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Energy Sector Management Assistance Programme

Kazakhstan

Natural Gas Investment Strategy Study

Volume 2

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JOINT UNDP / WORLD BANK
ENERGY SECTOR MANAGEMENT ASSISTANCE PROGRAMME (ESMAP)

PURPOSE

The Joint UNDP/World Bank Energy Sector Management Assistance Programme (ESMAP) is a special global technical assistance program run by the World Bank's Industry and Energy Department. ESMAP provides advice to governments on sustainable energy development. Established with the support of UNDP and 15 bilateral official donors in 1983, it focuses on policy and institutional reforms designed to promote increased private investment in energy and supply and end-use energy efficiency; natural gas development; and renewable, rural, and household energy.

GOVERNANCE AND OPERATIONS

ESMAP is governed by a Consultative Group (ESMAP CG), composed of representatives of the UNDP and World Bank, the governments and other institutions providing financial support, and the recipients of ESMAP's assistance. The ESMAP CG is chaired by the World Bank's Vice President, Finance and Private Sector Development, and advised by a Technical Advisory Group (TAG) of independent energy experts that reviews the Programme's strategic agenda, its work program, and other issues. ESMAP is staffed by a cadre of engineers, energy planners, and economists from the Industry and Energy Department of the World Bank. The Director of this Department is also the Manager of ESMAP, responsible for administering the Programme.

FUNDING

ESMAP is a cooperative effort supported by the World Bank, UNDP and other United Nations agencies, the European Community, Organization of American States (OAS), Latin American Energy Organization (OLADE), and public and private donors from countries including Australia, Belgium, Canada, Denmark, Germany, Finland, France, Iceland, Ireland, Italy, Japan, the Netherlands, New Zealand, Norway, Portugal, Sweden, Switzerland, the United Kingdom, and the United States.

FURTHER INFORMATION

An up-to-date listing of completed ESMAP projects is appended to this report. For further information or copies of completed ESMAP reports, contact:

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Kazakhstan

Natural Gas Investment Strategy Study

Volume 2

Appendices 1 through 3

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Energy Sector Management Assistance Programme
(ESMAP)

Oil and Gas Division
Industry and Energy Department
The World Bank

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Abbreviations and Acronyms

ADB	Asian Development Bank
BCF	Billion Cubic Feet (10^9 CF)
BCM	Billion Cubic Meters (10^9 CM)
BOD	Barrels of Oil Equivalent per Day
BOE	Barrels of Oil Equivalent
BOO	Build-Operate-Own
BOT	Build-Operate-Transfer
BOTAS	Turkish State Oil and Gas Company
BTU	British Thermal Units
CA	Central Asia
CAC	Central Asia Center
CAPEX	Capital Expenditure
CCGT	Combined Cycle Gas Turbine
CIF	Cost, Insurance and Freight (included)
CIS	Commonwealth of Independent States
CHP	Combined Heat and Power Plant
CM	Cubic Meter
CO_2	Carbon Dioxide
DFO	Distillate Fuel Oil (gas-oil)
EBRD	European Bank for Reconstruction and Development
EEPROM	Electrically Erasable Programmable ROM
EIB	European Investment Bank
EPC	Engineering, Procurement and Construction
ESMAP	Energy Sector Management Assistance Programme
ESCO	Energy Service Companies
ESR	Energy Sector Report
EU	European Union
FE	Far East
FGD	Flue Gas Desulphurization plant
FO	Fuel Oil
FSU	Former Soviet Union
G-7	USA, Japan, Germany, UK, France, Italy, Canada

GDP	Gross Domestic Product
GEF	Global Environment Facility
GOK	Government of Kazakhstan
GWh	Gigawatt hours (10^9 Wh)
HSE	Health, Safety and Environment
IAS	International Accounting Standards
IBRD	International Bank for Reconstruction and Development
IEA	International Energy Agency
IFC	International Finance Corporation
IOCs	International Oil Companies
IPP	Independent Power Plant
Kcal	Kilocalories
KWh	Kilowatt Hours (10^3 wh)
LDC	Local Distribution Company
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gas
LRMC	Long-Run Marginal Cost
LSTK	Lump-Sum Turn-Key
MCF	Thousand Cubic Feet
MCM	Thousand Cubic Meters
MMCM	Million Cubic Meters
ME	Middle East
MENR	Ministry of Energy and Natural Resources
MG	Ministry of Geology
MIGA	Multilateral Investment Guarantee Agency
MMBTU	Million British Thermal Units
MMSCFD	Million Standard Cubic Feet per Day
MMTCE	Million Tonnes of Coal Equivalent
MMTOE	Million Tonnes of Oil Equivalent
MOEC	Ministry of Electricity and Coal Industry
MOG	Ministry of Oil and Gas
MT	Metric Tonne
MW	Megawatt
NAG	Non Associated Gas
NG	Natural Gas
OECD	Organization for Economic Cooperation and Development

OECF	Overseas Economic Cooperation Fund
Opex	Operating Expenditure
p.a.	per annum
PSC	Production Sharing Contract
RFO	Residual Fuel Oil
ROM	Read Only Memory
R/P ratio	Reserves to Production Ratio
SA	South Asia
SAR	Staff Appraisal Report
SCF	Standard Cubic Feet measured at 60°F and 30 inch Hg
SEA	Southeast Asia
TCM	Trillion Cubic Meters (10^{12} CM)
TCE	Tons of Coal Equivalent
TOE	Tons of Oil Equivalent
UAE	United Arab Emirates
UGSS	Unified Gas Supply System, the transmission network of the former Soviet Union.
VAT	Value Added Tax
WB	World Bank

Definitions

OECD Europe: Austria, Belgium, Denmark, Finland, France, Germany, Greece, Iceland, Ireland, Italy, Luxembourg, The Netherlands, Norway, Portugal, Spain, Sweden, Switzerland, United Kingdom.

Eastern Europe: Poland, Czech Republic, Slovakia, Hungary, Rumania, Bulgaria, Slovenia, Croatia, Bosnia and Herzegovina, Yugoslavia (Serbia).

Former Soviet Union (FSU): Central Asian Republics - Kazakhstan, Uzbekistan, Turkmenistan, Kirgizistan, Tadjikistan. Caucauses - Georgia, Armenia, Azerbaijan. European part - Russian Federation, Ukraine, Belarus, Moldova, Lithuania, Estonia, Latvia.

Units of Measure

Natural Gas

1 MCF (1,000 CF) = 28.32 cubic meter = about 1 MM BTU = 252,000 Kcal

1 CM = about 9,000 Kcal

1 BCM= 35.3 BCF= about 0.9 MMTOE = about 1.35 MMTCE = (about 2.7 million tonnes of lignite)

LNG 1 ton = LNG 2.35 m^3 = about 1,400 m^3 of natural gas

Energy & Power

1KWh= 3,412 BTU= 860 Kcal

1,000 KWh= 3.412 mm BTU

1 MW = 1,000 KW

1 GWh of electricity consumes approximately:

250 tons of oil in an oil-fired conventional steam power plant

390 tons of coal in a coal-fired power plant

8,000,000 CF of natural gas in a combined-cycle power plant

Currency Unit

75 Tenge = US$1 as of April 1997

Appendix 1.1

Descriptions on Selected Priority Projects

A. Karachaganak Field Gas Processing Plant

A.1. A modern gas processing plant is an absolute requirement if any use is contemplated for this gas other than delivery to Orenburg, Russia. The current arrangement for gas processing in Orenburg is not only creating environmental issues but also significant economic losses because the raw gas produced at Karachaganak contains a high percentage of sulfur content (4.5% H_2S by weight) and cannot meet the export quality specification. Carry-over of LPG components (propane and butane) in the raw gas is another economic loss. Currently, 6 BCM/Y of raw gas is transferred to Orenburg. According to the Karachganak producer's plan in 1995, the gas production is expected to increase up to 25 BCM/Y at peak, and there is a need to exploit new markets for Karachaganak gas. If so, a gas processing plant to treat about 4 BCM/Y would be required for the first phase, including desulfurization and condensate stabilization. Expansion of the gas processing plant would be required as gas markets grow and gas production from the Karachaganak field increases.

B. Aktyubinsk Oblast - Flared Gas Utilization for Power Generation

Background

B.1. Aktyubinsk oblast has a constant deficit of electricity supply. In 1995 when there was deep economic depression, the electricity consumption was 2.54 billion Kwh. The power stations in the oblast (e.g. Aktyubinsk HEPC[1] and HEPC of the chrome industrial plant near Aktyubinsk) supplied only 0.348 billion Kwh or 14% of the total required capacity. The balance of 2.192 billion Kwh was imported from Russia at 4.5 cents per Kwh.

B.2. With gradual economic recovery, it is expected that the electricity consumption around 2005 will recover the 1990 level or about 3.7 billion Kwh. Thus, there is a clear need for additional power generation in the oblast.

B.3. The Zhanazol oil field is located about 240 Km south of the city Aktyubinsk. The field is currently flaring most of the associated gas produced from oil. In 1996, the volume of the flared gas was about 0.5 BCM (out of the total production of 0.679 BCM). The volume of the associated gas is expected to reach 1.28 BCM by the year 2000. Near Zhanazol, there are a few gas production sources[2] in the future. In particular, the Uritau filed is expected to have a potential to produce maximum about 2 BCM per year. In

[1] Heat and electricity co-generation plant.

[2] The Urihtau oil-gas-condensate field, the Kenkiak oil field, the Alibekmola oil-gas-condensate field, etc.

1996, the average gas import cost was US$ 31.4 per 1000 CM while the sales price at the Zhanazol gas was US$ 9 per 1000 CM.

Project Objectives

B.4. The principal objectives of the project are to:

a solve the environmental issue resulting from flared gas;

b promote efficient use of gas for markets with high market values; and

c support the commercialization of JSC Aktyubinsktransgas and further development of the gas sector.

Project Description

B.5. The project intends to complete the gas supply route from the Zhanazol field to users in Aktyubinsk and Alga by completing the unfinished 50.9 Km pipeline between Oktiabskoe and Alga, and by installing a gas compressor station at Zhanazol. Kazakhstan started the construction of a 530 mm diameter pipeline from Zhanazol to Aktyubinsk via Oktiabskoe and Alga about 5 years ago. However, due to the current financial crisis, a part of the pipeline is uncompleted. According to the Kazak design, the pipeline can cater up to 1 BCM of gas per year if a 2.5 MW gas compressor station is installed at Zhanazol. Then, the maximum operating pressure of the pipeline is 36 Kg/cm2.

B.6. The primary gas consumers would be the newly planned Aktyubinsk HEPC with the first stage capacity of 477 MW and industrial consumers in and near Aktyubinsk and Alga. The Aktyubinsk HEPC alone is expected to consume about 0.7 BCM per year.

B.7. In the future, it is possible to collect gas from the Uritau field and other fields near Zhanazol. If an additional pipeline to connect with the Bukhara - Ural transit pipeline is laid from Zhanazol via Emba, the second gas supply route to Aktyubinsk could be established.

Project Costs

B.8. The total project cost excluding contingencies is estimated at US$ 93.9 million equivalent. Summary project costs are given below:

(Unit: Million US$)

Project Component	*Local*	*Foreign*	*Total*
Completion of the unfinished pipeline	6	14.4	**20.4**
2.5 MW gas compressor station	1	2.5	**3.5**
Reconstruction of the Zhanazol gas processing plant (including LPG extraction)	(5)	(45)	**(50.0)**
Total	**12**	**61.9**	**93.9**

Preliminary Economic Analysis

B.9. Assuming the gas production cost at US$ 9.5 per 1000 CM and the sales values of gas at US$ 30 per 1000 CM, the whole sales values of LPG and condensate at US$ 100 per ton and US$ 70 per ton respectively and using the capital investment cost of US$ 93.9 million and the gas sales volume of 1 BCM per year, a preliminary calculation indicates an economic internal rate of return of 32.6% which implies that the project is highly economic. (Refer to Table 4 of Appendix 2.4 for the calculation of the economic rate of return.)

C. Kumkol and the Surrounding Oil Fields: Flared Gas Utilization

Background

C.1. Over the course of the past year, the Government's privatization program has resulted in the transfer of the producing assets of Kumkol and the surrounding oil fields to the private sector. Five private sector operators are now responsible for the operation and future development of these fields:

- Hurricane, which acquired the shares of Yushneftegaz has the largest presence in the area and is the operator of the Kumkol field. Production from Kumkol averaged 50,000 barrels per day (2.5 million tons per year) in 1996. Hurricane is currently undertaking a workover program and its target is to boost production to 60,000 barrels per day (or higher) by year end 1997. Future production levels could well exceed 100,000 barrels per day (5 million tons per year.)

- South Kumkol is owned by a joint venture of Hurricane and Lukoil. Discussions are ongoing concerning the operation of this portion of the Kumkol field.

- Kazgermunai, is owned by Hurricane (through its acquisition of the Yushneftegaz shares) and by a German joint venture (RWE/DEA and Erdoel-Erdgas) which has operating responsibility. (IFC also has a 7.5% interest in Kazgermunai.) Kazgermunai owns three fields, Akshabul, Nuraly and Aksai. and plans to start production from Akshabul late in 1997. Production is forecast to build to a peak level of 30,000 to 40,000 barrels per day.

- Kuatanlonmunai is developing two small fields south of Kumkol. Production from these fields is projected to reach a level of 13,000 barrels per day within two years.

- Turan Petroleum has obtained the rights to develop three fields (Hurricane owns a 50% share of these fields.) There is, at present, no development activity associated with these fields.

C.2. The operating agreements include a requirement that the operators develop plans for the utilization of the associated gas. A grace period, however, is incorporated in the agreements to allow the operators adequate time to develop these plans. During this grace period, flaring of associated gas will likely continue. Current estimates indicate a gas oil ratio on the order of 100 to 120 cubic meters of gas per ton of oil produced. Thus, when peak oil production levels are achieved in the region, associated gas production could well exceed 750 million cubic meters per year.

Gas Utilization Plan

C.3. The operators have undertaken some preliminary analysis of the gas utilization options. The options under consideration include:
- Extracting the NGLs from the gas stream;
- Reinjecting the whole gas stream or the residue gas as part of a reservoir management program;
- Utilizing the gas for power production to meet the requirements of the fields;
- Generating surplus power for sale within the region.

Very Preliminary Assessment

C.4. According to the information provided during the mission's stay in Kyzl-Orda and Kumkol, the available associated gas sources in the near future are limited to such operators as Hurricane, Kazgermunai and Kuatamlonmunai. Lukoil's current oil production rate is only 31 ton per day and Lukoil stated in its letter to the mission that there is no gas utilization plan in the near future. Turan Petroleum is currently not active and there is no gas utilization plan.

C.5. Using the oil production data given by the above operators and assuming 75% recovery rate for LPG and 90% for condensate, the production rates of LPG and condensate in the near future are summarized below:

Operators	Gas Flow Rate (BCM/Y)	Gas Composition C3, C4, C5+ (Mol. %)	LPG Recovery (Ton/Y)	Condensate Recovery (Ton/Y)
Hurricane	0.05 - 0.09	13.9, 9.6, 1.8	19,570 - 35,220	2,660 - 4,790
Kazgermunai	0.18 - 0.24	7.3, 3.0, 1.8	29,870 - 39,820	9,290 - 12,380
Kuatamlonmunai	0.013	Similar to the above	5,090	690
Total	*0.24 - 0.34*		*54,530 - 80,130*	*12,640 -17,860*

C.6. According to these operators' current plan, gas reinjection and power generation for their own use are of a high priority. Kazgermunai stated that the use of its gas for electricity export would be limited to maximum 30%. If so, the capacity of electricity generation for sale is limited. At best, the following electricity generation is anticipated.

Operators	Installed capacity (MW)	Generated capacity (million KWh) @ load factor 75%
Hurricane	30	197
Kazgermunai	30	197
Kuatamlonmunai	10	66
Total	*70*	*460*

C.7. Using the current cost yardsticks and whole sale prices (e.g. $120 per ton for LPG, $70 per ton for condensate and 3 cents for electricity) and assuming zero cost for gas, the preliminary calculations of the economic rate of return for each operator's LPG or electricity generation projects fall into a range of 15 to 22%. However, recalculation based on more accurate cost estimation and market survey is mandatory.

C.8. The region is also importing all its electric power. Consequently, there should be a ready market for any power produced for sale by the oil operators. Two issues, however, would have to be resolved. First, it will likely be necessary to construct a new transmission line from Kumkol to Kyzl-Orda. It is likely that financing for this line would have to be provided by the Kumkol area operators. Second, the issue of non payment remains a concern. The Kumkol area operators will likely require clear financial assurances before committing the capital investment to construct facilities to generate power for sale into the regional market.

Recommendations

C.9. At this stage, no effort has been made to coordinate these plans. Without coordination, there is a risk that the overall utilization of the associated gas will be sub-optimized. Consequently, it is the recommendation of the mission that a Steering Committee be established under the Chairmanship of a designated Government official (for example the Deputy Akim of the Kyzl-Orda oblast responsible for economic affairs) with representation from the national and local governments, each of the operating companies and LPG/electricity distribution companies. This Committee will be responsible for the development of a coordinated plan for the utilization of associated gas in the region.

C.10. While the Steering Committee will have responsibility to coordinate activities related to the utilization of associated gas, it is important to keep in mind that these gas resources are now owned by the private sector companies. Consequently, the primary responsibility for designing plans for the utilization of the associated gas from each individual field must remain with the operator of that field.

D. Rehabilitation and Modernization of the Bukhara- Shymkent- Almaty Transit Line

Background

D.1. The city of Almaty faces a sever gas supply constraint in the winter season. These days, the pipeline terminal pressure in Almaty is very low and fluctuates. Users for household heating cannot use gas under a safe and reliable condition. Although the current supply constraint mainly attributes to non-payment by consumers, improvement of the situation is expected as the privatization of the power sector and the recent nation-wide program proceed. The privatized power station in Alamty (Almaty CHP No.1 station) is willing to increase the use of gas in place of other fuels (coal and mazout) to minimize pollution.

D.2. There are two lines along the route from Shymkent to Almaty. The first line was built in 1963. Some sections were replaced during 1968 -1970. Although repairs were often made, some sections of the line are in a poor condition causing corrosion and leakage problems due to improper external coating and incomplete cathodic protection. Salty soil in some sections aggravated the corrosion problem. In these sections, the wall thickness of the pipes was decreased from 2 to 2.7 mm. Despite its design pressure of 55 Kg/cm2, the current operating pressure is only 32 Kg/cm2. This line has different pipe diameters ranging from 500 to 100 mm. As a result, the line prohibit the use of pigging.

D.3. The second line was installed during 1966 - 1990. The diameters of the line vary from 1000 to 500 mm. A few sections have not yet been completed. Along the pipeline between Zhambyl and Bishkek, there is an underground storage called Akyr-Tobe. The storage capacity is insufficient. Thus, the entire pipeline system is suboptimal.

D.4. The gas compressor stations of the pipeline are mainly equipped with electric motor driven centrifugal compressors. A few stations are using reciprocating compressors which are approaching the end of their useful lives. The engines used for compressor drivers at the Poltoratskoe underground storage (near Tashkent) require replacement.

D.5. At present, the pipeline system lacks a reliable flow measurement. Flow measurement is made by calculating pressure and temperature levels at various locations of the pipeline route. This indirect measurement is hardly accurate to figure out gas balances time to time. The volume of gas imported from Uzbekistan is measured at Gazli in Uzbekistan. In addition, there is no telecommunication system dedicated for the pipeline. Operational data/information are gathered to Alaugaz' operation center in Almaty using telephone lines.

Project Objectives

D.6. The main objectives of the project are to:

a rehabilitate the pipeline system to secure steady gas supply to Almaty using the system up to its design level and to extend its useful life;

b improve the existing gas measurement system for efficient use of gas; and

c support the commercialization of JSC Alaugaz and further development of the gas sector.

Project Description

D.7. The project includes following components:

- Replacement of 72 Km of pipes in Uzbek territory between Bukhara and Shymkent;
- Improvement of cathodic protection;
- Installation of a new compressor station in Komsomol in Kazak territory;
- Installation of flow calculation units at compressor stations;
- Installation of a new meter station at the border with Uzbekistan;
- Installation of telecommunication line between Akyr-Tobe and Almaty; and
- Expansion of the underground gas storage at Akyr-Tobe from the current 300 million CM to 700 million CM.

D.8. By replacing 72 Km of old pipes and installing a new compressor station at Komsomol, the flow capacity is expected to increase up to 8 BCM per year. At Zhambyl gas compressor station, installation of three new compressors is expected to complete within 1997.

D.9. Modernization of flow measurements and operational data gathering would be essential for efficient operation of the gas transit system. In particular, quick response is required for steady gas supply in response to daily and seasonal variations of gas demand in Almaty and other markets in southern Kazakhstan. In this connection, the expansion of the underground gas storage capacity (from 300 million CM to 700 million CM)[3] and the lifting capacity (from 2.5 million CM per day to 5 million CM per day) would also be necessary.

Project Costs

D.10. The total project cost excluding contingencies is estimated at US$ 74 million equivalent.

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[3] Another plan is to install a new under ground storage near Almaty.

(Unit: US$ million)

Project Component	*Local*	*Foreign*	***Total***
Replacement of 72 Km pipe	3	32	35
Improvement of cathodic protection	0.5	4.5	5
Komsomol new compressor station	0.5	1.5	2
Flow calculators at compressor stations	0.5	2.5	3
A new meter station at the border	0.5	2.5	3
Telecommunication (Akyr-Tobe/Almaty)	1.5	7.5	9
Expansion of Akyr-Tobe UG storage	3	14	17
Total	9.5	64.5	74

Comment

D.11. Considering the current issues of non-payment and/or payment arrears, the initial investment needs to target at rehabilitation of critical components only. Those components related to modernization may not be needed for a short while.

D.12. Since the southern pipeline system is also subject to the on-going privatization, more rigorous plan would be made by the successful bidder.

E. Development of the Amangueldy and other gas fields in Jumul Region

E.1. The gas fields in Zhambyl region are located less than 170 Km from the existing Southern gas transmission pipeline to Almaty, yet the gas supply potential is expected maximum 3 BCM/Y. Currently, a Kazak joint venture company, called Dosbol is pursuing the development of these fields. According to their estimate, a total of 170 billion CM of gas is recoverable in the region and 24.5 billion CM is proven in the Amangueldy field. Dosbol intends to promote the development in two phases as follows:

First Phase (from 1997)

- Development of the Amangueldy field including drilling of 6 wells and installation of a gas processing plant in Amangueldy with a design rate of 1.5 BCM/Y.
- Installation of a new 130 Km pipeline with a diameter of 500 mm from Amangueldy to a small town called Karatau about 35 Km north-west of Jumbul, from which gas can be transferred using an existing 500 mm diameter pipeline to the main transmission pipeline.
- Start gas production and transmission at the rate of about 1.5 BCM/Y, delivering gas to markets in Jumbul and Almaty.

Second Phase (from 1998)

- Full development of other gas fields and increase production up to 3 BCM/Y, including expansion of the gas processing plant.

E.2. According to Dosbol's estimate, the required capital investment for the First Phase is US$ 66 million and for the Second Phase, US$ 210 million. Gas from the Amangueldy field has a high pressure (about 235 atm at the well bottom) and is free from sulfur. Considering all the above favorable conditions of the gas fields, the supply cost of the gas is expected very attractive compared with the imported gas from Turkmenistan/Uzbekistan (currently US$ 40 per 1,000 CM). The Sev. Ucharap and Ucharap-Kempir-Tube fields contains 0.7% of high economic value helium, and the sales of this helium gas is also expected to improve the project economics.

E.3 The southern and western parts of Kazakhstan have about 25-30% of electricity supply shortage[4]. At present, these regions are importing electricity from the neighboring countries[5]. The primary solution to the above is to provide steady and sufficient gas supply to the Zhambyl regional power station as the capacity of the power station is currently under-utilized. As of June 3, 1997, 200 MW or less than 50% of the total capacity is in operation. The station currently uses the imported gas from Uzbekistan. According to Dosbol's preliminary calculation, the gas supply cost at Zhambyl city gate is estimated at about US$ 37 per 1000 CM. This is US$ 9 or about 20% below the current imported price (US$ 46 per 1000 CM). If Amangueldy gas is used at the power station, there is a possibility to decrease the electricity whole sale price (now US 2 cents per Kwh) by about 15%.

F. Rehabilitation of the Central Asia Center Gas Transmission Pipeline

F.1. The main Turkmen gas export corridor, the Central-Asia-Center (CAC) pipeline was built in 1960s and 1970s and today it requires substantial rehabilitation for its gas compressor stations. According to Kazkgaz' estimate, about US$ 110 million is required for the rehabilitation. The design capacity of the CAC pipeline is 80 BCM/Y and currently only 25 BCM/Y of Turkmen gas is transported to markets in the CIS and East and West European countries. Depending the utilization ratio of the above pipeline, the required rehabilitation cost may vary.

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[4] According to Kazenergo, the western Kazakhstan has a deficiency of 2.2 billion Kwh (or about 340 MW power generation capacity at 75% load factor using CCGT) or about 27.5% of its demand in 1996. The southern Kazakhstan has a deficiency of 3.2 billion Kwh (or about 490 MW power generation capacity) or about 24.65% of its demand.

[5] The southern region imports from Uzbekistan and Turkmenistan. In 1995, 0.782 billion Kwh from Uzbekistan at 4.5 cents per Kwh and o.427 billion Kwh from Turkmenistan at 4.5 cents per Kwh. The region also imported about 1.1 billion Kwh in the summer season from Tajikistan and Kyrgyzstan at 1.2 to 1.8 cents per Kwh. The western region imported 4.108 billion Kwh from Russia at 3.48 cents per Kwh in 1995.

F.2. Since the CAC pipeline is subject to privatization (e.g. a 15 year concession), a more detailed rehabilitation and modernization plan would be developed by the successful bidder.

G. Rehabilitation of Existing Gas Distribution and Installation of Meters

H.1. The existing gas distribution system was developed in 1960s and 1970s and today technical and physical losses are increasing due to corrosion and leakage. As with other CIS countries, most of small gas consumers do not possess gas meters. As a result, there is significant inefficiency in gas distribution operations. The principal objectives of the project are to:

a Promote efficient use of gas and mitigate environmental issues by rehabilitating and modernizing gas pipeline systems, replacing and inaccurate metering, and installing meters where none presently exist;

b Improve the physical accounting for gas and encourage an improved commercial basis for gas transactions through modernization of the existing facilities and meter installation;

c Support the commercialization of local gas distribution companies (which may not be immediate privatization) through technical assistance, training programs and the acquisition of modern office equipment.

G.2. This project will focus on the rehabilitation of the existing distribution system in Almaty and the southern region in which about 600,000 small commercial and residential consumers are using gas. The rehabilitation will be made to arrest any gas leakage and to establish more reliable gas distribution. Gas meters will be installed for these small gas consumers, most of which at present lack metering devices. This project will also include: (i) assistance in project implementation; (ii) training for management staff of local gas distribution companies; and (iii) upgrading of operating procedures.

G.3. GOK has recently decided to promote gas meter installation across the country (e.g. a decree titled "Resolution of the Government on regulation of the norms of consumption of heat, hot and cold water"). Reliable metering is required at national borders and at each major consumer in the domestic gas markets. According to the above decree, the completion of nation-wide meter installation for household consumers is by October 1, 1997. This may be difficult.

G.4 Meters are also required at each gas compressor station of the transit pipelines to measure the fuel gas consumption at the station. Large consumers have orifice plate type meters but each of them mostly needs an instrument unit to compensate the effect of the operating temperature and pressure and a new recorder. To maximize the economic benefits, household meters would be required initially for those customers using gas both for heating and cooking. If pre-payment meters are one of the preferred options, a pilot project could be launched targeting about 15,000 high income customers in Almaty or other cities.

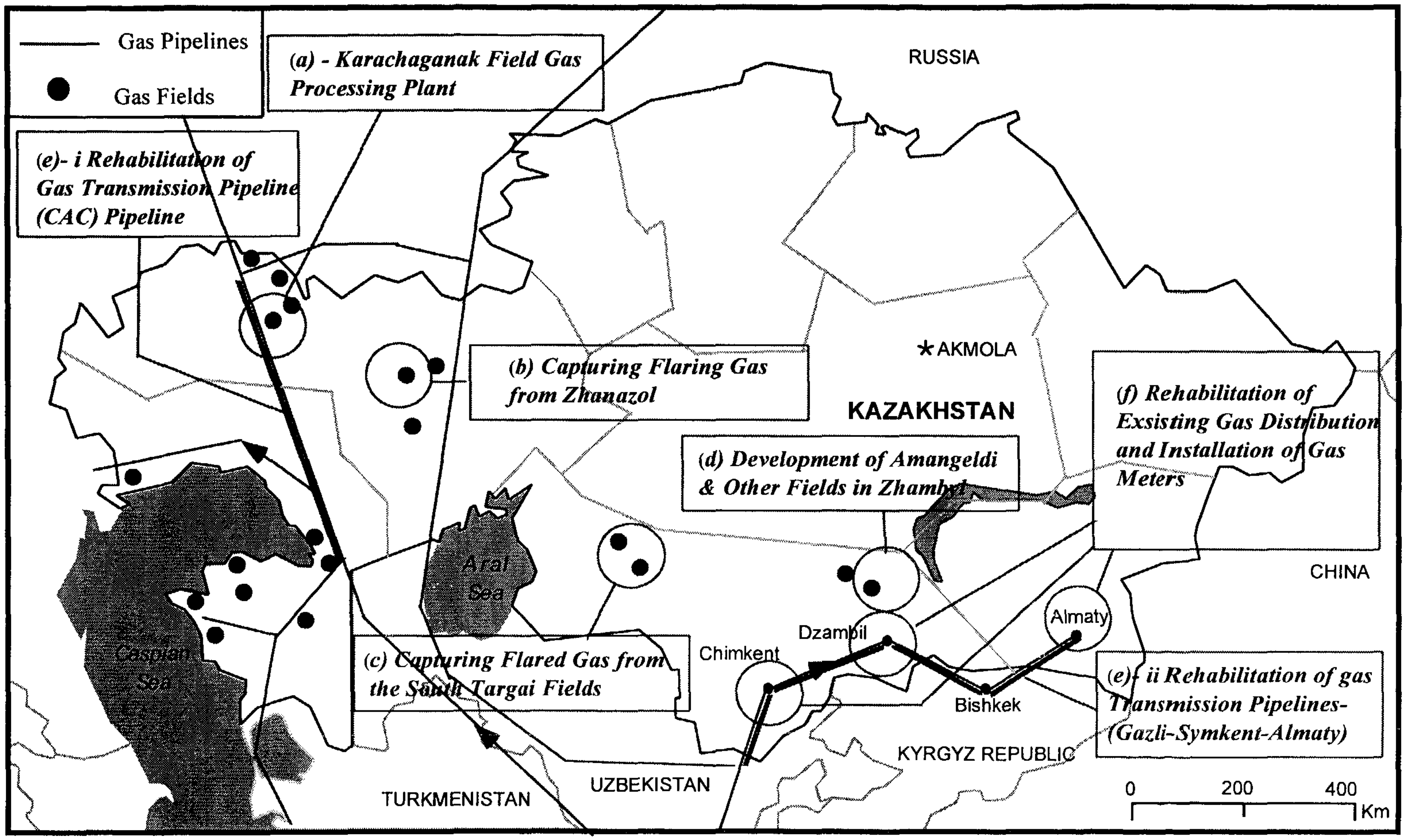
G.5 On a broad brush basis, the capital investment costs for the above project components are estimated as follows:

Project Component	*Unit Cost (US$ million)*	*Investment Cost (US$ million)*
a) Meter installation at national borders (2 at the border with Uzbekistan, 2 at the border with Russia, and 2 at the border with Kyrgyzstan) and rehabilitation of a few existing meter stations	6-7 per station	60
b) Installation of fuel gas meters at 20 compressor stations	0.02	0.4
c) Installation of instrument and recorder units for 1000 large industrial and commercial customers	0.01	1
d) Installation of gas meters for 270,000 household customers	0.00005	13.5
e) A pilot pre-payment meter project for 15,000 customers		3.3
Total		**78.2**

H. Gas Supply to Petropavlosk in North Kazakhstan

H.1. GOK has a plan to supply Russian gas to Petropavlosk using a gas exchange arrangement with Karachganak gas. The Russian gas source is located about 130 Km from Petropavlosk. According to very preliminary information, gas consumption in Petropavlosk is maximum 1.3 BCM per year. Laying a new 20 inch pipeline over 130 Km costs about $60 million. If about $20 per 1000 CM is chargeable for gas transmission from Russia, the project could be economically viable with the estimated gas supply cost of about $42 per 1000 CM (which would be below the market value of gas for power generation) assuming that the Karachganak gas cost is about $22 per 1000 CM at the inlet to the Soyuz line in Western Kazakhstan. A more comprehensive market analysis is crucial to determine the economic viability of the proposed project.

KAZAHKSTAN: High Priority Project Locations



This map is for reference only and has not been approved by the Map Design Unit of the World Bank Group.

Appendix 1.2

Preliminary Evaluation of Gas Pipeline Projects proposed by the Government

1. GOK once proposed two gas sector projects: (i) the Aksay Akmola pipeline project; (ii) in addition there is a plan to build a new pipeline from Chelkar to Symkent. The general objective are to reduce imports of gas, promote national security and gasify the Kzyl Orda and other oblasts. The specfic objectives are discussed under each project.

Table 1 Originally Government Proposed Gas Pipeline Projects

Project Name	*Transmission Gas Volume (BCM/Y)*	*Pipeline Configuration*	*Estimated Investment Cost (US$ million)*
Aksai - Akmola pipeline	12.7 (Aksai- Kr.Okt) 7.24 (Kr.Ok - Akmola)	40 inch x 475 Km & 40 inch x 1300 Km	626[1]+ 1,612.2[2]
Extension of the Bukhara - Tashkent - Alamaty pipeline (around Kyrgyzstan)	5 (First Pipeline)	28 inch x about 110 Km	56
Chelkar - Symkent pipeline	4.75	40 inch x 441 Km & 28 inch x 775 Km	1,220

2. These projects seem desirable. However, analysis shows that the first and third projects are economically and financially not realistic at this time and in the near future. Comments on the second project is given in paragraph 4. Their implementation would require a substantial increase in gas prices. Problems anticipated are as follows:

- Huge capital expenditures, in particular in foreign exchange.
- Thecost of gas is higher than that of alternatives such competing fuels (coal) or other gas supply scheme (imports) or other competing energy (hydro) in the target markets.
- The gas markets in the target areas are too small.
- Lack of distribution network alongside the proposed new pipelines.

1 Based on VECO's cost estimate in 1995.

2 Based on Okon/Enron's cost estimate in 1995.

3. *The Aksai - Akmola pipeline* would ensure a reliable gas supply to the consumers in West Kazakhstan, Aktyubinsk, Torgai and Kostanai. The further extension of the pipeline is intended to gasify of the Akmola region where high ash coal is creating significant environmental issues. The project would encounter these problems:

- *The extension of the Bukhara - Tashkent - Almaty pipeline* means completion of the second pipeline which Kazakhstan started construction in 1989 but is still partially uncompleted. GOK has a high intention to install a by-pass line around Kyrgyzstan. GOK considers the above pipeline is important to secure gas supply to Almaty with an increased capacity.
- *The Chelkar - Symkent pipeline* intends to connect gas producers in Western Kazakhstan with gas consuming industries in South Kazakhstan.

3. The objectives of these projects may appear to be modest. However, there are major bottlenecks to realize these projects in the near future. These are:

- Lack of sufficient gas markets to support the pipeline projects;
- The higher cost of gas supply than the costs of other competing fuels (coal) or other supply scheme of gas (imports) or other competing energy (hydro power) in the target markets;
- Lack of distribution network alongside the proposed new pipelines;
- Need for substantial increase of gas retail prices to maintain financial viability of each project; and
- Requirement of huge capital investment costs, in particular, in foreign exchange.

4. ***The Aksai - Akmola Pipeline Project:*** The first bottleneck seems to be lack of sufficient size of markets along the pipeline route. The following table presents the recent market survey conducted by EC Energy Center which appears to be closer to the realistic demand but still optimistic considering the current macro-economic situation. If natural gas is used in Akmola, the largest consumer is the power sector (estimated about 80%). According to the Ministry of Electricity and Coal Industry, coal costs in the Akmola region are about US$ 4-5 per ton. These seem unrealistically low, but have been beyond the scope of the gas strategy. Assuming these coal costs are accurate, then based on the supply of low-cost coal from Ekibustuz, it is unlikely for the power stations in Akmola to switch the fuel for power generation from coal to natural gas on a pure commercial basis.

Table 2 Natural Gas Demand along the Proposed Aksai-Akmola Pipeline

Unit: BCMY

Oblast	*Year 1996*	*Year 2000*		*Year 2005*		*Year 2010*	
West Kazakhstan	0.5	0.7	(0.497)	0.9	(1.007)	1.0	(1.115)
Aktyubinsk	1.0	1.3	(3.063)	1.5	(3.773)	1.75	(5.155)
Kostanai	1.1	1.3	(3.00)	1.55	(4.243)	1.6	(4.715)
Turgai	-	-	-	-	(0.445)	-	(0.931)
Kokchetau	-	-	-	0.25	(1.323)	0.3	(1.801)
Akmola	-	0.4	-	0.5	(2.415)	0.55	(2.759)
Total	2.6	3.7	(6.560)	4.7	(13.206)	5.2	(16.476)

Note: The figures in parentheses show the gas demand used for the VECO study.

5. Second, the supply cost of Karachganak gas to Akmola is very close to the market value for the power plants which are the largest conceivable consumers even if the gas supply volume is 7.2 BCM/Y (e.g. about US$ 70.2/1000 CM vs. US$ 70.6/1000 CM). If the market size is much smaller (even in 2000, estimated 0.5 BCM/Y), the supply cost of gas is much higher than US$ 70.2/1000 CM due to the economies of scale. This implies that the proposed project does not create any economic benefits unless large environmental credits are taken into account. The possible supply of Karachaganak gas to Aktyubinsk is competing with Zhanazol gas since the market size in Aktyubinsk is not large enough (e.g. 1.7 -1.75 BCM/Y). According to the preliminary calculation by ESMAP task force, the supply cost from Zhanazol is much lower than the cost of Karachganak gas (e.g. US$ 12.3/1000 CM vs. US$ 19.1/1000 CM[3])

6. ***Extension of the Bukhara-Tashkent-Almaty Pipeline:*** This pipeline requires major rehabilitation. Without rehabilitation, the transportable capacity would dwindle. Therefore, if the project is designed to rehabilitate and modernize the first pipeline system and/or to finish the uncompleted section of the second pipeline, it would create substantial economic benefits. However, if the project primarily aims at installation of a by-pass line around Kyrgyzstan, the project does not create any economic benefit other than resolving the payment issue with Kyrgyzstan. The latter case would be a political decision and access to international investors/financiers is unlikely without strong growth in demand.

7. ***The Chelkar - Symkent Pipeline:*** This project was originally designed in 1966 by Vnipi-gasodobycha, a Saratov design institute in Russia. The cost estimate

[3] This is based on the transfer volume of 12 BCM/Y. If the volume is smaller, the supply cost of Karachganak gas will increase. The cost of Zhanazol gas is based on 2 BCM/Y.

used is outdated. Using a western cost yardstick, the more likely project cost is as follows:

Table 3 Review of Capital Investment Costs for the Chelkar - Symkent Pipeline

		(Unit: US$ million)
	Vnipi Estimate	*Estimate based on a western cost yardstick*
Phase 1: Chelkar Leninsk 28 inch x 441 Km	148	271.7
1 Comp. St. (4.8 MW x 2)	(included in the above)	17.6
Phase 2: Chelkar -Leninsk-Symkent	634	855.7
28 inch x 191 Km		
40 inch x 1025 Km		
5 Comp. St. (9.8 Mw x1; 7.1 MW x 3; 5.1 MW x 2; 7.1 MW x 3; 4.6 MW x 1)	(included in the above)	88.2

8. Using the above western cost yard stick for the transportation of about 5 BCM/Y of gas to south-eastern Kazakhstan, the supply cost of Karachaganak gas to Almaty is roughly estimated about US$ 71 per 1000 CM which is compared with the supply cost of the imported gas to Almaty (about US$ 57.4/1000 CM @US$ 50/1000 CM at the national border with Uzbekistan) and the cost of Amangueldy gas (about US$ 35.6/1000 CM). Although the estimated supply cost of US$ 71/1000 CM is lower than the market value of gas for power generation in Almaty, this implies that the proposed project is not a least cost solution unless one or more than two of the following situations occur:

- gas supply from the imported sources is constrained;
- sharp increase of the import price of gas (to more than US$ 60/1000 CM); and
- the gas markets in the south-east regions expand sharply and gas supply from the import sources and the Jambul fields is not sufficient.

Appendix 2.1

Kazakhstan's Gas Reserves

1. Most estimates place Kazakhstan's technically and economically recoverable proven and probable reserves at about 2.1 billion MT (or 15.3 billion bbl) of oil (including gas condensate liquids), and between 1.6 and 1.8 TCM of gas. There are 134 oil producing fields and 79 gas fields located in 8 hydrocarbon oblasts in Kazakhstan. However, the distribution of oil reserves is highly uneven as almost 75% of the country's total are in the Kazakhstan part of the North Caspian Basin. Out of these, almost 1 billion tons are accounted for by the supergiant Tengiz and Karachaganak fields.

2. Major gas reserves are located in West Kazakhstan, Mangystau, and Atyrau oblasts which are all located in western Kazakhstan. The table below summarizes the in-place gas reserves in the hydrocarbon producing oblasts. Out of the total estimated in-place gas reserve of 2.8 TCM, about 1.8 TCM is non-associated gas and about 1 TCM is associated gas. Most of the gas produced in western Kazakhstan contains hydrogen sulphide and/or sulphur compounds. It is estimated that out of the total 2.8 TCM reserve, about 1.6 TCM of gas is highly sour.

3. Karachaganak is by far the laregest gas field in Kazakhstan, which holds more than 45% of the nation's remaining proved and probable gas reserves. Karachaganak is a large field, even by international standards. Karachaganak is a gas-condensate field and currently the producer's commercial interest is condensate production. Thus, most of the gas associated with the produced condensate is reinjected to the reservoir. Kazakhstan's other main gas reserves are also located largely in the western portion of the country, including the coastal Caspian Sea area. Utilization of gas in western Kazakhstan is expected to play an important role in the national economy, provided that the gas supply costs to domestic and/or international markets are competitive enough.

Table 1: Gas Reserves in Kazakhstan

Hydrocarbon Producing Oblasts and Major Fields	*Reserve (A+B+C1[1]) (million CM)*	*Total Reserve (million CM)*	*(%)*	*Gas Produced till 1994 (million CM)*
I. Aktyubinsk Oblast				
Zhanazol	130,026			40
Urihtau	38,480			20
Others	21,881	190,387	6.6	
II. Atyrau Oblast				
Tengiz	355,255			22,560
Imashev	78,679			
Others	46,159	480,093	16.7	
III. Zhambyl Oblast				
Ajrakti	2,079			
Amangeldi	8,143			
Others	12,049	22,271	0.8	
IV. Zhezhazgan Oblast				
Kumkol	8,710			
Others	665	9,375	0.3	
V. West Kazakhstan				
Karachaganak	1,322,390			37,440
West - Teplov	4,616			
Teplov	4,491			
Kamen	7,500			
Chinarev	40,453			
Others	14,411	1,393,861	48.5	
VI. Karaganda Oblast	972	972	0.0	
VII. Kizyl-Orda Oblast				
Nurali	2,030			
Bektas	2,626			
Others	11,060	15,716	0.6	
VIII. Mangystau Oblast	759,379	759,379	26.5	25,450
Grand Total	**2,872,054**	**2,872,054**	100.0	103,210 (include other than the above.)

Source: Kazakgaz/EC Energy Center, September 1996.

[1] For the definition of the categories, A, B, and C, refer to the box in the next page.

4. The production of natural gas in Kazakhstan had been steadily increasing over time till 1992. This rise in production was due to increased production of crude oil as most of the natural gas produced in this country was associated gas (e.g. Tengiz, Karachaganak, oil fields in Mangystau,etc). Most of non-associated gas has not yet been produced. Some smaller dry gas fields in the southeast near Zhambyl have not yet been developed, and future exploration work may reveal larger deposits at these locations. If such prospects are materialized, the gas from these fields would supply to the existing markets in nearby South Kazakhstan on an economically competitive basis.

Reserve Classification

The Soviet system of classification of reserves in use in Kazakhstan cannot be compared directly with the reserve classification system used in the West. While there are many similarities in the methodologies adopted for reserve classification, the decision criteria is quite different.

The Soviets classified the hydrocarbon potential of a region by using the letter classification A, B, C and D.

When discrete geologic traps with hydrocarbon bearing potential have been identified and mapped, the probable volumes of oil and gas is classified as C3 reserves.

Once a reservoir has been penetrated by a drill bit and information such as hydrocarbon saturation, gas/oil/water ratios etc. is available, and more accurate estimates of 'hydrocarbon in place' are made, the reservoir is now classified as C2.

Generally, additional work (i.e. delineation drilling, production testing) is undertaken on a C2 reservoir to estimate the volume of hydrocarbons that can be technically bought up to the surface. This additional information is the basis for classifying reserves as C1.

The soviet basis for determining if a hydrocarbon deposit can be brought to surface is based by applying all available choices to their technological maximum. In contrast, the practice in the west is to apply appropriate technological choices under a given cost structure under a given range of oil prices.

If a confirmed (C1) reservoir is approved for production by the appropriate authorities or the government, and work has already started on installing surface production and transport facilities, the reserves is classified as B.

Once a 'B' reservoir starts production, the status of the reserve is upgraded to 'A'.

Source: Dr. John D. Grace, Troika Energy Services in PlanEcon Energy Outlook, PlanEcon, 1992, Washington DC.

Appendix 2.2

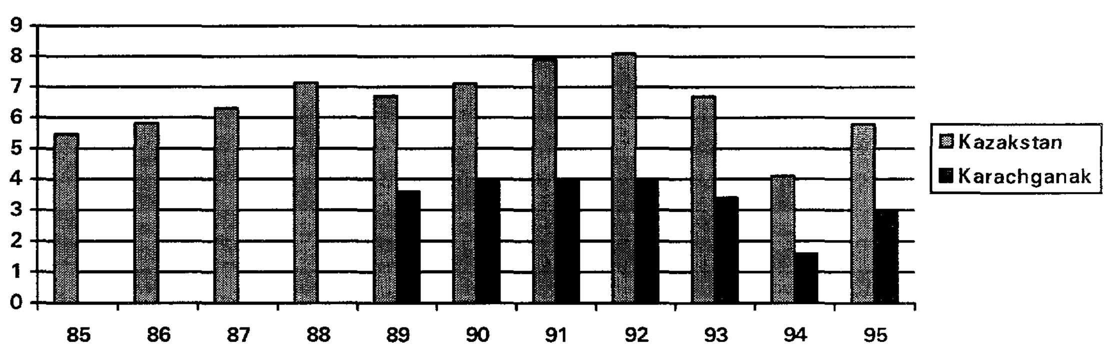
Present and Future Supplies

Domestic Gas Producers

1. Domestic gas production in 1996 is estimated to be approximately 6.6 BCM. Some 4.0 to - 4.5 BCM/Y is likely to be produced at the Karachaganak Field in 1996, all of which is exported in a raw state (and at a very low price) to Orenburg, Russia for processing and ultimate export via Russia's UGSS. Other main producers are also located in western Kazakhstan. At present, the produced gas is mainly used for oil field use (gas injection, gas lift, fuel gas, etc.) and overall not used effectively.

Figure 1: Historical Gas Production in Kazakhstan

(Unit: BCM)



Source: MOG and EC Energy Center

Karachaganak

2. The Karachaganak field is a super giant gas condensate field discovered in 1978 near Uralsk in West Kazakhstan, close to the Russian border. It covers an area of around 500 square kilometers. The reservoir depth ranges from 3,600 to 5,150 meters and the wellhead pressure is about 300 Bar. So far 250 wells were drilled and 70 wells were completed, among which 45 wells are producers. The production at Karachaganak started from 1989. The early production rates in 1992 were 4.5 MT/Y of condensates and 4 BCM/Y of gas. In May 1995, a provisional Production Sharing Contract (PSC) was signed among British Gas, AGIP, Gazprom and the Government/Kazakgaz to accelerate the development of the Karachaganak field. More recently Gazprom was replaced by Lukoil

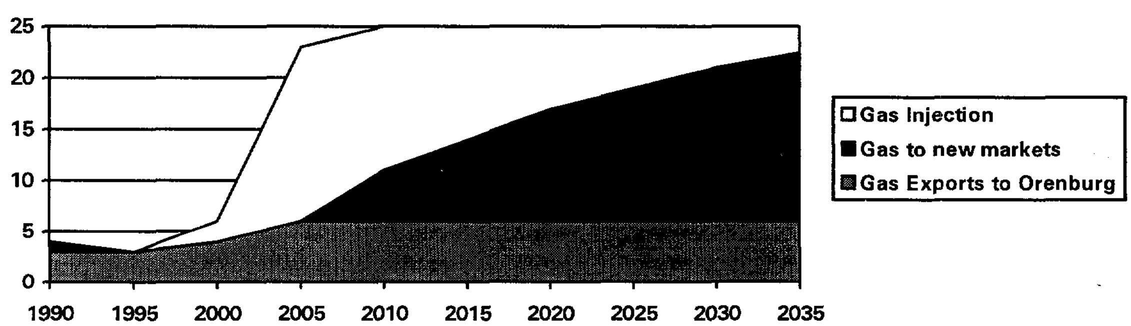
and Texaco joined the international consortium. These foreign companies form a Contractor Group in the form of non-incorporated joint venture.

3. Two condensate pipelines and three gas pipelines run from the Karachaganak field to Orenburg in Russia which is 140 Km away. Currently 3 MT/Y of condensates and 3 to 4 BCM/Y of raw sour gas are transported to Orenburg without gas conditioning. The Karachaganak gas contains about 4.5 percent of hydrogen sulphide and is highly sour. The gas is treated at the Orenburg gas processing plant and transferred to the Russian export pipeline. The condensates are treated at Orenburg and sent to a refinery in Ufa in Russia.

4. Kazakoil and the Contractor Group intends to expand the production of condensates and gas from the Karachaganak field. Once the CPC oil pipline (which runs from Tengiz to a Russian Black Sea port of Novoroshisk) has been completed, the Karachaganak producer expects to boost the production of condensates up to 9.4 MT/Y of which 6 MT/Y is for exports through the CPC pipeline, 3 MT/Y is for exports to Orenburg and 0.4 MT/Y is for local use. Proportionally, the production of gas will increase if the recovery of condensates is enhanced. At peak, the Karachaganak gas production is expected to reach 25 BCM/Y. According to the Contractor Group's technical study, the maximum allowable reinjection capacity is 10 BCM/Y. Since the present design capacity of the gas pipelines to Orenburg is limited to 6 BCM/Y, the Karachaganak producer is seriously looking for new gas markets to sell the surplus volume of 9 BCM/Y. The Orenburg gas processing plant can treat maximum 9 BCM/Y of raw gas.

Figure 2: Expected Gas Production at Karachaganak

(Unit: BCM/Y)



Source: The former MOG and British Gas

5. The main revenue source at Karachaganak is currently from the production of condensates. The terms of the provisional PSC urges the Contractor Group to exploit gas markets for their share of the produced gas.

Table 1: Karachganak Field Production Profile (Projection in 1995)

Year	*Number of Wells*	*Gas Production*	*Liquids Production*
1992		4.53	3.54
1993		4.53	3.54
1994		4.53	3.54
1995		4.53	3.54
1996		4.53	3.54
1997	87	9.24	5.19
1998	128	13.27	6.67
1999	157	15.92	7.85
2000	204	19.41	9.35
2001	222	19.86	9.98
2002	231	19.68	9.62
2003	255	21.33	10.10
2004	294	23.81	10.26
2005	299	25.10	10.52
2006	304	25.13	10.08
2007	309	24.96	9.66
2008	309	24.57	9.22
2009	316	23.95	8.82
2010	327	23.11	8.33
2011	335	21.55	7.77
2012	335	19.66	7.01
2013	335	18.54	6.44
2014	338	16.30	5.61
2015	355	15.33	5.06
2016	355	13.89	4.41
2017	355	12.55	3.70
2018	355	11.06	3.19
2019	355	10.80	3.04
2020	355	10.31	2.81
2021	355	9.59	2.48
2022	355	8.86	2.15
2023	355	8.39	1.97
2024	355	7.85	1.71
2025	355	7.15	1.46
2026	355	6.40	1.17
2027	355	5.84	0.97
2028	355	5.66	0.94
2029	355	5.52	0.91
2030	355	5.25	0.84
2031	355	4.99	0.78
2032	355	4.73	0.72

Table 2: Karachaganak Field Development Plan (in 1995)

1994	Transference of exploitation to a new field office
1994-1995	Reconstruction of Unit 3 and preparation of Unit 2 for production from one line. Capital workover of 20 existing wells.
1995	The beginning of injector wells drilling. The beginning of: the Unit 1 construction and gas preparation station construction.
1996	The completion of Unit 2 construction makes it possible to increase the gas preparation process to 9 billion m3 per year. The opening 10 injector wells begin to work at the end of 1996, the rate of injection will be 2 billion m3 per year.
1998	The beginning of operation of: first gas preparation line and Unit 1. * That makes possible to increase capacity of gas preparation facilities to 12 billion m3 per year. The number of injection wells runs up to 29, and the rate of injection becomes 6 billion m3 per year.
1999	The capacity of Unit 1 increases total field gas productivity to 16 billion m3 per year *. The rate of new wells drilling became constant (22 wells per year).
2001	59 new productive wells begins to operate.
2002	The capacity of gas processing in the field is 22 billion m3 per year. The rate of liquid hydrocarbon processing became constant (13.4 million tons per year).
2004	An oil processing plant begins operation.
2005	The whole field gas processing rate achieves 25 billion m3 per year (in July). That is possible owing to achievement of projected capacity for all gas processing facilities.
2006	The maximum sale: 13.4 million tons and 17 billion m3 per year.
2011	Drilling completed with completion of 304 new wells. The beginning of setting in operation of oil-processing plant.

Table 3: Raw Gas Quality from Karachganak Field

	(Vol %)	*(Weight %)*
CH4 (methane)	79.2	60.34
C2H6 (ethane)	5.94	8.5
C3H8 (propane)	2.52	5.29
i-C4H10 (iso butane)	0.37	1.02
n-C4H10 (N-butane)	0.66	1.83
C5+ (pentane +)	0.65	2.43
CO2 (carbon dioxide)	6.8	14.25
N (nitrogen)	0.71	0.95
H2S (hydrogen sulfide)	3.3	5.35
Mercaptan (SPSH)	0.03	0.05
Total	100	100

Molecular Weight: 21.04
Gas Density: 0.824 Kg/CM at 0 degree C and 0.1013 MPa

Other Fields

6. The Mangyshlak- Buzachi peninsula which lies to the east of the Caspian Sea is an important hydrocarbon producing zone. Associated gas production from oil fields such as Uzen and Zhetybay make up about 0.5 BCM per year of domestic gas production. These fields have been in production since the early 1960's and now are declining in output. While efforts are being made the stimulate the wells, the level of gas production from this region is not expected to improve dramatically.

7. The Atyrau region is close to the Caspian sea and contains the giant Tengiz field. Production of associated natural gas from this field is expected to play a large role in the future. While Tengiz has already started production, the oil production is being slowed down by lack of export routes to markets. At present, gas production is about 1 BCM per year. Once the CPC oil pipeline (which will run from Tengiz to the Russian Black Sea port of Novoroshisk) has been completed, Tengiz is expected to produce at a higher rate,perhaps 3 -5 BCM per year. The gas from Tengiz, Imashev and other fields in the Atyrau region contains a large percentage of mercaptan and hydrogen sulphide. Proper gas processing is absolutely necessary.

8. In Aktyubinsk region, there are a few small but promising sources of natural gas. These are Zhanazol and Urihtau fields with estimated proven , probable and possible reserves of 130 BCM and 40 BCM respectively. The Zhanazol field is currently flaring about 0.6 BCM of gas.

Prospects for Domestic Gas Production

9. Although actual gas production much depends on the market demand, the following table presents the production potential under a certain idealistic situation assuming major investments in each of these fields. While several fields still wait full appraisal, other fields such as the Zhanazol and Kumkol fields are flaring gas and are ready for production for market once gas transmission pipelines are available. Overall, Kazakhstan has significant potential to increase gas production in terms of the reserve volume, provided that the country can identify economically competitive markets. The major bottleneck appears to be access to major markets.

10. The current production is almost all associated gas. Most of non-associated gas has not been produced. Table 2 below presents a prediction by the former Ministry of Geology on the potential of domestic gas production. These sources are oil fields or gas-condensate fields. The possibility to exploit non-associated gas would be limited to the gas fields in Jambul oblast including the Amangueldy field, which are close to the existing southern pipeline to Almaty and expected to be competitive in gas supply costs to Almaty and other markes in southern Kazakhstan. More precise production planning is required before any investment decision making, taking account of market demand and gas supply costs to each market.

Table 4: Natural Gas Production Potential (1997 - 2010)

	(Unit: million CM)					
	1997	***1998***	***1999***	***2000***	***2005***	***2010***
I. Aktjubinsk region	868	1057	1246	1435	3554	4156
1. Zhanazol	868	977	1086	1185	1085	947
2. Kenkijak-Bozoba	-	30	60	94	229	205
3. Alibeckmola	-	50	100	156	240	204
4. Urihtau	-	-	-	-	2000	2800
II. Atyrau region	1850	2534	3124	3117	5116	5234
1. Tengiz SHO	1700	2400	3000	3000	5000	5000
III West Kazakhstan region	5000	5830	8095	9587	18060	25600
1. Karachaganak[1]	5000	5100	7000	8000	15000	22000
2. Kamenskoe and Teplovsko-Tokarevskaja	-	730	1095	1460	2260	2800
3. Chinarevskoe	-	-	-	127	800	800
IV. Mangystau region	597	730	829	894	912	792
1. Uzen	237	250	265	279	300	293
2. Zhetybay	107	132	138	128	80	62
3. Kalamkas	100	107	106	99	70	51
4. Ojmasha	65	133	190	226	191	117
V. Kiziorda + Zhambyl + Jezkaz + South Kazakhstan	222	248	299	354	389	303
1. Kumkol	201	208	205	201	185	167
TOTAL	8537	10399	13593	15387	28031	36085

Source: "Analysis of the Condition of the Oil-Gas Complex and its Raw Material Basis in the Republic of Kazakhstan" by the Ministry of Geology.

Gas Import Sources

11. In 1996 Kazakhstan imported about 6.6 BCM/Y of natural gas, primarily including supplies from Turkmenistan, Uzbekistan, and Russia[2]. This overall level of imported gas represented a 50% reduction in gas imports from the 1992 level of 12.5 BCM/Y. The increase in the import gas price primarily urged the downward trend of gas imports. The following table summarizes the country's historical gas balance:

[1] Based on British Gas/Agip's development plan in 1996.

[2] In 1994, 54% from Turkmenistan, 43% from Uzbekistan and 3% from Russia.

Table 5: Gas Imports/Exports

(Unit: MCM/Y)

	1991	*1992*	*1993*	*1994*
Gas Imports:				
Russia	1,450	1,439	1,159	382
Turkmenistan	3,694	9,517	6,216	4,290
Uzbekistan	4,435	1,489	4,503	3,391
Total Imports	9,579	12,445	11,877	8,063
Gas Exports	4,208	3,940	3,479	1,651
Net Imports	5,371	8,505	8,399	6,412

Source: MOG

12. According to the agreement between Kazakhstan and Turkmenistan of 10 May 1993 and beginning in 1994, the Bukhara-Ural pipeline was to receive 4 BCM/Y of gas to be transported to Kazakgaz' customers in the Kustanay and Aktyubinsk regions. Another 3 BCM/Y was to be supplied to Western Kazakhstan through the CAC pipeline.

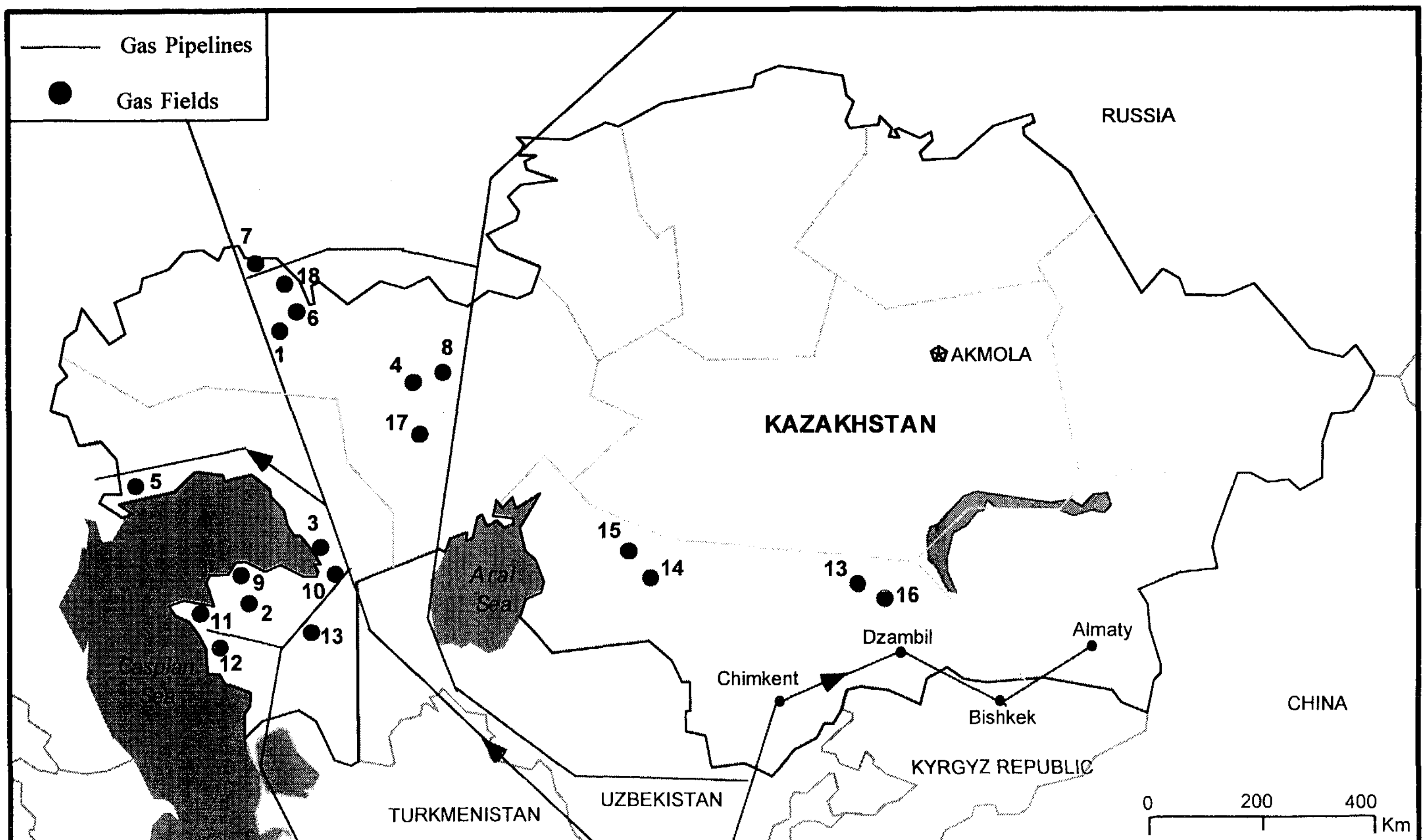
13. Gas from the Orenburg gas processing plant is supplied through the Orenburg-Novopskov pipeline and from the Bukhara-Ural pipeline. About 0.5 BCM of gas was supplied in 1990 by Russia to the Uralsk and Aktyubinsk regions. It is estimated that about 1.1 BCM of gas was supplied in 1995.

14. At present, the southern populated regions of Kazakhstan rely entirely on gas imports from Turkmenistan and Uzbekistan. (See map inset). Kazakhstan's main pipeline gas import pipeline route is from Gazli in Uzbekistan to Symkent.

KAZAKHSTAN

Estimated Proven Recoverable Natural Gas Reserves: 1995

Field Name	(BCM)	Field Name	(BCM)	Field Name	(BCM)
1. Karachaganak	1322	7. Kamen	40	13. Amangueldi	8
2. Kalamkas	520	8. Urihtau	40	14. Bektus	3
3. Tengizskoe	355	9. Jetibay	32	15. Nuraly	2
4. Janajol	130	10. Neanovskoe	24	16. Airaty	2
5. Imashevskoe	79	11. Tenge	23	17. Kzilskoe	2
6. Chinarevskoe	40	12. Kissimbaj	21	18. Tokarev	2



This map is for reference only and have not been approved by the Map Design Unit of the World Bank Group.

Table 4: Natural Gas Production Potential (1997 - 2010)

(Unit: million CM)

	1997	*1998*	*1999*	*2000*	*2005*	*2010*
I. Aktjubinsk region	868	1057	1246	1435	3554	4156
1. Zhanazol	868	977	1086	1185	1085	947
2. Kenkijak-Bozoba	-	30	60	94	229	205
3. Alibeckmola	-	50	100	156	240	204
4. Urihtau	-	-	-	-	2000	2800
II. Atyrau region	1850	2534	3124	3117	5116	5234
1. Tengiz SHO	1700	2400	3000	3000	5000	5000
III West Kazakhstan region	5000	5830	8095	9587	18060	25600
1. Karachaganak[1]	5000	5100	7000	8000	15000	22000
2. Kamenskoe and Teplovsko-Tokarevskaja	-	730	1095	1460	2260	2800
3. Chinarevskoe	-	-	-	127	800	800
IV. Mangystau region	597	730	829	894	912	792
1. Uzen	237	250	265	279	300	293
2. Zhetybay	107	132	138	128	80	62
3. Kalamkas	100	107	106	99	70	51
4. Ojmasha	65	133	190	226	191	117
V. Kiziorda + Zhambyl + Jezkaz + South Kazakhstan	222	248	299	354	389	303
1. Kumkol	201	208	205	201	185	167
TOTAL	8537	10399	13593	15387	28031	36085

Source: "Analysis of the Condition of the Oil-Gas Complex and its Raw Material Basis in the Republic of Kazakhstan" by the Ministry of Geology.

Gas Import Sources

11. In 1996 Kazakhstan imported about 6.6 BCM/Y of natural gas, primarily including supplies from Turkmenistan, Uzbekistan, and Russia[2]. This overall level of imported gas represented a 50% reduction in gas imports from the 1992 level of 12.5 BCM/Y. The increase in the import gas price primarily urged the downward trend of gas imports. The following table summarizes the country's historical gas balance:

[1] Based on British Gas/Agip's development plan in 1996.

[2] In 1994, 54% from Turkmenistan, 43% from Uzbekistan and 3% from Russia.

Table 5: Gas Imports/Exports

(Unit: MCM/Y)				
	1991	*1992*	*1993*	*1994*
Gas Imports:				
Russia	1,450	1,439	1,159	382
Turkmenistan	3,694	9,517	6,216	4,290
Uzbekistan	4,435	1,489	4,503	3,391
Total Imports	9,579	12,445	11,877	8,063
Gas Exports	4,208	3,940	3,479	1,651
Net Imports	5,371	8,505	8,399	6,412

Source: MOG

12. According to the agreement between Kazakhstan and Turkmenistan of 10 May 1993 and beginning in 1994, the Bukhara-Ural pipeline was to receive 4 BCM/Y of gas to be transported to Kazakgaz' customers in the Kustanay and Aktyubinsk regions. Another 3 BCM/Y was to be supplied to Western Kazakhstan through the CAC pipeline.

13. Gas from the Orenburg gas processing plant is supplied through the Orenburg-Novopskov pipeline and from the Bukhara-Ural pipeline. About 0.5 BCM of gas was supplied in 1990 by Russia to the Uralsk and Aktyubinsk regions. It is estimated that about 1.1 BCM of gas was supplied in 1995.

14. At present, the southern populated regions of Kazakhstan rely entirely on gas imports from Turkmenistan and Uzbekistan. (See map inset). Kazakhstan's main pipeline gas import pipeline route is from Gazli in Uzbekistan to Symkent.

Appendix 2.3 Gas Reserve Characteristics in Kazakstan (1/9)
1995

Gas Field	*Status*	*Type of Field*	*Reserves A+B+C*	*Gas Quality*						*Location*
				Helium	*Nitrogen*	*Ethane*	*Propane*	*Butane*	*H2S*	
I. Aktjubinsk Region										
Janajol	(In Production)	AG + Cap	130,026	-	-	108-128 g/m3	85.3-13.9 g/m3	39-101 g/m3	6.0	240 km to S from Aktjubinsk
Urihtau	(ready for exploitation)	AG + Cap	40,298	-	-	173 g/m3	74.1 g/m3	53.9 g/m3	1.8	245 km to S from Aktjubinsk
Kenkijak	(In Production)	AG	11,340	-	-	-	-	-	-	70 km to SW from railway station Emba
Kojasaj	(ready for exploitation)	AG + Cap	6,833	-	-	181 g/m3	174.2 g/m3	76 g/m3	-	240 km to S from Aktjubinsk
Karatube	(ready for exploitation)	AG	367	-	-	-	-	-	-	10 km to SW from the v. Jarkamis
Sinelnikovskoe	(In Production)	AG	809	-	-	-	-	-	-	250 km to S from Aktjubinsk
Alibekmola	(prospecting)	AG + Cap	0	-	-	-	-	-	-	215 km to S from Aktjubinsk
East Akjar	(prospecting)	AG	1,845	-	-	-	-	-	-	40 km to SE from the v. Jarkamis
Kzilojskoe	(ready for exploitation)	AG	1,488	0.15-0.03	8.3	0.7	0.05 (argon)	-	-	275 km to SW from Chelkar
Bazajskoe	(underground gas storage)	-	0	-	3.4-4.7	-	-	-	-	30 km W from the seacoast Aralskoe

Appendix 2.3 Gas Reserve Characteristics (continued) (2/9)
1995

Gas Field	Status	Type of Field	Reserves A+B+C	Gas Quality						Location
				Helium	*Nitrogen*	*Ethane*	*Propane*	*Butane*	*H2S*	
II. Atyrau Region										
Martishi	(In Production)	AG + Cap	99	-	1.5-5.8	3.5-16.0	1.0-26.3	-	tracks	76 km to W from Atyrau
Kamishitivoe Jugo-Zapadnoe	(In Production)	AG + Cap	305	-	-	10.3-25.3	3.3-19.5	-	0.7-7.6	80 km to SW from Atyrau
Zaburunie	(In Production)	AG + Cap	290	-	-	46.3	8.4	12.5	-	170 km to SW from Atyrau
Janatalap	(In Production)	AG + Cap	297	-	-	-	-	-	-	85 km to W from Atyrau
Rovnoe	(In Production)	AG	90	-	-	157.6 g/m3	65.1 g/m3	7.7	-	85 km to NE from Atyrau
Botahan	(In Production)	-	193	-	1.8-5.3	3.7-6.7	0.8-2.9	0.1-1.7	-	65 km to E from the railway station Kulsari
Oriskazgan	(In Production)	AG + Cap	77	-	-	14.0	14.0	0.6	-	230 km to NE from Atyrau
Kamishitovoe South-East	(In Production)	AG	45	-	0.3-1.8	16.8-28.6	2.4-15.5	0.3- 3.4	-	40 km to SW from Atyrau
Jetibaj Northern	(ready for exploitation)	AG + Cap	363	-	13.3-18.9	-	-	-	-	80 km to E from Aktau
Novobogatinskoe	(ready)	AG	123	-	-	-	-	-	-	40 km from Atyrau

Appendix 2.3 Gas Reserve Characteristics (continued) (3/9)
1995

Gas Field	Status	Type of Field	Reserves A+B+C	Gas Quality: Helium	Nitrogen	Ethane	Propane	Butane	H2S	Location
Matin	(ready)	AG + Cap	806	-	-	-	-	-	-	32 km to SW from v. Makat
Makat - Eastern	(ready to be developed)	AG + Cap	357	-	-	-	-	-	-	75 km to S from Novij (New)Uzen
Kulsari	(In Production)	AG + Cap	133	-	3.4	2.3-2.4	2.3-23.6	10.1	-	160 km to SE from Atyrau
Karaton	(In Production)	AG + Cap	141	-	-	-	-	-	-	150 km to SE from Atyrau
Tengizskoe	(ready to develop)	AG	355,255	-	1.2	162.4 g/m3	125.3 g/m3	46.2 g/m3	11.7-19.3	160 km to SE from Atyrau
Korolevskoe	(prospecting)	AG	16,382	-	-	-	-	-	-	115 km to SE from Atyrau
Akkuduk	(preserved)	AG	15	-	5.4	11.2	7.1	-	-	64 km to SE from the railway station Kulsari
Akingen	(preserved)	AG + Cap	398	-	1.0	1.0-3.7	0.2	0.1-0.2	-	40 km to SE from the railway station Kulsari
Kokarna Eastern	(preserved)	AG	8	-	12.9	6.7	9.3	9.1	-	150 km to SE from Atyrau
Karagan	(preserved)	AG	3	-	-	-	-	-	-	50 km to N from the railway station Kulsari
Tagigali	(preserved)	AG + Cap	106	-	29.2-12.3	-	-	-	-	80 km to SW from the railway station Kulsari

Appendix 2.3 Gas Reserve Characteristics in Kazakstan (continued) (4/9)

1995

Gas Field	Status	Type of Field	Reserves A+B+C	Gas Quality						Location
				Helium	Nitrogen	Ethane	Propane	Butane	H2S	
Imashevskoe	(prospecting)	AG + Cap	78,679	0.1	5.0	2.3	-	0.6	15.7	60 km to NE from Astrahan
Moldibak-Eastern	(prospecting)	AG + Cap	160	-	9.6-12.5	0.4-0.5		-	-	80 km to SW from Makat (deposit Kenbaj)
Kotirtas	(prospecting)	AG + Cap	69	-	6.9	13.3	7.8	-	-	80 km to SW from Makat
Oktjabrskoe	(preserved)	AG	0	-	3.1	2.3	0.1	-	-	160 km to SW from Atyrau
Aktube	(conserved)	AG	0	-	-	-	-	-	-	170 kn to SE from Aktau
Jetibaj	(In Production)	AG + Cap	10,595	-	10.3	-	-	-	-	80 km to SE from Aktau
Uznij		AG + Cap	15,104	-	16.2	-	-	-	-	45 km to S from the deposit Jetibaj
III. Zhambyl Region										
Ajrakti	(ready to develop)	NAG	2,079	0.2-0.3	44.2-14.1	-	-	-	-	110 km to N from Zhambyl
Amangeldi	(ready to develop)	NAG	8,143	0.2	-	-	-	-	-	150 km to N from Zhambyl
Anabaj	(prospecting)	NAG	3,120	-	3.0	-	-	-	-	185 km to N from Zhambyl
Kumirli	(prospecting)	NAG	1,533	0.7	24.1	-	-	-	-	70 km th NE from Uch Aral
Pridorojnoe	(prospecting)	NAG	7,396	0.2	-	9.3-14.6	-	-	2.6	260 km to S from Jezkazgan

Appendix 2.3 Gas Reserve Characteristics (continued) (5/9)
1995

Gas Field	Status	Type of Field	Reserves A+B+C	Gas Quality						Location
				Helium	Nitrogen	Ethane	Propane	Butane	H2S	
IV. Jezkazgan Region										
Kumkol	(In Production)	AG + Cap	8,710	0.1-0.2	3.3-10.7	163-251 g/m3	245-471 g/m3	304-624	-	230 km to SW from Jezkazgan
Ortalik	(preserved)	NAG	665	0.2-0.3	11.8-11.9	3.5	0.4	0.01-0.13	0.0	380 km to S from Jezkazgan
V. West-Kazakstan Region										
Karachaganak	(In Production)	AG + Cap	1,322,390	0.0	0.9	113-145 g/m3	83-66 g/m3	69-23 g/m3	3.3-3.6	115 km to NE from Uralsk
Zapadno-Teplovskoe	(prospecting)	AG + Cap	4,616	-	0.4-2.6	-	-	-	3.3-3.6	25 km to NW from Uralsk
	(prospecting)	NAG	2,553	-	-	-	-	-	-	60 km to NW from Uralsk
Gremjachinskoe										
	(prospecting)	AG + Cap	2,029	-	-	-	-	-	-	35 km to NW from Uralsk
East-Gremjachemskoe										
	(prospecting)	NAG	7,500	-	2.3-4.2	1.2	0.6-0.8	0.2-0.3	0.9-1.7	100 km to E from Uralsk
Kamenskoe										
	(prospecting)	NAG	40,453	-	-	-	-	-	-	75 km to NE from Uralsk
Chinarevskoe										
	(prospecting)	AG + Cap	2,095	-	2.3	1.2	0.6-0.8	0.2-0.3	0.9-1.7	72 km to NE from Uralsk
Tokarevskoe										
	(prospecting)	NAG	4,491	-	-	-	-	-	-	20 km To N from Uralsk
Teplovskoe										
Ciganovskoe	(prospecting)	NAG	308	-	-	-	-	-	-	62 km to NE from Uralsk

Appendix 2.3 Gas Reserve Characteristics (continued) (6/9)
1995

Gas Field	Status	Type of Field	Reserves A+B+C	Gas Quality						Location
				Helium	Nitrogen	Ethane	Propane	Butane	H2S	
Ulianovskoe	(prospecting)	NAG	1.753	-	-	-	-	-	-	50 km to NE from Uralsk
Dariinskoe	(prospecting)	NAG	1,585	-	-	-	-	-	-	30 km to NE from Uralsk
Prigranichnoe		AG	1,260	-	-	-	-	-	-	
Chingiz		AG	2,828	-	-	-	-	-	-	279 km to SE from Uralsk
VI. Karaganda Region										
Field of the mine Kirovskaja	(In Production)	NAG	972	-	-	-	-	-	-	Karaganda
VII. Kizilorda Region										
Ariskum	(ready to develop)	AG + Cap	6,810	-	0.5	110.8 g/m3	64.4 g/m3	118.3 g/m3	0.1	120 km to N from the railway station Jusali
Aksaj	(prospecting)	AG + Cap	744	-	-	-	-	-	-	124 km to NE from Kizilorda
Nurali	(prospecting)	AG + Cap	2,030	-	0.9	14.0	1.4	-	-	155 km to NW from Kizilorda
Akchabulak	(prospecting)	AG + Cap	858	-	0.9	-	-	-	-	122 km To N from Kizilorda
Konis	(prospecting)	AG + Cap	1,750	-	-	-	-	-	-	120 km to N from Kizilorda

Appendix 2.3 Gas Reserve Characteristics (continued) (7/9)
1995

Gas Field	*Status*	*Type of Field*	*Reserves A+B+C*	*Gas Quality* *Helium*	*Nitrogen*	*Ethane*	*Propane*	*Butane*	*H2S*	*Location*
Kzilkija	(prospecting)	AG + Cap	250	-	-	-	-	-	-	40 km from the deposit Kumkol
Bektas	(prospecting)	AG + Cap	2,626	-	-	-	-	-	-	Near Aktau
Ashiagar	(prospecting)	AG	648	-	-	-	-	-	-	120 km to N from Kizilorda
VIII. Mangistau Region										
Central and Eastern Prorva	(prospecting)	AG + Cap	8,461	0.01-0.02	0.8-1.3	3.5-3.7	2.8-0.6	-	-	170 km to SE from Atyrau
Eastern Prorva	(In Production)	AG + Cap	16,949	0.01-0.02	1.7-1.8	3.3-4.1	1.4-1.6	-	0.0	170 km to SE from Atyrau
Aktube	(In Production)	AG	434	-	1.7-7.5	5.2-19.2	2.0 - 5.3	0.9-2.0	-	170 km to SE from Atyrau
Dosmuhambetovskoe	(In Production)	AG	55	-	2.0	12.5	11.3	8.5	-	170 km to SE from Atyrau
Kissimbaj	(consevated)	AG + Cap	20,637	-	12.7	5.8-7.5	0.1-4.4	-	-	210 km to SE from Atyrau
Shagirli-Shumishti	(ready to develop)	NAG	20,486	tracks	3.9-7.3	-	-	-	-	500 km to SE from Atyrau
Borenkol	(prospeting)	AG + Cap	5,962	-	3.6-4.4	2.9-3.4	1.5-3.8	0.1	-	90 km to S from the railway station Kulsari
Tassim	(prospecting)	AG + Cap	1,516	-	6.1	3.2	0.4	-	-	55 km W from Opornaja

Appendix 2.3 Gas Reserve Characteristics (continued) (8/9)
1995

Gas Field	Status	Type of Field	Reserves A+B+C	Gas Quality						Location
				Helium	Nitrogen	Ethane	Propane	Butane	H2S	
Neanovskoe	(prospecting)	AG + Cap	23,835	-	-	-	-	-	-	140 km to NW from v. Beyneu
Kansu	(preserved)	NAG	4,313	0.1	-	-	-	-	-	125 km to SE from Novij Uzen
Southern Alamurun	(preserved)	NAG	1,046	-	-	-	-	-	-	270 km to SE from Aktau
Uzen (including Karamandibas)	(In Production)	AG + Cap	19,114	-	0.9	238-168 g/m3	260-141 g/m3	184-106 g/m3	-	150 km to SE from Aktau
Tenge	(In Production)	AG + Cap	23,445	-	0.3-1.5	83 g/m3	25.7 g/m3	12.1	-	120 km to SE from Aktau
Jetibay	(In Production)	AG + Cap	31,745	-		190-149 g/m3	152-171 g/m3	126-138 g/m3	-	80 km to SE from Aktau
TasbulAt	(In Production)	AG + Cap	7,840	-	0.7-1.8	113-126 g/m3	47.7-69.7 g/m3	19.3-31.4	-	90 km to SE from Aktau
Rakushechnoe	(In Production)	AG + Cap	3,236	-	-	-	-	-	-	100 km to SE from Atyrau
Southern Jetibaj	(In Production)	AG + Cap	8,203	-	-	-	-	-	-	75 km to SE from Aktau
Bekturli	(In Production)	AG + Cap	3,293	-	-	-	-	-	-	80 km to E from Aktau
Kalamkas	(In Production)	AG + Cap	519,739	-	-	-	-	-	-	196 km to N from Aktau
Western Tenge		AG + Cap	1,173	-	-	-	-	-	-	110 km to SE from Aktau

Appendix 2.3 Gas Reserve Characteristics (continued) (9/9)
1995

Gas Field	Status	Type of Field	Reserves A+B+C	Gas Quality						Location
				Helium	Nitrogen	Ethane	Propane	Butane	H2S	
Burmasha	(In Production)	AG	5,125	-	-	-	-	-	-	150 km to SE from Aktau
North Karagie	(In Production)	AG	7,758	-	-	-	-	-	-	60 km to NE from Aktau
Ojmasha	(In Production)	AG + Cap	17,284	-	-	-	-	-	-	22 km to NW from W. Eralievo
Aktas	(In Production)	AG + Cap	1,911	-	2.6-3.5	-	-	-	-	85 km to SE from Aktau
Dunga Espelisay	(ready to develop)	AG + Cap	2,832	-	9.3	8.9-16.0	-	-	-	50 km to N from Aktau
Sarsenbaj	(preserved)	NAG	1,920	-	3.7	-	-	-	-	109 km to SE from Aktau
Tamdi	(preserved)	NAG	1,067	-	-	-	-	-	-	210 km to SE from Aktau

Source: EC Energy Centre, Ministry of Geology

Appendix 2.4

Potential of LPG and Condensate Extraction and Associated Economics

1. The gas streams from a number of Kazakhstan's producing fields have a relatively high liquids content providing the opportunity to extract both LPG and hydrocarbon condensates. At peak production levels (assuming the country's gas fields are fully developed), Kazakhstan has the potential to extract close to 3 million tons per year of LPG and 1 million tons per year of condensates from its gas streams. (Details are provided in Attachment 1.) The Karachaganak field alone is capable of providing more than 1 million tons per year of LPG and about 0.4 million tons per year of condensate from its gas stream when peak gas production levels of 25 bcm per year are reached (the condensate volumes are over and above those which will be extracted directly from the field.)

2. In order to be able to deliver its gas to the European markets, Kazakhstan will have to invest in both sour gas processing facilities and gas liquids extraction facilities. Recovery of the extracted LPG could prove economically attractive provided that the recovery rate exceeds 100,000 tons per year and provided market outlets can be developed close enough to the extraction plants to ensure that transportation costs do not overwhelm the economics.

3. Kazakhstan's consumption of LPG peaked in 1991/92 at 700,000 tons per year. It has since declined to a level of 300,000 tons per year. The country imports its LPG, mainly from Russia, and is required to pay a price which is close to international levels. In 1996, Kazakhstan spent almost $90 million on LPG imports.

Table 1 LPG Consumption and Cost

	1990	*1991*	*1992*	*1993*	*1994*	*1995*	*1996*
LPG Consumption (Millions of tons)	0.4	0.7	0.7	0.6	0.5	0.3	0.3
Average LPG Cost (US$ per ton)	n/a	n/a	n/a	n/a	124	280	290
LPG Import Cost (US$ millions)	n/a	n/a	n/a	n/a	62	84	87

4. Although the cost of LPG transportation is very high, at current Mediterranean market prices, Kazakhstan could still net back a price for LPG exports of

about $60 per ton (see Table 2.) With this in mind, it would be reasonable to pursue development of the domestic market based on prices somewhere between the export net back level ($60/ton) and the current import level ($290/ton). While the deterioration in the economy has undoubtedly impacted LPG demand since 1991/1992, the substantial cost increase between 1994 and 1995 also had its effect. The potential undoubtedly exists to restore domestic demand levels, particularly if the product were priced at a level at or below the 1994 average import cost level. Preliminary economic calculations have, therefore, been based on an export price of $60/ton and a domestic price of $100/ton.

Table 2 Export LPG Prices Netted Back to Kazakhstan

	$/Ton
Mediterranean FOB Price	150
Transportation Cost from Kazakhstan	90
Netback Price in Kazakhstan	60

5. Very preliminary economics have been developed for investment in LPG and condensate recovery facilities at the following fields:

- Karachaganak;
- Kumkol, Maybulak, Aryskum, Konys and Bektus in the Kizyl-Orda and Zhezhazgan oblasts;
- Zhanazol; and
- Uritau.

Table 3 summarizes these preliminary economics, the details of which are provided in Attachments 2 through 5.

Table 3

Summary of Preliminary LPG and Condensate Recovery Economics

Field	Peak Sales Gas	Peak LPG Production	Peak Condensate Production	Capital Expenditures	Unleveraged IRR
	BCM/Year	Tons/Year	Tons/Year	US$ Millions	%
Karachaganak	25.0	1,300,000	470,000	405	20.0
Kumkol & Others	0.3	80,000	18,000	30[1]	about 20.0
Zhanazol	1.0	120,000	24,000	84	32.6
Uritau	2.1	240,000	335,000	173	29.4

Although these economics are very preliminary, they do indicate that a more detailed economic evaluation is warranted.

[1] Since the individual fields are now owned by different private sector firms, there may not be a single consolidated project. Instead, small scale individual LPG recovery projects are likely.

Table 1:
Potential of Gas Liquids Production from Kazak Gas Fields

Field Name	Peak Gas Production (BCM/Y)	Ethane Content (g/m3)	Propane Content (g/m3)	Buthane Content (g/m3)	Condensate Content	Ethane Production (Ton/Y)	Propane Production (Ton/Y)	Butane Production (Ton/Y)	Mixed LPG Production (Ton/Y)	Condensate Production (Ton/Y)
Airakty	0.24	NA								
Amangeldy	0.7	NA								
Bektas	0.14	NA								
Chinarev	3.51	NA								
Imashev	9.29	2.31%	1.06%	0.58%		215557.0	145073.3	79379.7	224453.0	
Kamen	0.48	1.20%	0.70%			5785.7	4950.0		4950.0	
Karachaganak	25	5.94%	2.52%	1.03%	0.65%	1491629.5	928125.0	379352.7	1307477.7	471068.6
Kumkol	1	18.50%	13.90%	5.80%	1.17%	185825.9	204776.8	85446.4	290223.2	33916.9
- Hurricane	0.09	18.60%	13.90%	9.60%	1.80%	16814.7	18429.9	12728.6	31158.5	4696.2
- Kazgermunai	0.24	15.66%	7.30%	3.00%	1.80%	37751.8	25810.7	10607.1	36417.9	12523.2
- Kuatamlonmun	0.013	15.66%	7.30%	3.00%	1.80%	2044.9	1398.1	574.6	1972.6	678.3
Kzyloy	0.08	0.70%	0.05%			562.5	58.9		58.9	
Nuraly	0.15	14%	1.40%			21093.8	3093.8		3093.8	
Tengiz	3	162.4	125.3	46.2		365400	281925	103950	385875.0	
Teplov-Tokarev	1.77	1.20%	0.70%	0.24%		21334.8	18253.1	6258.2	24511.3	
Uritau	2.12	7.84%	4.66%	2.25%	5.38%	166950.0	145541.8	70272.3	215814.1	330635.1
Zhanazol	1	9.99%	5.75%	1.99%	0.83%	100346.0	84709.8	29317.0	114026.8	24060.7
Total						2631096.6	1862146.2	777886.6	2640032.8	877579.1

DataSource: "Characteristics of the Deposits of the Republic of Kazakstan" by the Ministry of Geology except Karachganak,

and Zhnazol. Used the VECO data for Karachganak, and the data from EC Energy Center for Kumkol, Urithau and Zhanazol.

The gas components of the fields in Kumkol were provided by Harricane Co. and kazgermunai. Those for "Kuatamlonmunai" were assumed to be similar to Kazgermunai's comp

Note: Assumed 75% recovery for C3 and C4, and 90% recovery for C5+.

Appendix 2.5

Field name: Karachaganak (large field)
Gas Characteristics: Sour

Recoverable Reserves	42,473.3	(BCF)
Depth	5,600.0	(meters)
Additional Seismic	-	(US$MM)
Appraisal	-	(US$MM)
Development	405.0	(US$MM)
New Wells	-	(US$MM)
Gathering and Separation	5.0	(US$MM)
Gas Conditioning	400.0	(US$MM)
Gas Cost	0.25	(US$/MCF)

Assuming that the wellhead gas cost is $0.25/MCF,
the gas cost at the outlet of the gas plant is **$0.50/MCF.**
(=$0.25/MCF +$0.25/MCF)

year	*Gas Feed (BCF)*	*Sales gas Production (BCF)*	*Gas price (US$/MCF)*	*Gas sales revenue (US$MM)*	*LPG Production (Ton)*	*LPG price (US$/ton)*	*LPG sales revenue (US$MM)*	*Total Revenue (US$MM)*	*Capital Cost (US$MM)*	*Oerating Cost (US$MM)*	*Total Csot (US$MM)*	*Cash Flow (US$MM)*
1997	326.2	326.2	0.25	81.5	0	60.0	-	81.5	(202.5)	(85.5)	(288.0)	(206.4)
1998	468.4	468.4	0.25	117.1	0	60.0	-	117.1	(202.5)	(113.9)	(316.4)	(199.3)
1999	562.0	539.5	0.25	134.9	832,624	60.0	50.0	184.8		(132.6)	(132.6)	52.2
2000	685.2	657.8	0.25	164.4	1,015,152	60.0	60.9	225.4		(157.3)	(157.3)	68.1
2001	701.1	673.0	0.25	168.3	1,038,688	60.0	62.3	230.6	-	(160.5)	(160.5)	70.1
2002	694.7	666.9	0.25	166.7	1,029,273	60.0	61.8	228.5	-	(159.2)	(159.2)	69.3
2003	752.9	722.8	0.25	180.7	1,115,569	60.0	66.9	247.6	-	(170.8)	(170.8)	76.8
2004	840.5	806.9	0.25	201.7	1,245,274	60.0	74.7	276.4	-	(188.3)	(188.3)	88.1
2005	886.0	850.6	0.25	212.6	1,312,742	60.0	78.8	291.4	-	(197.5)	(197.5)	94.0
2006	887.1	851.6	0.25	212.9	1,314,311	60.0	78.9	291.8	-	(197.7)	(197.7)	94.1
2007	881.1	845.8	0.25	211.5	1,305,420	60.0	78.3	289.8	-	(196.5)	(196.5)	93.3
2008	867.3	832.6	0.25	208.2	1,285,023	60.0	77.1	285.3	-	(193.7)	(193.7)	91.5
2009	845.4	811.6	0.25	202.9	1,252,596	60.0	75.2	278.1	-	(189.3)	(189.3)	88.7
2010	815.8	783.2	0.25	195.8	1,208,664	60.0	72.5	268.3	-	(183.4)	(183.4)	84.9
2011	760.7	730.3	0.25	182.6	1,127,075	60.0	67.6	250.2	-	(172.4)	(172.4)	77.8
2012	694.0	666.2	0.25	166.6	1,028,227	60.0	61.7	228.3	-	(159.0)	(159.0)	69.2
2013	654.5	628.3	0.25	157.1	969,651	60.0	58.2	215.2	-	(151.1)	(151.1)	64.1
2014	575.4	552.4	0.25	138.1	852,498	60.0	51.1	189.2	-	(135.3)	(135.3)	53.9
2015	541.1	519.5	0.25	129.9	801,766	60.0	48.1	178.0	-	(128.5)	(128.5)	49.5
2016	490.3	470.7	0.25	117.7	726,454	60.0	43.6	161.3	-	(118.3)	(118.3)	42.9
2017	443.0	425.3	0.25	106.3	656,371	60.0	39.4	145.7	-	(108.9)	(108.9)	36.9
2018	390.4	374.8	0.25	93.7	578,443	60.0	34.7	128.4	-	(98.3)	(98.3)	30.1
2019	381.2	366.0	0.25	91.5	564,845	60.0	33.9	125.4	-	(96.5)	(96.5)	28.9
2020	363.9	349.4	0.25	87.3	539,218	60.0	32.4	119.7	-	(93.0)	(93.0)	26.7
2021	338.5	325.0	0.25	81.2	501,562	60.0	30.1	111.3	-	(88.0)	(88.0)	23.4
2022	312.8	300.2	0.25	75.1	463,382	60.0	27.8	102.9		(82.8)	(82.8)	20.1
2023	296.2	284.3	0.25	71.1	438,801	60.0	26.3	97.4		(79.5)	(79.5)	17.9
2024	277.1	266.0	0.25	66.5	410,559	60.0	24.6	91.1		(75.7)	(75.7)	15.5
2025	252.4	242.3	0.25	60.6	373,948	60.0	22.4	83.0		(70.7)	(70.7)	12.3
2026	225.9	216.9	0.25	54.2	334,723	60.0	20.1	74.3		(65.4)	(65.4)	8.9
2027	206.2	197.9	0.25	49.5	305,435	60.0	18.3	67.8		(61.5)	(61.5)	6.3
2028	199.8	191.8	0.25	48.0	296,021	60.0	17.8	65.7		(60.2)	(60.2)	5.5
2029	194.9	187.1	0.25	46.8	288,699	60.0	17.3	64.1		(59.2)	(59.2)	4.9
2030	185.3	177.9	0.25	44.5	274,578	60.0	16.5	61.0		(57.3)	(57.3)	3.6
2031	176.1	169.1	0.25	42.3	260,979	60.0	15.7	57.9		(55.5)	(55.5)	2.5
2032	167.0	160.3	0.25	40.1	247,381	60.0	14.8	54.9		(73.6)	(73.6)	(18.7)
TOTAL	18,340.5			4,409.7				5,969.4	(405.0)	(4,417.1)	(4,822.1)	1,068.7
NPV@15%	4,143.3			1,000.8				1,312.4	(329.2)	(962.9)	(1,292.1)	18.6

Note: The above production profile is based on the BG/Agip's plan in 1995.
The gas contains about 2.5% of propane and 1% of butane. Assumed 75% LPG component recovery.
LPG netback at Karachaganak is $150/ton @Balck Sea minus transport cost $90/ton ($150-$90=$60).

Appendix II-4

Table 3: Kumkol - Typical Field LPG/Condensate Extraction Economics

Year	Capex (US$ mm)	Incremental O & M (US$ mm)	Sales Gas Volume (million CM)	Gas Prod. Cost (US$/1000 CM)	Gas Sales Value (US$/1000 CM)	Gas Sales Revenue (US$ mm)	LPG Productio (Tons)	LPG Sales Revenue (US$ mm)	Condensate Production (Tons)	Condensate Sales Rev. (US$ mm)	Net Cash Flow (US$ mm)
1	7	0	0	0	35	0	0	0.00	0	0	-7.00
2	3	0.25	0	0	35	0	9787	1.17	1332.0	0.09	-1.98
3	0	0.5	0	0	35	0	19574	2.35	2663.0	0.19	2.04
4	0	0.5	0	0	35	0	19574	2.35	2663.0	0.19	2.04
5	0	0.5	0	0	35	0	19574	2.35	2663.0	0.19	2.04
6	0	0.5	0	0	35	0	19574	2.35	2663.0	0.19	2.04
7	0	0.5	0	0	35	0	19574	2.35	2663.0	0.19	2.04
8	0	0.5	0	0	35	0	19574	2.35	2663.0	0.19	2.04
9	0	0.5	0	0	35	0	19574	2.35	2663.0	0.19	2.04
10	0	0.5	0	0	35	0	19574	2.35	2663.0	0.19	2.04
11	0	0.5	0	0	35	0	19574	2.35	2663.0	0.19	2.04
12	0	0.5	0	0	35	0	19574	2.35	2663.0	0.19	2.04
13	0	0.5	0	0	35	0	19574	2.35	2663.0	0.19	2.04
14	0	0.5	0	0	35	0	19574	2.35	2663.0	0.19	2.04
15	0	0.5	0	0	35	0	19574	2.35	2663.0	0.19	2.04
16	0	0.5	0	0	35	0	19574	2.35	2663.0	0.19	2.04
17	0	0.5	0	0	35	0	19574	2.35	2663.0	0.19	2.04
18	0	0.5	0	0	35	0	19574	2.35	2663.0	0.19	2.04
19	0	0.5	0	0	35	0	19574	2.35	2663.0	0.19	2.04
20	0	0.5	0	0	35	0	19574	2.35	2663.0	0.19	2.04
21	0	0.5	0	0	35	0	19574	2.35	2663.0	0.19	2.04
22	0	0.5	0	0	35	0	19574	2.35	2663.0	0.19	2.04
	10		0			0	401267				-10.00
NPV@15%	$8.36										2.05

Note:

Assumed the gas composition is similar to that of the Kumkol field, e.g. C3 =13.9%, C4=9.6% and C5+=1.8%

IRR= 19.1%

Assumed 75% recovery for C3 and C4, and 90% recovery for C5+.

Assumed gas production cost is zero since flared gas is used. However, the dray gas is assumed to be used for reinjection.

Assumed $120 per ton for the LPG whole sale price.

Assumed $70 per ton for the whole sale price of condensate.

Assumed about 5% of the capex for the annual O & M costs.

Capex	US$ MM
LPG Plant	9
Others (Storage, Tanker, etc.)	1
Total	**10**

Appendix II-4

Table 4: Zhanazol Field - LPG/Condensate Extraction Economics

Year	Capex (US$ mm)	Incremental O & M (US$ mm)	Sales Gas Volume (million CM)	Gas Prod. Cost (US$/1000 CM)	Gas Sales Value (US$/1000 CM)	Gas Sales Revenue (US$ mm)	LPG Prod. (Tons)	LPG Sales Revenue (US$ mm)	Condensate Production (Tons)	Condensate Sales Reve. (US$ mm)	Total Revenue (US$ mm)	Net Cash Flow (US$ mm)
1	50.3	0	0	0	30	0	0.0	0	0	0	0	-50.3
2	33.6	4.2	500	9.5	30	10.25	61677.5	6.2	12005.4	1.2	17.6	-20.2
3	0	4.2	700	9.5	30	14.35	86348.4	8.6	16807.5	1.7	24.7	20.5
4	0	4.2	1000	9.5	30	20.5	123354.9	12.3	24010.7	2.4	35.2	31.0
5	0	4.2	1000	9.5	30	20.5	123354.9	12.3	24010.7	2.4	35.2	31.0
6	0	4.2	1000	9.5	30	20.5	123354.9	12.3	24010.7	2.4	35.2	31.0
7	0	4.2	1000	9.5	30	20.5	123354.9	12.3	24010.7	2.4	35.2	31.0
8	0	4.2	1000	9.5	30	20.5	123354.9	12.3	24010.7	2.4	35.2	31.0
9	0	4.2	1000	9.5	30	20.5	123354.9	12.3	24010.7	2.4	35.2	31.0
10	0	4.2	1000	9.5	30	20.5	123354.9	12.3	24010.7	2.4	35.2	31.0
11	0	4.2	1000	9.5	30	20.5	123354.9	12.3	24010.7	2.4	35.2	31.0
12	0	4.2	1000	9.5	30	20.5	123354.9	12.3	24010.7	2.4	35.2	31.0
13	0	4.2	1000	9.5	30	20.5	123354.9	12.3	24010.7	2.4	35.2	31.0
14	0	4.2	1000	9.5	30	20.5	123354.9	12.3	24010.7	2.4	35.2	31.0
15	0	4.2	1000	9.5	30	20.5	123354.9	12.3	24010.7	2.4	35.2	31.0
16	0	4.2	1000	9.5	30	20.5	123354.9	12.3	24010.7	2.4	35.2	31.0
17	0	4.2	1000	9.5	30	20.5	123354.9	12.3	24010.7	2.4	35.2	31.0
18	0	4.2	1000	9.5	30	20.5	123354.9	12.3	24010.7	2.4	35.2	31.0
19	0	4.2	1000	9.5	30	20.5	123354.9	12.3	24010.7	2.4	35.2	31.0
20	0	4.2	1000	9.5	30	20.5	123354.9	12.3	24010.7	2.4	35.2	31.0
21	0	4.2	1000	9.5	30	20.5	123354.9	12.3	24010.7	2.4	35.2	31.0
22	0	4.2	1000	9.5	30	20.5	123354.9	12.3	24010.7	2.4	35.2	31.0
	83.9		20200				2491769.2		485016.4		711.7786	539.8
NPV@15%	$69.15											$81.0

Capex	US$ MM
LPG Plant	50
Completion of Pipeline	20.4
2.5 MW gas comp. St.	3.5
Others (Storage, Tanker)	10
Total	**83.9**

IRR= 32.6%

Note: C3=5.75%, C4=1.99%, C5+=0.83%.
Assumed 75% recovery for C3 and C4, and 90% recovery for C5+.
The gas production cost is from Appendix II-8. $0.27 per bcf, e.g. $9.5 per 1000 CM is assumed.
Assumed $100 per ton for the LPG whole sale price.
Assumed $70 per ton for the whole sale price of condensate.
Assumed about 5% of the capex for the annual O & M cost.
Assumed that the whole sale gas price is same as the gas purchasing price in Q 4 of 1996, e.g. 2261 Tenge or $30 per 1000 CM.

Appendix II-4

Table 5: Uritau Field - LPG/Condensate Extraction Economics

Year	Capex (US$ mm)	Increment O & M (US$ mm)	Sales Gas Volume (million CM)	Gas Prod. Cost (US$/1000 CM)	Gas Sales Value (US$/100	Gas Sales Revenue (US$ mm)	LPG Prod. (Tons)	LPG Sale Revenue (US$ mm)	Condensate Production (Tons)	Condensate Sales Reve. (US$ mm)	Total Revenue (US$ mm)	Net Cash Flow (US$ mm)
1	126	0	0	0	30	0	0.0	0	0.0	0	0	-126
2	84	10.5	717	16.9	30	9.4	80552.1	8.1	111590.8	11.2	28.6	-65.9
3	0	10.5	1430	16.9	30	18.7	160654.8	16.1	222559.1	22.3	57.1	46.6
4	0	10.5	2150	16.9	30	28.2	241543.9	24.2	334616.8	33.5	85.8	75.3
5	0	10.5	2150	16.9	30	28.2	241543.9	24.2	334616.8	33.5	85.8	75.3
6	0	10.5	2150	16.9	30	28.2	241543.9	24.2	334616.8	33.5	85.8	75.3
7	0	10.5	2150	16.9	30	28.2	241543.9	24.2	334616.8	33.5	85.8	75.3
8	0	10.5	2150	16.9	30	28.2	241543.9	24.2	334616.8	33.5	85.8	75.3
9	0	10.5	2150	16.9	30	28.2	241543.9	24.2	334616.8	33.5	85.8	75.3
10	0	10.5	2150	16.9	30	28.2	241543.9	24.2	334616.8	33.5	85.8	75.3
11	0	10.5	2150	16.9	30	28.2	241543.9	24.2	334616.8	33.5	85.8	75.3
12	0	10.5	2150	16.9	30	28.2	241543.9	24.2	334616.8	33.5	85.8	75.3
13	0	10.5	2150	16.9	30	28.2	241543.9	24.2	334616.8	33.5	85.8	75.3
14	0	10.5	2150	16.9	30	28.2	241543.9	24.2	334616.8	33.5	85.8	75.3
15	0	10.5	2150	16.9	30	28.2	241543.9	24.2	334616.8	33.5	85.8	75.3
16	0	10.5	1790	16.9	30	23.4	201099.3	20.1	278587.9	27.9	71.4	60.9
17	0	10.5	1430	16.9	30	18.7	160654.8	16.1	222559.1	22.3	57.1	46.6
18	0	10.5	1430	16.9	30	18.7	160654.8	16.1	222559.1	22.3	57.1	46.6
19	0	10.5	1070	16.9	30	14.0	120210.2	12.0	166530.2	16.7	42.7	32.2
20	0	10.5	720	16.9	30	9.4	80889.1	8.1	112057.7	11.2	28.7	18.2
21	0	10.5	720	16.9	30	9.4	80889.1	8.1	112057.7	11.2	28.7	18.2
22	0	10.5	720	16.9	30	9.4	80889.1	8.1	112057.7	11.2	28.7	18.2
	210		35827				4025019.5		5575960.7		1429.432	998.9
NPV@15%	$173.08											$159.3
											IRR=	29.4%

Note: C3=4.66%, C4=2.25%, C5+=5.38%.

Assumed 75% recovery for C3 and C4, and 90% recovery for C5+.

The gas production cost is from Appendix II-8. $0.48 per bcf, e.g. $16.9 per 1000 CM is assumed.

Assumed $100 per ton for the LPG whole sale price.

Assumed $70 per ton for the whole sale price of condensate.

Assumed about 5% of the capex for the annual O & M cost.

Assumed that the whole sale gas price is same as the gas purchasing price in Q 4 of 1996, e.g. 2261 Tenge or $30 per 1000 CM.

Capex	US$ MM
LPG Plant	120
Pipeline (40" x 100 Km)	80
Others (Storage, Tanker)	10
Total	**210**

Appendix 2.5

Gas Production Cost Model

Summary of Gas Production Costs

1. In Kazakhstan, about 24 fields have been identified for possible natural gas development. In order to identify the most profitable fields for development, there is a need to estimate the cost of bringing the gas to the nearest market.

2. The economic analysis was undertaken by utilizing a cash flow model. The model utilizes very preliminary estimates on investments, operating costs and prices to generate a rudimentary idea about the price of delivery. This results obtained from this model should be seen as very preliminary and no investment or other decision should be made on the basis of these figures. The production costs and measures of profitability are provided for the readers convenience and are to be used for comparative purposes only.

3. Out of the 24 fields, 13 fields are considered high priority by the government. These fields are Airakty, Amangeldy, Bektas, Chinarev, Imashev, Kamen, Karachaganak, Kzyloy, Nuraly, Tengiz, Teplov-Tokarev, Urihtau and Zhanazhol. Among these fields, only Karachaganak, Tengiz and Zhanazhol are in production. The other fields are in the process of being developed.

Table 1

Indicative Gas Production Costs

		Peak Production	Capital Investment	Well Head Production Cost @15% Discount Rate	
Oblast	*Field Name*	*(BCM/Year)*	*(US $ Million)*	*($/MMBTU)*	*($/1000 cm)*
Aktyubinsk	Kzyloy	0.1	13	1.44	50.7
	Urihtau	2.2	80	0.48	16.9
	Zhanazol	4.5	59	0.27	9.5
Atyrau	Imashev	9.3	492	0.60	21.2
	Tengiz	5.0	68	0.30	10.6
West-Kazakhstan	Chinarev	3.5	208	0.65	22.9
	Kamen	0.5	40	0.82	28.9
	Karachaganak	25.1	400	0.50	17.7
	Teplov-tokarev	1.8	73	0.52	18.4
Kizyl-Orda	Bektas	0.1	20	1.34	47.2
	Nuraly	0.2	19	1.16	40.9
Zhambyl	Airakty	0.2	24	1.00	35.3
	Amangeldy	0.7	45	0.70	24.7

Source: ESMAP Task Force Estimates

Model Description

Time Frame

4. The timing of investments is presented below. Capital expenditures spread over a number of years is assumed to have been spent proportionally over the number of years. e.g.

- Seismic facilities 50% in year 1
  50% in year 2
- Exploration facilities 100% in year 3
- Delineation facilities 50% in year 3
  50% in year 4
- Production facilities 50% in year 4
  50% in year 5

Capital Costs

5. All investments subsequent to a field being declared commercial are considered capital costs. Seismic and exploration wells are currently expensed on an annual basis. The capital cost estimates utilized in this model are developed by staff of the Oil and Gas Division. These costs are developed utilizing general guidelines or 'Rule of Thumb' estimates. The investment and operating cost investments provided here should not be taken as an endorsement by ESMAP staff or form the basis for negotiations with private investors.

Appraisal Costs

6. The fields under consideration for investment were previously appraised under Soviet authorities with technology that is considerably different from the West. Additional appraisal work is required to gather additional data on reservoir characteristics and develop precise investment requirements.

7. Given the large size of the concessions, 800 km of additional seismic survey and 4 appraisal wells are required. The cost of acquiring seismic data at acceptable levels used in the West is estimated at $10,000 per km on onshore Kazakhstan. Appraisal wells drilled with the help of local drilling contractors is expected to cost 2 million USD for shallow wells of up to 1,000 meter depth. Wells of up to 3,000 meter depth are expected to cost 4 million USD. Appraisal wells with depths of more than 3,000 meters are considerably more expensive as local contractors do not possess the technology. Western companies are available for drilling deep wells for 10 million US$ per well.

Development Costs

8. The development costs of a field include development wells, production and gas processing facilities. In the case of associated gas, the development costs presented here is limited to the incremental facilities such as gas processing facilities.

9. The cost estimates of gathering/separation and gas conditioning facilities are estimated as follows:

	Units : US$ million	
	Sweet Gas	*Sour Gas*
Capacity: 90 BCF (15 MMCFD)		
Gathering/Separation Facilities:	3.9	4.9
Gas Conditioning Facilities:	2.6	3.9
Capacity: 300 BCF (50 MMCFD)		
Gathering/Separation Facilities:	5.5	6.3
Gas Conditioning Facilities:	4.4	6.6
Capacity: 900 BCF (150 MMCFD)		
Gathering/Separation Facilities:	8.1	9.3
Gas Conditioning Facilities:	8.0	12.0
Capacity: 3,000 BCF (500 MMCFD)		
Gathering/Separation Facilities:	14.6	16.8
Gas Conditioning Facilities:	17.0	25.5
Capacity: 9,000 BCF (1,500 MMCFD)		
Gathering/Separation Facilities:	27.6	31.7
Gas Conditioning Facilities:	35.2	52.8

Note: For the Karachganak gas field, about $400 million is estimated for full development, taking account of the requirement of gas conditioning to meet the export gas specification and extraction of liquid components.

Reserve Estimates and Production Rates

10. The reserves and production profile estimates are based on the data provided by Kazakgas. The reserve figures used for our calculations are category A, B, C1 and C2 of the Soviet system. (see the attached Box for description). The reserves of the 13 fields are given in the attached spreader sheets.

Field Name		(US$/MCF) Production Cost	Status	Gas Characteristics	
Airakty	Zhambyl	1.00		sweet	
Amangeldy	Zhambyl	0.70		sweet	
Bektas	Kizilarda	1.34		(no data)	
Chinarev	W. Kazakhstan	0.65		(no data)	
Imashev	Atyrau	0.60		sour	15.7 % H^2S
Kamen	W. Kazakhstan	0.80		sour	0.9-1.7 % H^2S
Karachaganak	W. Kazakhstan	0.50	(producing)	sour	3.6 % H^2S
Kzyloy	Aktyubinsk	1.44		sweet	
Nuraly	Kizilarda	1.16		sweet	
Tengiz	Atyrau	0.30	(producing, AG)	sour	11.7-19.3 % H^2S
Teplov-Tokarev	W. Kazakhstan	0.52		sour	3.6 % H^2S
Urihtau	Aktyubinsk	0.48		sour	1.8 % H^2S
Zhanazhol	Aktyubinsk	0.27	(producing, AG)	sour	6.0 % H^2S

11. The production curves are designed to extract 90% of the reserves over 21-year-production-period(see below) with the exception of Karachaganak, Tengiz and Zhonazhol. The annual production forecast for Karachaganak and Tengiz are obtained from BG/AGIP's production plan in 1995 and Kazakgaz's 'Pipeline Development Plan' in July 1996 respectively. Production Profile (Large Fields)

12. The production profile used for large fields (e.g. more than 200 BCM reserve)is as follows:

Time	Recoverable Reserves
year 5	2 %
year 6	4 %
year 7	6 %
year 8	6 %
year 9	6 %

Time	*Recoverable Reserves*
year 10	6 %
year 11	6 %
year 12	6 %
year 13	6 %
year 14	6 %
year 15	6 %
year 16	6 %
year 17	6 %
year 18	6 %
year 19	5 %
year 20	4 %
year 21	4 %
year 22	3 %
year 23	2 %
year 24	2 %
year 25	2 %

13. *For the fields smaller* than 200 BCM, namely Airkty, Kzloy, Nuraly and Bektas, seismic survey is not scheduled. The productions start from the fourth year and extract 90% of the reserves over 22 years (see below).

Production Profile (Small Fields)

Time	*Recoverable Reserves*
year 4	2 %
year 5	3 %
year 6	4 %
year 7	6 %
year 8	6 %
year 9	6 %
year 10	6 %
year 11	6 %

Time	*Recoverable Reserves*
year 12	6 %
year 13	6 %
year 14	6 %
year 15	6 %
year 16	6 %
year 17	6 %
year 18	5 %
year 19	5 %
year 20	4 %
year 21	3 %
year 22	3 %
year 23	2 %
year 24	2 %
year 25	2 %

Operating Costs

14. The operating costs include fixed expenses (5% of the development costs per year), variable expense(US$ 0.2/MCF), and abandonment costs (US$ 20 MM for fields larger than 200 BCF, US$ 4 MM for the fields smaller than 200 BCF).

Appendix 2.5

Field name: Airakty (small field)
Gas Characteristics: sweet

Recoverable Reserves	139.7	(BCF)		
Depth	2,100.0	(meters)	Capital Cost	0.72 (US$/MCF)
Additional Seismic	-	(US$MM)	Operating Cost	0.27 (US$/MCF)
Appraisal	16.0	(US$MM)	Total Cost	0.99 (US$/MCF)
Development	7.6	(US$MM)		
New Wells	-	(US$MM)		
Gathering and Separat	4.4	(US$MM)		
Gas Conditioning	3.2	(US$MM)		
Total Gas Cost	1.00	(US$/MCF)		

Year	*Production (BCF)*	*Gas Price (US$/MCF)*	*Revenue (US$MM)*	*Capital Cost (US$MM)*	*Operating Cost (US$MM)*	*Total Cost (US$MM)*	*Cash Flow (US$MM)*
1	0.0	1.0	0.0	(16.0)	0.0	(16.0)	(16.0)
2	0.0	1.0	0.0	(3.8)	0.0	(3.8)	(3.8)
3	0.0	1.0	0.0	(3.8)	0.0	(3.8)	(3.8)
4	2.8	1.0	2.8	0.0	(0.9)	(0.9)	1.9
5	4.2	1.0	4.2	0.0	(1.2)	(1.2)	3.0
6	5.6	1.0	5.6	0.0	(1.5)	(1.5)	4.1
7	7.0	1.0	7.0	0.0	(1.8)	(1.8)	5.2
8	8.4	1.0	8.4	0.0	(2.1)	(2.1)	6.3
9	8.4	1.0	8.4	0.0	(2.1)	(2.1)	6.3
10	8.4	1.0	8.4	0.0	(2.1)	(2.1)	6.3
11	8.4	1.0	8.4	0.0	(2.1)	(2.1)	6.3
12	8.4	1.0	8.4	0.0	(2.1)	(2.1)	6.3
13	8.4	1.0	8.4	0.0	(2.1)	(2.1)	6.3
14	8.4	1.0	8.4	0.0	(2.1)	(2.1)	6.3
15	8.4	1.0	8.4	0.0	(2.1)	(2.1)	6.3
16	8.4	1.0	8.4	0.0	(2.1)	(2.1)	6.3
17	8.4	1.0	8.4	0.0	(2.1)	(2.1)	6.3
18	7.0	1.0	7.0	0.0	(1.8)	(1.8)	1.2
19	7.0	1.0	7.0	0.0	(1.8)	(1.8)	5.2
20	5.6	1.0	5.6	0.0	(1.5)	(1.5)	4.1
21	4.2	1.0	4.2	0.0	(1.2)	(1.2)	3.0
22	4.2	1.0	4.2	0.0	(1.2)	(1.2)	3.0
23	2.8	1.0	2.8	0.0	(0.9)	(0.9)	1.9
24	2.8	1.0	2.8	0.0	(0.9)	(0.9)	1.9
25	2.8	1.0	2.8	0.0	(5.8)	(5.8)	(3.0)
TOTAL	139.7		139.7	(23.6)	(41.1)	(64.7)	70.9
15%	26.6		26.6	(19.3)	(7.1)	(26.3)	(0.0)

Appendix 2.5

Field name: Amangeldy (large field)
Gas Characteristics: sweet

Recoverable Reserves	410.1	(BCF)	Capital Cost	0.43	(US$/MCF)
Depth	2,200.0	(meters)	Operating Cost	0.26	(US$/MCF)
Additional Seismic	8.0	(US$MM)	Total Cost	0.69	(US$/MCF)
Appraisal	16.0	(US$MM)			
Development	21.0	(US$MM)			
New Wells	6.4	(US$MM)			
Gathering and Separat	6.0	(US$MM)			
Gas Conditioning	8.6	(US$MM)			
Total Gas Cost	0.70	(US$/MCF)			

Year	Production (BCF)	Gas Price (US$/MCF)	Revenue (US$MM)	Capital Cost (US$MM)	Operating Cost (US$MM)	Total Cost (US$MM)	Cash Flow (US$MM)
1	0.0	0.7	0.0	(8.0)	0.0	(8.0)	(8.0)
2	0.0	0.7	0.0	(16.0)	0.0	(16.0)	(16.0)
3	0.0	0.7	0.0	(10.5)	0.0	(10.5)	(10.5)
4	0.0	0.7	0.0	(10.5)	0.0	(10.5)	(10.5)
5	8.2	0.7	5.7	0.0	(2.7)	(2.7)	3.1
6	16.4	0.7	11.5	0.0	(4.3)	(4.3)	7.2
7	24.6	0.7	17.2	0.0	(6.0)	(6.0)	11.3
8	24.6	0.7	17.2	0.0	(6.0)	(6.0)	11.3
9	24.6	0.7	17.2	0.0	(6.0)	(6.0)	11.3
10	24.6	0.7	17.2	0.0	(6.0)	(6.0)	11.3
11	24.6	0.7	17.2	0.0	(6.0)	(6.0)	11.3
12	24.6	0.7	17.2	0.0	(6.0)	(6.0)	11.3
13	24.6	0.7	17.2	0.0	(6.0)	(6.0)	11.3
14	24.6	0.7	17.2	0.0	(6.0)	(6.0)	11.3
15	24.6	0.7	17.2	0.0	(6.0)	(6.0)	11.3
16	24.6	0.7	17.2	0.0	(6.0)	(6.0)	11.3
17	24.6	0.7	17.2	0.0	(6.0)	(6.0)	11.3
18	24.6	0.7	17.2	0.0	(6.0)	(6.0)	11.3
19	20.5	0.7	14.4	0.0	(5.2)	(5.2)	9.2
20	16.4	0.7	11.5	0.0	(4.3)	(4.3)	7.2
21	16.4	0.7	11.5	0.0	(4.3)	(4.3)	7.2
22	12.3	0.7	8.6	0.0	(3.5)	(3.5)	5.1
23	8.2	0.7	5.7	0.0	(2.7)	(2.7)	3.1
24	8.2	0.7	5.7	0.0	(2.7)	(2.7)	3.1
25	8.2	0.7	5.7	0.0	(22.7)	(22.7)	(16.9)
TOTAL	410.1		287.1	(45.0)	(124.1)	(169.1)	118.0
PV@15	73.6		51.5	(32.0)	(19.1)	(51.1)	0.4

Note: The above total investment cost is nearly equal to the Dosbol's estimated US$ 59.1 million minus the cost for 130 Km pipeline, US$14.1 million.

Appendix 2.5

Field name: Bektas (small field)
Gas Characteristics: No data (assumed sour)

Recoverable Reserves	83.4	(BCF)
Depth	1,000.0	(meters)
Additional Seismic	-	(US$MM)
Appraisal	12.0	(US$MM)
Development	7.9	(US$MM)
New Wells	-	(US$MM)
Gathering and Separat	4.9	(US$MM)
Gas Conditioning	3.0	(US$MM)
Total Gas Cost	1.34	(US$/MCF)

Capital Cost	1.01	(US$/MCF)
Operating Cost	0.31	(US$/MCF)
Total Cost	1.32	(US$/MCF)

Year	*Production (BCF)*	*Gas Price (US$/MCF)*	*Revenue (US$MM)*	*Capital Cost (US$MM)*	*Operating Cost (US$MM)*	*Total Cost (US$MM)*	*Cash Flow (US$MM)*
1	0.0	1.3	0.0	(12.0)	0.0	(12.0)	(12.0)
2	0.0	1.3	0.0	(4.0)	0.0	(4.0)	(4.0)
3	0.0	1.3	0.0	(4.0)	0.0	(4.0)	(4.0)
4	1.7	1.3	2.2	0.0	(0.7)	(0.7)	1.5
5	2.5	1.3	3.4	0.0	(0.9)	(0.9)	2.5
6	3.3	1.3	4.5	0.0	(1.1)	(1.1)	3.4
7	4.2	1.3	5.6	0.0	(1.2)	(1.2)	4.4
8	5.0	1.3	6.7	0.0	(1.4)	(1.4)	5.3
9	5.0	1.3	6.7	0.0	(1.4)	(1.4)	5.3
10	5.0	1.3	6.7	0.0	(1.4)	(1.4)	5.3
11	5.0	1.3	6.7	0.0	(1.4)	(1.4)	5.3
12	5.0	1.3	6.7	0.0	(1.4)	(1.4)	5.3
13	5.0	1.3	6.7	0.0	(1.4)	(1.4)	5.3
14	5.0	1.3	6.7	0.0	(1.4)	(1.4)	5.3
15	5.0	1.3	6.7	0.0	(1.4)	(1.4)	5.3
16	5.0	1.3	6.7	0.0	(1.4)	(1.4)	5.3
17	5.0	1.3	6.7	0.0	(1.4)	(1.4)	5.3
18	4.2	1.3	5.6	0.0	(1.2)	(1.2)	0.4
19	4.2	1.3	5.6	0.0	(1.2)	(1.2)	4.4
20	3.3	1.3	4.5	0.0	(1.1)	(1.1)	3.4
21	2.5	1.3	3.4	0.0	(0.9)	(0.9)	2.5
22	2.5	1.3	3.4	0.0	(0.9)	(0.9)	2.5
23	1.7	1.3	2.2	0.0	(0.7)	(0.7)	1.5
24	1.7	1.3	2.2	0.0	(0.7)	(0.7)	1.5
25	1.7	1.3	2.2	0.0	(5.2)	(5.2)	(3.0)
TOTAL	83.4		111.8	(19.9)	(29.9)	(49.8)	58.0
PV@15	15.9		21.3	(16.0)	(5.0)	(21.0)	0.0

Note: The above total investment cost is nearly equal to the Dosbol's estimated US$ 59.1 million minus the cost for 130 Km pipeline, US$14.1 million.

Appendix 2.5

Field name: Chinarev (large field)
Gas Characteristics: No data (Assumed sour)

Recoverable Reserves	2,063.5	(BCF)	Capital Cost	0.37	(US$/MCF)
Depth	5,100.0	(meters)	Operating Cost	0.28	(US$/MCF)
Additional Seismic	8.0	(US$MM)	Total Cost	0.65	(US$/MCF)
Appraisal	40.0	(US$MM)			
Development	159.9	(US$MM)			
New Wells	128.0	(US$MM)			
Gathering and Separat	13.1	(US$MM)			
Gas Conditioning	18.8	(US$MM)			
Total Gas Cost	0.65	(US$/MCF)			

Year	*Production (BCF)*	*Gas Price (US$/MCF)*	*Revenue (US$MM)*	*Capital Cost (US$MM)*	*Operating Cost (US$MM)*	*Total Cost (US$MM)*	*Cash Flow (US$MM)*
1	0.0	0.7	0.0	(8.0)	0.0	(8.0)	(8.0)
2	0.0	0.7	0.0	(40.0)	0.0	(40.0)	(40.0)
3	0.0	0.7	0.0	(80.0)	0.0	(80.0)	(80.0)
4	0.0	0.7	0.0	(80.0)	0.0	(80.0)	(80.0)
5	41.3	0.7	26.8	0.0	(16.2)	(16.2)	10.6
6	82.5	0.7	53.7	0.0	(24.5)	(24.5)	29.1
7	123.8	0.7	80.5	0.0	(32.8)	(32.8)	47.7
8	123.8	0.7	80.5	0.0	(32.8)	(32.8)	47.7
9	123.8	0.7	80.5	0.0	(32.8)	(32.8)	47.7
10	123.8	0.7	80.5	0.0	(32.8)	(32.8)	47.7
11	123.8	0.7	80.5	0.0	(32.8)	(32.8)	47.7
12	123.8	0.7	80.5	0.0	(32.8)	(32.8)	47.7
13	123.8	0.7	80.5	0.0	(32.8)	(32.8)	47.7
14	123.8	0.7	80.5	0.0	(32.8)	(32.8)	47.7
15	123.8	0.7	80.5	0.0	(32.8)	(32.8)	47.7
16	123.8	0.7	80.5	0.0	(32.8)	(32.8)	47.7
17	123.8	0.7	80.5	0.0	(32.8)	(32.8)	47.7
18	123.8	0.7	80.5	0.0	(32.8)	(32.8)	47.7
19	103.2	0.7	67.1	0.0	(28.6)	(28.6)	38.4
20	82.5	0.7	53.7	0.0	(24.5)	(24.5)	29.1
21	82.5	0.7	53.7	0.0	(24.5)	(24.5)	29.1
22	61.9	0.7	40.2	0.0	(20.4)	(20.4)	19.9
23	41.3	0.7	26.8	0.0	(16.2)	(16.2)	10.6
24	41.3	0.7	26.8	0.0	(16.2)	(16.2)	10.6
25	41.3	0.7	26.8	0.0	(36.2)	(36.2)	(9.4)
TOTAL	2,063.5		1,341.3	(207.9)	(600.6)	(808.5)	532.8
PV@15	370.2		240.7	(135.5)	(103.5)	(239.0)	1.7

Appendix 2.5

Field name: Imashev (large Field)
Gas Characteristics: No data (Assumed sour)

Recoverable Reserves	5468.0 (BCF)	Capital Cost	0.32 (US$/MCF)
Depth	4000.0 (meters)	Operating Cost	0.28 (US$/MCF)
Additional Seismic	8.0 (US$MM)	Total Cost	0.60 (US$/MCF)
Appraisal	40.0 (US$MM)		
Development	443.6 (US$MM)		
New Wells	384.0 (US$MM)		
Gathering and Separati	22.9 (US$MM)		
Gas Conditioning	36.7 (US$MM)		
Total Gas Cost	0.6 (US$/MCF)		

Year	*Production (BCF)*	*Gas Price (US$/MCF)*	*Revenue (US$MM)*	*Capital Cost (US$MM)*	*Operating Cost (US$MM)*	*Total Cost (US$MM)*	*Cash Flow (US$MM)*
1	0.0	0.6	0.0	(8.0)	0.0	(8.0)	(8.0)
2	0.0	0.6	0.0	(40.0)	0.0	(40.0)	(40.0)
3	0.0	0.6	0.0	(221.8)	0.0	(221.8)	(221.8)
4	0.0	0.6	0.0	(221.8)	0.0	(221.8)	(221.8)
5	109.4	0.6	65.6	0.0	(44.1)	(44.1)	21.6
6	218.7	0.6	131.2	0.0	(65.9)	(65.9)	65.3
7	328.1	0.6	196.8	0.0	(87.8)	(87.8)	109.1
8	328.1	0.6	196.8	0.0	(87.8)	(87.8)	109.1
9	328.1	0.6	196.8	0.0	(87.8)	(87.8)	109.1
10	328.1	0.6	196.8	0.0	(87.8)	(87.8)	109.1
11	328.1	0.6	196.8	0.0	(87.8)	(87.8)	109.1
12	328.1	0.6	196.8	0.0	(87.8)	(87.8)	109.1
13	328.1	0.6	196.8	0.0	(87.8)	(87.8)	109.1
14	328.1	0.6	196.8	0.0	(87.8)	(87.8)	109.1
15	328.1	0.6	196.8	0.0	(87.8)	(87.8)	109.1
16	328.1	0.6	196.8	0.0	(87.8)	(87.8)	109.1
17	328.1	0.6	196.8	0.0	(87.8)	(87.8)	109.1
18	328.1	0.6	196.8	0.0	(87.8)	(87.8)	109.1
19	273.4	0.6	164.0	0.0	(76.9)	(76.9)	87.2
20	218.7	0.6	131.2	0.0	(65.9)	(65.9)	65.3
21	218.7	0.6	131.2	0.0	(65.9)	(65.9)	65.3
22	164.0	0.6	98.4	0.0	(55.0)	(55.0)	43.4
23	109.4	0.6	65.6	0.0	(44.1)	(44.1)	21.6
24	109.4	0.6	65.6	0.0	(44.1)	(44.1)	21.6
25	109.4	0.6	65.6	0.0	(64.1)	(64.1)	1.6
TOTAL	5,468.0		3,280.8	(491.6)	(1,579.4)	(2,071.0)	1,209.8
PV@15	981.1		588.7	(309.9)	(276.9)	(586.7)	1.9

Appendix 2.5

Field name: Kamen (large field)
Gas Characteristics: Sour

Recoverable Reserves	285.8 (BCF)	Capital Cost	0.56 (US$/MCF)
Depth	3000.0 (meters)	Operating Cost	0.27 (US$/MCF)
Additional Seismic	8.0 (US$MM)	Total Cost	0.82 (US$/MCF)
Appraisal	16.0 (US$MM)		
Development	15.5 (US$MM)		
New Wells	3.2 (US$MM)		
Gathering and Separati	6.0 (US$MM)		
Gas Conditioning	6.3 (US$MM)		
Total Gas Cost	0.8 (US$/MCF)		

Year	*Production (BCF)*	*Gas Price (US$/MCF)*	*Revenue (US$MM)*	*Capital Cost (US$MM)*	*Operating Cost (US$MM)*	*Total Cost (US$MM)*	*Cash Flow (US$MM)*
1	0.0	0.8	0.0	(8.0)	0.0	(8.0)	(8.0)
2	0.0	0.8	0.0	(16.0)	0.0	(16.0)	(16.0)
3	0.0	0.8	0.0	(7.8)	0.0	(7.8)	(7.8)
4	0.0	0.8	0.0	(7.8)	0.0	(7.8)	(7.8)
5	5.7	0.8	4.7	0.0	(1.9)	(1.9)	2.8
6	11.4	0.8	9.4	0.0	(3.1)	(3.1)	6.3
7	17.1	0.8	14.1	0.0	(4.2)	(4.2)	9.9
8	17.1	0.8	14.1	0.0	(4.2)	(4.2)	9.9
9	17.1	0.8	14.1	0.0	(4.2)	(4.2)	9.9
10	17.1	0.8	14.1	0.0	(4.2)	(4.2)	9.9
11	17.1	0.8	14.1	0.0	(4.2)	(4.2)	9.9
12	17.1	0.8	14.1	0.0	(4.2)	(4.2)	9.9
13	17.1	0.8	14.1	0.0	(4.2)	(4.2)	9.9
14	17.1	0.8	14.1	0.0	(4.2)	(4.2)	9.9
15	17.1	0.8	14.1	0.0	(4.2)	(4.2)	9.9
16	17.1	0.8	14.1	0.0	(4.2)	(4.2)	9.9
17	17.1	0.8	14.1	0.0	(4.2)	(4.2)	9.9
18	17.1	0.8	14.1	0.0	(4.2)	(4.2)	9.9
19	14.3	0.8	11.7	0.0	(3.6)	(3.6)	8.1
20	11.4	0.8	9.4	0.0	(3.1)	(3.1)	6.3
21	11.4	0.8	9.4	0.0	(3.1)	(3.1)	6.3
22	8.6	0.8	7.0	0.0	(2.5)	(2.5)	4.5
23	5.7	0.8	4.7	0.0	(1.9)	(1.9)	2.8
24	5.7	0.8	4.7	0.0	(1.9)	(1.9)	2.8
25	5.7	0.8	4.7	0.0	(21.9)	(21.9)	(17.2)
TOTAL	285.8		234.3	(39.5)	(93.4)	(132.9)	101.4
PV@15	51.3		42.0	(28.6)	(13.7)	(42.2)	(0.2)

Appendix 2.5

Field name: Nuraly (small field)
Gas Characteristics: Sweet

Recoverable Reserv	89.9 (BCF)	Capital Cost	0.88 (US$/MCF)
Depth	1800.0 (meters)	Operating Cos	0.29 (US$/MCF)
Additional Seismic	0.0 (US$MM)	Total Cost	1.16 (US$/MCF)
Appraisal	12.0 (US$MM)		
Development	6.5 (US$MM)		
New Wells	0.0 (US$MM)		
Gathering and Separ	3.9 (US$MM)		
Gas Conditioning	2.6 (US$MM)		
Total Gas Cost	1.16 (US$/MCF)		

Year	*production (BCF)*	*gas price (US$/MCF)*	*revenue (US$MM)*	*capital cost (US$MM)*	*operating cost (US$MM)*	*total cost (US$MM)*	*cash flow (US$MM)*
1	0.0	1.16	-	(12.0)	-	(12.0)	(12.0)
2	0.0	1.16	-	(3.3)	-	(3.3)	(3.3)
3	0.0	1.16	-	(3.3)	-	(3.3)	(3.3)
4	1.8	1.16	2.1	-	(0.7)	(0.7)	1.4
5	2.7	1.16	3.1	-	(0.9)	(0.9)	2.3
6	3.6	1.16	4.2	-	(1.0)	(1.0)	3.1
7	4.5	1.16	5.2	-	(1.2)	(1.2)	4.0
8	5.4	1.16	6.3	-	(1.4)	(1.4)	4.9
9	5.4	1.16	6.3	-	(1.4)	(1.4)	4.9
10	5.4	1.16	6.3	-	(1.4)	(1.4)	4.9
11	5.4	1.16	6.3	-	(1.4)	(1.4)	4.9
12	5.4	1.16	6.3	-	(1.4)	(1.4)	4.9
13	5.4	1.16	6.3	-	(1.4)	(1.4)	4.9
14	5.4	1.16	6.3	-	(1.4)	(1.4)	4.9
15	5.4	1.16	6.3	-	(1.4)	(1.4)	4.9
16	5.4	1.16	6.3	-	(1.4)	(1.4)	4.9
17	5.4	1.16	6.3	-	(1.4)	(1.4)	4.9
18	4.5	1.16	5.2	-	(1.2)	(1.2)	(0.0)
19	4.5	1.16	5.2	-	(1.2)	(1.2)	4.0
20	3.6	1.16	4.2	-	(1.0)	(1.0)	3.1
21	2.7	1.16	3.1	-	(0.9)	(0.9)	2.3
22	2.7	1.16	3.1	-	(0.9)	(0.9)	2.3
23	1.8	1.16	2.1	-	(0.7)	(0.7)	1.4
24	1.8	1.16	2.1	-	(0.7)	(0.7)	1.4
25	1.8	1.16	2.1	-	(5.2)	(5.2)	(3.1)
TOTAL	89.9		104.3	(18.5)	(29.7)	(48.2)	52.1
PV@15	17.1		19.9	(15.0)	(4.9)	(20.0)	(0.4)

Appendix 2.5

Field name: Kzyloy (small field)
Gas Characteristics: sweet

Recoverable Reserves	47.3 (BCF)	Capital Cost	1.12 (US$/MCF)
Depth	400.0 (meters)	Operating Cos	0.32 (US$/MCF)
Additional Seismic	0.0 (US$MM)	Total Cost	1.44 (US$/MCF)
Appraisal	8.0 (US$MM)		
Development	4.5 (US$MM)		
New Wells	0.0 (US$MM)		
Gathering and Separati	2.7 (US$MM)		
Gas Conditioning	1.8 (US$MM)		
Total Gas Cost	1.44 (US$/MCF)		

Year	*production (BCF)*	*gas price (US$/MCF)*	*revenue (US$MM)*	*capital cost (US$MM)*	*operating cost (US$MM)*	*total cost (US$MM)*	*cash flow (US$MM)*
1	0.0	1.44	-	(8.0)	-	(8.0)	(8.0)
2	0.0	1.44	-	(2.3)	-	(2.3)	(2.3)
3	0.0	1.44	-	(2.3)	-	(2.3)	(2.3)
4	0.9	1.44	1.4	-	(0.4)	(0.4)	0.9
5	1.4	1.44	2.0	-	(0.5)	(0.5)	1.5
6	1.9	1.44	2.7	-	(0.6)	(0.6)	2.1
7	2.4	1.44	3.4	-	(0.7)	(0.7)	2.7
8	2.8	1.44	4.1	-	(0.8)	(0.8)	3.3
9	2.8	1.44	4.1	-	(0.8)	(0.8)	3.3
10	2.8	1.44	4.1	-	(0.8)	(0.8)	3.3
11	2.8	1.44	4.1	-	(0.8)	(0.8)	3.3
12	2.8	1.44	4.1	-	(0.8)	(0.8)	3.3
13	2.8	1.44	4.1	-	(0.8)	(0.8)	3.3
14	2.8	1.44	4.1	-	(0.8)	(0.8)	3.3
15	2.8	1.44	4.1	-	(0.8)	(0.8)	3.3
16	2.8	1.44	4.1	-	(0.8)	(0.8)	3.3
17	2.8	1.44	4.1	-	(0.8)	(0.8)	3.3
18	2.4	1.44	3.4	-	(0.7)	(0.7)	(1.3)
19	2.4	1.44	3.4	-	(0.7)	(0.7)	2.7
20	1.9	1.44	2.7	-	(0.6)	(0.6)	2.1
21	1.4	1.44	2.0	-	(0.5)	(0.5)	1.5
22	1.4	1.44	2.0	-	(0.5)	(0.5)	1.5
23	0.9	1.44	1.4	-	(0.4)	(0.4)	0.9
24	0.9	1.44	1.4	-	(0.4)	(0.4)	0.9
25	0.9	1.44	1.4	-	(4.7)	(4.7)	(3.3)
TOTAL	47.3		68.0	(12.5)	(18.7)	(31.2)	32.9
NPV@15	9.0		13.0	(10.1)	(2.9)	(13.0)	(0.4)

Appendix 2.5

Field Name: Teplov-Takarev
Gas Characteristics: Sour

Recoverable Reserves	1041.3 (BCF)	Capital Cost	0.26 (US$/MCF)
Depth	2900.0 (meters)	Operating Cost	0.25 (US$/MCF)
Additional Seismic	8.0 (US$MM)	Total Cost	0.52 (US$/MCF)
Appraisal	16.0 (US$MM)		
Development	49.4 (US$MM)		
New Wells	25.6 (US$MM)		
Gathering and Separati	10.2 (US$MM)		
Gas Conditioning	13.6 (US$MM)		
Total Gas Cost	0.5 (US$/MCF)		

Year	*Production (BCF)*	*Gas Price (US$/MCF)*	*Revenue (US$MM)*	*Capital Cost (US$MM)*	*Operating Cost (US$MM)*	*Total Cost (US$MM)*	*Cash Flow (US$MM)*
1	0.0	0.5	0.0	(8.0)	0.0	(8.0)	(8.0)
2	0.0	0.5	0.0	(16.0)	0.0	(16.0)	(16.0)
3	0.0	0.5	0.0	(24.7)	0.0	(24.7)	(24.7)
4	0.0	0.5	0.0	(24.7)	0.0	(24.7)	(24.7)
5	20.8	0.5	10.8	0.0	(6.6)	(6.6)	4.2
6	41.7	0.5	21.7	0.0	(10.8)	(10.8)	10.9
7	62.5	0.5	32.5	0.0	(15.0)	(15.0)	17.5
8	62.5	0.5	32.5	0.0	(15.0)	(15.0)	17.5
9	62.5	0.5	32.5	0.0	(15.0)	(15.0)	17.5
10	62.5	0.5	32.5	0.0	(15.0)	(15.0)	17.5
11	62.5	0.5	32.5	0.0	(15.0)	(15.0)	17.5
12	62.5	0.5	32.5	0.0	(15.0)	(15.0)	17.5
13	62.5	0.5	32.5	0.0	(15.0)	(15.0)	17.5
14	62.5	0.5	32.5	0.0	(15.0)	(15.0)	17.5
15	62.5	0.5	32.5	0.0	(15.0)	(15.0)	17.5
16	62.5	0.5	32.5	0.0	(15.0)	(15.0)	17.5
17	62.5	0.5	32.5	0.0	(15.0)	(15.0)	17.5
18	62.5	0.5	32.5	0.0	(15.0)	(15.0)	17.5
19	52.1	0.5	27.1	0.0	(12.9)	(12.9)	14.2
20	41.7	0.5	21.7	0.0	(10.8)	(10.8)	10.9
21	41.7	0.5	21.7	0.0	(10.8)	(10.8)	10.9
22	31.2	0.5	16.2	0.0	(8.7)	(8.7)	7.5
23	20.8	0.5	10.8	0.0	(6.6)	(6.6)	4.2
24	20.8	0.5	10.8	0.0	(6.6)	(6.6)	4.2
25	20.8	0.5	10.8	0.0	(26.6)	(26.6)	(15.8)
TOTAL	1,041.3		541.5	(73.4)	(280.1)	(353.5)	187.9
PV@15	186.8		97.2	(49.4)	(46.9)	(96.3)	0.8

Appendix 2.5

Field name: Tengiz (large field)
Gas Characteristics: Sour

Recoverable Reserves	10,662.8	(BCF)	Capital Cost	0.07	(US$/MCF)
Depth	3,900.0	(meters)	Operating Cos	0.23	(US$/MCF)
Additional Seismic	-	(US$MM)	Total Cost	0.30	(US$/MCF)
Appraisal	-	(US$MM)			
Development	67.9	(US$MM)			
New Wells	-	(US$MM)			
Gathering and Separat	4.0	(US$MM)			
Gas Conditioning	63.9	(US$MM)			
Total Gas Cost	0.30	(US$/MCF)			

year	*production (BCF)*	*gas price (US$/MCF)*	*revenue (US$MM)*	*capital cost (US$MM)*	*operating cost (US$MM)*	*total cost (US$MM)*	*cash flow (US$MM)*
1	105.9	0.30	31.8	(34.0)	(24.6)	(58.5)	(26.8)
2	109.4	0.30	32.8	(34.0)	(25.3)	(59.2)	(26.4)
3	176.5	0.30	53.0		(38.7)	(38.7)	14.3
4	176.5	0.30	53.0		(38.7)	(38.7)	14.3
5	123.6	0.30	37.1	-	(28.1)	(28.1)	9.0
6	123.6	0.30	37.1	-	(28.1)	(28.1)	9.0
7	123.6	0.30	37.1	-	(28.1)	(28.1)	9.0
8	123.6	0.30	37.1	-	(28.1)	(28.1)	9.0
9	123.6	0.30	37.1	-	(28.1)	(28.1)	9.0
10	105.9	0.30	31.8	-	(24.6)	(24.6)	7.2
11	105.9	0.30	31.8	-	(24.6)	(24.6)	7.2
12	105.9	0.30	31.8	-	(24.6)	(24.6)	7.2
13	105.9	0.30	31.8	-	(24.6)	(24.6)	7.2
14	105.9	0.30	31.8	-	(24.6)	(24.6)	7.2
15	105.9	0.30	31.8	-	(24.6)	(24.6)	7.2
16	105.9	0.30	31.8	-	(24.6)	(24.6)	7.2
17	105.9	0.30	31.8	-	(24.6)	(24.6)	7.2
18	105.9	0.30	31.8	-	(24.6)	(24.6)	7.2
19	105.9	0.30	31.8	-	(24.6)	(24.6)	7.2
20	105.9	0.30	31.8	-	(24.6)	(24.6)	7.2
21	105.9	0.30	31.8	-	(24.6)	(24.6)	7.2
22	105.9	0.30	31.8	-	(24.6)	(24.6)	7.2
23	105.9	0.30	31.8	-	(24.6)	(24.6)	7.2
24	105.9	0.30	31.8	-	(24.6)	(24.6)	7.2
25	105.9	0.30	31.8	-	(44.6)	(44.6)	(12.8)
TOTAL	2,880.7		864.2	(67.9)	(681.0)	(748.9)	115.3
PV@15	807.9		242.4	(55.2)	(184.1)	(239.3)	3.0

Appendix 2.5

Field name: Urihtau
Gas Characteristics: Sour

Recoverable Reserves	1,264.3	(BCF)	Capital Cost	0.24	(US$/MCF)
Depth	2,500.0	(meters)	Operating Cost	0.24	(US$/MCF)
Additional Seismic	8.0	(US$MM)	Total Cost	0.48	(US$/MCF)
Appraisal	20.0	(US$MM)			
Development	51.9	(US$MM)			
New Wells	25.6	(US$MM)			
Gathering and Separat	11.1	(US$MM)			
Gas Conditioning	15.2	(US$MM)			
Total Gas Cost	0.48	(US$/MCF)			

Year	*Production (BCF)*	*Gas Price US$/MCF*	*Revenue (US$MM)*	*Capital Cost (US$MM)*	*Operating Cost (US$MM)*	*Total Cost (US$MM)*	*Cash Flow (US$MM)*
1	0.0	0.48	-	(8.0)	-	(8.0)	(8.0)
2	0.0	0.48	-	(20.0)	-	(20.0)	(20.0)
3	0.0	0.48	-	(26.0)	-	(26.0)	(26.0)
4	0.0	0.48	-	(26.0)	-	(26.0)	(26.0)
5	25.3	0.48	12.1	-	(7.7)	(7.7)	4.5
6	50.6	0.48	24.3	-	(12.7)	(12.7)	11.6
7	75.9	0.48	36.4	-	(17.8)	(17.8)	18.6
8	75.9	0.48	36.4	-	(17.8)	(17.8)	18.6
9	75.9	0.48	36.4	-	(17.8)	(17.8)	18.6
10	75.9	0.48	36.4	-	(17.8)	(17.8)	18.6
11	75.9	0.48	36.4	-	(17.8)	(17.8)	18.6
12	75.9	0.48	36.4	-	(17.8)	(17.8)	18.6
13	75.9	0.48	36.4	-	(17.8)	(17.8)	18.6
14	75.9	0.48	36.4	-	(17.8)	(17.8)	18.6
15	75.9	0.48	36.4	-	(17.8)	(17.8)	18.6
16	75.9	0.48	36.4	-	(17.8)	(17.8)	18.6
17	75.9	0.48	36.4	-	(17.8)	(17.8)	18.6
18	75.9	0.48	36.4	-	(17.8)	(17.8)	18.6
19	63.2	0.48	30.3	-	(15.2)	(15.2)	15.1
20	50.6	0.48	24.3	-	(12.7)	(12.7)	11.6
21	50.6	0.48	24.3	-	(12.7)	(12.7)	11.6
22	37.9	0.48	18.2	-	(10.2)	(10.2)	8.0
23	25.3	0.48	12.1	-	(7.7)	(7.7)	4.5
24	25.3	0.48	12.1	-	(7.7)	(7.7)	4.5
25	25.3	0.48	12.1	-	(27.7)	(27.7)	(15.5)
TOTAL	1,264.3		606.9	(79.9)	(327.4)	(407.3)	199.6
PV@15	226.8		108.9	(54.0)	(55.3)	(109.3)	(0.4)

Appendix 2.5

Field name: Zhanazol (large field)
Gas Characteristics: Sour

Recoverable Reserves	3,193.4	(BCF)	Capital Cost	0.05	(US$/MCF)
Depth	3,700.0	(meters)	Operating Cos	0.22	(US$/MCF)
Additional Seismic	-	(US$MM)	Total Cost	0.27	(US$/MCF)
Appraisal	-	(US$MM)			
Development	58.7	(US$MM)			
New Wells	-	(US$MM)			
Gathering and Separati	3.0	(US$MM)			
Gas Conditioning	55.7	(US$MM)			
Total Gas Cost	0.27	(US$/MCF)			

year	*production (BCF)*	*gas price (US$/MCF)*	*revenue (US$MM)*	*capital cost (US$MM)*	*operating cost (US$MM)*	*total cost (US$MM)*	*cash flow (US$MM)*
1	63.9	0.27	17.2	(29.4)	(15.7)	(45.1)	(27.8)
2	127.7	0.27	34.5	(29.4)	(28.5)	(57.8)	(23.3)
3	159.7	0.27	43.1	-	(34.9)	(34.9)	8.2
4	159.7	0.27	43.1	-	(34.9)	(34.9)	8.2
5	159.7	0.27	43.1	-	(34.9)	(34.9)	8.2
6	159.7	0.27	34.5	-	(28.5)	(28.5)	6.0
7	159.7	0.27	43.1	-	(34.9)	(34.9)	8.2
8	159.7	0.27	43.1	-	(34.9)	(34.9)	8.2
9	159.7	0.27	43.1	-	(34.9)	(34.9)	8.2
10	159.7	0.27	43.1	-	(34.9)	(34.9)	8.2
11	159.7	0.27	43.1	-	(34.9)	(34.9)	8.2
12	159.7	0.27	43.1	-	(34.9)	(34.9)	8.2
13	159.7	0.27	43.1	-	(34.9)	(34.9)	8.2
14	159.7	0.27	43.1	-	(34.9)	(34.9)	8.2
15	127.7	0.27	34.5	-	(28.5)	(28.5)	6.0
16	127.7	0.27	34.5	-	(28.5)	(28.5)	6.0
17	127.7	0.27	34.5	-	(28.5)	(28.5)	6.0
18	127.7	0.27	34.5	-	(28.5)	(28.5)	6.0
19	95.8	0.27	25.9	-	(22.1)	(22.1)	3.8
20	95.8	0.27	25.9	-	(22.1)	(22.1)	3.8
21	95.8	0.27	25.9	-	(22.1)	(22.1)	3.8
22	95.8	0.27	25.9	-	(22.1)	(22.1)	3.8
23	63.9	0.27	17.2	-	(15.7)	(15.7)	1.5
24	63.9	0.27	17.2	-	(15.7)	(15.7)	1.5
25	63.9	0.27	17.2	-	(35.7)	(35.7)	(18.5)
TOTAL	3,193.4		853.6	(58.7)	(725.7)	(784.4)	69.2
NPV@15%	886.9		235.7	(47.7)	(194.2)	(241.9)	(6.2)

Note: 1) About $30 million added for possible compression requirement.
2) If the use of gas is limited to power generation in Aktubinsk through 400 mm dia. pipeline, the maximum production would be about 2 BCM/Y (or 71 BCF/Y) plus field use.

Appendix 2.6

Power Stations in Kazakhstan

1. Electricity consumption increased at about 5% annually during the early 1980s, but then stagnated, and has been in decline since 1990. In 1993 about 4 million customers consumed more than 69 Gwh, of which about 20 Gwh was imported. The current annual per capita consumption of 4,100 KWh is high relative to other countries with similar levels of per capita income, estimated at about US$ 959 in 1995. Although the electricity consumption has been declining since 1991, the Ministry of Energy and Natural Resources expects that the consumption in 2005 will recover up to the level experienced in 1991 (e.g. about 86 Gwh).

2. More than 87% (14,800 MW) of the nation's installed capacity is thermal based; 12% (2,073 MW) is, hydro; and there is a nuclear (Liquid Metal Fast Breeder Reactor) plant at Aktau. The major thermal stations are coal-fired, using coal with high ash content. Excluding environmental issues, coal is the lowest cost primary fuel in the North given the proximity to the coal mines of Ekibustuz and Karaganda. Most of power generation is based on mine-mouth stations. There is some gas or fuel oil-fired generating capacity along the corridor of gas pipelines and near the country's refineries, which also feed steam and/or hot water to district heating systems.

3. Kazakhstan's generating power and transmission system consists of three regional power grids -- the North, South, and the West -- with a combined installed capacity of about 17,200 MW in 64 power stations. The North consumes about 60 % of the available power in the country, the South consumes about 25 % and the rest is consumed West, the rest. In the southern region, 40% of the required electricity, or about 10 billion Kwh once used Kyrgyz hydropower. Today, the power import from Kyrgyzstan has often been interrupted and the electricity deficit is considered to be about 25% or 4 billion Kwh in a year. In the western region, 90% of the electricity is imported from Russia (to Uralsk about 1.5 billion Kwh and to Aktybinsk about 2.5 billion Kwh).

4. Kazakhstan's coal, oil and gas-powered electricity generating plants are generally operated as base-load facilities. During the peak consumption period, electricity is imported from Russia in the case of the North and West Zones, and from Turkmenistan and Uzbekistan in the South. However, its oil-and-gas-fired units appear to be dispatched to a somewhat greater degree than its coal units.

5. Much of the country's capacity is over 20 years old. Within the next five years it appears likely that at least 4,000 MW of capacity will need to be replaced. This may provide an opportunity to substitute gas for coal in the power sector. Up to this point, uncertainty regarding the availability of long term gas supplies has acted as a constraint to the use of gas in the power sector.

Table 1 Operational Power Plants

Plant Name	*Installed Capacity (MW)*	*Heat Capacity (GCal/Hr)*	*Fuel Type*	*Date of Commisioning*
		Thermal		
Ekibustuz (1)	4,000	-	coal	1980-84
Ekibustuz (2)	500	-	coal	1990
Ermak	2,400	-	coal	1968-75
Jumbul	1,230	-	gas/oil	1967-76
Alamty	173	223	gas/oil/coal	1962-64
Karaganda (1)	164	324	gas/oil/coal	1942-55
Karaganda (2)	648	300	gas/oil/coal	1962-64
Almaty CHP (1)	145	1,345	gas/oil/coal	1960-69
Almaty CHP (2)	510	879	coal	1980-91
Tekel CHP	24	92	coal	-
Ust-Kamenogorsk CHP	242	596	coal	1951-66
Leninogorsk CHP	57	329	coal	-
Sorgin CHP	50	314	coal	-
Atyrau CHP	227	59	gas/oil	1962-70
Aktiubinsk CHP	83	687	gas/oil	1943-87
Uralsk CHP	28	622	gas/oil	-
Karaganda CHP (1)	32	460	coal	1943-50
Karaganda CHP (2)	435	1,412	coal	1973-76
Karaganda CHP (3)	440	700	coal	1977-78
Balhash CHP	120	250	coal	1937-63
Djeskazakan CHP	177	409	coal	1955-62
Tentek CHP	18	202	coal	-
Kustanai CHP	12	498	gas/oil	-
Rundi CHP	131	805	gas/oil	-
Arkalik CHP	6	401	gas/oil	-
Pavloda CHP (1)	350	1,520	coal	1964-75
Pavloda CHP (2)	110	432	coal	1960-62
Pavloda CHP (3)	440	1,351	coal	1972-78
Petropavlovsk (2)	380	1,226	coal	1961-83
Tselinograd CHP (1)	26	766	coal	-
Tselinograd CHP (2)	240	540	coal	1979-83
Ekibustuz CHP	12	770	coal	-
Semipalatinsk CHP	6	275	coal	-
Jumbul CHP (4)	60	554	coal	1963
Symkent CHP (1 & 2)	42	462	gas/oil	-
Symkent CHP (3)	160	556	gas/oil	1981-83
Kizil-Orda	146	378	coal	1964-75
Kientau CHP	29	189	coal	-
Total	13,853	19,926		

Source: World Bank Energy Sector Review, 1993; EC Energy Center in Almaty, Oct. 96

Plant Name	Installed Capacity (MW)	Heat Capacity (GCal/Hr)	Fuel Type	Date of Commisioning
		Hydro Power		
Buhtarmin	675	-	-	1960-66
Ust-Kamenogorak	331	-	-	1952-59
Shulbinsk	585	-	-	1987-91
Almaty	48	-	-	1943
Small Hydro	8	-	-	
		Nuclear		
Aktau	150	200	-	1973
Various	1,100	3,500	-	-
Total	2,897	3,700		

Source: World Bank Energy Sector Review, 1993; EC Energy Center in Almaty, October 1996

Table 2 - Future Power Plants

Plant Name	*Installed Capacity (MW)*	*Heat Capacity (GCal/Hr)*	*Fuel Type*	*Date of Commisioning*
Under Construction				
Ykgres	640	-	coal	2001
Planned				
Symkent	640	-	gas	2005
Aktsubinsk	477	-	gas	2005
Kybrach (near Almaty)	82	-	hydro	2020
Mynock (near Almaty)	300	-	hydro	2020
Total	2,139	-		

Source: Kazenergo, October 96

Appendix 3.1

LEVEL OF FUEL CONSUMPTION IN KAZAKHSTAN (1/4)

			1990					*1991*				
			Volume of consumption		*Price*			*Volume of consumption*				
Œ		*Unit of*										
	NAME OF FUEL	*measure*	*Natural unit*	*Million tons of coal equival.*	*Natur. unit $ US*	*Tons of coal equival $ US*	*Cost, Million $ US*	*Natural unit*	*Million tons of coal equival.*	*Natur. unit $ US*	*Tons of coal equival $ US*	*Cost, Million $ US*
1	2	3	4	5	6	7	8	9	10	11	12	13
1.	**COAL, total**	Million	**78.7**	**49.7**				**82.9**	**53.1**			
	- industry	ton	23.4	17.8				25.0	19.1			
	- power industry		47.4	25.8				47.7	26.0			
	- domestic/municipal		4.0	3.1				4.4	3.6			
	- others		3.9	3.0				5.8	4.4			
2.	**Natural gas, total**	Billion	**13.7**	**16.3**				**11.2**	**16.3**			
	- industry	CM	6.0	7.2				5.2	6.9			
	- power industry		5.9	7.0				4.2	7.1			
	- domestic/municipal		1.3	1.5				1.4	1.7			
	- others		0.5	0.6				0.5	0.6			
3.	**Liquefied, total**	Million	**0.4**	**0.6**				**0.7**	**1.1**			
	- industry	ton	-	-				0.1	0.2			
	- power industry		-	-				-	-			
	- domestic/municipal		0.3	0.4				0.5	0.7			
	- others		0.1	0.2				0.1	0.2			
4.	**Mazut, total**	Million	**6.5**	**9.0**				**6.6**	**9.0**			
	- industry	ton	1.5	2.1				1.5	2.1			
	- power industry		2.9	4.0				2.9	4.0			
	- domestic/municipal		1.1	1.5				1.1	1.5			
	- others		1.0	1.4				1.1	1.4			
5.	**TOTAL**			**15.6**					**79.5**			
	- industry			27.1					28.3			
	- power industry			36.8					37.1			
	- domestic/municipal			6.5					7.5			
	- others			5.2					6.6			
PRODUCTION OF THE SECONDARY ENERGY RESOURCES ON THE HEAT-POWER STATIONS OF RK												
1.	Electricity	Billion KWh	78.8	9.6				77.6	9.5			
2.	Heat	Million GCal	72.0					72.5				

LEVEL OF FUEL CONSUMPTION IN KAZAKHSTAN (2/4)

Œ	NAME OF FUEL	Unit of measu-re	1992 Volume of consumption Natural unit	Million tons of coal equival.	Price Natur. unit $ US	Tons of coal equival $ US	Cost, Million $ US	1993 Volume of consumption Natural unit	Million tons of coal equival.	Price Natur. unit $ US	Tons of coal equival $ US	Cost, Million $ US
1	2	3	4	5	6	7	8	9	10	11	12	13
1.	**COAL, total**	Million	**82.0**	**52.2**				**81.1**	**51.7**			
	- industry	ton	23.2	17.7				21.5	16.3			
	- power industry		49.2	27.2				47.7	26.0			
	- domestic/municipal		4.3	3.3				4.7	3.7			
	- others		6.3	4.0				7.2	5.7			
2.	**Natural gas, total**	Billion	**11.1**	**13.3**				**9.5**	**11.2**			
	- industry	CM	4.7	5.6				4.1	4.7			
	- power industry		4.2	5.0				3.2	3.7			
	- domestic/municipal		1.5	1.8				1.5	1.9			
	- others		0.7	0.9				0.7	0.9			
3.	**Liquefied, total**	Million	**0.7**	**1.1**				**0.6**	**1.0**			
	- industry	ton	0.1	0.2				0.1	0.2			
	- power industry		-	-				-	-			
	- domestic/municipal		0.5	0.7				0.4	0.6			
	- others		0.1	0.2				0.1	0.2			
4.	**Mazut, total**	Million	**6.7**	**9.2**				**6.7**	**9.2**			
	- industry	ton	1.6	2.2				1.6	2.2			
	- power industry		2.7	3.7				2.5	3.5			
	- domestic/municipal		1.3	1.8				1.4	1.9			
	- others		1.1	1.5				1.2	1.6			
5.	**TOTAL**			**75.8**					**73.1**			
	- industry			25.7					23.4			
	- power industry			35.9					33.2			
	- domestic/municipal			7.6					8.1			
	- others			6.6					8.4			
PRODUCTION OF THE SECONDARY ENERGY RESOURCES ON THE HEAT-POWER STATIONS OF RK												
1.	Electricity	Billion KWh	75.3	9.2				69.0	8.4			
2.	Heat	Million GCal	71.6					70.3				

LEVEL OF FUEL CONSUMPTION IN KAZAKHSTAN (3/4)

			1994					1995				
			Volume of consumption		*Price*			*Volume of consumption*		*Price*		
Œ	*NAME OF FUEL*	*Unit of measure*	*Natural unit*	*Million tons of coal equival.*	*Natur. unit $ US*	*Tons of coal equival $ US*	*Cost, Million $ US*	*Natural unit*	*Million tons of coal equival.*	*Natur. unit $ US*	*Tons of coal equival $ US*	*Cost, Million $ US*
1	2	3	4	5	6	7	8	9	10	11	12	13
1.	**COAL, total**	Million	**73.7**	**46.5**	**5.1**	**8.2**	**379**	**62.6**	**38.3**	**11.1**	**18.1**	**695**
	- industry	ton	16.2	12.3				9.7	7.4			
	- power industry		43.3	23.1	2.56	4.8	111	41.3	22.0	5.2	9.8	216
	- domestic/municipal		4.9	3.7				5.2	4.0			
	- others		9.3	7.4				6.4	4.9			
2.	**Natural gas, total**	Billion	**6.9**	**8.2**	**30.4**	**25.6**	**210**	**8.3**	**9.9**	**48.8**	**40.9**	**405**
	- industry	CM	2.5	2.4				3.2	3.8			
	- power industry		2.2	2.6	30.4	25.6	67	2.9	3.5	48.8	40.9	141
	- domestic/municipal		1.5	2.3				1.5	1.8			
	- others		0.7	0.9				0.7	0.8			
3.	**Liquefied, total**	Million	**0.5**	**0.8**	**124**	**77.5**	**62**	**0.3**	**0.5**	**280**	**168**	**84**
	- industry	ton	-	-				-	-			
	- power industry		-	-				-	-			
	- domestic/municipal		0.4	0.6	124	88.3	50	0.3	0.5	280	168	84
	- others		0.1	0.2				-	-			
4.	**Mazut, total**	Million	**4.7**	**6.5**	**28**	**20.3**	**132**	**3.7**	**5.1**	**63**	**46**	**233**
	- industry	ton	1.0	1.4				0.8	1.2			
	- power industry		2.2	3.0	28	20.3	62	1.7	2.3	63	46	108
	- domestic/municipal		1.0	1.4				0.6	0.8			
	- others		0.5	0.7				0.6	0.7			
5.	**TOTAL**			**62.0**					**53.8**			
	- industry			16.1					12.4			
	- power industry			28.7					27.8			
	- domestic/municipal			8.0					7.1			
	- others			9.2					6.4			
PRODUCTION OF THE SECONDARY ENERGY RESOURCES ON THE HEAT-POWER STATIONS OF RK												
1.	Electricity Billion	KWh	63.7	7.8				59.8	7.3			
2.	Heat Million	Gcal	59.6					60.4				

LEVEL OF FUEL CONSUMPTION IN KAZAKHSTAN (4/4)

			1996				
			Volume of consumption		*Price*		
Œ	*NAME OF FUEL*	*Unit of measure*	*Natural unit*	*Million tons of coal equival.*	*Natur. unit $ US*	*Tons of coal equival $ US*	*Cost, Million $ US*
1	2	3	4	5	6	7	8
1.	**COAL, total**	Million	**58.2**	**36.8**	**16.8**	**26.6**	**978**
	- industry	ton	11.1	8.4			
	- power industry		35.4	19.5	8.0	14.5	283
	- domestic/municipal		5.7	4.3			
	- others		6.0	4.6			
2.	**Natural gas, total**	Billion	**7.8**	**9.3**	**50.0**	**41.9**	**390**
	- industry	CM	2.9	3.5			
	- power industry		2.7	3.2	50.0	42.2	135
	- domestic/municipal		1.5	1.8			
	- others		0.7	0.8			
3.	**Liquefied, total**	Million	**0.3**	**0.5**	**290**	**174**	**87**
	- industry	ton	-	-			
	- power industry		-	-			
	- domestic/municipal		0.3	0.5	290	174	87
	- others		-	-			
4.	**Mazut, total**	Million	**3.7**	**4.9**	**60**	**45.3**	**222**
	- industry	ton	0.8	1.1			
	- power industry		1.7	2.3	60	45.3	102
	- domestic/municipal		0.6	0.8			
	- others		0.5	0.7			
5.	**T O T A L**			51.5			
	- industry			13.0			
	- power industry			25.0			
	- domestic/municipal			7.4			
	- others			6.1			
PRODUCTION OF THE SECONDARY ENERGY RESOURCES ON THE HEAT-POWER STATIONS OF RK							
1.	Electricity	Billion KWh	58.5	7.1			
2.	Heat	Million GCal	60.0				

Appendix 3.2

Historic Demand of Natural Gas by Oblast

Economic Background

1. After independence in 1991 Kazakhstan has gone through a dramatic transformation of the economic system, including liberalization of the prices of most goods, individual's right to own private property, the Government privatization program, and the introduction of a national currency.

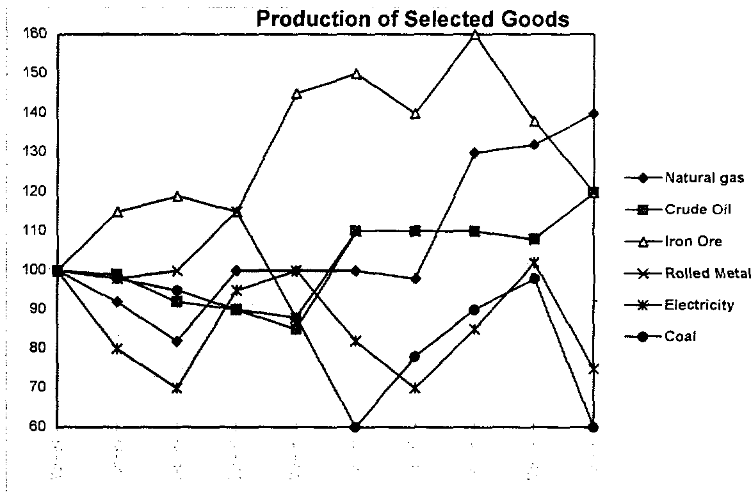
2. Although these steps have been important in transforming the economy, they have been accompanied by serious difficulties like a dramatic drop in the domestic economy and hyper inflation. While real GDP fell by an average of 13% per year from 1992 through 1994, the decrease was only 9% in 1995. Recent figures show stabilization of GDP throughout 1996, and the inflation has been substantially decreased from as much as 2000-3000 % per annum in 1992 and 1993 to about 2% per month at present. Official (but uncertain) unemployment figures show a sharp increase from about 40 000 in the beginning of 1994 to about 250 000 in June 1996. In addition enterprises have compelled workers to go on unpaid leave and work shorter hours.

3. The present economic deterioration in Kazakhstan is partly attributed to a large share of inefficient, capital-intensive industries engaged in the extraction of natural resources as well as in agricultural production. The foundation of high technology and consumer goods industries is weak. Kazakhstan was economically and technologically dependent on the more industrialized republics of the former Soviet Union, which are still its main trading partners. Trade with Russia accounts for more than 50% of exports and imports.

4. Industrial production fell 15-28% annually from 1992 to 1994, and the most affected industries were light industry, machine assembly, metalworking and construction materials. The main causes of the recession in industrial production have been the rise of operating costs, obsolete technologies and equipment, the absence in many cases of a rational organization of production, management and marketing, disruption of demand due to the breakup of the USSR, as well as shortage of operating funds and difficulties in obtaining bank credit.

5. As presented in Figure 1 below the development of production (in volume) for selected industries has varied considerably.

Figure 1: Production of Selected Goods 1994-96



Official forecasts by the Institute of Economic Development for 1997 indicate a slight increase in real GDP (102% of 1996 level).

Overall Energy Consumption

6. The overall energy consumption by source and production of electricity and heat for the years 1991-1996 are given in Appendix 3.1. The table below shows the 1995 overall consumption of energy by source in terms of million tons of coal equivalents[1]. The figures exclude hydro-power.

Table 1: Overall Consumption of Energy by Source. (1995)

(Unit: MILLION TONS Coal equivalents)

Sector	*COAL*	*GAS*	*LPG*	*MAZUT*
Industry	7.4	3.0		1.2
Power	22.0	3.4		2.3
Commun/ Residential	4.0	3.1		0.8
Others	4.9	0.5		0.7
Total	38.3	9.9	0.5	5.0
%	71	19	1	9

Total energy consumption (excluding hydro-power) was in 1995 equal to 54 MMTCE per year.

7. Coal supplies constitute 70% of the total energy consumption and 60% of the

[1] Coal equivalent: 7,000 Kcal/Kg-coal

coal is used for power plants. Natural gas covers 19 % of the total consumption, and is almost at the same level with coal for communal/residential use. Mazut (fuel oil) is less important than gas in industry, power and for communal/residential consumers.

8. Overall energy consumption has dropped 30% since 1990, e.g. from 76 million tonnes of coal equivalents to 54 million tonnes. The most dramatic reduction has been in industry which in 1995 only consumed about 40% of what it did in 1990. The consumption of electricity including hydro power (not shown in the table) by the industry has in comparison only been reduced to 70% of its 1990 level. The total consumption of fuels for thermal power production has gone down by 25% while communal/residential and other consumers have increased their direct consumption slightly since 1990. The reduction in consumption of gas since 1990 has been 40%, more than the overall reduction in energy consumption.

Historical Gas Markets

9. *Gas Balance:* Historical gas balance is presented below:

Table 2 Production, imports, exports and consumption for 1991, 1993, 1995 and 1996 (estimate) (Unit: BCM/Y)

	1991	*1993*	*1995*	*1996*
Production	7.9	4.5	5.8	6.6
Imports	9.6	11.9	5.7	5.0
Total Available	*17.5*	*16.4*	*11.5*	*11.6*
Exports	1.3	1.1	0.7	0.1
Consumpt.	11.2	9.5	8.3	7.8
Transp./loss	3.0	2.5	1.1	1.5
Oil field consumption	2.0	3.3	1.4	2.2
Total Demand	*17.5*	*16.4*	*11.5*	*11.6*

a *Production* has dropped to 84% of its 1991 level. Main reasons for the drop in production are production stoppages at Karachaganak due to the drilling Program, and drop in the amount of associated gas from the Uzen field.

b *Export* of gas has dropped to one tenth of its 1991 level.

c *Imports* have dropped to 50% of 1991 level mainly due to the general reduction of demand in the country, non-payment which has restricted supply and a considerable import price increase in 1993/94 (which recently has come down again). Possibly also the reduction in the amount of transit gas may have influenced the import volume since payment for transit is made in gas to Kazakhstan.

d Consumption is now 70% of 1991 level due to general recession in the economy with several big industries paralyzed or working at a bare minimum. Lack of ability to pay both by industries, power stations and the population has also curbed consumption.

e The use of gas for *transmission including losses* has been about 3% of production plus import and transit gas during the period. The transit gas has dropped from 81 BCM in 1991 to about 50 BCM in 1994.

f *The consumption of gas the oil production* is high mainly due to the fact that the oil needs to be heated for transport.

10. *Gas Consumption by Sector:* The overall consumption of gas by sector is given in Table 3. The same distribution by sector for each oblast is given in Table 10.

Table 3 Overall consumption by sector for 1991, 1993, 1995 and 1996
(Unit: MMCM/Y)

	1991 (%)	*1993 (%)*	*1995 (%)*	*1996 (%)*
Industry	5,200 (46)	4,100 (43)	3,200 (39)	2,800 (36)
Power	4,200 (37)	3200 (34)	2,900 (35)	2,700 (35)
Commercial/ Residential	1,400 (13)	1500 (16)	1,500 (18)	1,600 (20)
Others	400 (4)	700 (7)	700 (8)	700 (9)
Total	11,200 (100)	9,500 (100)	8,300 (100)	7,800 (100)

a The figures for power above are regarded to be quite reliable since they are based on data recorded for each station during visits to them. Figures for industry are given by the Ministry of Economy, and are the same as they have put into their energy savings Program. But they are not as reliable as those for power

b The commercial/residential sector includes both commercial, institutional and apartment building in urban areas. It also includes some institutional/apartment buildings in rural areas but these constitute only a minor portion. The "Others" includes agriculture and individual houses in rural areas. Nearly 800 000 apartments were supplied with gas in 1994, of which about 450 000 for cooking only and 350 000 for cooking and heating. About 200,000 new apartments have been supplied since 1990.

c The 50% drop in consumption of gas by the industry since 1991 reflects the very serious situation of this sector. This situation is further compounded by comparable reductions in industrial consumption of coal and mazut.

d Several big industries in the country have reduced their operation to a minimum or stopped. (See the description of the industrial sector by oblagas given in *Appendix*

3.3, "Gas Demand Projection".)

e The reduction in consumption of gas by the power sector since 1991 is also substantial, 35% . In the South some of this reduction is due to supply constraints, mainly unreliable supply of gas caused by non-payment and problems on the pipeline to Almaty.

f The stable consumption level in urban and rural non-industrial sectors reflects to some extent that more supplies have been available for these consumers who previously were constrained by industry and power demand. Possibly also the increase in prices for commercial/private consumers in recent years, who now pay the same as power and industry, has induced the gas companies to supply them more.

11. *Gas Consumption by Oblast:* Based on the present source of gas supply to different regions the *natural gas consuming areas* of Kazakhstan can broadly be divided into three:

(i) The South which includes the oblasts of Almaty, Symkent and South- Kazakhstan (Zhambyl) based on imported gas from Turkmenistan and Uzbekistan,

(ii) The West which includes the oblasts of Mangystau, Atyrau and West-Kazakhstan based on supply from local fields and the Central Asia - Center trunk line,

(iii) The oblasts of Aktyubinsk and Kostanai which are supplied from the Bukhara - Ural pipeline.

12. *The Southern region* has received gas since the pipeline from Gazli to Symkent-Zhambyl-Almaty was constructed from 1961 to 1971. It is the only region which has a developed gas distribution system which also includes rural areas. The supply of gas is based on imports from Turkmenistan and Uzbekistan. The gas from Turkmenistan is barter payment for use of the transit pipelines through Kazakhstan.

a The total population in the region is nearly 5.2m and is not expected to grow during the coming years. The distribution of the population and the number of apartments supplied with gas by oblast is as shown in Table 6. The number of apartments supplied for cooking and heating/cooking for each oblast and the development since 1990 are shown in Tables 11 and 12 respectively.

Table 4 Population 1995 and Number of Apartments in 1994 supplied with Gas by Oblast

OBLAST	*TOTAL POP.*	*URBAN POP.*	*NO. OF AP. WITH GAS*
Almaty	2,125,000	1,374,000[2]	272,000
Zhambyl	1,026,000	474,000	87,000
South Kaz.	2,002,000	766,000	164,000
Total	5,153,000	2,614,000	573,000

b The number of apartments supplied with gas for cooking and heating constitutes only about 10% of total apartments supplied in Almaty while it has a 50% share in the two other oblasts. The number of apartments supplied has increased by about 30% in all the three oblasts from 1990 to 1994. The consumption of gas per sector is for the region (three oblasts) are shown in Table 5.

Table 5 Almaty, Symkent and South-Kazakhstan: Consumption of gas by sector. 1992-96

	1992 (%)	*1993 (%)*	*1995 (%)*	*1996 (%)*
Industry	2100 (40)	1400 (34)	1400 (39)	900 (31)
Power	1900 (37)	1400 (34)	800 (22)	600 (21)
Commercial/Residential	900 (17)	900 (22)	1000 (28)	1000 (34)
Others	300 (6)	400 (10)	400 (11)	400 (14)
Total	5200	4100	3600	2900

c The overall consumption in the region has dropped considerably, e.g. to only 56% of the 1992 level as compared to an overall reduction in the country of 72%. In particular there has been a dramatic reduction in natural gas consumption by the industry (only 32% of 1992 level), but also in power which is at only 43% of the 1992 consumption. It is in particular the two power stations in Symkent which have reduced consumption (only 17% of 1992 level). As compared to the other regions supplied by gas, the power sector has in general a small share of total gas consumption. The one power station in Symkent interviewed in the market survey informed that it at the moment uses mazout only

d As can be seen from the table there have been slight increases in consumption in the commercial/residential and "others" sectors which, in addition, constitute much more here than in other regions of the country mainly due to a better developed distribution system with 30% more apartments supplied since 1990.

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2 of which 1162000 are living in Almaty

13. The *Western region* has received gas from a transit pipeline since it was built in the 1970's. The biggest cities are connected and the consumption of gas is limited by the distribution network. The network is poorly developed for agriculture and household/commercial consumption. Mainly the consumption is by power stations and industry. In particular the combined nuclear power and machine building plant in Aktau used to have a big consumption (2 BCM/y). The total population in the region is growing at 0.1 % per annum. The distribution of the population by oblast is as follows:

Table 6 Population 1995 and Number of Apartments in 1994 Supplied with Gas by Oblast

OBLAST	*TOTAL POP.*	*URBAN POP.*	*NO. OF AP. WITH GAS.*
Atyrau	454,000	266,000	12,000
Mangystau	337,000	269,000	15,000
West-Kazakhstan	668,000	273,000	33,000
Total	1,459,000	808,000	60,000

a The total population in this region is only 30% of that in the Southern Region, but the level of urbanization higher (55% as compared to 42% in the South). The share of the urban population supplied with gas is only half of that in the South indicating a good potential for increase. As seen from Appendix III the number of apartments in Mangystau is supplied with gas for cooking only, while nearly 80% of the apartments supplied in West-Kazakhstan have gas both for cooking and heating. The number of apartments supplied in Atyrau has dropped to nearly half in 1993 when they were included in Mangystau oblast.

b The consumption of gas per sector is for the region is shown in Table 7.

Table 7 Mangystau, Atyrau and West-Kazakhstan: Gas Consumption by Sector. 1992-96

Sector	*1992 (%)*	*1993 (%)*	*1995 (%)*	*1996 (%)*
Industry	1200 (39)	1400 (48)	800 (30)	800 (29)
Power	1700 (54)	1200 (41)	1700 (62)	1700 (60)
Commercial/ Residential	100 (6)	200 (7)	100 (4)	200 (7)
Others	100 (6)	100 (4)	100 (4)	100 (4)
Total	3100	2900	2700	2800

The overall consumption in the region has only dropped marginally, and all of it has occurred within industry.

14. *The Kostanai and Aktyubinsk oblasts* are supplied from the Bukhara - Ural pipeline. Kostanai is supplied via Kartali in Russia. Apparently the distribution network is little developed in Aktyubinsk and somewhat more in Kostanai.

a The distribution of the population and the number of apartments supplied with gas by oblast is as shown in Table 8.

Table 8 Population 1995 and Number of Apartments in 1994 Supplied with Gas by Oblast

OBLAST	TOTAL POP.	URBAN POP.	NO. OF AP. WITH GAS.
Kostanai	1,029,000	545,000	122,000
Aktyubinsk	746,000	402,000	84,000
Total	**1,775,000**	**947,000**	**206,000**

b The urban population constitutes 54% of the total which is similar to that of the other two regions. The share of the urban population supplied with gas is about the same as the Southern region, but the region is much more developed in this respect than the Western region. As much as 80 % of the apartments in Aktyubinsk have gas both for heating and cooking, while the share in Kostanai is about 70%. The number of apartments supplied with gas has increased from 1990 to 1994 by 25% in Kostanai and 33% in Aktyubinsk.

c The consumption of gas by sector is shown in Table 9.

Table 9 Kostanai and Aktyubinsk: Gas Consumption by Sector. 1992-96

Sector	*1992 (%)*	*1993 (%)*	*1995 (%)*	*1996 (%)*
Industry	1300 (50)	1300 (52)	1000 (50)	1100 (52)
Power	600 (23)	600 (24)	400 (20)	400 (19)
commercial/ Residential	500 (19)	400 (16)	400 (20)	400 (19)
Others	200 (8)	200 (8)	200 (10)	200 (10)
Total	2600	2500	2000	2100

The 20% drop in consumption since 1992 is equally shared by power, industry and the urban sector.

15. In the *Eastern and Northern region* of Kazakhstan there are 10 oblasts which are not supplied with natural gas. The main competing fuel in this region is coal which apparently is produced very cheaply at the Eikibastuz open pit mine (about US$ 4-5 per ton). In addition there are imports of electricity from Russia.

Table 10: Consumption of the natural and associated gas in the Republic of Kazakhstan

Billion CM

N A M E	*1992*	*1993*	*1994*	*1995*	*1996 (wait)*
1	2	3	4	5	6
Republic in whole,	**11.12**	**9.55**	**6.97**	**8.4**	**7.82**
including - power sector	4.2	3.2	2.2	2.9	2.7
- industry	4.7	4.1	2.5	3.2	2.8
- communal/municipal	1.5	1.55	1.57	1.59	1.62
- others	0.7	0.7	0.7	0.7	0.7
1. Almaty oblast,	**0.9**	**0.9**	**0.6**	**0.8**	**0.8**
including - power sector	0.2	0.3	-	0.1	0.1
- industry	0.3	0.1	0.1	0.2	0.2
- communal/municipal	0.4	0.4	0.4	0.4	0.4
- others	-	0.1	0.1	0.1	0.1
2. Zhambyl oblast,	**2.2**	**1.4**	**0.7**	**1.7**	**1.1**
including - power sector	1.1	0.7	0.2	0.6	0.4
- industry	0.7	0.4	0.1	0.7	0.3
- communal/municipal	0.2	0.2	0.3	0.3	0.3
- others	0.1	0.1	0.1	0.1	0.1
3. South-Kazakhstan oblast,	**2.2**	**1.8**	**1.2**	**1.1**	**1.0**
including - power sector	0.6	0.4	0.1	0.1	0.1
- industry	1.1	0.9	0.5	0.5	0.4
- communal/municipal	0.3	0.3	0.3	0.3	0.3
- others	0.2	0.2	0.2	0.2	0.2
4. Aktyubinsk oblast,	**1.0**	**1.0**	**0.9**	**0.9**	**1.0**
including - power sector	0.3	0.3	0.3	0.3	0.3
- industry	0.5	0.5	0.4	0.4	0.5
- communal/municipal	0.1	0.1	0.1	0.1	0.1
- others	0.1	0.1	0.1	0.1	0.1
5. Kostanai oblast,	**1.6**	**1.5**	**1.3**	**1.1**	**1.1**
including - power sector	0.3	0.3	0.1	0.1	0.1
- industry	0.8	0.8	0.8	0.6	0.6
- communal/municipal	0.4	0.3	0.3	0.3	0.3
- others	0.1	0.1	0.1	0.1	0.1
6. West-Kazakhstan oblast,	**0.5**	**0.5**	**0.4**	**0.4**	**0.5**
including - power sector	0.1	0.1	0.2	0.3	0.3
- industry	0.3	0.3	0.2	0.1	0.1
- communal/municipal	0.02	0.05	0.07	0.07	0.1
- others	0.1	0.1	0.1	-	-
7. Atyrau oblast,	**0.4**	**0.5**	**0.3**	**0.6**	**0.5**
including - power sector	-	-	0.1	0.1	0.1
- industry	0.3	0.3	0.1	0.3	0.2
- communal/municipal	0.1	0.1	0.1	0.1	0.1
- others	-	-	-	0.1	0.1
8. Mangystau oblast,	**2.2**	**1.9**	**1.5**	**1.7**	**1.8**
including - power sector	1.6	1.1	1.2	1.3	1.3
- industry	0.6	0.8	0.3	0.4	0.5
- communal/municipal	-	-	-	0.02	0.02
- others	-	-	-	-	-

Note: The source of data on the power sector for the 1995-1996 is the former Ministry of Oil and Gas Industries of the Republic of Kazakhstan

Table 11: Apartments supplied with natural gas in 1994 in the Republic of Kazakhstan

oblast	*Total*	*cooking*	*heating & cooking*
Republic in whole	790818	443981	346837
including - Almaty	272212	239426	32786
- Aktyubinsk	84158	15738	68420
- Àtyrau	12071	9348	2723
- Zhambyl	87024	46541	40483
- Êostanaj	122812	39600	83212
- Mangystau	15118	15188	-
- West- Kazakhstan	33482	7826	25656
- South-Kazakhstan	163941	70384	93557

Table 12: The number of apartments supplied with Natural Gas during 1990 - 1994 (by oblast)

Oblast	*1990*	*1991*	*1992*	*1993*	*1994*
Total	598,624	647,771	696,920	746,067	790,818
1. Almaty	208,878	218,604	228,331	238,057	272,212
2. Aktyubinsk	63,533	69,212	74,890	80,569	84,158
3. Atyrau	20,474	22,605	24,737	11,750	12,071
4. Zhambyl	64,112	71,749	79,387	87,024	87,024
5. Kostanai	98,585	106,661	114,736	122,812	122,812
6. Mangystau				15,118	15,118
7. Uralsk	12,284	19,350	26,416	33,482	33,482
8. South-Kazakhstan	130,758	139,590	148,423	157,255	163,941

Appendix 3.3

Gas Demand Projections

Introduction

1. Given the current macroeconomic situation in Kazakhstan with a number of uncertainties, in particular, prevailing non-payment, any gas demand projection would be "indicative". In Kazakhstan, there is limited gas supply infrastructure. At present, only 8 out of the total 18 oblasts are supplied with gas. This means that the country's gas consumption is not directly linked with the growth of GDP.

2. Most statistics in Kazakhstan are outdated and/or conflicting. There is almost no readily available and reliable information on gas markets. Thus the ESMAP task force has decided to carry out a preliminary market survey together with local consultants.

Methodology Adopted

3. The approach adopted is "bottom-up". Using local consultants (EC Energy Center), field interviews have been carried out to evaluate gas markets in 7 main gas consuming oblasts (Almaty, Zhambyl, South Kazakhstan, Aktyubinsk, Kostanai, West Kazakhstan and Atyrau), covering in each oblast an Oblgas company or LDC (where such exists), one power station, one district boiler house and one big gas consuming industry. The list of questionnaires used for the market survey is given in *Annex 1.*

4. Although the information obtained by the interview process was primarily used for the gas demand projection for the power and industrial subsectors, such basic factors as market values and the limitation of the existing gas supply infrastructure have been taken into account. The projection of gas consumption by communal/municipal users is primarily based on the interview process with the oblagas companies but adjusted considering some other factors such as population growth, energy efficiency, etc. The gas demand projection for "others" (e.g. farms, institutions and industries located outside urban areas) is more or less based on historical records. For those oblasts where no gas supply infrastructure exists at present but are likely to use gas (e.g. Akmola, Kokchetau, Kizil-Orda), potential power and/or industrial users have been listed, assuming the earliest realisation of new gas supply infrastructure. The gas demand projection for these new oblasts is most uncertain. (See Table 1 for the list of major power and industrial consumers in each oblast.) A more detailed background information is given in *Annex 2.*

Base Scenario

5. In general it is assumed that the decline in the economy has flattened out and that some increase up to year 2000 and beyond can be expected. This is consistent with the GDP forecast given in the Medium Term Public Investment Program (Sept. 1996). According to this the 1996 GDP is expected to record some growth, even if it is a modest level of less than half a percent. For the remaining years of the medium term program in 1997-1998, an average of 2 percent annual growth is anticipated. Within the framework of a modest growth in the economy, the projected gas demand by oblast and sector vary. In general the oil and gas rich oblasts are expected to have a much higher growth in gas demand than those oblasts without such resources. Where power is imported, switch over to gas fired power generation is expected. The consumption level of gas by other industrial enterprises is not expected to grow much beyond their peak levels by year 2010.

Assessment of Each Subsector's Gas Demand

6. **Power**: In general it would be viable to substitute existing coal fired plants and imported electricity with gas fired plants, given a high market value of gas for power generation (estimated at US$ 70 -80 per 1000 CM). Most of Kazakhstan's power stations are old and approaching their retirement age. In some oblasts, it is expected that more use of gas and less use of coal and mazout in the existing power plants and boiler houses (both of which are counted in the power sector). The use of coal or mazout will be competitive only at those power stations close to coal mines or and refineries.

7. The current power deficit in Kazakhstan is estimated at about 7 bn Kwh which is imported from Russia, Uzbekistan, Turkmenistan and Kyrgyzstan. To replace this import by gas fired power plants would require about 1.7 BCM of gas annually. The consumption of gas in power in 1992 was 4.2 BCM which is 0.5 BCM more than the 1996 level. Thus, in order to replace imported electricity and regain previous levels of gas consumption in existing plants, 2.2 BCM of gas would be required additionally. It would be reasonable to assume that coal and mazout being used by existing power stations will be substituted by gas where competitive[1]. Where energy supply is constrained and gas is available within the respective oblasts, it is conceivable that new gas fired power plants are constructed. These factors have been taken into account in combination with a modest increase in power and heating demand in line with the economic recovery.

8. The largest increase in the consumption of gas for power/heat production is projected for the following oblasts:

- Kyzl-Orda: + 900 million CM[2] (or additional 3.2 billion KWh power generation if all the gas is used for power generation) by 2010 based on the construction of new combine

[1] Those locations close to gas fields and existing pipelines, and far away from coal mines and refineries.
[2] Since the existing industry in Kyzl-Orda is declined and financially good markets are not near the Kumkol field, tremendous effort would be required to achieve successful commercial arrangements.

cycle power stations close to the Kumkol gas field for transmission to other oblasts over the national grid (a trunk line is located close to the field),

- Aktyubinsk: + 700 million CM (or additional 2.5 billion KWh power generation) by 2010 to be consumed by a newly constructed power plant, an existing old plant and new plants/boiler house to be erected/connected between 2000 and 2005. The electricity generated would substitute the imported power from Russia to Aktyubinsk, Kostanai, West-Kazakhstan and Atyrau.

- Zhambyl: + 500 million CM (or additional 1.8 billion Kwh power generation) by 2010 to be consumed mainly by a big regional power station which has a gas consuming capacity about 10 times the present level, a smaller station and district boiler houses. The power will substitute the electricity import from abroad to the South and will initially be based on imported gas which is very competitive with the cost of imported electricity. In the future, gas produced from the nearby Amangeldy field and other field in Zhambyl may substitute the imported gas.

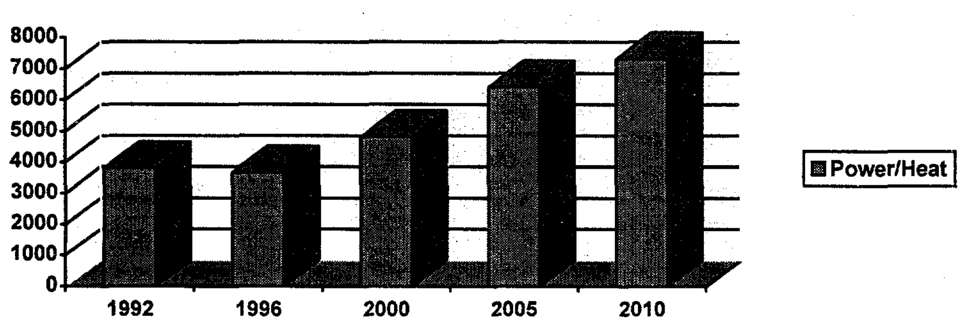
- West-Kazakhstan, Atyrau and Mangystau: + 400 to 500 million CM (or additional 1.4 to 1.8 billion Kwh power generation) each by 2010 to substitute the imported electricity from Russia and to increase production in the boiler houses.

Although there may be potential demand in Akmola corresponding to nearly 700 million CM (or about 2.9 billion Kwh power generation on gas firing) by 2010, the economic viability to supply gas to this oblast is currently not justified.

9. Considering increase from the present power consumption, power deficit in western and southern Kazakhstan and the need for replacement of the old coal fired power stations by gas fired plants, the above estimated growth of gas demand would be within a reasonable range. (See Table 2 for the present electricity balance in western and southern Kazakhstan.)

10. The gas demand in power/heating is predicted as given in Figure 1 below:

Figure 1: Gas Demand in Power/Heating
(Unit: million CM)



11. **Industry:** The projected industrial demand for gas is based on past consumption figures in existing industries and assessments of the potential growth of each major gas consuming industry in each oblast currently supplied with gas. The market value for gas in industry in the case to replace mazout is more than US$ 60 per 1000 CM. Thus, gas is competitive in those oblasts where gas supply infrastructure exists.

12. The consumption of gas in industry dropped considerably from 4.2 BCM in 1992 to nearly 2 BCM in 1996. It is not expected that the past peak consumption levels will be recovered by year 2010 due to the inherent structural and financial problems of the industrial sector. Most of the existing industries assessed are faced with a number of problems. It will take a long time before they are properly restructured and set on a sound footing again. A few large industries have been taken over by foreign management, which may indicate a somewhat positive signal for their business growth. Practically no new gas consuming industries have been envisaged before 2010.

13. The largest increase in the consumption of gas for industry is projected for the following oblasts:

- Zhambyl: +325 million CM by 2010 assuming the success of the ongoing reforming of seven large gas consuming industries,

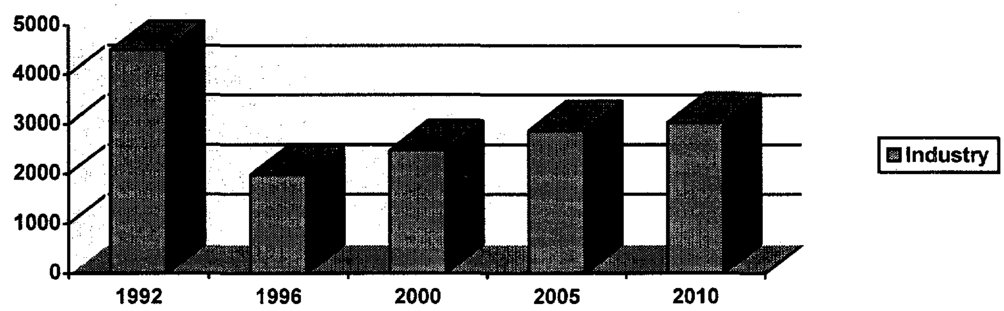
- South-Kazakhstan: + 170 million CM by 2010 based on the restructuring of 4 large gas consuming industries and a few small ones,

- Kostanai: + 160 million CM by 2010 based on resumption of gas demand by a few big industries currently privatised and under foreign management and the use of gas by a ore mining and processing plant,

- Almaty: + 100 million CM by 2010 based on a slow revival of 35 medium-sized gas consuming industries of which agro-processing for the local market seems to have the best potential.

14. The projected gas demand for the industrial sector is shown in Figure 2 below:

Figure 2: Gas Demand in Industry
(Unit: million CM)

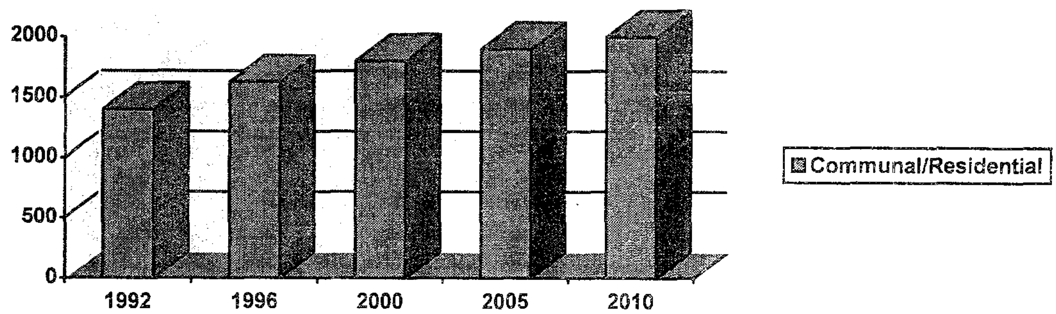


15. **Communal/residential**: This sector includes apartments and institutions/commercial buildings in urban area. As shown in Tables 11 and 12 of Appendix 3.2, the number of apartments supplied with gas had grown slowly during the 1990's while the consumption level had been fairly flat. Apart from a few oblasts mentioned below, the Oblgas companies have no plan to expand the communal/residential network before 2010. Consequently the increase of gas is limited to those oblasts where there is expansion plans, namely:

- Aktyubinsk: + 100 million CM which will be delivered to Aktyubinsk city where the distribution network is nearly completed,
- West-Kazakhstan: +100 million CM based on a continued increase in apartments supplied from the Karachaganak field as depicted by the Oblgas company,
- Atyrau: + 50 million CM which will be supplied from the Tengis field to apartments on the "right shore" of Ural,
- Mangystau: + 75 million CM which will be supplied to new areas in the South of the oblast from the Uzen field

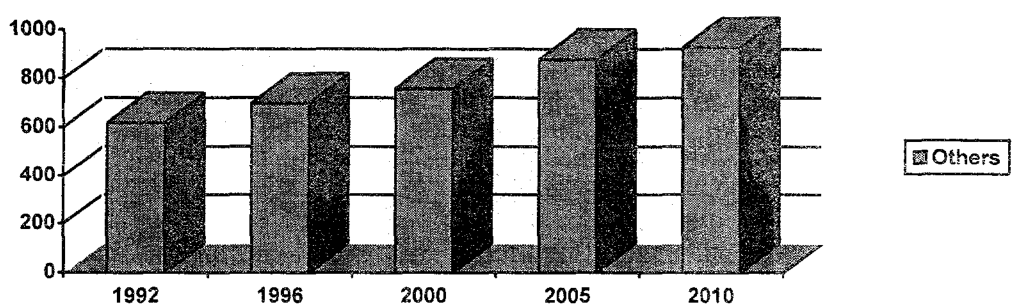
16. The projected gas demand for this sector is shown in Figure 3 below:

Figure 3: Gas Demand in Communal/Residential Consumers
(Unit: million CM)



17. **Others**: This sector includes farms, institutions and industries located outside urban areas. The consumption of gas in this sector has been stable throughout the 1990's. All the projected increase in the consumption is expected in West-Kazakhstan where new rural areas will be supplied with gas from the Karachaganak field. Figure 4 below shows the gas consumption in the sector.

Figure 4: Gas Demand in Others
(Unit: million CM)



18. **National Demand:** The estimated national demand that physically and economically can be met by existing and future gas sources is shown in the figure below. In Figure 5 below, the potential demand of Akmola, Kochetau and Kzy-Ord has been tentatively included. The demand projection by sector and oblast is given in Table 3.

Figure 5: Gas Demand in Kazakhstan
(Unit: million CM)

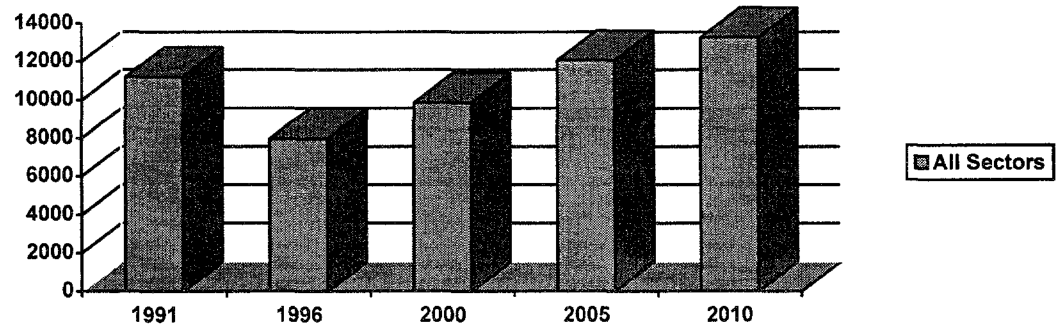


Table 1: List of Major Power Sector and Industrial Consumers

Name of consumer
1. Almaty oblast
1) Almaty HPC-1 (heat-power central)
2) West District Boiler-House (DBH)
3) North-East DBH
4) New-West DBH
5) Joint-Stock Company ``Massaget`` (JSC)
6) Almaty`s machine-tool plant ``XX years of October``
7) JSC Machine-building plant `Hydromach`
8) BH of the experimental metallurgical work-shop of the Institute of Metallurgy & Ore dressing of the National Academy of RK
9) Sanitarium `Alatau`
10) Industry of the motor-car roads
11) BH of Station Aksenger
12) JSC`Temir Zat`
13) Ministry of transport
14) Repair shop of the military unit 2468
15) Oil-material base
16) Industrial Combinat `Builder`
17) Industrial-building Association `Almatystroj`
18) Agroindustry of RK, including
- Brewery Œ 1
- Flori-cultural sovhoz ``Taugule``
- hot-houses sovhoz Almatinsky, Koktem
- Fruit and vegetable processing plant
- Biocombinat
- KZOSP, c. Kaskelen
- Industrial Association

``Almatyhleb`` (bread)
- Almatinskaja poultry farm
- PSP PO ``Remstrojtechnika``
- Combinat of building materials and constructions c. Kaskelen
- Poultry farm ``Chapaevskij``
19) JSC `Àl-Pam`
20) Kaskelenskoe enterprise of the light industry
21) KazNIITIPS
22) BH of the cloth factory, v, Fabrichnij
23) DBH, v. Fabrichnij
24) DBH, v. Burundaj
25) Others
2. Actubinsk oblast
1) HEPC, c. Aktyubinsk
2) DBH, c. Oktiabrsk
3) Plant of the chrome combinations
4) Plant of the agro-machines `Aktubcelmach`
5) Phosphorus mine Chilisajskij, w.v. Chilisaj
6) Oil-gas production enterprise `Îktjabrsk-neft`, c. Oktjabrsk
7) Donskoj ore mining and processing enter-prise, c. Chrometau
8) Plant 406 GA, c. Aktyubinsk
3. Atyrau oblast
1) HEP Central, c. Atyrau
2) West DBH
3) DBH-1, v. Kulsary
4) DBH-2, v. Kulsary
5) Closed enterprise G-4676
6) Base of the building industry Tengizneftestroj
4. Zhambyl oblast
1) State Regional Power Station
2) HEPC- 4
3) Zhambyl DBH - 4
4) Industrial Association ``Chemicalprom``
5) Plant of the super-phosphate
6) Plant of the spare parts
7) Plant of the metallic constructions
8) Glass - factory
9) Tannery
10) Sugar-refinery
11) Produced Association of the bread-baking industry
12) Workshop of broken-brick of the plant of silicate production
13) DBH - 2
14) NovoZhambylsky Phosphorus plant
15) BH, c. Janatas
16) DBH c. Karatau
17) BH of the Karatau Chemical Plant

5. West-Kazakhstan oblast
1) HEPC of c. Uralsk
2) Mechanical plant called after Voroshilov
3) Combinat of the road building materials
4) Plant Omega
5) Tannery
6. Kostanai oblast
1) HEPC-1, c. Kostanai
2) DBH - 1
3) DBH - 2
4) BH of the cloth materials combinat
5) Plant of the chemical fibre
6) Plant of the diesel motors.
7) Plant Kazogneupor
8) Lisakovskij ore mining and processing enterprise
9) Kacharskij ore mining and processing enterprise
7. Mangystau oblast
1). Mangystau electro-power generated combinat (MAEC)
2) Plant of plastic materials, Aktau
3) Prikaspijskij ore mining and processing enterprise
4) DBH-2, c. New Uzen
5) Mangystau oil processing plant
6) Central BH of N.Uzen
7) DBH, w.v. Jetybaj
8) DBH, w.v. Eralievo
8. South-Kazakhstan oblast
1) HEPC-1,2 , Shimkent
2) HEPC - 3 , Shimkent
3) DBH - 1,2, Shimkent
4) Shimkent Industrial Association (IA) ``Phosphorus``
5) Hydrolytic plant
6) IA `Shimkentshina`
7) Brewary
8) JSC ``NAN`` (Bread)
9) Leaden plant
10) Combinat of the building materials
11) Plant of cement
12) Combinat of the asbestos and cement constructions
13) JSC `Sasasbocement`
14)Bugunsk poultry farm
15) Tulkubass poultry farm
16) Hot-houses combinat of sovkhoz ``Pobeda``
17) JSC ``Jemis``

9. Akmola oblast
1) HEPC-1, c. Akmola
2) HEPC-2, c. Akmola
10. Kizyl-Orda oblast
1) HEPC-6, Kizyl-Orda
2) GTE of deposit Kumkol
11. Kokshetau oblast
1) DBH-1,2, c.Kokshetau

Note: For non-gasified oblasts, potential consumers are listed.

Table 2: Current Electricity Balance in Western and Southern Kazakhstan
(in 1990 and 1995)

(Unit: billion Kwh)

Region	Western Kazakhstan		Southern Kazakhstan	
	1990	*1995*	*1990*	*1995*
Electricity Consumption	11.87	8.86	26.43	14.78
Electricity Generation	7.22	5.31	16.27	10.47
Deficit	4.65	3.55	10.16	4.31

Source: Kazenergo, October 1996
Note: "Western Kazakhstan" here includes: West Kazakhstan, Aktyubinsk and Atyrau.
"Southern Kazakhstan" here includes: Almaty, Zhambyl, Symkent, Talkorgan and Kzyl-Orda.

Table 3: Kazakhstan - Gas Demand Projection

(Unit: million CM)

Oblast	1996	2000	2005	2010
Almaty	**822**	**945**	**1030**	**1060**
Power	147	230	270	280
Ind.	175	215	260	280
Com/mun.	400	400	400	400
Others	100	100	100	100
Zhambyl	**1202**	**1600**	**1650**	**1750**
Power	407	540	580	630
Ind.	395	660	670	720
Com/mun.	300	300	300	300
Others	100	100	100	100
South Kazakhstan	**818**	**1000**	**1070**	**1100**
Power	89	170	180	200
Ind.	229	330	390	400
Com/mun.	300	300	300	300
Others	200	200	200	200
Aktyubinsk	**1189**	**1640**	**1770**	**1770**
Power	575	930	1060	1060
Ind.	414	410	410	410
Com/mun.	100	200	200	200
Others	100	100	100	100

Kostanai	**1240**	**1340**	**1470**	**1590**
Power	290	310	310	350
Ind.	550	630	760	840
Com/mun.	300	300	300	300
Others	100	100	100	100
West Kazakhstan	**444**	**550**	**830**	**1030**
Power	270	300	400	500
Ind.	74	90	100	100
Com/mun.	100	100	150	200
Others	0	60	180	230
Atyrau	**810**	**1010**	**1240**	**1240**
Power	588	730	960	960
Ind.	22	30	30	30
Com/mun.	100	150	150	150
Others	100	100	100	100
Mangystau	**1446**	**1470**	**1760**	**1860**
Power	1300	1300	1530	1630
Ind.	120	120	130	130
Com/mun.	26	50	100	100
Others	0	0	0	0
Akmola			**(400)**	**(675)**
Power			(400)	(675)
Ind.				
Com/mun.				
Others				
Kokchetau			**(250)**	**(300)**
Power			(120)	(120)
Ind.			(130)	(130)
Com/mun.				(50)
Others				
Kizyl-Orda		**300**	**600**	**900**
Power		300	600	900
Ind.				
Com/mun.				
Others				
Total	7971	9855	12070	13275
Power	3666	4810	6410	7305
Ind.	1979	2485	2880	3040
Com/mun.	1626	1800	1900	2000
Others	700	760	880	930

Note: Gas consumption figures in Akmola and Kokchetau are based on a preliminary survey on potential users. Unless gas pipelines are installed, actual gas consumption does not take place. The "total" tentatively includes the gas consumption in Akmola and Kokchetau. In addition, there is a potential that Petropavlosk in North Kazakhstan oblast consumes maximum 1.3 BCM/Y if a 130 Km pipeline is installed from Russia.

Annex 1: Questionnaire list used for the market survey

POWER STATIONS

1. Name and location of enterprise.
2. Postal address, telephone, fax.
3. Family, Name, Patronymic of a leader of enterprise.
4. Family, Name, Patronymic of a questioned person.
5. Type of power station (description, project capacity, utilisation of the capacity, year of putting into operation, condition - depreciated of a basis equipment).
6. Kinds and sources of the used fuel by the project and at the present time.
7. Quantity, prices and cost of the used fuel
8. Volume of production and realisation of product
9. Current financial position, credit and debit debts.
10. Summary report of expenses on the production
11. Cost of the basis funds (including equipment) - primary and rest costs by years : 1991, 1993, 1995, 1996, cost of investment by years and on the period 1991-1996.
12. Calculation of the prime cost for the heat and electric energy.
13. Principal markets, clients, competitive kinds of fuel, share on the regional market ...
14. Plan of development of enterprise , including a possible conversion on gas utilisation, cost of development, sources of financing.
15. Evaluation of the perspective production by 2000, 2005, 2010.

Annex 2 Gas Demand Projection

Almaty oblast

Power/Heat

1. There are one power station (HEC-1 station) and six district boilers in the oblast which use gas. Two other power stations are fired on coal and mazout, and two are hydro stations. Total electricity production in the oblast was 4.8 billion Kwh in 1996, of which 3.6 billion Kwh was generated on coal, mazout and gas. The power stations also produced 6.6m Gcal of heating. There is a plan to convert the fuel of the two thermal power stations from coal/mazout to gas, in particular, from mazout to gas at HEC-2 (which generated about 2 billion Kwh in 1995/96).

2. The Southern three oblasts imported 3.2 billion Kwh in 1996 using the common Uzkazenergo and Almatyenergo grid, mainly from Turkmenistan and Kyrgystan[1]. There is a potential to increase the gas demand in the power up to a level of 1.2 BCM/year, if the three existing plants (or the replacement of these) are fired entirely on gas and electricity import is substituted by gas-fired plants in the oblast assuming that more than one-third of the imported gas could be transmitted to Almaty. It should be noted that in order to realize the above scenario, the rehabilitation of the existing southern transmission pipeline and the completion of the last section of the second pipeline near Almaty are required. Then, the transmission capacity to Almaty would be increased 3 BCM/year. Furthermore, large investments are needed for the refurbishment and fuel conversion of the existing stations and construction of new plants.

3. Given its near-retiring age, the power generation at HEC-1 station is not expected to increase beyond its current annual generation of 0.68 billion Kwh per year. The gas consumption at the station fell considerably during the 1960's from a level of 200 MMCM /Y to 143 MMCM/Y in 1995. In 1996, the gas consumption was only 64 MMCM. There was a constraint of steady gas supply to Almaty. As a result, coal and mazout replaced for gas. The HEC-1 station is willing to use more gas mainly due to environmental benefits if the gas supply condition improves. Assuming that the rehabilitation and expansion the southern transmission pipeline have been completed by 2000 and that the gas supply price will be kept below the market price of gas for power generation, it is expected the gas consumption level would recover at least up to 100 MMCM by 2000 and 150 MMCM by 2010. The steady gas supply also depends on the success of a long-term agreement with Uzbekistan and Turkmenistan.

4. The existing power stations in Almaty were commissioned in 1960s and are close to the end of their useful life. However, current uncertainties of the country's economic situation may not promote large investments in the near future. Therefore, the base case projection (which is given in this report) has been drawn in a conservative manner. If a new CCGT based 150 MW power station replaces the HEC-1 station, about 200 MMCM of gas is required each year. If a new 500 MW power station based on a CCGT (which replaces for the existing CHP-2 station) is installed, about 700 MMCM of gas is needed annually.

[1] No information on the break-down per oblast.

5. Gas consumption by boiler houses dropped to about 65% of its historic peak in the early 1990s. Increase of gas consumption is expected so as to improve the current supply constraint of heat. The gas consumption for heat generation is expected to grow from the current level of 85 MMCM to 130 MMCM in 2000. After 2000, not much growth is anticipated. Expected price increase would promote energy saving but the recovery of industrial activities may increase the number of consumers and thereby lead to the increase of overall consumption.

6. Overall, the gas consumption in the power/heat sector in Almaty is most uncertain. It largely depends on new installation of power stations which replace the existing capacities and/or cover the growth of power consumption.

Industry

7. The total industrial consumption of gas in Almaty dropped from about 300 MMCM in 1992 to about 175 MMCM in 1995/96. The gas is consumed by about 35 medium-sized factories, each with an average of 4 MMCM/year, and a number of small ones. Only four industries consume each more than 10 MMCM/year.

8. The gas consumption is expected to increase in tandem with the recovery of the economy. However, the growth of consumption could be slightly slower reflecting the retirement of a few old factories, energy efficiency driven by price growth, etc. No new large gas consuming industry is envisaged during the projected period. The projection of industrial consumption of gas is based on a brief assessment of several medium-sized industries. Apart from agro-processing industries which supply their products to the market of Almaty, the other industries reviewed are not expected to grow rapidly. Total industrial consumption of gas is projected to reach 215 MMCM in 2000, 260 MMCM in 2005, and 280 in 2010. the latter consumption figure is close to its historical peak consumption. The growth would be rapid before 2000 once debottlenecking of the transmission pipeline has been made. Later on energy efficiency may become more dominant, resulting in a slower growth rate.

Communal/municipal

9. This sector includes supply to households and commerce/institutions in urban areas. The number of apartments supplied with gas in Almaty has increased slightly during the 1990's (see Appendix 3.2), while the total gas consumption has been stable. Thus on average less gas is supplied to each apartment. None of the forecasts carried out by Kazak institutions, including the Almatygas (oblgas), envisage any growth in the communal/municipal sector in the country.

10. Moreover, the introduction of more meters and expected price increases are expected to promote energy saving and decrease consumption per each of the existing consumers. Due to financial constraints, the oblgas company (e.g. Almatygas) does not have any solid plan to expand its distribution network. Thus, no growth in the demand is envisaged.

Others

11. This sector includes a number of farms, industries and institutions located outside the urban areas. No information on individual consumers has been obtained. The consumption of gas in rural areas of Almaty oblast was stable throughout the 1990's, at about 100 MMCM/year. Due to the similar reasons as given in the previous section no increase in demand is projected.

Overall Demand

12. Reflecting the above discussions, the overall demand forecast for Almaty is summarized in *Table 1.*

Table 1. Almaty. Gas Demand Projection for 2000, 2005 and 2010

SECTOR	*1 995*	*1 996*	*2 000*	*2 005*	*2 010*
Total	875	822	945	1 030	1 060
Power[2]	200	147	230	270	280
Ind.	175	175	215	260	280
Com/mun	400	400	400	400	400
Others	100	100	100	100	100

13. In the interview, Almatygas has indicated the following overall consumption figures for the oblast: 1250 MMCM in 2000, 1350 MMCM in 2005, and 1750 MMCM in 2010. However, this lacks substantiation. As stated in the paragraph 6, it largely depends on the growth of the power sector.

Zhambyl oblast

Power/Heat

14. The total gross consumption of electricity in the oblast was 2 billion Kwh in 1996, of which 0.7 billion was recorded as a loss. The total production at the Zhambyl Regional Power station was around 4.3 billion Kwh in 1995/96 in addition to 22 000 Gcal of heat. Thus the power station exports electricity to other oblasts. The power station uses both gas (imported from Uzbekistan and Turkmenistan) and mazout. In 1996 it used 260 MMCM of gas, while its maximum capacity to use gas is 2.2 BCM. (It used 1.5 BCM in 1991). The design of the power station is based on gas firing and the station does not have any flue gas desulfurization unit. The station was 100 percent privatized in 1996 and is operated in a reasonably good condition. The station makes a firm sales agreement with each consumer and curtails power supply to non-payers. Thus, the station maintains financial stability. The station intends to consume more natural gas in place of mazout if gas is available at the current price level of US$ 47 per 1000

[2] As discussed in Paragraph 4, the projection given here is based on a conservative view. If new gas-fired power stations are installed, the consumption in the power sector is more than three times higher.

CM or below. In addition to the Regional Power station, there is Zhambyl HEPS-4 which produced 155 million Kwh in 1995 and 840 000 Gcal of heating. Its consumption of gas was 114 MMCM in 1996. There are three District Boiler Houses which used about 100 MMCM of gas in 1995/96.

15. According to the Institute of Energy, there is a potential for increase in the electricity production at the Regional station up to 5.5 billion Kwh by year 2000, e.g. by 28%, and about the same production of heat as today. At that level the maximum consumption of gas would theoretically increase up to a level of 1.5 BCM, in correspondence to the decrease of mazout consumption. Such a high level of electricity production and gas consumption is, however, not considered realistic due to immense problems of the economy in the South. It is therefore projected that the electricity production and gas demand will only increase gradually in line with the expected modest recovery of the economy in the region, e.g. from a current level of 380 MMCM of gas in the power to 490 MMCM in 2010. The largest increase is expected in the boiler houses which plan to work at full load due to their shorter distance to the consumers than the existing power stations. The maximum gas consumption by these boiler houses would be 170 MMCM in 2005. The total projected consumption of gas in power/heat is shown in Table 2.

16. There is, however, a potential for considerable growth in gas consumption by the Regional Power Station if the station needs to substitute most of the imported electricity (estimated at about 1.5 billion Kwh) which is currently priced at 3 cents/Kwh from Turkmenistan and Kyrgystan.

Industry

17. There are seven large gas consuming industries in the oblast, each with an annual consumption of 50 MMCM to more than 100 MMCM and 10 others with 10-50 MMCM each. In addition there is the Janata Phosphorus mine and enrichment complex which is in serious trouble (the boiler house did not consume any gas in 1996). The large gas consuming industries include inter alia chemical plants, two phosphorus plants and a sugar refinery. The consumption of gas in the industrial sector dropped considerably in 1996 at these two factories and two industrial boiler houses. A review of the industries has revealed that most of the small industries are not expected to increase production of gas consumption during the projection period. Only the "Industrial Association Chemicalprom" with new foreign management and one of the phosphorus plants with a new gas pipeline being installed are expected to have any significant increase in consumption. The two account for about half of total industrial increase in gas consumption between 1996 and 2000. The projected industrial gas demand, which is expected to recover its 1995 level by 2000. No potential demand above the projected level can be discerned at this point of time.

Communal/municipal

18. The number of apartments supplied with gas has increased steadily from 1990 to 1993. After that, the number is leveling off. The consumption of gas has been stable at 300 MMCM/year. No expansion of the main gas distribution network is planned by the oblgas company. With installation of more meters and the increase of gas price as proposed by the

government, it is unlikely that the gas consumption by households and commerce/institutions will increase. Potentially it could even decrease unless new consumers are connected.

Others

19. The demand for gas in the rural sector has been stable during the 1990's at 100 MMCM/year. No expansion of the gas network or demand are expected.

Overall Demand

20. The base forecast for Zhambyl is shown in Table 2.

Table 2. Zhambyl. Gas Demand Projection for 2000, 2005 and 2010

SECTOR	*1995*	*1996*	*2000*	*2005*	*2010*
Total	1 770	1 202	1 600	1 650	1 750
Power	687	407	540	580	630
Ind.	683	395	660	670	720
Com/mun	300	300	300	300	300
Others	100	100	100	100	100

21. At the interview with Zhambylgas, they have predicted an increase in gas demand as follows in 2900 MMCM in 2000, 3300 MMCM in 2005 and 3600 MMCM in 2010. However, they have stated that it is impossible to make such a forecast due to "lack of a substantiated economic forecast". As with the power sector in , the demand largely depends on the growth of the power sector.

Shimkent oblast

Power/Heat

22. The total gross electricity consumption in the oblast was in 1996, 2.5 billion Kwh of which 0.8 billion Kwh was recorded as a loss. The total generation by three thermal and one hydro station was 0.866 billion Kwh in 1995, of which the largest station, HEPS-3, generated 0.35 billion Kwh and 400 000 Gcal of heat. The import of electricity from abroad is estimated at 1.3 billion Kwh, the remaining (0.3 billion Kwh) being supplied from the national grid (mainly Zhambyl and Eikabustuz). Electricity from two different Eikabustuz plants is delivered in Shimkent at less than 3 cents/Kwh. The HEPS-3 station has reduced its gas consumption from 380 MMCM in 1991 to zero in 1996 due to problems with supply and agreement with the nearby Shimkent refinery (a barter of electricity for mazout). Total consumption of gas at the three power stations and the district boilers was 160 MMCM in 1995 but fell down to 90 MMCM in 1996. At the interview conducted by EC Energy Center, HEPS-3 did not give any indication of

future demand for gas, if the expansion of the plant is achieved with an investment of US$ 240 million.

23. The gas volume which replaces 1.6 billion Kwh which was imported and transmitted through the national electricity grid is about 400 MMCM/year. The Institute of Energy has projected gas consumption by the power stations and district boilers to be nearly 400 MMCM in 2000 and nearly 700 MMCM in 2005. These figures are viewed as very optimistic if not unrealistic.

24. Due to the high degree of uncertainty and the keen competition of mazout from the nearby refinery in Shimkent, high, low and medium gas consumption projections have been made for the power sector. These forecasts are not directly proportional to the growth of the electricity production. The competitiveness of gas could be determined by the cost of mazout and other vital factors like regularity of supply, payment conditions, possibility and conditions of barter, etc. Apparently the agreement with the Shimkent refinery is a binding factor. In the high forecast it has, however, been assumed that gas in the power stations will regain its 1993/94 level by 2000, e.g. 240 MMCM and thereafter grow by 1.5% growth annually in line with the economic recovery. In the low forecast it is assumed that no gas is consumed in 2000 by the power plants, which is a continuation of the past trend where the power plants use more and more mazout. The forecast shown in Table 3 below is in the middle of the two extremes. The district boiler houses are projected to continue its stable consumption of gas throughout the 1990's which has been around 50 MMCM a year. There are no plans to expand the supply of heating in the oblast.

Industry

25. There are four medium-sized gas consuming industries in the oblast (about 50 MMCM each), and 10 smaller ones. Gas consumption, mainly in the large industries, dropped from 340 MMCM in 1995 to 230 MMCM in 1996. The interviewed cement plant reduced its gas consumption from 310 MMCM in 1991 to 20 MMCM in 1996 using more mazout than before. The cement plant indicated that it can increase production considerably “given a market”. It has plans to convert the process to a dry production based on gas firing which is more energy efficient.

26. Some of the other large industries including a lead mine are operating at a very low level and are under restructuring. Based on a review of the industries it is not envisaged that gas consumption will grow much in most industries during the upcoming several years. Main growth in consumption is depicted for the lead mine/plant and the cement plant which will regain the 1995 consumption level by 2000. The growth in industrial gas consumption is shown in Table 3.

Communal/municipal

27. South-Kazakhstan has the second highest number of apartments supplied with gas in the country. The number has grown slowly during the 1990's while the total consumption has

been stable at 300 MMCM/year. No further expansion of the distribution network has been indicated by the oblgas company due to lack of profit in the operation. Meter installation and price increase would promote energy saving. Thus no increase in the sector's consumption of gas is envisaged for the review period.

Others

28. The oblast has the most extensive network of gas supply to rural areas in the country, supplying about 200 MMCM have been supplied annually. The consumption was stable throughout the 1990's. No expansion of the network or increase in demand are expected.

Overall Demand

29. The overall demand forecast for South-Kazakhstan is shown in Table 3.

Table 3. South-Kazakhstan. Gas Demand Projection for 2000, 2005 and 2010

SECTOR	1995	1996	2000	2005	2010
Total	1 001	818	1 000	1 070	1 100
Power	161	89	170	180	200
Ind.	340	229	330	390	400
Com/mun	300	300	300	300	300
Others	200	200	200	200	200

30. The "potential" demand indicated by the oblgas company is 1,835 MMCM in 2000 growing up to 1,940 MMCM in 2010. The historical maximum supply by the company was 2,500 MMCM in 1991. Given financial constraints, it is most unlikely to expand the supply capacity at such a high pace. The level of gas consumption largely depends on the growth of power sector.

Aktyubinsk

Power/Heat

31. The gross consumption of electricity in the oblast was 1.6 billion Kwh in 1996, of which 0.36 billion Kwh was recorded as a loss. In total 0.9 billion Kwh was produced by two thermal power stations in 1996, and a balance of 0.7 billion Kwh was imported from Russia. The largest station, Akturbo, which was commissioned in mid 1996, produced 0.6 billion Kwh and is able to cover the current electricity deficit once its full load operation has been attained. The plant is fully gas fired and consuming 200 MMCM a year. The other station, HEPC Aktyubinsk, consumed 375 MMCM of gas and 30 000 tons of mazout in 1996 as compared to the previous maximum consumption of 515 MMCM of gas. The plant also produces heat. As shown in the

table below there are plans to erect new power plants in the oblast, but this is expected to occur at the earliest between year 2000 and 2005. The surplus of electricity from these plants will mainly substitute electricity imported from Russia to West-Kazakhstan, Atyrau and Kostanai at a maximum of 2.5 billion Kwh by 2010. The three oblasts have today a deficit of 3.8 billion Kwh. In addition to gas consumption for electricity generation, a district boiler house in Oktiabrsk with a consumption of 230 MMCM annually is planned to be connected to gas mains by year 2000.

32. The projected consumption of gas in MMCM by existing and new power stations is shown below.

	2000	2005	2010
HEPC Aktyubinsk	400	400	400
Akturbo	300	300	300
DBH	230	230	230
Small new station		130	130
Large new station		200	700

Since the plans for a large new station is quite uncertain, its consumption of gas is not included in the base forecast shown in Table 4.

Industry

33. There are six large gas consuming industries in the oblast including a chrome mining and processing complex which consumed 250 MMCM of gas in 1996. According to the information obtained during the market survey none of the industries plan to expand production. Thus the total gas consumption in industry is not envisaged to grow during the period. Possibly improved energy efficiencies and increased prices based on market values may lead to reduction of industrial gas consumption.

Communal/municipal

34. The number of apartments supplied with gas in the oblast has grown from 63 000 in 1991 to 84 000 in 1994, and 94 000 in 1996. Thus there has been a 50% increase in the number of households supplied, but the amount supplied has been stable at 100 MMCM a year over the above period. The city of Aktyubinsk is currently supplied with gas using the Bukhara - Uralsk trunk line while Oktiabrsk urban area receives gas directly from the Zhanazol and Urihtau fields. The distribution network in the city of Aktyubinsk is being constructed and has partly been completed. The city will be able to receive larger amounts of gas after completion of the gas pipeline from the local fields and the distribution network. There will be a large increase in gas consumption by households leading to an envisaged doubling of the consumption in the communal/municipal sector by year 2000. There are no further plans of extending the network after this, and the installation of meters (starting with a planned 1000 in the near future) and increased prices will promote energy saving.

Others

35. The number of rural areas supplied with gas has been constant throughout the 1990's as has been the consumption. No increase in consumption is envisaged.

Overall Demand

36. The projected base demand of gas in Aktyubinsk is shown in *Table 4.*

Table 4. Aktyubinsk. Gas Demand Projection for 2000, 2005 and 2010

SECTOR	1995	1996	2000	2005	2010
Total	914	1 189	1 640	1 770	1 770
Power	400	575	930	1 060	1 060
Ind.	314	414	410	410	410
Com/mun	100	100	200	200	200
Others	100	100	100	100	100

37. The forecast made by the oblgas company indicates an increase in demand to 3.6 BCM in 2000 and 4.3 BCM in 2005/ 2010. These projected numbers in 2000 and 2005 are higher than the projected supply from the local fields. The oblgas company has assumed that 2.1 BCM will be consumed by new CCGT power stations. Given the current financial constrains, a sharp increase of gas consumption is unlikely. As with other oblasts, recovery up to the historical peak by 2005 would be realistic.

Kostanai

Power/heat

38. The gross consumption of power in the oblast was 3.2 billion Kwh of which 0.6 billion Kwh was recorded as a loss. The total power production in the oblast by two power stations was 0.55 billion Kwh in 1996, leaving a deficit of about 2.6 billion Kwh. The bulk of this deficits is supplied from the national grid, while a minor portion was imported from Russia. The Rudny power station accounts for 90% of oblast production of electricity. The existing power stations also deliver heat. Heat is also supplied from two district boiler houses. The consumption of gas in the power sector dropped from 480 MMCM in 1995 to 290 in 1996. The main reasons are aging of the plants (decreased capacity of boilers) and the non-payment of customers.

39. It is not envisaged that the power sector will increase its consumption of gas considerably during the review period, inter alia because imported mazout from Russia is competitive and because aging of the existing other power station does not warrant increased

power generation. The gas consumption in this plant is projected to decrease, from 180 MMCM at present to 150 MMCM in 2000 and onwards. The Rudny power station has a maximum gas consumption capacity of 260 MMCM a year. In the forecast shown in Table 5 below, it is assumed that 50% of the electricity and heat production will be based on mazout due to the competitiveness of Russian mazout supply. If only gas is used at the plant, the consumption will be increased by 150 MMCM. which could be regarded as a maximum projection. As stated above it is not envisaged that any

Industry

40. There are seven large gas consuming industries and mining complex in the oblast which used to consume about 850 MMCM. The consumption has decreased down to 550 MMCM, mainly due to operation problems at a chemical fiber plant, a diesel motor plant and an ore mining and processing complex. Due to non-payment the oblgas company cut off gas supply to a few companies. These plants are not expected to regain their previous production and consumption of gas, while the Kacharskij ore mining and processing plant is expected to start consuming gas (100 MMCM/year) by year 2000. A few of the industries are now being privatized including joint ventures with West European partners. The gas consumption by a few of the existing industries is expected to grow again. The overall gas consumption in the sector could reach previous levels by 2010. The overall forecast is based on the following assumptions: (i) the potential for resumption of the production in the large gas consuming industries is regarded as positive, also because they are being privatized and are getting foreign management; (2) mainly the Kacharskij ore mining and processing plant will consume gas at a rate of 100 MMCM/year by 2000; and (3) the supply cost of gas will be reduced due to the future supply from near-by fields as compared to that of the current imported gas.

Communal/municipal

41. The number of apartments consuming gas increased by 25% from 1990 to 1994 reaching 122 000. But the total consumption has been constant. Non-payment by the households and institutions is the main reason for the stagnation. The number of apartments supplied with gas is expected to increase by 1000 per year, inter alia when the pipeline from Rudnij to Kostanai has been completed. Despite this, the gas consumption in the sector is not expected to increase, mainly due to the introduction of meters and higher prices in line with the current pricing reform, both of which will promote energy saving.

Others

42. The number of rural areas supplied with gas has been constant throughout the 1990's as has been the consumption. No increase in consumption is envisaged.

Overall Demand

43. The projected base demand of gas in Kostanai is shown in Table 5.

Table 5. Kostanai. Gas Demand Projection for 2000, 2005 and 2010

SECTOR	1995	1996	2000	2005	2010
Total	1 434	1 240	1 340	1 470	1 590
Power	480	290	310	310	350
Ind.	554	550	630	760	840
Com/mun	300	300	300	300	300
Others	100	100	100	100	100

44. The forecast made by the oblgas company projects an increase in demand from the current 1.2 BCM to 2 BCM in year 2000 and as much as 3.1 BCM in 2010. The past peak demand was 1.5 BCM in 1991. The forecast by the Oblgas company seems very optimistic. The recovery of the historic peak by about 2005 is more realistic.

West-Kazakhstan

Power/Heat

45. The gross consumption of electricity in the oblast was in 1996 1 billion Kwh of which 0.25 billion Kwh was recorded as a loss. In total about 0.1 billion Kwh and 1 million Gcal of heating were produced by the Uralsk HEPC station in 1995/96, both of which are about 70% of its peak level experienced in 1991. The power deficit of 0.9 billion Kwh was covered by imports from Russia (0.6 billion Kwh) and through the national grid for the rest. The Uralsk power station consumed about 250 MMCM of gas in 1995/96 and a marginal amount of mazout. The power station predicted at the interview that the future electricity production will remain at the 1993/95 level, e.g. 0.13-0.15 billion Kwh annually.

46. The future demand for electricity is linked with the overall development of the areas close to the Karachaganak field. Due to the huge volumes of gas and very low supply costs of this field, the potential for industrial growth could be considered very positive since no plans or indications of future industrial establishments have been given.

47. Due to this uncertainty, alternative future gas consumption levels are indicated below. The power company has indicated at the interview that it contemplates to install another gas turbine and rehabilitate the boilers due to the worn-out condition of existing plant. Such upgrading with more substantial increase in gas consumption is only assumed to happen after 2000. Till then only a marginal increase in line with the recovery of the economy is expected to take place. Thereafter the consumption is projected to increase by 100 MMCM per five-year period as a result of fuel switch-over and the expected power growth. A maximum forecast,

which would require the installation of CCGT plants after 2000, depicts an additional consumption of 150 MMCM more in 2000 and 200 MMCM more in 2005 and 2010.

Industry

48. The industries in the oblast include three medium-sized gas consuming units which in total consumed about 75 MMCM of gas in 1995/96. The industry interviewed ("Zenith") has only marginally reduced its gas consumption during the 1990's. These industries are only expected to increase their gas demand in line with the general recovery of the economy during the period. The oblgas company projects increase in industry demand to as much as 310 MMCM in 1997 and 1.6 BCM in 2010. But this seems too optimistic, given the expected slow growth of economy.

Communal/municipal

49. The number of apartments supplied with gas during the 1990's has trebled and gas consumption by the sector is increasing. Since the development of this gas rich oblast is expected to continue, the gas consumption has been projected to increase in line with the past trend as forecast by the oblgas company (see Table 6).

Others

50. So far there has been no consumption of gas in the rural areas of the oblast. However, new rural areas close to the Karachaganak field are developed and planned to be supplied with gas. As seen from Table 6, a substantial increase in gas consumption is expected in these areas in line with the planned development of rural areas.

Overall Demand

51. The projected base demand of gas in West-Kazakhstan is shown in Table 6.

Table 6. West-Kazakhstan. Gas Demand Projection for 2000, 2005 and 2010

SECTOR	*1995*	*1996*	*2000*	*2005*	*2010*
Total	394	444	550	830	1 030
Power	253	270	300	400	500
Ind.	71	74	90	100	100
Com/mun	70	100	100	150	200
Others	0	0	60	180	230

52. The overall gas consumption of the oblast has been fairly stable at around 400 MMCM since 1991. The oblgas company, however, predicts a sharp increase in future demand, to 730 MMCM in 2000 and nearly 2 BCM in 2010, the realization of which largely depends on increased industrial consumption.

Atyrau

Power

53. The gross consumption of gas in the oblast was in 1996 1.3 billion Kwh of which 0.25 billion Kwh was recorded as a loss. The total production in the oblast was 1.1 billion Kwh plus heat (mainly by one power station). The power production has been stable since 1991. The deficit is covered by imports from Mangystau and Russia. The Atyrau Power Plant has increased its consumption of gas since 1991, consuming 400 MMCM in 1996, reducing considerably the consumption of oil and mazout. It is expected that the oil and gas rich oblast (Tengiz field) will increase power generation on gas firing during the review period. The power station has predicted that the current 1.1 billion Kwh of generation will be remain up to 2000. After that, it will install new plant with a capacity of 800m Kwh/year by 2005 and 1 billion Kwh/year by 2010.

54. The total electricity generation, however, will grow slower since the capacity of the existing plant is envisaged to drop to 0.8 billion Kwh in 2000 and 0.5 billion Kwh in 2010. The overall power generation capacity in the oblast will therefore be as follows: 1.1 billion Kwh in 2000; 1.7 billion Kwh in 2005; and 1.5 billion Kwh in 2010. Since the industrial base in the oblast is very weak despite oil and gas production in Tengiz. Surplus electricity will be exported to other oblasts. However, the gas supply potential of Tengiz is huge (3-5 BCM/year after 2000) and there is a potential for new industrial development which also would demand more electricity. In addition to the power plant there are three district boilers in the oblast which together consumed 180 MMCM in 1996, a drop of about 80 MMCM from the previous year.

55. Due to the uncertainty of the installation of a new plant, minimum and maximum consumption figures by the plant are expected 340 to 630 MMCM in 2005 and 180 to 630 MMCM in 2010. The maximum forecasts plus the expected growth in gas consumption by the boiler houses are used in Table 7 below.

Industry

56. There are very few industries in the oblast apart from the oil refinery with its own power station which consumes own gas. This consumption is not included in the forecast below. Apart from that, there is one military industry and one company producing construction material which consumed together about 30 MMCM in 1995. This consumption is assumed to be constant over the review period since there are no indications in the market survey of increased industrial production. As mentioned above, a large supply potential and the expected low supply costs give a comparative advantage for new industrial establishments. However, since there are no plans for such, it has not been reflected in the projected gas demand figures.

Communal/municipal

57. The number of apartments connected to gas has increased from about 20 000 in 1991 to 37 0000 in 1994 (of which 15 000 was included in Mangystau due to change of the border between the two oblasts in 1993). The current consumption is about 100 MMCM.

58. In tandem with the development of the Tengiz field, the oblgas company has planned to connect new apartments and a few small industries on the "right shore" of the river Ural. The cost of this is estimated at 119 million Tenge, and a contract is currently negotiated to undertake the installation. This is expected to increase consumption by 50% to 150 MMCM in year 2000.

Others

59. The number rural areas connected with gas has been stable since 1990 and is not expected to increase during the period. Thus the consumption of the sector is kept constant.

Table 7. Atyrau . Gas Demand Projection for 2000, 2005 and 2010

SECTOR	1995	1996	2000	2005	2010
Total	875	810	1 010	1 240	1 240
Power	646	588	730	960	960
Ind.	29	22	30	30	30
Com/mun	100	100	150	150	150
Others	100	100	100	100	100

60. The oblgas company has not made any forecast of increased consumption apart from that mentioned under the paragraph 58 above. It points out, however, that the financial situation of people and industries needs to be improved to increase gas sales.

Mangystau

Power

61. The gross consumption of electricity in the oblast was 5.2 billion Kwh in 1996 of which as much as 2 billion were recorded as a loss. The power generation by a huge complex in Aktau (which includes one nuclear power station, a desalination plant and a uranium enrichment plant) was 3.5 billion Kwh in 1996. Thus there is a power deficit of 1.7 billion Kwh. The power stations have reduced their consumption of gas from 1.6 BCM in 1992 to 1.3 BCM today. It is not expected that consumption of gas by the complex will increase during the review period due to structural problems of the complex. (Recently the uranium enrichment plant has stopped its operation.) In this connection it should be mentioned that the information on the prospect of the

complex is uncertain and difficult to obtain due to its military secrecy. In the forecast therefore increased consumption is only expected to come from four boiler houses after year 2000 as a result of the recovery of the economy. Gas will be supplied from the Uzen field. The potential demand of gas in the order of 400 MMCM annually if the current power deficit is substituted by gas fired plants. Such an amount of gas could be supplied from local fields in the oblast which have a combined supply potential of 800 MMCM in 2000.

Industry

62. Apart from the above complex, there are few gas consuming industries in the oblast, e.g. a plastic materials factory and the Prikaspijskij uranium ore mine. Together they consumed 120 MMCM in 1995/96, and their consumption is only expected to increase marginally in line with the general recovery of the economy (see Table 8).

Municipal/communal

63. About 15 000 apartments are currently connected with gas and the consumption is about 25 MMCM. It is planned to supply gas to new areas in the South of the oblast based on a number of small fields. Consequently a doubling of the gas demand is projected for year 2000, with another doubling of this by year 2005.

Others

64. There is no supply of rural areas in the oblast, and no new ones are expected to be connected.

Akmola

Power

65. The gross consumption of power in the oblast is 3 billion Kwh of which 950m Kwh are recorded as a loss. The total production of the oblast by two power stations is 2 billion Kwh (1.5 billion Kwh by HEPC1 and 0.5 billion Kwh by HEPC2), leaving a deficit of 1 billion Kwh which is supplied from the Eikabustuz coal fired plants. In addition there is a district boiler house. If gas is supplied to Akmola it could in the first instance be used to substitute the coal fired plants by gas. That has been assumed in the projection of potential demand of 400 MMCM in 2000 and 675 MMCM in 2010.

66. Today Akmola is mainly agricultural land with few industries. There is one agricultural machine building/assembly plant which has an agreement with the international corporation John Deer. But Akmola is selected as the new national capital of Kazakhstan which definitely will bring a lot of activity to the city. The construction of the new capital has started and a few government offices are moving from Almaty during 1997. But the scope and extent of future activities as a capital have not been established, and apparently there is little allocation for its development in the government budget. Thus no projection for industry, municipal and

communal has been made. Our preliminary calculations suggest that the demand in Akmola exceed about 5 BCM/Y for a new gas trunk pipeline to be considered.

Kokshetau

Power

67. The gross consumption of electricity in the oblast is 1.8 billion Kwh of which 0.3 Kwh are recorded as a loss. There is no production of electricity in the oblast, and the power is taken from the national grid. The oblast has no district boiler house but several small ones in different locations. In the assessment of potential demand it is assumed that Kokshetau will not have any power station during period since it so well placed in relation to nearby coal fired stations. Rather it is assumed that one district boiler house will be established with a consumption of 120 MMCM/year.

Industry/communal/municipal

68. Kokshetau is primarily an agricultural oblast, and any future gas consuming industry will be agro-based. In the projection it is assumed that a few large agro-processing industries in the city of Kokshetau can potentially be supplied with gas in the order of 130 MMCM from year 2005. It is also assumed that 50 MMCM of gas can be supplied to households and institutions from year 2010. But these projections are very speculative.

69. Gas in Kokshetau is in the same competitive position as Akmola, and clearly it is not viable to supply gas to the oblast (see the paragraph 65).

Kzyl-Orda

Power

70. The gross consumption of electricity in the oblast was in 1996 0.585 billion Kwh of which 200 million Kwh were recorded as loss. The production by the HEPC-6 was only 0.12 billion Kwh. The plant does not use gas. In addition the Kumkol field has a gas turbine plant for its own use. The national electricity trunk line is passing next to the field.

71. Due to availability of gas and its good location in relation to the national grid trunk line (220 KV), there is a plan to construct a Combine Cycle Gas Turbine Plant next to the field and to convert the fuel for the HEPC-6 to gas. The HEPC-6 and the new plant will consume about 150 MMCM/year each. In addition it is envisaged that two more gas plants will be established by year 2005 and additional two more by 2010. Based on this the total consumption of gas in power will be 300 MMCM in year 2000, 600 MMCM in 2005 and 900 MMCM in 2010. The electricity will cover the current power deficit in the oblast and go by the national grid to the South.

72. The principal issues in the oblast is declining industries and prevailing non-payment. Since all the oil and gas fields in Kumkol have been shifted to private sector owners, unless a financially viable scheme is drawn, the above plans may not be materialized. The current power deficit, in particular, the deficit in the city of Kzyl-Orda is primarily due to non-payment.

Industry/communal/municipal

73. There are no industry in the oblast that would consume gas, and it is not envisaged that gas will be supplied to households.

Appendix 3.4

Supply-Demand Integration

1. The projected national, regional and sectoral demand for gas can be met by existing or planned supply from local fields or import. In general there is more than enough gas available to meet domestic demand. Using the existing gas transmission network, several oblasts can be supplied from different sources (technically from most existing gas producing fields and from import).

2. A preliminary picture of gas supply-demand integration is summarized below for three gasified regions, e.g. Southern Kazakhstan, Aktubinsk and Kustanai, and Western Kazakhstan and one potential gas market in the near future, e.g. Kizil-Orda. Since all demand projections have been based on supply costs well below the market values of gas, the assessment of this integration attempts to determine the available gas sources and their competitiveness.

Southern Region

3. This region consists of Almaty, Zhambyl and South-Kazakhstan. The possible gas supply sources to this region in the near future are:

- Imported gas from Turkmenistan/Uzbekistan (Possibly up to 4.2 BCM/Y based on the present pipeline capacity); and
- Domestic gas possibly from the Amangueldy field and other fields in Zhambyl oblast (Expected max. 3 BCM/Y).

As the total gas demand in the region is estimated at about 3.9 BCM in year 2010, there is an enough supply volume provided that Kazakhstan can reach a long-term supply agreement with the above gas exporters and that the payment issue has been solved. Transportation of Karachganak gas through the proposed Chelkar-Symkent pipeline may not be economic.

4. The region has been receiving gas since the Gazli-Symkent-Zhambyl-Almaty pipeline was constructed since 1960s. In 1992 5.3 BCM of gas was imported through the pipeline to the region while it in 1996 was only 2.8 BCM (3.6 in 1995). Gas supply to Almaty decreased due to deteriorated physical conditions of the transmission pipeline. Non-payment to the suppliers abroad aggravated the supply situation. Because of this non-payment issue, Alaugaz cannot afford filling up the underground reservoir during the summer and thereby limiting the winter supply.

5. At present, the supply capacities of the major sections of the transmission pipeline from Gazli to Almaty are estimated as follows:

Gazli - Shimkent: 4.2 BCM/year[1]
Shimkent - Jambil: 4.2 BCM/year
Jambil-Bishek: 4.2 BCM/year
Bishek-Almaty: 0.9 BCM/year

6. The transmission line is being rehabilitated. When the remaining section of 60 km of the second line near Almaty has been completed, the supply capacity to Almaty would be increased by 3 BCM. Thus there will be no technical restriction on the supply capacity to meet the overall projected demand of nearly 4 BCM by year 2005.

7. It is proposed to develop the Amangeldy field including a pipeline of 130 km to Zhambyl for supply to the Southern Region. The field is estimated to produce about max. 3 BCM/year for 20 years. As presented in *Appendix 3.8*, "Gas Supply Economics", the supply cost of this gas to Symkent is expected less than US$ 30 per 1000 CM which is highly competitive with the imported gas. It seems therefore viable to maximize the supply from the Amangeldy field and import the balance which would be about 1 BCM by 2010. Since sufficient gas supply is feasible to the markets in the region, prioritization of gas delivery may not be an issue. However, a more precise assessment is required, taking into account seasonal and daily variations of gas demand.

Table 1: Regional Supply-Demand Balance (Southern Region)

(Unit: million CM)

		2000	***2005***	***2010***
Regional Demand		3,545	3,750	3,910
Possible Supply Sources	*Approximate Supply Cost to Almaty (US$/1000 CM)*			
Imported Gas from Turkmenistan/Uzbekistan	42.4 to 57.4[2]	4,200	4,200	4,200
Amangueldy and other fields in Jambil oblasts	35.6	-	1,000	3,000
Total Supply Potential		4,200	5,200	7,200
Balance (Surplus)		*655*	*1,450*	*3,290*

Note: The market value of gas for power generation in Almaty is about US$ 80 per 1000 even based on the regulated coal price of $4 per ton. Thus, the above gas supply costs could be economic.

[1] These numbers have not fully taken account of seasonal and daily variation of gas demand. If the variation is high, some districts may face with gas supply constraints.

[2] Based on $35 to $50 per 1000 CM at the national border

Aktyubinsk and Kustanai

8. These two oblasts are currently supplied with imported gas from the Bukhara-Uralsk pipeline mainly from Turkmenistan but to a lesser extent from Russia. The following gas supply sources are conceivable for these oblasts:

- Turkmenistan (current supplier, max. up to 3 BCM/Y is feasible after rehabilitation of the Bukhara-Uralsk line);
- Russia (current supplier, max. up to 3 BCM/Y is feasible after rehabilitation of the Bukhara-Ural line)[3];
- The Zhanazol field (max. 2 BCM/Y is feasible);
- The Uritau field (max. 2 BCM/Y is feasible); and
- The Karachganak field. (5 BCM/Y or more is feasible).

9. According to the agreement with Turkmenistan of 1993/94 the pipeline was to receive 4 BCM annually for the two oblasts. In addition gas is imported from Russia. In recent years only about 2.4 BCM has been consumed by the oblasts annually. The peak consumption was in 1992 with 2.6 BCM. The consumption is projected to increase to 3 BCM in 2000 and 3.4 BCM by 2010. The capacity of the trunk line is 13 BCM/year, of which 10 BCM/year are reserved for transit. Thus, about 0.4 BCM of the transit capacity will have to be allocated by 2010 for the projected demand if all should be met by import.

10. There are however two gas fields in Aktyubinsk, the Zhanazol and Urihtau fields, of which the first one is flaring 0.6 BCM of gas annually. The fields are planned to increase production to 1.5 BCM in 2000 and 4 BCM in year 2010. Preliminary estimates of supply costs to Aktyubinsk city from Zhanazol are US$ 10.5 per 1000 CM and from Urihtau US$ 22.9 in the case the design capacity of the pipeline to Aktyubinsk is 2 BCM/Y. The Urihtau field also is almost ready for production. These fields can meet half the demand by 2000 and the whole demand in 2010.

11. There is also an option to utilize the gas from Karachaganak in Aktyubinsk and Kustanai. The supply costs to Aktyubinsk are estimated at US$ 27.9/1000 CM based on a pipeline design capacity of 5 BCM/Y.

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[3] Since there is only one pipeline, both Turkmenistan and Russia cannot supply 3 BCM/Y of gas at the same time. More or less, it should be considered maximum 3 BCM/Y.

Table 2: Regional Supply-Demand Balance (Aktyubinsk and Kustanai)

(Unit: million CM)

		2000	*2005*	*2010*
Regional Demand		2,980	3,240	3,360
Possible Supply Sources	*Approximate Supply Cost (US$/1000 CM)*			
Turkmenistan or Russia	35 - 50[4]	3,000	3,000	3,000
Zhanazol	10.5	2,000	2,000	2,000
Uritau	22.9	0	2,000	2,000
Karachaganak	27.9	0	5,000	5,000
Total Supply Potential		5,000	14,000	14,000
Balance (Surplus)		*2,020*	*10,760*	*10,640*

Note: The market value of gas for power generation is close to US$ 80 per 1000 CM.

Western Region

12. This region consists of the oblasts of West-Kazakhstan, Atyrau and Mangystau. The demand of these oblasts is projected to increase from a current 2.7 BCM annually to 4 BCM in year 2010. This demand can easily be met by the supply from several local fields (Karachaganak, Uzen, Tengis and others). The supply costs of gas from these sources would range between US$ 10 and US$ 20 per 1000 CM which are well below import costs through the CAC pipeline running through the oblasts. Thus all the gas should be delivered from local sources.

Table 3: Regional Supply-Demand Balance (West-Kazakhstan Region)

(Unit: million CM)

		2000	*2005*	*2010*
Regional Demand		3,030	3,820	4,130
Possible Supply Sources	*Approximate Supply Cost (US$/1000 CM)*			
Karachganak	27.9[5]	5,000	5,000	5,000
Other fields	Not evaluated.	5,600[6]	9,000	9,600
Total Supply Potential		10,600	14,000	14,600
Balance (Surplus)		*7,570*	*10,180*	*10,470*

Note: The market value of gas for power generation is expected to be above US$ 80 per 1000 CM.

Kzyl-Orda

13. All the projected demand in this oblast will be supplied from the Kumkol field located in the oblast.

[4] These are gas import costs at the national border.
[5] Tentatively assumed same as with the cost to Aktubinsk.
[6] These figures are based on the predicted gas production in the three oblasts minus Karachganak production given in Table 2.4 of the main report.

Table 4: Regional Supply-Demand Balance (Kzyl-Orda)

(Unit: million CM)

		2000	*2005*	*2010*
Regional Demand		300	600	900
Possible Supply Sources	*Approximate Supply Cost (US$/1000 CM)*			
Kumkol and others	35[7]	800	800	800
Total Supply Potential		800	800	800
Balance (Surplus)		*500*	*200*	*100*

Note: The market value of gas for power generation is expected to be above US$ 80 per 1000 CM. As stated in Appendix 3.3, gas for new power generation other than oil field use may not be promising due to the prevailing non-payment issue in the oblast. If there is surplus gas, reinjection into the oil reservoirs would be made.

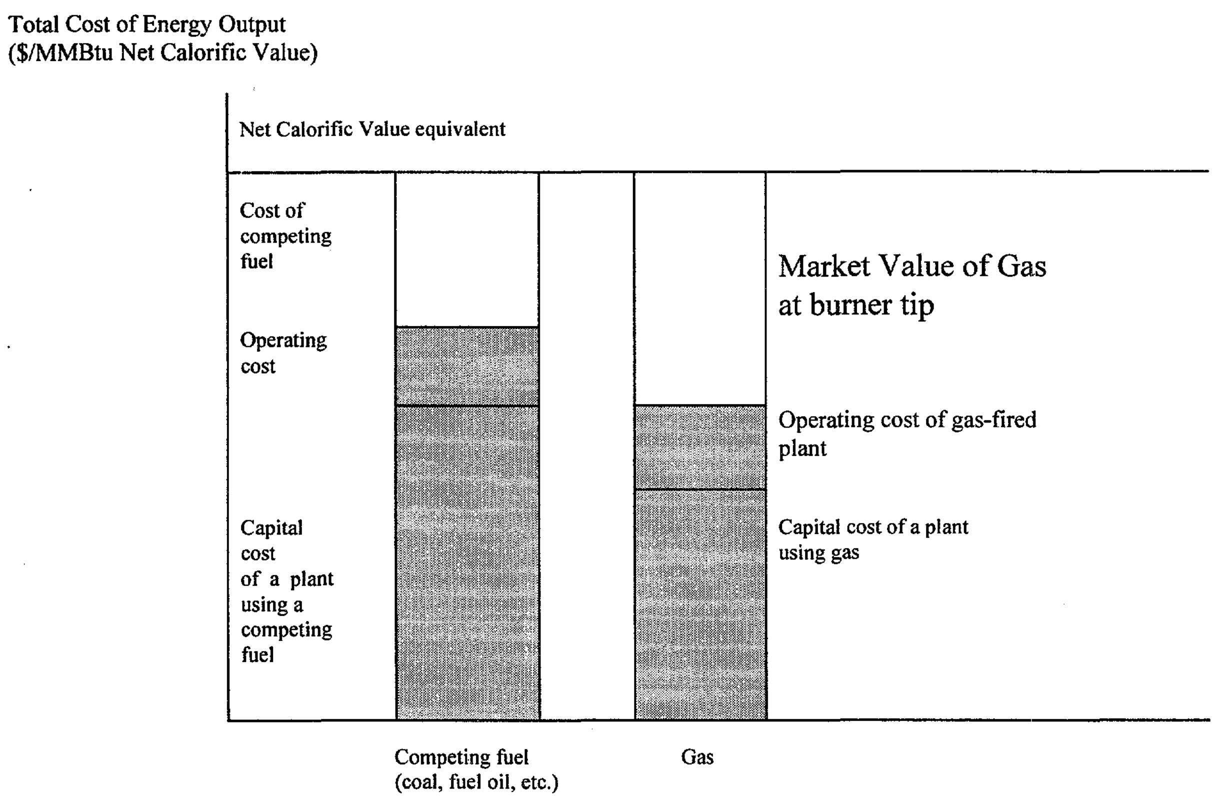
[7] Based on Table 3 of Appendix 2.5.

Appendix 3.5

Market Values of Natural Gas

1. The market value of gas is a key indicator of the economic viability of a gas project. It is defined as the maximum a gas supplier could charge a consumer and still remain competitive with other fuels. The market value is an upper limit on the price of gas. The principles of the calculation are illustrated as below:

Figure 1: Principles of Netback or Market Value of Gas Calculation



2. *Market Value of Gas for Power:* In the case of Kazakhstan, the cheapest fuel for power generation is coal mainly produced from the Ekibastuz open pit coal mine in the north-eastern region of Kazakhstan. Thus, the value of gas in power generation is, in general, obtained by comparing gas use in a Combined Cycle Gas Turbine (CCGT) plant with coal use in a conventional pulverized fuel steam turbine plant. According to information from the State Anti-monopoly Committee, the current mine-mouth regulated cost of Ekibastuz coal which has a

calorific value of 4,120 Kcal/Kg, is about 280 Tenge per ton (about US$ 4.18 per ton). The same information source released that the coal transport cost is about 137.1 Tenge (or US$ 2.05) per 1 ton of coal over 1000 Km transportation. A sample gas market value calculation was made based on a 600 MW power station in Almaty which is 1,500 Km away (transport distance) from the Ekibastuz coal mine. In this case the coal transport cost is calculated about US$ 3.07 per ton of coal. Using the following major assumptions for a conventional coal-fired power station and a CCGT power station, the gas market value in Almaty is calculated US$ 2.27 per MMBTU (or about US$ 80 per 1,000 CM). According to this calculation therefore, it should be possible to charge as much as US$ 80/1000 CM for gas in Almaty and still be competitive with a coal fired power plant. Since Ekibastuz coal has an ash content of about 30%, the costs of washing it should be added. Then the market value of gas would be even higher.

Table 1 Major Assumptions for the Sample Calculation of

Gas Market Value for Power

	Coal Plant	*CCGT Plant*
Rated Capacity	600 MW	600 MW
Thermal Efficiency	34 %	45 %
Load Factor	76 %	76 %
Unit Installation Cost	US$ 1,300 per KW Including FGD and 15% contingency	US$ 690 per KW Including 15% contingency
Operating Cost (per year)	2.5% of the Capex	4% of the Capex
Cost of Coal	US$ 0.44/MMBTU ($7.25/ton=$4.18 + $3.07)	To be calculated
Plant Construction Period	5 years	3 years

3. In the southern Kazakhstan, inexpensive imported hydro-power from Kyrgyzstan is potentially available. According to EC Energy Center, the cost of this hydro-power could be as low as US cent 4 per Kwh. For a CCGT with the same conditions listed above, it is calculated that the gas price to achieve a power generation cost of US cent 4 per Kwh is US$ 2.16/MMBTU (or US$ 76 per 1,000 CM). If the supply cost of the Kyrgyz hydro-power is less than US cent 4 per Kwh, the market value of natural gas in the southern region is lower than US$ 76/1000 CM.

4. These costs for coal and rail transport are very low by intrnational standards. A typical on-boad cost of coal with a heting value of 4,500 - 5,000 Kcal/Kg would be about $40/ton (or $2.2 per MMBTU) and a typical rail cost would be US$0.02 to 0.05 per ton per kilometer (equal to $30 to $75 per ton of coal or $1.65 to $4.1 per MMBTU over from Ekibustuz to Almaty over 1,500 Km). If the unregulated costs in Kazakhstan were to approach these levels, it would markedly change the gas potential.

5. *Market Value of Gas for General Industry:* The market value of gas in Kazak industry is, in general, set by the competing mazout (fuel oil). Costs of equipment are generally

similar (with the exceptions discussed below), and in this analysis they are assumed to be identical. Gas is therefore valued at thermal parity with Mazout, plus a premium arising from:

- Higher efficiency;
- Reduced emission control costs ("environmental premium");
- Reduced storage and working capital costs;
- Greater value in end-use (e.g. due to more favorable temperature characteristics).

The premium can be close to zero in some applications, especially steam raising, but is higher in some process heat applications. The premium is very specific to the individual application and can vary substantially even on the same industrial site.

6. In general, customers buying interruptible gas can readily switch fuels and therefore have gas values very close to fuel oil parity, with little or zero premium. This is also the case for feedstock users. Prices for interruptible gas and feedstock users, therefore, tend to be very close to fuel oil parity under market value pricing principles. Customers buying firm gas tend to have larger premiums for using gas, and pay higher prices. Some industrial users have gas oil as the competing fuel. These are mainly small consumers. Although they are quite numerous collectively, they account for only a small proportion of industrial demand .

7. According to the Anti-monopoly Committee, the current Mazout price at the Symkent refinery gate is 4,048 Tenge per ton (or US$ 60.42/ton). The current transport cost for Mazout is e.g. 412.5 Tenge (or US$ 6.16) per 1 ton over 1,000 Km. In the case of Almaty which is 600 Km away from Symkent, the supply cost of Mazout is calculated US$ 64.11 per ton (e.g. US$ 60.42 + US$ 3.69). Assuming the calorific value of Mazout as 9,000 Kcal/Kg, the thermal parity of natural gas is US$ 1.79 per MMBTU (or US$ 63 per 1,000 CM) without consideration of any premium.

8. *Market Value for Nitrogen Fertilizer:* Currently, there is no nitrogen fertilizer plant in Kazakhstan. In 1991, Kazakhstan consumed about 200,000 tons of nitrogen fertilizer (mainly Urea) which was imported from Russia and Uzbekistan. Given rich gas reserves and relatively low consumption of nitrogen fertilizer per hectare of cultivated land[1], it is conceivable to start the production of urea at around 1000 tons per day or 330,000 per year. The market value of gas for urea production could be estimated in comparison with the imported urea cost. In this regard, the following assumptions are used:

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1 Around 6 Kg in Nitrogen nutrient. (Source: EC TACIS Report, "Oil Refining, Gas Processing and Petrochemicals in Kazakhstan", June 1994).

Table 2 Major Assumptions for the Sample Calculation of

Gas Market Value for Nitrogen Fertilizer

Item	*Assumptions*
Rated Capacity	Ammonia 600 T/D, Urea 1000 T/D
Operation Factor	330 days per year
Plant Capital Investment Cost	US$ 250 million
Operating Cost (per year)	5% of the Capex
CIF Price of Imported Urea	US$ 200 per ton
Plant Construction Period	3 years
Discount Rate Used	15%

A preliminary calculation based on the above assumptions indicates approximately US$ 41 per 1000 CM (or US$ 1.16/MMBTU) for the market value of gas for nitrogen fertilizer.

9. *Market Value of Gas for Commercial/Residential Sector:* For residential and commercial users taking gas from the existing city distribution network, LPG is the competing fuel in Kazakhstan. Gas may be a premium over other fuels, especially in the residential sector, due to its greater convenience of use (no storage required, no labor to hand carry LPG cylinders, etc.). However, this is difficult to quantify. As with the gas value for industry, the cost of equipment for LPG fuel and that for gas use could be similar. Using a recent average LPG price of $200 per ton[2] and assuming a calorific value of 11,500 Kcal/Kg for LPG, the market value of gas in commercial/residential sector is calculated US$ 4.79 per MMBTU (or US$ 169 per 1,000 CM).

10. The current selling price of gas ranges between 2000 and 3000 Tenge (USD 30-43) per 1000 CM. Thus, apart from for fertilizer production in the South (where the selling price of gas is highest), the price of gas that can be charged and still be competitive with other fuels/import, is much higher than what is currently charged. Thus, there is a very good market potential for gas in Kazakhstan, in particular in the commercial/residential sector, in power generation and industry. Whether such market potential can be realized depends both on the availability of gas supply and its supply costs.

[2] LPG prices fall within a range of $134 and $290 per ton.

		GAS VALUE IN POWER								
			(Almaty)							
600 MW Coal Plant						600MW C.C. PLANT				
(including FGD and 15% contingency)						(including 15% contingency)				
Efficiency	34%					Efficiency	45%			
Rated Capacity	600 MW					Rated Capacity	600 MW			
Load Factor	76%					Load Factor	76%			
Unit inv. cost	$1300/kw					Unit inv.cost	$690/kw			
Ope. cost	2.5% of inv. cost					Ope. cost	4% of inv. cost			
Cost of Coal	$0.444/MMBTU ($7.25/Ton)					Plant inst. period	3 years			
Plant inst. period	5 years									
Year	Capex	Coal Consump.	Coal Cost	Opex	Capex + Opex	Capex	Opex	Capex + Opex	Gas Consump	Gas Consump
	(mm US$)	(10^6 MMBTU)	(mm US$)	(mm US$)	(mm US$)	(mm US$)	(mm US$)	(mm US$)	(10^6 m3)	(10^6 MMBTU)
1	78	0	0	0	78	124.2	0	124.2	0	0
2	156	0	0	0	156	186.3	0	186.3	0	0
3	234	0	0	0	234	103.5	0	103.5	0	0
4	234	40.07	17.79	19.5	271.2911	0	16.56	16.56	841	30.3
5	78	40.07	17.79	19.5	115.2911	0	16.56	16.56	841	30.3
6	0	40.07	17.79	19.5	37.29108	0	16.56	16.56	841	30.3
7	0	40.07	17.79	19.5	37.29108	0	16.56	16.56	841	30.3
8	0	40.07	17.79	19.5	37.29108	0	16.56	16.56	841	30.3
9	0	40.07	17.79	19.5	37.29108	0	16.56	16.56	841	30.3
10	0	40.07	17.79	19.5	37.29108	0	16.56	16.56	841	30.3
11	0	40.07	17.79	19.5	37.29108	0	16.56	16.56	841	30.3
12	0	40.07	17.79	19.5	37.29108	0	16.56	16.56	841	30.3
13	0	40.07	17.79	19.5	37.29108	0	16.56	16.56	841	30.3
14	0	40.07	17.79	19.5	37.29108	0	16.56	16.56	841	30.3
15	0	40.07	17.79	19.5	37.29108	0	16.56	16.56	841	30.3
16	0	40.07	17.79	19.5	37.29108	0	16.56	16.56	841	30.3
17	0	40.07	17.79	19.5	37.29108	0	16.56	16.56	841	30.3
18	0	40.07	17.79	19.5	37.29108	0	16.56	16.56	841	30.3
19	0	40.07	17.79	19.5	37.29108	0	16.56	16.56	841	30.3
20	0	40.07	17.79	19.5	37.29108	0	16.56	16.56	841	30.3
21	0	40.07	17.79	19.5	37.29108	0	16.56	16.56	841	30.3
22	0	40.07	17.79	19.5	37.29108	0	16.56	16.56	841	30.3
Total	780	761.33	338.0305	370.5	1488.531	414	314.64	728.64	15979	575.7
NPV@15%	$ 512.21	$163.30	$72.51	$79.47	$664.19	$316.92	$67.49	$384.41	$3,427.4	$123.49
						Gas netback value=		$ 2.27	per MMBTU	

		GAS VALUE IN POWER								
		(Akmola)								
600 MW Coal Plant						600MW C.C. PLANT				
(including FGD and 15% contingency)						(including 15% contingency)				
Efficiency	34%					Efficiency	45%			
Rated Capacity	600 MW					Rated Capacity	600 MW			
Load Factor	76%					Load Factor	76%			
Unit Inv. cost	$1300/kw					Unit Inv.cost	$690/kw			
Ope. cost	2.5% of Inv. cost					Ope. cost	4% of Inv. cost			
Cost of Coal	$0.245/MMBTU ($4/Ton)					Plant inst. period	3 years			
Plant inst. period	5 years									
Year	Capex	Coal Consump.	Coal Cost	Opex	Capex + Opex	Capex	Opex	Capex + Opex	Gas Consump	Gas Consump
	(mm US$)	(10^6 MMBTU)	(mm US$)	(mm US$)	(mm US$)	(mm US$)	(mm US$)	(mm US$)	(10^6 m3)	(10^6 MMBTU)
1	78	0	0	0	78	124.2	0	124.2	0	0
2	156	0	0	0	156	186.3	0	186.3	0	0
3	234	0	0	0	234	103.5	0	103.5	0	0
4	234	40.07	9.82	19.5	263.3172	0	16.56	16.56	841	30.3
5	78	40.07	9.82	19.5	107.3172	0	16.56	16.56	841	30.3
6	0	40.07	9.82	19.5	29.31715	0	16.56	16.56	841	30.3
7	0	40.07	9.82	19.5	29.31715	0	16.56	16.56	841	30.3
8	0	40.07	9.82	19.5	29.31715	0	16.56	16.56	841	30.3
9	0	40.07	9.82	19.5	29.31715	0	16.56	16.56	841	30.3
10	0	40.07	9.82	19.5	29.31715	0	16.56	16.56	841	30.3
11	0	40.07	9.82	19.5	29.31715	0	16.56	16.56	841	30.3
12	0	40.07	9.82	19.5	29.31715	0	16.56	16.56	841	30.3
13	0	40.07	9.82	19.5	29.31715	0	16.56	16.56	841	30.3
14	0	40.07	9.82	19.5	29.31715	0	16.56	16.56	841	30.3
15	0	40.07	9.82	19.5	29.31715	0	16.56	16.56	841	30.3
16	0	40.07	9.82	19.5	29.31715	0	16.56	16.56	841	30.3
17	0	40.07	9.82	19.5	29.31715	0	16.56	16.56	841	30.3
18	0	40.07	9.82	19.5	29.31715	0	16.56	16.56	841	30.3
19	0	40.07	9.82	19.5	29.31715	0	16.56	16.56	841	30.3
20	0	40.07	9.82	19.5	29.31715	0	16.56	16.56	841	30.3
21	0	40.07	9.82	19.5	29.31715	0	16.56	16.56	841	30.3
22	0	40.07	9.82	19.5	29.31715	0	16.56	16.56	841	30.3
Total	780	761.33	186.5259	370.5	1337.026	414	314.64	728.64	15979	575.7
NPV@15%	$ 512.21	$163.30	$40.01	$79.47	$631.69	$316.92	$67.49	$384.41	$3,427.4	$123.49
						Gas netback value=		$ 2.00	per MMBTU	

600MW C.C. PLANT
(including 15% contingency)

Efficiency	45%		
Rated Capacity	600 MW		
Load Factor	76%		
Unit inv.cost	$690/kw		
Ope. cost	4% of Inv. cost	Gas Cost	=
Plant inst. period	3 years	2.16	US$/MMBTU

Year	Capex	Opex	Capex + Opex	Gas Consump	Gas Consump	Fuel Cost	Total Cost	Power Gene.	Revenue @4c/Kwh	Cash Flow
	(mm US$)	(mm US$)	(mm US$)	(10^6 m3)	(10^6 MMBTU)	(mm US$)	(mm US$)	(mm Kwh)	(mm US$)	(mm US$)
1	124.2	0	124.2	0	0	0	124.2	0	0	-124.2
2	186.3	0	186.3	0	0	0	186.3	0	0	-186.3
3	103.5	0	103.5	0	0	0	103.5	0	0	-103.5
4	0	16.56	16.56	841	30.3	65.448	82.008	3994.56	159.78	77.7744
5	0	16.56	16.56	841	30.3	65.448	82.008	3994.56	159.78	77.7744
6	0	16.56	16.56	841	30.3	65.448	82.008	3994.56	159.78	77.7744
7	0	16.56	16.56	841	30.3	65.448	82.008	3994.56	159.78	77.7744
8	0	16.56	16.56	841	30.3	65.448	82.008	3994.56	159.78	77.7744
9	0	16.56	16.56	841	30.3	65.448	82.008	3994.56	159.78	77.7744
10	0	16.56	16.56	841	30.3	65.448	82.008	3994.56	159.78	77.7744
11	0	16.56	16.56	841	30.3	65.448	82.008	3994.56	159.78	77.7744
12	0	16.56	16.56	841	30.3	65.448	82.008	3994.56	159.78	77.7744
13	0	16.56	16.56	841	30.3	65.448	82.008	3994.56	159.78	77.7744
14	0	16.56	16.56	841	30.3	65.448	82.008	3994.56	159.78	77.7744
15	0	16.56	16.56	841	30.3	65.448	82.008	3994.56	159.78	77.7744
16	0	16.56	16.56	841	30.3	65.448	82.008	3994.56	159.78	77.7744
17	0	16.56	16.56	841	30.3	65.448	82.008	3994.56	159.78	77.7744
18	0	16.56	16.56	841	30.3	65.448	82.008	3994.56	159.78	77.7744
19	0	16.56	16.56	841	30.3	65.448	82.008	3994.56	159.78	77.7744
20	0	16.56	16.56	841	30.3	65.448	82.008	3994.56	159.78	77.7744
21	0	16.56	16.56	841	30.3	65.448	82.008	3994.56	159.78	77.7744
22	0	16.56	16.56	841	30.3	65.448	82.008	3994.56	159.78	77.7744
Total	**414**	**314.64**	**728.64**	**15979**	**575.7**		**1972.152**			**1063.714**
NPV@15%	**$316.92**	**$67.49**	**$384.41**	**$3,427.4**	**$123.49**		**$651.14**			**$0.04**

				600 T/D Ammonia & 1000 T/D Urea Plant			
Urea Price	200	(US$/ton)					
Gas Cost=	41	(US$/1000 CM)				15.04%	
Year	**Production**	**Revenue**	**Capex**	**Gas Cost**	**O&MCost(Ex.gas)**	**Cash Flow**	
	(Ton/Y)	($ MM)	($ MM)	($ MM)	($ MM)	($ MM)	
1			50			-50.00	
2			100			-100.00	
3			100			-100.00	
4	330000	66.00	0	8.04	12.50	45.46	
5	330000	66.00	0	8.04	12.50	45.46	
6	330000	66.00	0	8.04	12.50	45.46	
7	330000	66.00	0	8.04	12.50	45.46	
8	330000	66.00	0	8.04	12.50	45.46	
9	330000	66.00	0	8.04	12.50	45.46	
10	330000	66.00	0	8.04	12.50	45.46	
11	330000	66.00	0	8.04	12.50	45.46	
12	330000	66.00	0	8.04	12.50	45.46	
13	330000	66.00	0	8.04	12.50	45.46	
14	330000	66.00	0	8.04	12.50	45.46	
15	330000	66.00	0	8.04	12.50	45.46	
16	330000	66.00	0	8.04	12.50	45.46	
17	330000	66.00	0	8.04	12.50	45.46	
18	330000	66.00	0	8.04	12.50	45.46	
19	330000	66.00	0	8.04	12.50	45.46	
20	330000	66.00	0	8.04	12.50	45.46	
21	330000	66.00	0	8.04	12.50	45.46	
22	330000	66.00	0	8.04	12.50	45.46	
Total	**6270000**	**1254.00**	**250**	**152.7574**	**237.5**	**613.74**	
NPV@15	**$2,045,416**	**$409**	**$185**	**$50**	**$77**	**$0.43**	
Note:							
Gas Consumption:		Process gas = 5.79 x 10^6 Kcal/T-NH3=723.75 CM/T-NH3					
		Fuel gas= 2.55 x 10 ^6 Kcal/T-NH3=318.75 CM/T-NH3					
NH3 Consumption:		0.57T/T-Urea					
Gas Consumption per Ton Urea:			(723.75+318.75) x 0.57=594.225 CM/T-Urea				

Appendix 3.6: Production of Electricity/Heat and Fuel Consumption in Almaty, Zhambyl and Symkent (1990 - 1996)

POWER STATIONS	Years	Established electrical capacity	Disposed heating capacity	Production of electricity	Delivery of electricity	Delivery of heat	Expense of gas		Expense of mazut		Expense of coal		Total quantity of fuel
		MWt	Gcal/H	Million KwtH	Million KwtH	Thousand Gcal	Million nm3	Thousand ton of coal equivalent	Thousand ton of coal equivalent	Thousand ton of coal equivalent	Thousand ton of coal equivalent	Thousand ton of coal equivalent	Thousand ton of col equivalent
ALMATY													
1. Almaty Heat Electro - Central - 1 (HEC)	1990	145	1060	765,0	623,8	3963,6	309,3	359,3	199,3	281,2	241,9	147,3	787,8
	1991	145	1060	798,7	604,0	4044,1	314,1	363,4	190,3	265,1	281,8	177,3	805,8
	1992	145	1095	808,7	669,3	3613,7	240,5	278,3	185,9	259,4	325,3	196,3	734,0
	1993	145	1042	762,6	614,5	3811,8	197,4	228,9	196,5	278,7	411,7	251,8	759,4
	1994	145	913	685,4	540,7	3288,8	490,8	331,8	213,9	302,7	217,7	142,0	658,7
	1995	145	913	671,7	536,5	2786,6	143,6	166,9	102,9	145,1	395,2	261,8	573,8
	1996	145	913	680	543	2700	237	160	141	200	304	198	558
2. Almaty HEC-2	1990	510	855	2316,7	1993,3	3258,3	no	no	90,7	122,9	1652,9	994,4	1117,3
	1991	510	688	2297,9	1968,8	3279,9	no	no	82,1	111,3	1919,5	1098,0	1209,3
	1992	510	688	2589,7	2211,1	3430,1	no	no	43,1	59,0	2223,8	1249,1	1308,1
	1993	510	750	2592,3	2193,0	3900,8	no	no	22,3	30,4	2343,3	1336,3	1366,7
	1994	510	768	2185,5	1826,4	3587,0	no	no	13,9	18,9	2109,7	1195,8	1214,7
	1995	510	798	2073,3	1731,9	3527,9	no	no	13,5	18,4	1899,1	1112,704	1131,1
	1996	510	828	2000	1671	3450	no	no	12	17	1950	1105	1122
3. Almaty State Regional Power Station (SRPS)	1990	173	179	1053,6	924,3	459,0	no	no	24,0	33,3	897,1	504,5	537,8
	1991	173	179	1129,9	978,1	464,1	no	no	22,9	31,8	1000,2	536,9	568,7
	1992	173	179	1135,1	987,6	409,9	no	no	12,9	18,0	1071,5	569,9	588,0
	1993	173	179	1049,0	910,2	466,1	no	no	10,9	15,2	948,1	523,3	538,4
	1994	173	239	901,3	777,1	404,7	no	no	9,1	12,6	869,0	461,9	474,5
	1995	173	239	888,0	767,3	369,2	no	no	8,3	11,5	807,6	442,4	453,9
	1996	173	239	800	69,6	330	no	no	10	13	744	396	409

POWER STATIONS	Years	Established electric capacity	Disposed heating capacity	Production of electricity	Delivery of electricity	Delivery of heat	Expense of gas		Expense of mazut		Expense of coal		Total quantity of fuel
		MWt	Gcal/H	Million KwtH	Million KwtH	Thousand Gcal	Million nm3	Thousand ton of coal equivalent	Thousand ton of coal equivalent	Thousand ton of coal equivalent	Thousand ton of coal equivalent	Thousand ton of coal equivalent	Thousand ton of col equivalent
4. WEST DBH (District boiler house)	1990	no	680	no	no	1120,9	65,9	77,0	72,8	99,8	no	no	176,8
	1991	no	680	no	no	1193,8	71,6	83,6	77,5	106,3	no	no	189,9
	1992	no	680	no	no	1039,4	55,4	64,7	73,3	100,6	no	no	165,3
	1993	no	590	no	no	895,8	37,0	43,5	71,9	99,2	no	no	142,7
	1994	no	602	no	no	682,5	9,3	10,9	71,6	98,2	no	no	109,1
	1995	no	602	no	no	447,8	14,7	17,1	39,5	54,2	no	no	71,2
	1996	no	602	no	no	400	27	32	23	32	no	no	64
5. New-WEST DBH	1990	no	380	no	no	376,5	1,5	1,8	41,3	56,6	no	no	58,4
	1991	no	380	no	no	468,2	12,3	14,4	43,8	60,0	no	no	74,4
	1992	no	380	no	no	428,5	4,6	5,3	45,9	62,8	no	no	68,2
	1993	no	286	no	no	394,6	0,9	1,1	45,1	61,8	no	no	62,8
	1994	no	259	no	no	310,9	0	0,0	36,2	49,5	no	no	49,5
	1995	no	289	no	no	266,2	0,003	0,004	30,9	42,4	no	no	42,4
	1996	no	300	no	no	260	18	21	15	21	no	no	41
6. North-East DBH	1990	no	144	no	no	501,5	48,2	56,1	19,2	26,3	no	no	82,4
	1991	no	144	no	no	506,6	49,9	58,1	18,4	25,2	no	no	83,3
	1992	no	144	no	no	457,7	38,7	45,0	22,3	30,6	no	no	75,6
	1993	no	144	no	no	418,9	24,9	28,6	29,6	40,4	no	no	69,0
	1994	no	109	no	no	364,7	6,7	7,8	38,2	52,3	no	no	60,1
	1995	no	109	no	no	280,2	16,6	19,3	19,4	26,6	no	no	45,9
	1996	no	109	no	no	270	19	22	16	22	no	no	44

POWER STATIONS	Years	Established electric capacity	Disposed heating capacity	production of electricity	Delivery of electricity	Delivery of heat	Expense of gas		Expense of mazut		Expense of coal		Total quantity of fuel
		MWt	Gcal/H	Million KwtH	Million KwtH	Thousand Gcal	Million nm3	Thousand ton of coal equivalent	Thousand ton of coal equivalent	Thousand ton of coal equivalent	Thousand ton of coal equivalent	Thousand ton of coal equivalent	Thousand ton of col equivalent
7. DBH Orbita	1990	no	178	no	no	no data					no	no	
	1991	no	178	no	no	no data					no	no	
	1992	no	178	no	no	no data					no	no	
	1993	no	178	no	no	390,5	53,4	61,8	0,4	0,6	no	no	62,4
	1994	no	178	no	no	no data					no	no	
	1995	no	178	no	no	403,8	49,9	57,7	5,1	7,0	no	no	64,7
	1996	no	178	no	no	356	41	47	7	10	no	no	57
8. Southern DBH	1990	no	116	no	no	no data					no	no	
	1991	no	116	no	no	no data					no	no	
	1992	no	116	no	no	no data					no	no	
	1993	no	116	no	no	380,2	51,9	60,1	1,0	1,3	no	no	61,4
	1994	no	116	no	no	no data					no	no	
	1995	no	116	no	no	346,2	44,9	52,0	2,4	3,2	no	no	55,2
	1996	no	116	no	no	340	43	49	4	5	no	no	54

POWER STATIONS	Years	Established electric capacity	Disposed heating capacity	Production of electricity	Delivery of electricity	Delivery of heat	Expense of gas		Expense of mazut		Expense of coal		Total quantity of fuel
		MWt	Gcal/H	Million KwtH	Million KwtH	Thousand Gcal	Million nm3	Thousand ton of coal equivalent	Thousand ton of coal equivalent	Thousand ton of coal equivalent	Thousand ton of coal equivalent	Thousand ton of coal equivalent	Thousand ton of col equivalent
9. South-East DBH	1990	no	119	no	no	no data					no	no	
	1991	no	119	no	no	no data					no	no	
	1992	no	119	no	no	no data					no	no	
	1993	no	119	no	no	401,5	46,7	63,4	0,5	0,7	no	no	64,1
	1994	no	119	no	no	no data					no	no	
	1995	no	119	no	no	370,0	45,5	52,7	4,3	5,9	no	no	58,6
	1996	no	119	no	no	360	43	50	5,2	7	no	no	57
SyMKENT													
1. Symkent HEC-1 and 2	1990	42	476,0	178,3	129,9	1831,3	285,3	329,9	1,6	2,3	0,0	0,0	332,2
	1991	42	476,0	159,6	112,4	1757,4	272,0	314,5	4,9	7,0	0,9	0,3	321,8
	1992	42	480,0	147,0	102,0	1523,1	226,7	263,3	9,4	12,5	1,5	0,5	276,4
	1993	42	462,0	125,3	83,9	1443,8	211,2	247,1	9,4	12,3	4,2	1,7	261,1
	1994	42	465,0	70,5	40,0	851,9	97,2	113,7	28,0	37,5	5,2	2,3	153,6
	1995	42	315,0	55,9	28,4	599,5	85,0	98,1	5,5	7,3	4,8	2,1	107,4
	1996	42	315	30	15	580	78	90	8	10	5	2	102
2. Symkent HEC-3	1990	160	331,0	700,5	610,9	1438,7	397,1	457,3	9,3	12,2	no	no	469,5
	1991	160	331,0	706,7	620,4	1438,7	377,0	434,1	32,4	42,7	no	no	476,8
	1992	160	331,0	738,9	642,7	1257,3	283,7	326,7	112,2	153,0	no	no	479,7
	1993	160	319,2	573,1	486,7	929,0	133,2	152,0	161,1	216,7	no	no	368,7
	1994	160	335,7	494,1	419,6	610,8	1,8	2,1	222,4	296,2	no	no	298,3
	1995	160	335,7	427,2	356,7	393,9	33,5	38,1	171,2	225,5	no	no	263,6
	1996	160	319	200	167	360	17	19	83	110	no	no	129

POWER STATIONS	Years	Established electrical capacity	Disposed heating capacity	production of electricity	Delivery of electricity	Delivery of heat	Expense of gas		Expense of mazut		Expense of coal		Total quantity of fuel
		MWt	Gcal/H	Million KwtH	Million KwtH	Thousand Gcal	Million nm3	Thousand ton of coal equivalent	Thousand ton of coal equivalent	Thousand ton of coal equivalent	Thousand ton of coal equivalent	Thousand ton of coal equivalent	Thousand ton of col equivalent
3. Symkent DBH 1,2	1990	no	200,0	no	no	404,3	56,9	67,1	0,0	0,0	no	no	67,1
	1991	no	200,0	no	no	465,0	65,5	77,3	0,0	0,0	no	no	77,3
	1992	no	200,0	no	no	441,5	62,2	73,4	0,0	0,0	no	no	73,4
	1993	no	200,0	no	no	453,8	64,8	76,5	0,0	0,0	no	no	76,5
	1994	no	200,0	no	no	269,5	37,9	44,6	0,1	0,1	no	no	44,7
	1995	no	200,0	no	no	303,2	42,6	50,1	0,9	1,3	no	no	51,4
	1996	no	200	no	no	350	49	58	1	2	no	no	59
ZHAMBYL													
1. Zhambyl state's regional power station	1990	1230	0,0	8215,8	7754,8	38,3	1373,5	1606,0	813,4	1101,6	no	no	2707,6
	1991	1230	0,0	8046,5	7597,5	37,4	1526,7	1785,15	640,4	867,3	no	no	2652,5
	1992	1230	0,0	6758,1	6373,1	32,8	1158,3	1360,5	652,4	864,8	no	no	2225,2
	1993	1230	0,0	3791,5	3558,3	27,0	463,6	540,1	532,2	703,1	no	no	1243,2
	1994	1230	0,0	2016,3	1879,1	24,6	241,8	279,0	300,8	380,7	no	no	659,8
	1995	1230	0,0	4366,5	4117,902	21,7	952,6	1113,8	243,2	329,4	no	no	1443,2
	1996	1230	0,0	4000	3772	22	855	1000	264	358	no	no	1358

POWER STATIONS	Years	Established electric capacity	Disposed heating capacity	production of electricity	Delivery of electricity	Delivery of heat	Expense of gas		Expense of mazut		Expense of coal		Total quantity of fuel
		MWt	Gcal/H	Million KwtH	Million KwtH	Thousand Gcal	Million nm3	Thousand ton of coal equivalent	Thousand ton of coal equivalent	Thousand ton of coal equivalent	Thousand ton of coal equivalent	Thousand ton of coal equivalent	Thousand ton of col equivalent
2. Zhambyl Heat Electro-Power Station - 4	1990	60	623,0	332,9	264,7	1592,7	252,5	297,0	8,5	11,4	no	no	308,4
	1991	60	623,0	329,8	264,0	1540,9	244,3	287,4	9,2	12,3	no	no	299,7
	1992	60	623,0	289,7	224,5	1362,9	216,2	250,4	9,4	12,5	no	no	262,9
	1993	60	580,0	278,4	218,1	1193,9	187,1	217,3	11,7	16,2	no	no	233,4
	1994	60	584,0	153,3	104,7	838,7	103,7	120,4	27,1	36,5	no	no	156,9
	1995	60	584,0	201,1	154,4	842,1	132,8	154,2	8,2	11,0	no	no	165,2
	1996	60	584	50	38	800	116	135	5	7	no	no	142
3. Zhambyl district boiler house (DBH)	1990	no	200,0	no	no	138,5	25,6	29,6	0,0	0,0	no	no	29,6
	1991	no	200,0	no	no	259,6	38,3	44,4	0,0	0,0	no	no	44,4
	1992	no	200,0	no	no	317,6	46,7	54,1	0,0	0,0	no	no	54,1
	1993	no	200,0	no	no	292,3	42,6	49,5	0,0	0,0	no	no	49,5
	1994	no	200,0	no	no	211,8	28,8	33,4	1,7	2,4	no	no	35,8
	1995	no	200,0	no	no	207,1	29,6	34,3	0,4	0,6	no	no	34,9
	1996	no	200	no	no	200	29	33	0,4	0,5	no	no	34

Source: EC Energy Centre

Appendix 3.7

Description of the Existing Gas Infrastructure

Gas Transit Pipelines

1. Most gas pipeline assets in Kazakhstan are located within two major north-south corridors in the western part of the country. These lines form part of the original UGSS grid carrying domestic gas and imports from Turkmenistan and Uzbekistan northwest into Russia. In particular, all of Turkmenistan's gas exports transit through Uzbekistan and Kazakhstan in a double line which crosses east of the Caspian Sea, and then connects in far northwestern Kazakhstan to the Soyuz export line. Gas which Kazakhstan imports from Russia is used in the northwest regions, e.g, in Kostanai, Aktyubinsk and West-Kazakhstan (Uralsk).

2. The major gas transit pipelines in Kazakhstan are:

- The Central Asia to Central Europe gas export corridor which extends over 820 Km with 5 lines of 1,000 to 1,400 mm diameter and with a total design capacity of 185 MCM per day (or 67 BCM/Y)[1];
- The Bukhara to Ural corridor which extends over 630 Km, consisting of two of 1,000 mm diameter pipes with a design capacity of 40 MCM per day (or 14 BCM/Y);
- "Soyuz" and "Novopokov" lines which run in parallel over 380 Km inside Kazakhstan with 1,200 and 1,400 mm pipes and with a design capacity of 170 MCM per day;
- The Bukhara - Tashkent - Symkent- Zhambyl-Bishkek - Almaty line which extends over 700 Km with 700 to 1,020 mm pipes and with a design capacity of 36 MCM per day;
- The Makat - North Kafkaz line which extends over 370 Km with a 1,400 mm pipe and with a design capacity of 70 MCM per day.

In all, there are more than 26 gas compressor stations on the above pipelines, with more than 300 compressors.

3. The Orenburg-Western Border (Soyuz) pipeline in north-western Kazakhstan transports mainly Russian gas production as far as Alexandrovgay Compressor Station in Russia. A this point, the pipeline connects with the CAC pipeline and extends to Europe. The throughput capacity of the Soyuz line is 41 BCM/Y.

[1] Nominal capacity is 80 BCM/Y.

Theoretically, the pipeline can transport gas produced at the Karachaganak field to European export markets once Karachagnak gas is properly treated to meet the export gas specification. Other West Kazak gas fields can also be connected by relatively short-distance pipelines to the Soyuz line.

4. Kazakhstan does not possess gas transmission pipelines from the country's western gas producing areas to serve its existing markets in the far southeast (Almaty, Zhambul and Symkent), or potential markets in the central-northeastern region (principally Kokchetav, Turgai and Akmola). The current gas infrastructure was built in 1960s and 1970s as an integral component of the UGSS, with priority given to exports of Soviet natural gas resources wherever they were produced.

5. In addition to its lack of service to existing and potential Kazak markets, the nation's gas transmission network now requires major rehabilitation. The CAC line needs rehabilitation in the Karakalpak area. According to Kazakgaz, the highest priority is the section from Opornyy Compressor Station to Ural River (built in 1967) and about 70 Km from the Ural River to Bolakovo near the border with Russia. In addition, several portions of the pipeline have corrosion problems because of saline soils. The Soyuz line has also a similar corrosion problem inside Kazak territory. Despite its original design pressure of 55 Bar, the Bukhara-Ural pipeline is now operated at a reduced pressure around 40 Bar. The line caused metal corrosion and coating disbonding. In addition, many compressor stations require major overhauling and replacement of major parts for compressors and their drivers. Reflecting these circumstances, Kazakgaz estimates the average depreciation of the pipeline systems under Kazakgaz operation to be more than 70%. However, a more precise diagnosis would be required for accurate valuation of the pipeline system assets.

Table 1 List of Transmission Pipelines in Kazakhstan

Pipeline	*Year of Commi-ssion*	*Length (Km)*	*Pipe Dia. (mm)*	*Number of Comp. Stations*	*Capacity (MCM/ day)*	*Depre-ciation (%)*	*Gas Source*
Central Asia Center (CAC)				7	185		Turkmen
CAC-1	1969	279	1020			86.6	
CAC-2	1969	406	1220			86.6	
CAC-3	1972-75	821	1220			70.0	
CAC-4	1973	821	1420			73.3	
CAC-5	1988	821	1220			23.3	
Makat-Northern Caucasus	1987	371	1420	3	70	26.7	Turkmen
Orenburg-Novorskov	1976	380	1220	2	55	63.3	Russia
Orenburg-Western border	1978	380	1420	2	95	56.6	Russia
Bukhara-Ural	1965	639	1020	5	40	93.4	Turkmen
Gazli-Symkent	1988	314	1220	1	36		Uzbek/ Turkmen
Bukhara - Tashkent-Bishkek- Almaty	1961-91	684	1020	2	36		Uzbek/ Turkmen
Kartaly - Kostanai	1963	238	1220	2	15		Russia
Okarem-Beineu	1967	398	1220	2	15		Turkmen
Uzen-Aktau		150	1020		10		

Source: Kazakgaz & Alaugaz, 1996

Gas Distribution

6. The regional gas departments (RGD) of the gas transmission companies (e.g. Kazakgaz and Alaugaz) operate gas distribution. Natural gas is distributed to the following 8 oblasts under RGD's operation:

(i) Almaty, Jumbul and Symkent form the largest gas consumption center in the country.

(ii) Mangystau, Atyrau, Uralsk, Aktyubinsk and Kostanai receive gas from the transit gas pipelines. The distribution grid is less developed.

In the remaining oblasts[2], there is no gas distribution network and no natural gas is utilized. A more detailed list of gas distribution infrastructure is given in Annexes 5 and 7, "Performance Data on Gas Line Branches". Most of the existing distribution lines run above ground.

7. As with other CIS countries, most of small commercial and residential consumers do not have gas meters. Existing gas meters for large consumers are obsolete and inaccurate. For these large consumers and city gate stations, additional instrumentation loops with temperature and pressure compensation would be needed for more accurate measurements.

Gas Storage

8. To help accommodate seasonal variations in gas demand, there are two underground gas storage (UGS) facilities along the southern pipeline and another UGS along the Bukhara-Ural line:

Table 2: Gas Storage in Kazakhstan

Gas Storage Facilities:	*Oblast*	*Km-Post*	*Type*	*Capacity (Nominal/ Working, BCM)*	*Placed in Service*
Poltoratskei	South Kazakh.	522	Aquifer	760/545	1970
Akirtubinskiy	Zhambyl	884	Aquifer	750/300	1986
Bazaik	Aktyubinsk	932		3600/ /	

Source: Alaugaz and Kazakgaz

9. The lack of sufficient volume of gas storage at appropriate locations is one of the major issues in Kazakhstan. To smooth seasonal unbalance of gas consumption, Kazgyprogaz, a design institute in Almaty estimate that the active volume of gas storage in the south of Kazakhstan should be 3.4 billion CM, of which 900 million CM is served for the city of Almaty, and 250 million CM is for Taldy-Kurgan.

[2] Taldi-Korgan, Kizyl-Orda, Turgai, Petropavlovsk, Kokchetav, Akmola, Semipalatinsk, Pavlodar, Karaganda, Ust Kamenegorsk and Zhezkazgan

Gas Processing

10. The present gas processing facilities within Kazakhstan can nominally process more than 7 BCM of raw gas per year, as follows:

- Both the Novi-Uzen and Tengyz gas processing plants have a design capacity of 3 BCM.

- Another 1.5 BCM plant is in place for the Kamansko - Teplovsko - Tokarebo group of gas condensate deposits.

- Smaller gas processing plants are situated along major gas pipelines to treat gas from medium and smaller producing fields (total processing capacity: 500 MCM/year).

11. Acid gas and gas condensate produced from the Karachaganak field is currently transported out of the country in a wet, unprocessed stream and is processed at the Orenburg gas plant in Russia. MOG/Kazakgas currently plan to build a new gas processing facility with a design capacity of 4 BCM in Karachaganak by 2000, with ultimate capacity of 10 BCM during the 2000-2010 decade.

12. Kazakhstan's two gas processing plants are in very different situations. The Tengiz plant is a part of an overall field development project at Tengiz, which is operated jointly by Chevron and Tengizneftegaz ("Tengizchevroil"). The Tengiz field is at the beginning of its life and production of crude (and associated gas) is expected to increase to over 12 million tons/year by the end of the century. Initial problems with respect to The export of crude from the field should be resolved, followed by appropriate processing of the high mercaptan level of the crude. The plant receives a mixture of oil and gas from several wells in the field and separates to:

- LPG fraction (C3 and C4) and natural gas liquid (C3, C4 and C5);
- Dry gas (C1 and C2);
- Sulfur in a molten or solid form; and
- Stabilized crude oil.

The plant has a capacity to treat a maximum of 3 BCM of gas and 9 million tons of oil per year. Due to physical constraints of Tengiz oil exports, the plant is currently under-utilized. The produced LPG is sold to Alaugaz and the dry gas is sent to a transmission pipeline in West Kazakhstan. Sulfur is sold mainly in Russian markets.

13. Chevron has invested substantial financial resources in the Tengiz project and is committed to its development. Consequently, it is reasonably anticipated that the Tengiz project will provide Kazakhstan with significant hard currency revenues over the next 2 decades.

14. Novy Uzen, however, is located near production fields in the southern Mangyslak region. For the moment, the plant is operating at well below its full capacity, 3 BCM per year due to shortage of associated gas supplies. The plant produces the following products:

- Dry gas (C1);
- Ethane (C2);
- LPG (C3 and C4);
- Isobutane (iC4); and
- Condensate (C5+).

Currently, the plant has no possibility to export its main products. The dry gas is partly used for gas lift operation in the Uzen field (maximum 1 BCM per year) and the rest is sent to the gas transmission pipeline. Ethane is designed to be sent to the Aktau ethylene plant. LPG is sold to Alaugaz and naphtha is transported to the Atyrau refinery by railroad.

15. In addition, plans call for development of gas processing to serve the Karachaganak and other gas producing fields, with a total ultimate capacity of 15 BCM/Y. However, neither comprehensive feasibility studies nor financial arrangements have yet been made. Consequently, in addition to waste by flaring and/or venting associated gas in smaller oil fields, such valuable resources as LPG and condensates are not fully utilized.

Needs for Rehabilitation

16. Kazakhstan nominally possesses almost sufficient capacity of gas infrastructure to supply gas to the existing markets. Coupled with current macroeconomic constraints, the level of gas consumption is still low compared with its peak consumption experienced in 1991. As a result, some of the existing systems, are not fully utilized. In particular, the current transit capacity through the Central-Asia-Center (CAC) is only 25 BCM/Y despite its design capacity of 67 BCM/Y. The utilization of gas branch lines which belong to gas distribution companies in the north-western Kazakhstan region is also low, on average less than 50%. Therefore, the plan for rehabilitation needs to be made by matching the infrastructure capacity with the expected demand and by avoiding unnecessary expenditures. It is unlikely to recover the export quota of Turkmen gas to European markets from the current level to its peak capacity, 67 BCM/Y in the near future. If so, Turkmenistan should request the immediate rehabilitation, focusing on two to three out of the total five lines.

17. In the south-eastern region, gas supply is constrained despite its high demand for power generation. In this case, expansion of the pipeline as well as full scale

rehabilitation would be required, intending the increase of gas transmission capacity from today's 5 BCM/Y to 12 BCM/Y if new sales contracts to justify this demand are successfully made with large gas consumers for long-term gas supply.

18. At present, there is no metering station at the national border with the neighboring countries. The imported gas from Uzbekistan is measured at the Gazli station inside Uzbekistan. Turkmen gas which flows through the CAC line is not measured within Kazak territory. In response to increasing the import gas price and the importance of the revenue from transit service, more accurate gas flow measurement would be needed. Basically, only one modern metering station is needed for each cross-border gas sales/transit transaction and duplication of gas meter stations should be avoided. Measurement of cross-border gas flow may need to be discussed with neighboring countries for clear contractual arrangements.

19. As with other CIS countries, the existing gas distribution systems are in a poor state of repair, resulting in corrosion and leakage at various locations. Renewal of cathodic protection (for underground pipes), coating and gas leakage detection would be required. Existing meters at city gate stations and large consumers are outdated and inaccurate. However, this does not mean full replacement of orifice plates. One of the acute needs is a more accurate measurement procedure with temperature and pressure compensation. Accurate calibration equipment is also needed.

20. Use of the GOST code for manufactured goods should be allowed so far as the specified safety and quality standards are maintained. However, the rehabilitation and upgrading of the gas infrastructure requires a new design concept which largely emphasizes safety and environmental protection. In general, API recommended practices or equivalent should be incorporated into design considerations.

Needs for Modernization

21. At present, most of the small commercial and residential consumers do not have gas meters. The current practice of tariff collection is based on a presumption of gas consumption per each customer (ex. about 5 to 8 CM per such a customer each month). As cost recovery is a mandatory requirement, each LDC should install meters for all the customers and to impose payment. In this connection, introduction of prepayment meters is worth considering to change consumers' attitude as a measure to solve or decrease non-payment.

22. Despite its nominal capacity, the present system lacks flexibility for peak load shaving. Especially, this situation is serious in the south-eastern region. The region essentially requires expansion of gas storage and improving pump-in and pump-off capacities.

23. As the need for quick response increases, supervision and/or control via telecommunication linkage between gas transit companies and LDCs and/or large

consumers would be essential. Considering the investment cost, on-line control would not be required initially but an integrated operation center needs to be established in each gas consumption center.

24. Each LDC should have a hydraulic model covering its gas supply pipelines to major consumers so that it can make an optimum plan for future changes. Unnecessary redundancy of the pipeline network would be thus avoided. In addition, each LDC should have an unsophisticated monitoring system of daily operations to minimize technical and non-technical losses. Such modernization needs to be implemented in tandem with companies' management reform.

Annex 1

Gas Compressor Stations on the Kazakgaz Gas Transmission Pipelines

Compressor stations (CS)	*Number of units*	*Year of commissioning*	*Capacity, MW(In/Out Press. Kg/CM2)*
Gas-transport plant "Aktautransgas"			
I CS - The south part of gas pipelines **"Central Asia-Center"**, at location 501 km			
Line No. 1	6	1984,85,80,82	6 (37.5/55)
Line No. 2	5		6 (37.5/55)
Line No. 3	3		10
Line No. 4	not in operation		-
Line No. 5	not in operation		6 (37.5/55)
II CS Beinez workshop at location 390 km			
Line No. 1	6	1984-85	6 (37.5/55)
Line No. 2	6	1984,86,89,71	6 (37.5/55)
Line No. 3	6	1972,73,75	6 (37.5/55)
Line No. 4	6	2x1975;4x1985	10(50.7/75)
Line No. 4a	3	1989	10(50.7/75
Line No. 5	6	1985	6,3 (38/55)
Novij - Uzen (Beijnez)			
at location 390 km,	3	1975	10(34.5/55)
Say-Utes	?	?	?
Uzen, at location 69 km	3	?	10
Gaz-transport Plant "Jaiktransgaz"			
Gaz pipelines "Central Asia-Center" Kulsari, at location 598 km			
Line No. 1	6	1980-82	6 (37.5/55)
Line No. 2	6	1983,79,70,91,70,90	6 (37.5/55)
Line No. 3	3	1973	10(37.5/55)
Line No. 4	6	1989,91,90	10(50.7/75)
Line No. 4a	6	1981	10(50.7/75)
Line No. 5	6	1987	6 (37.5/55)
Makat, at location 695th km			
Line No. 1	6	1981/82	6 (36.5/55)
Line No. 2	6	1970	6 (36.5/55)
Line No. 3	3	1973	10(35.4/55)
Line No. 4	6	1988	10(50.7/75)
Line No. 4a	6	1981	10(50.7/75)
Line No. 5	6	1985-92	6 (38/58)

Compressor stations (CS)	*Number of units*	*Year of commissioning*	*Capacity, MW(In/Out Press. Kg/CM2)*
Inder, at location 851 km Line No. 3 Line No. 4a Line No. 4b Line No. 5	6 6 3 6	1973,85,87,73 4x1975,2x1985 1980 1987	6 (37.5/55) 10(50.7/75) 10(50.7/75) 6 (38.6/58)
Kisik-Kamis, at location 984 km Line No. 1 Line No. 3 Line No. 4 Line No. 4a Line No. 5	 6 3 6 3 6	 1980,85,80,80,85,81 1986,87,85 3x1974,2x1975 1x1979 1980 1985,80	 6 (37.5/55) 10(35.5/55) 10(50.7/55) 10(50.7/75) 6 (38.6/58)
Russian group, at location 1132 km			
The pipeline department of Redut Redut CS-1,picket 124,9km Tajman CS-2, picket 243 km Akkol CS-3, picket 362,3 km	 8 7 7	 1988-91 1993 1992,91,89,93,92,88,91	Design 75 10(52.8/74.5) 10(52.8/74.5) 10(52.8/74.5)
Russian group, 371 km			
Gaz transport plant "Aktobetransgaz", Uzbekiston frontier-806km gaz-main "Buhara-Ural" Bozoj, (South Usturt), at location 932 km on the underground gaz storage (UGS) CS on the UGS CS on the gaz main Begimbet (Middle Usturt), 1035 km Solenaja (Chelkar), 1142 km, Galdik (Novogodnij), 1247 km Krasnij Oktjabr (Molodejnaja) , 1359 km	 7 6 10 10 7 10 10	 1969 1986,87,88 1965 1987 1987 1965 1964	Design 55 1 (16/40) 6,3(17/29) 5 (55/75) 6,3 (38/56) 6,3 (38/56) 5 (37/55) 5 (37/55)
Gaz transport plant "Uralsktransgaz" CS Uralskaja, at location 245km Gaz main Sojuz Gaz main Novopskov CS Chipsa, picket 371 km Gaz main Sojuz Gaz main Novopskov	 7 4 7 4	 1979 1977 1979, 1st line in 1980 1977	 10(51/75.5) 10(35/55) 10(51/75.5) 10(35/55)

Annex 2

Information on the Existing Bukhara-Almaty Pipeline

First Line

Gas Pipeline Section	*Construction Date*	*Pipe Diameter x Thickness (mm)*	*Design Pressire (Kg/cm2)*	*Max. Operating Press (Kg/cm2)*
347-463	1966/87/89	1020 x 10.5	55	46
463-526	1962/66	820 x 9	55	55
526-626	1961/70	720 x 8	55	50-52
626-724	1968/70/82	820 x 9	55	50-54
724-1115	1969/70/89	720 x 8	55	37-55
1115-1324	1970/85/86	530 x 7	55	32-37

Second Line

Gas Pipeline Section	*Construction Date*	*Pipe Diameter x Thickness (mm)*	*Design Pressire (Kg/cm2)*	*Max. Operating Press (Kg/cm2)*
342-427	1966/77/78	1020 x 10.6	55	55
427-626	1971/76	820 x 9	55	55
648-724	1989	1020 x 8	55	55
724-765	1975	720 x 9	55	55
765-974	1989/90	1020 x 9	55	55
1115-1207	1976/78	530 x 9	55	55
1207-1277	1990	1020 x 9	55	55

Pipe materials used: ST20, 17-GS, 17 GIS and X70 (from Germany)
The pipes are prime-coated and covered with polyvinilchloride tape.

Annex 3

Information on Compressor Stations on the Bukhra- Almaty, Gazli-Symkent Pipeline

Station Name	*No. of Unit*	*Pressure in/out (Kg/cm2)*	*Type of Driver*	*Capacity (KW)*	*Start Date*
CS 3-A Chinaz	8	37/56	Electric Motor	400	1979
- 427 Km	2	38.6/56		6300	1990
CS 4 Poltororatskoe	3	37/54	Electric Motor	4000	1970
-522 Km					
UGSF Poltoratsoke	10	25/55	Gas Engine	1100	1966
		55/125			
CS 4-A Samsonovka	5	38/56	Electric Motor	4000	1981
-649 Km					
CS 5 Jumbul	10	25/55	Gas Engine	1100	1971
-826 Km					
UGSF Akyr-Tobe	6	25/55	Gas Engine	1100	1985
		55/125			

Source: Alaugaz

Note: All the above gas compressor units were supplied by Russian manufacturers.

Annex 4

Gas Distribution under JSC Alaugaz

Diameter (mm)	*Pipe Wall Thickness (mm)*	*Length (km)*
150	5	40
325	7	23
400	7	5
530	7	22

Annex 5

Performance Data on Gas Distribution of Kazakgaz - As of September 1995

No	*Name of gas distribution*	*Dia*	*Length*	*Pressure (Kg/cm2)*				*Capacity CM/D*		*Utilization*
		mm	Km	Planned		Actual (Ave.)		Plan	Act	%
				Start	End	Start	End			
	SE "Uralsktransgaz"									
	Orenburg-Novoans									
1	Uralsk city	377	10.8	55	54	41.7	38.9	709157	355917	50.1
2	Uralsk city	216	13.3	55	52	41.9	39.0	393914	53364	13.5
3	Furmanovo village	114	0.15	55	54	41.7	41.6	23246	5851	25.1
4	Darinsk village	159	0.6	55	54	41.8	41.6	31624	9387	29.6
5	Kamenka village	159	4.6	55	54	41.0	40.8	23381	6824	29.1
6	Perementoe village	114	0.63	55	54	41.0	40.8	26362	3045	11.5
7	Chikill village	168	0.5	55	54	42	41	43800		
8	Bagatyteva village	108	2.5	55	54.5	42	41	3887		
9	Karioba village	159	4.5	55	54.5	32	32	7196		
10	Rostani village	108	0.254	55	54	41.3	41.3	131400		
	Aksay-Akmola									
11	Aksai city	377	56.6	55	22	22	18	114260		
12	Tungun village	377/150	2.9	55	23	221 8	18	8952		

No	Name of gas distribution	Dia	Length	Pressure (Kg/cm2)				Capacity CM/Day		Utilization
		mm	Km	Planned		Actual (Ave.)		Plan	Act	%
				Start	End	Start	End			
	SE "Zhaiyktransgaz"									
	Central-Asia-Center									
1	Kazak soviet farm	108	0.35	55	44	44		8803	6606	75
2	Dezhragaz	325	0.3	55	45	45			47942	16.9
3	Kulsay	219		55	45	45		48072	21170	44
4	Dkazhgala village	108	0.25	55	45	45		27591		
5	Berezino village	159	1.01	55	40	40		3573	1095	30.6
6	Zhakat station	108/219	55	55	55			30485	10439	34
7	Furmanovo village	159	11.6	55	42	42		11694	6971	59.6
8	Krasny Partizan state farm	159	0.581	75				3371		
9	Zhanatalap state farm	108	0.258	55				3040	401	13.2
10	Ammangeldy state farm	108	1.5	55						
	Zhakat-North Caucas									
11	Atyrau	219	23	75				1804267	218562	12.1
12	Redut village	108	0.6	75				5105		
13	Akkistau village	159	7.5	75				33264		
14	Galochino village	159	9	75				36145		
15	Akkol village	159	6.8	75				13237		
16	Atyrau	530	33.4	75	55	45		1804267		76.9
17	Tayman	159	1.5	75						
18	Perovomayskiy state farm	108	0.6	75	55			10635		
19	Vodchiko siding way	108	12.8	75				21420		
20	VIR village	159	0.3	75				1217		
21	Kirton village	159	0.3	75				3343		
22	Kozgatylskiy state farm	70	0.2					5288		

No	*Name of gas distribution*	*Dia*	*Length*	*Pressure (Kg/cm2)*				*Capacity CM/D*		*Utilization*
		mm	Km	Planned		Actual (Ave.)		Plan	Act	%
				Start	End	Start	End			
	SE "Aktobetransgaz"									
	Bukhara-Ural									
1	Aktsubinsk city	530	158	55	35	38	25	1057300	700000	66.2
2	Aktsubinsk city	530	4	55	35	40.2	22	715400	24000	3.3
3	Alga city	219	29.2	55	34	40.2	21.5	85942	49000	57
4	Bestamak viallge	159	0.8	55	33	40.2	22	12750	5500	43.1
5	Chromatau city	273	4.4	55	37	40.2	23	75101	71200	94.8
6	Bugwtsay city	159	0.8	55	38	40.2	39.6	6400	1350	21.1
7	Iskra state farm	159	0.8	55	37	40.2	39			
8	Shelkar city	219	37.2	55	34	34	23	49300	35700	72.4
9	Zhanazolskoy branch	530	131	55	35	8.5	4			
10	Donskoy Mineral Concentration Plant	259	4.4	55				250499		
11	Kair village	159	0.6	55				2560		
12	Oktiabr village	325	38.5	55				398800		
13	Pokrovki village	89	1.5	55				4100		
14	Temir city	273	2	55				6200		
15	Keniaksai village	273	26.7	55				2000		
16	Akzhar village	159	20	55						

No	Name of gas distribution	Dia	Length	Pressure (Kg/cm2)				Capacity CM/D		Utilization
		mm	Km	Planned		Actual (Ave.)		Plan	Act	%
				Start	End	Start	End			
	SE "Aktautransgaz"									
	Central-Asia-Center (I,II & IV lines)									
1	Beykeu village	159	2	55	55	38	37.5	27700		96.8
2	Opornity village		5	55	55			5054		
3	Semskiy village	114	1.44	55	55	37.5	37.2	30660	1179	3.8
	Central-Asia-Center (III line)									
4	Say Utes branch	108	0.97	55	55	39	38	19871	4935	45.4
	Uzen-zhatibai-Shevchenko									
5	Aktau city	529	70.7	55	53			4481936		
6	Aktau city	325	149	55	25	39	6	140160	75400	53.7
7	Aktau city	72	149	55	40	39.3	25	3162		128.7
8	Uzen village	150	15	55		34.5	34	153295		
9	Zhetibai village	150	8	55						
10	Uzen AGPKS	108	2.5	55		34.5	34	6364		1.5
11	Karier	168	3.6	55	50	27	26.5	4080		42.2
12	Karakol Zhan station	108	0.8	55	55	37.2	37.5	30000		2.1
13	Aktau city 20 Km	108	0.2	55				40000	3504	8.7
14	SPK-112	108	0.21	55	35			374200		
15	Eset village	108	0.74	55	55					
16	Aktau city	325	144	55	55					

Source: Kazakgaz

Annex 6

List of Site Branches from the Main Transmission Line Symkent - Almaty line

No.	*Name of Distribution Station*	*Diameter (mm)*	*Length of Branch Line (Km)*
	Akbulak		
1	Tobolino	108	4.1
2	Leninsk	108	1.4
3	Kuyuk	108	0.1
4	#1 Symkent	325	7.4
5	#4 Symkent	530	1.3
6	Samsonovka	114	0.52
7	Sverdlovo	219	0.6
8	Sas-Tyube	114	0.93
9	Michurino	159	1
10	Visok	108	0.2
	Zhambyl		
11	Burnoe	159	2.91
12	#1 Zhambyl	325	6.9
13	#2 Zhambyl	530	22
14	#3 Zhambyl	219	0.15
15	Amangeldi	159	0.22
16	Mihaolovka	219	4.6
17	Merke	219	1.2
18	Lugovoe	159	1
19	Karatau	530	97.2
20	Akir-Tyube	426	4.2
21	Okchabrskoe	133	1.4
	Almaty		
22	Georgievka	219	3.1
23	Fabrichii	273	2.9
24	Kaskelen	325	1.7
25	Burundai	219	0.2
26	#1 Almaty	530	5.8
27	#2 Almaty	530	15.4

Source: Alaugaz

Annex 7:

Performance Data on Gas Distribution in Almaty, Zhambyl and Symkent

Name of Gas Distribution	*Diameter (mm)*	*Length (Km)*	*Inlet Press. (Kg/Cm2)*	*Annual Capacity ('000 CM)*
Almaty Oblast				
Almaty City No. 1	529	180	55	263,000
Almaty City No.2	529	18	55	1,670,000
Fabrichnij village	273	2.9	55	148,446
Kaskelen village	325	1.7	55	191,077
Burunja small town	219	0.2	55	226,447
Zhambyl Oblast				
Zhambyl City No. 1	325	69	55	450,111
Zhambyl City No. 2	325	15.3	55	770,764
Zhambyl City No. 3	219	0.2	55	1,393,196
Burnoe village	159	2.9	55	70,705
Marke village	219	1.2	55	81,526
Georgivka village	219	3.1	55	70,101
Lugovoe village	159	1.0	55	22,267
Oktiabskoe village	108	4.0	55	4,899
Mihailovka village	219	5.0	55	74,642
Amangeldy village	159	0.2	55	2,355
Kuratau village	530	97.2	55	457,231
Symkent (South Kazakhstan)				
Symkent City No. 1	325	7.4	55	1,698,180
Symkent City No. 2	530	1.3	55	1,355,000
Jetysay City	168	4.8	55	72,400
Kiroskij small town	159	3.2	55	31,000
Pahta-Aral village	159	0.2	55	51,000
Abaj village	108	0.3	55	36,600
Sary-Agach City	219	3.4	55	86,100
Tobolino village	108	4.1	55	12,200
Leninskoe village	108	1.4	55	27,900
Kuiuk state farm	108	0.1	55	5,900
Samsonovka village	114	0.52	55	25,300
Sverdlovka state farm	219	0.6	55	145,600
Sas-Tobe small town	114	0.9	55	232,000
Vannovka village	159	1.0	55	70,500
Vyskoe village	10	0.2	55	6,900

Appendix 3.8
Supply Economics

Gas Supply from Domestic Reserves

1. *Economic Analysis:* In Kazakhstan, about 24 fields have been identified for possible natural gas development. In order to identify the fields most suitable for development, these is a need to obtain information on the cost of bringing the gas to the nearest market. The economic analysis for each of the fields in consideration would provide preliminary estimates on the cost of delivery of natural gas. Of the 24 fields, 13 fields are considered high priority by the government. These fields are Airakty, Amangeldy, Bektas, Chinarev, Imashev, Kamen, Karachaganak, Kzyloy, Nuraly, Tengiz, Teplov-Tokarev, Urihtau and Zhanazhol. Among these fields, only Karachaganak, Tengiz and Zhanazhol are in production. The other fields wait development.

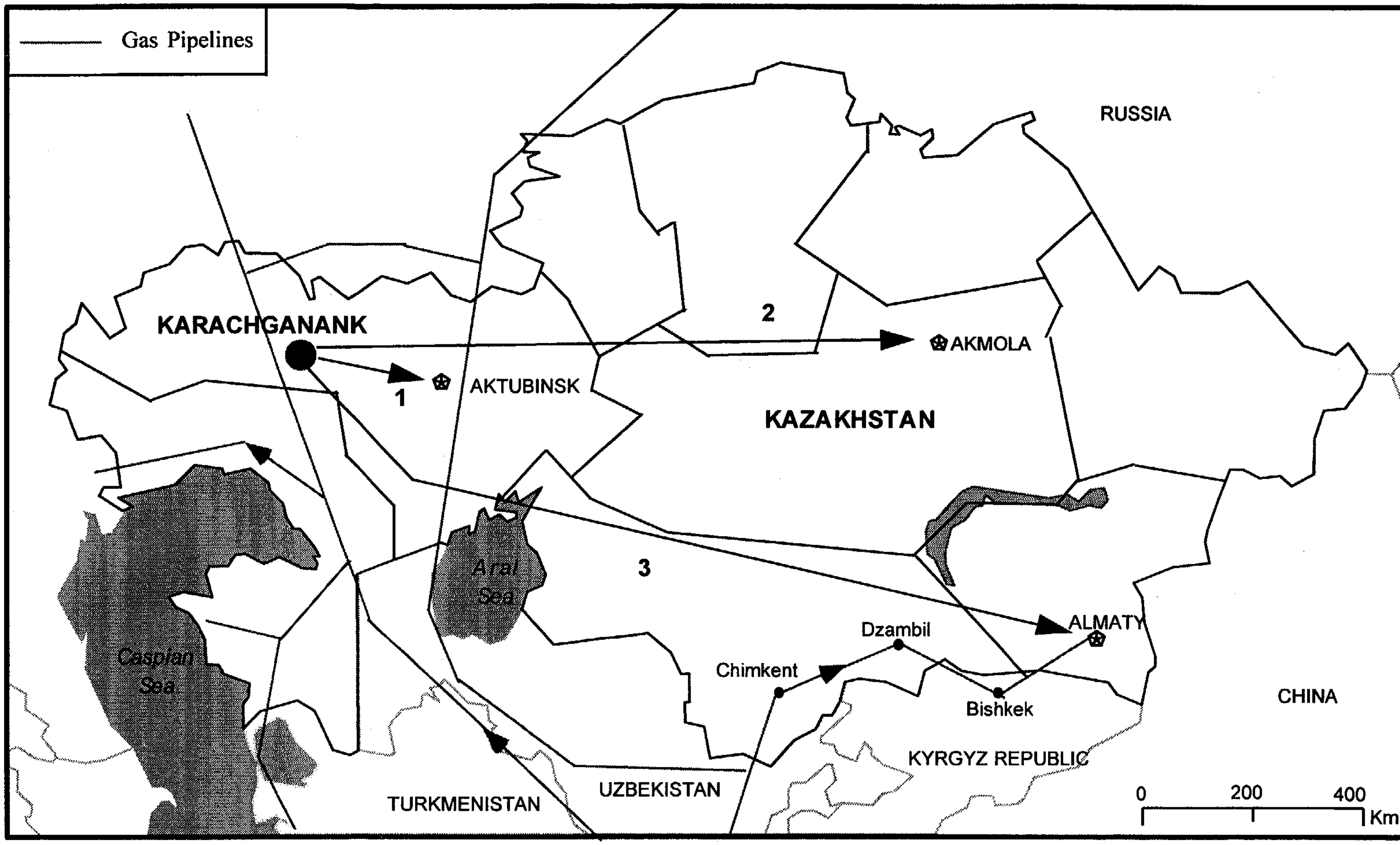
2. The analysis was undertaken by utilizing a cash flow model. The model utilizes very preliminary estimates on investments, operating costs and prices to generate a rudimentary idea about the cost of delivery. (See Appendix II-6 for the model and calculations.) This results obtained from this model are only indicative.

Table I: Indicative Gas Production Costs

Oblast	**Field Name**	**Peak Production (BCM/Y)**	**Capital Investment for Gas Prod. (US$ million)**	**Indicative Production Cost (at Field Outlet) @ 15% discount rate** ($/MMBTU)	($/1000CM)
Kizyl-Orda	Kzyloy	0.1	13	1.44	**50.8**
	Urihtau	2.2	80	0.48	**16.9**
	Zhanazol	4.5	59	0.27	**9.5**
Atyrau	Imashev	9.3	492	0.60	**21.2**
	Tengiz	5.0	68	0.30	**10.6**
West-Kazakhstan	Chinarev	3.5	208	0.65	**22.9**
	Kamen	0.5	40	0.82	**28.9**
	Karachaganak	25.1	400	0.50	**17.7**
	Teplov-tokarev	1.8	73	0.52	**18.4**
Kizyl-Orda	Bektas	0.1	20	1.34	**47.3**
	Nuraly	0.2	19	1.16	**40.9**
Zhambyl	Airakty	0.2	24	1.00	**35.3**
	Amangeldy	0.7	45	0.70	**24.7**

Source: ESMAP Task Force estimation.

KAZAKHSTAN
Natural Gas Supply from Karachaganak



This map is for reference only and have not been approved by the Map Design Unit of the World Bank Group.

1 Karachaganak to Aktubinsk; Volume - 5 BCM/Year; City Gate Cost - $ 27.9MCM
2 Karachaganak to Akmola; Volume - 7 BCM/Year; City Gate Cost - $79.1/MCM
3 Karachaganak to Almaty; Volume - 5 BCM/Year; City Gate Cost - $80.0/MCM

Gas Imports

3. The sources of gas imports are Turkmenistan and to a lesser degree Uzbekistan for gas markets in the southern region, and Russia for gas markets in the northern region. For comparison of gas supply costs at a national level, the gas price at the national border could be used. Turkmenistan gas is transmitted through: the Central Asia Center pipeline (5 lines); the Makat - Northern Caucasus pipeline; the Bukhara - Ural pipeline (2 lines); the Okarem - Beineu pipeline; and the Uzen - Aktau pipeline. Uzbek gas is sent using: the Gazly - Symkent pipeline; and the BGR - TBA pipeline. Russian gas is mainly transmitted through the Orenburg - Novopskov pipeline and the Orenburg - West Border pipeline. Russain gas supplied to Kostanai through the Kartaly - Kostanai pipeline. According to the current inter-governmental agreements, such border prices of imported gas are as follows:

Table 2: Current Border Price of Imported Gas

Import Sources	Border Price ($ Equivalent)
Turkmenistan	US$ 35 per 1,000 CM
Uzbekistan	US$ 35 per 1,000 CM
Russia	US$ 35 per 1,000 CM

Source: EC Energy Center, February, 1997

Gas Transmission Costs to Major Kazak Markets

4. Based on the information from the following sources, the indicative gas transmission costs have been calculated as tabulated below:

- The Aksai- Kr. Oktyabr pipline: Feasibility Study by VECO International Inc.
- The Kr. Oktyabr - Akmola pipeline: Feasibility Study by Okon/Enron
- The Chelkar - Symkent: "Pipeline Development Plan" by Kazakgaz, May 1996
- The Southern pipeline: Information from Alaugaz, May 1996

Table 3: Indicative Gas Transport Costs

Pipeline	**Distance (Km)**	**Design Rate (BCM/Y)**	**Max Flow by 2000 (BCM/Y)**	**Capex (US$ million)**	**IndicativeTransmission Cost @15 % Discount** ($/MMBTU)($/1000CM)	
Aksai - Kr Ok	475	12.7	11.76	626.0	0.29	**10.2**
Kr Ok - Akmola	1,300	7.24	7.24	1,612.2	1.45	**51.2**
Chelkar - Symkent	1,111	5.0	4.75	1,220[1]	1.26	**44.5**
The southern pipeline (Symkent - Almaty)	957	12	5.4	158.5(Rehabili -tation)	0.21	**7.4**

[1] The estimated investment cost has been modified using a similar cost yardstick used for the Okon/Enron study.

Supply Costs of Karachaganak Gas to Akmola and Almaty

4. Using the above calculated gas production cost and gas transmission costs, the supply costs of Karachaganak gas to the city gate of each city could be estimated as follows:

Table 4: Indicative Supply Costs of Karachaganak Gas to Almaty and Akmola

(Unit: US$ per MMBTU and US$/1000 CM (in parenthesis))

Desti-nation	Gas Delivery at Karacha-ganak	Aksai-KrOk	KrOk-Akmola	Chelkar-Symkent	Symkent-Almaty	Total Cost	Netback Value for Power[2]
Akmola	0.50	0.29	1.45	N.A.	N.A.	2.24 (**79.1**)[3]	2.00 (**70.6**)
Almaty	0.50	0.29	N.A.	1.26	0.21	2.26 (**79.8**)[4]	2.27 (**80.1**)

As shown above, the Karachaganak gas supply cost could be more than the gas netback value for power generation in Akmola, implying that such gas supply scheme may not create any economic benefit. The supply cost of Karachaganak gas to Almaty is nearly equal to the netback value for power generation, based on regulated prices for coal and for rail transport.

Supply Cost of Imported Gas to Almaty

5. The increasing gas import price is one of the major GOK's concerns. Since the current gas transit pipeline in the south crosses Kyrgystan territory, the gas import cost also depends on a transit agreement with Kyrgyzstan. Yet it would be useful to compare the import gas cost on a broad brush basis with the above Karachganak gas to Almaty. The following table presents such an indicative cost comparison. This implies that despite the increased gas import price, the supply of Karachaganak gas to Almaty may not yet be competitive.

Table 5: Indicative Supply Cost of Imported Gas to Almaty

Cases of Import Gas Price (US$ per 1000 CM)	Gas Transport Cost (from Symkent to Almaty) (US$ per 1000 CM)	Indicative Supply Cost of Imported Gas to Almaty (US$ per 1000 CM)
35	7.4	42.4
40	7.4	47.4
50	7.4	57.4
55	7.4	62.4

[2] See Section A of Chapter III, "Allocation and Market Values of Natural Gas"

[3] Based on design rates of 12 BCM/Y from Karachganak to Kr. Ok. and 7 BCM/Y rom Kr. Ok. to Akmola.

[4] Based on a design rate of 5 BCM/Y.

Supply Costs of Gas from Prospective Domestic Fields

6. The Amangueldy field and neighboring fields in Zhambyl oblast is located less than 200 Km from the existing southern transit pipeline. The reserve volume is not gigantic but the supply cost of Amangueldy gas to Almaty could be competitive. Similarly, gas supply to Kizyl-Orda from the Zhanazol and Urihtau fields (both of which are located within 200 Km from Kizyl-Orda) appears economically attractive. Very preliminary supply costs of the above gas supply options are presented below. Since the indicative gas market value for power generation in Almaty and Kizyl-Orda is about US$ 80 per 1000 CM, the above gas supply schemes would be economically viable.

Table 6: Indicative Supply Cost of Amangueldy Gas to Almaty and Supply Costs of Zhanazol and Urihtau Gas to Kizyl-Orda

Indicative Gas Delivery Cost (US$ per 1000 CM)	Indicative Transport Cost (US$ per 1000 CM)	Indicative Supply Cost to the City Gate (US$ per 1000 CM)
from Amangueldy (Max 3 BCM/Y): 24.7	3.5 (completion of unfinished 130 Km) + 7.4=10.9	to Almaty: 35.6
from Zhanazol (Max 2 BCM/Y): 9.5	1.0 (16" x completion of unfinished 30 Km)	to Kizyl-Orda: 10.5
from Karachaganak (Max. 5 BCM/Y): 17.7	10.2	to Kizyl-Orda 27.9
from Urihtau (Max 2 BCM/Y): 16.9	6.0 (16" x 180 Km)	to Kizyl-Orda: 22.9

		Aksai - Kr Ok Pipeline (VECO F/S)					
Year	Gross	Net	Proj Tariff	Revenue	Capex	Ope.Cost	Net Rev.
	Gas Sales	Gas Sales				Pipeline	
	(BCM/Y)	(BCM/Y)	($/MMBTU)	($ million)	($mm)	($mm)	
1	0	0	0.75	0	125.2		-125.2
2	0	0	0.75	0	281.7		-281.7
3	0	0	0.75	0	219.1		-219.1
4	4.76	4.52	0.75	122.04	0	11.22	110.8221
5	4.76	4.52	0.75	122.04	0	11.22	110.8221
6	4.76	4.52	0.75	122.04		11.22	110.8221
7	4.76	4.52	0.75	122.04		11.22	110.8221
8	4.76	4.52	0.75	122.04		11.22	110.8221
9	4.76	4.52	0.75	122.04		11.22	110.8221
10	4.76	4.52	0.75	122.04		11.22	110.8221
11	4.76	4.52	0.75	122.04		11.22	110.8221
12	4.76	4.52	0.75	122.04		11.22	110.8221
13	4.76	4.52	0.75	122.04		11.22	110.8221
14	4.76	4.52	0.75	122.04		11.22	110.8221
15	4.76	4.52	0.75	122.04		11.22	110.8221
16	4.76	4.52	0.75	122.04		11.22	110.8221
17	4.76	4.52	0.75	122.04		11.22	110.8221
18	4.76	4.52	0.75	122.04		11.22	110.8221
19	4.76	4.52	0.75	122.04		11.22	110.8221
20	4.76	4.52	0.75	122.04		11.22	110.8221
21	4.76	4.52	0.75	122.04		11.22	110.8221
22	4.76	4.52	0.75	122.04		11.22	110.8221
23	4.76	4.52	0.75	122.04		11.22	110.8221
24	4.76	4.52	0.75	122.04		11.22	110.8221
25	4.76	4.52	0.75	122.04		11.22	110.8221
26	4.76	4.52	0.75	122.04		11.22	110.8221
27	4.76	4.52	0.75	122.04		11.22	110.8221
28	4.76	4.52	0.75	122.04		11.22	110.8221
Total		113		3051	626	280.448	2144.552
NPV @15%				$519	$465.9	$72.5	$5.1

Year	Gross Gas Sales (BCM/Y)	Net Gas Sales (BCM/Y)	Proj Tariff ($/MMBTU)	Revenue ($ million)	Capex ($mm)	Ope.Cost Pipeline ($mm)	Net Rev. ($mm)
		Alaugaz Pipeline					
1	12	3.5	0.211	26.586	10	19	-2.4
2	12	3.5	0.211	26.586	24	20.200	-17.6
3	12	3.9	0.211	29.6244	24	21.400	-15.8
4	12	4.3	0.211	32.6628	24	22.600	-13.9
5	12	4.7	0.211	35.7012	24	23.800	-12.1
6	12	5.1	0.211	38.7396	24	25.000	-10.3
7	12	5.4	0.211	41.0184		25.000	16.0
8	12	5.4	0.211	41.0184		25.000	16.0
9	12	5.4	0.211	41.0184		25.000	16.0
10	12	5.4	0.211	41.0184		25.000	16.0
11	12	5.4	0.211	41.0184		25.000	16.0
12	12	5.4	0.211	41.0184		25.000	16.0
13	12	5.4	0.211	41.0184		25.000	16.0
14	12	5.4	0.211	41.0184		25.000	16.0
15	12	5.4	0.211	41.0184		25.000	16.0
16	12	5.4	0.211	41.0184		25.000	16.0
17	12	5.4	0.211	41.0184		25.000	16.0
18	12	5.4	0.211	41.0184		25.000	16.0
19	12	5.4	0.211	41.0184		25.000	16.0
20	12	5.4	0.211	41.0184		25.000	16.0
21	12	5.4	0.211	41.0184		25.000	16.0
22	12	5.4	0.211	41.0184		25.000	16.0
23	12	5.4	0.211	41.0184		25.000	16.0
24	12	5.4	0.211	41.0184		25.000	16.0
25	12	5.4	0.211	41.0184		25.000	16.0
26	12	5.4	0.211	41.0184		25.000	16.0
27	12	5.4	0.211	41.0184		25.000	16.0
28	12	5.4	0.211	41.0184		25.000	16.0
							0.0
Total		143.8		1092.305	130	682	280.3
NPV @15%				$229	$78.7	$150.2	($0.2)
						IRR	15.0%

Note: Used Alaugaz information, e.g. 620 million Tenge (or US$ 9.25 mm) for urgent repair and 10 billion Tenge (or US$ 149.25 mm) for rehabilitation of the line.

Assumed $130 million is required for the Symkent- Almaty Section.

The operating cost of the pipeline is based on Alaugaz operation cost in 1995 (e.g. 1,385 mm Tenge or US$ 18.5 mm) plus 5% of the new investment.

According to Kazakgaz' Pipeline Development Plan (May 1996), the gas market in the south regions is max. 5.4 bcm per year. (Alamty: 1.2; Zhambul: 2.2;South Kazak: 2.2).

		Chelkar - Symkent Line (5 BCM/Y)						
Year	Gross	Net	Proj Tariff	Revenue	Capex	Ope.Cost	Net Rev.	
	Gas Sales	Gas Sales				Pipeline		
	(BCM/Y)	(BCM/Y)	($/MMBTU)	($ million)	($mm)	($mm)		
1	0	0	1.26	0	224		-224	
2	0	0	1.26	0	504		-504	
3	0	0	1.26	0	392		-392	
4	5	4.75	1.26	215.46	0	20.07	195.3896	
5	5	4.75	1.26	215.46	0	20.07	195.3896	
6	5	4.75	1.26	215.46		20.07	195.3896	
7	5	4.75	1.26	215.46		20.07	195.3896	
8	5	4.75	1.26	215.46		20.07	195.3896	
9	5	4.75	1.26	215.46		20.07	195.3896	
10	5	4.75	1.26	215.46		20.07	195.3896	
11	5	4.75	1.26	215.46		20.07	195.3896	
12	5	4.75	1.26	215.46		20.07	195.3896	
13	5	4.75	1.26	215.46		20.07	195.3896	
14	5	4.75	1.26	215.46		20.07	195.3896	
15	5	4.75	1.26	215.46		20.07	195.3896	
16	5	4.75	1.26	215.46		20.07	195.3896	
17	5	4.75	1.26	215.46		20.07	195.3896	
18	5	4.75	1.26	215.46		20.07	195.3896	
19	5	4.75	1.26	215.46		20.07	195.3896	
20	5	4.75	1.26	215.46		20.07	195.3896	
21	5	4.75	1.26	215.46		20.07	195.3896	
22	5	4.75	1.26	215.46		20.07	195.3896	
23	5	4.75	1.26	215.46		20.07	195.3896	
24	5	4.75	1.26	215.46		20.07	195.3896	
25	5	4.75	1.26	215.46		20.07	195.3896	
26	5	4.75	1.26	215.46		20.07	195.3896	
27	5	4.75	1.26	215.46		20.07	195.3896	
28	5	4.75	1.26	215.46		20.07	195.3896	
Total		118.75		5386.5	1120	501.76	3764.74	
NPV @15%				$916	$833.6	$129.7	($3.2)	
						IRR	14.9%	

Note: The capex, US$ 1220 million is estimated using the cost yardstick for the Or. Kr. - Akmola pipeline. Details are given below:

OK-Akmola: Okon/Enron Estimate= US$ 1,612 million, total 52,000 in-Km (40 inch x 1300 Km)

Chelkar - Symkent: total 39,340 in-Km (40 inch x 441 Km plus 28 inch x 775 Km)

US$ 1,612 mm x (39,340/52,000)= US$ 1,220 mm

	Ok - Akomola Pipeline (Okon/Enron F/S)														
Gross	Net	Proj Tariff	Revenue			Capex					Ope.Cost				Net Rev.
Gas Sales	Gas Sales			Line	Comp	Meter St.	Total	Line	Comp	Meter St.	Energy	NW Loss	PSN Cost	Total	
(BCM/Y)	(BCM/Y)	($/MMBTU)	($ million)	($mm)	($mm)	($mm)	($mm)	($mm)	($mm)	($mm)	($mm)	($mm)	($mm)	($mm)	
0	0	1.45	0	586.963	0	21.179	608.142							0	-608.142
0	0	1.45	0	261.409	0	0.756	262.165							0	-262.165
0	0	1.45	0	596.078	143.583	2.268	741.929							0	-741.929
7.24	3.05	1.45	159.21			0		6.457	0	2.902	0.09	0.99	0.60	11.044	148.166
7.24	3.05	1.45	159.21			0		9.332	0	3.005	0.47	0.99	0.60	14.399	144.811
7.24	7.24	1.45	377.928					15.889	12.348	3.316	0.63	2.35	0.60	35.135	342.793
7.24	7.24	1.45	377.928					15.889	12.348	3.316	1.76	2.35	0.60	36.266	341.662
7.24	7.24	1.45	377.928					15.889	12.348	3.316	2.89	2.35	0.60	37.397	340.531
7.24	7.24	1.45	377.928					15.889	12.348	3.316	3.71	2.35	0.60	38.214	339.714
7.24	7.24	1.45	377.928					15.889	12.348	3.316	4.59	2.35	0.60	39.094	338.834
7.24	7.24	1.45	377.928					15.889	12.348	3.316	5.41	2.35	0.60	39.911	338.017
7.24	7.24	1.45	377.928					15.889	12.348	3.316	5.97	2.35	0.60	40.477	337.451
7.24	7.24	1.45	377.928					15.889	12.348	3.316	6.63	2.35	0.60	41.131	336.797
7.24	7.24	1.45	377.928					15.889	12.348	3.316	6.63	2.35	0.60	41.131	336.797
7.24	7.24	1.45	377.928					15.889	12.348	3.316	6.63	2.35	0.60	41.131	336.797
7.24	7.24	1.45	377.928					15.889	12.348	3.316	6.63	2.35	0.60	41.131	336.797
7.24	7.24	1.45	377.928					15.889	12.348	3.316	6.63	2.35	0.60	41.131	336.797
7.24	7.24	1.45	377.928					15.889	12.348	3.316	6.63	2.35	0.60	41.131	336.797
7.24	7.24	1.45	377.928					15.889	12.348	3.316	6.63	2.35	0.60	41.131	336.797
7.24	7.24	1.45	377.928					15.889	12.348	3.316	6.63	2.35	0.60	41.131	336.797
7.24	7.24	1.45	377.928					15.889	12.348	3.316	6.63	2.35	0.60	41.131	336.797
7.24	7.24	1.45	377.928					15.889	12.348	3.316	6.63	2.35	0.60	41.131	336.797
7.24	7.24	1.45	377.928					15.889	12.348	3.316	6.63	2.35	0.60	41.131	336.797
7.24	7.24	1.45	377.928					15.889	12.348	3.316	6.63	2.35	0.60	41.131	336.797
7.24	7.24	1.45	377.928					15.889	12.348	3.316	6.63	2.35	0.60	41.131	336.797
7.24	7.24	1.45	377.928					15.889	12.348	3.316	6.63	2.35	0.60	41.131	336.797
7.24	7.24	1.45	377.928					15.889	12.348	3.316	6.63	2.35	0.60	41.131	336.797
7.24	7.24	1.45	377.928					15.889	12.348	3.316	6.63	2.35	0.60	41.131	336.797
														0	
	172.62		9010.764	1444.45	143.583	24.203	1612.236	381.236	284.004	82.175	131.517	56.101	15	950.033	6448.495
			$1,373	$1,100.0	$94.4	$20.5	$1,214.9	$89.5	$59.7	$20.8	$21.3	$13.0	$3.9	$137.0	$20.7

		Amangueldy -Symkent (20 inch x 130 Km for 3 BCM/Y)					
Year	Gross	Net	Proj Tariff	Revenue	Capex	Ope.Cost	Net Rev.
	Gas Sales	Gas Sales				Pipeline	
	(BCM/Y)	(BCM/Y)	($/MMBTU)	($ million)	($mm)	($mm)	
1	0	0	0.1	0	26		-26
2	0	0	0.1	0	26		-26
3	1.5	1.5	0.1	5.4	0	0.93	4.46816
4	1.5	1.5	0.1	5.4	0	0.93	4.46816
5	3	3	0.1	10.8	0	0.93	9.86816
6	3	3	0.1	10.8		0.93	9.86816
7	3	3	0.1	10.8		0.93	9.86816
8	3	3	0.1	10.8		0.93	9.86816
9	3	3	0.1	10.8		0.93	9.86816
10	3	3	0.1	10.8		0.93	9.86816
11	3	3	0.1	10.8		0.93	9.86816
12	3	3	0.1	10.8		0.93	9.86816
13	3	3	0.1	10.8		0.93	9.86816
14	3	3	0.1	10.8		0.93	9.86816
15	3	3	0.1	10.8		0.93	9.86816
16	3	3	0.1	10.8		0.93	9.86816
17	3	3	0.1	10.8		0.93	9.86816
18	3	3	0.1	10.8		0.93	9.86816
19	3	3	0.1	10.8		0.93	9.86816
20	3	3	0.1	10.8		0.93	9.86816
21	3	3	0.1	10.8		0.93	9.86816
22	3	3	0.1	10.8		0.93	9.86816
23	3	3	0.1	10.8		0.93	9.86816
24	3	3	0.1	10.8		0.93	9.86816
25	3	3	0.1	10.8		0.93	9.86816
26	3	3	0.1	10.8		0.93	9.86816
27	3	3	0.1	10.8		0.93	9.86816
28	3	3	0.1	10.8		0.93	9.86816
Total		75		270	52	24.22784	193.7722
NPV @15%				$46	$42.3	$6.0	($0.5)
						IRR	14.8%

		Zhanazol- Aktyubinsk (16 inch x uncompleted 30 Km for 2 BCM/Y)					
Year	Gross	Net	Proj Tariff	Revenue	Capex	Ope.Cos	Net Rev.
	Gas Sales	Gas Sales				Pipeline	
	(BCM/Y)	(BCM/Y)	($/MMBTU	($ million)	($mm)	($mm)	
1	0	0	0.08	0	5		-5
2	0	0	0.08	0	5		-5
3	1	1	0.08	2.88	0	0.18	2.7008
4	1	1	0.08	2.88	0	0.18	2.7008
5	2	2	0.08	5.76	0	0.18	5.5808
6	2	2	0.08	5.76		0.18	5.5808
7	2	2	0.08	5.76		0.18	5.5808
8	2	2	0.08	5.76		0.18	5.5808
9	2	2	0.08	5.76		0.18	5.5808
10	2	2	0.08	5.76		0.18	5.5808
11	2	2	0.08	5.76		0.18	5.5808
12	2	2	0.08	5.76		0.18	5.5808
13	2	2	0.08	5.76		0.18	5.5808
14	2	2	0.08	5.76		0.18	5.5808
15	2	2	0.08	5.76		0.18	5.5808
16	2	2	0.08	5.76		0.18	5.5808
17	2	2	0.08	5.76		0.18	5.5808
18	2	2	0.08	5.76		0.18	5.5808
19	2	2	0.08	5.76		0.18	5.5808
20	2	2	0.08	5.76		0.18	5.5808
21	2	2	0.08	5.76		0.18	5.5808
22	2	2	0.08	5.76		0.18	5.5808
23	2	2	0.08	5.76		0.18	5.5808
24	2	2	0.08	5.76		0.18	5.5808
25	2	2	0.08	5.76		0.18	5.5808
26	2	2	0.08	5.76		0.18	5.5808
27	2	2	0.08	5.76		0.18	5.5808
28	2	2	0.08	5.76		0.18	5.5808
Total		50		144	10	4.6592	129.3408
NPV @15%				$25	$8.1	$1.2	$15.7
						IRR	36.1%

		Urihtau- Aktyubinsk (16 inch x 180 Km for 2 BCM/Y)					
Year	Gross	Net	Proj Tariff	Revenue	Capex	Ope.Cos	Net Rev.
	Gas Sales	Gas Sales				Pipeline	
	(BCM/Y)	(BCM/Y)	($/MMBTU	($ million)	($mm)	($mm)	
1	0	0	0.17	0	28.8		-28.8
2	0	0	0.17	0	28.8		-28.8
3	1	1	0.17	6.12	0	1.03	5.087808
4	1	1	0.17	6.12	0	1.03	5.087808
5	2	2	0.17	12.24	0	1.03	11.20781
6	2	2	0.17	12.24		1.03	11.20781
7	2	2	0.17	12.24		1.03	11.20781
8	2	2	0.17	12.24		1.03	11.20781
9	2	2	0.17	12.24		1.03	11.20781
10	2	2	0.17	12.24		1.03	11.20781
11	2	2	0.17	12.24		1.03	11.20781
12	2	2	0.17	12.24		1.03	11.20781
13	2	2	0.17	12.24		1.03	11.20781
14	2	2	0.17	12.24		1.03	11.20781
15	2	2	0.17	12.24		1.03	11.20781
16	2	2	0.17	12.24		1.03	11.20781
17	2	2	0.17	12.24		1.03	11.20781
18	2	2	0.17	12.24		1.03	11.20781
19	2	2	0.17	12.24		1.03	11.20781
20	2	2	0.17	12.24		1.03	11.20781
21	2	2	0.17	12.24		1.03	11.20781
22	2	2	0.17	12.24		1.03	11.20781
23	2	2	0.17	12.24		1.03	11.20781
24	2	2	0.17	12.24		1.03	11.20781
25	2	2	0.17	12.24		1.03	11.20781
26	2	2	0.17	12.24		1.03	11.20781
27	2	2	0.17	12.24		1.03	11.20781
28	2	2	0.17	12.24		1.03	11.20781
Total		50		306	57.6	26.83699	221.563
NPV @15%				$53	$46.8	$6.7	$0.7

Appendix 3.9

Hydraulic Analysis of Existing Gas Transmission Pipelines

Introduction

1. The existing gas transmission pipelines were built in 1960s, 70s and 80s. Most of the pipelines require major rehabilitation. The existing gas storage facilities are located inadequately and are insufficient in capacity. Given the expected growth of gas consumption in each consumption center in Kazakhstan, it is crucial to review and assess the bottlenecks of the present gas transmission system and to find a least cost solution.

2. A preliminary hydraulic analysis has been attempted to identify major bottlenecks of the following gas transmission pipelines:

- Central Asia Center (CAC) Pipeline System;
- Bukhara-Ural Pipeline System;
- Gazli/Bukhara-Symkent-Almaty Pipeline System; and
- Orenburg-Novopkosk Pipeline System.

Such a hydraulic analysis is essential for pipeline planning and operations and it is strongly recommended that all the Kazak gas companies possess such a design tool and conduct a similar analysis annually based on the future supply and demand situation, as desired from ongoing market surveys.

3. The information was given by Kazakgaz and EC Energy Center but was not necessarily detailed enough. Detailed information on length/diameter of all relevant pipeline sections and on the configuration of interconnections is not available. Also it is not very clear where exactly offtake points exist, how much gas is extracted, and what are the exact operating conditions. Therefore, the overall accuracy of this basic model structure is estimated in a range of +/- 50 to 75 %. Further follow-up analyses are needed before any investment decision, using more exact information based on site surveys.

Preliminary Findings

4. ***Central Asia Centre Pipeline System:*** The system was designed for a capacity of 185 million m^3/day (border to border). As a result of recent demand changes, the operating

capacity has dropped to a level of 95 million m^3/day. The result of the hydraulic analysis indicates that this reduced capacity can be handled even without two lines, CAC-1 and CAC-2 lines which require rehabilitation, and with a reduced operation mode at some of compressor stations (ex. without use of units 4 and 5 compressors at the KC-Oporny compressor station).

5. It is assumed that the bulk of the transit flow enters into the CAC via Uzbekistan. The pipeline system from the direction of Novy Uzen is able to transport a substantial flow from Turkmenistan toward the CAC. A flow rate of 36 million m3/day can be transported using this pipeline. The capacity of the pipeline branch toward the Northern Caucasus depends on the available pressure level at the entrance of the Makat compressor station. To maximise the operating capacity of this system, the entrance pressure at Makat should be maintained at least 70 Bar. With this pressure, a transport capacity of 70 million m3/day is achievable.

6. So long as the above reduced capacity is kept, no major bottlenecks are foreseen for the design of the present system. Described below are some recommended measures for upgrading the capacity of the CAC pipeline system:

- Rehabilitation program on the CAC-1 and CAC-2 to bring these line back into operation;
- At the KC-Oporny compressor station; make units 4 and 5 operational;
- Decrease the level of inner wall roughness as this exceeds international standards; and
- Optimise the operation of the lines with different pressure stages in such a way that the installed compression power is used in an optimal way.

7. ***Bukhara-Ural Pipeline System:*** This system was originally designed to transport 40 million m^3/day of gas from Uzbekistan to the border with Russia. The actual flow through the system has decreased dramatically. Today's flow rate is at about 4.5 million m3/day from the south (Uzbekistan) to the north (Russia). During summer when filling gas into the underground storage at Bazai, the flow is reversed.
Based on the supplied information regarding the operation conditions of the pipeline branches to Aktyubinsk/Alga and Kustanay/Lizakovsk, no major bottlenecks are foreseen in the near term so long as the above reduced capacity operation continues.

8. ***Gazli/Bukhara-Symkent-Bishek-Almaty Pipeline System:*** A basic assumption used for the hydraulic analysis is that there is no gas flow from the Bukhara to Symkent, Bishek and Almaty. The Bukhara branch pipeline is assumed to be entirely serving the markets in the Tashkent-region. The result of the hydraulic analysis indicates the requirement of the following measures:

- Take all existing lines that are out of operation back into full service (rehabilitation program).
- Increase the capacity of the Gazli-Symkent line by:
    1. Increasing the actual maximum operating pressure to the original level of 75 Bar.
    2. Eliminating liquid inclusion in the pipeline by installing filters and liquid drain facilities at strategic points (such as at the entrance of each compressor station).
    3. Installing additional two or three compressor units within Kazakhstan at the pipeline distance of 380 km.
- Add 22 km of 1020 millimetre pipeline upstream of the KC-4A compressor station.
- Double the last section up to Almaty with a pipe section of 47 km using a diameter of 1020 millimetre. (For optimisation of the pipe diameter, a further analysis is needed taking account of future demand.)
- Pipeline with compression bypassing Kyrgyzistan territory near Bishek. Length 152 km and a diameter of 1020 million (further optimisation needed). The effect of a pipeline only is minimal so compression in the bypass line is needed
- A total of 40 km pipeline would be needed between compressor stations KC-4A and KC-5 to strengthen the present operation which is currently catered by a single line.
- Recover the maximum operating pressure reduction from the present 33 Bar to 55 Bar in the section to Almaty (from the 1115 km point onwards).

9. If all the above measures are taken, the maximum flow rate to Almaty will be increased from the present level of 4 million m^3/day level to 12 million m^3/day. The total supply from the direction of Gazli will be increased from the current level of 15 million m^3/day to 50 million m3/day. A further analysis is needed for the Uzebek part of this line.

10. ***Orenburg-Novopkovsk Pipeline System:*** The two transit pipelines, e.g. the Soyuz and the Novopkovsk pipelines are under operation at 80 and 35 million m^3/day respectively, despite their design capacities of 95 million m^3/day for the Soyuz line and 55 million m^3/day for the Novopkovs line. To maximise the operating capacities close to the original design capacities, the following measures are recommended:

- Decrease the roughness of the pipe line inner wall;
- Upgrading one or two of the compressor station from single stage (a compression ratio of 1.45) to two stage compression (a ratio of 1.9).
- Make double pipelines for a section of 40 to 50 Km at the outlet side of each compressor station.

General Remarks for Upgrading the Capacity of Existing Pipeline Systems

For all the cases above, the following two measures could be effective to improve the transport capacity:

First, try to improve the operation conditions to close to the original design conditions. This may require extensive repairs of each pipeline section. In case existing small diameter pipelines require repairs, replacement by larger diameter pipes would be a better option.

Second, decrease the inner wall roughness of the existing pipes. Most of the existing pipelines have high fractions as a result of aged pipes and insufficient gas conditioning in terms of dehydration and sweetening. All calculations have been done with an assumption of pipe inner wall roughness of 100 *um* (micro meter). The following table presents possible improvement of flow conditions by smoothening inner pipe walls:

Table 1: Effect of inner wall roughness of the transport capacity

(Unit: million m 3/day)

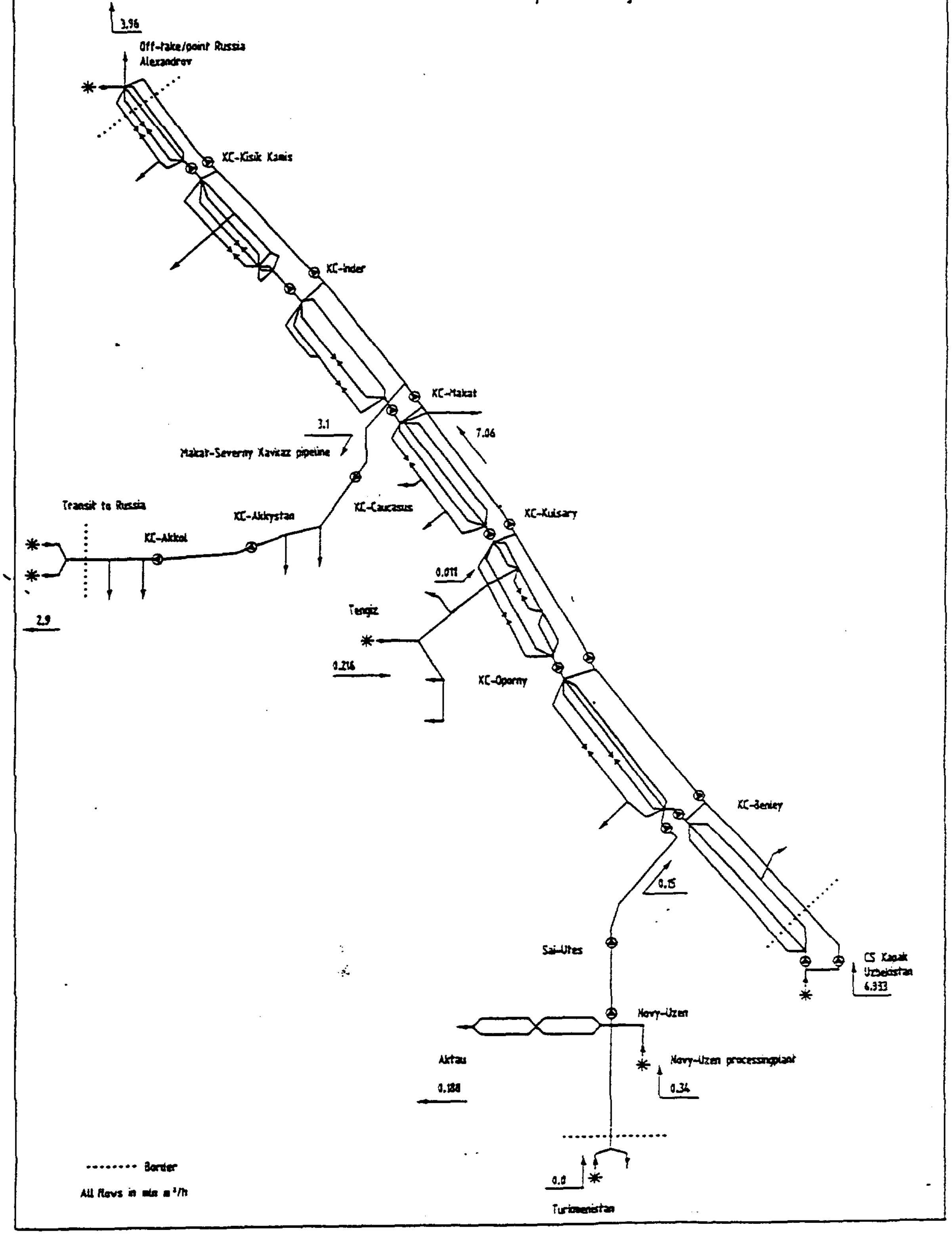
Pipeline	*Roughness 100 um*	*Roughness 25 um*	**Incremental Flow**
Soyuz	78	87	**9 (about 3.3 BCM)**
Novopskov	37	42	**5 (about 1.8 BCM)**

A high level of inner wall roughness could be caused due to a combination of the following reasons:

- Corrosion
- No inner wall coating applied during the construction of the pipeline
- Contamination by liquids in the pipeline (accumulation at low points)
- Contamination by solids materials like sand, etc.

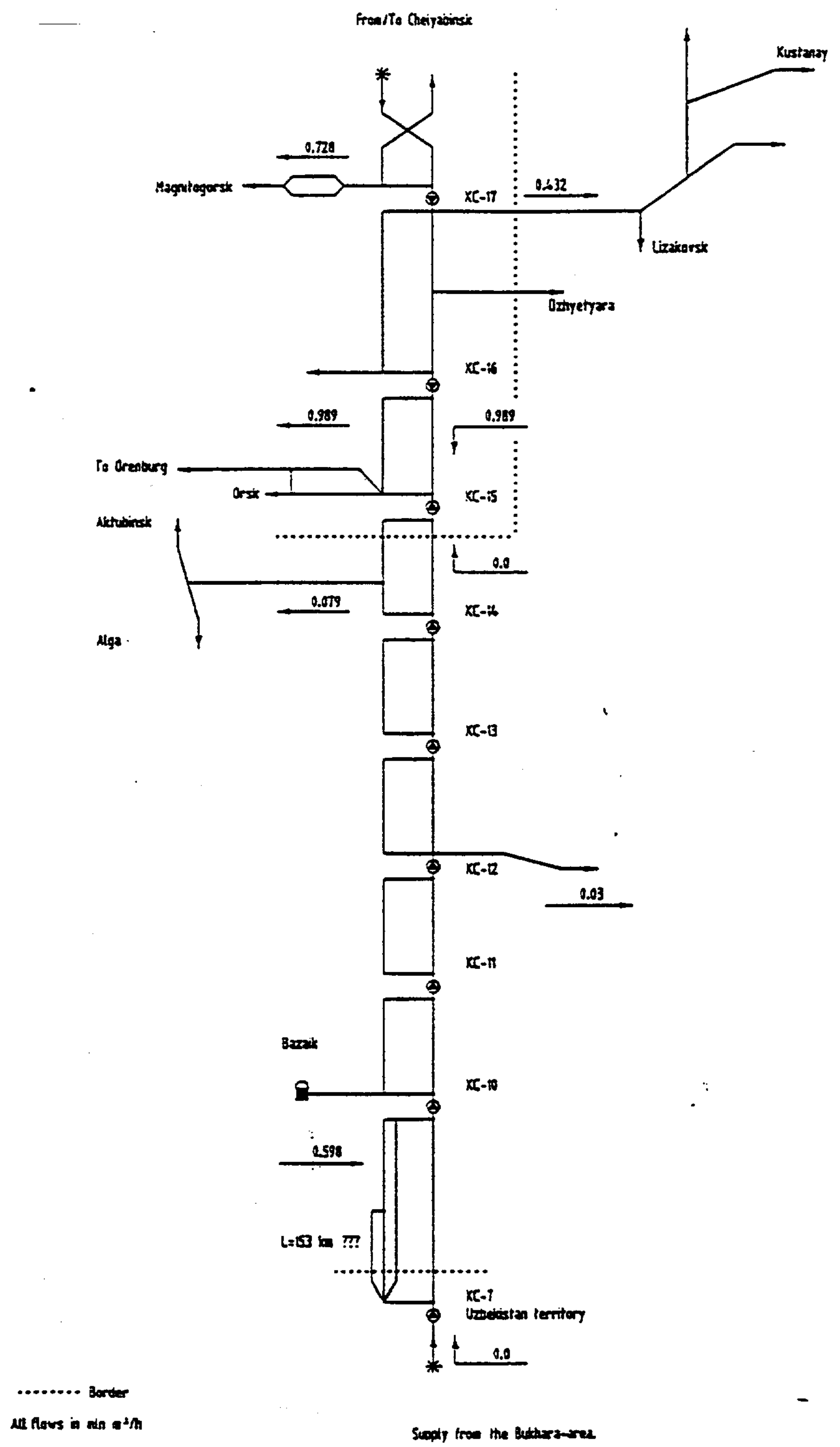
The first two reasons above are most serious. The last two could be improved by extensive scraper operations and preventing the influx of solids and liquids into the pipelines.

Middle Asia Center Pipelinesystem



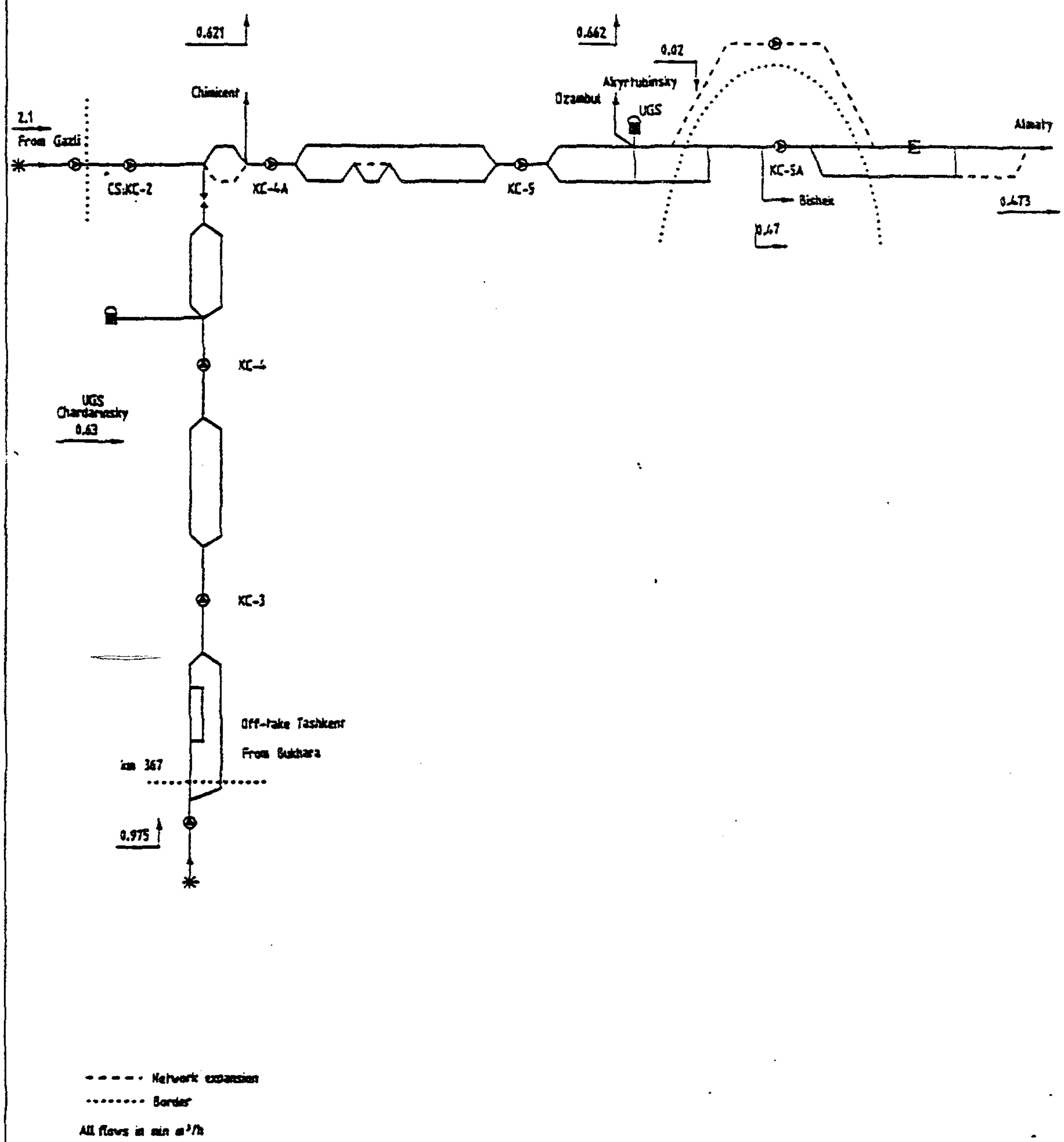
Scheme 1

Bukhara-ural Pipeline-system.



Scheme 2.

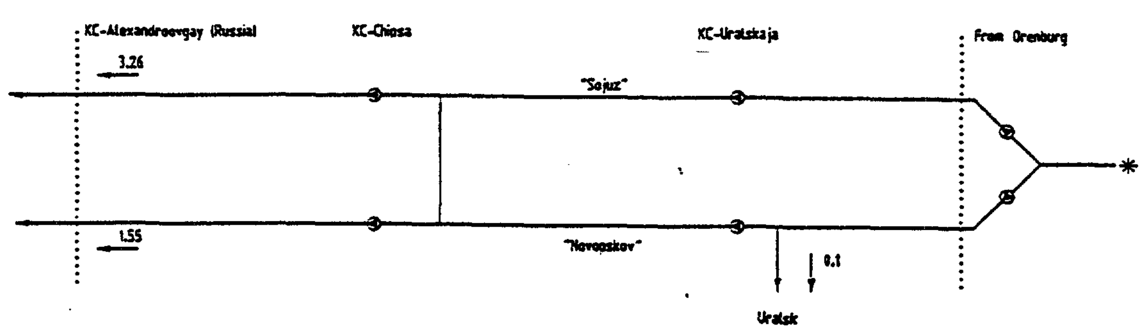
Gazli / Bukhara to Almaty



Scheme 3

Orenburg-Novopkovsk pipeline system

Uralsktransgaz



.... Border

All flows in mln m³/h

Scheme 4

Appendix 3.10
Existing Organizational Structure of Domestic Gas Operations

1. Till March 1997, the nation's petroleum industry had been organized by functions under the administrative oversight of the former Ministry of Oil and Gas (MOG) and the former Ministry of Geology (MG). Oil and gas production, transmission and distribution fell under the MOG, while petroleum exploration is under the MG. Oil production, refining and transportation are managed mostly by functionally-based regional associations. From March 1997, all these functions were shifted to the newly formed Ministry of Energy and Natural Resources (MENR). Furthermore, the oil industry is in the process of privatization and most of oil production fields and refineries are now owned either by joint ventures or private entities. The gas sector is also in the middle of privatization.

2. The decree of Cabinet Ministers, No. 1237 issued on October 6, 1995 specified to create the two joint stock companies for gas transmission, Kazakgaz and Alaugaz under MOG's supervision. The same decree specifies complete separation of the ownership of local gas distribution companies from that of the gas transmission companies. The same decree calls for creation of a joint stock company, "Karachaganakgas" which possesses the rights for production, processing and sale of hydrocarbon condensates and associated gas in the Karachaganak field. In March 1997, based on a new decree a national oil company called Kazakoil was created. The new company took over the assets of Karachaganakgas.

3. ***Kazakgaz***, a joint stock company has now decreased its assets and responsibility as a result of the on-going privatization and the recent administrative reforms. As of June 1997, Kazakgaz is still responsible for operation of a major local pipeline network primarily in western Kazakhstan and gas transit pipelines from Turkmenistan/Uzbekistan to Russia. Kazakgaz covers gas transmission to 5 oblasts: Western-Kazakhstan (or Uralsk); Atyrau; Mangystau; Akyubinsk; and Kostanai. Its operating responsibility ends at the gas distribution station in each oblast where the local gas distribution companies (oblagas companies) take over. At present, the joint stock company, Karachaganakgas is formed under Kazakgaz. Under Kazakgaz organization, another joint stock company, "Batystransgas" has been formed. This company is responsible for operations of the Central-Asia-Center (CAC) gas transmission pipelines from Turkmenistan/Uzbekistan and to Russia. Kazakgaz was once the sole national gas company and covers a majority share of the country's gas purchase from the neighboring gas producing countries (e.g. Turkmenistan, Uzbekistan and Russia). Kazakgaz is in the middle of its privatization process. Some international gas companies are interested in a 15 year concession agreement with Kazakgas for operation of the CAC pipeline. Therefore, the organizational structure of Kazakgaz is expected to change in the near future (by the end of 1997).

4. ***Alaugaz***, a joint stock company, has since 1994 been operating the country's main southern gas main transmission system, from Gazli to Almaty. Alaugaz primarily delivers natural gas from the southern border with Uzbekistan to the three populated oblasts in the southern Kazakhstan: Symkent (or South Kazakhstan), Zhambyl and Almaty. The State Committee for Public Property Management currently holds, on behalf of the Government of Kazakhstan, 90% percent of Alaugaz shares. Alaugaz is also responsible for LPG transportation.

5. ***Local Gas Distribution Companies (LDCs)*** **or "Oblagas" Companies** are currently operating under the management of eight individual oblast governments. However, the State Committeee for Public Property Management owns 90% of the individual LDCs' shares. Tariffs governing retail sales of LPG and natural gas are determined by the regional committees on prices and antimonopoly policies under the State Anti-Monopoly Committee, and then must be agreed upon by the regional governors.

6. The Government of Kazakhstan retains ownership of gas producing properties, e.g. gas resources at the field level. Operating companies (e.g, gas producers), include such enterprises as Mangystaumunaigas; Embaneft; Tengizneft; Aktyubinskneft; and Yuzhkazneftegas.

7. GOK has initiated a rapid privatization process for the gas sector. By December 1996, some international gas companies expressed their interest in a 15 year concession agreement with Kazakgaz for the operation of the CAC pipeline. The selection of the Kazakgaz partner is on a bid basis which was recommended by Kazcommerzbank and Paribas Bank, the consultants for the privatization. The Government intends a similar privatization process for the rest of the gas companies including oblagas companies, but the progress is so far retarded.[1]

8. Privatization is a major agenda/item in the power sector too. The former Ministry of Electricity and Coal Industry (MOEC) issued a decree (No. T-574) on July 18, 1996, to promote the privatization process, setting a target date as the middle of 1997 for privatization of large power stations, and the end of 1998 for the rest of power stations and electricity distribution companies. The national transmission grid owned by Kazenergo is subject to a five year concession.

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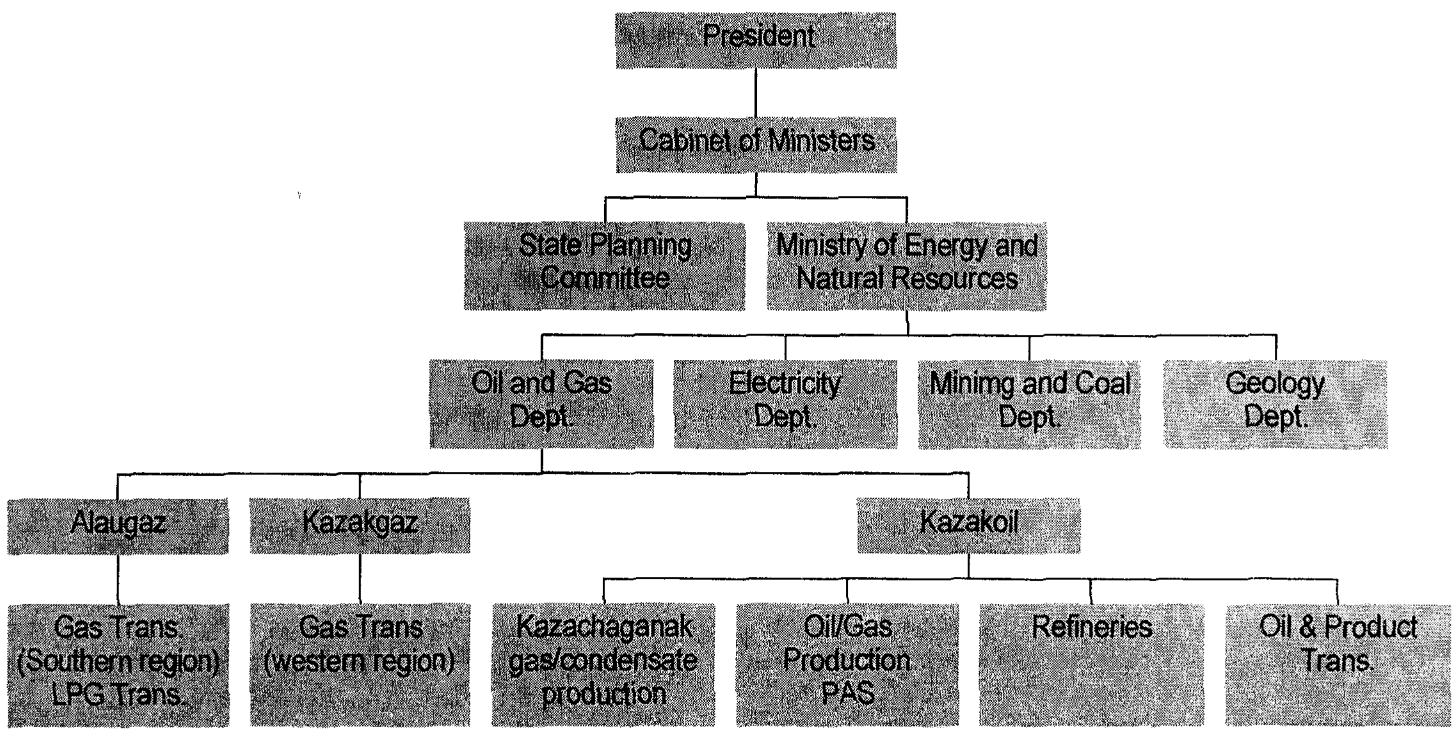
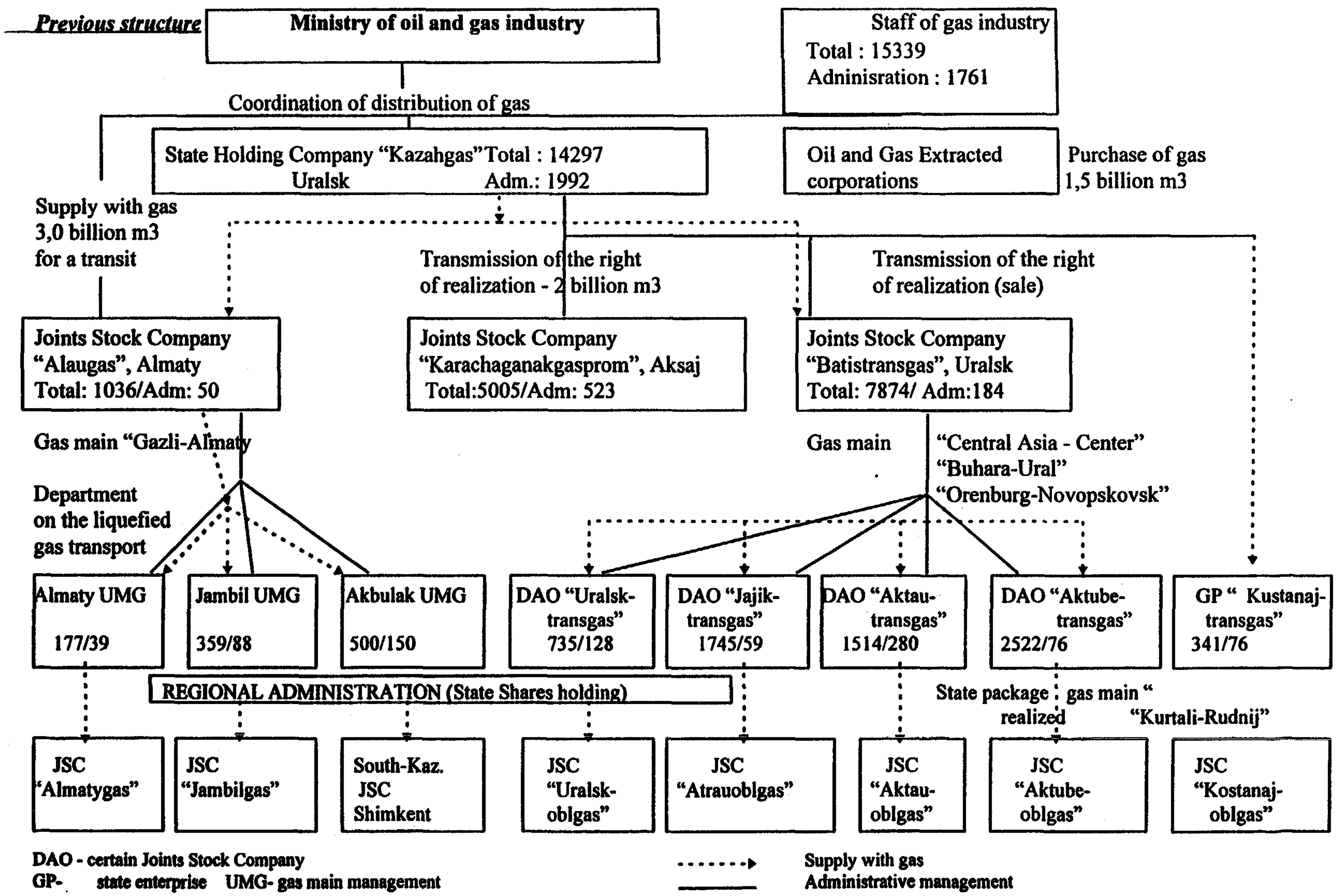
1 According to the Prime Minister's decree, No. 1126 dated September 17, 1996, the auction process for Kazakgaz was subject to complete by November 30, 1996, followed by a similar privatization process for Alaugaz and LDCs. The bid evaluation process is in delay. As of June 1997, negotiations with the bidders are underway.

Appendix 3-10
Figure 1
Organization of Energy Sector (After March 4, 1997)



Appendix 3.10 Existing Gas Sector Institutional Arrangement



Appendix 3.11

Non-payment Issue and Proposed Countermeasures

1. As with other CIS countries, there is a wide-spread non-payment issue in Kazak gas sector. Such non-payment starts from end consumers, creating a chain reaction of payment arrears in the gas supply chain. All gas companies are running substantial arrears in collections. Local gas distribution companies which supply gas to end users are unable to collect in a timely manner, if at all. In turn, they are building up accounts payable with gas transmission companies. According to Kazakgaz financial statements covering the first half of 1996, its account receivable reached in 1995 29,721 million Tenge or more than 200% of its annual revenue. There is no future for the gas sector unless the non-payment issue is solved.

2. Clearly Kazak gas sector, and its economy, cannot continue accumulation of accounts receivable in this manner. Recently the World Bank has worked with Azerbaijan in solving a similar non-payment issue. Given the similarity in its economic structure, most of the proposed action programs would be useful for Kazakhstan. The proposed remedies include:

- Exemptions to gas companies' right to cut off supply to non-payers should be strictly limited to services which are essential to the well-being of the population, and for which no alternative forms of energy are available (e.g. heating and cooking for hospitals, nursing homes, orphans). In other cases, gas companies should have the automatic right to cut off supply once accounts are more than two months in arrears, and should exercise this right without exemption.
- Mutual settlements should be allowed and encouraged.
- Barter settlements should be allowed and encouraged, subject to the qualification that the goods should be ready marketable and/or useful to gas companies either in its operations or in settlement of some portion of its operating costs (purchase of goods and services, payment of wages), and all goods are valued at true market prices.
- Gas companies have the right to apply to attach and seize assets of non-paying customers who are six months or more in arrears, and to auction these assets in settlement of accounts. (for large industrial customers only.)
- Gas companies should be able to access all bank accounts of customers, including those held in domestic and foreign currency, who are six months or more in arrears. (for large industrial customers only)
- Fines for late payment by industrial, commercial and communal customers should be high enough to exceed the cost of commercial credit. (A fine of 1 percent per day is suggested in Azerbaijan.)
- Residential customers should be required to pay their gas bills based on the price prevailing in the month in which the bill is paid. Customers who are in

arrears would therefore risk having to pay for prior gas usage at a higher price if prices have increase in the interim.

- In the event that supply is cut off for non-payment, gas companies should have the right to demand a deposit against future gas consumption before reconnecting the customer and should have the right to insist on a pre-payment meter.
- The principle of mutual settlements should be extended to include moneys owing to the Government. If Government agencies are in arrears, gas companies should be allowed to deduct the amounts owing from required remittances of VAT, income tax, and other taxes.
- The government should support gas companies' effort by voicing its support for the above measures, and by setting an example through timely settlement of its own accounts.
- The Government should make an inventory of cross-debtedness to see how much can be canceled out when all major cross-debts are considered. Each company should have a phased action plan for recovering accounts receivable, culminating in full prepayment metering and disciplinary action.
- In addition to the wide-spread installation of prepayment meters, from a specified date, the Government should make company chairmen and financial executives face disciplinary action, including job loss, if they fail to make payments promptly (to suppliers and workers).

The terms and conditions of gas sales need to be clearly reflected in contracts and those should be announced in the media in advance.

3. Of all the above measures, the power to cut off supply to non-paying gas customers would be the most important. This is a matter that Government should decide and then should leave totally to the gas companies. There are too many examples elsewhere of the cut off power being a sham because of behind the scenes political pressure. Gas companies should have no obligation to supply even strategic customers if they are not making serious efforts to pay for current consumption plus a contribution to their arrears. A similar situation prevails between gas transmission and gas distribution companies. It is non-viable to forgive failure to pay by distributors.

Pre-payment Meters

4. Given the extremely bad payment record in recent years, one possibility that might change behavior is the widespread introduction of electrically-controlled pre-payment meters. Pre-payment meters have following benefits to the country; customers; and gas companies:

Benefits to the Country

- Dramatically change consumers' behavior (force them to understand that energy is not free any longer);
- Enhance energy saving (at least 10%); and
- Provide a solid foundation for privatization of gas distribution companies.

Benefits to Customers

- Customers have complete freedom to buy gas in accordance with their willingness to use; and
- Customers need not worry about billing errors and problems of dealing with gas companies.

Benefits to Gas Companies

- Elimination of account receivables;
- Elimination of meter reading operators;
- Reduction of the overheads of producing bills; and
- Gas companies can contract out sales of pre-payment cards to other agents.

5. The pre-payment system for the utility sector in the United Kingdom has been very successful for customers having problems budgeting their energy expenses. Utility companies use the method to provide non-paying customers a choice between disconnection and installation of a pre-payment meter. The system has normally a high possibility to collect the amount of the arrears automatically. In South Africa, a pre-payment system is used for the electricity sector. The South African Electricity Distribution Industry (EDI) currently is applying the system for 2 million residential consumers in the near future and later on for additional 3 million consumers. A pilot project in one of South African cities in 1994 was very successful. More recently, Tanzania has started introduction of a similar pre-payment system for the electricity sector.

6. For actual introduction of pre-payment meters in Kazakhstan, further investigation is needed, covering a rigorous cost-benefit analysis. Nevertheless, there is a good possibility that a relatively expensive pre-paid meter would pay-off in the long-run. If it is feasible, the introduction of such meters would be implemented, first, on a pilot scale basis and based on a group of middle to higher income customers using significant amounts of gas, to achieve successful launch, and later on, gradually expanded to lower volume customers.

Appendix 3.12

Domestic Gas Companies' Financial Position

1. The Kazak gas companies have prepared their accounts according to Russian/Kazak standards. These differ from international accounting standards (IAS) principally in that the FSU accounting system uses a combination of a cash basis and reserve funds. An enterprise recognizes costs when payment is made and revenues when cash is received. By contrast, IAS uses accrual accounting, under which efforts are made to ensure that costs relating to production (e.g. shop-floor wages) are effectively charged in the period in which the goods are sold. (This is achieved through the inventory valuation method). (See Annex 1).

2. Most of the financial statements reviewed by the ESMAP task force are not fully transparent and clear. As it stands, international investors and financiers may face with significant difficulty in understanding the true position of the gas companies and as a result, they are discouraged despite the country's potential in exploiting rich energy resources. However, the financial results appear to be so bad, no commercial financial institution would provide medium- or long-term finance without a full Government guarantee.

3. Given wide spread non-payment, most of the gas companies are financially insolvent. Resolving the non-payment is the most important financial issue. It will be essential for the transmission companies to limit supplies to the quantity paid for, and for LDCs to do the same. It should be noted that Kazakgaz did not feel that its financial data, or a discussion thereof, would be relevant to the gas strategy.

Kazakgaz

4. The recent financial position of Kazakgaz is summarized in Table 1 below. The table indicates that Kazakgaz is effectively insolvent, given a high ratio of accounts receivable (44% of the total assets in 1995), a high percentage of accounts payable (35% of the total liabilities and equity), and insufficient investment funds.

Table 1: Estimated Kazakgaz Revenue in 1995 (Indicative)

(Unit: Million Tenge)

	CAC Pipeline Transit Operation	Gas/condensate Production	Gas Sales to Local Distribution Companies	Total
Sales	21,000	6,424	877	28,301
Expenses	15,578	4,817	674	21,069
Income	5,422	1,607	203	**7,232**

5. In response to sharply decreasing cash revenue, Kazakgaz has been bound to delay investments and expenditures for operations and maintenance and has fallen further into its arrears on payments to gas suppliers (Tengizchevroil, etc.), its workers and the tax authorities. In relation to the tax code, Kazakgas is supposed to pay tax on the profits it would have made if it had been paid. This is incompatible with modern business and the tax code needs rewriting to provide for write off of bad debts. As to the workers, their pay is a small part of the overall cost, and Kazakgas is encouraging the non-payment habit in society if it does not pay workers so that they, in turn, can pay for their purchases.

6.. Kazakgaz main revenue has come from operations of the CAC pipeline, followed by production of hydrocarbon condensates and gas from the Karachaganak gas/condensate field. The income from the transit operation of the CAC pipeline in 1995 is very roughly estimated at US$ 77 million (or about 5,400 million Tenge) based on the transit volume of 25 BCM and the transit tariff of US$ 1.5 per 1000 CM over 100 Km. This revenue accounts for about 75% of the total Kazakgaz revenue in 1995. The income from gas sales to the local distribution companies is only US$ 3 million (or 203 million Tenge).

7. The accounts receivable of Kazakgas amount to Tenge 29,721 million. This is equivalent to 13 months of total Kazakgas turnover. In 1995 accounts receivable grew by 6 months sales, based on the entire Kazakgaz operations. It is claimed that the transit operations and Karachaganak gas production are being paid for, in gas or in cash, as there is no reason for Kazakgaz to undertake these for other countries who are able to pay with oil or with gas, if they are not paid. In reality some of the transit operations or some of the Karachaganak production is not being paid. Should this be the case, it is incompatible with Turkmenistan cutting supplies in southern Kazakhstan due to non-payment. A possible explanation for the incompatibility of the accounts receivable and the turnover is a change in accounting basis regarding gas sales to local companies, following the transfer of Oblagas companies to the oblasts. There needs to be a full listing and reconciliation of Kazakgaz arrears to determine the real position.

8. The initial plans for privatization envisaged lease of the transit lines and a separate management/concession for Karachaganak. Should this be the case, it is evident that the privatization of the transit pipeline and the Karachaganak field would have an

enormous impact on Kazakgaz financial position and that the remaining company would have little in the way of financial resources to undertake investments for supplies within Kazakhstan. A major reform of the financial structure including pricing is required if Kazakgaz (and by implication, the other gas companies) is to secure financing so as to undertake new investments and ensure a reliable supply.

9. Kazakgaz had a major infusion of Tenge 13,731 million in capital stock in 1995, which is close to the increase in net fixed assets. It is assumed that this is an accounting adjustment so that the final assets shown are more accurately represented, and that the adjustment is not a measure designed to correct the Kazakgaz financial crisis.

10. The Kazakgaz "earnings" on sales to local distribution companies is approximately $3 million on turnover of 877 million Tenge ($12 million). While no information is given on the breakdown of expenses, when allowance is made for gas purchases, employees and materials, and the costs, the assumption is that the depreciation provision is $2-3 million. Expenditure on rehabilitation (excluding the transit pipelines) should be kept to this level. If greater expenditure is needed then the tariffs should be adjusted to provide for it. The proposal to spend approximately $2.2 billion on a pipeline to Akmola would need net cash flow (sales income less costs of gas, employees and materials) of about $330 million annually. This is incompatible with Kazakgas gross income from supplying other parts of Kazakhstan of $12 million.

Table 2: Kazakhgas Balance Sheets (1994 & 1995)

KAZAKHGAS BALANCE SHEETS (Current Tenge)
Unit: Million Tenge

YEAR	**1994**	**1995**
Assets		
Current Assets	*19,339*	*35,253*
Cash	55	646
short-term Investments	615	2
Account Receivable	14,960	29,721
Inventories	3,374	2,852
Advance Payments	228	303
Others	107	1,729
Investments	*43*	*234*
Property, Plant and Equipment	*16,225*	*31,862*
Original Value	26,956	48,394
Accumulated Depreciation	(10,731)	(16,532)
Total	**35,607**	**67,349**
Liabilities and Equity		
Liabilities	**20,843**	**29,966**
Current Liabilities	*19,641*	*29,966*
Short-Term Debt	4,745	3,482
Account Payable	11,816	23,836
Advance Payments	1	1,802
Accrued Liabilities	3,079	846
long-term Debt	*1,202*	-
Equity	**14,764**	**37,383**
Capital Stock	*24*	*13,731*
Retained Earnings	*14,740*	*23,652*
Total	**35,607**	**67,349**

Source: Kazakhgas financial statements of 94 and 95

Alaugaz

11. Alaugaz underwent a major restructuring in 1995, as the oblagaz companies separated from the transmission company. The financial statements of the oblagas companies are now reported separately. As a result, the total assets of Alaugas decreased substantially. In particular, this was reflected both in accounts receivable and payable. The financial statements in 1995 present a nominal improvement. In reality, the financial position of Alaugas remains critical. In fact, using IAS standards, Alaugas' financial position would be insolvent. It would be not be beneficial simply to write off substantial bad debts, resulting in very low and possibly negative equity assessment.

12. In 1995, total assets decreased 33.2%. Reportedly the accounts receivable were allocated between Alaugas and the local oblagaz companies depending on the amount of gas consumed by each oblast. In 1995 accounts receivable were reduced to a level where they only represented 4 weeks of sales. In 1996 they increased again and at the end of the year represented 36 weeks of sales. In part this can be explained by the lower sales figure. However it seems that accounts receivable are again building up because of the non-payment problem. The largest debtors are Kirgizgaz, Almatygaz, Shimkentgaz and Kazakhstanenergo. Alaugaz has been extensively using barter (including cars, buses and bread) to facilitate collection.

13. Overall fixed assets increased in all the years under review. This is because Alaugaz re-evaluated its fixed assets as all companies in Kazakhstan have been requested to do because of inflation[1]. In 1994 and 1995 the law required several increases. At present only one revaluation per year is required. Equity increased substantially from a deficit of T 936 million at 12/31/1994 to a positive figure of T 5,127 million at 12/31/1996. At 12/31/1996, the breakdown was as follows: capital: T 2,168 million; reserves: T 311 million; special funds: T 2,527 million and retained earnings: T 121 million. While some of this increase can be accounted partly by the revaluation of fixed assets, there must also be some external input. These figures were obtained using the old Russian accounting standards. Using IAS, equity would probably be considerably lower.

14. Return on equity is about 7.9% for US gas companies and 5% for Gas de France, while return on common equity was notionally 23.9%[2] for Alaugaz in 1996. Common equity as a percentage of total capitalization was 54.5% for US gas companies while that for Alaugaz was 79.8%[3].

[1] Revaluation of fixed assets is very frequent, especially in high inflation economies. Another variant is to use current cost accounting as British Gas does. Its tangible fixed assets are included in the balance sheets at their value to the business (current replacement cost). For instance land and buildings are valued periodically by chartered surveyors. The transmission system is valued based on engineering assessments of replacing existing assets.

[2] 1,233 divided by 5,127

[3] 5,127 divided by 6,427

15. As with Kazakgaz, a major item of expenditures is "the gas cost for own use and losses" accounting for about 33%. No such item exists in developed countries. Sales[4] decreased sharply from 1995 to 1996[5], perhaps as a result of the spin-off of the oblagaz companies. No explanation has been provided. In 1995 Alaugaz operations produced a profit of T 875 million. However non-operating results created a net loss/ expense of T 197 million. As a result, net profit shrank to T 678 million. In 1996, the net profit increased to T 1,223 million. However foreign exchange results were not disclosed. Net other expenses represented foreign exchange losses[6] (net of foreign exchange gains) on accounts receivable and accounts payable in foreign currency (US dollar). Because of the non-payment problem these foreign exchange losses are exacerbated as accounts receivable and payable remain outstanding for extended periods of time (sometimes 2 years).

16. Despite its nominal profit, Alaugaz is not substantially generating cash relative to its enormous needs. T 1,223 million or US$ 16 million hardly supports its proposed rehabilitation or modernization projects associated with the southern pipeline system in Kazakhstan, the total of which requires at least US$ 90 million for the capital investments[7]. Furthermore Alaugaz does not generate sufficient working capital to store gas during the summer for use during the winter. This has a negative influence on gas supplies in Almaty. At present its equity sources (e.g. reserves, special funds, etc.) are also not sufficient. Alaugaz thus needs to induce capital from outside sources. As these projects require importing a significant amount of foreign goods needing foreign exchange while the projects create local currency earnings, Alaugaz faces a major challenge of currency convertibility as well as a challenge in attracting foreign investors and financiers. For a company such as Alaugaz where the sales are less than they were in the recent past, prudent financial policy is to limit the capital investment to the amount provided for depreciation plus realized profit (where customers have paid). As gross income to cover all costs is only $27 million, the net cash will justify annual capital expenditure on modernization and rehabilitation of only a fraction of the proposed $50 million. The rule of thumb is that the cash flow from operations should be sufficient to give debt service coverage (e.g. 1.5 times) and should be sufficient to finance the local currency portion of the investment program. Moreover, that rehabilitation/replacement investment is fully met from internal cash flow. Alaugaz clearly fails in this respect.

17. The following measures would promote operational efficiency and profitability:

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[4] The Anti-Monopoly Committee provides a framework in which Alaugaz is free to establish its pricing. Alaugaz determines its rates within this framework based on volume and distance and the billing is done monthly.

[5] Income statement for 1995 covers 6 months. Income statement for 1996 covers 12 months.

[6] Such sizable foreign exchange losses should be eliminated. The best way would be to speed up the collection and payment cycles. There are also several financial techniques to prevent such losses from happening.

[7] Under its present financial status, Alaugaz alone is not able to implement the rehabilitation of the pipeline. As a result, the GOK wishes to promote rapid privatization using a concession contract with international investors.

- Clear right to cut off delinquent customers.
- Increase in tariffs to reflect costs more accurately.
- Repair and modernization of facilities and equipment so the pipeline system would operate more efficiently. This would improve profitability in he long run.
- Installation of metering equipment, especially at the borders of Kazakhstan with Kyrgyzstan, Turkmenistan, Uzbekistan and Russia.
- Streamline manpower and personnel.
- Development of capability to work on barter and exchange deals.
- Improve financial management and working capital so Alaugas can increase its storage capability and eliminate foreign exchange losses.

18. The recent financial position of Alaugaz is summarized in Tables 3 and 4.

Table 3: Alaugaz-Alamty Balance Sheet[8]

	(Unit: Million Tenge) 1994	1995	1996
Assets			
Fixed Assets (Gross)	2,638	3,583	5,395
Depreciation	-932	-1,376	-2,017
Net Fixed Assets	1,706	2,207	3,379
Project under construction	294	652	486
Financial Investments	4	5	5
Total long term assets	2,004	2,864	3,870
Inventory	677	782	731
Financial Reserve with Budget	1,349	704	241
Accounts Receivable	4,038	955	1,380
Other Assets	92	139	163
Cash and Banks	26	22	42
Total Current Assets	6,182	2,602	2,557
Total	**8,186**	**5,466**	**6,427**
Liability and Equity			
Equity			
Capital	10	10	2,168
Reserves	3	93	311
Special Funds	2,023	3,085	2,527
Retained Earnings	-2,972	35	121
Total Equity	-936	3,223	5,127
Liability			7
Long Term Bank Credits	19	14	337
Accounts Payable	8,279	602	388
Other Accounts Payable	87	98	
Provision for Bad Debt		1,055	
Advance Payments Received	52	81	
Other Liabilities	685	393	568
Total Liabilities	9,122	2,243	1,300
Total	**8,186**	**5,466**	**6,427**

Table 4: Alaugaz-Almaty Income Statement[9]

	1995	1996
Sales	6,343	2,010
Volume (million CM)		
Average Tariff (Tenge/1000 CM)		
Operating Expenses	5,468	787
Net Operating Profit	875	1,223
Net Other Expenses	197	
Net Income	**678**	

[8] Using Kazak accounting standards.

[9] The income statement for 1995 covers 6 months. The income statement for 1996 covers 12 months.

Local Gas Distribution Companies

19. The local oblagas companies analyzed, e.g. Alaugas-Shimkent (AS), and Atyrau Oblagas (AO) are in a weak financial position. They have been experiencing losses as their customers have not been able to pay their bills. They will be not able to finance their capital expenditures, as their internally generated funds are marginal. A summary of these gas companies' recent financial status is given in Table 5. Alaugas-Shimkent and Atyrau Oblagas are running at a small loss. Their main weakness is their inability to generate funds for anything other than gas purchase. In the absence of adequate payments to workers and to contractors and others for maintenance, their systems and the companies will fall apart. The data produced for Kostanai Oblagas may not be correct as the expenditure for wages and salaries is missing. It is meaningless to draw conclusions from erroneous figures. If this gas strategy is to be developed further there must be a means of persuading gas companies to cooperate on financial data.

Impact of Privatization and Long-Term Lease

20. No self-respecting international gas company will be willing to take on the transmission companies or the LDCs without clarity in the price setting system and clear and pragmatic rules of the game for collection for gas supplied. The issue may not be one of rescuing Kazakgaz and Alaugaz, as the privatization may make this a moot point, but instead the issue is how to ensure the financial viability of gas transmission and distribution. Experience from other countries shows that there should be no protected industries, as their managers will supply abuse it, and that if the fundamental services to the population cannot be made financially responsible so that they pay for their energy use, e.g. the water companies, then there needs to be a solution through the national budget. Similarly, given the weak infrastructure for subsidies targeted at the poor, the LDCs should be required to develop lifeline tariffs to permit a basic level of comfort at an affordable price. This may have to be accompanied by prepayment metering systems. Privatization reduces the scope for fudge and for delaying dealing with the problems; the advantage of early privatization is that one has to face up to problems right away and a solution has to be found before physical collapse of the system makes it a non-issue anyway. This comes at the high cost of possible over-hasty solutions and much lower privatization cash benefit

Table 5: Estimated Financial Information on Selected Oblagas Companies[10]

(Unit: Million Tenge)

	Alaugaz-Symkent		Kostanai Oblagas[11]		Atyrau Oblagas[12]
Income Statement	1994	1995	1995	1996 (9 months) Estimated	1996 (6 months)
Sales	**2,088**	**2,695**	**3,172**	**2,719**	**158**
Volume (million CM)	1,162	1,083	1,143	955	88
Average Tariff (T/1000 CM)	1,797	2,490	2,775	2,848	1,798
Operating Expenses	**2,026**	**2,998**	**806**	**1,146**	**164**
Purchase of Gas	1,958	2,809	662	1,020	143
Materials					
Network Repair	9	45	24	26	0
Maintenance	12	42	19	16	0
Workshop & General Expenses	10	43	101	83	21
Wages and Salaries	37	59	0	0	0
Gas Losses	0	0		1	0
Other Common Expenses					
Operating Income (or Loss)	**62**	**-303**	**2,366**	**1,573**	**-6**
Taxes	63	48	5	1	1
Fund for Urban Transport/Repairs	0	0	14	13	0
Net Operating Income (or Loss)	**-1**	**-351**	**2,347**	**1,559**	-7
Balance Sheet Information					
Gross Fixed Assets		447,042		568,237	58
Net Fixed Assets		279,189		381,449	40
Accounts Receivable (Oct 96)		2,614		866	
Accounts Payable (Oct 96)		4,139			
Number of Employees		1,046		815	597

Note: The gas purchases of Kostanai Gas do not match with the multiplication of the purchased volumes and the buying prices.

[10] Using Kazak accounting standards.
[11] Natural gas sales only.
[12] Natural gas sales only.

Summary and Recommendations

21. The gas sector is in the middle of a privatization process. Discussions have been held with Bridas of Argentina and Tractebel of Belgium for possible concession agreements for the operation of the CAC pipeline and other transmission pipelines. If so, Kazakgaz and Alaugaz face effective extinction. Overall, if they are to continue in any shape, restructuring is absolutely essential. To resolve short-term liquidity for the sector and lay the basis for effective financial management in the future, the following measures would be necessary:

a) legalization of counter measures against non-payment and strengthening of collection of receivables;
b) a combination of restructuring the tax code, the rescheduling of overdue tax liabilities (to the extent permissible under the Income Tax Code) and responsible cash infusion from the Government, as it is the state enterprises that are a major part of the problem;
c) improvement of operating efficiency, in particular, substantial decrease of "gas cost for own needs and losses" which is currently the largest cost item (about 33% in the third quarter of 1995) if this item is truly one of the costs;
d) the strengthening of its marketing capacity and ability to sell gas to large consumers (e.g. power stations, etc.); and
e) curtailment of work force to an appropriate size.

22. Each Oblagas company is almost in the same position. Unless drastic effort for restructuring and legal enforcement is taken to arrest non-payment, all gas companies in Kazakhstan will be financially non-viable and in time will fail to supply gas to anyone. The Government is encouraged to ensure a major restructuring as a matter of urgency.

23. The various gas companies need to maintain up to date lists of major bad payers, undertake an age analysis of the debts, and agree with each a plan of action to deal with the arrears. Government policy needs to be supportive on cut off if the problem persists. Prepayment metering could be an effective solution, as if the poor payers fail in their part of the settlement deal they will cut themselves off.

24. The accounting system and procedure needs to be rationalized so that audit becomes feasible. In this connection, the adoption of the IAS is important. In future, accounting should be computerized and financial control should be strengthened. All the gas companies should be ready for an audit and in the future they should consider an international audit. Other improvements for the accounting system include:

- Inventory and sales should be tested: (i) physical counts should be verified including beginning and ending inventory as well as purchases; the test should include observations as well as record keeping; (ii) the correctness of unit costs should be verified; (iii) the compilations (summarizing of the physical counts) should be tested.

- Management of accounts receivable: billing needs to be improved. Collections should be tightened. An aging of accounts receivable by categories is necessary. An appropriate provision for bad debt should be evaluated and set aside.
- Cash flow projections should be prepared including projections of cash inflows and outflows; it is impossible to survive without this management tool. These projections should be realistic.

Annex 1 Comparison of the Russian Accounting system with the IAS

This note discusses internationally accepted accounting standards (IAS) and how they differ from the old Russian/ Kazakh accounting standards. Potential investors and joint venture partners are much familiar with IAS. It is very important for Kazakh enterprises to present their accounts using an internationally prevalent method like IAS. Otherwise it is most difficult to deal with international investors and financiers. The introduction of IAS recently mandated is a step in the right direction[13]. However the implementation will be very difficult and time consuming.

Differences between old Russian/ Kazakh accounting system and Internationally Accepted Accounting Standards

A) **The Old Russian system** was using cash basis of accounting: an enterprise recognized revenues from selling goods and providing services in the period when it received the cash from the customer. IAS uses accrual accounting under which revenue is recognized when earned. Revenues and expenses are allocated among the years when the enterprise is in operation, as revenues should match expenses incurred to generate these revenues. This led to the distinction between product cost and period cost. Period costs are charged to the current period because no direct connection with revenue is anticipated. Examples include salaries of senior management and advertising expenses. Product costs are expensed and matched against the revenue in the period when the revenue is recognized. Examples include material, labor and overhead. They are carried into future periods if the revenue from the product is realized in subsequent periods.

B) Depreciation: under IAS, depreciation is a method of allocating the cost of an asset to the revenues produced by the asset. It is necessary to estimate in a realistic manner the useful life of the asset.

C) Accounts receivable and provision for bad debt: goods for which payment had not been received remained on the balance sheet of the supplier at full cost. Disputes on debt settlement were referred to appropriate authorities within the time stipulated by the relevant ministry. There was no provision for bad debt. Under IAS it is necessary to estimate sales that will prove uncollectible based on previous experience and general economic conditions and create a provision for bad debt. Non payment is a major problem in the country. A solution should be found to this issue. Individual negotiations with customers are a firs step.

D) Inventory valuation: under internationally accepted accounting standards, the inventory of work in progress or finished goods should be stated at the lower of cost or market. The FSU system required no comparison with market prices. Inventory was valued at the full cost of production. This included many costs, which according to international practices should be expensed as incurred. Inventory was overvalued.

E) Debt/ External borrowings represent a sizable part of the funding structure in a market economy. The enterprise is expected to generate the cash necessary to support the payment of interest. Not so under a centralized economy. If in the future enterprises borrow funds in order to finance their capital expenditures, they will need to generate funds internally to pay the interest as well as the principal.

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[13] The regulatory framework should include an audit requirement in addition to the accounting standards.

F) **Income statement**: No distinction was made between "product cost" and "period cost". A substantial amount of "period costs" were included in inventory as discussed above. As a result, net income was overvalued.

G) **Production/ sales for own use** represents a large amount and is not explained: This account should be scrutinized. For some companies this item is responsible for the lack of profitability. This lack of transparency is incompatible with a market economy.

H) **Cash flow:** enterprises need capital expenditures to maintain their installations and equipment up to date and also to expand their business. They should generate sufficient cash to meet these needs. The situation of Kazakh enterprises is extremely poor. Many of them are actually insolvent. It is as if they were liquidating themselves: starving to death. It is possible to attract outside financing only when some specific conditions are met including transparency of accounts. Outside financiers have definite expectations. Shareholders will expect dividends as well as appreciation of the equity. Lenders will expect payment of interest as well as repayment of principal.

I) **Audit**: bankers and investors base their decisions on financial information presented in the financial statements. These are prepared following international accounting standards (IAS). Certified public accountants are specialists in accounting[14]. When they perform an audit, they certify that the statements have prepared following IAS and can be relied upon. Without reliable financial information it is not possible for bankers and investors to invest or lend money.

Introduction of IAS in Kazakhstan

All enterprises in Kazakhstan are required to implement IAS by December 1997. While the objective is desirable, the implementation will be difficult. The accounting standards[15] have been written but they are still incomplete. There are omissions, misconstructions and inconsistencies. The methodology and instructions are still being written. A major problem is that there are very few Western trained accountants in Kazakhstan.

The managers we spoke to are getting organized to implement IAS. But they are having a difficult time because of the lack of resources. The gas companies do not have the financial means necessary to hire the required Western trained accountants. Probably the best will be for the Western partner under a concession or management contract to implement IAS. Then the gas companies might be able to satisfactorily undergo an international audit.

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[14] CPA's are instructed and trained as follows. First several courses in accounting, auditing techniques finance and business law are required. Second, several years of practice/ work under the supervision of an experienced auditor. During this period, several exams need to be passed successfully. When all those requirements are met, the qualification of CPA is obtained.

[15] IAS includes accounting standards, methodology and instructions:

- The accounting standards provide general solutions to accounting problems.
- The methodology clarifies and elaborates on the standards. It is an interpretation of the standards.
- The instructions discuss the application of the above to specific situations by management and the auditors.

It took many yeas to develop IAS to their present state. IAS are constantly being updated to find solutions to new problems as they arise.

Appendix 3.13

Methods to Improve Gas Tariff Collection

PREVIOUS PRE-PAYMENT SYSTEMS

This chapter will describe the merits and demerits of the different types of pre-payment systems. The first paragraph will describe a piece of history, the coin meter, although this type is still used in the United Kingdom. The second paragraph will show why the token meter is being replaced in the United Kingdom and why the utilities in the republic of South Africa are considering a smart card system. The magnetic card system is used in Hungary. This method of pre-payment is discussed in the third paragraph of this chapter.

The coin meter

In the beginning of pre-payment for gas (early 1900), meters had to be filled with coins. The main reason for using the coin meter was the better budgeting possibility for the consumer. The need for billing did not exist, but the meters had to be emptied quite often because too much cash in the meter would be asking for trouble. After a couple of visits the meter reader was carrying a large amount of money, this made him a simple target for criminals. It also happened that the meter was already emptied, or done by a burglar or by the customer, claiming he had been robbed. An other reason for this visit was the meter reading.

The token meter

A few different types of token meters exist. Utilities in the UK still use the key token mechanism. In the Republic of South Africa the standard is the use of a paper slip with encrypted code written on it. The user purchases the paper slip and types the encrypted code into his meter.

To overcome all the risks that the coin meter has, manufacturers tried to find a safer way to collect the money. The token meter was a solution for this problem. A piece of the key token broke when using it, so the pieces left in the meter were useless and utility personnel could walk the streets safely. The problem with the token meter was the operational costs. The main disadvantage of the token meter will be the high maintenance costs. Jamming of the key token, as experiences in the United Kingdom learn, can occur quite often. Meter readings will have to be done in the conventional way and the meter will have to be emptied once in a while to collect the token ends. The solution was the use of the magnetic card systems.

The magnetic card meter

The magnetic card possesses a magnetic strip that can be filled with digital information. This information is filled by the utility and is simply erasable by placing the magnetic strip in a magnetic field. The fixed information makes the card unique, it possesses the card code. The magnetic card can be purchased at the utility. The new card will be given a code for the amount of credit purchased. When the card has been inserted into the meter the card is made invalid by the meter. It is possible to use the magnetic card several times and to rewrite information on the card, but in comparison with the smart card the duration will be much shorter. The reason for the short duration is the mechanical wear of the magnetic strip.

The system has a constant operation, but most systems use disposable cards and therefore the environmental aspects of this system are debatable. Systems that use the possibility to rewrite the magnetic strip exist, but the magnetic card has a safety problem. It is quite easy to make a copy of the magnetic strip possessing the card code. Even if the meter has a code of its own to make the card unique, this code will be written on the card as well. Therefore it still would be quite easy to copy a card filled with credit several times and use these cards in the meter situated at home. To save costs by automatic meter readings and providing a safe system, all new pre-payment systems use smart cards.

SMART CARD METER

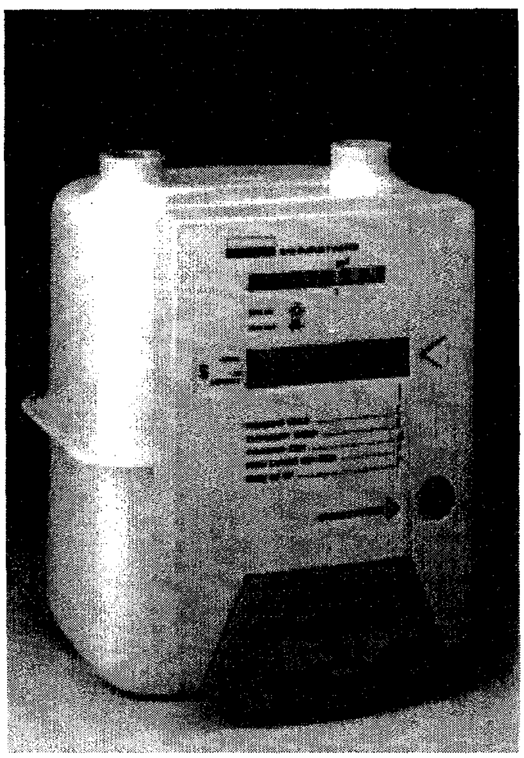
This chapter will describe the principle of the smart card pre-payment systems. For detailed information on the available systems is referred to the full report. This chapter will also explain the principal of the smart card and the gas meter, followed by the emergency credit feature. The following paragraphs will explain why a pre-payment system must be seen as a management information system and the other advantages of the system. Finally the disadvantages of the system will be discussed.

Smart card

New technology made it possible to safely rewrite information on the card. This type of card is called the smart card. The smart card possesses a ROM, EEPROM (Electrically Erasable Programmable ROM) or a FLASH-memory and a microprocessor. The ROM part is for all fixed information, such as the card code. The EEPROM or FLASH is for all variable information, such as caloric value, tariffs, meter readings etc. The EEPROM can be reprogrammed and read, but voltage is needed of another party because no battery is installed in the card. It is possible to program 4kB or even more on the EEPROM. The other possibility is the FLASH-memory. The difference between an

EEPROM and a FLASH-memory is the potential amount of memory programmed. It is possible to program hundreds of kilobytes on a FLASH-memory. This erasable memory is developed by Intel and eliminates the use of a battery. At this moment the need of such amounts of memory storage is not necessary, but also not interesting because of the high price of a FLASH-memory. The microprocessor is what makes the smart card smart. The microprocessor decides if it is possible to enter a memory cell.

Although the possibility of fraud has been reduced severely, no 100% safety can be given for the use of an EEPROM or a FLASH-memory. It should be noted that the electronic purse is going to be introduced in the Netherlands. Pilot systems were installed in cities with a high volume of students. The students, most of the time the persons trying to break a system, were not able to break into the smart card system.



Gas meter

Most smart card based pre-payment systems available are based on a conventional diaphragm gas meter. The principle of the diaphragm gas meter is described in the full report. This conventional diaphragm gas meter with additional valve interacts with a smart card accounting module integrated with or attached to the front of the meter. The module calculates the customers current credit level continuously and disconnects the supply when the customer runs out of prepaid credit.

It should be noted that pre-payment meters can easily be installed. In case of an existing meter only the meter has to be replaced. Placement of a domestic pressure regulator is optional.

Emergency credit

The situation can occur that the energy supply is low during unsocial hours or at times that the customer is not able to purchase new credit. The solution for such a problem is the availability of emergency credit. The amount of emergency credit can be defined by the utility in a flexible way, different types of customers can be given different amounts of credit. After the emergency credit has been used, the supply will be disconnected automatically. No reconnection cost are demanded by the utility. The insertion of the refilled smart card will give the customer energy supply, unless the bought credit is not sufficient to pay the emergency credit used.

This emergency credit is a solution for problem payers. First of all the customer is better able to budget his energy use and secondly is it the utilities benefit to have a short term debtor, a better cash flow is created.

When the customer runs out of prepaid credit and no emergency credit is left available, disconnection will follow automatically. When the customer refills his smart card and inserts it in the meter, it will take three minutes before the supply is enabled. During these three minutes the system automatically activates a leak test. This test guards against a gas flow if a gas bracket for example has not been shut. Only one pre-payment system available has this feature.

Management Information System

With a prepayment system the customer buys and pays for gas via a range of point of sale terminals situated in convenient locations such as supermarkets, general stores, petrol stations or post offices. This eliminate traditional billing. The customer is issued with a personal smart cards. When the smart card is inserted in the meter, credit and tariff data will be transferred to the meter and supply is enabled. At the same time the card itself receives data, such as meter readings and detected fraud attempt. The data is then transferred to the utility via a point of sale terminal at the time of the customer's next purchase. This period is different for each customer, but setting a maximum amount of purchase this period could be influenced by the utility.

The utility can reprogram the customer's card via the point of sale terminal. It is possible to alter individual customer's parameters, such as debt repayment, standing charges or changing a tariff for all customers or different tariffs for groups of customers. The utility can also directly reprogram on a visit by means of a maintenance specific smart card.

These features, available on all smart card based pre-payment systems, are the step to a management information system. All this data will be collected at the utilities mainframe computer. This data can be used to analyse customers purchasing habits and consumption trends. Besides this advantage other advantages will be summarised in the next paragraph.

Advantages of a smart card system

Companies benefits:

* improvement of cash flow;
* the influence of inflation will be reduced;
* debts can be avoided;
* elimination of billing;
* automatic meter readings, tariff changes and disconnection;
* reductions of visits to customer premises;

Customers benefits:

* no estimated use is charged to the customer;
* better budgeting of energy consumption is possible, savings in energy consumption is the result;
* emergency credit facility;
* unique smart card, if card is lost it cannot be used elsewhere;
* extra safety feature: disconnection if abnormal gas flow is recorded;
* tamper recording, fraud can be detected easily.

Retailers benefit:

* volume of trade increases due to a larger number of people visiting the shop.

Note: Some of these advantages count for other types of pre-payment systems as well.

Smart card's disadvantages

A problem of the pre-payment meter in general is the fact that the caloric value programmed in the meter itself, is in fact a value based on estimations instead of on the actual value of the gas used. The smart card pre-payment systems has the possibility to change the caloric value by giving the smart card the new 'estimated' value. It is possible to do a recalculation after a certain period of time, but none of the systems at the moment have the possibility to do this automatically

It is a fact that approximately 80 % of the need for gas occurs during winter time. To create a better spreading of energy costs, a solution might be to save credit by buying a fixed amount of credit each week. Another demerit is the high investments necessary for the system. A study in Kazakhstan must be done to investigate if the investments are profitable.

2.7 *Experiences in pre-payment*

This paragraph will roughly describe the experiences in pre-payment. For detailed information is referred to the full report.

Countries in which pre-payment is quite common are the United Kingdom and the republic of South Africa. Experiences with pre-payment on pilot scale exist in various countries all over the world. Most experience is gained with electricity and water pre-payment. The result seems to be extremely positive. Customers are better able to budget their energy expenses and would not want the meters to disappear. The utilities have the advantage of a better cash flow and some of them use the system for debt recovery as well. Besides that, the influence of inflation, strongly exists in developing countries, has been reduced.

FACTORS INFLUENCING THE OPERATING AND MAINTENANCE COSTS

This chapter will give information about the aspects that influence the operating and maintenance costs. The utilities using pre-payment systems were not willing to give real figures regarding these costs.

Operating costs

Factors influencing the operating costs differently in comparison with no metering and credit metering will be discussed in this paragraph. In case of not metering the gas flow, the operating costs will be switched from the billing department to the operating department of the system. The use of a mainframe at the utility together with several terminals will influence the number of employees in a cost effective way.

Comparing the operating costs in case of a credit metered system, the operating costs of a pre-payment system will drop significantly. The reason is the automatic meter reading instead of doing the meter reading by visiting the customers premises once or two times a year.

The costs of data transfer must be taken under consideration. The utility must make a telephone connection to each point of sale terminal every night. The operating costs in this regard depend on the data transfer prices varying in every country. British Gas calculated a 4 pence price per call.

Maintenance costs

Customers losing or damaging their smart cards will be considered as maintenance costs. Normal use will result in a duration of approximately ten years for the smart card. This prediction is made by the several manufacturers of the smart cards. The only way the card could be damaged is by bending the card at the spot where the chip is situated and by cracking of the material. The cost of a new card in case of loss can be gained from this particular customer.

Maintenance costs due to the battery will exceed in case of the use of zinc-carbon batteries. This is a common battery used for example, in a tours. The expectation of duration is estimated at 2 to 3 years. The costs of the battery are relatively low, but on the other hand the cost to implement these batteries are extremely high. The expectation of duration in case of the use of a lithium battery is estimated to be more than 10 years. The costs of the lithium battery exceeds the costs of the zinc-carbon battery with a factor 7.5 at this moment, but the total maintenance costs will be significantly lower.

CONTRACTUAL ASPECTS

This chapter will describe the necessary changes that must be made before a pre-payment system can be introduced. Knowing that the situation in Kazakhstan differs from the situation in the Netherlands, it will be difficult to give details, since not enough information about Kazakhstan is available.

At this moment it is not allowed in Kazakhstan to disconnect a customer from the gas supply. A comparable situation occurs in the Netherlands. It is possible to disconnect a customer, as long as the customer does not go to court. History shows a few cases in which the customer got reconnected even if they had not repaid their debts yet. The reason is that the court thinks the gas supply is a necessity of life.

In case of a pre-payment system the situation differs slightly. Disconnection is not done by the utility, but by the customer himself. The responsibility is transferred from the utility to the customer. The utility cannot influence the action of the meter, if the customer decides to spent his money on other means. Therefore legal advice should be taken into consideration.

A comparable situation to that of Kazakhstan occurs in the United Kingdom. It is legally not possible to disconnect a customer. But it is a fact that pre-payment systems are legally accepted in the United Kingdom and no situation occurred of customers taking the utility to court. In the full report a customers contract can be found. All considered it seems reasonable pre-payment will be possible in Kazakhstan as well.

PROPER INTRODUCTION OF PRE-PAYMENT METERS

In regard to pre-payment systems it is very important to create a customers acceptance basis. The users opinion is of decisive importance and therefore a proper introduction is necessary. A way to resolve this problem is described in this chapter.

Experience learn the importance of the consumers opinion. Experiences gained on a pilot scale in the Netherlands have not been totally successful. The fraud attempts seemed to get out of proportion. The reason of the consumers reaction seems to be the negative image the system had created. This negative image was created by introducing the system to consumers not wanting to pay and consumers having payment problems already.

To influence the customers acceptance basis it will be necessary to realise a gradual introduction. The introduction on a pilot scale, such as an apartment building, will create a marketing possibility for the energy company. This apartment building must be well chosen. The chance of success must be reasonably high. Therefore the average inhabitant should be having a modal income and besides that the average inhabitant should have an average social background.

Instead of picking out a modal income apartment building choosing for the upper class is another strategy. In this way the pre-payment system will be getting a positive image. The image which is so important for the systems success. The pre-payment systems would not be related to poverty, but with luxury instead.

The merits in the opinion of the consumers must be pointed out in a way the consumer thinks the whole operation is based on customer's satisfaction. Point of sale terminals should be placed not only at the nearest supermarket, but at sufficient places in the neighbourhood. The reason is to be sure the reloading process is not a counter argument given.

Such a project should be implemented in two or three places spread over the country. As written above, a model income apartment building at one place and choosing for the upper class at another place. Next to these projects an implementation of pre-payment systems for industrial use could be the third step.
The two or three projects described above should be operational for approximately one year. The preparation will take approximately half a year. This period is needed to inform all participants, to install the system and last, but not least to give an explanation to the consumers concerning the use of the system.

OTHER METHODS TO INFLUENCE CUSTOMERS BEHAVIOUR

A possible way of improving the payment records of consumers could be the introduction of credit gas meters for domestic and small commercial consumers (the principles of the different credit meters are described in the full report). Credit meters are approximately a factor 3.5 cheaper than a pre-payment system. This change in calculating to the real used amount of gas will be a tribute to the customers willingness in payment. On the other hand the customer is not used to pay for his energy consumption and therefore it is presumable that the effect is less than the effect accomplished with a pre-payment meter. The effect of credit gas meters could be upgraded.

The choice not to install meters at all is not the best choice that can be made. A way to calculate the energy bill could be by counting the number of square meter at the customers' premises. Most customers, as experiences learn, will not consider this a fair way of calculation and will continue their non-payment. Above all, such calculation methods do not consider the possible energy savings; customers cannot influence the energy bill and they will therefore not consider efficient energy consumption.

During the search for methods to influence customers' payment behaviour, some energy companies in the Netherlands were approached. One of these methods is used as a model for an effective payment collection. The method is based on the following thesis: 'each person capable of living in a society has the disposal of a certain amount of money'. The question is what the priority is for this person in making his payments.

The energy company has to create an environment in which the energy bill is one of the first bills paid by the customer. Such a major change in behaviour will not be successfully implemented from one day to the other. But some of the Dutch energy companies show that this is the method for savings in administration and debit costs without changing the infrastructure of the gas distribution and the billing. The solutions in their words is: 'rigid course of action and sticking rigidly to your own rules'.

The payment collection method of a Dutch energy company uses disconnection after non-payment for 15 weeks. This period will be shorted in the near future to 8 weeks. After this period the gas company will go to court to be able to levy a distrain. Before all this happens the company sends two exhortations to customer. The first one in the fifth week after the invoice and the second one follows in the eighth week. The administration costs of both exhortations will have to be paid by the customer. If the customer has not reacted at all, a letter is send. The letter contains the date and time of the disconnection and the costs of dis- and reconnection. After fifteen weeks the customer will be disconnected at the same date and the same time as written in the letter. Rigid course of action and sticking rigidly to your own rules. It is a matter of image.

CONCLUSIONS & RECOMMENDATIONS

This last chapter will give the conclusions of the search for methods to improve the gas tariff collection. To provide a practical guidance to transmission and distribution companies in Kazakhstan recommendation are made.

The image of the gas distribution company to the customer is essential. Customers will respect strict rules and actions. The energy company has to create an environment in which the energy bill is one of the first bills paid by the customer. To make such an environment possible it is necessary to have the possibility of disconnection. Disconnecting is a rigid method of preventing non-payment.

Beside this rigid course of action, which needs a lot of effort and money, pre-payment gas meters offer a great opportunity for improving the gas tariff collection. If pre-payment is well introduced the effect on the public image toward the gas distribution company could be positive. Pre-payment systems might seem quite expensive, but on the long run the systems could be cost effective. A study regarding cost effectiveness should be done for the situation in Kazakhstan.

It is recommendable to introduce a pre-payment system on a pilot-scale to a group of middle social class or higher social class customers. The introduction on a pilot scale will create a marketing possibility for the energy company. By introducing the system in the upper class, the system will get a positive image. After such an introduction, customers with bad payment records can be given the choice: disconnection from the gas supply or the luxury of a pre-payment budgeting system.

Besides these recommendations it should be noted that the use of a domestic pressure regulator at the customers' premises is a way to improve the distribution capacity. In that case the gas distribution can take place at 100 or 200 milli bar. The pressure regulator will drop the pressure to 30 milli bar for consumption. The effect is a higher capacity in the distribution network.

Appendix 3.14:
Potential Exchange Savings

Southern Kazakhstan

1. The pipeline infrastructure in Kazakhstan was designed as part of the overall transmission system of the former Soviet Union. As a result, the existing system does not permit Kazakhstan to operate in a self sufficient fashion. Instead, the gas delivery system operates in the following fashion:

a) The South region which includes the oblasts of Almaty, Dzambul and South Kazakhstan is entirely dependent for its gas supplies on imports from Turkmenistan and Uzbekistan.

b) The West region, which includes the oblasts of Mangystau, Atyrau and West Kazakhstan obtains its gas supplies from local fields and from Turkmenistan via the CAC line.

c) The oblasts of Aktjubinsk and Kostanai are supplied from the Bukhara - Ural pipeline and can receive gas from both Russia and Turkmenistan

2. The bulk of the country's gas resources are located in western Kazakhstan. This places them in close proximity to the major CAC pipeline connecting Central Asia to the southern link of the Siberian pipeline system transiting the Ukraine to the Slovakia border. These resources could economically supply the West region as well the Aktjubinsk oblast. They are, however some considerable distance from the population centers in southern Kazakhstan.

3. In looking to supply the South region in the future, Kazakhstan has three options:

a) To purchase and import gas from Turkmenistan and Uzbekistan. (This would be a continuation of the current practice.)

b) To construct pipeline links from the Karachaganak field to Kr-Oktyabri on the Bukhara - Ural pipeline and from Chelkar (further south on the Bukhara - Ural line) to Symkent in the South region. (Symkent is located on the Bukhara - Almaty pipeline.) Gas could then be supplied from Karachaganak to the South region.

c) To enter into a long term exchange arrangement whereby Turkmenistan and/or Uzbekistan would deliver gas into the South region via the Bukhara - Almaty line and would receive gas from Karachaganak delivered into the UGS system at Alexandrov for subsequent export to the FSU and European markets.

4. The exchange option is an alternative both to outright purchases of gas in the South and to the transportation of gas from Karachaganak to the South. The economics of the exchange need to be considered against both these alternatives.

The Economics of Exchange versus Purchase.

5. There are two key components to the economics of an arrangement to exchange gas supplies rather than purchase the gas outright:

a) The first component is the simple comparison between purchasing the gas outright and producing gas at Karachaganak and delivering it into the UGS system under an exchange arrangement. These economics are summarized in Table 1:

Table 1
The Economics of Exchange versus Purchase

$/1000 CM	Purchase Cost		Exchange Cost
Purchase Price	35.00	50.00	n/a
Production Cost	n/a	n/a	17.65
Transportation to UGSS	-	-	3.53
Loss of Transit Fees	-	-	12.00
Total Cost	35.00	50.00	33.18
Exchange Savings	**n/a**	**n/a**	**1.82/16.82**

This table requires some explanation:

- Two purchase prices are shown - the current price of $35/1000 CM and an assumed future price level of $50/1000 CM.
- The production cost is based on the assumed $0.50/mmbtu production cost level at Karachaganak.
- The transportation cost to UGSS is based on an estimated tariff of $0.10/mmbtu to cover the cost of a new pipeline connection to UGSS.
- The loss of transit fees results from the fact that under an exchange arrangement, Turkmenistan/Uzbekistan would no longer be transporting the exchange volume of gas across Kazakhstan. The loss is based on an assumed transit fee of $1.50/1000 CM per 100 kilometers i.e. $1.50 x 8.

As Table 1 indicates, the exchange offers Kazakhstan a saving on the order of $2/1000 CM when compared with the current import price of $35/1000 CM. As the price of imported gas increases, however, so will the savings. At an import price of $50/1000 CM the saving would be on the order of $17/1000 CM. It should also be noted that Turkmenistan and/or Uzbekistan would generate savings on the order of $12/1000 CM as a result of the exchange. The level of actual savings realized by each of the parties would, of course, be subject to negotiation of the specific exchange terms.

b) An exchange arrangement would also provide an assured outlet for a volume of gas equivalent to the amount being purchased. To the extent that Kazakhstan is able to generate sufficient market outlets to avoid flaring gas or cutting back condensate production, the economics of the exchange arrangement are those identified above. In the event, however, that Kazakhstan either does not have sufficient outlets to avoid flaring and/or curtailing condensate production, or in the event that Kazakhstan is forced to sell gas at distress prices, the financial benefits of the exchange will be significantly higher. Table 2 summarizes the ratio of gas to liquids production projected for Karachaganak.

Table 2
Gas and Liquids Production at Karachaganak

Year	Gas Production (Billion CM)	Liquids Production (Million CM)	Ratio
1998	13.27	6.67	67/33
1999	15.92	7.85	67/33
2000	19.41	9.35	67/33
2005	25.10	10.52	70/30
2010	23.11	8.33	74/26

Source: Karachaganak Field Development Plan (1995)

If Karachaganak condensate production were to be constrained as a result of insufficient market outlets for gas, the addition of demand outlets as a result of an exchange would have a significant and favorable impact on condensate production levels. In 2000, for example, if an environment of constrained condensate production were to exist as a result of insufficient gas demand, the addition of 1.0 BCM of gas demand as a result of an exchange would enable the production of an additional 0.5 million cubic meters of condensate (approximately 330,000 tons). Since the exchange potential in 2000 totals 3.5 BCM of gas, in an extreme case this could translate into the production of an additional 1.75 million cubic meters of condensate (approximately 1.2 million tons.)

6. An exchange arrangement would also have the benefit of significantly reducing the potential for future disputes concerning the price of imported gas. In an environment where gas prices, which are below international parity levels, are likely to rise, price disputes will be almost inevitable if the only arrangement in place is a simple purchase arrangement. Within this context it is worth noting that certain principles associated with an exchange arrangement are well established. Kazakhstan is currently paid for transporting Turkmen gas through the CAC line in the form of barter gas.[1]

[1] According to Kazakgaz, Kazakhstan receives 4.5 BCM of gas as the fee for transporting 25 BCM of Turkmen gas through the CAC line.

The Economics of Exchange versus Transportation Through a New Pipeline:

7. In the case of an exchange of gas versus transporting the gas from Karachaganak to the South region, the economics are dictated strictly by the comparative transportation costs. In either case the same volume of gas will be produced at Karachaganak and there will, therefore, be no potential issue related to the creation of additional demand outlets

8. In order to transport gas from Karachaganak to the South region additional pipeline links will be required. The build up of the tariff cost for such transportation is given in Table 3:

Table 3
Pipeline Transportation Costs
From Karachaganak to Symkent

Transportation Cost	Aksai - Kr Ok	Chelkar - Symkent	Total Cost
$/mmbtu	0.29	1.26	1.55
$/1000 CM	10.24	44.48	54.72

9. The economics of an exchange versus transportation of the gas from Karachaganak through new pipeline links are shown in Table 4:

Table 4
The Economics of Exchange versus Transportation
Through a New Pipeline

$/1000 CM	Transportation Cost	Exchange Cost
Production Cost	17.65	17.65
Transportation to Symkent	54.72	-
Transportation to UGSS	-	3.53
Loss of Transit Fees	-	12.00
Total Cost	72.37	33.18
Exchange Saving	**n/a**	**39.19**

The costs associated with transportation to UGSS and the loss of transit fees are the same as described for Table 1.

As Table 4 indicates, when compared with the alternative of transporting gas from Karachaganak through new pipeline links, the exchange offers savings on the order of $39/1000 CM.

Other Exchange Opportunities

10. While Kazakhstan should primarily focus on concluding an exchange arrangement with Turkmenistan and/or Uzbekistan to supply the South region, other opportunities do exist to establish exchange arrangements:

a) As has been noted the Aktjubinsk and Kostanai oblasts are supplied from the Bukhara - Ural pipeline and can receive gas from both Russia and Turkmenistan. To the extent gas is being imported to either oblast, an opportunity exists to enter into an exchange arrangement. The same is true with respect to any gas that Turkmenistan may supply to the West region via the CAC pipeline.

b) An opportunity exists to exchange gas for power with Tajikistan. While such gas would have to be supplied by Turkmenistan and/or Uzbekistan an exchange with Tajikistan could potentially increase the overall exchange volumes creating an additional outlet for Kazak gas.

c) Turkmenistan is constructing a pipeline link to Iran and may well extend this to Turkey. This could create an opportunity to enter into an additional exchange arrangement with Turkmenistan and diversify the potential range of export opportunities.

d) At present, Kazakhstan delivers sour gas from Karachaganak to Orenburg in Russia and purchases some volumes of processed gas from Russia for import into Kazakhstan. This arrangement could potentially be converted into either an exchange or a toll processing arrangement if the negotiated economics could justify such a change.

e) The Government has a plan to supply Russian gas to Petropavlosk which is located in the northern Kazakhstan, using a gas exchange arrangement with Karachaganak gas. According to very preliminary information, gas consumption in Petropavlosk is maximum 1.3 BCM per year. If the market is robust and the non-payment issue has been resolved, the proposed gas exchange would make sense.

Appendix 3.15

Energy Efficiency

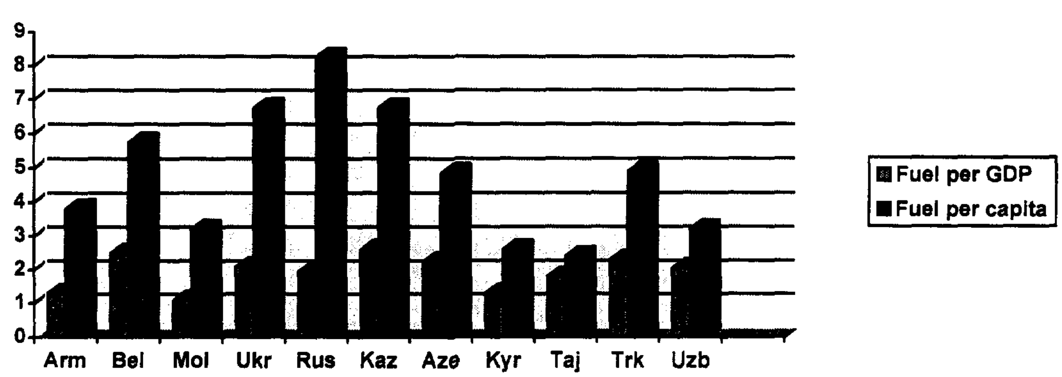
1. Energy intensity is high in Kazakhstan. Even by CIS standards, Kazakhstan's energy use per unit of output is high. The high energy intensity is characterized by inefficiencies and energy waste both on the supply and end use sides inherited from the former Soviet Union. This is, first, due to distorted energy pricing and second, due to obsolete industrial processes, poor insulation and inadequate design.

Table 1 International Comparison of Energy Intensities, 1992

Country	*GDP per capita (US$)*	*Primary Energy Consumption per capita (Kg oil eq. per person)*	*Energy Consumption per US$ of GDP (Kg oil eq. per person)*
Kazakhstan	**1,681**	**4,722**	**2.81**
Russia	2,601	5,665	2.18
China	435	600	1.38
Poland	2,183	2,407	1.10
Turkey	1,704	948	0.56
Portugal	8,117	1,816	0.22
Finland	18,774	5,560	0.30
France	22,994	4,034	0.18
Japan	29,486	3,568	0.12
Germany	22,199	3,930	0.18
United States	23,180	7,662	0.33

Source: World bank Development Report, 1994 and World Bank staff estimates

Figure 1: Energy Intensity of CIS Economies, 1990
(Unit: 1000 tons standard fuel per million rubles)



2. Kazakhstan clearly needs a strategy to bring its energy use first to FSU norms, then to Eastern European norms, and eventually to Western European norms. In the rest of this appendix the focus is particularly on the gas aspects of energy efficiency. There is insufficient information on how much of Kazakhstan's excess energy consumption is gas and how much is other fuels.

3. On the gas supply side, Kazakhstan flares 2-3 BCM per year of associated gas. This represents the entire associated gas production except for that used in field operations. To address this Kazakhstan should:

- consider seeking an exchange of Kazak associated gas for non-associated gas of neighboring countries;
- further investigate profitable domestic and export markets;
- give incentives to companies to avoid flaring;
- be willing to cooperate in laying pipelines to connect the associated gas to the grid and to customers;
- particularly look at power plant and industrial plant locations (for new plants) to see if they can use flared gas; and
- move towards banning of flaring.

4. There is a large potential for loss reduction in transmission and distribution of gas, and similarly for oil, electricity and district heating. Upgrading of the district heating system including introduction of variable flow and metering could reduce losses by as much as one third. Rehabilitation of the electricity transmission and distribution systems would reduce losses at least 5%.

5. The gas demand side is equally a sorry picture from the point of view of energy efficiency. Transmission and distribution companies have substantial "own use" of gas which has no parallel in western systems, and the terminology may well be a misname. The 20-30% of gas lost by the companies is unacceptable and unnecessary.

6. For use of all kinds of energy, there is a large possibility to reduce the country's energy losses. The recommended action programs include enforcement of payment, economic pricing and proper metering. Introducing proper legislation for promotion of energy efficiency, tax incentives for energy conservation and educating consumers would also be needed.

7. In terms of the customer energy efficiency, market mechanisms should be used when relevant, including establishment and cooperation with ESCO (energy service companies) which assist in energy saving in exchange for a share of benefits. In the shorter term the fundamental steps would include:

- enforce the obligation to pay. Non-payers have no incentive to be efficient.

- install meters for most users. They need to be charged by use to benefit from efficiency.
- use command and control procedures to require energy efficiency in all new power plants, major industrial plants, and in new buildings.
- when households are metered, encourage better household insulation (retrofitting of existing dwellings).

Energy efficiency in Kazakhstan is a priority. The above broad steps could be in time bring Kazakhstan's use close to the best prevailing in Eastern Europe. Further steps to achieve Western Europe levels require more sophisticated measures and should be deferred until the metering is in place.

Joint UNDP/World Bank

ENERGY SECTOR MANAGEMENT ASSISTANCE PROGRAMME (ESMAP)

LIST OF REPORTS ON COMPLETED ACTIVITIES

Region/Country	*Activity/Report Title*	*Date*	*Number*
	SUB-SAHARAN AFRICA (AFR)		
Africa Regional	Anglophone Africa Household Energy Workshop (English)	07/88	085/88
	Regional Power Seminar on Reducing Electric Power System Losses in Africa (English)	08/88	087/88
	Institutional Evaluation of EGL (English)	02/89	098/89
	Biomass Mapping Regional Workshops (English)	05/89	--
	Francophone Household Energy Workshop (French)	08/89	--
	Interafrican Electrical Engineering College: Proposals for Short- and Long-Term Development (English)	03/90	112/90
	Biomass Assessment and Mapping (English)	03/90	--
	Symposium on Power Sector Reform and Efficiency Improvement in Sub-Saharan Africa (English)	06/96	182/96
Angola	Energy Assessment (English and Portuguese)	05/89	4708-ANG
	Power Rehabilitation and Technical Assistance (English)	10/91	142/91
Benin	Energy Assessment (English and French)	06/85	5222-BEN
Botswana	Energy Assessment (English)	09/84	4998-BT
	Pump Electrification Prefeasibility Study (English)	01/86	047/86
	Review of Electricity Service Connection Policy (English)	07/87	071/87
	Tuli Block Farms Electrification Study (English)	07/87	072/87
	Household Energy Issues Study (English)	02/88	--
	Urban Household Energy Strategy Study (English)	05/91	132/91
Burkina Faso	Energy Assessment (English and French)	01/86	5730-BUR
	Technical Assistance Program (English)	03/86	052/86
	Urban Household Energy Strategy Study (English and French)	06/91	134/91
Burundi	Energy Assessment (English)	06/82	3778-BU
	Petroleum Supply Management (English)	01/84	012/84
	Status Report (English and French)	02/84	011/84
	Presentation of Energy Projects for the Fourth Five-Year Plan (1983-1987) (English and French)	05/85	036/85
	Improved Charcoal Cookstove Strategy (English and French)	09/85	042/85
	Peat Utilization Project (English)	11/85	046/85
	Energy Assessment (English and French)	01/92	9215-BU
Cape Verde	Energy Assessment (English and Portuguese)	08/84	5073-CV
	Household Energy Strategy Study (English)	02/90	110/90
Central African Republic	Energy Assessement (French)	08/92	9898-CAR
Chad	Elements of Strategy for Urban Household Energy The Case of N'djamena (French)	12/93	160/94
Comoros	Energy Assessment (English and French)	01/88	7104-COM
Congo	Energy Assessment (English)	01/88	6420-COB
	Power Development Plan (English and French)	03/90	106/90
Côte d'Ivoire	Energy Assessment (English and French)	04/85	5250-IVC
	Improved Biomass Utilization (English and French)	04/87	069/87
	Power System Efficiency Study (English)	12/87	--
	Power Sector Efficiency Study (French)	02/92	140/91
	Project of Energy Efficiency in Buildings (English)	09/95	175/95

Region/Country	*Activity/Report Title*	*Date*	*Number*
Ethiopia	Energy Assessment (English)	07/84	4741-ET
	Power System Efficiency Study (English)	10/85	045/85
	Agricultural Residue Briquetting Pilot Project (English)	12/86	062/86
	Bagasse Study (English)	12/86	063/86
	Cooking Efficiency Project (English)	12/87	--
	Energy Assessment (English)	02/96	179/96
Gabon	Energy Assessment (English)	07/88	6915-GA
The Gambia	Energy Assessment (English)	11/83	4743-GM
	Solar Water Heating Retrofit Project (English)	02/85	030/85
	Solar Photovoltaic Applications (English)	03/85	032/85
	Petroleum Supply Management Assistance (English)	04/85	035/85
Ghana	Energy Assessment (English)	11/86	6234-GH
	Energy Rationalization in the Industrial Sector (English)	06/88	084/88
	Sawmill Residues Utilization Study (English)	11/88	074/87
	Industrial Energy Efficiency (English)	11/92	148/92
Guinea	Energy Assessment (English)	11/86	6137-GUI
	Household Energy Strategy (English and French)	01/94	163/94
Guinea-Bissau	Energy Assessment (English and Portuguese)	08/84	5083-GUB
	Recommended Technical Assistance Projects (English & Portuguese)	04/85	033/85
	Management Options for the Electric Power and Water Supply Subsectors (English)	02/90	100/90
	Power and Water Institutional Restructuring (French)	04/91	118/91
Kenya	Energy Assessment (English)	05/82	3800-KE
	Power System Efficiency Study (English)	03/84	014/84
	Status Report (English)	05/84	016/84
	Coal Conversion Action Plan (English)	02/87	--
	Solar Water Heating Study (English)	02/87	066/87
	Peri-Urban Woodfuel Development (English)	10/87	076/87
	Power Master Plan (English)	11/87	--
	Power Loss Reduction Study (English)	09/96	186/96
Lesotho	Energy Assessment (English)	01/84	4676-LSO
Liberia	Energy Assessment (English)	12/84	5279-LBR
	Recommended Technical Assistance Projects (English)	06/85	038/85
	Power System Efficiency Study (English)	12/87	081/87
Madagascar	Energy Assessment (English)	01/87	5700-MAG
	Power System Efficiency Study (English and French)	12/87	075/87
	Environmental Impact of Woodfuels (French)	10/95	176/95
Malawi	Energy Assessment (English)	08/82	3903-MAL
	Technical Assistance to Improve the Efficiency of Fuelwood Use in the Tobacco Industry (English)	11/83	009/83
	Status Report (English)	01/84	013/84
Mali	Energy Assessment (English and French)	11/91	8423-MLI
	Household Energy Strategy (English and French)	03/92	147/92
Islamic Republic of Mauritania	Energy Assessment (English and French)	04/85	5224-MAU
	Household Energy Strategy Study (English and French)	07/90	123/90
Mauritius	Energy Assessment (English)	12/81	3510-MAS
	Status Report (English)	10/83	008/83
	Power System Efficiency Audit (English)	05/87	070/87

Region/Country	*Activity/Report Title*	*Date*	*Number*
Mauritius	Bagasse Power Potential (English)	10/87	077/87
	Energy Sector Review (English)	12/94	3643-MAS
Morocco	Energy Sector Institutional Development Study (English and French)	07/95	173/95
Mozambique	Energy Assessment (English)	01/87	6128-MOZ
	Household Electricity Utilization Study (English)	03/90	113/90
	Electricity Tariffs Study (English)	06/96	181/96
	Sample Survey of Low Voltage Electricity Customers	06/97	195/97
Namibia	Energy Assessment (English)	03/93	11320-NAM
Niger	Energy Assessment (French)	05/84	4642-NIR
	Status Report (English and French)	02/86	051/86
	Improved Stoves Project (English and French)	12/87	080/87
	Household Energy Conservation and Substitution (English and French)	01/88	082/88
Nigeria	Energy Assessment (English)	08/83	4440-UNI
	Energy Assessment (English)	07/93	11672-UNI
Rwanda	Energy Assessment (English)	06/82	3779-RW
	Status Report (English and French)	05/84	017/84
	Improved Charcoal Cookstove Strategy (English and French)	08/86	059/86
	Improved Charcoal Production Techniques (English and French)	02/87	065/87
	Energy Assessment (English and French)	07/91	8017-RW
	Commercialization of Improved Charcoal Stoves and Carbonization Techniques Mid-Term Progress Report (English and French)	12/91	141/91
SADC	SADC Regional Power Interconnection Study, Vols. I-IV (English)	12/93	--
SADCC	SADCC Regional Sector: Regional Capacity-Building Program for Energy Surveys and Policy Analysis (English)	11/91	--
Sao Tome and Principe	Energy Assessment (English)	10/85	5803-STP
Senegal	Energy Assessment (English)	07/83	4182-SE
	Status Report (English and French)	10/84	025/84
	Industrial Energy Conservation Study (English)	05/85	037/85
	Preparatory Assistance for Donor Meeting (English and French)	04/86	056/86
	Urban Household Energy Strategy (English)	02/89	096/89
	Industrial Energy Conservation Program (English)	05/94	165/94
Seychelles	Energy Assessment (English)	01/84	4693-SEY
	Electric Power System Efficiency Study (English)	08/84	021/84
Sierra Leone	Energy Assessment (English)	10/87	6597-SL
Somalia	Energy Assessment (English)	12/85	5796-SO
South Africa Republic of	Options for the Structure and Regulation of Natural Gas Industry (English)	05/95	172/95
Sudan	Management Assistance to the Ministry of Energy and Mining	05/83	003/83
	Energy Assessment (English)	07/83	4511-SU
	Power System Efficiency Study (English)	06/84	018/84
	Status Report (English)	11/84	026/84
	Wood Energy/Forestry Feasibility (English)	07/87	073/87
Swaziland	Energy Assessment (English)	02/87	6262-SW
	Household Energy Strategy Study	10/97	198/97
Tanzania	Energy Assessment (English)	11/84	4969-TA
	Peri-Urban Woodfuels Feasibility Study (English)	08/88	086/88
	Tobacco Curing Efficiency Study (English)	05/89	102/89
	Remote Sensing and Mapping of Woodlands (English)	06/90	--
	Industrial Energy Efficiency Technical Assistance (English)	08/90	122/90

Region/Country	*Activity/Report Title*	*Date*	*Number*
Togo	Energy Assessment (English)	06/85	5221-TO
	Wood Recovery in the Nangbeto Lake (English and French)	04/86	055/86
	Power Efficiency Improvement (English and French)	12/87	078/87
Uganda	Energy Assessment (English)	07/83	4453-UG
	Status Report (English)	08/84	020/84
	Institutional Review of the Energy Sector (English)	01/85	029/85
	Energy Efficiency in Tobacco Curing Industry (English)	02/86	049/86
	Fuelwood/Forestry Feasibility Study (English)	03/86	053/86
	Power System Efficiency Study (English)	12/88	092/88
	Energy Efficiency Improvement in the Brick and Tile Industry (English)	02/89	097/89
	Tobacco Curing Pilot Project (English)	03/89	UNDP Terminal Report
	Energy Assessment (English)	12/96	193/96
Zaire	Energy Assessment (English)	05/86	5837-ZR
Zambia	Energy Assessment (English)	01/83	4110-ZA
	Status Report (English)	08/85	039/85
	Energy Sector Institutional Review (English)	11/86	060/86
	Power Subsector Efficiency Study (English)	02/89	093/88
	Energy Strategy Study (English)	02/89	094/88
	Urban Household Energy Strategy Study (English)	08/90	121/90
Zimbabwe	Energy Assessment (English)	06/82	3765-ZIM
	Power System Efficiency Study (English)	06/83	005/83
	Status Report (English)	08/84	019/84
	Power Sector Management Assistance Project (English)	04/85	034/85
	Power Sector Management Institution Building (English)	09/89	--
	Petroleum Management Assistance (English)	12/89	109/89
	Charcoal Utilization Prefeasibility Study (English)	06/90	119/90
	Integrated Energy Strategy Evaluation (English)	01/92	8768-ZIM
	Energy Efficiency Technical Assistance Project: Strategic Framework for a National Energy Efficiency Improvement Program (English)	04/94	--
	Capacity Building for the National Energy Efficiency Improvement Programme (NEEIP) (English)	12/94	--

EAST ASIA AND PACIFIC (EAP)

Asia Regional	Pacific Household and Rural Energy Seminar (English)	11/90	--
China	County-Level Rural Energy Assessments (English)	05/89	101/89
	Fuelwood Forestry Preinvestment Study (English)	12/89	105/89
	Strategic Options for Power Sector Reform in China (English)	07/93	156/93
	Energy Efficiency and Pollution Control in Township and Village Enterprises (TVE) Industry (English)	11/94	168/94
	Energy for Rural Development in China: An Assessment Based on a Joint Chinese/ESMAP Study in Six Counties (English)	06/96	183/96
Fiji	Energy Assessment (English)	06/83	4462-FIJ
Indonesia	Energy Assessment (English)	11/81	3543-IND
	Status Report (English)	09/84	022/84
	Power Generation Efficiency Study (English)	02/86	050/86

Region/Country	*Activity/Report Title*	*Date*	*Number*
Indonesia	Energy Efficiency in the Brick, Tile and Lime Industries (English)	04/87	067/87
	Diesel Generating Plant Efficiency Study (English)	12/88	095/88
	Urban Household Energy Strategy Study (English)	02/90	107/90
	Biomass Gasifier Preinvestment Study Vols. I & II (English)	12/90	124/90
	Prospects for Biomass Power Generation with Emphasis on Palm Oil, Sugar, Rubberwood and Plywood Residues (English)	11/94	167/94
Lao PDR	Urban Electricity Demand Assessment Study (English)	03/93	154/93
Malaysia	Sabah Power System Efficiency Study (English)	03/87	068/87
	Gas Utilization Study (English)	09/91	9645-MA
Myanmar	Energy Assessment (English)	06/85	5416-BA
Papua New Guinea	Energy Assessment (English)	06/82	3882-PNG
	Status Report (English)	07/83	006/83
	Energy Strategy Paper (English)	--	--
	Institutional Review in the Energy Sector (English)	10/84	023/84
	Power Tariff Study (English)	10/84	024/84
Philippines	Commercial Potential for Power Production from Agricultural Residues (English)	12/93	157/93
	Energy Conservation Study (English)	08/94	--
Solomon Islands	Energy Assessment (English)	06/83	4404-SOL
	Energy Assessment (English)	01/92	979-SOL
South Pacific	Petroleum Transport in the South Pacific (English)	05/86	--
Thailand	Energy Assessment (English)	09/85	5793-TH
	Rural Energy Issues and Options (English)	09/85	044/85
	Accelerated Dissemination of Improved Stoves and Charcoal Kilns (English)	09/87	079/87
	Northeast Region Village Forestry and Woodfuels Preinvestment Study (English)	02/88	083/88
	Impact of Lower Oil Prices (English)	08/88	--
	Coal Development and Utilization Study (English)	10/89	--
Tonga	Energy Assessment (English)	06/85	5498-TON
Vanuatu	Energy Assessment (English)	06/85	5577-VA
Vietnam	Rural and Household Energy-Issues and Options (English)	01/94	161/94
	Power Sector Reform and Restructuring in Vietnam: Final Report to the Steering Committee (English and Vietnamese)	09/95	174/95
	Household Energy Technical Assistance: Improved Coal Briquetting and Commercialized Dissemination of Higher Efficiency Biomass and Coal Stoves (English)	01/96	178/96
Western Samoa	Energy Assessment (English)	06/85	5497-WSO

SOUTH ASIA (SAS)

Bangladesh	Energy Assessment (English)	10/82	3873-BD
	Priority Investment Program (English)	05/83	002/83
	Status Report (English)	04/84	015/84
	Power System Efficiency Study (English)	02/85	031/85
	Small Scale Uses of Gas Prefeasibility Study (English)	12/88	--
India	Opportunities for Commercialization of Nonconventional Energy Systems (English)	11/88	091/88

Region/Country	Activity/Report Title	Date	Number
India	Maharashtra Bagasse Energy Efficiency Project (English)	07/90	120/90
	Mini-Hydro Development on Irrigation Dams and Canal Drops Vols. I, II and III (English)	07/91	139/91
	WindFarm Pre-Investment Study (English)	12/92	150/92
	Power Sector Reform Seminar (English)	04/94	166/94
Nepal	Energy Assessment (English)	08/83	4474-NEP
	Status Report (English)	01/85	028/84
	Energy Efficiency & Fuel Substitution in Industries (English)	06/93	158/93
Pakistan	Household Energy Assessment (English)	05/88	--
	Assessment of Photovoltaic Programs, Applications, and Markets (English)	10/89	103/89
	National Household Energy Survey and Strategy Formulation Study: Project Terminal Report (English)	03/94	--
	Managing the Energy Transition (English)	10/94	--
	Lighting Efficiency Improvement Program Phase 1: Commercial Buildings Five Year Plan (English)	10/94	--
Sri Lanka	Energy Assessment (English)	05/82	3792-CE
	Power System Loss Reduction Study (English)	07/83	007/83
	Status Report (English)	01/84	010/84
	Industrial Energy Conservation Study (English)	03/86	054/86

EUROPE AND CENTRAL ASIA (ECA)

Region/Country	Activity/Report Title	Date	Number
Bulgaria	Natural Gas Policies and Issues (English)	10/96	188/96
Central and Eastern Europe	Power Sector Reform in Selected Countries	07/97	196/97
Eastern Europe	The Future of Natural Gas in Eastern Europe (English)	08/92	149/92
Kazakhstan and Kyrgyzstan	Opportunities for Renewable Energy Development	11/97	16855-KAZ
Kazakhstan	Natural Gas Investment Strategy Study, Volumes 1, 2 and 3	12/97	199/97
Poland	Energy Sector Restructuring Program Vols. I-V (English)	01/93	153/93
Portugal	Energy Assessment (English)	04/84	4824-PO
Romania	Natural Gas Development Strategy (English)	12/96	192/96
Turkey	Energy Assessment (English)	03/83	3877-TU

MIDDLE EAST AND NORTH AFRICA (MNA)

Region/Country	Activity/Report Title	Date	Number
Arab Republic of Egypt	Energy Assessment (English)	10/96	189/96
Morocco	Energy Assessment (English and French)	03/84	4157-MOR
	Status Report (English and French)	01/86	048/86
	Energy Sector Institutional Development Study (English and French)	05/95	173/95
Syria	Energy Assessment (English)	05/86	5822-SYR
	Electric Power Efficiency Study (English)	09/88	089/88
	Energy Efficiency Improvement in the Cement Sector (English)	04/89	099/89
	Energy Efficiency Improvement in the Fertilizer Sector (English)	06/90	115/90

Region/Country	*Activity/Report Title*	*Date*	*Number*
Tunisia	Fuel Substitution (English and French)	03/90	--
	Power Efficiency Study (English and French)	02/92	136/91
	Energy Management Strategy in the Residential and Tertiary Sectors (English)	04/92	146/92
	Renewable Energy Strategy Study, Volume I (French)	11/96	190A/96
	Renewable Energy Strategy Study, Volume II (French)	11/96	190B/96
Yemen	Energy Assessment (English)	12/84	4892-YAR
	Energy Investment Priorities (English)	02/87	6376-YAR
	Household Energy Strategy Study Phase I (English)	03/91	126/91

LATIN AMERICA AND THE CARIBBEAN (LAC)

LAC Regional	Regional Seminar on Electric Power System Loss Reduction in the Caribbean (English)	07/89	--
	Elimination of Lead in Gasoline in Latin America and the Caribbean (English and Spanish)	04/97	194/97
Bolivia	Energy Assessment (English)	04/83	4213-BO
	National Energy Plan (English)	12/87	--
	La Paz Private Power Technical Assistance (English)	11/90	111/90
	Prefeasibility Evaluation Rural Electrification and Demand Assessment (English and Spanish)	04/91	129/91
	National Energy Plan (Spanish)	08/91	131/91
	Private Power Generation and Transmission (English)	01/92	137/91
	Natural Gas Distribution: Economics and Regulation (English)	03/92	125/92
	Natural Gas Sector Policies and Issues (English and Spanish)	12/93	164/93
	Household Rural Energy Strategy (English and Spanish)	01/94	162/94
	Preparation of Capitalization of the Hydrocarbon Sector	12/96	191/96
Brazil	Energy Efficiency & Conservation: Strategic Partnership for Energy Efficiency in Brazil (English)	01/95	170/95
	Hydro and Thermal Power Sector Study	09/97	197/97
Chile	Energy Sector Review (English)	08/88	7129-CH
Colombia	Energy Strategy Paper (English)	12/86	--
	Power Sector Restructuring (English)	11/94	169/94
	Energy Efficiency Report for the Commercial and Public Sector (English)	06/96	184/96
Costa Rica	Energy Assessment (English and Spanish)	01/84	4655-CR
	Recommended Technical Assistance Projects (English)	11/84	027/84
	Forest Residues Utilization Study (English and Spanish)	02/90	108/90
Dominican Republic	Energy Assessment (English)	05/91	8234-DO
Ecuador	Energy Assessment (Spanish)	12/85	5865-EC
	Energy Strategy Phase I (Spanish)	07/88	--
	Energy Strategy (English)	04/91	--
	Private Minihydropower Development Study (English)	11/92	--
	Energy Pricing Subsidies and Interfuel Substitution (English)	08/94	11798-EC
	Energy Pricing, Poverty and Social Mitigation (English)	08/94	12831-EC
Guatemala	Issues and Options in the Energy Sector (English)	09/93	12160-GU
Haiti	Energy Assessment (English and French)	06/82	3672-HA
	Status Report (English and French)	08/85	041/85
	Household Energy Strategy (English and French)	12/91	143/91

Region/Country	*Activity/Report Title*	*Date*	*Number*
Honduras	Energy Assessment (English)	08/87	6476-HO
	Petroleum Supply Management (English)	03/91	128/91
Jamaica	Energy Assessment (English)	04/85	5466-JM
	Petroleum Procurement, Refining, and Distribution Study (English)	11/86	061/86
	Energy Efficiency Building Code Phase I (English)	03/88	--
	Energy Efficiency Standards and Labels Phase I (English)	03/88	--
	Management Information System Phase I (English)	03/88	--
	Charcoal Production Project (English)	09/88	090/88
	FIDCO Sawmill Residues Utilization Study (English)	09/88	088/88
	Energy Sector Strategy and Investment Planning Study (English)	07/92	135/92
Mexico	Improved Charcoal Production Within Forest Management for the State of Veracruz (English and Spanish)	08/91	138/91
	Energy Efficiency Management Technical Assistance to the Comision Nacional para el Ahorro de Energia (CONAE) (English)	04/96	180/96
Panama	Power System Efficiency Study (English)	06/83	004/83
Paraguay	Energy Assessment (English)	10/84	5145-PA
	Recommended Technical Assistance Projects (English)	09/85	--
	Status Report (English and Spanish)	09/85	043/85
Peru	Energy Assessment (English)	01/84	4677-PE
	Status Report (English)	08/85	040/85
	Proposal for a Stove Dissemination Program in the Sierra (English and Spanish)	02/87	064/87
	Energy Strategy (English and Spanish)	12/90	--
	Study of Energy Taxation and Liberalization of the Hydrocarbons Sector (English and Spanish)	120/93	159/93
Saint Lucia	Energy Assessment (English)	09/84	5111-SLU
St. Vincent and the Grenadines	Energy Assessment (English)	09/84	5103-STV
Trinidad and Tobago	Energy Assessment (English)	12/85	5930-TR

GLOBAL

	Energy End Use Efficiency: Research and Strategy (English)	11/89	--
	Women and Energy--A Resource Guide The International Network: Policies and Experience (English)	04/90	--
	Guidelines for Utility Customer Management and Metering (English and Spanish)	07/91	--
	Assessment of Personal Computer Models for Energy Planning in Developing Countries (English)	10/91	--
	Long-Term Gas Contracts Principles and Applications (English)	02/93	152/93
	Comparative Behavior of Firms Under Public and Private Ownership (English)	05/93	155/93
	Development of Regional Electric Power Networks (English)	10/94	--
	Roundtable on Energy Efficiency (English)	02/95	171/95
	Assessing Pollution Abatement Policies with a Case Study of Ankara (English)	11/95	177/95
	A Synopsis of the Third Annual Roundtable on Independent Power Projects: Rhetoric and Reality (English)	08/96	187/96

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