The Commercial Viability of the Trans-Caspian Gas Pipeline

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Prepared by:

Bhamy Shenoy, Ph.D.
Hagler Bailly Services

S. Gürcan Gülen, Ph.D.
Energy Institute

Michelle Michot Foss, Ph.D.
Director, Energy Institute

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Energy Institute
University of Houston
College of Business Administration
Houston, Texas 77204-6283
www.uh.edu/energyinstitute
E Mail: energyinstitute@uh.edu

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Executive Summary

Turkmenistan has large proved natural gas reserves. Potential markets for Turkmen gas are Turkey via a new pipeline, Europe via Turkey or Russia, Pakistan and India via a new pipeline through Afghanistan, and China via a new pipeline through neighboring Central Asian Republics. The Afghan pipeline is politically impossible for the foreseeable future. Cost estimates for the Chinese pipeline are extremely high, not to mention potential geopolitical problems among (within) the Central Asian Republics along its route, or in Western China. Also, it is clear that the best paying customers are in Western Europe. However, since Gazprom limits the use of its pipeline network for Turkmen exports to non-paying customers such as Ukraine, Turkmen exports have fallen to 77 bcf in 1998 from 2.4 tcf in 1987. Obviously, Turkmenistan would benefit greatly from an alternative export pipeline to the West. Of the two major routes for a Turkmenistan-Turkey pipeline that have been considered, the Trans-Caspian route has recently gathered greater support, at least in the U.S., than the Iranian option.

After analyzing the potential for gas demand in Turkey as well as Azerbaijan and Georgia, and carrying out a NPV analysis supported with numerous scenarios, we conclude that the Trans-Caspian pipeline is commercially viable and would bring positive, *but limited*, returns to Turkmenistan *under most scenarios*. This conclusion holds true even if Turkey is the sole buyer of Turkmen gas, albeit with low investment cost and high price assumptions. *Our analysis also indicates that the pipeline operators will be the clear winners if this pipeline gets built*. On the other hand, given the intense supplier competition to Turkey (further enhanced after the recent Azeri discoveries) and doubts about that market's potential, there are significant risks for both Turkmenistan and pipeline operators. However, the strategic importance of the pipeline is tremendous for Turkmenistan, which stands to gain significant independence from, and bargaining power against Gazprom. Therefore, *Turkmenistan will need to participate in the pipeline consortium in order to share both the risks and operation revenues with other stakeholders.*

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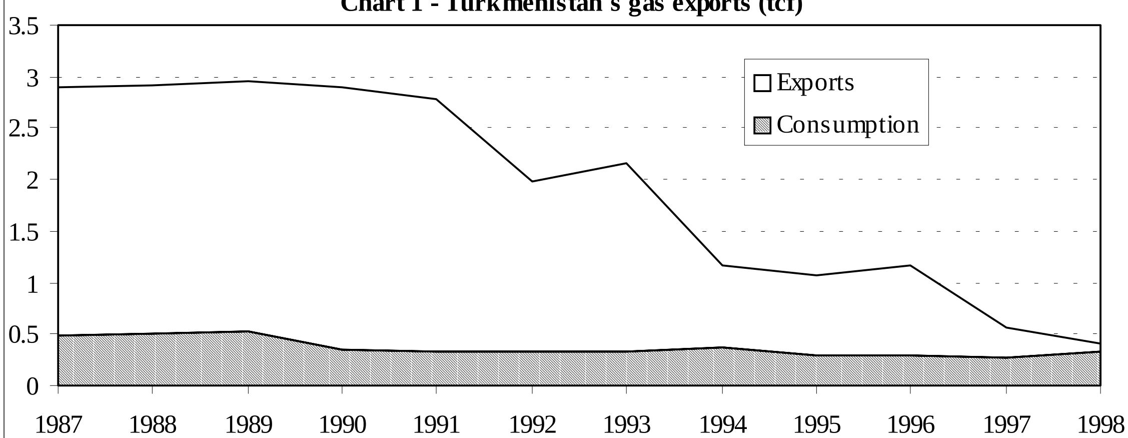
Natural Gas and Turkmenistan

Natural gas will continue to be the fastest growing primary energy source in the world for the foreseeable future. At the same time, the competition among natural gas suppliers will continue to increase. With 101 tcf of proved gas reserves (roughly two percent of total world reserves) Turkmenistan appears to be well positioned to benefit from increasing demand for natural gas. However, as compared to its competitors, Turkmenistan has certain disadvantages. Since the country is landlocked, LNG is not a viable alternative, and the country is farther away from hard-currency markets. After the collapse of the Soviet Union, natural gas resources in Turkmenistan have become too distant for major consumers, especially when Gazprom allows limited access to its pipeline system. Ukraine, the largest consumer of Turkmen gas in the 1990s, has not been able to pay its bills. After cutting off supplies to Ukraine at the end of the first quarter of 1997, Turkmenistan resumed supply to Ukraine at the end of December 1998. Although only part of the payments was to be made in cash, Turkmenistan had to cut supplies again in mid-1999 because of Ukraine's inability to pay. The result of these developments can be seen in **Chart 1**: Turkmen gas production fell to 413 bcf a year in 1998 from almost 3 tcf in the late 1980s. Accordingly, exports fell to 77 bcf in 1998 from 2.4 tcf in 1987.

In order to revive the Turkmen gas exports, alternative markets have been considered. Bridas and Unocal developed a potential pipeline route through Afghanistan, despite the civil unrest in that country, to serve the Pakistan market. Even today, after the formal exit of Unocal, Bridas remains interested in this project. Even if the Afghan problem can be somehow bypassed, Pakistan does not have an immediate need to import gas in the next five to seven years. Pakistan has been increasingly successful in finding and developing more of its own gas resources. Also, gas demand stagnates as a result of recent delays in power plant development. In addition, the possibility of supplying gas to India through Pakistan seems to be even more remote than ever as the relationship between these two countries continues to deteriorate. The Chinese market was also considered. The distance to be covered for Turkmen gas to reach potentially large markets in southeast China is such that estimates for the cost of building this pipeline reach upwards of $10 billion. As a result of all these constraints, European markets, beginning with that of Turkey, are currently targeted.

Chart 1 - Turkmenistan's gas exports (tcf)



Source: BP Amoco Statistical Review of World Energy 1999.

The EIA projects that gas consumption in Europe will increase to 27 tcf in 2020 from 15.1 tcf in 1998. This increase corresponds to an annual growth rate of 2.9 percent. Moreover, as gas reserves of the North

Sea are depleted and as countries of Central and Eastern Europe and the Black Sea region (including the Caucasus) continue on their path of economic development, prospects for the Turkmen gas should improve. Demand potential in Europe is evident in **Table 1**. The potential for serious competition from the Middle Eastern countries with 100+ R/P ratios as well as from Algeria and Nigeria is significant. Although most of these countries have similar transportation issues to address, some are rapidly developing their LNG export capacities (e.g., Algeria, Nigeria and Qatar) while others such as Iran and Iraq are getting ready to take advantage of their proximity to Turkey.

Russia remains the most immediate competitor for the Turkish and European markets. Gazprom exports significant amounts of natural gas to Europe (Table 1) and is not likely to provide additional capacity to Turkmen gas in its pipeline system. Under these circumstances, Turkmenistan would benefit greatly from an alternative pipeline. Two options have been talked about extensively: the Trans-Caspian and Iranian pipelines. The former, which is intended to bring Turkmen gas first to Turkey and then eventually to Europe under the Caspian Sea and via Azerbaijan and Georgia, has recently emerged as the more likely candidate. Iran already expressed its support for the latter project. In terms of total investment the Iranian pipeline would probably be cheaper than the Trans-Caspian pipeline, and would also avoid the potential legal problems surrounding the status of the Caspian Sea. But, the biggest drawback of the Iranian pipeline for Turkmenistan is the possible interruption or restriction of gas flow by Iran in the future. Russia, the largest natural gas reserves holder in the world, has been restraining Turkmenistan's gas exports for almost a decade now and it is very likely that Iran, owner of the second largest gas reserves in the world, may follow a similar strategy in the future. It is just a question of time before Iran will increase its ability to develop its own natural gas resources for export. It is this strategic reasoning, rather than the U.S. sanctions, which will make the Trans-Caspian line more attractive for Turkmenistan. Also, the short-run commercial viability of the Iranian pipeline would solely depend on the Turkish gas market while the Trans-Caspian pipeline may benefit from gas sales in Azerbaijan and Georgia in addition to sales in Turkey.

Table 1 – 1998 Consumption and Gas Imports in Europe (bcf) [a]

	Consumption	Russia	Share of Russia [b]	LNG	Share of LNG
Austria	268.3	194.2	72.4	--	--
Belgium [c]	487.1	--	--	151.8	31.2
Bulgaria	105.9	134.1	126.7	--	--
Czech Rep.	268.3	303.6	113.2	--	--
Finland	130.6	148.3	113.5	--	--
France	1323.8	360.1	27.2	345.9	26.1
Germany	2806.4	1140.2	40.6	--	--
Hungary	381.2	300.1	78.7	--	--
Italy	2019.2	589.5	29.2	70.6	3.5
Poland	367.1	264.8	72.1	--	--
Romania	642.5	134.1	20.9	--	--
Slovakia	201.2	243.6	121.1	--	--
Spain	462.4	--	--	208.3	45.0
Switzerland	91.8	17.7	19.2	--	--
Turkey	349.5	240.0	68.7	127.1	36.4
Others	5171.5	176.5	3.4	--	--
TOTAL	**15076.6**	**4246.6**	**28.2**	**903.7**	**6.0**

Source: BP Amoco Statistical Review of World Energy 1999.
Notes: [a] BP Amoco uses Cedigaz data for trade movements. [b] When the share of Russian gas in total consumption is more than 100 percent, this is potentially due to changes in storage as well as differences in data sources. [c] Belgium's and Luxembourg's consumption are reported together.

Turkey

For some time, Turkey has been the largest potential market proximal to natural gas from Turkmenistan. Most of the projected increase in gas demand was based on the assumption that Turkey would need a significant number of gas-fired power plants. Electricity demand in Turkey has been rising at about 7-8 percent a year since the 1980s. The country started using build-operate-transfer (BOT) and build-operate (BO) models extensively in the 1990s to allow private investment in the traditionally state-dominated power sector. However, legal problems delayed power plant developments until recently.[1]

As a result of these delays, even the state pipeline company, BOTAS, lowered its 2010 estimates of gas demand in Turkey from about 2.7 tcf to about 1.9 tcf (June 1998). Potentially, due to economic slowdown of late 1998 and early 1999, some industry analysts are even more conservative than BOTAS, with estimates for Turkish gas demand in 2010 ranging from 1 to 1.4 tcf. Nevertheless, gas consumption in Turkey has been increasing at more than 30 percent a year on average between 1987 and 1998. Given the rapid development of gas infrastructure in the early days, this may be misleading. But, between 1993 and 1998 consumption doubled, corresponding to an average annual growth rate of 15 percent, despite the problems in the power sector.

However, the new government of Turkey (formed May 28, 1999) was successful in passing a new legislation in August 13, 1999 that allows for international arbitration in concession contracts and limits Dan• • tay review period of contract to two months.[2] Although electricity services are still considered as public service, future privatization of the sector is now easier to visualize. Overall, this improved legal environment should stimulate investment in power generation, which in turn will raise the demand for natural gas. If gas-fired power plant construction can average 2,000 MW a year between 1999 and 2010 (as opposed to the official goal of 2,500 to 3,000 MW a year), gas demand in Turkey will reach 2 tcf, assuming that 60 percent of gas imports will be used in power generation. This growth corresponds to an annual increase of 17 percent.

Industrial use of natural gas, especially for cogeneration purposes, has also been increasing. Unaffected by the legal debates of the 1990s, in recent years 1,224 MW of cogeneration capacity was built. Another 1,485 MW of capacity has signed contracts and projects with a total capacity of 2,301 MW are under review. This upward trend should continue as BOTAS continues to expand its transmission and distribution grid in the industrialized western part of the country from Bursa toward Izmir. But, even in places where pipelines are already laid, many industrial users burn LPG and/or naphtha in their cogeneration units since there is not enough gas. As a result, industrialists without natural gas complain that they cannot compete in the long-run with companies that use cheaper natural gas. LPG is sold at about $10/mmBtu while natural gas is sold at about $4-5/mmBtu. Turkey is also considering the liberalization of the natural gas sector. Although BOTAS resists the idea, it is generally understood that a more liberalized natural gas market would allow industrial users and IPPs to import their own gas and local distribution networks to develop faster. Unlike electricity, natural gas services have not been established as public service and hence it should be easier to open the natural gas market to competition. The recent successes of the new government in passing international arbitration legislation and other legislation in compliance with IMF's guidelines to liberalize the Turkish economy provide hope for commercialization of the natural gas market in the near future.

Residential and commercial markets are also promising. Currently, the main natural gas pipeline from Russia through the Balkans passes through the Marmara region (northwest Turkey), the most populous and the most industrialized in Turkey before reaching Ankara in the Central Anatolian region. About 16-17 million people live in the Marmara region (about 10 million live in Istanbul alone), most with no access to natural gas. The region has four seasons with hot and humid summers, especially in July and August, and cold and wet winters. The heating season usually lasts from early October until late April;

[1] See *Power Marketization in Turkey* (May 1998), an Energy Institute White Paper by S. Gürcan Gülen.

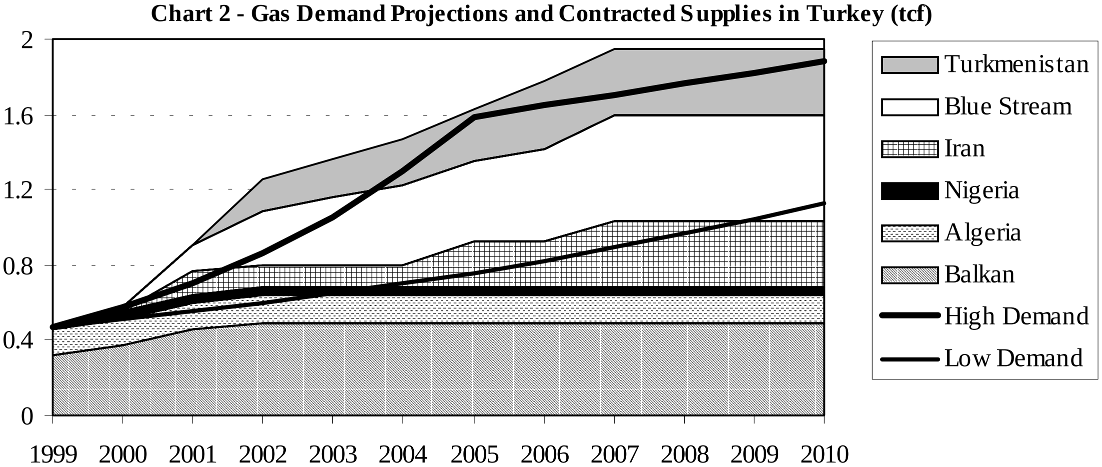
[2] Dan• • tay is the high court responsible for reviewing concession contracts.

but it is not unusual to experience single digits (in Celsius) even in September and May. Although the population of the region represents 26 percent of the total population, about 40 percent of disposable income in Turkey are generated in the Marmara region. Per capita GDP and per capita consumption of electricity is significantly larger than the averages for Turkey. For example, in Kocaeli per capita GDP is 2.5 times the Turkey average, which is about $6,000 based on purchasing power parity, and per capita consumption of electricity is 2.6 times the national average, which is about 1,300 kWh (1997 numbers, *State Institute of Statistics* and TEDAS). Residential users with access to natural gas pay about $6/mmBtu.

Chart 2 provides a range between a low-demand case and BOTAS' June 1998 estimates (the high-demand case) superimposed on total import potential for which there is some form of contractual agreement between Turkey and the exporting country. The chart clearly indicates that the Trans-Caspian pipeline will not be needed until the 2003-04 period even under the high-demand case *if both the Blue Stream and Iranian pipelines are built and can deliver contracted quantities in time, and if the Balkan pipeline's capacity can be increased in time*.

Iran already delayed and decreased the amount of its gas shipments to Turkey (*World Gas Intelligence*, June 29, 1999).[3] The Blue Stream pipeline will be the deepest undersea pipeline. Additionally, the bottom of Black Sea is uneven and the water is very corrosive at those depths.[4] Weather conditions can also be very difficult, especially during the winter. Therefore, it is very likely that there will be delays during the construction phase and potentially delays in supplies during the operation phase. More importantly, financing for the project is not fully secured yet. Meanwhile, BOTAS has not made significant progress in developing the Samsun-Ankara connection that would bring Blue Stream gas to the market. Nevertheless, in Chart 2 we represent the full amounts published in *World Gas Intelligence* (March 25, 1999). Regardless of these supply alternatives, a purchase agreement was signed between Turkey and Turkmenistan in late May 1999 for 177 bcf starting in 2002 and rising to 565 bcf by 2005. In **Charts 2** and **3**, we lower these estimates and assume that gas imports from Turkmenistan reach 353 bcf in 2006 and remain constant until 2011 when they reach 530 bcf.

Chart 2 - Gas Demand Projections and Contracted Supplies in Turkey (tcf)



Source: World Gas Intelligence (March 25 & June 29, 1999) and BOTAS (June 1998).

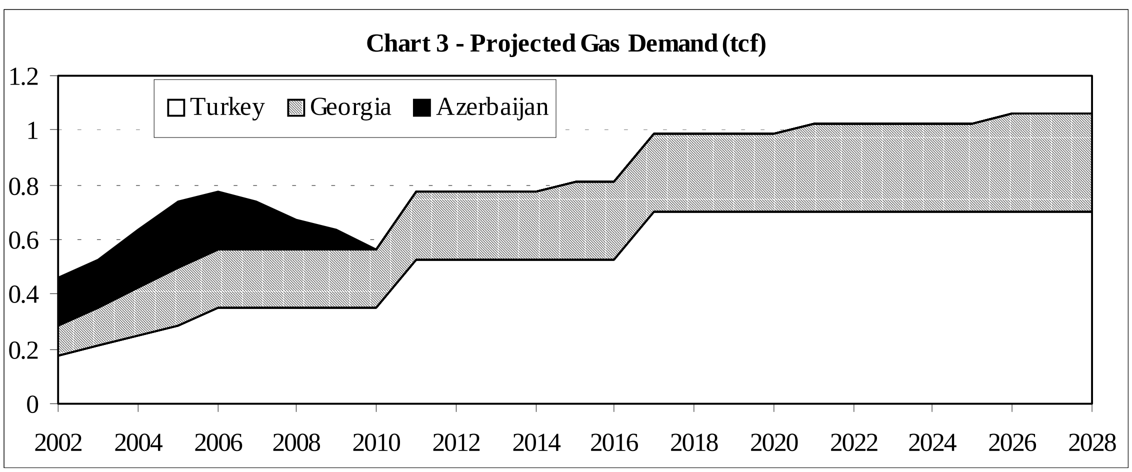
[3] Chart 2 represents these new amounts.
[4] The Caspian Sea poses its own challenges. The consensus among analysts, however, is such that the construction of the undersea portion of Blue Stream will be more challenging than the construction of the undersea portion of the Trans-Caspian pipeline. Further analysis of both projects may change this consensus.

Georgia

Although there is sufficient infrastructure for gas delivery in Georgia, significant investment is required to rehabilitate it. In 1992, Georgia imported 173 bcf of gas from Turkmenistan via the Russian pipeline system. In 1998, Georgia consumed about 53 bcf of gas – imported from Russia. If residential and commercial consumers can get access to gas, then Georgian gas demand will readily exceed 100 bcf per year. Those residential consumers who have access to gas are paying about $4.25/mmBtu whereas others are using electricity or LPG for their cooking and heating requirement. LPG is very expensive, with consumers having to pay as much as $14/mmBtu. The electricity market is privatized in Georgia and consumers have been paying their bills. When gas becomes available, consumers may happily switch from LPG to gas and should be able to pay for it. Georgia is in the process of privatizing local gas distribution companies with some smaller companies already privatized. For these reasons, the usual apprehension about the ability of customers in transition economies to pay for energy services does not seem to be applicable in the case of Georgia. Georgia also needs roughly 36 bcf a year for its power plants. World Bank officials acknowledge the potential of the Georgian gas market (*World Gas Intelligence*, August 12, 1999, page 6).

In **Chart 3**, we assume that Georgian demand for Turkmen gas would steadily increase from about 100 bcf in 2002 to 353 bcf in 2026 from both factors – switching from LPG to gas for domestic fuel and gas-fired electric power production. Basically, we assume that Georgia will go back to the consumption level of the early 1990s during the 2002-2010 period.

Since 1996, Georgia has had one of the fastest growing economies around the world, with GDP growth at over 10 percent for 1996 and at 11.3 percent in 1997. GDP continued to grow significantly in 1998 at about 7 percent despite the global economic crisis. 1998 GDP is estimated around $4.8 billion. In terms of purchasing power parity, this corresponds to a per capita GDP of $1,400. As in Turkey, however, per capita income is probably significantly higher in industrialized parts of the country and in major cities such as Tblisi.



Azerbaijan

Azerbaijan is similar to Georgia in that there is a well-developed gas infrastructure. Because of a limited supply of gas, consumption is considerably below the potential demand. Azerbaijan consumed 560 bcf in 1990 as compared to 184 bcf in 1998. Unlike Georgia, Azerbaijan has been subsidizing residential gas consumers considerably (gas to these consumers is nearly a “free good”) while charging the industrial consumers more or less market prices. In recent years attempts have been made to charge higher prices to the residential consumers.

Azerbaijan aims to increase domestic consumption of gas. Although the country is expected to develop its own resources and be self-sufficient by 2010, Azerbaijan may turn to one of its old suppliers, Turkmenistan, in the interim period. However Azerbaijan's ability to become self-sufficient depends upon how rapidly the country will be able to develop its recently discovered Shakh Deniz field which may contain as much as 11.3 tcf to 19.8 tcf of gas. In Chart 3, we assume that Azerbaijan consumes 172 bcf of Turkmen gas a year on average between 2002 and 2009, starting at 177 bcf in 2002 and peaking at 247 bcf in 2005. After 2010, Azeri gas will substitute for Turkmen gas. But this substitution can happen even earlier. If Shakh Deniz field economics turns out to be very attractive and gas can be produced at competitive prices with respect to Turkmenistan's gas, then Azerbaijan may become a tough competitor to Turkmenistan.

The Azeri economy is not performing as well as that of Georgia. In 1997, GDP was estimated at $4 billion, which translates into about $500 per capita GDP in terms of purchasing power parity. Nevertheless, the economy grew at 1% in 1996 and at 6% in 1997. Also, Azerbaijan continues to attract significant investment in its oil and gas sector. The Trans-Caspian pipeline will likely stimulate gas infrastructure development and rehabilitation in Azerbaijan as well. However, consumers' ability to pay remains an open question.

NPV Analysis of the Trans-Caspian Pipeline

From Chart 1, it is obvious that Turkmenistan has the potential of exporting more than 2 tcf of natural gas annually if the country had an alternative pipeline and paying customers along the way of that pipeline. Our goal is to evaluate whether the 2,000-km (1,250-mile) Trans-Caspian pipeline can be that alternative. Accordingly, we developed a model where the demand profiles for Azerbaijan, Georgia and Turkey represented in Chart 3 are used.[5] These profiles are then altered in certain scenarios to analyze the impact of lowered and/or delayed gas sales on the commercial viability of the project. Other key variables of the model, the range of possible values, and the values used for the base case are summarized in **Table 3**.

Table 3 – Factors Influencing the Economics of the Trans-Caspian Pipeline [a]

Variables	Range	Base Case [b]
IRR needed by pipeline investors	15-25%	20%
Investment	$2.4 – 3.45 billion	$3 billion
Equity (% of total investment)	30%	30%
Debt (total investment – equity)	70%	70%
Interest rate	10%	10%
Operating cost (% of total investment)	4-4.5%	4.5%
Transit fee [c]	$0.08/mmBtu	$0.08/mmBtu
Tariff	$1.08-2.00/mmBtu	$1.36/mmBtu
Cost of gas	$0.28-0.69/mmBtu	$0.42/mmBtu
Price of gas – Average	$2.03-2.19/mmBtu	$2.03/mmBtu
Price of gas – Turkey	$2.22-2.44/mmBtu	$2.22/mmBtu
Price of gas – Georgia	$1.81-1.97/mmBtu	$1.81/mmBtu
Price of gas – Azerbaijan	$1.67-1.83/mmBtu	$1.67/mmBtu
Cumulative Gas Sales	14.3-22.7 tcf	22.7 tcf
Tax rate	25%	25%

Notes: [a] *To obtain $ figures for 1,000 cm multiply with 36.* [b] *By "base case," we do not imply the most likely scenario, just a likely scenario. In terms of IRR and investment, however, the base case represents roughly the middle of our ranges. Also, other scenarios are more easily represented relative to the "base case."* [c] *Transit fee is applied only to gas not delivered to Azerbaijan and Georgia.*

[5] Note that we assess the commercial viability of the pipeline independent of the timing of its construction. Although in Charts 2 and 3 we assume that the pipeline will start delivering gas in 2002, this may be delayed as our discussion on the potential of Turkish gas market and other supply alternatives indicates. However, this delay will not affect the results of our analysis.

With the assumptions of the base case, the model yields the following results. The net present value (NPV) of total gas revenues over 30 years of operations is $10.4 billion. The NPV of pipeline (tariff) revenues is $1.8 billion and the NPV of transit fees (earned by transit countries, Azerbaijan and Georgia) is about $608 million. The NPV of sales to Turkmenistan is $1.3 billion. In short, for all stakeholders involved with the project, there will be positive returns.

As noted earlier, the base case is just a likely scenario, not necessarily the most likely scenario. As our previous discussion indicates, there are significant risks associated with this project, including fluctuations in the cost of the pipeline, demand forecasts and other geopolitical complications of the region. In order to address these issues, we analyze seven different scenarios. **Table 4** summarizes assumptions of each scenario that are different than the base case reported in column three of Table 3. All other assumptions are the same as in the base case. By design, pipeline investors are assured a minimum return. We account for this by adjusting the tariff rates. In column three of Table 4, we report these tariff rates.

Table 4 – Scenario Analysis

Scenario	Changes from the Base Case	Tariff Rate [a]
Base Case		$1.36 / $49
A	IRR requirement is reduced to 15%.	$1.14 / $41
B	IRR requirement is increased to 25%.	$1.56 / $56
C	The investment is lowered to $2.4 billion.	$1.08 / $39
D	The investment is increased to $3.45 billion.	$1.53 / $55
E	The investment is increased to $3.45 billion and prices are raised to $1.83 in Azerbaijan, $1.97 in Georgia and $2.39 in Turkey.	$1.50 / $54
F	No sales to Azerbaijan: cumulative sales are reduced to 21.4 tcf.	$1.64 / $59
G	No sales to Azerbaijan and Georgia; but investment is lowered to $2.4 billion, operating cost is lowered to 4% of the investment and the price in Turkey is raised to $2.44.	$2.00 / $72

Notes: [a] First figure is $ per mmBtu and the second figure is $ per 1,000 cm.

The first two scenarios represent potential changes in pipeline investors' perception of the project risk. An improvement in this perception is shown as a five-percent decline in the required IRR (scenario A), and a perception of higher risk is presented as an increase of five percent in the required IRR (scenario B). The next two scenarios are run to cover the range of estimates found in the industry press for the cost of building the Trans-Caspian pipeline.[6] Scenario E explores the impact of higher gas sale prices on the project even if the pipeline costs are high. In scenario F, we assume that Azerbaijan does not purchase any gas from this pipeline. Given the significant decline in returns to Turkmenistan under scenario F, we do not represent another scenario where sales to Georgia are eliminated, as the latter would obviously yield negative returns to Turkmenistan. Instead, we offer scenario G where the only buyer of Turkmen gas is Turkey, but the pipeline costs are low and Turkey pays a higher price.

Chart 4 compares the key results for each of these scenarios with those of the base case: cashflows to three main stakeholders, Turkmenistan (producer),[7] pipeline investors/operators (tariff revenues) and transit countries. From Chart 4, it is clear that Turkmenistan's returns (production cashflow) are most sensitive to changes in certain crucial variables. On the other hand, transit countries and pipeline

[6] Recently, the option of expanding the capacity of Baku-Supsa oil pipeline as the first leg of Baku-Ceyhan pipeline has gained prominence. Building the Trans-Caspian gas pipeline along the oil pipeline is considered to decrease costs, at least based on rights of way agreements. In that case, the cost of building the pipeline will more likely be near the low end of our estimates.

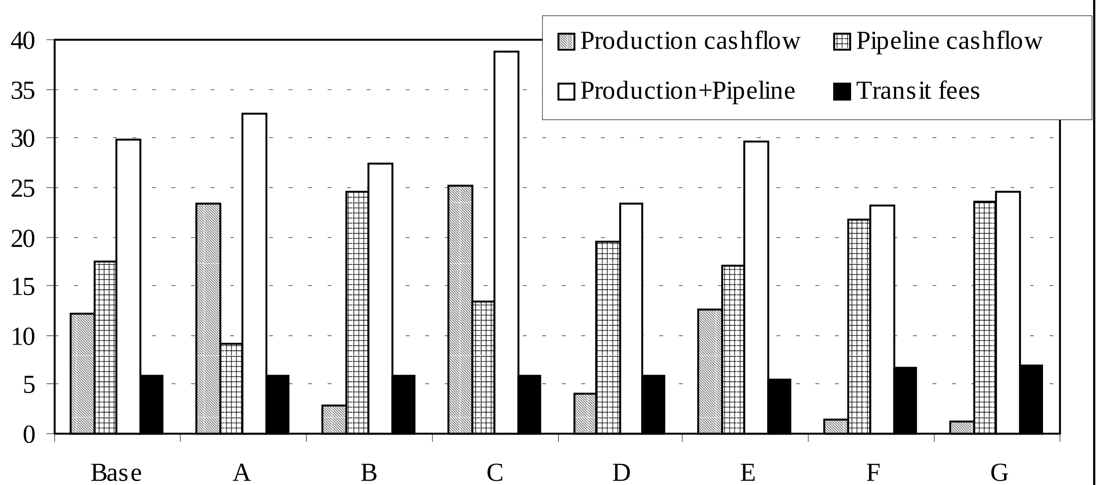
[7] Currently, almost 95 percent of natural gas is produced by the state company Turkmengas.

operators are guaranteed significant returns. The NPV of transit countries' revenues range from $480 million (scenario G) to $608 million in all other scenarios. The NPV of pipeline cashflows range from $960 million (scenario A) to about $2.6 billion (scenario B). In contrast, the NPV of production cashflows to Turkmenistan is $129 million in scenario F (no sales to Azerbaijan) and $80 million under scenario G. This last scenario is important in that it yields positive NPV for Turkmenistan even when Turkey is the only buyer, albeit under low investment and high price assumptions.[8]

Based on these results, we can draw a number of inferences. First, transit countries, Azerbaijan and Georgia, are clearly winners. In addition to collecting transit fees, they will have a more diversified portfolio of gas suppliers. This will certainly lower the cost of gas in these countries. For Azerbaijan, this pipeline will also provide a potential alternative to export gas in the future when the country develops its own gas resources.[9]

Second, in the long value chain of gas supplies from exploration and production to transportation to distribution, it is those involved in E&P who take the maximum risk and should get the maximum return, followed by those involved in transporting gas and finally distribution companies. However in the case of the Trans-Caspian pipeline transmission and distribution companies receive higher returns. Today in Georgia, gas to the residential consumers is sold at about $4.25/mmBtu, which is considerably higher than the gas supply cost of $1.7-2.00/mmBtu. This indicates an attractive margin to the distribution companies. Also, in Turkey the price of natural gas in electricity generation has been around $4.5/mmBtu ($6/mmBtu for residential users), which leaves BOTAS and/or municipally-owned LDCs with a decent margin even if BOTAS pays the high end of our price range, $2.44/mmBtu (unless tariff is larger than $2/mmBtu).[10]

Chart 4 - NPV of Key Returns as Percent of Total Gas Revenues



[8] Note that under this scenario, cost to Turkey including tariff and transit fees is about $4.52/mmBtu, which is about 8 percent higher than the current BOTAS price.

[9] There is already talk about this potential since BP Amoco's discovery of large gas resources in Shakh Deniz.

[10] In power generation, the price of natural gas in Turkey is about equal to the price of fuel oil and more than twice the price of lignite in net calorific basis (IEA/OECD *Energy Prices and Taxes*). However, coal-fired plants cost almost twice as much, take longer to build and are less efficient. In addition to these factors, increasing environmental awareness have been pushing Turkey toward gas-fired generation. So, attractive margins should remain.

As shown in Chart 4, in all scenarios excepting two (scenarios A and C), pipeline investors get higher cashflows than the producers do. This situation can be defended since the pipeline investors are taking the bigger risk. Even after getting take or pay contracts from all three consuming countries, the pipeline company is still exposed to the possibility of not being able to sell gas at the forecast level which will affect the cashflows. It may not be possible to eliminate political risks completely or to depend on political risk insurance for recovery. If Turkmenistan participates in the pipeline consortium, these risks can become more tolerable for other partners and, in return, Turkmenistan may benefit from the pipeline revenues to support its production cashflow. The "Production + Pipeline" column in Chart 4 shows the more stable nature of these returns when combined.

Conclusion

The Trans-Caspian pipeline is commercially viable and would bring positive returns to Turkmenistan **under most scenarios**. Our conclusion holds true even if Turkey is the sole buyer of Turkmen gas, albeit with low investment cost and high price assumptions (still within industry norms). Obviously, there are risks associated with the project and one can develop scenarios such that the project may no longer be viable or Turkmenistan may no longer receive positive returns. *Turkmenistan's participation in the pipeline consortium may be required not only to share these risks with other partners but also to increase the country's returns via a stake in pipeline revenues, which appear to be larger than production revenues in most cases.*

There have been doubts about Turkey's ability to intake all the gas the country agreed to buy from different suppliers because of delays in power plant development. However, the new legislation passed in August allows for international arbitration and limits the review of contracts by high courts. This improved environment should stimulate investment in new power plants. Liberalization of the natural gas market is also being discussed, which may increase the natural gas demand in Turkey. A recent announcement by Iran to delay and cut the amount of its gas imports to Turkey creates an opportunity for other suppliers, including Turkmenistan. At the same time, although our analysis indicates that the Trans-Caspian can survive along with Blue Stream and Iranian supplies, competitors, including Egypt and Iraq, are targeting the Turkish market as well. Therefore, there is pressure on Turkmenistan along with project companies and other supporters to expedite the realization of the Trans-Caspian pipeline.

Our analysis is also supported by the strategic benefits of the pipeline, which cannot always be represented in dollars but are equally important for countries in the region as well as for the U.S. and EU. Both Turkish and Turkmen officials consider the Trans-Caspian gas pipeline very valuable in terms of diversifying import sources (export routes) for Turkey (Turkmenistan) as well as strengthening relationships between Turkey and Turkmenistan. For successful diversification and to get the best price, Turkey can definitely use all supply options available. The fact that there will/may be excess capacity in any of these pipelines at any time provides Turkey with the opportunity to negotiate the best price and forces exporters to compete with each other. On the other hand, the pipeline provides Turkmenistan with a valuable bargaining tool against Gazprom. Today, the country is not in a position to negotiate with Russia for the use of Gazprom's pipeline system since it does not have any other alternative (except for limited exports to Iran) to export its huge developed gas reserves.[11] Also, once the Trans-Caspian pipeline is built and the cost for gas supply to Turkey is incurred, it should be economically attractive to supply gas to Europe. The economics can be even more attractive if gas can be swapped with Russia.

[11] The application of financial and economic option valuation methods to the analysis of natural gas pipelines indicates that uncommitted capacity in a pipeline is a valuable asset and possesses the payoff attributes of a call option. For details, please see "An Option Valuation Model for Options on Capacity in Integrated Landbased and 'Seaborne' Trunklines for Natural Gas and LNG" by Gregory Pickett in Conference Proceedings of 20th Annual North American Conference of USAEE/IAEE.