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North American Security of Natural Gas Supply in a Global Market (Working Draft)

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NORTH AMERICAN SECURITY OF NATURAL GAS SUPPLY IN A GLOBAL MARKET

(WORKING DRAFT)

By

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THIS PAPER WAS WRITTEN BY A RESEARCHER (OR RESEARCHERS) WHO PARTICIPATED IN A BAKER INSTITUTE STUDY, "*NATURAL GAS IN NORTH AMERICA: MARKETS AND SECURITY*." WHEREVER FEASIBLE, THIS PAPER WAS REVIEWED BY OUTSIDE EXPERTS BEFORE RELEASE. HOWEVER, THE RESEARCH AND VIEWS EXPRESSED IN THIS PAPER ARE THOSE OF THE INDIVIDUAL RESEARCHER(S) AND DO NOT NECESSARILY REPRESENT THE VIEWS OF THE JAMES A. BAKER III INSTITUTE FOR PUBLIC POLICY.

ABOUT THE POLICY REPORT

NATURAL GAS IN NORTH AMERICA:

MARKETS AND SECURITY

Predicted shortages in U.S. natural gas markets have prompted concern about the future of U.S. supply sources, both domestically and from abroad. The United States has a premier energy resource base, but it is a mature province that has reached peak production in many traditional producing regions. In recent years, environmental and land-use considerations have prompted the United States to remove significant acreage that was once available for exploration and energy development. Twenty years ago, nearly 75 percent of federal lands were available for private lease to oil and gas exploration companies. Since then, that share has fallen to 17 percent. At the same time, U.S. demand for natural gas is expected to grow close to 2.0 percent per year over the next two decades. With growth in domestic supplies of natural gas production in the lower 48 states expected to be constrained in the coming years, U.S. natural gas imports are expected to rise significantly in the next two decades, raising concerns about supply security and prompting questions about what is appropriate national natural gas policy.

The future development of the North American natural gas market will be highly influenced by U.S. policy choices and changes in international supply alternatives.

The Baker Institute Policy Report on *Natural Gas in North America: Markets and Security* brings together two research projects undertaken by the Baker Institute's Energy Forum. The first study focuses on the future development of the North American natural gas market and the factors that will influence supply security and pricing. This study considers, in particular, how access to domestic resources and the growth of international trade in liquefied natural gas will impact U.S. energy security. The second study examines the price relationship between oil and natural gas, with special attention given to natural gas demand in the industrial and power generation sectors – sectors in which natural gas can be displaced by competition from other fuels. This policy report is designed to help both market participants and policymakers understand the risks associated with various policy choices and market scenarios.

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About the Energy Forum at the James A. Baker III Institute for Public Policy

The **Baker Institute Energy Forum** is a multifaceted center that promotes original, forward-looking discussion and research on the energy-related challenges facing our society in the 21st century. The mission of the Energy Forum is to promote the development of informed and realistic public policy choices in the energy area by educating policy makers and the public about important trends—both regional and global—that shape the nature of global energy markets and influence the quantity and security of vital supplies needed to fuel world economic growth and prosperity.

The forum is one of several major foreign policy programs at the James A. Baker III Institute for Public Policy at Rice University. The mission of the Baker Institute is to help bridge the gap between the theory and practice of public policy by drawing together experts from academia, government, the media, business, and nongovernmental organizations. By involving both policymakers and scholars, the institute seeks to improve the debate on selected public policy issues and make a difference in the formulation, implementation, and evaluation of public policy.

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I. Introduction

The share of natural gas use worldwide has grown from 19 percent of total world primary energy to 23.3 percent over the past 25 years. In the United States, natural gas is an important fuel, representing 22 percent of total primary energy use in 2006. Natural gas has been a favored fuel because it is considered more secure than oil, environmentally cleaner than coal, and competitively priced compared to oil, nuclear power and renewable energy. Much of the recent growth in natural gas demand derives from the power generation sector. The wide spread adoption of combined-cycle technology in power generation has particularly favored the use of natural gas due to increased efficiency in electricity production.

Natural gas holds an important place in the U.S. electricity market as the second largest source of fuel after coal and the fastest growing fuel for power generation. About 19 percent of all electricity generated in the United States derives from the burning of natural gas, up from only about 10 percent in 1986 when wellhead natural gas prices were fully decontrolled. Around 52 percent of all new power stations built since 1995 have been gas-fired, but those plants have been larger than the average new plant (many of which were small wind generators) and thus, natural gas accounts for 90 percent of all new megawatts of capacity installed in the United States since 1995.

Natural gas is also important to other end-use sectors of the U.S. economy. In industry, despite the fact that demand for natural gas has declined in recent years, it still represents 41 percent of all fuel consumed in that sector. Natural gas is also a popular fuel for residential use for heating and cooking. Over 50 percent of Americans now heat their homes with natural gas, compared to 40 percent who use heating oil or electricity. Natural gas' share in the overall U.S. residential market stands at around 43 percent today.

At the same time that natural gas has become more important to industrialized economies like the United States, significant developing economies such as China and India have also begun to expand their use of natural gas. The costs of producing, shipping and regasifying liquefied natural gas (LNG) have fallen in recent years, encouraging natural gas use and stimulating a steady increase in the volume of gas traded in international markets. As natural gas has risen in importance as a fuel worldwide, there has been greater international focus on the security and availability of natural gas supplies. Concern for maintaining a secure supply of reasonably priced natural gas will increasingly be viewed as a vital national interest. In fact, an inability to increase supply in the face of rising demand in recent years in U.S. natural gas markets has prompted concern about the future of U.S. natural gas supply, both domestically and from abroad.

In recent years, environmental and land-use considerations have prompted the United States to remove significant acreage that was once available for exploration from energy development. This has occurred despite the fact that U.S. demand for natural gas is expected to grow substantially over the next two decades. Ironically, demand growth is being spurred by environmental concerns, particularly in the electricity generation sector, because natural gas is a cleaner burning fuel than oil or coal. At the same time environmental concerns of a different sort – related to conservancy – have resulted in over 125 trillion cubic feet (tcf) of natural gas being made unavailable for development.

U.S. demand for natural gas has grown from 16.2 tcf in 1986 to 21.7 tcf in 2006, representing an average growth of about 1.5 percent per year. Demand growth for natural gas in the U.S. power generation sector has averaged 4 percent a year over the last decade while residential and industrial demand has dipped slightly in recent years in response to rising prices. At the same time, while some regions in the Lower 48 are seeing strong growth in production, the overall domestic supply has remained relatively flat because other regions are experiencing dramatic declines. As a result of rising demand and flat production, U.S. natural gas imports are expected to rise significantly in the next two decades, raising concerns about supply security and raising questions about appropriate national natural gas policy.

Adding to the U.S. supply challenge is the rise in natural gas demand in Canada and Mexico. Industrial operations in the production of oil from heavy tar sands in Alberta are greatly increasing Canadian demand for natural gas. This has led some analysts to predict that Canadian natural gas supplies to the United States will decline over the next two decades. In addition, demand for natural gas as an industrial feedstock and for electricity generation in Mexico is soaring, meaning Mexico is increasingly looking to LNG imports despite its bountiful resource base. In 2006, Mexico imported 0.88 bcfd (or

16.2 percent of Mexican demand) from the United States, which is up from only 5 million cubic feet per day (mmcfd) in 1986 and is three times higher than the volumes in 2000. Moreover, Mexican demand is expected to increase by 3.4 percent a year, leaving Mexico increasingly dependent on foreign imports unless it can reform its energy sector. One LNG receiving terminal with a send out capacity of about 500 mmcfd recently opened on the east coast at Altamira, and another, Sempra's Energia Costa Azul LNG, with a send out capacity of 1 billion cubic feet per day (bcfd) is currently being constructed on the west coast in the Baja peninsula. The Baja terminal is expected to be operational in late 2008.

In 2006, U.S. imports were about 20 percent of end-use demand. Most of those imports (85.7 percent) arrived by pipeline from Canada. However, the increasing demand for natural gas in the tar sands industry in Canada is likely to limit Canadian pipeline exports to the United States in the future. Further growth in U.S. natural gas demand coupled with constraints on domestic natural gas supply arising from a variety of factors is therefore likely to drive higher imports in the form of LNG. Already LNG imports have risen from virtually zero in 1986 to just over 0.5 trillion cubic feet (tcf), or 2.9 percent of total U.S. natural gas consumption in 2006 (14 percent of total imports). The construction of 3 new LNG import facilities in the U.S. Gulf Coast with a total send out capacity of over 5.5 bcfd is well underway and will facilitate substantial new LNG imports in the coming years. The United States imports LNG from a variety of countries, which in 2006 included Trinidad and Tobago (66.7%), Egypt (20.5%), Nigeria (9.8%), and Algeria (3.0%).

Given the importance of the changing outlook for North American natural gas supply and U.S. oil and natural gas prices, the Baker Institute embarked on a two-year study "Natural Gas in North America: Markets and Security" to investigate the future development of the North American natural gas market and the factors that will influence security of supply and pricing. This study considers how access to domestic resources and the growth of international trade in LNG will impact U.S. energy security. It also analyzes the outlook for growth in natural gas demand given fuel competition in the power generation sector and the price relationship between oil and natural gas. The aim of the study is to help both market participants and policymakers to understand the risks associated with various policy choices and market scenarios and the factors that will influence supply and pricing in the coming decades.

In this study, we use the Baker Institute World Gas Trade Model (BIWGTM) to examine the effects of opening the areas within the United States that are currently closed to exploration. The BIWGTM simulates world natural gas supply, demand, trade and price developments based on the economics of resource supply, demand and commodity transportation. The returns to capital required by investors in the upstream and midstream sectors influence how rapidly new sources of supply are developed, and, therefore, the BIWGTM accounts for the intertemporal tradeoffs of developing resources now versus later by anticipating future prices in response to project developments. In addition, costs, anticipated prices and risk-adjusted required rates of return[1] also determine the development and utilization of transportation routes to market and whether resources move by pipeline, LNG tanker, or simply not at all. Thus, the potential supplies that lie in restricted regions in the United States are not simply a boon to the overall supply picture. Rather, they must compete for market share against all other potential sources of supply.

We consider the effects of different scenarios in both a *restricted* and *unrestricted* world. The restricted world is defined to be one in which, the Outer Continental Shelf (OCS) in the Pacific, Atlantic and eastern Gulf of Mexico, restricted regions of North Alaska, and acreage in the Rocky Mountain region (RMR) are all unavailable for development. The unrestricted world allows all of these areas to be open for development. We construct, run and analyze various scenarios, in both the restricted and unrestricted versions of the model, with a focus on examining the influence of access restrictions on U.S. security of gas supply and the potential influence on the natural gas market of rapid adoption of alternative technologies in both the restricted and unrestricted cases. In doing so, we are able to better understand the consequences of current policy, and assess the potential costs of maintaining the status quo.

[1] The required rates of return for capital investments are constructed so that the risks of investing in various regions around the globe are captured. See Hartley and Medlock (2005) "The Baker Institute World Gas Trade Model" *Natural Gas and Geopolitics from 1970 to 2040* (ed. David G. Victor, Amy M. Jaffe, and Mark H. Hayes) for more on this.

II. Access Restrictions

Access restrictions in the United States are in place due to explicit federal prohibition of drilling in environmentally sensitive areas or burdensome conditions required to secure drilling permits in other areas. In this section, we discuss the nature of such restrictions in the Outer Continental Shelf (OCS) and the Rocky Mountain region (RMR), and the quantity of resources that are effectively off-limits. Figure 1 and Table 1 illustrate the geographic extent, with the exception of Alaska, and the quantity of resources that are effectively stranded. It is these quantities that we either include or remove from consideration in the scenario analyses outlined below.

Figure 1: Lower 48 resources affected by access restrictions

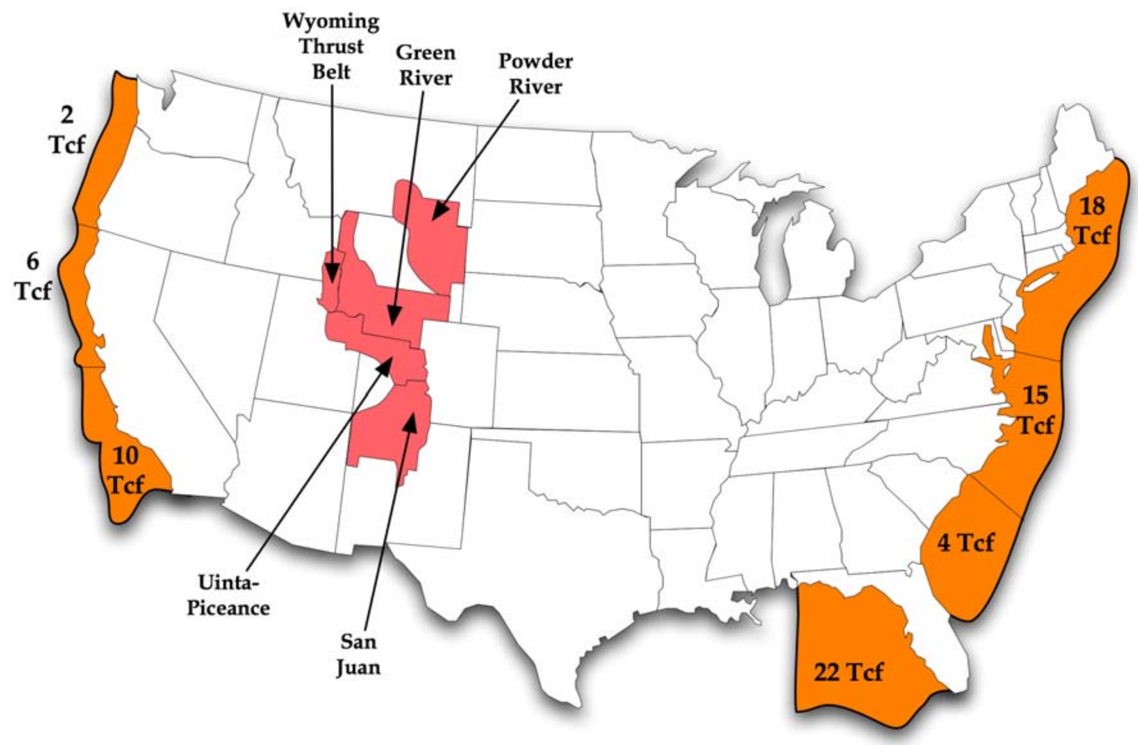


Table 1: U.S. resources affected by access restrictions

	Basin/Planning Region	Resource Off-limits (tcf)*	Source
Rocky Mountains	Wyoming Thrust Belt	9.6	*NPC, 2003*
	Green River	34.9	*NPC, 2003*
	Powder River	6.6	*NPC, 2003*
	Uinta-Piceance	6.5	*NPC, 2003*
	San Juan	2.6	*NPC, 2003*
OCS	Eastern Gulf of Mexico	22.1	*MMS, 2006*
	North Atlantic	18.0	*MMS, 2006*
	Middle Atlantic	15.1	*MMS, 2006*
	South Atlantic	3.9	*MMS, 2006*
	Washington/Oregon	2.3	*MMS, 2006*
	Northern/Central California	6.0	*MMS, 2006*
	Southern California	10.0	*MMS, 2006*
Total Lower 48 Resource		***137.6***	
Alaska	ANWR	8.6	*USGS, 2002*
	North Aleutian Basin	8.6	*MMS, 2006*
Total Resource		***154.8***	

* Numbers may not add due to rounding error.

The Outer Continental Shelf (OCS)

The Outer Continental Shelf (OCS) is defined as the offshore areas that stretch between three and 200 nautical miles from the U.S. coastline. In all states except Texas and Florida, areas within the first three nautical miles of the shoreline are managed by the state. In Texas and Florida, state waters extend to approximately nine nautical miles. Beyond 200 nautical miles is generally considered international waters, except where the geological continental margin extends beyond 200 nautical miles, as is the case in areas off Alaska, the Atlantic coast, and in the Gulf of Mexico. In these instances, the federal jurisdiction is extended.

The *Comprehensive Inventory of U.S. OCS Oil and Natural Gas Resources*, published by the Minerals Management Service of the U.S. Department of Interior (MMS) in 2006 as required by the Energy Policy Act of 2005, and the *Assessment of Undiscovered Technically Recoverable Oil and Gas Resources of the Nation's Outer Continental Shelf*, also published by the MMS in 2006, were used to determine the resources in the Atlantic, Pacific, Eastern Gulf of Mexico and Alaskan OCS. Cost curves for developing the resources are also available from the MMS studies. Figure 1 indicates the technically recoverable resource by planning area as assessed by the MMS. The total area of the Federal OCS is about 1.76 billion acres. Of this acreage, about 46 percent is under active lease for exploration, and about 20 percent of the active leases are actually under production.

As of 1953 with the passage of the Submerged Lands Act, states were given jurisdiction over coastal resources within the three mile limit. Also in 1953, the Outer Continental Shelf Lands Act (OCSLA) was passed, granting authority over all mineral resources on the OCS to the U.S. Secretary of the Interior. The OCSLA provides regulations and procedures for the leasing of federal OCS lands, ensures environmental protection of affected areas, and contains provisions that ensure that the government receives royalties for any production on federal lands. The MMS manages lease sales and collects royalties from oil and gas production.

Since the early 1990s, leasing in the OCS has only taken place in the Central and Western Gulf Coast of Mexico, primarily offshore of Texas and Louisiana and to a lesser extent Alabama. In most other areas, environmental concerns have prompted the establishment of moratoria that prohibit remaining OCS production. In fact, environmental concerns prompted the moratoria on development in the eastern Gulf of Mexico by President George H. W. Bush in 1990, and then extended through 2012 by President Bill Clinton. Currently, the only producing OCS areas are in the Western and Central Gulf of Mexico, and parts of California and Alaska. However, in 2006, the House of Representatives passed the *Deep Ocean Energy Resources Act*, which would lift the moratorium on drilling off most of the U.S. coastline. According to the proposed legislation, states retain the option to keep offshore drilling off limits within 100 miles of their coastlines. The Senate rejected the scope of the House's bill and instead passed a more restrictive bill, the *Gulf of Mexico Energy Security Act*, which the House later approved as well.

In December 2006, Congress passed and President George W. Bush signed into law the *U.S. Gulf of Mexico Energy Security Act*. The measure opened access to 8.3 million acres in the eastern and central Gulf, while providing a 125-mile buffer for the Florida coast. Gulf Coast states will receive 37.5 percent of the royalties generated from the leases. The MMS has proposed holding lease sales 206 and 224 for the central and eastern Gulf of Mexico on March 19, 2008, which would be the first sale in the eastern

Gulf of Mexico planning area to offer these blocks since 1988. In July 2007, the U.S. House of Representatives affirmed its annual moratorium on drilling in most of the OCS as part of its discussions for 2008 appropriations for the U.S. Department of the Interior.

The Rocky Mountain Region (RMR)

Access issues in the Rocky Mountain region (RMR) have been recently examined in four previous studies:

- *Natural Gas: Meeting the Challenges of the Nation's Growing Natural Gas Demand*, National Petroleum Council (1999) – This study considered the effects of Federal "no access" or "no surface occupancy" rules in several RMR basins.
- *Federal Lands Natural Gas Assessment: Southern Wyoming and Northwestern Colorado*, Department of Energy (2001) – This study examined the effect of Federal restrictions of "no access" or "no surface occupancy" in the Greater Green River basin.
- *Scientific Inventory of Onshore Federal Lands' Oil and Gas Resources and Reserves*, Departments of Energy and Interior (2002) – This study examined resource access in five basins (Green River, Powder River, Uinta-Piceance, San Juan-Paradox, and Montana Thrust Belt) in the RMR. The *Energy Policy and Conservation Act of 2000* directed the Departments of Energy and Interior to inventory all oil and gas resources on Federal lands.
- *Balancing Natural Gas Policy: Fueling the Demands of a Growing Economy*, National Petroleum Council (2003) – This study considered access restrictions arising from both Federal prohibition and conditions of approval that significantly raise development costs.

Because the 2003 NPC study is the most recent and most inclusive, the data generated for that study concerning access in the RMR was used in this study.

The 2003 NPC study used the other three studies listed above in its assessment of resource that is unavailable due to access restrictions. It also expanded its scope to consider resources whose access is restricted by "conditions of approval." Such restrictions were considered to prevent access if they resulted in lands being off-limits to drilling activity for at least nine months of the year. Generally speaking, this results in about 29 percent of natural gas resource in the RMR being off-limits to development, with development in some basins being more restricted than others. According to the 2003 NPC study,

> The term "conditions of approval" (CoA) refers to impediments to development that arise during the post-leasing permitting process. These CoAs arise from a variety of controlling authorities, but the most significant and wide-ranging tend to be those governed by three federal Acts:
>
> - The National Environmental Policy Act (NEPA)
> - The Endangered Species Act (ESA)
> - The National Historic Preservation Act (NHPA)
>
> - Volume IV: Supply Task Group Report (p.6-3)

A more detailed discussion of these CoA restrictions can be found in the 2003 NPC study, but a brief discussion follows herein. The results of outright prohibition to development and CoA restrictions are reported in Table 1 and Figure 1.

NEPA, enacted in 1969, is the act that established the Council on Environmental Quality, which ultimately mandated the performance of an Environmental Impact Statement (EIS) prior to any major infrastructure activity that alters the environment. An EIS can result in delays that exceed two years, as the review process can take exceedingly long. Moreover, according to the NPC, in some cases more than one EIS can be required when acreage falls into multiple jurisdictions.

Under the guidelines set forth by ESA, any person can file a petition to list a species as endangered. No specific qualifications are required to file such a petition. A submitted petition can result in substantial project delays as the proper governing agencies can determine if the species for which the petition has been filed actually meets the requirements set forth by the ESA. The most restrictive aspect of the ESA is the limitations that it can place on activity during different times of the year. If it is limiting enough, it can effectively render acreage inaccessible.

The NHPA, enacted in 1966, requires an archaeological assessment of lands prior to development so as to determine any cultural impact that the development activity may have. If it is determined that an archaeological resource is present on the affected acreage, then projects may be either significantly delayed as appropriate mitigation strategies are adopted, or entirely cancelled.

III. Scenario Description

In order to asses the effects of access restrictions in the RMR and OCS, we construct various scenarios using the BIWGTM. The following scenarios are designed to determine the effects of a complete lifting of restrictions on drilling when:

(S1) there are no other non-economic impediments to supplies, imported or otherwise

(S2) there are *temporary* disruptions in supply from the Middle East

(S3) there is a *permanent* disruption in supply from the Middle East

(S4) there are significant cost reductions in alternative energy technologies.

Since we examine two cases under each of the four scenarios, one where access is restricted and one where it is not, we can determine the impacts of access restrictions on price, domestic supply, and domestic demand under different circumstances. The differences between the outcomes in the two cases under each scenario allow us to determine which supplies are marginal under different scenarios and thus which suppliers to the United States would be affected the most by a lifting of access restrictions. This, in turn, allows a qualitative assessment of the energy security benefits of opening access to the resources that are currently off limits.

Table 2 outlines the scenarios in more detail. Hereafter, we shall refer to Scenario 1 – Case 1 as the Reference Case. All other scenarios will be referred to as Scenario 1-2, 2-1, 2-2, etc. where the first number represents the scenario and the second number represents the case. By no means is the list of scenarios we consider exhaustive, but it allows us to consider the effects of limited access to domestic resources when demand is more price elastic, and when import supply is less price elastic. Thus, it is possible to determine if the observed sensitivity to opening access is highly dependent on the relative price elasticities of demand and supply.

An important point is that forecasts of demand are different for each scenario. This is because the BIWGTM equates demand and supply in each period by adjusting price. Thus, price is endogenous. All other variables in the demand functions are taken to be exogenous. As a result, forecasts of those exogenous variables (income, population, weather, natural gas generation capacity, etc.) are required prior to each model run.

While variations in the assumed forecasts for the exogenous variables are important, we did not consider such variations within the scope of this project.

Table 2: Scenarios for analysis

	Scenario Description	Case 1	Case 2
Scenario 1	Only economic considerations matter	**Reference Case:** Access restrictions remain in place	Access restrictions lifted
Scenario 2	Instability in the Middle East results in temporary disruptions in regional exports	Access restrictions remain in place	Access restrictions lifted
Scenario 3	Regime change in the Middle East results in a permanent reduction in regional exports	Access restrictions remain in place	Access restrictions lifted
Scenario 4	Alternative technology is available at lower costs	Access restrictions remain in place	Access restrictions lifted

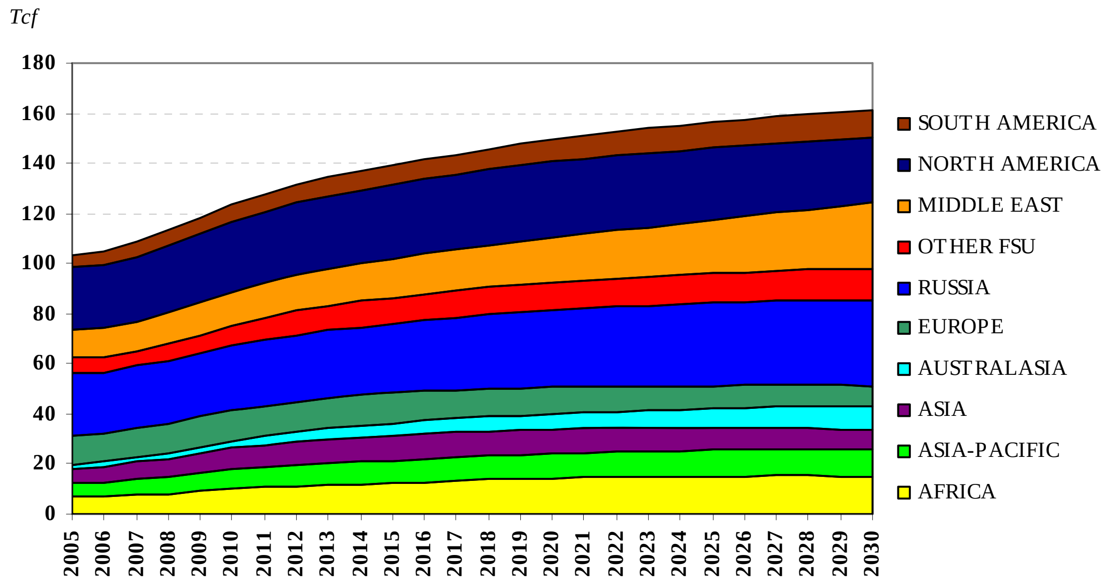
IV. Reference Case (Scenario 1-1)

The Reference Case is constructed under the assumption that existing access restrictions for drilling in the United States remain in place forever. We begin this section on the results of the reference case with a brief discussion of the results for the global gas market and follow with a more detailed description of the results for the United States.

Global results

Figures 2 and 3 present the reference case supply and demand projections. The figures present the data in regional aggregates in order to clearly discern trends. Tables A1 and A2 in the appendix provide the Reference Case projections for supply and demand aggregated at the individual country level.

Figure 2: Reference Case supply projections by regional aggregate



The Reference Case indicates that Russia will be the single largest producer of natural gas throughout the model time horizon. Most of the growth in Russia occurs in eastward exports, as supplies are developed to serve markets in Northeast Asia. In the Reference Case, Eastern Siberian gas begins flowing into northern China at the beginning of the next decade and eventually flows into the Korean peninsula. Despite the lack of significant expansion to the west, Russia remains the largest single supplier of natural gas to the European market, primarily by pipeline.

Russia ultimately provides supplies by both pipeline and LNG into both the Pacific and Atlantic basins. In the Pacific basin, production in the Sakhalin region is exported as LNG and also by pipeline to Japan. In addition, both Sakhalin production and Eastern Siberian production provides supply by pipeline to northeast China and the Korean peninsula. In the Atlantic basin, production in the Barents Sea eventually provides gas exports in the form of LNG beginning in the mid-2030's, but the majority of the gas produced in the region is exported via the northern European pipeline to Germany. The fact that Russia ultimately provides supply to both basins means Russia serve key role in global arbitrage since the "netback" price from sending supplies in any direction has to be the same.

Figure 2 also indicates that the Middle East emerges to a position of prominence over time. The largest exporters in the region are Qatar, the United Arab Emirates (UAE), Iran, and eventually Iraq. All Qatari and UAE exports occur as LNG, with Qatar being the largest exporter in the region through 2030. By contrast, Iraq begins to export gas north to Europe by pipeline through Turkey after 2015. Iranian gas is exported by pipeline to Pakistan and India beginning in 2025 and as LNG much earlier in the time horizon. In addition, existing infrastructure is expanded to move gas from Iran to Europe though Turkey and Armenia.

Figure 3: Demand projections by regional aggregate

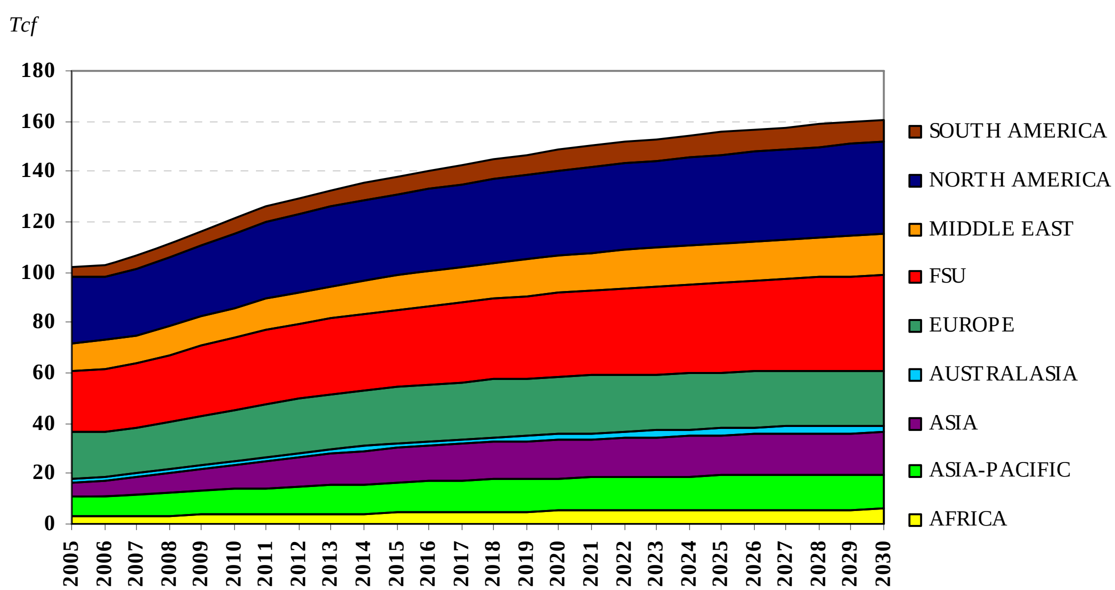
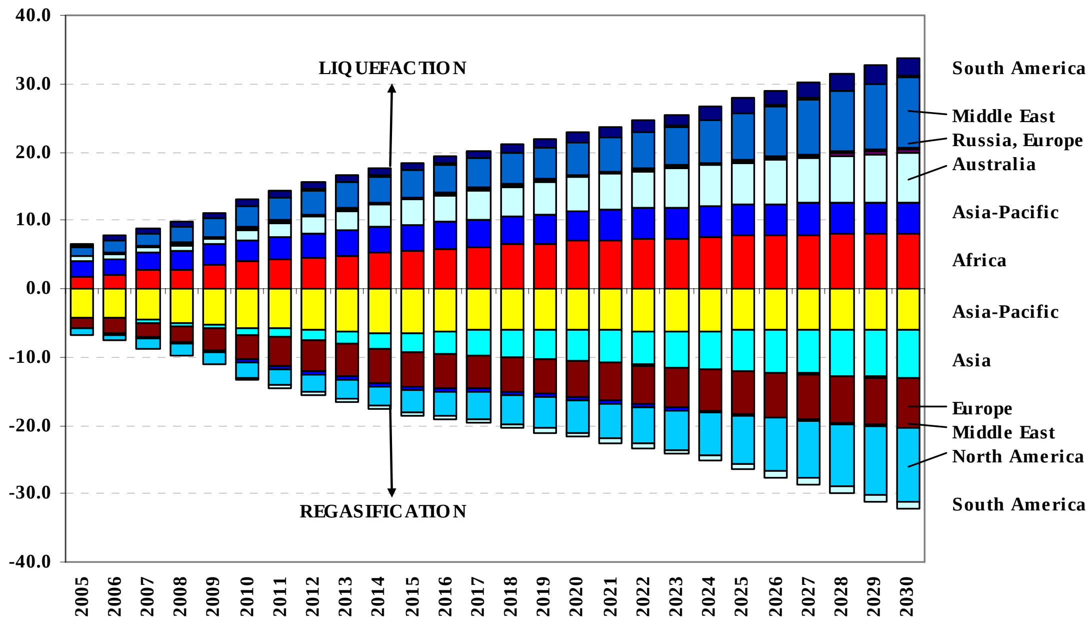


Figure 3 gives the demand projections for the Reference Case. The largest consuming regions are the traditional gas markets of North America, Europe and the former Soviet Union. The fastest growing regions, however, are in the Asia and Asia-Pacific, where demand growth tops 3.5 percent per year through 2030. Demand growth in the markets of China and India in particular serves to shift the flow of global supplies toward Asia over time.

Figure 4 summarizes global LNG imports and exports. As demand growth in North America, Europe and Asia outstrips domestic sources of supply, we see that LNG imports into these regions grow substantially, and make up the majority of all LNG regasification.

Figure 4: LNG Trade



In North America, a substantial amount of LNG is imported into Mexico and Canada over the modeling time horizon. In fact, Mexican imports into the Baja peninsula and the Gulf of California, and Canadian imports into New Brunswick ultimately are redirected to serve rising demand in the United States.

In Europe, strong demand growth, coupled with dwindling domestic supply, renders imports from multiple sources inevitable. Europe imports via pipeline from Africa, the Middle East, and Russia and via LNG from multiple sources in North and West Africa, the Middle East, and South America.

High demand growth in India and China also affect world LNG trade. In particular, the model suggests that Chinese LNG imports will grow by roughly 19 percent per year through 2030.

LNG supply is strongest from Australia and the countries of the Middle East. Qatar is an early leader in supplying LNG from the Middle East because other resource-rich players lack existing infrastructure and need to bear substantial fixed costs to enter the LNG market. Thus, Qatar benefits from a "first mover advantage" as demand must grow sufficiently to encourage expansion by other regional suppliers. Otherwise, additional early entry would drive down prices and lead to inadequate returns on investment. Therefore, entry by countries other than Qatar must be delayed until world demand in excess of alternative sources of supply is large enough to accommodate these incremental supplies.

The share of total world gas production coming from the Middle East is projected to rise from current levels of about 10 percent to just over 14 percent by 2025, and account for about 25 percent of all LNG shipments globally. Roughly half of Middle East LNG production is projected to flow into the Atlantic Basin, with the United States likely to receive about 20 to 25 percent of its LNG supplies from the Middle East.

Figure 5: Representative global prices (2005-2030)

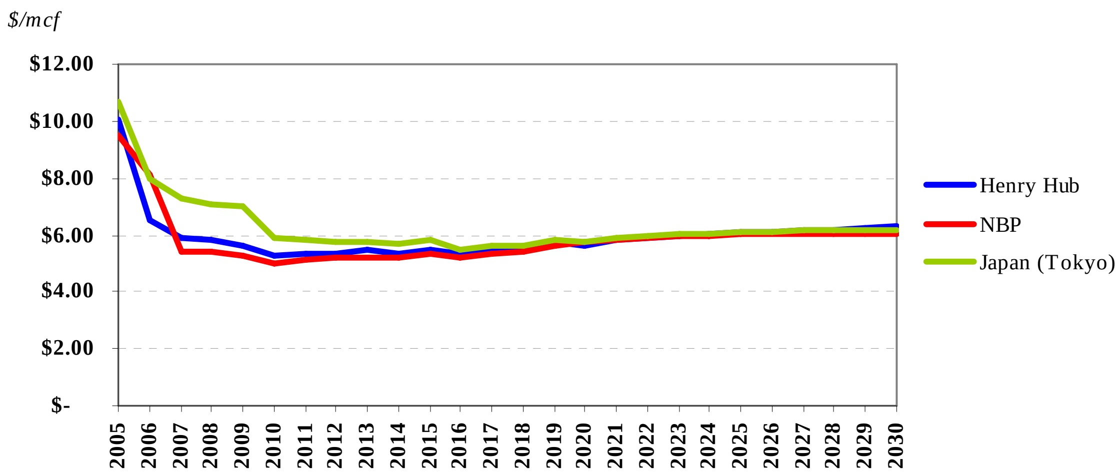


Figure 5 provides price projections for three locations around the globe, Henry Hub, NBP in the United Kingdom, and Tokyo. An interesting feature of these results is the fact that prices tend to converge to one another, reflecting the growth of LNG trade and the function it serves to arbitrage regional prices.

The United States in the Reference Case

In the Reference Case, where U.S. lands are not opened up for drilling, U.S. end-use natural gas demand climbs to 23.9 tcf in 2015 and 28.2 tcf in 2030, up from 20.0 tcf in 2006. Total demand in the United States grows at an average rate of 1.3 percent per year through 2030 in the Reference Case. The majority of this expansion comes from the power generation sector, which grows at an average annual rate of 3.1 percent. Power generation demand for natural gas grows from 6.2 tcf in 2006 to 9.4 tcf in 2015 and 13.0

tcf in 2030. The fastest growth in the power sector comes near the beginning of the time horizon, with growth rates in excess of 5% in some years. Figure 6 depicts U.S. demand by end-use sector in the Reference Case through 2030 along with the average annual growth rates.

In order to meet growing demands new supplies are needed. In the Reference Case, these supplies are developed on an economic basis from existing domestic sources but also must compete with resources from abroad. In fact, LNG imports grow considerably in the Reference Case, especially after 2020. While near term production growth in shale plays (Barnett, Fayetteville and Woodford) and the Rocky Mountain Region (Southwestern Wyoming, Piceance and Uinta basins in particular) provides a boost to domestic supplies in the nearer term, eventually, demand growth outpaces availability of these domestic supply sources, requiring high volumes of imported LNG.

Figure 6: Reference Case U.S. Demand (2005-2030)

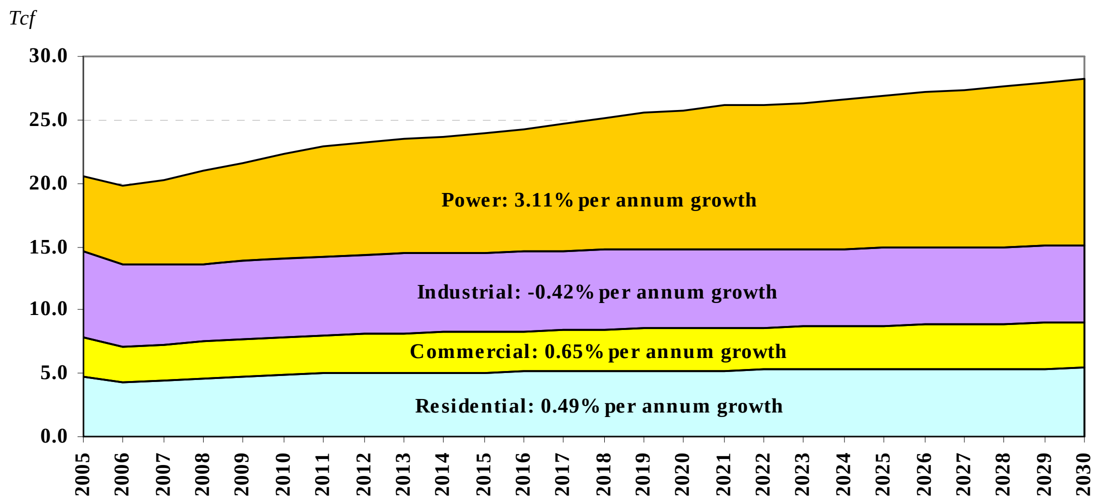


Figure 7: Reference Case U.S. Domestic Production (2005-2030)

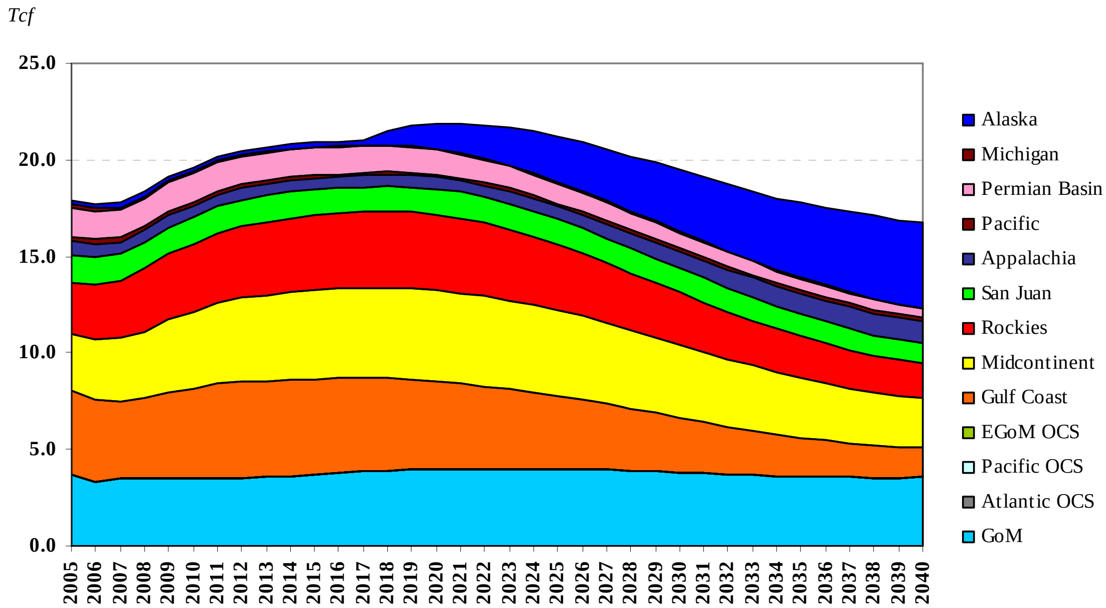


Figure 7 illustrates domestic production by regional aggregation through 2030. Regional aggregates are defined such that the Midcontinent includes Oklahoma, Arkansas, Kansas, Texas Railroad Commission District (RRC) 7B, 9, and 10, thus encompassing the Barnett, Fayetteville and Woodford shale plays. The Rockies includes Montana, North Dakota, Wyoming, Utah, and Colorado (except for the portion of Colorado that is included in the San Juan basin). The Gulf Coast includes Texas RRC districts 1-6, Alabama and Louisiana onshore, Florida and Mississippi.

In the Reference Case, U.S. natural gas production is projected to be roughly 20.8 tcf in 2015 and 19.3 tcf in 2030. Domestic production reaches a high of 21.8 tcf in 2021, largely due to growth in Alaskan supply. Importantly, however, flat to declining production in Canada, coupled with growth in Canadian demand, means some Alaskan gas is consumed in transit to the Lower 48. Thus, even though Alaskan production grows beyond 2020, there is still a strong need for other sources of supply, such as LNG.

In the intermediate term to 2015, dependence on imported LNG from the Middle East will not be large. In fact, LNG imports are projected to only climb to 2.42 tcf by 2015 or about 10.0 percent of U.S. demand by 2015. However, LNG imports accelerate beyond 2015 as domestic supplies become increasingly expensive. As a result, the United States will rely on imports for 20 percent of total natural gas consumption by 2025, growing to 31 percent by 2030. Of these imports, direct LNG imports (via U.S. based terminals) account for 80 percent in 2015 falling to 73 percent and lower in 2025 and beyond, with indirect LNG imports (those coming through Mexican and Canadian terminals and reshipped via pipeline to the United States) accounting for the growing remainder.

Figure 8: Reference Case U.S. LNG Imports (2005-2030)

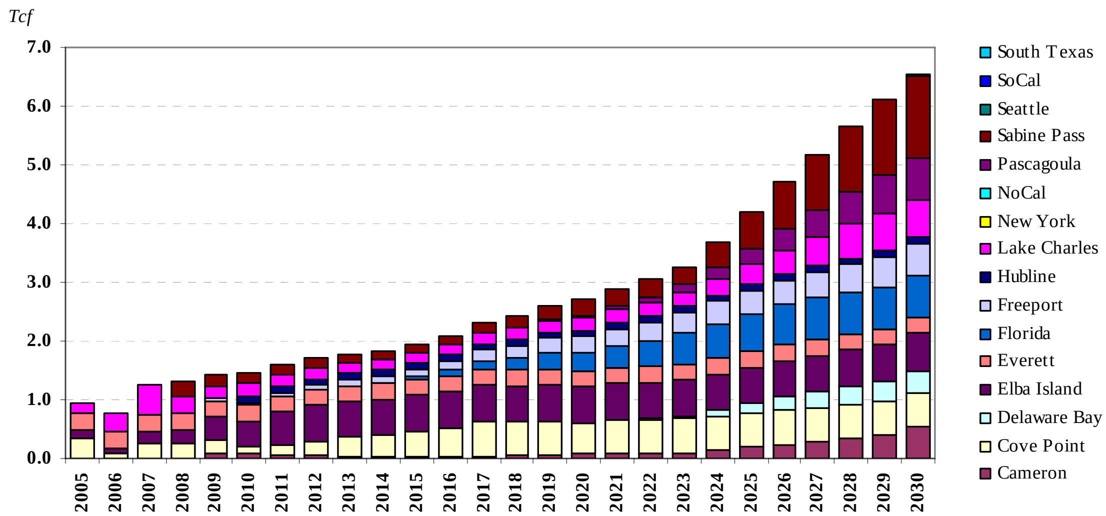
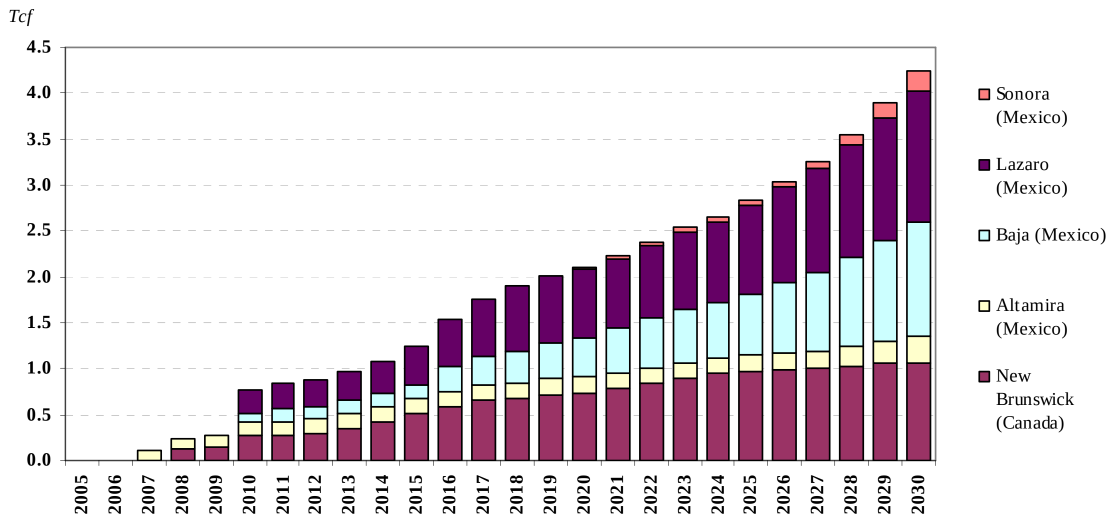


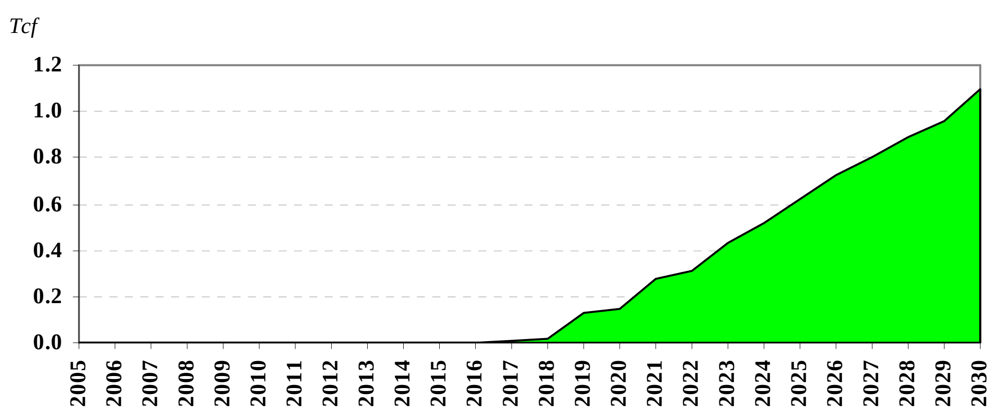
Figure 8 illustrates LNG imports into U.S. terminals and Figure 9 illustrates LNG imports into terminals in Mexico and Canada through 2030. Figure 9 is important because at least some of the LNG imports into Northeastern Canada and Western Mexico are destined to serve customers in the United States via pipeline.

Figure 9: Reference Case Canadian and Mexican LNG Imports (2005-2030)



Some demand is also met by an alternative, or so-called "backstop," technology. This alternative technology is modeled so that it can capture market share from natural gas in the power generation sector beginning in 2015, so long as the price of natural gas is high enough. The costs associated with alternative energy are specified in accordance with the Department of Energy's "nth-of-a-kind" technologies for integrated combined-cycle coal gasification (IGCC) and solar. IGCC can begin to take market share from natural gas in 2015, whereas solar energy begins to take market share in 2020. By 2030, the total combined market share that can be captured by these sources is 5 percent of total demand. Figure 10 depicts the backstop technology in the Reference Case.

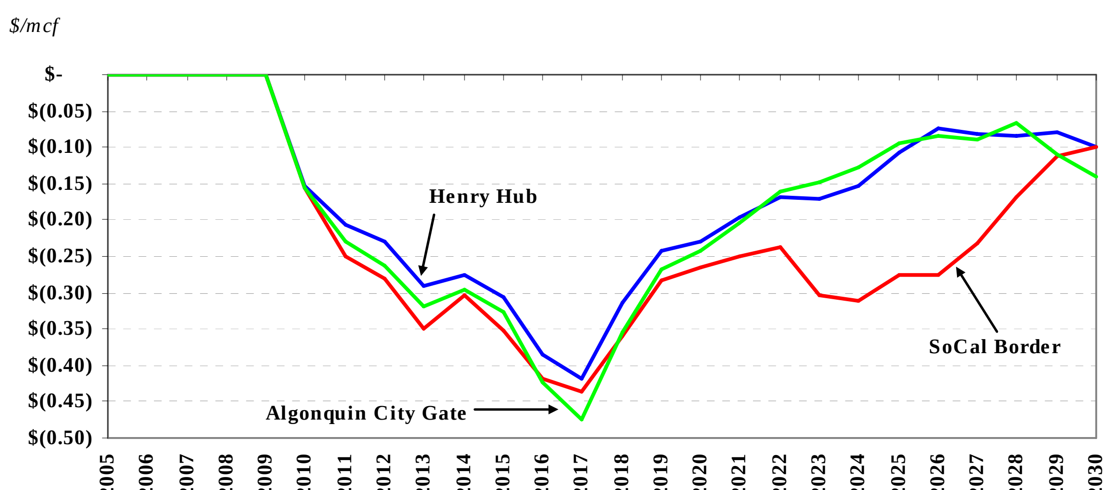
Figure 10: U.S. demand met by the backstop technology in Reference Case



V. The Effects of Removing Access Restrictions (Scenario 1-2)

Lifting access restrictions in the OCS (an estimated 81 tcf), Federal lands in the RMR (an estimated 57 tcf), and restricted regions in Alaska (an estimated 31 tcf) has a significant impact on the supply portfolio in the United States. Although there is a marked increase in natural gas production from the areas that are currently off-limits, the impacts on price are less significant, with the largest impacts coming in the latter part of next decade and diminishing in future time periods. The affect of lifting access restrictions on price at the Henry Hub, SoCal Border, and Algonquin City Gate is depicted in Figure 11. The price impacts are less substantial because the new domestic supply must compete with other sources of supply into the North American market and results in a changing mix of suppliers and not just incremental additions of cheaper domestic supply to the existing base of production. In the unrestricted scenario where all other factors remain unchanged, increasing production from the OCS and RMR is offset, relative to the Reference Case, by reductions in supplies from mature U.S. producing regions, reductions in LNG imports, and delays in Alaskan gas reaching the Lower 48.

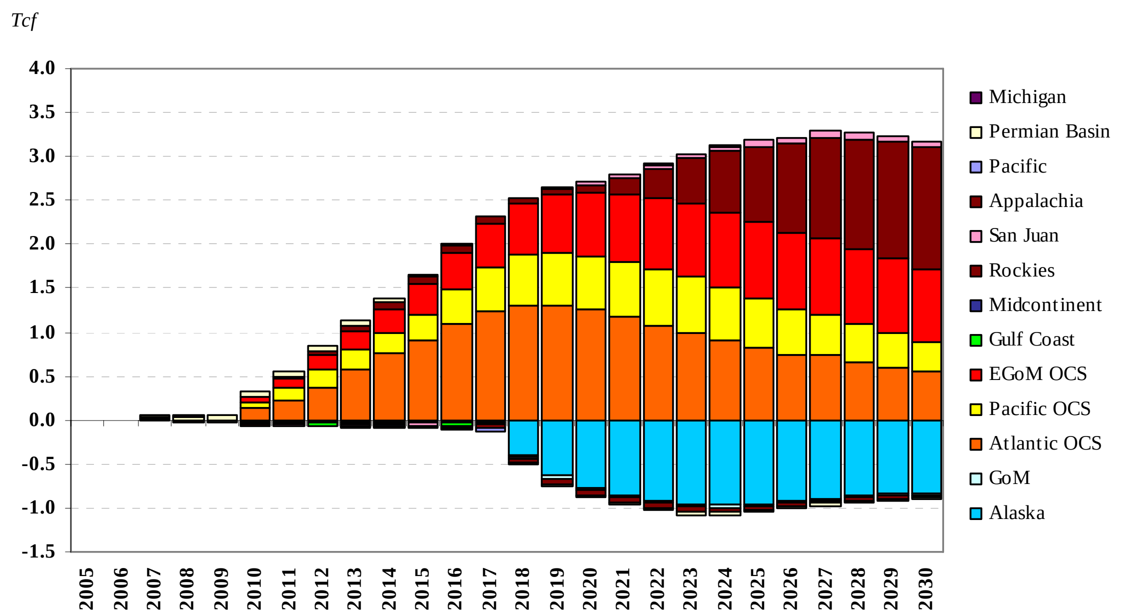
Figure 11: Price impacts of removing access restrictions



The price impacts in certain market areas, such as consuming regions on the East and West Coasts, are greater than at the Henry Hub, although not substantially so. This is due to the fact that allowing drilling activity along the Atlantic and Pacific Coasts, for example, provides supplies locally rather than via long-haul transportation from traditional supply regions such as the Gulf of Mexico. For example, the price at the SoCal Border is suppressed relative to the Reference Case due to increased production in both the Pacific OCS and the RMR, with the impact persisting much longer than in other locations.

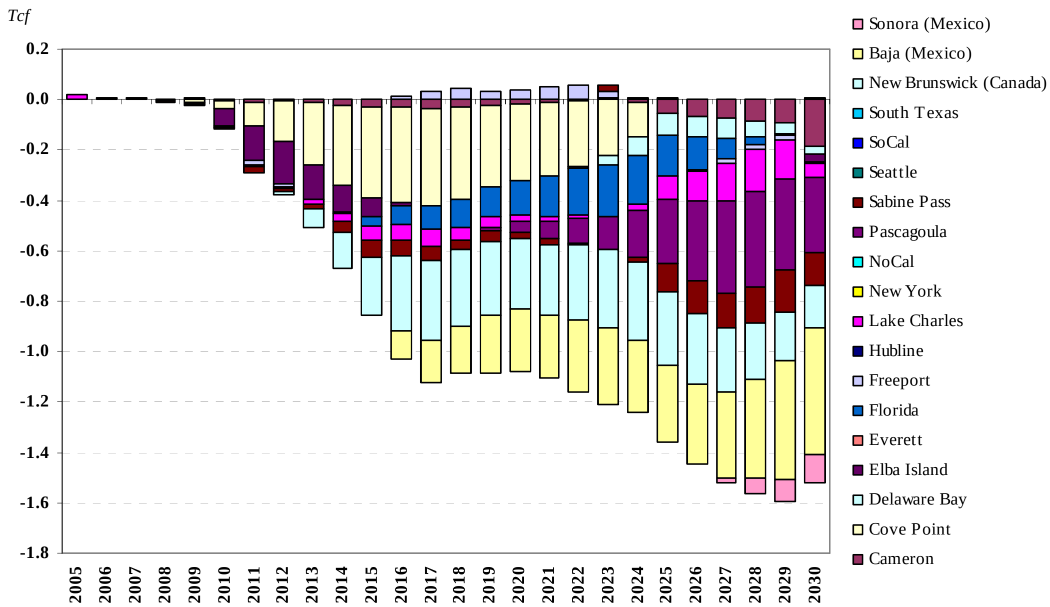
Figure 12 indicates the changes in U.S. production by regional aggregates when access restrictions are lifted. The largest offsetting impact is the reduction in supply from Alaska. While production in regions where restrictions currently exist increases by about 3.35 tcf in 2030 when those restrictions are lifted, a 0.9 tcf reduction in Alaskan supply, coupled with some smaller marginal declines in other regions, renders the net gain on supply much smaller at about 2.35 tcf. Thus, opening access to restricted areas results in higher overall production but also a reallocation of regional production.

Figure 12: Unrestricted case production minus restricted case production



From a commercial standpoint, if the firms involved in Alaskan developments are the same firms involved in developments in the OCS and the Rockies, opening access actually results in cannibalization of market share for those firms. Thus, it is important that policy give clear directive regarding future developments so as not to result in potentially large stranded costs.

Figure 13: U.S. LNG imports (No access restrictions minus Reference Case)



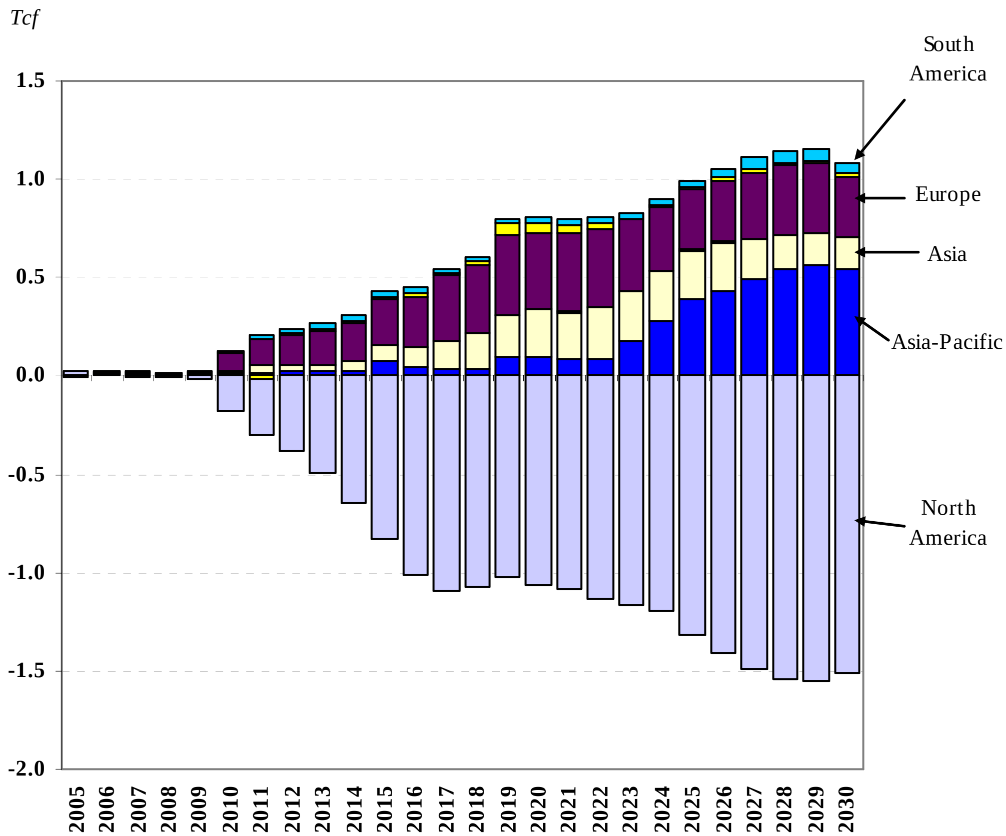
Higher Lower 48 production as a result of opening access also results in lower imports of LNG. Figure 13 depicts the change in LNG imports when access restrictions are lifted and all other factors remain unchanged. Total LNG imports into the United States in 2015 fall by about 0.85 tcf (or from about 2.4 tcf to 1.55 tcf) and in 2030 by 1.6 tcf (or from 8.8 tcf to 7.3 tcf). This figure includes pipeline imports to the United States from Mexico and Canada that are being reshipped from LNG import terminals from those countries. The decline under this scenario is represents a fall in LNG market share in the United States from just over 31 percent in the Reference Case in 2030 to 22 percent. The LNG receiving terminals that are most directly affected by the opening of access for drilling are those that are closest to these newly opened areas of the Atlantic, Pacific and east Gulf of Mexico OCS. For example, the terminals at Baja, New Brunswick, Pascagoula, Cove Point, and Delaware Bay see the largest volume reductions, in some years accounting for over 80 percent of the difference in overall import flows. This, like the situation with Alaska, represents some cannibalization of market share as companies who might drill in the now restricted OCS would be the same firms whose LNG would be pushed out of the U.S. market.

One offsetting factor to the loss of market share for LNG and Alaskan supplies is that fact that lower average prices give a slight boost to overall U.S. demand. When access restrictions are lifted, lower prices encourage a modest increase in demand of about 1.3 bcfd by 2030, of which 1.0 bcfd is added natural gas demand in the power generation sector.

While the change in average annual prices under this unrestricted scenario is not large, open access also allows existing demand to be served at lower cost. Thus, the net surplus benefits (including added consumer welfare) associated with expanded use of gas at lower prices can be quite large. For example, the benefit to consumers of a $0.42 reduction in price in 2017 (the maximum decrease seen over the modeling period) results in an annual saving of $10.3 billion for natural gas consumers. Of course, the benefits are lower in other years, but cumulative benefits still range into the many billions of dollars.

Open access also brings other potential benefits, such as providing a degree of diversification that mitigates the extent to which a cartel in international natural gas markets can operate effectively to threaten U.S. energy security. This increased diversification is evident in Figure 14, which depicts the changes in LNG imports by major regions around the world. We see that when access restrictions are removed, the resulting decline in North American LNG imports is accompanied by an increase in LNG imports in other regions around the world. This occurs as global prices are reduced and demand is encouraged. Thus, both energy security benefits as well as welfare benefits accrue to nations outside the United States as a result of eliminating access restrictions.

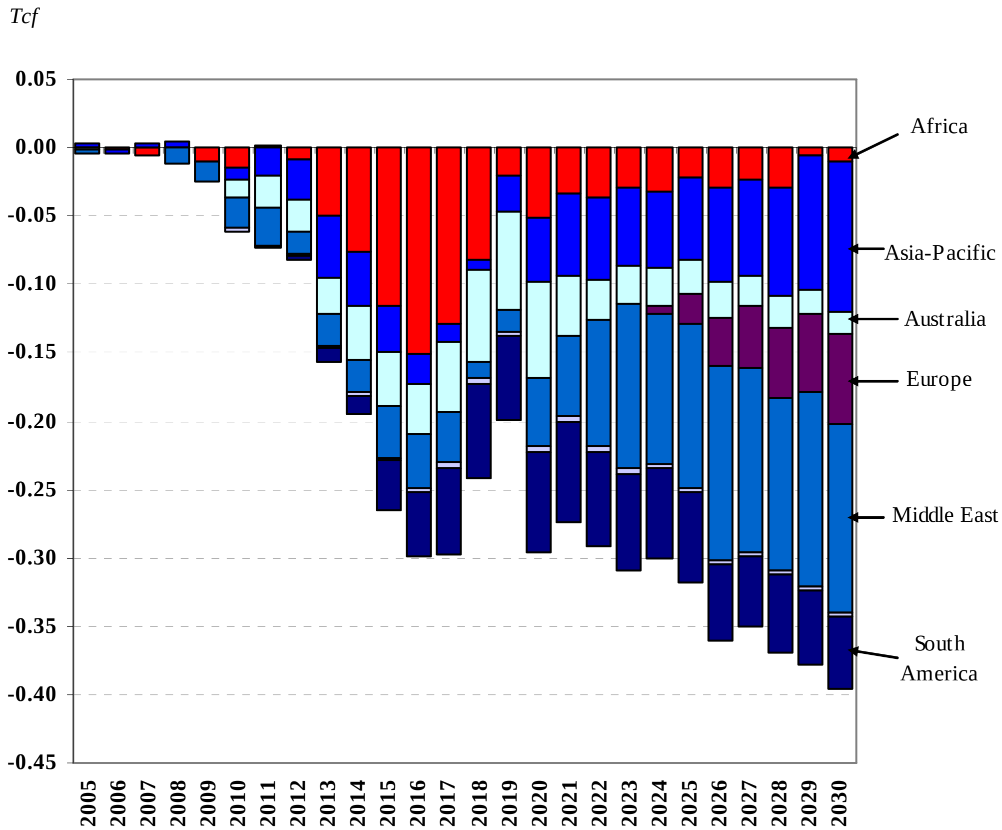
Figure 14: Changes in global LNG imports when access restrictions are lifted



In addition, when access restrictions are removed, LNG exports from the more marginal producers, which tend to be OPEC countries (Iran, other Middle East exporters, Venezuela, and to a lesser extent countries in North and West Africa), decline at the margin, falling collectively by 0.27 tcf in 2015, and as much as 0.43 tcf by 2030 (see Figure 15). Even though the volumes are small, the analysis suggests that this less constrained supply picture for the global market can contribute to rendering the United States and its allies less vulnerable to the will of any one producer, or the collective will of any group of producers, by enhancing the diversification of supply options. The wider swath of alternative supplies for Europe and northeast Asia translates into significantly reduced potential for producers in Russia and the Middle East to exert market power.

Aside from the general benefit of enhancing supply diversity, another benefit of removing access restrictions is the increased use of natural gas in power generation, which if it replaces coal, has environmental benefits. Since natural gas is a cleaner burning fuel than coal, for example, open access allows natural gas use to expand without having a significant impact on prices.

Figure 15: Changes in global LNG exports when access restrictions are lifted



VI. Scenario Analysis

In order to examine whether or not there are any additional benefits to removal of access restrictions, we also considered cases in which Middle East supply is disrupted and where penetration of alternative technology is greater. In general, we find that there is additional value to opening currently closed acreage to exploration and development when there are either temporary or permanent disruptions in supply. The benefit derives from the added diversity that arises from having access to more supply options, effectively increasing the elasticity of supply by moving domestic depletion constraints farther into the future.

There are also benefits from increasing the availability of alternative technologies at a lower cost. These benefits derive from the fact that alternatives raise the elasticity of demand for natural gas. By providing more options for energy services, consumers are able to shed natural gas demand more easily in the face of rising prices. This tends to mute the effects of long term maturation in domestic supplies. In effect, we do not need to develop higher cost natural gas resources as alternatives are available.

Temporary disruptions in Middle East output (Scenarios 2-1 and 2-2)

In these cases, the supply demand picture for North America is not substantially changed from Scenarios 1-1 and 1-2. This is because the nature of the shocks is temporary, and long term investment patterns are not altered in response to unexpected temporary shocks. However, short term behavior is noticeably different. In particular, modeling the disruptions in supply from the Middle East as periodic indicates that access to a broader domestic resource base acts as a buffer supply against such disruptions.

Timing of the disruption is important. In general, the later in time the disruption occurs, the greater its impact on the U.S. natural gas market. The reason is that the role of the Middle East expands as time passes, so that a disruption of supplies in 2030 will result in a much greater volumetric impact on the global gas market than a disruption in 2010. In addition, as time passes, the ability for other countries to respond becomes limited as the low cost resources outside of the Middle East have already been tapped and therefore are declining. A mitigating factor, however, is that as time passes, the availability of the backstop increases. Thus, with a more elastic demand curve for natural gas, a given change in supply has a smaller impact.

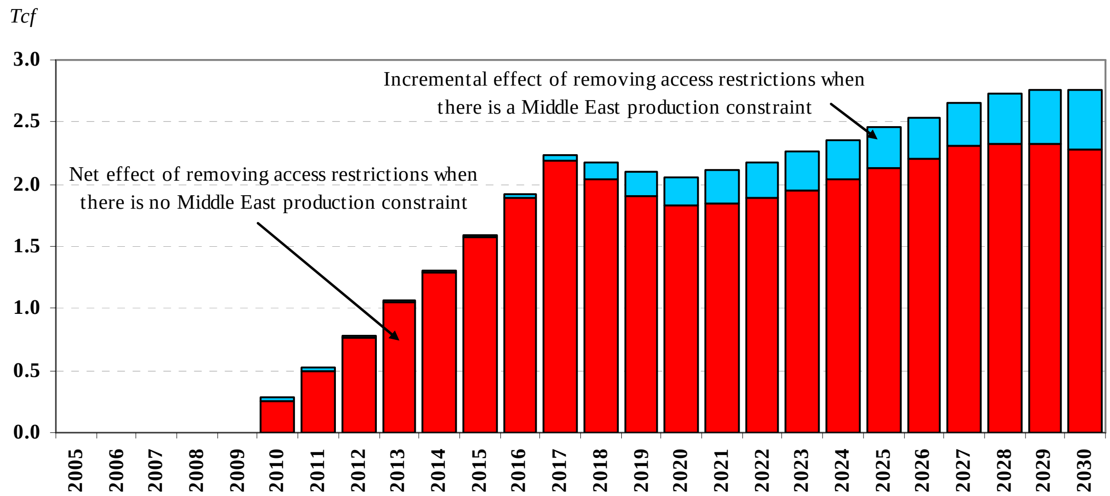
An unexpected disruption that reduces supply from the Middle East in 2020 by 15 percent (a cutoff of about 1.2 tcf of natural gas), only increases U.S. natural gas prices at the Henry Hub by around 20 cents in that year if access restrictions are in place versus when they are lifted. The relatively minimal price impact of a 15 percent cutoff of Middle East supply only amounts to a reduction in overall Atlantic Basin supply by about 0.6 tcf. European markets are able to draw slightly more heavily from pipeline suppliers in North Africa and Russia, which means less competition for supplies that need to go to the United States. The result is that U.S. LNG imports fall only slightly. The global flexibility that is present in 2020 — even in the case where U.S. OCS and Rocky Mountain areas are closed to drilling — mitigates the impact of such a temporary disruption. Globally, the relatively large number of suppliers means that a variety of foreign sources can make up for lost Middle East supply. Thus, supplies are reallocated around the globe so that the required response by any one producer to compensate for the lost 1.2 tcf of supply in a 150 tcf global market is relatively small.

Permanent reduction in Middle East output (Scenarios 3-1 and 3-2)

In the cases where Middle East supply is reduced significantly for a prolonged period of time relative to Scenarios 1-1 and 1-2, as might be the case if a cartel where to develop in the international natural gas market, the net result is slightly higher prices in both the United States and globally. Even in this scenario, the price impact is mitigated, however, as other regions of the world expand production to meet the shortfall.

In the United States, lifting access restrictions in this “GasOPEC” case results in a greater increase in production than when there is no constraint on Middle East production (see Figure 16). In fact, by 2030, U.S. domestic production is a 0.48 tcf (or 1.3 bcfd) higher. Thus, access to currently restricted areas effectively increases the elasticity of supply and thereby reduces the price effect of the Middle East production constraint. If the constraint is the result of cartel behavior, then open access limits the ability of the cartel to manipulate price and significantly weakens the monopoly power of any emerging cartel. In general, then, a key finding of the scenario analysis in this study is that the ability of any single producer, or group of producers, to raise natural gas prices will be limited by expanding access to U.S. domestic natural gas resources.

Figure 16: Middle East constraints, access restrictions and U.S. domestic production



As noted above, lifting access restrictions in the face of a temporary disruption does not yield substantial benefits in terms of lowering U.S. prices outright or in terms of making very large reductions in import levels. However, the contribution of expanded OCS and Rockies natural gas production could, nonetheless, be geopolitically important in combating the rise of a cartel in the international natural gas market, a so-called "GasOPEC." In effect, just as in the scenarios in which there were no production constraints in the Middle East (Scenarios 1-1 and 1-2), opening U.S. domestic drilling in the GasOPEC scenario enhances available supplies for Europe and northeast Asia and lowers global natural gas prices. The greater availability of supplies for Europe and northeast Asia translates into significantly reduced market power of producers in Russia and the Middle East. Furthermore, the higher elasticity of natural gas supply as a result of allowing greater access to resources in the United States also reduces market power in the sense that a larger reduction in cartel supply would be needed to achieve a given price increase.

In fact, opening access more fully in the OCS and Rocky Mountains not only enhances U.S. supply and thereby energy security at home but also positively impacts the global energy security situation by reducing the market power of key natural gas producers and thereby lowering the risks that vital natural gas supplies could be withheld for geopolitical ends or to garner exorbitant short-term rents. The main point is that the possibility of *incremental* latent increases in U.S. production capability restrains the options of a GasOPEC or dominant supplier like Russia. Increased access in the Lower 48 could thus also yield additional benefits in so far as it can reduce the impact of dominant suppliers of natural gas by increasing the elasticity of the demand curve net of other supplies that they face.

It should be noted that the ability of higher cost U.S. production to respond to a GasOPEC cutoff scenario could be even greater in a higher, oil price environment than used in this modeling exercise. The results presented here assume future oil prices based on U.S. Energy Information Administration's *Annual Energy Outlook 2007* forecast of $57.50 a barrel (in 2005 dollars) for 2007, $44.41 for 2014, and $51.63 a barrel for 2030. But oil prices in 2007 and beyond may exceed the EIA's forecast. If so, the demand for natural gas, and natural gas prices, would also be higher and the potential effects of having a more elastic U.S. supply curve would likely be even greater.

Greater availability of Backstop Technologies (Scenarios 4-1 and 4-2)

It might be argued that it would be preferable to reduce foreign gas suppliers' monopoly power not through domestic drilling but through the wider option of alternative energy in the electricity sector. Indeed, scenario analysis indicates that the lower prices ushered in with a lifting of OCS and Rocky Mountain restrictions also reduce the extent to which alternatives, such as coal-gasification and nuclear, are deployed. For example, in Scenario 1, alternative energy technologies, so-called backstop technologies, meet 1.1 tcf of demand by 2030 in the case where access is restricted but only 0.8 tcf when access is unrestricted. However, if we allow the backstop to be significantly cheaper, it is adopted much more aggressively (see Figure 17) than in the case where drilling access is unrestricted but the cost of alternative energy is higher. In fact, incremental use of the backstop technology when its cost is reduced is about 1.6 tcf in 2030.

Under the low cost alternative energy/open access to drilling scenario where technological cost breakthroughs allows alternative energy to compete more effectively with natural gas, LNG import requirements are reduced, just as is the case when lifting restrictions on access to drilling acreage in the currently blocked areas of the United States. Whereas in the open drilling access scenario LNG imports were reduced by 0.85 tcf in 2015 and 1.6 tcf in 2030, adding the availability of an alternative energy resource at a lower cost creates additional reductions in LNG imports (see Figure 18). Lower cost backstop supply reduces LNG imports by an *additional* 0.25 tcf in 2015 and 0.6 tcf in 2030 beyond reductions seen following the opening of drilling. The maximum incremental reduction in LNG imports as a result of lower cost technology occurs in 2027, at about an *additional* 0.8 tcf (or 2.2 bcfd).

The increased availability of backstop technologies at a lower cost increases the elasticity of demand, as consumers have more alternatives to natural gas at lower prices. Thus, the availability of an alternative low cost source of energy has the potential to bring about a similar set of benefits as opening more lands to drilling in terms of combating the potential monopoly power of a GasOPEC or a single very large gas supplier such as Russia.

Figure 17: Adoption of backstop technology

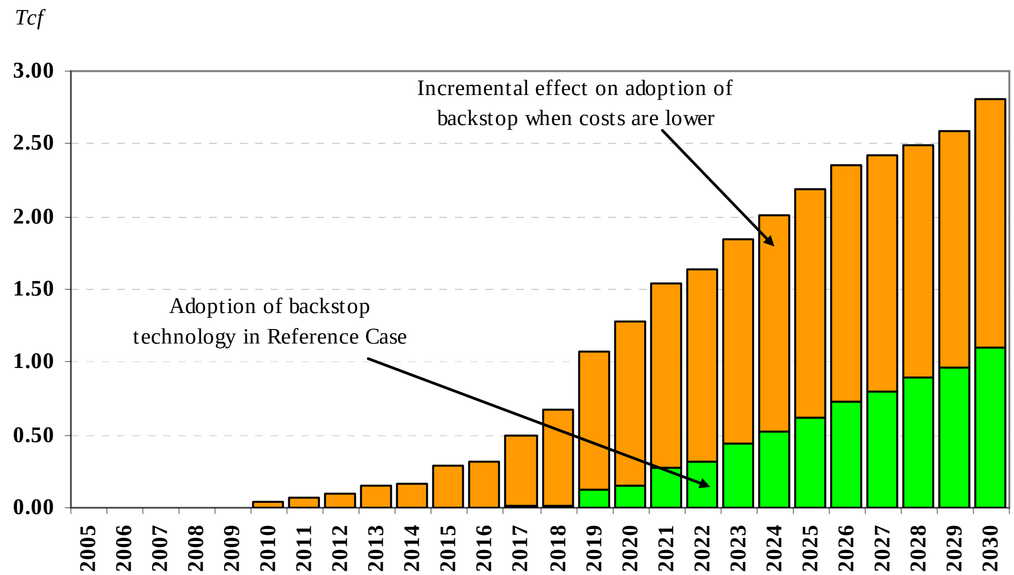
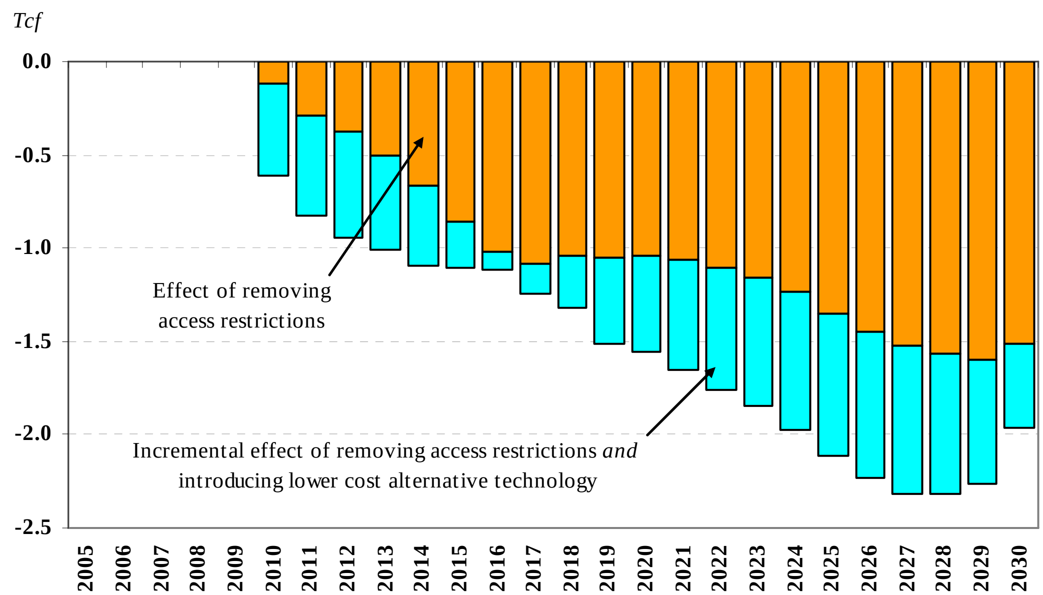


Figure 18: Low cost alternative technology, access restrictions, and LNG Imports



VII. Concluding Remarks

Under a business as usual scenario, or Reference Case, where U.S. lands are not opened for drilling, U.S. natural gas demand climbs to 23.9 tcf in 2015 and 28.2 tcf by 2030, up from 20.3 tcf currently and representing a gain of about 1.3 percent per year. Rising demand from the electricity sector contributes most prominently to this increase, with electricity demand for natural gas growing from 6.2 tcf currently to 9.4 in 2015 and 13.1 tcf in 2030.

U.S. natural gas production is projected to be roughly 20.8 tcf in 2015 and 19.5 tcf in 2030 in the Reference Case. In the short term to 2015, dependence on Middle East supply will not be large. LNG imports will only climb to 2.42 tcf by 2015 or about 10 percent of U.S. demand. However, under the Reference Case, the United States will rely on LNG imports for 20 percent of total natural gas consumption by 2025, and 31 percent by 2030. Of these imports, direct LNG imports (via U.S. based terminals) account for 80 percent in 2015 falling to 73 percent and lower in 2025 and beyond, with indirect LNG imports (those coming through Mexican and Canadian terminals and reshipped via pipeline to the U.S.) accounting for the growing remainder.

Also in the Reference Case, the share of total world gas production coming from the Middle East is projected to rise from current levels of about 10 percent to just over 16.3 percent by 2030 and about 25 percent of all LNG shipments globally. Roughly half of Middle East LNG production will be coming to the Atlantic Basin, with the U.S. likely to receive about 20 to 25 percent of its LNG supplies from the Middle East.

This supply picture has raised questions about growing dependence on the Middle East for both oil and gas supply. However, scenario analysis shows that opening restricted areas in the OCS and Rocky Mountains to drilling and natural gas resource development will not render the U.S. energy independent nor will it even lower U.S. dependence on LNG imports in 2015 by a significant volume. Price impacts are also limited, with U.S. prices only registering marginal reductions under scenarios where access to restricted areas is opened. And, in scenarios of a temporary or sporadic cutoff of Middle East supply, higher OCS and Rocky Mountain production again only produce limited benefits in pricing and supply diversification. In the intermediate term, supply diversity is available at a relatively reasonable cost from a wide variety of alternative fringe exporters in the global market.

Strategically, however, there is some benefit to opening restricted areas in the OCS and Rocky Mountains to drilling in terms of reducing the potential monopoly power of large foreign gas producers from the Middle East or former Soviet Union in global gas markets. This is especially true in the coming twenty to twenty five years when it is expected that the monopoly power of major natural gas producers like Russia and the Middle East will be rising. As demonstrated by scenario analysis, higher OCS production would weaken the market power of large foreign natural gas exporters in the global market and to the extent that it displaces higher cost U.S. unconventional and conventional onshore natural gas in the intermediate term, those domestic resources could be called upon more quickly during a period of market supply strain. However, as demonstrated by scenario analysis, this strategic benefit might also be achieved through technological breakthroughs that allow cost reductions in alternative energy.

In the immediate term, creating a system where the U.S. government could "borrow" natural gas inventories from domestic storage during a supply crisis or to counter a natural gas supply shutoff from a major gas producer or group of producers—a strategic natural gas reserve—might be more politically expedient than opening up environmentally-sensitive lands to immediate drilling. Longer term, a push to support the development of alternative energy can offer similar benefits to expanding the U.S. domestic natural gas production base.

Another alternative would be to exploit the potential for "net conservation benefit trades" in lands that have potential for natural gas resource development. Essentially, a net conservation benefit trade is an exchange of resources that results in a *net* gain in conservation outcomes, while at the same time releasing resources for other uses.

Examples of net conservation benefit trades include multiple land use, where productive practices are adjusted to maintain or enhance conservation values in situ. For example, new offshore development techniques allow most well infrastructure to be placed on the ocean floor allowing gas resources to be exploited with little or no scenic degradation. In sequential land use, productive land activities with a limited life span (for example, a mine) are pursued and followed by investments to restore the conservation benefit of the land after the activity is completed. Both multiple and sequential land use envisage a range of activities on the one piece of property. A third alternative involves using offsets, whereby a productive activity in one location is used to finance a conservation activity, or purchase conservation rights, elsewhere. Indeed, the trade of increased Lower 48 production for reduced Alaskan production could be viewed as an implicit net conservation benefit offset.

Mechanisms for conservation trading would employ something akin to a barter process. As long as environmental objectives can be specified in a measurable way (or even given an ordinal ranking)—for example the area of habitat land available for a particular endangered species—trades can be negotiated without the need for expressing all values in dollar terms. Parties wishing to use current conservation resources in a different way could pay for the privilege with actions, or by swapping for land areas that have higher conservation value.

While companies could voluntarily enter into offset agreements, it is risky to do so in the absence of suitable enabling legislation and widespread community debate and agreement about the value of such agreements. In particular, clear and transparent rules and procedures are needed to determine in advance, and as objectively as possible, the conservation cost of any damage from drilling activity and the value of any offsets financed by the energy company.

Appendix Table A1: World Supply

	2005	2010	2015	2020	2025	2030
WORLD	**103.5575**	**123.3271**	**139.3277**	**149.6185**	**156.4770**	**161.6047**
AFRICA	**6.7740**	**10.1353**	**12.4277**	**14.2864**	**15.0750**	**15.1485**
Algeria	3.3733	3.9950	4.4725	4.7422	4.5859	4.3590
Angola	0.0288	0.0560	0.3360	0.6648	0.8029	0.9001
East Africa	0.0041	0.0099	0.0289	0.0369	0.0771	0.1336
Egypt	1.5285	2.2816	2.5379	2.6375	2.6907	2.6808
Libya	0.5972	0.8952	1.3341	1.7914	1.8412	1.7122
Morocco						
Nigeria	0.8094	1.9635	2.1512	2.6619	3.1408	3.3888
Northwest Africa	0.1417	0.1920	0.2145	0.2068	0.2292	0.2283
Southern Africa	0.0865	0.0908	0.0942	0.0904	0.1133	0.1228
Tunisia	0.1497	0.1901	0.1286	0.1294	0.1947	0.2171
West Central Africa	0.0548	0.4612	1.1300	1.3250	1.3992	1.4056
ASIA-PACIFIC	**5.5908**	**7.5439**	**9.0375**	**9.8160**	**10.3777**	**10.3644**
Brunei	0.3876	0.5148	0.6800	0.6850	0.6897	0.7214
Indonesia	2.6683	3.6702	4.5543	5.2338	5.7842	6.1337
Japan	0.1121	0.1280	0.0568	0.0486	0.0300	0.0186
Malaysia	2.2568	2.9313	3.4286	3.5365	3.5502	3.2143
Phillipines	0.0975	0.1844	0.2431	0.2639	0.2917	0.2550
Singapore						
South Korea						
Taiwan	0.0685	0.1151	0.0746	0.0483	0.0318	0.0214
ASIA	**5.9339**	**8.6820**	**9.9819**	**9.7268**	**8.8883**	**8.1229**
Afghanistan	0.0007	0.0022	0.1212	0.1807	0.1993	0.3944
Bangladesh	0.4717	0.5625	0.7654	1.0231	1.0584	1.0014
China	2.0212	3.5365	3.6296	3.3009	3.0133	2.7391
Hong Kong						
India	1.1748	1.3104	1.5659	1.5343	1.3551	1.2370
Myanmar	0.3614	0.6828	1.0818	1.0389	0.9056	0.7845
Pakistan	0.9900	1.1660	1.3188	1.4366	1.5255	1.3888
Thailand	0.7715	1.1875	1.1968	0.8808	0.5751	0.4064
Vietnam/Laos/Cambodia	0.1426	0.2341	0.3024	0.3315	0.2561	0.1713
AUSTRALASIA	**1.6456**	**2.8008**	**4.8643**	**6.2197**	**7.7160**	**9.5047**
Australia	1.5016	2.5969	4.6156	6.0199	7.5782	9.4059
New Zealand	0.1404	0.1914	0.2341	0.1844	0.1226	0.0835
Papau New Guinea	0.0036	0.0125	0.0145	0.0154	0.0152	0.0152

Appendix Table A1 (cont.)

	2005	2010	2015	2020	2025	2030
EUROPE	**11.3666**	**12.2022**	**12.0745**	**10.6858**	**9.1887**	**8.0117**
Austria	0.0578	0.0582	0.0383	0.0249	0.0161	0.0105
Balkans	0.0634	0.1277	0.0932	0.0668	0.0462	0.0304
Belgium						
Bulgaria	0.0544	0.0364	0.0224	0.0137	0.0091	0.0080
Czech Republic	0.0061	0.0304	0.0324	0.0220	0.0143	0.0093
Denmark	0.3081	0.2784	0.2003	0.1437	0.1041	0.0849
Finland						
France	0.0406	0.0287	0.0239	0.0345	0.1403	0.3611
Germany	0.7007	0.7628	0.7224	0.6160	0.4783	0.3296
Greece						
Hungary	0.1069	0.1640	0.1504	0.1026	0.0664	0.0436
Ireland	0.0201	0.0214	0.0130	0.0083	0.0050	0.0030
Italy	0.4255	0.4037	0.2660	0.1871	0.2411	0.3499
Luxembourg						
Netherlands	2.7854	3.4451	3.5783	2.9932	1.9863	1.2088
Norway	2.9054	3.1739	3.4932	3.9812	4.4212	4.4144
Poland	0.2146	0.2817	0.2650	0.1941	0.1234	0.0783
Portugal						
Romania	0.4131	0.5954	0.4293	0.2902	0.1955	0.1320
Slovakia	0.0052	0.0136	0.0104	0.0070	0.0048	0.0034
Spain	0.0055	0.0030	0.0029	0.0047	0.0061	0.1294
Sweden						
Switzerland						
UK	3.2539	2.7773	2.7331	1.9957	1.3304	0.8150
FSU	**31.0185**	**33.0601**	**38.0649**	**41.7497**	**44.8062**	**46.9301**
Armenia						
Azerbaijan	0.2055	0.5626	0.8009	0.9041	1.2847	1.7833
Belarus						
Estonia						
Georgia						
Kazakhstan	0.8380	2.2896	3.4599	3.8496	3.7330	3.4042
Kyrgyzstan						
Latvia						
Lithuania						
Moldova						
Russia	25.2224	25.5565	27.6001	30.5486	32.9130	34.4033
Tajikistan						
Turkmenistan	1.9609	2.0557	2.2680	2.4463	3.0342	3.8992
Ukraine	0.6846	1.6865	2.2102	2.2155	1.9626	1.5918
Uzbekistan	2.1071	1.9091	1.7258	1.7855	1.8787	1.8483

Appendix Table A1 (cont.)

	2005	2010	2015	2020	2025	2030
MIDDLE EAST	**10.9985**	**13.1793**	**15.5651**	**17.9071**	**21.2772**	**26.3399**
Bahrain	0.3859	0.3962	0.4093	0.2596	0.4126	0.3913
Iran	3.2903	3.8780	4.8890	5.1589	6.0377	7.8955
Iraq	0.0927	0.0787	0.3898	1.5595	2.3661	2.9610
Israel	0.0216	0.0345	0.0469	0.0512	0.0534	0.0559
Jordan						
Kuwait	0.4432	0.4929	0.5702	0.6828	0.8057	0.9123
Oman	0.6312	0.7575	0.7384	0.7596	0.8005	0.8717
Qatar	1.6294	2.6544	3.3911	3.6993	3.8206	4.5258
Saudi Arabia	2.5751	2.7560	2.8776	3.1162	3.5804	4.4137
Syria	0.2020	0.2728	0.3146	0.3218	0.3139	0.2331
Turkey	0.0317	0.0752	0.0669	0.0442	0.0294	0.0199
UAE	1.6872	1.7722	1.8058	1.9299	2.4386	3.1816
Yemen	0.0083	0.0110	0.0655	0.3242	0.6181	0.8780
NORTH AMERICA	**25.2546**	**27.9120**	**29.6061**	**30.0891**	**28.6274**	**26.1786**
Canada	5.8910	6.1047	6.5199	6.3288	5.8970	5.4448
Mexico	1.4279	2.1255	2.1334	1.8243	1.4457	1.1330
USA	17.9357	19.6817	20.9529	21.9360	21.2847	19.6008
SOUTH AMERICA	**4.9750**	**6.8116**	**7.7058**	**9.1379**	**10.5205**	**11.0039**
Central America	0.0007	0.0044	0.0084	0.0200	0.0122	0.0074
Cuba	0.0144	0.0184	0.0230	0.0459	0.0770	0.0653
Other Carribean						
Argentina	1.6384	2.1026	2.2575	2.1441	2.0509	1.7743
Bolivia	0.2967	0.4647	0.5759	0.7282	0.7111	0.6876
Brazil	0.5360	0.6739	0.6956	0.7997	0.9353	1.0404
Chile	0.0472	0.0625	0.0683	0.0651	0.0603	0.0509
Colombia	0.2342	0.4171	0.6233	0.9043	1.1892	1.1970
Ecuador	0.0116	0.0107	0.0065	0.0170	0.0216	0.0166
Paraguay	0.0025	0.0446	0.0598	0.0703	0.0833	0.0627
Peru	0.0505	0.2660	0.3489	0.3723	0.4284	0.5114
Suriname/Guyana/French Guiana	0.0007	0.0020	0.0409	0.3298	0.6531	0.7446
Trinidad & Tobago	0.9862	1.4366	1.4404	1.5106	1.5707	1.5897
Uruguay						
Venezuela	1.1558	1.3081	1.5573	2.1305	2.7274	3.2559

Appendix Table A2: World Demand

	2005	2010	2015	2020	2025	2030
WORLD	**102.4074**	**121.3571**	**138.0573**	**148.5789**	**155.5343**	**160.5956**
AFRICA	**3.1380**	**3.7408**	**4.4569**	**5.1289**	**5.5247**	**5.8884**
Algeria	0.8351	0.9130	1.1929	1.5323	1.6293	1.7296
Angola	0.0288	0.0367	0.0405	0.0398	0.0384	0.0370
East Africa	0.0041	0.0054	0.0060	0.0066	0.0060	0.0055
Egypt	1.2327	1.4485	1.6130	1.7668	1.8740	1.9786
Libya	0.2101	0.3082	0.3460	0.3581	0.3778	0.3883
Morocco	0.0018	0.0021	0.0023	0.0022	0.0019	0.0019
Nigeria	0.3733	0.4525	0.5869	0.7481	0.9008	1.0312
Northwest Africa	0.1417	0.1920	0.2191	0.2222	0.2333	0.2339
Southern Africa	0.0865	0.1093	0.1155	0.1119	0.1200	0.1271
Tunisia	0.1691	0.1947	0.2573	0.2663	0.2724	0.2835
West Central Africa	0.0548	0.0784	0.0775	0.0745	0.0708	0.0718
ASIA-PACIFIC	**7.4750**	**9.9602**	**11.8747**	**13.0233**	**13.6540**	**13.8198**
Brunei	0.0847	0.0876	0.0920	0.0970	0.1017	0.1065
Indonesia	1.4071	1.7486	2.0680	2.3119	2.5695	3.1432
Japan	3.0023	4.1222	5.1141	5.7135	5.8016	5.2048
Malaysia	1.2031	1.5462	1.7026	1.8091	1.9103	2.0044
Phillipines	0.0975	0.1844	0.2431	0.2639	0.2917	0.2797
Singapore	0.2382	0.4431	0.5823	0.6435	0.6898	0.7369
South Korea	1.0467	1.3760	1.5655	1.6291	1.7026	1.7108
Taiwan	0.3955	0.4520	0.5070	0.5553	0.5868	0.6335
ASIA	**6.0902**	**9.7740**	**13.7675**	**15.1290**	**15.9836**	**16.5597**
Afghanistan	0.0007	0.0022	0.0038	0.0047	0.0051	0.0053
Bangladesh	0.4717	0.5625	0.6172	0.6581	0.6894	0.7200
China	1.8735	4.0410	6.8982	7.6453	7.9995	8.2160
Hong Kong	0.1106	0.0990	0.0952	0.0974	0.1019	0.1087
India	1.2789	1.7905	2.1986	2.4963	2.7186	2.8249
Myanmar	0.1274	0.1537	0.1664	0.1775	0.1851	0.1928
Pakistan	0.9900	1.1660	1.3188	1.4366	1.5266	1.5813
Thailand	1.0948	1.7249	2.1670	2.2816	2.4019	2.5222
Vietnam/Laos/Cambodia	0.1426	0.2341	0.3024	0.3315	0.3554	0.3885
AUSTRALASIA	**1.0671**	**1.5280**	**1.9743**	**2.3452**	**2.6966**	**2.9596**
Australia	0.9231	1.3241	1.7256	2.1017	2.4487	2.6991
New Zealand	0.1404	0.1914	0.2341	0.2280	0.2327	0.2453
Papau New Guinea	0.0036	0.0125	0.0145	0.0154	0.0152	0.0152

Appendix Table A2 (cont.)

	2005	2010	2015	2020	2025	2030
EUROPE	**18.8262**	**20.4338**	**22.1173**	**22.9034**	**22.3090**	**21.7178**
Austria	0.3307	0.3264	0.3318	0.2848	0.2078	0.0947
Balkans	0.1485	0.1697	0.1792	0.1920	0.2118	0.2389
Belgium	0.5959	0.6705	0.7484	0.7933	0.8327	0.8824
Bulgaria	0.1858	0.1508	0.2008	0.2203	0.2433	0.2733
Czech Republic	0.3257	0.3313	0.3343	0.3139	0.2836	0.2428
Denmark	0.1714	0.2155	0.2334	0.2439	0.2545	0.2689
Finland	0.1523	0.1875	0.1978	0.2090	0.2211	0.2398
France	1.6960	1.8359	1.9769	2.0580	2.1397	2.2676
Germany	3.4747	3.8383	4.0586	4.0450	3.6622	3.1749
Greece	0.0977	0.1708	0.2210	0.2514	0.2766	0.2897
Hungary	0.5156	0.4938	0.4957	0.4543	0.3385	0.2025
Ireland	0.1398	0.1688	0.1732	0.1798	0.1891	0.2015
Italy	2.9651	3.0313	3.3314	3.5354	3.7169	3.9396
Luxembourg	0.0487	0.0444	0.0418	0.0415	0.0422	0.0438
Netherlands	1.7029	1.6866	1.7595	1.8504	1.9527	2.0738
Norway	0.1917	0.2636	0.2775	0.2898	0.3031	0.3199
Poland	0.5591	0.6086	0.6358	0.6522	0.6125	0.5924
Portugal	0.1572	0.2398	0.3251	0.3741	0.4153	0.4593
Romania	0.6263	0.8173	0.9471	0.9790	1.0231	1.0893
Slovakia	0.2236	0.2360	0.2409	0.2460	0.2513	0.2612
Spain	1.0972	1.2999	1.4533	1.5388	1.6031	1.6939
Sweden	0.0321	0.0376	0.0365	0.0352	0.0350	0.0362
Switzerland	0.1170	0.1203	0.1273	0.1311	0.1348	0.1406
UK	3.2711	3.4890	3.7902	3.9842	3.3579	2.6909
FSU	**24.3237**	**28.6355**	**30.9696**	**33.1644**	**36.0308**	**37.9915**
Armenia	0.0613	0.0588	0.0602	0.0632	0.0668	0.0745
Azerbaijan	0.3740	0.3766	0.3820	0.4485	0.6117	0.6484
Belarus	0.7245	0.7490	0.9567	1.0508	1.0674	1.1106
Estonia	0.0524	0.0455	0.0433	0.0448	0.0478	0.0525
Georgia	0.0531	0.0434	0.0399	0.0399	0.0412	0.0434
Kazakhstan	1.0972	1.0211	1.1841	1.1671	1.1731	1.2230
Kyrgyzstan	0.0267	0.0296	0.0281	0.0277	0.0283	0.0292
Latvia	0.0669	0.0608	0.0589	0.0610	0.0648	0.0703
Lithuania	0.1056	0.0923	0.0899	0.0938	0.1000	0.1085
Moldova	0.0897	0.0868	0.0884	0.0911	0.0940	0.0974
Russia	16.1505	20.1884	21.4842	22.2444	23.3333	24.7715
Tajikistan	0.0515	0.0454	0.0410	0.0392	0.0390	0.0392
Turkmenistan	0.6414	0.6657	0.8411	0.9410	0.9481	0.9775
Ukraine	3.1420	3.3833	3.8354	4.9607	6.4654	6.7357
Uzbekistan	1.6870	1.7887	1.8364	1.8913	1.9499	2.0100

Appendix Table A2 (cont.)

	2005	2010	2015	2020	2025	2030
MIDDLE EAST	**10.9296**	**11.8794**	**13.7386**	**14.6748**	**15.3716**	**16.2820**
Bahrain	0.3859	0.3962	0.4093	0.4264	0.4477	0.4707
Iran	3.7207	3.9364	5.1829	5.6002	5.7902	6.0821
Iraq	0.0883	0.0687	0.0508	0.0476	0.0479	0.0500
Israel	0.0256	0.0346	0.0466	0.0498	0.0535	0.0587
Jordan	0.0562	0.0538	0.0416	0.0388	0.0383	0.0391
Kuwait	0.4432	0.4857	0.5009	0.5166	0.5275	0.5483
Oman	0.3304	0.3880	0.3730	0.3775	0.3899	0.4067
Qatar	0.6738	0.6071	0.6423	0.7402	0.8229	0.8920
Saudi Arabia	2.5669	2.7474	2.8466	3.0157	3.1834	3.4100
Syria	0.2020	0.2728	0.3146	0.3262	0.3371	0.3577
Turkey	0.9421	1.3775	1.7846	1.9370	2.0612	2.2228
UAE	1.4863	1.4997	1.5332	1.5867	1.6606	1.7331
Yemen	0.0083	0.0114	0.0122	0.0121	0.0113	0.0108
NORTH AMERICA	**25.9618**	**29.3530**	**32.0156**	**34.1905**	**35.2611**	**36.4897**
Canada	3.5943	4.2222	4.7854	5.1414	5.3777	5.5565
Mexico	1.8486	2.8788	3.2764	3.4272	3.6149	3.8357
USA	20.5189	22.2520	23.9538	25.6218	26.2685	27.0975
SOUTH AMERICA	**4.5958**	**6.0526**	**7.1428**	**8.0195**	**8.7030**	**8.8871**
Central America	0.0007	0.0044	0.0084	0.0094	0.0070	0.0062
Cuba	0.0144	0.0184	0.0230	0.0225	0.0227	0.0239
Other Carribean	0.0342	0.0613	0.1139	0.1364	0.1431	0.1513
Argentina	1.4544	1.7401	1.9111	2.0116	2.0917	2.1774
Bolivia	0.0759	0.0935	0.0988	0.1050	0.1084	0.1114
Brazil	0.6661	1.1537	1.4655	1.6139	1.7302	1.8616
Chile	0.3086	0.4625	0.5600	0.5996	0.6353	0.4277
Colombia	0.2132	0.3607	0.5610	0.6656	0.6461	0.6666
Ecuador	0.0116	0.0199	0.0248	0.0289	0.0264	0.0259
Paraguay	0.0007	0.0025	0.0036	0.0040	0.0039	0.0034
Peru	0.0505	0.0721	0.0858	0.1065	0.1371	0.1447
Suriname/Guyana/French Guiana	0.0007	0.0020	0.0027	0.0031	0.0033	0.0035
Trinidad & Tobago	0.5851	0.7020	0.7244	0.7622	0.8092	0.8645
Uruguay	0.0032	0.0051	0.0049	0.0043	0.0038	0.0036
Venezuela	1.1764	1.3543	1.5549	1.9466	2.3347	2.4154