Oversight and Safety Division

Gas Services

Natural Gas Rate Review Handbook

Railroad Commission of Texas

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Table of Contents

INTRODUCTION 1

A. Purpose of Regulation 1
B. Explanation of Packet Layout 2
C. Frequently Asked Questions 2

Chapter I. JURISDICTION AND PROCEDURES 7

Section 1 - Jurisdiction 7

Section 2 - Procedures at the City Level 7
A. Statement of Intent 8
B. Notice 8
C. Disposition 9
D. Hearing 10
E. Environs Rates 10
F. Jurisdiction over Gas Utility Rate Cases 12

Chapter II. OVERVIEW OF RATE REGULATION 13

Section 1 - Rate Regulation - A Summary 13
A. Rate Base 13
B. Cost of Capital 13
C. Operating Costs 14
D. Rate Design 15

Chapter III. RATESETTING 16

Section 1 - Rate Base 16
A. Test Year 16
B. Invested Capital 16
C. Allocation of System-Wide Assets to a Distribution System 16
D. Current Cost (Reproduction Cost New) 17
E. Other Rate Base Items 17
F. Rate Base Summary 21

Section 2 - Cost of Capital 23
A. Capital Structure 23
B. Debt and Preferred Stock 24
C. Equity 25
D. Small Utilities 29
E. Attrition and Erosion 30
F. Additional Sources of Capital 30

G. Weighted Average (or Composite) Cost of Capital 30

Section 3 - Return on Rate Base 31

Section 4 - Revenue and Expenses 32
A. Allocation Among Classes of Consumers 32
B. Revenue 33
C. Expenses 35

Section 5 - Rates 40
A. Revenue Requirement 40
B. Rate Design 41
C. Tariffs 41
D. Sample Calculations for Revenue Adjustments 43

Chapter IV. BEFORE THE COMMISSION 57

Section 1- Procedures on Appeal from City 57
A. Representation 57
B. Filing of Documents 57
C. Motions 59
D. Computation of Time 59
E. Postponements, Continuances and Extensions of Deadlines 59
F. Ex Parte Consultation 60
G. Interventions and Prefiled Testimony 60
H. Discovery 60
I. Alignment of Parties 60
J. Consolidation 61
K. Stipulations 61
L. Objections to Prefiled Testimony 61
M. Prehearing Conference 61
N. Court Reporter and Transcripts 61
O. Order of Procedure at Hearing 61
P. Evidence 62
Q. Objections Made at Hearing 62
R. Documentary Evidence 62
S. Official Notice 62
T. Expert Testimony 63
U. Preservation of Excluded Evidence 63
V. Briefs, Closing Statements, and Reply Briefs 63
W. Late-Filed Exhibits 63
X. Proposal for Decision, Exceptions and Replies 63
Y. Notification of Open Meeting 64
Z. Oral Argument 64
AA.Effective Date 64

BB.Motions for Rehearing 64

Chapter V. INTERIM RATE ADJUSTMENT 65

Chapter VI. COST OF SERVICE ADJUSTMENT 68

Chapter VII. GLOSSARY OF GAS UTILITY TERMS 71

BIBLIOGRAPHY 77

INTRODUCTION

This handbook is intended to assist municipalities, consultants, gas utilities and other interested persons in understanding the principles and procedures involved in natural gas utility rate regulation. Exercise of judgment is required in resolving the issues surrounding utility rate requests, and the methodologies set out herein are presented only as possible methods for resolving the issues identified. The methodologies and suggestions in this handbook by no means represent Railroad Commission of Texas policy, precedent or a mandate. This handbook is intended to only provide broad guidance to those that have questions about rate making. Also, the handbook is not intended as a substitute for advice from your attorney or qualified rate consultant. Titles 3 and 4 of the current Texas Utilities Code (TEX. UTIL. CODE), and the Railroad Commission of Texas' (Commission) Special Rules of Practice and Procedure, Substantive Rules, and General Rules of Practice and Procedure should be followed if there are any conflicts between the statutes, the rules and this handbook.

A. PURPOSE OF REGULATION

Regulation of public utilities is intended to operate in lieu of the competitive forces that are believed to control prices for goods and services provided by most business organizations. Utilities invest large sums of money at the outset to build the facilities required to serve their customers. Since a utility's initial capital investment is so high, the existence of competing utilities would be wasteful and inefficient. That is why utilities are referred to as "natural monopolies." Normally, utilities operate most efficiently as monopolies, but with the potential market abuses of a monopoly.

The Gas Utility Regulatory Act, The Cox Act, and other miscellaneous statutory provisions have been revised and combined, along with the statutes governing the regulation of electric and telephone utilities, into a statute referred to as the **TEXAS UTILITIES CODE (TEX. UTIL. CODE). Title 3** of the **TEX. UTIL. CODE** replaces the Gas Utility Regulatory Act and the Cox Act, while **Title 4** replaces the other miscellaneous provisions.

The bill that codified the statutes was drafted by the Texas Legislative Council in 1997. The process involved reclassifying and rearranging the statutes in a more logical order to make the statutes more accessible, understandable, and usable. The 75th Legislature enacted the bill, Governor Bush signed it, and it became effective September 1, 1997.

These statutes provide comprehensive regulation of gas utilities in lieu of competition. Each regulatory authority is empowered by the **TEX. UTIL. CODE** to enact rules and regulations as necessary to adequately perform its statutory duty. Commission rules cited in this manual are not binding upon a municipality when it is exercising its original jurisdiction, but they are applicable when a case is appealed to the Commission and the municipality is a party to the appeal.

On December 24, 2004, the Commission created a rule (§ 7.7101 of 16 TEX. ADMIN. CODE) to implement **TEX. UTIL. CODE**, § 104.301 (sometimes referred to as the Gas Reliability Infrastructure Program or GRIP), which was enacted by the 78th Legislature. These statutory and rule provisions promote investment in infrastructure that will improve the reliability and safety of the Texas natural gas system. Previously, the only way for a utility to increase its rates was to file with the regulatory authorities a formal Statement of Intent rate package, including a comprehensive cost of service rate case. This is sometimes referenced as “traditional” rate making. The Interim Rate Adjustment (IRA) statute and rule allow a gas utility to apply with the regulatory authority for an interim adjustment to its base rates to recover the cost of new infrastructure investment made by a utility since its last comprehensive rate case. When a utility applies for an interim rate adjustment, it is not required to submit a comprehensive rate package demonstrating the reasonableness of its cost of service. More details of the IRA requirements are discussed in a following chapter in this handbook.

B. EXPLANATION OF PACKET LAYOUT

This handbook contains seven Chapters following the Introduction. The first Chapter explains the legal authority under which a city may act to set natural gas rates, and explains procedural steps that are appropriate at the city level. The second Chapter provides a broad overview of ratemaking methodology. The third Chapter also deals with the substance of rate calculation, but in much greater detail. The fourth Chapter sets out procedures to be followed before the Railroad Commission in the event that the city's rate setting action is appealed. The fifth Chapter discusses the specific requirements and particulars of the Interim Rate Adjustment filing that is an option to the utility. The sixth chapter discusses the use and applicability of Cost of Service Adjustments (COSA) approved by the Commission. Finally, the seventh Chapter contains a glossary of terms and a bibliography.

C. TEXAS NATURAL GAS RATES -- FREQUENTLY ASKED QUESTIONS

Q: How many Texas customers obtain gas through natural gas distribution systems?
A: Texas natural gas distribution systems include 30 investor owned utilities and 84 municipally owned systems through 2010. These natural gas distribution systems serve 4.5 million customers, which comprise domestic households, small commercial, and large industrial customers.

Q: How many Texas cities are served by natural gas distribution systems?
A: Over 1,100 Texas cities are served by natural gas distribution systems. 85 of these cities are served by municipally owned distribution systems. The rest of these cities are served by investor owned utilities.

Q: How much gas is purchased through natural gas distribution systems in Texas?
A: 392 billion cubic feet of gas was purchased through natural gas distribution systems in2010. This was 16% of all gas consumed in Texas (2,367 billion cubic feet). Gas sales through natural gas distribution systems (municipal and investor owned) totaled over $115 billion in 2010.

Q: Who has jurisdiction over natural gas rates in most Texas municipalities?

A: The majority of Texas municipalities are served by investor owned utilities. In these municipalities, the municipality grants a franchise to a utility company, and the municipality has original jurisdiction (and the Railroad Commission has exclusive appellate authority) over the rates, operations, and services of the natural gas utility within the municipality. The Railroad Commission has no authority over the rates, operations, and services of a municipally owned gas utility within the municipality's boundaries.

Q: If I live in a municipality which is served by an investor owned natural gas utility and I have a concern about my natural gas rates or bill, to whom do I complain?

A: Since the municipality has original jurisdiction over the rates, operations, and services of the natural gas utility within the municipality, customer complaints should be addressed to the municipal department which is responsible for the administration of this contract.

Q: Does the Railroad Commission of Texas have jurisdiction over a city's natural gas rates?

A: By statute, the city, as the regulatory authority, has a legal obligation to set rates that are just and reasonable. If the utility or any other party to the proceeding at the city is not satisfied with the rates set by the city, that aggrieved party may appeal the city's rate ordinance to the Commission, where rates will be determined through a formal evidentiary rate case proceeding. The city has standing to participate in this appeal as a party. An appeal by any party of the rates set by Commission order would go to Travis County District Court.

The Commission monitors the overall quality of service and rates provided to a city by an investor owned utility. Through regular audits, the Commission assures, among other service issues, that the utility charges its customers the rates which have been formally authorized, and orders refunds if customers have been overcharged.

Q: Does the Railroad Commission of Texas have jurisdiction over any other natural gas rates?

A: Yes, the Commission has exclusive original jurisdiction over natural gas utility rates in areas outside of municipalities, such as "environs", "unincorporated areas" and "special rate areas." Areas adjacent to a municipality and served by the same distribution system serving the municipality are referred to as "environs." Areas outside and not adjacent to an incorporated municipality are referred to as "unincorporated areas" or can be "special rate areas." Unincorporated areas are areas that are not adjacent to a municipality but have rates the same as a nearby municipality served by the same utility. Special rates by definition are rates applicable only to service by a given utility within a specified area and not specifically keyed to the rates charged in an incorporated area. Also, the Commission has exclusive original jurisdiction over the rates and services of a utility, such as a natural gas pipeline, that delivers gas to a distribution utility, or "city gate rates". And, in the case of Interim Rate Adjustments (IRA), both the Cities and the Commission have the authority to approve an IRA within their jurisdictions. A municipal denial of a proposed IRA may be appealed by the utility to the Commission.

Q: Can the Railroad Commission of Texas provide assistance to municipalities which are faced with a proposed natural gas rate increase?

A: A municipality may request the Railroad Commission of Texas to advise and assist the municipality on a natural gas utility matter pending before the Commission, a court, or the municipality's governing body. Cities should be aware, however, that budget constraints imposed by the Legislature limit the resources that the Commission has available for providing assistance to municipalities. This Rate Review Handbook can provide a general guidance and the Commission has placed many Proposals for Decision, Orders and schedules on its web site for review. The handbook contains a comprehensive review of the ratemaking process. Information regarding these publications is available by phone at (512) 463-7167 or in the Gas Services section of the agency's web site: **www.rrc.state.tx.us**.

Q: What other sources of assistance regarding evaluation of proposed rate increases are available to a city?

A: City staff may have the expertise required to evaluate a proposed rate increase. If necessary, many consultants, attorneys, and associations are available to provide assistance, usually on a fee basis.

Q Can a utility change my city's natural gas rates?

A: A utility can propose to raise or lower the rates it charges to provide natural gas distribution service within a city. Proposals to increase rates are most common. A utility must follow a specific, formal process to propose and implement a rate increase. But, a rate decrease can be implemented simply through the filing of a new tariff.

Q: What is the process a utility must follow to propose a rate increase?

A: A utility must file a written statement of intent to increase rates with the city it serves and publish notice in a local newspaper for four successive weeks, and may not put the increased rates into effect until at least 35 days after filing the statement of intent. Upon the filing of a statement of intent, the city may take one of several actions:

1. The city may take no action at all, in which case the proposed rate increase will automatically take effect after day 35.
2. Unless the increase is a "a major change" (*i.e.*, one that would increase the aggregate revenues of the utility more than the greater of $100,000 or 2.5 percent), the city, for good cause shown and under any conditions the city may prescribe, may allow a rate increase to take effect before the end of the 35 day period.
3. The city may suspend the proposed rate increase for an additional 90 days beyond the 35th day (a total of 125 days from the date that the initial rate increase was filed). If, after 90 days from the date that the statement of intent of proposed rate increase was filed, the city has not established final rates, the utility may put into effect a rate less than or equal to the proposed rate upon filing a bond payable to the city. If, by the 125th day from the date the statement of intent was filed, the city has not adopted a rate ordinance setting final rates, then the city is considered

to have approved the rates proposed by the utility, and they go into effect after the 125th day.

4. The city may expressly deny any rate increase, in which case the utility may:
   a) maintain the existing rate schedule;
   b) appeal to the Commission the city's rate ordinance denying the requested increase in rates; or,
   c) file with the city a statement of intent proposing a different rate increase.
5. The city may expressly grant a lower than requested rate increase, in which case the utility may:
   a) appeal to the Commission the city's rate ordinance denying the requested increase in rates and setting rates at a lower level than requested;
   b) put the new rates into effect (even though they are lower than the utility originally requested), and file with the city a new statement of intent proposing another rate increase; or,
   c) simply put the new rates into effect (even though they are lower than the utility originally requested).
6. The city may expressly approve the requested rate increase as filed.

Q: How often can a utility propose a rate increase to a city?

A: A utility can propose a rate increase to a city as often as the utility desires. In practice, proposals to increase rates rarely occur more frequently than once per year. Often many years pass before a utility seeks a rate increase. Within the requirements of the IRA, once invoked a utility must file for an adjustment annually *and* file a Statement of Intent within 5 years of the initial IRA filing for a full rate review.

Q: If a city denies a proposed rate increase and it is appealed to the Commission or district court, what expenses will the city and its ratepayers face?

A: The governing body of any municipality participating in or conducting ratemaking proceedings may select and engage rate consultants, accountants, auditors, attorneys, and/or engineers to advise and represent the municipality with litigation or natural gas utility ratemaking proceedings before any regulatory authority or in court. The natural gas utility engaged in those proceedings is required to reimburse the governing body for the costs of those services only to the extent that the costs are found reasonable by the applicable regulatory authority. The natural gas utility commonly recoups these costs along with its own reasonable rate case expenses by applying a surcharge, which is determined by the regulatory authority, to its utility rates for that particular municipality. This surcharge usually is applied on a per customer or per Mcf basis and is typically spread out over a period of time to reduce its impact on ratepayers. The regulatory authority typically monitors the amount of money collected under the surcharge to ensure that the utility does not over collect.

Q: What percentage increase is being proposed in the statement of intent?

A: Most statements of intent propose a percentage rate increase. The percentage increase is most frequently stated as the increase in total revenues, including the portion of revenues which covers the cost of natural gas purchases. Since the cost of natural gas is simply passed through to the customer without a profit, some prefer to exclude from the calculation of a rate increase revenues which cover the cost of natural gas purchases. The following example illustrates the difference between including and excluding cost of natural gas pass-through revenue when calculating a percentage rate increase.

	Present Rates	Proposed Rates	% Rate Increase
Total Operating Revenue (Including Cost of Gas)	$300,000	$315,000	**5%**
Cost of Gas	$220,000	$225,000	
Total Operating Revenue (Excluding Cost of Gas)	$80,000	$90,000	**12.5%**

Q: Where can I get further information regarding the topics discussed in this section?

A: Call the Gas Services at (512) 463-7167 or visit the Commission's web site at www.rrc.state.tx.us.

CHAPTER I.
JURISDICTION AND PROCEDURES

SECTION 1 - JURISDICTION

City jurisdiction over natural gas distribution rates and services was implied under the Cox Act and was specifically granted in the Gas Utility Regulatory Act. A municipality has original jurisdiction over the rates, operations and services provided by any gas utility distributing natural gas within the city or town limits pursuant to TEX. UTIL. CODE § 103.001. In contrast, TEX. UTIL. CODE § 102.001 gives the Commission original jurisdiction over utility distribution rates and services outside the city limits and in other unincorporated areas and over city gate sales, and appellate jurisdiction to review the rate ordinances or orders of municipalities.

As a regulatory authority, as defined in TEX. UTIL. CODE § 101.003(13), the city has the authority:

- To make reasonable inspections of the papers, books, accounts, documents, or other business records of the utility. TEX. UTIL. CODE § 102.203

- To require the filing of rates, rules, and regulations. TEX. UTIL. CODE § 102.151

- To fix just and reasonable standards of service to be followed by the utility. TEX. UTIL. CODE § 104.252

- To provide for the examination and testing of equipment. TEX. UTIL. CODE § 102.205

- To engage rate consultants, accountants, auditors, attorneys and engineers to assist in ratemaking proceedings. TEX. UTIL. CODE § 103.022.

- To establish rates. TEX. UTIL. CODE § 103.001.

TEX. UTIL. CODE § 103.022 gives cities the right to hire rate consultants, auditors, attorneys, and engineers to assist with the ratemaking proceedings upon request by the city; the public utility is required to reimburse the governing body for the reasonable costs of such services, which are passed on to the ratepayers. A city may, of course, elect to pay for such services from tax-generated revenue. The city should plan expenditures not only on a basis of reasonableness but also on a basis of cost effectiveness.

Under TEX. UTIL. CODE § 102.005, the Commission may advise and assist municipalities upon request in connection with questions and proceedings under the statute. Cities should be aware, however, that budgetary constraints imposed by the Legislature limit the resources that the Commission has available for providing such assistance.

SECTION 2 - PROCEDURES AT THE CITY LEVEL

The procedures and legal standards for ratemaking proceedings are generally contained in TEX. UTIL. CODE Chapters 102 and 104. Ratemaking proceedings are typically initiated by a utility by filing a statement of intent to increase rates under TEX. UTIL. CODE § 104.102. The utility must provide notice in accordance with TEX. UTIL. CODE § 104.103. The city, however, may initiate a rate proceeding on its own motion or on the complaint of any affected person, and if, after notice and hearing, it finds that existing rates are unreasonable or in violation of the law, it may adopt new rates. TEX. UTIL. CODE § 104.151.

A. STATEMENT OF INTENT

Under the terms of TEX. UTIL. CODE § 104.102, a utility may not increase its rates without filing, at least 35 days prior to the effective date of the proposed increase, a statement of intent with the regulatory authority having original jurisdiction. TEX. UTIL. CODE § 104.102 sets out requirements for the content of the statement of intent, which must:

- specify a proposed effective date which is at least 35 days after the filing date, except upon a showing of good cause;
- state the proposed revisions of tariffs and schedules and specify in detail each proposed increase;
- state the effect of the proposed increase on company revenue;
- state the classes and numbers of utility customers affected; and,
- contain such other information as may be required by the regulatory authority's rules and regulations.

B. NOTICE

A copy of the statement of intent must be mailed or delivered to the appropriate officer of each affected municipality. TEX. UTIL. CODE § 104.102(b). If a proper statement of intent has been filed, the city may proceed with its rate determination. If the statement of intent is defective, the city may allow the filing of a proper or amended statement of intent. The statute does not require that statements of intent include data to support the rate request. However, because the city must evaluate the basis of the request in order to determine its reasonableness, the city shall require the utility to submit supporting information to the city during the course of the city's investigation of the merits of the rate request. TEX. UTIL. CODE § 103.021.

In addition to filing the statement of intent with the city, the utility must publish notice for four successive weeks in a newspaper having general circulation in each county with territory affected by the proposed change. The time limits and publication requirements set out in TEX. UTIL. CODE § 104.103 do not apply to a complaint proceeding under TEX. UTIL. CODE § 104.151.

Instead of publishing newspaper notice, a gas utility may provide notice to the public in an area outside the affected municipality or in a municipality with a population of less than 2,500 by either mailing the notice to each customer or including the notice in each customer's bill. TEX. UTIL. CODE § 104.103(b).

C. DISPOSITION

Rate proceedings before the city may generally be processed according to any applicable provisions of the city charter. However, TEX. UTIL. CODE § 103.021(b) requires that the city make its rate determination using the procedures and requirements of Title 3, Subtitle A (the Gas Utility Regulatory Act) of the Texas Utilities Code.

Once the proper statement of intent is filed and notice is given, the city council may on its own motion or upon the complaint of any affected person hold a hearing or hearings to determine the propriety of the change. This decision may be made at any time within 30 days from the date when the change would or has become effective, upon reasonable notice to all affected parties. TEX. UTIL. CODE § 104.105. The city council is required to provide an opportunity for hearing in each case where the change would constitute a major change as defined in TEX. UTIL. CODE § 104.101. TEX. UTIL. CODE § 104.104 prohibits a major change to take effect prior to the end of the 35-day period prescribed by TEX. UTIL. CODE § 104.102. An informal proceeding may satisfy the requirement if no complaint is received before the expiration of 45 days after notice of the change has been filed.

Once the statement of intent has been filed, the city has several options for handling the rate request. It may take no action and allow the proposed rate increase to take effect automatically at least 35 days after the date of filing. Or the city, depending on what its investigation reveals, may:

1) expressly deny any rate increase;

2) expressly grant the proposed rate increase in full;

3) expressly grant a rate increase less than that requested;

4) expressly set rates that are lower than the rates the utility is charging.

The city council should maintain a formal record of its decision, whether through ordinance or minutes. Whatever the city's decision, the utility should be advised promptly in writing.

If the city finds that it cannot make an informed decision before the proposed effective date, it may suspend the proposed rate pursuant to TEX. UTIL. CODE § 104.107. Upon delivery to the affected utility of a written statement of its reasons, the city may suspend the operation of the rate schedule for a period of 90 days beyond the date on which the schedule would otherwise have gone into effect giving the city a total of 125 days to review the proposed rate increase.

If the city has not made a final determination within 125 days after the proposed effective date, TEX. UTIL. CODE § 104.107(b) provides that the regulatory authority is considered to have approved the rate schedule. This approval, however, is subject to the city's authority thereafter to continue a hearing in progress.

If the city chooses to suspend the rates, it may consider establishing temporary rates for the period of suspension. TEX. UTIL. CODE § 104.108. Temporary rates may be subject to credit or refund upon setting the final rate. Bonded rates do not apply to cities, because they have to make a decision by the 125th day (which is 90 days from the date the rates would otherwise have gone into effect). TEX. UTIL. CODE § 104.109.

D. HEARING

TEX. UTIL. CODE § 102.251 requires that a record be kept of the proceeding before the city. TEX. UTIL. CODE § 102.252 provides that all parties to the proceeding are entitled to be heard in person or by an attorney. Although the TEX. UTIL. CODE does not define the term "party," TEX. UTIL. CODE § 105.051 refers to complaints made by any "affected person." Presumably, any "affected person" may be permitted to become a party to the proceeding. An "affected person" is defined in TEX. UTIL. CODE § 101.003(1) as a gas utility affected by an action of a regulatory authority, a person whose utility service or rates are affected by a proceeding before a regulatory authority, or a person who is a competitor of a gas utility with respect to a service performed by the utility or wants to enter into competition with a gas utility. Mere participation in the proceeding does not confer party status on a person. Party status is conferred only when the city names or admits the person as a party to the proceeding. A party to the proceeding may appeal the city's action to the Railroad Commission. See TEX. ATT'Y GEN. OP. NO. MW-355 (1981).

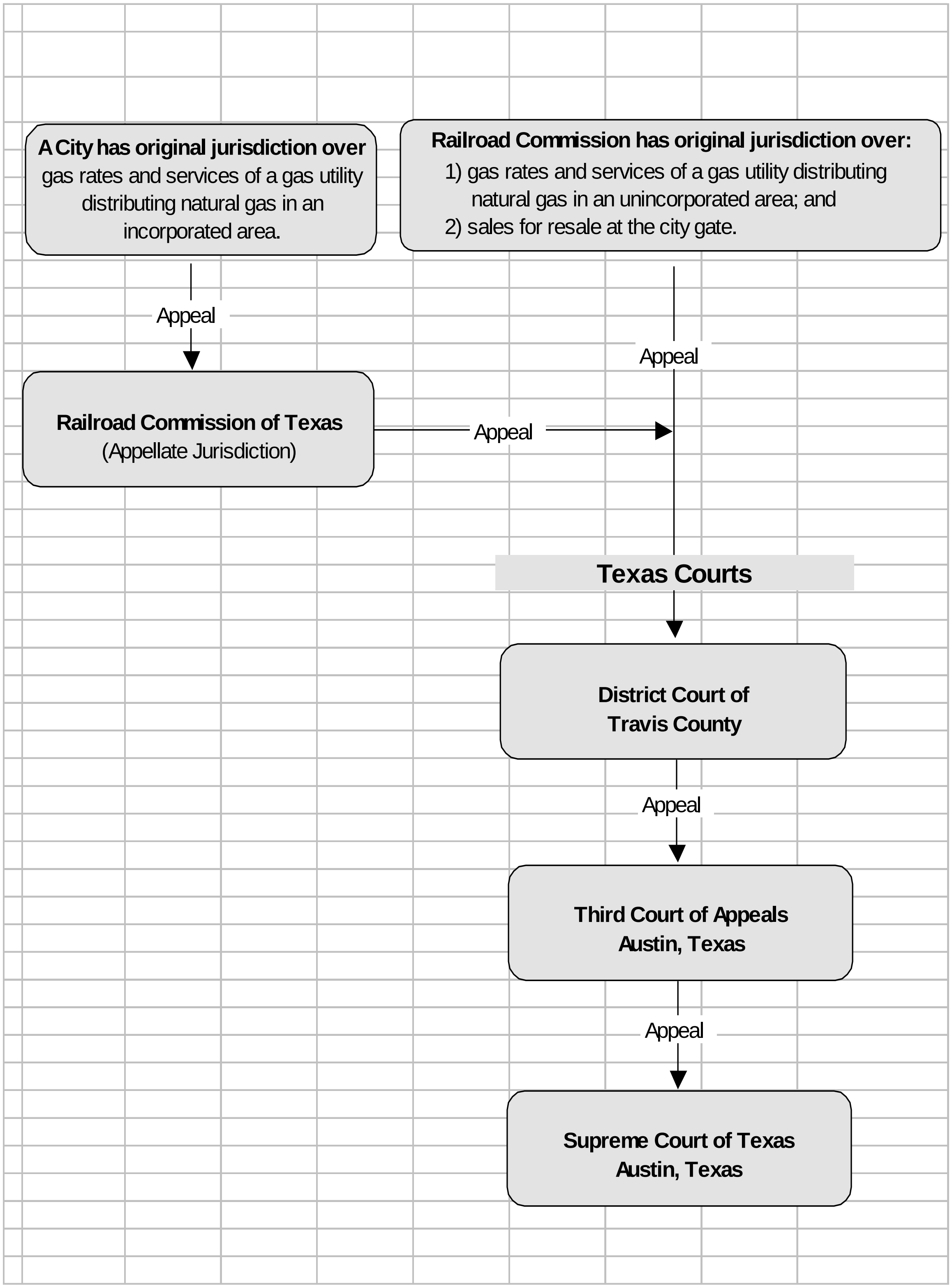
A city has several options available concerning the scope of the data it will consider in connection with applications for rate increases. The city may consider data covering the utility's cost of providing service in just the municipality, or it may consider system-wide data. TEX. UTIL. CODE § 103.021. In appropriate situations, the city may limit the scope of the hearing to consider an identifiable rate factor that can be easily segregated. See *Railroad Comm'n v. City of Fort Worth*, 576 S.W.2d 899 (Tex. Civ. App.--Austin 1979, writ. ref'd n. r. e.).

E. ENVIRONS RATES

The Railroad Commission of Texas has original jurisdiction over gas rates outside of city limits. TEX. UTIL. CODE § 102.001. If a gas utility operates a system that serves both within and outside the city limits and the utility desires a uniform rate covering both areas, it must file two separate statements of intent, one with the city to increase rates in the city and one with the Commission to increase rates in the service area outside the city limits, known as the "environs." Commission special rule § 7.220(b) (16 TEX. ADMIN. CODE § 7.220(b)) provides that the utility may generally implement the same rate in the environs as has been approved by the city council for the incorporated areas. If the utility files simultaneously with the city and the Commission, it is likely that the Commission would suspend any proposed environs rate until the city has had an opportunity to make an independent decision concerning a proposed rate change in the city. In the past, a utility would typically file a statement of intent to increase rates for an environs area to match the rates already approved by the adjacent city. Once the city has taken action on the statement of intent and has established a new city rate, the Commission may allow the utility to charge the same rate in the environs. Commission substantive rule § 7.45, governing quality of service, applies to the environs areas and becomes part of the environs rates notwithstanding whether the same rules are in effect in the related incorporated area. When a city has granted rates which reflect a late charge, such rates may be approved for the environs. Further, the Commission has required that adjustment clauses included as part of an environs rate conform with Commission substantive rule§ 7.5525, regarding lost and unaccounted for gas, and has precluded establishing certain rate designs and indexing procedures in areas of Commission original jurisdiction.

In recent years, utilities and municipal representatives have preferred having the Commission concurrently hear both the environs statement of intent to increase rates and the appeal by the utility of a denial by the municipality. The two docketed rate cases are consolidated and heard together for time and economic efficiency. Since 2005, the vast majority of the utility's municipal and environs rate cases are heard together. Additionally, utilities are expected to file schedules and workpapers sufficient to support the requested increase. Failure to file supporting schedules and workpapers has resulted in filings being considered deficient. It is important that utilities adequately support their request.

F. JURISDICTION OVER GAS UTILITY RATE CASES



CHAPTER II.
OVERVIEW OF RATE REGULATION

SECTION 1 - RATE REGULATION: A SUMMARY

Cost is the basis of utility ratemaking. A utility is entitled to rates which generate revenue equal to its costs. These costs fall into two categories: capital costs and operating costs. A utility's operating costs are its reasonable and necessary expenses. For purposes of rate regulation, a utility's capital costs are considered to be its required **return on investment** or its weighted average cost of money multiplied by the total amount of its investment in the utility system, frequently referred to as the **rate base**. The regulator must identify the appropriate rate base, the cost to the utility of the money invested in the rate base, and the cost of operations. The task then is to design rates that fairly generate revenue equal to the costs incurred. TEX. UTIL. CODE § 104.051.

Utilities are required to adopt the Federal Energy Regulatory Commission's (FERC) Uniform System of Accounts (USOA). TEX. UTIL. CODE § 102.101 and 16 TEX. ADMIN. CODE § 7.310. The FERC USOA provides specific instructions for account record keeping and the manner in which the utility must treat certain items, including gas plant. All statement of intent filings should attest to the utility's adoption and use of the FERC USOA for all operating and reporting purposes.

A. RATE BASE

Rate base is the utility's investment in the system. A utility's rate base may be calculated as: 1) original cost less book depreciation (**net invested capital**); 2) **reproduction cost new** less adjustment for age and condition (**net current cost**); or 3) some combination of net invested capital and net current cost. TEX. UTIL. CODE § 104.053(b) provides that these methods may be reasonably balanced using a weighting of 60 percent to 75 percent net invested capital and 40 percent to 25 percent net current cost, to calculate the adjusted value of invested capital.

Other components of the rate base are **working capital**, **customer deposits**, **deferred taxes**, **construction work in progress (CWIP)**, and **retirement work in progress**.

When evaluating the utility's rate base information, the regulator should be alert to allocation issues, which, if not carefully scrutinized, could result in improper rates. For a discussion of allocation of system wide assets to a distribution system, see Chapter III, Section 1.C.

B. COST OF CAPITAL

The **cost of capital** (the cost of borrowing money) can be used to adjust the rate base. The statute offers only a general standard, i.e., "a fair return on the adjusted value of the invested capital used and useful in providing service to the public." TEX. UTIL. CODE § 104.052.

To calculate the cost of capital, a rate must be assigned to each component of the capital structure. Normally, the rates applied to debt and preferred stock are embedded; that is, they may be simply taken from the utility's books. The regulator should be aware that debt is sometimes listed at current interest rates when it was incurred at older, lower interest rates. Interest rates applied to each issue of debt should be studied.

The **cost of equity** is an area in which there is potential for a cost overstatement, because it can only be estimated. A utility's justification for cost of equity should be studied carefully and checked against other cost formulas.

To determine the utility's **weighted average cost of capital**, the cost of each component should be multiplied by the weight of each component, and these weighted costs should then simply be added. The product of this weighted average cost of capital and net invested capital is the utility's required monetary return.

The utility's cost of capital includes several components, of which debt, preferred stock, and equity are the most common. In addition, if the utility chooses to make no rate base adjustment for customer deposits and deferred taxes, these should be included in the utility's capital structure. To avoid overstatement of the higher cost equity component, capital costs can be assigned to the various components of the rate base. Close attention should be paid to companies which are either subsidiaries or operating divisions of larger companies. In this case, the utility may use a capital structure with a higher equity ratio.

C. OPERATING COSTS

Operating costs must be reimbursed from the rates, so the rate base is adjusted for operating costs. The starting point for calculating a utility's operating costs is book revenue and expenses. Revenue and expenses associated with the sale of goods and services other than utility services should be excluded; e.g., sale of gas ranges, installation, etc. Certain expenses associated with advertising and charitable contributions may be excluded. Political contributions and lobbying expenses must be excluded under TEX. UTIL. CODE§ 104.057. All payments made to affiliated suppliers, defined in TEX. UTIL. CODE § 101.003(2) require careful scrutiny to be certain that prices have not been inflated. All payments made to affiliates must meet the standards of TEX. UTIL. CODE § 104.055. Failure to properly document affiliate transactions and provide the documentation required in TEX. UTIL. CODE § 104.055 could result in a filing being considered deficient or a denial of affiliate expenses.

If allocations are necessary, the utility should consider using a Cost Allocation Model (or Manual) (“CAM”), to support its allocation methodology. Methods used to allocate revenue and expenses should be scrutinized. Allocation issues fall into several categories. First, the utility may allocate among classes of consumers, i.e., industrial vs. residential and commercial. Second, the utility may allocate particular facilities and expenses to a particular distribution system. Third, the utility may allocate portions of its general plant and management salaries to each distribution system. Facilities and expenses should not be charged to more than one distribution system.

After allocated book revenue and expenses are determined, the utility may attempt to justify adjustments to these revenue and expenses. The most frequently proposed adjustment is to account for variances in gas consumption due to abnormal weather. In addition to weather, the utility may justify other known and measurable changes, such as changes in tax rates, postage rates, salaries, etc. If these adjustments are, in fact, known and measurable, they should be allowed. Just because a change is known and measurable, its reasonableness must also be determined, such as a known and measurable salary increase. However, the utility may also attempt to justify other adjustments for attrition, erosion, price elasticity and inflation. Since these adjustments may be speculative in nature, they should be studied closely. Further discussion of these adjustments follows in Chapter III, Section 2.

The difference between adjusted revenue and expenses is adjusted gross income. Application of the appropriate federal income tax rate to this gross income results in the adjusted net income. The difference between the adjusted net income and the required monetary return is the required net income increase. By dividing the net income deficiency by the tax reciprocal, one derives the gross revenue deficiency. This, added to the adjusted revenue, results in the total required revenue.

D. RATE DESIGN

Rate Design is the manner in which the utility bills its customers. The utility’s rate design should charge customers a fair amount for the type and amount of gas use, while allowing the utility to recover enough revenue to cover its costs and make a reasonable rate of return, or profit. The choice among the various rate designs is primarily a matter of policy. Usually, the policy involves a choice between multi-block rates and single-block rates. In the case of multi-block rates, the utility is allowed to charge a differing rate for higher volume purchases. A single-block rate is a fixed charge per unit of gas consumption. A utility may also include a customer charge to be paid regardless of consumption.

Other rate schedule issues deal with the allowance of purchased gas and other adjustment clauses. A purchased gas adjustment clause is a valuable tool to allow a utility's rates to fluctuate according to a utility's cost of gas. Normally, this cost of gas will fluctuate more frequently than the utility is able to seek and obtain rate changes. The regulator should also study the utility's need for a factor to recover costs of lost and unaccounted for gas.

CHAPTER III.
RATESETTING

SECTION 1 - RATE BASE

Under TEX. UTIL. CODE § 104.053, the adjusted value of invested capital is the rate base. See *Southwestern Bell Telephone Company v. Public Utility Comm'n,* 517 S.W.2d 503 (Tex. 1978). Invested capital has been defined as original cost less depreciation. The rate base is comprised of a reasonable balance between original cost less depreciation and current cost less an adjustment for present age and condition.

A. TEST YEAR

TEX. UTIL. CODE § 101.003(16) defines test year as the most recent 12 months for which operating data for a gas utility are available. A test year shall commence with a calendar quarter or fiscal year quarter.

The present practice of the Commission is to use asset balances as of the test year end adjusted for known changes, as opposed to the average balance for the test year, because year end data more accurately represents existing conditions on which to base rates for the future.

B. INVESTED CAPITAL

This includes all items used to provide utility service at the actual cost of the property at the time it was dedicated to utility service, whether by the present owner or his predecessor, less accumulated depreciation. TEX. UTIL. CODE § 104.053. The FERC USOA provides specific instructions for gas plant accounting.

The Commission requires the straight-line method of depreciation for determining test year depreciation and amortization expense. TEX. UTIL. CODE §§ 102.152 and 104.054 and Commission substantive rule § 7.5252(a).

If the utility engages in both utility and non-utility activities, the investment must be fairly and justly allocated between utility and non-utility activities. Commission substantive rule § 7.5252(c).

C. ALLOCATION OF SYSTEM-WIDE ASSETS TO A DISTRIBUTION SYSTEM

Frequently, the utility will allocate its **general plant** or other assets to the distribution system under consideration. Normally, the utility should not need to allocate the **distribution plant** accounts, if separate accounts have been maintained for each distribution system. If the utility needs to allocate distribution plant accounts, however, one accepted method for doing so is on the basis of linear feet of pipe. Such an allocation can raise problems if the utility allocates newer facilities in its system to an older distribution system where the pipe has been depreciated.

In the case of a general plant, the most frequent allocation method seen is on the basis of number of customers. This allocation is acceptable, since most general plant expenses are customer-based (e.g., billing, accounting, etc.). In addition, general plant must frequently be allocated among different business enterprises. This is particularly true in the case of diversified energy corporations which include utility divisions. For this purpose, a multi-factor formula is generally used. Such a formula may include: 1) sales revenue; 2) plant in service; 3) operating expenses excluding overhead; 4) number of labor dollars for personnel; and 5) number of operating units. The allocation factors should be chosen to best reflect actual cost correlation. The weighting is usually equal unless some unusual circumstance dictates otherwise.

D. CURRENT COST (REPRODUCTION COST NEW)

Current Cost or Reproduction Cost New involves the application of current prices to existing assets. The objective is to determine the cost required to reproduce those assets presently in use. Replacement cost, on the other hand, represents the application of present prices to similar assets, some of which may be technologically superior to assets actually in use. Since Commission practice involves the strict duplication of existing utility property, replacement cost is not considered. See Webb, *Utility Rate Base Valuation in an Inflationary economy, Public Utility Regulation in Texas - A Symposium,* 28 Baylor L. Rev. 823 (1976).

An alternative approach to determining current cost involves the application of trend indices to the original cost of various assets. For example, the Handy-Whitman Index, the Engineering News Record Building Construction Index, and the Wholesale Price Index (developed by the U.S. Department of Labor) have been used.

The adjustment for age and condition represents the difference in value between the present plant and what it would be if new. The Commission presently uses an adjustment for age and condition equal to the ratio of accumulated depreciation to original cost.

It is important to note that the Commission prefers the use of original cost, less accumulated depreciation, to determine rate base. Other methods, if necessary and adequately supported, may be approved.

E. OTHER RATE BASE ITEMS

1. Construction Work In Progress

Many utilities urge the inclusion of an account for construction work in progress (CWIP) in the rate base. It should be included as a component of the rate base only where necessary to the financial integrity of the utility, at cost as recorded on the books of the utility, TEX. UTIL. CODE§ 104.053. The Commission allows CWIP only when convinced that without it, the utility cannot meet its capital obligations, raise needed capital, or that there will be an impairment of the utility's service. Commission substantive rule§ 7.5212.

16 TEX. ADMIN. CODE § 7.5212.

An allowance for funds used during construction (AFUDC) may be capitalized at a reasonable rate at the time the item goes on line in those instances where CWIP is not included in the rate base. Commission substantive rule § 7.5212. 16 TEX. ADMIN. CODE § 7.5212.

2. Working Capital

The Commission prefers the use of a **lead-lag study** to determine working capital. If a utility does not have the means to perform or to hire a consultant to perform a lead-lag study, Commission practice is to provide for 45 days or 12.5 percent of operating expense, excluding cost of gas purchased, depreciation and taxes, plus the 13-month average amount of materials and supplies and the average prepayments.

3. Contributions in Aid of Construction and Customer Advances

Donations or contributions of cash, services, or property from individuals, companies, states, municipalities or other governmental agencies, and others for construction purposes, and advances by customers which are to be refunded either wholly or in part, are accorded two optional treatments. Such funds are deducted from the rate base and not included in the company's capital structure, or they are left in the company's rate base and are included in the company's capital structure at the company's cost, if any.

Note: The Texas Supreme Court held in *Sunbelt Utilities v. the Public Utility Commission*, 589 S.W. 2d 392 (Tex. 1979) that, where the developer of property and the utility have common ownership, the developer's cost of installing the utility system was recovered from the utility's customers through sale of the lots, and was therefore a customer contribution in aid of construction and was properly excluded from rate base.

4. Customer Deposits

Two optional treatments are accorded customer deposits: 1) The deposits are deducted from the rate base and the interest paid to the customer on these funds pursuant to TEX. UTIL. CODE Chapter 183 is included as an expense item; or 2) the deposits are left in the company's rate base, and they are included as a part of the company's capital structure.

5. Investment Tax Credit

Pursuant to TEX. UTIL. CODE § 104.056, the tax savings derived from the investment tax credits taken by the company are to be divided between present and future customers to the extent allowed by the Internal Revenue Code.

It has been Commission practice not to reduce the rate base for pre-1971 investment tax credits. Commission substantive rule § 7.501(3). 16 TEX. ADMIN. CODE § 7.501(3).

The treatment accorded post 1970 investment tax credits depends upon the election made by the company under Section 46 of the Internal Revenue Code. If the company has made no election, it is deemed that a rate base reduction election has been made. Under this election, the Internal Revenue Code allows a rate base reduction in the amount of any investment tax credit taken. However, the reduction must be restored to the rate base in equal installments over the life of the assets on which the credit is taken.

Therefore, a utility must take either the Section 46 reduction or a rate base reduction. If the company has made a cost of service reduction election under Section 46 of the Internal Revenue Code, a rate base reduction is prohibited. Any rate base reduction, even if it is achieved in an indirect manner, will cause the company to lose its eligibility to claim the credit. The treatment to be accorded a cost of service reduction is discussed in Chapter III, Section 4, Revenue and Expenses. Table III - 1 presents an example calculation of the impact of the investment tax credit based on a 2004 test year. In this example, the rate base would be reduced by $8,850.

TABLE III – 1

(a)	(b)	(c)	(d)	(e)	(f)	(g)
Year Credit Taken	Amount of Credit	Servic e Life	Annual Credit (b) /(c)	Multiplier (Test Yr. - (a)	Restoratio n (d) x (e)	Net Reductio n (b) - (f)
2000	$2,500	10 yrs.	$250	3	$750	$1,750
2001	$4,000	20 yrs.	$200	3	$600	$3,400
2002	$2,000	20 yrs.	$100	2	$200	$1,800
2003	$2,000	20 yrs.	$100	1	$100	$1,900
Total						$8,850

6. Deferred Income Taxes

Deferred taxes arise because of timing differences between the recognition of certain items for **book** (i.e., liberalized depreciation for tax purposes and straight line depreciation for book purposes). Further, the company may expense interest and real property taxes accruing during construction projects for tax purposes, but it may capitalize these items and write them off over the life of the asset for book purposes.

Two approaches, flow-through and normalization, have been developed for the treatment of a utility's federal income tax liabilities. The flow-through method attempts to recognize as tax expense for regulatory purposes the actual tax shown on the return. TEX. UTIL. CODE§ 104.056 has been interpreted by the Commission to prohibit the flow-through method because of the mandate in TEX. UTIL. CODE § 104.056(a)(1) that the benefits of tax savings be balanced equitably between present and future customers.

Under the normalization approach, the company accumulates in its deferred tax accounts the difference between the amount of income tax it pays and the amount it shows for book purposes. One normalization method is to reduce the rate base by the amount of deferred taxes attributable to a particular system. An alternative method is to make no rate base reduction for deferred taxes, but to include all of the company's deferred taxes as a part of its capital structure at zero cost. The normalization approach meets the statutory intent of sharing the benefits of tax savings between present and future customers, because this approach spreads the tax savings over the life of the asset.

Note: Commission substantive rule 16 TEX. ADMIN. CODE § 7.501(2) requires a gas utility to report the amount of any income tax savings or deferrals derived from the application of such methods as liberalized depreciation or amortization.

7. Insurance Reserve

Some utilities are self-insured and have a reserve account for use in the event of losses. Some cities urge that the insurance reserve should reduce the rate base, even though the insurance reserve is not included in the rate base. The reserve is not a rate base reduction under present Commission practice.

8. Retirement of Plant Assets

The retirement of a plant asset from service is accounted for by crediting the book cost to the utility plant account in which it is included. At the same time, accumulated depreciation is debited with the original cost and the cost of removal and credited with the salvage value and any other amounts recovered, such as insurance.

9. Acquisition Adjustment

When a company pays a purchase price above the net original cost for a utility operating unit or system, it often requests an acquisition adjustment as a rate base addition. The acquisition adjustment is equal to the difference between the price paid and the net original cost. Similarly, when a company pays a purchase price that is below the net original cost for a utility operating unit or system, an acquisition adjustment is used by the Commission to reflect the actual investment for the purpose of calculating a return on rate base. Such an item may be a proper expense to be amortized.

10. Summary of the Impact of the above Rate base Items

Each of the above rate base items can be included as a rate base deduction or included in **capital structure**, but not both, because the utility should only be allowed to recover for each item once. Table III - 2 presents the impact of each of the above rate base items if they are included as a rate base deduction or included in capital structure.

TABLE III – 2

Other Rate Base Items	Treatment I Contributions and Advances, Customer Deposits and Deferred Income Taxes Used as Rate Base Reduction	Treatment II Contributions and Advances, Customer Deposits and Deferred Income Taxes Included in Capital Structure
Construction Work in Progress	$0	$0
Working Capital	$508,850	$508,850
Contributions & Advances	$(20,000)	$0
Customer Deposits	$(120,000)	$0
Investment Tax Credit	$(8,850)	$(8,850)
Deferred Income Taxes	$(200,000)	$0
Insurance Reserves	$0	$0
Retirement of Plant Assets	$0	$0
Acquisition Adjustments	$0	$0
Totals	$160,000	$500,000

F. RATE BASE SUMMARY

TEX. UTIL. CODE § 104.053 requires gas utility rates to be based on the adjusted value of invested capital used and useful to the utility in providing service, and that the adjusted value shall be computed on the basis of a reasonable balance between the original cost (less depreciation) and the current cost (less an adjustment for age and condition). Commission practice, if necessary, is to weigh net original cost at 60 percent and net current cost at 40 percent. Under TEX. UTIL. CODE § 104.053, the weighting to be applied to each of the components is discretionary with the regulatory authority so long as net original cost is weighed no less than 60 percent nor more than 75 percent and net current cost is weighed no more than 40 percent or less than 25 percent.

The regulatory authority has the discretion to set the percentages of each element in the rate base within the limits TEX. UTIL. CODE § 104.053 on a case-by-case basis, in order to adjust the monetary return to the proper level. See *Southwestern Bell Telephone Company v. Public Utility Commission*, 571 S.W. 2d 503 (Tex. 1978).

Table III - 3 summarizes the calculation of total rate base as discussed in Chapter 3, Section 1 and illustrates an example of the 60/40 weighting of original/current plant cost.

TABLE III – 3

Invested Capital	$1,000,000
Less Accumulated Depreciation	$ 200,000
Net Original Cost	$ 800,000
Other Rate Base Items (Net)	$ 500,000
Total Invested Capital	(a) $1,300,000
Current Cost	$2,000,000
Less Adjustment for Age and Condition	$ 400,000
Net Current Cost	$1,600,000
Rate Base	
Net Original Cost = 800,000 x 60% =	$ 480,000
Net Current Cost = 1,600,000 x 40% =	$ 640,000
Other Rate Base Items (added since original plant was constructed)	$ 500,000
Total Rate Base (Adjusted Value Rate Base)	(b) $1,620,000

(a) The composite cost of capital may be applied to this figure to determine the required monetary return

(b) The require monetary return is then divided by this figure to determine the rate of return on the adjusted value of invested capital rate base.

SECTION 2 - COST OF CAPITAL

Utilities acquire capital primarily by borrowing (debt) or selling stock (equity). Like pipe or stationery, money has a "cost". That cost is determined by the return the lender or investor requires. Financial theory postulates that returns must be commensurate with the investment risk. That is, the higher the risk, the higher the return. This Section will examine issues relating to capital structure and the cost of debt, preferred stock, equity, and other sources of funds, in order to develop an estimate of the utilities' cost of capital, alternatively referred to as its rate of return. Once a company's capital structure and actual or estimated costs of debt and equity have been identified, the company's overall rate of return can be estimated by determining its weighted average cost of capital (WACC). This is described in greater detail in section G.

A. CAPITAL STRUCTURE

In order to determine a utility's cost of capital, it is necessary to determine the types of investment in the company. The ratios of the various sources of capital to total permanent capital is called the utility's capital structure. Because some sources of money are more costly than others, the utility's capital structure can have a significant impact on the overall cost of capital.

The first step in arriving at a proper capital structure is to determine the amount and types of total permanent capital invested in the company. Short-term debt is often used by corporations as a form of interim financing until long-term financing is available. Company records will show if short-term debt has been relied on in recent years. If short-term debt is part of the permanent capital structure, adjustments will be needed. The ratio of short-term debt to total capital commonly fluctuates broadly over time. In this case, a trending or averaging technique, tempered by judgment, will provide an acceptable ratio of short-term debt to total capital.

Trends in corporate capital structures should be examined before automatically assigning the end of the test year's capital component weighting. Company activity in the capital markets, or lack of it, may skew its capital structure when compared to its historical norm. It is important to realize that capital structures evolve as a company's scope of activities and risks changes.

Companies maintain a capital structure that management deems to be optimal given the mix and risk of corporate activities. Gas distribution companies typically have high debt to equity ratios when compared to other industries. Problems arise in rate cases where the gas utility is part of a diversified corporation. In these cases, the Commission generally looks at the parent corporation's consolidated capital structure, weights the individual components, and assigns them to the investment in the utility. If the consolidated capital structure is far out of line with the industry average, as shown in Moody's Utility

Manual, a typical industry capital structure may be considered.

Another consideration is the capital structure of small utilities. Some small utilities are heavily equity financed. A company can reasonably be expected to lower the overall cost to its ratepayers by using debt financing, but this determination should be made only after very careful consideration. Often a small utility may not have the financial capacity to borrow long-term fixed rate funds. They might even lack the financial strength to support or even qualify for short-term borrowing. If a determination is made that the company could have issued debt at reasonable cost and security, a reasonable capital structure for the company can be assigned for ratemaking purposes.

B. DEBT AND PREFERRED STOCK

The company's books should clearly display the cost of long-term and short-term debt. If debt will be maturing while the rates will be in effect, replacement costs of that debt should be considered. In any case, the proper cost of debt is the embedded cost of debt with adjustments made for current maturities.

If the original debt was sold at a discount, or if expenses were incurred in contracting for the debt, it is proper that the utility be allowed to increase the coupon rate to amortize the discount or debt expenses. For debt sold at a premium, the premium should be amortized so as to decrease the coupon interest rate.

Table III - 4 presents an example of an accepted method of determining a company's embedded cost of debt. The same procedure should be followed to calculate the embedded cost of preferred stock.

TABLE III – 4

(a)	(b)	(c)	(d)
	Amount Issued and Not Refunded or Canceled	Percent of Total (b / Total)	Weighted Cost (a x c)
First Mortgage Bonds			
5% due 2000	$ 1,000,000	10.00%	0.50%
6% due 2005	$ 500,000	5.00%	0.30%
Sinking Fund Debentures			
6.25% due 1998	$ 2,000,000	20.00%	1.25%
8% due 2005	$ 6,500,000	65.00%	5.20%

Total	$10,000,000	100.00%	7.25%

The weighted average cost of debt or preferred stock is obtained by multiplying the interest rate of a particular issue by the ratio of that issue to total permanent debt or preferred capital. This must be done for each issue and the components must then be added to arrive at the embedded cost.

C. EQUITY

1. Fundamentals of the Cost of Equity

The cost of equity capital is much more difficult to determine. It does not have a stated rate of return or interest as do loans, bonds or preferred stock. An equity investor still expects to receive a return on their investment. This return is in the form of dividends or increases in the value of the stock, or both. The cost of equity to a company is the rate of return necessary to get investors to purchase the company's stock. This rate is not directly observable in the market place but must be estimated for ratemaking purposes.

The law requires that the estimated cost of equity be high enough to allow the company "to maintain its financial integrity, to attract capital and to compensate its investors for the risks assumed." *Federal Power Commission v. Hope Natural Gas Company*, 320 U.S. 591, 64 s. Ct- 281, 88 L. ED- 333 (1944). In another case, the Supreme Court of Texas said the rate of return must be high enough to attract ample capital but need not be beyond that [amount] *Railroad Commission v. Houston Natural Gas Corporation*, 289 S.W. 2d 559 (Tex. 1956), *Southwestern Bell Telephone Company v. Public Utility Commission*, 571 s.w. 2d 203 (Tex. 1978).

2. Techniques for Estimating the Cost of Equity

Four methods for determining the cost of equity are most frequently presented to the Commission. Those methods, which will be specifically addressed below are: a) discounted cash flow, b) discounted cash flow on comparable companies, and c) the capital asset pricing model (CAPM) and d) comparable earnings analysis.. Utilities will often employ more than one technique in estimating the cost of equity.

a. Discounted Cash Flow (DCF)

Discounted cash flow is the most widely accepted method of estimating the cost of equity for publicly traded companies. The DCF technique presumes the basic efficiency of the market place in setting the price of a stock. It is the action of the market place that reflects the true cost of capital. The underlying assumption of the DCF model is that investors are buying securities based on their expected dividend yield and increased value.

The DCF formula attempts to reproduce that price mechanism to arrive at an estimate for equity return. The constant growth derivation of the DCF is shown as Expected Return = Dividend rate per share + growth.

$$K_e = \frac{D_1}{P_o} + g$$

Where K_e = expected rate of return on equity (the utility's cost of equity)
D_1 = dividends in the upcoming year
P_o = current price (a trend of 2 or 3 months)
g = long-term growth expectations

In estimating "g", the analyst is not concerned with the rate at which the firm will actually grow, but rather the long-term growth expectations of the investors. Judgment is required as past performance cannot be automatically assumed to continue indefinitely. Changes in market potential, gas supply, competitive pricing, regulation, economic climate, all have an impact on growth. Investors form their expectations of future growth by analyzing past performance as a guide to the direction the company is headed. Some utilities also use the growth projection for their company as found in Value Line Investment Survey, or other reported analyst estimates. The growth in earnings can be estimated by analyzing the growth in earnings per share (eps), in dividends per share (dps), and in net book value per share (nbv) over the past 10 to 15 years.

b. DCF on Comparable Companies

Many gas utilities in Texas are part of diversified energy companies. Their operations typically include exploration, drilling, production, and transmission, as well as distribution. The market determined cost of equity for such a company reflects the risks of all the company's operations combined. The calculation of the cost of equity for the distribution operations of the company, separate from other company functions, is frequently difficult. To solve this problem, several of the utilities have recently used the approach of selecting "pure" distribution companies throughout the country, such as those used in Moody's Public Utility Manual. A DCF analysis is then conducted on each company of this group to arrive at an average range for the cost of equity.

c. Capital Asset Pricing Model (CAPM)

The Capital Asset Pricing Model (CAPM) is another widely employed equity valuation model that bases the equity cost of capital on the relationship between risk and expected return. The general form of its equation is given as:

$$K_e = R_f + \exists(R_p)$$

Where K_e = expected rate of return on equity (the utility's cost of equity)
R_f = the market "risk free" rate
$\exists$ = the stock's beta coefficient

R_p = the market risk premium

Originally developed to analyze the required rates of returns on assets held in portfolios, the rationale behind the CAPM is that investors need to be compensated in two ways: time value of money and risk. The time value of money is represented by the risk-free (R_f) rate in the formula and compensates the investors for placing money in any investment over a period of time. Long-term treasury security rates are typically used to provide this term in the equation. The other half of the formula represents risk and calculates the amount of compensation the investor needs for taking on additional risk. This is calculated by taking a risk measure ∃ (beta) derived from the relative risk of a particular stock compared to that of the entire market, and then applying this as an adjustment to the aggregate market risk premium (R_p). The market risk premium is typically calculated as an overall market rate of return for some period, minus the risk free rate. Beta values are calculated and published by investment services and are then applied to the formula to complete the estimate calculation.

The logical basis of the CAPM has lead to its continued wide use among analysts and in academia, though its empirical results have been mixed and suggest that the CAPM is a better concept applied to investment portfolios than individual stocks. Nonetheless, CAPM remains a useful technique in estimating equity returns.

d. Comparable Earnings

The cost of equity to a public utility has been estimated by comparing the accounting rates of return earned by other firms on their equity capital over one or more historical time periods. The formula for this calculation is as follows:

$$ROE_{it} = \frac{X_{it}}{BE_{it}}$$

Where ROE_{it} = return on book equity for firm i in period t

X_{it} = net income for firm i in period t

BE_{it} = firm i's average book equity in period t

These returns are averaged for each year and then the yearly averages are averaged or trended to arrive at the utility's cost of equity.

The reasons supporting this type of comparable earnings analysis are:

- The average returns realized by other firms are representative of the productivity of common equity in the economy, and
- A utility's equity capital must provide comparable returns to compensate

existing stockholders and attract additional investors.

The problems with this approach are:

- It assumes that other firms have actually earned, on average, their cost of equity on net book value and that the required return has not changed significantly over time.

- It is not a market-oriented concept and fails to recognize the prospective nature of investors' required returns.

- It is vague in defining comparable risk firms and may result in significant measurement ambiguities.

- Because it is dependent upon what other regulatory bodies have decided, significant circularity problems can arise.

- The returns on book equity do not conform to the expected positive relationship between risk and required returns.

Utilities often include diversified companies in their presentation. Only pure distribution companies should be used such as those listed in Moody's Public Utility Manual.

3. Adjustments to the Cost of Equity

a. Risk Differences

Cost of equity estimates for the utility division of a diversified energy corporation usually require a downward adjustment to reflect lower risk in relation to the company's total risk. The company's full range of operations (distribution, exploration, drilling and production) generates its total risk. Measuring the relative risk for various operations is difficult to do with precision. Using a DCF analysis on pure gas distribution companies is one way to avoid having to make these measurements.

b. Diversification Benefits

Another factor that could reduce the cost of equity for a subsidiary or division of a diversified energy company is the reduction that comes from the parent company's reduced risk because of diversification. Known as the “portfolio effect,” it simply means that, as a company diversifies, it is able to reduce risk, thus lowering the cost of equity.

c. Size

Most of the large diversified companies raise all their capital at the parent company level since it is less expensive than if each individual subsidiary or division were to attempt to raise capital on its own. The benefit of having access to financial markets through a large diversified company reduces a gas distribution division's or subsidiary's cost of equity, as well as its cost of debt. Therefore, a downward adjustment would be in order for utility companies that obtain capital in this manner.

d. Market-to-Book Ratio

Occasionally, a publicly-traded utility will seek a market-to-book adjustment. For example, if the market value of its shares is lower than book value during the test year because of market pressure, the cost of equity may be adjusted to reflect a more typical test year cost of equity. Thus, the cost of equity provides a basis for determining a fair return to equity. However, other considerations might warrant an adjustment to this minimum for the use of capital in an effort to achieve other objectives deemed in the public interest.

Although issuance and flotation costs may range from 3 to 5 percent, it is likely that the dilution to existing stockholders' equity from such costs is inconsequential. Finally, purported market pressure associated with the sale of additional equity could cause the market price to fall below book value. The Commission staff has attempted to measure market pressure for one of the large utilities and found that on the average it was of insufficient magnitude to be measured. However, if the company currently has plans to issue stock during the expected life of the proposed rates, a market-to-book adjustment might be in order.

D. SMALL UTILITIES

A lack of market data on smaller utilities makes it difficult to estimate the cost of equity capital. A good approach for estimating this cost is to use the cost of equity for large utilities as a benchmark. This can then be applied to the smaller company adjusted for differences in financial and business risk. Business risk is the uncertainty of revenue and operating expenses. Financial risk results from using debt and involves the uncertainty of operating income being high enough to cover the fixed costs of capital.

In assessing financial risk, the capital structure of the utility can be compared to that of the average pure gas distribution system. Some small utilities may be almost totally debt or equity financed. A low debt ratio reduces the financial risk and would reduce the cost of equity, but may raise the overall cost of capital since debt is a less expensive source of capital. On the other hand, companies with high debt ratios have higher financial risk and a higher cost of equity. But they probably have a lower overall cost of capital. Reduced (increased) financial risk would warrant a downward (upward) adjustment in the cost of equity unless a hypothetical capital structure has been used.

Such factors as company size, degree of diversification, service area, growth characteristics, reliability of gas supply, and management expertise can influence the certainty of revenue and expenses and, thus, are business risks. The higher a utility's business risks, the higher its cost of equity.

The usual arguments for a higher cost of equity for small firms are that they have greater business risk and less liquidity.

E. ATTRITION AND EROSION

Although the Commission has not granted an allowance for attrition and erosion, many companies argue that an allowance should be made specifically to cover these problems. If an allowance for such is granted by the regulatory authority, it should not be included as part of the cost of capital, but should be a specific increment set out for that purpose. This will prevent confusion if the higher rate is not actually achieved. Evidence needs to be obtained to show what the actual effects of attrition and erosion have been and to distinguish these from revenue requirements based on adjusted figures. Some allowance would also be needed for any additional revenue that will be derived from expected future growth.

Attrition may be defined as the utility's inability to earn the authorized rate of return. This inability may arise from an erosion of company earnings resulting from a disproportionate change in the revenue-cost-rate base relationship over time.

F. ADDITIONAL SOURCES OF CAPITAL

Deferred taxes, **contributions in aid of construction**, **customer advances** and customer deposits, if not used as a rate base deduction, are included as a part of the capital structure.

G. WEIGHTED AVERAGE (OR COMPOSITE) COST OF CAPITAL

Once the costs associated with each method of financing that a utility employs is known or estimated, the utility's overall cost of capital or rate of return can be calculated through its weighted average cost of capital (WACC). The WACC multiplies the ratio of each financial component in the company's capital structure by its relative cost and then sums these weighted averages to calculate the overall cost of capital.

Table III - 5 presents a basic example of determining a company's weighted average cost of capital using a capital structure of long-term debt and common equity with their associated costs:

TABLE III - 5

	Amount	Cost	% of Total Capitalization	Weighted Avg Cost
Long Term Debt	$ 33,000	7.25%	55.00%	3.99%
Common Equity	$ 27,000	10.50%	45.00%	4.73%
Total	$ 60,000		100.00%	8.71%

SECTION 3 – RETURN ON RATE BASE

Table III - 6 presents a more complex example of the WACC in the case of a company that has used multiple forms of financing in its capital structure. As above however, the method of determining a company's weighted average cost of capital remains the same:

TABLE III – 6

Original Cost (Table III-3)	$1,000,000
Less: Accumulated Depreciation (Table III-3)	$ (200,000)
Net Original Cost (Table III-3)	$ 800,000
Add: Other Rate Base Items (Table III-3)	$ 500,000
Total Invested Capital (Table III-3)	$1,300,000
Multiplied By: Weighted Avg. Cost of Capital (Table III-5)	9.83%
Required **Monetary Return** on Invested Capital	$ 127,790
Divided By: Adjusted Value Rate Base (Table III-3)	$1,620,000
Rate of Return on **Adjusted Value Rate Base**	7.89%

The monetary return on invested capital, which is equal to a company's demonstrated cost of capital should be divided by the adjusted value rate base to determine the required rate of return. Some utilities might take the composite cost of capital and apply it to the adjusted value rate base instead of the total invested capital to determine a required monetary return (i.e. apply the 9.83% cost of capital to the $1,620,000 adjusted value rate base, instead of the $1,300,000 invested capital). It has been the position of the Commission that this is incorrect, and would yield rates that would be far above a reasonable return on invested capital and more than a fair return on adjusted value.

As the Supreme Court of Texas in the Southwestern Bell[1] case indicated, a regulatory authority must establish rates within the general guidelines established by TEX. UTIL. CODE Chapter 104 (i.e. not less than a reasonable return on invested capital or more than a fair return on the adjusted value rate base). This does not deny that the appropriate rate base is the adjusted value rate base. It recognizes that the most efficient way to determine a utility's actual monetary needs is to use market derived cost of capital applied to invested capital.

[1] *Southwestern Bell Telephone Co. v. Public Utility Commission of Texas*, 571 SW2d 503 (Tex. 1978).

SECTION 4 - REVENUE AND EXPENSES

A utility's net income should equal the required monetary return on the utility's rate base. Net income is defined in TEX. UTIL. CODE § 104.055 as the total revenue less all reasonable and necessary expenses as determined by the regulatory authority.

Only those payments found reasonable are included as expense items. TEX. UTIL. CODE § 104.055 provides the authority for promulgating reasonable rules and regulations with respect to the allowance or disallowance of certain expenses. Consequently, the Commission has adopted Commission substantive rules §§ 7.501, 7.5252, 7.115, and 7.5414 for determining revenue and expenses.

A. ALLOCATION AMONG CLASSES OF CONSUMERS

The revenue and expenses, which are subject to allocation, fall into two categories: either they are fixed (non-volume-related) or they are variable (volume-related). Rate base assets are generally allocated the same as fixed expenses.

Variable revenue and expenses (primarily gas sales revenue and gas costs) are uniformly allocated according to volume of consumption by each class of consumer during the test year, with adjustment for weather. See **Weather Normalization** Adjustment, Chapter III, Section 5(D)(1)(b). Thus, variable expenses seldom create major problems.

Problems frequently arise, however, in the allocation of fixed assets and expenses. Several of the more common methodologies are set out below.

1. Peak Demand Allocation

The **peak demand** methodology allocates fixed assets and expenses according to the volume consumed by each customer class on the system peak demand day of the test year (this is called the coincident peak). This method assumes that fixed assets and expenses are determined by the capacity required to serve all customers during a period of peak demand.

Other methods can be used to measure and allocate peak demand to different customer classes. These are referred to as modified peak demand methodologies. For example, peak demand can be determined based on the non-coincident peak, or the total of the peak demand experienced by each customer class, regardless of the day incurred. Another modification of peak demand is calculated using the average of more than one peak demand day during the test year. This method can moderate the allocation of costs to a customer class with just one large peak demand.

Since peak demands imposed by residential and small commercial customers are far in excess of average demands, the larger portion of the rate base is often allocated to residential and small commercial customers. As a result, a system designed to meet the needs of these primary customers will necessarily carry a large excess capacity that is seldom used. Some utilities can make this excess capacity available to other customers if they can use gas on an interruptible basis or are unlikely to need large amounts of gas during periods of peak residential and commercial demand. Revenue received in this way can then be used to offset the higher costs allocated to residential and commercial customers.

2. Volumetric Allocation

According to this method, fixed assets and expenses are simply allocated in the same manner as variable revenue and expenses. Since the industrial class frequently consumes the majority of gas by volume, this allocation methodology results in much lower residential and commercial rates. However, this methodology ignores the role of peak demand on fixed assets and expenses.

3. 50/50 Seaboard

The 50/50 Seaboard allocation method was developed by the Federal Power Commission as a way to allocate fixed assets while simultaneously recognizing the volumetric and peak demand factors. Simply stated, this allocation uses 50 percent of each factor. Either peak demand or modified peak demand allocation may be used for the peak demand factor.

4. Modified 75/25 Seaboard

The modified 75/25 Seaboard allocation formula is the same as the 50/50 methodology, except that 75 percent volume and 25 percent peak demand is used. The reason for this modification is a policy in favor of conservation. Gas users are more likely to conserve when they incur a higher per unit cost for gas.

When more obscure allocation formulas are used, the utility should justify their use. Results should be compared to those outlined above. Remember, no allocation method results in the only correct result. No matter how precise the calculations included in the utility's rate justification appear, allocation is a matter of judgment and public policy.

B. REVENUE

1. Gas Sales

Most utility revenue come from gas sales. Adjustments to test year gas sales volumes and prices are typically required. Common adjustments include growth normalization, weather normalization and rate increase annualization. Revenue also should be adjusted to reflect the current gas purchase cost above the base rate that is recouped through the purchased gas adjustment clause.

a. Growth Normalization

For consistency when using a year-end test year, book revenue should be adjusted to show a full year's billing for *all* customers receiving service at the end of the test year. This adjustment is required to match the test year revenue with the year-end investment. Adjustments are based on actual monthly active customer records when available. If records are not readily available, Commission policy is to assume that changes in the number of active customers occurred evenly during the test year.

b. **Weather Normalization**

Gas sales adjustments are commonly made to account for the net effect of below average and above average heating degree-days during a test year. The adjustment is computed by comparing the actual number of **heating degree days** to the normal heating degree-days experienced in the area for the test year. Test year gas sales volumes and revenue are adjusted to reflect a normal **heating degree day** year.

Normal heating degree-day information is based on U.S. Weather Bureau statistics by weather station. The data is published monthly with annual information available in the July issue of *Climatological Data, National Oceanic and Atmospheric Administration, Environmental Data and Information Service, National Climatic Center, Ashville, N.C.* www.ncdc.noaa.gov

c. Rate Annualization

If a utility had a rate increase effective for any customer class during the test year, revenue should be increased for that class to show the effective rate for the entire year.

d. Purchased Gas Cost Above Base Rate

Revenue should reflect the current gas purchase cost above the base rate that is recouped through the **purchased gas adjustment clause (PGA)**. The amount should include the unrecovered balance in any correcting account. This amount should be shown separately.

2. Other Revenue

Other utility revenue includes (a) allowance for funds used during construction (AFUDC), (b) prompt payment discounts and (c) revenue from non-utility sources.

a. **Allowance for Funds Used During Construction (AFUDC)**

If a utility includes **AFUDC** as other income during the test year and the Construction work in progress (CWIP) account is disallowed, **AFUDC** should also be removed.

b. Inducement For Prompt Payment

If a utility offers an incentive for prompt bill payment by allowing a discount or charges a penalty for late payments, an adjustment may be necessary. Penalties collected for late payments should be included under Other Revenue, unless the most current rates in effect during the test year have no provision for late penalties. No adjustment is required if the most current rates in effect during the test year eliminate late payment penalties.

c. Revenue from Non-Utility Sources

Under TEX. UTIL. CODE §§ 102.153 and 104.058, no profit or loss resulting from the sale or lease of appliances, fixtures, equipment or other merchandise shall be considered in determining utility rates, to the extent that such merchandise is not integral to the provision of utility service. Commission substantive rule § 7.5252(c) dictates that revenue from non-utility operations be excluded from ratemaking calculations for gas utility service unless it is clearly shown to be integral to utility operations.

C. EXPENSES

Adjustments to expenses consistent with the revenue adjustments associated with gas sales volumes and prices are typically required in a test year. Common adjustments include growth normalization, weather normalization and rate annualization. Expenses also should be adjusted to reflect the current purchase gas cost below the base rate that is refunded through the **purchased gas adjustment clause**.

1. Lost and Unaccounted for Gas (LUG)

Commission substantive rule § 7.5525(b)(1) allows a utility to expense a maximum of five percent (5%) of its lost and unaccounted for gas for distribution systems and three percent (3%) for transmission systems in a test year. Lost and unaccounted for gas is the difference between the amounts metered in and out of a system.

All lost and unaccounted for gas is presumed "lost" unless a utility can provide evidence in a ratemaking proceeding that the unaccounted for gas represented company uses, liquids extraction or meter errors. The Commission may allow greater than five percent (5%) lost gas if special circumstances can be shown by the utility.

2. Advertising, Membership Dues and Charitable Contributions

Commission substantive rule § 7.5414(a) dictates that actual advertising expenses are allowed for ratemaking purposes up to one-half of one percent (0.5%) of the gross receipts of the utility for public utility services. This encourages utilities to fix leaks.

Certain types of expenses, listed below, are excluded:

- advertising expenses for influencing public opinion related to legislative, administrative or electoral matters;

- expenses associated with any controversial issue of public importance;

- expenses in support of social, recreational, fraternal or religious entities; and

- contributions or donations to charitable, religious or nonprofit entities.

3. Past Regulatory Expense

A utility's administrative and general expense account may include amortization for past regulatory expense. If the prior expense will be recouped before the effective date of the new rate schedule, this amount should be eliminated.

If the prior expense has not been recouped before the effective date of the new rates, the remaining balance should be added to the present regulatory expense and amortized over the period of years estimated between rate cases.

Rate case expenses can be included in base rates, but historical Commission policy indicates that the preferred treatment of rate case expense recovery is as a surcharge, as discussed in Chapter III, Section 5, Tariffs.

4. Depreciation Expense

Commission substantive rule § 7.5252(a) dictates that straight-line depreciation over the useful life expectancy of any item or facility is required for ratemaking purposes.

Historical Commission practice has been to disallow depreciation rate adjustments unless fully supported by a depreciation study. The study should include the average service lives of the property groups, salvage factors and adequacy of the present booked depreciation reserve.

If a utility depreciates its assets over a shorter life than allowed by the Internal Revenue Code, Commission practice has been to adjust the undepreciated cost of the assets over the longer service life unless supported by a depreciation study.

The methodologies used to compute depreciation expense and accumulated depreciation in the rate base should be consistent. *City of Weslaco v. General Telephone Co. of S.W.*, 359 S.W.2d 260 (Tex. Civ. App.-San Antonio, 1962, writ ref'd n.r.e.). Also, the Texas Supreme Court held that it was proper to exclude any depreciation expense on assets attributable to contribution in aid of construction. *Sunbelt Utilities v. Public Util. Comm'n*, 589 S.W.2d 392 (Tex. 1979).

Table III-7 shows a sample computation for straight-line depreciation. Assume a utility has depreciable assets totaling $1,000,000 and the average estimated useful lives are 10 years.

TABLE III – 7

Depreciable Assets @ Original Cost	$1,000,000
Less: Accumulated Depreciation (3 years @ $100,000/year)	300,000
Net Book Cost	$ 700,000

As shown above, the utility would take an annual depreciation expense of $100,000 each year. Assuming three of the 10 years have elapsed, the utility's balance sheet would show a net book cost of $700,000.

If the regulatory authority determined that the correct average service life was 28 years instead of 10 years, the three elapsed years would be deducted from the 28, resulting in a remaining useful life of 25 years. Thereafter, the $700,000 net book value would be divided by 25 for a new annual depreciation expense of $28,000. No adjustment would be made to the accumulated depreciation account other than the annual credits of $28,000.

5. Other Taxes

Revenue related taxes should be adjusted consistent with adjustments made to revenue.

6. Other Growth Expenses

If revenue adjustments were made due to increased customer counts during the test year, corresponding adjustments should be made for the associated incremental expenses incurred by the utility. Expenses requiring adjustment would include gas sales expense, information expense and customer accounts and service.
Other expense adjustments may be required where costs have increased or decreased during the test year to bring these accounts to year-end level.

7. Known Changes

Adjustments for known changes that will occur after the end of the test year are generally allowed if supporting evidence is presented in a ratemaking proceeding. The evidence should include a reasonably certain amount and effective date of the change. Two common examples of reasonably known changes are union contracts and postal rate increases.

8. Interest on Customer Deposits

If customer deposits have been used as a rate base deduction, the interest expense associated with the deposits should be included as an adjustment.

9. Federal Income Tax Expense (FIT)

If adjusted revenue and expenses for the test year yield a net operating income greater than zero, a utility is allowed to recoup through an adjustment the federal income tax owed. Table III - 8 shows a typical FIT calculation.

TABLE III – 8

DESCRIPTION	AMOUNT	TOTAL
Return on Investment		
Rate Base at Original Cost (Total Invested Capital from Table III-3)	$1,300,000	
Rate of Return (assumed for this example)	10.15%	
Monetary Return on Investment		$131,950
Interest Expense (Cost of Capital)		
Rate Base at Original Cost (Total Invested Capital from Table III-3)	$1,300,000	
Weighted Avg. Cost of Capital (Table III-5)	9.83%	
Total Interest Expense		$127,790
After Tax Income		$4,160
Gross-up Factor		1.538462
Taxable Income		$6,400
Federal Income Tax Rate		35%
Federal Income Tax Expense		$2,240

The return on investment is calculated by multiplying the rate base at original cost by the rate of return. Interest expense, computed by multiplying the rate base at original cost by the weighted cost of debt, is subtracted from the return on investment for the resulting after tax income. A gross-up factor, computed using (1/(1-tax rate)), is applied to the after tax income for the resulting taxable income. The applicable federal tax rate is then applied to the taxable income to arrive at the FIT. The Internal Revenue Service publishes a range of corporate tax rates for each tax year, so consult a corporate tax expert or accountant for a utility's appropriate rate.

For other factors that affect a utility's taxable income, such as investment tax credits and the situations described below, consult a corporate tax expert or accountant for the appropriate adjustment to a utility's taxable income.

When a utility is part of a larger entity and has a net operating loss, or its allocable portion of income tax deductions exceed test year income, the taxable income is negative which results in federal income tax savings to the larger entity. That savings would result in a credit adjustment to test year income.

SECTION 5 - RATES

A. REVENUE REQUIREMENT

1. Revenue Deficiency or Surplus

The total revenue deficiency or surplus is determined by subtracting adjusted test year expenses from revenue. Revenue deficiencies are more common during protested ratemaking proceedings because utilities can lower their rates by filing new tariffs with their customers and the Commission without a formal hearing.

A typical example of revenue deficiency is a test year net operating income loss and test year net operating loss sustained by a utility system that is part of a larger legally taxable entity.

Table III - 9 shows the test year adjusted net operating income loss calculation.

TABLE III – 9

Total Invested Capital (Table III-3)	$ 1,300,000
Weighted Average Cost of Capital (Table III-5)	x 0.0983
Required Monetary Return (Table III-6)	$ 127,790
Adjusted Net Operating Income (loss)	$ (117,130)
Net Operating Income Deficiency	$ 10,660
Tax Reciprocal[1]	0.6175
Gross Revenue Deficiency	$ 17,263
[1]Tax Reciprocal	
Incremental Revenue	1.0000
Incremental Occupation Tax	0.0200
Incremental Street and Alley Rental	0.0300
Incremental Taxable Income	0.9500
Incremental FIT at 35% (0.950x0.35)	0.3325
Incremental Net Operating Income	0.6175

To calculate the tax reciprocal subtract the revenue sensitive taxes from one. This remainder, incremental taxable income, is then multiplied by the incremental FIT rate (which ranges from 15 percent to 38 percent). Subtract the product from the incremental taxable income to yield the tax reciprocal.

B. RATE DESIGN

The rate structure of a utility determines how the revenue need will be recovered from each class and type of service provided by the utility. The rate structure is largely a matter of preference to be settled by the utility and the regulatory authority.

Rates designed to recover the full cost of providing service to a given customer may be a desirable objective of rate design. Allocation techniques are extremely imprecise. Because of the imprecision of allocation techniques, the courts have recognized the discretion of a regulatory authority in designing rates. Rates do not necessarily have to be set on the "cost" of providing a service.

A regulatory authority may consider factors other than cost. Those factors must address whether the resulting rate structure is just, reasonable, and not unduly discriminatory. But a utility must be consistent and may not arbitrarily alter relevant factors. The burden of proof of the utility includes the obligation to produce relevant information regarding a proposed change in rate design. *Texas Alarm and Signal Assoc. v. Public Utility Commission of Texas*, 603 5.W.2d 766 (Tex. 1980).

Utility charges are commonly classified as customer related or commodity related. The customer charge may be considered the minimum amount a customer pays to receive gas service. This charge may or may not reflect the entire fixed cost of providing the customer service. It has been argued that a customer charge of a magnitude necessary to recover all the fixed costs in providing service to the customer would be so large as to be unacceptable to most consumers.

The second component of the rate, the commodity charge, may be assessed through a straight line meter rate, a per Mcf (thousand cubic feet) charge for all consumption, or a block meter rate with increasing or decreasing charges for each block of consumption. Historically, many utilities have offered declining block rates whereby increased consumption is billed at decreasing rates per Mcf blocks. However, the declining block rate schedule discourages conservation.

Rate design is becoming an increasingly important tool for regulatory authorities, utilities, and customers in implementing energy conservation policies. Effective rate design options include off-peak pricing and time of day pricing that better match the cost of producing energy to when it is consumed, incentive rates for alternative sources of energy, and inverted block rates where increased consumption is billed at increasing rates per Mcf block.

C. TARIFFS

Tariffs set forth the rate that should be collected by the utility for each type of service provided. A tariff includes all rates and charges collected directly or indirectly by any public utility for any service, product, or commodity as part of their utility operation. TEX. UTIL. CODE § 101.003(12).

1. Service Charges

Some utilities have sought approval of service charges for items such as reconnections, appliance services, yard line replacements and returned checks. Proposed changes in service charges must be cost justified or based on revenue need.

2. Inducement for Prompt Payment

The Quality of Service Rule, Commission substantive rule § 7.45(4)(B), allows a utility to offer an inducement for prompt payment of bills by allowing a discount in the amount of five percent. 16 TEX. ADMIN. CODE § 7.45(4)(B).

3. Purchased Gas Adjustment (PGA)

A purchased gas adjustment (PGA) clause allows the utility to recover its fuel costs on a timely basis without the need for a formal rate proceeding. The use of fuel adjustment clauses has been upheld by the Texas Supreme Court, *San Antonio Ind. S. D. v. City of San Antonio*, 550 S.W.2d 262 (Tex. 1977).

The Commission has adopted Commission substantive rule § 7.5519(a) which sets forth the criteria used by the Commission in determining whether to grant a gas utility a purchased gas adjustment clause. These factors include but are not limited to: 1) the ability of the gas utility to control prices for gas purchased as affected by competition and relative competitive advantage; 2) the probability of frequent price changes; and 3) the availability of alternative gas supply sources.

Purchased gas adjustment clauses usually include a base cost of gas. Gas cost increases or decreases from this base are calculated and spread across the amount of gas consumed on a volumetric basis. In changing this base, a regulator should be certain the base used in the PGA clause conforms to the base used in base rates.

4. Separate Surcharges

It has become more common in recent years for the regulatory authority to allow utilities to recover rate case expenses, certain taxes, increases in taxes over what has already been recognized in the cost of service, or other expenses through a separate surcharge on the customer's bill. Reasonable rate case expenses may be included in the expense schedule in setting the final rates or as a surcharge. A surcharge makes the rate case expenses more visible and insures that the utility neither over collects nor under collects those costs. The surcharge should encompass any authorized but unrecovered rate case expenses from prior dockets. A surcharge has the advantage that rate case expenses may be allocated on a per customer basis or a per Mcf basis. The size of the surcharge per Mcf and the accounting convenience of the regulatory authority and the utility should determine which method is used. The surcharge typically is spread over a period of time to reduce its impact on ratepayers.

Rate case expenses can be collected through a fixed monthly surcharge or a volumetric surcharge and can be collected for up to three years, although typically the surcharge is authorized for approximately 12 to 24 months. A fixed monthly surcharge is designed to recover the rate case expense on a per bill basis. A volumetric surcharge is designed to recover the rate case expense according to consumption over a specified period of time. When collected volumetrically, it is preferable to set a fixed rate, collected from specific customers, with a flexible collection period, since the volumes used to calculate the fixed rate are estimated volumes. Language such as, "recovered over approximately 24 months" provides assurance to the utility that the full amount of authorized expense will be recovered.

If a surcharge is authorized, interest on the unrecovered balance may be allowed. Interest may be calculated monthly, expressed as a monthly percentage (annual interest rate divided by 12 months) and included in the recovery. Interest calculations should not be added to the unrecovered balance to prevent the collection of interest on interest. The Commission, if interest is allowed, will often use the deposit interest rate set annually each December by the Public Utility Commission.

A surcharge is often collected from all customer classes affected by the rate increase or rate case. The surcharge may be allocated among the customer classes for an equitable collection using the same rate design allocation used to set the commodity rate for each class of customer. A periodic report of the utility's collection of rate case expense is required by the Commission for docket compliance. This report can be quarterly, semi-annual or annual, depending upon the length of time set for collection. Quarterly or semi-annual is preferred. The report should identify the unrecovered balance, the collection by class of customer, the volumes used for collection by class of customer, the interest calculation, if authorized, and the ending balance by month. The terms of the report should be included in an ordering paragraph of the order.

D. SAMPLE CALCULATIONS FOR REVENUE ADJUSTMENTS

These adjustments attempt to take information from the test year and average and annualize the information to determine what an average year should look like.

1. GAS SALES REVENUE ADJUSTMENTS

a. CUSTOMER GROWTH ADJUSTMENT

Step 1. For each class of customers, determine the net increase (or decrease) in the number of customers consuming gas. This step is accomplished by subtracting the number of customers at the end of the test year from the number of customers at the beginning of the test year.

Assumption: The test year is the 12-month period ending December 31.

Number of customers:	January 1	1,000
	December 31	1,120
	Net Increase	120

Step 2. For each class of customers, determine the number of bills for each month of the test year. If a detailed bill analysis is available, actual numbers should be utilized. (A bill analysis should include, among other things, the number of Mcf sold during each month at each rate block for each class of customers, the number of bills per month at each rate block for each class of customers, and the respective dollar amounts relating thereto.) In the absence of a detailed bill analysis, it may be assumed that the net increase in the number of bills occurred evenly throughout the test year.

Assumptions: No bill analysis was available, and a proportionate share (i.e. 1/12) of the net increase in customers occurred at the beginning of each month.

$$\text{Net monthly increase} = \frac{\text{Net annual increase}}{\text{Number of months}}$$

$$= \frac{\text{120 customer bills}}{\text{12 months}}$$

$$= \text{10 bills per month}$$

Adjusted number of bills:

(1) Month of the Year	(2) Net Monthly Increase		(3) Number of Months Elapsed		(4) Cumulative Increase In Bills (2)x(3)		(5) Number of Bills at Jan. 1		(6) Adjusted Number of Bills (4)+(5)
January	10	x	1	=	10	+	1,000	=	1,010
February	10	x	2	=	20	+	1,000	=	1,020
March	10	x	3	=	30	+	1,000	=	1,030
April	10	x	4	=	40	+	1,000	=	1,040
May	10	x	5	=	50	+	1,000	=	1,050
June	10	x	6	=	60	+	1,000	=	1,060
July	10	x	7	=	70	+	1,000	=	1,070
August	10	x	8	=	80	+	1,000	=	1,080
September	10	x	9	=	90	+	1,000	=	1,090

October	10	x	10	=	100	+	1,000	=	1,100
November	10	x	11	=	110	+	1,000	=	1,110
December	10	x	12	=	120	+	1,000	=	1,120

Step 3. For each class of customers, determine the quantity of gas sold during each month of the test year. (The month of February will be used as an example)

Assumption: 10,200 Mcf of gas was sold during February.

Step 4. For each class of customers, determine the revenue collected during each month of the test year.

Assumptions: During the test year, the base rates for this class of customers were as follows:

1 Mcf or fraction thereof	$3.00
All consumption over 1 Mcf	$2.50 per Mcf

Also, revenue passed through the purchased gas adjustment clause during the month of February equaled $0.25 per Mcf.

Revenue collected during February:

(1,020 Mcf)	($3.00 per Mcf)	=	$ 3,060[2]
(9,180 Mcf)	($2.50 per Mcf)	=	$22,950[3]
(10,200 Mcf)	($0.25 per Mcf)	=	$ 2,550[4]
			$28,560

Step 5. For each class of customers, determine the average number of Mcf per bill for each month of the test year.

Average number of Mcf per bill for February:

Consumption during February 10,200 Mcf

[2] Since there were 1,020 bills during the month of February (See #2 above), each bill included at least some consumption under the first rate block. Consequently, consumption under the first rate block equaled 1,020 Mcf (1,020 bills x 1 Mcf per bill).

[3] Since there were only two rate blocks, gas not consumed under the first block must have been consumed under the second. (10,200 Mcf - 1,020 Mcf consumed under the first block = 9,180 Mcf consumed under the second block.)

[4] The dollar amount passed through the purchased gas adjustment clause was expressed on a per Mcf basis and applied to all Mcf consumed during the month of February.

$$\frac{}{\text{Number of Bills during February}} = \frac{}{\text{1,020 bills}} = 10 \text{ Mcf per bill}$$

Step 6. For each class of customers, determine the average revenue per Mcf for each month of the test year.

Average revenue per Mcf for February:

$$\frac{\text{February Revenue}}{\text{February Consumption}} = \frac{\$28,560}{\text{10,200 Mcf}} = \$2.80 \text{ per Mcf}$$

Step 7. For each class of customers, determine the number of additional bills which would have been issued during each month of the test year. This step is accomplished by subtracting the adjusted number of bills per month from the number of bills at the end of the test year.

Number of additional bills per month:

(1) Month of the Year	(2) Number of Bills at Year End		(3) Adjusted Number of Bills		(4) Number of Additional Bills (2)-(3)
January	1,120	-	1,010	=	110
February	1,120	-	1,020	=	100
March	1,120	-	1,030	=	90
April	1,120	-	1,040	=	80
May	1,120	-	1,050	=	70
June	1,120	-	1,060	=	60
July	1,120	-	1,070	=	50
August	1,120	-	1,080	=	40
September	1,120	-	1,090	=	30
October	1,120	-	1,100	=	20
November	1,120	-	1,110	=	10
December	1,120	-	1,120	=	0

Step 8. For each class of customers, determine the average number of additional Mcf that would have been sold during each month of the test year if all of the customers were on the system the whole year.

Average number of additional Mcf sold during February:

(Average number of Mcf per bill) x (Number of Additional Bills) =
(10 Mcf per bill) x (100 bills) = 1,000 Mcf

Step 9. For each class of customers, determine the monthly revenue adjustment for each month of the test year.

Monthly revenue adjustment for February:

(Average monthly revenue per Mcf) x (Average number of additional Mcf sold during month) = ($2.80 per Mcf) x (1,000 Mcf) = $2,800

Step 10. For each class of customers, add the 12 monthly revenue adjustments (Step #9 above) to arrive at the total adjustment to revenue to account for growth.

Assumptions:	Test year revenue (unadjusted)	$430,000
	Total growth adjustment	21,000
	Test year Revenue adjusted for growth	$451,000

b. WEATHER NORMALIZATION ADJUSTMENT

(All figures should have already been adjusted for customer growth)

Step 1. Determine the quantity of gas sold and amount of revenue collected during the test year.

Quantity of gas actually sold during test year	100,000 Mcf
Adjustment for growth (Assumed)	10,000 Mcf
Adjusted quantity of gas	110,000 Mcf

Revenue collected during test year	$430,000
Adjustment for growth	21,000
Adjusted revenue (See Step #10 above)	$451,000

Step 2. Ascertain those months during which no Heating **Degree Days (HDDs)** occurred:

Assumption: No Heating degree-days occurred during the months of June, July and August. Heating Degree Days occurred during all other months of the test year.

Step 3. Determine the average monthly base load quantity and revenue for the relevant period, i.e., June, July and August.

Month	Base Load Quantity	Base Load Revenue
June	6,400 Mcf	$26,240
July	6,000 Mcf	24,600

August	5,900 Mcf	24,190
Totals	18,300 Mcf	$75,030

$$\text{Average monthly quantity (Base Load)} = \frac{18{,}300 \text{ Mcf}}{3 \text{ months}}$$

$$= 6{,}100 \text{ Mcf per month}$$

$$\text{Average monthly revenue (Base Load)} = \frac{\$75{,}030}{3 \text{ months}}$$

$$= \$25{,}010 \text{ per month}$$

Step 4. Annualize the average monthly base load quantity and revenue amounts by multiplying each figure by 12.

Annual base load quantity:

(Average monthly base load quantity) x (12 months) =
(6,100 Mcf per month) x (12 months) = 73,200 Mcf

Annual base load revenue:

(Average monthly base load revenue) x (12 months) =
($25,010 per month) x (12 months) = $300,120

Step 5. Determine the heating load by subtracting the annual base load quantity from the adjusted quantity of gas sold during the test year (See #1 above).

Adjusted quantity of gas	110,000 Mcf
Annual base load quantity	73,200 Mcf
Heating Load	36,800 Mcf

Step 6. Determine the number of Heating Degree Days actually experienced during the test year. The source is the National Oceanic and Atmospheric Administration National Climatic Center, Ashville, N.C.

Assumption: Test year HDDs = 4,872

Step 7. Ascertain the number of HDDs normally experienced in the area.

Assumption: Normal HDDs = 4,800

Step 8. Determine the HDD Factor by dividing the normal HDDs into the test year HDDs.

$$\text{HDD Factor} = \frac{\text{Test year HDDs}}{\text{Normal HDDs}}$$

$$= \frac{4{,}872 \text{ HDDs}}{4{,}800 \text{ HDDs}}$$

$$= 1.015$$ [5]

Step 9. Determine the Adjusted Heating Load by dividing the HDD Factor into the Heating Load.

$$\text{Adjusted Heating Load} = \frac{\text{Heating Load}}{\text{HDD Factor}}$$

$$= \frac{36{,}800 \text{ Mcf}}{1.015}$$

$$= 36{,}256 \text{ Mcf}$$

Step 10. Determine the Mcf adjustment for normal weather by subtracting the Heating Load from the Adjusted Heating Load.

Mcf adjustment: Adjusted Heating Load		36,256 Mcf
Heating Load		-36,800 Mcf
Adjustment		-544 Mcf[6]

Step 11. Determine the heating load revenue by subtracting annual base load revenue from adjusted test year revenue.

Heating load revenue:

[5] Since the HDD Factor is greater than one, weather during the test year was colder than normal. If actual weather had been warmer than normal, the resulting HDD Factor would be less than one.

[6] Since this is a negative number, the adjustment will involve a reduction in test year volumes.

Adjusted test year revenue	$451,000
Annual Base Load Revenue	-$300,120
Heating Load Revenue	$150,880

Step 12. Determine the average revenue per heating load by dividing the heating load into the heating load revenue.

$$\text{Average revenue per heating load:} = \frac{\text{Heating load revenue}}{\text{Heating Load}}$$

$$= \frac{\$150{,}880}{36{,}800 \text{ Mcf}}$$

$$= \$4.10 \text{ per Mcf}$$

Step 13. Determine the weather normalization adjustment by multiplying the Mcf adjustment by the average revenue per heating load.

Weather normalization adjustment:

(-544 Mcf) x ($4.10 per Mcf) = -$2,230

Step 14. Adjust test year revenue to normalize for weather.

Test year revenue	$430,000	
Adjustment for growth	$ 21,000	$451,000
Adjustment for weather		$ -2,230
Adjusted test year revenue		$448,770

c. RATE ANNUALIZATION ADJUSTMENT

(All figures already should have been adjusted for customer growth and weather)

Step 1. For each class of customers, ascertain whether any rate increase took place during or after the test year.

Assumption: An increase in residential rates occurred during the test year.

Step 2. Determine the adjusted quantity of gas sold during the test year. (This figure should reflect the growth and weather adjustments.)

Assumption: 100,000 Mcf of gas was sold during the test year to residential customers. After a 10,000 Mcf upward adjustment for growth and a 544 Mcf downward adjustment for weather, the adjusted sales quantity equaled 109,456 Mcf.

Step 3. Determine the rates applicable at the end of the test year (or later, if applicable).

Assumption: Residential rates at the end of the test year were as follows:

1 Mcf or fraction thereof	$5.00
All consumption over 1 Mcf	$4.10 per Mcf

Also, revenue passed through the purchased gas adjustment clause during the last month of the test year was $0.28 per Mcf. This is the amount by which the current cost of gas exceeded the base cost.

Step 4. Multiply the adjusted quantity of gas (See Step #2 above) by the current rate (See Step #3 above) to arrive at test year revenue adjusted for growth, weather, and a change in rates.

Assumption: Number of bills for test year = 13,440 (1,120 bills per month x 12 months).

Annual Consumption at 1st Block:

(13,440 bills) x (1 Mcf per bill) = 13,440 Mcf

Annual Consumption at 2nd Block:

(109,456 total Mcf*) - (13,440 Mcf at 1st Block) = 96,016 Mcf

* See Step #2 above

Adjusted Revenue:

1st Block:	(13,440 Mcf) x ($5.00 per Mcf)	=	$ 67,200
2nd Block:	(96,016 Mcf) x ($4.10 per Mcf)	=	$393,666
PGA Clause:	(109,456 Mcf) x ($0.28 per Mcf)	=	$ 30,648
			$491,514

The $491,514 figure represents test year revenue from residential gas sales after adjustment for growth, weather, and increased rates.

2. PURCHASED GAS EXPENSE ADJUSTMENTS

a. CUSTOMER GROWTH ADJUSTMENT

Step 1. For each class of customers, determine the average number of additional Mcf that would have been sold during each month of the test year with the higher number of customers. (This calculation was performed in Step #8 of the growth adjustment to revenue - Ch.III, Sec. 5(D)(1)(a)).

Average number of additional Mcf sold during the month of February = 1,000 Mcf

Step 2. For each class of customers, determine the monthly weighted average cost of gas on a per Mcf basis by dividing the monthly purchases of gas into the monthly purchased gas expense (Assumed to be $27,600 for February). February purchased gas expense

$$\frac{\text{February purchased gas expense}}{\text{February purchases}} = \frac{\$27{,}600}{11{,}040 \text{ Mcf}} = \$2.50 \text{ per Mcf}$$

Step 3. For each class of customers, multiply the average number of additional Mcf that would have been sold during each month with the higher number of customers (Step #1 above) by the purchased gas expense for that month (Step #2 above) to arrive at the monthly adjustment.

February Adjustment = (1,000 Mcf) x ($2.50 per Mcf) = $2,500

Step 4. For each class of customers, add the 12 monthly expense adjustments to arrive at the total purchased gas expense growth adjustment.

Assumption: The sum of the 12 monthly expense adjustments is $27,500.

Step 5. For each class of customers, add the purchased gas expense growth adjustment to test year purchased gas expense.

Assumption: Purchased gas expense (unadjusted) for gas sold to this class of customers was $300,000.

Test year purchased gas expense (unadjusted)	$300,000
Purchased gas expense growth adjustment	<u>$ 27,500</u>
Purchased gas expense adjusted for growth	$327,500

b. WEATHER NORMALIZATION ADJUSTMENT

(All figures already should have been adjusted for growth)

Step 1. Determine the Mcf adjustment for normal weather (This calculation was performed in Step #10 of the weather normalization adjustment to revenue - Ch III, Sec.5(D)(1)(b)).

Mcf adjustment = -544 Mcf

Step 2. Determine the average purchase price per Mcf by dividing the quantity of gas sold during the test year into the amount spent to purchase that gas.

$$\frac{\text{Test year purchased gas expense}}{\text{Test year sales}} = \frac{\$327{,}500}{110{,}000\text{ Mcf}} = \$2.98 \text{ per Mcf (rounded)}$$

Step 3. Multiply the Mcf adjustment (Step #1 above) by the average purchase price (Step #2 above) to arrive at the weather normalization adjustment to the purchased gas expense.

(Mcf adjustment) x (Average purchase price) = (-544 Mcf) x ($2.98 per Mcf) = -$1,621 (rounded)

Step 4. Make the weather normalization adjustment to purchased gas expense.

Test year purchased gas expense	$300,000
Adjustment for growth	$+27,500
	$327,500
Adjustment to normalize for weather	$ -1,621
Purchased gas expense adjusted for growth and weather	$325,879

c. ADJUSTMENT TO REFLECT CHANGE IN BASE COST OF GAS

Step 1. Determine whether or not the base cost of gas will be changed. If a change will occur, identify the new base cost of gas.

Assumption: Base cost of gas will be increased from $3.00 per Mcf to $3.28 per Mcf, which is the latest weighted average cost of gas.

Step 2. Determine the adjusted quantity of gas sold during the test year. This amount was calculated in Step #2 of the adjustment to revenue to annualize a rate increase. Ch.III, Sec. 5(D)(1)(c).

Adjusted sales quantity = 109,456 Mcf

Step 3. Determine the adjustment to reflect the change in the base cost of gas as follows:

Adjustment = (adjusted sales quantity) x (per Mcf increase in base cost)

= (109,456 Mcf) x ($0.28 per Mcf)

= $30,648

Step 4. Make the adjustment to reflect the change in the base cost of gas as follows:

Purchased gas expense adjusted for growth and weather	$325,879
Adjustment to reflect change in base cost of gas	$ 30,648
Adjusted purchased gas expense	$356,527

d. LOST AND UNACCOUNTED FOR GAS ADJUSTMENT

Assumption: Quantity of gas metered into the system was 252,890 Mcf
Quantity of gas sold was 228,659 Mcf

Step 1. Determine the quantity of gas used by the utility for authorized company use.

Assumption: The Company showed that 4,000 Mcf had been consumed for company use, and the regulatory authority approved this quantity.

Step 2. Determine the percentage allowance for lost and unaccounted for gas. The Railroad Commission typically allows five percent for a distribution system.

Step 3. Determine the quantity of gas representing lost and unaccounted for gas for the most recent twelve-month period ending June 30 as follows:

(Quantity of gas metered into the system) - (Quantity of gas sold) - (Quantity of company used gas)

= (252,890 Mcf) - (228,659 Mcf) - (4,000 Mcf)

= 20,231 Mcf

Step 4. Determine the percentage of lost and unaccounted-for gas experienced by the Company as follows:

$$\frac{20{,}231 \text{ Mcf}}{252{,}890 \text{ Mcf}} = 8\% \text{ (rounded)}$$

Step 5. Since the eight percent lost and unaccounted for gas percentage experienced by the Company exceeded the five percent ceiling established by the regulatory authority, the five percent allowance should be calculated as follows:
(Quantity of gas metered in) x (5%)

= (252,890 Mcf) x (0.05)

= (12,645 Mcf (rounded))

Step 6. Determine the lost and unaccounted for gas adjustment as follows:

(Excess lost and unaccounted for gas) x (Adjusted base cost of gas)

= (12,645 Mcf) x ($3.28 per Mcf)

= $41,476

Step 7. Make the adjustment for lost and unaccounted for gas as follows:

Purchased gas expense as adjusted for growth, weather, and change in base cost of gas	$356,527
Adjustment for lost and unaccounted for gas	$ 41,476
Total adjusted purchased gas expense	$398,003

3. PURCHASED GAS ADJUSTMENT (PGA) CLAUSE

a. LOST AND UNACCOUNTED FOR GAS ADJUSTMENT FACTOR

A typical purchased gas adjustment (PGA) clause will include a factor to reflect an allowance for lost and unaccounted for gas. This factor may be calculated by using the following formula:

$$\text{Factor} = 1 + \frac{(\text{Percentage Allowance}) \times (\text{Adjusted Purchased Gas Expense})}{\text{Adjusted sales revenue}}$$

$$= 1 + \frac{(0.05) \times (\$803{,}284)}{\$1{,}000{,}000^{7}}$$

$$= 1 + \frac{\$\ \ 40{,}164}{\$\ 1{,}000{,}000}$$

$$= 1.0402 \text{ (rounded)}$$

b. ADJUSTMENT TO INCREASE BASE OF PGA CLAUSE

Where a percent adjustment to present base rates is the preferred method of arriving at a new rate schedule, the base of the PGA clause is increased as follows:

1. Determine the new base of the PGA clause (usually the most current cost of gas).

[7] The $1,000,000 was assumed to be the adjusted sales revenue from all classes of customers.

2. Determine the difference between the present base and the new base.

3. Multiply the difference determined in Item 2 times the number of Mcf sold during the test year, as adjusted for growth, weather, etc.

4. Add the amount determined in Item 3 to the revenue deficiency before making the percent adjustment to the base rates.

Where a new rate schedule is to be designed, simply determine the new base for the PGA clause and adjust revenue and expenses accordingly. No additional steps are required.

The base of the PGA clause must equal the cost of gas incorporated into the base rates.

The Commission encourages the inclusion of all gas cost in the PGA and discourages the inclusion of any gas cost in service rates. This improves transparency by isolating the various components of a natural gas bill, separating the cost of service from the cost of gas.

CHAPTER IV.
BEFORE THE COMMISSION

SECTION 1 - PROCEDURES ON APPEAL FROM CITY

The Railroad Commission of Texas has exclusive appellate jurisdiction over rates set by cities. TEX. UTIL. CODE § 102.001(b). A party to a rate proceeding before a municipality's governing body may appeal the governing body's decision to the Commission. TEX. UTIL. CODE § 103.051. The residents of a municipality may appeal to the Commission the decision of the municipality's governing body in a rate proceeding by filing with the Commission a petition for review signed by a number of qualified voters of the municipality equal to at least the lesser of 20,000 or 10 percent of the qualified voters of the municipality. TEX. UTIL. CODE § 103.052. The ratepayers of a municipally owned utility who are outside the municipality may appeal to the Commission an action of the municipality's governing body affecting the municipally owned utility's rates by filing with the Commission a petition for review signed by a number of ratepayers served by the utility outside the municipality equal to at least the lesser of 10,000 or five percent of those ratepayers. A petition for review is properly signed if signed by a person or the spouse of a person in whose name residential utility service is carried. For purposes of determining ratepayers, each person who receives a separate bill is a ratepayer. A person who receives more than one bill may not be counted as more than one ratepayer. TEX. UTIL. CODE § 103.053.

A. REPRESENTATION

Parties may represent themselves in a proceeding or may appear through any person authorized by the parties to represent them. Commission general rule § 1.65.

B. FILING OF DOCUMENTS

Two copies of all pleadings initiating a proceeding shall be filed with the Director of the Oversight and Safety Division. Once the proceeding is docketed and a hearings examiner is assigned, two copies of all other pleadings and documents shall be filed with the Docket Services Section of the Office of General Counsel. Commission rules §§ 1.24 and 7.2. Pleadings and other documents filed with the Office of General Counsel shall be deemed filed only when they are actually received by the Docket Services Section of the Commission's Office of General Counsel. Pleadings filed after 5:00 p.m. local time of the commission shall be deemed filed the first day following that is not a Saturday, Sunday, or official state holiday. Commission general rule § 1.24. Normal business hours are from 8:00 a.m. to 5:00 p.m. Monday through Friday, excluding State holidays. Commission general rule§ 7.201. See Commission rules §§ 1.22 -1.29 for classification, form, and content of pleadings. Documents may be filed in person or mailed to:

Director Oversight and Safety Division Railroad Commission of Texas P.O. Box 12967 Austin, Texas 78711-2967	Docket Services Office of General Counsel Railroad Commission of Texas P.O. Box 12967 Austin, Texas 78711-2967

Steps in a Rate Case

Step	Action	Timeline
1	Utility files Statement of Intent to increase rates with the city	35 days before effective date. TEX. UTIL. CODE § 104.102(a).
2	City holds hearing, adopts or rejects proposed rates. TEX. UTIL. CODE §§ 103.021-103.022.	Upon complaint by an affected person, hearing must be entered on within 30 days after the effective date of the increase. TEX. UTIL. CODE § 104.105(a).
3	A party to the city's proceeding, the residents of the municipality, or the ratepayers outside of the municipality may appeal to the governing body of the municipality. TEX. UTIL. CODE § 103.054(b).	Not later than the 30th day after the date of the final decision by Commission filing a petition for review. TEX. UTIL. CODE §§ 103.051-103.054; Commission rule § 7.5.
4	Commission holds a hearing.	
5	Commission Hearings Examiner issues Proposal for Decision (PFD).	Within 60 days after the hearing is Finally closed. Gov't Code 2001.143
6	Exceptions and Replies are filed. after the date of service of a PFD.	Exceptions: within 15 days Replies: within 10 days after the deadline for filing Exceptions. Commission general rule § 1.142(a).
7	Railroad Commission issues Order.	Within 185 days after the date the appeal is perfected, or the utility's proposed rates are considered approved. TEX. UTIL. CODE § 103.05.

8	Motions for rehearing.	Within 20 days after the date the final decision or order. Commission general rule § 1.149.
9	Appeals to the Courts. TEX. UTIL. CODE § 103.024 & 105.001.	Not later than the 30th day after the date on which the Commission's decision is final and appealable. TEX. GOV'T CODE § 2001.176.

C. MOTIONS

Under Commission general rule § 1.27, all motions, unless dictated into the record, must be in writing. All motions must set forth the relief sought and the reasons therefore. If based on alleged facts that are not a matter of record, the motion may be supported by an affidavit. Motions shall be served on all parties in accordance with Commission general rule § 1.48.

D. COMPUTATION OF TIME

In computing any period of time, the day from which the period of time begins to run shall not be included, but the last day of the period being computed shall be included. The period ends at 5:00 p.m. on the last day of the period unless the last day falls on a Saturday, Sunday, or State holiday, in which case the period ends on the next State working day. Commission general rule § 1.8.

E. POSTPONEMENTS, CONTINUANCES AND EXTENSIONS OF DEADLINES

The time for filing any pleading or other document may be extended upon the granting of a motion for extension of time. Except for good cause shown, the motion shall be filed with the Examiner or the Commission prior to the applicable deadline. The motion shall show that there is good cause for an extension of time and that the need for the extension is not caused by the negligence, indifference, or lack of diligence of the person filing the motion. A copy of the motion must be served upon all parties of record contemporaneously with its filing. Commission general rule § 1.8(b).

Motions for continuance of a hearing must be in writing and filed not less than five days prior to the hearing, except for good cause shown. Motions must set forth specific grounds for which the moving party seeks continuance, shall make reference to all similar motions filed in the proceeding, and shall state whether all parties agree with the relief requested. Continuances will not be granted based on the need for discovery if discovery requests have not previously been served upon the person from whom discovery is sought, except when necessary due to surprise or discovery of facts or evidence previously undisclosed despite the diligence of the moving party. Commission general rule § 1.124.

F. EX PARTE CONSULTATION

No person, party or representative may communicate, directly or indirectly, with any member of the Commission or the Examiner concerning any issue of fact or law, except on notice and opportunity for each party to participate. Commission general rule § 1.6; TEX. GOV'T CODE § 2001.061.

G. INTERVENTIONS AND PREFILED TESTIMONY

Any person who has a justifiable or administratively cognizable interest wishing to be designated as a party in a contested case may file a petition for leave to intervene at least five days prior to the hearing date. Commission rule § 1.64. The Examiner may require or permit written testimony and exhibits to be filed and served on all parties at a specified date prior to the hearing. Commission general rule § 1.105.

H. DISCOVERY

The parties are encouraged to promptly engage in informal discovery. Reasonable requests and cooperation should characterize prehearing discovery. Each party is expected to make an effort to provide information requested by other parties in a timely manner. Discovery may be in the form of oral depositions, written interrogatories, requests for admission of facts or identity of documents, requests for production, examination, and copying of documents and other materials, and requests for entry upon and examination of property. Commission general rule § 1.81(a); Texas Rules of Civil Procedure (TRCP) Rule § 192.1. The scope of discovery is the same as that provided by the TRCP. Commission general rule § 1.81(b); TRCP Rule § 192.3.

The Examiner may issue discovery orders such as protective orders and orders compelling discovery responses when necessary. Requests for discovery orders shall contain a statement under oath or affirmation that, after due diligence, the desired information cannot be obtained through informal means, and that good cause exists for requiring discovery. Commission general rule § 1.85(b). *Also see* the Administrative Procedures Act (APA), TEX. GOV'T CODE§ 2001.090. The Commission or the Examiner may also issue sanctions against a party that fails to comply with a discovery order. Commission general rule § 1.85(c).

I. ALIGNMENT OF PARTIES

Parties with common interests or positions in a proceeding may make a joint presentation, including oral representation, presentation of evidence and briefing, if desired. Parties intending to align should promptly notify the Examiner and other parties. However, alignment will not prejudice the right of any party to present a separate point of view where their position differs from that of the group with which they are aligned. The Examiner may align the parties if they fail to align themselves. Commission general rule § 1.61.

J. CONSOLIDATION

When two or more applications, petitions, or other proceedings involve common questions of law or fact, the Commission, Legal Division director, or the examiner may consolidate the proceedings or direct that there be a joint hearing without formal consolidation and may take other action to avoid unnecessary costs or delay and to ensure due process. Commission general rule § 1.125.

K. STIPULATIONS

The parties should stipulate to issues whenever possible. Stipulations, other than those made at the hearing, should be in writing and signed by all parties. Commission general rule § 1.123.

L. OBJECTIONS TO PREFILED TESTIMONY

If the Examiner allows them, written objections and responses to objections to prefiled testimony may be filed with Docket Services prior to the date of the hearing. If an objection is made either prior to or during the hearing, the Examiner may rule at that time or reserve ruling on the objection.

M. PREHEARING CONFERENCE

The Examiner may schedule a prehearing conference. At the conference, the parties or their representatives should be prepared to discuss procedural and substantive matters involved in the proceeding, and should be authorized to make commitments. The conference may concern motions, settlement, the amendment of pleadings, admissions or stipulations which will avoid the unnecessary introduction of evidence, limitations on the number of witnesses, time to be allotted to each party for presentation of its direct case or for cross-examination at the hearing, hearing procedure, and any other matter that will equitably expedite the proceeding. The Examiner may notify the parties in writing of the disposition of and rulings made on all matters considered at the prehearing conference. Commission general rule § 1.122.

N. COURT REPORTER AND TRANSCRIPT

When requested by the Commission, the Examiner, or a party, a court reporter will be present at the hearing to record and transcribe the hearing. Commission general rule § 1.129. Anyone may obtain a copy of the transcript at set rates by making arrangements with the reporter.

O. ORDER OF PROCEDURE AT HEARING

The Hearings Examiner will open the hearing with a statement of the scope and purpose of the hearing. The Examiner will then request appearances for the record by all parties.

Thereafter, parties may make motions or opening statements. Commission general rule § 1.128(a).

Following opening statements, if any, each party will be allowed to proceed with their direct case. The petitioner, applicant, or complainant shall be entitled to open and close. The Examiner will determine at what stage intervenors shall be permitted to offer evidence. The Examiner may direct that closing argument be made in writing. The Examiner may alter the order of procedure if necessary for efficient conduct of the hearing. Commission general rule § 1.128(b).

P. EVIDENCE

The rules of evidence as applied in non-jury cases in the Texas District Courts shall be followed. Commission general rule § 1.101. A witness may adopt their prefiled testimony, which may be entered into the record without the written testimony being read. A witness who is offering written testimony shall be sworn and shall identify the written testimony as a true and accurate representation of what the testimony would be if the witness were to testify orally, after which the witness shall submit to voir dire and cross-examination. Written testimony shall be subject to the same evidentiary objections as oral testimony. Commission general rule § 1.105.(a).

Q. OBJECTIONS MADE AT HEARING

Objections made at the hearing should be sufficiently specific so that the Examiner may know what action the objecting party desires and the basis of the objection. Unless requested by the Examiner, supporting statutes and cases need not be cited, but a party should feel free to do so if such inclusions would be helpful.

R. DOCUMENTARY EVIDENCE

A copy or excerpt of a document may be admitted as evidence if the original is not readily available and if authenticity is established by competent evidence. When numerous documents are offered, the Examiner may limit those admitted to a number of documents which are typical and representative. The Examiner may require the abstracting or summarizing of relevant data from documents and the presentation of abstracts or summaries in exhibit form. All parties shall have the right to examine the documents abstracted or summarized. Commission general rule § 1.104. *See* Texas Rules of Evidence (TRE) rule 1005. For example, summaries of business records are admissible if the underlying records are admissible business records. *Purolator Corp. v. Railroad Commission*, 548 S.W.2d 486, 489 (writ ref'd n.r.e.); TRE 1006.

S. OFFICIAL NOTICE

The Examiner may take official notice of judicially heard and determined (cognizable) facts and generally recognized facts within the area of the Commission's specialized knowledge. Commission general rule § 1.102. Matters contained within the

Commission's records are considered to fall within the area of agency expertise and are therefore officially cognizable. Texas Administrative Procedures Act (APA), TEX. GOV'T CODE § 2001.090.

T. EXPERT TESTIMONY

If scientific, technical, or other specialized knowledge will assist the trier of fact to understand the evidence or to determine a fact in issue, a witness qualified as an expert by knowledge, skill, experience, training, or education may testify thereto in the form of an opinion or otherwise. TRE 702.

U. PRESERVATION OF EXCLUDED EVIDENCE

If an exhibit is identified, objected to, and excluded, the examiner may determine whether or not the party offering the exhibit wishes to withdraw the offer; if so, the examiner shall permit the return of the exhibit to the party. If the excluded exhibit is not withdrawn, it shall be given an exhibit number for identification, shall be endorsed by the examiner with the ruling, and shall be included in the record for the purpose of preserving an exception. Commission general rule § 1.106(c).

When the Examiner excludes testimony, the party offering the evidence shall be permitted to make an offer of proof prior to the close of the hearing. The party may make the offer by dictating or submitting in writing the substance of the proposed testimony or by perfecting a bill of exceptions as in civil trials. The Examiner may direct the manner in which the offer is made and may ask questions if necessary to conclude that the evidence would be as represented. The Examiner and opposing parties shall be entitled to cross-examine any witness testifying on a bill of exceptions and to develop evidence on the bill. The Examiner may direct that bills of exception be transcribed separately and that reporter's costs be assessed against the proponent of the bill, subject to Commission review of the Examiner's ruling. Commission general rule § 1.108.

V. BRIEFS, CLOSING STATEMENTS, AND REPLY BRIEFS

The Examiner may require submission of briefs on legal issues at any time. After the hearing, the Examiner may require written closing statements or briefs, and written responses to closing statements, before closing the record.

W. LATE-FILED EXHIBITS

No exhibit shall be filed after the hearing has been completed, unless specifically requested and permitted by the Examiner. If the filing of a late-filed exhibit is permitted, copies shall be served on all parties of record, who will have the opportunity to respond and submit additional relevant responsive evidence. Commission general rule § 1.106(d).

X. PROPOSAL FOR DECISION, EXCEPTIONS AND REPLIES

If a majority of the Commissioners have not heard the case or read the record, the decision, if adverse to a party other than the Commission, may not be made until a Proposal for Decision (PFD) is served on the parties and an opportunity is afforded to each party adversely affected to file exceptions and present briefs to the Commission. The parties may waive the PFD requirement by written stipulation. Commission general rule § 1.141(a). Any party may file exceptions to the PFD within 15 days after the date of service of the PFD. Replies to such exceptions may be filed within 10 days after the deadline for filing such exceptions. Commission general rule § 1.142(a).

Y. NOTIFICATION OF OPEN MEETING

After the PFD is issued and exceptions and replies are filed, the Examiner will schedule the docket for consideration by the Commission at open meeting. The parties will be notified of the open meeting date through publication in the Texas Register. Parties will be notified by mail of any order issued by the Commission.

Z. ORAL ARGUMENT

Any party may request oral argument before the Commission prior to the final disposition of any proceeding, but oral argument will be allowed only at the discretion of the Commission. A request for oral argument may be made by separate pleading or may be included in a party's exceptions, reply to exceptions, brief, or motion for rehearing. Commission general rule § 1.144.

AA. EFFECTIVE DATE

The effective date of a final decision or order, unless otherwise stated, is the date of Commission action, and the effective date shall be incorporated into the body of the decision. Commission general rule § 1.147.

BB. MOTIONS FOR REHEARING

A Motion for Rehearing must be filed by a party within 20 days after the date the party or its attorney of record is notified of the final decision or order. Commission general rule § 1.149(a).

CHAPTER V.
INTERIM RATE ADJUSTMENT

SECTION 1 - BACKGROUND

A. INTERIM RATE ADJUSTMENT RULE (IRA)

On December 24, 2004, the Commission created a rule (§7.7101 of TEX. ADMIN. CODE) to implement TEX. UTIL. CODE §104.301, which was enacted by the 78th Legislature. These statutory and rule provisions promote investment in infrastructure that will improve the reliability and safety of the Texas natural gas system. Previously, the only way for a utility to increase its rates was to file with the Commission a formal Statement of Intent rate package, including a comprehensive cost of service rate case. This is sometimes referenced as “traditional” rate making. Now, the IRA statute and rule allow a gas utility to apply with the regulatory authority for an adjustment to its base rates to recover the cost of new infrastructure investment made by a utility since its last comprehensive rate case. When a utility applies for an interim rate adjustment, it is not required to submit a comprehensive rate package demonstrating the reasonableness of its cost of service.

The IRA allows a gas utility to file a tariff or rate schedule reflecting an adjustment to its rates to recover the cost of new investment in its infrastructure made since the Commission's most recent order setting rates. Through the interim rate adjustment, a utility may recover its return on investment, depreciation expense, and related taxes. Any utility that applies for an interim rate adjustment is required to file a traditional rate case package, showing its comprehensive cost of service, within five years of filing for its first IRA.

B. MOST RECENT RATE CASE

The revenue to be recovered through an interim rate adjustment is incremental to the revenue requirement established in a gas utilities most recent rate case before the Commission for the area in which the interim rate adjustment is to be implemented. For the first interim rate adjustment following a traditional or comprehensive rate case, the allowed adjustment is based on the difference between the gas utility's invested capital at the end of the rate case test-year and the invested capital at the end of the calendar-year following the end of the rate case test-year.

In a traditional rate case, the evidence presented by a utility usually establishes the return on investment, depreciation expense, and incremental federal income tax, which are then used to calculate the revenue that is to be collected by the utility. The Commission’s final order setting a utility’s gas rates usually memorializes these components. The factors used to calculate the return on investment, depreciation expense, and incremental federal income tax, which, in turn, are used to compute the revenues to be collected through the interim rate adjustment, must be the same as those established or used in the final order setting rates in the gas utility's most recent rate case for the area in which the interim rate adjustment is to be implemented. The same concept applies to a utility's allocation requirements. The gas utility must allocate the revenue to be collected through the interim rate adjustment among the gas utility's customer classes in the same manner as the cost of service was allocated among customer classes in the utility's most recent rate case.

SECTION 2 - KEY STEPS A UTILITY MUST FOLLOW WHEN USING IRA

1. Utility must have completed a formal Statement of Intent rate case within two years of filing for an initial interim rate adjustment (IRA). The bench mark issues for review and approval in an interim rate adjustment application are set in this formal rate case – those issues are return of investment, the value established for tangible assets and the depreciation expense related to those tangible assets, and related taxes. Also, established in the formal rate case is how these interim rate expenses will be allocated between the different customer classes (residential, commercial and industrial). This allocation method is established in the formal rate case.

2. The Interim Rate Adjustment rule does not require an evidentiary proceeding (rate case). The statute and the rule require the regulatory authority only to review a utility's method of calculating the interim rate adjustment. The interim rate adjustment application must include the following reports/documentation:

3. Utility must provide the regulatory authority certification that it will complete its notice to utility's customers before an interim rate adjustment can be implemented,

4. Provide an annual investment project report (what hard assets have been put into use or retired since the formal rate case or previous IRA and the value of those assets less depreciation expense),

5. File the annual earnings monitoring report which demonstrates the utility's earnings and overall rate of return during the preceding calendar year. A gas utility whose annual earnings monitoring report shows that the utility is earning a return on invested capital of more than 75 basis points above the return established by the Commission's final order setting rates in the utility's most recent rate case, shall include with its annual earnings monitoring report a statement of the reasons the proposed IRA rates are not unreasonable or in violation of the Commission rule.

6. The allocation factors used to allocate between customer classes and the number of customers used to calculate the adjustment for each customer class.

7. Utility is required to file on an annual basis an interim rate adjustment whether or not it had any new investments in the prior year. On the fifth anniversary of the first interim rate adjustment filing the utility is required to file a formal rate case, including a comprehensive cost of service rate review. After the approval by the regulatory authority of the traditional rate case the interim rate adjustment process can begin again.

8. Whether the investment in hard assets is used and useful to the customers – new pipe, new meters, new computer billing system, etc.

9. Are the benchmarks set in the traditional rate case being met: return on investment; depreciation expense; ad valorem taxes; revenue related taxes; and federal income taxes?

10. Is the utility allocating collection of the interim adjustment revenues in the same manner that it allocated its overall cost of service in its most recent rate case?

SECTION 3 - SAMPLE IRA CALCULATION

	12/31/03	12/31/04
Net Investment (traditional rate case value vs. IRA increase)	$1,428*	$1,470
Increase in Net Investment (incremental increase)		42
Authorized Return on Capital investment (benchmark set in rate case)		8.25%

Incremental Return on Net Invest.	$3.47
Incremental Deprecation Expense	$2.93
Incremental Fed, and Other Taxes	$4.30
Incremental Rev. Requirement (money needed to cover these new costs)	$10.65

Annual Number of Customer Bills (14 customers X 12 months) = 168 Bills
Monthly increase per Customer bill ($10.65/168 bills) = $0.06/month

***** For the 1st year IRA this amount will be the net investment or rate base that was established in the formal Statement of Intent rate case.

CHAPTER VI.
COST OF SERVICE ADJUSTMENT

SECTION 1 - BACKGROUND

A. RECENT LITIGATED CASES BEFORE THE RAILROAD COMMISSION OF TEXAS

Until recently, the Commission did not approve proposed Cost of Service Adjustments (COSA). However, in December 2008, the Commission approved a COSA in GUD No. 9791, Statement of Intent Filed by CenterPoint Energy Entex to Increase the Rates in the Unincorporated Areas of the Texas Cost Division. Prior to December 2008, utilities had only three options to increase service rates, a traditional statement of intent to change rates, the use of an Interim Rate Adjustment, or through a Relocation Cost Recovery filing. A number of cities in the State of Texas have approved a Rate Review Mechanism, or an RRM. The Commission has not been presented an opportunity to decide on an RRM. However, its calculation is very similar to the COSA.

B. MECHANISM

The mechanism for calculation of a COSA is dictated by the tariff approved or the language of the final order approving rates. The Commission does not have a rule in place to provide guidance. As a result, there may be slight variations from one COSA to the next. However, the mechanics are basically the same.

The COSA is intended to provide the utility a mechanism for changing the rate to reflect changes in Operating Expenses, Plant in Service, Return on Investment and Texas Franchise Taxes. There may be other components of the COSA calculation as approved on a case-by-case basis. The primary difference between the mechanics of an Interim Rate Adjustment and a COSA is the inclusion of changes in Operating Expenses and Revenues in a COSA. In the COSAs approved by the Commission, there is a cap or limit to the actual increase in any one of the components. The initial approval of a COSA may also include a requirement that the utility file a traditional statement of intent rate request within a certain number of years following the initial approval of the COSA.

Calculated on an annual basis, the regulatory authority has a finite time period with which to conduct its review, usually 90 days. In most COSAs, if, within the 90 day review period, the company and the regulatory authority with original jurisdiction have not reached agreement on the proposed cost of service adjustment rate, the regulatory authority may take action to deny such adjustment and the company has the right to appeal that decision.

Like an IRA, a COSA calculation typically uses key factors set during the most recent rate case. These factors may include allocation rates and methodologies, depreciation rates, and rate of return.

SECTION 2 – DETERMINING FACTORS IN COST OF SERVICE ADJUSTMENTS

Some cities in Texas and the Commission have approved several different types of adjustments that effectively allow a utility to adjust the base rates for changes in the cost to serve its customers. Because the cities and the Commission have no specific rule in place for guidance on key mechanism factors or on the formula itself, each has its own data points for calculation. Generally though, the mechanisms are designed to allow the utility a mechanism to adjust its base rates for changes in operation and maintenance expenses, investment, taxes, working capital and other applicable expenses. Two primary advantages to these adjustments are the reduction of rate case expenses to litigate Statement of Intents and the reduction of regulatory lag to the utility. The regulatory authorities retain all statutory regulatory authority and can initiate a rate inquiry at any time.

There is a set structure for the COSA calculation, and the regulatory authority has the ability to review the adjustment and conduct discovery as necessary within the review period. Several of the adjustments have caps or limits on the overall increase, limiting the amount of the increase to the customer. The utility must use key components from the most recent rate case, such as the rate of return and allocation factors.

Key Factors or Data Points in COSAs:

Set period for filing, determination of account balances, and application, i.e., must file by a certain date using a calendar year for calculations and effective on a set date.

Must use recently approved depreciation methods and rates, rate of return, 13-month averages for specific accounts, actual tax account balance, allocation rates and methodologies approved in recent rate case, specific customer count calculations.

Must provide notice, attestation of schedules, and reimbursement of expenses to the regulatory authority for their review.

Procedures for filing, regulatory review, appeal process and reimbursement of regulatory expenses.

SECTION 3 – SAMPLE COST OF SERVICE ADJUSTMENT CALCULATION

Step 1: Determine the Balances of Expenses:

Applicable Expenses
Operating Expenses:
Depreciation and Amortization Expense
Taxes Other than Federal Income Tax
Operation and Maintenance Expenses
Customer Related Expenses

Administrative and General Expenses
Interest on Customer Deposits

Step 2: Determine the Return on Investment:

Net Utility Plant
Other rate base items (materials and supplies inventory and prepayments)
Cash Working Capital
Less:
Customer Deposits
Customer Advances
Deferred Federal Income Taxes

Step 3: Calculate the Adjustment:

Sample Formula

COSA =

$$\frac{\text{(Operating Expenses + Return on Investment + Franchise Tax – Actual Non-Gas and Other Revenues)}}{\text{(1 – Texas Franchise Tax Statutory Rate)}}$$

CHAPTER VII.
GLOSSARY OF GAS UTILITY TERMS

Above the Line -- A term used in the National Association of Regulatory Utility Commissioners (NARUC) system of accounts to refer to revenue and expenses which are allowable for ratemaking purposes.

Accelerated Depreciation -- A form of liberalized depreciation in which the asset is depreciated more rapidly in years immediately following capitalization than in later years. This depreciation is taken for tax purposes only, since straight-line depreciation is the only allowable treatment for ratemaking purposes.

Accrued Depreciation -- The amount of depreciation expense taken on an asset since the initial capitalization of the asset.

Acquisition Adjustment -- The difference between the purchase price paid by a company for a utility system and the book value of that system at the time of sale, amortized over some period.

Adjusted Value Rate Base -- A weighted average between original cost, less depreciation; and current cost, less an adjustment for present age and condition.

Affiliate -- Any corporation or other entity which owns a portion of a utility's stock, or otherwise exercises control over the utility. See TEX. UTIL. CODE § 101.003.

Allocation -- The apportionment of rate base, revenue, and expenses among classes of consumers, distribution systems, or business enterprises.

Allowance for Funds Used During Construction (AFUDC) -- An expense allowed a utility to compensate for the cost of funds used during the construction of utility assets. This allowance is not allowed if the utility is permitted to include construction work in progress in rate base.

Attrition -- Erosion in the ability of a utility to earn authorized rates of return.

Base Load -- A volume of that serves as a constant load over a period of time.

Base Rate -- The utility's rates exclusive of the purchased gas adjustment clause.

Below the Line -- A term from the NARUC system of accounts which refers to revenue and expenses which are not allowable for ratemaking purposes. Frequently, these revenue and expenses relate to non-utility related operations of a diversified energy corporation, or to utility related expenses which are not allowable for ratemaking purposes for some reason. An example of the latter is charitable contributions.

Book (Cost) -- The amount at which property or assets are recorded in a company's accounts without deducting depreciation, amortization, or various other items.

Business Risk -- The basic risk inherent in a firm's operations, the uncertainty of revenue and operating expenses.

Capital Structure -- The financing of the firm represented by long-term debt, preferred stock, and equity.

CAPM - - Capital Asset Pricing Model used in estimating a utilities cost of equity.

Ccf - - One hundred cubic feet.

City Gate -- The central point in the distribution system where gas is stepped down from the high-pressure transmission line to the lower-pressure distribution lines. Normally, a meter is attached to the city gate, and the gas transferred through the city gate is charged at a rate referred to as the city gate rate. The Commission sets this rate.

Comparable Earnings -- A technique for estimating the cost of equity based upon the average cost of equity for similar companies.

Completed Work Not Yet Classified (CWNC) - - The amount of construction capital completed but not yet classified in the appropriate FERC accounts.

Construction Work in Progress (CWIP) -- An allowance to rate base for funds committed to construction of assets which will be placed in utility service at a future date.

Contributions in Aid of Construction -- The payment of funds to a utility to induce the utility to construct additional facilities in order to serve a customer. A typical example of these contributions is charges for mainline and service line extension.

Cost of Capital -- The weighted average of the cost of various sources of capital, generally consisting of outstanding securities such as mortgage debt, preferred and preference stock, common stock, etc., and retained earnings.

Cost of Equity -- The cost to a company of borrowing money through equity capital. The sum of capital from retained earnings and the issuance of stocks.

Cost of Service -- The fundamental principle of utility ratemaking, which states that the utility should be allowed the opportunity to earn its total cost of service, including operating costs and capital costs, but no more.

Cost of Service Adjustment -- A COSA allows utility rates to vary according to the utility's investment and operating expenses without a statement of intent filing.
Customer Advances -- Money used by a company, normally for future building projects.

Customer Deposits -- An amount of money required by a natural gas distribution company for providing natural gas service to a residential or commercial customer. The deposit amount for residential customers is based on 1/6 of an annual bill, accrues interest and is refunded after twelve months of good payment history.

DCF - - Discounted Cash Flow model used in estimating a utility's cost of equity.

De novo -- A type of appeal in which the lower-court record is not used to review the case. Rather, the case is retried, as if the parties had come to the appellate court originally. Rate case appeals are heard by the Railroad Commission on a de novo basis.

Debt Finance Adjustment Clause -- A clause in a utility's rates to allow the utility to increase the rates to pay the interest costs associated with obtaining debt capital. A debt finance adjustment clause is normally only considered in the case of a marginally solvent utility which may be unable to obtain debt capital unless such a clause appears in the utility's rates.

Debt Ratio -- Total debt divided by total assets. In the context of this packet, it is defined as long-term debt divided by total long-term (permanent) capital.

Debt/Equity Ratio -- Long-term debt divided by stockholders' equity.

Deferred Taxes -- Federal Income taxes which, by virtue of accelerated or liberalized depreciation or other tax devices are deferred to a future date.

Depreciation Reserve Ratio-- The ratio of accrued depreciation to original cost. This ratio is frequently used to calculate the adjustment for age and condition.

Distribution -- The enterprise of selling natural gas to the burner tip customer.

Distribution Plant -- Mains, service connections, and equipment that carry or control the supply of natural gas from the point of local supply to and including the sales meters

Elasticity -- The variation in demand according to the price of the commodity.

Embedded -- A fixed capital cost, such as interest on debt or dividends on preferred stock. This is distinguished from variable capital costs, such as return to equity.

Environs -- The area surrounding an incorporated city, but not within the limits of the city, which include residential and commercial customers who are served off of the same distribution system as residential and commercial customers inside the city limits.

Ex Parte -- Any instance of communication where all parties to the case are not given notice and opportunity to participate.

External Funds -- Funds acquired through borrowing or by selling new common or preferred stock.

FERC USOA - - Federal Energy Regulatory Commission Uniform System of Accounts.

Financial Risk -- Risk which is caused by a greater percentage of debt being owed by a business enterprise. This is to be distinguished from business risk.

Flotation Costs -- The cost of issuing stock.

Fuel Adjustment Clause (FAC) -- A term which is synonymous with and used interchangeably with purchased gas adjustment clause.

General Plant -- The portion of a utility plant which is associated with management, customer service, billing, and other support functions.

GRIP -- Gas Reliability Infrastructure Program. (See Interim Rate Adjustment)

GURA -- Gas Utility Regulatory Act.

Hearing in Progress -- Period of time between issuance of Notice of Hearing and final decision.

Heating Degree Day (HDD) -- A unit of measure of the extent to which the average daily temperature falls below 65. This unit is utilized to estimate heating-related energy consumption.

Heating Load -- The difference between the annual adjusted quantity of gas and the annualized average base load for those months with no heating degree-days.

Interim Rate -- Rates which are allowed to be charged by a utility, subject to refund, to allow the utility to recover its operating costs and debt service costs pending the outcome of a rate proceeding.

Interim Rate Adjustment (IRA or GRIP) - - An interim adjustment to utility rates to reflect changes in investment without a statement of intent filing. An IRA is allowed under statute and Commission rule.

Lead - Lag Study -- A study to determine the cost of the time lag between the point when a service is rendered and the related operating costs are incurred and the point when the revenues to recover such costs are received. The operating funds to fill the lag are usually supplied by the investor and becomes a fixed commitment to the enterprise.

Long-term debt -- All debt due in more than 12 months.

Market Pressure -- The drop in price that occurs when new issues are placed in the market because of the sudden excess supply of a particular security.

Mcf -- One thousand cubic feet.

MMBtu - - One Million British Thermal Units.

Monetary Return --The return a company is allowed to recover for its cost of operation and an additional return component that covers the cost of capital used to support the investment in the company.

Net book value per share -- Book equity divided by the number of outstanding shares of common stock.

Net Current Cost -- Reproduction cost new less adjustment for age and condition.

Net Invested Capital -- Original cost of system less book depreciation.

Notice of Hearing -- A document issued to notify affected parties of the date, time, and location of a hearing in a contested case.

Off Peak Pricing -- A rate design in which rates are lower in periods of reduced demand. This type of pricing increases a utility's load factor, since it encourages consumption in off-peak periods. An example of this type of pricing is summer/winter rates. Another example is time-of-day pricing.

Peak Demand -- The maximum load during a specified period of time.

Portfolio Effect -- The extent to which the variation in returns (risk) on a combination of assets (a "portfolio") is less than the sum of the variations of the individual assets.

Proposal for Decision -- A document containing the reasoning behind a decision recommended to the Commission by the Hearings Examiner.

PURA -- Public Utility Regulatory Act.

Purchased Gas Adjustment Clause (PGA) -- A clause in the utility's tariff that allows variation of the utility's rates according to variation in the utility's weighted average cost of gas.

Rate Base -- A utility’s investment in the system, used to calculate the required monetary return on investment.

Rate of Return -- Percentage of utility’s invested capital, which the utility recovers through its rates. Also See **Return on Investment**.

Regulatory Lag -- The period which is required for a utility regulatory authority to consider a rate increase request filed by a utility.

Relation back -- The act of making a rate order effective prior to issuance. Rates may be related back to any period after the regulatory authority acquires jurisdiction.

Reproduction Cost New -- The estimated cost of replacing the utility's system with similar new equipment at the present time.

Retention Rate -- The percentage of earnings not paid out in the form of dividends.

Retirement Work-ln-Progress -- An adjustment to rate base and to accumulated depreciation to account for assets which are in the process of retirement.

Return on Investment -- Percentage of a utility's invested capital it recovers through its rates. Also See **Monetary Return**.

Statement of Intent -- The document required to be filed under GURA with the regulatory authority having original jurisdiction in order to request a change in rates.

Straight-line Depreciation -- Depreciation in which the annual depreciation expense is equaled each year over the life of the asset.

Suspension -- Postponement of the effective date of the proposed rate increases accomplished by issuance of an appropriate order or ordinance.

System-wide Rates -- Rates which are set based upon rate base, revenue, and expense figures of a utility's entire system, rather than a particular incorporated area.

TEX. ADMIN. CODE – 16 Texas Administrative Code

TEX. UTIL. CODE -- Texas Utilities Code Titles 3 and 4.

Weather Normalization -- A clause in utility rates which adjusts customer bills to reflect normal temperatures. If temperatures during the measured period are warmer than normal, customers receive a surcharge. If temperatures during the measured period are colder than normal, customers receive a credit.

Working Capital -- Used broadly, the term refers to those rate-base allowances other than the utility plant in service and may include material, fuels, supplies, etc. In the narrower use, commonly referred to as cash working capital, it relates to the investor-supplied funds necessary to meet operating expense or going-concern requirements of business. There is normally a time lag between the point when a service is rendered and the related operating costs are incurred and the point when the revenues to recover such costs are received. The operating funds to fill the lag are usually supplied by the investor and becomes a fixed commitment to the enterprise.

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