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THE BAKER INSTITUTE WORLD GAS TRADE MODEL

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About the Geopolitics of Natural Gas Study

Natural gas is rapidly gaining in geopolitical importance. Gas has grown from a marginal fuel consumed in regionally disconnected markets to a fuel that is transported across great distances for consumption in many different economic sectors. Increasingly, natural gas is the fuel of choice for consumers seeking its relatively low environmental impact, especially for electric power generation. As a result, world gas consumption is projected to more than double over the next three decades, rising from 23% to 28% of world total primary energy demand by 2030 and surpassing coal as the world's number two energy source and potentially overtaking oil's share in many large industrialized economies.

The growing importance of natural gas imports to modern economies will force new thinking about energy security. The Energy Forum of the James A. Baker III Institute for Public Policy and the Program on Energy and Sustainable Development at the Stanford University Institute for International Studies are completing a major effort to investigate the geopolitical consequences of a major shift to natural gas in world energy markets. The study utilizes historical case studies as well as advanced economic modeling to examine the interplay between economic and political factors in the development of natural gas resources; our aim is to shed light on the political challenges that may accompany a shift to a gas-fed world.

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About the Authors

Peter R. Hartley is chairman of Rice University's Department of Economics and is widely published on such theoretical and applied economic issues as money and banking; business cycles; utilities and airlines regulation; internal financial and energy, environmental, health, and labor economics. His current research at Rice involves development of Rice's World Gas Trade Model; study of financial intermediaries, liquidity and borrowing constraints, and applied microeconomics. He gained policy experience as a member of the a team of economists advocating and advising on reform of the Australian electricity supply industry and worked for the prime minister's department in the Australian federal government in the mid-'70s.

Kenneth B. Medlock III is currently a visiting professor of economics at Rice University and energy consultant to the James A Baker III Institute for Public Policy. Prior to returning to Rice, Dr. Medlock served as a corporate consultant at El Paso Energy Corporation. While at El Paso, he was responsible for fundamental analysis of North American natural gas, petroleum, and power markets. He also served as the lead modeler on the Modeling Sub-group for the National Petroleum Council study of long-term natural gas markets in North America, which was released 2003. From May 2000 to May 2001, Dr. Medlock held the MD Anderson Fellowship at the James A. Baker III Institute for Public Policy. He received a doctorate in Economics from Rice University in May 2000 and his areas of research specialization are in the fields of energy and environmental economics and policy and macroeconomic theory. Dr. Medlock has published several articles and book chapters on energy economics including articles in *The Energy Journal* and *The Journal of Transport Economics and Policy* and is co-winner with Dr. Ronald Soligo for the 2001 Best Paper Prize from the International Association for Energy Economics.

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The Baker Institute World Gas Trade Model

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ABSTRACT

This working paper describes a spatial and intertemporal equilibrium model of the world market for natural gas. Specifically, the model calculates a pattern of production, transportation routes and prices to equate demands and supplies while maximizing the present value of producer rents within a competitive framework. Data incorporated into the specifications of supplies and demands in each location are taken from a variety of sources including the *United States Geological Survey*, the *Energy Information Administration*, the *International Energy Agency*, the *World Bank* and various industry sources. A subsequent working paper uses the model to investigate the possible effects of a number of scenarios including possible political developments.

INTRODUCTION

Natural gas has increased from roughly 19% of world primary energy demand in 1980 to about 23% in 2002.[1] Natural gas is now produced and consumed in 43 countries around the world, and the *International Energy Agency* (IEA, 2004) predicts that world natural gas demand will be about 90% higher by 2030. They also project the share of gas in world primary energy demand to increase from 23% in 2002 to 25% in 2030, with gas potentially overtaking coal as the world's second largest energy source. The IEA predicts that the power sector will account for 60% of the increase in gas demand.

[1] Figures are based on Energy Information Administration (EIA, 2004).

Much of current world production of natural gas is coming from mature basins in the United States and the North Sea.[2] Russia, the second largest current producer after the United States, currently accounts for almost one quarter of world production of natural gas but has substantial reserves that remain untapped. Furthermore, Russia and the countries of the former Soviet Union[3] rank first globally in undiscovered natural gas potential.[4] These countries already export considerable quantities of natural gas to Europe, and they are expected to become important suppliers to the growing needs in Asia.

The countries of the Middle East also have substantial natural gas resources, both proved and potential, which are relatively untapped. With the reemerging interest in LNG, the Middle East is well positioned to become a major supplier given its proximity to growing markets for gas imports in South Asia and Europe. Particular interest in developing export projects in Qatar and Iran reflect those countries' massive reserves and strategic location to serve growing markets in both the East and the West.

European demand for natural gas currently totals more than 18 trillion cubic feet (tcf) per year. The Russian state-monopoly Gazprom supplied European countries with 4.8 tcf of gas in 2003, and it has contracted to increase this to 6.6 tcf by 2010. However, to meet rising European demand for gas, Russia will need to further develop natural gas fields on the Yamal peninsula and Shtokmanovskoye region, as well as build new infrastructure for delivery. Similarly, Italy recently completed a new pipeline to import natural gas from Libya. European buyers are also considering additional purchases of LNG from various sources in Africa and the Middle East, with new LNG importing terminals under consideration in various locations in Western Europe.

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[2] Reported reserves in the U.S. have actually increased in each of the past few years. However, much of the increase has been in unconventional deposits that typically produce at lower rates, such as coal bed methane in the Rocky Mountains. Lower production rates, ceteris paribus, distribute cash flows more toward the future, thus lowering the NPV of such deposits. Unconventional deposits may also have higher per unit costs of exploitation. Hence, as production shifts to unconventional deposits, the long run market price must be higher to justify the capital outlay.

[3] Hereafter, these countries will be referred to collectively as the FSU.

[4] United States Geologic Survey, *World Resource Assessment, 2000.*

It has also been proposed that Russia build natural gas pipelines to China and South Korea from producing areas in East Siberia and to Japan and South Korea from the Sakhalin Islands. Gazprom estimates that gas reserves in the Russian Republic of Sakha/Yakutia and in East Siberia total about 230 tcf and that these regions have a production potential of at least 2 tcf per year. Other estimates put probable reserves for the Russian Far East at 50 to 65 tcf for the Sakhalin Islands, 35 tcf for Yakutia and 50 to 105 tcf for East Siberia.[5]

A consortium led by Royal Dutch Shell has announced that it will be building a major LNG liquefaction facility on the Sakhalin Islands. The expected primary consuming markets for Sakhalin LNG are in Japan and South Korea, with potential delivery to China and the U.S. West Coast. Royal Dutch Shell's $10 billion Sakhalin energy project is expected to export 234 bcf per year of LNG by 2007, increasing to 468 bcf in the next decade. The Shell consortium Sakhalin-2 block is said to contain up to 16 tcf of natural gas. Another consortium, led by ExxonMobil and including Gazpromneft, is developing the Sakhalin-1 project. This project could supply Japan, via pipeline, with up to 300 bcf of natural gas per year. The Sakhalin-1 area is said to contain as much as 14 tcf of natural gas.[6] Several other consortiums have plans to develop other Sakhalin projects in the future. For example, in return for bringing Gazprom into Sakhalin-2, Shell may receive acreage in Sakhalin-3 when it is re-tendered next year.[7] Gazpromneft also has a 51% stake in a joint venture with BP to develop Sakhalin-5 acreage.

Strategically, Russian natural gas supplies could become an important source of diversification for Japan, China and South Korea from dependence on energy supplies from the Persian Gulf. More generally, increased volumes of Russian gas exports to Asia could have considerable ramifications for liquefied natural gas (LNG) pricing to Asia.

[5] Troner, Alan, "Japan and The Russian Far East: The Economics and Competitive Impact of Least Cost Gas Imports", Baker Institute working paper, available at www.bakerinstitute.org.
[6] Troner, op cit and Hartley and Brito, "Using Sakhalin Natural Gas in Japan", Baker Institute working paper available at www.bakerinstitute.org.
[7] "Sakhalin-2 to Expand –With Gazprom Aboard" World Gas Intelligence, October 13, 2004

In coming decades, North America is also projected to become a major importer of LNG. Although U.S. annual net imports of natural gas have exceeded 1 tcf since 1988, rising to more than 3 tcf after 1999, most of this has come from Canada via pipeline. LNG was imported from Algeria in small quantities in the late 1970s and early 1980s, while other sources have included Australia, Nigeria, Oman and Qatar (all in the late 1990s). In the last few years, however, Trinidad and Tobago has emerged as a more substantial source of LNG imports to the US. The internet publication *Power Market Today* from Intelligence Press Inc[8] noted on November 28, 2004 that, "as of September 2004, … [the] four operating … LNG import terminals in North America [had] a combined peak [output] capacity of 3.105 bcf per day and expansion plans for another 2.63 bcf per day. In addition, there were plans for another 46 LNG import terminal projects with an expected total combined peak [output] capacity of more than 45 bcf per day. Of those 46 terminals, eight, with a total peak [output capacity] of 8.9 bcf per day, had received final regulatory approvals. Another 24 projects are already in various stages of the regulatory approval process, and 14 additional LNG projects remain in the planning stages." The EIA (International Energy Outlook 2004) projects imports of LNG into North America of 4.8 tcf per year in 2025. Many industry analysts regard this estimate to be conservative.

China and India are also expected to be major users of natural gas in the coming years. Both countries have already begun importing LNG, and each is considering a variety of proposals to import natural gas via pipeline. In the case of India, proposed source countries include Iran, Myanmar, and Bangladesh, while pipelines linking China to Kazakhstan and Vietnam have been mooted in addition to, or perhaps as alternatives to, the Russian-Chinese links discussed above.

These developments foreshadow a substantial expansion in world trade in natural gas. Until recently, natural gas markets were isolated from each other. Limited availability of regasification, shipping, and liquefaction capacity, as well as prohibitive costs, constrained the exploitation of remote gas deposits and inhibited the flow of LNG from one region of the globe to another. Asia was the early focus of the LNG business, and Japan remains by far the largest importer of LNG, consuming close to two-thirds of all LNG traded worldwide. South Korea is

[8] Available at http://intelligencepress.com/features/lng/

the second largest importer. Although LNG represented roughly 5% of world natural gas consumption in the 1990s, LNG is expected to take a larger share of the global gas market in the coming decades. In recent years, many of the costs associated with the movement of LNG to distant markets have fallen, creating new opportunities for LNG to compete in expanding world natural gas markets.

THE BAKER INSTITUTE WORLD GAS TRADE MODEL

The Baker Institute World Gas Trade Model (BIWGTM) provides a framework for examining the effects of critical economic and political influences on the global natural gas market within a framework grounded in geologic data and economic theory. The resource data underlying the model is based on an assessment produced by the United States Geological Survey (USGS). That supply data is combined with economic models of the demand for natural gas, which include important determinants of natural gas use such as the level of economic development, the price of natural gas, the price of competing fuels, and population growth. The costs of constructing new pipelines and LNG facilities have been estimated using data on previous and potential projects available from the EIA and industry sources.

The extent of regional detail reflects not only the availability of data but also the issues that will be later examined in case study scenarios. For large markets, such as China, the U.S., India and Japan, sub-regional detail has been created to gain more accurate results. In these cases, *intra*-country capacity constraints could have a significant effect on the current or likely future overall pattern of world trade in natural gas.

The BIWGTM is a dynamic spatial general equilibrium model. The solution algorithm is based on the software platform *Market Builder* from *Altos Management Partners*, a flexible modeling system widely used in industry. The software calculates a dynamic spatial equilibrium[9]

[9] The equilibrium solution need not be economically efficient. It would be if all capital and other costs represented true opportunity costs, but this need not be the case. For example, a monopoly supplier might earn excess returns on a natural gas deposit by delaying development. The excess returns on capital invested in gas production would then result in an inefficient allocation of resources. The model also allows for taxes, which generally will produce an inefficient outcome.

where supply and demand is balanced at each location in each period such that all spatial and temporal arbitrage opportunities are eliminated.[10] The model thus seeks an equilibrium in which the sources of supply, the demand sinks, and the transportation links connecting them, are developed over time to maximize the net present value of new supply and transportation projects while simultaneously accounting for the impact of these new developments on current and future prices. Output from the model includes regional natural gas prices, pipeline and LNG capacity additions and flows, growth in natural gas reserves from existing fields and undiscovered deposits, and regional production and demand.

Transportation links connecting markets transmit price signals as well as volumes of physical commodity. Thus, for example, building a new link to take gas to a market with high prices will raise prices to consumers from the exporting region and lower prices in the importing region. More generally, it is in this manner that markets become increasingly connected over time as profitable spatial arbitrage opportunities are exploited until they are eliminated. In a *global* natural gas market as predicted by the BIWGTM, events in one region of the world generally influence all other regions. For instance, political factors affecting relations between Russia and China will affect gas flows and prices throughout the world, not just in northeast Asia.

MARKET STRUCTURE IN THE BIWGTM

Current and projected increases in the demand for natural gas, as well as the desire on the part of producers to monetize stranded natural gas resources, have expanded the depth and geographical extent of both sides of the LNG market. Expanding the market alternatives available to both producers and consumers of natural gas reduces the risk of investing in infrastructure, thereby encouraging further development of the natural gas market. Moreover, with a greater number of available supply or demand alternatives and growth in the size of end-

[10] The absence of intertemporal arbitrage opportunities within the model period is a necessary but not a sufficient condition for maximizing the present value from resource supply. Since future exploitation is always an alternative to current production, a maximizing solution also requires that a value of the resource beyond the model time horizon be specified. In our model, the required additional conditions are obtained by assuming that a "backstop" technology ultimately limits the price at which natural gas can be sold.

use markets located around the globe, the average distance between neighboring suppliers or neighboring demanders falls, increasing the opportunities for price arbitrage. The resulting increase in trading opportunities increases market liquidity.

An increase in market liquidity could produce a relatively rapid shift in the market equilibrium away from long-term bilateral contracts to a world of multilateral trading and an increased number of commodity trades. The explanation is that market structure is partly endogenous. Expectations about the future evolution of the market influence investment and trading decisions today, and these, in turn, further influence market developments tomorrow. Once market participants begin to expect a change in market structure, their investment decisions accelerate the change.[11]

The model examined in this paper assumes that such a change in market structure has already occurred by treating LNG as a commodity that is traded somewhat analogously to the way oil is traded today. Thus, while the near term evolution of the market will most likely be dictated by contract rigidities, we have assumed that the market will evolve according to a long-term solution characterized by more flexibility. Long-term contracts are allowed to affect the risks borne by different parties, but not physical flows of gas. Evidence of emerging corporate behavior in the gas world, and in particular the increasing prominence of swap agreements and spot sales, supports this approach. In essence, we assume that the LNG as well as the pipeline gas market behave as if contracted trades can be swapped with alternative cargoes whenever such arrangements are cost effective. Even today, this is generally true in the longer term, where any contracted flow that is not least cost can be, and usually is, replaced by swap arrangements that allow the financial terms of contracts to be satisfied regardless of where physical delivery actually occurs.[12] The financial arrangements in the contracts, however, will affect risks and the ability to swap deliveries significantly.[13]

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[11] Brito and Hartley (2001) present a formal model of the evolution of the LNG market from a world of long-term bilateral contracts to one where LNG is traded more like the way that oil is traded today. A key implication of their analysis is that multiple equilibrium outcomes are possible, so that small changes in costs can dramatically change market structure.

[12] During industry review of this effort, it was generally agreed that this approach best captures the current transition of global LNG markets. Increasingly, deliveries are being made through

DEMAND FOR NATURAL GAS

Economic growth, expanding power generation requirements, and environmental considerations are the primary explanations for projected rapid increases in natural gas demand. According to the EIA (International Energy Outlook 2004), natural gas consumption in Europe is projected to rise by about 2.0% per annum in the next 2 decades, as governments encourage natural gas as an alternative to more carbon intensive fuels such as oil and coal. In North America, natural gas use is expected to rise about 1.4% per year, with growth in the power generation sector expected rise even faster. Mexican demand is expected to rise by about 3.9% per year through 2025 as the Mexican government pursues policies to replace oil as a fuel for electricity generation. Rapid economic growth in developing Asian countries is expected to result in increases in natural gas demand of about 3.5% per annum through 2025, with Chinese demand forecast to grow at an astounding 6.9% per year and Indian demand at 4.8% per year over the same time horizon. This growth will occur primarily in electricity generation, but residential and commercial cooking and heating, and industrial demand, will also expand.

Demand for natural gas in developed economies has been spurred by increasingly stringent environmental controls. Natural gas is less polluting than coal or oil and does not present some of the problems, such as waste disposal, that are associated with nuclear power. Deregulation of wholesale electricity markets also has increased the demand for generating plants with smaller economies of scale, which has been met by the simultaneous development of combined cycle gas turbines (CCGT).[14] Prior to the development of CCGT, gas turbines had much lower capacities than coal or nuclear plants and were only used as peaking plants. CCGT technology raised both the economically efficient scale of operation and the thermal efficiency of gas plants. The greater thermal efficiency of CCGT plants also allows them to have similar operating costs to coal plants even though natural gas feedstock is more expensive than coal on a

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swaps that allow producers to deliver to the lowest cost destinations relative to the location of their production facilities.

[13] In a model examined later, we use different discount rates for producers in different regions to reflect varying degrees of political risk.

[14] Deregulation has increased competition in the provision of new electricity generation plants. As shown for example by Hartley and Kyle (1989), more competitive electricity markets favor more frequent construction of generating plants, with each new plant having a smaller capacity.

per BTU basis. Consequently, CCGT plants operate for longer hours in the year than did the older style gas turbines, which, in turn, raises the demand for natural gas.

Developments in the transportation sector could accelerate projected trends as technologies that convert natural gas into transportation fuel could further increase the demand for natural gas. Already, compressed natural gas is used as fuel for mass transit bus systems, taxicabs and commercial vehicles in many large cities in the United States, Canada, and elsewhere. In addition, innovations in the development of hydrogen fuel cells target natural gas as a primary fuel source. The demand for transport fuels may also indirectly increase the demand for natural gas as an input into the production of unconventional oil resources such as the Athabasca Tar Sands in Western Canada.[15]

Conversely, further development of coal gasification, nuclear or renewable energy technologies may slow the increase in demand for natural gas as a fuel for generating electricity. Since combined cycle gas turbines for electricity generation have played a prominent role in expanding the demand for natural gas over the last two decades, any development that disadvantages natural gas as a means of generating electricity could substantially slow projected growth in natural gas demand.

[15] The tar sands in Alberta have oil potential estimated at about 1.7 trillion barrels of oil, of which approximately 300 billion barrels are thought to be recoverable at reasonable costrrNatural gas is used to produce the power, steam, and hydrogen needed to mine and process tar sands. The huge shovels that scoop up the sand operate on electricity, although the electricity plants also supply excess power to the grid, while co-generated steam is used to separate the bitumen from the sand. Hydrogen separately produced from gas is used to process the bitumen into synthetic crude. Existing oil sands operations use about 900 mcf of natural gas per day, but this is expected to increase to about 2 bcf per day by 2010.

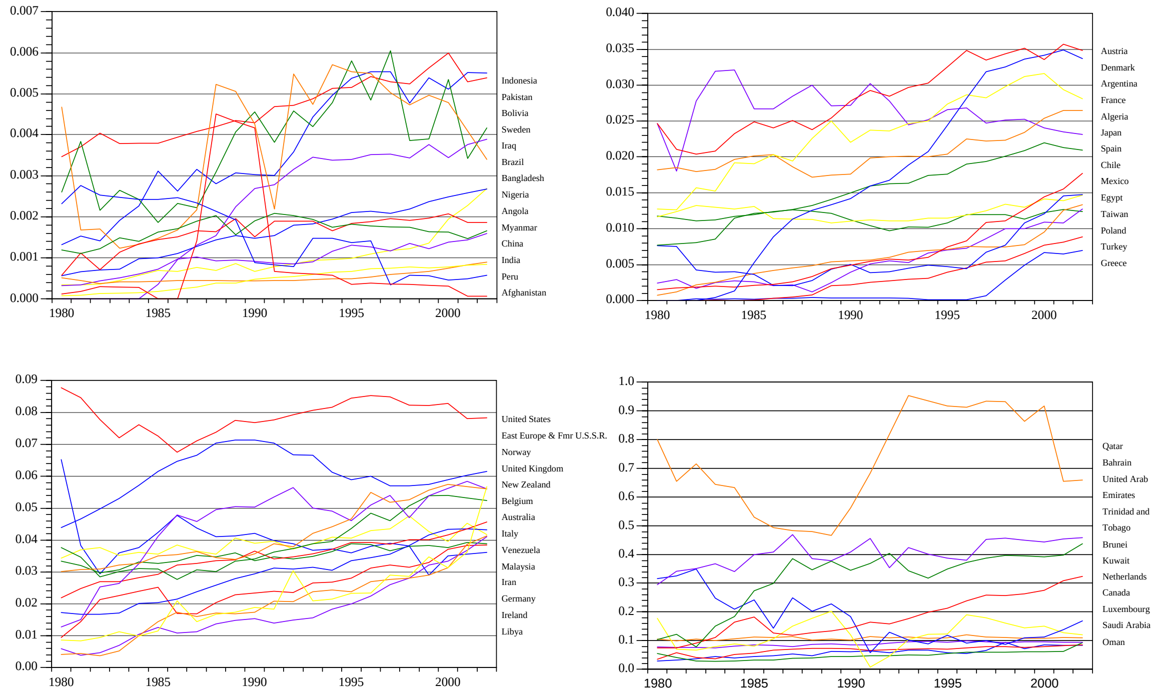

Figure 1: Historical demand for natural gas (annual mcf/person), selected countries

Figure 1 illustrates per capita annual natural gas consumption (in mcf) for a sample of countries over the period 1980–2002.[16] Countries have been grouped into sets with similar levels of per capita consumption. As one moves from the top left panel to the bottom right, the level of per capita gas consumption rises. Generally, per capita consumption tends to increase with the level of economic development both as one moves from one panel to the next and within a given country over time. Resource endowments also play a major role. The largest per capita consumption is found in countries that are major producers, while some countries with smaller per capita consumption, like Sweden, France and Japan, generate a substantial proportion of their electricity from nuclear power plants.

The demand forecasts in the BIWGTM are based on the assumption that there are five major determinants for natural gas demand: population, economic development, resource endowments and other country specific attributes, the relative price of different primary fuels and new technological developments. In constructing the demand relationship, we first estimated

[16] The data comes from the EIA web site.

models to extrapolate patterns of economic and population growth into the future.[17] Following Medlock and Soligo (2001), we then estimated total primary energy demand per capita as a function of the level of economic development. Finally, we estimated a function relating the *share* of natural gas in total primary energy to real energy prices and the level of economic development.[18]

An advantage of this multi-step approach is that theory can guide the choice of functional form at each stage. For example, by choosing a suitable functional form, we can constrain the share of natural gas in primary energy to lie between zero and one. This helps to ensure that demand forecasts that extend substantially beyond the sample period neither expand uncontrollably nor decline precipitously in the face of large out-of-sample changes in the exogenous variables. Although the focus of our analysis extends only through 2040, it is necessary to forecast demand over a much longer period. The reason is that investments depend on expected future prices. As we explain in more detail below, we assume that new technologies will compete with natural gas and ultimately establish a competitive ceiling for natural gas prices. The model time horizon needs to be large enough for this assumption to be realistic.

We use E_{it} to denote the consumption of primary energy in quadrillion (10^{15}) BTU per thousand of population in country *i* and year *t*. We use the level of GDP per capita measured in purchasing power parity terms in 1995 real international dollars (denoted y_{it}) to proxy the level of economic development in country *i* and year *t*. We then estimated the following equation (estimated standard errors are indicated below each coefficient):[19]

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[17] The estimation used data on population and economic growth from the World Bank supplemented by the well known Summers and Heston data set. The latter data has been used for a large number of studies on international economic growth and development. It is available at the Center for International Comparisons, the University of Pennsylvania, http://pwt.econ.upenn.edu/.

[18] Primary energy demand and natural gas demand data were obtained from the EIA web site. The IEA web site provided international energy price data.

[19] The cross-section time series model was estimated on 172 countries with an average of 18.7 years per country (resulting in 3218 total observations). The shortest time series for any country was 7 years while the longest was 21 years (1980-2001). Since the error term was autocorrelated, the lagged dependent variable was instrumented with E_{it-2}, y_{it-1}, and y_{it-1}^2. Autocorrelation in total energy services demand per capita could reflect dynamic interactions between energy supply and the overall level of economic activity. The within country $R^2 = 0.8063$, while the between

$$E_{it} = a_i + \underset{(0.0110)}{0.8228}\ E_{it-1} + \underset{(0.0852)}{0.4040}\ y_{it} - \underset{(0.0051)}{0.0145}\ y_{it}^2 + \varepsilon_{it} \tag{1}$$

where the coefficients a_i are country-specific effects. The positive coefficient on y_{it} implies that per capita energy demand rises as the economy develops, but the negative coefficient on the quadratic term implies that the increase occurs at a declining rate.[20] This result is consistent with the notion that both the income elasticity of energy demand and the energy intensity of a country decline with the level of economic development.[21]

To estimate the own- and cross-price elasticities of demand, we used 23 years of data on 29 OECD economies from the IEA *Energy Statistics and Balances for OECD Countries* that include prices of natural gas, oil and coal. The econometric analysis did not reveal a significant effect of coal prices on the demand for natural gas once oil and gas prices had been included. As a result, coal prices were omitted from the analysis.[22] The estimated equation then related the share of natural gas in primary energy demand in country i and year t (θ_{it}^{NG}) to the real prices of natural gas and crude oil and the level of economic development measured by real GDP per capita (measured in purchasing power parity terms). The latter variable captures the idea that natural gas is a "premium fuel." Increased environmental regulation in wealthier economies encourages the use of cleaner burning natural gas, while higher wealth facilitates the large

country $R^2 = 0.9961$. The F-statistic for the test of joint statistical significance of the country-specific fixed effects was $F_{171,3043} = 2.77$, indicating that there are systematic country-specific differences that are not explained by the level of economic development.

[20] The quadratic only approximates the true relationship, in particular because we would not expect energy per capita to decline. Nevertheless, the quadratic in equation (1) attains a maximum at a per capita income of more than $1.136 million 1995 U.S. dollars, which is more than 10 times any feasible per capita income level for any country in 2100.

[21] See Medlock and Soligo (2001) for more discussion of this issue.

[22] There is more than one plausible explanation for the lack of significance of coal prices. Two such arguments are: (1) since coal varies substantially in quality, coal prices are more difficult to measure and the series we used may therefore contain substantial error, and (2) coal became a close substitute for gas only when CCGT allowed gas to be used for base load power generation, and this occurs only in recent years. Previously, gas turbines competed with fuel oil to generate peak load power.

investments required to deliver gas supplies to customers. The functional form we estimated guarantees that the share, θ_{it}^{NG}, remains bounded between zero and one:[23]

$$\begin{aligned} \ln\left(-\ln\theta_{it}^{NG}\right) = b_i + \underset{(0.0149)}{0.8291}\ \ln\left(-\ln\theta_{it-1}^{NG}\right) + \underset{(0.0059)}{0.0335}\ \ln Png_{it} \\ - \underset{(0.0059)}{0.0302}\ \ln Poil_{it} - \underset{(0.0118)}{0.0677}\ \ln y_{it} + \xi_{it} \end{aligned} \tag{2}$$

for country i in year t and where the country specific effect b_i represents resource availabilities or other characteristics, and the variance of the error differs by country.

By differentiating equation (2), we see that the elasticity of per capita natural gas demand with respect to its various arguments is:

$$\begin{aligned} &\frac{\theta_{t-1}^{NG}}{\theta_t^{NG}}\frac{\partial\theta_t^{NG}}{\partial\theta_{t-1}^{NG}} = 0.8291\frac{\ln\theta_t^{NG}}{\ln\theta_{t-1}^{NG}}, \\ &-\frac{Png_t}{\theta_t^{NG}}\frac{\partial\theta_t^{NG}}{\partial Png_t} = -0.0335\ln\theta_t^{NG}, \\ &\frac{Poil_t}{\theta_t^{NG}}\frac{\partial\theta_t^{NG}}{\partial Poil_t} = -0.0302\ln\theta_t^{NG},\ \text{and} \\ &\frac{y_t}{\theta_t^{NG}}\frac{\partial\theta_t^{NG}}{\partial y_t} = -0.0677\ln\theta_t^{NG} \end{aligned} \tag{3}$$

In particular, the functional form in equation (2) implies that the elasticity of demand for natural gas with respect to prices and per capita GDP declines toward zero as θ^{NG} rises (recall that $\theta^{NG} < 1$, so $\ln\theta^{NG} < 0$). The lagged dependent variable on the right hand side of equation (2)

[23] The combined cross-section time series model was estimated for 29 countries with an average of 18.9 years per country (resulting in 548 total observations). Unlike the energy services demand equation, Hausman tests did not suggest that the lagged dependent variable was endogenous, while allowing for a common first order autoregressive structure across panels produced an estimated coefficient of only 0.0365. Hausman tests also did not suggest that the real prices were endogenous to the natural gas share in any one country. Instead of using instrumental variables, we therefore focused on modeling heteroskedasticity using generalized least squares. Heterogeneity may be more important for the share equation because country specific differences in resource endowments are likely to explain a substantial fraction of the variation in the data. The log likelihood of the cross-sectional time series model was 1054.247, while the chi-square statistic for testing whether the estimated coefficients are jointly significantly different from zero was 106629.16 with 32 degrees of freedom.

implies that the long run elasticity of demand with respect to the prices and per capita income will be approximately 5.85 times larger than the short run elasticity.

Figure 2 illustrates the resulting long run demand curves for various levels of per capita real GDP, *y*. These curves become more inelastic as the share approaches zero or one. If the gas share were close to one, further declines in prices could not greatly stimulate gas demand. Similarly, if the share is already close to zero, price increases will do little to further decrease gas demand.

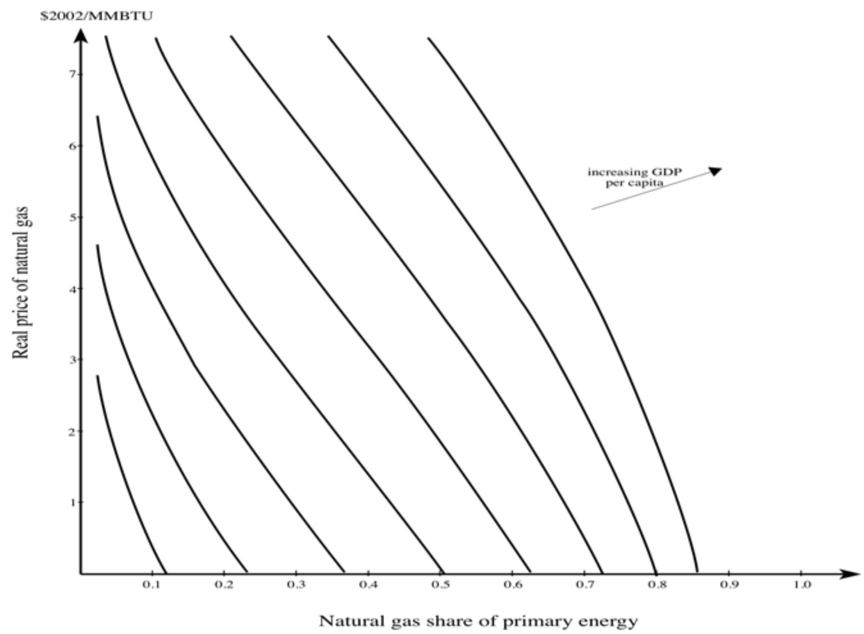

Figure 2: Long-run demand curve for different per capita GDP levels

In order to use equations (1) and (2) to forecast natural gas demand, we need to forecast energy prices, population and real GDP (in purchasing power parity terms) for each country. While the price of natural gas will be calculated endogenously in the model to equate supplies to demands at each demand location, we include an exogenous forecast of the price of oil. In the base case, we assumed oil prices will follow the Reference Case forecast from the EIA's *International Energy Outlook* (IEO), which carries through 2025. Beyond 2025, we linked the oil price projection to a gas price that asymptotes to $5/mmbtu (the backstop price, see discussion below) by 2100. In doing so, we take the ratio of the IEO world oil price and U.S. wellhead price (both in $/mmbtu) in 2025, and hold it constant. This results in a world oil price (in real 2000$) that rises from $27/bbl, or about $4.66/mmbtu, in 2025 to $31.20, or approximately $5.38/mmbtu, by 2100.

Our model of economic growth is based on the notion of economic convergence. In particular, capital and labor mobility, as well as the flow of trade in goods and services, should tend to increase economic growth rates in less developed regions relative to more developed regions. Holding things such as legal institutions and technologies fixed, returns to investment ought to be higher in locations where capital is relatively scarce. Therefore, firms have an incentive to increase investment in those locations rather than locations where capital is relatively abundant. Similarly, if workers can migrate, they also have an incentive to seek employment where their skills earn the highest real wage. Both capital and labor mobility ought therefore to raise per capita income growth rates in locations where per capita income is currently below average and reduce it in locations with per capita incomes above the current average. Furthermore, even in the absence of international flows of capital and labor, trade in goods and services will tend to reduce differences in income. This result is commonly referred to as factor price equalization. Regions with high payments to a particular factor of production will tend to import goods intensive in the use of that factor. This, in turn, will tend to raise factor payments in the exporting country while simultaneously reducing them in the importing one.

Yet another vehicle for convergence involves the diffusion of technology. Wealthier nations have a higher standard of living in part because they use more productive technologies. As those technologies spread into less developed nations, differences in productivity decline. As a result, the spread of technological innovations will also tend to produce convergence of living standards over time.

In our statistical analysis, we use real GDP per capita adjusted for purchasing power parity differences as the basic measure of living standards. We also assume the United States as the leading country. In other words, we assume that the living standards in other countries will tend to converge toward those of the U.S. over the next century. Our empirical specification also assumes that living standards in the U.S. (and by extension in other countries too as they approach the U.S. level) will tend to increase over time but at a diminishing rate. The main motivation for this assumption is that, as the economy matures, economic activity shifts toward the service sector where past technological progress has been low, and foreseeable opportunities for future technological progress appear limited, relative to the manufacturing and agricultural sectors of the economy. Specifically, we estimated the following equation for real per capita GDP growth, defined as $\dot{y}_{it} = \ln y_{it} - \ln y_{it-1}$ in country i in year t (estimated standard errors are in parentheses):[24]

$$\begin{array}{l} \dot{y}_{it} = c_i + \underset{(0.0886)}{0.9362}\ \dot{y}_{it-1} + \underset{(0.1178)}{0.9431}\ (1/\ln y_{it-1}) - \underset{(0.7009)}{6.1930}\ (\dot{y}_{it-1}/\ln y_{it-1}) \\ \qquad - \underset{(0.0030)}{0.0152}\ (\ln y_{it-1} - \ln y_{USt-1}) + \zeta_{it} \end{array} \qquad (4)$$

where c_i is a country specific constant effect (reflecting, for example, persistent differences in legal or political institutions), y_{it} is the level of real per capita GDP in purchasing power parity terms and y_{USt} is the corresponding U.S. real per capita GDP in year t. The variance of the error term, ζ_{it}, was allowed to vary across countries. The negative coefficient on the difference between country i GDP per capita and U.S. GDP per capita implies that per capita growth rates of other countries will tend to converge toward those of the United States over time. The positive coefficient on the inverse log level of per capita GDP ($1/\ln y_{it}$) implies that growth rates will tend to diminish as per capita GDP increases. Furthermore, the negative coefficient on the interaction term implies that growth rates will tend to become more persistent as the economy matures.[25]

Before we used equation (4) to forecast future economic growth, we adjusted the country-specific constant terms c_i. The reason for doing so is that the constants reflect the average experience of a country over the sample period while the recent experience might be more salient

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[24] The equation was estimated for 173 countries with an average sample of 37.6 years for each country and a maximum sample size of 52 years for any one country. The log likelihood of the cross-sectional time series model was 10513.88, while the chi-square statistic for testing whether the estimated coefficients together are significantly different from zero was 1311.39 with 176 degrees of freedom.

[25] Since $1/\ln y$ ranges from a maximum of 0.18 in the sample to a minimum of 0.085 out of sample, the *net* coefficient on the lagged dependent variable ranges from -0.186 to 0.4057, implying that the model is dynamically stable.

for projecting future developments. We therefore calculated a value of c_i for each year from 1996 to 2002 by using the estimated coefficients from the regression and the actual data for each country. We then averaged these values with the estimated constant term, thereby giving increased weight to recent experience.

We also estimated a simple model where economic development reduces population growth rates.[26] Specifically, defining the approximate population growth rate in country i in year t as $\dot{P}_{it} = \ln P_{it} - \ln P_{it-1}$, we estimated the following model (estimated standard errors of the coefficients are again in parentheses):[27]

$$\dot{P}_{it} = d_i + \underset{(0.0080)}{0.7882}\ \dot{P}_{it-1} + \underset{(0.1922)}{1.5769}\ 1/y_{it-1} + \upsilon_{it} \qquad (5)$$

where, y_{it} is again the per capita real GDP, d_i is a country specific constant effect and the error terms for each country are again allowed to have different variances.

In using the model to make forecasts, we modified the country-specific constants so that the implied average population growth from 2000 to 2015 matched the World Bank forecast average population growth over the same period. The motivation is that the World Bank forecast may be based on demographic considerations (particularly the current age profile of the population) that are not accounted for in equation (5).

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[26] Many reasons could explain why birth rates decline as per capita incomes rise. As income rises, the opportunity cost of having children rises as more women enter the labor force and their wages rise. Moreover, children cost more to raise and educate. Initially, we examined a model where economic development at first raises population growth rates by bringing improved health care, water supplies and other living standard advances that raise survival rates for children and increase life spans. We found, however, that the terms needed to allow for a rising initial population growth rate as a function of y added little to the within sample explanatory value of the model once we also allowed for country specific effects. In addition, these terms were irrelevant for projected out of sample population growth rates.

[27] The equation was estimated for 173 countries with an average sample of 38.1 years for each country and a maximum sample size of 52 years for any one country. The log likelihood of the cross-sectional time series model was 27864.99, while the chi-square statistic for testing whether the estimated coefficients together are significantly different from zero was 114349.55 with 174 degrees of freedom.

Finally, the demand curves included in the model were modified from curves such as those graphed in Figure 1 in order to accommodate the potential adoption of "backstop" technologies. There are many substitutes for natural gas in generating electricity, ranging from hydroelectricity, diesel and fuel oil for supplying peak power, to coal, nuclear and newer renewable technologies like wind or solar power for supplying base load power. There also are substitutes for the other uses of natural gas. Indeed, prior to the widespread use of natural gas, many cities had plants to gasify coal and distribute it to industrial and household consumers.[28] Until the 1940s, almost all fuel gas distributed for residential or commercial use in the United States was produced by the gasification of coal or coke.

The estimated elasticity of demand incorporated into the model reflects the substitution possibilities between gas and other fuels that are available within the estimation period. However, this estimated elasticity does not reflect new technologies that may increase substitutability, particularly at higher prices for natural gas. For example, the gas produced from coal using newer technologies is a closer substitute for natural gas than was the case in the 1940s, while production costs also are lower in real terms. As another example, experimental Integrated Gasification Combined Cycle (IGCC) electricity generating plants are already in operation in the U.S. (at West Terra Haute, Indiana and Tampa, Florida) and overseas (Spain, Netherlands, Germany, Japan and India). In August 2004, the American Electric Power Company announced plans to build at least one commercial-scale IGCC plant. Current IGCC plants are dramatically cleaner than conventional coal-fired generating plants, producing only 3% of the sulfur, 18% of the nitrogen oxide, 50% of the mercury and 80% of the CO_2 of an equivalent capacity conventional coal-fired plant without scrubbers. Using current technologies, generating electricity using IGCC is said to be competitive with natural gas CCGT in the U.S. at a natural gas price of $3.50-$4.00 per mcf (see, for example, documents available at http://www.netl.doe.gov, the National Energy Technology Laboratory, U.S. Department of Energy).

[28] Commercial gasification of coal began in 1792, while the first coal gasification company in the United States, the Baltimore Gas Company, was established 1816.

We allow for the possibility that new technologies could begin to displace natural gas substantially late in the model time horizon. The backstop technology is first made available in 2020, but can only meet a small portion of demand. It becomes increasingly available in subsequent years, where availability is dictated by a Gompertz curve ($y = ab^{q^t}$) as drawn in Figure 3.[29]

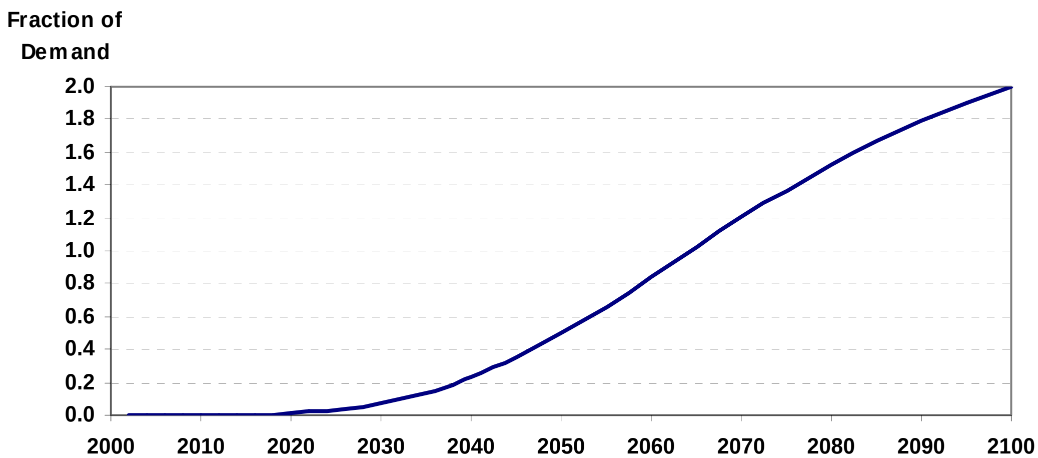

Figure 3: Availability of Backstop Technology

In order to define the available backstop quantity, we must first define a reference demand level that the backstop is assumed to satisfy. Note that the reference demand is *not* the demand forecast by the model, which is calculated endogenously. Rather, the reference demand provides a benchmark to establish a predetermined quantity of backstop assumed to be available at a given price in a given year. If the total demand calculated by the model is less (more) than the reference demand, the backstop will supply a larger (smaller) proportion of demand than illustrated in Figure 3. To calculate the reference demand, we estimated natural gas demand using the method described above for reference oil and natural gas prices. Then, the parameters

[29] The parameters of the Gompertz function determine the minimum (b) and maximum (a) values of y and the rate of ascent (q) through time (t). For the function used here, a=2.5, b=0.005, and q=0.9612.

of the curve depicted in Figure 3 are chosen so that the backstop can supply all of the reference demand by 2100 at a price of \$5.50/mmbtu.[30]

To be more specific, beginning in 2020, we subtracted an upward sloping supply curve of a close substitute for gas from the constant elasticity demand curve. In 2020, this curve has an intercept of \$5/mmbtu, rising to satisfy 0.625% of the reference demand for natural gas (half the corresponding percentage number for 2020 in Figure 3) at a price of \$5.50/mmbtu and a maximum of 1.25% of the reference demand for a natural gas price of \$10/mmbtu or above. The substitute technology is then assumed to become increasingly available, as illustrated in Figure 4 for a location where the reference demand is 1.41 tcf in 2020 (red curves), 2.34 tcf in 2040 (blue curves), 3.50 tcf in 2060 (green curves), 5.25 tcf in 2080 (orange curves) and 7.5 tcf in 2100. The vertical dashed lines in each case represent the reference case demands at this location in each year.

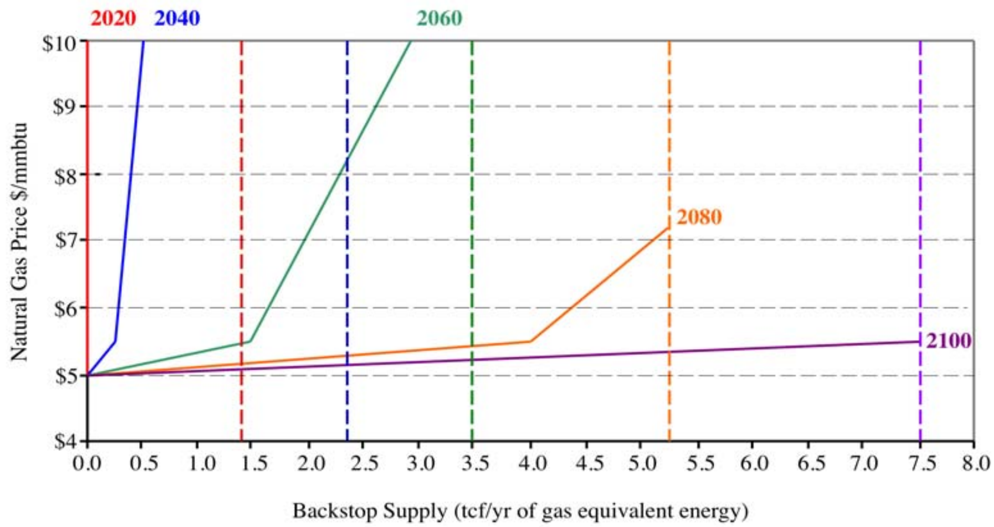

Figure 4: The hypothetical supply of a gas substitute, 2020-2100

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[30] The quantities are somewhat arbitrary. They are chosen so that the backstop does not penetrate the market too rapidly, but is sufficient in later years to ensure all demand can be satisfied between \$5.00 and \$5.50. We allow the backstop to displace natural gas in this manner because the type of energy consumed is related to installed capital. Allowing capital stocks to be replaced at a reasonable rate would slow the growth of the backstop initially, as the cost of capital equipment that consumes natural gas as an input is sunk. However, a competitive backstop would also slow, if not stop, the installation of natural gas capital equipment, so that the use of the backstop would begin to accelerate as older capital is continually replaced.

While the initial price at which the backstop technology can be supplied remains at $5/mmbtu (in 2002 prices), the percentages of reference demand assumed to be satisfied at a price of $5.50/mmbtu or $10/mmbtu increase each year according to the curve in Figure 3. In 2040, for example, the substitute technology is assumed to be capable of satisfying about 11.4% of the reference demand at a price of $5.50/mmbtu and about 22.8% at a price of $10/mmbtu. By 2100, the percentage of demand that can be satisfied by the backstop at a price of $5.50/mmbtu increases to 100%.[31]

CURRENT AND POTENTIAL SUPPLY SOURCES

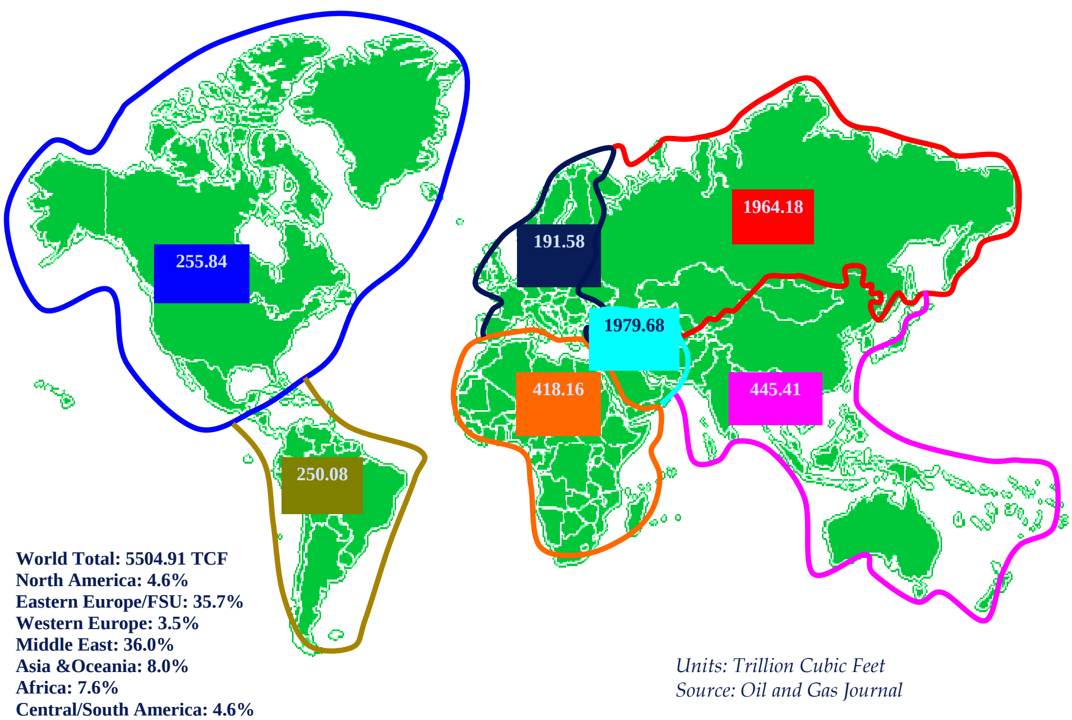

Figure 5: Proved Natural Gas Reserves by Region, 2003

To model the evolution of the world natural gas market, we must determine where new sources of supply are likely to be developed to meet the rising demand. We use, as the primary

[31] This does not imply that natural gas is no longer consumed. Rather, all resources that can still be extracted and competitively supplied at a price of $5.50/mmbtu (in 2002 prices) will be used. Moreover, not all regions reach the backstop simultaneously. Areas with large deposits of natural gas tend to see exports fall but continue to consume natural gas domestically.

data source for this exercise, regional resource potential as given in the P-50 resource estimates from the *World Resource Assessment* of the United States Geological Survey (USGS, 2000).[32] Resources are divided into three categories: proved reserves, growth in known reserves, and undiscovered resource.

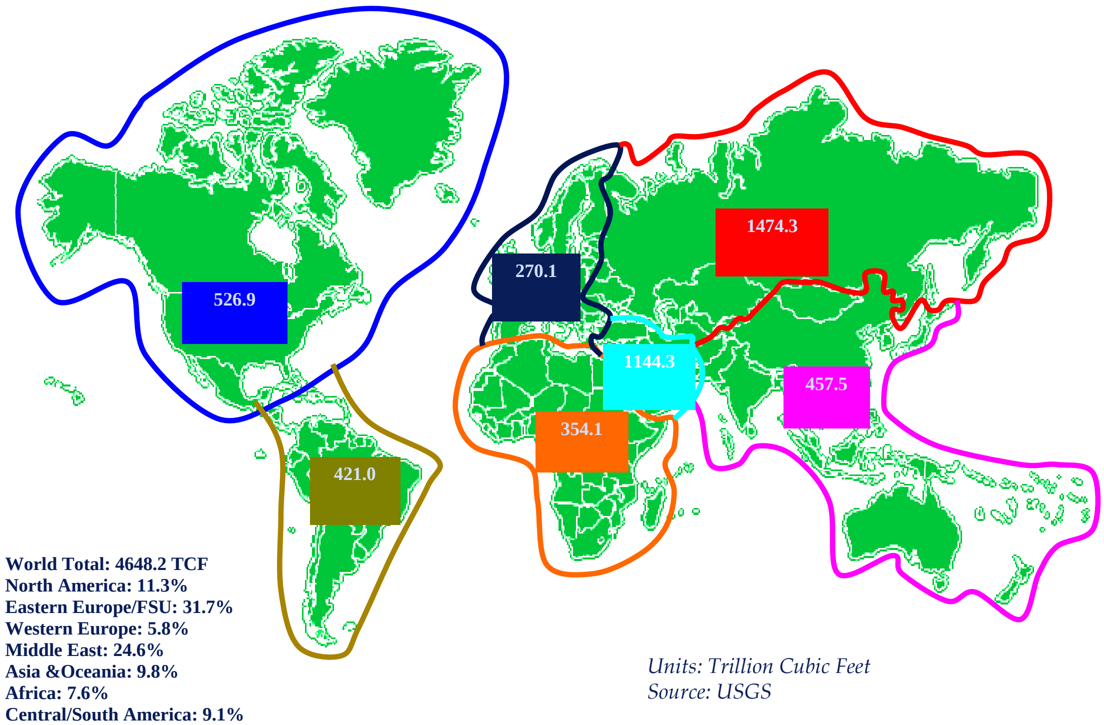

Figure 6: Undiscovered Natural Gas by Region, 2000 estimates

The USGS data includes both associated and unassociated natural gas resources, estimates for both conventional and unconventional gas deposits in North America, and conventional gas deposits in the rest of the world.[33] The USGS estimates of reserve growth in

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[32] We supplemented the USGS data with data from the Australian Bureau of Agricultural and Resource Economics (Dickson and Noble, 2003) and Geosciences Australia (2001). In particular, Geosciences Australia used a methodology similar to that used by the USGS to assess the resource potential of Australian basins that were not assessed quantitatively by the USGS.

[33] The lack of unconventional resource estimates outside of North America is a function of the lack of exploration and development of commercial unconventional natural gas deposits in other regions of the world. Australia also already has some coal bed methane (CBM) production, while several companies have announced plans to examine further CBM production. The Australian data sources referenced above provided estimates of economically viable CBM resources in the coalfields of eastern Australia. While the lack of such data for other regions underestimates the

existing fields and undiscovered resources uses a stochastic simulation of the success of past exploration and development in particular types of deposits in different regions.[34] Figures 5 and 6 are constructed using the USGS database, and indicate, in particular, the significant role that Russia and the Middle East may play in supplying natural gas to the rest of the world in coming decades.

Capital cost of resource development

The resource data for each field include estimates of minimum, median and maximum depth as well as field size. Using data for the United States, Canada, and Mexico, we estimate equations relating the capital cost of development and operating and maintenance costs to the median estimate of recoverable reserves and the depth measures.

The Modeling Subgroup of the National Petroleum Council (NPC) study (National Petroleum Council, 2003) of the North American natural gas market developed data for long run marginal cost curves to be used in the *Market Builder* platform. These curves are characterized by three cost levels $\{c_1, c_2, c_3\}$ where c_1 is capital cost of developing the first incremental unit of gas, c_2 is the capital cost of the 75th-percentile of the estimated median reserves, and c_3 is the capital cost of the median resource estimate. The approximate curves for the United States, Canada, and Mexico were based on proprietary industry information supplied by firms participating in the NPC study. While the NPC used many other variables in a discovery-process model to develop the cost estimates for basins in North America, we found that the three cost measures could be reasonably explained by the median estimate of recoverable reserves and the three depth measures–the minimum, maximum and median depth of resources in the field. Total resource enters the equation as an inverse, implying there are economies of scale in developing resources. Specifically, we estimated the following three equations:[35]

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global resource potential, it is unlikely to have a substantial impact in the time horizon considered in this exercise. We would expect the massive quantities of economically accessible reserves of conventional natural gas outside North America and Australia to be exploited before the industry moves on to exploit substantial deposits of unconventional reserves.

[34] See website of USGS for more details on their data.

[35] Each equation included a set of regional indicator variables. Since most of these coefficients are of little interest for applying the estimated equations internationally, they have not been

$$c_2 = -0.0207 + \underset{(0.1998)}{} \; 0.00066 \; MedD + 0.000014 \; (MedD/Res) \tag{6}$$

$$\qquad (0.1998) \quad (0.000075) \qquad\qquad (0.000002)$$

$$N = 316, \quad R^2 = 0.427$$

$$c_1 = -0.0619 + 0.3838 \; c_2 - 0.00009 \; MinD + 0.000009 \; (MinD/Res)$$

$$\qquad (0.1998) \quad (0.0155) \qquad (0.000027) \qquad\qquad (0.000001)$$

$$N = 221, \quad R^2 = 0.855$$

$$c_3 = -4.4073 + 6.4009 \; c_2 - 0.00161 \; MaxD + 0.000024 \; (MaxD/Res)$$

$$\qquad (0.9912) \quad (0.2516) \qquad (0.000229) \qquad\qquad (0.000006)$$

$$N = 221, \quad R^2 = 0.859$$

where *MedD*, *MinD* and *MaxD* are, respectively, the median, minimum and maximum well depth and *Res* is the median estimate of the ultimately recoverable reserves from the field.

The estimated equations were then used to construct long run marginal capital costs curves for all resources outside of North America. Field depth and resource size were obtained from the USGS *World Resource Assessment*, which is available online. The resulting long run marginal capital cost curve for the undiscovered resources in selected regions is depicted in Figure 7.

Recent years have seen substantial declines in the costs of exploiting a given hydrocarbon resource. Advances in computer hardware, signal processing software, and remote sensing technology have all played a role. To allow for further technological change in the mining industry, the future costs of reserve additions are assumed to decline according to the rates used

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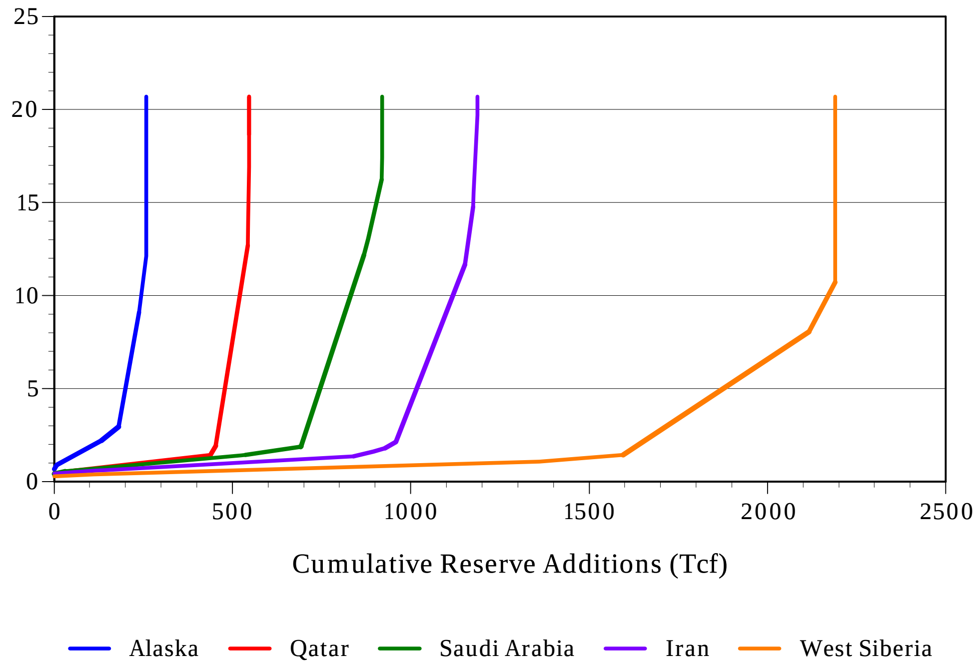
reported. The constant terms as reported are chosen so that the equations fit the means of the reported variables ignoring regional effects. The complete equations with fixed regional effects are available from the authors. One regional effect of interest is the higher costs of exploiting Alaskan deposits, since the costs due to harsh weather are also likely to apply to other resources located above the Arctic circle. Unfortunately, we did not have $\{c_1, c_2, c_3\}$ for Alaska. Nevertheless, we added a premium for exploiting fields in the Barents Sea, Sakhalin and Greenland to make them comparable to the Alaskan costs. Estimated standard errors are placed in parentheses below each coefficient. The equation for c_2 includes additional observations since only the median field depth was available for Canada, Mexico and offshore fields in the US.

in the NPC study "Balancing Natural Gas Policy." Thus, the curves illustrated in Figure 7 are only valid for the year 2002, which is the initial year of the model. Beyond 2002, all such curves will shift down by the assumed rate of technological innovation in finding and development costs.



Sources: USGS, EIA, author calculations

Figure 7: Estimated Long Run Cost of Supply Curves for Selected Regions

Operating and maintenance costs

The NPC study also produced estimates of the operating and maintenance costs (*OM*) associated with exploiting different fields in the United States, Canada, and Mexico. We also found that these costs were predictably related to the resource size and depth measures. As with capital costs, we included an inverse term in total resources to capture the economies of scale in exploiting resources.[36] In contrast to the capital costs, however, we found a systematic

[36] The terms in median depth imply that costs decline up to a depth of around 1600 meters. Since the minimum median depth in our North American data set is 400 meters, while the average median depth is slightly over 2500 meters, only about 26% of the fields show declining costs

relationship in the regional effects. Specifically, in the operating costs regression, the offshore regions of the United States and Mexico displayed higher costs. Hence, we included an indicator variable (*Off*) to capture the distinction between operating costs for onshore and offshore fields. The estimated regression equation was:

$$
\begin{aligned}
OM &= \underset{(0.01786)}{0.00972} + \underset{(0.01875)}{0.32952} \cdot Off + \underset{(0.000004)}{0.000027} \cdot MedD + \underset{(14.2720)}{67.3652} \cdot (1/MedD) + \underset{(0.00028)}{0.00356} \cdot (1/\mathrm{Re}\,s) \qquad (7) \\
N &= 316, \quad R^2 = 0.6436
\end{aligned}
$$

As with capital costs, the inverse term in total resources implies that there are some economies of scale in exploiting resources.[37] In addition, we assumed that operating costs will decline at the rates contained in the recently released National Petroleum Council "Balancing Natural Gas Policy."

TRANSPORT LINKS AND THE WORLD NATURAL GAS MARKET

About 73% of the world's proven gas reserves are located in the former Soviet Union and the Middle East, and moving those supplies to distant consuming markets will present new technical, logistic and economic challenges. Indeed, construction of transportation infrastructure is currently the major barrier to increased world natural gas consumption.[38]

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with increasing depth. Most of these are located in Western Canada, the Rockies and northeast Mexico. Perhaps shallow deposits are correlated with other geological features, such as highly folded rock layers, that raise extraction costs.

[37] The terms in median depth imply that costs decline up to a depth of around 1600 meters. Since the minimum median depth in our North American data set is 400 meters, while the average median depth is slightly over 2500 meters, only about 26% of the fields show declining costs with increasing depth. Most of these are located in Western Canada, the Rockies and northeast Mexico. Perhaps shallow deposits are correlated with other geological features, such as highly folded rock layers, that raise extraction costs.

[38] According to the IEA (2003), cumulative investments in the global natural gas industry of $3.1 trillion, or $105 billion per year, will be needed to meet rising demand for gas between 2001 and 2030. Exploration and development of gas fields are projected to require over half of this investment, with more than two thirds of the new capacity replacing declining production in existing fields. Investment in LNG facilities is expected to double after 2020. Investment in Russia will be a critical factor to world gas supply. The IEA projects that investment in Russian infrastructure will need to exceed $330 billion over the next thirty years in order to meet domestic demands and for export to other industrialized countries. The average of $11 billion per year compares with Russian investment of $9 billion in gas fields and infrastructure in 2000.

In order to connect supply to demand, the model includes a simplified representation of existing pipeline links and all liquefaction and regasification terminals. Projects already under construction also are exogenously input into the model with the associated capacity becoming available at the expected start-up date of the projects. In addition, transportation links can be added based on current investment cost, current and future prices, and, therefore, anticipated net benefits from the future flows. Supply sources compete for end-use markets via a specified range of transportation options thought to be feasible.[39] In particular, the model chooses the manner in which natural gas flows to consumers, either as LNG or via pipeline, in order to maximize the rents to the wellhead. Equivalently, the model seeks a solution that minimizes the discounted capital costs of expansion and the operating and maintenance costs of utilizing new and existing capacity. Hence, supplies earning the greatest rents (or with the highest "netbacks"), once all relevant costs of getting the resource to market have been taken into account, are extracted first. Supplies that are isolated from end-use markets or located in areas lacking prior infrastructure development are, therefore, disadvantaged due to the comparatively high cost of transportation.

Currently, most natural gas is transported by the well-developed pipeline infrastructures in North America and Europe that connect major consuming and producing regions. In Asia, liquefied natural gas (LNG) is the primary means of connecting end-users to supply, most of which originates in remote locations and must be transported in refrigerated vessels. International trade in LNG, though currently small relative to pipeline flows, has been occurring for over 30 years and involves shipments from close to a dozen countries.

[39] The model allows only for a limited number of transportation options to be specified in advance. However, once we have a solution for an assumed potential network, a new transportation option can be introduced when the price difference between two nodes suggests that it would be profitable to construct such a link.

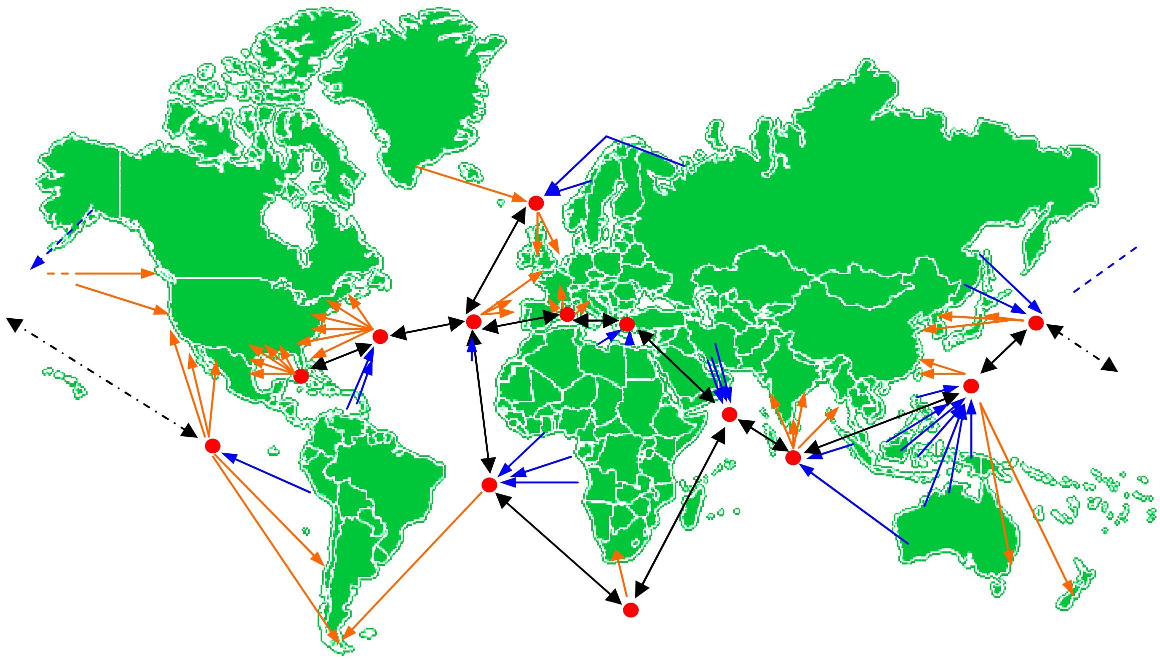


Figure 8: LNG transportation network

A complicating factor in modeling investment in transportation links is that they are inherently discrete, linking a supply source with a particular demand sink. In order to accurately forecast the development of transportation links, one needs to consider a wide range of current and future potential options. It is very easy to bias the results by inadvertently precluding viable options. One way to minimize this problem is to model the transportation system using a "hub and spoke" framework. This breaks particular links down into notional transportation from a supply source to a regional hub and then from the regional hub to the demand sinks. Such an arrangement is less sensitive to the presence of any one link in the network. Swap agreements would be the physical analog of the "hub and spoke" arrangement in the model. Although one particular supplier linked in the model to a notional hub may have a contract with one particular demander linked to the same hub, the model solution will not be affected if any supplier to the hub in question fulfills the contract with the demander. In fact, such a "hub and spoke" representation ensures least cost flows and higher netbacks in an equilibrium solution. Figure 8 illustrates the "hub and spoke" framework for LNG proposed in the model.

Costs for development, construction, and operation and maintenance of transportation links are of critical importance to the model outcome. For example, further reductions in costs in liquefaction, shipping and regasification would accelerate the development of a liquid market in natural gas. Thus, in order to model market evolution, estimates of liquefaction, shipping and regasification costs are required.

The average capital costs for liquefaction for any potential project, as given in the IEA's *World Energy Investment Outlook* (WEIO) 2003, are $4.11 per mcf of annual throughput capacity. These costs, however, have been adjusted using various industry sources to reflect regional deviations about the average. The actual costs assumed in the model are given in Figure 9. It should be noted that these costs are not the sole determinant of the decision to develop LNG liquefaction. In particular, differences in the feed gas costs, which are determined by the costs of developing reserves and which change through the model time horizon, serve either to offset or exacerbate the differences in liquefaction costs across regions. Therefore, the full cost to the tailgate of the liquefaction facility can differ substantially from project to project.

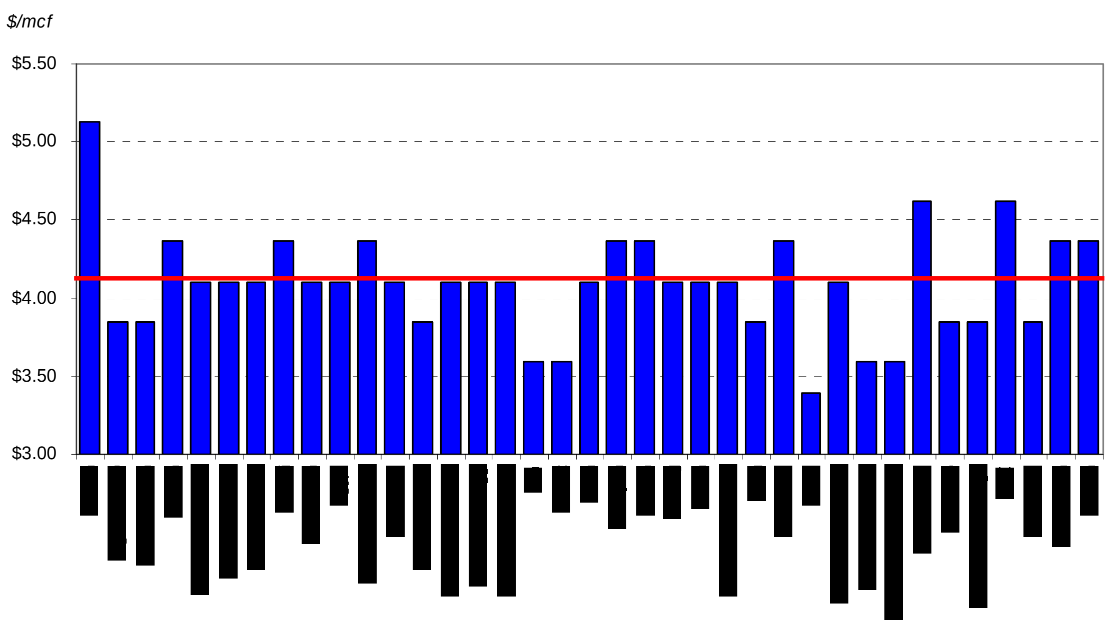


Figure 9: LNG Liquefaction Costs

To estimate the shipping costs, we modified point-to-point data from industry sources. The costs (in $2002/mcf) are lease rates, which include an implicit return to capital as well as operating and maintenance expenses. They were available from various existing and proposed liquefaction locations to various existing and proposed regasification terminals. To fit the shipping costs for point-to-point deliveries to the hub-and-spoke representation in Figure 8, we regressed the point-to-point costs on a set of indicator variables for each of the hub flows implicitly included in each point-to-point route. For each liquefaction node *i*, there is just one hub where LNG is presumed to go initially, while each regasification terminal *j* also is assumed to obtain its LNG from just one hub. Let the associated shipping costs be β_i^L and β_j^R respectively. In addition, let the total number of inter-hub routes be *H* and number them *h* = 1, …, *H*, with associated shipping costs β_h. The cost on a particular route between *i* and *j* can then be written as:

$$C_{ij} = \beta_i^L + \sum_{h=1}^{H} \beta_h D_h^{ij} + \beta_j^R \tag{8}$$

where D_h^{ij} is an indicator variable taking the value of 1 if the inter-hub route *h* is part of the shortest route between *i* and *j* and 0 otherwise.

The original data set contained 26 different points of origination and multiple destinations, but not all origination and destination pairs are included. For example, data from Peru was available to only four delivery locales, whereas data from Qatar was available to 32 different delivery locales. We nevertheless could estimate the cost of shipping on each of the routes drawn in Figure 8, except for the routes involving Argentina.[40] The results are given in Table 2 in the appendix.

The capital costs of regasification included in the model vary by location, ranging from \$1.02 to \$3.69 per mcf of annual throughput capacity. The variation in costs results from a variety of factors, one being variation in the cost of land. The estimates used in the model are generated by using costs in a number of reports (CERA 2002, IEA 2003, industry estimates and the trigger prices for regasification terminals reported in EIA AEO 2004). For all terminals outside the United States, except Japan, Taiwan, and Hong Kong, we used the cost for regasification reported in the WEIO (IEA, 2003). For the United States, CERA reports a range of regasification costs by capacity in areas characterized as “Low Cost” and “High Cost”, but they

[40] In the latter case, we pro-rated the shipping costs involving (respectively) Peru and Brazil on the basis of distances covered.

do not identify specific high and low cost areas. However, the EIA reports trigger prices for investment in regasification capacity in different regions of the United States. Using the CERA and other industry estimates, we fit a regression describing cost as a function of capacity. The EIA data was then used to identify where in the low-to-high cost range different regions fall. In the U.S., this ranks, in descending order of cost, the West Coast, the Northeast, South Atlantic, and the Gulf Coast region. The "high cost" CERA estimates and industry estimates were also used for Japan, Taiwan and Hong Kong.

Taken together, the required differential from liquefaction intake to regasification tailgate falls between $2.54 and $3.09 per mcf of annual throughput capacity. Note, however, the actual number will vary by shipping distance and regasification location and will change over time as feed gas costs change and technological innovations occur in the LNG chain. Table 1 gives indicative costs for shipping LNG between a number of origination and destination pairs. Note the costs reported in Table 1 do not include feed gas costs for liquefaction.

Table 1: Indicative LNG costs (excluding cost of feed gas) 2002

Note: Price differential required for expansion… Cost of Capital included

	Liquefaction	Shipping	Regas	Total
Trinidad to Boston	$ 0.82	$ 0.25	$ 0.69	$ 1.75
Trinidad to Lake Charles	$ 0.82	$ 0.32	$ 0.21	$ 1.35
Algeria to Boston	$ 0.82	$ 0.45	$ 0.69	$ 1.96
Algeria to Lake Charles	$ 0.82	$ 0.63	$ 0.22	$ 1.66
Nigeria to Lake Charles	$ 0.82	$ 0.77	$ 0.22	$ 1.81
Qatar to Lake Charles	$ 0.82	$ 1.17	$ 0.23	$ 2.22
Qatar to Baja	$ 0.82	$ 1.32	$ 0.28	$ 2.41
NW Shelf to Baja	$ 0.82	$ 0.99	$ 0.27	$ 2.07
Norway to Cove Point	$ 0.82	$ 0.57	$ 0.36	$ 1.74

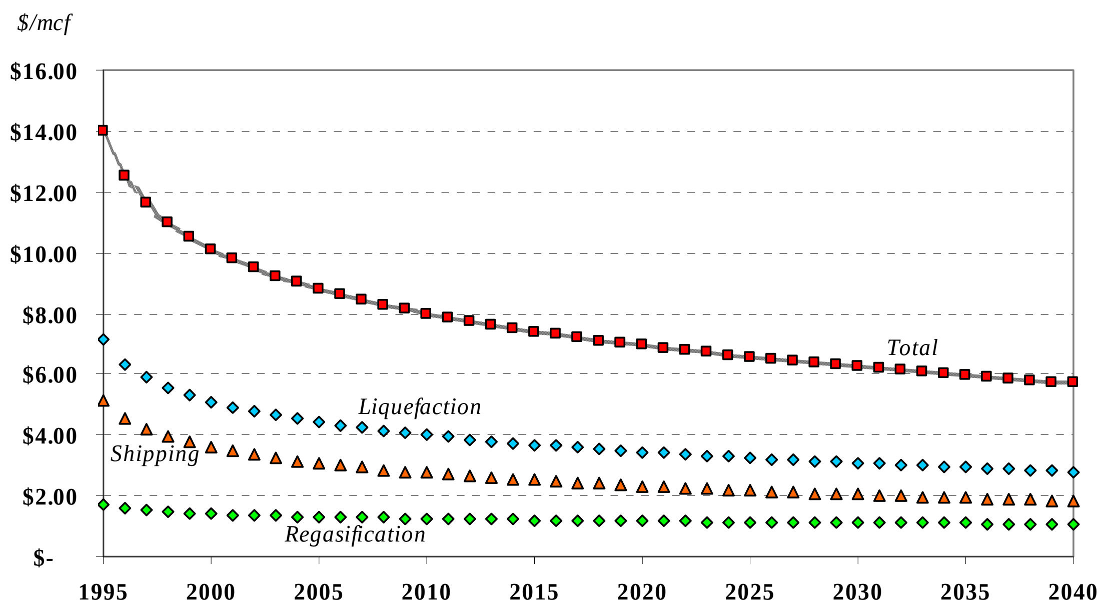
Sources:

1. "The Global Liquefied Natural Gas Market: Status and Outlook" (December 2003), U.S. EIA
2. Various Industry Consultant Reports
3. Author's estimates (see text)

The costs in Table 1 are indicative costs for 2002. We allowed these costs to change over time as a result of technological change because there have been substantial declines in LNG costs and further declines are anticipated. To accommodate this, we used the projected rate of cost declines in liquefaction, shipping and regasification as given in the WEIO (IEA, 2003). According to the WEIO, total costs for liquefaction, shipping and regasification have fallen from about \$14.00/mcf in 1995 to about \$10.12/mcf in 2000, and will continue to fall to about \$7.99/mcf by 2010. In order to extrapolate this progress, we fit a regression equation of the form:

$$Cost_t = \alpha + \beta \cdot \ln(Time) \tag{9}$$

to the point estimates of past, current and future costs for each piece of the LNG "value chain" (liquefaction, shipping and regasification). Figure 10 depicts the resulting cost estimates through 2040.



Source: *World Energy Investment Outlook, 2003*, International Energy Agency

Figure 10: Technological progress in transporting LNG

We also use historical data to estimate the costs associated with building pipelines. The EIA has published project specific data for 52 pipeline projects in the report "Expansion and Change on the U.S. Natural Gas Pipeline Network–2002". We used this data to estimate a regression equation (with an R^2 of 0.690) that expresses the up-front cost per unit of capacity (also known as the specific capital cost, SCC) as a function of miles, capacity, and geography. OLS regression on the cross-section data yields the following estimates:

$$\ln(SCC_i) = \underset{(0.514)}{-0.152} + \underset{(0.072)}{0.290} \cdot \ln(miles_i) - \underset{(0.108)}{0.384} \cdot \ln(capacity_i) + \underset{(0.260)}{0.776} \cdot D_{Mountain,i} + \underset{(0.323)}{1.072} \cdot D_{Water,i} + \underset{(0.252)}{1.243} \cdot D_{Population,i} \quad (10)$$

where the variables $D_{n,i}$ are indicator variables that take the value of 1 or 0. For example, if the project is in a mountainous region, is offshore, or crosses densely populated areas, then $D_{Mountain,i}$, $D_{Water,i}$, and $D_{Population,i}$, respectively, take the value of 1. The positive coefficients indicate that an increase in length, crossing mountains, moving offshore, and/or developing in populous areas will raise the cost of a project. The negative coefficient on ln(*capacity*) indicates that larger capacity results in *per unit* cost reductions, which implies that there are economies of scale associated with pipeline construction.

Equation (10) was then used to estimate the cost of any generic pipeline project based on miles, capacity, and geographical location. For example, the Gulfstream project, extending from Mobile Bay, Alabama to Tampa Bay, Florida, is calculated according to the EIA data to have a SCC of $3.05 per mcf. The estimated value using the methodology applied herein is $3.20 per mcf. Likewise, the estimated SCC of the Kern River Pipeline is $2.63 per mcf.

A rate-of-return calculation generated the tariffs on pipelines. Specifically, the tariff rate was calculated such that the present value of the tariff revenue at 50% capacity utilization, using the required return on investment (see next section) as a discount rate, just recovers the up-front capital cost in twenty years. As an example, suppose the weighted average cost of capital (WACC) is 8.4%. To recover an upfront outlay of $3.20 per mcf (such as the Gulfstream pipeline) over a period of twenty years, the tariff would need to be about $0.46 per mcf. However, pipeline capacity is not always fully utilized. In practice, the tariff typically allows some costs (for example maintenance and fuel) always to be recovered, while another proportion is dependent upon capacity utilization. For example, any molecule of gas transported on a pipeline (such as the Gulfstream) may incur a charge of, say, $0.06 plus a 1.5% fuel charge. As capacity utilization rises from 0% to 100%, the tariff on the pipeline grows. This occurs because as capacity becomes scarce, shippers bid up the price of using the pipeline. We set the parameters describing this scarcity premium such that at any load factor above 50%, the pipeline owner earns rents. In the case of the Gulfstream pipeline, the tariff rises to $0.46 per mcf at 50% utilization, and $0.75 per mcf at 92% utilization, which would be akin to a fully loaded rate. The tariff can then rise as high as $15 per mcf at a load factor of 100% although this will not occur in an unconstrained long run equilibrium. Such rents would more than compensate for capacity expansion, or alternative supply options will develop.

REQUIRED RETURNS ON INVESTMENTS

The BIWGTM solves not only for a spatial equilibrium of supply and demand in each year but also for new investments in resource development, transportation, liquefaction, and/or regasification capacity. The investments are assumed to yield a competitive rate of return, such that the NPV of the marginal unit of capacity is non-negative. The project life of all new investments is assumed to be 100 years, and the tax life is assumed to be 20 years. The tax levied on income earned from projects is assumed to be 40%, and property tax and insurance is assumed to be 2.5%.

The model uses a weighted average cost of capital to determine the net present value of each increment of new capital. The debt-equity ratio is allowed to differ across different categories of investment. Pipeline investments are taken to be the most highly levered (with 90% debt), reflecting the likelihood that pipeline transportation rates will be regulated and hence the income stream will be very predictable. LNG investments are assumed to have a higher equity level (30% equity). Most of these will only be undertaken if a substantial fraction of the anticipated output is contracted in advance using bankable contracts. Mining investments are taken to be the most risky category with an assumed debt ratio of only 40%. In addition to differing levels of leverage, the different categories of investments are assumed to have differing required rates of return on equity again as a reflection of differing risks. Specifically, the required return on equity (ROE) for pipeline capacity is 12% (real), and the ROE on upstream investments is 15% (real). The real interest rate on debt is set at 8% for all projects. The assumptions regarding required returns are based on numerous meetings with industry sources.

For the reference case model, the required rate of return on equity (ROE) is assumed identical across regions. In the working paper on "Political and Economic Influences on the Future World Market for Natural Gas", we examine a modified model where rates of return also vary geographically to reflect differences in risks of investing in different countries. While the latter model is more realistic and will form the basis for our subsequent scenario analysis, we first examine the model with uniform rates so we can investigate the consequences of allowing required rates of return on investments to vary.

THE BASE CASE SOLUTION

Figure 11 presents the supply projections in the Base Case. In many cases, these have been aggregated at the regional level to make the graph easier to read. Table 3 in the appendix presents the numerical results for a larger number of individual countries and a selection of years. Table 4 presents results for demand. It is important to note that the Base Case represents the outcomes of a world in which there are no political constraints. Thus, by corollary, one could think of these results as occurring if the countries throughout the world shared relationships similar to those shared by Canada and the United States.

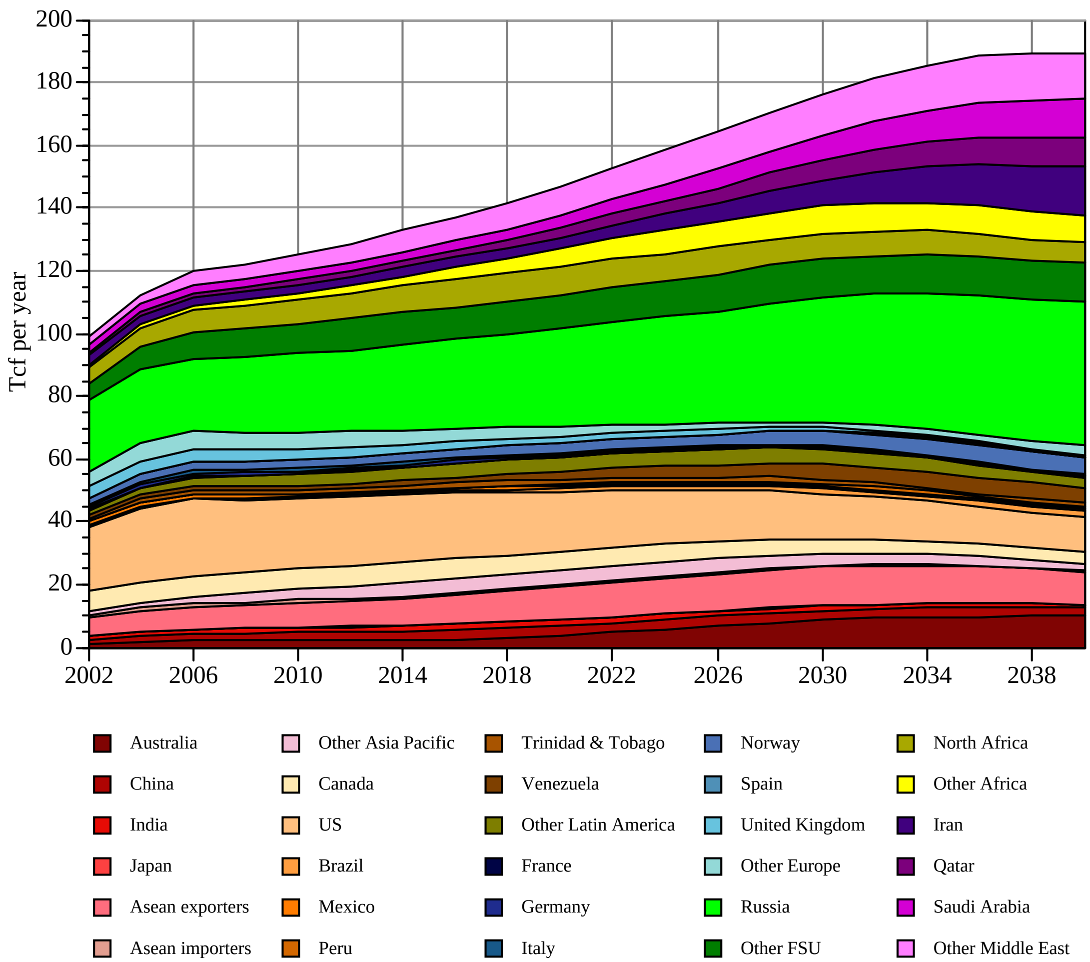


Figure 10: Supply projections–major countries or regions

The model suggests, absent potential policy constraints, that Russia will play a pivotal role in price formation in a more flexible and integrated global natural gas market. Russia is projected to be the single largest producer of natural gas until 2040, although beyond 2038 the Middle East as a region (which, of course, is an aggregation of countries) becomes the largest global supplier. Russia is also strategically positioned to move large amounts of gas to consuming markets in both the Atlantic and Pacific, giving it the potential to play an important role in linking prices between the two regions. In the Base Case, Eastern Siberian gas begins flowing into Northern China at the beginning of the next decade and eventually flows into the Korean peninsula. Toward the end of the model time horizon, specifically 2035-2040, northeast Asian demand grows sufficiently to make the construction of a pipeline from Western Siberia to Eastern Siberia economic, and gas begins to flow into China from Western Siberia. Throughout the model period, Russia is also a very large supplier to Europe via pipeline. Once Russian pipeline gas is simultaneously flowing both east and west, production in the Western Siberian basin becomes the arbitrage point between Europe and Asia, thus linking gas prices in the two regions.

The model also indicates that Russia will enter the LNG export market in both the Pacific and Atlantic basins. In the Pacific basin, production in the Sakhalin region is exported as LNG but also flows to Japan via pipeline beginning in 2010. In the Atlantic basin, production in the Barents Sea eventually provides gas exports in the form of LNG beginning in the mid-2020's.[41] This ultimately provides another link between gas prices in North America, Europe, and Asia. Specifically, when gas is simultaneously flowing in all three directions out of Russia, the "netback" price from sending the gas in any of the three directions has to be the same. Russia benefits not only from its location and size of resources but also because it was one of the first major gas exporters and has access to a sophisticated network of infrastructure already in place (see case study, Victor/Victor).

Figure 11 also indicates that, in aggregate, the Middle East will become an important future supplier of natural gas, with production surpassing that of the U.S. in 2022 and North

[41] Production from the Barents Sea also moves to Europe via a pipeline through St Petersburg from 2008.

America as a whole in 2026. The largest exporters of the Middle Eastern region are Qatar, Iran, UAE, and late in the time horizon, Saudi Arabia. The majority of these exports occur as LNG. However, barring from consideration any prohibitive political factors, pipeline infrastructure is developed to move Iranian gas through Pakistan to India. In addition, existing infrastructure is expanded to move gas from Iran to Europe though Turkey and Armenia.

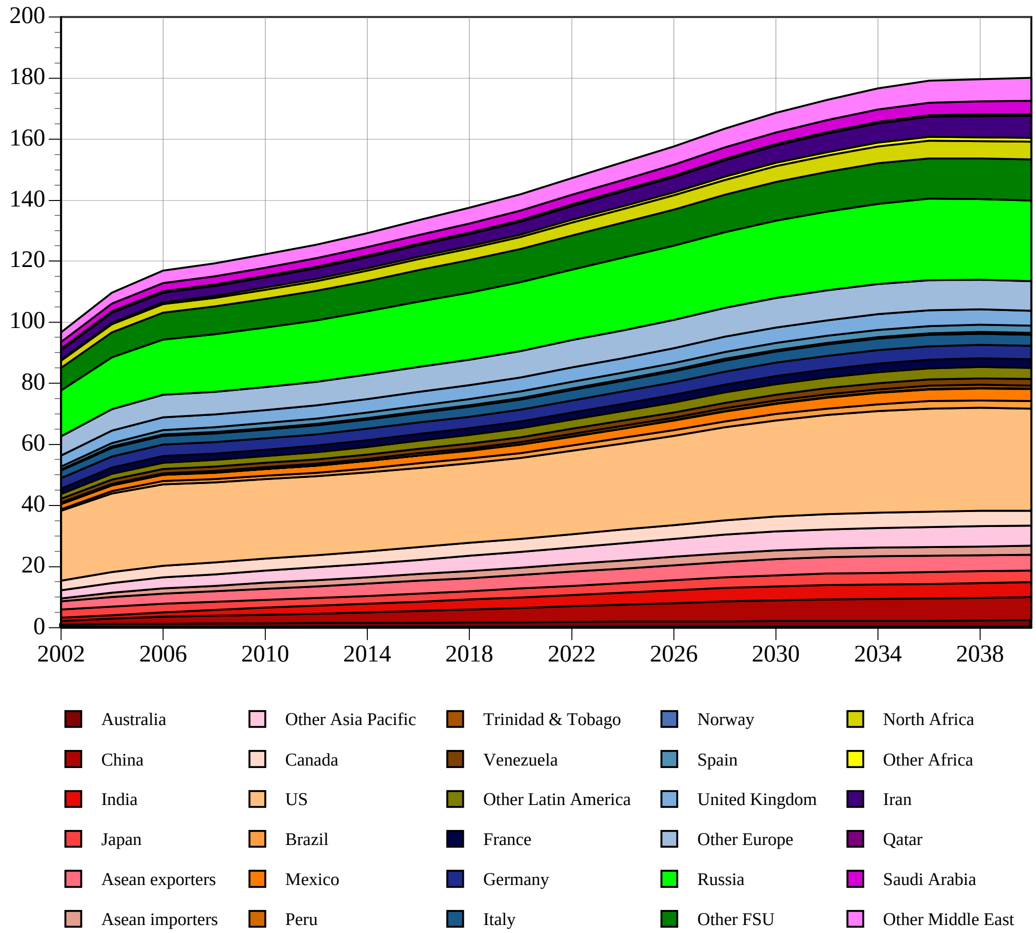


Figure 12: Demand net of backstop supply–major countries or regions

Figure 12 gives the demand projections for the Base Case. (Note that quantity differences between Figures 11 and 12 are due to natural gas used as fuel in the transportation process.) Interestingly, although Russia is the largest single national source for natural gas throughout most of the model period, Figure 12 shows that Russia is simultaneously a large consumer. Demand growth in Iran and Saudi also limit exports from the Middle East. Thus, despite these countries' prominence in the future of global natural gas supply, their export capacity is limited by domestic requirements.

The largest consuming regions are North America and Europe. North American demand, in particular, is large prior to the introduction of the backstop technology beginning in 2020. Japan, which is primarily dependent upon LNG supplies, also adopts the backstop technology relatively early. The model also projects that strong European demand growth will eventually lead to fairly aggressive adoption of the backstop technology, but not before it draws on Nigerian supplies via the Trans-Saharan pipeline (from Nigeria to Algeria), which is constructed in the beginning of the next decade.

Figure 13 summarizes the implications of the above changes in supply and demand for international trade in natural gas via both pipeline and LNG. Note that this figure consolidates trade within each of the identified regions. Figure 14 focuses on LNG imports alone, while Figure 15 graphs model projections for LNG exports.

The change in LNG imports is particularly striking. The United States surpasses Japan as the largest LNG importer by the end of next decade. Although Japan shifts marginally to pipeline imports with the development of a Sakhalin pipeline, North American production is increasingly unable to keep pace with North American demand. Price increases following the depletion of low cost resources in North America allow LNG to take an increasing share of the North American market and limit growth in demand. Particularly beyond 2040, aggressive adoption of the backstop technology abates demand. Nevertheless, the U.S. becomes a premium region drawing on gas supplies from around the world as imports of natural gas grow throughout the modeling period. Alaskan resources are an important source of future supply, as the model constructs capacity into Alberta beginning in 2014, but supply from Alaska neither collapses the North American price, nor eliminates the need for imported LNG.[42]

[42] Rather, Alaskan pipeline gas replaces declining Western Canadian Sedimentary Basin production, delaying further exploitation of marginal Canadian resources. While many analysts have predicted a substantial price impact of Alaskan supplies, the model results suggest that Alaskan gas will merely stabilize prices in the medium term. With a lead time approaching 10

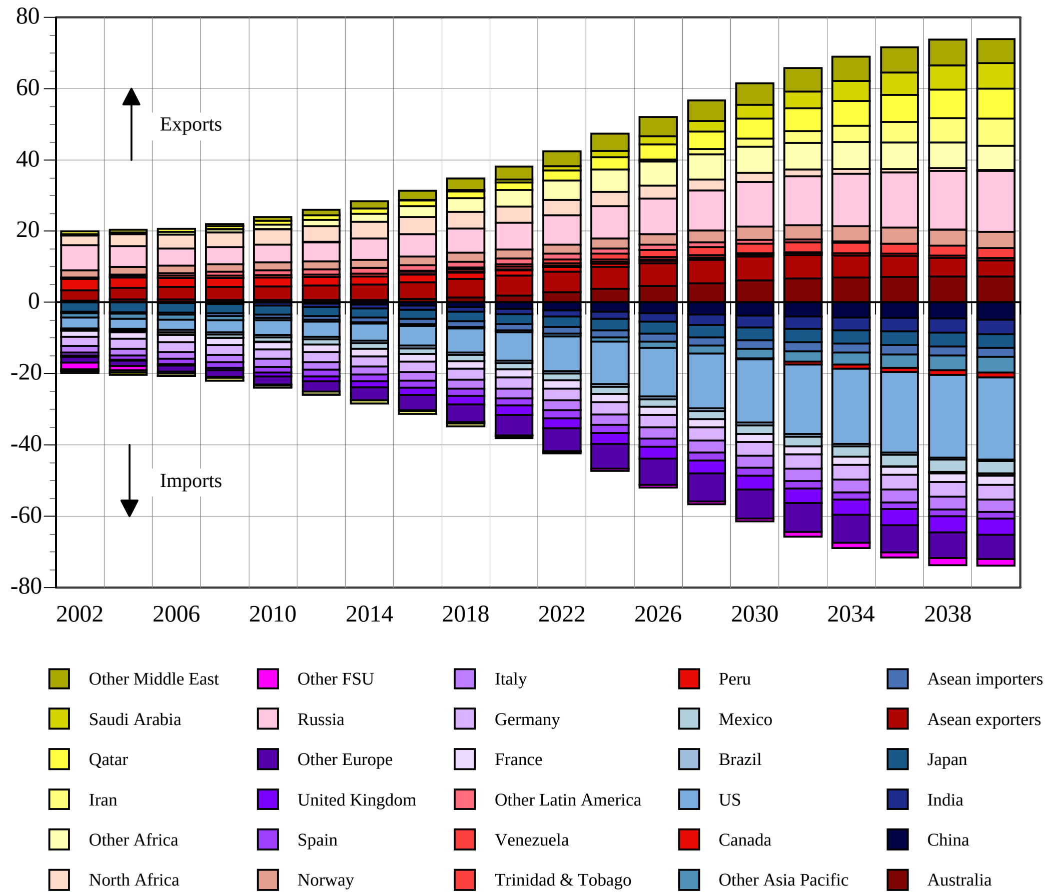


Figure 13: Major natural gas trades between regions

Mexico and Canada add to North American LNG imports by the end of the modeling horizon. Mexico (Pacific plus Atlantic imports) overtakes Japan as an importer of LNG at about the same time as the United States, although some of that gas is actually destined for the U.S. market. [43] Mexican domestic demand growth is stimulated by Mexican government policy favoring conversion of existing fuel oil facilities as well as targeting gas as the fuel for new plants. Early in the period, demand for natural gas in Canada is stimulated by the production of

years, producers will have adequate time to adjust their behavior once an Alaskan project is announced. Intertemporal arbitrage in complete forward markets will then smooth the price impact of Alaskan supply.

[43] A substantial portion of the Mexican imports into Baja California, which accelerate in the 2020's and 2030's, are also destined for the U.S. West Coast. The model assumes that LNG regasification terminals are cheaper to build in Mexico than in southern California. The cost differential is more than enough to compensate for the additional costs of piping gas to California.

oil from tar sands, while later in the model time horizon LNG imports into northeast Canada are stimulated by demand in the New England region of the U.S.

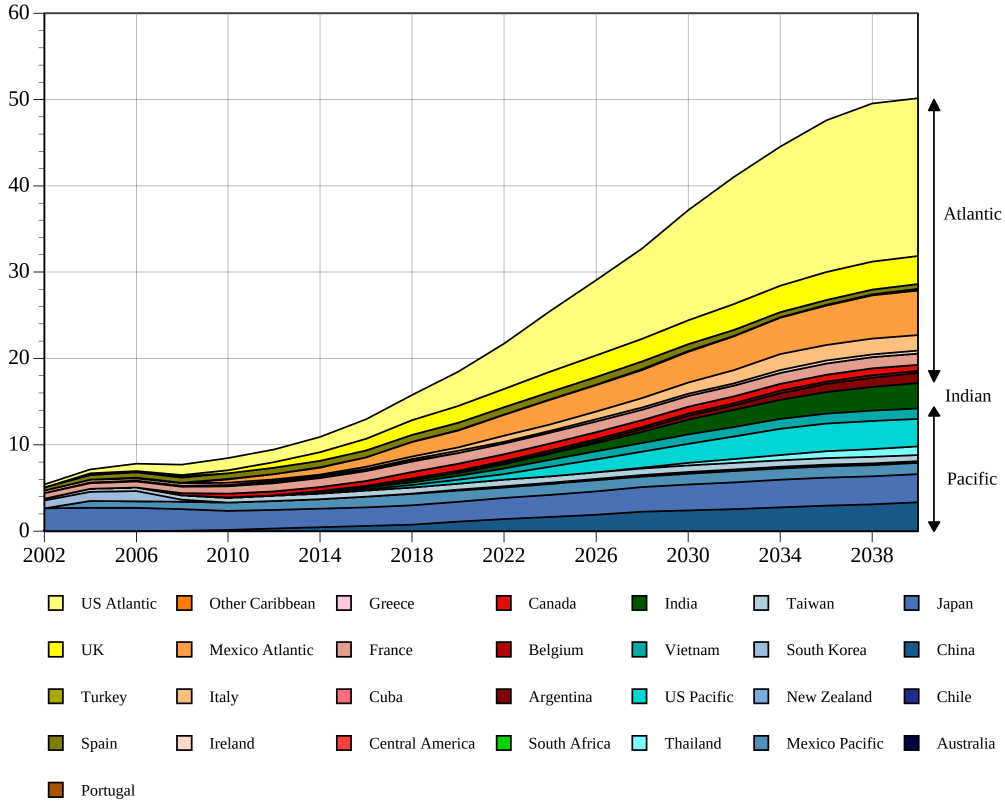


Figure 14: LNG Importers

Demand growth in Europe also outpaces indigenous production, making Europe the second largest importing region as a whole.[44] Increasing availability of the backstop also causes European imports to level off by the end of the model horizon. Europe imports via pipeline from Africa, the Middle East, and Russia as well as via LNG. The UK more or less matches Japan as an importer of LNG by 2020, while total European demand for LNG overtakes Japanese demand in the middle of the next decade.

High demand growth in India and China also affect world trade. In particular, the model implies that India and China also rival Japan as importers of LNG by 2030 even though LNG

[44] Note that trade between two countries in "other Europe," for example, is not counted as inter-regional trade for the purposes of Figure 13.

imports to China are limited to the southeast. In the early part of the model period, both India and China obtain supplies from domestic sources, while both countries also become large importers via pipeline.

Another notable feature of Figure 13 is the very small impact of South America in global natural gas markets. The continent as a whole is neither a large importer nor a large exporter of natural gas at any time in the model horizon. There is, however, substantial trade in gas between countries within the continent. In particular, Brazil and Argentina are large consumers and eventually become large importers as their domestic resources become relatively expensive.

Toward the end of the modeling period, the Middle East becomes the largest gas exporting region, with Qatar being the leading exporter from that region. Russia is a dominant exporter throughout the model period. In early years, Canada is a relatively large exporter to the United States, but its exports fade by the early 2020s, with its balance largely offset by the import of Alaskan gas in transit to the U.S. The ASEAN exporting countries remain significant suppliers throughout the model period although some ASEAN countries also become significant importers beginning in 2025. Australia also becomes a substantial exporter from 2025. The Australian share is particularly evident in the graph of LNG exporters (Figure 15).

Qatar, Iran, and to a lesser extent Saudi Arabia and the UAE also become large exporters of LNG. Although Iraq is also a large exporter, it utilizes pipeline routes (both new and existing) to Syria and Turkey and on to Europe. For the period up to 2015, Indonesia, North Africa, Malaysia, Australia, Qatar, Nigeria, and Trinidad and Tobago all have significant shares in LNG supply. By 2040, Qatar and Australia are the two largest LNG suppliers, followed in order by Iran, Russia, Indonesia, Saudi Arabia, the UAE, Venezuela, and Nigeria. The flow of LNG from the four largest suppliers makes up over half of all LNG supply in 2040. It is important, however, to note the scale of LNG exports. While these countries dominate LNG trade, they are not necessarily the largest suppliers of natural gas in the world. Russian exports by pipeline roughly equal the sum of the five largest LNG export volumes combined.

Qatar is an early leader in supplying LNG from the Middle East. Other resource-rich players lacking existing infrastructure needed to bear substantial fixed costs to enter the LNG market. Early entry would drive down prices and lead to inadequate returns on investment. Therefore, entry must be delayed until world demand in excess of alternative sources of supply is large enough to accommodate these incremental supplies. Thus, the principle of "first mover advantage" plays a crucial role in the development of the LNG market. Consequently, Iranian LNG supplies do not enter the world market until 2016, Saudi Arabia does not begin to supply LNG until 2022, and Russian Barents Sea LNG exports begin only in 2024. However, all three of these countries are also better placed than is Qatar to supply large consumers via pipeline. Iran eventually supplies India and Turkey while Saudi Arabia supplies Egypt, Syria and Jordan, via pipeline.

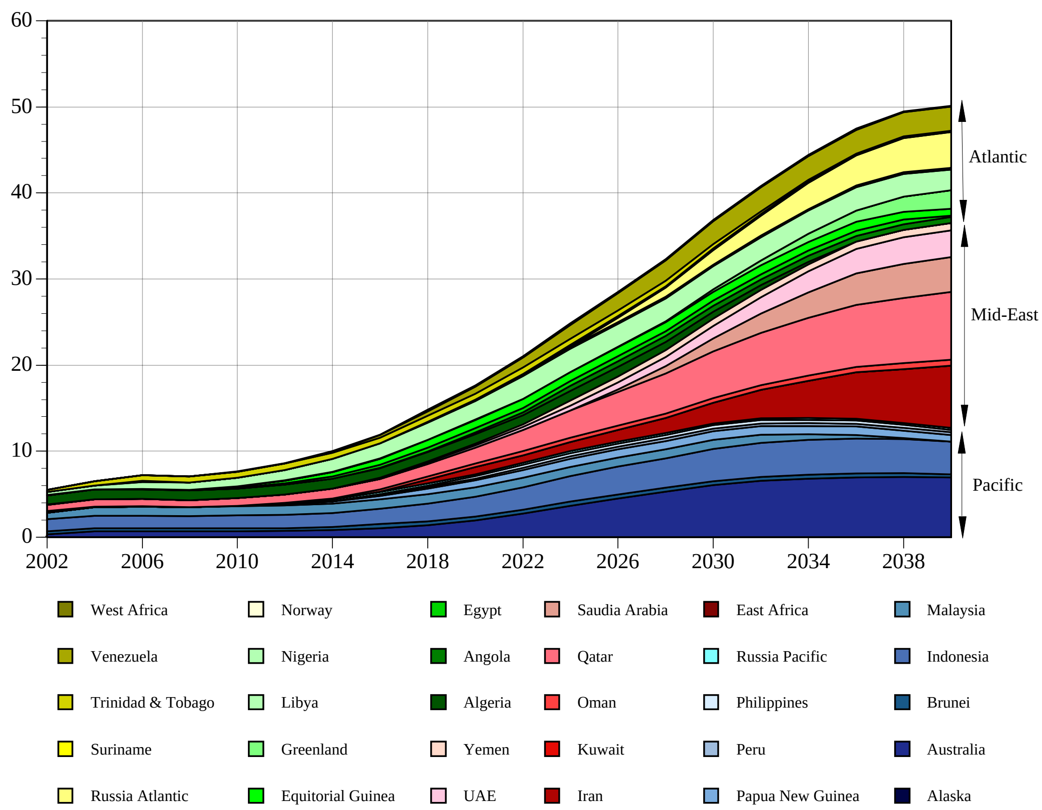


Figure 15: LNG Exporters

Figure 16 provides price projections for six locations. Henry Hub and Zeebrugge already are reference pricing nodes, and possibly Tokyo, Beijing or Delhi could evolve as representative pricing nodes in Asia and Buenos Aires in South America. The most prominent feature of Figure 16 is the convergence of prices over time as other countries, like Japan today, become dependent upon LNG as their marginal source of natural gas.

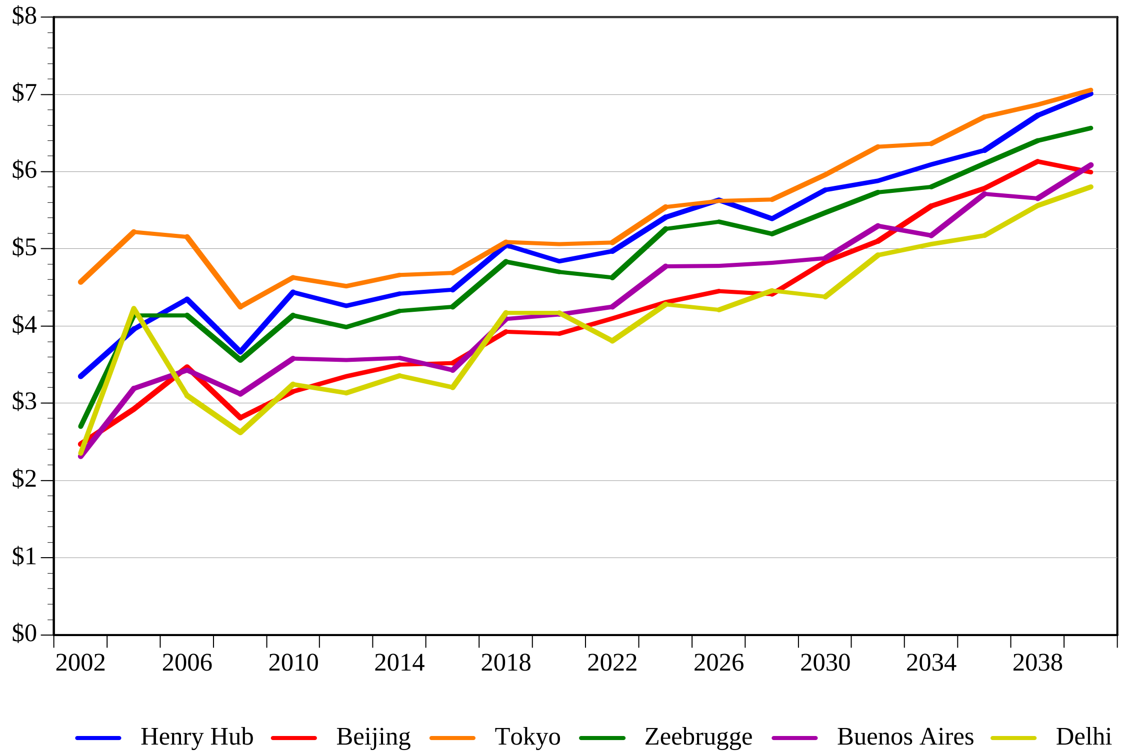


Figure 16: Representative price projections

Increasing use of the backstop technologies leads to a reduction in prices beyond the model horizon. As end users substitute away from natural gas in the locations where gas becomes more expensive, the cost of gas for the remaining users actually declines, curtailing the demand for the backstop technologies. As a result of the backstop technology, natural gas is eventually (late in the century) only consumed in large relative quantities in regions where it is in relative abundance, such as the Middle East, Russia and Australia.

CONCLUDING REMARKS

We have presented an equilibrium model of the evolution of the world market for natural gas over the next three decades. The model was constructed on geologic and economic fundamentals and respects well-known economic principles that resource extraction and trade should eliminate profitable spatial and intertemporal arbitrage opportunities.

The widespread use of LNG predicted by the model and the extension of major pipeline systems to span continents will link markets for natural gas around the world. A consequence is that wholesale prices will tend to converge over time while regional shocks will have global consequences.

Another central finding is that Russia is destined to play a central role in linking the European and Asian markets for natural gas. Eventually, it is likely that Russia also will enter the LNG market in both the Atlantic and Pacific basins. As a result, Russia is likely to play a pivotal role in price arbitrage. Nevertheless, we also found that Russia's ability to exploit its dominant position is somewhat limited. Any restriction on Russian supply is likely to stimulate alternative sources of supply around the world, including the Middle East, Southeast Asia, Australia, and Norway. In addition, higher natural gas prices would not be welcome in Russia, which is one of the largest gas consumers in the world. Finally, natural gas differs from oil in that a reasonably good substitute for gas is available at a cost that is not dramatically higher than prices normally expected to prevail over the model horizon. Any long-term increase in gas prices above the $5/mcf range is likely to stimulate demand for these backstop technologies.

This last point emphasizes that natural gas is a "transition fuel." This is true of any depletable resource with an alternative whose cost is, at present, prohibitive. The central question for any transition fuel concerns its shelf life… just how long will natural gas be consumed? Demand for natural gas has been greatly stimulated in the short term by the expanding use of natural gas in electricity generation. Moreover, most projections indicate that future natural gas demand growth will come primarily from the power generation sector. There are, however, many alternative ways to generate electricity at comparable cost to CCGT, while other uses for natural gas can also be satisfied, for example, by "syngas" manufactured from coal or even by hydrogen. Indeed, before the widespread use of natural gas, coal gas was reticulated in many cities in the United States and Europe and provided many similar services to those provided by natural gas today.

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APPENDIX

LNG SHIPPING COSTS

Table 2: Estimated shipping costs for the route structure in Figure 6

Routes	Parameter Estimate	Standard Error
1. Liquefaction to Hub:		
UAE -- Middle East	0.0562	0.0169
Qatar, Iran -- Middle East	0.0619	0.0169
Oman -- Middle East	0.0050	0.0169
Indonesia (Arun) -- Indian Ocean	0.0000	0.0190
Indonesia (Bontang), Brunei, Malaysia -- South Asia Pacific	0.0231	0.0190
Indonesia (Tangguh) -- South Asia Pacific	0.0762	0.0190
Australia (Darwin) -- South Asia Pacific	0.0727	0.0190
Australia (NW Shelf) -- South Asia Pacific	0.0857	0.0190
Sakhalin -- North Pacific	-0.0001	0.0199
Alaska -- North Pacific	0.3451	0.0390
Peru, Bolivia -- American South Pacific	0.1355	0.0423
Angola, Guinea, Nigeria, Brazil -- South Atlantic	0.0554	0.0213
Trinidad, Venezuela -- North Atlantic	0.0620	0.0216
Barents Sea -- North Sea	0.1028	0.0281
Norway -- North Sea	0.0728	0.0281
Libya, Egypt -- East Mediterranean	0.0283	0.0223
Algeria–West Mediterranean	0.0283	0.0223
2. Hub to Regasification		
Indian Ocean -- India East	0.1655	0.0251
Indian Ocean -- India South	0.1680	0.0251
Indian Ocean -- India West	0.1747	0.0251
South Asia Pacific -- South China	0.2428	0.0248
South Asia Pacific -- Taiwan	0.2034	0.0241
North Pacific -- South Korea, South	0.0688	0.0271
North Pacific -- South Korea, North	0.0841	0.0271
North Pacific -- NE China	0.0903	0.0271
North Pacific -- Japan	0.1134	0.0271
American South Pacific -- Baja, S. California	0.1811	0.0278
American South Pacific -- SW Mexico	0.2589	0.0278
Caribbean -- Lake Charles, Louisiana Gulf	0.0200	0.0294
Caribbean -- Freeport	0.0287	0.0294
Caribbean–Mexico (Altamira)	0.0327	0.0294
Caribbean -- Florida	0.2273	0.0262
U.S. North Atlantic -- New Brunswick	0.1327	0.0262
U.S. North Atlantic -- Everett	0.1840	0.0262
U.S. North Atlantic -- Cove Point	0.2180	0.0262
U.S. North Atlantic -- Elba	0.2293	0.0262
U.S. North Atlantic -- Humboldt	0.4690	0.0251
European North Atlantic -- Portugal	0.1487	0.0210
European North Atlantic -- NW Spain	0.2051	0.0209
European North Atlantic -- France Atlantic	0.2082	0.0210
North Sea -- Zeebrugge (Netherlands)	0.1769	0.0276
North Sea -- UK	0.1774	0.0276
West Mediterranean -- SE Spain	0.1640	0.0204
West Mediterranean -- Italy	0.1656	0.0205
West Mediterranean -- France Mediterranean	0.1665	0.0205
East Mediterranean -- Greece	0.1599	0.0201

East Mediterranean -- Turkey	0.1847	0.0201
3. Hub to Hub		
Middle East -- Indian Ocean	0.1349	0.0132
Indian Ocean -- South Asia Pacific	0.2163	0.0131
South Asia Pacific -- North Pacific	0.2645	0.0164
North Pacific -- American South Pacific	0.4590	0.0230
U.S. North Atlantic -- Caribbean	0.3033	0.0262
U.S. North Atlantic -- European North Atlantic	0.2082	0.0142
European North Atlantic -- South Atlantic	0.2560	0.0155
European North Atlantic -- North Sea	0.0715	0.0225
European North Atlantic -- West Mediterranean	0.1072	0.0109
West Mediterranean -- East Mediterranean	0.0936	0.0135
East Mediterranean -- Middle East	0.4500	0.0167

$R^2 = 0.9905$

Table 3: Supply projections for selected regions and years (tcf)

	2002	2006	2010	2016	2020	2026	2030	2036	2040
AFRICA	5.87	8.31	9.65	12.70	14.53	16.69	16.79	16.23	14.86
Algeria	3.70	4.36	4.61	4.81	4.55	3.80	3.12	2.35	2.04
Angola	0.03	0.08	0.11	0.16	0.36	0.85	0.91	0.90	0.90
East Africa	0.00	0.00	0.03	0.10	0.13	0.17	0.21	0.44	0.47
Egypt	1.06	1.37	1.57	2.04	2.30	2.67	2.88	3.15	3.14
Libya	0.26	0.94	1.28	1.63	1.71	1.81	1.76	1.34	1.11
Morocco	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Nigeria	0.61	1.04	1.30	2.54	3.68	5.31	5.93	6.24	5.73
Southern Africa	0.07	0.10	0.06	0.06	0.08	0.12	0.09	0.12	0.11
Tunisia	0.11	0.18	0.22	0.24	0.26	0.35	0.29	0.21	0.18
West Africa	0.00	0.03	0.10	0.19	0.27	0.27	0.28	0.27	0.21
West Central Coast Africa	0.04	0.22	0.38	0.92	1.18	1.35	1.31	1.19	0.98
ASIA-PACIFIC	11.63	16.08	18.43	21.80	24.57	28.37	29.92	28.96	26.80
Afghanistan	0.00	0.01	0.18	0.31	0.41	0.56	0.57	0.58	0.45
Australia	1.37	2.14	2.09	2.69	3.85	6.87	8.64	9.87	10.10
Bangladesh	0.38	0.71	1.07	1.23	1.24	1.14	0.96	0.65	0.51
Brunei	0.45	0.49	0.52	0.60	0.72	0.88	0.95	0.79	0.64
China	1.29	2.29	2.70	2.97	2.94	3.10	3.16	3.04	2.81
Hong Kong	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
India	1.02	1.32	1.55	1.94	2.02	1.76	1.39	1.04	0.80
Indonesia	2.94	3.29	3.48	4.05	4.78	5.95	6.69	6.99	6.59
Japan	0.09	0.08	0.06	0.06	0.06	0.03	0.02	0.01	0.01
Malaysia	1.98	2.61	2.84	3.14	3.24	3.28	3.16	2.56	2.07
Myanmar	0.25	0.42	0.70	0.95	1.01	1.02	0.94	0.62	0.49
New Zealand	0.18	0.25	0.24	0.22	0.16	0.10	0.07	0.06	0.04
Pakistan	0.84	1.10	1.52	1.86	1.91	1.30	0.95	0.64	0.52
Papua New Guinea	0.00	0.00	0.20	0.64	1.00	1.18	1.25	1.07	0.86
Philippines	0.07	0.13	0.15	0.25	0.47	0.65	0.70	0.73	0.61
Singapore	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
South Korea	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Taiwan	0.09	0.10	0.07	0.04	0.03	0.03	0.03	0.02	0.02
Thailand	0.57	0.77	0.69	0.58	0.53	0.39	0.32	0.22	0.19
Vietnam/Laos/Cambodia	0.10	0.36	0.36	0.28	0.19	0.12	0.10	0.07	0.07
EUROPE	11.99	14.46	13.22	11.21	9.74	8.33	8.77	9.85	10.07
Austria	0.07	0.07	0.05	0.03	0.02	0.01	0.01	0.01	0.00
Balkans	0.19	0.31	0.26	0.17	0.12	0.07	0.05	0.04	0.03
Belgium & Luxembourg	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Bulgaria	0.03	0.05	0.03	0.02	0.01	0.01	0.01	0.01	0.01
Czech Republic	0.06	0.07	0.05	0.03	0.02	0.01	0.01	0.01	0.01
Denmark (incl. Greenland)	0.19	0.23	0.21	0.14	0.10	0.09	0.37	1.49	2.33
Finland	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
France	0.07	0.08	0.06	0.04	0.05	0.19	0.41	0.52	0.40
Germany	0.77	1.01	0.95	0.91	0.83	0.60	0.46	0.28	0.19
Greece	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Hungary	0.23	0.31	0.21	0.12	0.09	0.05	0.04	0.03	0.02
Ireland	0.03	0.06	0.04	0.02	0.02	0.01	0.01	0.01	0.00
Italy	0.82	1.00	0.80	0.76	0.67	0.43	0.30	0.18	0.20

Netherlands	2.77	3.25	3.17	2.63	2.07	1.33	0.97	0.58	0.45
Norway	2.27	2.67	2.75	3.01	3.12	3.69	4.56	5.41	5.32
Poland	0.33	0.50	0.38	0.21	0.15	0.09	0.07	0.05	0.04
Portugal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Romania	0.73	0.99	0.85	0.54	0.37	0.23	0.18	0.12	0.10
Slovakia	0.04	0.04	0.03	0.02	0.02	0.01	0.01	0.00	0.00
Spain	0.01	0.01	0.00	0.00	0.01	0.01	0.11	0.40	0.45
Sweden	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Switzerland	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
United Kingdom	3.38	3.81	3.37	2.56	2.08	1.51	1.22	0.73	0.51
FORMER SOVIET UNION	28.54	31.87	34.67	38.70	42.10	47.56	52.03	56.78	58.26
Armenia	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Azerbaijan	0.34	0.78	0.93	1.01	1.13	1.62	2.12	2.67	2.78
Belarus	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Estonia	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Georgia	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Kazakhstan	1.21	2.89	3.51	3.65	3.54	3.17	2.93	2.44	2.10
Kyrgyzstan	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Latvia	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Lithuania	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Moldova	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Russia	22.87	23.46	25.16	28.42	31.15	35.80	39.68	44.48	46.01
Tajikistan	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Turkmenistan	1.63	1.65	1.70	1.94	2.37	3.24	3.84	4.84	5.56
Ukraine	0.69	1.25	1.51	1.80	2.00	1.85	1.63	1.00	0.80
Uzbekistan	1.81	1.85	1.87	1.88	1.90	1.88	1.83	1.36	1.01
MIDDLE EAST	8.95	10.81	12.46	16.06	19.80	28.55	35.81	47.47	52.11
Bahrain	0.33	0.32	0.24	0.17	0.19	0.43	0.52	0.49	0.39
Iran	2.68	2.67	2.64	3.04	3.79	5.93	8.34	13.01	15.62
Iraq	0.07	0.76	1.65	2.93	3.73	4.73	5.14	5.39	5.26
Kuwait	0.35	0.38	0.89	1.50	1.66	1.70	1.70	1.69	1.50
Oman	0.43	0.29	0.22	0.44	0.67	1.02	1.09	1.30	1.40
Qatar	1.19	1.39	1.61	2.12	2.78	4.92	6.48	8.53	9.39
Saudi Arabia	2.24	2.60	2.67	3.22	4.06	6.07	7.94	10.97	12.16
Syria/Jordan	0.20	0.60	0.60	0.43	0.30	0.18	0.15	0.11	0.10
Turkey	0.03	0.09	0.06	0.03	0.02	0.02	0.01	0.01	0.01
UAE	1.43	1.65	1.73	1.92	2.13	2.70	3.47	5.00	5.26
Yemen	0.00	0.06	0.14	0.27	0.46	0.86	0.97	0.96	1.01
NORTH AMERICA	28.04	32.48	29.97	28.33	26.05	22.64	20.14	16.41	15.03
Canada	6.44	6.65	6.56	6.42	5.97	5.42	4.74	3.95	3.85
Mexico	1.24	1.41	1.00	0.89	1.01	1.04	1.01	0.67	0.53
United States	20.36	24.42	22.41	21.02	19.07	16.17	14.39	11.80	10.66
CENTRAL/SOUTH AMERICA	4.19	5.72	6.88	8.52	9.95	12.03	13.01	12.78	12.43
Argentina	1.28	1.48	1.52	1.55	1.51	1.53	1.50	1.10	0.89
Bolivia	0.18	0.50	0.58	0.72	0.77	0.98	1.03	0.95	0.85
Brazil	0.38	0.38	0.46	0.71	0.98	1.14	1.37	1.87	2.30
Central America	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Chile	0.11	0.24	0.25	0.23	0.26	0.26	0.23	0.16	0.14
Colombia	0.24	0.33	0.92	1.23	1.26	1.22	1.16	0.89	0.71

Cuba	0.02	0.04	0.07	0.07	0.05	0.03	0.03	0.02	0.02
Ecuador	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.04	0.04
Other Caribbean	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Paraguay	0.00	0.07	0.09	0.07	0.06	0.05	0.04	0.03	0.02
Peru	0.01	0.04	0.06	0.22	0.42	0.57	0.65	0.79	0.79
Suriname/Guyana/Fr. Guiana	0.00	0.07	0.23	0.47	0.63	0.73	0.74	0.72	0.54
Trinidad & Tobago	0.75	1.24	1.35	1.45	1.56	1.61	1.51	1.05	0.93
Uruguay	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Venezuela	1.22	1.31	1.35	1.80	2.43	3.90	4.74	5.18	5.21
WORLD TOTAL	**99.22**	**119.73**	**125.29**	**137.31**	**146.72**	**164.17**	**176.47**	**188.48**	**189.55**

Table 4: Demand projections for selected regions and years (tcf)

	2002	2006	2010	2016	2020	2026	2030	2036	2040
AFRICA	2.65	3.35	3.69	4.33	4.81	5.56	6.08	6.83	6.95
Algeria	0.82	0.89	0.95	1.11	1.23	1.45	1.60	1.84	1.77
Angola	0.03	0.05	0.06	0.07	0.09	0.11	0.12	0.14	0.16
East Africa	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01
Egypt	1.05	1.33	1.47	1.71	1.88	2.16	2.37	2.70	2.82
Libya	0.24	0.30	0.33	0.38	0.42	0.49	0.53	0.57	0.56
Morocco	0.02	0.05	0.06	0.07	0.08	0.09	0.09	0.09	0.09
Nigeria	0.22	0.27	0.29	0.37	0.42	0.51	0.58	0.68	0.74
Southern Africa	0.07	0.14	0.16	0.16	0.15	0.15	0.13	0.12	0.10
Tunisia	0.16	0.21	0.24	0.29	0.33	0.39	0.43	0.45	0.47
West Africa	0.00	0.03	0.07	0.10	0.12	0.13	0.13	0.13	0.12
West Central Coast Africa	0.04	0.07	0.07	0.07	0.08	0.08	0.09	0.10	0.10
ASIA-PACIFIC	12.22	16.19	18.27	21.69	24.23	28.28	30.42	31.92	31.94
Afghanistan	0.01	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.03
Australia	0.96	1.33	1.44	1.63	1.79	1.99	2.11	2.27	2.35
Bangladesh	0.37	0.49	0.56	0.66	0.72	0.82	0.87	0.91	0.93
Brunei	0.07	0.08	0.08	0.09	0.09	0.09	0.10	0.11	0.11
China	1.33	2.18	2.69	3.68	4.49	5.83	6.48	6.93	7.13
Hong Kong	0.03	0.04	0.03	0.03	0.03	0.03	0.03	0.02	0.02
India	0.97	1.49	2.31	2.97	3.38	3.99	4.30	4.56	4.58
Indonesia	1.31	1.63	1.74	1.92	2.04	2.22	2.33	2.31	2.23
Japan	2.71	2.73	2.49	2.61	2.80	3.25	3.54	3.74	3.71
Malaysia	1.09	1.35	1.48	1.70	1.85	2.10	2.25	2.29	2.25
Myanmar	0.08	0.11	0.13	0.15	0.16	0.18	0.19	0.19	0.19
New Zealand	0.18	0.23	0.24	0.25	0.26	0.27	0.27	0.25	0.24
Pakistan	0.83	1.08	1.19	1.39	1.53	1.76	1.95	2.25	2.17
Papua New Guinea	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Philippines	0.07	0.12	0.14	0.17	0.20	0.23	0.26	0.28	0.29
Singapore	0.04	0.09	0.10	0.12	0.13	0.14	0.15	0.13	0.12
South Korea	0.88	1.17	1.25	1.53	1.74	2.03	2.20	2.25	2.25
Taiwan	0.30	0.53	0.60	0.69	0.73	0.76	0.76	0.73	0.70
Thailand	0.89	1.18	1.27	1.37	1.42	1.49	1.46	1.43	1.40
Vietnam/Laos/Cambodia	0.10	0.35	0.51	0.72	0.85	1.05	1.14	1.23	1.24
EUROPE	18.65	22.01	22.34	23.77	24.90	26.35	27.17	27.86	27.46
Austria	0.31	0.36	0.36	0.39	0.41	0.43	0.44	0.46	0.46
Balkans	0.18	0.26	0.27	0.28	0.30	0.31	0.31	0.29	0.28
Belgium & Luxembourg	0.66	0.75	0.74	0.77	0.79	0.82	0.84	0.88	0.87
Bulgaria	0.19	0.17	0.15	0.15	0.16	0.18	0.19	0.19	0.19
Czech Republic	0.35	0.38	0.36	0.38	0.40	0.42	0.44	0.47	0.48
Denmark (incl. Greenland)	0.21	0.27	0.28	0.30	0.31	0.32	0.33	0.33	0.33
Finland	0.18	0.23	0.23	0.25	0.27	0.31	0.33	0.32	0.32
France	1.77	2.10	2.06	2.15	2.23	2.39	2.54	2.72	2.72
Germany	3.31	3.72	3.61	3.72	3.84	4.00	4.12	4.25	4.22
Greece	0.08	0.13	0.14	0.17	0.20	0.25	0.28	0.28	0.28
Hungary	0.49	0.57	0.60	0.68	0.75	0.83	0.86	0.88	0.87
Ireland	0.17	0.25	0.28	0.30	0.30	0.32	0.33	0.34	0.34
Italy	2.60	2.86	2.89	3.11	3.28	3.47	3.55	3.60	3.54

Netherlands	1.64	1.87	1.92	2.03	2.11	2.16	2.21	2.25	2.20
Norway	0.29	0.40	0.42	0.45	0.48	0.50	0.51	0.53	0.53
Poland	0.49	0.63	0.64	0.70	0.76	0.85	0.87	0.88	0.86
Portugal	0.12	0.24	0.29	0.34	0.37	0.39	0.40	0.40	0.40
Romania	0.68	0.68	0.67	0.73	0.80	0.91	0.94	0.97	0.96
Slovakia	0.28	0.31	0.31	0.32	0.33	0.34	0.34	0.34	0.33
Spain	0.85	1.43	1.64	1.91	2.06	2.21	2.24	2.28	2.26
Sweden	0.04	0.06	0.05	0.05	0.05	0.05	0.05	0.06	0.06
Switzerland	0.12	0.15	0.14	0.14	0.14	0.15	0.16	0.17	0.17
United Kingdom	3.67	4.21	4.29	4.45	4.57	4.75	4.90	4.99	4.81
FORMER SOVIET UNION	22.34	26.70	28.52	31.24	33.12	35.89	37.50	38.26	37.33
Armenia	0.04	0.06	0.06	0.06	0.06	0.06	0.07	0.07	0.06
Azerbaijan	0.35	0.54	0.64	0.77	0.85	0.97	1.05	1.17	1.18
Belarus	0.64	0.74	0.76	0.78	0.80	0.84	0.85	0.81	0.78
Estonia	0.05	0.08	0.09	0.11	0.12	0.14	0.15	0.15	0.15
Georgia	0.05	0.09	0.11	0.13	0.15	0.16	0.17	0.18	0.17
Kazakhstan	0.59	0.75	0.80	0.89	0.97	1.09	1.16	1.26	1.32
Kyrgyzstan	0.08	0.12	0.15	0.19	0.21	0.25	0.28	0.29	0.29
Latvia	0.06	0.08	0.08	0.09	0.10	0.12	0.12	0.12	0.12
Lithuania	0.11	0.13	0.13	0.14	0.15	0.17	0.17	0.17	0.17
Moldova	0.08	0.11	0.12	0.13	0.14	0.14	0.14	0.14	0.13
Russia	15.10	18.04	19.31	21.12	22.32	24.05	25.10	25.26	24.31
Tajikistan	0.05	0.06	0.06	0.06	0.07	0.07	0.08	0.08	0.08
Turkmenistan	0.43	0.56	0.64	0.75	0.83	0.95	1.03	1.17	1.26
Ukraine	3.01	3.52	3.63	3.85	4.01	4.26	4.29	4.22	4.12
Uzbekistan	1.70	1.83	1.94	2.16	2.33	2.62	2.83	3.17	3.18
MIDDLE EAST	8.84	10.20	10.63	11.81	12.88	14.69	16.01	17.93	18.93
Bahrain	0.34	0.36	0.38	0.42	0.46	0.53	0.58	0.65	0.63
Iran	3.06	3.18	3.22	3.67	4.13	4.93	5.53	6.45	7.05
Iraq	0.06	0.11	0.12	0.19	0.26	0.39	0.50	0.66	0.76
Kuwait	0.33	0.37	0.37	0.38	0.41	0.46	0.50	0.56	0.60
Oman	0.24	0.30	0.34	0.39	0.43	0.49	0.54	0.60	0.65
Qatar	0.41	0.45	0.46	0.47	0.48	0.50	0.51	0.53	0.54
Saudi Arabia	2.17	2.56	2.67	2.91	3.11	3.44	3.69	4.06	4.31
Syria/Jordan	0.20	0.28	0.26	0.28	0.31	0.36	0.39	0.45	0.48
Turkey	0.68	0.96	1.07	1.27	1.43	1.67	1.84	2.01	1.95
UAE	1.34	1.64	1.72	1.79	1.82	1.86	1.87	1.87	1.88
Yemen	0.00	0.00	0.02	0.04	0.05	0.06	0.07	0.07	0.08
NORTH AMERICA	27.68	32.58	31.95	32.38	33.16	36.42	38.91	41.35	40.93
Canada	3.08	3.88	3.97	4.15	4.27	4.55	4.77	4.92	4.82
Mexico	1.61	2.03	2.15	2.47	2.70	3.08	3.37	3.74	3.87
United States	22.99	26.67	25.83	25.76	26.19	28.79	30.78	32.69	32.24
CENTRAL/SOUTH AMERICA	3.79	4.83	5.28	6.09	6.68	7.64	8.18	8.88	9.22
Argentina	1.09	1.28	1.39	1.62	1.79	2.06	2.20	2.37	2.42
Bolivia	0.04	0.06	0.08	0.09	0.10	0.12	0.13	0.14	0.14
Brazil	0.50	0.92	1.08	1.34	1.50	1.79	1.95	2.20	2.35
Central America	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Chile	0.25	0.34	0.37	0.39	0.41	0.44	0.44	0.46	0.46
Colombia	0.19	0.27	0.30	0.33	0.36	0.39	0.42	0.43	0.38

Cuba	0.01	0.03	0.03	0.03	0.03	0.03	0.02	0.02	0.02
Ecuador	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Other Caribbean	0.02	0.04	0.04	0.04	0.05	0.05	0.06	0.07	0.08
Paraguay	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01
Peru	0.01	0.03	0.04	0.06	0.07	0.08	0.09	0.10	0.11
Suriname/Guyana/Fr. Guiana	0.00	0.00	0.01	0.02	0.02	0.03	0.03	0.03	0.03
Trinidad & Tobago	0.44	0.53	0.61	0.71	0.78	0.89	0.97	1.00	1.02
Uruguay	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Venezuela	1.23	1.31	1.32	1.43	1.55	1.72	1.84	2.03	2.17
WORLD TOTAL	**96.18**	**115.86**	**120.67**	**131.32**	**139.78**	**154.83**	**164.28**	**173.02**	**172.74**