Cross-Border Oil and Gas Pipelines: Problems and Prospects

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Joint UNDP/World Bank Energy Sector Management Assistance Programme
(ESMAP)

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Acknowledgments

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Abbreviations and Acronyms

ACG	Azeri, Chirag, deepwater Gunashly field complex
AEC	Alberta Energy Company
AIOC	Azerbaijan International Operating Company
ANP	Agencia Nacional do Petroleo
Aramco	Arabian American Oil Company
BG	British Gas
BPS	Baltic Pipeline System
BTB	Consortium of British Gas, Tenneco (now El Paso Energy), and Broken Hill Proprietary
BTC	Baku-Tbilisi-Ceyhan
CCGT	Combined-Cycle Gas Turbine
CDU	Central Dispatch Unit
CO2	Carbon Dioxide
CIF	Cost, Insurance, Freight
COMECON	Council for Mutual Economic Cooperation
CPC	Caspian Pipeline Consortium
CPC-K	Caspian Pipeline Consortium in Kazakhstan
CPC-R	Caspian Pipeline Consortium in Russia
EBRD	European Bank for Reconstruction and Development
ECT	Energy Charter Treaty
EIB	European Investment Bank
EMPL	Europe Maghreb Pipeline Ltd.
ESMAP	Joint UNDP/World Bank Energy Sector Management Assistance Programme
FEC	Federal Energy Commission
FOI	Feasibility of Investment
FSU	Former Soviet Union
GATT	General Agreement on Tariffs and Trade
GIE	Gulf Interstate Engineering
GDF	German Democratic Republic
GIOC	Georgian International Oil Corporation
Glavneftesnab	Main Administration for Oil and Refined Products Supply
GME	Gazoduc Maghreb Europe
GPC	Georgia Pipeline Company
GPTN	Gomel Oil Transportation Enterprise “Druzhba”

GTB	Gas Trans-Boliviano
GTN	Glavtransneft
HGA	Host Government Agreement
HSE	Health, Safety, and Environment
ICSID	International Center for Settlement of Investment Disputes
IEA	International Energy Agency
IGA	Intergovernmental Agreements
IPC	Iraq Petroleum Company
IPSA	International Production Sharing Agreement
JSC	Joint Stock Company
JV	Joint Venture
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gas
MEP	Main Export Pipeline
NHI	National Hydrocarbon Institute
NOx	Nitrous Oxides
NPTN	Novopolotosk Oil Transportation Enterprise “Druzhba”
NREP	Northern Route Export Pipeline
OAPEC	Arab Organization of Petroleum Exporting Countries
ODU	Integrated Dispatch Administration
OECD	Organization for Economic Cooperation and Development
OPEC	Organization of Petroleum Exporting Countries
PCOA	Pipeline Construction and Operating Agreement
PEN	Spain’s National Energy Plan
PFLP	Popular Front for the Liberation of Palestine
PSA	Production Sharing Agreement
RSFSR	Russian Soviet Federated Socialist Republics
SA	Sociedad Anonima
SCA	Suez Canal Authority
SCADA	Supervisory Control and Data Acquisition System
SNPP	Société Nationale des Produits Petroliers
SOCAR	State Oil Company of Azerbaijan
SOx	Sulphur Oxide
SPMS	Single-point moorings
T&D	Throughput and Deficiency
TBG	Transportadora Brasileira Gasoduto Bolivia Brasil, BA

TCO	Tengiz Chevroil
TEN	Trans-European Network
TGN	Transportadora de Gas del Norte
TCQ	Transport Capacity Quantity
UAE	United Arab Emirates
U.K.	United Kingdom
UN	United Nations
U.S.	United States
UNICITRAL	UN Commission on International Trade Law
VAT	Value Added Tax
VTO	Foreign Trade Association
WREP	Western Route Export Pipeline
WTO	World Trade Organization
YPFB	Yacimentos Petrolíferos y Fiscales Bolivianos

Units of Measure

Bcm	Billion cubic meters
Bcm/y	Billion cubic meters per year
Mb/d	Million barrels per day
Dwt	Deadweight metric tons
Mt/y	Million metric tons per year
B/d	Barrels per day
MW	Megawatts
Mb/d	Million barrels per day
Mcm/d	Million cubic meters per day
Mcf/d	Thousand cubic feet per day
MMcf/d	Million cubic feet per day
MBtu	Million British thermal units

Executive Summary

1. In the near future, the world will need more cross-border pipelines for oil and gas. Two factors explain the reasons for this need:

- Reserves close to traditional markets are being depleted. Newer, more remote sources of oil and gas will be required. Many of these will require pipeline delivery either because they are landlocked or, in the case of gas, because liquefied natural gas (LNG) projects are less attractive than pipelines, other than for distances in excess of 3,000km.
- Many gas markets have in the past been constrained by regulatory and institutional factors. In recent years these constraints have been eroded. A potential "dash for gas" furthermore is being reinforced in many areas by a combination of gas sector reform, creating gas-to-gas competition; electricity sector reform, leading to strong demand for combined-cycle gas turbine (CCGT) generation; and concerns about the environmental damage caused by the consumption of other hydrocarbons.

2. The problem is that cross-border oil and gas pipelines have a history of vulnerability to disruption and of generating conflict. While it is true that most operating pipelines have avoided such problems, the minority that have such a history have cast a much greater shadow than their actual numbers might justify. This negative perception inhibits both the operation of existing lines and the building of new ones. In particular, the risks perceived as inherent in cross-border pipelines may increase the cost of finance. In addition to threatening the viability of projects, higher financing costs also seriously impact the delivered cost of the fuel. This is especially true for gas, for which the only viable alternative is LNG; despite some improvements, conversion to LNG remains a costly option and may deliver too much gas for many markets to absorb.

3. All this has serious consequences for the producers and consumers of oil and gas at both ends of the line. The purpose of this report is to seek ways in which such disruption and conflict can be prevented, mitigated, or contained. It especially focuses on the ways in which the various players can contribute to this process, and in particular focuses on the respective roles of the public and private sectors.

4. The starting point is to identify what causes conflict and disruption to throughput. The methodology is simple. Cross-border pipelines have three relevant dimensions: they involve the use of pipelines, the use of cross-border trade, and they may involve the use of transit. Each has certain innate characteristics that lead to consequences (see table 1.1). Various combinations of these consequences lead to three results that in turn create conflict or the potential for conflict (although many of these consequences would exist in many commercial transactions). These are:

- Different parties, each with different interests, are involved.

- There is no overarching legal regime that can be used to police and regulate activities and contracts.
- The context created by the characteristics invites conflict because profit and rent are to be shared between the various parties and mechanisms exist to encourage one or other party to seek a greater share of that profit and rent.

5. During the course of this analysis, it will be important in many instances to differentiate between oil and gas pipelines since the characteristics, consequences, and results often differ. The main differentiating factors between oil and gas are as follows:

- There is normally much greater rent associated with oil than with gas.
- Security of supply is more important for gas than for oil, because gas outages involve much greater reconnection problems.
- Gas pipeline transportation involves very different technical issues from those of oil; for example, in terms of issues such as grid balancing.
- The environmental threats from oil and gas pipelines differ significantly.
- The extent of competition, in terms of transport methods, differs.

6. Having created this theoretical framework, the report considers practice: that is, the ways in which each characteristic, consequence, and result has been managed (or not) in actual projects. Twelve case studies are contained in Appendix 1. In the light of the experience of these 12 pipelines, the report ends by considering the practices that have been demonstrated to contribute to the minimization of conflict. It also considers what more can be done by all parties to further reduce the conflict associated with cross-border pipelines. There are four overarching conditions of best practice, as follows:

- The rules are clearly defined and accepted.
- Projects are driven by commercial considerations.
- There are credible threats to deter the obsolescing bargain.
- There are mechanisms to create a balance of interest.

7. Each of these conditions is considered in Chapter 4, which concludes with a section on what more can be done.

8. The main findings of the report are as follows:

(a) Where the rules of the game are clearly defined and accepted, cross-border pipelines have succeeded. A context of clear and accepted rules is essential to the creation of an environment in which the commercial drivers of cross-border pipelines are able to resolve issues and problems.

(b) The best practices are those that allow for flexibility of contract, and the best guardian against future uncertainties is the impartial discipline of competition and the marketplace. (In practice such an environment is difficult to achieve, not least because pipelines involve monopoly elements.) Contracts that have the flexibility to deal with obvious foreseeable changes also are valuable.

(c) Where relationships are governed purely by commercial considerations, differences are more easily resolved. Best practice would seem to be for the state to set the context and then move aside to allow the fullest involvement of the private sector. While it is tempting to argue that state involvement creates problems and therefore should be minimized, the case studies do not support this blanket view. State involvement can cause serious problems in cases where the state lacks a clear framework for private investment. But where the optimal mix of legislation and regulation is in transition, for example, and may be far distant, the state must provide interim support for pipeline projects.

(d) Measures to minimize exposure to the problems associated with the obsolescing bargain are essential. Such measures must include credible threats to counter the temptation that might otherwise lead one party to unilaterally change the terms of an agreement. The process of globalization is important in this regard because of the value it confers on reputation in the securing of investment. One option is for the transit government to subject itself to sanctions.

(e) Pipeline projects need mechanisms to create alignment and a balance of interest between the parties. Such mechanisms include contracts, ownership and joint ventures, concessions, treaties, political relations, and public pledges to civil society.

(f) In no circumstances should a project be left to the mercy of naked bargaining power: this is guaranteed to leave at least one party feeling aggrieved. If all parties feel they are benefiting from the project, they will have an incentive to stay with it and to work out any conflicts or disputes that may arise.

What more can be done?

(g) Strengthen the accepted international norms of investment. The process of globalization will assist in this, but its effect would be reinforced if neutral arbitration clauses were to govern all of the relevant agreements.

(h) Strengthen the international sources of objective, third-party arbitration. The World Trade Organization and the Energy Charter Treaty provide options for third-party arbitration.

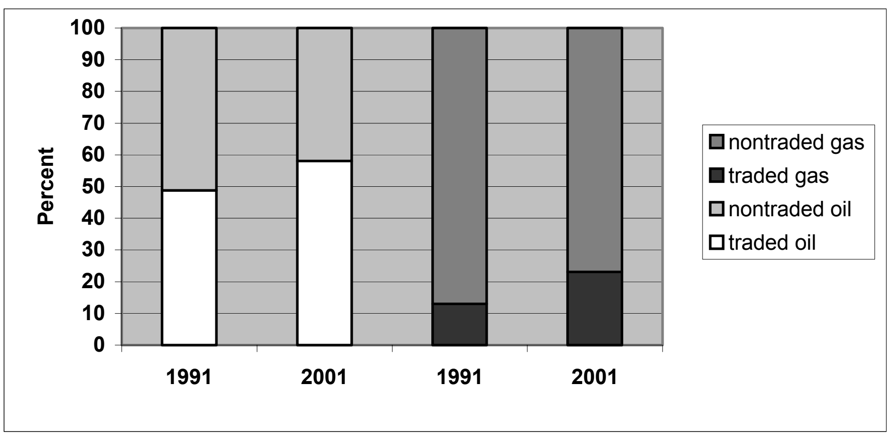
1

Introduction

The Role of Cross-Border Pipelines in the Past

1.1 The cross-border oil and gas trade has grown significantly in the past 50 years. Figure 1.1 shows the recent growth in such trade as a proportion of all traded and nontraded oil and gas.

Figure 1.1: The Growth in Cross-Border Trade in Oil and Gas



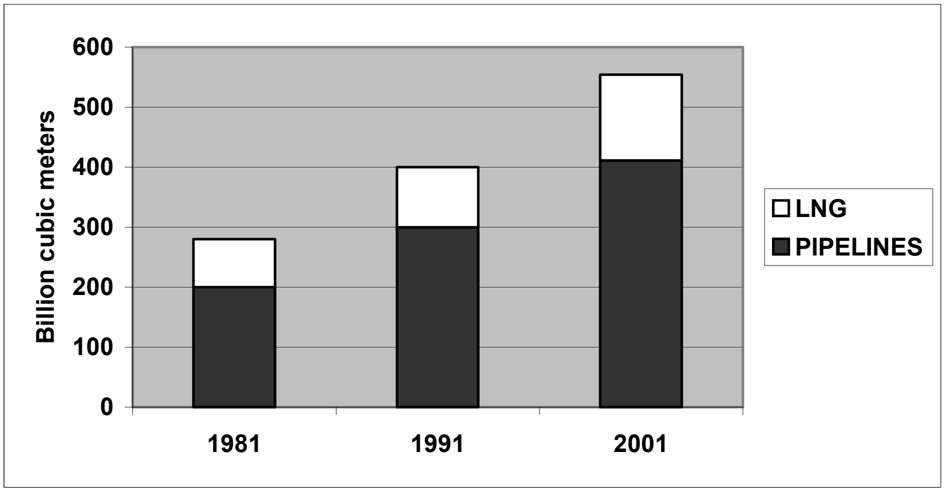
Source: BP Statistical Review of World Energy (various years)

1.2 How much of the oil trade is carried by pipeline is uncertain. The vast majority of oil moves in ocean-going tankers, and in addition to pipelines also is shipped by rail and trucks, with the result that precise data collection on transport methods is difficult. However, for gas there are only two serious transport options[1]: pipelines and

[1] Gas also can be transported as "embodied gas," by which the gas is used to produce for export energy-intensive goods such as metals or petrochemicals. Gas-to-liquids technology provides another option, but while a number of new plants are planned the use of this technology is limited to a few pilot plants. A final

liquefied natural gas (LNG). Data on gas transportation methods thus are more readily available, as can be seen from figure 1.2.

Figure 1.2: The Growth in Cross-Border Gas Trade (by Transport Mode)



Source: BP Statistical Review of World Energy (various years)

The Future Role of Cross-Border Pipelines

1.3 In the near future, the world will need more cross-border pipelines. Two factors explain this need: the location of oil and gas reserves and the patterns of energy demand.

1.4 **Location of reserves.** Reserves close to traditional markets are being depleted (see figure 1.3), and these markets are starting to look to newer, more remote sources of oil and gas for their needs. The successful exploitation of many of these sources will require pipeline delivery. In the case of oil, for example, some of the newer basins, notably those of the Caspian region, are landlocked. For other countries such as China, a vulnerability to naval blockade raises security-of-supply concerns against oil importation by tanker.[2]

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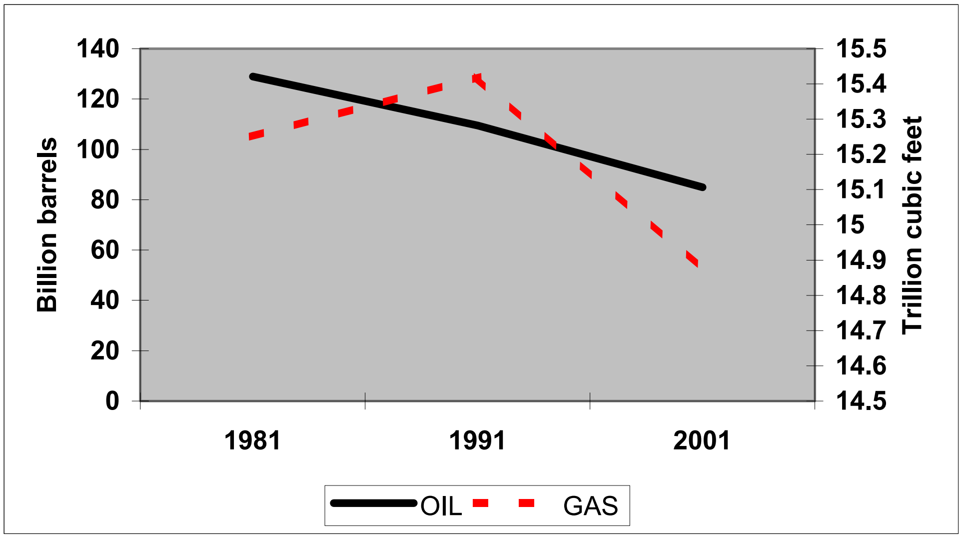
option is "gas-by-wire" (the transmission of gas-generated electricity), but the distance over which this form of transportation is viable is limited by transmission losses.

[2] Philip Andrews-Speed, Xuanli Liao, and Roland Dannreuther, "The Strategic Implications of China's Energy Needs," Adelphi Paper 346, the International Institute for Strategic Studies and Oxford University Press, 2002. Despite these concerns, China appears still willing to import LNG.

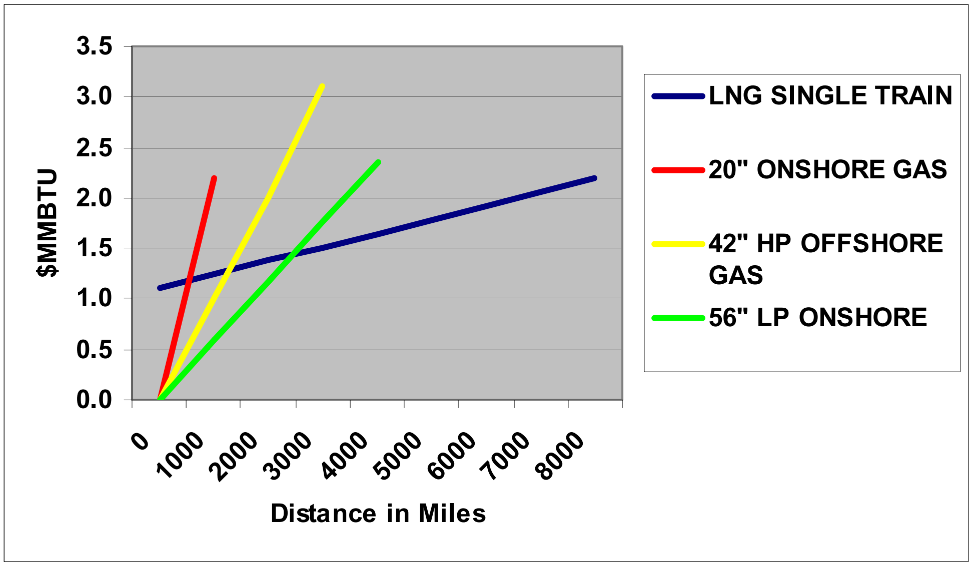
Figure 1.3 Proven Oil and Gas Reserves in the OECD



Source: BP Statistical Review of World Energy (various years)

1.5 For gas, the case for pipelines is even more compelling. Gas reserves close to market are declining, thus requiring gas to move further. The only alternative to pipeline transportation, liquefied natural gas, is cost-competitive with pipelines only over distances in excess of 3,000 miles (4,800km) (see figure 1.4). Despite recent improvements arising from scale economies and new forms of financing, LNG projects remain extremely expensive.

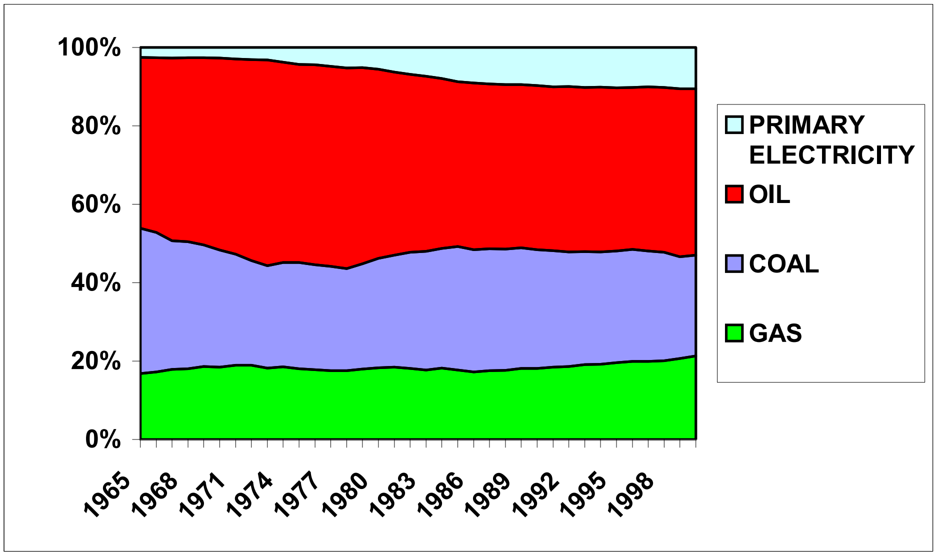
Figure 1.4: The Relative Costs of Transporting Gas



Source: Jim Jensen Associates

1.6 **Changes to energy demand patterns.** Regulatory, institutional, and economic barriers in the past constrained the use of gas (with the notable exception of within the former Soviet Union). The future will see a greater role for gas in the primary energy mix (see figure 1.5).

Figure 1.5: The Share of Gas in Primary Energy outside the Former Soviet Union 1965-2000



Source: BP Statistical Review of World Energy (various years)

1.7 In the Organization for Economic Cooperation and Development (OECD) countries, three factors limited the use of gas:

- Transportation problems meant that in many countries gas was not available.
- In the 1970s, the so-called "premium fuel" argument posited that because gas had so many advantages it was too precious to burn. As a consequence, for example, regulation both in the United States and the European Union specifically prevented the use of gas for power generation.
- Outside the United States, most gas suppliers were public sector utilities with monopoly and sometimes monopsony status. Gas prices thus were held artificially high and were uncompetitive.

1.8 In the developing economies, in many cases gas simply was not available. While during the 1970s some countries discovered gas reserves, their development for domestic use was painfully slow. Two reasons for this are:

- The realization of domestic gas consumption requires expensive infrastructure involving foreign exchange. Faced with the debt crisis of the

1980s, many developing countries could not afford the necessary infrastructure.

- Despite the often attractive project economics, many foreign companies were reluctant to help develop gas resources for domestic use because of the lack of convertibility of the domestic currency.

1.9 The gas export option also faced barriers:

- *The size of gas reserves.* An export project requires a minimum size of gas reserves to justify the huge upfront investments.[3] Because of the currency convertibility problem, even those companies that had discovered some reserves lost their enthusiasm for further exploration. The reserves found often were suboptimal for export projects.
- *The problems of negotiating export contracts.* Most export contracts are for periods of 15–20 years. In an uncertain energy market, this span of contract means that the contract must be both flexible enough to address changing circumstances but rigid enough to be worth signing. Determining price is especially problematic if the gas is being sold into a "project supply market" where no "gas price" exists.[4] To protect the financial viability of the project for producers and consumers, an absolute floor and an absolute ceiling price must be agreed. These fixed numbers must have validity over the life of the contract, and this in a world where it is hard to determine energy prices for one year ahead, let alone 15 or 20 years ahead.
- *Security of supply.* Security of supply is of much greater importance for gas than it is for other fuels. For electricity or oil products the loss of supply incurs outage costs, but when supply is restored, reconnection is simple. This is not so with gas. Because there is a danger that appliances may not have been switched off or that air may have entered the pipes, supply restoration ideally requires a gas engineer at every burner tip. The inflexibility in gas supply networks means it is difficult to replace lost supply quickly, with the result that importers tend to be wary of gas.
- *The problems of long-distance transportation.* Transporting gas is far more expensive than transporting oil. Gas pipeline transit, and the

[3] A pipeline project requires at least 2 trillion cubic feet; a 2 million ton per year LNG project requires 5 trillion cubic feet.

[4] It is useful to distinguish between "commodity supply markets" and "project supply markets" for gas. In the former there are a number of buyers and sellers, an existing grid delivery system, and widespread gas use. There therefore exists a gas price determined by gas-to-gas competition. In "project supply markets," by contrast, there are very few buyers, limited delivery mechanisms, and limited gas use. Thus the gas price must be negotiated by contract, frequently linked into some other more widely traded competing energy source (usually oil). There are only a few countries where a "commodity supply market" exists; these include the United States, Canada, the United Kingdom, and Argentina. As many of the barriers described here erode, more such markets will emerge.

alternative, LNG projects, face a range of both potential and actual problems. Those of LNG, while diminishing, can be characterized as complex, extremely expensive, and plagued by long lead times. The cost of a project, including gasfield development, liquefaction plant, special LNG tankers, and the regasification plant, in the past typically would be quoted at US$9–12 billion. The process of liquefaction furthermore was highly energy intensive, with around 15–18 percent of the gas effectively wasted in producing the liquid. LNG also raises safety concerns since it represents highly concentrated energy. Past projects were extremely inflexible and spot trading in LNG almost unheard of. And such projects offered limited revenue benefit to the governments concerned.

1.10 Over the last 10 years, forces have been working to reduce or remove these constraints, leading to a growing role for gas in primary energy and with it a need for more cross-border gas pipelines. These forces for change include the following:

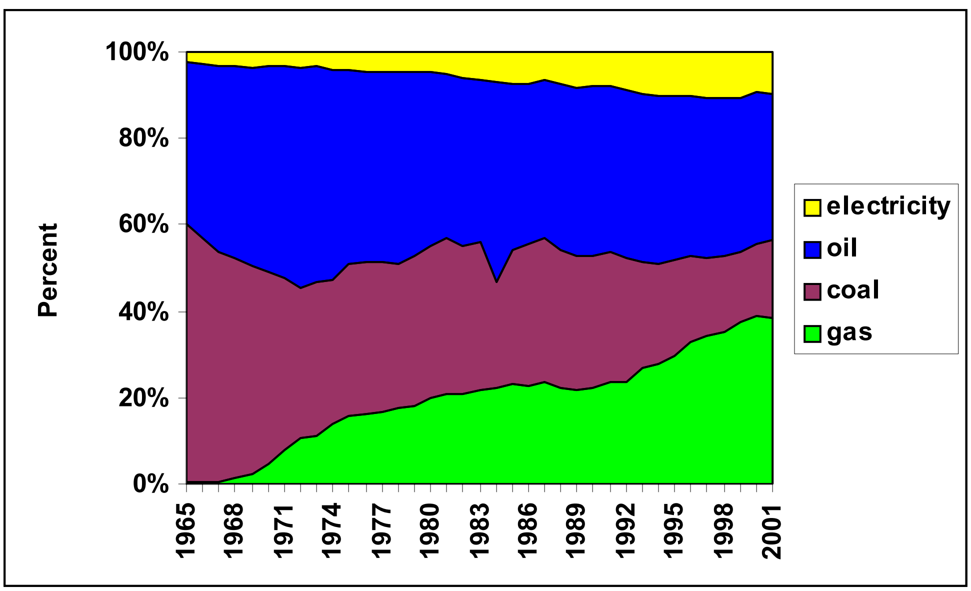
- Regulatory restrictions on gas consumption arising from the "premium fuel" argument were removed in the OECD in the early 1990s.
- Of the hydrocarbons, gas is relatively environmentally friendly, having high conversion efficiencies from useable to useful energy. It is also relatively clean. Burning natural gas emits only 75 percent of the NOx and 50 percent of the CO2 released by the burning of other hydrocarbons. It emits no SOx. If the Kyoto Protocol emission targets are to be achieved without the use of more nuclear power, the only realistic option is considerably greater use of gas.
- Governments are deregulating and liberalizing electricity to encourage private sector investment, and private investors in electricity generation have a strong preference for combined-cycle gas turbine (CCGT) technology, for three primary reasons: (a) economies of scale are less relevant, so small plants are economic; (b) conversion efficiency is around 60–65 percent, compared to 30–33 percent in conventional thermal stations; and (c) the lead time on plants is short—a plant can be completed in two years, with some generation beginning in one year. CCGT projects thus have a potential for short paybacks that is attractive to private investors. The International Energy Agency's (IEA's) Reference Scenario in its World Energy Outlook 2000 sees a substantial rise in gas-fired power generation: between 1997 and 2020 in OECD Europe gas-fired power generation is forecast to rise from 12 to 38 percent of total electricity generation, in OECD North America from 12 to 27 percent, and in OECD Pacific from 19 to 26 percent.
- Gas markets increasingly are being deregulated and liberalized, promoting the development of commodity supply markets and gas-to-gas competition. Prices, therefore, can be expected to fall. Developments in

the European gas market under pressure from the European Union exemplify this change.

- The gas transportation situation is improving. Work is being done on technical solutions such as gas-to-liquid and gas-by-wire transportation, and it is worthwhile also mentioning the improvements in LNG handling. A combination of technological developments, economies of scale, and new methods of project finance mean LNG project costs and lead times are falling. More projects also are coming onstream, raising the likelihood of improved flexibility in LNG trading. In 2000, a number of companies ordered LNG tankers for independent operations, presaging a large potential increase in spot trading.

1.11 Gas consumption thus is expected to rise. The example of the United Kingdom provides an insight into how this can occur (see figure 1.6). Since the late 1980s, most of the barriers discussed earlier have been removed in the United Kingdom. As can be seen, the consequences for the share of gas have been formidable.

Figure 1.6: The Share of Gas in Primary Energy Consumption in the United Kingdom

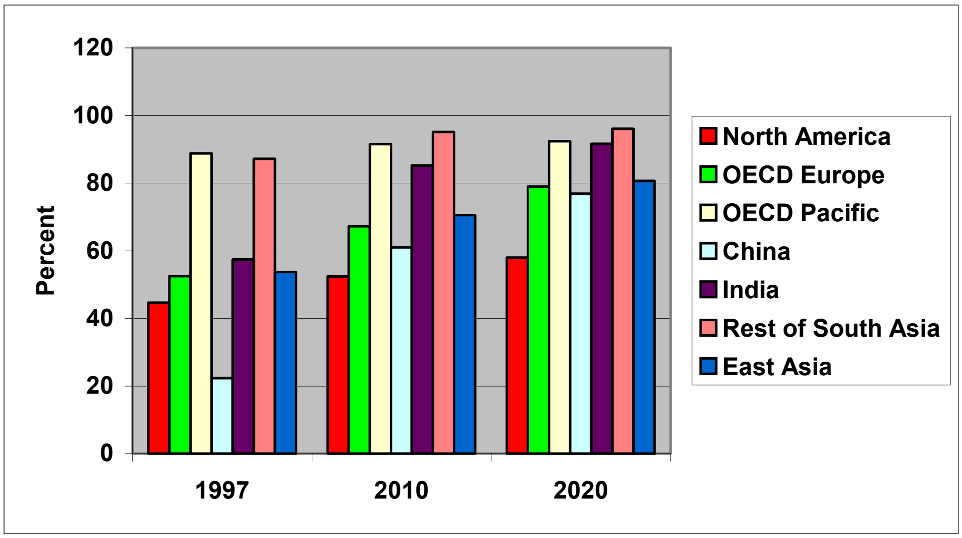


Source: BP Statistical Review of World Energy (various years)

1.12 Changes in reserve location and energy demand patterns imply growing imbalances between oil and gas consuming and oil and gas producing regions. This in turn implies that cross-border trade must grow. For the purposes of illustration, figure 1.7

portrays a projection from the IEA of the dependence of several major regions on imported oil. It should be noted that this regional approach makes no demonstration of the need for greater intraregional cross-border trade.

Figure 1.7: Dependence on Imported Oil



Source: IEA World Energy Outlook 2000

1.13 More cross-border pipelines clearly will be needed for oil and gas. Obstacles, however, exist to the implementation of these pipelines that first must be addressed.

The Problems of Cross-Border Pipelines

1.14 The number of successful cross-border oil and gas pipelines, exemplified by those in North America and Western Europe, outweigh the problem pipelines, but the problem cases nonetheless have tended to have a disproportionate affect on project planning. And cross-border pipelines have a long history, especially where transit is involved, of vulnerability to disruption and conflict.

1.15 The conflicts that have affected cross-border pipelines have taken many forms. There is a widespread view that conflicts over pipelines, including those due to incompatible legal and regulatory regimes, arise because of politics. Some conflicts undeniably have been political, including those that have grown out of a legacy of political divisions. For example, some of the problems of the Iraq Petroleum Company (IPC) line through Syria arose because of ideological differences between the two factions of the Arab Ba'ath Party (see Appendix 1, Case Study 4). Attempts to build a gas pipeline from Iran to India have stalled on long-standing disputes between India and

Pakistan.[5] More recently, plans to run a gas export pipeline from Bolivia to the Chilean coast have fallen foul of a dispute from the 19th century, when Chile annexed part of Bolivia, preventing Bolivian access to the Pacific. Instead a longer, higher risk route through Peru to the coast is being considered.

1.16 These are clear examples of political conflicts, but many conflicts are based on economic issues,[6] ranging from failure to agree on the terms of transit and on profit and rent sharing to issues regarding the obsolescing bargain.[7] The histories of the Iraqi export lines (case study 4) and Tapline (case study 5) are littered with such disputes. Economic-based conflicts also can include squabbles between joint venture partners, reflecting the differences between public and private companies or between vertically integrated companies and standalone ventures. Should a receiving or transit country also be an oil or gas exporter there is the further danger that it may seek to reduce throughput to capture market share for itself, as the case of the Iraqi export lines through Saudi Arabia (case study 4) illustrates.

1.17 In general, such disputes and conflicts can be explained in the following way. All cross-border pipelines have their own characteristics, each of which may be associated with certain consequences.[8] Together, these consequences may combine to produce one or more of three results liable to generate dispute and conflict, as follows:

1. Different parties with different interests are involved in the pipeline project.
2. There is no overarching legal jurisdiction to police and regulate activities and contracts.
3. The projects attract profit and rent to be shared between the various parties.

1.18 The potential for conflict that is implicit in these results can have serious implications for the producers and consumers of oil and gas at both ends of the line. The purpose of this report is to seek ways to prevent, mitigate, or contain such conflict and the disruption that it causes. The report focuses especially on how the various players can contribute to this process, examining in particular the respective roles of the public and the private sector. It also seeks, through the examination of existing pipeline projects, to define industry best practices.

Methodology

[5] Economic barriers also have been in play. Thus India appears reluctant to commit to an offtake at prices that will make investment in the line attractive.
[6] For example, see Paul Stevens, "Pipelines or Pipe Dreams? Lessons from the History of Arab Transit Pipelines," *Middle East Journal*, Spring 2000: pp. 224–241.
[7] This term, coined by Ray Vernon in the 1960s, describes a situation in which, once the investment has been sunk and operations begin, relative bargaining power switches to the government from the company. This encourages the government to try unilaterally to secure a greater share of the rent.
[8] Individually, the characteristics and consequences are not unique to cross-border pipelines. Collectively, however, they produce serious consequences for such pipelines.

1.19 There are three primary components to the operation of a cross-border pipeline: (a) the pipeline itself, (b) cross-border trade, and (c) in some cases, the use of transit. Each component has certain innate characteristics, each of which bears consequences (see table 1.1). Combinations of these consequences can give rise to one or more of the three results, outlined above, that create conflict or the potential for conflict.

1.20 Chapter 2 examines in greater detail these characteristics and consequences. Chapter 3 considers how the pipeline projects studied in Appendix 1 managed these consequences and how their management evolved in response to experience and changing circumstances. The gaps in problem management are identified and discussed in chapter 4, with a view to identifying who should be responsible for filling these gaps and how this should be achieved. In particular, chapter 4 focuses on the relative responsibilities of the public and the private sector.

Table 1.1: The Characteristics and Consequences of Cross-Border Oil and Gas Pipelines

CHARACTERISTICS	*CONSEQUENCES (figures in parentheses identify which of the three numbered results in paragraph 1.17 follow)*
Transit	
Requires transit agreement	Involves governments (1, 2)
May involve competing for markets	Increases the number of players (1)
May involve competing for volumes	Transit governments have different objectives (1)
	Transit revenues are a zero sum game (3)
Cross-Border[9]	
Need contracts governed by different legal regimes	Different legal and regulatory regimes apply (2)
Need to move between differing legal and regulatory environments	Differing energy markets are involved (regulation, structure, degree of competition) (1)
	Imports may compete with a national project (1)
	Benefits must be shared across the border (3)
Pipelines	
Subject to economies of scale	The "bygones rule" operates (3)
Large upfront investment	Full-capacity operation is key to profitability (3)
High fixed costs	Requires regulation (1, 2)
Potential for natural monopoly	Limited flexibility (3)
Changing capacity is difficult once built	

[9] That is., a situation in which the pipeline must cross the territory of a third party to get to market. This territory has the ability (national or regional) to abrogate unilaterally international agreements.

Long-lived specific projects	Fixed routes once built (3) Vulnerable to changing circumstances (2, 3)
History of state involvement	Regulation exists (1, 2) Public versus private interests (1)
Part of a longer value chain; that is, part of vertical integration	Rent to share (3) Rent may be volatile (3) Regulation required (1, 2)
Subject to market failure –Competition –Security of supply and strategic importance –Environmental damage in building and operation	Regulation required (1, 2) Public versus private interests (1)

The Difference between Oil and Gas

1.21 During the course of the analysis outlined in paragraphs 1.19-1.20, it will be important in many instances to differentiate between oil and gas pipelines since the characteristics, consequences, and results of the two often differ.[10]

1.22 Normally, there is much greater rent to be divided from oil than gas. Rent arises from two sources. In a competitive market, low-cost producers will gain a producers' surplus: the difference between costs and the ruling price. Both oil and gas attract such rent. Large, uniform, and favorably located reservoirs have much lower costs than small, fragmented reservoirs in difficult locations. For example, the fully built-up cost of new production in Saudi Arabia is some US$2 per barrel, while deep offshore it can rise to as much as US$12–14 per barrel. Another source of rent is supernormal profit, which becomes available where supply restrictions force up price. Here oil secures much greater rent, because the existence of OPEC (the Organization of Petroleum Exporting Countries) allows market manipulation on a grand scale. In certain countries or regional markets a lack of competition may do the same for gas, but this is less common. Much larger rents in oil create a greater temptation to transit governments to increase their share of the rent.

1.23 Another source of surplus also favors oil over gas. Where gas and oil have no substitutes they can command high prices to the final consumer. This allows consumer governments to impose high levels of sales taxes. (These are transfer payments rather than rent, but still add to the "pot," the division of which might be a source of conflict.)

[10] As will become apparent, there are also crucial differences between different gas situations, depending upon whether it is traded in a commodity supply or a project supply market (see also footnote 5).

This applies most obviously to transport fuels—gasoline and diesel—because there are few competing alternative fuels. In some cases gas also attracts sales taxes, but this is much less common.

1.24 Where there is no open market structure for gas, rent sharing along the value chain is determined not by market mechanisms but by contracts. Because the oil market is a global market while that for gas is not, it is more likely that rent sharing for oil will be driven by market mechanisms.

1.25 Security of supply is more important for gas than oil since gas outages involve much greater problems of reconnection (see paragraph 1.9). Gas pipelines have different operating characteristics; for example, they must address issues such as grid balancing.

1.26 Gas moving into commodity supply markets always carries a volume risk on the marketing side, since throughput is dependent on market consumption. While this is also somewhat true to a certain extent of oil, the greater flexibility for oil transport makes the volume risk much greater for gas. Frequently such risks are covered by "minimum pay" or "take or pay" clauses in the contracts. For non-OPEC oil, there are no volume restrictions in the international oil market while OPEC is willing and able to behave as the residual supplier. For oil, cross-border trade pipeline throughput, therefore, is determined by production rather than by the market.

1.27 Because oil costs less to transport via pipeline than does gas, the CIF (cost, insurance, and freight) component of the final price is much lower for oil than for gas. Oil pipelines thus remain viable over much longer distances than do gas pipelines, giving planners the flexibility to avoid transit routes and their attendant problems.

1.28 The environmental threats from oil and gas pipelines differ significantly. Where leaks from a gas pipeline present an explosion problem,[11] spills from an oil pipeline risk despoiling large areas of terrain.

1.29 Another significant difference between the movement of oil and gas is in the modes of transportation available for each. Other than via pipeline, the only practical means of moving gas[12] is in the form of LNG, and LNG is competitive only where the distances involved are greater than 3,000 miles (4,800km). Oil, in contrast, is more easily moved, which means that oil pipelines potentially face much greater competition. Historically, the most striking demonstrations of this fact are Tapline (case study 5) and SuMed (case study 3), which were constructed to ship oil to the European market in preference to tanker routes from Ras Tanura via Africa or the Suez Canal. The collapse in tanker rates following the first oil shock of 1973 effectively killed the economic advantage of Tapline, leading eventually to its closure.

[11] Natural gas (methane) is a "greenhouse gas." Released into the atmosphere, it provides another source of environmental harm.
[12] See footnote 1 for a qualification of this statement.

1.30 Finally, the producers and consumers of gas delivered by pipeline are tightly linked. Any interruption to the flow would risk devaluing the entire investment both upstream and downstream of the pipeline. In the case of oil, this is less true: the producer has much greater opportunity to sell elsewhere, and the consumer likewise has greater opportunity to buy from elsewhere.

2

The Analytic Framework

The Characteristics of Cross-Border Pipelines and Their Consequences

The economics of pipelines

2.1 Pipeline economics have five main characteristics: economies of scale; the long life of specific projects; state involvement; the pipeline's place within a longer value chain; and finally the pipeline's susceptibility to market failure.

Economies of scale

2.2 The capacity of a pipeline is the square of its radius. This is an exponential factor that presents potentially large technical economies of scale. The capital cost of the pipeline is a function of its surface area; its throughput is a function of the capacity. This exponential relationship means as capacity increases, average fixed costs fall rapidly. There are no obvious diseconomies of scale. In the world of pipeline economics, big is beautiful (see figure 2.1).

2.3 This simple fact of physics gives rise to a number of characteristics:

- Pipelines involve large upfront investments. Costs vary depending on the terrain: mountainous rough territory normally costs far more than flat open territory.
- The structure of pipeline costs is characterized by high fixed costs and low variable costs. Other than from specific maintenance, the only significant variable cost is for the fuel to the pump, and often this is provided at concessional rates. The greater part of total costs—all of which are fixed—go to the laying of the pipeline and construction of the pumping stations. Thus, total costs are largely independent of the throughput.
- Pipelines are natural monopolies. It is clearly more economic in terms of unit transport costs to have one pipeline of 36 inches than three of 12 inches.

- Once the pipeline is built it is difficult to increase capacity, and the potential economies of scale are effectively used up.[13] A monopolist supplier of pipeline services, equating marginal costs and marginal revenues, in theory would build a below-optimum-capacity line to restrict supply and to secure elements of monopoly profit.

2.4 These characteristics give rise to a number of consequences that are key to understanding why pipelines may attract conflict:

- High fixed costs mean the "bygones rule" is extremely powerful. That is, if an operation is profitable it will continue: even if losses are incurred, provided that variable costs are covered and some contribution is being made to fixed costs, continued operation and (its loss minimizing consequences) is preferred to closure. Assuming economic rationality on the part of the owners, this means that they will continue to operate the pipeline for as long as there is any revenue to be gained. The result is a strong temptation for governments to take advantage of the obsolescing bargain, and in turn the creation of an imperative that the pipeline operators achieve a quick payback.[14]
- Because of high fixed costs, full-capacity operation is extremely important. Below-capacity operation spreads fixed costs exponentially around a lower throughput, and this can seriously damage the pipeline's profitability. For a 20-inch (51mm) pipeline, unit costs virtually double at 50 percent capacity. In the early stages of operation, a line probably will operate at less than full capacity. This gives the pipeline owner an incentive to secure more throughput. The best way to ensure full-capacity operation typically is for the pipeline owner to produce the oil or gas at one end and to lift at the other. Ownership of the throughput is a better guarantee than contracted throughput, since contracts can be broken. As a consequence, pipelines frequently are part of a vertically integrated operation.
- Because of the natural monopoly dimension to pipelines, regulation is necessary to protect consumers. This is either to protect consumers of monopolistic pipeline services or consumers of products flowing through monopolistic pipelines. Such regulation may relate to the building of the line, in terms of determining capacity, or to the operation of the line once built. It also should address either third-party access or common carriage, to ensure that other parties have access to use of the pipeline. (Third-party

[13] It is possible to increase throughput by adding pipeline loops or increasing the pumping power although this requires retrofitting pump stations. An easier way to increase throughput is to add a drag reducing agent to the crude, allowing it to flow more easily.
[14] One consequence may be that rapid development of the oil or gas resources may endow a case of "resource curse" on the country receiving the revenues.

access rights permit an owner of potential throughput to demand access on commercial terms, if necessary with government enforcement, providing there is surplus capacity on the line;[15] common carriage rights apply where no excess capacity exists, and require existing users to reduce their throughput on a pro rata basis to allow access.) However, regulated access can carry important implications for financing pipelines. Where political risk is high, financing is likely to be heavily dependent on upstream producer equity and equity holders are almost certain to demand (and get) preferential access as the price for investing. Thus governments face the choice of being tough on regulated access and inhibiting investment in both the pipeline and the upstream.

Long-lived specific projects

2.5 Pipelines, subject to both maintenance and the nature of the throughput, have an operating life of at least 20 years. Once the line is built the routing is fixed (although it may be possible to build spurs to avoid specific areas, as was recently done to take the NREP line around Chechen territory—see Case Study 4). Two consequences follow:

- Once the pipeline is built it either moves oil and gas between two points or it does not. This complete lack of flexibility makes it a potential hostage to fortune in any negotiations. Furthermore, once the line is built and commissioned, the relative bargaining power of the parties concerned changes, with the result that they may feel disinclined to bow to the discipline of markets or competition. This can encourage opportunistic behavior.
- The agreements that govern the building and operation of a line must be sustainable over a long period and through changing circumstances. This inevitably is problematic. The agreements must accommodate all foreseeable changes in circumstances, but by definition they cannot manage major unforeseen or unforeseeable changes. Problems may arise, for example, as changes in the price of the oil or gas conveyed make the throughput more or less valuable. When this occurs the role of the line in the value chain will alter, encouraging attempts to secure a greater share of the rent. The agreements also should address the alignment of interests: the longer the relationship must survive, the greater is the possibility that the interests of the parties concerned will diverge. Finally, the fundamental decision on pipeline capacity must be made up front, and the longer the life of the project, the greater is the chance that the pipe will mismatch this stated capacity.

[15] This can be complicated, since the owner of the line is entitled to reserve some excess capacity to accommodate expected further throughput.

2.6 The greater the confidence of investors that the conditions under which the project is financed will hold the lower will be the risk spread, the lower will be the possible maturity, and therefore the lower will be the financing costs.

History of government involvement

2.7 Most major pipelines have some dimension of government control. First and foremost, the permanent use of land for a pipeline requires state approval. The potential of market failure also traditionally requires government intervention. And in many cases, there is simply a legacy of government involvement. Oil and gas pipelines historically were seen, and often still are, as projects of national strategic importance. As such, their construction and operation often have been undertaken by state-owned companies. Several consequences follow:

- There are questions of what a government should ask in return for ceding sovereignty over a pipeline route, and what the rights and obligations of the government should be in such situations.
- Invariably, regulations relating to pipelines exist in the legislative armory available to government. These range from health, safety, and environment (HSE) regulation to access regulation affecting the profitability and returns associated with the pipeline. Key issues are the roles to be played, the division of work between government and the private investor with regard to the sharing of risk and rent, and avoidance of the obsolescing bargain.
- There may be fundamental differences of interest between the public and private players involved. A private investor seeks to earn interest or profit commensurate with the risks and the alternative investments available. A government, in contrast, must protect the well-being of its citizens, improve economic prosperity, maintain public order, guard sovereignty, and return a maximum of revenues to the state budget.
- The lack of separation between the political and commercial roles of a sovereign government can make the government vulnerable in its commercial role to noncommercial considerations. This can potentially introduce distortions to the economy and reduce economic efficiency.

The pipeline as part of a longer value chain

2.8 A pipeline is simply a means of moving valuable oil or gas from one point to another. Its value is therefore intimately tied up with the value of what is being moved. In addition, pipeline control can have serious implications for competition at both ends of the line. It is not uncommon for a vertically integrated pipeline owner to try to restrict access to the line by potential third party users to limit competition among producers and consumers. It is no coincidence that Standard Oil, which came to dominate the U.S. oil industry in the 19th century, began as a pipeline company that gradually gained control of the oilfields upstream and the refineries downstream. The consequences inherent in this situation include the following:

- There is profit associated with the operation of a pipeline as a normal commercial transaction, and the project must earn this profit to be viable. However, the presence of profit is complicated because the gas and (especially) oil projects of which the pipeline may be an integral part also attract rent (see paragraphs 1.21-1.30). This rent must be shared between the interested parties, but there is no obvious, objective way to divide rent. Pipelines are highly vulnerable. If any part of the pipeline is unable to operate, in the absence of an immediate alternative means of transportation all the rent is postponed.[16] Interruptions to operations not only threaten the return on the pipeline but also may jeopardize the return (profit and rent) on investments at both ends.
- The rent to be shared is likely to be volatile, depending on the rate of throughput of the line but more obviously on the vagaries of pricing of the oil or gas being transported.
- The competitive implications of pipeline control present the potential for market failure and hence government intervention.

Pipelines are subject to market failure

2.9 There are several sources of market failure associated with oil and gas pipelines and two sources of externality:[17] the environmental consequences of building the pipeline; and the potential damage from operations, most obviously from unintended leakages. Energy security of supply additionally is a major concern, particularly in the case of gas, for which alternative supplies are difficult to secure at short notice. As previously discussed, imperfect competition, the result of a natural monopoly or of constraints placed on competition by vertical integration, is a major source of market failure for pipelines. There are two primary consequences of market failure:

- Divergences of interest emerge between the public and private sector over pipelines.
- In the presence of market failure, governments must intervene, using a regulatory process either to promote competition or to internalize

[16] It is not "lost," because the oil or gas that is not produced today can be produced tomorrow. The price tomorrow, however, may differ from that of today and the time value of money means some rent is lost through postponement.

[17] Market failure occurs when market forces alone would lead to a misallocation of resources. Conventionally economists identify three sources of market failure: imperfect competition arising from monopoly elements or lack of information whereby prices (and hence their signal role) are distorted; externalities, where there are divergences between private costs and benefits and public costs and benefits thus the costs and benefits of the project are under or over stated; finally there are public goods which are goods whose consumption is nonrival and exclusion from consumption is not feasible meaning markets cannot allocate resources because there is neither a demand nor a supply curve.

externalities. However, such intervention is only justified if it produces a better outcome than leaving it to the market. It is effectively a trade-off between market failure and potential government failure.

The nature of cross-border trade

2.10 There are two relevant characteristics of cross-border trade: it requires that contracts be drawn that establish property rights and responsibilities from within potentially different legal regimes, and that a cross-border pipeline must operate between differing legal and regulatory regimes. Put simply, the difference between cross-border trade and internal trade is the absence in the former situation of a single overarching jurisdiction. A number of potentially serious consequences follow:

- Above all, in the presence of two independent sovereign jurisdictions there is no obvious mechanism for conflict resolution. International arbitration offers a solution to this problem, but recourse to such arbitration must be agreed to and adhered to.
- The interests of different parties will likely differ. There is a natural conflict of interest between the buyer and the seller, but other situations also may arise. The pipeline delivery close to the market of gas imported from Country A may inhibit the development of indigenous gas fields in Country B, for example.
- Reconciling different legal and regulatory regimes frequently will increase the transactions costs of building and operating a pipeline.
- Importers become vulnerable to the possibility of denial of oil or gas supplies, and exporters to the denial of their markets. Neighboring countries often have a record of hostility, for example, and pipelines in the past have become victims to the testosterone of history. Alternatively, the monopoly power of the seller or monopsony power of the buyer may create an economic motive for the cessation of supplies.
- Rights and obligations can differ. For example, in the context of HSE regulations the party responsible for damage may not be subject to the jurisdiction of the courts where the damage is located.
- The nature of the gas or oil market may differ greatly between the two countries connected by a pipeline. For example, one may be a commodity supply market and the other a project supply market. Levels of competition may differ, as may price regulation. One result of this is that the risks in the two markets also will differ.

2.11 The importance of these consequences depends on several factors—most obviously on how different the two jurisdictions are. For example, the legal framework in OECD countries broadly follows common principles, reducing friction between parties in dispute typically to a confrontation over detail. The acceptance through the General

Agreement on Tariffs and Trade, (GATT) the World Trade Organization, (WTO) or even the Energy Charter Treaty, (ECT) of international norms also can limit the negative impacts of differing jurisdictions. The efficiency of markets and the presence of competition additionally can minimize the consequences of legal differences: generally, the greater the importance of markets, the less the legal dimension matters (provided property rights are secure). For example, if oil and gas are priced competitively, there is much less incentive to disrupt the transaction. The presence of an alternative source of imports or alternative market for exports likewise will minimize the potential consequences of lack of an overarching legal jurisdiction, provided that the opportunity cost of a cut-off in supply is similar for both parties.

The nature of transit trade

2.12 Transit trade faces the problems of any cross-border trade, but compounds the problems outlined above through increasing the number of parties engaged in a project. If there is more than one transit country, this compounding effect obviously is magnified.[18]

2.13 The interests of a "pure transit" country are fundamentally different from those of an exporting or importing country.[19] Expressed simply, exporting and importing countries have more to lose by spoiling a deal than does a transit country. Transit countries only stand to lose their transit revenue when actively interfering with a deal, although such behavior may also damage their international standing if they unilaterally interfere with bilateral or multilateral agreements

2.14 Once transit is introduced, a transit fee is involved. The basis of this fee is obscure. One view argues it is a form of compensation for the state surrendering part of its sovereignty; this reasoning is rather undermined, however, by the fact that while the pipeline is being constructed and operated it is still subject to the jurisdiction of the state. Another view sees the transit fee as a reward for helping to realize the value added in a cross-border oil or gas trade (both the profit and the rent). A third view is that the fee confers to the transit state a significant portion of the saving that is made by using the transit route versus the next lowest cost alternative (in the absence of a viable alternative transport route this logic would reward the transit country with a large part of the whole value of the oil or gas exporting project, but this would be in response to the monopoly position of the transit country). Some further argue that assessment of the fee depends on international norms that use charges per volume per kilometer. This argument, however, tends to ignore the role of bargaining and the role of competing transport options, which is key to limiting any transit fee.

[18] Examples of pipelines that transit more than one country include the former IPC line, from Iraq via Syria and Lebanon; Tapline, from Saudi Arabia through Jordan, Syria, and Lebanon; and the Russian gas export line since the breakup of the Soviet Union.

[19] "Pure transit" implies the country does not lift oil or gas for its own use from the line.

2.15 The transit fee normally relates to the throughput of the line. Often it involves the transit country off-taking some throughput. This is particularly relevant for gas since the transit country can gain from the economies of scale in circumstances where the domestic market of the transit country may be too small to itself to justify a gas pipeline. The transit country also may gain other benefits, such as securing political support from countries or simply by advancing free trade.

The Consequences and the Results

2.16 Collectively, the characteristics and consequences listed in the previous section have led to disputes and conflicts. Generically, these can be attributed to three factors: different parties with different interests; the lack of an overarching jurisdiction to manage conflict; and the absence of a mechanism to determine the division of profit and rent.[20] These factors are discussed below, together with some initial observations arising from the case studies.

Cross-border pipelines involve different parties with different interests

2.17 Pipeline projects necessarily involve different parties with different interests. In so far as transit increases the number and diversity of players, this can aggravate conflict. A number of obvious divisions exist:

- The public sector may have very different objectives from the private sector. Economic reform and liberalization, through expanding the role of the private sector, may well accentuate these differences. One of the difficulties is determining who should do what.

  The private sector plays an important sponsoring role. For transitional periods in emerging markets, the state, by its assumption of residual risks, may be indispensable to the facilitation of a project. Once a clear regulatory framework has been established, however, and the rights and obligations of private investors have been clearly and credibly defined, there is every reason to leave the project to the private sector. This would limit the role of the state to regulatory and fiscal matters. Many of the case studies described in Appendix 1 demonstrate this model. If in the course of a project a private sector is just emerging, the state (or state company) can play a positive role by guaranteeing the minimum demand required (for a gas project) and by assuming some early risks that, because of regulatory and legal uncertainties,

[20] Arguably, profit is easier to share since there is some notion of reward for inputs. Since rent is, however, either a "gift" of nature or of imperfect competition there is no obvious, objective way of sharing other than by naked bargaining power. This can lead to great instability if one side is able to bargain so hard the other side signs up to an unbalanced deal which later becomes unstable leading to disputes.

private companies are unwilling to accept until privatization has been completed.

- Governments pursue their national interests, and these may differ. Exporting countries want reliable income, high rent, and the optimal development of their hydrocarbon reserves. Consuming/importing countries want secure supplies at competitive prices. Pure transit countries want taxes/rent as reward for granting access and as protection from any negative HSE consequences. Where noncommercial motivations are important, such divergences are accentuated: this provides a good reason to maximize the role of commercial drivers in such projects, but often politics makes this impossible.

- The different companies involved may have different objectives. Most obviously, a vertically integrated entity will behave differently from a standalone venture. A standalone pipeline company will simply be interested in maximizing throughput at the highest tariff it can charge. Once vertically integrated, however, the company must also consider the impact of its activity on operations at either end. If both the upstream and downstream ends of the pipeline are characterized by competitive markets, as is frequently the case for oil, this is no problem. However, if either end has elements of imperfect competition the game changes, since this introduces the temptation to use the pipeline to reinforce a monopolistic position. This is particularly relevant for gas, where transportation limitations make it easier to capture markets. Problems arising from these divisions of interest can be dealt with under the competition law and policies of the relevant country. As such, they do not have a specific cross-border dimension and so are not discussed further in this report.[21]

- Within a country, regional interests may differ from those of the central government. Clearly both will seek to maximize their benefits from pipelines, and this is in the context of what typically is a zero sum game. Although this is an important and sensitive issue, it is not one for cross-border pipelines in terms of sovereign nation states and is not pursued further in this report.

[21] For a more detailed discussion of these issues, see Paul Stevens, "Pipeline Regulation and the North Sea Oil Infrastructure," in G. Mackerron and P.J.G. Pearson (eds), *The UK Energy Experience: a Model or a Warning?,* Imperial College Press, London, 1996: pp. 109–122.

The lack of an overarching jurisdiction to manage conflict

2.18 As previously discussed, there is no overarching legal jurisdiction to police and regulate activities and contracts. In the past, the parties in many cross-border pipeline agreements have tried to overcome this problem by making use of an independent source of conflict resolution, such as international arbitration. This is key to the rationale of the ECT, which will be discussed later. Ultimately, however, the findings of international arbitration may not be legally binding, and if the rewards have been sufficiently tempting sovereign governments have in the past treated such findings in a cavalier fashion. It is interesting to speculate how far this will remain true as globalization makes economic success increasingly dependent upon an ability to attract investment—which in turn requires investor confidence in property rights and the sanctity of the contract. For example, case study 4 shows clearly that Turkey in the 1970s was an unreliable transit country. This was at a time when Turkey had a limited desire for foreign investment. Today, foreign investment is central to Turkey's economic strategy, and as the country has become very conscious of its reputation among foreign investors it is likely also to be a very different transit partner.

2.19 In circumstances in which there is no overarching legal framework, the presentation of a credible alternative to the pipeline in question can help draw the different parties to an agreement. A market alternative can help to define and clarify expectations and can provide benchmarks for the economic gain that each party may reasonably expect from the project. The existence of viable alternatives offers some protection against the obsolescing bargain. In this context of alternatives, the economists' concept of "contestable markets" can play a crucial role. It is not necessary to actually have an operating alternative: the theory of contestable markets argues that simply the threat of entry (that is, the alternative) is sufficient to influence the behavior of the incumbent.

There is profit and rent to be shared, but no obvious mechanism to determine the share

2.20 The economic context of cross-border pipelines invites conflict because the projects attract profit and rent that must be shared among the parties. This is compounded by the fact that mechanisms exist which arise from the underlying economics of pipelines that encourage one or another party to seek an ever greater share. For example, the bygones rule postulates that if variable costs are being covered and some contribution is being made to fixed costs, an operation should continue even if losses are accrued. Because of the innate cost structure of pipelines, which have very low variable costs, revenue can be squeezed out of even an extremely unprofitable pipeline. The inflexibility inherent in pipelines additionally creates hostages to fortune who are vulnerable in a bargaining situation.

2.21 In a well-conceived project, the interests of all stakeholders are balanced and aligned for the lifetime of the project. While intertwined, alignment and balance of interests are different: alignment refers to the relationship between the parties and is achieved largely by the instruments that fix that relationship; balance of interests refers to the allocation of risks and rewards among the parties involved. Successful projects are those that find an alignment and balance of interests among the parties that is stable over the life of the project and in which no participant perceives itself as worse off than it would be under an alternative course of action.

2.22 Every successful pipeline project features a well-balanced and usually sophisticated alignment of the interests of all stakeholders. A well-balanced alignment of interests must encompass not only the existing balance of the interests of all stakeholders but also the mechanisms to ensure a balance over time, to adjust the balance to changed circumstances, and to enforce the agreed-on balance. Transparency is essential to achievement of this alignment for its role in engendering mutual trust among all parties concerned. At the start of a project, joint committees involving all participating project members can help to find a fair alignment of economic interest by assessing the technical, environmental, and economic feasibility of the project. Public websites and the presence of an ombudsman for affected populations can contribute to the discovery of solutions acceptable to all civil society stakeholders. International financial institutions can play a positive role in mitigating the political risks by endorsing the commitments of the parties and ensuring observance of international standards related to health, safety, the environment, and the integrity of indigenous peoples.

2.23 One obvious barrier to the realization of mutual trust is that requirements of commercial confidentiality often mean that the terms of cross-border trade or transit are not publicly available. This considerably restricts any benchmarking based upon economic comparisons.

3

The Case Studies

Introduction

3.1 Appendix 1 contains 12 case studies of cross-border pipeline trade in oil and gas. Their purpose is twofold. First, they provide empirical support for the theoretical assertions presented in Chapter 2. Second, they provide examples of good and bad practice in the context of cross-border oil and gas pipeline projects. This informs the policy debate that is the prime purpose of the study.

3.2 The case studies have been divided into four categories. The first two categories include projects that have a long history, subdivided into those that can be categorized as successful (TransMed, the cross-border pipelines of the former Soviet Union, and the SuMed oil pipeline) and as failures (the Iraqi export lines and Tapline). The third category includes pipeline projects that are too new to be defined as successes or failures (the Baku Early Oil Project, the Maghreb–Europe gas pipeline, the Bolivia–Brazil gas line, the Caspian Pipeline Consortium oil line, and the Canada–United States Express Pipeline). The final category comprises pipelines that are still under consideration or have only recently begun operation (the Baltic Pipeline System and the GasAndes pipeline).

3.3 The case studies thus provide a cross section of successful and failed projects and of those that are yet to be judged. It is worth mentioning at this point how success or failure are defined here. For example, the failed projects had long lives and probably recovered their capital investments; as such, they could by some criteria be viewed a commercial success. For the purposes of this report, however, the terms "success" and "failure" are applied according to the degree of conflict generated by the project, coupled with its operating experience in terms of interrupted throughput.

3.4 It is also worth mentioning that the case studies included here are an arbitrary rather than representative selection, with the projects chosen being taken primary for illustrative purposes. There are many other pipelines that could have been chosen. For example, a number of projects currently in development have recently had a high news profile, such as the Baku–Tblisi–Ceyhan (BTC line) line to get Azeri oil into the Mediterranean and the Chad–Cameroon line, which was the subject of a recent World Bank review. There are many long-established success stories, such as the Russian gas export line into Europe, and there is also a great deal of material related to cross-border gas trade in Europe that links into pipeline issues. [22]

3.5 Two main sources have been used to provide these case studies:

- Ralf Dickel, *Cross-Border Oil and Gas Pipeline Projects: Analysis and Case Studies*, the World Bank, review version, 5 September 2001
- Paul Stevens, "Pipelines or Pipe Dreams? Lessons from the History of Arab Transit Pipelines," *Middle East Journal*, spring 2000, pp. 224–241

3.6 The reader is directed to the original sources where detailed references may be required. Many of the details of cross-border trade remain confidential, however, the result of a mixture of private commercial confidentiality concerns and perceived strategic state interests. The details of contracts, prices, and transit fees often are simply not available.

3.7 This chapter draws on the case studies to provide a discussion of good and bad practice in relation to the sources of conflict discussed in chapter 2.

Lessons To Be Learned from the Case Studies

3.8 Chapter 2, "The Consequences and the Results," described the underlying problems of cross-border pipelines in terms of three issues: the conflicting interests of the parties, the lack of an over-arching jurisdiction, and the lack of a mechanism to share the rent. The following section pursues these issues by drawing on specific examples from the case studies.

The conflicting interests of the parties

The roles of the private and public sectors

3.9 **Case Study 1: TransMed.** The TransMed line was completely driven by state interests. All the initial negotiations were between Sonatrach and Eni, the state oil companies of Algeria and Italy, with the Tunisian government joining later. Thus all the contractual relations were based upon government agreements. What was clear from the outset, however, was that in all three cases there was a strong political will to make the project work. For example, when there was a problem over the gas price negotiations, the Italian government offered a "political subsidy" to the tune of US$0.40 per million British Thermal Units (MBtu) to bridge the gap between the two sides.

3.10 **Case Study 2: The Transneft System.** Transneft originally was entirely a state entity of the Soviet Union. In the new transition environment, the Russian state apparently has not yet found an optimal coordination between the public and private

[22] For example see ESMAP, Long Term Gas Contracts: Principles and Applications. Report No. 152/93. January 1993.

sectors. Signs of this problem are the lack of increase in upstream production as well as the lack of agreements for the transit of Kazakh oil outside the Caspian Pipeline Consortium (CPC). The Russian state apparently is still caught in a double role as a sovereign state and owner of a commercial entity.

3.11 The problems of the Transneft system stem in part from the telescope effect. This phenomenon—of progressively decreasing export capacity toward the periphery of the former Soviet Union (FSU)—reflects both the exceptional, landlocked situation of Russia and the legacy of the political divide between East and West that focused the Soviet Union's exports on the "near abroad" states of the Council for Mutual Economic Cooperation (COMECON) and not on world oil markets. The telescope effect thus hindered Russian exports to the "far abroad;" that is, world markets. Unfortunately, the export quota the Russian state imposes on private companies has impeded a reorientation of Russian exports to world markets. This quota discourages private solutions because of the misalignment between a private company potentially investing in debottlenecking downstream of the Russian border but benefiting only by its export quota. Possible approaches to creating the right incentives for private oil companies to invest in widening the scope for FSU hydrocarbon exports could involve either the establishment of a common-carrier scheme for creating extra capacity downstream of the Russian border (an initiative that would originate from outside Russia), or the abolition by Russia of its export quota (which would leave to the private oil companies the question of how much transit capacity they could book on the Russian system and the system downstream of the Russian border).

3.12 Another significant factor affecting the transit of Kazakh oil through Russia is the state ownership of Transneft and control of the actual tariff system. This combination does not seem to offer enough incentive, as the tariff would hardly cover the additional expenses caused by the transit of additional oil from Kazakhstan.

3.13 **Case Study 3: The SuMed pipeline.** The SuMed (Suez–Mediterranean) pipeline includes no private sector involvement. All of the governments involved in this joint venture nonetheless have been operating on purely commercial principles, with considerable success.

3.14 **Case Study 4: The Iraqi export lines.** In none of the three Iraqi export lines—the IPC line via Syria and Lebanon, the Turkish lines, and the IPSA lines through Saudi Arabia—was there any private sector involvement. One of the negative consequences of this is that the experience was tainted by the political maneuvering of the various governments. As the TransMed and SuMed experiences show, however, (case studies 1 and 4), this is not an automatic consequence of state involvement.

3.15 **Case Study 5: Tapline.** Tapline was from the outset a private sector initiative, and was at the time the largest privately financed construction project in the world. Rights of way, however, (including within Saudi Arabia, which was the exporting country) had to be negotiated with governments, rendering the project a classic example of the private sector trying to operate within a context set by the government. The first experience of dispute came in 1960 with Saudi Arabia (not technically a transit country), driven in part by the political ambitions of the then Minister of Oil. After 1970 the other transit countries, most notably Syria, began to pressure the private company for greater fees. During these negotiations, the private company did receive support from the Saudi Arabian government.

3.16 **Case Study 6: The Baku Early Oil Project.** Private oil companies drove the Baku project in terms of commercial and technical aspects although politics also played a key role. The involvement of state companies in production and transit through Georgia provided mechanisms for sharing information and project revenues with the involved governments. In this case, state involvement was not a decisive factor for success, but nor did it hinder success. Most risks were assumed by the private sector State Oil Company of Azerbaijan, (SOCAR) did assume some commercial risk), however; for example, the cost overruns in building the Baku–Supsa pipeline could be offset against cost oil under the production sharing agreement (PSA) with Azerbaijan. An important element behind Georgia's acceptance of the transit deal was general political support, mainly that of the United States. The U.S. government was also instrumental in supporting the dual-pipeline solution. For the Georgian government, the idea of developing an East–West "energy and transport corridor" also was a compelling argument for it to back the Western Route Export Pipeline (WREP).

3.17 **Case Study 7: The Maghreb Gas Pipeline.** Private investors were again a driving force in the case of the Maghreb pipeline out of Algeria, providing the capital necessary to explore and prove more of Algeria's ample gas reserves as a basis for another of the country's export projects. With regard to ensuring the marketing of gas, the Spanish government played a crucial temporary role in the project by persuading the Spanish power companies to switch 7,000MW of generating capacity to natural gas and by encouraging industrial and household demand for gas. The Spanish state also ensured, by creating the special-purpose company Sagane, that the commitments of the state-owned gas company were guaranteed until the privatization of the state gas company was complete and the newly privatized company was able to take over its commitments under the Maghreb project.

3.18 **Case Study 8: The Caspian Pipeline Consortium (CPC) Project.** At the outset of this project, the Russian and Kazakh states were the owners of assets that could only be valorized by integrating them into a pipeline system for the export of Caspian oil and of oil from Siberia. At the beginning, the states were in a commercial rather than a sovereign role. The states alone, however, were not able to provide and organize financing because the private companies did not want to participate on the basis of throughput agreements alone. The project was only realized when the oil producers were accepted as full joint-venture (JV) partners in the project, not just as partners of a throughput agreement. Acceptance as joint-venture partners gave the producers the influence they wanted over the operation of the pipeline.

3.19 The JV agreement in the CPC pipeline project, which facilitates the structure and handling of the project, provides the main balance for the project between the private companies and the states, and between the states is provided for in a single JV agreement, which facilitates the structure and handling of the project.

3.20 The Russian and Kazakh states play dual roles as investor and as regulatory and legislative authority. This may be an interesting scheme for the interim; that is, while generally applicable legislation is not yet in place. The two states (that is., Russia and Kazakhstan) are involved as partners in the JV agreement and thereby have undertaken certain commitments of concomitant with their administrative capacity. In this way, the states become subject to arbitration procedures with the companies.

3.21 **Case Study 9: The Express Pipeline between Canada and the United States.** This is a pure pipeline transportation company sponsored entirely by the private sector. It operates under uniform management and maintains a remarkable balance between pursuing a competitive process for committing a part of the capacity under long-term shipping contracts while offering the remaining capacity on a spot market for short-term capacity.

3.22 **Case Study 10: The Bolivia–Brazil Gas Gas Pipeline.** Private investors played an important role in initiating, promoting, and coordinating the Bolivia–Brazil gas pipeline project. Opening exploration in Bolivia to the private sector created the reserve basis needed for the project and beyond. At a critical point in the development of the project, however, the Brazilian state monopoly Petrobras, with the encouragement of the Brazilian president, assumed most of the outstanding risks of the project. In return for capacity rights, Petrobras provided a turnkey contract to counter the risks of cost overruns on the Bolivian side of the pipeline. The company also agreed at a critical point to acquire a large part of the pipeline capacity in Bolivia. In addition, Petrobras assumed the real risks of the minimum-pay obligation because the regional Brazilian companies that were ultimately to bear that risk existed only on paper at the time Petrobras made its commitment (discussions of the privatization of Petrobras began at the time of the pipeline).

3.23 **Case Study 11: The Baltic Pipeline System (BPS).** After looking for other ways to involve the private sector, the Russian state finally imposed the financing of the Baltic pipeline extension—a potential win-win situation—on the private oil industry. In the end, the Russian state promoted the Baltic pipeline extension against the protestations of private industry, which felt that the extension would not be commercially optimal compared with other alternatives. These other options, however, would have involved other states downstream of the Russian border. The Baltic pipeline seems effective as a way of increasing Russian oil export potential, but it comes at the price of forcing an extra transit surcharge on all private companies using the Transneft system. The Russian state initially sought to involve the private companies in the construction of increased export capacity. The choice arose between the commercially more attractive alternative of export via Finland and the commercially less attractive alternative of a purely Russian scheme—which would significantly preclude any interference by a non-Russian actor in one of Russia's main export-earning capacities. The Russian state handled this obvious conflict of interest between itself and private investors by deciding in Russia's national interest and opting for an interventionist solution imposing the BPS. The pipeline is expected to reduce some of the export bottlenecks originating from the telescope effect.

3.24 **Case Study 12: The GasAndes pipeline.** The case of the GasAndes gas pipeline between Argentina and Chile is an example of a cross-border project in which years were lost as both states tried to involve themselves in the commercial aspects of the project. When a reasonable framework for the private sector finally was established in both countries and both states agreed to confine their involvement to working on a framework in a bilateral protocol, leaving the commercial decisions to private companies, the project was able to proceed.

The interests of different governments

3.25 The message that emerges from the case studies on the conflicting interests of governments is clear. Where the prime consideration of the governments concerned is essentially commercial there are far fewer problems than in situations where political or strategic factors play the major role. While exporting and importing governments have different interests, at a commercial level these are no different from the differences between private sellers and buyers. Where commercial concerns drive a project, the problems arising from differing interests are simply those associated with any commercial contract and can be solved by negotiation and governed by agreements (although it might be argued that governments are less effective than the private sector in such matters). The Algerian gas export pipelines TransMed and the Maghreb line[23] and SuMed work because, for all the governments involved, the prime concern is commercial success.

3.26 The worst problems arise when the main motivations are political. Even if the original motivations of the project are commercial, as politics impinge those commercial considerations tend to get pushed down the agenda. The examples of the Iraqi export lines (Case Study 4) and Tapline (Case Study 5) illustrate this point.

The lack of an overarching jurisdiction: Dealing with changed circumstances in the future

3.27 Markets and competition, even the threat of competition, are a proven, objective way not only to find a balance between parties but also to adapt to changes in the future.

3.28 Where such market instruments are not available, the parties must look for instruments that will preserve a balance once it is found. This is equally true when the balance of power changes with the commitment of an irreversible investment and when market and other unforeseeable developments require a rebalancing.

[23] In both cases, although the projects began as purely government-run projects, privatization moved one or more parties out of the public sector and into the private sector during the life of the project.

3.29 **Case Study 1: The TransMed line.** In the case of the TransMed line, the gas price eventually was linked to the crude oil price. Changes in the world energy markets thus fed into the gas price as a matter of course. Ownership of the Algerian gas additionally switched to Italy once the gas crossed into Tunisia. If Tunisia as the transit country had decided to be difficult, its dispute thus would have been with Italy rather than Algeria.

3.30 **Case Study 2: The Transneft case.** Any conflicts in the Transneft case most likely would center on access rules for transport capacity within Russia and downstream of Russia. Such conflicts thus would tend to be about access to business rather than disputes over interference with private investment.

3.31 **Case Study 3: The SuMed pipeline.** Because of the commercial orientation of SuMed, changed circumstances, most obviously changes in tanker rates affecting the competing route around Africa and changes in Suez Canal tariffs, were dealt with simply by responding in a commercial manner. The introduction of flexible tariffs in 1993 managed to solve any potential problems.

3.32 **Case Study 4: The Iraqi export lines.** An obvious source of weakness in the Iraqi pipeline projects was that, as far as is known, there was no mechanism to deal with changed circumstances other than raw negotiating power—and this in a context where negotiations were much influenced (and soured) by political relations. Thus every change in circumstance became a trigger for conflict and a source of confrontation, with the main weapon of the transit countries being interruption of line throughput. There was simply no other viable alternative.

3.33 **Case Study 5: Tapline.** As with the Iraqi projects, as far as is known there was no formal mechanism in the Tapline agreements to manage changes in circumstances. For the Aramco partners (which were the same as the Tapline partners), however, there was always the very real alternative to Tapline of tanker loading at Ras Tanura. The combination of ever-greater demands by Syria in particular, coupled with the collapse in tanker rates following the first oil shock of 1973–74, effectively placed a ceiling on how far the transit countries could in practice exploit the situation to secure a greater share of the rent. In effect, it was market mechanisms that, in the end, contained the issue of changed circumstances.

3.34 **Case Study 6: The Baku Early Oil Project.** The Azeri production sharing agreement (PSA) was driven by competition between companies applying for participation in a geologically very promising area; the number of similar opportunities elsewhere meant that Azerbaijan in its turn also had to offer competitive terms. The question of alternatives lay at the heart of the project sponsors' decision to invest in a dual pipeline. Georgia's favorable transit agreement with the Azerbaijan International Operating Company (AIOC) no doubt owes something to the clear alternative available to AIOC (as well as to the political benefits it brought to Georgia). It was also influenced insofar as Georgia saw the line as a loss leader to attract the larger BTC project.

Similarly, Russia's concern to provide a viable substitute for the troubled route through Chechnya reflects its awareness of the other options open to AIOC.

3.35 The PSA, the host government agreement between Georgia and AIOC, and the pipeline construction and operating agreements all provide for dispute resolution by international arbitration or expert procedures. All states involved (Russia, although it has yet to ratify, Azerbaijan, and Georgia) have acceded to the Energy Charter Treaty (ECT), which provides conciliation and arbitration procedures.

3.36 **Case Study 7: The Maghreb gas pipeline.** Algeria and Spain had a credible alternative to transit through Morocco: they could have increased their existing trade in liquefied natural gas (LNG). The difference between the known costs of the existing LNG scheme and the projected savings of the pipeline defined the upper limit of the rent available for the transit country, Morocco. Because Morocco was not dependent on Algerian gas, it was free to refuse transit; it did, however, have an incentive in the form of the related revenue.

3.37 Both Algeria and Spain had alternatives that provided benchmarks for their sales agreement. Algeria could have increased its exports of LNG to Turkey and other markets outside Europe. The country's TransMed pipeline agreement (Case Study 1) with Italy provided another benchmark. On the Spanish side, although energy demand was growing fast, the exploitation of natural gas was not the only way to meet that demand: the Spanish government, in fact, had to put pressure on the country's power industry to switch 7,000MW of existing generating capacity to gas to create the economic basis for the pipeline project. Spain also could have imported more crude oil or fuel oil products—an alternative that is reflected in the pegging of the gas price—or could have expanded its LNG imports; for example, from the Bonny project in Nigeria.

3.38 Although little is known in public, it can be assumed that the gas sales agreements between the Spanish and Portuguese companies Enagas and Transgas, as buyers, and Sonatrach, as seller, have provisions for the international arbitration of disputes, as is usual in such contracts.

3.39 **Case Study 8: The Caspian Pipeline Consortium project.** The shareholders of the Tengiz field had other basic export alternatives from the Caspian Sea. The CPC, in fact, was created as an alternative to other schemes that might not have been as attractive, as they either would have involved several transit countries (for example, the proposed Baku–Tiblisi–Ceyhan export pipeline via Azerbaijan, Georgia, and Turkey) or would have run into politically sensitive issues (such as export via Iran). In addition, the CPC scheme seemed to be the most economical major export pipeline scheme, given that it involved a shorter time until export capacity was online for the producing company and country. On the other hand, Russia and Kazakhstan had an interest in using their existing pipeline assets, which otherwise would have been idle. For Russia, the CPC presented an alternative access to deep-sea harbors for oil from its own territory, while using the economies of scale offered by Kazakh oil.

3.40 A restructuring agreement was drawn up that binds all parties to try to resolve disputes between themselves in an amicable manner. The agreement nonetheless also provides for international arbitration as a mechanism for conflict resolution if the parties cannot otherwise agree. If the parties do not agree otherwise, the arbitrator would be nominated by the Secretary General of the Permanent Court of Arbitration in The Hague, and arbitration would take place in Stockholm under UN Commission on International Trade Law (UNCITRAL) rules. Kazakhstan and Russia are both signatories of the ECT.

3.41 **Case Study 9: The Express Pipeline between Canada and the United States.** The Express Pipeline is specifically designed for maximum flexibility. The pipeline operators, are committed to expanding capacity and allocating it in a competitive process, as and when demand manifests itself.

3.42 **Case Study 10: The Bolivia–Brazil gas pipeline.** Brazil and Petrobras could have met the growth in demand for energy by producing more fuel oil at Petrobras' refineries. The decision instead was taken to turn to gas. Given this situation, heavy fuel oil provided the natural benchmark for the economics of the gas pipeline project, and this is reflected in the gas pricing provisions. Across the border, while Bolivia's export project to Argentina was dwindling, it served as a benchmark for Bolivian expectations. The level of proven gas reserves in Bolivia during the time that the state company, YPFB, controlled exploration was too low to provide any significant impetus for the project. This changed quickly once the Bolivian upstream sector was privatized. International oil companies obviously considered the Bolivian acreage and the terms under which it was opened for exploration attractive compared with alternatives elsewhere in the world. Proven reserves soared, providing an adequate margin of comfort for the project.

3.43 **Case Study 11: The Baltic Pipeline System.** From the Russian point of view, the primary motivation for the increased export of Russian oil or of extra transit (mainly of Kazakh oil) is not to access existing capacity in Russia, but rather to address bottlenecks downstream of the Russian border. These bottlenecks are outside Russia's control, and the country's export quota mechanism dilutes the incentive for private companies to invest here. Creating credible mechanisms under Russian control—such as the Baltic pipeline or the CPC system—to encourage a more lenient attitude toward Russian transit in countries downstream seems a logical step for the country and clearly is a main motivation for Russia in constructing the Baltic pipeline expansion instead of increasing export and harbor capacity in Finland or in the Baltic states.

3.44 An apparent alternative to the Baltic pipeline system would be to create incentives for adding capacity downstream of the Russian border (for example, by abolishing the export quota system). Under such circumstances the oil producers themselves would have to provide for the corresponding transit agreements downstream of the Russian border to match their export volumes, and this need might give the producers enough incentive to invest in additional downstream transit capacity.

3.45 Any eventual dispute regarding the extra fee imposed on all companies exporting crude oil for using the Transneft system would not be an issue the private company would have to take up with Transneft; rather, the company would have to take it up with the regulatory authorities.

3.46 **Case Study 12: The GasAndes pipeline.** In the GasAndes project, the governments of Argentina and Chile signed bilateral protocols that, in addition to setting out a general framework, also created regulations for cross-border pipelines and general rules to support cooperation between the two states in the promotion of other such projects.

The lack of a rent sharing mechanism: The alignment and balance of interests

3.47 **Case Study 1: TransMed.** The alignment of interests in the TransMed case followed a protracted set of negotiations over gas price terms. Once the agreement had been signed, there was a sense that all sides stood to gain from a successful operation. Several other factors further explain Tunisia's good behavior as a transit country. First, the agreement made the gas the property of the Italian lifters as soon as it crossed the Algerian border. Potentially this would sidestep any politically motivated disputes between Algeria and Tunisia. Second, during the 1980s and after, a central pillar of Tunisia's development strategy was to encourage foreign investment. This would act to defuse any temptation to unilaterally abrogate the transit agreement. Finally, Tunisia opted to take its transit fee in gas, giving it a vested interest in maintaining the throughput of the line and countervailing any temptation to interfere with the flow.

3.48 **Case Study 2: The Transneft system.** In the case of the Transneft system, alignment of interests was established during the Soviet period. A central, uniform management, driven by technical considerations and the economic mechanisms of a centrally planned economy, originally ran this huge system. The export capacity of the system, with the exceptions of export harbors at the Black Sea and the Baltic Sea, was confined to the COMECON states, and the onshore system was characterized by the telescoping effect previously discussed. The breakup of the Soviet Union and the resulting turn to global markets saw the structure of the pipeline system divided into segments defined by the newly independent states and produced a large number of new parties to be aligned. Furthermore, the alignment between transportation and production of the planned Soviet economy had to be replaced by alignment mechanisms appropriate to an economy driven by competition and a larger role of exports. The Russian part of the system, Transneft, inherited the large Russian oil transport system. This has large idle capacity stemming from the slump in energy consumption in all of the former Soviet states; the bottlenecks for exports nonetheless are downstream of Russia, where tariffs for the capacity use are considerably higher than those in Russia.

3.49 Given the unique change dimensions in this case, it is not surprising that a suitable alignment and balance has yet to be found between the main actors for exports from Russia and actors for transit through Russia using the Transneft system. There seems to be a lack of attraction upstream for these actors, because their interest arguably has not yet been taken into account. Even given attractive production sharing agreements, the lack of export capacity and the less attractive prices of the Russian internal oil market, combined with the export quota scheme based on the pipeline bottlenecks downstream of Russia, so far seem to be hindering further exploration and exploitation of additional Russian oil reserves.

3.50 The use of the export quota as an allocation mechanism for the bottlenecks in capacity downstream of the Russian border so far has failed to produce the necessary incentives for removing these bottlenecks. The same applies for utilization of spare transport capacity for oil transit from the Caspian region.

3.51 **Case Study 3: The SuMed pipeline.** Given the commercial orientation of the government partners, and in particular the benefits accruing to the Gulf oil exporters, all sides have gained as the result of SuMed's operation. Given that the tariffs are nondiscriminatory, the government partners benefit directly according to their equity share, but they also gain insofar as SuMed gives their crude a competitive edge in the Mediterranean.

3.52 **Case Study 4: The Iraqi export lines.** These lines exhibit all of the classic problems associated with a lack of alignment of interests. The political divisions between Iraq and Syria spilled over into the pipeline operations, and economic issues over transit fees also caused problems. Syria exhibited the typical characteristics of a bad transit country, and there was little Iraq could do to pressure Syria either politically or militarily. Syria's "socialist" development strategy meant the country had no interest in foreign investment, and there was therefore no constraint from this direction on Syria's preparedness to act unilaterally and arbitrarily over the terms of pipeline access. Finally, for Syria the transit fees and the crude oil offtake represented a major source of foreign exchange that it naturally wished to maximize. Iraq ultimately was forced to seek alternatives to the Syrian pipeline, looking at routes first through Turkey and then through Saudi Arabia.

3.53 **Case 5: Tapline.** As with the Iraqi example, the Tapline project lacked a mechanism able, during the course of negotiations, to secure an alignment of interests. The initial alignment was altered as circumstances changed, creating friction (although in part this misalignment was also clouded by political issues). Interestingly, the two transit countries that were dependent on Tapline for their crude refinery inputs, Jordan and Lebanon, tended to be less aggressive over transit fee negotiations than was Syria, despite the fact that Syria was not dependent on these inputs. This fact would tend to support the view that a greater alignment of interests can help mitigate conflict.

3.54 **Case 6: The Baku Early Oil Project.** The composition of the Azerbaijan International Operating Company (AIOC) seems to be well balanced, representing all of the powers in the region. (Iran, which was not invited to join the AIOC, was placated by the grant of a share in another Azerbaijan field.) The economic balance between the AIOC and Azerbaijan is defined by a typical production sharing agreement. It can be assumed that risks and rewards in the agreement are well balanced, given the geological potential of the Caspian Sea and the ample opportunities for international oil companies (IOCs) to invest elsewhere. Transit costs and transit fees are dealt with in the PSA as costs to be recovered from cost oil. During the cost-oil phase, interruptions of transit would be relatively detrimental to the IOCs, whereas in the profit-oil phase interruptions would be relatively detrimental to the Azeri government. The "insurance" costs provided by the dual pipeline would tend to fall on the Azeri government, as these extra costs extend the time required to reach the full profit-oil level. The mutual interest of the Azeri government and the AIOC in keeping the project going is obvious.

3.55 Georgia was compensated for integrating an existing oil pipeline system into the new transit system and for the security services it provides. The upgrade and refurbishment of the existing pipeline, in fact, alleviated a potential environmental problem for the country. No yardstick exists for the transit rent in this case, but Georgia could have refused to conclude a transit agreement until it received a sufficiently attractive rent. In evaluating the balance of the Georgian transit arrangements, political factors—such as political backup by the United States and Turkey—obviously played a role and must be taken into account. Georgia also realized political benefits from the project, in the sense that the deal has helped to balance its relations with the powers in the region. Georgia's total revenue depends on actual throughput, which gives the country an incentive to keep oil flowing. So far, it is not drawing off any part of the throughput for domestic use nor accessing pipeline capacity for domestic production. Exactly how far the benefits extend of being a transit country for oil and gas from the Caspian region remains to be seen, however.

3.56 The commitments of all sides in the Baku-Supsa pipeline project are "sealed" by the participation of the International Finance Corporation. The interests of other stakeholders—for example, with regard to the environment—have been addressed through application of the World Bank Group's standards.

3.57 Throughput through Russia on the northern route is secured by a ship-or-pay provision that depends on the actual transport capacity availability. The effectiveness of that provision, which gives the Russians an incentive to maintain the scheme, was demonstrated by the extent of the Russian effort to provide a substitute for the section of the pipeline passing through Chechnya.

3.58 **Case Study 7: The Maghreb gas pipeline.** A prominent feature of the Maghreb gas pipeline project is that Algeria is not involved in handling the gas past its border with Morocco. This arrangement, which is similar to that of the TransMed line, appears wise given the delicate relationship between the two states. Transit costs nonetheless are reflected, albeit not explicitly, in the sales agreements between Sonatrach and Enagas and Transgas, in that the price paid to Algeria is low enough for the latter to be able to resell the gas competitively while also recovering the costs of transit through Morocco. So far, Morocco has not chosen to take Algerian gas in kind (for power generation) but has elected instead to construct new coal-based power capacity—in this way avoiding becoming dependent on Algerian gas. This refusal by Morocco to make a commitment to Algerian gas may explain Algeria's recent consideration of a 300km pipeline directly across the Mediterranean from Arzew to Cartagena in Spain; early reports of the first substantial hydrocarbon finds in Morocco, on the other hand, indicate that Morocco may become a competitor of Algeria.

3.59 Information sharing about the project characterized the relationship between Morocco and Spain, (and later Portugal), first through Omegaz, which conducted the feasibility studies, and later through Morocco's admittedly almost symbolic participation in Metragas, the construction and operating company. The buyers (Spain and Portugal) carried the cost of the transit system, and they paid for the transit pipeline's construction and operation. Morocco shares in the price and volume risks of the project—Morocco's transit fee is determined as a share of the overall project rent—aligns the transit country's interests with those of producers and consumers. That the transit fee is linked to the price of the gas (directly if the transit fee is paid in cash and indirectly if it is taken in kind) provides a mechanism whereby Morocco shares the ups and downs in the price of gas and thus maintains a fair share of the rent in good times and bad.

3.60 Although Morocco's share may vary with the level of throughput (under future transport agreements), the formula for determining the transit fee is not subject to renegotiation. This gives the deal the necessary stability.

3.61 Between Sonatrach, as seller, and Enagas and Transgas, as buyers, the balance of interest follows the pattern of other long-term gas sales agreements, with a typical term of approximately 20 years, firm obligations for availability, and offtake protected by a minimum-pay provision and a price-review option. By pegging the sales price to the prices of displaced fuels, the sales agreement ensures that the income due to the Algerian producers and the Algerian state will follow the price movements typical for oil revenues. For the buyers, the mechanism should ensure competitiveness with alternative fuels.

3.62 The alignment between Enagas and Transgas is reflected in their ownership shares in the pipeline sections passing through Spain and Portugal, which in turn reflect the likely use of capacity.

3.63 The European Union supported the project by assisting with financing. The substantial participation of the European Investment Bank (averaging 45 percent) in all parts of the chain from Algeria to Portugal mitigated risks and greatly improved financing conditions. Environmental concerns were addressed by applying the standards of the European Investment Bank.

3.64 **Case Study 8: The CPC pipeline.** The CPC pipeline project gives the producers in the Tengiz and other Kazakh oil fields stable access to world oil markets. For Russian oil producers, it also increases access to world oil markets.

3.65 For both states the outcome is favorable because it allows for a substantial increase in oil production and a corresponding revenue from the PSAs. It also grants the valorization of existing pipeline investment in both countries as input by the states to the joint venture, thus generating future income to the states from the tariff revenue of the pipeline JV and mitigating any need for higher transit fees. This is an exceptional case of linking the interests of states and private companies via a JV agreement that deals with all major issues of the pipeline project, including the settlement of disputes, and creates a uniform governance mechanism for the pipeline across the two countries involved. The regional administrative units—the *oblasts*—also get a share of the revenue.

3.66 The CPC project also is a case of a pipeline that transits through a state that is a competing oil producer with the original producing state. As the international oil market has no restrictions, the joint use of an export pipeline does not raise a significant conflict of interest.

3.67 The oil companies financed the project without the need to involve international financing institutions. The balance between the companies, between the companies and the states, and between the states themselves primarily is provided for in a single agreement (that is, the JV agreement), which eases the structure and handling of the project.

3.68 **Case Study 9: The Express Pipeline between Canada and the United States.** In this case the rent sharing is simply based upon contracts drawn up in what is effectively a competitive market. The interests of the parties thus are aligned by market mechanisms.

3.69 **Case Study 10: The Bolivia–Brazil Gas Pipeline.** Ensuring adequate gas demand in Brazil, a country that lacked a significant gas infrastructure and the corresponding regulatory framework, was the basic challenge in this case. That both Bolivia and Brazil were starting to open up to private investors (for example, in exploration in Bolivia and in gas distribution in Brazil) constituted an additional challenge.

3.70 The same private investors are involved in the pipeline project on both sides of the border, albeit with different shares in the two pipeline companies. On the Bolivian side, the role of the former state company, YPFB, was greatly reduced (in the end, YPFB had no direct participation in the pipeline). In what can be seen as an effort to accommodate concerns of the labor unions, however, which once exerted a strong influence on YPFB, the pension funds participated as shareholders in both the Bolivian and the Brazilian pipeline companies. YPFB also retained a role in collecting gas from the producers as gas production moved into private hands.

3.71 Petrobras is involved on both sides of the border as a shareholder in the respective pipeline companies and through ownership of transportation rights. Future gas buyers in Brazil may gain access to the pipeline capacity under the third-party-access regime that governs use of the pipeline's committed capacity.

3.72 Petrobras assumed the major marketing risk of the Bolivian producers by agreeing to a minimum-pay contract. The company passes that risk on to the newly created distribution companies in the states of Brazil while mitigating the risks of nonperformance by these companies by holding minority shares in all of them. The gas price is linked initially to the price of heavy fuel oil, the main competitor of gas, with a discount that is large enough to make gas marketable and to pay for the infrastructure required to bring the gas to industrial customers.

3.73 The World Bank Group's credit guarantee on the Brazilian side and its additional involvement in the project on both sides of the border substantially improved the project's credibility. The World Bank Group was also crucial in harmonizing environmental standards at both ends of the pipeline.

3.74 The appointment of an ombudsman for indigenous people affected by the building of the pipeline and the transparency provided by a project website helped to address environmental concerns and to minimize any adverse effects of the project.

3.75 **Case Study 11: The Baltic pipeline system.** The Baltic export scheme was imposed on the oil companies, has lacked voluntary agreement, and seems far from balanced, as all oil-exporting companies must contribute regardless of their potential to benefit from the additional export capacity. The scheme nonetheless does open up extra export potential for Russian and Caspian oil to the international oil markets, thereby creating incentives for upstream development. This clearly is in the interest of the producing companies and of Russia, which would stand to gain additional PSA revenue, and it could also attract additional transit of Kazakh oil.

3.76 **Case Study 12: GasAndes.** The GasAndes project was in the end commercially driven, based upon a 25-year gas supply contract. The pipeline notably has suffered from problems with environmental issues on part of its route through Chile, although these environmental concerns could be countered by the benefits to air quality in Santiago as a result of the greater gas use in the urban area.

4

Best Practice, and What More Can Be Done?

4.1 This chapter concludes by considering the practices that have in existing projects contributed to the minimization of conflict and to the relative success of the project. It also considers what more can be done by all parties to try to further reduce the conflict associated with cross-border pipelines.

4.2 At the outset it is crucial to emphasize that there are no simple, definitive solutions to the problems discussed in this report. There are, however, four overarching requirements of good practice:

- the rules are clearly defined and accepted
- projects are driven by commercial considerations
- there are credible threats to avoid the obsolescing bargain
- there are mechanisms to create a balance of interest

4.3 Each of these is considered in the following sections. The chapter concludes with a section on what more can be done.

The Rules Are Clearly Defined and Accepted

4.4 The case studies demonstrate that for a cross-border pipeline to be successful, the rules of the game must first be clearly defined and accepted by all parties.[24] This requires an environment of stable legislation and independent and predictable regulation, with a neutral judicial system and a government record of minimal interference. This however is the ideal, and even in the OECD context such a world does not exist. Legislation changes as public moods swing, and can be perverse and sometime ill-informed. Judges can be unpredictable or corrupt. The first thing governments learn about market forces is that the market forces government to intervene. Where the system gropes toward the optimal, however, as is the case in the OECD, it is more likely to create an environment in which the commercial drivers of cross-border pipelines are

[24] This is not to say that the successful pipelines have been dispute-free. What constitutes "clearly defined" is a matter for legal disputation.

allowed to resolve issues and problems. The public sector ideally should set the rules of the game and let the private sector play.

4.5 In a similar vein, where the relevant jurisdictions are similar it is easier to manage differences. For example, in OECD countries, where cross-border pipelines have a long history of relative success, there is a commonality of jurisdiction. While there may be crucial differences in the legal and regulatory systems, they nonetheless all provide a credible and functional framework for commercial investment.

4.6 Another key success factor is the minimization of government interference in commercial decisions, thus limiting the potential damage should political interests differ. (Where the "commercial" players are national oil companies this may not be easily realized.) Differing government interests may be mitigated by the signing of bilateral or multilateral agreements that clearly define responsibilities and conflict resolution mechanisms. These agreements should then be made public. While a sovereign government can renege on an agreement, placing the terms of the agreement in the public domain adds significantly to the reputation damage if it is clear the position the government would take is greedy or unreasonable.

4.7 The best practices are those that allow for flexibility in the contract, particularly in circumstances of unforeseen or unforeseeable changes such as political and economic crisis or natural disasters. This requires the use of parameters and of reopener clauses, although the latter suffer from the fundamental problem that once a pipeline is built, the relative bargaining power changes. To address this, the contracts governing the Maghreb line and the Bolivia–Brazil line contain provisions (mainly related to pricing) that can be readjusted according to defined criteria to find a new balance between the parties.

4.8 The best guardian against future uncertainties is the impartial discipline of competition and the marketplace. If this is allowed to work, changing circumstances are in theory accommodated. In practice this is difficult to achieve, however, not least because pipelines often are associated with monopoly elements.

4.9 A second factor that helps minimize conflict is the ability of a contract to deal with obvious foreseeable changes, such as changes to price, production profiles, and reserves. Such changes can be related to objective parameters. Gas prices, for example, might be linked to oil prices, as is the norm in many gas agreements; transit fees might be linked into an inflation index (as is the case for the WREP), to maintain real value, and also linked to the throughput, as is the situation for many of the case studies. A further advantage of linking terms into some form of objective criteria is that this helps protect against the use (or abuse) of naked bargaining power, which invariably produces aggrieved parties.

4.10 Another useful clause is a renegotiation clause. Success has tended to be associated with projects in which no party feels worse off than it would have felt if an alternative course had been taken.

4.11 It is unrealistic, however, to expect that the signatories to an agreement can be held to the terms of that agreement if circumstances change to the degree that maintaining the agreement becomes unreasonable. Defining "unreasonable" in an objective way is, of course, highly problematic.

4.12 By far the best solution to the problem of securing a balance of interests is to create a context in which conflict resolution is subject to some objective mechanism that lies outside the control of the interested parties (see also paragraphs 4.18–4.47). This will require that some degree of sovereignty be sacrificed, but in reality this is a standard concession wherever foreign investment is involved. Many of the case studies cited in this report have clauses in their contracts that offer recourse to international arbitration, often involving chambers of commerce in third countries, in the event of dispute. Enforcing the findings of such tribunals remains an issue, but the reputational dimension acts as an incentive to the various parties to accept such independent findings. To ignore or reject the results of international arbitration would have serious consequences for reputation and subsequent investment.

Projects Are Driven by Commercial Considerations

4.13 Where relationships are governed purely by commercial considerations, differences are relatively easily resolved, since there is an implicit opportunity cost and benefit in changing the terms of the relationship. Trading oil and gas on purely commercial terms thus should mean that any alternatives would provide limited cost or other benefits. Competitive markets also deal well with uncertainties and changes in circumstance: if the players in any particular arrangement are dissatisfied with their position, in theory they can simply buy from elsewhere or sell elsewhere. In practice, the monopoly nature of cross-border pipelines means that competition may be difficult if not impossible to achieve.

4.14 Frequently, projects that are driven by politics rather than commercial considerations end in failure. It is too early to tell if the overt political drivers behind the various Caspian export pipelines will prove to be a problem, but best practice would seem to be for the state to set the context and the private sector, to the fullest extent possible, to run the project. The context of a project should include protection against elements of market failure, notably in the context of HSE and competition. A key factor in the progression of the GasAndes line was the withdrawal of the Chilean and Argentine governments from the commercial dimension; the success of the Caspian Pipeline Consortium similarly depended upon the retreat of the Russian and Kazakh governments to permit private sector involvement in the project.

4.15 It is tempting thus to argue that state involvement creates problems and should be minimized, but the case studies do not support this blanket view. While it is certainly true that state involvement in the case of the Iraqi export lines, Tapline, and to some extent in the cross-border pipelines of the former Soviet Union caused and is causing great problems, state involvement elsewhere in the Algerian export gas lines, SuMed, and the CPC project proved no barrier to a successful project.

4.16 Where state involvement can cause serious problems is in cases where it lacks a clear framework for private investment. If the state is in transition,[25] this too can cause difficulties, simply because the rules keep changing.

4.17 In many cases where the optimal mix of legislation and regulation is far distant, the state does need to provide interim support for pipeline projects. For example, during the privatization of the gas sector in Spain it was crucial for the Maghreb pipeline that the Spanish government guaranteed a minimum demand for gas. Equally, the involvement of Petrobras in the Bolivia–Brazil gas line, at the behest of the President of Brazil, was a defining factor for the project.

There Are Credible Threats to Avoid the Obsolescing Bargain

4.18 Much of the history of problems with cross-border pipelines can be explained in terms of the obsolescing bargain. Strategies to minimize exposure to the obsolescing bargain are essential.

4.19 One important mechanism is a credible threat to counter the temptation for one party or other to try and unilaterally change the terms of agreement. Credible threats also have the virtue of forcing agreements, for fear that an opportunity will be lost. Thus, for example, the simultaneous negotiations of the Baku Early Oil Project for the WREP and the NREP kept both on track and provided a benchmark by which to evaluate terms on both projects.

4.20 One threat that may be employed depends on the ability of one or other partner to switch from the fuel carried by the pipeline to either an alternative source or an alternative fuel. This tends to be easier to achieve in the case of oil than gas, but the option nonetheless often arises to revert from gas to the fuel it replaced.

4.21 The process of globalization also is creating a mechanism to limit the tendency of governments with conflicting interests to interfere with pipeline projects. Success in a globalized economy requires, among other things, the ability to attract foreign investment. Anything that might be perceived as bad behavior over a cross-border pipeline would clearly damage the reputation of a government and potentially also its investment flows. This pressure to exercise self-control exists only if the country is a participant in the global economy, however. If existing sanctions or an already poor reputation are in place, there is little incentive for a government to behave in a way that would attract foreign investment. The converse may in fact be true: if the cross-border pipeline is a major source of foreign exchange, the rogue government may have every incentive instead to try and maximize transit revenue.

4.22 In addition to threats, incentives to resist the temptation to pursue the obsolescing bargain also are important. In many cases, for example, the transit fee is a

[25] The term “transition economy” conventionally is used to describe the former communist countries of Central and Eastern Europe and Central Asia. Given the extent of reform and deregulation taking place in many developing countries, however, the term could equally well be applied to them.

function of a pipeline's throughput. In the case of the CPC line, the states involved additionally will share in the commercial success of the project.

4.23 Another option is to link energy access for the transit country to energy access for the downstream country. This has been suggested in the context of the Iran–Pakistan–India gas pipeline: namely that the agreement should include a clause to the effect that if Pakistan were to try and prevent delivery of gas to India (by implication for political reasons), gas deliveries to Pakistan would automatically cease.

4.24 The transit government furthermore may self-impose sanctions; for example, by surrendering some degree of sovereignty so that in the event of a dispute the aggrieved party would have some means, outside the control of the transit government, of securing redress. In a sense, commercial companies routinely do this when they sign agreements that are subject to a specific jurisdiction. Absent bankruptcy, they are obliged to meet the terms of the agreement or face the consequences.

4.25 A variant on this theme is to create collateral for the investor outside the government's jurisdiction. This would take some form of escrow account under the control of a third party on which an aggrieved party could call for compensation. Should the transit government hold assets under another jurisdiction, these also could be seized in the event of a dispute.

4.26 All of these solutions would require the various government parties to leave dispute resolution in the hands of an independent third party, such as an international chamber of commerce, the World Trade Organization, (WTO) or the Energy Charter Treaty (ECT). This is discussed further in paragraphs 4.35–4.47.

Mechanisms to Create Alignment and a Balance of Interest

4.27 The instruments used to align the interests of the parties to a pipeline agreement are contracts, ownership, and joint ventures, concessions, treaties, political relations, and eventually public pledges with regard to civil society. The case studies demonstrate the use of a large variety of combinations of these instruments. For Baku–Supsa, for example, the producing consortium runs like a thread through the project, holding a production sharing agreement with Azerbaijan and a host government agreement with Georgia, backed by a parallel intergovernmental agreement between Georgia and Azerbaijan. In addition, both countries are members of IFC and EBRD, which are providing financing. For the Caspian Pipeline Consortium, the thread is a joint-venture agreement that lines up in a single governing document both the states involved and the private investors.

4.28 The Maghreb case does not have a comparable thread running through the whole project, but it does have a clear delineation of responsibilities: from production to the delivery point, Sonatrach and its partners are responsible; downstream of the delivery point, Enagas and Transgas are responsible. Within their sphere of responsibility, Enagas and Transgas participate in all segments of the pipeline and have transportation and concession agreements with Morocco; the two companies thus serve as the aligning thread for the portion of the project downstream of the delivery point. The only instrument tying all the states together is the Tripartite Ministerial meeting (of Algeria, Morocco, and Spain) and the Tripartite Ministerial Monitoring Committee, set up at the same meeting in Madrid. The one thread that might be said to run through the project as a whole is the involvement of the European Investment Bank (EIB) in the financing of all sections of the pipeline.

4.29 In the Bolivia–Brazil case, the thread running through the project is the participation of Petrobras as shareholder in all parts of the chain, upstream through its shares in the Bolivian and Brazilian part of the pipeline and downstream through its shares in the distribution companies, supported by various agreements on transportation, gas purchase, and financing. The states involved did not enter any formal treaty on the project, but are both members of the World Bank Group, which is providing financing.

4.30 In the Transneft case, the starting point for the project was the disruption of the former alignment between production and transportation in Russia and the downstream countries, and the reinforcement of that effect by the Russian export quota system. The main issue seems to be that Transneft will offer some of its free capacity to producers in Russia or to serve as transit, mainly for Kazakh oil. Given Transneft's size and ample spare capacity, it can engage the use of this capacity by offering a transportation contract that eventually would have some specific tie-in measures. To date, however, no alignment has been found between Russia and the downstream states, whether initiated by private companies (which are discouraged by the export quota system), by Transneft, or the Russian state, or by anyone else. Because of difficulties either real or anticipated, Russia has thus far failed to find an alignment with the private oil industry that would increase its export capacity for Russian oil. The state has instead covered the financing of the Baltic pipeline system by levying an extra charge on all oil transportation for export.

4.31 The case studies seem to suggest that alignments have been driven by the sponsors with the most immediate interest in the project, and that often those sponsors are also the initiators and organizers of the project and its unifying thread: for example, through ownership in all segments of the project (as in Baku–Supsa and Bolivia–Brazil) or through subscription to the main governing agreements (as in CPC). This does not exclude supporting treaties, involvement of international financial institutions in which host states are all members, or other political support.

4.32 The one circumstance to be avoided at all costs is that of leaving the project to the mercy of naked bargaining power once the line is operating, since this is guaranteed to make at least one party feel aggrieved. Avoidance of this problem is out of the hands of the project planners, however, given the capability of sovereign governments to abrogate all agreements. In the end, the only deterrent against such behavior may be the reputational cost that it would bring. Establishing upfront legitimacy of the governing agreements through balanced allocations of risks and rewards is a critical factor in this context.

4.33 Another common mechanism in many projects, and one that might be encouraged, is that of giving a company from the transit country a small share in the pipeline project as a means of sharing information and possibly even sharing risks or rent. If all parties feel they have benefited from the project, there clearly creates an incentive to stay with the project and try to work out conflicts and disputes.

What More Can Be Done?

4.34 The first step is to strengthen the accepted international norms of investment. The process of globalization will assist in this process, but progress would be further advanced if neutral arbitration clauses were to govern all relevant agreements. One way of achieving this would be for any entity financing such projects to insist on neutral arbitration as a requirement—a step that would be unlikely to raise any problems since for the most part it is now the accepted norm.

4.35 A common barrier to the development of cross-border pipelines is the "Catch 22" situation in which a government's lack of a positive track record on foreign investment inhibits the development of a pipeline, which prevents the government from developing a track record. In these circumstances, some form of catalyst is required to break the loop. At the very least, the government should subject itself to some form of sanctions mechanism; for example, by providing collateral to the investor that could be retained should the state fail to honor its agreements. Defining failure in such circumstances could in itself be controversial, further requiring the government and the investor to agree to some form of third-party conflict resolution.

4.36 It also is necessary that the international sources of objective third-party arbitration be reinforced. There are two dimensions to this. First, the generally accepted international norms regarding private foreign investment need to be strengthened. One of the reasons that pipeline projects in the OECD have tended to be successful is that there exists in the OECD a commonality of attitudes to and treatment of foreign investment. While disputes and doubtful practices persist, they are less significant and more easily contained than in situations where there is a wide disparity of attitudes and treatment.

4.37 Second, there is a need to create or otherwise strengthen the international institutions capable of managing conflict. The WTO is a case in point, maintaining as it does clear guidelines on the issues of charging for transit and not exploiting a monopoly position arising from geography. In theory, many of the problems over transit fee disputes could be solved by Article 5 of GATT, which allows freedom of transit and restricts transit charges to cost recovery only. While this definition includes a notion of "reasonable" profit, however, what this translates into is obviously highly contentious. This is especially true where the pipeline investment has already been written off or has a very low book value due to inflation.

4.38 The newest instrument that seeks to provide conflict resolution is the Energy Charter Treaty (ECT).

4.39 The ECT has established a credible self-commitment requirement for each of its member states. Member states, by signing and ratifying the treaty, give their consent to the submission of disputes to international arbitration in the event that an investor in an energy project chooses this course. At the time of this report, 51 states, mainly from Europe and Asia, had acceded to the ECT. Of these, forty-three states and the European Community had ratified it.

4.40 Transit issues are covered by Article 7 of the ECT. These include access, conditions of access, and noninterference with transit. There is a general obligation for states to facilitate and to establish pricing for transit of energy without discrimination as to the origin or destination of ownership and without imposing any unreasonable delays, restrictions, or charges. When transit is not feasible given the existing capacity, contracting parties shall not place any obstacle in the way of the new capacity being established.

4.41 In the event of a dispute, it is up to the investor to choose to submit the dispute in writing either to the International Center for Settlement of Investment Disputes (ICSID) under the ICSID convention; to arbitration under the UN Commission on International Trade Law (UNCITRAL) rules; or to an arbitral procedure under the Institute of the Stockholm Chamber of Commerce. The final threats are the enforcing mechanisms of the New York convention, by which an arbitral award can be enforced at least with regard to assets outside the country concerned.

4.42 This procedure is also called the diagonal rule, because an investor can directly address a dispute with a state without the involvement of its home state. This procedure gives the investor the comfort of a settlement procedure outside a national judicial system whose independence may not yet have been confirmed, and it avoids the lengthy procedures of state-to-state dispute resolution. (This conflict resolution procedure under the ECT applies to energy-related investment, whether cross-border or not.)

4.43 The mechanism established by the ECT could be characterized as an intermediate mechanism for a situation in which there is a judicial system with which investors are comfortable but in which there is a project-specific commitment by the states not to interfere and to submit to conflict resolution by a third party

4.44 A transit protocol is being negotiated to broaden and strengthen the scope of Article 7. Progress has been slow, however, as underlined by the postponement of the adoption date from the end of 2000 until (to date) March 2003.

4.45 It is too early to determine how effective the ECT is likely to be in alleviating conflicts and helping to resolve conflict. Problems remain. Russia, which is a key country for transit, has yet to ratify the treaty, and the United States and Canada remain outside the treaty, precluding U.S. and Canadian companies from access to the arbitration procedures. The treaty also is as vulnerable as any transit agreement to abuse by its signatory states (although abrogation of a multilateral document would involve a higher cost than that of a simple bilateral agreement with a neighbor). There also is a widespread view that the treaty was hastily written and skates over serious disagreements between the signatories.[26] In practice, its meaning and effectiveness await courtroom examination and precedent, and this may take a long period to emerge.

4.46 A last recommendation to improve the management of cross-border pipelines is to seek greater transparency of the terms involved, so that observers can clearly see should one party unilaterally try to breach an agreement. The Bolivia–Brazil project demonstrated a commitment to such transparency by creating a website furnishing shareholders all information relevant to their interests and by installing an ombudsman to deal with environmental concerns. Similarly, the establishment of Omegaz to assess the economics and feasibility of the Maghreb project jointly by all relevant parties was helpful in creating an alignment of interest.

[26] See C. Bamberger and T.W. Waelde, "The Energy Charter Treaty: Entering a New Phase," Working Paper, CEPMLP, University of Dundee, 1998); and T.W. Waelde (ed.), *The Energy Charter Treaty: An East-West Gateway for Investment and Trade*, London: Kluwer Law International, 1996.

Appendix 1

The Case Studies

Long-Term Success Cases

Case Study 1: TransMed Pipeline between Algeria and Italy, via Tunisia

1. Algeria's early experience with liquefied natural gas (LNG) exports was unhappy, with projects horribly over budget and bedeviled by disputes over prices and delivery terms.

2. In 1970, Bechtel undertook a study, completed in October 1972, of the viability of a gas pipeline from Algeria to Sicily. The cost of the line to the Sicilian coast was estimated at US$850 million (by September 1977, the cost to the Italian mainland was reported at US$2.3 billion). In a 1971 interview, President Houari Boumedienne further raised the idea of running a gas line to the European mainland via Morocco. In October 1973, Algerian and Italian state corporations Sonatrach and Eni agreed to build a 2,500km line from Hassi R'Mel to La Spezia, east of Genoa, for delivery of 11Bcm/y (billion cubic meters per year) of gas. In December 1973, Eni signed an agreement with Tunisia to construct the 288km Tunisian section. This was to be run by Eni, Sonatrach, and the Tunisian government. In 1976, a further study was commissioned by Segamo (Sonatrach, Gaz de France, and Enagaz of Spain) for a 40Bcm/y gas pipeline between Algeria and Europe. In early 1977, it was reported that the line already under construction had been abandoned by Eni because of "the harsh economic demands made by Tunisia." In June 1977 the project was revived on the reopening of negotiations between Tunisia and Eni, and the following month the two sides reached an agreement.

3. One contractual device of interest was the ownership of the gas. Immediately after the gas crossed the Algerian border into Tunisia, it became the property of the Italian lifters.

4. In December 1978, Sonatrach borrowed US$915 million to build the Algeria section. In April 1979, a US$100 million loan was syndicated for the Tunisian section and in February 1980 a loan for the Mediterranean section was raised. Discussions began to expand the capacity of the line from 12.5Bcm/y to 18Bcm/y.

5. The line was completed in 1981 and filling began in the summer that year. Deliveries, however, were delayed by negotiations over the gas price. The original 1977

agreement priced the gas at 76.9 percent of the French price for Algerian LNG, indexed against a basket of fuel oil and gas oil. The second oil shock overtook these computations. In October 1982, agreement was reached. The negotiations had ranged between Algeria's price of US$5.00 per MBtu at the Algerian border and Eni's price of US$3.80 per MBtu. The final agreement set the price at US$4.41 per MBtu, of which US$4.01 would be paid by Eni and the remainder by the Italian government, as a "political" subsidy. The price was to be indexed against a basket of crudes rather than products and crude.

6. The line was inaugurated on May 18, 1983 and deliveries commenced in June. In May the Algerian government announced its intention to double capacity with a second line. Following the oil price collapse of 1986, gas prices fell according to the agreed formula. The fourth-quarter price for 1986 worked out at US$2.00 per MBtu at the Algeria border. In November 1989, an agreement was reached to add a fourth pipeline to the TransMed system, to increase throughput by some 4–6Bcm/y. It was later announced that this agreement was delayed because of an inability to agree on price, but in December 1990 a new supply deal between Sonatrach and Snam (the gas subsidiary of the Italian national oil company Ente Nazionale Idrocarburi) was announced. This was followed in March 1991 by agreement to expand the line. Operation of the line since has been smooth and uninterrupted by disputes. Perhaps surprisingly in view of the political turmoil in Algeria, the TransMed line also has remained free from sabotage attempts. Only in November 1997 was the flow disrupted, for four days, by a fire described as a "technical incident."

7. In 2001, TransMed delivered 21.85Bcm to Italy and 1.2Bcm to Tunisia. This accounted for 34 percent of Italian gas consumption and all of Tunisia's consumption.

Case Study 2: The Cross-Border Pipelines of the Former Soviet Union

8. The energy transportation infrastructure of the former Soviet Union (FSU) extends almost halfway around the globe and is the most extensive interconnected cross-border oil and natural gas pipeline network in the world. Perhaps most important, its largely landlocked energy resources comprise one-third of proven world gas reserves, and the region has the potential to produce approximately 10 percent of the world's crude production for decades to come. By any standard measure—cost of new investment, distance, diameter, or capacity—this region promises to be the most active in the development of new cross-border energy transportation systems for at least the next two decades. Already proposed are major new export pipelines and marine terminals to serve markets in Turkey and China and a number of countries in Europe, the Middle East, and Central Asia.

9. Central to the unfolding story of energy trade and economic development in the region have been its geography; the extensive infrastructure (in place); the unprecedented transition process; the wide distribution of energy resources and markets; the structure of the industry; the cross-border treaties and agreements, disputes, and

resolutions; and the mixture of public and private sector involvement. The framework that Russia and the other regional producing and transit states adopt for cross-border pipelines consequently will have profound effects on the region and on the markets that these states serve.

10. Without question, the existing crude oil pipelines that connect the vast resources of the region to its markets are a strategic asset to the regional producing states, the transit states, and the energy markets the network serves. Both because of its present capacity and its significant potential for extension, the pipeline network will exert a significant influence on the manner and speed with which economic reform will occur in the energy sector of each of the republics, and will significantly influence trade between the republics. The operating practices of the pipeline networks will prove crucial.

11. A full appreciation of the current cross-border and transit operations and practices of the extensive crude oil trunk line system in the Russian Federation and former Soviet states requires a basic knowledge of its origin and evolution.

12. Before 1970, the system of oil and refined product pipelines was operated by Glavneftesnab (Main Administration for Oil and Refined Product Supply), the organization subordinated directly to the Council of Ministers of the Russian Soviet Federated Socialist Republics (RSFSR). Glavneftesnab was effectively a ministry at a constituent republic level, operating all product and oil pipelines in the Soviet Union on behalf of the state. Regional enterprises operated pipelines in each of the regions. These were the forerunners of the current pipeline enterprises in each of the states in the FSU.

13. The first major crude oil export project began in 1956, when the Soviet Union decided to build a dedicated marine crude oil export terminal at Tsemesskaya Bay, near Novorossiysk. The engineering, design, and economic evaluations took 10 years to complete, and the first berth was constructed in 1964. The Black Sea Pipeline Association was formed in 1967 to operate these important export terminal and regional pipelines. The associated Sheskharis and Grushovaya tank farms were completed in 1969.

14. In 1959, the 10th COMECON (Council for Mutual Economic Cooperation) Session agreed that a major crude trunk oil pipeline should be constructed to deliver oil from the Soviet Union to Poland, Czechoslovakia, the German Democratic Republic (GDR), Poland, Latvia, and Lithuania. This pipeline would later become known as the Druzhba (Friendship) pipeline. The following year construction began. Each country through which the system would transit was responsible for providing the materials and services necessary for the construction of the pipeline on its territory. In 1962, the pipeline delivered its first oil to Czechoslovakia; in September 1963, to Hungary; in November 1963, to Poland; and in December 1963, to the GDR.

15. Given that the primary purpose of Druzhba was to supply a majority of the crude oil requirements of the COMECON states, the line was designed to “telescope” down in size and therefore capacity as the system extended farther from the Russian border.

16. When the Druzhba pipeline system was constructed, in the Soviet era, it was operated by an affiliate of the Ministry of Gas, the Integrated Dispatch Administration (ODU, in its Russian initials) and was known as the ODU Druzhba. Later, that organization was transferred to the Russian Federation's Ministry of Fuel and Energy as the Central Dispatch Unit (CDU) for oil movements.

17. In 1970, the responsibility for oil pipeline administration shifted to the Oil and Gas Ministry of the Soviet Union. On October 30 that year, a Resolution of the Council of Ministers of the USSR (1970 N. 889) formed the Main Industry Enterprise for Oil Transportation and Distribution (Glavtransneft, GTN). Table A1 shows Glavtransneft's trunk pipeline system in the Soviet Union. GTN consisted of all 17 of the pipeline associations of the Union of Soviet Socialist Republics. Note that all of the pipeline associations except those in the Georgian and Turkmenistan pipeline systems are directly interconnected with the rest of the system.

Table A1: Trunk Pipelines in the Soviet Union Republics Operated by Glavtransneft

Republic	*Storage* — *Number of tanks*	*Storage* — *Capacity ('000m^3)*	*Length of pipelines ('000km)*	*Pump stations*
RSFSR	981	13,871	49.0	442
Ukraine	69	714	3.5	31
Kazakhstan	114	1,049	4.9	46
Byelorussia	39	795	2.8	21
Latvia	—	—	0.4	3
Lithuania	—	—	0.3	3
Azerbaijan	27	204	0.7	5
Turkmenistan	10	50	0.5	5
Georgia	10	40	0.5	4
Kirgizia	—	—	0.4	—
Uzbekistan	6	12	0.9	8
TOTAL	1,256	16,735	63.9	570

Note: These pipelines represent all of the pipeline systems of the Soviet Union, including the systems in the Caspian states.

18. Under the Soviet Union's command economy, GTN performed the "merchant function," or perhaps more accurately the merchant function according to a command economy model. GTN "purchased" oil from production associations at state-ordered prices and sold to Soviet refineries at state-ordered prices. A subdivision of Gosplan (the Soviet central planning agency), Gosplan Crude, independently determined prices for each production association based on expected costs and levels of production based on the submission and review of their plans.

19. GTN was responsible for implementing Gosplan's general plan for the distribution of crude, the supply of refineries, and the transportation of crude export volumes. Producers were unconcerned about the final destination of the oil they produced: Glavtransneft simply paid them a state-ordered price at the injection point for

the crude they produced. Similarly, refineries were not concerned with the specific source of production they received. The GTN enterprise was responsible for deciding where and how to blend crude streams and for determining an optimal centralized distribution plan. GTN also had the responsibility to solve any crude transportation and distribution problems that arose, such as those caused by production shortfalls or interruptions at individual refineries.

20. During the Glavtransneft era, the VTO (Foreign Trade Association) Soyuzneftexport was the state organization in charge of all exports from the Soviet Union of crude to COMECON and other international destinations. Its principal responsibilities included fulfillment of government obligations under interstate agreements, signing export contracts, and negotiating oil export and counter trade arrangements. Soyuzneftexport was subordinated to the Ministry of Foreign Trade and was listed as the shipper of record on all exports.

21. Glavtransneft's role was limited to implementing the Soviet Union's plans for the distribution of crude. With respect to exports and cross-border trade, GTN would be told what volume of crude was to be delivered to the Port of Novorossiysk, Adamovo Zastava (now in Belarus, near the Polish border), or other border crossings, and GTN's obligation was to see that the state orders were carried out.

22. Given the great distances between the resources and the destination markets and the harsh climate, the challenges of operating this extensive integrated pipeline network were substantial. The professionals at GTN were the key players with respect to planning and implementing modifications of the pipeline systems both within the Soviet Union and in the territories of COMECON countries. As noted earlier, Soyuzneftexport, not GTN, was responsible for "marketing activities" outside the Soviet Union, such as executing trade agreements.

23. The Soviet government signed intergovernmental agreements with Eastern Bloc countries on delivery of crude oil, as part of COMECON multilateral interchange programs for commodities and manufactured products. Such agreements were ordinarily signed for a five-year term. The price of oil was set in "convertible rubles" and calculated as the function of international market prices. The average of the world market oil price for the previous five years served as the notional basis for these transactions. The system allowed payments for export volumes on a barter basis, and the state paid the shipping costs.

24. The Glavtransneft mainline crude pipeline system was the most extensive in the world. (The refined product pipeline system is much smaller than the crude oil system and is discussed briefly below. Transnefteproduct, which handled refined oil products, continued to operate as a single integrated system for the most part after the dissolution of the Soviet Union.) The crude pipeline system was designed primarily to connect four major producing regions—the three Russian regions of western Siberia, the Urals, and northern Russia and Kazakhstan—with various domestic Soviet refining and petrochemical centers as well as with the export markets in the COMECON states. To a

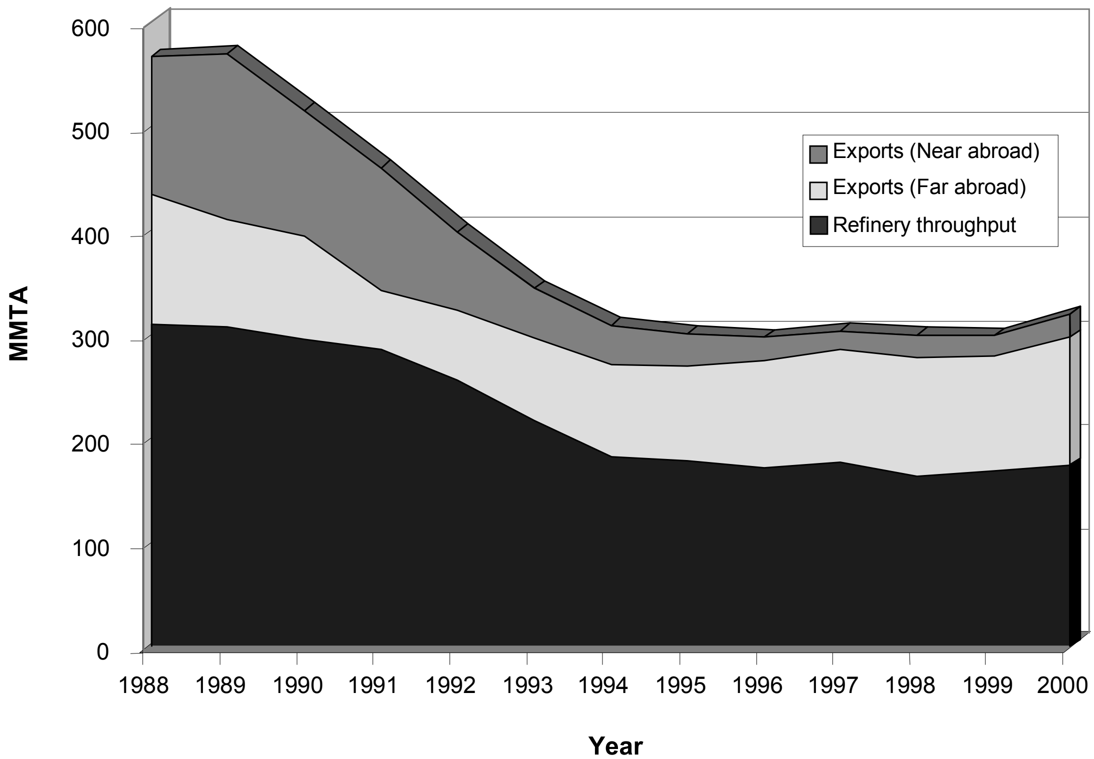
limited extent, it also provided access to Western markets via ports at Novorossiysk, Tuapse, Odessa, and Ventspils. The crude oil pipeline system was distributed over an area of approximately 7.8 million square kilometers. The vast majority of the system, 74.9 percent of installed pipe, was within the borders of the Russian Federation. Most of the remainder was in Kazakhstan (10.67 percent), Ukraine (5.24 percent), and Byelorussia (now Belarus; 4.51 percent).

25. The system was designed to transport approximately 12 million barrels of oil a day. This vast system connected the major producing regions of the Soviet Union to the major refining centers and to export terminals and connecting facilities. The GTN system included approximately 63,900km of pipeline, 570 pumping stations, and a storage capacity of approximately 16.735 billion cubic meters (Bcm). Given the concentration of the industry, it is not surprising that most of the pipelines GTN operated were large in diameter (74.7 percent were between 720mm and 1,220mm). The state-owned network transported more than 95 percent of the oil produced in the Soviet Union.

26. GTN operated as a single integrated enterprise. This fact assured GTN of extensive flexibility and reliability in executing cross-border crude oil trade transactions. For example, a benefit of a single, integrated system is the ability to direct flows readily and arrange exchanges of crude. This enabled the system to export crude produced in republics such as Kazakhstan or Azerbaijan even where the physical configuration of the system did not directly accommodate such movements.

27. During the Soviet era, as noted, the primary cross-border markets for Russian production were the states of the Soviet Union and the COMECON countries. In the post-Soviet era, trends shifted markedly. Figure A1 shows refinery throughput and the trends in crude deliveries to domestic, “near abroad,” markets (Ukraine, Belarus, and Lithuania) and to “far abroad” export markets between 1988 and 2000.

Figure A1: Russian Federation: Refinery Throughput and Exports, 1988–2000



28. Note that the two governmental acts that led to the establishment of Transneft also specified the structure of Transnefteproduct, the refined product pipeline system. The refined product pipelines remained under the jurisdiction of the Russian government. Accordingly, after the dissolution of the Soviet Union, oil pipelines on the territories of the newly independent states emerged as independent carriers not affiliated with Transneft. Meanwhile, Russia claimed all refined product pipelines, no matter on whose territory they are located.

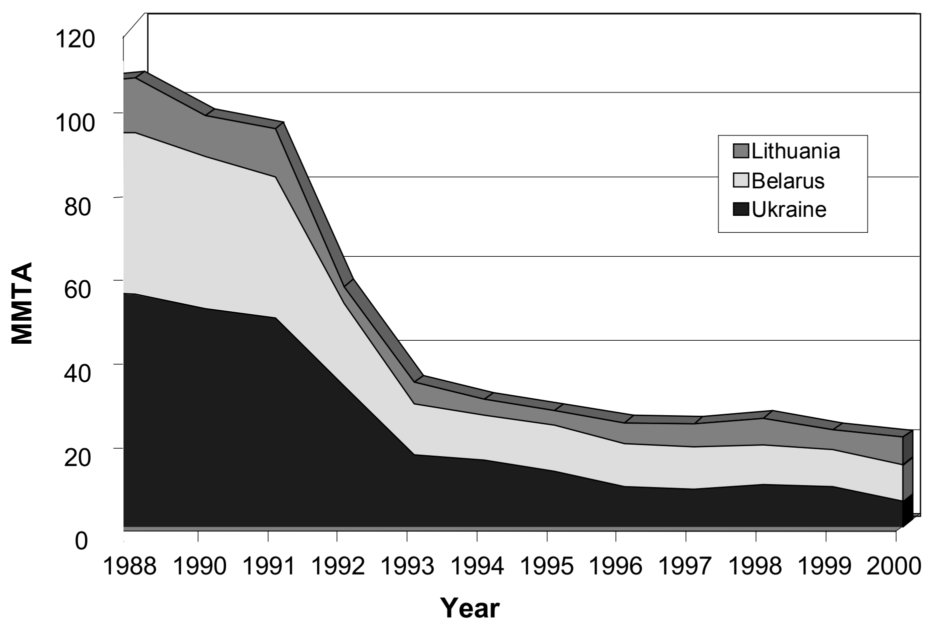
29. Note in figure A1 the substantial decline in deliveries to the near abroad that occurred with the dissolution of the Soviet Union. The reasons for the decline are several. To begin with, the transition economies of the former COMECON client states were unable to sustain their previous level of crude imports from Russia—even at subsidized prices. Moreover, when they did import, the Eastern European states were now seeking to diversify their sources of supply. The chart also shows that Russian exports to the far abroad did not increase as logically would have been expected as a

market reaction to the collapse of demand in the near abroad. This can be explained in part by the crude export restrictions imposed by the Russian government, the telescoping nature of the Druzhba pipeline system, and the actions of some Eastern European countries to diversify sources of supply (that is, emphasizing expanding connections “from” rather than “to” Western European crude pipeline networks).

30. As figure A1 also shows, crude oil production declined in the Russian Federation as a result of natural field declines and lack of investment. This decline reached a low point in 1998 of 6.169 million barrels per day (Mb/d) and then proceeded to a steady and strong recovery. By 2002, production was running at 7.66Mb/d, and it is projected by the International Energy Agency to reach 8.21Mb/d in 2003. Refinery throughput also declined in Russia, but not to the extent experienced in the near abroad. The Russian Federation imposed domestic price controls and therefore did not experience the same magnitude of decline in domestic demand.

31. Figure A2 shows GTN’s crude oil deliveries to the near abroad states of Ukraine, Belarus, and Lithuania from 1988 to 2000.

Figure A2: GTN Crude Oil Deliveries to the Near Abroad (Ukraine, Belarus, and Lithuania), 1988–2000



Note: Data are not available for 1989

32. In 1991, the GTN system was divided according to political boundaries. Each of the states of the FSU formed state enterprises to operate the crude oil trunk lines located on their territory. JSC Transneft was the entity formed to operate the Russian

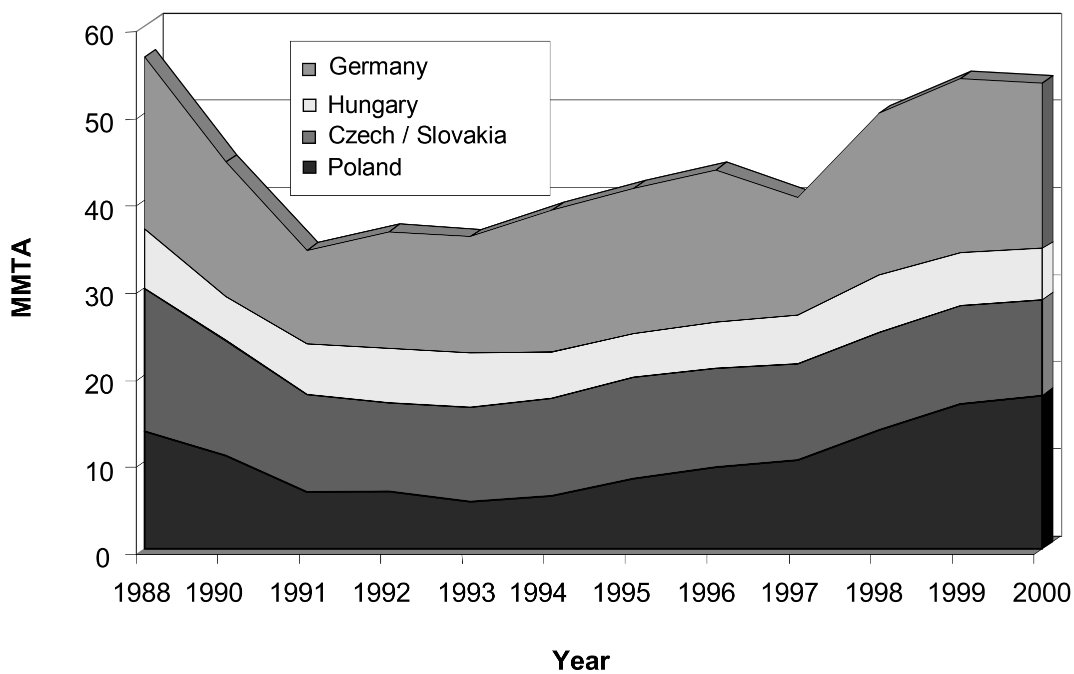
portion of the GTN network. In addition to Druzhba Briansk in the Russian Federation, the Druzhba system was divided into five additional entities (see table A2).

Table A2: Additional Political Divisions among FSU Countries of the Druzhba System, 1991

Company	*Country*	*Headquarters*
Gomel Oil Transportation Enterprise (GPTN) "Druzhba"	Belarus	Gomel
Novopolotsk Oil Transportation Enterprise (NPTN) "Druzhba"	Belarus	Novopolotsk
Lviv Oil Transportation Enterprise "Druzhba"	Ukraine	Lviv
Joint Latvian–Russian Venture for Oil and Refined Product Transportation JSC "LatRosTrans"	Russia–Latvia	Daugavpils
"Naftotekis" Oil Transportation Enterprise	Lithuania	Birzhai

33. The formation of the FSU states and the resulting "new relevance" of the borders between the FSU states raised a number of cross-border issues. As noted in the discussion of figure A1, demand declined from the near abroad former Soviet client states, particularly Ukraine and Belarus, which were now undergoing economic transition. This created significant idle capacity at the western borders of the Russian Federation—a situation that was compounded by the physical and market limitations at existing export destinations, which had the effect of "stranding" this capacity. Because of concerns over market limits, the Russian Federation restricted the transit of Kazakh production to relatively modest levels. Figure A3 shows pipeline exports to the far abroad over the Druzhba system from 1988 to 2000, and box A1 shows the organization of Transneft after 1992.

Figure A3: Crude Oil Exports to the Far Abroad via the Druzhba Pipeline, 1988–2000



Note: Data are not available for 1989.

Box A1: The Organization of Transneft after 1992

The pipeline system of the Russian Federation has remained the most important link in the interconnected system in terms of level of throughput, length of pipeline, and extent of cross-border connections. Transneft was officially formed pursuant to the Decree of the President of the Russian Federation, No. 1403, of November 17, 1992, and the Ordinance of the RF Council of Ministers #810 of August 14, 1993 "On the Establishment of JSC Transneft." Transneft was responsible for coordinating the operations of the 12 Russian regional pipeline enterprises in the Russian Federation (joint stock pipeline associations) and the affiliated technical institutes.

Affiliates of JSC Transneft	
Regional transport companies	*Service companies*
North Western Siberian Pipeline Association Druzhba Pipeline Association	Technical Diagnostic Center (Pipeline inspection)
Volga Pipeline Association	Svyaz Transneft (Communication

Trans Siberian Pipeline Association
Urals Siberian Pipeline Association
Central Siberian Pipeline Association
Black Sea Pipeline Association
Upper Volga Pipeline Association
Caspian and Caucasus Pipeline Association
Northern Caucasus Pipeline Association
Upper Volga Pipeline Association
Northern Pipeline Association

Enterprise)
Podvodtruprovod (Underwater pipeline services)
Volga Underwater Inspection
Giprotruprovod (Pipeline design)
Stoineft (Pipeline construction)

Transneft and its affiliated pipeline associations operated approximately 49,300km of pipeline, and the combined storage capacity of all tank farms operated by Transneft was approximately 14 million cubic meters. Transneft itself became responsible for executing authorized export movements; distributing hard currency tariffs between the affiliated associations; coordinating, dispatching, and managing oil movement activity, and providing technical support services, including pipeline inspection.

The network is often described as an integrated technological and economic system. A 1996 report, "Present Condition of Oil and Petroleum Product Transportation Systems," by the Russian Academy of Sciences argued that it was important to maintain the monopoly structure of the system.

The following examples demonstrate the efficiency of Russian pipeline system operation. The pipeline tariffs in Ukraine on a metric ton/kilometer basis exceed Russian tariffs by a factor of 1.8 on the route to Odessa and are 3 times higher on the route to the Western border; compared to Russian tariffs, transit fees charged by Byelorussia are 1.6 times higher on the route to Poland and Germany and 2.6 times on the route to Ventspils, where Latvian tariffs are 2.4 times and Lithuanian tariffs 4 times the value of the Russian tariffs.

Any attempt to break up the Russian pipeline system or change its ownership structure would result in a rapid increase in transportation tariffs, cause havoc on the Russian oil market, and reduce the profitability of oil exports. Preservation of the system's integrity is one of the key objectives of JSC Transneft set forth by the state.

Clearly it would not have made sense to divide the interconnected systems that are designed for the primary purpose of transporting crude production from West Siberian fields to domestic and export markets. In fairness, however, the efficiency claimed above is in large part a function of the result of the decline in valuation of the ruble: Transneft still employs approximately 45,000 people.

34. A Presidential Decree in 1992 specified that Transneft would operate as a "common carrier," providing services to producers on a tariff basis. Transneft would no longer perform the merchant function that its predecessor performed during the Soviet era. This was the first major step in the transition of the oil sector to a market economy. The producers from then on became responsible for marketing their own production, but

with state-imposed constraints on their marketing "options." Price controls initially remained in place for domestic markets in the Russian Federation, and as cross-border markets brought higher prices, the government set up controls on export access. The justification for the controls was a shortage of export capacity downstream of the Russian border; the underlying reason for the controls, however, was to ensure domestic supply arrangements.

35. In 1999, the reference to the supply of the internal market was deleted from the export allocation regulations. For exports, however, "the principal of equal accessibility proportionately to the volumes of extraction (refining) of oil and oil products" (item 1 of Decision No. 209 of February 28, 1995) seems to have been maintained. This effectively discourages any initiative by a single company to debottleneck the export stream downstream of the Russian border, as doing so would favor its competitors. It thus constitutes an internal obstacle to the export of crude oils and oil products that reflects an external obstacle. Even without the reference to the internal market this obstacle would pile up crude flow inside Russia, creating a downward price pressure in Russia that might translate into another disincentive for further exploration.

36. Although numerous changes have taken place with respect to export access for Russian producers, the rules governing transit throughputs have remained essentially constant. Transit access is governed by intergovernmental agreements (IGAs). Transit volumes subject to IGAs are given priority access on the Transneft system.

37. Transneft, in its new role of common carrier, provided tariff-based service to owners and shippers of crude oil. Route tariffs from point origin to destination were the sum of segment tariffs, which in turn were calculated on a proportionate basis (linked to projected freight turnover, measured in metric tons/kilometer and facility-specific distribution of tariff revenue for each of the constituent pipeline operators serving a particular route). Tariffs were cost-based. The costs included pumping cost, the regulated rate of return, and taxes and disbursements to investment (hard currency), and insurance (rubles) funds. The tariff does include amortization of the original investment—even beyond the original investment. The original investment, however, has been devaluated by heavy inflation, so that the capital part of the tariff bears no realistic relation to current investment costs for a comparable pipeline. In addition, the allowed return on historic assets was very low.

38. Transneft was mandated to provide service on a nondiscriminatory basis. However, the "nondiscriminatory clause" applied only within classifications of service. For example, tariffs for domestic crude movements were stated in rubles and varied with distance, whereas tariffs for deliveries to hard currency markets were based on the ruble tariffs plus a flat hard currency surcharge (since 1992; in 1998 the export surcharge was changed to a distance basis). The surcharge initially was designed to provide the hard currency necessary to purchase imported equipment. Export shippers thus were responsible for all hard currency costs of the system. In 1998, Transneft introduced transit tariffs denominated only in dollars that were higher than tariffs for Russian

exporters for the same route. Technically, the Federal Energy Commission (FEC) of Russia should approve all tariff changes; however, in the case of the transit tariffs the administration and the FEC tacitly followed the practice of Transneft. From the FEC's perspective, the tariffs were of less concern in that the higher transit tariffs reduce the level of tariffs for Russian shippers.

39. Despite the GTN system being divided by national boundaries at the dissolution of the Soviet Union, it was still essential that from an operations and technical perspective the system should continue to function on a coordinated basis. In 1992, at a meeting in Surgut, six parties (Transneft [the Russian Federation]; Ukrneftehim (Ukraine); Druzhba–Novopolotsk Oil Transportation Enterprise [Belarus]; Druzhba–Gomel Oil Pipeline Administration [Belarus]; Latvia Oil Transportation State Enterprise [Latvia]; and Naftotekis–Birzhaysk State Enterprise [Lithuania]) recognized the technological unity of the Trunk Oil Pipeline System of Russia. As a result, Ukraine, Belarus, Latvia, and Lithuania agreed to coordinate their activities on the scheduling of oil movements and to harmonize tariff practices. The agreements with respect to coordinating oil movements have remained in place (the system could not function without this cooperation), unfortunately, those provisions relating to the development of a single contract and harmonizing tariffs were not implemented.

40. Immediately following the dissolution of Soviet Union, significant changes took place in the crude flow patterns and operations of the former Glavtransneft:

- Crude production declined significantly in the Russian Federation.
- Market signals had an immediate effect on crude demand in the nonproducing states (less so in producing states, because domestic prices were set at levels far below world market levels and because of restrictions on crude oil exports). A number of the states followed the lead of the Russian Federation in charging rates on export / transit deliveries according to the ability to pay.
- Former Soviet client states in Eastern Europe sought to diversify their sources of crude supply, partly through concern about declining production in the Russian Federation and partly for economic security.
- Crude export flows to world markets via marine terminals increased within existing capacity, as deliveries to traditional markets via pipeline declined.
- In a few instances, the direction of flow in pipeline segments such as the Adria pipeline was reversed, such that oil flowed from world markets into the Balkans and Hungary. In another case, the direction of flow was reversed to enable transit volumes from Azerbaijan to be exported via the port of Novorossiysk.

41. Figure A1 shows how the distribution of production in the Russian Federation changed during this period. Crude production declined significantly, but deliveries of exports to the far abroad remained relatively stable. Numerous factors have contributed to this result. Early on, the need for foreign hard currency earnings influenced government policy, but much of the later change can be attributed to market factors. For example, demand in Russia and other FSU states declined significantly as a result of the general economic collapse. In particular, the activity of the FSU's military–industrial complex declined precipitously. For private parties, market signals also had an impact on demand, as internal prices to these users increased substantially. Government policies also have varied considerably over the period with respect to the basis for supply to cooperative farms, the military, and so on.

42. Table A3 shows an estimate of currently usable "passport export capacity" at the western borders of the Russian Federation. Passport capacity is determined according to technical standards, and information on it is not available in the public domain. The process is roughly equivalent to the determination of maximum operating pressure for specific pipelines in North America, which is based on various technical and risk factors. It is clear from the estimate that the determination of passport capacity has not been used as a vehicle to protect local markets, as the passport capacity of 200 million metric tons per year (Mt/y) listed for export pipelines significantly exceeds the actual exports in 2000 of 120.6 Mt/y. As figure A2 shows, the surplus in export capacity (within Russia) arose primarily as a result of the sharp decline in exports to Ukraine and Belarus after the breakup of the Soviet Union.

43. Table A3 may surprise some who share the common belief that export capacity from the Russian Federation is in short supply. The Russian authorities limited and controlled the access to export capacity of Russian and Kazakh producers, but Russia itself has no shortage of physical export capacity.

Table A3: Current Design and Passport Oil Export Capacity of the Russian Federation

Western border segment	*Design capacity (Mt/y)*	*Current passport capacity (Mt/y)*
Yarolslavl–Velikiye Luki (Belarus)	50.0	50.0
Samara–Lisichansk (Ukraine)	82.0	56.5
Nikolskoye–Kremenchug (Ukraine)	17.0	10.5
Visokoye–Mozyr 1 (Belarus)	28.8	20.0
Visokoye–Mozyr 2 (Belarus)	53.0	49.0
Vysokoye–Polotsk 1 & 2 (Belarus)	39.2	14.0
Total	270.0	200.0

44. The following are a few of the key challenges facing the carriers that originally made up the GTN if the extended system is to realize its full potential as a cross-border pipeline:

- All of the economies of the region are undergoing a transition that is unprecedented in its scale and complexity. Demand for crude oil from domestic and traditional markets now respond to market signals and supply and usage patterns have significantly altered.
- The pipeline networks serving the region were developed with the Soviet Union and its needs in mind. Fifteen independent states now introduce market principles rather than a single command economy controlled from the center. Individual commercial interests and diverse political considerations have come into play. In the Soviet era, whether the oil delivered to Eastern Europe was produced in Russia or Kazakhstan was irrelevant. Since the dissolution of the Soviet Union, however, Russian policymakers might view production in Kazakhstan as a potential source of competition in markets served by Russian producers. Today, separate commercial and national interests are at stake.
- The pipeline networks were laid out without consideration for national boundaries or the interests of individual states. For example, Kazakhstan has more than 6,300km of crude oil pipelines, yet there are no physical facilities in place by which production in western Kazakhstan can be delivered to Kazakhstan's refineries in the east.
- The fragmentation of the GTN system into a number of state concerns and the resulting focus on national boundaries and interests by the regional states and their enterprises has hindered the development of the full potential of this historic network. It can be anticipated that this situation will evolve in time as economic incentives and market signals do their work, but the situation in the meantime is far less than optimal.

45. Immediately after the breakup of the Soviet Union, the Russian Federation and Kazakhstan were the only producing countries with crude available to export via pipeline. Transneft accommodated a limited amount of transit volumes from Kazakhstan. The level of access has been subject to intergovernmental agreement that has been negotiated on a year-by-year basis. With the decline in traditional markets and the reorientation of exports to world markets via marine terminals, Russia took a cautious view with respect to the transit of crude through its territory. Box A2 briefly summarizes the market perceptions that have prevented Transneft, up to this point, from realizing its full potential to provide cross-border transit services.

Box A2: The Russian Dilemma: Surplus Capacity but Export Constraints

As noted earlier in this case study, the Russian Federation has ample physical export capacity at its borders. Marine export terminals, however, have been operating at near capacity, and the markets directly connected by pipeline have to varying degrees been limited by market constraints, both economic and political. The carriers, as state-owned enterprises in each of the transit states, did not have the resources and were not prepared to expand export capacity on a speculative basis. In many of the Eastern European states, the primary focus of the carrier was on transporting crude oil imports to domestic refineries and not on commercial transit opportunities.

In a market framework, the solution was obvious. Empower the private sector (that is, the producers) to negotiate expansion of export capacity with the owners of the facilities. For this to work, it was necessary to put in place a regulatory framework that would enable regional producers to obtain and secure access to idle capacity as well as to any capacity made available through their financial support. Because the Russian Federation controlled access to export capacity beyond its borders, however, producers financing the expansion of export capacity would benefit only to a limited extent.

After the dissolution of the Soviet Union, officials of the Russian Ministry of Fuel and Energy viewed crude export markets as a "fixed pie." From the perspective of Russian officials, any transit volumes allowed would directly reduce crude exports from Russian producers. Although in a narrow sense this view had some validity (in the light of the landlocked consumers linked to the existing Druzhba system), Russian officials failed to recognize that ready and immediate market solutions were available to expand the pie.

46. The Russian Federation and many of the regional states' attitudes toward the transit of crude from neighboring states have evolved significantly over the past few years. The following are some of the more important changes:

- Russian officials, Transneft, and a number of the transit states now recognize that expanding production in Kazakhstan and other Caspian states represents an important commercial opportunity. In Russia, this has clearly been reinforced by the example of the Caspian Pipeline Consortium (CPC).
- Policymakers in Russia are beginning to recognize that a window of opportunity exists with respect to their participation in the transport of Caspian resources to world markets. They understand that if they do not act soon, alternative solutions may bypass Russia entirely. They recognize the win-win nature of cooperating on transit issues: additional throughput from transit volumes

lowers the unit costs to all Russian producers (through economies of scale), expands beneficial trade and commerce with neighboring states, provides potential attractive sources of crude for domestic markets, results in favorable international recognition, and so on. In May 2002, Russia signed an agreement with Kazakhstan which divided the North Caspian seabed between the two; it also reached agreement on the joint development of three disputed offshore fields. In June 2002, a 15-year deal was signed for not less than 350,000b/d of Kazakh crude to be exported via Russia, in addition to the CPC throughput. This seemed to signal the realization by both sides that working together at the government level would benefit both sides.

- In making use of idle capacity for transit, Transneft is covering only its operational costs. It thus is motivated not by profits or business opportunities, but primarily by state policy. Looking to the future, however, Transneft can see that as "connected" Russian production declines, additional transit would create jobs and valorize investment that otherwise would be idle.
- The Russian authorities recognize that greater access can be provided to producers in Kazakhstan, Turkmenistan, and Azerbaijan without reducing access for Russian producers. To the extent that additional marine export capacity at the ports of Primorsk, Porvoo, Gdansk, Rostok, and Omishalj can be readily accessed or developed, transit oil could move to world markets with positive rather than negative effects on Russian producers. The crude from the Caspian states will get to world markets; it is just a question of how and who will receive the benefits related to the transportation links chosen.
- Russia risks the loss of a significant amount of access to traditional markets from bypass pipelines (for example, Yuzhny–Brody) if alternative routes are selected.
- Transneft and a number of the transit states now recognize that competitive factors, not state mandates, will likely determine regional crude flow patterns. Transneft recently has been taking actions to improve commercial terms for transit shippers, including the use of term access and tariffs and quality banking (without a quality bank, producers of higher quality crude, particularly Caspian producers, suffer a significant economic loss). For example, in the case of transit volumes from Azerbaijan, the Russian Federation offered a term agreement with stable tariffs, and recently offered to deliver transit crude on a segregated basis.

- Transneft initiated a project to integrate the Druzhba line with the Adria line that runs from the Adriatic port of Omisalj in Croatia to Hungary. In October 2000, Yukos announced specific plans for the project. On completion this would allow the direct exports of Russian oil to the Adriatic, the wider Mediterranean, and beyond, since Omislaj can take tankers of up to 350,000 metric tons.
- Problems over oil transit via Ukraine also keep reappearing. By mid-2002, none of Transneft's plans for export pipelines involved Ukraine. The Sukhodolnaya–Rodionovska bypass, which became operational in 2001, in fact was aimed specifically at avoiding Ukraine: the 260km line directly links two other pipelines bypassing the Lisichansk–Tikhoretsk section in Ukraine. During the construction of the bypass, Ukraine actually offered to reduce tariffs if construction was suspended.
- The surge in Russian production in the last few years has eroded the spare capacity in the export system. By November 2002, it was reported that the Druzhba line was operating close to its highest capacity (1.2Mb/d) in years.

47. In summary, the pipeline network of the former Soviet Union is the most extensive cross-border system in the world. This network will continue to have an important role in transporting the energy resources produced in the region to world markets. The potential of the network to serve both producing and consuming states is enormous. The only question that remains is whether the political leaders in the region will take the actions necessary to enable the network to realize its full potential. At the time of publication of this report, Russia still had not ratified the Energy Charter Treaty.

Case Study 3: The SuMed oil pipeline

48. The Suez–Mediterranean pipeline (SuMed) is a 320km line running from Ain Sukhna on the Gulf of Suez to Sidi Kerir on the Mediterranean coast. The pipeline, comprising two parallel 42-inch (1,067mm) lines, was opened in 1978 with a capacity of 1.6 million barrels per day (Mb/d). Completion of the Dashour pumping station capacity in 1994 increased capacity to 2.5Mb/d. Both ends of the pipeline have storage capacity of up to 24 million barrels. At Ain Sukhna, four single-point moorings (spms) can take vessels of up to 500,000 deadweight metric tons (dwt) and at Sidi Kerir six spms can take vessels of up to 350,000dwt. Sidi Kerir has become a major crude oil storage facility for the Mediterranean. The new Middle East Oil Refinery, Midor, the first refinery in Egypt to attract private sector participation, is linked to SuMed via a 20-inch (508mm), 11km line.

49. In 2000, it is estimated that SuMed transported 2.2Mb/d northbound, largely from Saudi Arabia. This compares to 700,000b/d shipped through the Suez Canal. The Suez Canal Authority (SCA) and SuMed actually compete for transit. In 1993, in an effort to attract business from the SCA and from the third option of ocean transportation

around southern Africa, SuMed announced a policy of flexible tariffs to replace its previously fixed tariffs. In 2000, it was reported that the SCA was trying to reach a deal with SuMed that would oblige those smaller tankers capable of using the canal to use it rather than use SuMed.

50. The line in effect provides an alternative to the Suez Canal. Strictly speaking, it is not a transit pipeline, since it is entirely in Egyptian territory, but by linking the Red Sea and the Mediterranean it does act in some sense as a cross-border pipeline.

51. The pipeline is a joint venture owned by the Arab Pipeline Company. The shareholders are the governments of Egypt (50 percent), Saudi Arabia (15 percent), Kuwait (15 percent), the UAE (15 percent), and Qatar (5 percent). In 1997, the 15 percent held by Petromin on behalf of the Saudi government was taken over by Saudi Aramco. On its formation in 1976, Saudi Aramco took a US$100 million loan from Apicorp, the investment arm of the Arab Organization of Petroleum Exporting Countries (OAPEC).

Long-Term Failures

Case Study 4: The Iraqi crude oil export pipelines

52. In the 1930s, the prospective export of Iraqi oil from the Kirkuk field led to pressure from the British partners in Iraq Petroleum Company (IPC) for a line via British-mandated Palestine and from the French for a line via French-mandated Lebanon and Syria. The result was a compromise, a single line out of Kirkuk that divided into two after Haditha to deliver oil to Tripoli and Haifa. A first 12-inch (305mm) line was completed in 1934, with a capacity of 4 million metric tons per year (Mt/y). In 1946, work started on a second, parallel line; this was a 16-inch (406mm) diameter line but would have been larger if its dollar shortage had not prevented IPC buying larger pipe from the United States. After the creation of Israel, the Haifa branch closed. In 1950, work began on a 30–32-inch (762–813mm), 14Mt/y line from Kirkuk to Banias. This was completed in 1952, raising the overall capacity of the system to 16Mt/y. In 1956, the lines were badly damaged by the Syrian army in response to the Anglo-French seizure of the Suez Canal zone, but they eventually were repaired.

53. The 1931 agreement that created the line freed the IPC from paying transit fees or taxation, except on profit from products sold locally. The only benefit granted to the Lebanese and Syrian governments, which were signatories to the agreement, was a 2 pence loading fee on every metric ton loaded at the terminals. Although the agreement had a 70-year life, the introduction of 50-50 upstream profit sharing in the early 1950s prompted Syria and Lebanon to seek similar treatment for the pipelines. In November 1955, the IPC and Syria signed a new agreement, with Lebanon following suit in 1959. This provided for a transit fee (1 shilling and 4 pence per 100 metric ton-miles), a loading fee of 1 shilling per metric ton, and an annual payment of £250,000 for protection and other services. This was based on notional profit calculations allowing for a 50-50 profit

split. As with all such calculations there was plenty of scope for further dispute and interpretation.

54. In August 1966, an extreme wing of the Ba'ath Party took over the Syrian government and requested a renegotiation of the transit fee. The government's claim was that by increasing the line capacity, the IPC had reduced average costs and realized a higher profit base. Negotiations were relatively simple, except that the Syrian government insisted on retroactive payments. The companies, fearful of setting a precedent, refused. On November 16, with no agreement in sight, the government issued a warning, setting forth a formula for profit sharing. This was rejected by the IPC, and on November 23 negotiations were broken off. Syria unilaterally raised the transit fee by 46 percent and the loading fee by 92 percent. In addition, a further 3 shillings transit fee was levied to compensate for the IPC's "underpayment." This was to be retained until all "accounts are settled with the company." The IPC filled its storage in Banias and ceased pumping. Shortly afterward, alleged pumping problems in the Syrian section resulted in the line being unable to feed the Lebanese spur. The IPC was not allowed to investigate the problem. Both sides then proceeded to make claims and counter claims regarding the interpretation of the 50-50 profit sharing deal.

55. It is unclear how far the dispute was founded in economics or politics. Syria's perspective was this was "an episode in a broader struggle to free the Arab nation from the domination of Western imperialism and exploitation by oil monopolists." For the IPC, conceding to Syria would have created a dangerous precedent that could have plagued its owners in their relations with other Middle Eastern governments. The IPC owners additionally were under pressure from other regional governments to expand production. Cutbacks in Iraq, blamed on Syria, provided welcome relief.

56. It was growing pressure from Iraq on both Syria and the IPC that reopened negotiations, with agreement reached in March 1967 based on terms offered earlier by the IPC. Syrian compliance in the end came because it transpired that the loss of Iraqi oil had been easily managed by the industry: there was a danger of permanent closure of the line that would derive Syria of much-needed foreign exchange.

57. In 1971, as part of the Teheran and Tripoli price agreements, a new transit agreement emerged between Syria and Tapline that would double Syrian revenue at full capacity. Syria therefore approached the IPC to renegotiate terms, and in July 1971 there was a substantial increase in fees. In June 1972, Iraq nationalized the IPC and Syria immediately nationalized IPC's assets in Syria, requiring negotiation of a new agreement. Syria requested a doubling of transit fees and favorable prices for crude used domestically. Negotiations faltered and in January 1973 Syria threatened unilateral action. Strengthening oil prices undermined Iraq's bargaining position and forced Iraqi acceptance. This left Iraq bitter and determined to short-circuit Syria's command over Iraq's exports. In June 1973, however, Iraq announced an interest-free loan of US$22 million for Syria to expand the line's capacity, and in September it was announced that Entrepose of France had been awarded a US$44 million contract to expand the line by 200,000b/d to 1.4Mb/d.

58. In 1975, Syria again requested renegotiation of the 1973 terms, as was allowed by the agreement. Negotiations took place in the context of much higher prices, following the first oil shock. Syria wanted an increase in transit fees, and Iraq wanted a reduction in Syrian domestic offtake or a higher price. In 1975, Syria's net income from transit fees was US$100 million, with the price discount on crude offtake worth a further US$88 million. By the terms of the 1973 agreement, Syrian and Lebanon could lift crude at US$2.45 per barrel in 1973, rising to US$2.75 per barrel by the end of 1975. The first oil shock effectively quadrupled prices. By 1975, Lebanon and Syria were lifting Iraq crude at US$3.05 per barrel, compared to its market price of US$11.85. Lebanon could lift up to 1.5 million metric tons per year, but Syria could lift as much as it needed for domestic consumption.

59. Iraq now had alternative routes (see below), and in March 1976 pumping stopped and the Strategic Pipeline diverted the oil south. In October 1978, rumors suggested a new Syrian–Iraqi rapprochement, triggered by the Camp David Accords, could lead to a resumption of operations. Pumping resumed in February 1979 at 80,000b/d; the new arrangement involved transit fees that were "a little bit less" than Iraqi dues paid to Turkey, and involved various offtake arrangements.

60. Exports ceased in September 1980 with the Iraqi invasion of Iran, amid much speculation over the extent of the damage to the Iraqi facilities. At the beginning of December it was announced that the Banias line would reopen at 200,000b/d; this it did in February 1981. In March 1981, agreement was also reached to resume pumping through the Lebanese spur, and the first loadings followed in December 1981. Shortly thereafter, plans were announced to increase the Turkish line capacity (see below) from 700,000b/d to 900,000–1,000,000b/d by increasing the pumping stations. Meanwhile, in February 1981 Turkey had pressed for a rise in transit fees from US$0.38 per metric ton to US$1.20 per metric ton, this reflecting Turkey's view of Iraq's desperation. By mid-1981, Iraq was exporting 650,000b/d through Turkey and 300,000b/d through Syria. Syrian throughput was held down by technical problems and also problems of a "political nature and related to Syria's demands for higher transit fees." Both lines experienced periodic sabotage attacks, but disruptions were short-lived.

61. In April 1982, the IPC line was closed as a result of a deal by which Iran would supply Syria with 180,000b/d. The deal was clearly aimed at weakening Iraq's war capabilities. Syria initially claimed the IPC line closure was due to disputes over transit fees, but later admitted to a political decision. By mid-1985, there were reports that Syria was cannibalizing the line for its own oil operations. In 1987, there were rumors of talks regarding the reopening of the line, but nothing substantive emerged. The rumors resurfaced in early 1998 but few took them seriously.

62. Overall, the operating record of the IPC line was poor. The line was closed for a substantial part of its operating life and a significant part of this closure was a result of economic factors.

63. Iraq, faced with the abysmal performance of the IPC line, took the strategic decision to break Syria's hold over export routes and decided on a "Strategic North–South pipeline" from Haditha to Fao at the head of the Persian Gulf. The line, which could pump Rumaila oil to the Mediterranean or Kirkuk oil to the Gulf, would increase Iraq's ability to export via the Gulf. The construction contract was awarded in May 1970 and the 300,000–400,000b/d line was opened in December 1975, with the eventual potential to run 1 million b/d north or 880,000b/d going south. In September 1973, Iraq signed a US$122 million contract with Brown and Root to develop a deep-sea terminal at Khor al-Khafji (renamed Mina Al Bakr in 1975), 40km offshore from Fao with a capacity of 120 million metric tons per year (Mt/y). The berths could handle tankers of up to 350,000dwt.

64. Turkey was the other obvious alternative and had been considered by the IPC as early as 1956 amid the Suez crisis. A gas pipeline from Kirkuk to southeast Turkey had been under discussion since early 1967, and in early 1971 the talks with Turkey began in earnest. A crude line also was discussed. In October 1972, Iraq announced negotiations with Snam Progetti for a 500,000b/d pipeline to a Turkish Mediterranean port. In May 1973, a protocol was signed for a 40-inch (1,016mm), 25 Mt/y crude line, to exit at Dortyol. The final, 20-year agreement was signed on 27 August, paying a transit fee of US$0.35 per barrel. The agreement provoked a hostile Syrian response; Iraq was "betraying the masses" and "delivering the Arabs' oil weapon into the hands of the imperialists and Zionists at a time when they most need to use it in the battle of destiny." There was an initial eight-month delay in implementation because Turkey had problems raising finance for its part of the line. Once the Turkish parliament ratified the agreement the line, however, was built in some haste and was inaugurated in January 1977, with a capacity of 35Mt/y.

65. The 1973 agreement allowed Turkey to lift 10Mt/y for domestic consumption, to be increased to 14Mt/y after 1983. Disputes over the price of this crude led to delays in operation, and the first crude was only loaded on May 25, 1977 when the US$0.35 had been raised to US$0.38 to allow for dollar depreciation.

66. While the Turkish and Strategic Lines meant Iraq was no longer dependent upon Syria for market access, Iraq's transit problems were far from over. Closure of the IPC line between 1976 and 1979 left Turkey as the sole transit country, although the Strategic North-South Line prevented Turkey from securing a monopoly position. In November 1977, Iraq suspended deliveries to Turkey pending payment of US$150 million for oil lifted. This was when market conditions meant there was little interest in Iraqi crude from Dortyol. Pumping resumed in December following payment arrangements, but was suspended again in January 1978 as payment failed to materialize. Perhaps surprisingly, this did not stop pumping to the export terminal. Domestic supplies to Turkey were eventually resumed in September 1978, following a barter agreement. The line suffered occasional disruption due to sabotage or accident, but closure was short-lived.

67. In mid-1981, the idea was broached for a pipeline across Saudi Arabia. By March 1982, Saudi Arabia granted rights-of-way permission and reports emerged of a line (IPSA 1) of 1.0–1.6Mb/d. These plans received a major boost when Syria closed the IPC pipeline in April. By October 1983, a 630km tie-in line, with more than 1Mb/d excess capacity, was being considered for Rumaila to the existing Ghawar–Yanbu Petroline (at the PS3 pumping station). Reports also hinted at another line through Jordan, exiting at Aqaba. In May 1984, the Saudi cabinet approved in principle the agreement to build the tie-in line, but questions over how Iraq would finance the line remained unanswered.

68. In July 1984, plans were reported of a parallel Turkish line that would increase the Turkish capacity to 1.5Mb/d. A protocol for this line was signed in August with the final agreement in April 1985. The line was inaugurated on July 27, 1987 at a cost of US$485 million, with transit fees set at US$0.65. In April 1988, it was reported that Turkey was interesting in expanding the capacity of the second line to 1Mb/d. Turkey's revenues from the pipeline at this time were approximately US$350–360 million per year. At the same time, Iraq announced that it was considering building a second north–south strategic line with a capacity of 900,000b/d.

69. In April 1985, plans were announced for an independent line through Saudi Arabia with a capacity of 1.6Mb/d (IPSA 2) This would track the east–west Petroline line but would have its own loading terminal at Yanbu. The first Iraqi exports from Yanbu via IPSA 1 were in September 1985. In October 1986, these exports ceased for two months to allow engineering work to complete the tie-in and expand capacity. Since this was a time of strong price competition, it is tempting to conclude that from the Saudi perspective the temporary loss of Iraqi crude would have been welcome. This suspicion was confirmed when for February 1987 it was announced (to Iraq's "bafflement and frustration") that the Saudi authorities had restricted Iraqi exports to 250,000b/d, well below what had been expected. This was when Saudi Arabia was desperate to persuade markets of the credibility of the US$18 per barrel OPEC target that had been agreed the previous December. IPSA 2, which had by now a total project cost of US$2 billion, began operation in September 1989, but full operation was delayed because of incomplete pumping stations. The formal inauguration took place in January 1990. Both IPSA lines were closed following Iraq's 1990 invasion of Kuwait. In January 1991, the Iraqi Revolutionary Command Council abrogated all agreements with Saudi Arabia, including those covering the IPSA operations.

70. In 1991, discussion began about Iraqi oil exports resuming under a UN humanitarian banner. Turkey immediately demanded a substantial increase in transit fees, including a one-off lump sum payment of US$264 million regardless of throughput. Iraq, however, was not yet interested in resuming exports under UN auspices. Disputes over fees were compounded by a debate over whether or not to flush the line and what should happen to the flushed oil. In September 1996, a memorandum of agreement was signed between Iraq and Turkey that covered these issues.

71. In the last couple of years there have been widespread reports that Iraq was using the old IPC line with a view to exporting crude via Syria and thereby circumventing UN sanctions. These reports have been denied by both Iraq and Syria.

Case Study 5: The Tapline crude oil pipeline to the Mediterranean via Jordan, Syria, and Lebanon

72. The idea of running a pipeline from the Persian Gulf to the Mediterranean was first proposed in 1943 from within the U.S. Government, which was seeking to improve U.S. access to Gulf oil and ensure a "continuous supply of cheap oil." Powerful opposition from the U.S. domestic oil industry, fearing competition, buried the proposal. In July 1945, California Arabian—the Saudi concession holders—organized the Trans-Arabian Pipeline Company (Tapline) to build such a line privately. Negotiations over rights of way provided a foretaste of problems. Transit through Palestine (the first option) was granted free of charge. Securing rights through Lebanon and Syria, however, was more complex, as both sought to squeeze higher transit fees. Agreement eventually was reached in January 1949: Lebanon and Syria would share annual pipeline "royalties," based upon the amount of oil carried but with a minimum guaranteed annual payment. Construction was completed in late 1950, by which time California Arabian had become the Arabian American Oil Company (Aramco). The Tapline ownership reflected this new structure.

73. The project was the world's largest privately financed construction project. The initial capacity was 320,000 barrels per day; this increased in 1957 to 450,000b/d with the construction of auxiliary pumping stations between the main stations at Qaisumah, Rafha, Badanah, and Turaif in Saudi Arabia.

74. In 1960, newly appointed Saudi Oil Minister Abdallah Tariki criticized the Tapline agreement, arguing for a profit share. The original agreement gave the Saudi government a "reasonable" transit fee from Tapline, based on a most-favored transit fee basis in the Middle East. Tariki pointed out that crude oil delivered to the Mediterranean was charged at Gulf rather than Mediterranean posted prices, with Tapline pocketing the difference—which was supposed to reflect the tanker cost via the long haul route. According to Tariki, this shifted Tapline's profits to the Aramco parent companies away from Aramco, thereby avoiding sharing with the Saudi government. In 1962, the appointment of Zaki Yamani as the next oil minister triggered negotiations that led in March 1963 to an agreement that allowed for retroactive recovery of readjusted Tapline profits.

75. In 1969, Tapline closed for 112 days following sabotage in the Golan Heights by the Popular Front for the Liberation of Palestine (PFLP). The act attracted considerable criticism in the Arab world since the main losers would be Arab governments. (The Middle East Economic Survey estimated the losses at US$17.1 million.) In November 1969, the PFLP again claimed responsibility for two breaches in southern Lebanon, although in each case the line was repaired within 24 hours. Tapline was sabotaged twice in September 1971 in Jordan, but again repairs took less than 48

hours. A further series of sabotage attacks took place in Jordan but at no point were loading operations at Sidon affected. These and other accidental ruptures confirm the fact that, contrary to popular opinion, if access is possible for repair it is extremely difficult to sabotage pipelines effectively.

76. In May 1970, Tapline was ruptured near Deraa by a bulldozer working on telephone cables. Syria refused to allow repairs without a new transit agreement. This appeared in January 1971, giving double transit fees and a lump sum of US$9 million to cover other claims. Although political motives were also at play, it is significant that when the Syrian government changed (and the political climate with it) the financial demands remained. Closure came at an opportune time for Libya, which was negotiating for higher posted prices. Closure aggravated crude shortages in the Mediterranean, improving Libya's bargaining position. While there is no evidence of collusion, in 1971 Libya made a substantial aid donation to Syria. Lebanon was unhappy about Syria's stance since it threatened transit fees and crude availability for Sidon's Medreco refinery. Lebanon's disquiet was reinforced by rumors that Saudi Arabia was considering closing Tapline permanently.

77. Following the Syrian agreement, similar terms were offered to and accepted by both Lebanon and Jordan. However, the higher transit fees meant that the Aramco partners began to view Tapline as marginal transport: falling European demand was met by reduced Tapline throughput rather than by lower tanker lifting from Ras Tanura. Pumping also stopped occasionally because storage capacity at Sidon was full, reflecting limited offtake needs. But financial disputes did not always lead to closure. For example, in 1972 a dispute over lifting by Jordan for its Zarqa refinery led instead to a payments standoff, in which payments between both sides (Tapline to Jordan for transit and Jordan to Tapline for offtake) were suspended until agreement could be reached.

78. The collapse in tanker rates following the first oil shock of 1973 had a significant impact on the costs of Gulf loading versus the Mediterranean. This was reinforced as Aramco expanded its Gulf loading capacity. In September 1974, a new terminal with a capacity of 1Mb/d was inaugurated at Ju'aymah. Subsequently, Tapline throughput frequently fell to low levels, reflecting cheaper Gulf options. In February 1975, Tapline announced that it would close as the November 1974 tax and royalty changes in Saudi Arabia moved the tax-paid cost of Sidon deliveries into the red. The Saudi government expressed disquiet over the closure and suggested it would "endeavor to reopen the pipeline under fair and reasonable terms." As a compromise, oil was pumped to Jordan's Zarqa refinery and Lebanon's Medreco refinery. Disputes over the price of crude and arrears nonetheless led to periodic shutdowns. In 1981, Tapline agreed to supply Syria with oil to replace oil that was lost because of the outbreak of the Iraq–Iran war. The crude was to be lifted at Zahrani and shipped to Banias.

79. Following the Saudi takeover of Aramco in 1976, ownership of Tapline reverted to the four U.S. Aramco partners. In June 1982, the Israeli invasion closed the section in south Lebanon, and in December 1983 Tapline abandoned its assets in Syria and Lebanon. Supplies to Zarqa continued, although disputes over prices and payments

were frequent. In late 1983, Tapline announced also that it would cease its Jordanian operations at the end of 1985 (although intermittent supplies to Zarqa continued after this date). In 1990, Tapline's assets in Saudi Arabia became a division of Saudi Aramco and deliveries to Jordan ceased. The influence of Tapline nonetheless remained. The threat of resuming oil flows to Jordan via Tapline, and thereby halting Iraqi imports (the only legitimate Iraqi oil exports under UN sanctions), persuaded Iraq to accept humanitarian exports under UN Resolution 986.

Recent Pipeline Projects

Case Study 6: The Baku Early Oil Project

80. Baku's Early Oil Project involves the development of part of the Chirag oilfield in the Caspian Sea. It is the first stage of a phased development of the Azeri, Chirag, deepwater Gunashly (ACG) field complex, the completion of which is expected to result in the recovery of approximately 4 billion barrels of oil at a total cost of approximately US$10 billion.

81. The project called for the reconstruction and refurbishment of two pipelines that transport oil for export: the Northern Route Export Pipeline (NREP), which runs north to Novorossiysk on the Black Sea coast of Russia, and the Western Route Export Pipeline (WREP), which runs west to Supsa on the Black Sea coast of Georgia. NREP began operation in November 1997, with an initial capacity of 100,000 barrels per day; WREP opened in April 1999 with a capacity of 120,000b/d. Table A4 shows the chronology of the project through 1999.

Table A4: Chronology of the Early Baku Oil Project

Year	*Month*	*Accomplishment*
1994	September	Production sharing agreement for ACG fields signed
1994	December	Azerbaijan International Operating Company (AIOC) formed
1995	October	AIOC makes dual-pipeline decision: Baku–Supsa and Baku–Novorossiysk
1996	February	AIOC and Transneft sign agreement for Baku–Novorossiysk pipeline (NREP)
1996	March	Host government agreement (HGA) signed for Baku–Supsa pipeline (WREP)
1997	November	AIOC commences production at Chirag platform
1997	December	Baku–Novorossiysk pipeline begins operation
1999	April	Baku–Supsa pipeline begins operation

82. The focus of this case study is WREP, a dedicated pipeline scheme under which new sections of pipeline were constructed and other sections refurbished. NREP, by contrast, chiefly involves a transport agreement through an existing oil pipeline grid in Azerbaijan and Russia, parts of which are to be refurbished. Comprehensive information on WREP is in the public domain, whereas the transport contract that is the centerpiece of the NREP scheme is proprietary and confidential.

83. The total estimated cost of the early oil project is US$2.0 billion, US$574 million of which is for the WREP pipeline and terminal. The Azerbaijan International Operating Company (AIOC) was responsible for financing the WREP and NREP segments in Azerbaijan. Transneft, the Russian state oil pipeline operator, financed the Russian portion of NREP.

84. Under its production sharing agreement (PSA) with SOCAR (the State Oil Company of Azerbaijan), AIOC had to make a recommendation to the steering committee on export routes for the early oil produced from the ACG fields. All expenditures incurred in connection with the refurbishment of existing pipelines or the construction of new pipelines for export of the oil were considered under the PSA to be "petroleum costs," to be reimbursed from sales revenues before profit oil is shared between the sponsor and the state of Azerbaijan. This arrangement mitigated the effect of the dual-pipeline decision on the sponsor's profit by reducing and postponing a corresponding part of the state's revenue.

85. AIOC's October 1995 decision to adopt a dual-pipeline strategy was based on a combination of commercial and geopolitical factors. The company's primary goal was to lessen the oil transportation risk posed by political tensions in the region. With two pipeline routes, oil could continue to flow in the event of temporary disruption in any one area, thereby mitigating a single conflict's effect on the project. The dual-pipeline decision also helped to balance competing geopolitical interests by providing Russia and Georgia with commercial benefits while preventing any single country from securing monopoly control over Caspian export routes. By not favoring a single route, AIOC also was able to avoid the risk of dealing with a discontented party that might take action in the region to undermine the project. The strategy also allowed AIOC to make the best use of existing infrastructure, thereby securing early export capacity at the least cost. Finally, the dual-pipeline option prevented competition over export routes from stalling the project.

86. The U.S. government actively supported the dual-pipeline decision, which matched its general policy of pursuing complementary routes to reduce dependence on any single export option. The United States also played a key role in AIOC's decision not to adopt alternative routes that would have exported early oil to world markets through Iran. Exportation of crude oil to Teheran would have enabled a swap agreement involving crude oil export facilities on the Persian Gulf, the refineries close to Teheran being already supplied by pipeline with crude oil from Iranian oilfields linked to the Gulf. The Iranian route would likely have been less expensive than the Georgian route, but in view of the situation in Iran and the existence of the Iran–Libya Sanctions Act, which prohibits

U.S. citizens and companies from participating in projects that benefit Iran, the Iranian alternative was not considered.

87. NREP became fully operational in November 1997. The pipeline uses a preexisting pipeline system from Baku to the Russian border and then proceeds through the existing Russian oil pipeline grid to Novorossiysk via Grozni (Chechnya) and Tikhoretsk. Azeri oil is commingled en route with other oil from Russia destined for the port of Novorossiysk. The total distance from Baku to Novorossiysk is about 1,600km, of which 150km lies in Chechnya. The Azerbaijan section of NREP is operated by SOCAR, and the Russian section by Transneft. The section in Azerbaijan had been used to import Russian oil for processing in Azeri refineries and had to be reversed for the early oil project; AIOC spent an estimated US$50 million to upgrade and modernize this section of the pipeline. Transneft was responsible for the necessary upgrading of parts of the pipeline system within Russia. The initial capacity of the 28-inch (711mm) pipe is 100,000b/d. In addition to oil from the ACG fields, NREP exports other crude oil exported by SOCAR.

88. Under a 10-year-agreement signed between Transneft and AIOC in February 1996—the first long-term oil-transport agreement executed by Transneft with any producer—Transneft will guarantee transport of 32 million metric tons of Azeri crude oil over seven years (reaching 5 million metric tons a year in 2002), at a cost of US$15.67 per metric ton. Transneft takes title to the oil at the Azeri–Russian border and is responsible for delivering an equivalent quantity of oil, albeit of different quality, at Novorossiysk. The low-sulfur Azeri oil that NREP carries is blended with Russia's high-sulfur "export blend."

89. NREP runs through the unstable region of Chechnya, and oil exports have been disrupted since January 1999 by a series of stoppages caused by explosions, fires, and theft-related damage associated with the Russian–Chechen conflict. Transneft has responded by arranging to transport Azeri oil through Russia by rail along a route that bypasses Chechnya. Oil pumped from Azerbaijan is taken out of the pipeline at Izerbash in the Dagestan region of Russia, put on railcars, transported to Tikhoretsk, put back into the pipeline, and pumped to Novorossiysk. In spring 2000, Transneft completed a 300km bypass between Dagestan and Tikhoretsk.

90. The construction of the bypass is an indicator of Russia's determination to make NREP an attractive option for the Main Export Pipeline (MEP) from Baku to Ceyhan, Turkey. MEP is the principal pipeline intended for the export of crude oil from the contract area, designed to transport about 1Mb/d. It is believed that the capacity of the Baku–Novorossiysk line could be increased by up to about 300,000b/d. AIOC and the Georgian government have signed a host government agreement dealing with the transit through Georgia. The preengineering of the pipeline section in Turkey has begun, but pipeline construction will not begin until Azerbaijan has succeeded in increasing oil production to the level necessary to make MEP economic.

91. WREP from Baku to Supsa involved constructing a pipeline in Azerbaijan from the terminal at Sangachal to the Georgian border, reconstructing and refurbishing an existing pipeline in Georgia to be used exclusively for the transport of AIOC oil, installing pumping stations, and constructing an export terminal, storage facilities, and offshore loading facilities at Supsa. The pipeline is 920km long and has an initial capacity of 120,000b/d. Estimated at US$315 million, costs reached US$574 million when long stretches of the pipelines in Georgia were replaced instead of being refurbished as originally planned. AIOC was responsible for financing the project.

92. The Baku–Supsa pipeline was inaugurated on April 17, 1999, as a tanker of AIOC oil bound for Italy left Supsa. Georgian President Eduard Shevardnadze, Azeri President Heydar Aliyev, and Ukrainian President Leonid Kuchma were present at this historical event, which marked the end of Russia’s monopoly on oil transportation routes from the Caspian region. Ambassador Richard Morningstar, special advisor to the U.S. President for Caspian Basin energy development, was also present at the ceremony.

93. In March 1996, the government of Georgia and the oil companies forming AIOC signed a host government agreement (HGA) for the Baku–Supsa pipeline. Under the agreement, AIOC operates the Azerbaijan section of the pipeline on behalf of the unincorporated joint venture partners. In Georgia, the Georgian Pipeline Company (GPC), an operating company owned by the joint venture partners through AIOC, operates the pipeline and terminal. AIOC will return ownership of the pipeline to Georgia after 30 years of operation.

94. Under the HGA the foreign oil companies are entitled to full exemptions from all taxes related to their pipeline operations or to the petroleum that is transported through and exported from the facilities. The foreign oil companies also have the right to import into and reexport from Georgia, free of any taxes or restrictions and in their own name, all equipment, materials, machinery, tools, vehicles, spare parts, goods, and supplies necessary for the conduct of pipeline operations. All employees of the foreign oil companies and foreign contractors who are not citizens of Georgia and who are engaged in pipeline operations are also exempt from payment of any form of Georgian personal income tax.

95. The Georgian government also agreed to ensure the safety and security of the facilities and personnel involved in pipeline operations and to protect them from loss, injury, and damage resulting from war, civil war, sabotage, blockade, revolution, riot, insurrection, civil disturbance, terrorism, commercial extortion, and organized crime. The Georgian government agreed to dedicate a security force formed from the government’s security forces to provide physical security for the facilities and for personnel engaged in pipeline operations. The costs associated with this security force were assumed by the government and are not subject to reimbursement by the operating company.

96. The pipeline construction and operating agreement (PCOA), signed by the Georgian International Oil Corporation (GIOC) and the foreign oil companies forming AIOC, constituted an appendix to the HGA. The primary subject addressed in the

agreement concerns the tariff structure for the pipeline. Under the agreement, AIOC must pay GIOC an inflation-adjusted transit fee of US$0.17 per barrel of petroleum transported through the pipeline.

97. This rent-sharing formula does not change during the lifetime of the agreement. Any increase in the agreed tariff must be balanced by a corresponding capital reimbursement. GIOC therefore may request a change in the tariff only after it makes a corresponding capital reimbursement toward the costs of the construction operations incurred by the oil companies. Even then, the oil companies and GIOC must agree before the tariff can be increased. The change in the tariff must provide the oil companies with an overall economic benefit equal to that which they would have gained if the proposed capital reimbursement were not made and if the tariff had not been increased. If the parties fail to reach an agreement, they must submit to nonbinding conciliation and mediation. If the problem remains unsolved, GIOC is not obliged to make a capital reimbursement and the existing tariff continues in effect. GIOC cannot give a notice of a capital reimbursement for one year following the previous notice. Failure to adjust the tariff does not constitute grounds for arbitration.

98. The PCOA also specifies environmental standards and safety practices for pipeline operations. AIOC is liable for all losses and damages suffered by the Georgian government or third parties due to the failure of AIOC to comply with the mitigation and monitoring provisions of the approved environmental impact assessment, the technical standards specified in the agreement, and applicable environmental laws. The operating company must immediately notify GIOC of all emergencies or events. It may request the Georgian government to assist in repair efforts, in which case it must reimburse the government for its assistance.

99. Liabilities and indemnities of the parties are also governed by the PCOA. GIOC shall not be liable for the bodily injury or death of any employee of the oil companies or for the loss of or damage to property of the oil companies arising from or related to pipeline operations. Nor is GIOC liable to third parties in such events, unless the event results from an action of a GIOC member is due to a defect in the existing pipeline facilities prior to the effective date of the agreement. The oil companies are not liable for the bodily injury or death of any GIOC employee or for loss or damage to GIOC property arising from or related to pipeline operations, nor are they liable for injury or damage to third parties because of defects in the existing pipeline facilities prior to the effective date of the agreement, or for loss of, damage to, or destruction of pipeline facilities arising from willful misconduct by GIOC.

100. War and civil strife affected the Caucasus region for much of the 1990s. Political tensions in Nagorno–Karabakh, Chechnya, Abkhazia, South Ossetia, and Adzharia have continued despite ongoing efforts to resolve them. The escalation of any of these conflicts would pose a direct oil transportation risk to the project. The Baku–Novorossiysk pipeline has been closed since May 1999 due to the Russian–Chechen conflict.

101. As long as export routes through Iran and Russia are difficult for political reasons, Georgia will remain the key transit country not only for the Baku–Supsa pipeline but also for future Caspian oil and gas pipelines. The Georgian government is responsible for ensuring the security of its segment of the Baku–Supsa pipeline under the HGA and has agreed to provide, at its expense, physical security for the facilities and personnel engaged in pipeline operations. President Shevardnadze has managed to stabilize the political situation in his country, which has suffered from civil war and separatist struggles since 1992, but he has faced two assassination attempts. A return to instability in Georgia could jeopardize the development of oil and gas projects in the Caspian region.

102. The risk of expropriation in the early oil project is mitigated by several facts. If Georgia were to expropriate the pipeline and cause AIOC to terminate pipeline operations, it would lose transit revenues. Azerbaijan would lose transit and tax revenues, plus its share of profit oil. AIOC's losses would correspond to its investment and net revenues from the petroleum that it could not export.

103. Contractually, expropriation of the pipeline would constitute a dispute between the government of Georgia and AIOC. Under the HGA, all disputes arising between the government of Georgia and any or all of the oil companies, if not amicably resolved, are to be definitively settled in Stockholm before a panel of three arbitrators operating under the arbitration rules of the UN Commission on International Trade Law (UNCITRAL). The tribunal's award would be final and binding on the parties and immediately enforceable.

104. Although the initial cost of the Baku–Supsa pipeline was estimated at US$315 million, AIOC in the end invested US$574 million to complete the project. Most of the overrun is attributable to AIOC's decision to replace large sections of the pipeline rather than refurbish it. The lack of infrastructure in Georgia and Azerbaijan to support the project also increased costs. Under the production sharing agreement, the cost overrun is shared between AIOC and Azerbaijan.

105. The interruption of oil exports through NREP or WREP because of technical problems in pipeline operations would constitute a risk chiefly for Azerbaijan, Georgia, and Russia. AIOC could mitigate its risk by switching pipelines, unless both pipelines closed simultaneously. Following the closure of NREP in May 1999, AIOC switched all of its exports to WREP. Transneft has suffered from the decrease in transit revenue as a result of this switch, despite continuing to ship SOCAR oil by rail around Chechnya. Russia likewise has suffered from a reduction of profit taxes on Transneft.

106. WREP, recently refurbished and rebuilt according to international standards, is operated by AIOC. NREP was built according to standards prevailing in Russia 20 years ago; it is operated by Transneft and SOCAR. With respect to NREP, AIOC has no control over issues such as pipeline safety or maintenance—factors that increase the risk of unscheduled pipeline downtime. AIOC can mitigate this risk by switching exports to WREP up to the amount of available capacity.

107. Transneft runs the risk that AIOC may elect, purely on the basis of its optimization efforts, not to use NREP. According to some reports, Transneft appears to be protected by a ship-or-pay clause, but whether such a clause in fact exists is not publicly known.

108. The environmental standards and safety practices for pipeline operations are set by the PCOA. Leaks and spills that result in significant damage to the environment or property constitute such a risk. AIOC is liable for all losses and damages suffered by the Georgian government or third parties due to the failure of the operating company to comply with the mitigation and monitoring provisions of the approved environmental impact assessment, the technical standards specified in the agreement, and applicable environmental laws.

109. The PCOA does not cover leaks, spills, or explosions resulting from the actions of third parties. In the event of an oil spill due to the act of a third party no certain criteria exist for assigning liability. The Georgian government or the operating company could undertake remedial or repair efforts, but they would have no mechanism by which to obtain reimbursement for their costs. If pipeline operations were halted due to an oil spill caused by a third party, AIOC, Georgia, and Azerbaijan would share the environmental risk.

110. Effective mechanisms for the resolution of disputes and enforcement of agreements are essential for the successful implementation of any cross-border oil pipeline project. As noted earlier, little is known about the arrangements surrounding NREP. With respect to WREP, the PSA, HGA, and PCOA all contain articles on arbitration that constitute the conflict-resolution structure for the Baku–Supsa Early Oil Pipeline. The Russian Federation (1960) and Georgia (1994) are signatories of the Convention on the Recognition and Enforcement of Foreign Arbitral Awards (New York, 1958). Azerbaijan has not signed this convention.

111. The applicable law and arbitration clauses for the PCOA are similar to those of the HGA. All disputes except for technical disputes are resolved as under the HGA. Technical disputes arising between the parties concerning the meaning of “good international oil industry standards and practices,” “good working order,” “common and prevailing international oil industry standards and practices,” the “reasonably prudent operator,” the environmental impact assessment or baseline study, and any tariff modification would be resolved by a single expert who, in the absence of agreement by the parties, may be nominated by the chairman of the Energy Section of the International Bar Association. The arbitrator’s determination in respect of the dispute would be final and binding.

112. NREP kept experiencing problems because of forced interruptions to operations. The result was that at times AIOC was forced to cut production because of a lack of export capacity. As a result, AIOC gave up its commitment to put some crude into NREP and began to rely entirely on WREP. In July 1999, Transneft announced its intention to close NREP and replace it by rail transport (while keeping the same transport

tariff of US$2.20 per barrel). In the end, a 312km bypass was constructed around Chechen territory at a cost of US$160–200 million. The bypass was completed in March 2000.

113. The operations of WREP have been successful, albeit with occasional minor problems. For example, in November 1999 the line was temporarily closed because of flooding, and in May 2002 it was again closed while an "illegal valve" was removed. Throughput of the line in 2002 was approximately 125,000b/d.

Case Study 7: The Maghreb-Europe Gas Pipeline from Algeria to Spain via Morocco

114. The Maghreb–Europe Natural Gas Pipeline Project (Gazoduc Maghreb Europe; GME) involved the construction and operation of a 1,620km pipeline system to bring gas from the Hassi R'Mel field in Algeria, across Morocco and the Strait of Gibraltar, to interconnect with the gas grids of Spain and Portugal and into the rest of the western European gas transport system. The pipeline's capacity of 8 billion cubic meters per year can be expanded to 18.5Bcm/y by means of looping and by adding compressor stations along the route. The cost for the initial scheme of the GME was US$2.2 billion.

115. As table A5 shows, the GME is made up of five main and two secondary sections.

Table A5: Structure of the Maghreb–Europe Gas Pipeline

From	*To*	*Length (km)*	*Diameter (inches/mm)*	*Owner/Operator (% stake)*
Hassi R'Mel	Algerian/Moroccan border	518	48/1,219	Sonatrach
Morocco	Cap Spartel (Moroccan coast)	522	48/1,219	EMPL/Metragaz
Strait of Gibraltar	Split between Morocco and Spain	35	2 x 22/559	EMPL/Metragaz
Spanish coast	Cordoba, Spain	269	48/1,219	Enagas (67%) Transgas (33%)
Cordoba	Badalajoz (Spanish/Portuguese border)	269	28/711	Enagas (51%), Transgas (49%)
Campo Mairo (secondary section)	Braga, Portugal	408	28/711	Transgas (88%), Enagas (12%)
Braga (secondary section)	Tuy (Portuguese/Spanish border)	74	28/711	Transgas (51%), Enagas (49%)

116. The primary gas source for the GME project is the Hassi R'Mel gas and condensate field, which initially held proven reserves of about 2,400Bcm, accounting for more than half of the country's total proven gas reserves of 3,500Bcm. The field is

connected to all other gas-producing fields further south, such that all Algerian gas for export and domestic use is channeled via Hassi R'Mel, which serves as the main dispatch center for Algeria's gas production. The larger part of the gas, however, is used for reinjection into the Hassi R'Mel field to maintain reservoir pressure and to optimize the recovery of condensates.

117. In 1992, Sonatrach (Algeria) and Enagas (Spain) concluded a natural gas sale agreement for the delivery of a plateau level of 6Bcm/y through the year 2020. In 1994, Sonatrach and Transgas (Portugal) signed an agreement for the delivery of a plateau level of 2.5Bcm/y of Algerian gas over a period of 25 years, beginning in 1997. The GME began to supply gas to Spain in November 1996 and to Portugal in January 1997. The parties expected to reach the contractually agreed plateau levels in 2000.

118. Before the GME was developed, Algeria and Spain had already enjoyed two decades of LNG trade with each other and with other countries, which demonstrated the economic viability of gas transport between the two countries and that provided a good benchmark against which to compare the economics of the gas pipeline. The preexisting alternative of LNG also provided sound protection against exaggerated claims for transit fees.

119. By 1990, border and other issues were being addressed between Algeria and Morocco, clearing the way for a project that had first been envisaged 17 years earlier.

120. From the beginning, the GME pipeline had the support of the European Union. It was a priority of the Trans-European Network (TEN), an EU undertaking designed to promote projects that further the integration of energy grids within the EU and between the EU and its suppliers. Under the TEN program the EU is funding feasibility studies and helping to finance other projects. The European Investment Bank (EIB), the EU's long-term financing institution, found the GME project attractive because it supported the EU's policies of increasing and diversifying energy supplies and of encouraging the use of clean natural gas by industry and households. Ultimately, the EIB provided more than 1.1 billion euros (US$1.15 billion) for various sections of the GME, including those located outside Europe. This not only met a significant part of the project's capital requirements but also acted as a catalyst for mobilizing funds from other sources.

121. In December 1990, companies in those countries that had a potential interest in the GME project formed a study group, referred to as OMEGAZ, to examine the possibility of routing a gas pipeline through Morocco and the Strait of Gibraltar. The OMEGAZ group included Sonatrach (Algeria), a producer; the Société Nationale des Produits Petroliers (SNPP, Morocco), an organization in the transit country; and Enagas, Gas de Portugal (the predecessor of Transgas), Gaz de France, and Ruhrgas, potential consumers.

122. The GME project was announced in April 1991 following a meeting in Madrid of the energy ministers of Algeria, Morocco, and Spain (see table A6 for a chronology). In their declaration the parties expressed a desire for the realization of the

project and the establishment of the bases for its implementation. The ministers declared that the pipeline would enhance economic cooperation among the participating countries and among the countries of the Maghreb and the European Community in general. A Tripartite Ministerial Monitoring Committee was set up to oversee the implementation of the project. Enagas SA (Spain) and SNPP (Morocco) were designated as the companies that would implement the project.

Table A6: Chronology of the GME pipeline

Year	*Month*	*Accomplishment*
1990	December	OMEGAZ study group for GME is established
1991	April	Algeria, Morocco, and Spain set up Tripartite Ministerial Monitoring Committee
1992	July	Pipeline construction and operation agreement is signed
1992		Sonatrach and Enagas conclude gas purchase agreement
1994	April	Sonatrach and Transgas conclude gas purchase agreement
1996	November	GME begins to supply gas to Spain
1997	April	GME begins to supply gas to Portugal

123. Under a July 1992 agreement signed by the Moroccan government, Enagas, and SNPP, the Moroccan government authorized Enagas to build, use, and operate the pipeline within the corporate structure specified by the agreement. With the commencement of pipeline operations, Morocco was to receive “royalty gas,” defined as 7 percent of the gas actually transported, as payment of the transit fee. The transit fee in turn was defined as representing compensation for the tax exemption offered to the project by Morocco and for the use of the land over which the line ran. Under the agreement, Morocco can choose on relatively short notice to receive its royalty gas in kind or in cash.

124. To finance the pipeline in Morocco and in the Moroccan portion of the Strait of Gibraltar, Enagas (9 percent) and the Spanish government (91 percent) in 1992 created a new company, Sagane SA, which in turn established Europe Maghreb Pipeline Ltd (EMPL). In 1994, Transgas of Portugal acquired 27.4 percent of EMPL. Construction and operation of the pipeline was handled by Metragaz, which is owned jointly by EMPL and SNPP (see box A3).

Box A3: Corporate Structure of the Moroccan Transit Section of the GME Pipeline

The *Société Nationale des Produits Petroliers* (SNPP) holds legal title to the gas pipeline in Morocco. SNPP's capital stock is held entirely by the Moroccan state.

Europe Maghreb Pipeline Ltd (EMPL) is responsible for financing and implementing the project. EMPL has the right to use the pipeline for a period of 25 years. The users of the gas pipeline hold EMPL's capital stock in proportion to their share in the transportation capacity. EMPL was created in July 1992 by an agreement between Enagas and Sonatrach. At present, 72.6 percent of EMPL is owned by Sagane and 27.4 percent by Transgas.

Société pour la Construction Gazoduc Maghreb Europe (Metragaz Construction). Created under Moroccan law in July 1992 by an agreement between EMPL and SNPP, Metragaz Construction is responsible for managing the construction work on behalf of EMPL.

Metragaz Operation is responsible for the repair, maintenance, and operation of the pipeline on behalf of EMPL. It is jointly owned by EMPL and SNPP and is organized under Moroccan law.

Strait of Gibraltar

That part of the GME that lies under the Strait of Gibraltar has its own corporate structure. In Moroccan waters the ownership structure is the same as that of the Moroccan land segment. Domestic Spanish law governs the segment of the GME lying in Spanish waters. Enagas holds the concession and operating rights, but the pipeline is owned by Gasoducto Al-Andalus (67 percent Enagas, 33 percent Transgas).

125. In 1992, Sonatrach concluded a gas sale contract with Enagas providing for the delivery of Algerian natural gas to Spain. Deliveries were to begin in 1996 and reach 3.2Bcm/y of gas in 1997. The agreement anticipated that quantities would further increase in stages, to reach a plateau level of 6Bcm/y by 2000. Deliveries would continue at this level until 2020. Structured as a long-term take-or-pay contract, the agreement includes a firm minimum payment provision and pegs the gas price to the price of displaced fuels (fuel basket and basket of crudes). The pricing provisions can be reviewed at intervals of several years.

126. In June 1994, Gas Natural SDG SA, which holds shares in regional gas companies in Spain and South America, purchased 91 percent of Enagas from the Spanish state. It acquired the remaining 9 percent in September 1997. Gas Natural is currently owned by Repsol (45 percent), La Caixa (25 percent), and other shareholders (30 percent). Enagas continues to import and transmit gas (as in the GME project).

127. During the privatization of Enagas in 1994, the Spanish government honored its commitments to the Maghreb–Europe pipeline project through a series of steps. To insulate Enagas from the specific risks posed in the initial phase of the project, particularly those related to technical risks during the startup period, Spain's state-owned National Hydrocarbon Institute (NHI) remained engaged in the project, assuming a 91 percent share in Sagane (with Enagas holding the other 9 percent of the shares). Sagane in turn assumed shares in EMPL, which financed the Moroccan part of the pipeline, and became a partner in Metragaz, which was responsible for building and operating the Moroccan sector of the GME.

128. Public sector ownership of Sagane was intended to be temporary, with Enagas/Gas Natural holding a purchase option on NHI's shares. That option was exercised as soon as the GME entered into operation in 1996.

129. Portugal joined the GME consortium in November 1994. Sonatrach and Transgas agreed to a 25-year gas sales contract, beginning in October 1996 and calling for a plateau level of 2.5Bcm/y. Transgas also acquired 27.4 percent of EMPL from Sagane under an agreement signed between Transgas and NHI.

130. Detailed engineering work began in 1992 and construction was completed in June 1996. All sections of the pipeline were laid without major incident and with due regard for the environment both during and after construction.

131. Natural gas flows through the pipeline to Spain began in November 1996, consolidating Algeria's position as a major exporter of natural gas to that country. King Juan Carlos inaugurated the Spanish section of the GME on December 9, 1996. Portugal began receiving Algerian gas through the pipeline in April 1997.

132. The total cost of the GME (including the Portuguese sections) is estimated at US$2.2 billion. The pattern of financing followed the project's ownership structure: each section owner financed 15 percent of the section's cost, with the remaining 85 percent provided by multilateral agencies, export credit agencies, and commercial banks. The EIB provided a significant part of the project's capital and helped to mobilize funds from other sources (see table A7).

Table A7: Financing of the Maghreb–Europe Pipeline (percentage, unless otherwise indicated)

Section	*Cost (US$ millions)*	*Self Equity*	*European Union Funds*	*European Investment Bank*	*Export Credit Agencies*	*Commercial Banks*
Algerian	675	15		37	48	
Moroccan	760	15		49	13	23
Strait	145	15		49	13	23
Spanish 1	280	15	32	53		
Spanish 2	170	15	39	46		
Portuguese 1	220	15	39	46		
Portuguese 2	40	15	39	15		31
Total	2,290	15	11	45	19	10

133. The civil strife in Algeria during the 1990s raised legitimate concerns about the security of supply. Spanish and Portuguese officials proceeded with the project in the belief that no government in Algiers would choose to put gas exports at risk, but foreigners working in the oil and gas sector have been seriously threatened during the civil unrest. In 1994, Bechtel renegotiated its construction contracts to reflect the increased risks that its employees face. Algeria's energy sector otherwise has generally remained isolated from the conflict. Major oil and gas fields are located in the remote interior of the country and protected by multiple tiers of security forces. During the construction phase of the GME project, Algeria was able to lay the pipeline from the Hassi R'Mel field to the Moroccan border within 12 months and without a single incident. Operations have been very smooth. In 2001, the line delivered 6.54Bcm of gas to Spain and 2.2Bcm to Portugal. This represented 36 percent of Spanish gas consumption and 88 percent of Portuguese. In September 2002, it was announced that the line capacity would be increased by 50 percent from its level of 8.5Bcm by enhancing the gas turbine equipment. This itself is a stamp of approval for the successful operation of the line.

134. In any cross-border gas scheme the seller must be able to enforce its claim for payment in convertible currency at internationally competitive prices. Algeria's currency transfer risk is minimal, because the gas sales contract stipulates payment in U.S. dollars and because both Spain and Portugal allow domestic energy prices to follow international energy prices. With the Spanish peseta and Portuguese escudo (now the euro) freely convertible, domestic gas prices, even if paid in the local currency, would reflect the movement of international energy prices and the exchange rate of the local currency.

135. Implementation of the EU gas directive of August 10, 1998 may carry some regulatory risk, to the extent that it could widen the choices available to gas consumers in Spain and Portugal, thereby causing Enagas and Transgas to lose market share and threatening their ability to fulfill the minimum payment provisions of their contracts. The directive itself provides some protection, however, for any company that might become unable to fulfill this obligation. How such risks are dealt with in the gas sales agreements is not publicly known.

136. State-owned Sonatrach has not had exclusive access to Algeria's gas reserves since 1993, but it still holds exclusive rights to market the country's gas. Given the soundness of Algeria's reserves and the proven reliability of Algeria as a gas supplier, the possibility that a change in regulation would negatively affect the reliability of gas exports seems remote—even more so with the arrival of President Bouteflika and his reform platform.

137. The principal contract in the GME project is the sales agreement between Sonatrach, Enagas, and Transgas. The risk of nonperformance is mitigated by a price review clause that allows the commercial balance of the contract to be adjusted by the parties according to agreed rules. In case of disagreement the contract provides for resolution by a third party. Combined with the contract's enforcement clauses and a conflict resolution clause that provides for international arbitration, the risk of unilateral abrogation of the sales agreement appears to be small.

138. Supporting the sales agreement are transportation contracts linking Enagas, Transgas, and EMPL. Because the contractual responsibilities of Enagas and Transgas are roughly in line with their throughput, these contracts cannot be considered to be a risk. Any threat by Morocco to renegotiate the transit agreement seems limited, because Morocco's fee depends on throughput and because the parties to the gas sales agreement have proven alternatives, at least in the long term, to transit through Morocco.

139. The principal contract-related risk would be a change in the nature of one or more of the contract partners; for example, through privatization. In such a case it would be important for the privatizing party to provide unambiguously for the assumption of its contractual responsibilities, as Spain did in the case of Enagas.

140. Sonatrach, Enagas, Transgas, and Morocco would share the impacts of reduced production. Any interruption of Sonatrach's production in Algeria would be shared by the parties involved: Morocco would lose transit revenues, Sonatrach would lose gas sale revenues, and Enagas and Transgas would lose gas supplies and thereby their margins on any gas that they could otherwise have sold to customers and that they were unable to replace from other sources.

141. Given the limited demand for gas from this pipeline in Algeria and Morocco, compared to the capacity of the GME project, the market risk in the GME project stems from the fact that the pipeline is dedicated to the Spanish and Portuguese markets. Enagas and Transgas are responsible for marketing the gas in their respective territories, a responsibility underpinned by the take-or-pay gas sale agreements between

the companies and Sonatrach. Under the agreements, Enagas and Transgas have agreed to purchase gas at a combined plateau level of 8.5Bcm/y until 2020, with a corresponding minimum payment level (the standard would be around 80 percent of the contractual capacity for each year).

142. Sonatrach is depending on growth taking place in the Spanish and Portuguese markets as forecast by Enagas and Transgas. The Spanish government has played a critical role in the development of the natural gas market in Spain through its National Energy Plan (PEN), which includes a protocol signed by the electric power industry and Enagas agreeing to convert to gas 7,300MW of existing power generation capacity. PEN helped to increase natural gas consumption in Spain from around 6Bcm/y in 1992 to the present level of 15Bcm/y. The fulfillment of Enagas' obligations depends largely on the power plants observing the protocol.

143. In the Portuguese case, growth depends on the timely construction of new gas infrastructure and a new gas-fired power plant. EU agencies have aided in the development of the Portuguese and Spanish natural gas markets by providing assistance and loans for the construction of gas transmission and gas distribution networks.

144. Although the minimum payment provision would not protect Sonatrach against a complete collapse of the market, it does give the company protection against efforts by its customers to optimize their purchases. Because the minimum pay volumes have to be paid for whether or not they are taken, taking gas from other suppliers before fulfilling the minimum payment provision would be suboptimal regardless of the other suppliers' prices.

145. On the other hand, there is a substantial upside potential in the GME project for Sonatrach and its customers, because the capacity of the pipeline can easily be doubled to serve additional demand in Spain and Portugal or to serve markets further north.

146. Sonatrach assumed the construction cost and cost overrun risks for the Algerian section of the GME. Enagas and Transgas were responsible for the construction of the Moroccan, Spanish, and Portuguese sections and for the section at the Strait of Gibraltar. During the construction period, Sagane, which was created by the Spanish public sector for this purpose, assumed the risks associated with construction of the Moroccan section.

147. If any part of the GME pipeline is prevented from operating by reasons of *force majeure*, all parties share the risk, as each would lose the income linked to the missing throughput capacity.

148. Because the contract price is linked to the prices of displaced fuels, the risks and opportunities created by changing oil prices are mainly borne by the seller. The buyer's risk is mitigated to the extent that the buyer can pass on to the consumer increases in purchase prices. Imbalances in the sharing of the market value of the gas are subject to readjustment under the price review clause. Morocco shares in the price risk

and the benefit to the extent that it elects to collect its transit fee in cash. When taking the fee in kind, the value of the gas used will naturally depend on its market value.

Case Study 8: The Caspian Pipeline Consortium

149. The Caspian Pipeline Consortium (CPC) involves the extension of an existing oil pipeline to produce a new cross-border crude oil pipeline from western Kazakhstan to a marine terminal on the Russian portion of the Black Sea coast. The new project has several key elements:

- The CPC represents a major new project in the region. The project took advantage of existing infrastructure in the Russian Federation and Kazakhstan but it also required new construction of some 750km of large-diameter pipeline and the development of a major oil terminal and marine loading facilities.
- It exemplifies the important role of public and private cooperation, especially where legal and regulatory regimes are still in transition.
- The CPC is organized as a joint venture of the governments of the Russian Federation, Kazakhstan, and the Sultanate of Oman with major international and national oil companies. All major issues are dealt with by the joint venture agreement.
- Although divided for technical and legal reasons into two entities (CPC-R in Russia and CPC-K in Kazakhstan), the CPC is managed as a unitary enterprise.
- The project employed creative financing arrangements that aligned the interests of key stakeholders in the project: existing infrastructure owned by the states was transferred to the CPC in exchange for subordinated debt, and new construction was financed with equity funds from private shareholders. This approach enabled the project, once restructured, to proceed in a timely manner.
- The project provides participating producers with stable tariffs and secure access terms.

150. Kazakhstan and the Caspian region have an abundance of hydrocarbon resources—resources extensive enough to make crude oil exports the driving force behind the development of the full economic potential of the region. First, however, it was necessary for the region to develop a pipeline capacity large enough and sufficiently secure to ensure reliable oil exports to favorable markets. The CPC project, which is nearing completion, exemplifies how it is possible to construct a cross-border pipeline in the most complex commercial and political environments.

151. The CPC system comprises a crude oil pipeline from Kazakhstan that traverses the northern shore of the Caspian Sea through Russia to the port at

Novorossiysk. The route originates at the Tengiz field and reaches the Black Sea via Atyrau, Komsomolskaya, and Kropotkin. It terminates at the new Yuzhnaya Ozerevka terminal near Novorossiysk, where the crude will be loaded onto tankers. The initial design capacity will be approximately 30 million metric tons per year (Mt/y), an amount comparable with the current crude oil export capacity at the port of Novorossiysk. The expected ultimate system capacity of the CPC after expansion of the system, including tank and storage facilities is expected to be 67Mt/y. To reach this ultimate design capacity, the CPC will need to add additional pumping and storage capacity as well as to expand offshore facilities.

152. The cost of the first phase of the project is expected to be approximately US$2.65 billion, a sum that covers installation of a new pipeline and infrastructure as well as the rehabilitation and upgrading of existing facilities. The tasks involved are extensive and include installation or upgrading of pump stations, valve stations, cathodic protection, a supervisory control and data acquisition system (SCADA) for automatic monitoring of the pipeline, storage tanks, volume metering and custody transfer facilities, and power supply systems. In addition, a new marine crude export terminal with two single-point mooring (spm) facilities is being constructed at Yuzhnaya Ozerevka.

153. It was during the Soviet era that Chevron Oil began negotiations for the development of the Tengiz field. In 1993, Chevron and Kazakhstan concluded the negotiations by signing a license agreement. At that time, Kazakhstan's capacity to export crude oil to world markets was limited to about 40,000 barrels per day. Transneft provided this capacity through a pipeline connection from Atyrau to Samara and from there to various export destinations via the Transneft system and connecting pipelines. The reliance on Transneft came at a price: Kazakhstan's export quotas via this route were subject to annual renegotiations of an intergovernmental agreement with the Russian Federation. The CPC consequently was conceived with the goal of enabling Kazakhstan to provide access to world oil markets, via a dedicated export pipeline system, to the joint venture TengizChevroil (TCO) and other regional producers.

154. Kazakhstan and Oman signed the original pipeline consortium agreement on June 17, 1992. The representatives of the Sultanate of Oman had served as advisors to Kazakhstan in negotiating the licensing agreement for the Tengiz field. They recognized the importance of the development of a dedicated export pipeline system and were the originators of the original CPC concept. Russia joined the consortium agreement by a protocol to the agreement (the "Russian Protocol") on July 23, 1992. The Supreme Soviet of the Russian Federation ratified the consortium agreement and the Russian Protocol (collectively referred to as the "Government Agreements") by Decree No. 5300-1 on June 30, 1993. Azerbaijan was invited to participate but declined to do so. The preconditions for creating the CPC thus were established.

155. In 1992, the three founding members agreed to an organizational and commercial framework and a division of responsibilities. The governments of Russia and Kazakhstan guaranteed stable legal and economic terms for the CPC project, rights of way, access to local infrastructure, utilities, the transfer of approximately 750km of

existing idle pipelines and related facilities to the CPC, and the exemption of the CPC from taxation. The government of Oman had responsibility for coordinating project development efforts, preparing mandatory economic and feasibility studies, and providing administrative support and arranging financing. Oman also agreed to provide the funds necessary for the early development efforts. The CPC was formed in July 1992 as a corporate vehicle for the design, financing, construction, ownership, and operation of the CPC pipeline system. The three founding members of the CPC became equal class A shareholders in the Caspian Pipeline Consortium Ltd, a Bermuda company.

156. The original plan was to finance the CPC on a project finance basis. The underlying assumption was that the TCO joint venture and other regional producers would be willing to provide throughput and deficiency agreements (T&Ds)[27] that would enable the CPC to attract capital from multilateral and other financial institutions to construct the project. The assumption that producers would be willing to provide T&Ds turned out to be incorrect: they declined to provide T&D agreements under the terms offered because they did not want to bear the financial risks of the project without having a say in the management of the construction and operation of the system.

157. The representatives of Oman were unable to obtain financing for the CPC without shipper T&Ds. Extensive negotiations followed in which Chevron and representatives of the founding members discussed a variety of alternative arrangements. This issue was resolved in December 1996, when the CPC and the founding members signed a restructuring agreement with Chevron and a group of other producers. This agreement allowed the 50-50 division of equity ownership among the participating governments of Russia, Kazakhstan, and the Sultanate of Oman, on the one hand, and a consortium of domestic and international companies on the other (the companies included Chevron, LukArco, Rosneft-Shell, Mobil, Agip, BG, Amoco-Kazakoil, and Oryx). Table A8 shows the respective shares of the governments and companies.

[27] T&D agreements are guarantees by producers to ship a specified level of throughput over a specific pipeline. Generally, if the producers do not ship the specified volume they must make equivalent payments to the carrier according to the terms of the agreement. Producers signing T&Ds on multi-billion-dollar pipelines thus bear significant risks related to the energy transportation facility. Export pipelines are vital to the success of upstream investments, and producers accordingly have a vital interest in the organization, structure, design, construction details, and operation of the facilities. Oil producers generally are unwilling to provide T&D agreements for crude oil pipelines unless they can participate directly in the project or are assured that a well-defined regulatory and legal regime covers pipeline operations.

Table A8: Composition of the Caspian Pipeline Consortium (percentage of equity held)

Government/company	*Country*	*Share (%)*
Russian Federation		24.0
Kazakhstan		19.0
Sultanate of Oman		7.0
Chevron CPC Company	United States	15.0
LukArco B.V.	Russian/U.S. JV	12.5
Rosneft-Shell	Russian/U.K./Dutch JV	7.5
Mobil CPC Company	United States	7.5
Agip International N.V.	Italy	2.0
BG Overseas Holdings Ltd.	United Kingdom	2.0
Kazakhstan Pipeline Ventures L.L.C.	Kazakhstan	1.75
Oryx CPC L.L.C.	United States	1.75

Note: JV = joint venture

158. The rights and obligations of the parties were also specified in the restructuring agreement.

159. The Russian Federation agreed to enter into treaties and agreements as provided in the contracts. These included the issuance of a decree by the government of Russia declaring the support of Russia for the CPC project. The decree affirmed the execution of the agreement and agreed to assist the parties by taking reasonable steps to ensure the successful design, construction, completion, operation, and maintenance of the CPC project. The agreements further committed to instruct the relevant authorities of the Russian Federation as necessary to ensure that Russian organizations would comply with the country's obligations. Finally, they specified that the president of Russia would issue a decree exempting the CPC-R from existing currency conversion requirements.

160. The government of Kazakhstan issued a similar decree declaring its support for the CPC project and affirming the execution of the restructuring agreement. Kazakhstan agreed to assist the parties to the agreement by taking such actions as are reasonably necessary to ensure the successful design, construction, completion, operation, and maintenance of the CPC project. It also agreed to instruct the relevant authorities of Kazakhstan to comply with the country's contractual obligations.

161. Other responsibilities of Russia and Kazakhstan are as follows:

- to guarantee the stability of the fundamental legal and economic terms, including rights of way, taxation, tariffs, and environmental impact provisions
- to facilitate the use of regional infrastructure facilities (utilities)
- to cooperate with producer companies should financing from international financial institutions be pursued
- to confirm the tax-exempt status with respect to value-added taxation (VAT) of the transfer of assets and certain other activities of the CPC
- to confirm that the project would not be subject to pipeline transportation or port fees
- to agree to take all legal measures to maintain or, if necessary, restore the economic parameters of the project to their intended state
- to permit currency transactions in U.S. dollars

162. The responsibilities that previously had been undertaken by representatives of the government of Oman transferred to the new organizations, and the producing companies agreed to provide 100 percent of the financing for the project

163. The producer companies agreed to fund the costs of the project, which included some previously incurred expenditures. Each producer company agreed to be severally and proportionately responsible for providing cash or guarantees, in the funding percentages shown in table A9.

Table A9: Responsibilities for Funding of Caspian Pipeline by the Producer Companies

Producer company	*Funding percentage*
Chevron	30.0
LukArco B.V.	25.0
Mobil CPC Company	15.0
Rosneft-Shell	15.0
Agip International N.V.	4.0
BG Overseas Holdings Ltd.	4.0
Oryx CPC L.L.C.	3.5
Kazakhstan Pipeline Ventures L.L.C.	3.5

164. The producer companies agreed that on the acquisition date each would furnish cash or letters of credit from a creditworthy international bank in the amount of its funding percentage of US$315 million to CPC-R and US$35 million to CPC-K. The producers also agreed to provide throughput or other guarantees as required should financing be pursued from international financial institutions.

165. Also on the acquisition date, each participating producer company was to provide documentation that its ultimate parent, intermediate parent, or financial institution ("guarantor") would guarantee the payment and performance of the producer of its contractual operations.

166. A unique feature of the agreement is that the CPC operates as a unitary project even though for technical reasons separate corporations represent the project in Kazakhstan (CPC-K) and Russia (CPC-R). The restructuring agreement contains detailed provisions on the priorities for distributing cashflow. The agreement also addresses accounting practices, cash shortfalls, construction overruns, and other details. In addition, it provides for the timing of the payment of subordinated notes on the transferred assets and dividend policy. In sum, the agreement made every attempt to clarify the manner in which the CPC would be operated from a commercial perspective. The rationale for this level of detail is that it helps reduce the possibilities of disputes over budget processes, decisionmaking procedures, tariff practices, and allocation of access.

167. Illustrating the comprehensive nature of the transportation agreements for a major cross-border pipeline project, table A10 shows the contents of the draft oil transportation agreement for the CPC. It is one of the crucial agreements of the project.

Table A10: Contents of the Draft Oil Transportation Agreement

Preamble
Definitions
Commitments to nominations
Capacity allocation
Capacity apportionment
Ownership of shipment
Common stream operation
Quality adjustments
Line fill and tank bottom inventories
Diversion of reconsignment (in-line transfers)
Liability of the parties:
Claim suits and time for filing
Direction of flow
Pumpability factors
Maintenance periods
Suspension of services
Contingencies (*force majeure* and excuse of performance)
Mutual interdependence of CPC-R and CPC-K transportation agreements
Topping plant fuel supply (CPC-R only)
Vessel (tanker) operations
Notices and communications
Connection agreements
Schedule of tariff rates
Payment of transportation and other charges
Confidentiality
Right to audit
General provisions
Exhibits to the Draft Oil Transportation Agreement
Exhibit a: Rules and regulations
Exhibit b: Terminal regulations manual
Exhibit c: Oil spill contingency plan
Exhibit d: Quality bank procedure

168. In addition to the restructuring agreement, the parties subscribed to acquisition agreements and amendments to earlier governmental agreements.

169. Once the project was restructured, Russia and Kazakhstan began the process of transferring the relevant existing pipeline assets to the CPC. As the parties had previously agreed, an independent evaluation determined the value of the transferred assets, which came to US$292 and US$232 million, respectively, for Russia and Kazakhstan. Russia and Kazakhstan then each received a subordinated note as compensation for these assets. Oman also received a note covering its expenditures to date.

170. On May 16, 1997 the restructuring was completed, and the newly constituted consortium committed to construct a 1,500km pipeline between Russia's Black Sea coast and the oilfields of northwestern Kazakhstan, including the Tengiz field. Table A11 shows the full chronology of the project to the present.

Table A11: Chronology of the CPC Project, 1992–2001

Year	*Month*	*Accomplishment*
1992	June	Caspian Pipeline Consortium founded by Kazakhstan and Oman
1992	July	The Russian Federation joins the CPC as a founding member
1992	July	CPC Ltd formed and incorporated in Bermuda
1992	November	Discussions begin with TengizChevroil on the transportation agreement
1994	November	The CPC Board decides to proceed with Phase 1 of the CPC
1996	December	CPC restructuring agreement signed
1997	May	CPC-R and CPC-K incorporated in Russia and Kazakhstan
1998	May	The expert commission of the Russian Federation (State Ecological Expertise) gave official approval to the CPC investment feasibility study. CPC started working on the feasibility study for construction
1998	August	CPC completed the feasibility study for construction and submitted it to the regional authorities and state expertise bodies
1999	February	CPC completed execution of necessary documents for the allocation of land plots for all new construction in Russia. CPC also proceeded with compensation for land use under the laws of the Russian Federation
1999	May	Groundbreaking ceremony for CPC
1999	November	Ribbon-cutting ceremony held in the Krasnodar Krai in southern Russia to commemorate the laying of CPC's first line pipes. At the same time, pipe laying began in the Stavropol Krai
2000	November	"Golden Weld Ceremony," marking completion of the final pipe joint

		connecting the Caspian pipeline system from Tengiz to Novorossiysk
2001	March 26	Beginning of CPC's line fill
2001	October 15	First tanker loaded
2001	November	Shareholders announce a transport tariff of US$3.59 per barrel per 100km
2001	December	Pipeline inaugurated with a nameplate capacity of 560,000b/d. Opening delayed by several problems, including the setting up of a quality bank for the CPC blend and bureaucratic problems over customs documents
2002	December	Line is carrying 400,000b/d

171. The CPC project begins at the main petroleum pumping station in Tengiz. The terminus is to be a new marine terminal in the vicinity of Yuzhnaya Ozereyevka, northwest of Novorossiysk. The CPC pipeline system includes the following elements:

- the existing 752km Tengiz–Komsomolskaya section of the Tengiz–Astrakhan–Grozny pipeline system
- a new oil pipeline of 751km, extending from the Komsomolskaya pump station to the new marine terminal at Black Sea, with pump station
- a tank farm, terminal, and marine facilities

172. The length of the CPC pipeline system is 1,503km. Table A12 shows the breakdown of distance by country and region of the pipeline system.

Table A12: Projected or Accomplished Pipeline Distances and Construction Responsibilities by Country and Region of the CPC Pipeline System

Route length through a territory	*Segment of pipeline (from km x to km y)*	*Segment length, km*
1. Republic of Kazakhstan	0–452	452
2. Russian Federation, including:	452–1,503	1,503
2.1. Astrakhan region	452–674	222
new construction	—	—
2.2. Kalmykia republic	674–949	275
new construction	752–949	197
2.3. Stavropol region	949–1,201	252
new construction	949–1,201	252
2.4. Krasnodar region	1,201–1,503	302
new construction	1,201–1,503	302

173. The diameter of the existing pipeline between Tengiz and Komsomolskaya is 40 inches (1,020mm). The newly constructed pipeline has the following diameters:

- from Komsomolskaya to Kropotkin: 480 km of 40-inch (1,020mm) pipe
- from Kropotkin to the tank farm: 257 km of 42-inch (1,070mm) pipe
- the section between the tank farm and the shore facilities: about 9km of 56-inch (1,420 mm) pipe
- loading lines from the shore facilities to the spms: each about 5km, designed to be constructed of 42-inch (1,070 mm) pipe

174. At the completion of phase one, the CPC will have a throughput capacity of approximately 30Mt/y. The CPC will be expanded in a series of phases to its maximum throughput capacity of 67Mt/y. The phases are planned to correspond to the development plans of the participating producers and are to be funded from operations revenue.

175. The construction of the pipeline system was a major undertaking involving international and domestic contractors and suppliers. The original estimated cost of phase one of the project was US$1.625 billion; the estimated actual cost now is expected to be approximately US$2.65 billion. The projected cost of developing CPC to its full capacity is US$4.5 billion.

176. The restructuring agreement specified the initial tariff for the transportation of Caspian Origin Crude at US$25 (in 1996 dollar terms) per metric ton, inclusive of all charges for terminal facilities. The tariff for Kropotkin-origin crude was 31 percent of the total tariff for Caspian-origin crude. The level of tariffs is to be indexed annually by the change in the U.S. producer price index for finished goods, as published by the U.S. Department of Labor's Bureau of Labor Statistics. The tariffs for third-party shippers, if any, have not yet been determined, although by agreement the tariffs are to be market based. The parties plan to review the tariff when the shareholders receive the final capital costs for the construction and commissioning of the CPC project.

177. The host governments agreed to exempt the tariff practices of the CPC from independent review by the regulatory authorities. This was agreed in order to assure the producers responsible for financing the project of reliable and secure access arrangements and predictable costs of transportation. The system was essentially conceived for the participants as a dedicated system in which regulatory intervention would be unnecessary and burdensome.

178. The Russian Federation and Kazakhstan will benefit directly from the operations of the CPC. As founding members of the consortium, the two countries will

receive dividends based on their equity interest. They also will recover the value of assets transferred to the CPC (the subordinated debt mentioned above) and will receive tax revenues: Russian central and regional governments will receive an estimated US$23.3 billion in tax revenues and earnings, and Kazakhstan will receive about US$8.2 billion. Under the terms of the production agreement with Chevron, Kazakhstan will be entitled to receive US$420 million from Chevron once a dedicated export system is in place to transport the crude oil from Tengiz and Korolev fields to international markets.

179. Other projected benefits of the CPC include the following:

- The completion of the CPC system will enable full-scale development to proceed of the Tengiz, Karachaganak, and other regional oil reserves.
- In combination with existing options the completion of the CPC system will provide for all of the crude oil export requirements from Kazakhstan for this decade.
- The CPC system will improve netback values for all stakeholders in Kazakhstan and the Russian Federation.
- The completion of the system will stimulate and accelerate upstream investment and other investment in essential infrastructure for the region.

180. The CPC is the largest single foreign investment project in the Russian Federation. The successful completion of this important cross-border pipeline highlights the following:

- Regional trade and cooperation on major cross-border pipeline projects can be beneficial for both countries. The CPC not only will provide access to export markets for crude produced in Russia and Kazakhstan, but also will create significant economies of scale that will benefit both countries.
- Regional states in economic transition can cooperate in essential and constructive ways to establish, by treaty and agreements, the sound legal, fiscal, and commercial framework necessary for the success of complex projects.
- Completion of the CPC project will facilitate the attraction of the capital necessary to develop the oil potential of the northern Caspian region.
- Cooperation by international and domestic enterprises on major infrastructure provides significant benefits, including technology transfers; the certification of domestic suppliers; sharing of knowledge and experience on commercial, legal, and administrative practices; and socioeconomic benefits such as

employment and the creation of a sustainable and stable revenue source for public purposes. It also introduces domestic enterprise to international standards in the areas of management, design, construction, operation, environmental protection, and safety, and alerts international companies to regional practices and the qualifications of regional suppliers and resources.

- The operation of the pipeline will have significant and ongoing beneficial effects on the communities along its route, in the form of jobs, mainly during construction, and revenues during operation.

181. The CPC also provides an interesting illustration of the distribution of risk for a major cross-border pipeline. The CPC pipeline can be characterized as a proprietary pipeline as opposed to a common-carrier pipeline. That is, the consortium constructed the pipeline for the primary purpose of serving the oil transportation needs of the participating producers and founding states, and the project generally is reserved to transport production from specific fields to export markets. At the same time, the producers are responsible for 100 percent of the funding of the project.

182. For shipper-owned pipelines in which the shippers enter into throughput agreements according to their shares, the distinction of risk between the carrier and the participating producers is somewhat academic. The risks nonetheless are important. The production sharing agreement stipulates that the shippers bear the crude price risks, the throughput (committed volume) risks, and the market risks. In the CPC case, the shippers are themselves participating producers and therefore also bear the primary risks of the pipeline, including the operating, environmental, financial, and political risks.

183. If crude prices and market conditions make the production of crude uneconomic in the region, throughputs on the system will decline. The participating producers will be affected in their investments both upstream and in the CPC. In essence, the producers have taken on the majority of both the transportation and the production risks.

184. All of the private parties participating in the project are oil producers. The interests of individual producers, however, vary significantly. Specifically, the original allocation of capacity rights does not correspond directly to the equity interests held by the shareholders. Even so, the relationship also varies between the expected production levels of the various producers and their capacity rights. At one extreme, Chevron's interest in the CPC is less than its expected share of production from the Tengiz field, so its risk of not utilizing its capacity rights is relatively small. At the other extreme, LukArco and Rosneft-Shell did not have regional production at the time of the agreement to correspond to their capacity rights, so their initial exposure was comparatively greater.

185. A common concern in a joint-interest shipper-owned pipeline is how the parties will make expansion decisions. Perhaps even more of an issue is the financing of expansions in terms of the obligations they may impose on the existing shareholders. For the CPC, the restructuring agreement suggested that future expansions would take place

only if sufficient demand was present and the expansions could be paid for out of operational revenues.

186. The restructuring agreement specified that each shareholder would have a preferential right to capacity for its equity production in accordance with the capacity allocation schedule.

187. According to the restructuring agreement, the producer-owners and Oman have the right to ship, according to their preferential right to capacity, equity production from any affiliated shipper. The governments of Russia and Kazakhstan have the right to assign their respective preferential rights to capacity to the equity production of any person (that is, legal "person," or corporation) producing liquid hydrocarbons within the territorial borders of Russia and Kazakhstan, respectively.

188. The CPC employs a "waterfall" capacity allocation procedure for any excess capacity that becomes available. Through this iterative process, shareholders have the opportunity to secure access to excess export capacity proportional to their holding. Only if the shareholders do not wish to use this excess capacity will it be made available to third parties, a process consistent with the proprietary nature of the system.

189. At the time the CPC was restructured, the participating producers committed the production from specific fields to the project. The agreement thus holds that if a shareholder with capacity rights has available production and the CPC project is fully operational, the shareholder is obliged to transport volumes up to its allocated rights through the CPC. If it fails to do so, it must pay the tariff equivalent to having transported those volumes through the segment the shareholder normally would be expected to use. This obligation is reduced or eliminated to the extent that the excess capacity is reallocated to and utilized by other parties. The producer also is liable for deficiency payments if it possesses rights for long-haul movements but is only able to transfer its excess allocation to a short-haul shipper.

190. In the reverse case—that is, if any segment of the CPC project has insufficient capacity to accommodate the qualified monthly nominations of the producers—each shareholder, whether or not it has made a monthly nomination for the segment, is entitled to receive a proportionate share of the operating capacity that actually is available, in accordance with the shareholder's percentage entitlement to operating capacity, as specified in the restructuring agreement.

191. A key feature of the CPC is the care that the consortium founders took at the outset to align the interests of the stakeholders. All of the participants to a certain extent bear the commercial risks associated with the project, and all have a "proprietary" interest in the project's success.

192. As noted earlier, the consortium agreement carefully defined the actions and responsibilities of the founding members and the producers. The agreement also included detailed provisions that provided a clear framework for the relationship between the parties. In addition, treaties, decrees, and other agreements were put in place. The

participants also agreed to international arbitration for disputes that they were not otherwise able to resolve. These agreements mitigated many of the project's commercial risks. Some details of the conflict resolution process follow.

193. Effective mechanisms for the resolution of disputes and the enforcement of agreements are essential for the successful implementation of any cross-border oil pipeline project. In the restructuring agreement, the CPC specified that the agreement would be governed according to the laws of England, without regard to rules concerning conflict of law and without taking into account the intent of the parties. The agreement provided, however, that CPC-R and CPC-K would be formed under the joint stock company laws of Russia and Kazakhstan, respectively. The parties also agreed to try to resolve all disputes, claims, or controversies occurring between them in an amicable manner.

194. The agreement provides for international arbitration if the parties cannot otherwise agree. If the claimant and respondent cannot reach an agreement independently, or if they cannot mutually agree on an arbitrator, then the Secretary General of the Permanent Court of Arbitration at The Hague will appoint an arbitrator. Arbitration proceedings would be conducted in English and Russian in Stockholm, Sweden, under the arbitration rules of UNCITRAL, unless the parties to the dispute unanimously modified the location or rules.

195. The arbitrators would form their decision by majority vote and deliver it in writing. The parties then would be obliged to regard the decision of the arbitrators as final, binding, and enforceable by any court of competent jurisdiction. Judgment may be executed against the assets of the losing party or parties in any jurisdiction.

196. The success of a major cross-border pipeline depends on the presence of all of the conditions necessary to attract capital on favorable terms. These conditions include the support of producers and creditworthy parties, the presence of all necessary contracts and agreements, a sound organizational structure, and favorable economic fundamentals (supply and demand issues, along with other market and competitive considerations). Risk factors such as environmental hazards and volatile world energy markets must be carefully considered and mitigated, rights of way must be secured, and security issues must be studied and resolved. These represent only a few of the requirements. The tasks involved can seem overwhelming, but the lesson of the CPC's success is that if the sponsors and the host governments proceed in a systematic, cooperative, and organized fashion, the challenges can be overcome.

197. For the CPC, this process took more than 10 years. Even then, the producers' willingness to take full responsibility for financing the project expedited the process. That the CPC has been successfully completed and has begun filling the line shows that this can be done even in a complex and challenging environment. The experience of CPC thus should inspire the development of other new oil and gas pipelines in the region. The expanded pipeline capacity already in place furthermore will provide a

basis for accelerating upstream investment that could in turn provide the economic drivers for other regional infrastructure projects.

Case Study 9: The Express Pipeline between Canada and the United States

198. The Express Pipeline is a 785-mile, 24-inch (610mm) pipeline connecting Canadian and U.S. Rocky Mountains crude oil production to various markets in the Rocky Mountains and, through a connecting carrier, to areas of the U.S. Midwest. The pipeline originates at terminal facilities at Hardisty, Alberta, runs south across the international border near Wild Horse, Alberta, and terminates near Casper, Wyoming. It was designed to deliver 172,000 barrels per day.

199. Alberta Energy Company (AEC) originally conceived the Express Pipeline project in 1992. At the time, production of crude oil in British Columbia, Alberta, and Saskatchewan exceeded the pipeline capacity to favorable markets, and existing pipelines were unable to handle heavy and sour crudes. This combination of export pipeline constraints in western Canada and the lack of market diversification resulted in significant discounting in the value received by producers for their crude production in the existing markets served—Western Canadian producers, governmental authorities, and other stakeholders in the region all suffered an opportunity cost from shut-in production. AEC identified the Rocky Mountain states as a logical export destination for expanding western Canadian production.

200. The Express Pipeline began as a corporate joint venture, common-carrier oil pipeline. It is classified as an independent pipeline, as the majority of throughput is from nonowners. The project sponsors sought to obtain sufficient support from producers, in the form of term throughput contracts, to enable them to attract financing for the project on favorable terms. The project sponsors were only willing to proceed with the project if they could obtain sufficient term service contracts prior to the construction of the pipeline.

201. Regulations in both Canada and the United States require the Express Pipeline to operate as a common carrier, providing service to all parties according to published tariffs. It cannot "unduly discriminate" against any eligible shipper. A unique feature of the pipeline is that it provides both term (or "contract") and spot services to shippers. Any shipper that signed a term pipeline transportation service agreement during the open season (autumn 1995) obtained secure capacity rights and stable tariff arrangements for the term (5, 10, or 15 years) selected. (In an open season process the project sponsors can test the market for support, and the contracts signed serve as a basis for attracting the capital necessary for the project to proceed.) Shippers that chose instead to ship on a spot basis are subject to the published tariff at the time they wish to ship, and access is subject to the limits of the capacity available to spot shippers. Express obtained through the open season process term contracts for approximately 145,000b/d of the line's 172,000b/d capacity. Table A13 shows the commercial options that were available to shippers.

Table A13: Commercial Options Available to Shippers on Express Pipeline: Schedule of Tolls, Hardisty, Alberta, to Guernsey, Wyoming (US$ per m^3)

	Term of the agreement		
Crude type	*5 years*	*10 years*	*15 years*
Light	*8.806*	*8.177*	*7.233*
Medium	*9.510*	*8.831*	*7.812*
High	*10.570*	*9.812*	*8.680*

202. The tariffs offered were based on market considerations, reflecting the risks of cost overruns to the extent the market would permit. Any future expansion of transport capacity would again be arranged as a new open season.

203. Both Canada and the United States have well-developed regulatory procedures that must be followed by the sponsors of interstate pipeline projects. For the portion of the project in Canada, the Express Pipeline is required to follow Canadian rules and regulations; for the portion in the United States, U.S. federal and state regulations are in force. With respect to tariffs, Express applied for an order in both jurisdictions approving a market-based toll methodology. The system's proposed initial toll schedule reflects four tiers of service. The toll for monthly spot service is the highest and is proposed to vary with market conditions. The fixed tolls shown in table A13 were proposed for shippers that subscribed to 5, 10, and 15-year transportation service agreements during the line's open season.

204. Both the National Energy Board of Canada and the Federal Energy Regulatory Commission approved Express's application and the related commercial terms. They concluded in this case that it was not unduly discriminatory to offer preferred access and reduced tariffs to shippers willing to sign long-term contracts, provided that the opportunity available at the time of the signing (that is, during the design phase) was offered to all potential shippers.

205. Term shippers are required to ship or pay at the appropriate tariff the full volumes to which they are committed. They are, however, also allowed to trade their excess capacity as spot to make up the difference in earnings. Term producers took on the throughput risk, and therefore the carrier offered them a lower tariff because they are sharing in the project risks.

206. Spot shippers run the risk of not having access to sufficient capacity at the time they wish to ship. If demand for spot export capacity exceeds supply, each spot shipper is allocated a proportional share of the uncommitted capacity available. If other export alternatives are at capacity, the spot shipper risks having to shut in production. They also face the risk that the tariffs might rise significantly, as Express can change tariffs at any time. Where capacity is available on alternative export pipelines, however,

the spot shipper's maximum exposure is the tariff level offered by the competitive alternative, adjusted for difference in market revenue.

207. In the case of Express, the major share of the throughput or crude supply risk is borne by the shippers that have signed term contracts. The line's throughput risk is limited to the uncommitted portion of the capacity; that is, the spot shipments and the capacity that becomes available at the end of the term agreements. Express assumed significant economic risks with respect to capital cost overruns and financing.

208. For the capacity available for spot shipments, Express bears the market risk, as governed by alternative transportation and marketing possibilities. Unlike the case for term contracts, Express can apply to change spot tariffs to reflect market conditions at any time.

209. Express primarily relied on shipper contracts to obtain the collateral necessary to obtain debt finance from financial institutions and the approval of the boards of directors of its respective sponsors.

210. In June 2001, a new shipping connection was added in Montana that interconnected with Conoco's Glacier Pipeline, which moves up to 30,000b/d. In November 2002, it was reported that a consortium consisting of BCGas Inc., Borealis Infrastructure Management Inc., and the Ontario Teachers Pension Plan (each with one-third interest) entered into an agreement to acquire the Express Pipeline System. The group was reported to be paying Canadian $1,175 million, which also involved assuming a debt of Canadian $582 million. The deal requires regulatory approval and was expected to be completed in January 2003.

Case Study 10: The Bolivia–Brazil Gas pipeline

211. Brazil has a long history of seeking full control of its natural resources and a large role for the state in providing services, including energy services. In 1953, the government established Petrobras, a state monopoly, for the exploration and exploitation of petroleum and gas, refining, maritime transportation, and pipeline transportation. The only areas not covered by Petrobras were the distribution of petroleum products, which was open to foreign investors, and the distribution of natural gas, which could be carried out only by distribution companies owned by Brazilian state governments. The Brazilian Constitution of 1988 reinforced the monopoly position of Petrobras and left fuel prices in the control of the government. Prices were used to control inflation, resulting in subsidies of fuels such as liquefied petroleum gas (LPG) and fuel oil, which would have to compete with future imports of natural gas.

212. Major contributions to Brazil's energy sector came from the country's own hydropower resources and from domestic and imported crude oil. Exploitation of Brazil's modest gas reserves had been secondary to the development of oil. Although gas distribution companies were founded in Rio de Janeiro and Sao Paulo during the 19th century, the gas was manufactured from coal and naphtha. It was only in 1988 that

natural gas supplied by Petrobras from local oilfields was introduced into the Sao Paulo network.

213. The idea of importing natural gas from Bolivia had been under consideration for several decades, but various obstacles stood in the way. Petrobras was content to continue business as usual, focusing on oil: expansion of the gas business might have displaced fuel oil produced by Petrobras' refineries, obliging its export at low international prices.

214. In 1990, when the governments of Bolivia and Brazil decided to reexamine the gas export project, the share of natural gas in Brazil's energy matrix was still only about 3 percent. Brazil, however, was forecasting strong growth in energy demand. Natural gas had the potential to offset an increasing dependence on more expensive fuels such as LPG, which needed to be imported, and fuelwood, which was causing deforestation. An expansion of the gas sector would also allow Brazil to diversify its energy sources with an environmentally friendly fuel.

215. The motives on the Bolivian side were primarily economic. Bolivia had been exporting gas by pipeline to Argentina since the 1970s, but new discoveries in Argentina gave notice that the arrangement was no longer tenable. Because sales to Argentina accounted for some 80 percent of Bolivia's total gas production, it was critical to find an alternative market to sustain the country's export earnings.

216. After a preliminary feasibility study, in 1993 the two state monopolies, Petrobras and Yacimentos Petroliferos y Fiscales Bolivianos (YPFB), signed a 20-year gas sales agreement for an initial supply of 8 million cubic meters per day (Mcm/d) of natural gas. The amount would increase linearly over the first eight years of the contract to a plateau level of 16Mcm/d.

217. Given the high demand for social sector projects in both countries, public funding of the new pipeline project was out of the question. The challenge was how to attract private financing for a US$2 billion project linking two countries with traditions of noneconomic fuel-pricing policies and nontransparent government regulation. That success would require the development of a new gas market in the receiving country further complicated the picture.

218. In both countries there was a growing perception that private participation in the energy sector could bring economic benefits and lessen the risks assumed by the government. This perception was strengthened by trends toward increasing globalization of energy markets and the rapid increase in private capital flows to developing countries, coupled with the recent successful privatizations in Argentina.

219. In Bolivia, President Sanchez de Lozada had been elected on a platform of privatization of state enterprises, including oil and gas, and YPFB was being prepared for capitalization and sale by international tender.

220. In Brazil, an intense political debate on the validity of the national monopolies had started, fueled by the prospect of upcoming federal elections and a

constitutional review that was believed might allow greater participation by the private sector. Those in favor of change argued that continuation of the Petrobras monopoly would leave the sector starved for investment capital and handicapped by traditional policies imposed by government. Petrobras' pricing structure on petroleum fuels heavily cross-subsidized the alcohol program and maintained the same fuel prices across all of Brazil. The reformists were boosted by the 1994 presidential victory of Fernando Henrique Cardoso, who was elected on a platform of promising to sustain recent successes in fighting hyperinflation and promoting privatization.

221. After the election, with the Brazilian constitutional review process beginning in earnest, the hydrocarbon sector faced several strategic options, ranging from monopoly business as usual to relinquishment of all monopolies on oil and gas, including import and export, refining, and inland transportation. In November 1995, a constitutional amendment removed the constitutional barriers to private sector participation in oil and gas activities, thereby effectively ending Petrobras' monopoly. Congress passed the Concession Law for Public Services, which required that all concessions for public services (including gas distribution) be awarded through competitive bidding. Although the abolition of the Petrobras monopoly would still require implementing legislation, the two events greatly improved the possibilities for attracting private capital to the sector.

222. Other obstacles to the development of a gas market with private participation still remained, however. The most important of these was government control over fuel prices.

223. As a first step to raising private financing for the pipeline project, Petrobras in 1994 embarked on a series of road shows to attract private equity partners for a new pipeline company on the Brazilian side. Petrobras ultimately selected a consortium of British Gas, Tenneco (now El Paso Energy), and Broken Hill Proprietary. The consortium, known as BTB, formed Transportadora Brasileira Gasoduto Bolívia-Brasil, SA (TBG), to assume ownership of the Brazilian part of the pipeline. Fifty-one percent of TBG's stock was held by Petrobras.

224. The private partners soon began to signal to the Brazilian government that realization of the project would require fair access to downstream markets and market-based pricing policies consistent with those recommended earlier by the World Bank for encouraging development of the country's hydrocarbon industry. Such policies were included in the hydrocarbon law approved by Brazil's Congress in August 1997.

225. On the Bolivian side, a partnership agreement was reached between Enron and YPFB that included development of the Bolivian section of the pipeline. At the time, YPFB was being prepared for capitalization and sale by international tender. Legislation passed in 1996 committed Bolivian reserves to the export project and defined a diminished—but still critical—role for YPFB as the aggregator and shipper of future gas exports to Brazil.

226. Shortly thereafter YPFB was split into two private exploration and production companies and one oil and gas transportation company, with participation by well-known international players such as Amoco, Enron, Shell, and Yacimentos Petroliferos Fiscales, the oil and gas company of Argentina. Bolivian pension funds owned 50 percent of the newly capitalized companies. The Bolivian transportation company, Gas Trans-Boliviano SA (GTB), was formed for the gas export project as a private joint venture among Enron, Shell, and Bolivian pension funds. In June 2002, it was reported that Enron's role was continuing despite its financial problems in the United States.

227. The export project originally was conceived by Petrobras and YPFB, primarily to supply gas to the Brazilian industrial sector; gas for power generation was still an uncertain prospect at the time the private investors came onboard.

228. The ownership structure of the Bolivian and Brazilian transport companies is shown in table A14. The Bolivian side of the project structure is essentially private. On the Brazilian side, majority ownership (51 percent) resides with GasPetro, a wholly owned subsidiary of Petrobras. The structure nevertheless allows a degree of cross-border ownership by each group.

229. During the project development phase, technical, environmental, and financial committees were formed with representation from all of the sponsor groups to resolve issues and ensure the cross-border harmonization of the project. This feature was to prove beneficial in enabling smooth coordination of the project.

Table A14: Ownership Structure of Bolivian and Brazilian Transport Companies

Company	*Constituents*
Bolivian Gas Transport Company (*Gas Trans-Boliviano*, GTB)	
Bolt JV: 85 percent	Shell/Enron: 40 percent Transredes (a 50/50 partnership of Shell/Enron and Bolivian Pension Funds): 60 percent
BTB: 6 percent	BHP: 33.3 percent El Paso Energy: 33.3 percent British Gas: 33.3 percent
GasPetro: 9 percent	Petrobras: 100 percent
Brazilian Gas Transport Company (*Transportadora Brasileira Gasoduto Bolivia Brasil*, TBG)	
GasPetro: 51 percent	Petrobras: 100 percent
BTB: 25 percent	BHP: 33.3 percent El Paso Energy: 33.3 percent British Gas: 33.3 percent
Shell/Enron/Transredes: 20 percent	
Private investors: 4 percent	

230. As late as 1997 no firm financing plan was in place. The project required a large, bulky, upfront investment with a gradual buildup of tariff revenues and a final gas price that would provide incentives for a speedy uptake of gas by industrial users and eventually power plants. Equally daunting was the fact that of the five Brazilian states through which the pipeline would pass only one, Sao Paulo, had a gas distribution network that could accept Bolivian gas. The distribution systems in the other states would have to be developed from scratch.

231. Market soundings had indicated a lack of long-term commercial funding for the project. The available commercial debt would be high in cost with short maturity (8–10 year terms) because of perceived political and regulatory risks linked to Brazil's economic circumstances and political culture. It looked as though the financing costs could result in a final gas price that would hinder market penetration during the critical initial years.

232. Commercial lenders also perceived some supply risks, since Bolivia's proven and probable reserves of approximately 200 billion cubic meters could meet only 80 percent of the gas sales contract. The World Bank did not share these supply concerns: it noted that the capitalization of YPFB had attracted some US$1 billion in private capital for further exploration and development.

233. In 1997, the World Bank and other multilateral financial institutions, convinced that both countries were serious about opening their hydrocarbon sectors to competition and private participation, decided to appraise the project. World Bank analysis showed the project to be economically viable and the best of several alternatives, including using different pipeline routes from Bolivia, constructing a pipeline from Argentina to Brazil, and constructing large gas-fired power plants in Bolivia and transporting the power to Brazil through high-voltage transmission lines. The final route for the pipeline was selected to minimize its environmental impact, and the project includes full measures to protect the interests of indigenous people living near the pipeline.

234. On the Brazilian side, multilateral lending and partial credit guarantees offered the prospect of longer loan maturities and an appropriate gas price for penetrating the market. In December 1997, the World Bank agreed to provide a direct loan of US$130 million and to continue preparing a partial credit guarantee of US$180 million to TBG. Other multilateral institutions, including the Inter-American Development Bank, provided additional financing totaling US$380 million. The multilateral financing covered 40 percent of the financing requirements as senior debt. Petrobras provided another 40 percent, sourced from bilateral agencies, and the equity sponsors provided the rest (see table A15).

Table A15: Funding for the Bolivia–Brazil Gas Pipeline, 1997 (US$ millions)

Funding source	*GTB (Bolivia)*	*TBG (Brazil)*
Shareholder equity (including subordinated loans)	75	310
Petrobras transport capacity option, with Brazilian National Development Bank and Andean Development Corporation financing	81	302
Petrobras loan, with Jexim/Marubeni and Brazilian National Development Bank financing		348
Petrobras advance payment contract, with Jexim/Marubeni financing	280	
World Bank loan		130
World Bank partial credit guarantee		180
Inter-American Development Bank		240
Corporación Andina de Fomento		80
European Investment Bank		60
Total	**436**	**1,650**

235. On the Bolivian side, only 20 percent of the necessary financing was available in the form of shareholder equity. With the Bolivian government unprepared to provide sovereign guarantees, little progress was made to close the financing gap. The Brazilian government, realizing that the deadlock threatened to delay the project, urged Petrobras to seek a solution.

236. Petrobras responded with two mechanisms. First, it agreed to arrange financing for a fixed-price, turnkey construction contract for the Bolivian section of the pipeline, with repayment through the waiver of future transportation fees on the Bolivian side; this financing was arranged through Jexim, the Japanese Export-Import Bank. Second, Petrobras agreed, at its own risk, to prepurchase 6Mcm/d of the uncommitted upside capacity of the pipeline on both sides of the border, an arrangement that became known as the transport capacity option. Petrobras can use this capacity without paying a capacity-based transportation charge to the pipeline companies, but it must still pay a variable transport charge to cover such items as compressor fuel. Petrobras financed the transport capacity option through the Brazilian National Development Bank and the Andean Development Corporation.

237. Petrobras and YPFB are signatories to the sales contract for 16Mcm/d of gas. YPFB collects the gas from the producers and transports it to the border under a ship-or-pay transportation contract between YPFB and GTB. Petrobras takes ownership of the gas at the border and has a ship-or-pay transport contract with TBG. Petrobras has

back-to-back take-or-pay contracts with the gas distribution companies in the five states traversed by the pipeline.

238. Achieving the pipeline's full capacity of 30Mcm/d will require the installation of compressor stations along the route as flow is increased. For contractual purposes, the capacity is subdivided into three major tranches of capacity:

- transport capacity quantity (TCQ) capacity for the first zero to 18Mcm/d (including the capacity required to transport the 16Mcm/d agreed between Petrobras and YPFB)
- transport capacity option for the next 18–24Mcm/d
- transport capacity excess for final 24–30Mcm/d

239. Petrobras had agreed to take the TCQ and transport capacity option very early in the project development phase. Shortly thereafter, Petrobras also agreed to contract the transport capacity excess[28] through a ship-or-pay contract with the transporters. To commit to the full capacity represented a substantial risk for Petrobras, which ultimately was willing to bet that both the reserves in Bolivia and the market in Brazil could be developed sufficiently to use the full capacity of the pipeline. Petrobras still has not firmed up projects to fully utilize the transport capacity excess tranche; but with the high demand for gas-fueled thermal power generation in southeastern Brazil, it is likely to do so.

240. The volume ramp-up profile for the pipeline indicates that transport capacity is likely to be fully utilized by 2004, and, under arbitration by the new federal hydrocarbon regulatory agency, the Agencia Nacional do Petroleo (ANP), third parties have negotiated with TBG to utilize the available capacity that exists in the short term. This will be the first practical example of third-party access to a gas transportation pipeline in Brazil. Petrobras has undoubtedly secured a strong position on capacity use of the pipeline because of its willingness to take substantial commercial risks, even when there were still many uncertainties about how quickly the market for natural gas in Brazil could be developed.

241. Petrobras bears most of the risk on both sides of the border. Although the gas supply risk on the Bolivian side falls on YPFB, this risk is considered small because of the likelihood of additional supply becoming available from new discoveries in southern Bolivia and northern Argentina. Nonetheless, if YPFB fails to deliver the contractual volumes of gas, Petrobras will be entitled to claim financial compensation from YPFB.

242. The most serious risk was considered to be the market risk in Brazil. Four of the five distribution companies involved in the project were paper companies only, with no pipes in the ground. Gas would have to penetrate a market dominated by

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[28] At the time, no other sponsor offered to purchase the transport capacity excess due to the uncertainty of development of Brazil's gas market.

subsidized, low-priced, high-sulfur fuel oil. To mitigate the price risk, the gas distribution companies reached a collective agreement with Petrobras that the city-gate price of Bolivian gas delivered to the distribution companies would be set equal to 85 percent of the local price of high-sulfur fuel oil for the first five years of pipeline operation, an arrangement that would help ensure that natural gas could compete in the market until full deregulation of fuel prices. After five years, the commodity price would be set on a pass-through basis using the price-indexing formula in the gas supply agreement between YPFB and Petrobras.

243. Through its subsidiary, BR Distribudora, Petrobras has taken a minority equity stake in several of the local gas distribution companies, with the notable exception of the state of Sao Paulo. (Other shareholders include the states themselves, British Gas, Enron, Shell, and, most recently, Italgas.) Although the ultimate market risk still lies with the distribution companies, it is Petrobras that is contractually obligated to pay YPFB for the gas and the transport companies for transport services.

244. Through its turnkey construction contract, Petrobras bears the construction risk on the Bolivian side. Finally, if the pipeline in Brazil is not built on time, Petrobras will incur financial penalties payable to YPFB and the distribution companies.

245. Because of the size and scope of the pipeline project, it played a key role in opening the Brazilian hydrocarbon sector to competition and private participation. The project and accompanying policy reforms have established the principles of unbundling and transparent pricing in transactions involving gas supply, transportation, and distribution. The pipeline has promoted interfuel competition in Brazil and has introduced the principles of third-party access to gas pipelines.

246. Since the pipeline would involve an enormous construction effort and tight deadlines, the construction packages were placed for international competitive bidding on the basis of individual construction spreads (individual tender procedure documents for different sections of the pipeline). Contractors would be allowed to bid for single or multiple spreads. This approach would ensure a good number of qualified domestic bidders with high mobilization resources, while also ensuring the lowest overall price. The Bolivian section of the pipeline (approximately 500km) was offered as a single spread, with the trunkline from the border to Sao Paulo (1,500km) divided into six spreads and the southern leg (1,100km) into five. Each of the three major sections attracted 10 to 20 bids from international construction companies, sometimes in association with regional companies. Final prices were somewhat lower than the original construction estimates.

247. Construction of the main trunkline to Sao Paulo was completed on schedule in December 1998, and the southern leg to Porto Alegre was finished in March 1999. The pipeline is expected to reach its full capacity of 30Mcm/d by 2004. In 2001, Bolivia sent 2.5Bcm of gas to Brazil, representing 23 percent of Brazilian gas consumption.

248. As noted, Petrobras secured the full transport capacity in the belief that sufficient gas discoveries would be made in Bolivia and that the Brazilian gas market would develop sufficiently. In fact, since commencement of pipeline construction Bolivia's proven and probable gas reserves have increased fivefold. Today, Bolivian gas reserves are being developed by Petrobras' subsidiary in Bolivia, and by several other producers. Some of the non-Petrobras production is already being exported through the pipeline. A recently announced emergency power plan for Brazil indicates that the Brazilian market can absorb much more than the delivery capacity of the pipeline. Petrobras thus seems to have secured for itself a very strong position with respect to pipeline capacity and the market. Despite this, several new natural gas import pipelines linking the Argentine gas network to Brazil are being planned or built (Petrobras has either no ownership or a minority participation in these projects). It is with this next wave of gas projects that new, competitive suppliers will be introduced to the Brazilian market.

249. Social and environmental aspects of the project were given the highest priority by the World Bank during project preparation. As the construction proceeded, these arrangements were overseen by a sponsors' environmental and social committee that had responsibility for coordinating all environmental issues for the pipeline in both countries. The committee was supported in the field by environmental inspection consultants who determined whether or not the environmental protection provisions were being met, and an independent environmental auditor was assigned to audit compliance with environmental and social conditions. An ombudsman was appointed to report directly to the World Bank and other multilateral sponsors to ensure effective coordination among the project, local and regional government agencies, and civil society (including nongovernmental organizations); to monitor implementation of the social and environmental compensation programs; and to respond to concerns raised by civil society.

250. The indigenous peoples who reside within the area of influence of the pipeline (three groups in Bolivia and three in Brazil) were encouraged to participate in any decisions affecting them, and the integrity of the natural habitats through which the pipeline passes was assured by a strengthening of the local environmental protection agencies. In view of future exploration activities that the project could stimulate in Bolivia, the Vice Ministry for Energy and Hydrocarbons has prepared a detailed study of likely areas for future exploration and their probable environmental and social impact. Indigenous groups live close to many of these areas. To ensure that any future exploration complies with best environmental practices, the project includes institutional strengthening of the Vice Ministry for Energy and Hydrocarbons, which will monitor such activities.

251. The new federal hydrocarbon regulatory agency, ANP, is fully functioning and has issued several key regulations for the gas sector, including provisions mandating third-party access to gas pipelines with spare capacity and access to oil pipelines and infrastructure, including terminals and storage facilities. Several other new gas-import

pipeline projects are being implemented or are in advanced stages of planning, including pipelines from Argentina and Uruguay.

252. The Hydrocarbon Law stipulated that fuel price should be deregulated by August 6, 2000. Although macroeconomic issues delayed full deregulation of fuel prices until the end of 2001, the government of Brazil has made substantial progress on deregulation. For domestically produced natural gas, the government directives mandate the unbundling of gas prices and the linking of petroleum commodity prices to international prices.

Case Study 11: The Baltic Pipeline System

253. The Baltic Pipeline System (BPS) project has three primary objectives: to (a) expand Russian crude oil exports, (b) increase leverage when negotiating with transit states, and (c) increase security of access to export markets.

254. The BPS is a new oil export pipeline and marine terminal in the Russian Federation designed to serve domestic and transit producers. It includes several points of special interest:

- It illustrates the implementation of a pipeline project in an economy in transition.
- It exemplifies the financing and construction of an export crude oil pipeline and terminal by a state-owned pipeline in the Russian Federation.
- It shows how an export pipeline project whose goal is primarily to address national economic security issues is being implemented.
- It illustrates how the objectives of pipeline projects evolve over time.
- It illustrates the importance of sound and competitive tariff policies for transit states.

255. This case study is a brief description of a project that Transneft is implementing to address both the needs of producers in the Komi Arctic region and the potential needs of transit shippers from the Caspian.

256. The BPS project has been implemented at a time when the Russian Federation is in the midst of a major economic transition from a command to a state economy. This case study highlights the use of an alternative financing mechanisms that was employed when conventional financing arrangements were not available.

257. As proposed, the BPS export pipeline system would originate in the northwestern portion of the Russian Federation and will terminate at a new marine terminal at Primorsk, near St. Petersburg. The project has evolved considerably since its inception. Originally it was conceived as a dedicated commercial export pipeline, similar to that of the CPC (see case study 9), for the specific purposes of exporting to world

markets projected crude oil production from the Timan–Pechora province and other regions within the Komi Republic and the Nenets Autonomous Region. Like the CPC, it was originally envisioned as a standalone commercial operation owned by a consortium. The consortium in this case was expected to include JSC Transneft, international and domestic oil producers, and other international pipeline enterprises.

258. At the outset, it was generally accepted that BPS would be established as an independent pipeline. Work on structuring the BPS project began in 1995. Transneft's vision was that the participating producers would provide throughput commitments to help raise the necessary financing for the project. Producers willing to invest in BPS would receive an equity stake based on their level of equity investment. Transneft's equity share was to be determined on the basis of the value of its existing pipeline assets that would be transferred by Transneft to the consortium.

259. In 1995, Transneft invited regional producers to participate in a meeting on the proposed BPS. As a result of the meeting, a working group and a steering committee were formed to oversee the preparation of the formally required Declaration of Intent and the Feasibility of Investment for the project, as well as a joint study of alternative pipeline routes and options and alternative terminal destinations. The original working group included representatives of Transneft, Rosneft, KomiTEC, Conoco, Amoco, Total, IPL / Williams, British Gas, and Neste.

260. Shortly thereafter, the parties signed a joint study agreement under which they accepted responsibility for financing the feasibility study. This subsequent study evaluated potential export route options, the required scope of the project, the optimal diameter and throughput capacity of the pipeline, and terminal options, with the goal of identifying the optimal engineering solutions. The results of the study are described in box A4.

Box A4: Results of the Feasibility Study Exploring Technical, Route, and Terminal Options

The joint feasibility study looked at a variety of potential solutions for the BPS project. These included the development of a new terminal at Primorsk; extending the pipeline to the existing terminal at Porvoo in Finland, to serve Finnish and other export markets; and expanding export capacity to the port of Ventspils in Latvia. The results of the route options evaluation indicated that the expansion of existing export routes, such as Ventspils, or the utilization of the port of Porvoo were more attractive from an incremental capital cost perspective than the construction of a new terminal facility at Primorsk—at least in the near term. Construction of a new terminal could be economically justified only if substantial throughputs could be attracted from other regions or if construction of the terminal were to be delayed until production increased in the Komi region. (This presented a chicken-and-egg dilemma, as additional investment to increase production would probably only be attracted if there were sufficient extra export capacity to world markets.)

The majority view of the study group was that extending the pipeline to Finland would be the logical first phase, and that revenues generated from those pipeline operations, when economically justified, could be used to develop Primorsk.

The Russian authorities disagreed. Specifically, the government of Leningrad (St. Petersburg) Region, the territory where the proposed port of Primorsk was to be located, argued that if the line to Porvoo were to be completed and commissioned earlier than the terminal of Primorsk, it might delay indefinitely the construction of the Russian export terminal. Further, many felt that Russia, as a matter of economic security, needed on its own territory a second oil export terminal to the world market. To reinforce their argument, officials noted that transit states had been charging exorbitant tariffs: the port fees at Ventspils and Odessa, for example, had been as high as US$7 a metric ton; even at their highest level, the port fees at Novorossiysk were only US$3.50.

261. Ultimately, the attempt to form an independent pipeline was abandoned. BPS is an important example of how various stakeholders (Transneft, the producers, and other potential investors and the government of the Russian Federation) in an export pipeline can look at the same set of facts but legitimately come to different conclusions. It is worth stating at the outset that the differences in perspectives of the parties involved should not be surprising, given that the Russian Federation and the entire region was in the throes of an unprecedented transition from a command economy to a market economy.

262. As early as 1995, Transneft, the representative of the state, was ready to move on the project. Transneft representatives wanted to begin detailed engineering and technical studies, as they had done in the past, and to defer the commercial considerations

to a later date. The crude producers, however, were more interested in defining from the start the commercial framework for the project. Some of the their main commercial concerns addressed the following:

- the commercial structure of the project
- the comparison of capital costs to other possible export solutions
- access rights for those who participate
- tariff principles for the project
- the allowed rate of return on the project
- management and decisionmaking procedures
- liability issues, especially with respect to prior environmental damage

263. Transneft was not in a position to address these questions, which were mainly the responsibility of other government authorities. In addition, the economic and legal framework for upstream development was not yet settled. The crude producers understandably were reluctant to commit themselves to a new, high capital cost project before these important commercial issues were resolved.

264. Those potential investors (the pipeline companies and other investors) that were nonproducers were primarily concerned with allowed returns, obtaining secure throughput commitments, and other standard investor concerns such as taxes, currency issues, and profit distribution matters.

265. The government of the Russian Federation saw the BPS project as a way to improve the economic security of one of its most important exports: crucially, the BPS would provide a second major oil export facility on Russian territory. After the dissolution of the Soviet Union, the transit states downstream of Russia had significantly increased crude oil transit tariffs. Given the shortage of export outlets, the state enterprises in the transit states had, in the view of the Russians, taken advantage of their market power. In June 1997, Presidential Decree N554 stressed the priority nature of the project and the importance of the "intensification" of cargo (including crude oil and refined products) through the Russian Baltic Sea ports. The BPS project was seen as providing a competitive alternative to existing marine terminals in the transit states. Table A16 shows the chronology of the Baltic pipeline project.

Table A16: Chronology of the Baltic Pipeline Project

Year	*Month*	*Activity*
1993	April	Government of the Russian Federation issued Ordinance N 728-R on the expeditious development of transportation systems in Russia. The port of Primorsk is first mentioned.
1995	August	Transneft invites Russian and Western oil producers operating in the Komi and Nenets regions to discuss the structure of the proposed BPS consortium. Dorsch Consult is put in charge of developing the Feasibility of Investment (FOI).
1995	October	A working group and a steering committee are formed to review the provisions of the proposed FOI and decide on the route selection. A joint study agreement is signed.
1996	January	Transneft sets forth a condition that construction of a new Russian port of Primorsk is indispensable. The Declaration of Intent is drafted.
1996	March	An oil batching study is commissioned to IPL/Williams. The number of reviewed route options is reduced from 17 to 4, with the double-port option referred to as the preferred option.
1997	April	The government of the Leningrad Region signs an agreement with the Ministry of Transport securing the role of "project customer" for the Primorsk terminal.
1997	June	President Yeltsin signs Decree N554, "On Transit of Cargo through the Littoral Territories of the Gulf of Finland."
1997	October	The Russian Federation (RF) Government issues Resolution N1325, "On Construction and Operation of the Baltic Pipeline System."
1997	November	Giprotruboprovod, Neste, and Maritime System Technology complete the FOI.
1998	February	The FOI is approved by the Expert Panel of the RF Government. The World Bank grants US$2.5 million for adaptation of the FOI to the requirements of international financial institutions. Gulf Interstate Engineering (GIE) is contracted to do this work.
1998	November	GIE completes the adaptation of the FOI.
1999	January	Transneft signs an agreement with YUKOS (one of the three largest privately owned Russian oil companies) under which YUKOS commits to ship 3 million metric tons per year through BPS.
1999	March	Transneft is named "project customer" by the government for the pipeline portion of the BPS project.
1999	April	The RF Government issues Resolution N476, "On Financing the Construction of the Baltic Pipeline System in 1999." An investment tariff is introduced.

1999	June	The BPS is presented to multilaterals. The European Bank for Reconstruction and Development (EBRD) expresses interest in the project.
1999	August	Transneft announces competitive bidding to select BPS construction contractors. Land allocation is completed.
1999	September	Implementing the Order of the Ministry of Fuel and Energy, Transneft sets up JSC Baltic Pipeline System, an affiliate of JSC Upper Volga Pipeline Association. 100 percent of shares belong to the state, but 25 percent will later be distributed among the shippers.
1999	December	All environmental approvals for the first phase of the project are secured.
2000	May	Start of BPS construction.
2001	November	The second phase is approved.
2001	December	The new terminal at Primorsk is opened and the line becomes operational. The first tanker is loaded.
2002	June	Work on the second phase begins and construction starts in September. Scheduled for completion in December 2003.

266. The projected total length of the BPS from Kharyaga to Primorsk is 2,700km. The system is to begin at a new head pump station at Kharyaga in the Komi region, and as envisioned will comprise the following components:

- A new Kharyaga–Usinsk line
- The existing pipelines Usinsk–Ukhta, Ukhta–Yaroslavl, and Yaroslavl–Kirishi
- A new line from Kirishi to Primorsk
- A new port terminal at Primorsk on the coast of the Baltic Sea, 130km north of St. Petersburg and 40km south of Vyborg. The port and related facilities will occupy 400 to 500 hectares of land.

267. The project is to be phased. The first phase is projected to provide 12 million metric tons per year (Mt/y) (240,000 barrels per day) of export capacity, including a tank farm with a storage capacity of 500,000 cubic meters. The original estimated cost of this phase was approximately US$460 million, with the final bill coming in at US$500 million. Construction started in May 2000 and the first tanker loaded in December 2001. The second stage will increase the export capacity to a total of 30Mt/y (600,000b/d), and will require the construction of three pumping stations and eight reservoirs and the enlargement of the Yaroslav–Kirishi oil pipeline. This expansion is estimated to cost US$200–250 million; it is expected to bring the Russian government US$100 million per year and save US$1.5 billion in transit tariffs.

268. As designed, the port will be capable of handling BalticMax-size vessels (approximately 150,000 dwt)—the largest tankers capable of navigating the Baltic Sea.

The port is in the lee of islands but is in a region subject to heavy ice conditions in winter. The sea freezes for two to five months each year. Ice thickness averages 430mm (the thickest registered was 630mm). In winter, icebreakers will escort tankers.

BPS: The State Decides

269. Transneft and Russian authorities became frustrated at the delays and at the length and complexity of putting together an independent commercial pipeline project. The development of oil projects in the Komi Arctic region were not proceeding at the pace expected when the BPS was originally conceived. Given the government's interest in proceeding with the BPS project, Transneft began to look at alternative sources of throughputs for the system. Specifically, Transneft studied the potential of utilizing this route to export western Siberian production as well as transit volumes from Kazakhstan. For these volumes, the connection point with the BPS would be Yaroslavl. Oil from western Siberia would be delivered via the existing Surgut–Polotsk line. With respect to transit volumes from Kazakhstan, Transneft proposed reversing the existing Almetyevsk–Samara lines to provide a direct connection for Kazakh oil to Samara. Transneft indicated that this action would be taken only with throughput commitments from Kazakh producers.

270. In April 1999, the project took a new direction when Prime Minister Primakov issued a resolution on the financing of the BPS project (see box A5).

Box A5: Resolution on the Financing of the Baltic Export Pipeline System

THE GOVERNMENT OF THE RUSSIAN FEDERATION:
RESOLUTION NO. 476 of April 30, 1999

On Financing the Construction of the Baltic Export Pipeline System in 1999

The Government of the Russian Federation hereby resolves:

To endorse the joint proposal made by the Ministry of Fuel and Energy of the Russian Federation, the Federal Energy Commission of the Russian Federation, and Joint Stock Company for Oil Transportation (hereinafter JSC Transneft) on the attraction in 1999 of the equivalent of 100 million dollars worth of investment resources for the purpose of financing the Baltic Export Pipeline System by means of introducing a target investment tariff, charged by JSC Transneft to shippers exporting oil via the system of crude oil pipeline mains of the Russian Federation.

The Federal Energy Commission of the Russian Federation shall approve and put in effect, as of May 1, 1999, a target investment tariff that would be applied by JSC Transneft to crude oil volumes, exported via the system of crude oil pipeline mains of the Russian Federation.

To determine that disbursement of target investment resources for the purpose of financing of the Baltic Export Pipeline System be included in JSC Transneft operating and marketing costs.

The Ministry of Fuel and Energy of the Russian Federation, the Ministry of Transportation of the Russian Federation, and the Ministry of Economy of the Russian Federation shall approve the list of proposed facilities constituting the Baltic Export Pipeline System and reach an agreement, in compliance with applicable procedures, on the partial reassignment by the Ministry of Transportation of the Russian Federation of its functions as the State Administration, commissioning the financing and the construction of the crude oil loading facilities integrated into a marine terminal in the port of Primorsk, Leningrad Oblast, to JSC Transneft.

The Ministry of Fuel and Energy of the Russian Federation, the Ministry for State Property Management of the Russian Federation, and JSC Transneft shall submit their proposals on the procedure for formation of the Russian Federation's equity share in the Open-Ended Joint Stock Company "Baltic Pipeline System," and the sale, in accordance with applicable regulations, of a portion of the stock of this Joint Stock Company to oil shippers participating in the formation of the target investment tariff.

The Ministry of Fuel and Energy of the Russian Federation, the Federal Energy Commission of the Russian Federation, and JSC Transneft, jointly with the Ministry of Finance, the Ministry of Taxation, and the Ministry of Economy of the Russian Federation, shall develop a procedure for accounting and monitoring of the appropriation of resources, accumulated by collection of the target investment tariff, with the view that these resources shall be used exclusively for the purpose of financing the construction of the Baltic Export Pipeline System through competitive bidding for procurement of materials (works, services).

Signed: Chairman of the RF Government, Ye. Primakov

[Note: Paragraph 4 at the time was interpreted as providing that the producers were to be given equity interest in the project in exchange for paying the targeted investment tariff.]

271. Once the state made the decision to proceed with the project as a matter of state priority, the obvious issue was how BPS would be financed. The government authorized Transneft to impose a tariff surcharge on all crude oil exports of US$1.43 per metric ton. Imposing surcharges technically violated the tariff methodology adopted by the Federal Energy Commission of Russia. The FEC, in a generic rule making, had decided that tariffs should provide a carrier with revenue adequate only for maintaining and operating existing facilities, not for constructing new pipelines. This is a fundamental "user pays" principle, in which shippers are only required to pay the costs of facilities

they use. The FEC tariff methodology is similar to the cost-based methodology used in the regulatory sector in North America.

272. The FEC relented in the light of the government decision. It nonetheless raised its concerns with the government and was advised to prepare, jointly with Transneft, recommendations on how the producers could be compensated in the future for paying surcharges now. The primary concepts suggested were to provide them with equity interest in BPS or to allow a future offset in tariffs. As noted earlier, the new administration decided against such compensation.

273. This facilities surcharge raised approximately US$106 million, which enabled Transneft to begin the project without further delay.

274. Transneft is in discussions with the EBRD and other potential lenders to secure some debt finance. In the meantime, revenue generated from existing operations remains the primary source of financing. In 2000 the FEC, with government urging, approved four increases of the hard currency tariffs applicable to export shippers, increasing the hard currency tariff by almost 100 percent. The formal justification for these increases was the government's decision to reimburse Transneft for the remaining costs of the Chechen bypass construction. The bypass costs since have been recovered, but the increases in tariffs have been left in effect. This could provide approximately US$130 million in 2001 that could be used for BPS.

275. As things stand, the project risks are borne primarily by the state, which decided to proceed with the project. all shippers and producers that use the Transneft system, however, have directly borne the cost of this decision. If the project is not successful from a commercial perspective, under current practices the unrecovered costs would simply be rolled into total system revenue requirements and be reflected in tariffs for other segments.

276. Some Russian producers have made commitments of throughput for the system, but these have been informal and are not enforceable by either the carrier or the shipper. Given the state control over crude oil export access, no mechanism is in place that would ensure a shipper of secure export access. The tariffs, or access terms, have not been specified, and the producers are not subject to deficiency payments if they do not ship the volume specified. Should BPS seek to obtain financing from international lending institutions, these institutions undoubtedly will require more formal arrangements with respect to throughput commitments from shippers.

277. Transneft's direct risks (as the experience of the Chechen bypass project demonstrated) are limited. Should throughputs not materialize on one system, Transneft would simply increase the tariffs on other routes to cover the costs. The indirect risks, in contrast, are quite high. If not limited, the use of surcharges would likely reduce or discourage investment in fields connected to the Transneft system.

278. The benefits of the project should include the following:

- Expanded crude oil export capacity from Russian territory

- Competition to existing export facilities such as Ventspils, Odessa, and Gdansk
- Improved economic security, given the fact that oil is a vital export for Russia
- Potential liberalization of domestic energy markets as a result of expanded export capacity
- More favorable netbacks to export for all stakeholders as a result of increased competition
- Productive use of some of the idle facilities and the capacity that is already in place
- Diverse socioeconomic benefits, including a positive impact on domestic employment as a result of the construction and operation of the facilities

279. A potential downside of the project lies in the environmental concerns in that the pipeline runs close to St. Petersburg and the city's drinking water supply. The pipeline also crosses the nature reserve on the Karelian peninsula.

280. Potential adverse consequences of the use of surcharges and subsidies include the following:

- The practice of using subsidies and surcharges to finance the construction of new export facilities, if not clearly limited, will make it difficult to attract capital to upstream projects. Uncertainties as to future tariff levels (specifically any surcharges that might be added to tariffs) will be a matter of significant concern to producers and financial institutions alike.
- The practice of imposing surcharges on existing shippers to subsidize an unrelated project is not consistent with international norms and sets a negative precedent for transit states. If all parties in the region were to pursue "national solutions" by adding surcharges to transportation costs the result would be increased transportation costs and the emergence of a suboptimal transportation network for the region.
- If carried to the extreme, the use of subsidies in Russia, Ukraine, and other states could result in wasteful duplication of facilities.

281. In summary, the Baltic Pipeline System will provide the Russian Federation with an additional crude oil export outlet. Perhaps more importantly, it will give Russian producers leverage when negotiating with existing transit export routes.

282. The level of future oil production and exports from the region in no small degree will depend on the availability of competitive access to favorable markets. It will

also depend on the tax and legal regimes applied to upstream development. Transneft and the carriers that formerly made up the GTN (Glavtransneft, the Main Industry Enterprise for Oil Transportation and Distribution) system clearly have the potential to play a prominent role in the transportation of crude resources to world markets from new producing regions in the Russian Federation and the Caspian. Attracting significant long-term volumes will only be possible if the carriers in the transit states and policymakers in those countries are willing to address essential commercial requirements in a timely and reliable manner. If the former GTN enterprises individually or collectively fail to take advantage of these opportunities, the producers in the Caspian will seek alternative transportation solutions, bypassing the existing interconnected pipeline network. This would result in duplication of facilities and would almost certainly reduce the netbacks for most producers in the region. It also would make crude supplies more costly in the historic markets served by the existing interconnected system and would increase the environmental risks from crude transportation in the region.

Case Study 12: The GasAndes Pipeline

283. The Gasaducto GasAndes (GasAndes Pipeline) is a US$350 million pipeline that transports natural gas from Argentina west across the Andes mountains to Santiago, Chile. The 465km, 24-inch (610mm) pipeline links with the Transportadora de Gas del Norte (TGN) pipeline system at La Mora compressor station southeast of the Argentine city of Mendoza. The initial capacity of the pipeline was 119 million cubic feet per day (Mcf/d). This was expanded to 252Mcf/d in 1998 and was expected to further increase to 427Mcf/d in 2002; by 2016 it is projected to reach 686Mcf/d. The GasAndes pipeline became operational in August 1997.

284. The project had been under discussion since the 1980s but no decisive progress was made in the negotiations between Argentina and Chile until both states finally decided to leave the commercial question to the private sector. In 1995 both countries signed a bilateral protocol that set a general framework and regulations for the construction of cross-border pipeline projects and that set some general rules for cooperation between the two states. As soon as the protocol came into effect the private sector not only engaged in the GasAndes project, which was successfully completed, but also in another cross-border gas pipeline that is to be completed soon.

285. Nova Gas International leads the GasAndes group with a 56.5 percent interest in the pipeline. Other partners in GasAndes include Chilgener SA, Chile's second-largest power generator (15 percent); MetroGas SA, Santiago's gas distribution company (15 percent); and Cia. General de Combustibles (13.5 percent). In July 1998, Total also acquired a 10 percent interest in the GasAndes pipeline. In September 1995 the consortium awarded pipeline construction contracts worth a combined US$220 million to Techint and McKee del Plata of Argentina. The pipes were supplied by SIAT South America, an associate company of Confab Tubos del Brasil.

286. The GasAndes group has signed 25-year supply agreements with MetroGas and four power plants in the Santiago region, for a total of nearly 350MMcf/d.

In 1997, MetroGas contracted 59.5MMcf/d of gas deliveries, to be received into Santiago at two delivery points: City Gate 1 in the Puente Alto district in the south of the city, and City Gate 2 in San Bernardo in the southwest. Also in 1997, the 350MW gas-fired power generating plant Central Renca, owned by Sociedad Electrico Santiago SA (ESSA) and Nova Gas International (15 percent), contracted to take 60.9MMcf/d. GasAndes has also signed contracts with Endesa, Chilgener, and Colbun for three other 350MW gas-fired power plants that were to be built by 2002. Peak delivery for the four power plants in May 2001 was expected to be 238.14MMcf/d.

287. The GasAndes project has suffered from considerable public relations difficulties, a result of the country's lack of experience with gas pipelines and consequent public safety fears. The pipeline also has come under criticism for what is seen as its potential for harm to the environment in the town of San Alfonso, a scenic mountain town and popular recreation area for Santiago, and to the natural sanctuary at Cascada de las Animas. A coalition of environmentalists and residents, seeking to preserve their rural communities from Santiago's widening urbanization, protested the project. The National Environment Commission (Conama) had approved the project in January 1996, giving GasAndes right of passage and clearing the way for construction, but it reversed its ruling in the face of the protests. GasAndes later managed to lift the injunction that Conama imposed, but the environmental review process delayed the start of construction.

288. The GasAndes consortium, led by Nova Gas International, has publicly stressed the benefits for Chile that the pipeline represents. Natural gas is expected to reduce energy costs for industry and electricity tariffs in the Santiago area. The use of natural gas in industry and public transportation also is likely to contribute to the cleaning of Santiago's heavily polluted air.

289. In 2000, a US$50 million, 91km, 16-inch (406mm) extension of the line was announced. The extension will deliver gas to industrial and residential consumers in the central O'Higgins region of Chile. In 2001, Argentina supplied 4.6 billion cubic meters of gas to Chile, equivalent to 82 percent of Chile's gas consumption.