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

Barry T. Smith

CHAIRMAN BARRY T. SMITHERMAN

David Porter

COMMISSIONER DAVID PORTER

Christi Craddick

COMMISSIONER CHRISTI CRADDICK

ATTEST:

Kathy Way

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 UNINCORPORATED TOWNS AND RURAL AREAS OF AUSTIN, COLORADO, GRIMES, HARRIS, MONTGOMERY, AND WALLER COUNTIES, TEXAS	§ § § § § § §	**GAS UTILITIES DOCKET NO. 10190**

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 OShea ______________________ 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 ______________________ Stephen Mack Counsel for City of Magnolia	Signed this 19th day of February, 2013.

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 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 1/10th 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.

EXHIBIT A

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.

EXHIBIT A

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.

EXHIBIT A

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 (A)	Normalized Billing Determinants (B)	Normalized Base Revenue (C)	Proposed Rates Rate Design (D)	Base With Increase (E)	Total Base Increase (F)	Proposed Total Revenues (G)	Percentage Increase (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%

321153 P
1/14/13 D

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 Pacie 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 (A)	Schedule Reference	Plant Per Books (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.