**BEFORE THE**
**LOUISIANA PUBLIC SERVICE COMMISSION**

**LOUISIANA PUBLIC SERVICE COMMISSION**
**EX PARTE.**

**Docket No. U-22407 - In Re: Development of Rules, Regulations, Practices and Procedures Relative to the Weighted Average Cost of Gas Filings made by Jurisdictional Gas Utilities.**
**(Decided at Open Session held January 20, 1999)**

# GENERAL ORDER

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## I. PREFACE

### A. PROCEDURAL OVERVIEW

**The Louisiana Public Service Commission ("Commission") instituted this proceeding to develop standards governing the ratemaking treatment of purchased gas costs incurred by gas utilities operating in the State of Louisiana. More specifically, this proceeding was designed to address issues concerning the costs eligible for recovery through Cost of Purchased Gas Adjustment Clause mechanisms[1] ("PGAs" or "PGA mechanisms") and to standardize various reporting and review requirements. This proceeding stems from the Commission's *Ex Parte: Investigation into the Gas Costs Included in the Purchased Gas Adjustment Clause Filed by Trans Louisiana Gas Company, Docket No. U-19997*, which demonstrated the need to standardize purchased gas cost reporting and review procedures. In that proceeding, the Commission was faced with the difficult task of reviewing the reasonableness of the gas purchasing practices, policies and costs of Louisiana Intrastate Gas Company ("LIG") and Trans Louisiana Gas Company ("TransLa") over a 10-year period. In a General Order adopted by the Commission on October 1, 1997 and issued on November 6, 1997, the Commission adopted similar uniform standards governing the recovery of fuel costs incurred by electric generating utility companies through fuel adjustment clauses. *(Louisiana Public Service Commission ex parte. In re: Development of Standards Governing the Treatment and Allocation of Fuel Costs by Electric Utility Companies, Docket No. U-21497*, (November 6, 1997)).**

**In its investigation of TransLa's PGA and LIG's WACOG mechanisms, the Commission Staff identified costs collected through the PGA and WACOG which should have more properly been reflected in base rates. Also identified were purchased gas costs which should have been recovered from non-jurisdictional customers. In order to address these issues on an industry-wide basis and establish definitive standards for the use of PGA mechanisms, the instant generic proceeding was established.**

**Action in this Docket will have industry-wide implications and, therefore, the Commission has treated it as a rule-making proceeding. All Louisiana gas utilities were invited to participate, as were their customers. Parties taking active roles in this proceeding included: the Commission through its in-house Staff and counsel, outside consultants and Special Counsel; representatives of Arkla, Entex, Louisiana Gas Service ("LGS") and TransLa (collectively "the Combined Local Distribution Companies" ("CLDC"); Entergy Gulf States, Inc.; South Coast Gas Company; and Livingston Gas Company.**

**On July 23, 1997, a Technical Conference was held to elicit general comments concerning the adoption of PGA reporting and review procedures. In addition, all utility companies were invited to provide comments to the Commission. A proposed set of rules was circulated to all parties, and comments were again submitted to the Commission. Based on these comments a second draft of the proposed rules was circulated at a second technical conference held on June 10, 1998. A third draft was circulated to all parties on November 5, 1998 and additional comments were received. Many of the suggestions contained in these comments were incorporated into this final Proposed General Order. Thus this General Order is the product of a collaborative process involving the Commission and all interested industry representatives who chose to participate.**

### B. GENERAL HISTORY OF THE FUEL ADJUSTMENT CLAUSE

[1] Includes weighted average cost of gas ("WACOG") filings.

**Fuel adjustment clauses such as the PGA mechanism utilized by Louisiana gas utilities have been authorized for use for more than forty years. *See, e.g., City of Norfolk v. Virginia Electric Power Co.,* 197 Va. 505, 90 S.E.2d 140 (1955). The use of such mechanisms was recently reviewed by the Louisiana Supreme Court in *Daily Advertiser v. TransLa,* 612 So.2d 7 (La. 1993). The PGA mechanism permits utilities to recoup purchased gas costs on an ongoing basis through adjustments to the gas cost component of a utility's rates without a comprehensive review of the utility's costs. Utility non-gas costs are presently reviewed in base rate proceedings. Periodic adjustment clauses are generally authorized when regulatory commissions identify a particular expense (*i.e.,* purchased gas costs) that is subject to significant fluctuation compared to the utility's other costs, represents a large component of the utility's cost of service, and is generally outside the control of the utility.**

**Most state regulatory commissions have adopted PGA mechanisms for gas utilities subject to their jurisdiction.**

**"[F]uel adjustment clauses are not designed to allow the utility to earn a profit; rather, they are recoupment devices designed to permit a dollar-for-dollar recovery of fluctuations in fuel costs." *Daily Advertiser,* 612 So.2d at 24. Because only actual purchased gas costs should be recovered through the PGA (with no return), neither the utility nor ratepayers should be harmed by the use of an appropriate purchased gas adjustment mechanism.**

**Normally, a utility is prohibited from charging any rate other than the last rate approved by the Commission in a base rate case. However, the use of a PGA mechanism to recover purchased gas costs, while an exception to this rule, has become an accepted regulatory practice. Commission approval of a PGA mechanism permits the utility to make monthly adjustments to its rates without the scrutiny applied in a base rate proceeding. If a utility were to manipulate or abuse its PGA, ratepayers may be harmed.**

**Even when a PGA is utilized, regulatory commissions must have the ability to exercise full ratemaking review over the reasonableness of a utility's purchased gas costs. For this reason, regulators retain jurisdiction to review and determine, after the fact, whether the costs passed through to consumers under such a clause were prudently incurred, produced just and reasonable rates, and were properly included in rates. This ability to more closely review the costs passed through the purchased gas cost adjustment clause is crucial to ensuring that ratepayers are protected.**

## C. HISTORY OF THE PURCHASED GAS ADJUSTMENT CLAUSE IN LOUISIANA

**On April 16, 1971, the Commission adopted a General Order approving a "Cost of Gas Adjustment Clause" for all gas distribution companies subject to the Commission's jurisdiction. On February 2, 1972 and June 22, 1972, the Commission amended its April 16, 1971 General Order and also approved a "Cost of Gas Adjustment Clause" for all intrastate natural gas pipelines subject to its jurisdiction. In these Orders, the Commission recognized that the price of gas to distribution companies and intrastate pipelines at the source of supply was affected by the regulation of the Federal Power Commission, and that distribution companies and intrastate pipelines were frequently faced with increased costs over which the Commission had no direct control. Under its then existing procedures, distribution companies and intrastate pipelines were required to either absorb increases in the cost of gas, apply to the Commission for rate relief to recoup these increases, or abandon these sources of gas supply to the interstate pipelines. If gas costs decreased, the distribution companies and intrastate pipelines retained the difference between the cost of gas included in base rates and the lower price they actually paid. An alternative approach, which was adopted by the Commission, was to allow companies subject to its jurisdiction to pass on to its customers the exact amount of the increase or decrease in gas costs. This pass through provision was referred to as a cost of gas adjustment clause. The flow through of gas costs permitted the utilities to recover their actual cost of gas in a timely manner.**

**Since adoption of the PGA mechanism, issues have arisen periodically regarding the costs properly eligible for recovery through a company's PGA. (*See, e.g., Ex Parte:***

***Investigation Into Gas Costs Included In The Purchased Gas Adjustment Clause Filed By Trans Louisiana Gas Company, Docket No. U-19997.*)** **The Commission's General Orders adopting PGA mechanisms did not contain detailed standards regarding the costs eligible for recovery through the PGA. Additionally, the composition of charges associated with the acquisition of gas have changed since the early 1970s. This proceeding was instituted to specify the costs eligible for recovery through the PGA mechanism and to establish uniform standards and reporting requirements for all gas utilities in the state. These standards and reporting requirements will facilitate the Commission Staff's review of the utilities' PGA filings, and provide guidance to the utilities concerning what costs are authorized for inclusion in the PGA mechanism.**

## II. STATEMENT OF GENERAL PRINCIPLES AND OVERVIEW

### A. PURPOSE

**The purpose of the Louisiana Cost of Gas Adjustment Clause is to provide gas utilities the opportunity to recover, on a timely basis, all prudently incurred purchased gas costs. Only direct purchased gas costs incurred consistent with best cost gas procurement standards (*i.e.*, the lowest prudently incurred costs consistent with the need to provide safe, adequate and reliable service) are eligible for recovery through the PGA mechanism. The PGA mechanism has been established due to the materiality and historical volatility of purchased gas costs. In general, only the direct costs associated with natural gas supplies purchased by the utility to serve its jurisdictional sales customers are recoverable through the PGA. The PGA should not be considered a supplement to or be utilized by a utility to avoid the traditional base ratemaking process for base rate costs without the full consideration of all revenue requirement issues. Exceptions to the guidelines contained in this Order may be granted as provided in this Order or as directed by a majority vote of the Commission.**

### B. OVERVIEW OF GENERAL FILING REQUIREMENTS

**Sales rates charged by gas utilities consist of two components. The first component is a margin or base rate allowance designed to recover non-gas costs such as return on investment, operation and maintenance expenses, depreciation expense and taxes. The non-gas component is determined by the Commission in base rate proceedings. The second component of rates is the gas cost component which is intended to provide for the recovery of the costs of acquiring the gas sold by the utility. The gas cost component of rates is generally based on a utility's weighted average cost of gas. The gas cost component of sales rates charged by most Louisiana gas utilities is presently adjusted through a PGA mechanism on a monthly basis. Typically, the gas cost component of rates is based on the actual monthly purchased gas costs incurred by the utility during a preceding historic month. As such, the gas cost rate charged by a gas utility during a particular month may not be indicative of the actual costs being incurred by the utility during that month.**

**The Commission in this Order classifies gas utilities by size into three categories, and establishes different PGA filing and reporting requirements for each category. Group I gas utilities are defined as all local gas distribution companies serving in excess of 25,000 jurisdictional customers. Group II gas utilities are defined as those local gas distribution companies serving less than 25,000 but more than 500 jurisdictional customers. Group III gas utilities are defined as those local gas distribution companies serving less than 500 jurisdictional customers. In addition, intrastate pipelines making WACOG sales to Louisiana jurisdictional customers are required to make filings as set forth below.**

**The specific filing requirements for Group I gas utilities are presented below and in Appendix B. The specific filing requirements for Group II gas utilities are discussed and explained in greater detail later in this General Order. Filing requirements for Group III gas utilities and intrastate pipelines making WACOG sales to Louisiana jurisdictional customers will be developed on a case-by-case basis. To the extent that an intrastate pipeline makes no WACOG sales to Louisiana jurisdictional customers, it may be exempted from filing information pursuant to this Order by filing a request with the Commission.**

**C. GROUP I UTILITIES**

**In general, Group I utilities are required to file supporting information on a monthly basis as soon as practicable prior to the applicable billing month. The "A" set of schedules will identify the gas cost rate to be applicable during the billing month, and will be based on the utility's projected cost of gas for the billing month. The "B" set of schedules will identify the utility's actual purchased gas costs, as well as other information, experienced during the month which is two months prior to the billing month. On an annual basis, Group I gas utilities will file the information shown on Appendix B Schedules C-1 through C-2. The "C" set of schedules establish procedures to collect, or return, under-recoveries or over-recoveries of purchased gas costs experienced during a utility's designated annual review period.**

**The following additional information shall be submitted by each company with its annual review period filing:**

**ADDITIONAL INFORMATION TO BE SUBMITTED WITH ANNUAL REVIEW PERIOD FILING**

1. **Provide actual and, if otherwise prepared or maintained, weather normalized jurisdictional sales volumes and number of customers by rate schedule for each month during the review period. Include supporting normalization workpapers and documentation.**

2. **Provide actual and, if otherwise prepared or maintained, weather normalized non-jurisdictional sales and transportation volumes and number of customers by rate schedule for each month during the review period. Include supporting normalization workpapers and documentation.**

3. **Provide a detailed supply and requirement schedule for the Company's review period peak day season. The schedules should include deliveries to meet demands by source (e.g., Koch Gateway, Texas Eastern by rate schedule) and requirements by customer classification (Residential, Commercial). Separately identify deliveries and requirements for non-jurisdictional sales and transportation customers. Also provide applicable weather data.**

4. **Provide the same source (capacity entitlements) and requirements information requested in the previous question for the design day used by the Company for capacity planning purposes.**

5. **Provide a summary identifying the salient features of each of the following in effect during the review period. Salient features include contract party, effective term and applicable contract entitlements (daily, annual, seasonal, etc.).**

   a. **All firm transportation and no-notice agreements by type. Indicate whether the capacity is available at the Company's citygate to meet design day requirements or is upstream capacity. Identify the applicable downstream pipeline for each upstream arrangement.**

   b. **All storage, gathering and exchange agreements. Indicate if each agreement provides design day capacity at the citygate or requires separate transportation (identify) service to effectuate delivery. Include any on-system storage and peak shaving facilities used by the Company.**

   c. **Reconcile the capacity entitlements identified in subparts a and b with the design day entitlements provided in response to the previous question.**

**d. Specifically identify any changes to the Company's capacity entitlements identified in subparts (a) or (b) which occurred during the review period and any changes which will occur during the next review period.**

**6. Provide an explanation and all calculations, workpapers and data bases relied upon to develop the Company's winter season design day sendout projections. Include relevant data showing how the jurisdictional and non-jurisdictional sales and transportation components of sendout for each class were determined. Include data on computer diskette to the extent available. Also explicitly identify the Company's design day criteria, the associated probability of occurrence and provide historical data supporting the Company's probability claim.**

**7. Identify the salient features of each <u>firm</u> gas supply arrangement in effect during the review period (exclude local production contracts). Salient features include:**

**a. producer name;**
**b. daily, seasonal and annual contract quantities;**
**c. pricing provisions;**
**d. minimum take provisions;**
**e. flexibility to adjust nominations;**
**f. interstate pipeline delivery path (for the most contiguous pipeline); and**
**g. whether the title to the gas passes at an upstream location or at the citygate.**

**8. For each of the Company's contract storage arrangements and on system storage, identify the maximum daily injection and withdrawal rates when storages are full and the decline in deliverability which occurs as top gas is withdrawn.**

**9. Provide a schedule separately identifying all interruptions of transportation or sales service on the Company's system during the review period due to supply shortages or capacity constraints on the Company or its upstream interstate pipeline suppliers. Also identify the primary factors which lead to the interruption.**

**10. Identify whether any unauthorized usage or overrun penalties have been assessed against the Company by its pipeline suppliers during the review period. Identify the reason for each assessment.**

**11. Provide a large scale map of the Company's distribution system showing interstate pipeline interconnects.**

12. For the review period, please provide a copy of the actual <u>monthly</u> planning document prepared by the Company which indicates how much gas should be purchased and delivered on the Company's various pipelines/receipt points just before the Company purchases its gas supplies and places its nominations with each supplier and pipeline. The document should show anticipated demands of jurisdictional and non-jurisdictional sales customers, balancing requirements of transportation customers (if applicable), storage injections/withdrawals, off-system sales quantities (if applicable), capacity which can be released, etc. The document should also show, based on applicable pipeline variable transportation charges and gas supply locational price differences, the receipt points/capacity the Company seeks to fill first. If no such monthly planning documents are prepared, actual data should be provided after the fact.

13. If not identified in the previous question, please identify the gas supply locational price differential (from NYMEX or other benchmark) utilized for planning purposes on a monthly basis for each location the Company purchased gas during the review period. Also identify the variable transportation and shrinkage charges applicable at each receipt location the Company purchased gas. If no such monthly planning is utilized, actual data should be provided after the fact.

14. Provide a copy of the most recent long-term gas supply and capacity planning documents prepared by the Company.

Designated review periods for each gas utility are identified in Appendix A. Schedule C-2 addresses: the LUFG percent to be assessed the various customers served by a utility to recover the costs associated with lost and unaccounted-for and company use gas and other information a utility is required to submit to demonstrate it is adhering to a best cost procurement standard for PGA customers. The "D" set of schedules seek additional statistical data and are to be filed monthly.

The Commission, shall investigate the purchased gas costs incurred by each Group I gas utility during its designated review period for compliance with the requirements of this General Order. Each such investigation by the Commission shall result in an Audit Report. The Audit Report shall contain specific findings and recommendations concerning the utility's compliance with this General Order. The Audit Report shall be docketed. Hearings may be held to determine if inappropriate costs have been recovered through a utility's PGA, and to address any other issues raised by the PGA filings and addressed in the Audit Report. Upon conclusion of the Commission Staff's investigation and hearings, the Commission shall enter an order approving the utility's review period purchased gas costs that it finds are eligible for recovery through the PGA mechanism. Costs approved as eligible for recovery through the PGA mechanism shall no longer be subject to review except in instances where the Commission's investigation and Audit Report were based on inaccurate information provided by the utility.

The gas costs incurred by each Group I utility will be reviewed no less frequently than every other year. This will be done for several reasons. First, such reviews will provide a better match between actual industry circumstances which existed during the review period and those existing during the Commission Staff's investigation of review period procurement activity. Therefore, these reviews will reduce the potential for hindsight adjustments to a utility's gas costs. Second, frequent reviews will permit the Commission to evaluate anticipated changes in a utility's procurement practices and arrangements on a more timely basis. Third, periodic reviews will reduce instances where the facts associated with a utility's procurement decision can no longer be recalled. Fourth, these reviews will reduce the likelihood of ineligible costs being recovered from ratepayers. Finally, the Commission does not envision that, once instituted, the review procedure will be burdensome for utilities.

## D. GROUP II UTILITIES

Group II utilities are required to adhere to the same filing procedures and requirements as Group I utilities with the following exceptions. The Commission is requiring all Group II utilities to make an initial periodic review filing after the first year of operation under this General Order, to ensure adherence with this General Order. Thereafter, Group II utilities will be required to submit periodic review filings as directed by the Commission, depending on the nature of the utility's operations and gas procurement arrangements. It is likely that the comprehensive Audits of Group II utilities will not be required as frequently as for Group I utilities. A recommended filing schedule for each Group II utility will be included in the Audit Report issued by the Commission Staff. The Commission's order addressing the utility's review period purchased gas costs will approve a filing schedule for each Group II utility.

## E. GROUP III UTILITIES

Current data reflects that all Group III utilities have no more than 200 customers. In addition, in many cases these utilities obtain all of their gas from a single supplier at a fixed price. For these reasons it may not be necessary for Group III utilities to file with the same frequency, or in the same detail as Group I and II utilities. The Commission Staff will develop filing procedures and requirements for Group III utilities. All Group III utilities will, however, be required to make filings with the Commission no less frequently than every six months, using the procedures and requirements developed by the Commission Staff.

In addition, Commission Staff anticipates that much of the information Group I utilities are required to submit will simply not be applicable to Group II and Group III utilities. Such information includes data concerning capacity release, off-system sales, and storage activity; and throughput for non-jurisdictional sale and transportation customers. Therefore, the filing requirements of Group II and Group III utilities will be significantly less than that imposed on Group I utilities.

## III. GUIDELINES GOVERNING THE ELIGIBILITY OF COSTS RECOVERABLE THROUGH THE PGA MECHANISM

### A. GOALS AND OBJECTIVES

The guidelines and methodologies contained in this General Order are designed to address the appropriateness of the recovery of specific costs through the PGA mechanism. These guidelines are intended to provide more detail to the Statement of General Principles and have been designed to provide consistent and equitable standards for all Louisiana gas utilities to follow in the preparation of their PGA filings.

### B. SPECIFIC GUIDELINES

The following guidelines provide a listing of costs specifically eligible and costs specifically ineligible for recovery through the PGA mechanism. While these listings address costs known to be currently incurred by the gas utilities, modifications may be necessary in the future as the industry undergoes further changes.

**1. Costs Eligible for Recovery through the PGA.** The following costs are eligible for recovery through a gas utility's PGA provided these costs are necessary to serve its jurisdictional sales customers on a best cost basis. To the extent a question arises concerning the eligibility of costs recoverable through the PGA, it is the responsibility of the gas utility to specifically identify, and bring to the Commission's attention for Commission's consideration, those costs in the utility's PGA filing.

a. Current charges directly associated with transportation service provided by an interstate or intrastate pipeline. Includes the reservation (demand), variable (commodity) and fuel retention charges associated with physically delivering gas to the Company's citygate or to an off-system contract storage facility. Also includes Gas Research Institute ("GRI") and Annual Charge Adjustment ("ACA") surcharges imposed by the FERC.

b. Current charges directly associated with storage service provided by an interstate or intrastate pipeline (contract storage). Includes deliverability (demand), capacity, injection and withdrawal and storage loss charges. Storage deliverability (demand) and capacity charges are recoverable over the course of the year in the same manner as other pipeline reservation or demand charges. Volumetric injection, withdrawal and storage loss charges are to be included as an element of the cost of gas in storage and recovered when the gas is withdrawn from storage. Similarly, the gas supply commodity costs associated with the gas injected into storage, whether off-system contract storage or the utility's on-system storage, are only eligible for inclusion in the PGA when the supplies are withdrawn from storage.

c. Current charges directly associated with gathering or processing service provided by an entity other than the gas utility.

d. Current charges directly associated with sales service provided by an interstate or intrastate pipeline. Includes demand and commodity charges.

e. Current charges for commodity supplies of natural gas or liquefied gas obtained from producers, brokers or marketers, or other suppliers at the point of title transfer to the gas utility.

f. Current gas supplier reservation (demand) charges for supplies of natural gas or liquefied gas obtained from producers, brokers, marketers or other suppliers.

g. On-system lost and unaccounted-for and company use gas (“LUFG”) associated with serving PGA sales customers.

h. Refunds and credits associated with transportation, storage or sales services previously purchased to serve PGA sales customers and included in PGA rates.

i. Revenues received from the release of interstate or intrastate pipeline capacity held to meet the requirements of PGA sales customers.

j. Net margins associated with sales to non-PGA sales customers which were effectuated by the use of capacity and gas supplies reserved and paid for by PGA sales customers.

k. Transition costs included in the rates for services purchased from another regulated entity specifically approved for recovery by the Commission. Includes take-or-pay contract reformation, buyout and buydown costs and gas supply realignment and stranded costs.

l. Prudently incurred costs associated with various financial instruments purchased by the gas utility to stabilize PGA rates. Includes the transactions costs associated with the purchase of futures contracts and options.

**2. Costs Not Eligible for Recovery through the PGA.** Generally, any costs incurred by a gas utility associated with the delivery of gas from its citygate to its jurisdictional sales customers, with the exception of on-system lost and unaccounted-for and company use gas associated with serving PGA sales customers, are ineligible for recovery through the PGA. Examples of costs ineligible for recovery through the PGA are:

a. Any purchased gas costs incurred in association with service to non-jurisdictional customers. Includes the costs associated with balancing and LUFG associated with transportation and non-jurisdictional sales service.

b. Costs associated with on-system storage facilities (except LUFG).

c. Operation and maintenance costs. Includes accounting and other administrative costs.

d. Procurement costs. Includes salaries, wages, and overheads for personnel in fuel purchasing department.

e. Property taxes including ad valorem taxes. Includes property taxes on facilities owned or leased by utility such as storage facilities.

f. Depreciation and amortization costs. Includes depreciation of facilities owned by utility.

g. Interest expense or carrying charges (other than Commission authorized return on under-recoveries and over-recoveries) on capital investments and inventories. Includes interest on gas in storage inventory.

h. Commissions paid by the utility to secure gas supplies on behalf of PGA sales customers except as discussed in Section IV(C).

i. Gas purchased in advance by a utility for which a prepayment is made is not eligible for recovery until the utility actually takes delivery of the prepurchased gas supplies.

j. Transition costs included in the rates for services purchased from another regulated entity not specifically approved for recovery by the Commission. Includes take-or-pay, contract information, buyout and buydown costs and gas supply realignment and stranded costs.

## C. GLOSSARY OF TERMS

***ACA*** *-- Annual Charge Adjustment*
***Administrative Cost(s)*** *-- A subset of operations and maintenance expenses that are a part of a utility company's cost of service (e.g., salaries, office supplies and expenses, outside services, injuries and damages).*
***Ad valorem tax*** *-- A tax imposed as a percent of value.*
***Affiliate*** *-- A business concern owned or controlled in whole or in part by another business concern, in this case the Local Distribution Company (LDC) or the same business concern which owns the LDC.*
***Best Cost Procurement Standards*** *-- procurement at the lowest, prudently incurred cost consistent with the need to provide safe, adequate, and reliable service.*
***Billing Month*** *-- Used in the context of Purchased Gas Adjustment Mechanisms, the billing month is the month for which the service is being billed; the billing month typically follows two months after the correspondent operating, or reconciled month.*
***Buyout*** *-- A swap is closed and settled at current price.*
***Capacity (gas)*** *-- The maximum amount of natural gas that can be produced, transported, stored, distributed, or utilized in a given period of time under design conditions.*
***Capacity Release Revenues*** *-- Those revenues associated with the assignment, allocation, or release of firm gas transportation rights to another party authorized under Order No. 636, done on a permanent or temporary basis, and awarded to the highest bidder.*
***Cashout*** *-- A procedure in which shippers are allowed to resolve imbalances by cash payments, in contrast to making up imbalances with gas balances in-kind.*
***Citygate*** *-- The point of interconnect between a gas utility and an interstate or intrastate pipeline or LDC.*
***Commission*** *-- The Louisiana Public Service Commission.*
***Commodity Costs*** *-- Those costs that are allocated on the basis of actual use of service.*
***Customers; Commercial*** *-- A sector of customers or service defined as non-manufacturing business establishment, including hotels, motels, restaurants, wholesale businesses, retail stores, and health, social and educational institutions. A utility may classify the commercial sector as all consumers whose demand or annual use exceeds some specified limit. The limit may be set by the utility based on the rate schedule of the utility.*
***Customers; Industrial*** *-- Service to any company, corporation, partnership or sole proprietor primarily engaged in operations which create or change raw or unfinished materials into an upgraded form or product. This includes all establishments in the Mining Division and the Manufacturing Division of the Standard Industrial Classification. Also included in this class are direct gas sales to electric generating plants, including municipally-owned.*
***Customers; Residential*** *-- The residential sector is defined as private household establishments which consume energy primarily for space heating, water heating, air conditioning, lighting, refrigeration, cooking and clothes drying. The classification of an individual consumer's account, where the use is both residential and commercial, is based on principal use.*
***Demand/Reservation*** *-- Normally used to refer to a shipper's entitlement to receive delivery of natural gas its system at a given instant or averaged over a designated period, usually expressed in MCFs or MMBtus.*
***Deminimus - Refund*** *-- A purchased gas cost refund received by an LDC which, when divided by sales for a month would have an effect of less than $0.10 per mcf on the GCR.*
***FERC*** *-- Federal Energy Regulatory Commission.*
***GCR*** *-- Gas Cost Recovery*
***GRI*** *-- Gas Research Institute*
***Imbalance*** *-- A discrepancy between a transporter's receipts and deliveries of natural gas for a shipper. Can refer to a local distribution company or an end user as a shipper on a pipeline or an end user as a shipper on an LDC. Most pipelines require that a shipper's deliveries to the pipeline and receipts from the pipeline remain in balance over a given period of time or the pipeline may assess charges until the imbalance is cured.*
***Interstate Gas Pipeline*** *-- A natural gas pipeline company that is engaged in the transportation of natural gas across state boundaries, and is therefore subject to FERC jurisdiction and/or FERC regulation under the NGA.*

***Intrastate Gas Pipeline*** -- *A natural gas pipeline company that is engaged in the transportation or natural gas not subject to the FERC jurisdiction under the NGA.*
***LDC --*** *Local Distribution Company.*
***Lost and Unaccounted for Gas (LUFG)*** -- *The difference between gas received by the LDC or pipeline and gas delivered to customers due to metering inaccuracies, leakage, and/or theft. Company use for compressor fuel and other operations may also be included.*
***NGA***-- *Natural Gas Act.*
***Net Margin --*** *Revenues less applicable expenses.*
***Net Margins from Off-System Sales*** -- *The difference before income taxes, between the amount of revenue realized from the off-system sale of gas (utilizing capacity reserved for jurisdictional ratepayers) and the delivered cost of gas to the customer.*
***Off-System Sales*** -- *Sales by an LDC to customers which do not receive distribution service.*
***Over/Under recoveries*** -- *The differences between forecast dollar recovery amounts and actual dollar recovery amounts.*
***Purchased Gas Adjustment*** -- *The adjustment in Local Distribution Company billings for fluctuations in gas prices from suppliers.*
***Rate Stabilization Program --*** *A program designed to reduce fluctuations in rates. Such programs include buying a portion of the utility's gas supplies directly from a supplier at the then prevailing market price, and the purchase of various financial instruments.*
***Realignment of Costs*** -- *Refers to the shifting of cost recovery from base rates to the PGA or from the PGA to the base rates.*
***Storage*** -- *Service in which natural gas is received by the seller of the service and held for the account of the customer for redelivery at a later time. Storage services are typically utilized by customers to allow more uniform purchase or sales of natural gas throughout the year, despite seasonal variations in end-use demand. Storage service is also a critical element of the peak period deliverability of many interstate natural gas pipelines and distributors. Injection, withdrawal and holding fees are usually charged, and limits on rates, times of injection and withdrawal and maximum volume to be held are usually imposed.*
***Storage Loss Charge*** -- *The charge assessed by a storage provider for losses of gas in storage and/or gas used for storage injections and withdrawals, normally assessed in the form of a percentage of gas injected, thereby reducing gas available for withdrawal.*
***Straight-fixed-variable (SFV) Rate Design*** -- *A rate design method applied by the FERC on gas pipelines which allocates all fixed costs to the demand component and all variable costs to the commodity, or usage component.*
***Stranded Costs*** -- *Under FERC Order 636, costs associated with certain gas pipeline assets previously used to provide bundled sales service, such as gas in storage and capacity on upstream pipelines, can no longer be assigned to customers of the unbundled services.*
***Take or Pay*** -- *A contract provision obligating the buyer to pay for a certain minimum quantity of product, whether or not the buyer actually takes that quantity during the stated period.*

## IV. METHODOLOGIES

### A. ON-SYSTEM LOST AND UNACCOUNTED-FOR AND COMPANY USE ("LUFG")

Unless otherwise approved by the Commission and demonstrated by the gas utility that an alternative approach is warranted, LUFG is to be allocated between PGA and other customers on a volumetric basis. The assessed LUFG percentage must be based on a three-year average of actual experience. Estimates of LUFG will not be accepted. Use of estimates will result in no recovery of LUFG through the PGA. Under no circumstances may LUFG recoverable from sales customers exceed 6 percent of purchase volumes on an annual basis.

### B. USE OF PROJECTED PURCHASED GAS COSTS

Interstate and intrastate charges should be based on the most recent FERC or Commission approved rates. Gas supply commodity cost projections should be based on the actual price of the supply, if known. If actual prices for certain purchases are not known (as with spot market purchases or purchases with prices based on a published index), gas supply commodity cost projections for these purchases should reflect the closing New York Mercantile Exchange ("NYMEX") index price(s) for the applicable billing month, adjusted for a locational pricing differential with the applicable premium/discount. The locational pricing differential should be based on published data reasonably anticipated, or on actual experienced price differentials.

The Commission is approving the use of projected purchased gas costs for several reasons. Use of projected cost data should provide a better match between a gas utility's actual costs and purchased gas recoveries. This will serve to minimize purchased gas cost under and overrecoveries as well as to send more accurate price signals to ratepayers. In addition, sufficient market pricing data exists to make the projection process relatively straightforward. The use of projected purchased gas costs is optional for Group II and III utilities.

### C. COMMISSIONS AND FEES PAID TO THIRD-PARTIES

Except as specified below, commissions and fees associated with arrangements wherein the utility engages a third-party to purchase gas on behalf of jurisdictional sales customers are not eligible for recovery through the PGA. The Commission's concern with respect to such costs is that the utility's base rates have been set in recognition that the utility will incur such costs to procure gas on behalf of PGA sales customers. If such costs are also recovered through the PGA, a double recovery of such costs will occur. Exemptions to the requirement that all commissions and fees be recovered through base rates may be authorized by the Commission if such costs are removed from a utility's base rates during a base rate proceeding. At the time of issuance of this order, several LDCs have identified specific instances where commissions or fees are being paid as part of the cost of the gas supplies which they are purchasing. In some instances, these purchases involve limited quantities of gas for isolated service areas or on secondary pipelines where it would be impractical for the LDC to undertake this activity on its own. In another instance, the LDC has found it more cost effective to arrange for an outside entity to purchase its gas supplies than to hire the internal staff to do so because of its relatively small size. Based on the information provided during this proceeding, we are approving exemptions to allow the following commissions and fees to be included in the PGAs of the LDC involved: amounts incurred by ARKLA for purchases of supplies to serve the former LNT system; amounts paid by LGS and amounts paid by Livingston Gas for purchases of its system supplies.

### D. CAPACITY RELEASE REVENUES AND NET MARGINS FROM OFF-SYSTEM SALES

Unless otherwise authorized by the Commission, 100 percent of the revenues realized by utilities from the release of interstate pipeline and storage capacity reserved to serve PGA customers will be credited to PGA customers. The net margins generated from off-system sales effectuated using capacity reserved to serve PGA customers will be shared between PGA customers and the Company with PGA customers receiving credit for 70 percent of the net margin before income taxes.[2] This 70/30 sharing shall be effective through April 30, 2001. At that time the Commission will review the operation of the sharing mechanism to determine whether it will be continued in its present form or revised to respond to changing market conditions.

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[2] For example: An off-system sale is effectuated using capacity reserved to serve PGA customers and the sale price is $3.00/mcf. The cost of gas delivered to the customer is $2.50/mcf. The "net margin from the off-system sale" in this example is $.50/mcf and the sharing would be $.35/mcf to ratepayers and $.15/mcf to shareholders.

The requirement that capacity release revenues be credited to PGA customers was previously addressed in the Commission's General Order of June, 1994 addresses this issue and requires such treatment. (*General Order: In Re: Requirement That Gas Local Distribution Companies Flow Through Their Purchased Gas Adjustment Clause Revenues Realized By The Sale Of Pipeline, And Storage Capacity And Related Revenues From Interstate Pipeline Suppliers* (June, 1994)).

Off-system sales made by LDCs using capacity that was not reserved to serve PGA customers shall be reported to the Commission each month, at the time each LDC makes its PGA filing.

**E. RATE STABILITY**

The Commission strongly encourages, but is not requiring, gas utilities to adopt gas procurement programs which will increase the stability of their PGA rates. The Commission is encouraging systematic, rather than speculative, approaches to rate stability. Rate stability programs may be implemented by purchasing gas directly from a supplier or through the purchase of various financial instruments. Such programs include contracting for a portion of the utility's gas supplies in advance of delivery at the then prevailing market price and the purchase of various financial instruments.

The Commission will not exercise hindsight and penalize gas utilities if, through the use of best cost gas procurement policies, purchases made in advance at the then prevailing market price are priced higher than the market price at the time of delivery. Similarly, the Commission will not reward gas utilities if purchases made in advance are priced lower than the market price at the time of delivery. Just as all other purchases made by a gas utility are reviewed, advance purchases will be reviewed to ensure that a gas utility's contracting practices are prudent and reasonable. For example, advance purchases should be made at market prices and purchased quantities should be consistent with a gas utility's requirements and should not lead to the purchase of supplies in excess of requirements.

Gas utilities must notify the Commission of their rate stabilization programs before the transaction costs or losses associated with the purchase of financial instruments may be recovered through the PGA. Rate stabilization programs which involve the use of financial instruments may be proposed as part of a utility's annual revenue filing. Notification does not constitute approval by the Commission.

**F. OVER/UNDER RECOVERIES**

Louisiana gas utilities should monitor the over/(under) recovery of purchased gas costs to provide a true-up or reconciliation of actual recoverable costs to actual recovery revenues. This computation should be based solely upon Louisiana jurisdictional sales. This computation should be made in accordance with the appropriate "C" schedule. However, the utility may seek authorization to adjust the surcharge during the interim period if the level of over (under) recoveries so warrant. The Commission is requiring annual reconciliations to mitigate the fluctuation in PGA rates which may otherwise occur if a shorter (i.e., monthly) reconciliation period is utilized.

**G. CARRYING CHARGES ON OVER/(UNDER) RECOVERIES**

The over/(under) recovery computation should include interest on the balance existing at the end of each billing month. Consistent with the standards adopted in Docket No. U-21497 for electric utilities, the interest rate to be applied to over and under-recoveries is the prime bank lending rate published in the Wall Street Journal on the last business day of each month. This computation should be made in accordance with the appropriate "C" schedule.

**H. SUPPLIER REFUNDS**

Generally, except as described below, supplier refunds will be amortized over a 12-month period, beginning the month immediately after receipt through a separate refund credit, unless otherwise directed by the Commission. The refund credit will be computed in accordance with

Schedule B-4A and reflected on Schedule A-1 (Purchase Gas Adjustment). The total refund amount, with interest, will be reflected on Schedule B-1 (Summary of Actual Purchased Gas Costs) in the month received. Interest will be included in the refund amount reflected on Schedule B-1 from the date of receipt until the commencement of the amortization period based on the prime lending rate published in the Wall Street Journal on the last day of the month in which the refund is received. Under this procedure interest will accrue on the unamortized refund balance through the Reconciliation of Actual Purchased Gas Costs and Revenues (Schedule C-1).

The Commission is providing an alternative method for dealing with de minimis refunds, where de minimis refunds are defined as those which, if amortized over a one month period, would impact a company's monthly Gas Cost Rate by less than 10 cents per Mcf. De minimis refunds will be identified on Schedule B-4C in the month received. The refund amounts will also be reflected on the Schedule A-3 (Projected Commodity Component of Purchase Gas Adjustment) in the month immediately after receipt and Schedule B-1 (Summary of Actual Purchased Gas Costs) in the month received. Interest will be included in the amount reflected on Schedule B-1 from the date of receipt until the commencement of the amortization period based on the prime lending rate published in the Wall Street Journal on the last day of the month in which the refund is received.

## I. DIFFERENTIATION AMONG CUSTOMERS

Unless demonstrated by the gas utility that an alternative approach is warranted and previously approved by the Commission, all retail sales jurisdictional customers will be assessed the same PGA rate calculated based on the utility's weighted average cost of gas as shown on Schedule A.

## J. CONTRACT BUYOUTS/TRANSITION COSTS

Gas utilities are obligated to obtain the lowest cost of gas practical, consistent with the requirement to provide safe, adequate and reliable service. Therefore, utilities are obligated to engage in prudent and economic contract buyouts. Utilities are also obligated to seek prior Commission approval for the recovery of contract buyout costs through the PGA and demonstrate prudence and the associated economic benefits. This includes both explicit contract buyouts as well as implicit buyouts through price renegotiation.

Costs associated with the restructuring of the natural gas industry must similarly be approved by the Commission prior to recovery through the PGA of each utility. Such costs include take-or-pay contract buyout/buydown costs, gas supply realignment and stranded costs incurred by interstate and intrastate pipelines. The Commission will consider the allocation of contract buyout and transition costs between jurisdictional and non-jurisdictional customers when a utility files to recover such costs.

## K. CORRECTIONS OF ERRORS AND PRIOR PERIOD ADJUSTMENTS

Gas utilities are obligated to correct reporting or filing errors, whether positive or negative as soon as they become aware of such errors. Corrections to errors should include interest from the effective date of the error through the effective date of correction. Gas utilities are also obligated to reflect prior period adjustments made by pipelines or suppliers in the monthly cost of gas reports filed with the Commission.

## L. TIMING

Gas utilities will file projected cost of gas reports (Schedule A) and actual cost of gas reports (Schedule B) as soon as practicable prior to the applicable billing month. The utility is permitted to charge the PGA rate reflected in its projected cost of gas report unless it is specifically notified otherwise by the Commission Staff. Such permission to charge this PGA rate does not constitute Commission approval of the rate.

An annual report (Schedule C) shall be filed by each utility within 90 days after the conclusion of the utility's designated review period. A gas utility is authorized to reflect in its next (or concurrent) monthly projected gas cost filing the over/(under) recovery amortization surcharge filed in Schedule C subject to refund, pending the results of the Commission Staff's investigation as to whether the purchased gas costs incurred by each utility during its designated annual review period were consistent with the requirements of this General Order.

### M. REALIGNMENT OF COSTS

To the extent a gas utility is currently recovering in base rates costs eligible for recovery through its PGA, or is recovering costs through its PGA not eligible for PGA recovery as directed in this General Order, the utility must file with the Commission to realign its rates consistent with the requirements of this Order. It is the Commission's intention that any realignment be revenue neutral for the utility.

### N. PRIOR APPROVALS

To the extent that the Commission has specifically approved PGA recovery for specific costs, that treatment should continue unless and until a change is authorized by the Commission.

### O. EXCEPTIONS

The Commission retains the authority to make exceptions to the guidelines contained in this General Order to allow recovery or provide refunds through the PGA for specific costs. This authority shall be exercised by majority vote of the Commission pursuant to application by the utility or upon the Commission's own motion.

### P. TREATMENT OF EXCEPTIONS AND UNCERTAINTIES

Costs for which the appropriate treatment is uncertain should *not* be recovered through the PGA mechanism without prior approval by the Commission.

### Q. DELINEATIONS OF AFFILIATE TRANSACTIONS

To the extent a gas utility incurs purchased gas costs from an affiliated party or entity and seeks to recover those costs through the PGA mechanism, the utility must identify the transaction on the "A" and "B" Schedules.

The utility is only allowed to recover the lower of actual cost or market for costs incurred through an affiliated party. Recoverable cost is determined on the same basis as if the gas utility incurred the cost directly.[3]

## V. REPORTING

### A. GOALS AND OBJECTIVES

1. Level of Detail. The information provided by gas utilities in their PGA filings should be sufficiently detailed to permit the Commission, its Staff and customers to determine the type of costs, the quantity purchased, the total and per unit costs, the over and under collection adjustment, carrying charges, lost and unaccounted-for percentages, changes in the costs, prior approvals, proposed exceptions, and uncertainties.

[3] Because of the potential for abuse, purchases of gas from affiliated entities must be closely monitored and scrutinized. However, as discussed in Section III, E ("RATE STABILITY") above, the Commission will not exercise hindsight and penalize gas utilities if, through the use of best cost gas procurement policies, prudent purchases made in advance at the then prevailing market price are priced higher than the market price at the time of delivery. This is so even if the purchase is made from an affiliated entity. Similarly, the Commission will not reward gas utilities if purchases made in advance from an affiliated entity are priced lower than the market price at the time of delivery.

2. Adherence to Guidelines. In making their PGA filings, gas utilities should fully comply with the guidelines contained in this General Order and provide the information required herein and in the attached schedules.

## B. FORMAT FOR COMPUTATIONS AND FILINGS

1. Projected Monthly Cost of Gas (Schedules A-1 through A-3)

2. Actual Monthly Cost of Gas (Schedules B-1 through B-9)

3. Annual Review Period Filing (Schedules C-1 through C-2)

4. Monthly Statistical Data with 12-month Historical Data (Schedule D)

5. Pursuant to written application by a utility, the Executive Secretary may approve minor modifications to standard schedules, formats and instructions for good cause shown. For the first year after implementation of this Order, any such minor modifications approved by the Executive Secretary shall be presented to the Commission at its next Business and Executive session at which time the Commission shall ratify, alter or reject such modifications.

## C. REQUIRED FILINGS AND SUPPORTING DOCUMENTATION

1. Detailed Reports. Each gas utility shall submit, at the intervals required by this Order, the detailed information identified on Schedule Sets A, B, C and D as required by this Order.

2. Other Supporting Information. If the Commission, its Staff or consultants, at any time, has questions concerning any of the information contained in the utility's filings or the utility's gas purchase practices or policies, it may request additional information or data and such information or data will be provided by the gas utility within ten business days from the date of request. Information and data requests includes formal and informal discovery that may be submitted by the Commission, its Staff or consultants.

## D. AFFIDAVIT

1. Sworn Statement. Each filing by a gas utility shall be accompanied by a sworn statement by the responsible utility executive that the filing has adhered to all of the Commission guidelines as contained in this General Order.

2. Identification of Exception/Uncertainties/Changes. In the affidavit described in Section V, paragraph D.1 above, the utility shall identify any exceptions or uncertainties in the types of costs it seeks to pass through its PGA mechanism. The utility must also submit a formal application to the Commission as stated in Section IV(M) of this Order, for approval of any proposed exceptions or uncertainties. For any proposed exceptions or uncertainties, the utility should identify the nature of the cost and the reason it is seeking to recover the cost through the PGA Clause. However, the gas utilities are prohibited from seeking PGA Clause recovery of base ratemaking items in circumvention of the principles and guidelines of this General Order. For those exceptions already granted, the utility should identify the Commission Order granting the exception including the date of that Order.

## VI. OTHER PROCEDURAL ISSUES

### A. STAFF REVIEW AND AUDIT

1. Periodic Audit. No less than every other year, the Commission Staff shall perform an audit of the purchased gas costs incurred by each Group I gas utility during its designated annual review period. Audits of Group II and Group III utilities will be conducted as ordered by the Commission. In connection with the periodic audit, each gas utility is required to provide the Commission Staff with any backup information required and to respond to data requests and other requests for information propounded by the Commission Staff, which may include special counsel and outside consultants. The gas utilities are to make their books and records available to the Commission Staff to facilitate the completion of such audit. Customers of gas utilities shall have the opportunity to participate in these audits subject to appropriate proprietary and confidentiality safeguards.

2. Audit Report. Each audit conducted by the Commission Staff shall result in an Audit Report containing the results of the investigation. That report must contain specific findings and recommendations concerning whether the costs passed through the PGA Clause were or were not reasonable and prudent, and whether the costs were appropriate for recovery in the PGA Clause mechanism consistent with this General Order. The Staff's Audit Report shall not reveal sensitive and proprietary information.

3. Publication in Commission Bulletin and Hearings. Opportunity for Comment by Interested Parties. Notice of the issuance of the Audit Report for each gas utility shall be published in the Official Commission Bulletin. The utility or any individual or group of ratepayers of that utility shall have an opportunity of comment on the Audit Report and a hearing will be conducted prior to final action by the Commission. The Commission may accept the Audit Report as written, make modifications and order changes and/or refunds where appropriate.

### B. BURDEN OF PROOF

Each gas utility has the burden of proving that the costs passed through its PGA Clause were prudently incurred, produced just and reasonable rates, were necessary to the provision of gas service, and were eligible for recovery through the PGA Clause.

### C. RETENTION OF DOCUMENTATION

Consistent with legal records retention requirements, each gas utility utilizing a PGA Clause must maintain the records to support its procurement costs for a period of at least seven years from the end of designated review period in which the costs were incurred or are sought to be recovered through the PGA. Copies of contracts relating to gas purchases and any modifications to those contracts must be maintained for at least seven years after those contracts and modifications remain effective. In addition, should any annual or other audit of gas utility's purchased gas costs become the subject of a Commission investigation, all documents pertaining to those costs must be maintained until all final appeals of any Commission action have been exhausted.

### D. COST REALIGNMENT

The Commission shall realign the recovery of costs, on a revenue neutral basis, between the PGA Clause mechanism and base rates within one year from the adoption of this General Order, whether through scheduled annual earnings reviews or dockets opened specifically for this purpose. It is the intent of this Order that no utility shall be benefitted or disadvantaged by the transition to the methods of accounting for, and recovery of, purchased gas costs required by this Order.

### E. PROPRIETARY INFORMATION

The Commission is cognizant that gas utilities may claim that some of the information required to be reported by this Order is proprietary, confidential, or can be trade secrets. To the extent that any information required to be provided by this Order is provided to the Federal Energy Regulatory Commission or any other public agency, is published, reported or otherwise disseminated outside of the utility or is otherwise a matter of public record, it will not be considered proprietary or confidential information or a trade secret. If a claim is made that information is proprietary, confidential, or a trade secret that issue shall be addressed in accordance with the provisions of the Commission's August 31, 1992 General Order "In re: Treatment of Information Designated as Trade Secret, Proprietary, or Confidential." If the Commission determines that any such information is proprietary, confidential or a trade secret requiring exemption from public disclosure, that exemption shall expire no later than two years from such Commission determination or at such earlier time as the Commission may designate. In the case of contracts, the exemption shall expire no more than two years from the termination date of the contract.

### F. STANDARD GAS TARIFF

Currently, the Tariffs filed with the Commission by gas utilities vary widely both as to form and content. In order to (1) alleviate the burden on the Commission Staff in having to deal with these different (and sometimes inconsistent) tariffs; (2) promote ease of understanding of the tariffs by Staff, customers, the general public and the utility; and (3) assure that the tariffs provide consistent information, we will adopt uniform tariff guidelines, procedures, and formats. An explanatory statement of the requirements for these tariffs and a sample standard gas tariff are attached hereto as Appendix D. It is the intent of the Commission that all gas utilities submit revised tariffs consistent with the requirements of Appendix D to the Commission Staff within 90 days of the adoption of this General Order.

**BY ORDER OF THE COMMISSION**
**BATON ROUGE, LOUISIANA**
MARCH 24, 1999

/S/ C. DALE SITTIG
DISTRICT IV
CHAIRMAN C. DALE SITTIG

/S/ JACK "JAY" A. BLOSSMAN, JR.
DISTRICT I
VICE CHAIRMAN JACK "JAY" A. BLOSSMAN, JR.

/S/ DON OWEN
DISTRICT V
COMMISSIONER DON OWEN

/S/ IRMA MUSE DIXON
DISTRICT III
COMMISSIONER IRMA MUSE DIXON

/S/ LAWRENCE C. ST. BLANC
SECRETARY
LAWRENCE C. ST. BLANC

/S/ JAMES M. FIELD
DISTRICT II
COMMISSIONER JAMES M. FIELD

THIS ORDER HAS ATTACHMENTS

PLEASE CALL 324-1418