[2] The company has since added many new developments to its natural gas distribution system.

4. Books and Records

Real Provencher and Alan Lovenger testified that HNG maintains its books and records in accordance with the Commission's regulations.[3] Namely, Rule 7.310 requires that each gas utility utilize the Federal Energy Regulatory Commission's (FERC) Uniform System of Accounts prescribed for Natural Gas Companies subject to the provision of the Natural Gas Act for all operating and reporting purposes. The FERC Uniform System of Accounts is applicable to all gas utility and gas utility related operations. Mr. Provencher asserted that the company maintains its books and records in accordance with Commission Rule 7.310 and the amounts included therein are therefore subject to the presumption that they are reasonable and necessary. HNG has established that it has fully complied with the requirements of Rule 7.310 and the Examiners find that the amounts noted therein are subject to the presumption encapsulated in Rule 7.503.

5. Settlement Agreement

a. Overall Revenue Requirement and Rates

The company initially requested a system-wide revenue requirement increase of $902,974.[4] The *Settlement Agreement* contemplates an increase of $436,076. This represented a decrease from the initial request of $466,898. Thus, the Settlement Agreement represents a decrease of nearly 52% compared to the original amount requested. The company provided a full cost of service analysis, testimony and workpapers in support of its initial request.

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[2] GUD No. 9731, FOF No. 6

[3] HNG Ex. 8 Provencher Direct, p. 10 & HNG Ex. 20, Lovinger Direct.

[4] HNG Ex. 10 Loy Direct, Schedule F.

The *Settlement Agreement* contemplates that the rate increase be implemented in two stages. The first stage occurs during the first year after the Final Order is issued in this case. The initial changes in rates would increase revenues by $385,466. The second stage occurs one year from the date of the final order in this docket. At that juncture, rates would increase and produce additional revenues totaling $50,610.

The initially proposed rates were composed as follows: A customer charge of $23.61and a volumetric charge of $8.3858. The *Settlement Agreement* contemplates the following initial rate: A customer charge of $17.10 and a volumetric rate of $7.0500. The rates would increase to a customer charge of $18.35 and a volumetric rate of $7.050 one year from the date of the Final Order is issued in this proceeding. Table 1 below provides an analysis of the change in rates for residential customers as a result of the proposed Settlement Agreement. The average residential customer, who consumes 6 Mcf, will experience a 27% increase in rates, without gas costs.

Table 1
Final Impact for Residential Customers in Year 2

	Current Rates	Settled Rates	% Increase
1	20.87	25.40	22%
2	26.23	32.45	24%
3	31.60	39.50	25%
4	36.96	46.55	26%
5	42.33	53.60	27%
6	47.69	60.65	27%
7	53.06	67.70	28%
8	58.42	74.75	28%
9	63.79	81.80	28%
10	69.15	88.85	28%

b. **Cost of Capital**

The *Settlement Agreement* includes specific components related to the cost of capital to be applied in future interim rate adjustment (IRA) proceedings. Table 2 below sets out the components of the agreed capital structure.

Table 2

	Capital Structure	Debt/Equity Cost	Weighted Cost of Capital
Long-Term Debt	44.5%	7.0%	3.115%
Common Equity	55.5%	10.6%	5.883%
Rate of Return	100%		~ **9%**

The overall rate of return and the individual components are consistent with recent Commission precedent and the Examiners find that they are just and reasonable.

c. **CapGas Acquisition**

(1) Introduction

In 2008, HNG purchased the stock of CapGas, a local natural gas distribution company. Section 102.051 of GURA requires that the Commission investigate the transaction to determine whether that the acquisition is consistent with the public interest. In reaching its determination, the Commission shall consider the reasonable value of the property, facilities, or securities to be acquired, disposed of, merged, or consolidated.

The signatories to the *Settlement Agreement* stipulated that the original cost associated with the assets acquired from CapGas shall be the amounts posted on the books and records of HNG based on the trending study performed by GDS, as reflected on Exhibit C to the Settlement Agreement. The signatories further stipulated that a negative acquisition amount of ($536,148) associated with the CapGas acquisition may be included in rate base for purposes of setting rates in this proceeding. Finally, the signatories agreed that the total negative acquisition amount on HNG's books and records shall be amortized over twelve years below the line. The Examiners find that Section 102.051 requires that the Commission evaluate the terms of the Settlement Agreement to determine whether the merger of CapGas and HNG is in the public interest.

(2) Valuation

(a) Background

The *Settlement Agreement* requires consideration of the valuation of the transaction for purposes of the books and records and for ratemaking purposes. Accordingly, the Commission must determine the value of the CapGas assets for Hughes' *books and records* at the time of acquisition for accounting purposes under the Federal Energy Regulatory Commission's (FERC) Uniform System of Accounts (USOA). Additionally, the Commission must also evaluate any adjustments, including any acquisition adjustments for rate making purposes.

HNG purchased the stock of CapGas, a local natural gas distribution company with approximately 1,100 customers and 177,652 feet of mains in Harris, Waller, Grimes, Austin and Colorado counties in 2008. The Harris County distribution system was located just south of HNG's existing distribution system.[5] Hughes Natural Gas, Inc. acquired all of the outstanding CapGas stock for total consideration of $550,000.[6]

Mr. Provencher, testified that CapGas' financial records had not been properly maintained under FERC rules for many years. Although, CapGas did use the account numbers prescribed by the FERC Uniform System of Accounts ("USOA"), they did not maintain their books according to the USOA instructions. CapGas' books were maintained on a federal income tax basis. Depreciation expense and accumulated depreciation reflected accelerated double declining balance tax deprecation with useful asset lives as short as seven years. Because CapGas was under severe pressure to reduce cash out-flows, it also expensed as much plant as was required to ensure no federal taxes would be payable. CapGas not only expensed rather than capitalize plant, it also did not maintain plant records according to FERC accounting standards.

CapGas did not maintain work orders supporting their plant additions and did not capitalize labor, benefits and overhead as required by the USOA to properly establish the original cost of plant in service.[7] HNG concluded that CapGas' books reflected neither original cost nor straight-line depreciation.[8] Further, the former owner of CapGas acknowledged that the plant values on CapGas books were not maintained according to the FERC standards, but were maintained for federal income tax purposes only.[9] This was determined from discussions with the previous owner's tax accountant and reviewing prior years' tax returns. [10]

HNG claims it is possible to independently verify that the CapGas annual reports do not reflect original cost. This independent verification of CapGas non-compliance with FERC is by using the CapGas 2006 Annual Report[11] values. The annual report states the gross plant value for Account 376 Mains is $290,231, representing 239,141 feet of mains, or an average installed value of $1.21 per foot. Of the 239,141 feet represented, approximately 50,140 feet of mains (ranging from 1.25" to 4") were added fairly recently during the 2000 to 2006 period. HNG believes this clearly demonstrates that the plant values presented in the 2007 CapGas Annual Reports were significantly understated and unreasonable, since it was not possible to install distribution mains at $1.21 per foot during this time.[12]

(b) Valuation of the CapGas System:

HNG concluded that CapGas did not maintain its books according to the USOA instructions. CapGas' books were maintained on a federal income tax basis. Thus, the books

[5] HNG Ex. 8, Provencher Direct, p. 48, lns.18-21.
[6] HNG Ex. 8, Provencher Direct, p. 49, lns.6-7
[7] HNG Ex. 8, Provencher Direct, p. 51, lns.17-22, p. 52, lns. 1-6.
[8] HNG Ex. 8, Provencher Direct, p. 52, lns. 16-17.
[9] HNG Ex. 10, Loy Direct, p. 13, lns.14-16.
[10] HNG Ex. 10, Loy Direct, p. 15, lns. 5-6.

[11] The 2006 Annual Report is used in this example because the Commission changed the format in the 2007 Annual report in which Account 376 Mains are not broken out.
[12] HNG Ex. 10, Loy Direct, p. 15, lns. 10-17.

and records did not reflect original cost or straight-line depreciation. The Federal Energy Regulatory Commission (FERC) Uniform System of Accounts (USOA) Gas Plant Instruction 1C states:

> The detailed gas plant accounts (301 to 399, inclusive) shall be stated on the basis of cost to the utility of plant constructed by it and the original cost, *estimated if not known*, of plant acquired as an operating unit or system(emphasis added)

In order to estimate the original cost of the newly acquired CapGas plant HNG engaged GDS to prepare an Original Cost Study. An original cost trending study is used to determine original cost and accumulated depreciation absent reliable records. The resulting reliable values of the various utility plant items reflect the different "in service" dates which are reasonable proxies for the original cost values required by statute. If the value of an item is known at any point in time, trending indices can be used to estimate its value at any other point in time.[13]

No systematic inventory existed, therefore the acquired Capital Gas Distribution asset inventory was developed from a combination of what little historical data existed and field survey and map reproduction. Resources relied upon for base information to develop the inventory included:[14]

- Historical Cap Gas inventory worksheets
- Notes and discussions with Jackie Smith, Cap Gas' long-time general manager
- Maps and drawings supplied by the company
- Maps and subdivision plats from other sources
- Field measurements and verification
- Created system maps

Once a reliable inventory is developed the assets are trended using two procedures to derive the computation of the original cost; the calculation of reproduction cost values and the application of construction cost indices.

Reproduction cost values were calculated used to reflect what the installed costs of the facilities would be if replaced at the current point in time. Then a ratio of construction cost indices representative of Texas utilities was applied to reflect what the installed costs would have been at the time of installation. Reproduction costs were determined by using average current prices for units of construction for various components of equipment and facilities of the gas systems. Typical units and costs of construction are, for example, dollars per foot of gas line installed or total cost per customer meter installed. In this particular analysis, the unit costs were reflective of typical construction, equipment, and facility costs for approximately the end of 2007. The unit prices were developed from a variety of sources including: (1) actual costs used by Hughes Gas in its construction operations; (2) information from suppliers, contractors, and other gas utilities; and (3) construction cost information from widely used resources such as *R. S. Means Heavy Construction Cost Data*. It is noted that the RRC guidelines require that

[13] HNG Ex. 10, Loy Direct, p. 10, lns. 5-8

[14] HNG Ex. 10, Loy Direct, CEL-4, p. 5-7.

reproduction costs for the assets be done at the cost for the type of assets actually being replaced. The reproduction costs were then adjusted for age and condition to reflect the difference in value between the actual facility and what it would be if new. This was done by applying the appropriate depreciation rates for the asset accounts using the theoretical service lives adopted by Hughes Gas in its ongoing regulatory business. The assets were organized along the FERC account guidelines.

Next, a ratio of construction cost indices representative of Texas utilities was applied to reflect what the installed costs would have been at the time of installation. This analysis used three separate indices as appropriate: (1) Handy-Whitman Index of Gas Utility Construction Costs for the South Central Region (Region 4, which includes Texas); (2) the ENR (formerly Engineering News Record) Index of Building Cost Trends; and (3) the Bureau of Reclamation Construction Cost Trends. The Handy-Whitman Index was the primary reference source used for this study because it has indices specifically for the gas utility sector, and utility regulators and the industry routinely accept it.

Hughes originally proposed to use the trending value study with no acquisition adjustment in its rate base in the cost of service. As of the acquisition date, December, 2007, the trending analysis results valued the CapGas assets purchased by HNG at a net book value of $1,601,755, Table 3 below. As of the end of the test year in this case, September 30, 2012, updated for retirements and additional depreciation, the net book value is $1,178,846, Table 4 below.

Table 3

HUGHES NATURAL GAS, INC.
UPDATED TEST YEAR ENDING SEPTEMBER 30, 2012
RESULTS OF CAPGAS TRENDED ORIGINAL COST STUDY
AS OF ACQUISITION DATE: 12/31/2007

Line No	Description (A)	Trended Original Cost Value (B)	Total Accumulated Depreciation (C)	Net Book Value (D)	Annual Depreciation Expense (E)
1	(376) Mains	$ 1,335,649	$ (381,862)	$ 953,787	$ 33,391
2	CIAC Main Extensions *	(75,263)	19,128	(56,135)	(1,882)
3	(378) Meas & Reg Station	298,109	(131,461)	166,648	9,034
4	(380) Services	1,275,413	(737,958)	537,455	51,017
5	Total	$ 2,833,908	$ (1,232,153)	$1,601,755	$ 91,560

* Discovered after the Trended Original Cost Study. See WP Sch B-1.2.

Table 4

HUGHES NATURAL GAS, INC.
UPDATED TEST YEAR ENDING SEPTEMBER 30, 2012
RESULTS OF CAPGAS TRENDED ORIGINAL COST STUDY
REFLECTED AS OF 9/30/2012

Line No	Description	Trended Original Cost Value	Plant Retired	Depr Exp 1/2008 thru 9/2012	Trended Plant In Rate Base	Trended Plant Depr Expense
	(A)	(B)	(C)	(D)	(E)	(F)
1	(376) Mains	$ 1,335,649	$ (96,550)		$ 1,239,098	$ 30,977
2	Accum. Depr.	(381,862)	87,916	(147,143)	(441,089)	
3	CIAC Main Ext	($75,263)			(75,263)	(1,882)
4	Accum Amort	$19,128		8,937	28,065	
5	(378) Meas & Reg Station	298,109	(60,447)		237,662	7,202
6	Accum. Depr.	(131,461)	57,140	(34,209)	(108,530)	
7	(380) Services	1,275,413	(19,870)		1,255,543	50,222
8	Accum. Depr.	(737,958)	19,870	(238,553)	(956,641)	
9	Total Net Plant	$ 1,601,755			$ 1,178,846	$ 86,519
10	Total Gross Plant	2,833,908			2,657,040	86,519
11	Total Accumulated Depreciation	(1,232,153)			(1,478,195)	
12	Total Net Plant	$ 1,601,755			$ 1,178,846	$ 86,519

(c) Acquisition Adjustment:

An acquisition adjustment is defined in the FERC USOA as the difference between the price paid for plant acquired as an operating unit or system and the original cost of plant net of accumulated depreciation. When the price paid is greater than the original cost this results in a positive acquisition adjustment. When the purchase price is less than the original cost, as in HNG's purchase of CapGas, the result is a negative acquisition adjustment.

GURA specifies that only the original cost of utility plant at the time it is dedicated to public service by the first owner, adjusted for depreciation, should be included in the utility's rate base.[15] This is known as the "net original cost" law or rule.[16]

The Commission decision will determine if it should depart from the original cost standard and include some or all of the negative acquisition adjustment. GURA §104.053 allows the Commission to determine a reasonable rate base for HNG to earn on. In this proceeding HNG argued that that the values in the trending study should be used for original cost. HNG proposed an alternative valuation applying GURA § 104.053 if the Commission determined that an acquisition adjustment was appropriate. HNG's alternative, not incorporated in the Settlement Agreement, suggested that the Commission should use a weighting of no more than 60% for the inaccurate CapGas annual report values, with the 2007 annual report accumulated depreciation adjusted to straight line depreciation. This can be accomplished by applying the GDS original cost study accumulated depreciation to gross plant ratio to the CapGas gross plant value. This will produce a lower accumulated depreciation value that would be a reasonable substitute for

[15] GURA §104.053(b)(1)
[16] HNG Ex. 10, Loy Direct, p. 18, lns. 16-18, p. 19, lns. 1-2.

the annual report's accelerated depreciation, and would be representative of the straight-line depreciation method required by the Commission. The remaining 40% should reflect the reconstruction cost new of the facilities, adjusted for age and condition. The starting point of the original cost study is a replacement cost new study and should be used in this GURA calculation. The results can be seen in Table 5, below.[17]

Table 5

HUGHES NATURAL GAS, INC.
UPDATED TEST YEAR ENDING SEPTEMBER 30, 2012
COMPUTATION OF CAPGAS ACQUSITION ADJUSTMENT TO BE REFLECTED IN RATE BASE
USING FAIR VALUE MIX OF 60% CAPGAS BOOKS TO 40% REPLACEMENT COST ADJUSTED FOR AGE & CONDITION PER GUD No. 8310-8316

Description (A)	Adjusted 2007 Annual Report Value * (B)	Apply 60% Fair Value (B) (C)	GDS Study Replacement Cost (D)	Apply 40% Fair Value (D) (E)	Fair Value Col (C) + (E) Plant (F)	Plant Retired (G)	Depr Exp 1/2008 thru 9/2012 (H)	Fair Value Plant Per Rate Base (I)
(376) Mains	$342,383	$205,430	$2,285,845	$914,338	$1,119,768	($77,080)		$1,042,688
Accum. Depr./ Age & Cond	($96,835)	($58,101)	($1,025,063)	($410,025)	($468,126)	$70,187	($132,972)	($530,912)
(378) Meas & Reg Station	$76,418	$45,851	$455,979	$182,392	$228,242	($48,257)		$179,985
Accum. Depr./ Age & Cond	($33,337)	($20,002)	($252,061)	($100,824)	($120,826)	$45,617	($32,850)	($108,059)
(380) Services	$307,649	$184,589	$1,824,576	$729,830	$914,420	($15,863)		$898,557
Accum. Depr./ Age & Cond	($182,286)	($109,371)	($1,145,886)	($458,354)	($567,726)	$15,863	($173,740)	($725,602)
Total Gross	$726,450	$435,870	$4,566,400	$1,826,560	$2,262,430	($141,201)		$2,121,229
Total Accum Depr	($312,458)	($187,475)	($2,423,010)	($969,204)	($1,156,679)	$131,668	($339,562)	($1,364,573)
	$413,992	$248,395	$2,143,390	$857,356	$1,105,751	($9,533)	($339,562)	**$756,656**
As Reflected in Plant as of 9/30/2012								$ 1,178,846
Acqusition Adjustment to be Reflected in Rate Base Using Fair Value Computation								**($422,190)**
Net CapGas Acquisition Adjustment On Books at 9/2012								($1,099,458)
Resulting Acquisition Adjustment on Books to be Excluded from Rate Base								**($677,268)**
Gross Plant Per Annual Report			$726,450					
Apply Original Cost Study Accumulated Depr/Gross Plant Ratio $1,251,281 / $2,909,171 = 43.01%			($312,458)					
Allocate Estimated Net Plant on Original Cost Study Values			**$413,992**					

(d) Settlement Agreement:

The alternative adopted in the *Settlement Agreement* was similar to HNG's proposed alternative. The *Settlement Agreement* adopted used a weighting of no more than 70% for the inaccurate CapGas annual report values, with the 2007 annual report accumulated depreciation

[17] HNG Ex. 10, Loy Direct, p. 35, lns. 16-21.

adjusted to straight line depreciation. This was accomplished by applying the GDS original cost study accumulated depreciation to gross plant ratio to the CapGas gross plant value. This will produce a lower accumulated depreciation value that would be a reasonable substitute for the annual report's accelerated depreciation, and would be representative of the straight-line depreciation method required by the Commission. The remaining 30% reflects the reconstruction cost new of the facilities, adjusted for age and condition. The starting point of the original cost study is a replacement cost new study and should be used in this GURA calculation. The results are illustrated in Table 6, below.

Table 6

HUGHES NATURAL GAS, INC.
UPDATED TEST YEAR ENDING SEPTEMBER 30, 2012
COMPUTATION OF CAPGAS ACQUSITION ADJUSTMENT TO BE REFLECTED IN RATE BASE
USING FAIR VALUE MIX OF 70% CAPGAS BOOKS TO 30% REPLACEMENT COST ADJUSTED FOR AGE & CONDITION PER GUD No. 8310-8316

Description (A)	Adjusted 2007 Annual Report Value * (B)	Apply 70% Annual Report Value (B) (C)	GDS Study Replacement Cost (D)	Apply 30% Replacement Value (D) (E)	Fair Value Col (C) + (E) Plant (F)	Plant Retired (G)	Depr Exp 1/2008 thru 9/2012 (H)	Fair Value Plant Per Rate Base (I)
(376) Mains	$342,383	$239,668	$2,285,845	$685,754	$925,422	($63,998)		$861,424
Accum. Depr./ Age & Cond	($96,835)	($67,785)	($1,025,063)	($307,519)	($375,304)	$58,274	($109,894)	($426,923)
(378) Meas & Reg Station	$76,418	$53,493	$455,979	$136,794	$190,286	($40,067)		$150,219
Accum. Depr./ Age & Cond	($33,337)	($23,336)	($252,061)	($75,618)	($98,954)	$37,875	($27,387)	($88,466)
(380) Services	$307,649	$215,354	$1,824,576	$547,373	$762,727	($13,171)		$749,556
Accum. Depr./ Age & Cond	($182,286)	($127,600)	($1,145,886)	($343,766)	($471,366)	$13,171	($144,918)	($603,113)
Total Gross	$726,450	$508,515	$4,566,400	$1,369,920	$1,878,435	($117,235)		$1,761,200
Total Accum Depr	($312,458)	($218,720)	($2,423,010)	($726,903)	($945,623)	$109,320	($282,199)	($1,118,502)
	$413,992	$289,795	$2,143,390	$643,017	$932,812	($7,915)	($282,199)	**$642,697**
As Reflected in Plant as of 9/30/2012								$ 1,178,846
Acqusition Adjustment to be Reflected in Rate Base Using Fair Value Computation								**($536,148)**
Net CapGas Acquisition Adjustment On Books at 9/2012								($1,099,458)
Resulting Acquisition Adjustment on Books to be Excluded from Rate Base								**($563,309)**
Gross Plant Per Annual Report			$726,450					
Apply Original Cost Study Accumulated Depr/Gross Plant Ratio			($312,458)					
$1,251,281 / $2,909,171 = 43.01%								
Allocate Estimated Net Plant on Original Cost Study Values			**$413,992**					

(e) Examiners' Findings and Recommendations on Settlement.

In the previous CapGas docket, GUD 8310-8316, signed March 29, 1993, the Commission acknowledged that the CapGas plant values were incorrect and CapGas was ordered by the Commission to book plant according to NARUC. In GUD No 8310-8316, the Commission also developed an alternative methodology to value the CapGas plant for ratemaking purposes. The alternative methodology used, was a variant of a trending cost study.[18] In that case, the Commission relied on GURA 104.053 to determine a reasonable rate base value for CapGas to earn on. The original cost of the plant was not known so the Commission used 30% of the value of plant from a replacement cost new study and 70% of the value of the plant that was booked.[19]

The Commission applied this provision and gave the CapGas tax "per books" values a 70% weighting, and applied the remaining 30% weighting to the plant values determined by a replacement cost new adjusted for age and condition study. The Commission determined that the application of GURA § 104.053 was a reasonable approach to determining rate base values as compared to the values CapGas initially proposed.[20]

HNG utilized the CapGas 2006 Annual Report[21] gross plant value for Account 376 Mains to illustrate the price per foot as follows; $290,231, representing 239,141 feet of mains, or an average installed value of $1.21 per foot. The Examiners believe this calculation used accumulated depreciation not gross plant of account 376 at year end in error. The Examiners calculation of gross plant per foot cost is as follows; $546,900[22] representing 232,829[23] feet of mains, or an average installed value of $2.35 per foot.

Utilizing the trended analysis results, the Examiner's calculate a gross plant value for Account 376 Mains to illustrate the price per foot as follows; $1,335,649, representing 232,829 feet of mains, or an average installed value of $5.74 per foot. The following table compares gross plant per foot for Atmos Mid-Tex and Centerpoint Houston. This comparison was not available for a 2006 test year because of the timing of the rate cases but serves as general comparison of per foot costs of mains.

Table 7

Utility	Source	Gross Plant – Mains 376	Feet of Main	Average Cost per foot
Atmos Mid-Tex	GUD 9762 TYE 6/30/07	$ 1,139,665,872 Note (1)	147,761,265 Note (2)	$7.71
Centerpoint Houston	GUD 9902 TYE 9/30/09	$ 351,576,229 Note (3)	71,358,330 Note (4)	$4.93

(1) CCCS-4, p. 1
(2) CCCS-4, p. 2
(3) Sch. 2a
(4) WP HD-1

Despite the error noted above, the Examiners agree with HNG that this comparison demonstrates that the plant values presented in the 2006 CapGas Annual Reports were

[18] HNG Ex. 10, Direct Testimony of Charles E. Loy, p. 13, lns. 11-14.
[19] HNG Ex. 10, Direct Testimony of Charles E. Loy, p. 26, lns.19-21, p. 27, lns. 1-4.
[20] HNG Ex. 10, Direct Testimony of Charles E. Loy, p. 34, lns. 31-36.

[21] The 2006 Annual Report is used in this example because the Commission changed the format in the 2007 Annual report in which Account 376 Mains are not broken out.
[22] 2006 CapGas Annual Report, page 19, line 66.
[23] HNG Ex. CEL-4, p. 12.

significantly understated and unreasonable. Based upon the evidence presented in this case and the analysis in Table 7 above it does not appear reasonable that distribution mains could be installed at $2.35 per foot during this time period. Other evidence, discussed above, presented by HNG related to the books and records of CapGas also support the conclusion that the plant values calculated by CapGas were inaccurate.

Therefore, the Examiner's find that HNG established that CapGas did not follow FERC guidelines and therefore HNG did not have a reliable basis to value the CapGas assets. The Examiners also find that the trending study methodology is a reasonable methodology for determining reliable original plant values. Accordingly the Examiners find that the results of the trending study reflected in Table 4 are just and reasonable for original cost for the books and records of HNG.

Turning to the issue of the acquisition adjustment the Examiners find as follows. The acquisition the negative adjustment of a ($536,148) reflected in the settlement agreement is just and reasonable. The methodology used to arrive at the acquisition adjustment is consistent with the methodology applied in the prior CapGas proceeding.

(3) Public Interest Determination

In GUD No. 9670 the Commission evaluated the public interest provisions applicable to Section 102.051. In evaluating the transaction applicable in that case, the Commission evaluated the public interest by considering the following factors:[24]

1. The reasonable value of property, facilities, or securities;
2. investments made to enhance or improve reliability;
3. actions implemented to enhance or improve safety;
4. efforts to enhance or improve customer service quality;
5. measures accomplished for improvements to operations, management, and administrative process;
6. community benefits resulting from the acquisition;
7. impacts on bond ratings and investment community's view of the acquisition;
8. efficiencies and economies of scope and scale resulting from the acquisition;
9. liability avoidance or mitigation as a result of the acquisition; and,
10. effect on customer rates.

The valuation of CapGas was analyzed above. In this docket, HNG witness Mr. Provencher testified that CapGas was a failing distribution system, both from a financial standpoint, and in terms of the physical condition of the deteriorating pipeline facilities. He stated that as a part of the company's due diligence effort for the acquisition of CapGas, HNG had the assets of CapGas catalogued and digitally mapped, and a pipeline integrity risk assessment was conducted by GDS. GDS recommended that fourteen sections of the distribution system be considered for replacement. These were PVC and steel mains and services originally

[24] GUD No. 9670, Petition for de novo Review of the Reduction of the Gas Utility Rates of Atmos Energy Corp., Mid-Tex Division, by the Cities of Addison, Bedford, Benbrock, et al. & Statement of Intent filed by Atmos Energy Corp., Mid-Tex Division, Finding of Fact No. 167.

installed between 1961 and 1975. The steel mains had no cathodic protection. From 2008 through 2011, HNG completed twelve construction projects to replace 44,350 feet of mains and services in what were formerly the CapGas service areas. The original cost of these replacements was $958,214.[25]

Mr. Provencher testified that CapGas' former customers benefited from the acquisition as the CapGas customers did not experience any of the negative consequences of having a utility close its doors, such as interruptions of service, poor emergency response, loss of deposits, and billing issues. HNG substantially improved system integrity, safety and reliability in short order without any disruption in service.[26]

The Examiners recommend that the Commission find that the acquisition of CapGas by HNG was in the public interest. The company established that CapGas was in a precarious financial position and that the customers of that system avoided the consequences of having a utility close its doors. The record in this proceeding established that HNG made investments to enhance and improve the reliability and safety of the system. Mr. Provencher's testimony regarding the condition of CapGas is not contradicted.

The Examiners find that HNG has established that the merger of HNG and CapGas was in the public interest. The record in this case established that the method of valuation for HNG's books and records and for ratemaking, contemplated in the Settlement Agreement is just and reasonable.

d. **Depreciation Rates**

HNG proposed depreciation rates that appear to be generally consistent with the depreciation rates set in GUD No. 9731, HNG's last rate proceeding. The Settlement Agreement adopts those depreciation rates. Those rates were not based upon a depreciation study. Instead they appear to have been based upon a statistical report prepared by the Edison Electric Institute/American Gas Association (EEI/AGA) for gas distribution plants entitled, Depreciation Statistic Report.[27] In light of the current size of the system, the Examiners find that the proposed depreciation rates are reasonable. Although certain components of the overall depreciation rates do not match a survey of depreciation rates approved for both large and small utilities in the last decade, the proposed depreciation rates appear to be consistent with the depreciation rates of smaller utilities.[28]

The Examiners are concerned, however, that a depreciation study has not been conducted by HNG throughout the entire period of its operation of this system. As noted above, HNG began serving its first development in 1997. A depreciation study has not been performed in at least fifteen years. Further, HNG has indicated that it expects substantial growth in the future.[29]

[25] HNG Ex. 8, Provencher Direct, p. 52, lns. 19-23 – p. 53, lns. 1-2.
[26] HNG Ex. 8, Provencher Direct, p. 6, lns. 5-8.
[27] GUD No. 9731, Proposal for Decision, p. 13.
[28] HNG Ex. 27, Clayton Rebuttal, p. 13.
[29] HNG Ex. 8 Provencher Direct, p. 12.

The Examiners recommend that HNG be directed to prepare a depreciation study prior to the next *Statement of Intent* filing and that the study accompany the next *Statement of Intent* proceeding filed pursuant to Section 104.102.

e. **Income Tax Rates**

The Settlement Agreement declares that the income tax expense shall be calculated using an assumed 35% income tax rate. This is consistent with Commission precedent and the Examiners find that it is just and reasonable.

f. **Affiliate Transactions - Gas Purchasing and Capital Expenditures**

The signatories to the Settlement Agreement agreed to jointly develop a transparent, expanded, competitive, annual request for bid process with the assistance of a qualified third party consultant related to gas purchasing practices an planned capital and maintenance expenditure within six months from the date of the Final Order in this case.

The Examiners find that this provision is just and reasonable. This provision, along with the development of a cost allocation manual address issues related to the affiliate transactions of HNG. The Gas Utility Regulatory Act requires that specific findings must be made by the appropriate regulatory authority before rates may be adopted. Those findings include (1) a specific finding of the reasonableness and necessity of each item or class of items allowed; and (2) a finding that the price to the gas utility is not higher than the prices charged by the supplying affiliate to its other affiliates or division or to a non-affiliated person for the same item or class of items. The Examiners conclude that, the nature of the settlement makes it impossible to know for certain whether the expenses related to the affiliate are included in rates. Thus, the Examiners find that the evidence in the record of this case regarding HNG's affiliates must be evaluated to comply with the statutory requirements.

HNG is a member of an affiliated group of five companies. *Hughes Gas Resources, Inc.* (HGR) is the parent company of the group and is a non-regulated affiliate. HGR provides capital funding to each of its four wholly owned subsidiaries including HNG. *Goliad Midstream Energy, LLC* (Goliad) is a wholly owned subsidiary of HGR that buys and sells natural gas to local distribution companies in Montgomery and Harris Counties. *Pinehurst Utility Construction* (Pinehurst) is also a wholly owned subsidiary of HGR and provides construction services to HNG, to another affiliate, and to unrelated third parties. *Alamo Pipeline, LLC* (Alamo) is also a wholly owned subsidiary of HGR that provides natural gas transportation in Harris and Montgomery County. Real Provencher and Frank Hicks are owners of HGR and officers and directors of the various subsidiaries.

Additionally, HNG engaged in transactions with Decker Prairie Properties, LLC (DPP). DPP is a limited liability company that is not a member of the HGR group. HNG rents office space from DPP. DPP is operated by the spouse of Frank Hicks and, although it is not technically an affiliate of HNG, HNG asserted that DPP has been treated as an affiliate.

Problems regarding the affiliate transaction were an underlying problem of the filing in GUD No. 10083. Indeed, the affiliate transactions resulted in a disallowance in HNG's first *Statement of Intent* proceeding at the Commission, GUD No 9731. The Examiners find that HNG has established that the affiliate transactions are just and reasonable and satisfy the affiliate transaction standard of GURA.

The evidence in the record established that the services provided by the affiliates were necessary to the operation of HNG. To ensure that the expenses are reasonable, HNG developed a cost allocation manual, Hughes Gas Resources, Inc., Affiliate Cost Allocation Manual and Summary of Affiliate Transactions (CAM), that governs the allocation of all expenses among the affiliates. The document summarized the procedures followed by HGR and its affiliate to allocate affiliate costs to ensure compliance with regulatory requirements. The goal of the CAM is to prevent subsidization of the non-regulated entities by the regulated entities.

As to Goliad and Alamo, the Examiners note that Mr. Provencher testified that he has no day-to-day responsibilities in the company. In GUD No. 10083, Mr. Provencher provided testimony that he prepared invoices on behalf of Goliad and Alamo. Those tasks are now performed by a utility accounting specialists and the expenses related to those tasks are allocated as outlined in the CAM. Shared employees began using an online time-tracking service in 2011 and the costs of the time-tracking service are paid by the non-regulated affiliates. Further, the Examiners note that, although Goliad provided gas procurement services during the test year, Mr. Provencher stated that currently HNG conducts no business with Goliad. Finally, the Examiners observe that in GUD No. 10083, the *Proposal for Decision* objected to the fact that transactions between HNG and DPP were not memorialized in writing. The record in this case established that, consistent with the requirements of the CAM, lease agreement between HNG and DPP has been memorialized.

The Examiners find that HNG has established that its transactions with its affiliates are just and reasonable. Furthermore, the Examiners find that that the price to HNG is not higher than the prices charged by the supplying affiliate to its other affiliates or division or to a non-affiliated person for the same item or class of items. The *Settlement Agreement* does not clarify whether the CAM will be maintained. Due to the issues posed in this proceeding, the Examiners recommend that the Commission specifically order that the CAM will be maintained and updated at least on an annual basis and at any time that the corporate structure is changed after the Final Order is issued in this proceeding.

g. **Relocation Cost Recovery Surcharge**

HNG recorded $563,963 in pipeline relocation costs associated with the relocation of facilities to accommodate construction or improvement of a highway, TxDOT FM 1774. The signatories agreed that the Pipeline Relocation Cost in FERC Account 106 related to this projected not be included with the rates approved in this docket. Instead, HNG may, at its option, make a future filing pursuant to Section 104.112 to recover the portion of the Pipeline relocation Cost. The Examiners find that the terms of the *Settlement Agreement* related to the pipeline relocation project are just and reasonable.

6. Rate Case Expenses

a. Introduction

Rule 7.5530 provides that in any rate proceeding, any utility and/or municipality claiming reimbursement for its rate case expenses pursuant to Texas Utilities Code, §103.022(b), shall have the burden to prove the reasonableness of such rate case expenses by a preponderance of the evidence. Each gas utility and/or municipality shall detail and itemize all rate case expenses and allocations. Each entity seeking recovery of rate case expenses must provide evidence showing the reasonableness of the cost of all professional services, including but not limited to:

(1) the amount of work done;
(2) the time and labor required to accomplish the work;
(3) the nature, extent, and difficulty of the work done;
(4) the originality of the work;
(5) the charges by others for work of the same or similar nature; and
(6) any other factors taken into account in setting the amount of the compensation.

Furthermore, Commission rules mandate that in determining the reasonableness of the rate case expenses, the Commission shall consider all relevant factors including but not limited to those set out previously, and shall also consider whether the request for a rate change was warranted, whether there was duplication of services or testimony, whether the work was relevant and reasonably necessary to the proceeding, and whether the complexity and expense of the work was commensurate with both the complexity of the issues in the proceeding and the amount of the increase sought as well as the amount of any increase granted.

b. Overall Request

In prosecuting this proceeding and GUD No. 10083 HNG expended $1,156,819 in rate case expenses. In GUD No. 10102, the rate case expense proceeding to consider the rate case expenses of the City of Magnolia in GUD No. 10083, the Commission provided that the company could bring forward into this case those rate case expenses incurred in GUD No. 10083 that were just and reasonable and of benefit in this proceeding. Of the total in rate case expense incurred by HNG, HNG seeks recovery of only $650,000.

Table 8 below sets out the total rate case expenses for all related proceedings:

Table 8
Rate Case Expenses for GUD Nos. 10083, 10102, and 10190

Total Legal Expenses	$479,721
Total Consulting Expenses	$440,829
Total Other Expenses	$12,269
Future estimated Expenses	$224,000
TOTAL REQUESTED	$1,156,819

HNG noted that expenses that are directly attributable to GUD No. 10190 totaled $552,403. On the other hand, expenses directly attributable to GUD No. 10083 were $602,416.

Mr. Loy and Ms. Hodgins testified in support of rate case expenses. Mr. Loy and Ms. Hodgins testified that the attorney's fees ranged from $250/hour to $525/hour. This is confirmed from the billing records that are in evidence. The attorneys working on this case each have extensive experience in utility regulation and administrative law. Each witness testified that the range is within the hourly rate for law firms with similar profiles and that the rates are just and reasonable. Mr. Loy asserted further that the fees for the attorneys are in line with the other who practice in the public utility area before the Commission. Further, Ms. Hodgins testified that an attorney with a lower billing rate than the maximum performed the majority of the work.

The consultants' rates ranged between $65/hour and $350/hour. Mr. Loy testified that these rates are reasonable and consistent with our below the hourly rate of other individuals with expertise on the subject matters addressed.

Mr. Loy and Ms. Hodgins each concluded that the legal and consulting fees were just and reasonable. Further, each witness made the following assertions:

- The hourly rates charged by attorneys and consultants were reasonable rates charged by firms in cases addressing utility rate matters;
- The attorneys and consultants did not charge any expenses for luxury items and did not incur any airline, lodging, or meal expenses;
- The amount of work done, was well as, the time and labor required to accomplish the work was reasonable given the nature of the issues addressed; and,
- The complexity and expense of the work was relevant and reasonably necessary to the proceeding, and was commensurate with both the complexity of the issues and necessary to completing the mater before the Commission.

c. **Examiners' Recommendation**

The Examiners reviewed all billing, invoices and evidence submitted by HNG. The Examiners found no evidence of double-billing, excess charges, inappropriate documentation of work, or other charges that were not incurred as a direct result of the parties prosecuting or defending GUD No. 10190 and the related dockets. These filings demonstrate that no expenses were charged for any luxury items, that there were no first – class airfare or use of non-commercial aircraft, no luxury hotel charges, no limousine service, no meals in excess of $25 per person, no charges for sporting events, alchoholic drinks or other entertainment.

Furthermore, the detailed billings and invoices have been reviewed and there are no instances of billing in excess of 12 hours per day or being charged more than once for a service or expenditure. Nor, was the hourly rate charged higher than the agreed upon rate. In addition, the expenses for transcripts were necessary to conclude these proceedings.

The Examiners find that the amount of time spent is commensurate with the number, complexity and gravity of the issues posed by HNG in this filing. The evidence shows that the law firms and the consulting experts limited the issues and the amount of time and personnel reviewing and participating in the proceeding in an effort to keep rate case expenses down. The time spent was commensurate with the minimum amount of time required to review a rate case of this size and to participate in the hearing and briefing of the issues. Thus, the total fees and expenses incurred by the law firm and the consulting experts are proportionate to the efforts necessary to represent the parties, given the complexity of the issues, the originality of the work, and the magnitude of the rate increase proposed.

The Examiners recognize that the total rate case expense requested exceeds the expenses of GUD No. 10190. Thus, the expenses necessarily include some portion of expense in GUD No. 10083. The Examiners find that based upon the evidence presented in this proceeding, HNG seeks to recover a portion of costs from GUD No. 10083 which were reasonably in support of the testimony that was filed in this case. For example, the model prepared in support of the rate request was developed in GUD No. 10083. Mr. Loy testified that relatively minor modifications were required to update the schedule for purposes of GUD No. 10190. A similar example relates to the legal fees incurred in GUD No. 10083 that are included in the rate case expense request in this proceeding. Ms. Hodgins noted that work product involving the drafting of notice to customers and the protective order were not changed in this proceeding.

The Examiners conclude that due to the unique circumstances of this proceeding it is reasonable to include expenses incurred in GUD No. 10083 as part of the rate case expenses in this proceeding. Namely, those circumstances clearly enabled the use of work product developed in GUD No. 10083 in this proceeding. Although unprecedented, such treatment is justified by atypical juxtaposition of these proceedings.

Furthermore, the Examiners find that this case presented unique issues which are not present in cases involving utilities of this size. First, the acquisition of CapGas presented difficult and unique circumstances which impacted the overall expenses of the proceeding. Second, the corporate structure of the utility increased the legal complexity of this proceeding and necessitated the development of the CAM. In conclusion, the Examiners recommend that HNG be allowed to recover $650,000 in rate case expenses.

7. Tariffs

The Settlement Agreement includes an agreement on several tariffs, including the general tariff applicable, tax adjustment, weather normalization adjustment, cost of gas tariff, pipeline safety and regulatory program tariff, rate case expense surcharge, miscellaneous services tariff, and tariffs related to deposits, line extension, the quality of service, and curtailment. The Examiners find that the proposed tariffs are just and reasonable.

8. Conclusion

The Examiners find that the rate elements agreed to by the parties in the *Settlement Agreement* are just and reasonable and recommend approval of rates consistent with the settlement.

Respectfully submitted,

Gene Montes
Hearings Examiner
Hearings Division

Rose A. Ruiz
Rose Ruiz
Technical Examiner
Hearings Division

BEFORE THE
RAILROAD COMMISSION OF TEXAS

STATEMENT OF INTENT OF HUGHES NATURAL GAS, INC. TO CHANGE GAS DISTRIBUTION RATES IN THE UNINCORPORATED TOWNS AND RURAL AREAS OF AUSTIN, COLORADO, GRIMES, HARRIS, MONTGOMERY AND WALLER COUNTIES, TEXAS	§ § § § § § § §	**GAS UTILITIES DOCKET NO. 10190**

FINAL ORDER

Notice of Open Meeting to consider this Order was duly posted with the Secretary of State within the time period provided by law pursuant to TEX. GOV'T CODE ANN. § 551.001, *et seq*., (Vernon 2011). The Railroad Commission of Texas adopts the following findings of fact and conclusions of law and orders as follows:

FINDINGS OF FACT

1. Hughes Natural Gas, Inc., (HNG) is a gas utility as that term is defined in the Texas Utility Code.

2. On July 6, 2012, HNG filed a *Statement of Intent* to change gas distribution rates in the unincorporated areas of Austin, Colorado, Grimes, Harris, Montgomery and Waller Counties, Texas.

3. The implementation of the proposed rates was suspended on August 7, 2012.

4. Staff of the Railroad Commission of Texas (Staff) intervened in this proceeding on July 12, 2012.

5. The City of Magnolia intervened in this proceeding on September 4, 2012.

6. Two individual customers intervened in this proceeding: Michael C. Kelly and Henry Oncken.

7. The previous *Statement of Intent* proceeding filed by HNG was docketed as GUD No. 10083, and consolidated cases.

8. A hearing was conducted in that case, the Examiners issued a *Proposal for Decision* and the Commission ultimately issued a *Final Order* rejecting the proposed increase on January 10, 2012.

9. Six months later, on July 6, 2012, HNG filed this proceeding.

10. Notice of the filing in this proceeding was provided to all customers within all unincorporated areas served by HNG by publishing a notice each week for four successive weeks, beginning the week of approximately August 13, 2012 and running through the week of approximately September 3, 2012, in a newspaper having a general circulation in each city affected by the proposed increase.

11. The publication of notice meets the statutory and rule requirements of notice and provides sufficient information to ratepayers about the statement of intent.

12. A hearing was held from February 6, 2013 through February 8, 2013. On February 19, 2013, a Settlement Agreement was filed in this case.

13. HNG, Staff, and the City of Magnolia are signatories to the Settlement Agreement. No objection was filed by Mr. Oncken or Mr. Kelley.

14. The test year in this filing is allegedly based upon the financial data for the twelve month period ended September 30, 2012

15. During the test year, services were provided by affiliates of HNG to the utility.

16. The record in this case established that that the services provided by its affiliates on behalf of HNG are reasonable and necessary.

17. The record in this case established that the affiliate expenses included in the company's filing are reasonable and necessary costs of providing gas utility service, and the prices charged to HNG are no higher than he prices charged by the supplying affiliate to HNG's other affiliates, or to a non-affiliated person for the same item or class of items.

18. To ensure compliance with regulatory requirements related to affiliate transactions, HNG developed a Cost Allocation Manual (CAM). It is reasonable to require that HNG maintain the CAM and update the CAM on an annual basis and at any time that the corporate structure of HNG and its affiliate is changed after this entry of this Final Order.

19. Furthermore, it is reasonable for HNG, the City of Magnolia, and Staff to jointly develop a transparent, expanded, competitive, annual request for bid process as set out in the Settlement Agreement.

20. HNG established that the utility has fully complied with the books and records requirements of Rule 7.310 and the amounts included therein are therefore subject to the presumption encapsulated in Rule 7.503 that those amounts are reasonable and necessary.

21. The company initially requested a net revenue requirement increase of $902,974 for the standard rate classes.

22. The Settlement Agreement contemplates an increase of $436,076. This represented a decrease from the initial request of $466,898.

23. The record in this case established that an increase of $436,076 is just and reasonable.

24. The Settlement Agreement proposed that the rate increase be implemented in two phases. The Settlement Agreement contemplates the following initial rate: A customer charge of $17.10 and a volumetric rate of $7.0500. The rates would increase to a customer charge of $18.35 and a volumetric rate of $7.050 one year from the date of the Final Order is issued in this proceeding.

25. The following capital structure and weighted cost of capital, including the pre-tax return, is reflective of the HNG's actual capital structure and is just and reasonable. This cost of capital reflects that agreed by the Signatories in the Settlement Agreement reached in this docket.

	Capital Structure	Debt/Equity Cost	Weighted Cost of Capital
Long-Term Debt	44.5%	7.0%	3.115%
Common Equity	55.5%	10.6%	5.883%
Rate of Return	100%		**9%**

26. In 2008, HNG purchased the stock of Captial Gas Distribution, Inc. (CapGas).

27. Prior to the acquisition, CapGas did not follow the FERC Uniform System of Accounts in recording plant balances.

28. The plant values presented in the CapGas Annual Reports were significantly understated and unreasonable.

29. It is reasonable that the original costs associated with the assets acquired from CapGas be the amounts posed on the books and records of the company based on the trending study performed by HNG's consultants.

30. An acquisition adjustment is defined in the FERC Uniform System of Accounts as the difference between the price paid for plant acquired as an operating unit or system and the original cost of plant net of accumulated depreciation.

31. It is reasonable that the total negative acquisition amount on HNG's books and records shall be amortized over twelve years below the line beginning on the date incurred.

32. Due to the unique circumstances of this case, a negative acquisition adjustment in the amount of ($536,148) is reasonable for purposes of setting rates because the purchase price was less than the original cost.

33. At the time of the acquisition CapGas was a failing distribution financially and physically.

34. After the acquisition HNG had the assets of CapGas catalogued and digitally mapped, and a pipeline integrity risk assessment was conducted by GDS.

35. HNG replaced several segments of the CapGas system.

36. From 2008 through 2011, HNG completed twelve construction projects to replace 44,350 feet of mains and services in what were formerly the CapGas service areas. .

37. CapGas' former customers benefited from the acquisition as the CapGas customers did not experience any of the negative consequences of having a utility close its doors, such as interruptions of service, poor emergency response, loss of deposits, and billing issues.

38. HNG substantially improved system integrity, safety and reliability in short order without any disruption in service.

39. The acquisition of CapGas by HNG was in the public interest.

40. HNG proposed depreciation rates are consistent with the depreciation rates set in GUD No. 9731, HNG's last rate proceeding.

41. Those rates were based, in part, upon a statistical report prepared by the Edison Electric Institute/American Gas Association (EEI/AGA) for gas distribution plants entitled, Depreciation Statistic Report

42. The Settlement Agreement adopts those depreciation rates.

43. The proposed depreciation rates appear to be consistent with the depreciation rates of smaller utilities. In light of the current size of the system the depreciation rates are reasonable.

44. A depreciation study, however, has not been performed since HNG began providing service and it is reasonable to require HNG to prepare a depreciation study prior to its next Statement of Intent proceeding.

45. It is reasonable that the income tax rate for HNG be calculated based upon an assumed 35% income tax rate.

46. It is reasonable that HNG not file an interim rate adjustment proceeding for the environs in calendar year 2013 and the its first interim rate adjustment filing occur no sooner than October 1, 2014 as set out in the attached Settlement Agreement.

47. In prosecuting GUD No. 10083 and GUD No. 10190 and all related proceedings, HNG incurred $1,156,819 in rate case expenses.

48. HNG has not previously recovered any of its rate case expenses.

49. HNG seeks recovery of $650,000 in rate case expenses.

50. The hourly rates charged by attorneys and consultants were reasonable rates charged by firms in cases addressing utility rate matters.

51. The attorneys and consultants did not charge any expenses for luxury items and did not incur any airline, lodging, or meal expenses.

52. The amount of work done was well as, the time and labor required to accomplish the work was reasonable given the nature of the issues addressed.

53. The complexity and expense of the work was relevant and reasonably necessary to the proceeding, and was commensurate with both the complexity of the issues and necessary to completing the matter before the Commission.

54. Work product developed by the attorneys and consultants in GUD No. 10083 was directly relevant to the filing in this proceeding and due to the unique circumstances of these filings it is reasonable to allow recovery of those expenses for work product pertaining to this proceeding.

55. The rate case expenses in the amount of $650,000 are reasonable and it is reasonable that those expenses be recovered through a volumetric charge of $0.57 per Mcf until the $650,000 is recovered.

56. The attached *Settlement Agreement* and the attached tariffs are just and reasonable.

CONCLUSIONS OF LAW

1. Hughes Natural Gas, Inc., (HNG) is a "Gas Utility" as defined in TEX. UTIL. CODE ANN. §101.003(7) (Vernon 2007 and Supp. 2011) and §121.001(Vernon 2007) and is therefore subject to the jurisdiction of the Railroad Commission of Texas ("Commission").

2. The Commission has jurisdiction over HNG and HNG's Statement of Intent pursuant to TEX. UTIL. CODE ANN. §§ 102.001, 103.022, 103.054, 103.055, 104.001 and 104.201 (Vernon 2007 and Supp. 2011).

3. Under TEX. UTIL. CODE ANN. §102.001 (Vernon 2007 and Supp. 2011), the Commission has exclusive original jurisdiction over the rates and services of a gas utility that distributes natural gas in areas outside of a municipality and over the rates and services of a gas utility that transmits, transports, delivers, or sells natural gas to a gas utility that distributes the gas to the public.

4. This proceeding was conducted in accordance with the requirements of the Gas Utility regulatory Act (GURA), and the Administrative Procedure Act, TEX. GOV'T CODE ANN. §§ 2001.001 *et seq.* (Vernon 2008 & Supp. 2011) ("APA").

5. In accordance with TEX. UTIL. CODE ANN. §104.103 (Vernon 2007 and Supp. 2011), 16 TEX. ADMIN. CODE ANN. §§ 7.230 and 7.235, adequate notice was properly provided.

6. In accordance with TEX. UTIL. CODE ANN. §104.102 (Vernon 2007 and Supp. 2011), 16 TEX. ADMIN. CODE ANN. §§ 7.205 and 7.210, HNG filed its Statement of Intent to change gas distribution rates.

7. HNG failed to meet its burden of proof in accordance with the provisions of TEX. UTIL. CODE ANN. §104.008 (Vernon 2007 and Supp. 2011) on the elements of its requested rate increase identified in this order.

8. The revenue, rates, rate design, and service charges proposed by HNG are not found to be just and reasonable, not unreasonably preferential, prejudicial, or discriminatory, and are not sufficient, equitable, and consistent in application to each class of consumer, as required by TEX. UTIL. CODE ANN. §104.003 (Vernon 2007 and Supp. 2011).

9. The revenue, rates, rate design, and service charges proposed by HNG, as amended by the Commission and identified in the schedules attached to this order, are just and reasonable, are not unreasonably preferential, prejudicial, or discriminatory, and are sufficient, equitable, and consistent in application to each class of consumer, as required by TEX. UTIL. CODE ANN. (Vernon 2007 and Supp. 2011).

10. The Commission has assured that the rates, operations, and services established in this docket are just and reasonable to customers and to the utilities in accordance with the stated purpose of the Texas Utilities Code, Subtitle A, expressed under TEX. UTIL. CODE ANN. §101.002 (Vernon 2007).

11. The overall revenues as established by the findings of fact and attached schedules are reasonable; fix an overall level of revenues for HNG that will permit the company a reasonable opportunity to earn a reasonable return on its invested capital used and useful in providing service to the public over and above its reasonable and necessary operating expenses, as required by TEX. UTIL. CODE ANN. § 104.051 (Vernon 2007 and Supp. 2011); and otherwise comply with Chapter 104 of the Texas Utilities Code Annotated

12. The revenue, rates, rate design, and service charges proposed will not yield to HNG more than a fair return on the adjusted value of the invested capital used and useful in

rendering service to the public, as required by TEX. UTIL. CODE ANN. § 104.052 (Vernon 2007 and Supp. 2011).

13. The rates established in this docket comport with the requirements of TEX. UTIL. CODE ANN. §104.053 (Vernon 2007 and Supp. 2011) and are based upon the adjusted value of invested capital used and useful, where the adjusted value is a reasonable balance between the original cost, less depreciation, and current cost, less adjustment for present age and condition.

14. The rates established in this case comply with the affiliate transaction standard set out in TEX. UTIL. CODE ANN. § 104.055 (Vernon 2007 and Supp. 2011). Namely, in establishing a gas utility's rates, the regulatory authority may not allow a gas utility's payment to an affiliate for the cost of a service, property, right or other item or for an interest expense to be included as capital cost or an expense related to gas utility service expect to the extent that the regulatory authority finds the payment is reasonable and necessary for each item or class of items as determined by the regulatory authority. That finding must include (1) a specific finding of reasonableness and necessity to each class of items allowed; and (2) a finding that the price to the gas utility is not higher than the prices charged by the supplying affiliate to its other affiliates or divisions or to a nonaffiliated person for the same item or class of items.

15. GURA §104.053 allows the Commission to determine a reasonable rate base for HNG to earn on. Gas utility rates shall be based on the adjusted value of invested capital used and useful to the utility in providing service and that adjusted value shall be computed on the basis of a reasonable balance between: (1) original cost, less depreciation; and (2) current cost, less an adjustment for present age and condition. Furthermore, the regulatory authority may determine a reasonable balance that reflects: (1) not less than 60 percent nor more than 75 percent of the original cost of the property at the time the property was dedicated to public use, whether by the gas utility that is the present owner or by a predecessor, less depreciation; and (2) not less than 25 percent nor more than 40 percent of the current cost less an adjustment for present age and condition. Additionally, in determining a reasonable balance, the regulatory authority may consider inflation, deflation, quality of service being provided, growth rate of the service area, and need for the gas utility to attract new capital. Further, construction work in progress, at cost as recorded on the gas utility's books, may be included as part of the adjusted value of invested capital used by and useful to the utility in providing service, as necessary to the financial integrity of the utility. Costs of facilities, revenues, expenses, taxes, and reserves shall be separated or allocated as prescribed by the regulatory authority. The term "original cost" means the actual money cost or the actual money value of consideration paid other than money.

16. It is reasonable for the Commission to allow HNG to include a Purchased Gas Adjustment Clause in its rates to provide for the recovery of all of its gas costs, in accordance with 16 TEX. ADMIN. CODE § 7.5519.

17. HNG is required by 16 TEX. ADMIN. CODE §7.315 to file electronic tariffs incorporating rates consistent with this Order within thirty days of the date of this Order.

18. HNG has established that the company's books and records conform with 16 TEX. ADMIN. CODE § 7.310 to utilize the Federal Energy Regulatory Commission's (FERC) Uniform System of Accounts (USOA) prescribed for natural gas companies and HNG is thus entitled to the presumption that the amounts included therein are reasonable and necessary in accordance with Commission Rule 7.503

IT IS THEREFORE ORDERED that HNG's proposed schedule of rates is hereby **DENIED**.

IT IS FURTHER ORDERED that the rates, rate design, and service charges established in the findings of fact and conclusions of law and shown on the attached tariffs for HNG are **APPROVED**.

IT IS FURTHER ORDERED that the Settlement Agreement of the parties attached to this Final Order is hereby approved.

IT IS FURTHER ORDERED that, in accordance with 16 TEX. ADMIN. CODE §7.315, within 30 days of the date this Order is signed, HNG shall electronically file tariffs and rate schedules with the Gas Services Division. The tariffs shall incorporate rates, rate design, and service charges consistent with this Order, as stated in the findings of fact and conclusions of law and shown on the attached Schedules.

IT IS FURTHER ORDERED that a HNG to prepare a depreciation study prior to its next Statement of Intent proceeding

IT IS FURTHER ORDERED that all proposed findings of fact and conclusions of law not specifically adopted in this Order are hereby **DENIED**.

IT IS ALSO ORDERED that all pending motions and requests for relief not previously granted or granted herein are hereby **DENIED**.

This Order will not be final and effective until 20 days after a party is notified of the Commission's order. A party is presumed to have been notified of the Commission's order three days after the date on which the notice is actually mailed. If a timely motion for rehearing is filed by any party at interest, this order shall not become final and effective until such motion is overruled, or if such motion is granted, this order shall be subject to further action by the Commission. Pursuant to TEX. GOV'T CODE ANN. §2001.146(e), the time allotted for Commission action on a motion for rehearing in this case prior to its being overruled by operation of law, is hereby extended until 90 days from the date the order is served on the parties.

SIGNED this 26th day of March, 2013.

RAILROAD COMMISSION OF TEXAS

____

CHAIRMAN BARRY T. SMITHERMAN

____

COMMISSIONER DAVID PORTER

____

COMMISSIONER CHRISTI CRADDICK

ATTEST:

____

SECRETARY

FINAL ORDER EXHIBIT 1

BEFORE THE
RAILROAD COMMISSION OF TEXAS
GAS SERVICES DIVISION

RE: HUGHES NATURAL GAS, INC.	§	
STATEMENT OF INTENT TO CHANGE	§	
GAS DISTRIBUTION RATES IN THE	§	**GAS UTILITIES DOCKET**
UNINCORPORATED TOWNS AND RURAL	§	**NO. 10190**
AREAS OF AUSTIN, COLORADO, GRIMES,	§	
HARRIS, MONTGOMERY, AND WALLER	§	
COUNTIES, TEXAS	§	

SETTLEMENT AGREEMENT

The Signatories to this Settlement Agreement ("Agreement") are Hughes Natural Gas, Inc. ("HNG"), Staff of the Railroad Commission of Texas ("Staff") In addition, the City of Magnolia is a Signatory to portions of this Agreement. The City of Magnolia is in agreement with Article I: Sections (B), (D), and (F), and Article II in its entirety of this Agreement. The City of Magnolia takes no position with respect to the remaining Sections of the Agreement. In Article I: Sections (B), (D), and (F), and Article II, the term "Signatories" means HNG, Staff and the City of Magnolia. In all other Sections, the term "Signatories" means HNG and Staff. Intervenors Michael Kelley and Henry Oncken are not opposed to this Agreement.

RECITALS

WHEREAS, on July 6, 2012, HNG filed an application requesting authority to change its rates in the unincorporated towns and rural areas of Austin, Colorado, Grimes, Harris, Montgomery and Waller Counties, Texas; and

WHEREAS, the Commission docketed the rate case as GUD 10190; and

WHEREAS, Commission Staff and City of Magnolia sought intervention and were granted party status in GUD No. 10190; and

WHEREAS, on November 2, 2012, HNG supplemented its filing with a new test year ending September 30, 2012; and

WHEREAS, HNG's supplemental test year requested an overall revenue increase of approximately $947,000 consisting of a monthly customer charge of $23.61 and a volumetric charge of $8.3858 per Mcf. HNG also requested that the Commission approve a surcharge to recover all rate case expenses allowed by law; and

WHEREAS, on January 14, 2013, Staff and the City of Magnolia ("Magnolia") filed Direct Testimony; and

WHEREAS, on January 15, 2013, the Commission clarified the scope of the City of Magnolia's participation in Docket 10190; and

WHEREAS, on January 22, 2013, HNG filed its rate case expense update in this case.

WHEREAS, on January 30, 2013, Staff filed its Errata to Schedule 8 of the Direct Testimony of Mark Brock; and

WHEREAS, on January 30, 2013, the City of Magnolia filed its rate case expense update in this case; and

WHEREAS, on January 31, 2013, HNG filed its Rebuttal Testimony;

WHEREAS, between July 6, 2012 and February 4, 2013, the Signatories engaged in extensive discovery regarding the issues in dispute; and

WHEREAS, on February 5-6, 2013, the hearing on the merits in the above referenced case was conducted; and

WHEREAS, the Signatories agree that resolution of this docket by settlement agreement will significantly reduce the amount of reimbursable rate case expenses associated with this docket; and

WHEREAS, the Signatories wish to avoid the uncertainty, time, inconvenience and expense of further litigation by compromising, resolving and settling forever certain differences and matters in controversy among them with respect to HNG's Application in Docket 10190.

NOW, THEREFORE, in consideration of the mutual agreements and covenants established herein, the Signatories, through their undersigned representatives, agree to and recommend for approval by the Commission the following Settlement Terms as a means of concluding the above referenced docket filed by HNG for its environs customers without the need for protracted litigation:

ARTICLE I SETTLEMENT TERMS

The Signatories hereby enter into a settlement on the following terms:

A. **Rates**

1. The Signatories agree to the rates, terms and conditions reflected in the tariffs attached to this Settlement Agreement as Exhibit A. The tariffs attached as Exhibit A replace those tariffs currently in effect in the environs of HNG's service territory. These tariffs should allow HNG to recover an additional estimated $385,466 in annual base revenues in 2013 and an additional estimated $50,610 over and above 2013 base revenues one year from the date of the final order in this Docket, as illustrated in the proof of revenues attached as part of Exhibit B to this Settlement Agreement. Except as specifically provided herein, the Signatories agree that the total revenue increase is a "black box" figure and is not tied to any specific expense or rate base item. The Signatories further agree that the rates, terms and conditions reflected in Exhibit A to this Settlement Agreement comply with the rate setting requirements of Chapter 104 of the Texas Utilities Code. The gas rates, terms and conditions established by this Settlement

Agreement shall be effective for bills rendered on or after the date of approval by the Commission.

2. The Signatories agree to the following customer charges and volumetric rates to be applied to normalized, updated test year customer bills (40,488) and volumes (190,318 Mcf). These rates are reflected in the rate schedules attached as Exhibit A.

Customer Charge: $17.10 customer charge

Volumetric Charge: $7.05 volumetric charge

The above rates are estimates to equivalent revenues within the City of Magnolia that will be effective with the 2013 City of Magnolia Cost of Service Adjustment, assuming that the City's Cost of Service results in a rate increase capped at the percentage change in the Consumer Price Index for All Urban Customers for the applicable year.

3. The Signatories agree to the following customer charge and volumetric rates to be effective for bills rendered on or after one year after the date of the Final Order in GUD No. 10190:

Customer Charge: $18.35 customer charge

Volumetric Charge: $7.05 volumetric charge

The above rates are estimates to equivalent revenues within the City of Magnolia that will be effective with the 2014 City of Magnolia Cost of Service Adjustment, assuming that the City's Cost of Service results in a rate increase capped at the percentage change in the Consumer Price Index for All Urban Customers for the applicable year.

B. <u>Cost of Capital</u>

The Signatories agree to the following capital structure and cost of capital:

Return on Equity	10.60%
Debt Cost	7.0%
Capital Structure	55.5% equity/44.5% debt
Overall Return on Investment	9%

C. **Cap Gas**

1. The Signatories stipulate that the original cost associated with the assets acquired from Capital Gas Distribution, Inc. ("CapGas") shall be the amounts posted on the books and records of the Company based on the trending study performed by GDS (per the terms of existing settlement agreement), as reflected on Exhibit C to this Settlement Agreement.

2. The Signatories stipulate that a negative acquisition amount of $536,148 associated with the CapGas acquisition has been included in rate base for the purpose of setting rates in this proceeding.

3. The Signatories stipulate that the total negative acquisition amount on HNG's books and records shall be amortized over twelve years below the line beginning at the date incurred.

D. **Depreciation Rates**

The Signatories agree that the asset lives and depreciation rates reflected in Exhibit D to this Settlement Agreement are reasonable.

E. **Income Tax Expense**

The Signatories agree that HNG's reasonable income tax expense shall be calculated using a 35% income tax rate..

F. **Gas Purchasing and Capital Expenditures**

The Signatories agree in principle to jointly develop a transparent, expanded, competitive, annual request for bid process (with the assistance of a qualified third party consultant) related to gas purchasing practices and planned capital and maintenance expenditures within six months from the date of the Final Order in GUD No. 10190.

G. Relocation Cost Recovery Surcharge

In this Section G, the term "pipeline relocation cost" refers to the cost of relocating a facility to accommodate construction or improvement of a highway, road, street, public way, or other public work by or on behalf of the United States, Texas, a political subdivision of Texas, or another entity having eminent domain power that is not reimbursed by a source other than as provided in Tex. Util. Code 104.112.

The Signatories agree that the Pipeline Relocation Cost in FERC Account 106 related to the TxDOT FM 1774 Widening project at the end of the test year in the amount of $593,963 is not included within the rates approved in this docket. HNG, at its option, may make a future filing under GURA § 104.112 to recover the portion of Pipeline Relocation Cost included within this account (as well as any other Pipeline Relocation Cost incurred to complete the TxDOT FM 1774 Widening project) through a volumetric charge over 3 years.. This provision only addresses the TxDOT FM 1774 Widening project and does not limit the rights of the Signatories with respect to future relocation projects.

H. Future IRA Filings

1. HNG agrees that it will not file an IRA for the environs in calendar year 2013, and that its first IRA filing will occur no sooner than October 1, 2014 for the time period September 30, 2012 to December 31, 2013.

2. For purposes of the IRA, the following factors shall be used until changed by a subsequent rate proceeding:

a. The capital structure and related components as shown above in Section B;
b. For the initial IRA filing, the Net Investment as of September 30, 2012 as shown on Exhibit E;
c. Federal income tax will be calculated in accordance with Section E above.

I. <u>Rate Case Expenses</u>

The Signatories agree that rate case expenses in the amount of $650,000 are reasonable and may be recovered through a volumetric charge of $0.57 per Mcf until the $650,000 is recovered.

J. <u>Future Statement of Intent Filings</u>

Hughes agrees not file a statement of intent to increase environs rates for two years from the date of the final order in Docket 10190.

ARTICLE II MISCELLANEOUS

A. No Precedent

Because the matters resolved herein are resolved on the basis of compromise and settlement, nothing in this Agreement should be considered precedent. No Signatory shall be deemed to have agreed to the propriety of any theory or principle that may be said to underlie any of the issues resolved by this Agreement. Because this is a settlement, the Signatories recognize that no party is under any obligation to take the same position in any other docket, except as specifically required by this Agreement, whether or not the docket presents the same or similar circumstances. This Agreement is binding on each of the Signatories only for the purpose of settling the issues herein and for no other purpose. Oral and written statements made during the course of settlement negotiations shall not be used as an admission or concession of any sort or as evidence in this or any other proceeding.

B. Commission Approval

The Signatories agree that the terms of the Agreement are interdependent and indivisible, and that if the Commission enters an order that is inconsistent with this Agreement, then any Signatory may withdraw without being deemed to have waived any procedural right or to have taken any substantive position on any fact or issue by virtue of that Signatory's entry into the Agreement or its subsequent withdrawal.

C. Entire Agreement

This Agreement is the entire understanding and agreement of the Signatories to this Agreement and it supersedes prior understandings and agreements, if any, among the Signatories with respect to the subject matter of the Agreement. There are no representations, agreements, arrangements, or understandings, oral or written, concerning the subject matter hereof between and among the Signatories to this Agreement that are not fully expressed herein.

D. Authorization to Sign

Each person executing this Agreement represents that he or she is authorized to sign the Agreement on behalf of the party represented.

E. Countersigned Originals

This document may be countersigned by each Signatory on separate originals. Each signature shall be treated as if it is an original signature.

This Agreement has been executed, approved, and agreed to by the Signatories hereto in multiple counterparts, each of which shall be deemed an original, on the date indicated below by the Signatories hereto, by and through their undersigned duly authorized representatives. This Agreement shall be effective and binding when it is signed by all Signatories.

Signature Page 1

HNG Tammy Wavle Shea Counsel for HNG	Signed this 19th day of February, 2013.
Staff of Railroad Commission of Texas ____________________ John Pierce Griffin Counsel for Staff of Railroad Commission of Texas	Signed this ____ day of February, 2013.
City of Magnolia, Texas Stephen Mack Counsel for City of Magnolia	Signed this 19th day of February, 2013.

Signature Page 1

HNG OShea Tammy Wavle Shea Counsel for HNG	Signed this 19th day of February, 2013.
Staff of Railroad Commission of Texas John Pierce Griffin John Pierce Griffin Counsel for Staff of Railroad Commission of Texas	Signed this 19th day of February, 2013.
City of Magnolia, Texas ____________________ Stephen Mack Counsel for City of Magnolia	Signed this ____ day of February, 2013.

EXHIBIT A

HUGHES NATURAL GAS, INC.
TARIFF FOR NATURAL GAS SERVICE

1.0 General Tariff

1.1 **Application of tariffs.** The tariffs of Hughes Natural Gas, Inc. (Hughes) apply only to areas served by Hughes in the following named unincorporated areas:

Bellville environs, Brenham environs, Columbus environs, Conroe environs, Hempstead environs, Magnolia environs, Montgomery environs, Navasota environs, Prairie View environs, Stagecoach environs, Todd Mission environs, Tomball environs, Waller environs.

1.2 **(A) Rates.** The following rates are effective for bills rendered on and after the date of the Commission's Final Order in Gas Utilities Docket No. 10190:

1.2.1 Monthly Customer Charge, residential and commercial customers:
$17.10, applies per meter, per month

1.2.2 Volumetric Fee, residential and commercial customers:
$7.05, applies per thousand cubic feet (Mcf)

(B) Rates. The following rates are effective for bills rendered one year after the date of the Commission's Final Order in Gas Utilities Docket No. 10190:

1.2.3 Monthly Customer Charge, residential and commercial customers:
$18.35, applies per meter, per month

1.2.4 Volumetric Fee, residential and commercial customers:
$7.05, applies per thousand cubic feet (Mcf)

1.3 **Customer Bills.** Hughes' bills are rendered monthly to customers. Each bill shall include the following:

- Monthly Customer Charge,
- Volumetric Fee, as adjusted by the Weather Normalization Factor, if applicable,
- Cost of Gas,
- Tax Adjustment, if applicable
- Rate Case Expense Surcharge,
- Miscellaneous Service fees, if applicable,
- Deposit fees or credits, if applicable,
- Line Extension charges, if applicable, and
- Pipeline Safety and Regulatory Program Surcharge, once annually.

The Monthly Customer Charge is the minimum amount included on a customer bill.

Hughes may, at its option, bill the Volumetric Fee in thousands of cubic feet (Mcf) or in hundreds of cubic feet (Ccf). The Volumetric Fee per Ccf is $1/10^{th}$ of the Volumetric Fee per Mcf.

The due date for remittance of a payment to Hughes shall be not less than 15 days after the date the bill is issued, in accordance with 16 TEX. ADMIN. CODE §7.45(4)(A). Hughes late payment fee applicable to bill payments received after the due date is zero ($0.00).

1.4 **Tax Adjustment.** Any applicable Taxes including ad Valorem Taxes and State Franchise Taxes affecting the Cost of Service shall be reflected as separate line items specifically identifying the tax on Customer invoices, and shall be reported to the Commission. The tax adjustment shall be an amount equivalent to the proportionate part of an existing tax or new tax or any governmental imposition, rental fee, or charge levies, assessed or imposed subsequent to the effective date of this tariff.

1.4.1 Formula. The tax adjustment is calculated in accordance with the following formula:

Tax Amount

Divided by

Volume (Mcf) billed that month

Equals

Tax adjustment, applied per Mcf

In this formula, the Volume (Mcf) billed refers to the volume of gas sold during the usage month that the adjustment is included on customer bills.

1.4.2 Reconciliation. Within 45 days after applying a tax adjustment and collecting the adjustment, the Company shall provide the Commission a reconciliation detailing the calculation of the adjustment and reconciling the amounts collected. If the reconciliation reflects either an over-recovery or an under-recovery of revenues of more than $0.50 per customer, such amount shall be carried forward and applied in the next billing cycle. If the over-recovery or an under-recovery of revenues is less than $0.50 per customer, the Company shall carry-forward the amount until the next application of the tax adjustment.

2.0 Weather Normalization Tariff

2.1 **WNF**. The Weather Normalization Factor (WNF) is a factor that adjusts the Volumetric Fee for each 1,000 cubic feet (Mcf) of natural gas sold. The WNF is designed to refund over-collections and to surcharge for under-collections of revenue due to colder than normal or warmer than normal weather. In order to reflect weather variances in a timely and accurate manner, the WNF is calculated monthly and is based on monthly weather information for the five-month period beginning with November and ending with March.

2.2 **Formula**. The WNF is calculated, as follows:

[Adjusted Heating Load plus Base Non-Heating Load] divided by Total Volumes Sold

Where:

Adjusted Heating Load (Mcf) = Heating Load divided by HDD Factor

AvgHDD = Average heating degree-days for a calendar month as measured by the National Oceanic and Atmospheric Administration (NOAA) for the period 1980 through 2010 at their weather station in Conroe, Texas. The AvgHDD values used to calculate the WNF are: November 191, December 428, January 453, February 320, March 172.

Base Non-Heating Load (Mcf) = 2.00 times the number of bills issued

Bills = Number of bills issued to customers for gas sold that month

HDD = A heating degree day is a measurement of demand for energy to heat houses and businesses. The WNF is based upon actual heating degree-days for a calendar month as measured by the NOAA at their weather station located in Conroe, Texas.

HDD Factor (Heating Degree-Day Factor) = HDD divided by AvgHDD

Heating Load (Mcf) = Total Volumes Sold minus Base Non-Heating Load

Weather Normalization months = November, December, January, February, March

2.3 **Report.** Within 45 days from the last day in each Weather Normalization month, the company shall provide to the Commission, in spreadsheet format, one *WNF Compliance Report* per month to demonstrate how the company calculated the WNF, using the following format:

FORMAT FOR WNF COMPLIANCE REPORT

Line 1	AvgHDD
Lines 2-3	blank
Line 4	HDDs (for Conroe weather station)
Lines 5-6	blank
Line 7	Bills
Line 8	blank
Line 9	Base Non-heating load (Mcf), which is Line 7 times 2.19
Line 10	blank
Line 11	Total Volumes Sold
Line 12	blank
Line 13	Heating Load (Mcf), which is Line 11 minus Line 9
Lines 14-15	blank
Line 16	HDD Factor, which is Line 4 divided by Line 2
Line 17	blank
Line 18	Adjusted Heating Load (Mcf), which is Line 13 divided by Line 16
Line 19	blank
Line 20	WNF, which is [(Line 18 plus Line 9) divided by Line 11)]
Lines 21-22	blank
Line 23	Volumetric Fee ($ per Mcf)
Line 24	blank
Line 25	Adjusted Volumetric Fee (Line 23 times Line 20)
Lines 26-27	blank
Line 28	Effect on revenue, which is [(Line 25 minus Line 23) x Line 11)]

Each report shall have a column of data for each of the five Weather Normalization months, with fields populated for the latest and prior months in a winter season.

3.0 Cost of Gas Tariff

3.1 Identification on bills. Hughes shall include on each customer bill the reasonable and necessary cost of gas purchased by Hughes.

3.2 Definitions. The following definitions apply to this Cost of Gas Tariff:

3.2.1 Cost of Gas. The total calculation, under this Cost of Gas Tariff, consisting of the commodity cost, a reconciliation component, and related fees and taxes.

3.2.2 Cost of purchased gas. The weighted average cost of gas purchased by Hughes from all sources, calculated by summing the cost of gas purchased and applicable third party charges, then, dividing that sum by total volumes purchased.

3.2.3 Purchases / Sales ratio. A ratio determined by dividing the total volumes purchased for customers during the twelve month period ending June 30 by the sum of volumes sold to customers. For the purpose of this computation, all volumes shall be stated at 14.65 pound-force per square inch absolute (psia). Such ratio shall in no event exceed 1.0526 i.e. 1 / (1 - .05) unless expressly authorized by the applicable regulatory authority.

3.2.4 Reconciliation account. The account maintained by Hughes to ensure that, over time, Hughes will neither over-collect nor under-collect revenues as a result of the operation of this Cost of Gas Tariff. Entries shall be made monthly to reflect:

- the total amounts paid to Hughes' suppliers for natural gas applicable to general service customers, as recorded in the company's books and records,
- revenues produced by the operation of this Cost of Gas Tariff,
- refunds, payments, or charges provided for herein or as approved by the regulatory authority.

3.2.5 Reconciliation audit. An annual review by Hughes of its books and records for each twelve month period ending with the June accounting month to determine the amount of over-collection or under-collection occurring during that twelve month period. The reconciliation audit conducted by Hughes shall determine:

- the total amount paid for gas purchased by Hughes to provide service to its general service customers during the period,
- the revenues received from operation of the provision of this Cost of Gas Tariff, reduced by the amount of revenue-associated fees and taxes paid on those revenues,
- the total amount of refunds made to customers during the period and any other revenues or credits received by Hughes as a result of relevant gas purchases or operation of this Cost of Gas Tariff,
- an adjustment, if necessary, for lost and unaccounted for gas during the period in excess of five (5) percent of purchases.

3.2.6 Reconciliation component. The amount to be returned to or recovered from customers each month on customer bills covering usage for September through May, as a result of Hughes' reconciliation audit.

3.3 **Determination and application of the reconciliation component.** If the reconciliation audit reflects either an over-recovery or an under-recovery of revenues, such amount shall be divided by the general service customer sales volumes, for the period beginning with the preceding October billing cycle through the June billing cycle. The reconciliation component, so determined to collect any revenue shortfall or to return any excess revenue, shall be applied for a nine (9) month period beginning with the next October billing cycle and continuing through the next June billing cycle at which time it will terminate until a new reconciliation component is determined.

3.4 **Surcharge or refund procedures.** In the event that the rates and charges of Hughes' suppliers are retroactively reduced, and a refund of any previous payment is made to Hughes, Hughes shall make a similar refund to its general service customers. Similarly, Hughes may surcharge its general service customers for retroactive payments made for gas previously delivered into the system. If the payment or refund related to gas purchased by Hughes is for a period of twelve consecutive months or longer, the total amount recovered or refunded shall be divided by the general services sales made to general service customers during this applicable period. With regard to amounts received or paid that are applicable to periods less than twelve consecutive months, Hughes shall refund or collect such amounts using one of the following three methods:

3.4.1 over the same period of time as the over-charge or under-charge occurred,

3.4.2 over the same number of units sold during the period of the over-charge or under-charge, or

3.4.3 include the entire amount in the reconciliation account. Refunds or charges shall be entered into the reconciliation account as they are collected from or returned to customers. For the purpose of Sec. 3.5, the entry shall be made on the same basis used to determine the refund or charge component of the cost of gas and shall be subject to the calculation set forth in Sec. 3.4, above.

3.5 **Report.** By August 31 of each year, Hughes shall file with the Commission, an annual *Cost of Gas Reconciliation Report*. The annual reconciliation report shall include, but not necessarily be limited to:

3.6.1 a tabulation of volumes of gas purchased and costs incurred listed by account or type of gas, supplier and source, by month, for the twelve months ending June 30;

3.6.2 a tabulation of gas volumes sold to general service customers and the related Cost of Gas Tariff revenues;

3.6.3 a summary of all other costs and refunds made during the year and the status of the reconciliation account.

4.0 Pipeline Safety and Regulatory Program Tariff

4.1 **Fee**. Once annually, Hughes' shall remit to the Commission the fee required in 16 TEX. ADMIN. CODE §8.201.

4.2 **Surcharge**. During the next billing cycle following Hughes' remittance to the Commission of the fee, Hughes shall include on its customers' bills a Pipeline Safety and Regulatory Program Surcharge, to the extent authorized in 16 TEX. ADMIN. CODE §8.201.

4.3 **Formula.** The Rule 8.201 surcharge is calculated in accordance with the following formula:

Rule 8.201(b) fee assessed by the Commission on Hughes
Divided by
Number of meters billed
Equals
Rule 8.201(b)(3) surcharge, applied per customer meter, once annually

In this formula, the number of meters billed refers to the number of meters billed during the billing month that precedes the month the Rule 8.201(b)(3) surcharge is included on customer bills.

5.0 Rate Case Expense Surcharge

5.1 The Rate case Expense Surcharge shall be in effect beginning on or after the date of the Commission's Final Order in Gas Utilities Docket No. 10190 and will continue for approximately six years until all of the rate case expense recovery approved in the Final Order is fully recovered.

5.2 The surcharge rate shall be $0.57 per Mcf.

5.3 Formula:

Fee Approved by the Commission of $0.57 per Mcf

Multiplied by

Volume (Mcf) billed that month

Equals

the Rate Case Expense Surcharge on that bill

5.4 This surcharge is in addition to other rates and surcharges set forth in this tariff.

5.5 Report. Hughes shall file an annual Reconciliation of the Rate Case Expense Surcharge collected during the previous calendar year with the Commission. The Report shall be filed when the RRC Annual Report is filed.

6.0 Miscellaneous Services Tariff

6.1 New service and restoration of service

Initiation of new service	$45, per trip
Restoration of service, after termination for non-payment or for a leak on a customer-owned facility	$45, per trip
Restoration of service, after service turn-off at request of customer or customer's agent	$45, per trip
Restoration of service, following a system disruption due to a natural disaster or an area emergency	$0.00, per trip

6.2 Turn-off service

Turn-off service, after termination for non-payment or for a leak on a customer-owned facility	$45, per turn-off
Turn-off service, at request of customer or customer's agent	$45, per turn-off
Turn-off service, following a system disruption due to a natural disaster or an area emergency	$0.00, per turn-off

6.3 Meter testing

Remove existing meter for testing as requested by customer (including setting a suitable replacement at existing tap), when no such test has been performed on the meter in four (4) or more years or when meter is found to be more than nominally defective per 16 TAC §7.45(7)(B)(iv)(II).	$0.00
Customer Service Agent charge associated with meter testing requested by the customer, only if the meter has been tested within the past four (4) years and, upon retesting, meter is found to correctly record usage.	Actual cost, up to $26.23 per hour
Field Service Technician charge and vehicle operations costs associated with meter testing requested by the customer, only if the meter has been tested within the past four (4) years and, upon retesting, meter is found to correctly record usage.	Actual cost, up to $30.84 per hour, maximum $89.95 per trip

6.4	**Change customer meter**	$75, per trip, plus materials
6.5	**Change residential meter location**	$350 first meter, plus materials
6.6	**Additional meters in manifold**	$55, per meter
6.7	**Meter re-read**	
	Meter re-read, when the meter has not been tested in more than four years or when the meter is found to be more than nominally defective.	$0.00
	Meter re-read requested by customer, if the meter has been tested within four years and the prior meter read is found to be correct.	$35, per trip
6.8	**Collection call**	$35, per trip
6.9	**Returned check charge**	$30, per return

7.0 Deposit Tariff

7.1 **Application.** Hughes may require a customer deposit from a customer that does not have acceptable credit bureau or other utility report of good standing.

7.2 **Formula.** If a customer is required to make a deposit, the amount of the deposit shall not exceed an amount equivalent to one-sixth of the customer's estimated annual billings. If there is no billing history on the customer's account, then the one-sixth rule will be applied to the customer's account based on similarly-situated customers located in the geographic area.

7.3 **Exemptions.** Hughes shall not require a person who is exempt from deposit requirements to make a deposit, as outlined in 16 TEX. ADMIN. CODE §7.45(5)(C).

7.4 **Deposit refunds.** Hughes shall automatically refund each deposit, with interest, to customers who meet the requirements in 16 TEX. ADMIN. CODE §7.45(5)(F).

7.5 **Deposit practices.** Hughes has adopted the deposit practices in the Commission's Quality of Service Rule at 16 TEX. ADMIN. CODE §7.45(5).

8.0 Line Extension Tariff

8.1 New mains, 100 feet or less. Hughes' charge for installation and extension of new mains, under normal conditions, not larger than two inches in diameter and not more than 100 feet in length is $0.00.

8.2 New mains, more than 100 feet. For installation and extension of new mains, under normal conditions, not larger than two inches in diameter, after the first 100 feet, Hughes charges the actual cost.

8.3 Reporting requirement. Hughes shall provide a copy of its most current line extension policy to the Commission, addressed to the Director of the Gas Services Division. No contribution in aid of construction will be required of any customer except as provided for in Hughes' line extension policy filed with the Commission, as set forth in 16 TEX. ADMIN. CODE §7.45(8)(B).

9.0 Quality of Service Tariff

Hughes has adopted the Quality of Services standards in the Commission's Quality of Service rules, as set forth in 16 TEX. ADMIN. CODE §7.45. The Commission's Quality of Services rules outline requirements applicable to continuity of service, customer relations, refusals of service, discontinuance of service, deposits, billing, meters, and new construction.

10.0 Curtailment Tariff

Hughes has adopted the Commission's curtailment requirements in 16 TEX. ADMIN. CODE §7.305 and §7.455 and in the Commission's Order in Gas Utilities Docket No. 489.

EXHIBIT B

HUGHES NATURAL GAS, INC.
UPDATED TEST YEAR ENDING SEPTEMBER 30, 2012

PROOF OF REVENUE

Line No.	Description	Normalized Billing Determinants	Normalized Base Revenue	Proposed Rates Rate Design	Base With Increase	Total Base Increase	Proposed Total Revenues	Percentage Increase
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
	Unincorporated Service Area Only							
	At Final Order GUD No. 10190 Date							
1	MCF	190,317.9	$ 1,021,055	**$7.0500**	$ 1,341,741	$ 320,686	$ 1,341,741	31.41%
2	Bills	40,488	627,564	**$17.10**	692,345	64,781	692,345	10.32%
3	Total		$ 1,648,619		$ 2,034,086	$ 385,466	$ 2,034,086	**23.38%**
	One Year After Final Order GUD No. 10190 Date							
4	MCF	190,317.9	$ 1,341,741	**$7.0500**	$ 1,341,741	$ -	$ 1,341,741	0.00%
5	Bills	40,488	692,345	**$18.35**	742,955	50,610	742,955	7.31%
6	Total		$ 2,034,086		$ 2,084,696	$ 50,610	$ 2,084,696	**2.49%**

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1/14/13 0

BEFORE THE
RAILROAD COMMISSION OF TEXAS
GAS SERVICES DIVISION

RE: HUGHES NATURAL GAS, INC. STATEMENT OF INTENT TO CHANGE GAS DISTRIBUTION RATES IN THE UNINCORPORATED TOWNS AND RURAL AREAS OF AUSTIN, COLORADO, GRIMES, HARRIS, MONTGOMERY, AND WALLER COUNTIES, TEXAS	§ § § § § § §	GAS UTILITIES DOCKET NO. 10190

NONUNANIMOUS SETTLEMENT AGREEMENT

The Signatories to this NonUnanimous Stipulation (Stipulation) are Hughes Natural Gas, Inc. (HNG) and Staff of the Railroad Commission of Texas (Staff).[1] The parties who are signing the Stipulation shall be referred to individually either as a Signatory or by the acronym assigned above, and collectively as the Signatories.

RECITALS

WHEREAS, on July 6, 2012, HNG filed an application in Commission Docket No. 10190 requesting authority to change its rates;

WHEREAS, on November 2, 2012, HNG supplemented its filing with a new test year ending September 30, 2012;

WHEREAS, on December 12, 2012, a settlement conference was held among Staff, the City of Magnolia, and HNG;

WHEREAS, the Signatories wish to avoid the uncertainty, time, inconvenience and expense of further litigation by compromising, resolving and settling forever certain differences and matters in controversy among them with respect to HNG's Application in Docket 10102.

[1] HNG has been informed that the City of Magnolia is opposed to this Stipulation. HNG is not aware of the positions of the other intervenors.

NOW, THEREFORE, the Signatories, through their undersigned representatives, agree to the following:

ARTICLE I

The Signatories hereby enter into a settlement on the following terms:

A. HNG's capital structure for the purposes of ratemaking in this proceeding shall be comprised of 44.5% debt and 55.5% equity.

B. A negative acquisition amount of $536,148 associated with the CapGas acquisition will be included in rate base for the purpose of setting rates in this docket as reflected in Updated Exhibit CEL-6, attached hereto as Exhibit A.

C. The total negative acquisition amount on HNG's books and records shall be amortized over twelve years below the line beginning at the date incurred.

ARTICLE II

A. No Precedent

Because the matters resolved herein are resolved on the basis of compromise and settlement, nothing in this Stipulation should be considered precedent. No Signatory shall be deemed to have agreed to the propriety of any theory or principle that may be said to underlie any of the issues resolved by this Stipulation. Because this is a settlement, the Signatories recognize that no party is under any obligation to take the same position in any other docket, except as specifically required by this Stipulation, whether or not the docket presents the same or similar circumstances. This Stipulation is binding on each of the Signatories only for the purpose of settling the issues herein and for no other purpose. Oral and written statements made during the course of settlement negotiations shall not be used as an admission or concession of any sort or as evidence in this or any other proceeding.

B. Entire Agreement

This Stipulation is the entire understanding and agreement of the parties to this Stipulation, and it supersedes prior understandings and agreements, if any, among the parties with respect to the subject matter of the Stipulation. There are no representations, agreements, arrangements, or understandings, oral or written, concerning the subject matter hereof between and among the parties to this Stipulation which are not fully expressed herein.

C. Authorization to Sign

Each person executing this Stipulation represents that he or she is authorized to sign the Stipulation on behalf of the party represented.

D. Countersigned Originals

This document may be countersigned by each Signatory on separate originals. Each signature shall be treated as if it is an original signature.

This Stipulation has been executed, approved, and agreed to by the Signatories hereto in multiple counterparts, each of which shall be deemed an original, on the date indicated below by the Signatories hereto, by and through their undersigned duly authorized representatives. This Stipulation shall be effective and binding when it is signed by all Signatories.

Signature Page 1

HNG Tammy Shea Tammy Wavle Shea Counsel for HNG	Signed this 14th day of January, 2012.
Staff of Railroad Commission of Texas John Pierce Griffin John Griffin Counsel for Staff of Railroad Commission of Texas	Signed this 14th day of January, 2012.

HUGHES NATURAL GAS, INC.
UPDATED TEST YEAR ENDING SEPTEMBER 30, 2012

COMPUTATION OF CAPGAS ACQUSITION ADJUSTMENT TO BE REFLECTED IN RATE BASE
USING FAIR VALUE MIX OF 70% CAPGAS BOOKS TO 30% REPLACEMENT COST ADJUSTED FOR AGE & CONDITION PER GUD No. 8310-8316

Line No	Description	Adjusted 2007 Annual Report Value *	Apply 70% Fair Value (B)	GDS Study Replacement Cost	Apply 30% Fair Value (D)	Fair Value Col (C) + (E) Plant	Plant Retired	Depr Exp 1/2008 thru 9/2012	Fair Value Plant Per Rate Base
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
1	(376) Mains	$342,383	$239,668	$2,285,845	$685,754	$925,422	($63,998)		$861,424
2	Accum. Depr./ Age & Cond	($96,835)	($67,785)	($1,025,063)	($307,519)	($375,304)	$58,274	($109,894)	($426,923)
3	(378) Meas & Reg Station	$76,418	$53,493	$455,979	$136,794	$190,286	($40,067)		$150,219
4	Accum. Depr./ Age & Cond	($33,337)	($23,336)	($252,061)	($75,618)	($98,954)	$37,875	($27,387)	($88,466)
5	(380) Services	$307,649	$215,354	$1,824,576	$547,373	$762,727	($13,171)		$749,556
6	Accum. Depr./ Age & Cond	($182,286)	($127,600)	($1,145,886)	($343,766)	($471,366)	$13,171	($144,918)	($603,113)
7	Total Gross	$726,450	$508,515	$4,566,400	$1,369,920	$1,878,435	($117,235)		$1,761,200
8	Total Accum Depr	($312,458)	($218,720)	($2,423,010)	($726,903)	($945,623)	$109,320	($282,199)	($1,118,502)
9		$413,992	$289,795	$2,143,390	$643,017	$932,812	($7,915)	($282,199)	$642,697
10	As Reflected in Plant as of 9/30/2012 In Schedules Filed on November 2, 2012 in Schedule B-3.1								$1,178,846
11	Rate Making Acqusition Adjustment to be Reflected in Rate Base Per Agreed Settlement with Staff								($536,148)

Adjust CapGas 2007 Annual Report Amount to Estimate Straight Line Depreciation

*	Gross Plant Per Annual Report	$726,450
	Apply Original Cost Study Accumulated Depr/Gross Plant Ratio	($312,458)
	$1,251,281 / $2,909,171 = 43.01%	
	Allocate Estimated Net Plant on Original Cost Study Values	$413,992

Fraley, Deborah E.

From: Fraley, Deborah E.
Sent: Tuesday, January 15, 2013 1:54 PM
To: Daniel J. Lawton; Stephen Mack; 'John Griffin'; Michael C. Kelley
Cc: Shea, Tammy; realp@hughesnaturalgas.com; Stone, David; 'Nick Weaver'
Subject: HNG/Dkt. No. 10190; Statement of Intent to Increase Gas Rates - Nonunanimous Settlement Agreement
Attachments: 2773_001.pdf.pdf

Attached please find a copy of the executed Nonunanimous Settlement Agreement.

Fraley, Deborah E.

From: Fraley, Deborah E.
Sent: Wednesday, January 16, 2013 9:16 AM
To: C. Mark Evarts (Mark.Evarts@rrc.state.tx.us)
Cc: Shea, Tammy; realp@hughesnaturalgas.com; Stone, David; 'Nick Weaver'
Subject: HNG/Dkt. No. 10190; Statement of Intent to Increase Gas Rates
Attachments: 2787_001.pdf.pdf; 2788_001.pdf.pdf

Mr. Evarts,

Attached please find executed copies of the Nonunanimous Settlement Agreement and bond filing.

EXHIBIT D

HUGHES NATURAL GAS, INC.

UPDATED TEST YEAR ENDING SEPTEMBER 30, 2012
DETAIL OF PLANT DEPRECIATION RATES

Line No	Description (A)	Service Life (C)	Annual Depreciation (D)
1	**Intangible**	n/a	n/a
	DISTRIBUTION PLANT		
2	(374) Land & Land Rights	n/a	n/a
3	(376) Mains	40	2.50%
4	(379) Meas & Reg Station	33	3.03%
5	(380) Services	25	4.00%
	GENERAL PLANT		
6	(391) Office Furniture & Equipment	10	10.00%
7	(392) Transportation Equipment	3	33.33%
8	(397) Comm., Comp & Software	5	20.00%
9	(398) Miscellaneous General Plant	5	20.00%

EXHIBIT E

HUGHES NATURAL GAS, INC.
UPDATED TEST YEAR ENDING SEPTEMBER 30, 2012
CALCULATION OF INVESTMENT FOR FUTURE IRA FILINGS

Line No	Description	Schedule Reference	Plant Per Books
	(A)		(B)
1	Intangible Plant	Sch B-1	$ 300
2	Distribution Plant	Sch B-1	12,525,104
3	General Plant	Sch B-1	411,412
4	Gross Plant In Service		$ 12,936,816
5	Depr & Amort Reserves	Sch B-2	(3,296,084)
6	Net Plant in Service	Sch B	**$ 9,640,732**

FINAL ORDER EXHIBIT 2

HUGHES NATURAL GAS, INC.
TARIFF FOR NATURAL GAS SERVICE

1.0 General Tariff

1.1 Application of tariffs. The tariffs of Hughes Natural Gas, Inc. (Hughes) apply only to areas served by Hughes in the following named unincorporated areas:

Bellville environs, Brenham environs, Columbus environs, Conroe environs, Hempstead environs, Magnolia environs, Montgomery environs, Navasota environs, Prairie View environs, Stagecoach environs, Todd Mission environs, Tomball environs, Waller environs.

1.2 (A) Rates. The following rates are effective for bills rendered on and after the date of the Commission's Final Order in Gas Utilities Docket No. 10190:

1.2.1 Monthly Customer Charge, residential and commercial customers:
$17.10, applies per meter, per month

1.2.2 Volumetric Fee, residential and commercial customers:
$7.05, applies per thousand cubic feet (Mcf)

(B) Rates. The following rates are effective for bills rendered one year after the date of the Commission's Final Order in Gas Utilities Docket No. 10190:

1.2.3 Monthly Customer Charge, residential and commercial customers:
$18.35, applies per meter, per month

1.2.4 Volumetric Fee, residential and commercial customers:
$7.05, applies per thousand cubic feet (Mcf)

1.3 Customer Bills. Hughes' bills are rendered monthly to customers. Each bill shall include the following:

- Monthly Customer Charge,
- Volumetric Fee, as adjusted by the Weather Normalization Factor, if applicable,
- Cost of Gas,
- Tax Adjustment, if applicable
- Rate Case Expense Surcharge,
- Miscellaneous Service fees, if applicable,
- Deposit fees or credits, if applicable,
- Line Extension charges, if applicable, and
- Pipeline Safety and Regulatory Program Surcharge, once annually.

The Monthly Customer Charge is the minimum amount included on a customer bill.

Hughes may, at its option, bill the Volumetric Fee in thousands of cubic feet (Mcf) or in hundreds of cubic feet (Ccf). The Volumetric Fee per Ccf is 1/10th of the Volumetric Fee per Mcf.

The due date for remittance of a payment to Hughes shall be not less than 15 days after the date the bill is issued, in accordance with 16 TEX. ADMIN. CODE §7.45(4)(A). Hughes late payment fee applicable to bill payments received after the due date is zero ($0.00).

1.4 **Tax Adjustment.** Any applicable Taxes including ad Valorem Taxes and State Franchise Taxes affecting the Cost of Service shall be reflected as separate line items specifically identifying the tax on Customer invoices, and shall be reported to the Commission. The tax adjustment shall be an amount equivalent to the proportionate part of an existing tax or new tax or any governmental imposition, rental fee, or charge levies, assessed or imposed subsequent to the effective date of this tariff.

1.4.1 Formula. The tax adjustment is calculated in accordance with the following formula:

Tax Amount

Divided by

Volume (Mcf) billed that month

Equals

Tax adjustment, applied per Mcf

In this formula, the Volume (Mcf) billed refers to the volume of gas sold during the usage month that the adjustment is included on customer bills.

1.4.2 Reconciliation. Within 45 days after applying a tax adjustment and collecting the adjustment, the Company shall provide the Commission a reconciliation detailing the calculation of the adjustment and reconciling the amounts collected. If the reconciliation reflects either an over-recovery or an under-recovery of revenues of more than $0.50 per customer, such amount shall be carried forward and applied in the next billing cycle. If the over-recovery or an under-recovery of revenues is less than $0.50 per customer, the Company shall carry-forward the amount until the next application of the tax adjustment.

2.0 Weather Normalization Tariff

2.1 **WNF**. The Weather Normalization Factor (WNF) is a factor that adjusts the Volumetric Fee for each 1,000 cubic feet (Mcf) of natural gas sold. The WNF is designed to refund over-collections and to surcharge for under-collections of revenue due to colder than normal or warmer than normal weather. In order to reflect weather variances in a timely and accurate manner, the WNF is calculated monthly and is based on monthly weather information for the five-month period beginning with November and ending with March.

2.2 **Formula**. The WNF is calculated, as follows:

[Adjusted Heating Load plus Base Non-Heating Load] divided by Total Volumes Sold

Where:

Adjusted Heating Load (Mcf) = Heating Load divided by HDD Factor

AvgHDD = Average heating degree-days for a calendar month as measured by the National Oceanic and Atmospheric Administration (NOAA) for the period 1980 through 2010 at their weather station in Conroe, Texas. The AvgHDD values used to calculate the WNF are: November 191, December 428, January 453, February 320, March 172.

Base Non-Heating Load (Mcf) = 2.00 times the number of bills issued

Bills = Number of bills issued to customers for gas sold that month

HDD = A heating degree day is a measurement of demand for energy to heat houses and businesses. The WNF is based upon actual heating degree-days for a calendar month as measured by the NOAA at their weather station located in Conroe, Texas.

HDD Factor (Heating Degree-Day Factor) = HDD divided by AvgHDD

Heating Load (Mcf) = Total Volumes Sold minus Base Non-Heating Load

Weather Normalization months = November, December, January, February, March

2.3 **Report**. Within 45 days from the last day in each Weather Normalization month, the company shall provide to the Commission, in spreadsheet format, one *WNF Compliance Report* per month to demonstrate how the company calculated the WNF, using the following format:

FORMAT FOR WNF COMPLIANCE REPORT

Line 1	AvgHDD
Lines 2-3	blank
Line 4	HDDs (for Conroe weather station)
Lines 5-6	blank
Line 7	Bills
Line 8	blank
Line 9	Base Non-heating load (Mcf), which is Line 7 times 2.19
Line 10	blank
Line 11	Total Volumes Sold
Line 12	blank
Line 13	Heating Load (Mcf), which is Line 11 minus Line 9
Lines 14-15	blank
Line 16	HDD Factor, which is Line 4 divided by Line 2
Line 17	blank
Line 18	Adjusted Heating Load (Mcf), which is Line 13 divided by Line 16
Line 19	blank
Line 20	WNF, which is [(Line 18 plus Line 9) divided by Line 11)]
Lines 21-22	blank
Line 23	Volumetric Fee ($ per Mcf)
Line 24	blank
Line 25	Adjusted Volumetric Fee (Line 23 times Line 20)
Lines 26-27	blank
Line 28	Effect on revenue, which is [(Line 25 minus Line 23) x Line 11)]

Each report shall have a column of data for each of the five Weather Normalization months, with fields populated for the latest and prior months in a winter season.

3.0 **Cost of Gas Tariff**

3.1 **Identification on bills**. Hughes shall include on each customer bill the reasonable and necessary cost of gas purchased by Hughes.

3.2 **Definitions**. The following definitions apply to this Cost of Gas Tariff:

3.2.1 Cost of Gas. The total calculation, under this Cost of Gas Tariff, consisting of the commodity cost, a reconciliation component, and related fees and taxes.

3.2.2 Cost of purchased gas. The weighted average cost of gas purchased by Hughes from all sources, calculated by summing the cost of gas purchased and applicable third party charges, then, dividing that sum by total volumes purchased.

3.2.3 Purchases / Sales ratio. A ratio determined by dividing the total volumes purchased for customers during the twelve month period ending June 30 by the sum of volumes sold to customers. For the purpose of this computation, all volumes shall be stated at 14.65 pound-force per square inch absolute (psia). Such ratio shall in no event exceed 1.0526 i.e. 1 / (1 - .05) unless expressly authorized by the applicable regulatory authority.

3.2.4 Reconciliation account. The account maintained by Hughes to ensure that, over time, Hughes will neither over-collect nor under-collect revenues as a result of the operation of this Cost of Gas Tariff. Entries shall be made monthly to reflect:

- the total amounts paid to Hughes' suppliers for natural gas applicable to general service customers, as recorded in the company's books and records,

- revenues produced by the operation of this Cost of Gas Tariff,

- refunds, payments, or charges provided for herein or as approved by the regulatory authority.

3.2.5 Reconciliation audit. An annual review by Hughes of its books and records for each twelve month period ending with the June accounting month to determine the amount of over-collection or under-collection occurring during that twelve month period. The reconciliation audit conducted by Hughes shall determine:

- the total amount paid for gas purchased by Hughes to provide service to its general service customers during the period,

- the revenues received from operation of the provision of this Cost of Gas Tariff, reduced by the amount of revenue-associated fees and taxes paid on those revenues,

- the total amount of refunds made to customers during the period and any other revenues or credits received by Hughes as a result of relevant gas purchases or operation of this Cost of Gas Tariff,

- an adjustment, if necessary, for lost and unaccounted for gas during the period in excess of five (5) percent of purchases.

3.2.6 Reconciliation component. The amount to be returned to or recovered from customers each month on customer bills covering usage for September through May, as a result of Hughes' reconciliation audit.

3.3 **Determination and application of the reconciliation component**. If the reconciliation audit reflects either an over-recovery or an under-recovery of revenues, such amount shall be divided by the general service customer sales volumes, for the period beginning with the preceding October billing cycle through the June billing cycle. The reconciliation component, so determined to collect any revenue shortfall or to return any excess revenue, shall be applied for a nine (9) month period beginning with the next October billing cycle and continuing through the next June billing cycle at which time it will terminate until a new reconciliation component is determined.

3.4 **Surcharge or refund procedures**. In the event that the rates and charges of Hughes' suppliers are retroactively reduced, and a refund of any previous payment is made to Hughes, Hughes shall make a similar refund to its general service customers. Similarly, Hughes may surcharge its general service customers for retroactive payments made for gas previously delivered into the system. If the payment or refund related to gas purchased by Hughes is for a period of twelve consecutive months or longer, the total amount recovered or refunded shall be divided by the general services sales made to general service customers during this applicable period. With regard to amounts received or paid that are applicable to periods less than twelve consecutive months, Hughes shall refund or collect such amounts using one of the following three methods:

3.4.1 over the same period of time as the over-charge or under-charge occurred,

3.4.2 over the same number of units sold during the period of the over-charge or under-charge, or

3.4.3 include the entire amount in the reconciliation account. Refunds or charges shall be entered into the reconciliation account as they are collected from or returned to customers. For the purpose of Sec. 3.5, the entry shall be made on the same basis used to determine the refund or charge component of the cost of gas and shall be subject to the calculation set forth in Sec. 3.4, above.

3.5 **Report**. By August 31 of each year, Hughes shall file with the Commission, an annual *Cost of Gas Reconciliation Report*. The annual reconciliation report shall include, but not necessarily be limited to:

3.6.1 a tabulation of volumes of gas purchased and costs incurred listed by account or type of gas, supplier and source, by month, for the twelve months ending June 30;

3.6.2 a tabulation of gas volumes sold to general service customers and the related Cost of Gas Tariff revenues;

3.6.3 a summary of all other costs and refunds made during the year and the status of the reconciliation account.

4.0 Pipeline Safety and Regulatory Program Tariff

4.1 Fee. Once annually, Hughes' shall remit to the Commission the fee required in 16 TEX. ADMIN. CODE §8.201.

4.2 Surcharge. During the next billing cycle following Hughes' remittance to the Commission of the fee, Hughes shall include on its customers' bills a Pipeline Safety and Regulatory Program Surcharge, to the extent authorized in 16 TEX. ADMIN. CODE §8.201.

4.3 Formula. The Rule 8.201 surcharge is calculated in accordance with the following formula:

Rule 8.201(b) fee assessed by the Commission on Hughes
Divided by
Number of meters billed
Equals
Rule 8.201(b)(3) surcharge, applied per customer meter, once annually

In this formula, the number of meters billed refers to the number of meters billed during the billing month that precedes the month the Rule 8.201(b)(3) surcharge is included on customer bills.

5.0 Rate Case Expense Surcharge

5.1 The Rate case Expense Surcharge shall be in effect beginning on or after the date of the Commission's Final Order in Gas Utilities Docket No. 10190 and will continue for approximately six years until all of the rate case expense recovery approved in the Final Order is fully recovered.

5.2 The surcharge rate shall be $0.57 per Mcf.

5.3 Formula:

Fee Approved by the Commission of $0.57 per Mcf

Multiplied by

Volume (Mcf) billed that month

Equals

the Rate Case Expense Surcharge on that bill

5.4 This surcharge is in addition to other rates and surcharges set forth in this tariff.

5.5 Report. Hughes shall file an annual Reconciliation of the Rate Case Expense Surcharge collected during the previous calendar year with the Commission. The Report shall be filed when the RRC Annual Report is filed.

6.0 Miscellaneous Services Tariff

6.1 New service and restoration of service

Initiation of new service	$45, per trip
Restoration of service, after termination for non-payment or for a leak on a customer-owned facility	$45, per trip
Restoration of service, after service turn-off at request of customer or customer's agent	$45, per trip
Restoration of service, following a system disruption due to a natural disaster or an area emergency	$0.00, per trip

6.2 Turn-off service

Turn-off service, after termination for non-payment or for a leak on a customer-owned facility	$45, per turn-off
Turn-off service, at request of customer or customer's agent	$45, per turn-off
Turn-off service, following a system disruption due to a natural disaster or an area emergency	$0.00, per turn-off

6.3 Meter testing

Remove existing meter for testing as requested by customer (including setting a suitable replacement at existing tap), when no such test has been performed on the meter in four (4) or more years or when meter is found to be more than nominally defective per 16 TAC §7.45(7)(B)(iv)(II).	$0.00
Customer Service Agent charge associated with meter testing requested by the customer, only if the meter has been tested within the past four (4) years and, upon retesting, meter is found to correctly record usage.	Actual cost, up to $26.23 per hour
Field Service Technician charge and vehicle operations costs associated with meter testing requested by the customer, only if the meter has been tested within the past four (4) years and, upon retesting, meter is found to correctly record usage.	Actual cost, up to $30.84 per hour, maximum $89.95 per trip

6.4	**Change customer meter**	$75, per trip, plus materials
6.5	**Change residential meter location**	$350 first meter, plus materials
6.6	**Additional meters in manifold**	$55, per meter
6.7	**Meter re-read**	
	Meter re-read, when the meter has not been tested in more than four years or when the meter is found to be more than nominally defective.	$0.00
	Meter re-read requested by customer, if the meter has been tested within four years and the prior meter read is found to be correct.	$35, per trip
6.8	**Collection call**	$35, per trip
6.9	**Returned check charge**	$30, per return

7.0 Deposit Tariff

7.1 Application. Hughes may require a customer deposit from a customer that does not have acceptable credit bureau or other utility report of good standing.

7.2 Formula. If a customer is required to make a deposit, the amount of the deposit shall not exceed an amount equivalent to one-sixth of the customer's estimated annual billings. If there is no billing history on the customer's account, then the one-sixth rule will be applied to the customer's account based on similarly-situated customers located in the geographic area.

7.3 Exemptions. Hughes shall not require a person who is exempt from deposit requirements to make a deposit, as outlined in 16 TEX. ADMIN. CODE §7.45(5)(C).

7.4 Deposit refunds. Hughes shall automatically refund each deposit, with interest, to customers who meet the requirements in 16 TEX. ADMIN. CODE §7.45(5)(F).

7.5 Deposit practices. Hughes has adopted the deposit practices in the Commission's Quality of Service Rule at 16 TEX. ADMIN. CODE §7.45(5).

8.0 Line Extension Tariff

8.1 **New mains, 100 feet or less**. Hughes' charge for installation and extension of new mains, under normal conditions, not larger than two inches in diameter and not more than 100 feet in length is $0.00.

8.2 **New mains, more than 100 feet**. For installation and extension of new mains, under normal conditions, not larger than two inches in diameter, after the first 100 feet, Hughes charges the actual cost.

8.3 **Reporting requirement**. Hughes shall provide a copy of its most current line extension policy to the Commission, addressed to the Director of the Gas Services Division. No contribution in aid of construction will be required of any customer except as provided for in Hughes' line extension policy filed with the Commission, as set forth in 16 TEX. ADMIN. CODE §7.45(8)(B).

9.0 Quality of Service Tariff

Hughes has adopted the Quality of Services standards in the Commission's Quality of Service rules, as set forth in 16 TEX. ADMIN. CODE §7.45. The Commission's Quality of Services rules outline requirements applicable to continuity of service, customer relations, refusals of service, discontinuance of service, deposits, billing, meters, and new construction.

10.0 Curtailment Tariff

Hughes has adopted the Commission's curtailment requirements in 16 TEX. ADMIN. CODE §7.305 and §7.455 and in the Commission's Order in Gas Utilities Docket No. 489.