TARIFF METHODOLOGY FOR NATURAL GAS SERVICE

AZERBAIJAN ENERGY ASSISTANCE PROJECT, CONTRACT NO. GS-10F-0017K, TASK ORDER 112-M-00-03-00022-00

FINAL REPORT

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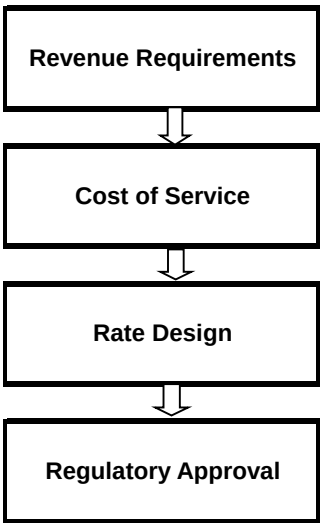
EXECUTIVE SUMMARY

This report describes a proposed methodology for natural gas tariff design in Azerbaijan and recommends the development and implementation of new customer classes, each with its own tariff that is based on the cost of providing natural gas service.

The process of rate design and regulatory approval consists of four stages:



Each stage of the process consists of several specific steps, which are described in this report. Additionally, certain policy questions, such as the return to shareholders, must be addressed at each stage.

The Revenue Requirement is the total amount needed by the natural gas utility to meet all costs of operations during a one-year period, known as the "test year". It consist of:

$$RR = [\ PGC + TEBIT + T\ ] + [\ R \times RAB\ ]$$

Where:

RR	=	Revenue Requirements
PGC	=	Purchased gas supply costs
TEBIT	=	Total Expenses Before Interest and Taxes
T	=	Taxes
R	=	Return
RAB	=	Regulatory Asset Base

It is recommended that the Regulatory Authority adopt a Chart of Accounts for the natural gas company, which would specify each cost and revenue component with a distinctive account number. This Chart of Accounts would also be used for the annual filings of company information to the Regulator.

After the calculation of the annual revenue requirement, a cost-of-service study is done to determine the cost of providing natural gas service to each type, or class of customer. The

report describes the cost of service methodology, which consists of the allocation of all components of the revenue requirements. At this stage, the utility must decide on customer classes in order to allocate the total revenue requirements to each class. In this report, five customer classes are provided as example:

- Residential
- General Service
- Large Commercial and Industrial
- District Heating
- Thermal Power Plants

Several appropriate allocation factors are used, each of which must be calculated from system operations or costs. For example, the relative amount of sales to each customer class is used to allocate the cost of purchased gas.

After the cost-of-service study has been completed, the actual design of the tariff structures must be determined and the pricing for each calculated. A two-part tariff structure is considered in the report to illustrate overall approach of calculation of complex multi-part tariffs. The two-part structure includes a customer price and a commodity price and the three-part structure also includes a demand charge, based on the peak demand of the thermal power plant. Multi part tariff structures more closely represent the cost of providing the natural gas service to each customer class and also provide AzeriGas with a more stable income flow throughout the year. In addition, such tariff structures more closely follow the changes in the cost of providing the natural gas service as actual volumes of deliveries deviate from the planned amounts.

Once the cost-of-service study is completed, the company applies to the Regulatory Authority for approval of the proposed tariffs, which also includes the approval of the customer classification. This process involves the filing of supporting documents and exhibits for regulatory and public scrutiny and analyses.

I. INTRODUCTION

This report describes a proposed methodology for developing tariffs for natural gas in Azerbaijan.

The process of developing and implementing tariffs consists of four major stages, each containing numerous steps that involve mathematical calculations as well as expert judgments in technical, financial and accounting areas. The process involves:

- *Revenue Requirement* – The determination of annual amount of revenue required by the company to cover all costs of operations and providing a return for stakeholders.

- *Cost of Service Analysis* – The determination of the company's costs of providing service to each type of customer through the functionalization of costs and the allocation of the revenue requirements to all customer classes.

- *Rate Design* – The design of the structure of the rates for each type of customer.

- *Regulatory Approval* – The regulatory process of analyzing the company's requests for changes in the tariffs, followed by the approval of the revenue requirement and the rates design/prices for each customer category.

The first three stages involve the tariff methodology while the fourth is the regulatory approval stage whereby the Regulatory Authority considers the tariff proposals, analyzes the information and data, and then renders a decision on the final tariff for implementation by the utility. A schematic diagram of the overall process, the steps within each category, and the policy decisions needed in each category are shown in Figure No. 1.

Figure No. 1

ENERGY SECTOR RATE DESIGN & APPROVAL PROCESSES

PROCESSES	STEPS	POLICIES
Revenue Requirement	1. Determine Cost Components a. Production/Purchases b. Asset value determination c. Annual O&M Costs d. Depreciation Expenses e. Taxes & other f. Working capital g. Return 2. Calculate Annual Rev. Req't	1. Return 2. Adjustments 3. Depreciation 4. Working capital 5. Capital Structure
Cost of Service	1. Functionalization of costs 2. Classification of costs 3. Customer classes definition 4. Determine Allocation Factors 5. Allocation of costs	1. Separation of Functions 2. Allocation Factors 3. Customer Cost Components 4. Losses
Rate Design	1. Determine rate structures for each customer class and/or functional component 2. Use COS to set prices/rates a. Commodity/Energy charge b. Demand charge c. Customer charge 3. Determine billing determinants (kwh, kw, tcm, customers) 4. Calculate new revenue 5. Compare #2 with Rev Req't 6. Adjust final prices to meet Rev. Req't	1. Amount to include in Customer Charge 2. Billing determinant for Demand Charge 3. Innovative Rate designs (I.e. TOU rates, etc.) 4. Subsidies 5. Political considerations 6. Other
Regulatory Approval	1. Filing by Company 2. Review by Commission 3. Public hearings 4. Approval by Commission 5. Final price adjustments 6. Implementation	1. Filing policies & Procedures 2. Review procedures 3. Public Participation

Objectives

The objectives of this proposed tariff methodology are to:

1. Enhance financial sustainability of the natural gas industry,
2. Foster the provision of safe and reliable gas service at affordable and fair tariffs levels,
3. Separate the regulated and non-regulated business costs
4. Create necessary conditions prone for attraction of the needed capital to the sector, at reasonable costs, for system upgrade and efficient expansion,
5. Encourage the efficient use of natural gas by each customer class.

It is recommended, that the implementation of the proposed tariff system is conducted along with the implementation of targeted State safety-net programs to protect the most vulnerable consumer households who truly cannot afford to pay rising utility bills across many utility sectors.

Goals

The measures to be undertaken to assist with these objectives include:

1. *Implementation of cost recovery tariffs,* providing the utility the opportunity to recover its economic cost of service,
2. *Introduction of pass-through mechanisms* for timely recovery of actual costs of purchased gas,
3. *Development of effective regulatory policies to help provide needed capital* to the sector to implement capital investment programs, secure efficient system expansion and provide for just and reasonable return on investment,
4. O*ther regulatory incentives* to encourage the utility to aggressively reduce excess technical, commercial, and nonpayment (bad debt) losses,
5. *Development and implementation of new customer classification* to better track technical and economic characteristics of consumption and associated costs of servicing different customer categories;

New Policies

It should be noted that some additional recommendations that support the tariff methodology are contained herein, most notably:

- The need for a new Chart of Accounts for the natural gas sector entities and which the Regulatory Authority of Azerbaijan approves along with the associated reporting requirements.

- Example of new classification of customers in the natural gas sector that better reflects the characteristics of cost causation for each category.
- Introduction of new tariff structures for all classes of customers.

II. PARTICULARITIES OF CURRENT OPERATIONS OF AZERIGAS

Rendered Services

At present, JSC “Azerigas” is a state-owned vertically integrated gas supply utility that is involved in purchase, transportation, underground storage and distribution of natural gas across the whole territory of Azerbaijan, including Nakhchevan region.

Azerigas purchases domestically produced natural gas and obtains imported gas from Russia also through the other state-owned company, SOCAR, which operates as a single buyer on the Azeri gas market. The gas enters the high-pressure transportation system, which is operated by Azerigasnegl, the transportation division of Azerigas, and further is transported for underground storing to Garadag and Galmaz storage facilities and for distribution to the regional distribution divisions.

Part of the obtained gas is sold by Azerigasnegl directly to the customers connected to the high-pressure system.

The profound peculiarity of the current operation of Azerigas is the presence of three different types of gas in the system, which differ both in their quality and acquisition costs.

Purified and treated imported natural gas from Russia comes through Shirvanovka gas compressor station and is transported via a dedicated pipeline that goes further south along the Astara-Ahirvanovka gas pipeline and then to west along the Gazi-Mammad – Gasakh gas

route. Imported gas has never been mixed with the locally produced gas and is exclusively supplied to Azerenergy for thermal power generation.

Locally produced natural gas enters the system from the south-east. Part of it, that makes up about 62%, undergoes adequate treatment at the gas treatment plant at Garadag, and the rest, the so-called "untreated" gas enters the high-pressure system directly from oil and gas fields without necessary dehydration and conditioning due to the lack of production capacities at the gas treatment plant.

Imported gas is not intended for underground storing and is completely consumed by Azerenergy directly from the system. Part of domestically produced gas is transported to the underground storage and the rest enters the middle and low-pressure gas system directly.

The gas distribution system of Azerbaijan is divided into regions and is operated by regional distribution divisions of Azerigas.

As a single vertically integrated gas-supply utility, Azerigas renders the following services to its customers:

- gas transportation service, which at the moment is rendered solely for Azerenergy;
- gas supply service from the high-pressure system, and
- gas supply service from middle and low-pressure system.

Current System of Natural Gas Tariffs

The current system of natural gas tariff is built on the simple classification of customers, which, in an exaggerated manner can be described as "Azeraluminum" and the rest. At present all customer classes are supplied at the same gas tariff, which is equal to 200 ths AZM/ths cm. The JSC "Azeraluminium" is singled out of all industrial customers and is supplied at 122.5 ths. AZM/ths cm (it is not shown in tables below), which is almost two times lower than the rate for other groups. Before the enactment of a series of the recent gas tariff changes the gas supply tariff varied for different types of customers.

Gas Tariffs – 2004

Customer Category	AZM/MCM		US$/MCM	
	w/o VAT	with VAT	w/o VAT	with VAT
Residential	30,135	35,560	6.15	7.26
Budget/Utilities/SOEs	91,613	108,103	18.69	22.06
Commercial	203,390	240,000	41.50	48.97

The recent developments in retail gas tariff in Azerbaijan are shown in the table below:

Date	Per 1000 m^3 (1 USD=4800 AZM)	Residential	Utility & budgetary	SOCAR	Industry and commerce	Azerenerji	Greenhouses
January 2001	AZM	35560	106301	83200	236000	194700	106301
	USD.	7,4	22,1	17,3	49,2	40,6	22,1
January 2004	AZM	35560	106301	83200	236000	194700	236000
	USD.	7,4	22,1	17,3	49,2	40,6	49,2
November 2004	AZM	81000	236000	236000	236000	236000	236000
	USD.	16,9	49,2	49,2	49,2	49,2	49,2
March 2005	AZM	236000	236000	236000	236000	236000	236000
	USD.	49,2	49,2	49,2	49,2	49,2	49,2

The customer classes, per se, presently used in Azerbaijan, were developed primarily for statistical reporting needs. A year ago, the tariff for residential customers was increased and became equal to the tariff applied to other customer groups. Before this increase residential customers paid 112.0 ths AZM per ths cm.

The level of effective natural gas tariff for JSC “Azeraluminum” intentionally is not discussed here because further analysis is needed to answer the question whether this rate can be classified as an economic development rate or is an example of cross subsidization. To answer the question about the level of cross subsidization not only for Azeraluminum, but in general, it will be required to conduct a detailed cost of service study on the basis of actual technical and economic data, which are not available for general public. The methodology of cost-of-service study will be illustrated later in this report and complemented with proxy data, which may not reflect the actual situation due to proximity of used inputs.

III. REVENUE REQUIREMENT

In order to remain viable, the Licensee must be given the opportunity to recover its prudently incurred total cost of providing natural gas service to its various Customer classes. The total revenue a Licensee is authorized to recover through its tariffs is called the total *Revenue Requirement*, or the total cost of service.

The Licensee's total annual revenue requirement shall consist of

1. Purchased gas supply costs (PSG)
2. Total Expenses Before Interest & Taxes (TEBIT)
3. Regulatory Asset Base (RAB)
4. Applicable taxes (T)
5. Return (R)

The formula for the revenue requirement (RR) is:

$$RR = [PSG + TEBIT + T] + [R \times RAB]$$

Only those authorized costs associated with the specific licensed activity, and reported in accordance with the Chart of Accounts[1] should be included as a component of the total revenue requirement for recovery through the tariffs.

Test Period

The Licensee's total annual revenue requirement shall be based upon the most recent twelve-months of actual cost experience, adjusted for changes in revenues and costs, which are known and measurable with reasonable accuracy at the time of the tariff filing, and which are to be incurred during the first annual period when the tariffs will be in effect.

In the future, AzeriGas and the Tariff Council should consider the use of a forecasted test period, particularly as the expansion of the natural gas distribution system continues and the annually construction costs are incurred. The forecasted test period would include forecasts of the sales and revenues as well as the additional capital costs and expenses that would be spent in providing service to the new customers.

Calculation Method for Cost Components

This part of the methodology discusses the calculation methods for the various components of the total annual revenue requirement.

Purchased Gas Supply Cost

[1] The Tariff Council should develop and adopt the Chart of Accounts for Azerigas and should base its reporting requirements on this chart.

Purchased gas supply costs comprise over 75% of the total gas industry costs. To remain viable, the Licensee must have the opportunity to recover its prudently incurred purchased gas supply costs in a timely manner.

Wholesale Gas Supply Costs

As in the future Azerbaijan opens up the market and allows export and import of natural gas to other organizations than SOCAR, Tariff Council shall establish the maximum prices for import of natural gas, and shall have regulatory oversight of the prices for natural gas exports.

Import and Export Licensees shall recover their gas supply costs based upon the terms specified in the required supply contracts. These terms should include appropriate adjustment mechanisms to address factors such as changes in prices, quantities, and exchange rates.

Distribution Licensee Gas Supply Costs

The Distribution Licensee shall recover its authorized level of purchased gas supply costs through the Purchased Gas Cost Charge (PGC), as defined in Section 16, which shall be a component of the retail tariff. The PGC charge includes a semi-annual adjustment to compensate the Licensee for the difference between its forecasted gas costs and the actual costs incurred.

Total Expenses Before Interest and Taxes

Total Expenses before Interest and Taxes (TEBIT) shall include the following groups of costs:

1. Operating costs. This group shall include: costs of goods and services sold, sales and marketing (or metering, billing and collection) expenses, administrative and general expenses and other operating expenses.

   [Notes: A) The cost of goods and services costs shall include the technical losses (as allowed) and other operating costs shall include the commercial losses (as allowed). The terms Technical Losses and Commercial losses or whatever we choose to replace these terms with shall be defined some place in the text. B) All operating costs are usually additionally categorized into Operation and Maintenance Costs. C) Other Operating expenses shall also include allowable bad debt expense as follows: the Licensee shall have the opportunity to recover an amount of bad debt expense each year based upon a declining schedule of allowable bad debt expenses over the five-year period, as established by the Tariff Council. The level of allowable bad debt expenses shall be set to provide the Licensee a financial incentive to aggressively reduce such losses. To assist with the determination of this declining schedule of allowable bad debt expense, the Licensee will, within six months of the effective date of this order, provide the Tariff Council with an evaluation of its accounts receivable,

differentiating the receivables by customer class and the age of the receivables (e.g. 30, 60, 90 and 180 days and longer).]

2. Non-operating costs. This group shall include expenses related to the sales of assets, expenses from exchange rate differences, borrowing costs excluding interest, expenses from impairment of assets and other non-operating expenses

3. Prior period expenses
   (Note: non-operating and prior period expenses are not categorized as Operation and Maintenance expenses)[2]

TEBIT should not include losses from disasters and other extraordinary costs which should be recovered under different provisions.

TEBIT should not include expenses that are not related to the licensed activity for which the RR are being determined. A system of cost allocation (tracking and assignment of all costs) should be recommended by Tariff Council based on the mandatory use of a uniform system of accounts and a set of cost assignment rules.

The Licensee must maintain accounting records that are sufficient to allow the recording and reporting of the account detail. Only the costs, or categories of costs, appropriately reported in accordance with the Chart of Accounts shall be recoverable through the tariffs.

As part of the tariff application, the Licensee shall provide (a) the actual TEBIT for the prior year, (b) the actual/forecast TEBIT expenditures for the current year, and (c) the estimated expenses for the forecasted test year.

Return Policy

The Tariff Council's return policy is designed to provide the Licensee the opportunity to earn revenues that are sufficient to pay interest on debt and to provide a reasonable return to shareholders.

The primary objectives of the return policy are (a) to develop and maintain sound Licensee credit, and (b) to attract needed capital investment to the sector at reasonable costs to efficiently rehabilitate and expand the natural gas networks.

Calculation of Allowed Return

The allowed return shall be calculated by multiplying the regulatory asset base, as defined below, by the allowed rate-of-return.

[*Discuss return policy with regard to wholesale suppliers*.]

[2] It is a normal regulatory practice to introduce a standard chart of accounts for regulated industries. These charts of accounts are tailored to particularities of operation of each regulated industry.

Regulatory Asset Base

1. The regulatory asset base (RAB) shall be defined as (a) the recognized value of the assets that are used and useful in providing the licensed service, net of capital grants, less (b) the accumulated depreciation on the gross value of these assets, plus (c) the capital investment in projects that are under construction and which shall be completed with one year, plus (d) the working capital requirement. For tariffs, the RAB must be approved by the Tariff Council.

2. Method to Calculate the RAB

   The RAB shall be calculated as follows:

   1. Recognized gross value of used and useful assets
   2. Less: Capital grants (e.g. customer payment for construction)
   3. Less: Accumulated depreciation reserves
   4. Plus: Construction work in progress (as allowed)
   5. Plus: Working Capital Requirement
   6. Equals: Regulatory asset base

   The recognized value of the RAB for the initial calculation under this new tariff methodology is specified in Appendix D.

3. The RAB shall be adjusted each year to reflect (a) the addition of investment in assets, which are used and useful in conducting the licensed activity, net of capital grants, less (b) allowed depreciation expense plus (c) the allowed investment for construction work in progress for gas assets that shall be completed within one year plus (d) any changes in the working capital requirement.

4. Adjustments to Maintain Real Value of RAB

   Since most new assets will be acquired from foreign markets, they will be paid for in US dollars, or the equivalent thereof. Because of the possibility of the continued devaluation of the Azerbaijan manat, the real value of the assets purchased outside of Azerbaijan, but used in the natural gas sector, must be maintained for regulatory purposes. Appendix G describes the potential problem and contains a recommendation for how this problem should be treated.

Allowed Rate-of-Return

1. In conventional regulatory practice, the allowed rate of return is set equal to the estimated weighted average cost of capital (WACC). The WACC is the average of the cost of debt and the cost of equity for the Licensee, weighted according to the share of each of these financing sources in the capital structure.

2. Because the commercial capital markets in Azerbaijan are in the process of development, the allowed rates-of-return for the Transportation and Distribution Licensees, respectively, shall be as authorized by the Tariff Council for the next five-year period.

3. To encourage new capital investment, the Tariff Council may differentiate the rates-of-return applied to (a) the existing RAB value, determined as of the effective date of this new tariff methodology, and (b) the new capital investments made by the Licensee after this effective date.

4. The allowed return, stated in Manats, shall take into account the changes in the exchange rate, as described earlier and also in Appendix G.

5. The Licensee is not guaranteed to earn the authorized amount of return. The actual amount of return that is earned by the Licensee will be equal to the operating income after taxes, computed as follows:

Calculation of Earned Annual Return
Manat '000

1. Total operating revenue (including other operating revenues)	xxx
2. Total operating expenses:	
3. Operation and maintenance expenses	xxx
4. Depreciation expense	xxx
5. Taxes	xxx
6. Total operating expenses	Lines 3 + 4 + 5
7. *Operating Income after Taxes = Return on RAB*	Lines 1 - 6
8. Regulatory Asset Base (RAB)	xxx
9. Rate of Return	Line 7 / 8

Regulatory Working Capital

Working capital requirement is the amount of funds that the Licensee needs to maintain supply inventories, meet prepayment obligations, and to meet cash needs for operating expenses between the time the Licensee renders service and when it collects revenues for those services. The use of these capital funds impose carrying (interest) costs on the Licensee for which it is entitled to be compensated, based upon efficient working capital levels.

Depreciation Expense

1. Annual depreciation expense shall be determined in accordance with the tax and accounting laws of Azerbaijan, and calculated on the book value of assets that are used and useful in providing gas service. The annual depreciation expense shall be recorded in accordance with the Tariff Council's chart of asset accounts.

2. Similar to the annual adjustments to the RAB referenced earlier, annual depreciation expense shall also be appropriately adjusted to reflect changes in the exchange rate of the Manat to the U.S. Dollar.

3. Depreciation expense should be applied to repay the principal amount of debt and equity investment; to effectively reinvest these funds into the natural gas systems.

4. Depreciation expense is related to the expenditures needed to replace assets as they age. Because existing gas assets are already highly depreciated, and the required investment to maintain and replace these ageing assets has not been undertaken, additional tariff funding may be required for this purpose. However, only a portion of the total system capacity is being used. Customers should not be required to pay for unnecessary assets.

Taxes and Other Charges

The Licensee shall have the opportunity to recover in tariffs the taxes and other charges, including unrecovered VAT or subsidies that could be considered as costs, incurred by the Licensee in the annual period that the tariffs will be in effect.

Other Operating Revenues

Other Operating Revenues shall include all revenues received from sources other than sales of natural gas service. These other revenues are collected by the Licensee for any other services rendered that use the assets and/or personnel of the licensed activity, that are not part of the normal gas service. Because such revenues are produced through the use of the assets and/or personnel, the expenses of which have been borne by Licensee's gas customers, the gas service customers may be given a credit for these revenues through a reduction in their revenue requirement.

Adjustment Procedures

The Licensees total revenue requirement shall be determined and adjusted according to procedures summarized below:

- *Purchased gas costs* that are prudently incurred shall be recovered through a pass-through mechanism, adjusted semi-annually.

- *Capital costs* shall be recovered through annual depreciation expense and the return components of the tariff, based upon the Licensee's authorized capital investment program. The financing cost for regulatory working capital shall also be a component of the annual revenue requirement.

- *The total operating and non-operating expenses before interest and taxes*, including gas system operation and maintenance, customer meter reading, billing, collections,

and administrative and general expenses and other shall be determined by the TARIFF COUNCIL based upon the Licensee's application for a change in these cost items (such applications shall be made no more frequently than once per year.) TEBIT shall be adjusted, including adjustments for costs that are impacted by exchange rate changes, based upon an application for a tariff change filed by the Licensee in accordance with the procedures specified in this tariff methodology.

- *Uncollectible accounts expense* (bad debt expense) shall be established at incentive levels based upon a declining schedule of allowable bad debt expenses over the five-year period.

- *Taxes and other charges* shall be recovered as a pass-through on an annual basis.

- *Commercial and technical losses*, shall be established at incentive levels based upon a declining schedule of allowable losses over the five-year period.

IV. COST OF SERVICE

The next step in the tariff design process is the Cost-of-Service (COS) study. One goal of energy rate design is to implement tariffs that reflect the costs to the company of providing the service to each type of customer. A COS study provides information to show the relative costs that each customer class contributes to the overall costs of providing service to all customers. In this analysis, the total costs (revenue requirements) are allocated to each customer class. A cost-of-service study is an analyses of the costs associated with providing service to each customer class.

This section of the report describes the methodology for performing a cost-of-service study.

A cost-of-service study has six steps:

- Functionalization
- Classification
- Customer classification
- Determination of Allocation Factors
- Allocation of costs
- Report

Functionalization of Costs

The first step in the cost-of-service study is to divide each cost component into the functional group to which it belongs.

In an integrated utility, such as AzeriGas, the system consists of three major functional areas: transportation, storage and distribution. Not all of these functional areas are involved in providing service to each customer class. For example, the distribution system is not used to provide the service to the thermal generators. Therefore, the costs associated with the distribution system should not be included in the tariffs of the generators.

Classification of Costs

The next step is to classify the costs components. Cost classification consists of fixed costs, variable costs, customer costs, and administrative and general costs.

Fixed costs (Demand Costs) are those costs that are borne by the company regardless of the amount of natural gas sold. These costs are capital costs associated with the fixed assets of the company and other costs that must be paid regardless of the sales or number of customers.

Variable costs (Commodity Costs) are those costs that vary with the amount of sales to customers. These cost components include the costs for natural gas supplies and some of the costs associated with the number of customers served by the company.

Customer costs are those costs directly associated with the service provided to customers and include meter reading, billing and collections. In some cases, the costs of meters and service are considered to be customer costs.

Administrative and General cost are those costs associated with the general management of the company. They are generally divided into the fixed (demand) cost and the customer cost components. Some of these costs are fixed and do not vary with the amount of sales or the number of customers, but most for AzeriGas vary with the number of customers that are served.

The following table is an example of the 2004 revenue requirements for AzeriGas and gas sector as a whole, by cost element, separated into the three costs classifications. The detailed work sheet is shown in Appendix D.

AzeriGas Cost Classification Summary for 2004

Cost Element	Amounts in Thousand Manats			
	Commodity	Demand	Customer	Total
Purchased Imported Natural Gas	1,144,688,313.6	0.0	0.0	1,144,688,313.6
Purchased Local Natural Gas	305,973,980.8	0.0	0.0	305,973,980.8
Gas Storage	0.0	10,603,370.4	0.0	10,603,370.4
Transportation	0.0	32,374,058.6	0.0	32,374,058.6
Distribution	0.0	2,015,960.6	3,814,384.7	5,830,345
Customer Accounts Expenses	0.0	0.0	21,444,087.4	21,444,087
Administrative & General	0.0	7,107,531.7	23,128,631.6	30,236,163.3
Depreciation	0.0	27,965,141.5	10,306,521.4	38,271,662.9
Taxes	11,225,403.3	18,455,446.4	45,503,752.9	75,184,603
Return	0.0	94,660,817.0	34,887,129.9	129,547,947.0
Working Capital	0.0	610,667.1	1,987,197.8	2,597,864.9
Total Revenue Requirement for Azerigaz	**317,199,384.1**	**193,792,993.2**	**141,071,705.7**	**652,064,083**
Total Revenue Requirement for the Gas Industry	**1,461,887,697.7**	**193,792,993.2**	**141,071,705.7**	**1,796,752,397**

Note, that Azerigas does charge Azerenerji (i.e. thermal power plants) for commodity cost of supplied gas. As was mentioned earlier, SOCAR performs the functions of a single gas importer for the country, and commodity cost of gas Azerigas pays to SOCAR. Due to such arrangements revenue requirements for Azerigas represent total cost of supply for all customers except Azerenerji, for which only transportation costs are included. Therefore, tariffs calculated on the basis of revenue requirements for Azeranaji will represent total tariffs

for all customers and transportation tariff for thermal power plants. Calculation of total tariffs for Azeranarji requires consideration of total revenue for the whole sector, including revenue requirements for SOCAR (or in other words, commodity costs of imported gas).

Customer Class Definition

Customers are classified into homogeneous groups, based on their load and usage characteristics. Presumably, the costs of providing service to each group are nearly the same for all customers within that group. It is desirable to have different rate classification for different customer classifications, therefore a logical and fair classification of customer groups is necessary.

The customer classifications proposed by AzeriGas were developed with data from the company for the year 2004. A full description of the analyses and the results are provided in Appendix B. The recommended customer classes are:

- *Residential* - A Residential class is defined as natural gas service supplied for residential purposes - cooking, clothes drying, water heating, space heating, by individual meter in a single family dwelling or building, in an individual apartment, or to no more than 4 Apartments served by a single meter (one customer) in a multiple family dwelling, or portion thereof.

- *General Service* - General Service Class is defined as natural gas service supplied to customers primarily engaged in wholesale or retail trade, industrial processes, agriculture, forestry, transportation, communication, sanitary services, finance, insurance, and any other non-residential type service.

- *Compressed Natural Gas* - The Compressed Natural Gas Stations Class is defined as a natural gas service supplied to customers exclusively engaged into supply of compressed natural gas for vehicles.

- *District Heating* - The District Heating Class is defined as a natural gas service supplied to boiler houses engaged exclusively in production of thermal power.

- *Thermal Power Plants* - The Thermal Power Plants class is defined as natural gas distribution service, used by entities with a primary end use of generating electricity for sale to or use by, an electric distributor for redistribution to electric-consuming customers.

- *Large Volume Customers* - The Large Volume Customers Class is defined as a natural gas service supplied to the customers with an annual usage of no less than 5 billion cubic meters, which do not belong to the customer classes as described above.

Allocation Factors

For each cost component, shown in the revenue requirement section, an allocation factor is needed to allocate those costs. This step is very important since these factors can influence the ultimate prices paid by each class of customer. Therefore, careful consideration should be paid by the cost-of-service analyst in determining the appropriate allocation factors for each cost component. Equal consideration must be paid to the data availability and quality in calculating the allocation factors.

The criteria for selecting appropriate allocation factors is to develop factors that most closely represent the cost causation by each customer class. For example, the total costs of purchased natural gas supplies is directly proportional to the total use of each customer class, therefore an appropriate allocator of the total purchased gas costs is the proportion of each customer classes' use to the total of all gas use for the company.

The allocation factors used in the enclosed cost-of-service study (Appendix C) were developed using actual data from AzeriGas for calendar year 2004. The allocation factors for this report are shown in the following table, with a complete description of the development of these allocation factors shown in Appendix C.

It should be noted that allocation factor Nos. 8-12 are calculated internally in the spreadsheet using the results from the use of the previous factors. Therefore, they are different when allocation factor No. 1 is changed from the CP to the NCP. The worksheets that show the development of all of the allocation factors are shown in Appendix D, which are the COS spreadsheets.

Allocation Factors for Cost-of-Service

No.	Factor	Used to Allocate
1	System Peak	System Capacity costs
	Non-Coincidental Peak	System Capacity costs
2	Annual Sales w/o transportation	Purchased gas costs
3	Annual Sales with transportation	Total Commodity Costs
4	Number of Customers	Customer Service costs
5	Meter Reading	Meter reading costs
6	Bad Debt	Uncollectible cots
7	Customer Records & Collections	Customer records and collections
8	Transportation/Distribution Assets	General and Intangible assets
9	Total Assets	Depreciation and Return
10	Total Distribution & Other Expenses	Total Other expenses
11	Dist. & Cust. Acc'tg less Uncollectible	Administrative & General Costs
12	Distribution, Cust. Acc't and A&G Exp.	Taxes, Working capital

Allocation of Costs

The last step is to allocate each cost component using the allocation factors described in the previous section. In this step, each category and sub-category of costs that are shown in the revenue requirements are allocated to each customer class using the allocation factors described above. The results show the total and relative costs for each of the customer classes and can then be used in the rate design process.

For AzeriGas, the COS study and its results are shown in Appendix D and are summarized here for two different methods for the allocation of system assets (Allocation Factor No.1). One method, called the Coincident Peak (CP), uses the single system peak day with the ratio of each class's contribution to the peak day as its allocator. The other method, called the Non-coincidental Peak (NCP), uses the peak day of each class, regardless of when the system peak day, and is the ratio of each class's peak to the sum of the peaks of all classes.

The following table presents the results of the total COS study using the system peak day allocator.

AzeriGas Total Cost of Service
System Peak Day Allocation Results for 2004

No.	Class of Service	Allocated Total Azerigas Revenue Requirement (Thousand AZM)	Percent of Total Azerigas Revenue Requirement	Allocated Total Gas Sector Revenue Requirement (Thousand AZM)	Percent of Total Gas Sector Revenue Requirement
1	Residential	404,010,703	61.96%	404,010,703	22.49%
2	General Service	37,384,464	5.73%	37,384,464	2.08%
4	Large Volume Customers	88,666,983	13.60%	88,666,983	4.93%
5	Thermal Power Plants	105,655,657	16.20%	1,250,343,971	69.59%
6	District Heating	16,342,406	2.51%	16,342,406	0.91%
7	Total Revenue Requirement	652,060,213	100.00%	1,796,748,526	100.00%

The following table presents the results of the Non-coincidental peak allocation method.

AzeriGas Total Cost of Service
Non-Coincidental Peak Allocation Results for 2004

No.	Class of Service	Allocated Total Azerigas Revenue Requirement (Thousand AZM)	Percent of Total Azerigas Revenue Requirement	Allocated Total Gas Sector Revenue Requirement (Thousand AZM)	Percent of Total Gas Sector Revenue Requirement
1	Residential	403,105,509	61.82%	403,105,509	22.44%
2	General Service	38,421,175	5.89%	38,421,175	2.14%
4	Large Volume Customers	88,795,802	13.62%	88,795,802	4.94%
5	Thermal Power Plants	105,122,061	16.12%	1,249,810,375	69.56%
6	District Heating	16,615,665	2.55%	16,615,665	0.92%
7	Total Revenue Requirement	652,060,213	100.00%	1,796,748,526	100.00%

When designing two or three-part tariffs, it is necessary to perform a cost-of-service study that provides the cost allocations for each of the three cost components: commodity, demand and customer. Appendix D contains the work sheets that do this for AzeriGas. A summary of these results is shown in the following table.

Summary of Cost of Service for Azerigas by Cost Classification for 2004
(Amounts in Thousand AZM)

Cost Classification	Residential	General Service	Large Com'l & Industrial	Thermal Power Plants	District Heating	Total Azerigas Costs 2004
Commodity						
CP	220,339,436	23,628,879	65,317,654	1,473,698	6,439,718	317,199,384
NCP	220,339,436	23,628,879	65,317,654	1,473,698	6,439,718	317,199,384
Demand						
CP	97,138,134	6,659,881	14,021,249	72,175,449	3,795,452	193,790,165
NCP	96,232,941	7,696,592	14,150,068	71,641,853	4,068,711	193,790,165
Customer						
CP	86,185,155	7,111,751	9,367,554	32,289,502	6,116,702	141,070,663
NCP	86,178,260	7,122,749	9,369,348	32,280,649	6,119,658	141,070,663
Total						
CP	403,662,725	37,400,510	88,706,456	105,938,649	16,351,872	652,060,213
NCP	402,750,636	38,448,219	88,837,069	105,396,200	16,628,087	652,060,213

Summary of Cost of Service for Gas Sector by Cost Classification for 2004
(Amounts in Thousand AZM)

Cost Classification	Residential	General Service	Large Com'l & Industrial	Thermal Power Plants	District Heating	Total Gas Sector Costs 2004
Commodity						
CP	220,339,436	23,628,879	65,317,654	1,146,162,012	6,439,718	1,461,887,698
NCP	220,339,436	23,628,879	65,317,654	1,146,162,012	6,439,718	1,461,887,698
Demand						
CP	97,138,134	6,659,881	14,021,249	72,175,449	3,795,452	193,790,165
NCP	96,232,941	7,696,592	14,150,068	71,641,853	4,068,711	193,790,165
Customer						
CP	86,185,155	7,111,751	9,367,554	32,289,502	6,116,702	141,070,663
NCP	86,178,260	7,122,749	9,369,348	32,280,649	6,119,658	141,070,663
Total						
CP	403,662,725	37,400,510	88,706,456	1,250,626,963	16,351,872	1,796,748,526
NCP	402,750,636	38,448,219	88,837,069	1,250,084,514	16,628,087	1,796,748,526

Report

The results of the Cost-of-Service study should be summarized in a report that can be used for rate design and other tariff issues (i.e. connection charge policies, etc.). It should be submitted to the Tariff Council and made available for public review. All of the detailed accounting information should also be made available for review by the Tariff Council.

V. RATE DESIGN

Rate design is the process of developing the actual rates for each customer class that ensures the recovery of the revenue requirements. The steps involved include:

1. Development of the rate structures for each customer class;
2. Development of the billing determinants;
3. Calculating the prices for each portion of the rate structures;
4. Calculating the revenues with the new prices
5. Reconciling the pricing with the Revenue Requirements
6. Recommendations

Rate Structures

Rate structures are the actual categories of measurable items to which the pricing is applied to produce the billing for each customer. Energy service rate structures for each customer classification may be different but should be designed to closely match them with the cost-of-service results.

Rate structures should be as simple as possible and there are several practicalities that should be remembered in designing rate structures. These include metering, billing and customer understanding and acceptance. Traditionally, the components of rate structures consider customer costs, commodity costs, and demand costs.

The **customer costs** consists of the monthly fixed costs that AzeriGas has in reading the meters, billing and collections, and a fixed cost component for the installation necessary to provide natural gas service to the customer. These costs are incurred regardless of the amount of natural gas that the customer uses.

The **commodity costs** are those costs that are directly incurred in purchasing the natural gas from the supplier and vary depending upon the amount of natural gas actually consumed by the customer.

The **demand costs** are those costs that are incurred by AzeriGas in providing the peak load of the customer at any given time during the month. AzeriGas incurs the costs of providing the facilities (i.e. pipelines, storage, etc.) for meeting a designated peak load of the customer, regardless of whether the customer actually uses that peaking amount during the month. Because of the administrative requirements and costs, these types of charges are usually set for only very large consumers.

Until now, Azerbaijan has had only one structure for most customers: the commodity portion (i.e. tcm). However, AzeriGas plans to present to the TARIFF COUNCIL for approval two- and three-part rate structures that will better reflect the actual cost of service for each customer class.

Two-part rate structures consist of a customer charge and a commodity charge and are proposed here to better reflect the cost of providing service to consumers by AzeriGas. In this rate structure, the monthly bill for each consumer would consist of a fixed customer charge and a commodity charge that would be based on the monthly gas usage, as recorded by the billing meter.

Another important reason for a two-part tariff is that it will result in more revenue stability for the company, thus preventing the large swings in revenue that result from changes in weather. From the customers' perspective, the two-part cost structure will provide better information so that they can make proper economic choices in their use of energy. If the variable cost of gas is much lower than the average cost, then the consumer may use more gas and less electricity or produce more products because the cost of production is lower on a per-unit basis.

Billing Determinants

Billing determinants are those measurable items of providing the service to customers and are used with the appropriate prices to calculate the monthly customer bills. These billing determinants include:

- the amount of energy used (tcm);
- the peak daily use of the customers; and,
- the customer.

For rate analyses, the total annual billing determinants for each customer class are developed for use in calculating the annual revenues of the regulated services of the company.

Prices

Prices are the amounts for each unit of energy, capacity or customer service and are applied with the billing determinants to calculate the monthly bills. The pricing of energy consists of applying prices based on the results of the cost-of-service study. For example, the unit price of natural gas would be equal to the allocated revenue requirement (cost) from the cost-of-service study divided by the billing determinant. For each cost component and for each class of service, the prices are calculated as follows:

$$\text{Commodity Price} = \frac{\text{Total Class Commodity Costs}}{\text{Total Class tcm}} = \text{Manats/tcm}$$

$$\text{Customer Price} = \frac{\text{Total Customer Cost}}{\text{Total Number of Customer bills}} = \text{Manats/customer}$$

$$\text{Demand Price} = \frac{\text{Total Demand Costs}}{\text{Total Peak Demand of All Customers in Class}} = \text{Manats/TCM}_{\text{Peak Load Day}}$$

Calculating the Revenues

After the pricing and billing determinants are calculated, the annual revenues are calculated for all classes of customers and then totaled to determine the annual revenues that would be received under the proposed rates (prices).

Reconciliation of Prices

Following the calculation of revenue with the new prices, the next step is to reconcile this total with the revenue requirement. Due to rounding and other calculations, the totals of both are likely to be slightly different. Therefore, this final step is to adjust the final prices so that the total new revenues are equal to the revenue requirement.

The following table provides an example of the revenue calculation under the existing prices and the proposed prices. It also demonstrates the price change (amount and percent) for each customer class with the proposed prices.

Revenue Calculations for Existing and Proposed Tariffs

Rate Class	Billing Determinants	Existing Tariffs		Proposed Tariffs	
		Price	Revenue	Price	Revenue
Residential	Total Bills	Manats/Bill		Manats/Bill	
	Total tcm	Manats/tcm		Manats/tcm	
General Service	Total Bills	Manats/Bill		Manats/Bill	
	Total tcm	Manats/tcm		Manats/tcm	
District Heating	Total Bills	Manats/Bill		Manats/Bill	
	Total tcm	Manats/tcm		Manats/tcm	
Thermal Power Plants	Total Bills	Manats/Bill		Manats/Bill	
	Total tcm	Manats/tcm		Manats/tcm	
Large Volume Customers	Total Bills	Manats/Bill		Manats/Bill	
	Total tcm	Manats/tcm		Manats/tcm	
	Total Peak tcm	Manats/Peak tcm		Manats/Peak tcm	
Total Revenue					
Percent Change					

Note: Since the existing tariffs contain only a commodity charge, then the prices shown in the table for the customer charge (i.e. Manats/Bill) and peak consumption charge (i.e. Manats/Peak tcm) would be zero. In addition, since the structure of the existing tariff (single commodity charge) differs from the structure of proposed tariff even comparison of existing and proposed commodity charges makes no sense. For these reasons this table does not indicate numeral values.

Recommended Rate Designs

This section describes the recommended rate designs for

Retail Tariff

The allowed maximum average unit revenue (Manat/tcm) charged under the retail tariffs shall be calculated in accordance with the following formula:

Maximum Average Retail Tariff Revenue (Manat/tcm)

$$maxAR = PGC + \frac{Trans}{1 - LD} + Dist$$

where:

maxAR = maximum average retail tariff revenue in Manat/tcm
PGC = purchased gas cost charge, as defined in Section 16.
Trans = transportation costs, average cost per unit
Dist = distribution costs, average cost per unit
LD = authorized distribution technical and commercial losses, expressed as a decimal.

The details for calculating the Purchased Gas Costs Charge, Transportation Tariff, and Distribution Tariff are provided below.

PURCHASED GAS COST CHARGE (PGC)

The Purchased Gas Cost Charge shall be applicable to the Customers receiving gas supply from the Distribution Licensee under the retail tariff schedules. The retail tariffs for gas service shall be increased or decreased, from time to time, as provided in the TARIFF COUNCIL regulations, to reflect changes in the level of the PGC.

Calculation Method to Determine the Purchase Gas Cost Charge (PGC)

The Distribution Licensee shall compute the PGC as follows:

1. The License shall estimate its purchased gas costs for the forecasted twelve-month period commencing in October of each year through the succeeding September.

2. The total costs as determined in (1) above shall be adjusted on a semi-annual basis, as described in the Purchased Gas Adjustment Clause, below, to reflect changes in gas prices, quantities, exchange rates, and taxes, which differ from the initially forecasted levels.

3. The adjusted costs resulting from (2) above shall be divided by the estimated applicable sales for the period over which the PGC charge is to be in effect, to determine the cost per thousand cubic meters. This cost shall also be adjusted to reflect the applicable taxes.

PGC Calculation Formulas

1. The purchased gas costs, in Manat per thousand cubic meters (tcm), shall be computed in accordance with the following formula:

$$PGC = \frac{C - PGA}{S} \times \frac{1}{(1 - T)}$$

where:

PGC = purchased gas costs, in Manat/tcm, forecast for the twelve-month period
C = the forecasted cost of purchased natural gas, in Manat, calculated as set forth in Section II.
PGA = the purchased gas cost adjustment as described in Chapter II
S = projected tcm of gas to be billed to customers during the projected period when the charge will be in effect

T = the applicable taxes on natural gas purchases, expressed as a decimal.

Purchased gas costs shall include such portion of the Licensee's "own use" as authorized by the Tariff Council.

2. Calculation of purchased gas cost: " C " component –

The "C", forecasted cost of natural gas in the above formula, shall be calculated as follows:

$$C = \frac{APGC}{(1-LD)} \times S$$

APGC = average purchased gas cost, Manat/tcm, determined by forecasting the total cost of natural gas purchased by the Distribution Licensee and dividing this sum by the estimated total gas to be delivered at the distribution interface with the gas transportation pipeline.

The APGC will be set on the basis of the forecast for the twelve-month period commencing in October of each year and may be adjusted, as needed, after six months.

LD = the allowable distribution loss factor for the combined level of technical and commercial losses, expressed as a decimal.

3. Purchased Gas Adjustment Clause (PGA)

The PGA clause is designed to compensate the Licensees for the difference between the forecasted natural gas costs and the gas costs based upon actual gas prices, quantities, exchanges rates, and applicable taxes for the prior period PGC. The PGA shall also provide for reconciliation between estimated and actual cost recovery in the previous PGA period.

4. The Purchased Gas Cost Charge shall be calculated two times each year to be effective October 1, and April 1. [3]

Transportation Tariff

Availability:

The Transportation tariff(s) shall be applicable to (a) Distribution Licensees, (b) Export Licensees, (c) Direct Customers, (d) large commercial and industrial Customers with

[3] Purchased gas cost provisions generally provide for interim changes, between the six-month reviews, if gas costs (or exchange rates) rise by greater than a certain percentage, e.g. 10% before the next review. The Law, however, currently states that tariffs must be in effect for a minimum of six months; thus more frequent changes are not allowed.

consumption of 5,000 tcm or more per year, and (e) international customers having gas transited through the Republic of Azerbaijan.

The payment of the Transportation tariff allows qualifying customers non-discriminatory access to the transportation of customer-owned natural gas up to the level of the Customer's Demand Charge Quantity, as defined below; based upon the terms defined in the required contract for this service.

The Transportation tariff(s) shall consist of (a) the fixed monthly Demand Charge, plus (b) an allowance for compression gas and system losses.

Calculation of the Fixed Monthly Demand Charge

The maximum fixed monthly Demand Charge shall be computed by dividing the Transportation Licensee's total annual revenue requirement,[4] excluding compression fuel and system losses, by 12 and dividing this amount by the sum of maximum actual metered daily consumption of the transportation customers, the Demand Charge Quantities ("DCQ"), as defined below.

The Fixed Monthly Demand Charge is the minimum payment that must be made each month by the Customer (the payment of this charge is not dependent on the amount of gas transported for the Customer). The monthly Demand Charge shall be stated as follows: Manat/m^3/DCQ.[5]

Determination of the Demand Charge Quantity

The DCQ shall be determined by the Customer's maximum daily requirements in terms of thousand cubic meters.

(a) The DCQ level shall be the highest actual daily metered consumption registered from an approved meter reading device at the Customer's premises within a period of one year preceding the date when the Demand Charge is computed, if such information is available.

(b) If this information is not available the DCQ shall be set equal to the product of (1) the highest winter monthly consumption for the most recent winter period, divided by the applicable number of days in the respective billing month, and (2) the change in sales/use year-on-year.

(c) If historical consumption is not available, then the initial DCQ level shall be based upon the Customer's gas utilization equipment expressed in consumption per day, and after twelve months of actual consumption has been metered, the DCQ level shall be re-determined.

Allowance for Compression Fuel and Authorized System Losses

[4] The cost of transportation shall also include the gas dispatch and storage costs.

[5] The monthly Demand Charge is equal to the annual demand charge divided by 12. If the transportation customer fails to pay the monthly demand charges, and the annualized amount is determined to be uncollectible or bad debt, this amount should form part of the bad debt expense referenced in Chapter 2 (Other O&M Expenses).

The Transportation Customer shall provide the transportation Licensee on delivery of the Customer-owned gas, a natural gas in-kind allowance, equal to the gas used for compressor fuel and system losses, as authorized by the Tariff Council, expressed as a percent of the gas transported. For this purpose, the customer must deliver to the transportation company more gas than the Customer consumes to cover compression fuel and losses.

Retail Tariff Design by Customer Class

Residential Service – Customer Class R

1. Availability:

   This service shall be available to residential customers in individual residence or to a multiple dwelling unit building consisting of two to four dwelling units for domestic requirements.

2. The tariff for the Residential Service shall consist of the following components:

   (A) Fixed Monthly Customer Charge (Manats/Customer/Month)

   The fixed monthly Customer Charge shall include that portion of the “customer costs” for the residential service, as defined in Section 13, as approved by the Tariff Council.

   (B) Commodity Charge (Manats/tcm)

   The Commodity Charge shall include the remaining applicable costs to serve the residential customer class.

3. The Customer Charge shall be the minimum bill each month.

General Service – Customer Class GS

1. Availability:

   This service shall be available for commercial and/or industrial applications for customers consuming less than 1,000 tcm per year, as determined by the Licensee.

2. The tariff for the GS Customers shall consist of the following components:

   (A) Fixed Monthly Customer Charge (Manats/Customer/Month) plus

   (B) Commodity Charge (Manats/tcm).

3. The Customer Charge shall be the Customer’s minimum bill each month.

Large Commercial and Industrial Class – Customer Class LCI

1. Availability:

   This service shall be available for large commercial and/or industrial applications for customers consuming 1,000 tcm or more per year, as determined by the Licensee.

2. The tariff for the Large Commercial and Industrial Customers shall consist of the following components:

   (A) Fixed Monthly Customer Charge (Manats/Customer/Month)

   (B) Demand Charge (Manats/cm/DCQ)

   The Demand Charge shall be the sum of (a) the applicable Transportation Demand Charge, plus (b) the Distribution Demand Charge.

   Computation of Distribution Demand Charge

   The Distribution Demand Charge shall be computed in a similar manner as the Transportation Demand Charge, applying the distribution demand costs as the basis of the charge, as described in Section 17.03. The Distribution charge shall be phased-in over the five-year period.

   (C) Commodity Charge (Manats/tcm)

   The Commodity Charge shall include the remaining applicable costs to serve the LCI customer class.

3. The Customer's minimum bill each month shall consist of the fixed monthly Customer Charge plus the Demand Charge.

Thermal Power Plants – Customer Class TPP

1. Availability:

   This service shall be available to licensed thermal power plants.

2. The tariff for thermal power plants shall consist of the following components:

   (A) Fixed Monthly Customer Charge (Manat/Customer/Month),
   (B) Demand Charge (Manats/cm/ DCQ),

   The Demand Charge shall be the sum of (a) the applicable Transportation Demand Charge, plus (b) the Demand Charge for Distribution Service.

   (C) Commodity Charge (Manats/tcm).

3. The Customer's minimum bill each month shall consist of the fixed monthly Customer Charge plus the Demand Charge.

District Heating Companies – Customer Class DH

1. Availability:

   This service shall be available to licensed District Heating Companies.

2. The tariff for the district heating Licensees shall consist of the following components:

   The tariff for the GS Customers shall consist of the following components:

   (A) Fixed Monthly Customer Charge (Manats/Customer/Month) plus
   (B) Commodity Charge (Manats/tcm).

3. The Customer Charge shall be the Customer's minimum bill each month.

Examples of Retail Tariff

Examples of natural gas retail tariff are presented in the following tables. Note, that to calculate revenue to be collected through customer charge for the residential, general service and district heating customer classes, demand and customer allocations were summed up. Both approaches, i.e. based on single coincident peak and non-coincident peak were illustrated. It is also important to note that for tariff calculations total revenue requirement for gas sector was used.

Retail Tariff Example (CP)

Rate Class	Billing Determinants	Unit	Revenue ths AZM	Proposed Tariff Price	Price Unit
Residential	916,000	Num. of Bills	183,323,289	16.68	Manats/Bill/Month
	2,688,940	tcm	220,339,436	81.94	Manats/tcm
General Service	3000	Num. of Bills	13,771,632	382.55	Manats/Bill/Month
	296,791	tcm	23,628,879	79.61	Manats/tcm
District Heating	346	Num. of Bills	9,912,154	2387.32	Manats/Bill/Month
	78,749	tcm	6,439,718	81.78	Manats/tcm
Thermal Power Plants	4	Num. of Bills	32,289,502	672697.95	Manats/Bill/Month
	4,585,950	tcm	1,146,162,012	249.93	Manats/tcm
	15,858	peak tcm	72,175,449	4551.33	Manats/Peak tcm
Large Volume Customers	4	Num. of Bills	9,367,554	195157.37	Manats/Bill/Month
	826,130	tcm	65,317,654	79.06	Manats/tcm
	2,212	peak tcm	14,021,249	6338.72	Manats/Peak tcm

Retail Tariff Example (NCP)

Rate Class	Billing Determinants	Unit	Revenue ths AZM	Proposed Tariff Price	Price Unit
Residential	916,000	Num. of Bills	182,411,200	16.59	Manats/Bill/Month
	2,688,940	tcm	220,339,436	81.94	Manats/tcm
General Service	3000	Num. of Bills	14,819,341	411.65	Manats/Bill/Month
	296,791	tcm	23,628,879	79.61	Manats/tcm
District Heating	346	Num. of Bills	10,188,369	2453.85	Manats/Bill/Month
	78,749	tcm	6,439,718	81.78	Manats/tcm
Thermal Power Plants	4	Num. of Bills	32,280,649	672513.52	Manats/Bill/Month
	4,585,950	tcm	1,146,162,012	249.93	Manats/tcm
	15,858	peak tcm	71,641,853	4517.68	Manats/Peak tcm
Large Volume Customers	4	Num. of Bills	9,369,348	195194.74	Manats/Bill/Month
	826,130	tcm	65,317,654	79.06	Manats/tcm
	2,212	peak tcm	14,150,068	6396.96	Manats/Peak tcm

VI. REGULATORY APPROVAL

The Tariff Council must approve the proposed tariffs prior to their implementation. This section of the report discusses the steps involved in this process and the information that should be filed by the company.

Filing Requirements

The Licensee shall file an application with the Tariff Council for any proposed change in the existing tariffs or regulations, or for the introduction of new tariffs or regulations. The Tariff Council shall prescribe the form, content, and timing of such filing requirements. This requirement shall include the periodic filing to recover costs and revenues associated with pass-through mechanisms. The Licensee must file the required financial data and work papers in accordance with the Tariff Council's Chart of Accounts.

The Tariff Council filing requirements will include an explanation of the impact of the proposed change on the existing customers, including work papers showing the estimated effect on revenue and costs over the twelve-months period commencing on the proposed effective date of the filing.

For general tariff increases the Licensee shall also provide projected financial statements demonstrating the estimated impact of the proposed change on: the income statement, balance sheet, and cash flow statements. In addition to the forecast period, the Licensee shall submit the cost detail for (a) the most recent historical fiscal year, (b) the actual/estimated current year. The filing must include a statement executed by the chief accounting officer or other authorized accounting representative of the Licensee that the cost statements and supporting data are accurate.

Public Process

The Tariff Council tariff review and approval process provides an opportunity for Licensees, Customers, government officials, and other intervenors to present their opinions and offer their own proposals in an open public hearing, according to the hearing procedural rules established by the Tariff Council. The Tariff Council will consider the evidence and views presented by all participants in the tariff proceeding as part of the regulatory approval process.

Approval and Implementation

At the conclusion of the public process, the Tariff Council will issue a resolution that approves the tariffs at the level of revenue requirements that they deem appropriate.

APPENDIX A - DEFINITIONS

Allocation – The procedural step in a cost of service study whereby joint costs are allocated among customer classes based on demand, energy, and some other cost-related feature of service

Construction Work in Progress (CWIP) - A utility=s investment in a new plant which has not yet been placed in service. Usually referred to in relation to its inclusion in the utility=s rate base during the construction period, allowing the utility to recover at least some of the financing costs for the capital invested. The financing costs, which ultimately become a part of the total cost of the plant, are thus reduced; allowing CWIP in a utility=s rate base lessens Manatatic rate increases when the plant goes into service.

Cost Classification – Separation of cost components into one of three categories: customer costs, demand costs, and commodity costs.

Cost Functionalization – Separation of costs components into functional categories: purchased gas costs, transportation costs, storage and distribution costs.

Cost of Service - The amount of money it takes to serve different classes of customers (residential, commercial, industrial) that use electricity in different ways and in different amounts. Serving different customers requires varying levels of investment on the utility=s part; this is generally reflected in varying rates.

Cost of Service Study - A study of the costs incurred by the utility in producing, transmitting, and distributing natural gas to its customers by customer class, in relation to revenues collected from each class or projected to be collected under existing or proposed rates. The cost analyzed may be the average historical (embedded) cost of the existing plant and expenses in a “test year”, past or future; or they may be the long run incremental costs of the utility’s service, that is, the cost, per year, of the capacity and customer load planned for the next decade, expressed in dollars.

Depreciation - A term used to describe the cost to a company of using up certain assets over a period of time. The wear and tear, decay, obsolescence and depletion of plant and equipment are stated as bookkeeping charges (requiring no payment of cash) and are deductible as expense for income tax purposes. In engineering economic studies, it the process by which invested capital (original cost of plant) is recovered (net salvage is involved in the process).

Load Factor – the ratio of maximum consumption rate (maximum demand for electrical customers or maximum daily consumption for natural gas customers) to the average consumption rate over a period of time. E.g. average annual load factor for gas customers is calculated as follows:

Load Factor = Maximum Daily Consumption/(365*Annual Consumption).

Operation & Maintenance Expense - Costs that relate to the normal operating, maintenance and administrative activities of a business.

Purchased Gas Supply – The natural gas purchased from a wholesale gas company for the purposes of selling to the ultimate consumers.

Regulatory Asset Base - The amount invested on which a regulatory agency allows companies to earn a return; the rate base includes power plants, substations, transmission lines, office equipment and working capital. The law allows a company to earn a fair rate of return on its investment, and the dollar amount of that return is determined, in part, by the rate base.

Return - Income available after costs of operation (including interest on debt) are subtracted from revenue.

Revenue Requirement - The revenue level required by the utility to supply a specified level of output and earn a specified rate of return.

Test Period - Usually a twelve-month period of a utility's operations from which evidence is derived to set rates.

Working Capital - The amount of cash required to operate a utility during the interim between the rendering of service and the receipt of payment.

APPENDIX B – CUSTOMER CLASSIFICATIONS

General Principles of Classification

It is a widely acknowledged principle that the cost of customer service should be used as a primary standard for setting regulated rates for natural gas service. This principle holds for all types of natural monopolistic utility services subjected to cost-of-service regulation and it is universally applied to electric power, natural gas, and heat supply as well as water supply and sewerage.

Customer differentiation usually is based on consumption volume, requested capacity (which corresponds to maximum daily consumption for the gas service), season, time of use, connection terms, type of service (firm or non-firm, the level of curtailment, etc). For electric service it is often augmented with the level of voltage at which the service is provided, or., which is similar for the natural gas service, the level of pressure. In general, these consumption characteristics can be used for the delineation of customers by customer class. Ideally, each class should consist of a homogeneous group of consumers, which possess similar consumption patterns so that the customers from one class impose more or less equal cost burden on the system to serve them. In addition to technical parameters, the customer classification may also capture such economic parameters as the value of service, opportunity of bypass, price elasticity of consumption.

After the classifications have been established, it is often employed to determine the cost of service for each class. The results of cost-of-service study are then used as the first approximation of rates to be charged to different types of customers.

Well-defined customer classes present a solid basis for predictability of reaction of each customer class on the changes in the supply conditions. From the customers prospective, correct classification allows to develop the rates that provide correct price signals to consumers. From the stand point of a supplier, properly defined classification permits the supplier to forecast the impacts of rate changes on the overall revenue to ensure stable financial operation for the company.

Commonly accepted practice of setting tariffs for natural gas in the US allows for two-tier classification. At the first level, the customers are subdivided into broad groups such as residential, general commercial and industrial, large volume customers, firm and non-firm customers. Further on, these broad categories are divided into more narrow groups, so that for each group an individual rate schedule is developed. A consumption volume or load factor is used as primary parameter for such differentiation.

At the same time, a large number of customer categories and classes impair the process of rate development. Administration of billing and collection process becomes more expensive, so that additional benefits acquired from the classification that captures subtle differences in consumption pattern and conditions of service may be overweighed by the necessity to maintain and operate sophisticated customer information systems.

In Azerbaijan the natural gas customers have never been separated into customer classes exclusively on the basis of consumption characteristics, rather they were grouped by type of industry or their main economic activity or ownership, which were used primarily for statistical reporting. The following customer classes are considered at the moment:

- Residential Customers
    - With Metered Consumption
    - With Non-Metered Consumption
- Communal Service and Budget Organizations
- Industrial Customers
- Non-Government Enterprises
- SOCAR
- Azerenergy
- Greenhouses

This classification practically does not capture individual consumption pattern of each customer class, with the exception of Azerenergy, Industrial Enterprises or SOCAR which are considered as individual classes. For example, Communal Service and Budget Organizations are made up by enterprises financed from the budgets of different levels. This group of customers includes ministries, regional administrations, libraries, hospitals, kindergartens, bathhouses, district heating utilities, and water and sewerage utilities. Out of this list the district heating utilities possess quite unique consumption pattern – they practically consume gas during December – February and are always peaking in January. Though the others also peak during approximately the same period, their load factor is substantially higher than the load factor of heating utilities. Or which is the same, their peak consumption is much less profound than the average consumption over a year.

Another example of a controversial customer group is Non-Government Enterprises and Industrial Customers. The non-government enterprise group includes such customers as restaurants, cafes, small industrial and communal service enterprises (like laundries and bakeries), which mainly belong to the private sector. On the other hand, industrial customers also include large private industrial enterprises. It is logical to use widely accepted delineation by size of a customer, rather then ownership. The reason being that customer size plays substantial role in cost causation for the system to serve a customer, while ownership is important mainly for statistics. It is commonly used practice to consider the group of large customers (instead of present industrial customers) and general service customers (instead of non-government enterprises).

Individual consideration of Azerenergy as a separate customer group is mainly driven not by the fact that thermal power plants possess pretty unique consumption schedules, which single them out of the rest of large consumers, but by the fact that Azerigas renders transportation service to power plants, and SOCAR's gas for power plants supply..

Potentially, the other reason to separate SOCAR and Azerenergy out of other industrial enterprises is related to existing practice of subsidization and offsets of payments between state owned companies – both SOCAR and Azerenergy belong to the state.

Finally, the treatment of greenhouses as a separate customer class in existing classification can be explained by predatory pricing, presently exercised by Azerigas. This group of customers exists not due to the uniqueness of its consumption characteristics and therefore, commonality of cost to serve them, but rather their ability to pay higher rates.

Appropriate classification of customers strikes a balance between two different goals: on the one hand, it introduces customer classes in such a way so that they account for the differences in the cost of supply, value of service, etc. On the other hand, it keeps the total

number of classes limited, makes them easy and simple to understand, and does not impose unjustified burden on the overall process of billing and collection.

Rational for Classification

The analysis of customer classes began with a review of the operational data on natural gas delivery by customer group. It is a common practice to use for these purposes statistics of actual daily deliveries to each customer group. Since these data were not available, we based our approach on a monthly data for 2004 and 2005, which were used as proxies instead of data on daily delivery. The data are presented in Table 1, Figure 1 presents them in graphical form.

As can be seen from the graph, for both years peak deliveries from the system occurred in December, in January and February the consumption slightly subsided, then in March ramped up again, though, less profoundly that in December. After that it steadily fell until August-September, which mark the beginning of the next period of seasonal growth.

Analysis of the graph allows to draw a conclusion that the main contributor to profound seasonal variations is ambient temperature (along with wind and humidity). Process usage of gas by industry does not exhibit noticeable seasonal variations due to seasonality of production – its graph remained pretty much stable all year around. The next group of customers, the communal service and budget organizations, demonstrate some increase during winter season. It is clear that this increase is mainly caused by local boiler houses. In Azerbaijan the heating season typically starts on November 15 and continues through late March-early April, depending on the weather conditions. But compared on daily basis, the volumes of gas consumed in November and March-April period are substantially less than consumption during January-February, when district heating service is at its highest.

It could be expected that thermal power plants also demonstrated noticeable seasonality in their consumption over a year, but this is not the case in Azerbaijan. Indeed, the thermal power plants increase their usage of gas in December, but the relative increment for this month compared with the average annual consumptions is not very profound.

The biggest contributor into seasonal variations[6] of natural gas consumption is residential sector. As the graph shows, in December monthly deliveries to this group of customers is almost 2.5 times higher than in August, when its consumption drops to the lowest annual level.

It can be expected that thermal power plants also exhibit substantial seasonal variations in consumption, but however strange it is, this variation is much less profound than the changes in residential consumption. It also can be seen from the graph: in 2004 maximum consumption at TPPs occurred in December and was equal 491.6 mln cm, while minimum consumption took place in August and amounted to 288.8 mln cm. In other words, it was 1.7 times higher than the lowest level.

Of course, gas consumption of budget organizations also peaks up during winter months, but their contribution is much less substantial than that of the communal service and budget organizations. The latter set a record for the system in terms of seasonal variability, expressed as a ratio of peak monthly consumption to the lowest one: the variability for this customer group reaches 16.4 times.

[6] Expressed in million cubic meters.

An obvious reason for such a vast variations is boiler houses, which are assigned to this group of customers. For example, the boiler houses do not use natural gas during April-November altogether.

As rough-cut analysis showed, large customers do not impose on the system substantial burden of seasonally varying consumption. For example, Fig 2 shows the pattern of consumption of the customers with monthly consumption above 3 mln cubic meters. Thermal power plants and boiler houses (collectively) were not included into this group due to substantial seasonality of their consumption.

Four enterprises meeting the established consumption threshold are Azerbeftyag (Oil Refinery), Garadag Cement, JSC “Azeraluminum”, and JSC “Azerchemistry”. As follows from the graph, the consumption of natural gas at these enterprises is driven mainly by technological needs, therefore, it is not subjected to substantial seasonal variations.

Thermal power plants intentionally were not added to the group of large customers of gas, and there are two reasons to explain this decision.

Firstly, thermal power plants were supplied exclusively with gas imported from Russia. For this purpose, SOCAR performed functions of gas importer.

From this stand point, thermal power plants had to pay commodity charge for gas (should that existed in a separate form) to SOCAR. Azerigaz rendered transportation service only, and has to be remunerated exclusively for this activity. Thus, thermal power plants (or Azerenergy in other words) make up a group of transportation customers.

Secondly, aggregated collective consumption of Azerenergy exhibits seasonal variations, which are substantially more noticeable contrary to the consumption of large customers. Figure 3 illustrates this statement. As the picture shows, for both years 2005 and 2005 it was typical for the power plants to have two peaks during a year: the first occurred in December, the second was observed in March (in 2004) or April (in 2005). This phenomenon can be explained by the fact that during these months Russia increased gas supply to Azerbaijan, and natural gas became available for generation needs, which resulted, on the one hand, in peaks of gas consumption at TPP, and on the other, in lower share of residual oil used at TPPs during these months.

Table 1. Monthly Consumption of Gas in 2004-2005 by Customer Class.

Month	2004-Jan	2004-Feb	2004-Mar	2004-Apr	2004-May	2004-Jun	2004-Jul	2004-Aug	2004-Sep	2004-Oct	2004-Nov	2004-Dec
Residential Sector	326.2	303.4	287.9	233.4	189.7	140.3	131.4	123.0	130.6	176.1	264.1	**382.9**
Average Annual Consumption	224.1	224.1	224.1	224.1	224.1	224.1	224.1	224.1	224.1	224.1	224.1	224.1
Industry	72.7	66.3	74.2	67.1	74.9	70.5	66.8	63.6	73.3	76.2	**76.5**	72.9
Average Annual Consumption	71.2	71.2	71.2	71.2	71.2	71.2	71.2	71.2	71.2	71.2	71.2	71.2
Communal Service and Budget Organizations	**66.2**	53.5	49.4	25.1	15.1	10.2	4.0	4.0	4.8	7.6	11.6	36.3
Average Annual Consumption	24.0	24.0	24.0	24.0	24.0	24.0	24.0	24.0	24.0	24.0	24.0	24.0
Non-Budget Organizations	4.5	4.2	4.3	4.3	4.5	4.3	4.2	4.6	5.2	5.5	6.1	**7.3**
Average Annual Consumption	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9
Total Local Gas	469.6	427.3	415.8	329.9	284.1	225.2	206.4	195.2	213.9	265.3	358.4	**499.4**
Average Annual Consumption	324.2	324.2	324.2	324.2	324.2	324.2	324.2	324.2	324.2	324.2	324.2	324.2
Imported Gas (Thermal Power Plants)	410.8	366.7	432.9	367	362.9	359.2	324.85	288.8	380.5	384.8	415.9	**491.6**
Average Annual Consumption	382.2	382.2	382.2	382.2	382.2	382.2	382.2	382.2	382.2	382.2	382.2	382.2
Total Consumption of Gas	880.4	794.0	848.7	696.9	647.0	584.4	531.3	484.0	594.4	650.1	774.3	**991.0**
Average Annual Consumption	706.4	706.4	706.4	706.4	706.4	706.4	706.4	706.4	706.4	706.4	706.4	706.4

Month	2005-Jan	2005-Feb	2005-Mar	2005-Apr	2005-May	2005-Jun	2005-Jul	2005-Aug	2005-Sep	2005-Oct	2005-Nov	2005-Dec
Residential Sector	343.1	370.1	355.4	266.0	202.1	154.1	140.4	132.3	139.4	192.4	316.4	**400.7**
Average Annual Consumption	251.0	251.0	251.0	251.0	251.0	251.0	251.0	251.0	251.0	251.0	251.0	251.0
Industry	66.9	49.8	66.7	73.9	69.6	74.4	78.5	80.6	75.5	**83.7**	76.3	68.5
Average Annual Consumption	72.0	72.0	72.0	72.0	72.0	72.0	72.0	72.0	72.0	72.0	72.0	72.0
Communal Service and Budget Organizations	**53.1**	46.1	45.7	20.2	9.0	7.8	6.4	6.9	10.1	11.5	22.9	37.5
Average Annual Consumption	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1
Non-Budget Organizations	7.5	8.2	7.9	7.5	7.8	7.3	6.7	6.4	7.2	7.6	7.9	**9.2**
Average Annual Consumption	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6
Total Local Gas	470.5	474.1	475.6	367.6	288.4	243.6	232.0	226.2	232.2	295.2	423.5	**515.9**
Average Annual Consumption	353.7	353.7	353.7	353.7	353.7	353.7	353.7	353.7	353.7	353.7	353.7	353.7
Imported Gas (Thermal Power Plants)	351.2	365.9	399.1	**437.1**	380.1	307	315.5	303.6	282.2	303.3	411.2	430.7
Average Annual Consumption	357.2	357.2	357.2	357.2	357.2	357.2	357.2	357.2	357.2	357.2	357.2	357.2
Total Consumption of Gas	821.7	840.0	874.7	804.7	668.5	550.6	547.5	529.8	514.4	598.5	834.7	**946.6**
Average Annual Consumption	711.0	711.0	711.0	711.0	711.0	711.0	711.0	711.0	711.0	711.0	711.0	711.0

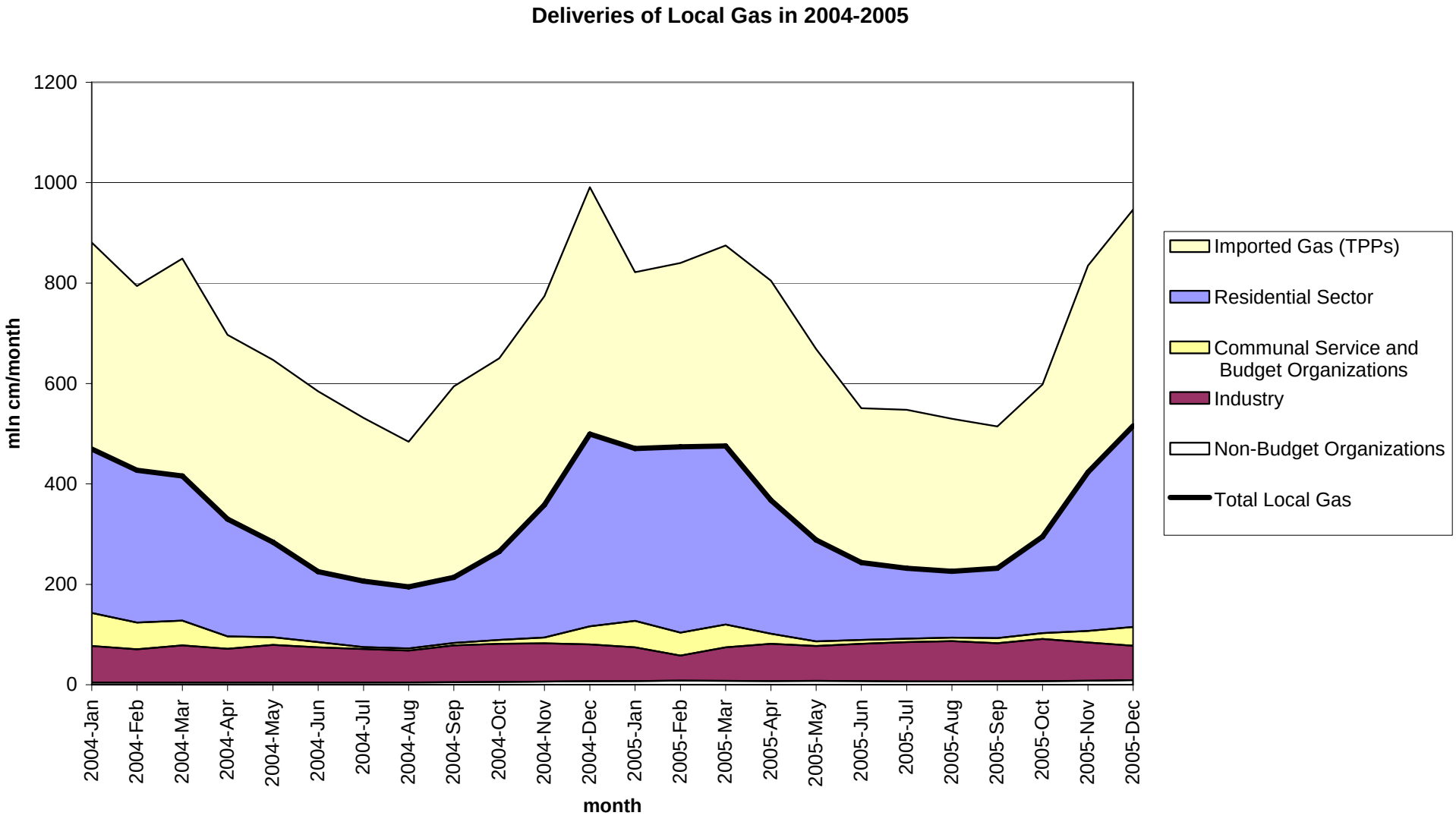


Figure 1. Deliveries of Gas in 2004-2005.

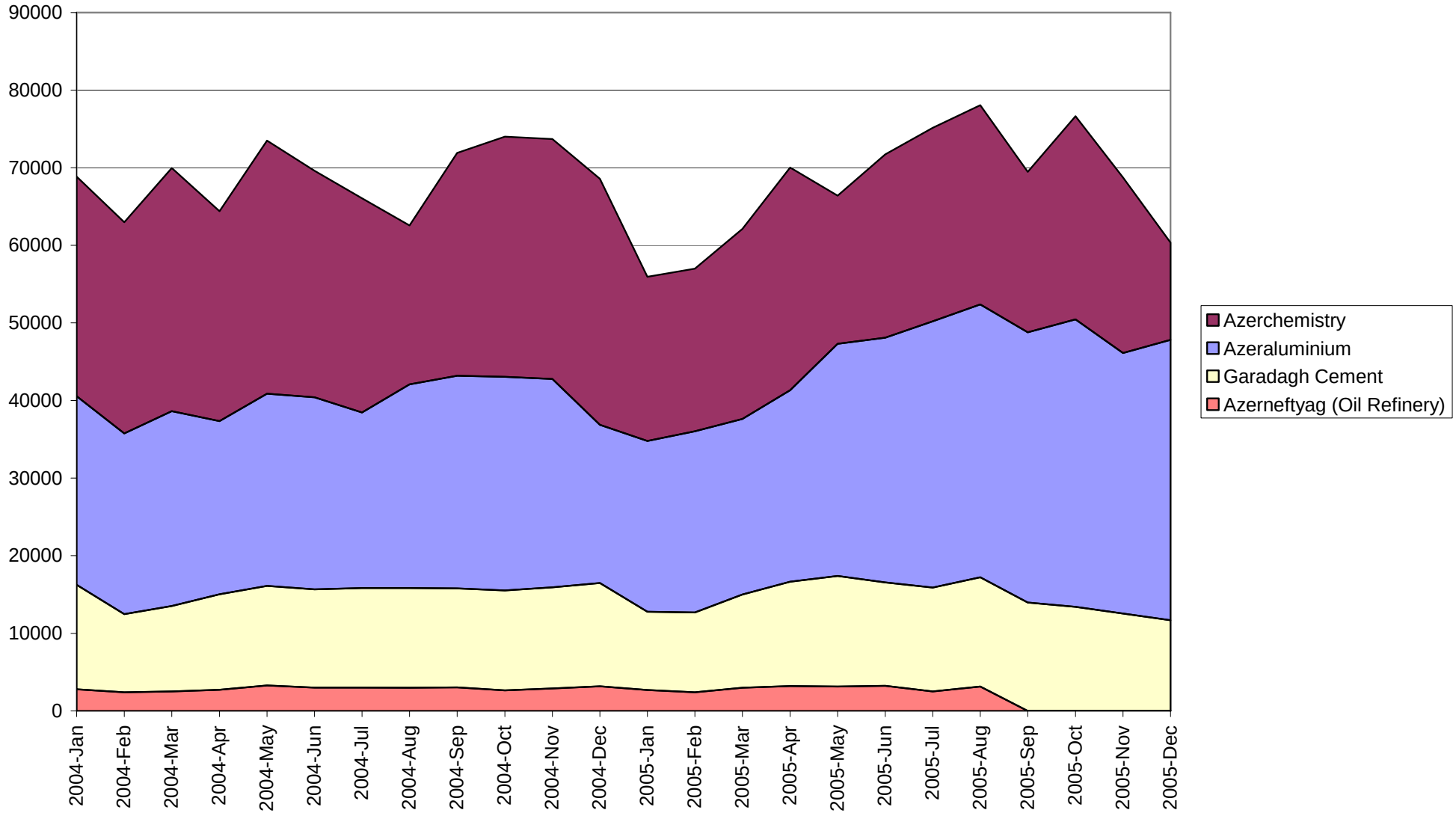


Figure 2. Deliveries of Gas to Large Customers in 2004-2005.

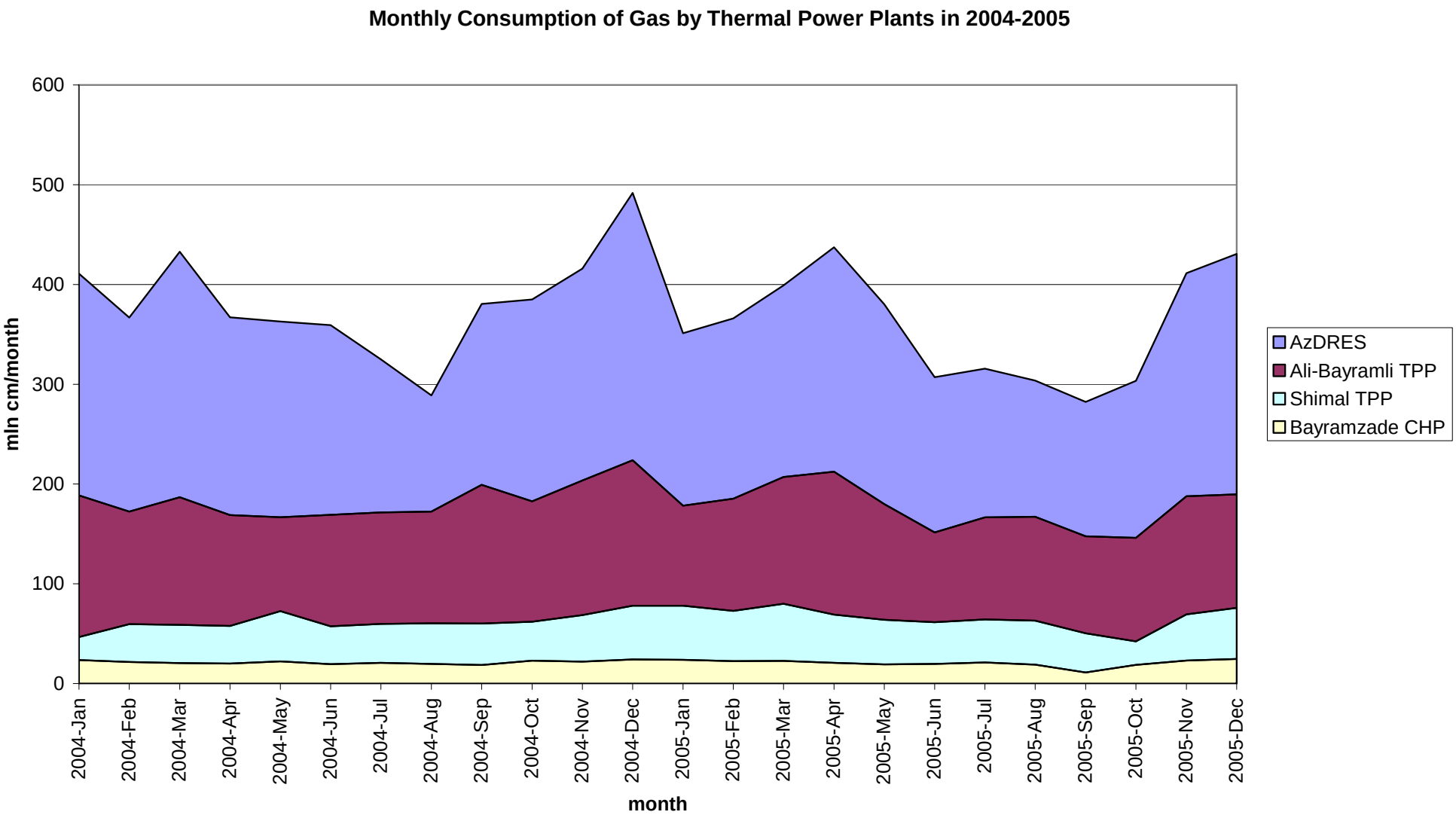


Figure 3. Deliveries of Gas to Azerenergy in 2004-2005.

Table 2. Sales of Gas by Proposed Customer Group (mln cm/month).

	2004-Jan	2004-Feb	2004-Mar	2004-Apr	2004-May	2004-Jun	2004-Jul	2004-Aug	2004-Sep	2004-Oct	2004-Nov	2004-Dec
Residential Customers	326.2	303.4	287.9	233.4	189.7	140.3	131.4	123.0	130.6	176.1	264.1	382.9
General Service Customers	51.8	40.2	44.4	31.2	20.4	15.0	8.5	9.4	10.9	14.6	19.2	31.1
District Heating	22.7	20.7	13.5	0.9	0.6	0.4	0.5	0.3	0.4	0.7	1.3	16.8
Thermal Power Plants	410.8	366.7	432.9	367	362.9	359.2	324.85	288.8	380.5	384.8	415.9	491.6
Large Volume Customers	68.8	63.0	70.0	64.4	73.5	69.6	66.1	62.6	71.9	74.0	73.7	68.6
Total Consumption of Gas	880.4	794.0	848.7	696.9	647.0	584.4	531.3	484.0	594.4	650.1	774.3	991.0

	2005-Jan	2005-Feb	2005-Mar	2005-Apr	2005-May	2005-Jun	2005-Jul	2005-Aug	2005-Sep	2005-Oct	2005-Nov	2005-Dec
Residential Customers	343.1	370.1	355.4	266.0	202.1	154.1	140.4	132.3	139.4	192.4	316.4	400.7
General Service Customers	52.3	28.6	40.5	30.3	19.1	17.1	15.9	15.4	23.0	25.5	31.7	37.0
District Heating	19.2	18.4	17.6	1.2	0.9	0.7	0.5	0.4	0.4	0.6	6.7	17.9
Thermal Power Plants	351.2	365.9	399.1	437.1	380.1	307	315.5	303.6	282.2	303.3	411.2	430.7
Large Volume Customers	55.9	57.0	62.1	70.0	66.4	71.7	75.1	78.1	69.5	76.6	68.7	60.4
Total Consumption of Gas	821.7	840.0	874.7	804.7	668.5	550.6	547.5	529.8	514.4	598.5	834.7	946.6

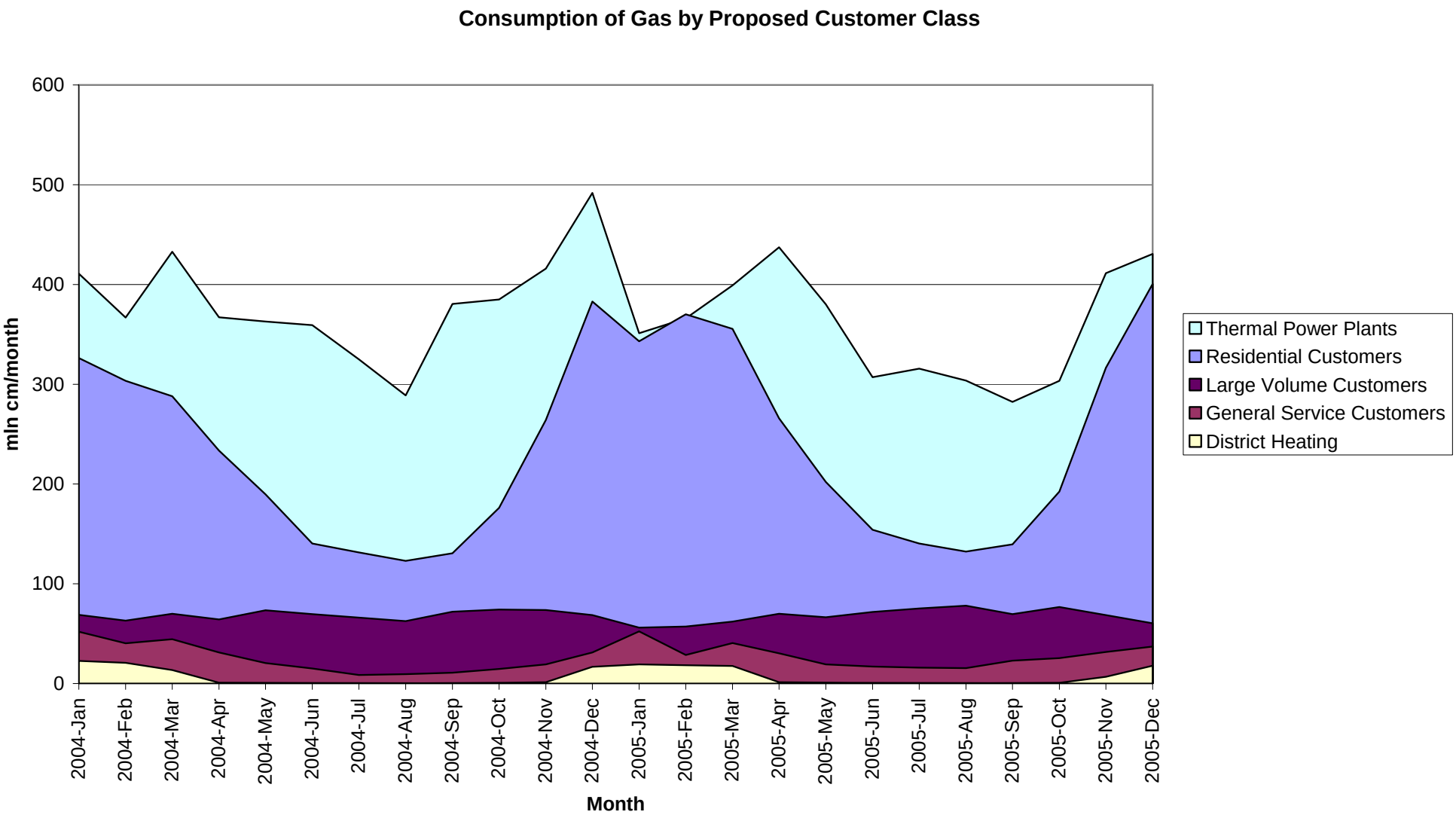


Figure 4. Sales of Gas by Proposed Customer Class (2004-2005).

The customer classes obtained through the described process are as follows:

1. Residential customers;
2. General Service Class (small industrial and commercial customers);
3. District Heating;
4. Thermal Power plants; and,
5. Large Volume Customers.

Table 2 and Figure 4 provide processed gas sales data for 2004 and 2005, which are based on the proposed customer categories.

Examples of Customer Classes

Customer classes proposed for this tariff methodology are described below.

Residential Customers

A Residential class is defined as natural gas service supplied for residential purposes - cooking, clothes drying, water heating, space heating, by individual meter in a single family dwelling or building, in an individual apartment, or to no more than 4 apartments served by a single meter (one customer) in a multiple family dwelling, or portion thereof.

Weather normalized monthly consumption of a residential customer should not exceed 500 m^3 of gas, otherwise the customer shall be transferred to the general service (small commercial/industrial) class of service.

General Service

General Service Class is defined as natural gas service supplied to customers other than generators of electric power or producers of thermal energy, and primarily engaged in wholesale or retail trade, industrial processes, agriculture, forestry, transportation, communication, sanitary services, finance, insurance, and any other non-residential type service.

Weather normalized annual usage of a customer of small commercial/industrial class of service should not exceed 2.4 mln. m^3 per month.

Any customer whose annual usage falls below or exceeds applicable annual usage levels will be transferred to the appropriate class of service and rate schedule for which the customer is eligible and is one which the customer selects.

District Heating

A District Heating Class is defined as a natural gas service supplied to boiler houses engaged exclusively in production of thermal power. The service shall be provided through a separate meter intended solely for metering the supply of natural gas for thermal power production. Any customer who is simultaneously involved in other types of businesses should ensure separate individual metering for this service.

A customer receiving other types of services shall be classified according to applicable definitions for these services.

Thermal Power Plants

A Thermal Power Plants class is defined as natural gas service, used by entities with a primary end use of generating electricity for sale to or use by, an electric distributor for redistribution to electric-consuming customers. Further, it is defined as natural gas service for which the natural gas consumed in the taking of the service is used in the production of electricity as a primary fuel and not for other purposes in the generation of electrical energy process.

Customers must have a minimum hourly demand of ??300 dekatherms per hour (3,000 therms per hour)?? to qualify for the class.

Large Volume Customers

A Large Volume Customers Class is defined as a natural gas service supplied to the customers that do not belong to the customer classes as described above. These customers are primarily engaged in wholesale or retail trade, industrial processes, agriculture, transportation, communication, sanitary services, finance, insurance, and any other types of businesses other than supply of compressed natural gas for vehicles, generation of electric power and production of thermal energy for district heating systems.

Weather normalized monthly usage of a customer of Large Volume Customers class of service shall not be less than 2.4 mln. m^3 per month.

Any customer whose monthly usage falls below its applicable monthly usage level will be transferred to the appropriate of service and rate schedule for which the customer is eligible and is one which the customer selects.

APPENDIX C – ALLOCATION FACTORS

Introduction

The Cost-of-Service studies are done to evaluate the cost of providing natural gas service to each customer classification. To do this, each component of the total revenue requirement is allocated to each customer class, and then summed to provide the revenue requirement for each. This section of the report summarizes the results of the analysis defining the allocation factors for each class of gas customers. The following are the classes of customers, which are defined and considered in this analysis:

- Residential;
- Large commercial and industrial;
- District heating;
- General service (includes small commercial and industrial customers); and,
- Power generators.

Allocation factors are used to apportion the all cost components to each class of customers. For gas utility operations, the three basic allocators are the same as the cost classifications: capacity, commodity, and customer. Within each of these, there may be more than one allocator.

The following table shows the allocation factors recommended for AzeriGas in this proposed tariff methodology. Each allocation factor is described below in Table No 1.

Table No. 1
Allocation Factors

Allocator	Factor No.	Description
CAPACITY ALLOCATORS		
Single Coincident Peak	1	Based on the customer class loads on the system peak day
Non-coincident Peak	1	Based on the peak day loads of each of the customer classes
COMMODITY ALLOCATORS		
Annual Gas Sales (Excluding Transportation) tcm	2	Ratio of total gas use of each customer class to the total system use, excluding the transportation
Annual Gas Sales (including Transportation) tcm	3	Ratio of total gas use of each customer class to the total system use, including the transportation
CUSTOMER ALLOCATORS		
Number of Customers	4	Ratio of number of customers of each class to the total number of customers
Meter Reading	5	Based on weighted costs of meter reading for each class of customer
Bad Debt	6	Uncollectible accounts expenses
Customer Records & Collections	7	Based on weighted costs for customer records and collections for each customer class
ASSET ALLOCATORS		
Transportation, Distribution	8	Based on ratio of load using the transportation and distribution systems
Total Assets	9	Based on the ratio of total assets
INTERNALLY DEVELOPED ALLOCATORS		
Total Distribution Expenses	10	Based on distribution Expenses
Distribution Plus Customer Accounting Expenses, less Uncollectible Accounts Expense	11	Distribution Plus Customer Accounting Expenses, less Uncollectible Accounts Expense
Distribution, Customer Acct. (less bad debt), plus Admin. & General	12	Distribution, Customer Acct. (less bad debt), plus Admin. & General

Single Coincident peak

The coincident peak method allocates capacity-related costs based on the demands of the various classes of customers at the time of the system peak. The rationale for this method is that the utility's costs associated with its maximum load should be divided among the customers causing that peak. Under this method, the allocator for capacity costs is the ratio of the demand of the various classes of customers at the time of the system peak to the total demand at that time.

To apply the single coincident peak method of cost allocation, operative data on daily gas consumption for the recent year should have been used. However, these data were not available, instead monthly statistic on sales for 2004 and 2005 was used as a proxy.[7] After compiling all daily data for each month of 2004 and 2005, the system peak day has been selected.

The next step was to group the customers into the above - mentioned classes, and define their consumption at the time of the system peak. Based on this, the data were derived to represent peak consumption of each customer class as follows.

- residential customers[8] 12351.9 tcm;
- large volume customers 2212.1 tcm;
- district heating customers 542.5 tcm;
- general service customers 1003.5 tcm; and,
- generators 15858.1 tcm.

Table No. 2 overleaf shows the contribution to the system peak for each class of service.

[7] For the sake of methodological clarity, further description refers to peak day, though actually used data pertained to months.
[8] To determine daily data, actual monthly sales of 2005 were divided by the number of days for each month, respectively.

Table 2
Peak consumption for each customer class.

Customer class	Peak usage, in tcm
Residential	12351.9
General Service	1003.5
Large Commercial & Industrial	2212.1
Generators	15858.1
District Heating	542.5

The peak day consumption data for each customer class was used to calculate capacity allocator. The results are summarized in Table No. 3 below.

Table 3
Capacity cost allocation by the single coincident peak.

Customer class	Peak usage, in tcm	Ratio to system peak
Residential	12351.9	0.386
General Service	1003.5	0.031
Large Commercial & Industrial	2212.1	0.069
Generators	15858.1	0.496
District Heating	542.5	0.017
Total system peak	31968.1	1.000

The results of this table are interpreted in the following way: residential and thermal power plants district heating classes bear 38.6 and 49.6 percent of the capacity costs respectively, large volume customers, general service, and district heating classes bear 6.9, 3.1 and 1.7 percent respectively.

Non-coincidental Peak Allocator

The Non-coincident peak (NCP) method allocates capacity-related costs based on the demands of the various classes of customers at the time of the class peak, regardless of the total system peak. The rationale for this method is that the utility's costs associated with its requirements to meet the maximum loads of each customer class should be divided among the customers based on their proportion of class peak to the total of all class peaks. Under this method, the allocator for capacity costs is the ratio of the

demand of the various classes of customers to the summation of the total peak demands of all customer classes.

The maximum usage of each customer class regardless of the total system peak is summarized in Table No. 4 below.

Table No. 4
Maximum usage of each customer class under the NCP method

Customer class	Maximum usage, in tcm
Residential	12351.9
General Service	1672.1
Large Commercial & Industrial	2387.3
Generators	15858.1
District Heating	731.0

The maximum consumption data for each customer class is used to calculate capacity allocator under the non-coincident peak method. The results are summarized in Table No. 5 presented below.

Table No. 5
Capacity cost allocation by the non-coincident peak

Customer class	Maximum usage, in tcm	Ratio to system peak
Residential	12351.9	0.374
General Service	1672.1	0.051
Large Commercial & Industrial	2387.3	0.072
Generators	15858.1	0.481
District Heating	731.0	0.022
Total system peak	33000.4	1.000

The results of this table are interpreted in the following way: under the non-coincident peak method, residential and thermal power plants classes bear 37.4 and 48.6 percent of the capacity costs respectively, large commercial & industrial, general service, and district heating classes bear 7.2, 5.1 and 2.2 percent respectively.

Note, that that the results of allocations based on coincident and non-coincident peak demand methods described above are very close to each other. It is explained by the application of average monthly data instead of actual data on daily sales, which may result in substantially different amounts for each customer class, depending on applied methodology.

Commodity allocator

Commodity costs are allocated to the customer classes based on their annual consumption.

To apply this allocator, data on monthly sales to each customer class were received from the Dispatch center of the AzeriGas. These data then were aggregated into the total annual sales, and used to calculate commodity allocators by dividing sales of each customer class to the total sales.

The results are summarized in the Table No. 6.

Table 6
Commodity allocator

Customer class	Annual Sales, in tcm	Ratio to total sales
Residential	2,688,940.0	0.317
General Service	296,791.3	0.035
Large Commercial & Industrial	826,129.8	0.097
Generators	4,585,950.0	0.541
District Heating	78,748.9	0.009
Total sales	8,476,560.0	1.000

As it is shown in the table, residential and thermal power plants classes bear 31.7 and 54.1 percent of the total commodity costs respectively, large commercial & industrial, general service, and district heating classes bear 9.7, 3.5 and 0.9 percent respectively.

Customer allocators

Customer costs are allocated based on the number of customers or a weighted number of customers. These costs are allocated directly to the customers of a particular class of service. In this study two customer allocators are considered, i.e. meter reading and bad debt allocators.

Meter reading allocator

To apply the meter reading allocator, number of customers for each customer class was received from the Dispatch center of the AzeriGas.
To obtain weighted customers, these data were multiplied by the average number of meters per customer and population expense. Because of the lack of data, proportions for expenses for each customer class were estimated indicating that, for example,

expenses to serve large commercial and industrial customers are 20 times higher than expenses for residential class, etc. It is also roughly estimated that the average number of meters per customer is equal to 1.

Based on this description, the meter reading allocator was calculated by dividing number of customers or weighted customers by the total number of customers.

The results are summarized in the Table 7.

Table 7
Meter reading allocator

Customer class	Number of customers	Allocator based on the number of customers	Average meters per customer	Population expense	Weighted customers	Allocator based on the weighted customers
Residential	916,000	0.9963517861	1	1	916,000	0.9859215568
Large Commercial & Industrial	4	0.0000043509	1	20	80	0.0000861067
District Heating	346	0.0003763512	1	20	6,920	0.0074482284
General Service	3,000	0.0032631609	1	2	6,000	0.0064580015
Generators	4	0.0000043509	1	20	80	0.0000861067
Total	919,354	1.0000000000			929,080	1.0000000000

Bad debt allocator

Because of data absence for bad debt evaluation, it is estimated that uncollectible accounts expense is 20% for residential sector and 16% for the rest classes of customers.

Asset Based Allocations

Assets related allocations should be performed on the basis values of different types of assets, the accounting and recording of which is maintained by the company on ongoing basis. However, at present, the official financial information generated according to the existing chart of accounts and sub-accounts and accounting policies do not provide the level of details sufficient to derive these allocators. It is envisaged that in the future, the new chart of sub-accounts, which are currently developed, will remedy the situation and provide enough information for calculations. In the meantime, for those assets which are not segregated out of the total bulk but needed for allocations, the appropriate proxies were used. These proxies reflect the values of asset components, separately registered under existing classification, and performing close functions to the assets needed for allocations.

Calculation of assets related allocations is described below.

Transmission Assets

Total value of net transmission assets, 1,005,886,501 thousand Manats, represents the value of the following components as shown in Table No. 8. To arrive at these values, officially reported data for gross amount of each line item was taken from financial reports of AzeriGasNegl and then scaled in proportion of total assets to net assets.

Table No. 8
Transmission Assets

Description	Amount (Thousand Manats)
Land (Buildings)	6,045,456
Structures (Structures)	487,754,678
Mains (Transmission Equipment)	482,461,511
Compressor Station Equip. (Machinery)	21,057,351
Measuring and Reg. Equip. (Means of Transport and Other Non-current Assets)	8,567,505
Total Transportation	1,005,886,501

Item titles in brackets correspond to existing classification.

The value of transmission assets was allocated to the customer classes on the basis of class's participation in total system peak. Rationale for this allocation is based on the premise that the transportation system was built to handle the loads imposed on a system by different customer classes during a peak day. Therefore, each class is responsible for a portion of transmission assets proportional to the class' contribution to the system peak.

Underground Storage Assets

Total value of net underground storage assets, 172,452,478 thousand Manats, represents the value of the following components as shown in Table No. 9. It was derived in a similar way to the value of transmission assets.

Table No.9
Underground Storage Assets

Description	Amount (Thousand Manats)
Land (Buildings)	3,694,069
Structures (Structures)	110,185,272
Mains (Transmission Equipment)	5,282,173
Compressor Station Equip. (Machinery)	25,561,470
Measuring and Reg. Equip. (Means of Transport and Other Non-current Assets)	11,979,965

Meters, meter installation (Implements and Tools)	281,716
Regulators, installation (Other Non-Current Assets)	15,440,812
Total Underground Storage	172,425,478

Peculiar feature of operation of the gas system in Azerbaijan is that imported Russian does not get into the underground storage, but is directly supplied to the thermal power plants. For this reason the allocation of the gas storage assets was performed on the basis of coincident and non-coincident peaks without account of the load of thermal power plants.

Distribution Assets

It was not possible to obtain all necessary details from existing accounting information, therefore the values of separate items were estimated and than the total was derived. It was done through the following steps. First the total accumulated gross values for each line item of Table No. 10 were taken from official financial report of Azerigaz for 2005 for Baku distribution networks. It was assumed that this structure would pretty close represent similar items for all distribution networks of Azerbaijan. From the same set of documents it was known that net total fixed assets, used for gas service in Azerbaijan in 2005 made up 1,344,394,562.4 ths AZM. They were composed of 1,005,886,501 ths AZM of the net transportation assets, 1,724,254,78.3 ths AZM of the net underground storage assets, which left 166,082,583 ths AZM for the total net distribution assets. This amount was allocated among different line items in proportion of gross amounts for each item for Baku distribution networks.

The values of separate items are presented below in Table No. 9 with the asset items, registered under existing classification given in brackets.

Table No. 10
Distribution Assets

Description	Amount (Thousand Manats)
Land (Buildings)	3,109,323
Structures (Structures)	574,561
Mains (Transmission equipment)	108,053,560
Compressor Station Equip. (Machinery and Equipment)	47,392,993
Measuring and Reg. Equip.	0
Services (Means of Transportation)	5,883,620
Meters, meter installation (Implements and Tools)	1,055,162
Regulators, installation (Other Non-Current Assets)	13,365
Total Distribution	166,082,583

Assets related to land and structures amount to 3,109,323 and 574,561 thousand. Manats respectively. They were allocated on the basis of single coincident peak.

Total value of mains in amount of 108,053,560 thousand. Manats were allocated in two step procedure. First, it was apportioned between demand and customer. This

allocation assumes that mains related assets serve dual purposes – major part of them is used to handle the supply during conditions of maximum load, while the smaller is employed for customer service.

Total value was split in proportion of 71: 29 between the demand and customer service. This proportion reflects the relationship between similar values for a sample of U.S. companies. After the apportioning, the demand related assets of 76,569,422 thousand Manats were allocated on the basis of single coincident peak, while customer related assets of 31,484,138 thousand Manats were allocated on the basis of number of customers.

The same approach was applied to service related assets, but in this case the major portion of assets was assigned to the customer service rather than demand. The total amount of the services was 5,883,620 thousand Manats, which was allocated in proportion of 8:92. This ratio represents similar relationships in costs for several US companies. As a result of the allocation was 5,431,201 thousand Manats were assigned to customer service and 452,419 thousand Manats to demand. Similarly to the value of mains, the demand and customer portions were than allocated to the classes on the basis of their responsibility in system peak and a number of customers respectively.

The amount of meter related assets, 1,055,162 thousand Manats, was allocated to customer classes on the basis of meter reading allocator.

Compressor station related assets amounted to 47,392,993 thousand Manats. It was assumed that assets related to measuring and regulating equipment had been included into compressor assets. These types of assets were allocated to customer classes on the basis of single coincident peak.

Total value of transmission and distribution assets was calculated through the summation of the individual items for each customer class.

The value of General Assets was assessed to equal 3,641,560 thousand Manats. It is related to total administration and management functions was allocated to the customer classes in proportion to total annual sales including transportation. The rational for such an allocation assumes that these functions are required to ensure the operation of the system during the whole year to provide sufficient supply to the customers.

Intangible assets were approximated by the amount of 30,800 thousand Manats, which in official reporting documents represented long-term investments into gas sector. It was allocated to customer classes on the basis of total sales including transportation.

The value of Total Assets in Service 1,348,053,558 thousand. Manats were calculated as a sum of Transmission, Distribution and General Assets.

Allocators ## 8 and 9, Transportation and Distribution Assets, and Total Assets, were derived as a share of a customer class in combined value of appropriate assets.

Allocator #10, Total Distribution Expenses without Other Expenses, was calculated as a sum of separate cost items for the whole function of distribution without Other Expenses.

Allocator #11, Total Costs of Distribution, was calculated as total distribution expenses plus customer accounts expense without costs of bad debt.

Allocator #12 was calculated on the basis of the sum of distribution expenses, customer accounts expenses (without bad debt) and administration and general expenses.

APPENDIX D – EXAMPLE OF COST OF SERVICE WORK SHEETS

D-1 - Cost Classification

D-2 - Asset Classification

D-3 - Cost of Service - Coincidental Peak Allocation Method

D-3.1 Total Cost of Service

D-3.2 Commodity Cost of Service

D-3.3 Demand Cost of Service

D-3.4 Customer Cost of Service

D-4 - Cost of Service - Non-Coincidental Peak Allocation Method

D-4.1 Total Cost of Service

D-4.2 Commodity Cost of Service

D-4.3 Demand Cost of Service

D-4.4 Customer Cost of Service

D-5 Asset Allocations

D-5.1 Total Gas Asset Allocation (Coincidental Peak)

D-5.2 Demand Gas Asset Allocation (Coincidental Peak)

D-5.3 Customer Gas Asset Allocation (Coincidental Peak)

D-5.4 Total Gas Asset Allocation (Non-coincidental Peak)

D-5.5 Demand Gas Asset Allocation (Non-Coincidental Peak)

D-5.6 Customer Gas Asset Allocation (Non-Coincidental Peak)

D-6 Allocation Factors

D-6.1 Coincidental Peak Allocators

D-6.2 Non-Coincidental Peak Allocators

Appendix D-1

Cost Classification

Cost Element	Amounts in Thousand Manats			
	Commodity	Demand	Customer	Total
Purchased Imported Natural Gas	1,144,688,313.6	0.0	0.0	1,144,688,314
Purchased Local Natural Gas	305,973,980.8	0.0	0.0	305,973,981
Gas Storage	0.0	10,603,370.4	0.0	10,603,370
Transportation	0.0	32,374,058.6	0.0	32,374,059
Distribution				
Mains	0.0	1,556,561.3	640,043.9	2,196,605
Services	0.0	126,681.2	1,520,772.7	1,647,454
Regulating Stations	0.0	329,483.3	0.0	329,483
Meters, regulators, Cust. Installations	0.0	0.0	1,647,453.8	1,647,454
Other	0.0	3,234.8	6,114.4	9,349
Total Distribution Expenses	0.0	2,015,960.6	3,814,384.7	5,830,345
Customer Accounts				
Meter Reading	0.0	0.0	549,151.3	549,151
Cust. Records & Collections Exp.	0.0	0.0	2,196,605.1	2,196,605
Uncollectible Accounts	0.0	0.0	18,698,331.0	18,698,331
Total Customer Accounts Expenses	0.0	0.0	21,444,087.4	21,444,087
Administrative & General	0.0	7,107,531.7	23,128,631.6	30,236,163
Depreciation	0.0	27,965,141.5	10,306,521.4	38,271,663
Taxes				
Social Insurance	0.0	1,676,928.9	5,456,870.1	7,133,799
Other	0.0	1,215,567.2	3,955,550.8	5,171,118
Profit	0.0	1,152,900.7	424,890.5	1,577,791
VAT	11,225,403.3	14,410,049.5	35,666,441.6	61,301,894
Total Taxes	11,225,403.3	18,455,446.4	45,503,752.9	75,184,603
Return	0.0	94,660,817.0	34,887,129.9	129,547,947
Working Capital	0.0	610,667.1	1,987,197.8	2,597,865
Total Revenue Requirement for Azerigaz	**317,199,384.1**	**193,792,993.2**	**141,071,705.7**	**652,064,083**
Total Revenue Requirement for the Gas Industry	**1,461,887,697.7**	**193,792,993.2**	**141,071,705.7**	**1,796,752,397**

Appendix D-2

Asset Classification

Asset	Commodity	Demand	Customer	Total
Intangible Assets	0	0	30,800	30,800
Gas Storage Assets	0	172,425,478	0	172,425,478
Transmission Assets	0	1,005,886,501	0	1,005,886,501
Distribution Assets				
Land	0	3,109,323	0	3,109,323
Structures and Improvements	0	574,561	0	574,561
Mains				
Demand	0	76,569,422	0	76,569,422
Customer	0	0	31,484,138	31,484,138
Compressor Station Equip.	0	47,392,993	0	47,392,993
Measuring and Reg. Equip.	0	0	0	0
Services				
Demand	0	452,419	0	452,419
Customer	0	0	5,431,201	5,431,201
Meters, meter installation	0	0	1,055,162	1,055,162
Regulators, installation	0	0	0	0
Total Distribution	0	128,098,719	37,970,500	166,069,219
Subtotal Assets (Storage, T&D)	0	1,306,410,698	37,970,500	1,344,381,198
General Assets	0	1,820,780	1,820,780	3,641,560
Total Assets in Service	0	1,308,231,478	39,822,080	1,348,053,558

Appendix D-3

Cost of Service

Coincidental Peak Allocation Method

D-3.1 Total Cost of Service

D-3.2 Commodity Cost of Service

D-3.3 Demand Cost of Service

D-3.4 Customer Cost of Service

D-3.1 Total Cost of Service (CP)

	Allocation factor	Residential	General Service	Large Volume Customers	Thermal Power Plants	District Heating	Total Costs 2004 ths. AZM
Revenue Requirement							
Purchased Imported Natural Gas	**3'**	0	0	0	1,144,688,314	0	1,144,688,314
Purchased Local Natural Gas	**2**	211,469,583	23,340,920	64,970,332	0	6,193,146	305,973,981
Gas Storage	**1'**	8,129,843	660,489	1,455,972	0	357,066	10,603,370
Transportatoin	**1**	12,508,755	1,016,243	2,240,191	16,059,480	549,389	32,374,059
Distribution							
Mains							
Demand (CP)	**1**	601,430	48,862	107,710	772,152	26,415	1,556,569
Customer	**4**	637,701	2,089	3	3	241	640,036
Direct Assignment							
Services							
Demand (CP)	**1**	48,947	3,977	8,766	62,841	2,150	126,680
Customer	**4**	1,515,225	4,963	7	7	572	1,520,773
Direct Assignment							
Regualting Stations	**1**	127,306	10,343	22,799	163,444	5,591	329,483
Meters, regulators, customer installations	**5**	1,624,260	10,639	142	142	12,271	1,647,454
Other	**10**	7,316	130	224	1,604	76	9,349
Total Distribution Expenses		4,562,186	81,001	139,650	1,000,191	47,316	5,830,345
Distribution excluding Other		4,554,871	80,871	139,427	998,588	47,240	5,820,996
Customer Accounts							
Meter Reading	**5**	541,420	3,546	47	47	4,090	549,151
Cust. Records & Collections Expenses	**7**	1,672,877	135,450	125,653	125,653	136,973	2,196,605
Uncollectible Accounts	**6**	4,451,984	3,561,587	3,561,587	3,561,587	3,561,587	18,698,331
Total Customer Accounts Expense		6,666,280	3,700,584	3,687,287	3,687,287	3,702,650	21,444,087
Distribution and Cust. Accounts - Uncollectible		6,776,483	219,998	265,350	1,125,891	188,379	8,576,102
Distribution plus Customer Accounting		5,103,606	84,548	139,698	1,000,239	51,406	
Administrative and general	**11**	23,891,373	775,631	935,527	3,969,477	664,154	30,236,163
Distr., Cust. Accounts, (less bad debt), A&G		30,667,856	995,629	1,200,878	5,095,368	852,533	38,812,265
Depreciation	**9**	17,299,075	1,322,756	2,910,001	16,026,197	712,760	38,270,788
TAXES							
Social Insurance	**12**	5,636,835	182,999	220,725	936,542	156,698	7,133,799
Other	**12**	4,086,005	132,652	159,998	678,877	113,587	5,171,118
Profit	**9**	713,173	54,532	119,968	660,698	29,384	1,577,755
VAT	**12**	48,438,237	1,572,543	1,896,722	8,047,861	1,346,531	61,301,894
Total Taxes		58,874,250	1,942,726	2,397,413	10,323,978	1,646,200	75,184,567
RETURN	**9**	58,556,630	4,477,472	9,850,229	54,247,994	2,412,662	129,544,987
WORKING CAPITAL REQUIREMENTS	**12**	2,052,726	66,642	80,380	341,054	57,064	2,597,865
Less:							
OTHER OPERATING INCOMES		0	0	0	0	0	
TOTAL AZERIGAZ REVENUE REQUIREMENT		404,010,703	37,384,464	88,666,983	105,655,657	16,342,406	652,060,213
Billing Determinants		2,688,940	296,791	826,130	4,585,950	78,749	
Azerigas Revenue Requirement (AZM/tcm)		150,249	125,962	107,328	23,039	207,526	
(USD/tcm)		31.30	26.24	22.36	4.80	43.23	
TOTAL REVENUE FOR GAS SECTOR		404,010,703	37,384,464	88,666,983	1,250,343,971	16,342,406	1,796,748,526
Gas Sector Revenue Requirement (AZM/tcm)		150,249	125,962	107,328	272,647	207,526	
(USD/tcm)		31.30	26.24	22.36	56.80	43.23	

D-3.2 Commodity Cost of Service (CP)

	Allocation factor	Residential	General Service	Large Volume Customers	Thermal Power Plants	District Heating	Total Costs 2004 ths. AZM
Revenue Requirement							
Purchased Imported Natural Gas	**3'**	0	0	0	1,144,688,314	0	1,144,688,314
Purchased Local Natural Gas	**2**	211,469,583	23,340,920	64,970,332	0	6,193,146	305,973,981
Gas Storage	**1'**	0	0	0	0	0	0
Transportatoin	**1**	0	0	0	0	0	0
Distribution							
Mains							
Demand (CP)	**1**	0	0	0	0	0	0
Customer	**4**	0	0	0	0	0	0
Direct Assignment							
Services							
Demand (CP)	**1**	0	0	0	0	0	0
Customer	**4**	0	0	0	0	0	0
Direct Assignment							
Regualting Stations	**1**	0	0	0	0	0	0
Meters, regulators, customer installations	**5**	0	0	0	0	0	0
Other	**10**	0	0	0	0	0	0
Total Distribution Expenses		0	0	0	0	0	0
Distribution excluding Other		0	0	0	0	0	0
Customer Accounts							
Meter Reading	**5**	0	0	0	0	0	0
Cust. Records & Collections Expenses	**7**	0	0	0	0	0	0
Uncollectible Accounts	**6**	0	0	0	0	0	0
Total Customer Accounts Expense		0	0	0	0	0	0
Distribution and Cust. Accounts - Uncollectible		0	0	0	0	0	0
Distribution plus Customer Accounting		0	0	0	0	0	
Administrative and general	**11**	0	0	0	0	0	0
Distr., Cust. Accounts, (less bad debt), A&G		0	0	0	0	0	0
Depreciation	**9**	0	0	0	0	0	0
TAXES							
Social Insurance	**12**	0	0	0	0	0	0
Other	**12**	0	0	0	0	0	0
Profit	**9**	0	0	0	0	0	0
VAT	**12**	8,869,852	287,959	347,322	1,473,698	246,572	11,225,403
Total Taxes		8,869,852	287,959	347,322	1,473,698	246,572	11,225,403
RETURN	**9**	0	0	0	0	0	0
WORKING CAPITAL REQUIREMENTS	**12**	0	0	0	0	0	0
Less:							
OTHER OPERATING INCOMES		0	0	0	0	0	
TOTAL AZERIGAZ REVENUE REQUIREMENT		220,339,436	23,628,879	65,317,654	1,473,698	6,439,718	317,199,384
Billing Determinants		2,688,940	296,791	826,130	4,585,950	78,749	
Azerigas Revenue Requirement (AZM/tcm)		81,943	79,614	79,065	321	81,775	
(USD/tcm)		17.07	16.59	16.47	0.07	17.04	
TOTAL REVENUE FOR GAS SECTOR		220,339,436	23,628,879	65,317,654	1,146,162,012	6,439,718	1,461,887,698
Gas Sector Revenue Requirement (AZM/tcm)		81,943	79,614	79,065	249,929	81,775	
(USD/tcm)		17.07	16.59	16.47	52.07	17.04	

D-3.3 Demand Cost of Service (CP)

	Allocation factor	Residential	General Service	Large Volume Customers	Thermal Power Plants	District Heating	Total Costs 2004 ths. AZM
Revenue Requirement							
Purchased Imported Natural Gas	**3'**	0	0	0	0	0	0
Purchased Local Natural Gas	**2**	0	0	0	0	0	0
Gas Storage	**1'**	8,129,843	660,489	1,455,972	0	357,066	10,603,370
Transportatoin	**1**	12,508,755	1,016,243	2,240,191	16,059,480	549,389	32,374,059
Distribution							
Mains							
Demand (CP)	**1**	601,427	48,861	107,710	772,148	26,415	1,556,561
Customer	**4**	0	0	0	0	0	0
Direct Assignment							
Services							
Demand (CP)	**1**	48,947	3,977	8,766	62,841	2,150	126,681
Customer	**4**	0	0	0	0	0	0
Direct Assignment							
Regualting Stations	**1**	127,306	10,343	22,799	163,444	5,591	329,483
Meters, regulators, customer installations	**5**	0	0	0	0	0	0
Other	**10**	2,531	45	77	555	26	3,235
Total Distribution Expenses		780,212	63,226	139,352	998,988	34,182	2,015,961
Distribution excluding Other		777,681	63,181	139,275	998,433	34,156	2,012,726
Customer Accounts							
Meter Reading	**5**	0	0	0	0	0	0
Cust. Records & Collections Expenses	**7**	0	0	0	0	0	0
Uncollectible Accounts	**6**	0	0	0	0	0	0
Total Customer Accounts Expense		0	0	0	0	0	0
Distribution and Cust. Accounts - Uncollectible		780,212	63,226	139,352	998,988	34,182	2,015,961
Distribution plus Customer Accounting		780,212	63,226	139,352	998,988	34,182	
Administrative and general	**11**	5,616,079	182,326	219,912	933,094	156,121	7,107,532
Distr., Cust. Accounts, (less bad debt), A&G		6,396,292	245,551	359,264	1,932,082	190,303	9,123,492
Depreciation	**9**	12,640,451	966,539	2,126,341	11,710,358	520,814	27,964,503
TAXES							
Social Insurance	**12**	1,325,040	43,017	51,885	220,151	36,835	1,676,929
Other	**12**	960,491	31,182	37,610	159,583	26,701	1,215,567
Profit	**9**	521,120	39,847	87,661	482,775	21,471	1,152,874
VAT	**12**	11,386,229	369,653	445,857	1,891,786	316,525	14,410,049
Total Taxes		14,192,880	483,699	623,014	2,754,295	401,531	18,455,420
RETURN	**9**	42,787,390	3,271,693	7,197,572	39,639,064	1,762,934	94,658,654
WORKING CAPITAL REQUIREMENTS	**12**	482,524	15,665	18,894	80,170	13,414	610,667
Less:							
OTHER OPERATING INCOMES		0	0	0	0	0	
TOTAL AZERIGAZ REVENUE REQUIREMENT		97,138,134	6,659,881	14,021,249	72,175,449	3,795,452	193,790,165
Billing Determinants		2,688,940	296,791	826,130	4,585,950	78,749	
Azerigas Revenue Requirement (AZM/tcm)		36,125	22,440	16,972	15,738	48,197	
(USD/tcm)		7.53	4.67	3.54	3.28	10.04	
TOTAL REVENUE FOR GAS SECTOR		97,138,134	6,659,881	14,021,249	72,175,449	3,795,452	193,790,165
Gas Sector Revenue Requirement (AZM/tcm)		36,125	22,440	16,972	15,738	48,197	
(USD/tcm)		7.53	4.67	3.54	3.28	10.04	

D-3.4 Customer Cost of Service (CP)

	Allocation factor	Residential	General Service	Large Volume Customers	Thermal Power Plants	District Heating	Total Costs 2004 ths. AZM
Revenue Requirement							
Purchased Imported Natural Gas	**3'**	0	0	0	0	0	0
Purchased Local Natural Gas	**2**	0	0	0	0	0	0
Gas Storage	**1'**	0	0	0	0	0	0
Transportatoin	**1**	0	0	0	0	0	0
Distribution							
Mains							
Demand (CP)	**1**	175,244	14,237	31,384	224,989	7,697	453,551
Customer	**4**	185,813	609	1	1	70	186,493
Direct Assignment							
Services							
Demand (CP)	**1**	45,183	3,671	8,092	58,009	1,984	116,939
Customer	**4**	1,398,712	4,581	6	6	528	1,403,833
Direct Assignment							
Regualting Stations	**1**	0	0	0	0	0	0
Meters, regulators, customer installations	**5**	1,624,260	10,639	142	142	12,271	1,647,454
Other	**10**	4,784	85	146	1,049	50	6,114
Total Distribution Expenses		3,433,996	33,822	39,772	284,195	22,600	3,814,385
Distribution excluding Other		3,429,212	33,737	39,625	283,146	22,550	3,808,270
Customer Accounts							
Meter Reading	**5**	541,420	3,546	47	47	4,090	549,151
Cust. Records & Collections Expenses	**7**	1,672,877	135,450	125,653	125,653	136,973	2,196,605
Uncollectible Accounts	**6**	4,451,984	3,561,587	3,561,587	3,561,587	3,561,587	18,698,331
Total Customer Accounts Expense		6,666,280	3,700,584	3,687,287	3,687,287	3,702,650	21,444,087
Distribution and Cust. Accounts - Uncollectible		5,648,293	172,818	165,471	409,895	163,663	6,560,141
Distribution plus Customer Accounting		3,975,416	37,368	39,819	284,242	26,690	
Administrative and general	**11**	18,275,294	593,306	715,616	3,036,383	508,033	23,128,632
Distr., Cust. Accounts, (less bad debt), A&G		23,923,587	766,124	881,087	3,446,278	671,697	29,688,773
Depreciation	**9**	4,658,624	356,217	783,660	4,315,839	191,946	10,306,286
TAXES							
Social Insurance	**12**	4,311,794	139,982	168,839	716,391	119,863	5,456,870
Other	**12**	3,125,514	101,470	122,387	519,294	86,886	3,955,551
Profit	**9**	192,054	14,685	32,307	177,922	7,913	424,881
VAT	**12**	28,182,156	914,931	1,103,544	4,682,377	783,434	35,666,442
Total Taxes		35,811,518	1,171,068	1,427,077	6,095,984	998,096	45,503,743
RETURN	**9**	15,769,241	1,205,779	2,652,657	14,608,929	649,727	34,886,333
WORKING CAPITAL REQUIREMENTS	**12**	1,570,202	50,976	61,485	260,884	43,650	1,987,198
Less:							
OTHER OPERATING INCOMES		0	0	0	0	0	
TOTAL AZERIGAZ REVENUE REQUIREMENT		86,185,155	7,111,751	9,367,554	32,289,502	6,116,702	141,070,663
Billing Determinants		2,688,940	296,791	826,130	4,585,950	78,749	
Azerigas Revenue Requirement (AZM/tcm)		32,052	23,962	11,339	7,041	77,673	
(USD/tcm)		6.68	4.99	2.36	1.47	16.18	
TOTAL REVENUE FOR GAS SECTOR		86,185,155	7,111,751	9,367,554	32,289,502	6,116,702	141,070,663
Gas Sector Revenue Requirement (AZM/tcm)		32,052	23,962	11,339	7,041	77,673	
(USD/tcm)		6.68	4.99	2.36	1.47	16.18	

Appendix D-4

Cost of Service

Non-Coincidental Peak Allocation Method

D-4.1 Total Cost of Service (NCP)

	Allocation factor	Residential	General Service	Large Volume Customers	Thermal Power Plants	District Heating	Total Costs 2004 ths. AZM
Revenue Requirement							
Purchased Imported Natural Gas	**3'**	0	0	0	1,144,688,314	0	1,144,688,314
Purchased Local Natural Gas	**2**	211,469,583	23,340,920	64,970,332	0	6,193,146	305,973,981
Gas Storage	**1'**	7,640,268	1,034,278	1,476,665	0	452,160	10,603,370
Tansportation (Non-Coincident Peak)	**1**	12,117,463	1,640,364	2,341,989	15,557,116	717,126	32,374,059
Distribution							
Mains							
Demand (NCP)	**1**	582,617	78,870	112,605	747,998	34,480	1,556,569
Customer	**4**	637,701	2,089	3	3	241	640,036
Direct Assignment							
Services							
Demand (NCP)	**1**	47,416	6,419	9,164	60,875	2,806	126,680
Customer	**4**	1,515,225	4,963	7	7	572	1,520,773
Direct Assignment							
Regualting Stations (NCP)	**1**	123,324	16,695	23,835	158,331	7,298	329,483
Meters, regulators, customer installations	**5**	1,624,260	10,639	142	142	12,271	1,647,454
Other	**10**	7,316	130	224	1,604	76	9,349
Total Distribution Expenses (NCP)		4,537,859	119,804	145,979	968,959	57,744	5,830,345
Distribution excluding Other (NCP)		4,530,544	119,674	145,755	967,355	57,668	5,820,996
Customer Accounts							
Meter Reading	**5**	541,420	3,546	47	47	4,090	549,151
Cust. Records & Collections Expenses	**7**	1,672,877	135,450	125,653	125,653	136,973	2,196,605
Uncollectible Accounts	**6**	4,451,984	3,561,587	3,561,587	3,561,587	3,561,587	18,698,331
Total Customer Accounts Expense		6,666,280	3,700,584	3,687,287	3,687,287	3,702,650	21,444,087
Distribution and Cust. Accounts - Uncollectible (NCP)		6,752,156	258,800	271,679	1,094,659	198,807	8,576,102
Distribution plus Customer Accounting		5,103,606	84,548	139,698	1,000,239	51,406	
Administrative and general	**11**	23,891,373	775,631	935,527	3,969,477	664,154	30,236,163
Distr., Cust. Accounts, (less bad debt), A&G (NCP)		30,643,529	1,034,432	1,207,207	5,064,136	862,962	38,812,265
Depreciation	**9**	17,299,075	1,322,756	2,910,001	16,026,197	712,760	38,270,788
TAXES							
Social Insurance	**12**	5,636,835	182,999	220,725	936,542	156,698	7,133,799
Other	**12**	4,086,005	132,652	159,998	678,877	113,587	5,171,118
Profit	**9**	713,173	54,532	119,968	660,698	29,384	1,577,755
VAT	**12**	48,438,237	1,572,543	1,896,722	8,047,861	1,346,531	61,301,894
Total Taxes		58,874,250	1,942,726	2,397,413	10,323,978	1,646,200	75,184,567
RETURN	**9**	58,556,630	4,477,472	9,850,229	54,247,994	2,412,662	129,544,987
WORKING CAPITAL REQUIREMENTS	**12**	2,052,726	66,642	80,380	341,054	57,064	2,597,865
Less:							
OTHER OPERATING INCOMES		0	0	0	0	0	
TOTAL AZERIGAS REVENUE REQUIREMENT (NCP)		403,105,509	38,421,175	88,795,802	105,122,061	16,615,665	652,060,213
Billing Determinants		2,688,940	296,791	826,130	4,585,950	78,749	
Azerigas Revenue Requirement (AZM/tcm) (NCP)		149,912	129,455	107,484	22,923	210,996	
(USD/tcm) (NCP)		31.23	26.97	22.39	4.78	43.96	
TOTAL REVENUE FOR GAS SECTOR (NCP)		403,105,509	38,421,175	88,795,802	1,249,810,375	16,615,665	1,796,748,526
Gas sector Revenue Requirement (AZM/tcm) (NCP)		149,912	129,455	107,484	272,530	210,996	
(USD/tcm) (NCP)		31.23	26.97	22.39	56.78	43.96	

D-4.2 Commodity Cost of Service (NCP)

	Allocation factor	Residential	General Service	Large Volume Customers	Thermal Power Plants	District Heating	Total Costs 2004 ths. AZM
Revenue Requirement							
Purchased Imported Natural Gas	**3'**	0	0	0	1,144,688,314	0	1,144,688,314
Purchased Local Natural Gas	**2**	211,469,583	23,340,920	64,970,332	0	6,193,146	305,973,981
Gas Storage	**1'**	0	0	0	0	0	0
Transportatoin	**1**	0	0	0	0	0	0
Distribution							
Mains							
Demand (CP)	**1**	0	0	0	0	0	0
Customer	**4**	0	0	0	0	0	0
Direct Assignment							
Services							
Demand (CP)	**1**	0	0	0	0	0	0
Customer	**4**	0	0	0	0	0	0
Direct Assignment							
Regualting Stations	**1**	0	0	0	0	0	0
Meters, regulators, customer installations	**5**	0	0	0	0	0	0
Other	**10**	0	0	0	0	0	0
Total Distribution Expenses		0	0	0	0	0	0
Distribution excluding Other		0	0	0	0	0	0
Customer Accounts							
Meter Reading	**5**	0	0	0	0	0	0
Cust. Records & Collections Expenses	**7**	0	0	0	0	0	0
Uncollectible Accounts	**6**	0	0	0	0	0	0
Total Customer Accounts Expense		0	0	0	0	0	0
Distribution and Cust. Accounts - Uncollectible		0	0	0	0	0	0
Distribution plus Customer Accounting		0	0	0	0	0	
Administrative and general	**11**	0	0	0	0	0	0
Distr., Cust. Accounts, (less bad debt), A&G		0	0	0	0	0	0
Depreciation	**9**	0	0	0	0	0	0
TAXES							
Social Insurance	**12**	0	0	0	0	0	0
Other	**12**	0	0	0	0	0	0
Profit	**9**	0	0	0	0	0	0
VAT	**12**	8,869,852	287,959	347,322	1,473,698	246,572	11,225,403
Total Taxes		8,869,852	287,959	347,322	1,473,698	246,572	11,225,403
RETURN	**9**	0	0	0	0	0	0
WORKING CAPITAL REQUIREMENTS	**12**	0	0	0	0	0	0
Less:							
OTHER OPERATING INCOMES		0	0	0	0	0	
TOTAL AZERIGAZ REVENUE REQUIREMENT		220,339,436	23,628,879	65,317,654	1,473,698	6,439,718	317,199,384
Billing Determinants		2,688,940	296,791	826,130	4,585,950	78,749	
Azerigas Revenue Requirement (AZM/tcm)		81,943	79,614	79,065	321	81,775	
(USD/tcm)		17.07	16.59	16.47	0.07	17.04	
TOTAL REVENUE FOR GAS SECTOR		220,339,436	23,628,879	65,317,654	1,146,162,012	6,439,718	1,461,887,698
Gas Sector Revenue Requirement (AZM/tcm)		81,943	79,614	79,065	249,929	81,775	
(USD/tcm)		17.07	16.59	16.47	52.07	17.04	

D-4.3 Demand Cost of Service (NCP)

	Allocation factor	Residential	General Service	Large Volume Customers	Thermal Power Plants	District Heating	Total Costs 2004 ths. AZM
Revenue Requirement							
Purchased Imported Natural Gas	**3'**	0	0	0	0	0	0
Purchased Local Natural Gas	**2**	0	0	0	0	0	0
Gas Storage	**1'**	7,640,268	1,034,278	1,476,665	0	452,160	10,603,370
Tansportation (Non-Coincident Peak)	**1**	12,117,463	1,640,364	2,341,989	15,557,116	717,126	32,374,059
Distribution							
Mains							
Demand (NCP)	**1**	582,614	78,870	112,604	747,994	34,480	1,556,561
Customer	**4**	0	0	0	0	0	0
Direct Assignment							
Services							
Demand (NCP)	**1**	47,416	6,419	9,164	60,876	2,806	126,681
Customer	**4**	0	0	0	0	0	0
Direct Assignment							
Regualting Stations (NCP)	**1**	123,324	16,695	23,835	158,331	7,298	329,483
Meters, regulators, customer installations	**5**	0	0	0	0	0	0
Other	**10**	2,531	45	77	555	26	3,235
Total Distribution Expenses (NCP)		755,885	102,028	145,681	967,756	44,611	2,015,961
Distribution excluding Other (NCP)		753,354	101,983	145,604	967,201	44,584	2,012,726
Customer Accounts							
Meter Reading	**5**	0	0	0	0	0	0
Cust. Records & Collections Expenses	**7**	0	0	0	0	0	0
Uncollectible Accounts	**6**	0	0	0	0	0	0
Total Customer Accounts Expense		0	0	0	0	0	0
Distribution and Cust. Accounts - Uncollectible (NCP)		755,885	102,028	145,681	967,756	44,611	2,015,961
Distribution plus Customer Accounting		780,212	63,226	139,352	998,988	34,182	
Administrative and general	**11**	5,616,079	182,326	219,912	933,094	156,121	7,107,532
Distr., Cust. Accounts, (less bad debt), A&G (NCP)		6,371,965	284,353	365,593	1,900,849	200,732	9,123,492
Depreciation	**9**	12,640,451	966,539	2,126,341	11,710,358	520,814	27,964,503
TAXES							
Social Insurance	**12**	1,325,040	43,017	51,885	220,151	36,835	1,676,929
Other	**12**	960,491	31,182	37,610	159,583	26,701	1,215,567
Profit	**9**	521,120	39,847	87,661	482,775	21,471	1,152,874
VAT	**12**	11,386,229	369,653	445,857	1,891,786	316,525	14,410,049
Total Taxes		14,192,880	483,699	623,014	2,754,295	401,531	18,455,420
RETURN	**9**	42,787,390	3,271,693	7,197,572	39,639,064	1,762,934	94,658,654
WORKING CAPITAL REQUIREMENTS	**12**	482,524	15,665	18,894	80,170	13,414	610,667
Less:							
OTHER OPERATING INCOMES		0	0	0	0	0	
TOTAL AZERIGAS REVENUE REQUIREMENT (NCP)		96,232,941	7,696,592	14,150,068	71,641,853	4,068,711	193,790,165
Billing Determinants		2,688,940	296,791	826,130	4,585,950	78,749	
Azerigas Revenue Requirement (AZM/tcm) (NCP)		35,788	25,933	17,128	15,622	51,667	
(USD/tcm) (NCP)		7.46	5.40	3.57	3.25	10.76	
TOTAL REVENUE FOR GAS SECTOR (NCP)		96,232,941	7,696,592	14,150,068	71,641,853	4,068,711	193,790,165
Gas sector Revenue Requirement (AZM/tcm) (NCP)		35,788	25,933	17,128	15,622	51,667	
(USD/tcm) (NCP)		7.46	5.40	3.57	3.25	10.76	

D-4.4 Customer Cost of Service (NCP)

	Allocation factor	Residential	General Service	Large Volume Customers	Thermal Power Plants	District Heating	Total Costs 2004 ths. AZM
Revenue Requirement							
Purchased Imported Natural Gas	**3'**	0	0	0	0	0	0
Purchased Local Natural Gas	**2**	0	0	0	0	0	0
Gas Storage	**1'**	0	0	0	0	0	0
Tansportation (Non-Coincident Peak)	**1**	0	0	0	0	0	0
Distribution							
Mains							
Demand (NCP)	**1**	169,762	22,981	32,811	217,951	10,047	453,551
Customer	**4**	185,813	609	1	1	70	186,493
Direct Assignment							
Services							
Demand (NCP)	**1**	43,770	5,925	8,460	56,194	2,590	116,939
Customer	**4**	1,398,712	4,581	6	6	528	1,403,833
Direct Assignment							
Regualting Stations (NCP)	**1**	0	0	0	0	0	0
Meters, regulators, customer installations	**5**	1,624,260	10,639	142	142	12,271	1,647,454
Other	**10**	4,784	85	146	1,049	50	6,114
Total Distribution Expenses (NCP)		3,427,101	44,820	41,565	275,343	25,556	3,814,385
Distribution excluding Other (NCP)		3,422,317	44,735	41,419	274,294	25,506	3,808,270
Customer Accounts							
Meter Reading	**5**	541,420	3,546	47	47	4,090	549,151
Cust. Records & Collections Expenses	**7**	1,672,877	135,450	125,653	125,653	136,973	2,196,605
Uncollectible Accounts	**6**	4,451,984	3,561,587	3,561,587	3,561,587	3,561,587	18,698,331
Total Customer Accounts Expense		6,666,280	3,700,584	3,687,287	3,687,287	3,702,650	21,444,087
Distribution and Cust. Accounts - Uncollectible (NCP)		5,641,398	183,817	167,265	401,043	166,619	6,560,141
Distribution plus Customer Accounting		3,975,416	37,368	39,819	284,242	26,690	
Administrative and general	**11**	18,275,294	593,306	715,616	3,036,383	508,033	23,128,632
Distr., Cust. Accounts, (less bad debt), A&G (NCP)		23,916,692	777,122	882,881	3,437,425	674,652	29,688,773
Depreciation	**9**	4,658,624	356,217	783,660	4,315,839	191,946	10,306,286
TAXES							
Social Insurance	**12**	4,311,794	139,982	168,839	716,391	119,863	5,456,870
Other	**12**	3,125,514	101,470	122,387	519,294	86,886	3,955,551
Profit	**9**	192,054	14,685	32,307	177,922	7,913	424,881
VAT	**12**	28,182,156	914,931	1,103,544	4,682,377	783,434	35,666,442
Total Taxes		35,811,518	1,171,068	1,427,077	6,095,984	998,096	45,503,743
RETURN	**9**	15,769,241	1,205,779	2,652,657	14,608,929	649,727	34,886,333
WORKING CAPITAL REQUIREMENTS	**12**	1,570,202	50,976	61,485	260,884	43,650	1,987,198
Less:							
OTHER OPERATING INCOMES		0	0	0	0	0	
TOTAL AZERIGAS REVENUE REQUIREMENT (NCP)		86,178,260	7,122,749	9,369,348	32,280,649	6,119,658	141,070,663
Billing Determinants		2,688,940	296,791	826,130	4,585,950	78,749	
Azerigas Revenue Requirement (AZM/tcm) (NCP)		32,049	23,999	11,341	7,039	77,711	
(USD/tcm) (NCP)		6.68	5.00	2.36	1.47	16.19	
TOTAL REVENUE FOR GAS SECTOR (NCP)		86,178,260	7,122,749	9,369,348	32,280,649	6,119,658	141,070,663
Gas sector Revenue Requirement (AZM/tcm) (NCP)		32,049	23,999	11,341	7,039	77,711	
(USD/tcm) (NCP)		6.68	5.00	2.36	1.47	16.19	

D-5 Asset Allocations

Coincidental Peak

D-5.1 Total Gas Asset Allocation

D-5.2 Demand Gas Asset Allocation

D-5.3 Customer Gas Asset Allocation

Non-Coincidental Peak

D-5.4 Total Gas Asset Allocation

D-5.5 Demand Gas Asset Allocation

D-5.6 Customer Gas Asset Allocation

D-5.1 Total Gas Asset Allocation (CP)

Asset	Allocation factor	Residential	General Service	Large Volume Customers	Thermal Power Plants	District Heating	Total Costs 2004 ths. AZM
Intangible Assets	**8**	13,933	1,065	2,340	12,888	574	30,800
Gas Storage Assets	**1**	66,622,110	5,412,551	11,931,344	85,533,406	2,926,068	172,425,478
Transmission Assets	**1**	388,656,488	31,575,449	69,604,435	498,980,193	17,069,936	1,005,886,501
Distribution Assets							
Land	**1**	1,201,387	97,604	215,156	1,542,411	52,765	3,109,323
Structures and Improvements	**1**	222,000	18,036	39,758	285,017	9,750	574,561
Mains							
Demand	**1**	29,585,050	2,403,565	5,298,382	37,983,038	1,299,386	76,569,422
Customer	**4**	31,369,277	102,738	137	137	11,849	31,484,138
Compressor Station Equip.	**1**	18,311,802	1,487,698	3,279,458	23,509,775	804,261	47,392,993
Measuring and Reg. Equip.	**1**	0	0	0	0	0	0
Services							
Demand	**1**	174,807	14,202	31,306	224,427	7,678	452,419
Customer	**4**	5,411,387	17,723	24	24	2,044	5,431,201
Meters, meter installation	**5**	1,040,307	6,814	91	91	7,859	1,055,162
Regulators, installation	**5**	0	0	0	0	0	0
Total Distribution		87,316,016	4,148,379	8,864,312	63,544,919	2,195,593	166,069,219
Subtotal Assets (Storage, T&D)	**2**	929,150,025	102,554,778	285,465,099	0	27,211,296	1,344,381,198
General Assets	**8**	1,647,379	125,859	276,682	1,523,726	67,913	3,641,560
Total Assets in Service		930,811,338	102,681,701	285,744,122	1,536,614	27,279,783	1,348,053,558

D-5.2 Demand Gas Asset Allocation (CP)

Asset	Allocation factor	Residential	General Service	Large Volume Customers	Thermal Power Plants	District Heating	Total Costs 2004 ths. AZM
Intangible Assets	**8**	0	0	0	0	0	0
Gas Storage Assets	**1**	66,622,110	5,412,551	11,931,344	85,533,406	2,926,068	172,425,478
Transmission Assets	**1**	388,656,488	31,575,449	69,604,435	498,980,193	17,069,936	1,005,886,501
Distribution Assets							
Land	**1**	1,201,387	97,604	215,156	1,542,411	52,765	3,109,323
Structures and Improvements	**1**	222,000	18,036	39,758	285,017	9,750	574,561
Mains							
Demand	**1**	29,585,050	2,403,565	5,298,382	37,983,038	1,299,386	76,569,422
Customer	**4**	0	0	0	0	0	0
Compressor Station Equip.	**1**	18,311,802	1,487,698	3,279,458	23,509,775	804,261	47,392,993
Measuring and Reg. Equip.	**1**	0	0	0	0	0	0
Services							
Demand	**1**	174,807	14,202	31,306	224,427	7,678	452,419
Customer	**4**	0	0	0	0	0	0
Meters, meter installation	**5**	0	0	0	0	0	0
Regulators, installation	**5**	0	0	0	0	0	0
Total Distribution		49,495,045	4,021,104	8,864,061	63,544,668	2,173,841	128,098,719
Subtotal Assets (Storage, T&D)	**2**	902,907,252	99,658,236	277,402,466	0	26,442,744	1,306,410,698
General Assets	**8**	823,690	62,930	138,341	761,863	33,956	1,820,780
Total Assets in Service		903,730,941	99,721,165	277,540,807	761,863	26,476,701	1,308,231,478

D-5.3 Customer Gas Asset Allocation (CP)

Asset	Allocation factor	Residential	General Service	Large Volume Customers	Thermal Power Plants	District Heating	Total Costs 2004 ths. AZM
Intangible Assets	**8**	13,933	1,065	2,340	12,888	574	30,800
Gas Storage Assets	**1**	0	0	0	0	0	0
Transmission Assets	**1**	0	0	0	0	0	0
Distribution Assets							
Land	**1**	0	0	0	0	0	0
Structures and Improvements	**1**	0	0	0	0	0	0
Mains							
Demand	**1**	0	0	0	0	0	0
Customer	**4**	31,369,277	102,738	137	137	11,849	31,484,138
Compressor Station Equip.	**1**	0	0	0	0	0	0
Measuring and Reg. Equip.	**1**	0	0	0	0	0	0
Services							
Demand	**1**	0	0	0	0	0	0
Customer	**4**	5,411,387	17,723	24	24	2,044	5,431,201
Meters, meter installation	**5**	1,040,307	6,814	91	91	7,859	1,055,162
Regulators, installation	**5**	0	0	0	0	0	0
Total Distribution		37,820,970	127,275	251	251	21,752	37,970,500
Subtotal Assets (Storage, T&D)	**2**	26,242,774	2,896,542	8,062,633	0	768,552	37,970,500
General Assets	**8**	823,690	62,930	138,341	761,863	33,956	1,820,780
Total Assets in Service		27,080,397	2,960,536	8,203,315	774,751	803,083	39,822,080

D-5.4 Total Gas Asset Allocation (NCP)

Asset	Allocation factor	Residential	General Service	Large Volume Customers	Thermal Power Plants	District Heating	Total Costs 2004 ths. AZM
Intangible Assets	**8**	13,933	1,065	2,340	12,888	574	30,800
Gas Storage Assets	**1**	64,538,074	8,736,641	12,473,526	82,857,798	3,819,439	172,425,478
Transmission Assets	**1**	376,498,754	50,967,346	72,767,386	483,371,375	22,281,640	1,005,886,501
Distribution Assets							
Land	**1**	1,163,805	157,547	224,933	1,494,162	68,875	3,109,323
Structures and Improvements	**1**	215,056	29,112	41,565	276,101	12,727	574,561
Mains							
Demand	**1**	28,659,587	3,879,702	5,539,151	36,794,874	1,696,108	76,569,422
Customer	**4**		102,738	137	137	11,849	114,861
Compressor Station Equip.	**1**	17,738,982	2,401,359	3,428,482	22,774,355	1,049,814	47,392,993
Measuring and Reg. Equip.	**1**	0	0	0	0	0	0
Services							
Demand	**1**	169,338	22,924	32,729	217,407	10,022	452,419
Customer	**4**	5,411,387	17,723	24	24	2,044	5,431,201
Meters, meter installation	**5**	1,040,307	6,814	91	91	7,859	1,055,162
Regulators, installation	**5**	0	0	0	0	0	0
Total Distribution		54,398,463	6,617,920	9,267,111	61,557,150	2,859,299	134,699,942
Subtotal Assets (Storage, T&D)	**2**	929,150,025	102,554,778	285,465,099	0	27,211,296	1,344,381,198
General Assets	**8**	1,647,379	125,859	276,682	1,523,726	67,913	3,641,560
Total Assets in Service		930,811,338	102,681,701	285,744,122	1,536,614	27,279,783	1,348,053,558

D-5.5 Demand Gas Asset Allocation (NCP)

Asset	Allocation factor	Residential	General Service	Large Volume Customers	Thermal Power Plants	District Heating	Total Costs 2004 ths. AZM
Intangible Assets	**8**	0	0	0	0	0	0
Gas Storage Assets	**1**	64,538,074	8,736,641	12,473,526	82,857,798	3,819,439	172,425,478
Transmission Assets	**1**	376,498,754	50,967,346	72,767,386	483,371,375	22,281,640	1,005,886,501
Distribution Assets							
Land	**1**	1,163,805	157,547	224,933	1,494,162	68,875	3,109,323
Structures and Improvements	**1**	215,056	29,112	41,565	276,101	12,727	574,561
Mains							
Demand	**1**	28,659,587	3,879,702	5,539,151	36,794,874	1,696,108	76,569,422
Customer	**4**		0	0	0	0	0
Compressor Station Equip.	**1**	17,738,982	2,401,359	3,428,482	22,774,355	1,049,814	47,392,993
Measuring and Reg. Equip.	**1**	0	0	0	0	0	0
Services							
Demand	**1**	169,338	22,924	32,729	217,407	10,022	452,419
Customer	**4**	0	0	0	0	0	0
Meters, meter installation	**5**	0	0	0	0	0	0
Regulators, installation	**5**	0	0	0	0	0	0
Total Distribution		47,946,769	6,490,645	9,266,860	61,556,899	2,837,546	128,098,719
Subtotal Assets (Storage, T&D)	**2**	902,907,252	99,658,236	277,402,466	0	26,442,744	1,306,410,698
General Assets	**8**	823,690	62,930	138,341	761,863	33,956	1,820,780
Total Assets in Service		903,730,941	99,721,165	277,540,807	761,863	26,476,701	1,308,231,478

D-5.6 Customer Gas Asset Allocation (NCP)

Asset	Allocation factor	Residential	General Service	Large Volume Customers	Thermal Power Plants	District Heating	Total Costs 2004 ths. AZM
Intangible Assets	**8**	13,933	1,065	2,340	12,888	574	30,800
Gas Storage Assets	**1**	0	0	0	0	0	0
Transmission Assets	**1**	0	0	0	0	0	0
Distribution Assets							
Land	**1**	0	0	0	0	0	0
Structures and Improvements	**1**	0	0	0	0	0	0
Mains							
Demand	**1**	0	0	0	0	0	0
Customer	**4**	31,369,277	102,738	137	137	11,849	31,484,138
Compressor Station Equip.	**1**	0	0	0	0	0	0
Measuring and Reg. Equip.	**1**	0	0	0	0	0	0
Services							
Demand	**1**	0	0	0	0	0	0
Customer	**4**	5,411,387	17,723	24	24	2,044	5,431,201
Meters, meter installation	**5**	1,040,307	6,814	91	91	7,859	1,055,162
Regulators, installation	**5**	0	0	0	0	0	0
Total Distribution		37,820,970	127,275	251	251	21,752	37,970,500
Subtotal Assets (Storage, T&D)	**2**	26,242,774	2,896,542	8,062,633	0	768,552	37,970,500
General Assets	**8**	823,690	62,930	138,341	761,863	33,956	1,820,780
Total Assets in Service		27,080,397	2,960,536	8,203,315	774,751	803,083	39,822,080

D-6 Allocation Factors

D-6.1 Coincidental Peak Allocators

D-6.2 Non-Coincidental Peak Allocators

D-6.1 Coincidental Peak Allocators

Description of Allocation Factors	Factor No.	Total	Residential	General Service	Large Volume Customers	Thermal Power Plants	District Heating
Capacity Allocators							
Single Coincident Peak	**1**	31,968	12,352	1,004	2,212	15,858	543
		1.00000	0.38638	0.03139	0.06920	0.49606	0.01697
Single Coincident Peak without TPPs (for Gas Storage Allocation)	**1'**	16,110	12,352	1,004	2,212	0	543
		1.00000	0.76672	0.06229	0.13731	0.00000	0.03367
Commodity Allocators							
Annual Gas Sales (Excluding Transportation) tcm	**2**	3,890,610	2,688,940	296,791	826,130	0	78,749
		1.00000	0.69114	0.07628	0.21234	0.00000	0.02024
Annual Gas Sales (Including Transportation) tcm	**3**	8,476,560	2,688,940	296,791	826,130	4,585,950	78,749
		1.00000	0.31722	0.03501	0.09746	0.54102	0.00929
Annual Transportation of Gas	**3'**	4,585,950	0	0	0	4,585,950	0
		1.00000	0.00000	0.00000	0.00000	1.00000	0.00000
Customer Allocators							
Number of Customers	**4**	919,354	916,000	3,000	4	4	346
		1.00000	0.99635	0.00326	0.00000	0.00000	0.00038
Meter Reading							
Number of Customers	**5**	919,354	916,000	3,000	4	4	346
Average Number of Meters per Customer			1	1	1	1	1
Residential Meter Reading Expenses = 1			1	2	20	20	20
Allocation on Weighted Average Number of Customers		929,080	916,000	6,000	80	80	6,920
		1.00000	0.98592	0.00646	0.00009	0.00009	0.00745
Bad Debt Allocator							
Bad Debt Expense	**6**	0.84000	20%	16%	16%	16%	16%
		1.00000	0.23810	0.19048	0.19048	0.19048	0.19048
Meter Reading and Collection	**7**	1.0	0.8	0.1	0.1	0.1	0.1
Asset Allocators							
Transmission, Distribution Assets	**8**	1,344,381,198	608,175,003	46,464,298	102,144,873	562,525,112	25,071,912
		1.00000	0.45238	0.03456	0.07598	0.41843	0.01865
Total Assets	**9**	1,348,053,558	609,330,181	46,591,800	102,499,782	564,495,253	25,105,742
		0.99998	0.45201	0.03456	0.07604	0.41875	0.01862
Internally Developed Allocators							
Total Disrtibution Expenses, Other Distribution Expenses	**10**	5,820,996	4,554,871	80,871	139,427	998,588	47,240
		1.00000	0.78249	0.01389	0.02395	0.17155	0.00812
Distribution Plus Customer Accounting Expenses, less Uncollectible							
Distribution Expsense, Customer Accounting Expenses,							
less Bad Debt Expense	**11**	8,576,102	6,776,483	219,998	265,350	1,125,891	188,379
		1.00000	0.79016	0.02565	0.03094	0.13128	0.02197
Distribution, Customer Acct. (less bad debt),	**12**	38,812,265	30,667,856	995,629	1,200,878	5,095,368	852,533
plus Admin. & General		1.00000	0.79016	0.02565	0.03094	0.13128	0.02197

D-6.2 Non-Coincidental Peak Allocators

Description of Allocation Factors	Factor No.	Total	Residential	General Service	Large Volume Customers	Thermal Power Plants	District Heating
Capacity Allocators							
Non-Coincident Peak	1	33000	12351.9	1672.1	2387.3	15858.1	731.0
		1.00000	0.37430	0.05067	0.07234	0.48054	0.02215
Non-Coincident Peak without TPPs (for Gas Storage Allocation)	1'	17142	12351.9	1672.1	2387.3	0.0	731.0
		1.00000	0.72055	0.09754	0.13926	0.00000	0.04264
Commodity Allocators							
Annual Gas Sales (Excluding Transportation) tcm	**2**	3,890,610	2,688,940	296,791	826,130	0	78,749
		1.00000	0.69114	0.07628	0.21234	0.00000	0.02024
Annual Gas Sales (Including Transportation) tcm	**3**	8,476,560	2,688,940	296,791	826,130	4,585,950	78,749
		1.00000	0.31722	0.03501	0.09746	0.54102	0.00929
Annual Transportation of Gas	**3'**	4,585,950	0	0	0	4,585,950	0
		1.00000	0.00000	0.00000	0.00000	1.00000	0.00000
Customer Allocators							
Number of Customers	**4**	919,354	916,000	3,000	4	4	346
		1.00000	0.99635	0.00326	0.00000	0.00000	0.00038
Meter Reading							
Number of Customers	**5**	919,354	916,000	3,000	4	4	346
Average Number of Meters per Customer			1	1	1	1	1
Residential Meter Reading Expenses = 1			1	2	20	20	20
Allocation on Weighted Average Number of Customers		929,080	916,000	6,000	80	80	6,920
		1.00000	0.98592	0.00646	0.00009	0.00009	0.00745
Bad Debt Allocator							
Revenues by class		706706.0	320,775	52,994	137,974	137,974	56,989
Bad Debt Expense	**6**	0.84000	20%	16%	16%	16%	16%
		1.00000	0.23810	0.19048	0.19048	0.19048	0.19048
Meter Reading and Collection	**7**	1.0	0.8	0.1	0.1	0.1	0.1
Asset Allocators							
Transmission, Distribution Assets	**8**	1,344,381,198	608,175,003	46,464,298	102,144,873	562,525,112	25,071,912
		1.00000	0.45238	0.03456	0.07598	0.41843	0.01865
Total Assets	**9**	1,348,053,558	609,330,181	46,591,800	102,499,782	564,495,253	25,105,742
		0.99998	0.45201	0.03456	0.07604	0.41875	0.01862
Internally Developed Allocators							
Total Disrtibution Expenses, Other Distribution Expenses	**10**	5,820,996	4,554,871	80,871	139,427	998,588	47,240
		1.00000	0.78249	0.01389	0.02395	0.17155	0.00812
Distribution Plus Customer Accounting Expenses, less Uncollectible							
Distribution Expsense, Customer Accounting Expenses,							
less Bad Debt Expense	**11**	8,576,102	6,776,483	219,998	265,350	1,125,891	188,379
		1.00000	0.79016	0.02565	0.03094	0.13128	0.02197
Distribution, Customer Acct. (less bad debt),	**12**	38,812,265	30,667,856	995,629	1,200,878	5,095,368	852,533
plus Admin. & General		1.00000	0.79016	0.02565	0.03094	0.13128	0.02197

APENDIX E – CALCULATION OF WORKING CAPITAL

Example of the Calculation of Regulatory Working Capital

The individual components of regulatory working capital are: (1) cash working capital; (2) fuel inventory; (3) materials and supplies inventories; and (4) prepayments.

1. Cash Working Capital

Cash working capital represents the investment required for cash to pay for operating expenses, cash balances, and similar needs, between the time expenditures are required to provide services and the time collections are received for such services.

Approximately sixty days of operating and maintenance (O&M) expenses, exclusive of purchased gas costs, is used in the formula below to compute cash working capital:

$$\text{Cash working capital} = \frac{\text{O\&M Expenses less Purch.Gas-for-Resale Costs}}{6}$$

2. Fuel Inventory

An average fuel inventory balance is used in the formula below to parallel the method used for determining asset investment, as compared to a year-end balance. The Tariff Council will consult with industry to insure that this is an appropriate balancing method.

$$\text{Fuel Inventory} = \frac{\text{Sum of 12 months fuel inventory}}{12}$$

3. Materials and Supplies

Similarly, a 12-month average balance is used to determine the materials and supplies requirement.

$$\text{Materials and Supplies} = \frac{\text{Sum of 12 months value of materials and supplies}}{12}$$

4. Prepayments

Prepayments are made in advance of the period to which they apply and include items such as prepaid rents, insurance and taxes. Because an investment is required before these funds are recovered a return is allowed on the invested funds. Often the average measurement period encompasses more than a single year, because certain pre-paid expenses, such as pre-paid insurance often are made for periods in excess of one year.

$$\text{Prepayments} = \frac{\text{One Average year of pre-paid items}}{12}$$

The return on regulatory working capital will then be calculated as follows:

(Cash working capital + Fuel Inventory + Materials and Supplies inventory + Prepayments) x the Rate-of-Return

Eventually, the PGC clause will need to be revised to reflect the cost of gas injected and withdrawal from storage, to ensure that the customers are charged the cost for the gas they actually consume.

APPENDIX H – ECONOMIC DATA

Actual data from Azerigas financial reporting forms for 2004 were used in this report. In particular, revenue requirement was reconstructed on the basis of information from 1-IF Form presented below.

Note, that Azerigas generates its reporting information for the following categories of business (original terminology is preserved):

- general, which combines data for all businesses of the enterprise;
- construction, it represents a report on capital expenditures of the enterprise;
- non-core business, which reports data on activities non related to gas supply;
- gas, which collectively represents transmission (Azerigasnegl), underground storage and distribution businesses;
- transmission (Azerigaznegl), which reports data on operation of high pressure system of Azerbaijan;
- gas storage, which reports data on operation of natural gas storage facilities; and
- supposedly, distribution, though total data on distribution were not available at the time of preparation of this report.
-

At the time of preparation of this report a set of reporting forms 1, 2 and 1-IF for 2004 were available for gas, Azerigasnegl and storage. The data for distribution were calculated as a difference between gas and transmission and storage. Such calculation was based on the presumption of that internal turnover among these branches of the enterprise was very small.

Another reason to use data for 2004 was based on the fact that part of high-pressure gas system, previously operated by Azerigasnegl, in 2005 was transferred to Baku distribution enterprise. Due to that separation of costs by technological functions (transmission, storage and distribution) was lost.

Data from 1-IF Form for gas, transmission (Azerigasnegl), storage and distribution (as calculated) for 2004 are presented in the table below.

Data for purchased local natural gas, gas storage, transportation, distribution, depreciation, taxes accounts were taken directly from 1-IF Form.

Return was calculated on the basis of 2004 net assets for gas and 9.6% rate of return. The latter was derived by PA in its tariff work for Azerenerji. This amount was taken for Azerigas due to proximity of these two enterprise.

Administrative & General, and Working Capital accounts were estimated.

Total imported natural gas costs were calculated based on sales to Azerenerji 4,585,950 tcm, 141 tcm technical losses, price of imported gas 52 USD/tcm and 4800 AZM/USD exchange rate.

Data from 2004 balance sheets for gas, Azerigaznegl and storage were used to derive asset allocaters described in Appendix C.

1-IF Form for 2004

		Gas	Transportation (Azerigasnegl)	Storage	Baku Distribution Enterprise	Total Regions	Total Distribution
Materials and supplies	010	316,926,224.8	309,652,986.9	3,330,752.3	1,915,477.8	2,027,007.8	3,942,485.6
Raw Materials	011	3,158,139.9	1,717,139.1		622,235.4	818,765.4	1,441,000.8
Components and Semi-Finished Goods	012					0.0	0.0
Fuel	013	1,820,504.5	703,222.0	206,437.0	449,026.9	461,818.6	910,845.5
Electric Power	014	1,159,857.5	137,077.0	909,656.3	63,215.5	49,908.7	113,124.2
Puchased Services	015	4,813,742.1	1,121,568.0	2,214,659.0	781,000.0	696,515.1	1,477,515.1
Royalties (Cost of Gas)	016	305,973,980.8	305,973,980.8			0.0	0.0
Payroll	020	24,769,641.3	7,661,750.9	2,142,717.2	8,788,223.9	6,176,949.3	14,965,173.2
Incuding Staff Payroll	021					0.0	0.0
Social Seciruty Payment	030	7,133,799.0	2,191,933.3	604,048.7	2,548,059.3	1,789,757.7	4,337,817.0
Depreciation	040	38,271,662.9	15,404,622.3	14,217,000.0	2,528,540.2	6,121,500.4	8,650,040.6
Other Costs (051-053; 055-066)	050	27,022,024.9	18,841,368.3	4,456,076.8	1,723,412.1	2,001,167.7	3,724,579.8
Communication	051	475,481.8	116,431.0		157,218.6	201,832.2	359,050.8
Site Protection and Security	052	1,500.0				1,500.0	1,500.0
Business Trips	053	310,301.1	109,784.8			200,516.3	200,516.3
Transportation and Lodging	054	3,144.2				3,144.2	3,144.2
IT Services	055	2,492.0				2,492.0	2,492.0
Bank Fees and Interest Expenses	056	672,364.7	192,557.4	92,313.9	200,224.5	187,268.9	387,493.4
Depreciation of Intengible Assets	057	57,594.6	43,736.5			13,858.1	13,858.1
Lease	058	20,068.1				20,068.1	20,068.1
Representation Expenses	059					0.0	0.0
Communal Services	060	374,152.5		69,775.4	170,058.9	134,318.2	304,377.1
Transportation Services	061	6,370.0				6,370.0	6,370.0
Current Repair	062	1,218,350.6		865,087.0		353,263.6	353,263.6
Capital Repair	063	5,901,143.4	5,557,301.3	10,000.0	176,229.3	157,612.8	333,842.1
Obligatory Insurance	064	196,370.2		13,480.0		182,890.2	182,890.2
Taxes, Included into Cost of Sales	065	3,150,861.2	1,021,595.0	1,908,554.0	143,773.7	76,938.5	220,712.2
Other Payments	066	14,634,974.7	11,799,962.3	1,496,866.5	875,907.1	462,238.8	1,338,145.9
Total (010+020+030+040+050)	067	414,497,505.4	353,752,661.7	24,820,370.4	17,673,772.2	18,250,701.1	35,924,473.3

APENDIX I - BIBLIOGRAPHY

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