MARKET ANALYSIS
FOR
SABINE PASS LNG EXPORT PROJECT

Prepared for:

Sabine Pass LNG, L.P.

FERC Docket Nos. CP04-47, CP05-396, PF10-24

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August 23, 2010

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Summary of Assignment

This report supports Sabine Pass Liquefaction, L.L.C.'s application to the Department of Energy and the Federal Energy Regulatory Commission for a proposed natural gas liquefaction and export project in Cameron Parish, Louisiana. The proposed liquefaction and export facility would be a modification of existing import, storage, and vaporization facilities which were constructed pursuant to authority granted under FERC Dockets No. CP04-47-000 (Sabine Pass LNG and Pipeline Project or Phase I facilities) and CP05-396-000 (Sabine Pass LNG Phase II Project or Phase II facilities), with further FERC processing under Docket No. PF10-24-000.

For the purposes of Sabine Pass Liquefaction, L.L.C.'s application, Navigant Consulting Inc. was asked to provide our independent assessment of the potential impact of the proposed liquefaction and export project on supply availability and natural gas prices in North America. This report draws from our experience and knowledge of the North American gas resource base, as well as our technical modeling and scenario analysis capabilities. In this report summarizing our analysis and modeling, Navigant Consulting provides a high-level forward-looking view of natural gas market dynamics in North America, covering supply, demand, price trends, and significant factors likely to affect the gas market from the year 2015 through 2035. Following that discussion, the heart of the report discusses the results of our gas market modeling and scenario analysis that we performed using the GPCM Natural Gas Market Forecasting System (licensed from RBAC, Inc.) to analyze the potential impacts of liquefying and exporting approximately 2.0 Bcf per day (730 Bcf per year, net of fuel used and inerts removed during liquefaction) of domestically-produced gas at the Sabine Pass facility from 2015 through 2035.

The analysis includes the development and analysis of five gas market scenarios, based on two reference cases. The particular scenarios were selected to bookend a reasonable range of supply/demand scenarios against which the addition of LNG exports could be tested. The first set of cases assumes the U.S. Energy Information Administration's demand numbers (shown in blue, below). The EIA's gas demand numbers account only for the influence of greenhouse gas (GHG) laws and regulations actually in force as of the present. The second set assumes Navigant Consulting's higher demand (shown in yellow, below). Navigant Consulting's gas demand numbers account for the increased role of natural gas particularly as an electric generation fuel in a carbon-constrained future. Descriptions follow.

Case Name	*Description*
GHG As-Is	The **GHG As-Is Case** is based on NCI's Spring 2010 Forecast of June 2010. The Spring 2010 Forecast incorporates NCI's extensive work done on North American gas shale supply resources. The GHG As-Is Case modifies the Spring 2010 Forecast by substituting the gas demand from the Energy Information Agency's 2010 AEO Reference Case for the higher NCI Spring 2010 Forecast demand. The EIA's demand numbers were developed by the EIA by assuming that only existing GHG-related laws and regulations will be in place throughout the study timeframe.
Moderate Export	The **GHG As-Is, Moderate Export Case** 'forces' exports from Sabine Pass LNG of **1.0 Bcfd** beginning 2015 . Otherwise the case is the same as the GHG As-Is Case. The effects on prices are the specific focus.
High Export	The **GHG As-Is, High Export Case** 'forces' exports from Sabine Pass LNG of **2.0 Bcfd** beginning 2015. Otherwise the case is the same as the GHG As-Is Case. The effects on prices are the specific focus.
GHG Plus	The **GHG Plus Case** uses the same infrastructure assumptions as the GHG As-Is Case, but demand is increased in two ways. First, demand is taken straight from the NCI Spring 2010 Forecast, which incorporates the demand- and supply-increasing effects of U.S. carbon policy at the state and federal level. Second, it incorporates demand for natural gas as a vehicle fuel from the U.S. EIA's Annual Energy Outlook 2010, *2027 Phaseout With Expanded Market Potential*, which is almost ten times higher than vehicle demand in the EIA's Reference Case. (The "phaseout" refers to the timing of terminating government incentives for NGV development.)
High Export	The **GHG Plus, High Export Case** is based on the same assumptions as the GHG Plus case but in addition 'forces' exports from Sabine Pass LNG of LNG to 2.0 Bcfd beginning 2015. The effects on prices are the specific focus.

Executive Summary / Key Takeaways

Navigant Consulting (NCI) modeled five scenarios to examine the possible price effects of manufacturing and exporting approximately 2.0 billion cubic feet per day (Bcfd) of liquefied natural gas from the Sabine Pass LNG facility in Cameron Parish, Louisiana. All dollar figures are average annual monthly prices in "real" (2009) dollars per MMBtu.

Based on the U.S. Energy Information Agency's demand forecast for natural gas, which includes growth in natural gas vehicle fuel to 0.5 Bcfd by 2035 (the ***GHG As-Is*** Cases), NCI modeling showed the forward price curve for the period 2015-2035 to rise from $3.29 per MMBtu to $6.97 per MMBtu, assuming no exports of LNG at Sabine Pass. The addition of 1.0 Bcfd of LNG exports at Sabine Pass increases Henry Hub forward prices by only $0.20 per MMBtu (6.1%) in 2015, and by only slightly more, $0.23 per MMBtu (3.3%), in 2035, compared to the no-export GHG As-Is Case. The addition of 2.0 Bcfd of liquefaction demand increases Henry Hub prices by $0.35 per MMBtu (10.6%) in 2015 and $0.49 per MMBtu (7.0%) in 2035, compared to the no-export GHG As-Is Case, a fairly moderate impact on prices in the market.

Using Navigant Consulting's demand assumptions, which assume higher natural gas demand in response to greenhouse gas reduction goals, plus a client-specified increase in natural gas vehicle fuel demand that reaches 4.7 Bcfd by 2035 (the ***GHG Plus*** Cases), the forward price curve starts in 2015 at $4.50 per MMBtu and moves up to $11.43 per MMBtu by 2035, assuming no LNG exports. The addition of 2.0 Bcfd of LNG exports at Sabine Pass moves Henry Hub forward prices by $0.52 per MMBtu (4.0%) in 2015, and $0.90 per MMBtu (7.9%) in 2035, compared to the no-export GHG Plus Case.

Significantly, the analysis shows that, on a percentage basis, the increases in price associated with the addition of liquefaction demand are similar across all cases. In other words, in the lower demand GHG As-Is Case, the percentage increases in prices were very similar to the price increases in the high demand cases. All test cases in both demand scenarios produced single-digit percentage increases except Year 2015 in the GHG As-Is, High Export Case, which yielded a 10.6 percent move.

Year	Metric	GHG As-Is Base	GHG As-Is *Moderate*	GHG As-Is *High*	GHG Plus Base	GHG Plus *High*
2015	*Price (MMBtu)*	$3.29	$3.49	$3.64	$4.50	$5.02
	Diff. from Base		$0.20	$0.35		$0.52
	% Increase		6.1%	10.6%		4.0%
2035	*Price (MMBtu)*	$6.97	$7.20	$7.46	$11.43	$12.33
	Diff. from Base		$$0.23	$0.49		$0.90
	% Increase		3.3%	7.0%		7.9%

Table 1: Summary of Prices from Test Cases

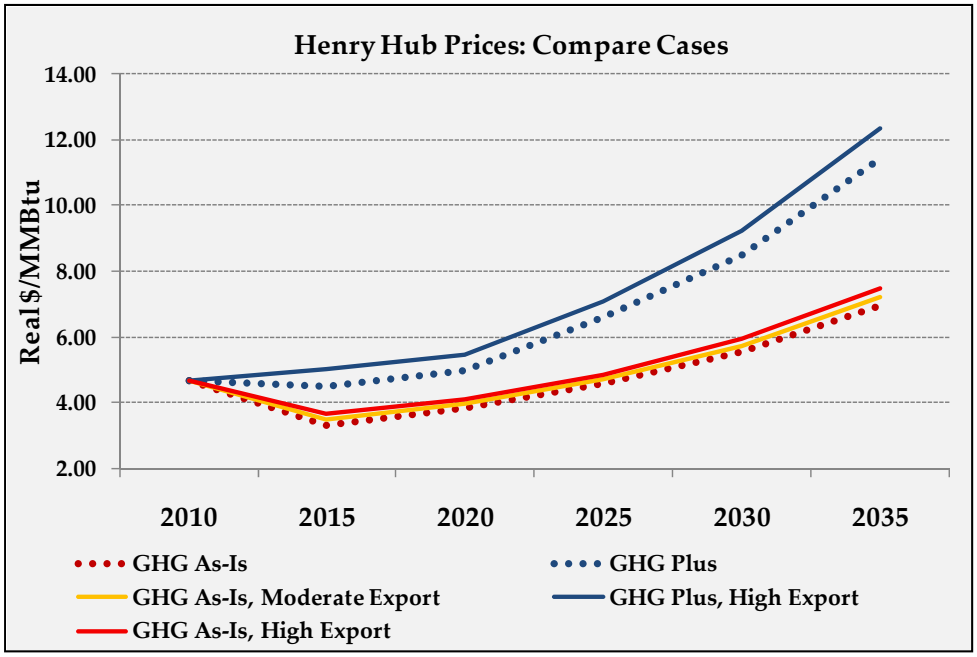

Figure 1: Henry Hub Prices: Compare Cases

We also examined whether any price effects in the Sabine Pass region translated into price effects in the capacity-constrained Northeast markets, represented by Transco Zone 6-New York, Dominion South Point in Ohio/West Virginia, and Texas Eastern M-3 in Pennsylvania. Our findings were that none of the export scenarios have a significant impact on Northeast market prices relative to prices in the Gulf Coast region. The largest difference in basis[1] caused by an export scenario occurs at Dominion South Point in 2035 for the GHG Plus Case. The addition of 2.0 Bcfd of export gas (plus 0.2 Bcfd for plant fuel consumption) yields a basis at that time and location that is 6.6 cents per MMBtu weaker than in the GHG Plus Case. All other changes in basis values are smaller. We view the effects on regional Northeast prices from the export of up to 2.0 Bcfd of LNG from Sabine Pass as negligible.

In all of the scenarios in the analysis, the model draws from existing gas fields and production curves identified in NCI's Spring 2010 base model of North America. The model also is based upon existing North American pipeline and LNG terminal infrastructure, augmented by planned expansions that have been publicly announced and that are likely to be built based upon the best publicly available information. Some projects, notably the proposed Mackenzie Pipeline in northern Canada, were excluded from the model because they were judged to be too uncertain at this time for inclusion in the model. No unannounced infrastructure projects were introduced into the model.

In developing the gas supply assumptions, Navigant Consulting has attempted to be conservative in its estimates of supply growth potential. In focusing upon only existing gas shale resource developments, we have not accounted for any additional plays that are yet to be identified and

[1] "Basis" is the difference between the cash price at a given physical trading location and the price of the Henry Hub NYMEX contract. Basis plus NYMEX equals the price at the physical location.

developed. The recent history of resource discovery and the sharp growth in estimated reserves of shale gas indicate that additional new shale resources will in all likelihood be developed in the forecast timeframe to 2035.

The likelihood of shale gas development is further reinforced by the fact that many shale formations also contain natural gas liquids (NGLs), which strengthens the economic prospects of shale. For example, several energy companies including Enbridge, Enterprise Products Partners, Buckeye Partners, Kinder Morgan, and Dominion have recently announced plans to build or enhance NGL gathering and transmission systems in the Marcellus shale formation; the Eagle Ford formation in Texas is being developed as an NGL play as much as a natural gas play. The additional economic value of NGLs from these plays was not considered in NCI's modeling, which further reinforces the conservative nature of future shale growth estimates used in this study.

The continued strong development of shale gas appears to be a logical assumption, given the existing mapped resources that possess the geologic structure to contain gas shale, and other information available concerning gas shale. Additional supply from resources beyond what has been modeled would only tend to dampen the upward price response modeled by the addition of 2.0 Bcfd of exports at Sabine Pass. In light of this, we view the price outcomes of our modeled analysis at the two different demand levels as establishing the upper range of impacts that exports from the Sabine Pass LNG project might have on natural gas prices.

We furthermore are of the view that, based upon our knowledge of the North American resource base, the size of the gas resource in North America is more than adequate to serve all forecast domestic demand through the study period to 2035 as well as the demand added by Cheniere's proposed liquefaction facility.

Overview of Proposed Export Operations at Sabine Pass LNG

Existing Regasification Facility

Cheniere Energy's Sabine Pass LNG facility is located in Cameron Parish, Louisiana, on the Sabine River, which separates Texas from Louisiana.

Figure 2: Sabine Pass LNG Location Map

The facility was initially constructed to import LNG. It sits on the Sabine River Navigation Channel, 3.7 nautical miles from the Gulf of Mexico. The channel is maintained at a depth of 40 feet and is not subject to tidal limitations. The terminal's two docks are recessed so that no part of an LNG vessel protrudes into the open waterway while docked.

Phase 1 of Sabine Pass LNG began service in 2008. The first stage of the Phase 2 expansion was completed in 2009. With a total send-out capacity of 4.0 Bcfd and 16.8 Bcf of on-site storage capacity, the Sabine Pass terminal is the largest LNG receiving terminal in the world, as measured by regasification capacity. It is capable of receiving and unloading approximately 400 LNG vessels each year.

In June 2010, Cheniere received approval from the U.S. Department of Energy to re-export foreign-sourced liquefied natural gas from the Sabine Pass terminal. With the Federal Energy Regulatory Commission's earlier approval, the facility is now fully authorized to re-export imported LNG.

Proposed Liquefaction Facility

Subsequent to the approval to re-export imported LNG, Cheniere announced on June 3, 2010, its intent to build the first LNG liquefaction plant in the United States in 40 years, based on the projected growth of domestic gas resources, driven by the dramatic increase in the accessibility of shale gas. (The only other natural gas liquefaction plant in the U.S. is the Kenai plant, in Alaska, owned by ConocoPhillips and Marathon Oil.)

Cheniere's preliminary plans call for up to four LNG production trains, each with the capacity to produce approximately 3.5 million tonnes (183 Bcf) per year of LNG. Two trains would be built by 2015, for an annual liquefaction and export capacity of 366 Bcf (about 1.0 Bcfd), with further expansion based on customer interest. The liquefaction project has received initial interest from LNG buyers as well as from domestic gas producers who are potentially interested in committing supply.

The proposed liquefaction facilities would be located on approximately 120 acres of the existing 853-acre Sabine Pass LNG site, and utilize the existing Sabine Pass LNG marine facilities. The liquefaction facilities would be designed to process a peak daily intake[2] of approximately 2.4 Bcfd of domestically-produced natural gas (including fuel and inerts) delivered from the Cheniere Creole Trail Pipeline and, potentially, the Kinder Morgan Louisiana Pipeline. LNG would be exported by LNG carriers via marine transit through the Sabine Pass Channel. The facility would be operated as a bidirectional facility and have the simultaneous capability to liquefy for export and to import and regasify.

Rationale for Exporting Domestically Produced LNG

As we understand, the Sabine Pass import facility was designed when supply-demand projections indicated that domestically produced natural gas would be inadequate to meet future demand growth. In 2008, Navigant Consulting and other industry observers identified the rapidly expanding development of natural gas from shale. While geologists and natural gas production companies had always been aware of shale-based gas resources, such resources were regarded as uneconomic to recover in most instances.

Natural gas prices increased substantially in the first decade of this century compared to the previous decade, and culminated in significantly higher prices in 2007-2008. These higher prices supported the development of new techniques in shale gas recovery. Most notably, horizontal drilling and hydraulic fracturing techniques were refined and systematized in ways that dramatically increased efficiencies and reduced costs.

In the few short years since 2007 or 2008, the outlook for natural gas production in North America has reversed from an expectation of supply deficit, in which LNG would have to be imported to meet demand, to an expectation of supply surpluses, in which domestic gas resources are more than adequate to satisfy projected demand. To a less dramatic extent, demand projections have also been increased as new markets are seen to be developing for natural gas as a result of its inherent qualities of supply abundance and sustainability, and its low carbon content, which positions it as a key

[2] The liquefaction trains will be capable of producing more LNG for export at times since the liquefaction process uses gas fired turbines and air cooled heat exchangers, both more effective in colder weather.

contributor to the low-carbon economy of the future. This demand potential has been muted at present due to the lingering effects of one of the most significant recessions in modern history.

Size of the Shale Gas Resource

To illustrate the size of the shale gas resource and its rapid development, consider the following. U.S. natural gas production increased from about 51.3 Bcfd in April 2005 to about 59.4 Bcfd in April 2010, even as overall rig counts fell from 1,163 to 959. (See **Figure 3:** *U.S. Gas Production*.) This is an increase of 16 percent in five years. The increase in production has been driven by shale, as evidenced by the increase in horizontal drill rig counts and the decrease in vertical (conventional) rig counts. (See ***Figure 4:*** *U.S. Gas Rig Type Shift* and **Figure 5:** *Five-Year Rig Count and Gas Production*.)

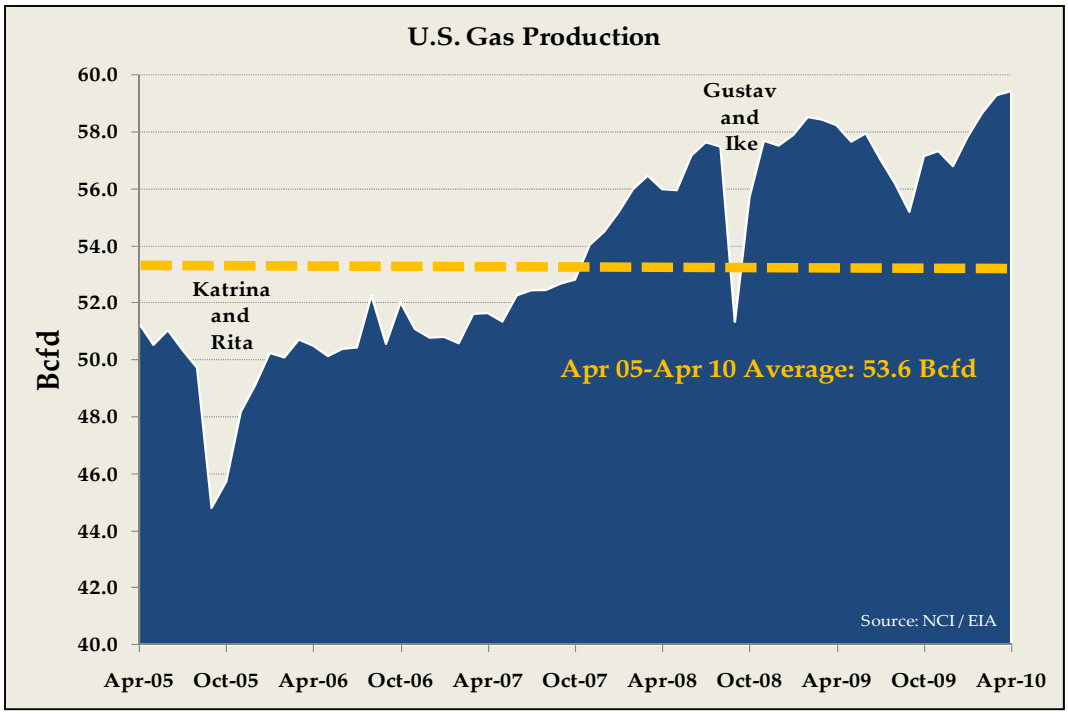

Figure 3: U.S. Gas Production History

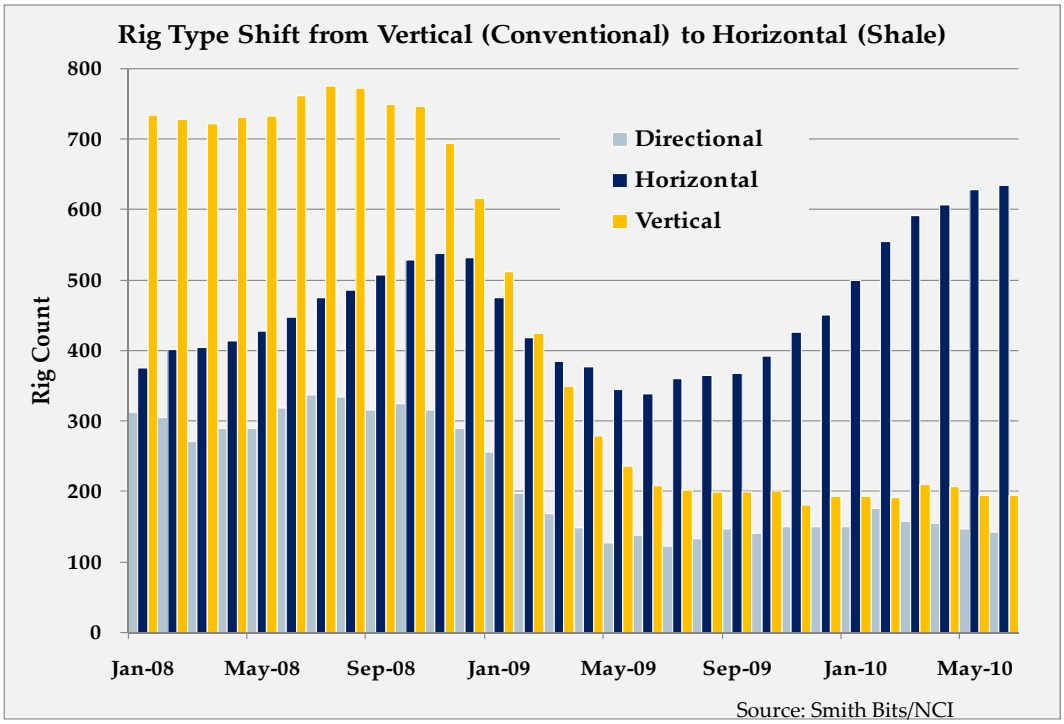

Figure 4: U.S. Gas Rig Type Shift

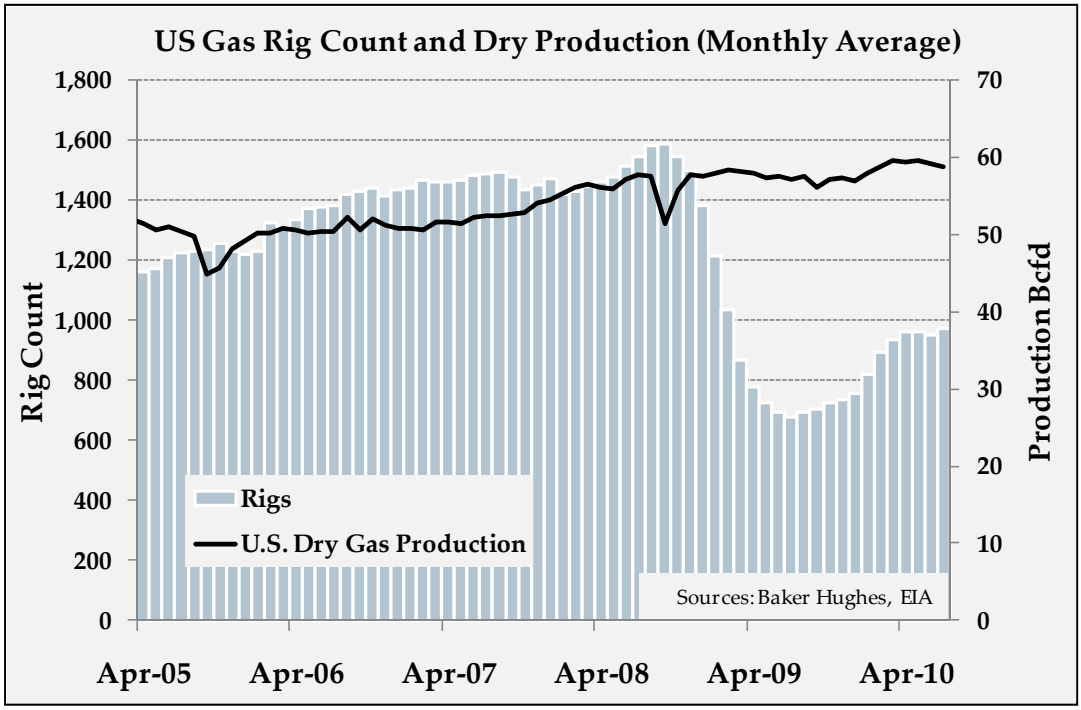

Figure 5: Five-Year Rig Count and Gas Production

The growth in shale gas production in just the past three years has been phenomenal, as shown in the graph in **Figure 6:** *Shale Production 2007-2010*. Shale output from six major basins under development grew from 2.6 Bcfd in January 2007 to 13.1 Bcfd in June 2010, an increase of more than 400 percent in a period of less than three and a half years.

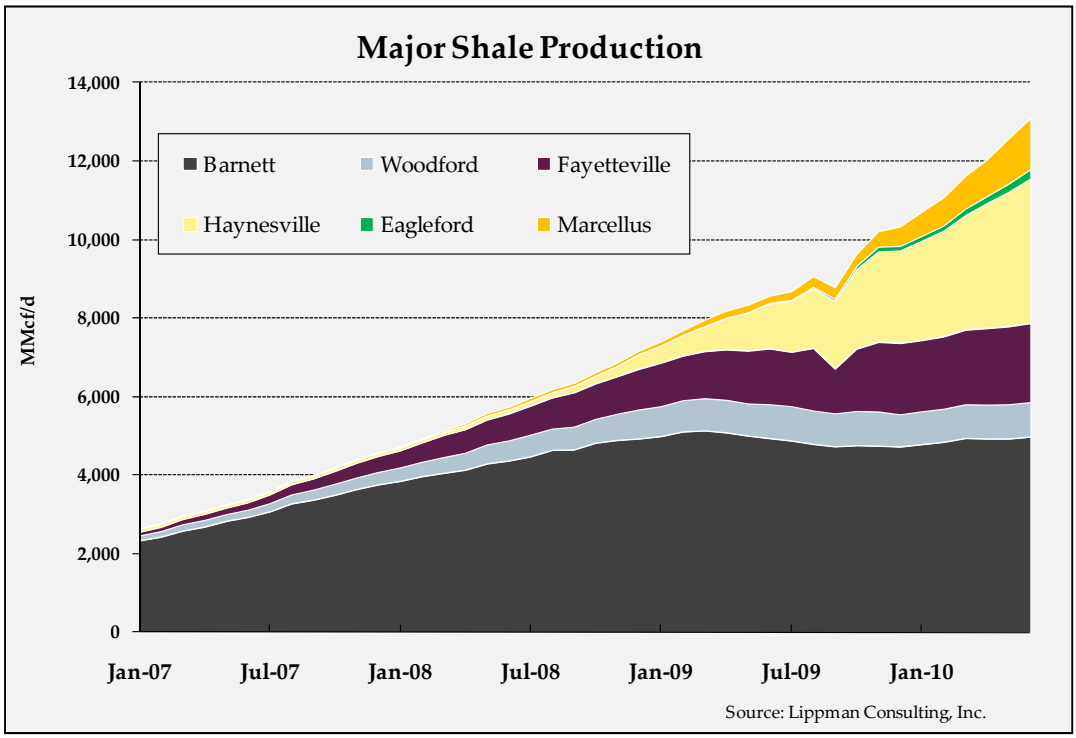

Figure 6: Shale Production 2007-2010

In Navigant Consulting's estimation, the size of the shale gas resource in North America is more than adequate to serve all forecast domestic demand through the study period to 2035 as well as the demand added by Cheniere's proposed liquefaction facility, likely without significantly affecting North American and regional prices. But this conjecture was what was to be tested through our scenario modeling exercise for the Cheniere LNG project.

The geographic scope of the U.S.'s shale gas resource can be seen in the following map from the Energy Information Administration. In Navigant Consulting's groundbreaking study on the subject of emerging shale gas resources, we estimated the maximum recoverable reserves from shale to be 842 trillion cubic feet (Tcf), boosting the maximum recoverable reserves for all of the U.S. to 2,247 Tcf.[3]

Several of these shale formations have yet to be exploited in any meaningful way. Additionally, North America is in an early phase of discovery for this resource. For example, the Marcellus Shale formation was virtually unheard of in 2007. Recently, Dr. Terry Engelder of Penn State University

[3] *North American Natural Gas Supply Assessment*, by Navigant Consulting for American Clean Skies Foundation, July 4, 2008, available at http://www.cleanskies.org/pdf/navigant-natural-gas-supply-0708.pdf

estimated that the Marcellus has a 50 percent chance of containing 489 Tcf of recoverable gas.[4] Currently, the entire United States uses about 23 Tcf per year, or less than 5 percent of the Marcellus's potential production.[5] Another recent study by Penn State estimates that production from the Marcellus will grow from 327 million cubic feet per day during 2009 to 13.5 *billion* cubic feet per day by 2020.[6]

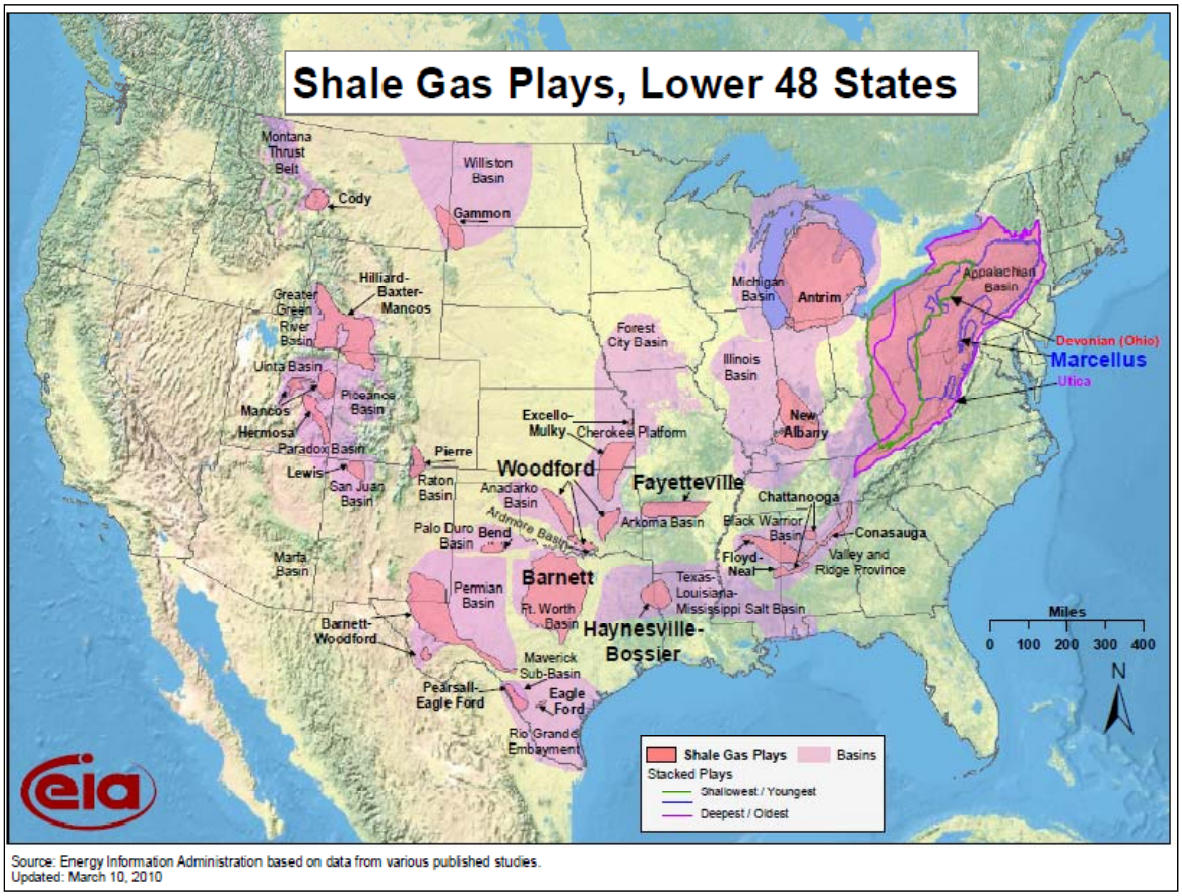

Figure 7: EIA Lower-48 Shale Play Map

In its recently published study, ***The Future of Natural Gas***, the Massachusetts Institute of Technology stated that "The current mean projection of the recoverable shale gas resource [in the U.S., excluding Canada] is approximately 650 Tcf … approximately 400 Tcf [of which] could be economically developed with a gas price at or below $6/MMBtu at the well-head."[7] The Potential Gas Committee of

[4] Basin Oil & Gas magazine, August 2009, pg 22, available at http://www.geosc.psu.edu/~engelder/references/link155.pdf

[5] EIA, Natural Gas Consumption by End Use, annual table, release date 7/29/2010, available at http://www.eia.gov/dnav/ng/ng_cons_sum_dcu_nus_a.htm

[6] Penn State University, *The Economic Impacts of the Pennsylvania Marcellus Shale Natural Gas Play: An Update*, May 24, 2010, page 19.

[7] MIT, *The Future of Natural Gas*, Executive Summary, pg xii.

the Colorado School of Mines estimates that the recoverable shale gas resource in North America is 2,074 Tcf—enough to supply domestic needs at 2009 usage rates (62.6 Bcfd) for 90 years. Of this total, 616 Tcf is shale gas.

Character of the Shale Gas Resource

The character of the shale gas resource reinforces its future growth potential. Finding economically producible amounts of conventional gas has historically been expensive due largely to geologic risk. Dry or quickly depleted wells are not uncommon in the conventional gas world. Conventional gas is trapped in porous rock formations, typically sandstone, under an impermeable layer of cap rock. It is produced by drilling through the cap into the porous formation, liberating the gas. Despite advances in technology, finding and producing conventional gas still has a large component of exploration risk, with the possibility that a well will be a dry hole or "duster" with no deliverability or production following drilling.

In unconventional shale gas, geologic risk is significantly reduced. Many large shale resource plays in the U.S. and Canada have been identified, and with new technology have become much more certain to be produced in commercial quantities. The reliability of discovery and production has led shale gas development to be likened more to a manufacturing process rather than an exploration process with its attendant risk.

Gas in a shale formation is entrained in the shale itself. It does not accumulate in pockets under cap rock. It tends to be distributed in consistent quantities over great volumes of the shale. Often, drilling techniques allow a single drill rig to drill multiple horizontal wells up to two miles in length into a given formation. Each bore has the potential to produce gas. Since the shale plays can be dozens or even hundreds of miles long and often several hundred feet thick, the risk of not finding a producible formation is low.

The horizontal well, once it is properly located in the targeted formation, is then enabled to produce volumes large enough to be economic through the use of hydraulic fracturing ("fracking"). Water, sand, and a small amount of chemicals are injected at high pressure to fracture the shale so that it releases the gas. As is the case with most shale wells, initial production (IP) rates are high, but drop off steeply within the first two years. However, once a well has declined to 10-20 percent of initial production, the expectation of many scientists in the industry are that it should produce at that lower rate with a very slow decline for many years. The graph below typifies a shale well decline curve. [8]

[8] *The Economic Impacts of the Pennsylvania Marcellus Shale Natural Gas Play: An Update*, Considine, Watson, and Blumsack, Penn State University, May 24, 2010, page 16, available at http://www.energyindepth.org/wp-content/uploads/2009/03/PSU-Marcellus-Updated-Economic-Impact.pdf

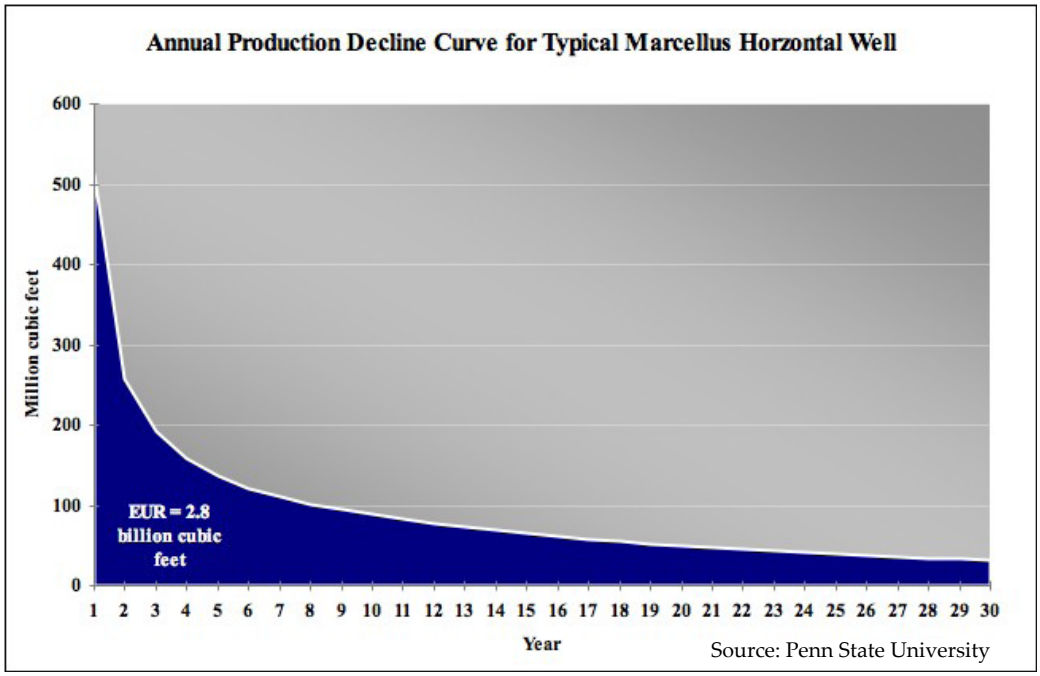

Figure 8: Shale Gas Well Decline Curve

The certainty of production allows shale gas production to be managed in response to demand. If demand is growing, additional shale wells can be drilled to meet it and mitigate the IP decline from the initial well. If demand however subsides, drilling rates can also be reduced or drilling discontinued completely in response.

The likelihood of shale gas development is further reinforced by the fact that many shale formations also contain natural gas liquids (NGLs), which strengthens the economic prospects of shale. For example, several energy companies including Enbridge, Enterprise Products Partners, Buckeye Partners, Kinder Morgan, and Dominion have recently announced plans to build or enhance NGL gathering and transmission systems in the Marcellus shale formation; the Eagle Ford formation in Texas is being developed as an NGL play as much as a natural gas play.

Assumed LNG Production for Sabine Pass LNG Exports

For purposes of this study, the Sabine Pass LNG export facility is assumed to have an export capacity of 2.0 Bcfd net of fuels and inerts removed during liquefaction (i.e., all four trains constructed and operating at maximum capacity) starting in January, 2015. This level of export would require 2.2 Bcfd of supply, assuming that the liquefaction process consumes natural gas as a fuel at the rate of 10 percent.

Gas would be brought to the plant via the Creole Trail Pipeline and the Kinder Morgan Louisiana Pipeline. These two pipelines would in turn access domestic shale gas supplies from the Barnett Shale and Haynesville Shale Basins as well as other gas sources.

Specific export destinations and pricing were not modeled. The design intent of this analysis is to assess the supply, demand, and price effects on domestic supply of exporting as much as 2.0 Bcfd of supply (plus fuel) regardless of overseas market economics.

Basic Modeling Assumptions

About Navigant Consulting's Spring 2010 Forecast

Twice a year, Navigant Consulting issues a forecast of gas prices, demand, and supply. The forecast incorporates NCI's extensive work done on North American unconventional gas supply including the rapidly growing gas shale supply resources. It projects natural gas forward prices and monthly basis differentials at 92 market points, and pipeline flows throughout the entire North American grid, through 2035. Price projections for purposes of this report focus on Henry Hub, which is the underlying physical location of the natural gas NYMEX futures contract, and is in Louisiana, not far from Sabine Pass LNG. Additional price points in the Northeast are included to demonstrate the effect of supply and demand on key markets that have exhibited very volatile prices.

The forecast models supply by state or region, imports and exports (including LNG by terminal), storage, and sectoral demand on a monthly basis.

The NCI forecast accounts for changes in gas demand driven by government policy regarding greenhouse gas (GHG) reductions. NCI believes that such policies are inevitable, and that they will favor growth in natural gas usage because of gas's lower GHG content relative to other fossil fuels, particularly coal. This is evidenced by ongoing public policy steps being taken and programs already in existence such as California's AB 32 (the Global Warming Solutions Act of 2006) and the Regional Greenhouse Gas Initiative (RGGI) in the Northeast, and various renewable performance standards (RPS) and other initiatives.

To reflect these GHG reductions in the forecast, we assume a reduction of coal-fired generation output of 1.0 percent per year starting in 2015, continuing through 2035. This coal-fired capacity is replaced by an equivalent amount of gas generation that is translated into gas volumes using an average heat rate of 7,079 Btu per kilowatt-hour. Additionally, we assume a carbon tax adder starting in 2015 at $20.10 per ton ($1.26 per MMBtu),[9] increasing to $54.40 per ton ($3.41 per MMBtu) in 2035, based on recent analysis from the EPA of the proposed American Power Act of 2010.[10] We assume this adder will impact the electric generation sector starting in 2015, the industrial sector starting in 2017, and the residential and commercial sectors starting in 2019.

The level of reduction in coal generation assumed as a result of carbon emission limits and the coincident increase in gas demand are somewhat arbitrary. However, we believe they are conservative in light of the generally discussed goal of reducing carbon dioxide emissions by 80% of 2005 levels by 2050, and that our assumptions reflect the likely effect that such initiatives are apt to have.

Using these assumptions, electric generation gas consumption in the Spring 2010 Forecast grows at an average rate of 2.4 percent from 2010 through 2035.

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[9] Assumes 125 lbs per MMBtu

[10] EPA's analysis can be found at http://www.epa.gov/climatechange/economics/economicanalyses.html

Industrial gas demand continues to decline at a modest average rate of -0.3% for the entire forecast period due to effects of higher gas prices and an ongoing structural shift of certain industries offshore.

Residential/Commercial demand is relatively flat.

All scenarios in this report are ultimately derived from NCI's Spring 2010 Forecast. Each scenario is described separately, and the modifications from the Spring 2010 Forecast are made clear.

The following assumptions remain constant for all cases.

Infrastructure

Modeling used existing pipeline and LNG terminal infrastructure, augmented by planned expansions that have been publicly announced and that are likely to be built. Pipelines are assumed to have sufficient capacity to move gas from supply sources to demand centers. Some local expansions have been assumed and built into the model in future years to relieve expected bottlenecks. In these cases, supply availability has been vetted to provide reasonable comfort that it will be available.

Some proposed projects have been excluded from the model, most notably the Mackenzie Pipeline in northern Canada, which we believe to be uneconomic and facing significant environmental challenges. No unannounced infrastructure projects were introduced into the model. The Alaska Gas Pipeline project is assumed to be online in 2025 at 4.5 Bcfd, with available supply phased in up to 2029. Other notable regional pipelines assumed to be operational by 2015 include Bison, Golden Pass, Fayetteville Express, Ruby, and Tiger. See Appendix A for a list of future pipelines and projected capacity levels that are included in the model.

LNG import capacity is assumed to be 18.5 Bcfd from 2015 onward. The load factor of each facility is solved by the model as a function of domestic supply and demand.

Supply Basins

All supply in NCI's model comes from currently established basins. The forecasts assume no new resource discoveries beyond gas fields already identified as of Spring 2010 in North America. Estimates of production capacity are based on empirical production data. Assumptions for production capacity are the same for all cases; no production adjustments are made on a forecast -by-forecast basis. No additional basins are assumed to come online in the study period timeframe. This should be regarded as a conservative assumption, given the rate at which new shale resources have been identified over the past few years and existing estimates of the North American natural gas resource base.

GHG As-Is Case

The **GHG As-Is Case** is derived from NCI's Spring 2010 Forecast of June 2010, modified as described below.

The GHG As-Is Case substitutes the gas demand from the EIA's *2010 Annual Energy Outlook Reference Case* for the higher Spring 2010 Forecast demand. The EIA's *Reference Case* assumes that only existing GHG-related laws and regulations will be in place throughout the study timeframe. (Thus the name "As-Is.") Most significantly, electric generation demand in the GHG As-Is Case is substantially lower than in NCI's Spring 2010 Forecast, as shown in the graph below.

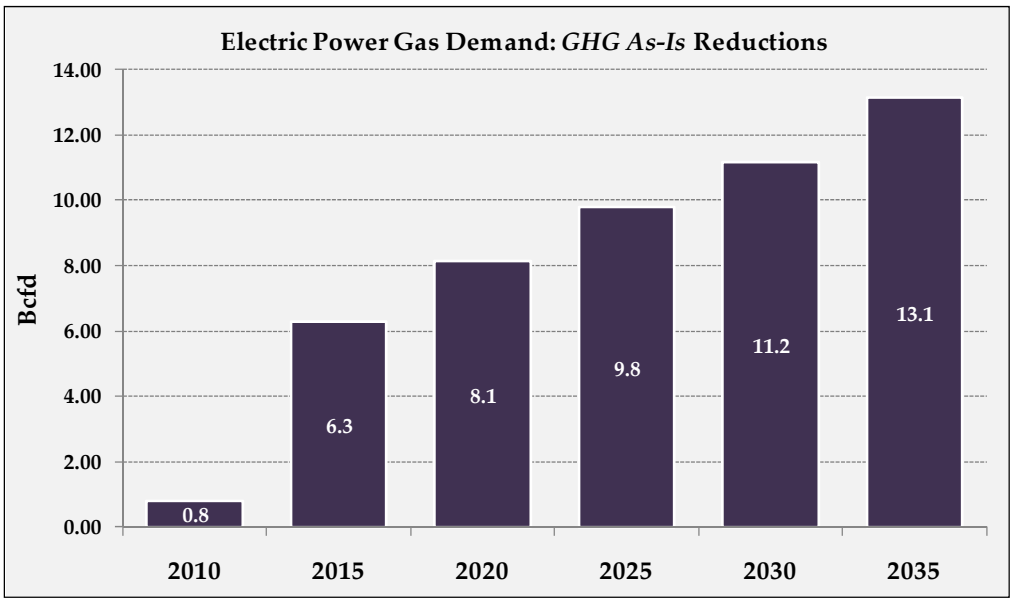

Figure 9: GHG As-Is Case, Reductions in Gas Demand for Electric Power

All other inputs and assumptions, including supply sources and infrastructure, remain the same as in the Spring 2010 Forecast.

Demand

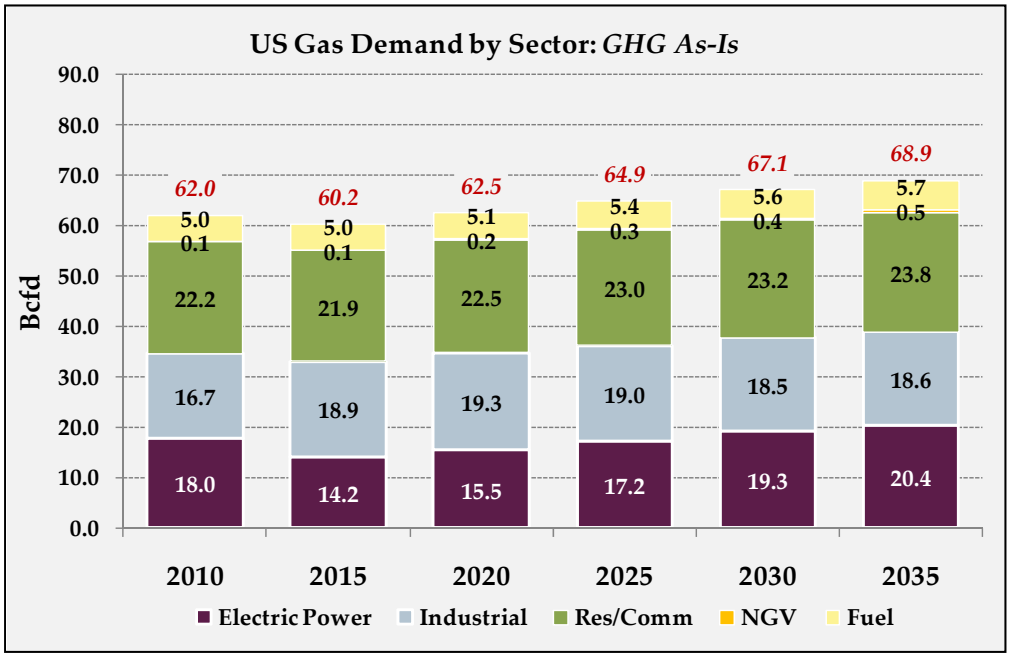

Figure 10: GHG As-Is Demand

In the EIA's AEO 2010 demand scenario, rapid installation of renewables between 2010 and 2015 displaces some natural gas baseload electric generation; hence, a decline in demand. The EIA assumes that gas-fired electric generation will be the marginal supply, and that coal will be cheaper and thus tend to have a greater share of baseload generation. Electric generation demand resumes its growth trajectory after 2015.

Supply

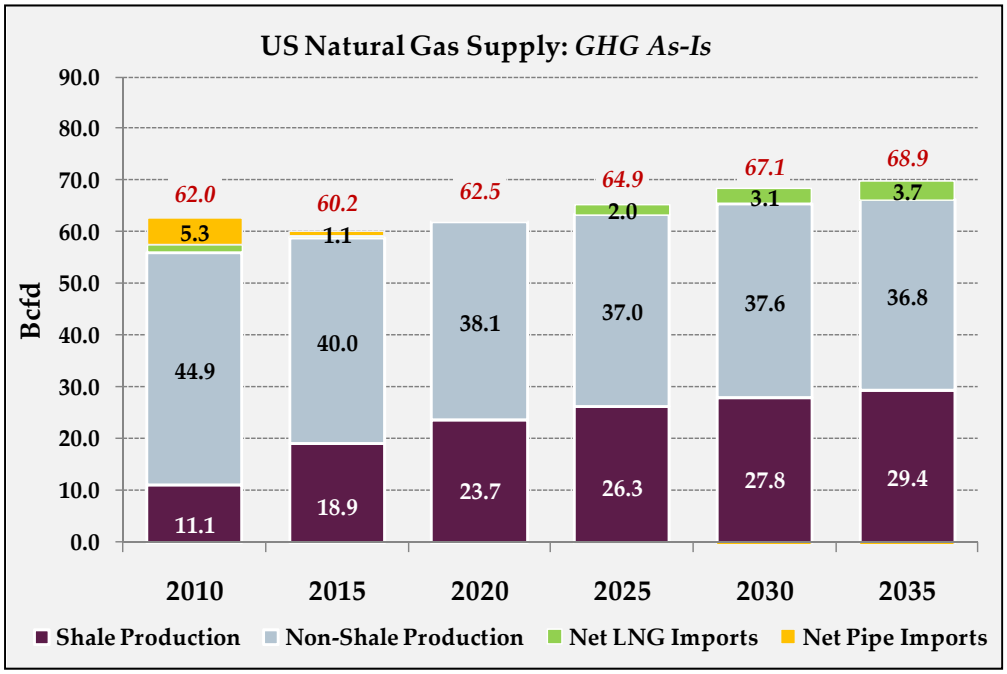

Figure 11: GHG As-Is Supply

In the GHG As-Is Case, shale supply grows from 18.9 Bcfd in 2015 to 29.4 Bcfd in 2035. Overall demand growth moves from 60.2 Bcfd in 2015 to 68.9 Bcfd in 2035. Pipeline imports from Canada decline as conventional supply in that country continues to decline and, to a lesser extent, supply in general is absorbed increasingly by increasing domestic demand in Canada including demand from the oil sands in Alberta. LNG imports rise slightly, to 3.7 Bcfd by 2035, as it is able to compete on price at the margin with domestic production.

Resultant Gas Prices

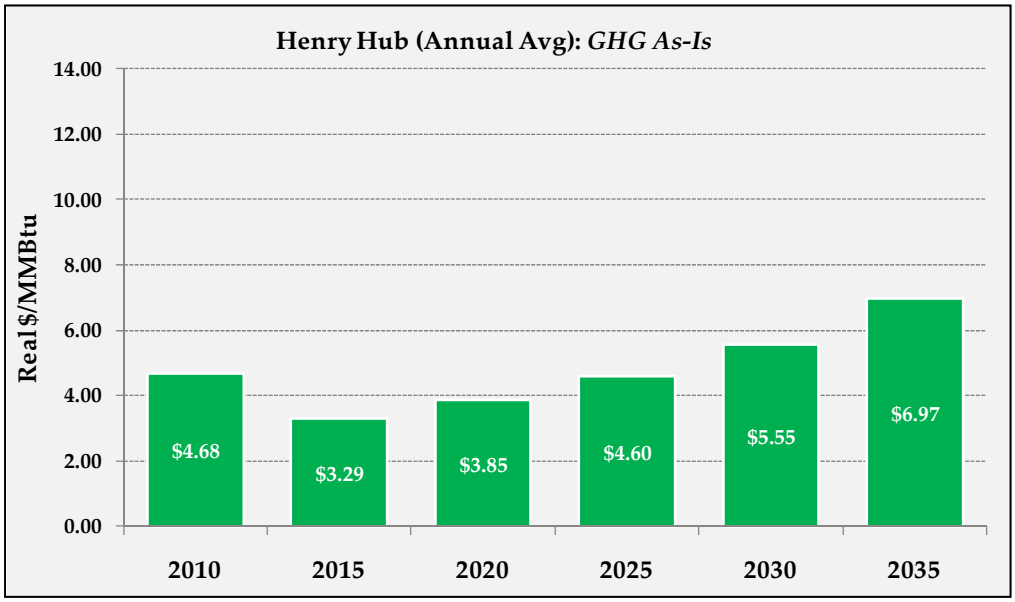

Figure 12: GHG As-Is Resultant Gas Prices

Prices remain weak through 2020, due to aggressive shale gas growth outstripping the assumed low EIA demand, which does not anticipate GHG reductions and coal displacement. The dip in prices shown from 2010 to 2015 is a result of the demand numbers from the EIA's Reference Case. The forecast in 2015 reflects an oversupply relative to demand.

GHG As-Is, Moderate Export Case

The **GHG As-Is, Moderate Export Case** tests the effects of liquefying and exporting 1.0 Bcfd of domestically-sourced gas from the Sabine Pass facility beginning 2015. All other inputs and assumptions remain the same as in the GHG As-Is Case.

Demand (in the form of feedstock to the liquefaction facility) and supply (in the form of export LNG) both increase by 1.1 Bcfd over the study period, reflecting 1.0 Bcf/d average LNG exports plus facility fuel consumption.. Numbers below are net of these offsetting increases.

Demand

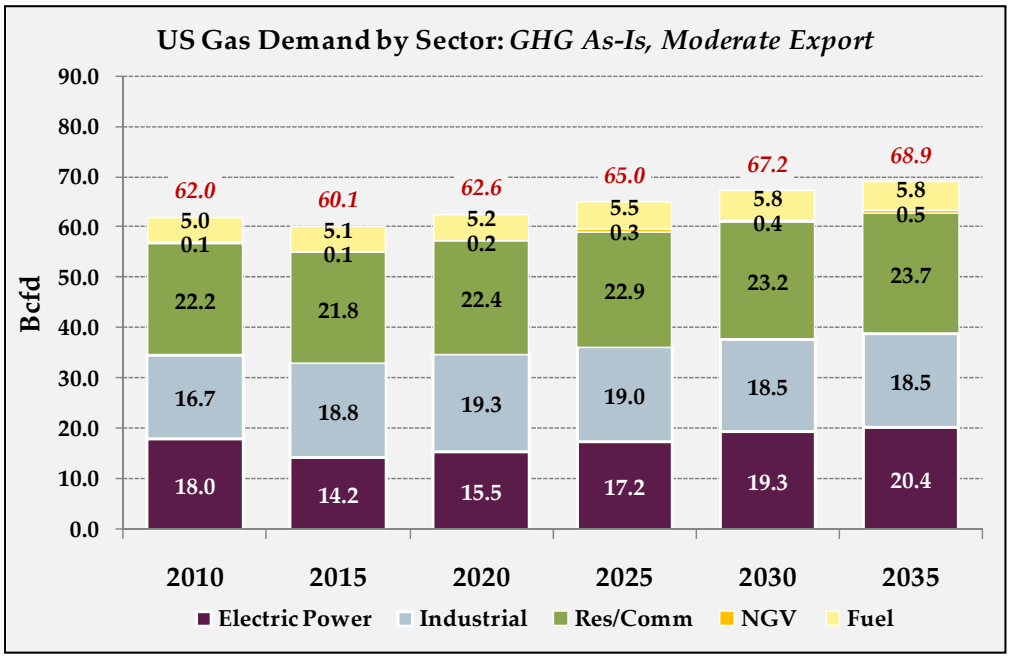

Figure 13: GHG As-Is, Moderate Export Demand

Adding 1.0 Bcfd at Sabine Pass for export does not alter the demand mix appreciably from the GHG As-Is Case. Fuel usage increases slightly, reflecting an increase in domestic production and fuel usage at the Sabine Pass facility.

Supply

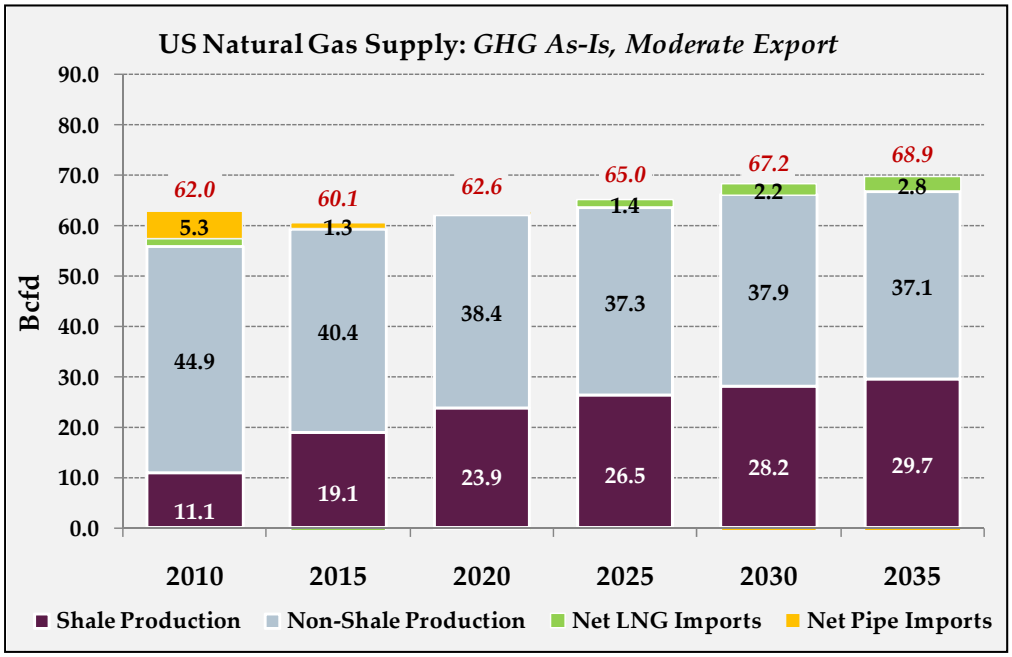

Figure 14: GHG As-Is, Moderate Export Supply

Adding 1.0 Bcfd at Sabine Pass for export causes net LNG imports to back off by 0.9 Bcfd compared to the GHG As-Is Case. To balance, domestic production increases by 0.7 Bcfd and pipeline imports increase by 0.2 Bcfd.

Resultant Gas Prices

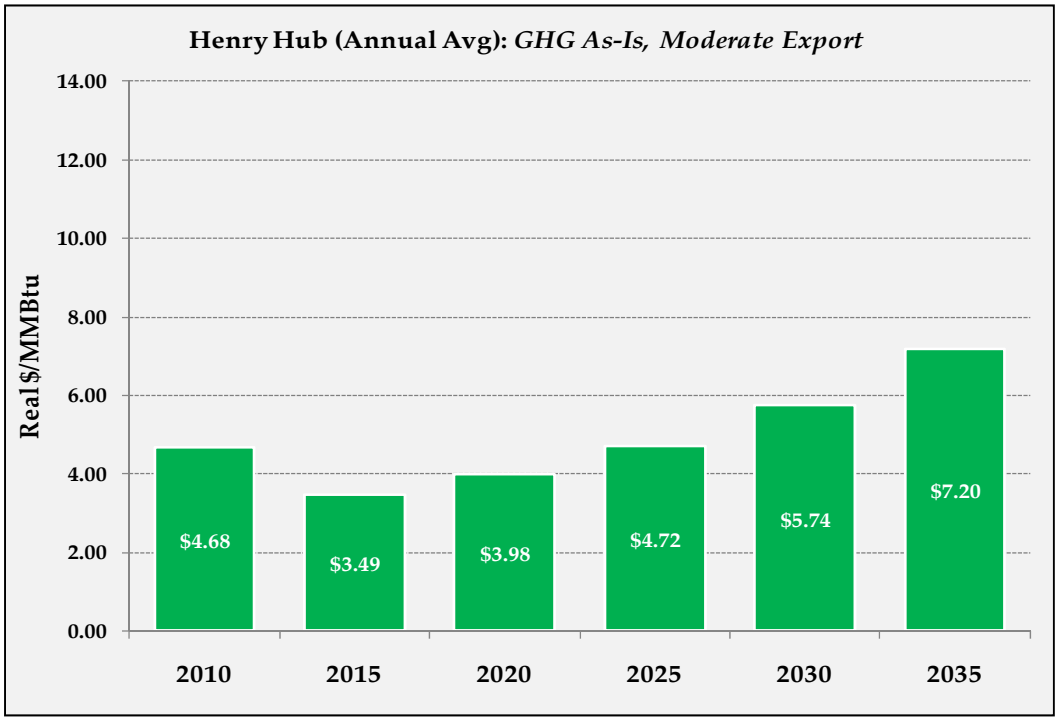

Figure 15: GHG As-Is, Moderate Export Prices

Prices rise slightly in the As-Is, Moderate Export Case, due to the additional demand created by export of 1.0 Bcfd of LNG.

Year	Base As-Is Price	As-Is, Moderate Price	*Moderate* less *Base As-Is*
2010	4.68	4.68	0.00
2015	3.29	3.49	0.20
2020	3.85	3.98	0.13
2025	4.69	4.72	0.13
2030	5.55	5.74	0.19
2035	6.97	7.20	0.23

Table 2: Henry Hub Price Difference, GHG As-Is Moderate Export Case

The maximum change in Northeast basis values for the GHG As-Is Moderate Export Case is $0.011 per MMBtu in 2035, at Dominion South Point. See ***Export Effect on Northeast Market Prices*** on page 34 for a table of basis price effects.

GHG As-Is, High Export Case

The **GHG As-Is, High Export Case** tests the effects of liquefying and exporting 2.0 Bcfd (rather than 1.0 Bcfd) of domestically-sourced gas from the Sabine Pass facility beginning 2015. All other inputs and assumptions remain the same as in the GHG As-Is Case.

Demand (in the form of feedstock to the liquefaction facility) and supply (in the form of export LNG) both increase by 2.2 Bcfd over the study period, reflecting 2.0 Bcfd average LNG exports plus facility fuel consumption. Numbers below are net of these offsetting increases.

Demand

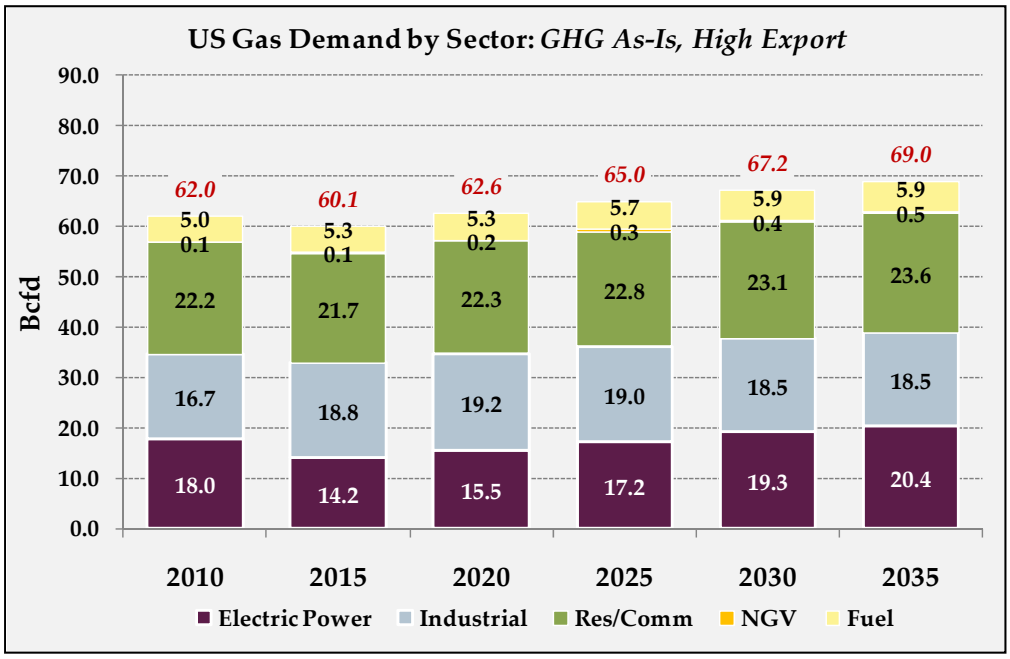

Figure 16: GHG As-Is, High Export Demand

Adding 2.0 Bcfd of exports slightly changes the distribution of demand in each year beyond 2010. Fuel usage increase slightly, reflecting an increase in domestic production and fuel usage at the Sabine Pass facility. Other demand is reduced.

Supply

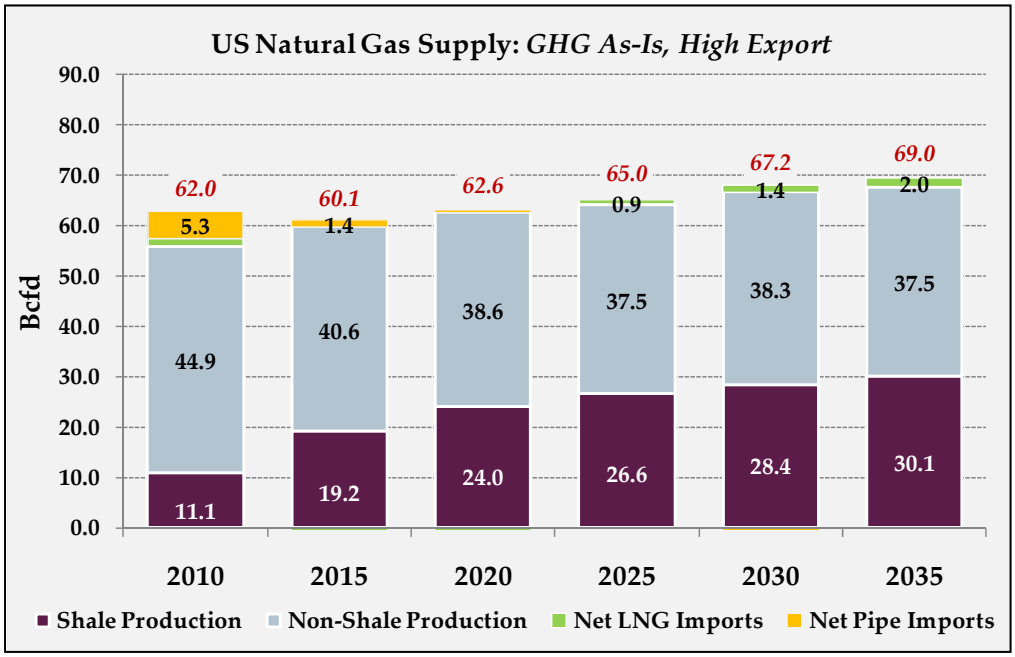

Figure 17: GHG As-Is, High Export Supply

Adding 2.0 Bcfd of exports at Sabine Pass increases domestic production by 1.4 Bcfd, net pipeline imports by 0.3 Bcfd, and 0.3 Bcfd of LNG imports in 2035.

Resultant Gas Prices

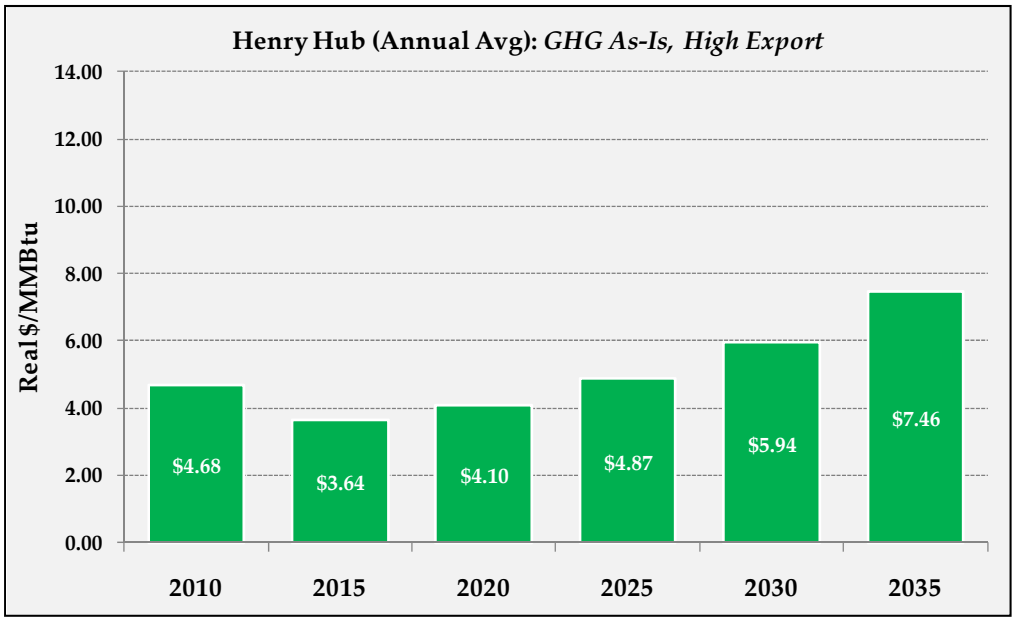

Figure 18: GHG As-Is, High Export Prices

The table below shows that the highest price differential compared to the GHG As-Is Case is $0.49 per MMBtu, which occurs in 2035. The 2035 price for the As-Is High Export Case is $0.26 per MMBtu above the price for the As-Is Moderate Export Case.

Year	Base As-Is Price	As-Is, *Moderate* Price	As-Is, *High* Price	*High* less *Base As-Is*	*High* less *Moderate As-Is*
2010	4.68	4.68	4.68	0.00	0.00
2015	3.29	3.49	3.64	0.35	0.15
2020	3.85	3.98	4.10	0.25	0.12
2025	4.69	4.72	4.87	0.27	0.14
2030	5.55	5.74	5.94	0.39	0.20
2035	6.97	7.20	7.46	0.49	0.26

Table 3: Henry Hub Price Difference, GHG As-Is High Export Case

The maximum change in Northeast basis values for the GHG As-Is High Export Case is $0.042 per MMBtu in 2035, at Dominion South Point. See ***Export Effect on Northeast Market Prices*** on page 34 for a table of basis price effects.

GHG Plus Case

The **GHG Plus Case** is based upon NCI's Spring 2010 Forecast, which was prepared in June 2010 using the GPCM gas pipeline network modeling software. The NCI Spring 2010 forecast has been modified as described below.

Demand

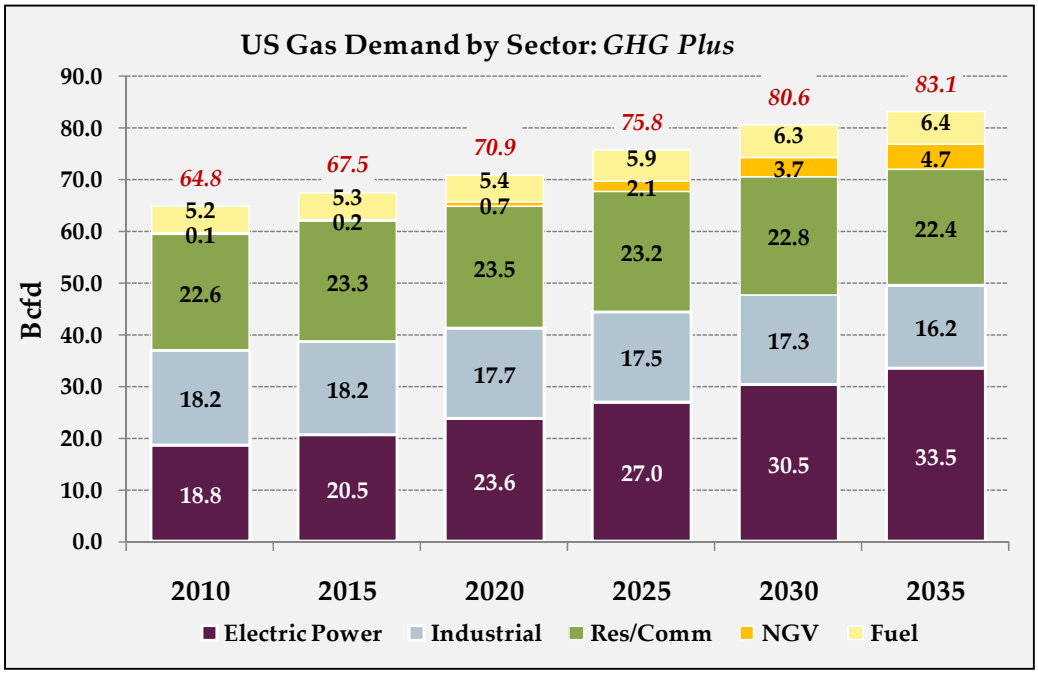

Figure 19: GHG Plus U.S. Natural Gas Demand

The GHG Plus Case projects overall U.S. natural gas demand to grow from 64.8 Bcfd in 2015 to approximately 83.1 Bcfd by 2035, an increase of 28% over the 20-year period. This growth will be driven primarily by the electric generation sector, which is likely to be impacted by mandated reductions in energy-related GHG emissions.

Natural Gas Vehicle Demand: High Case

The GHG Plus Case includes additional demand assumptions that were used to develop a maximalist outlook for any price sensitivities caused by demand for liquefaction and export. This additional demand comes from the EIA's *2027 Phaseout and Expanded Market Heavy-Duty Vehicle Fuel Use Case*,[11] which puts forward a scenario in which natural gas becomes a preferred vehicle fuel. While NCI's

[11] http://www.eia.doe.gov/oiaf/aeo/natgas_fuel.html

Spring 2010 Forecast assumes an average national consumption of 0.5 Bcfd by 2035 for natural gas vehicles, the EIA 2027 Phaseout Case assumes a much larger volume, 4.7 Bcfd.

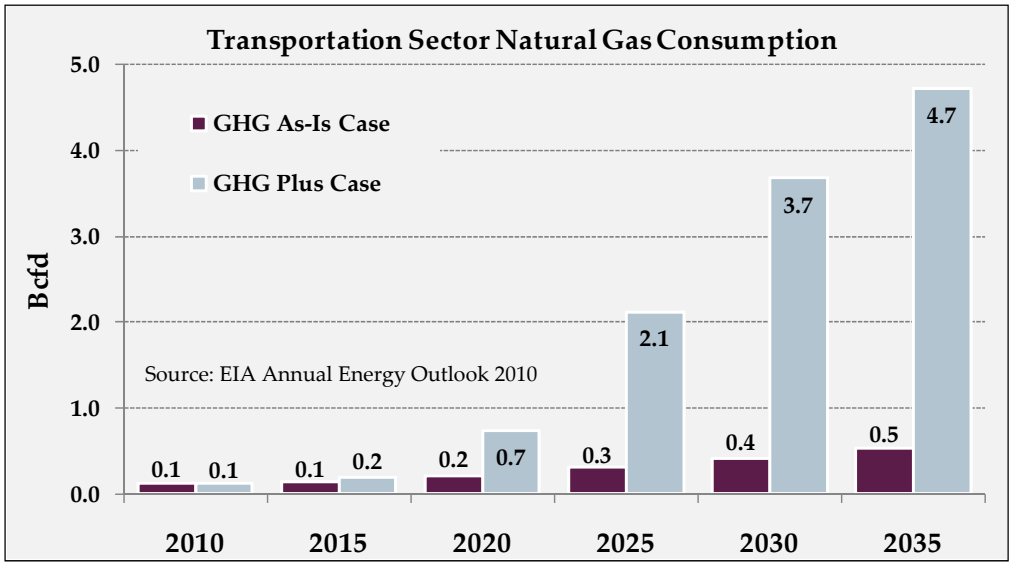

Figure 20: Natural Gas Vehicle Demand, GHG Plus Case Compared to GHG As-Is

The Effect of Carbon Reduction Policies on Natural Gas Demand

In recognition of the high probability that legislation, programs, and policies at both the state and federal level in the U.S. will continue to be enacted to reduce GHGs, our forecast assumes that measures will be adopted to substantially reduce GHG emissions in the future.

Coal demand is expected to be increasingly impacted by concerns over GHG emissions, RPS and other possible GHG and climate change public policy initiatives. These initiatives will tend to favor gas, because gas produces about half the GHGs per kilowatt hour as coal. The introduction of a carbon price, either through a tax or a cap-and-trade system, will further shift electric generation fuel demand from coal to gas.

As a result, the GHG Plus Case retains the projected electric generation demand for natural gas from our Spring 2010 Forecast. Electric generation demand is projected to grow at an average annual rate of 2.4% from 2010 through 2035, based upon coal-to-gas substitution.

Electric Generation Demand in the Southeast under the GHG Plus Case

The following table illustrates the natural gas demand for electric generation fuel projected in the GHG Pus Case in the Southeastern U.S. The Southeast includes the West South Central, East South Central, and South Atlantic census regions.

Year	Southeast (Bcfd)	U.S. (Bcfd)	SE % of U.S.
2010	10.2	18.8	54%
2015	11.1	20.5	54%
2020	12.7	23.6	54%
2025	14.4	27.0	53%
2030	16.1	30.5	53%
2035	17.7	33.5	53%

Table 4: GHG Plus Case, Southeast Electric Power Demand

Supply

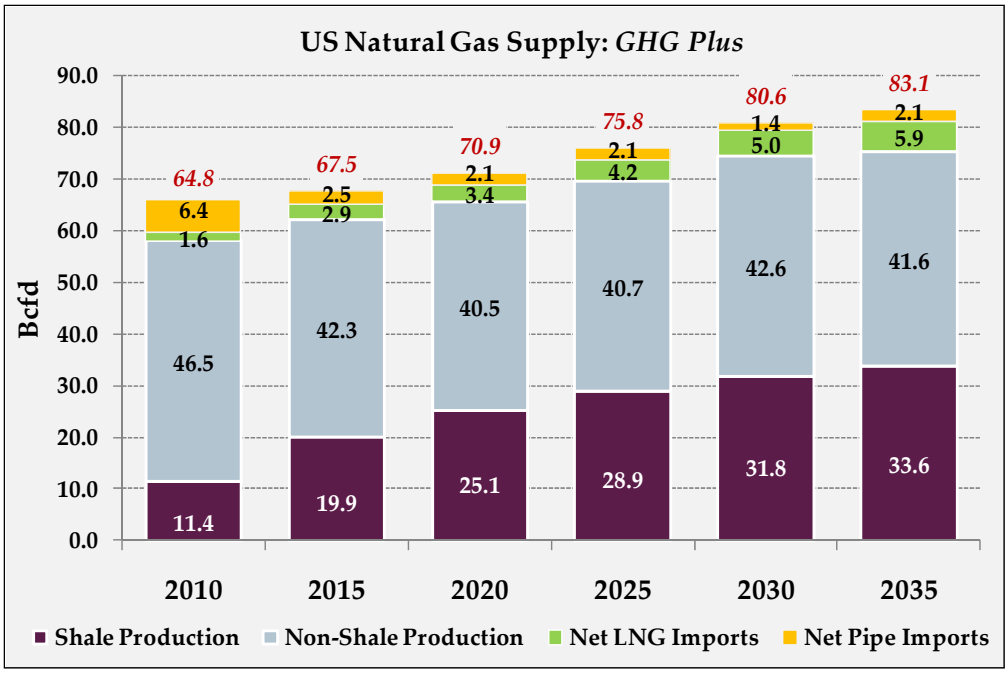

Figure 21: GHG Plus U.S. Natural Gas Supply

The GHG Plus Case shows a significant increase in supply relative to the GHG As-Is Case. This increase responds to increased demand caused by the preference for lower-carbon natural gas over coal as electric generation fuel, and for increased NGV fuel. By 2035, supply is 83.1 Bcfd, compared to the supply in the GHG As-Is Case of 68.9 Bcfd.

Resultant Gas Prices

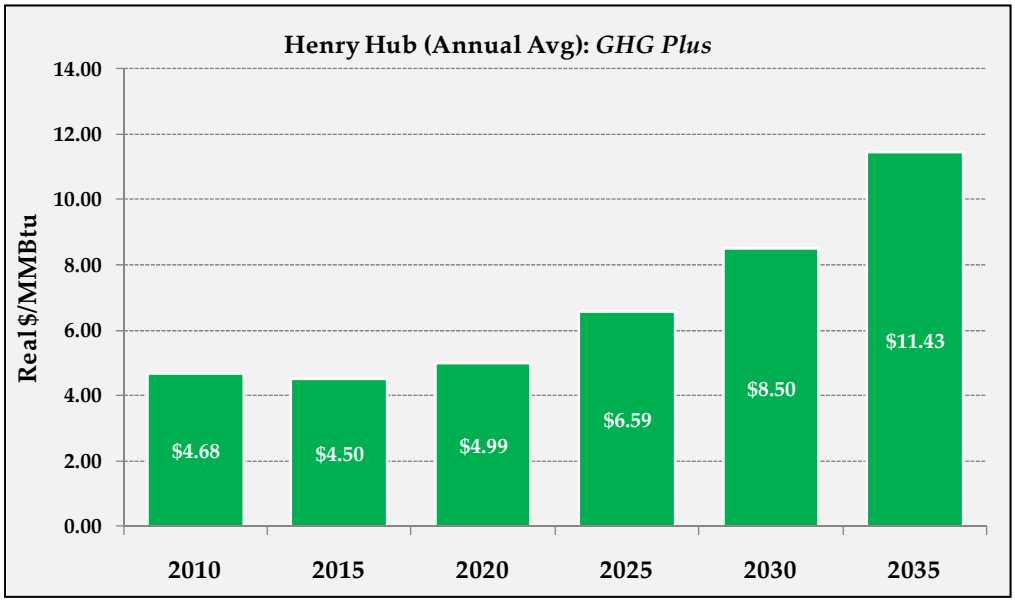

Figure 22: GHG Plus Prices

Even with the addition of 8.4 Bcfd in 2020 to the supply/demand balance in the GHG As-Is Case, prices in the GHG Plus Case remain under $5.00 per MMBtu through that year. After 2020, prices increase steadily, reaching $11.43 per MMBtu in 2035, when 14.2 Bcfd in additional demand is added.

GHG Plus, High Export Case

The **GHG Plus, High Export Case** tests the effects of liquefying and exporting 2.0 Bcfd of domestically-sourced gas from the Sabine Pass facility beginning 2015. All other inputs and assumptions remain the same as in the GHG Plus Case.

Demand (in the form of feedstock to the liquefaction facility) and supply (in the form of export LNG) both increase by 2.2 Bcfd over the study period, reflecting 2.0 Bcfd average LNG exports plus facility fuel consumption. Numbers below are net of these offsetting increases.

Demand

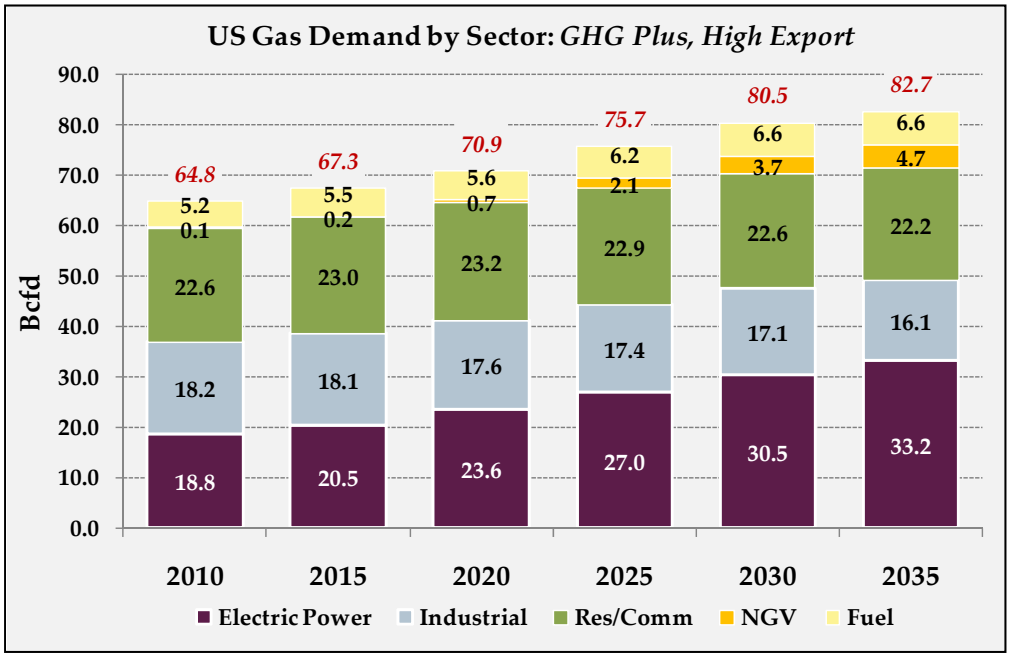

Figure 23: GHG Plus, High Export Demand

Adding 2.0 Bcfd of exports (plus 0.2 Bcfd for plant fuel consumption) slightly changes the distribution of demand in the study timeframe of 2015-2035. In 2035, overall demand (net of the 2.0 Bcfd exports) is reduced by 0.4 Bcfd due to the modest price increases at the margin caused by the additional 2.0 Bcfd. Electric power, industrial, and residential demand all come off slightly, while fuel use rises in response to increased domestic production and export facility fuel. Reduced net LNG imports account for the overall supply reduction.

Supply

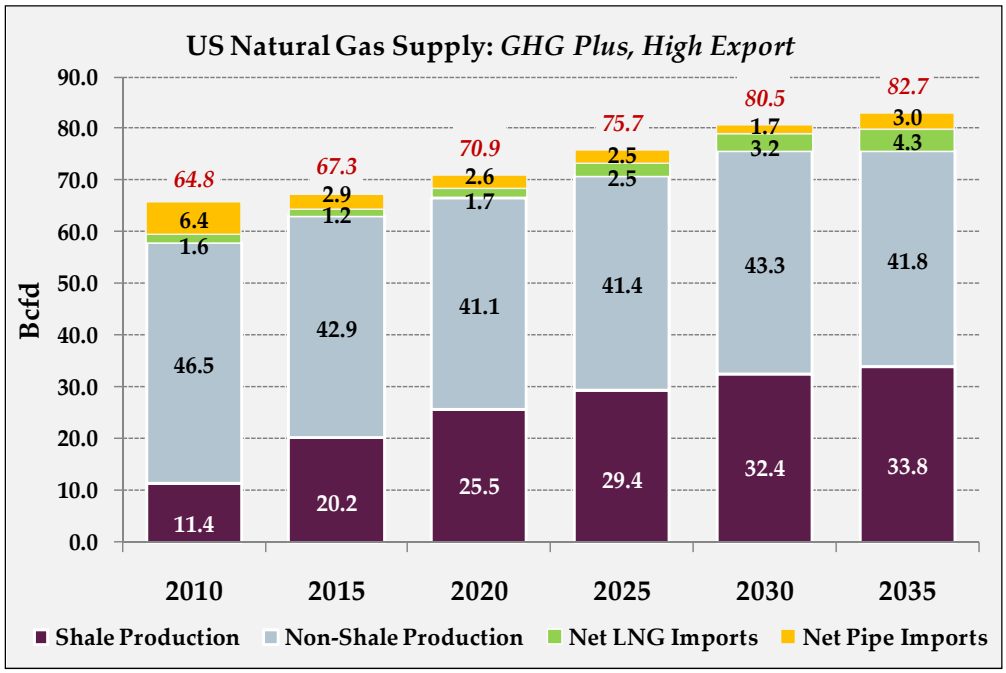

Figure 24: GHG Plus, High Export Supply

Adding 2.0 Bcfd of exports at Sabine Pass (plus 0.2 Bcfd for plant fuel consumption) increases domestic production by 0.4 Bcfd in 2035 compared to the GHG Plus base case. Net pipeline imports increase by 0.9 Bcfd. Net LNG imports decrease by 1.6 Bcfd. Overall, total supply decreases by 0.4 Bcfd compared to the GHG Plus Case.

Resultant Gas Prices

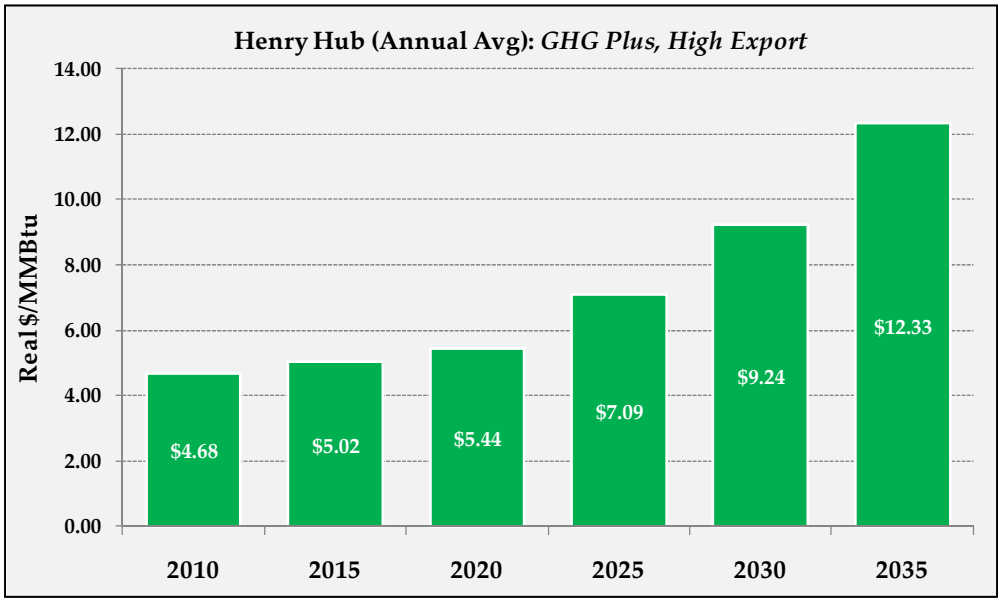

Figure 25: GHG Plus, High Export Prices

The addition of 2.2 Bcfd to the GHG Plus Case causes prices to rise moderately. The increase averages $0.55 per MMBtu (9.0%) from 2015 through 2030, and $0.62 per MMBtu (8.6%) from 2015 through 2035. Prices remain under $6.00 per MMBtu through 2020. After 2020, prices increase steadily, reaching $12.33 per MMBtu in 2035.

The table below shows that the highest price differential for the GHG Plus, High Export Case compared to the GHG Plus base case is $0.90 per MMBtu, which occurs in 2035.

Year	GHG-Plus *Base* Price	GHG-Plus *High* Price	Plus *High* less Plus *Base*
2010	4.68	4.68	0.00
2015	4.50	5.02	0.52
2020	4.99	5.44	0.45
2025	6.59	7.09	0.50
2030	8.50	9.24	0.73
2035	11.43	12.33	0.90

Table 5: Henry Hub Price Difference, GHG Plus High Export Case

The maximum change in Northeast basis values for the GHG Plus High Export Case is $0.066 per MMBtu in 2035, at Dominion South Point. See ***Export Effect on Northeast Market Prices*** on page 34 for a table of basis price effects.

Export Effect on Northeast Market Prices

In addition to assessing the impact of exports from the Sabine Pass facility on prices in the Henry Hub region, Navigant Consulting assessed the impact on basis in the key Northeast market region.

Our findings were that none of the export scenarios have a significant impact on Northeast market prices relative to Gulf Coast prices. As can be seen from the table below, the largest difference in basis[12] caused by an export scenario occurs at Dominion South Point in 2035 for the GHG Plus Case. The addition of 2.0 Bcfd of export gas (plus 0.2 Bcfd for plant fuel consumption) yields a basis at that time and location that is 6.6 cents per MMBtu weaker than in the GHG Plus Case. This is likely due primarily to increased domestic production in the Marcellus shale play in response to increased domestic demand. Also, it may be a response to higher absolute Henry Hub prices in the GHG Plus, High Export Case. In any event, the vast majority of data points for basis in the Northeast show no significant impact. See the following table for detail.

Dominion, South Point - Basis Differentials

Period	GHG Plus less GHG Plus, High Export	GHG As-Is less GHG As-Is, High Export	GHG As-Is less GHG As-Is, Moderate Export
2010	-0.001	-0.001	-0.001
2015	0.024	0.015	0.008
2020	0.005	0.007	-0.003
2025	0.022	0.019	0.003
2030	0.052	0.033	0.013
2035	0.066	0.042	0.011

Texas Eastern, M-3- Basis Differentials

Period	GHG Plus less GHG Plus, High Export	GHG As-Is less GHG As-Is, High Export	GHG As-Is less GHG As-Is, Moderate Export
2010	-0.001	-0.002	-0.002
2015	0.018	0.021	0.010
2020	0.007	0.015	0.005
2025	0.016	0.016	0.003
2030	0.030	0.018	0.006
2035	0.044	0.026	0.001

Transco, zone 6 N.Y. - Basis Differentials

Period	GHG Plus less GHG Plus, High Export	GHG As-Is less GHG As-Is, High Export	GHG As-Is less GHG As-Is, Moderate Export
2010	0.000	-0.002	-0.002
2015	0.017	0.021	0.010
2020	0.007	0.017	0.007
2025	0.015	0.015	0.003
2030	0.022	0.018	0.006
2035	0.041	0.023	0.001

Table 6: Changes in Basis Values in the Northeast

[12] "Basis" is the difference between the cash price at a given physical trading location and the price of the Henry Hub NYMEX contract. Basis plus NYMEX equals the price at the physical location.

Appendix A: Future Pipelines in Spring 2010 Forecast Model

Pipeline	Year	New Capacity
LNG Neptune Header	Mar-10	400
Elba Express	Jun-10	1500
Golden Pass Pipe Line	Jul-10	2000
LNG Golden Pass Header	Jul-10	2000
Bison Pipeline	Nov-10	477
Fayetteville Express	Jan-11	2000
LNG Manzanillo Header [1]	Apr-11	500
Ruby	Apr-11	1250
Tiger	Jun-11	2000
LNG Gulf Clean Energy Header	Oct-11	1500
Rockies Connector	Nov-13	870
CrossTex North Texas	Jan-15	750
El Paso (Samalayuca)	Jan-15	312
Florida Gas (Market Panhandle)	Jan-15	500
Florida Gas (Zone 3)	Jan-15	500
Florida Gas (Zone 3 Rcpt)	Jan-15	500
Grasslands Pipeline	Jan-15	200
Gulf Crossing (Delivery)	Jan-15	1000
Gulf Crossing (Throughput)	Jan-15	1000
Gulf Crossing (TX/OK Rcpt)	Jan-15	1000
Teppco OPAL/Pioneer (WY)	Jan-15	600
Texas Gas (Fayetteville)	Jan-15	409
Texas Gas (Fayetteville Rcpt)	Jan-15	409
Wyoming Interstate (Mainline)	Jan-15	225
LNG Manzanillo Header	Apr-15	100
Questar (Fidlar to KRGT)	Jan-18	400

Pipeline	Year	New Capacity
Rockies Express (Z1: Mkr-Wam)	Jan-18	500
Rockies Express (Z1: Opal-Wam)	Jan-18	500
Rockies Express (Z1: Wam Sup)	Jan-18	332
Rockies Express (Z1: Wam-Chey)	Jan-18	500
Rockies Express (Z2 West)	Jan-18	500
Rockies Express (Z3 to Lebanon)	Jan-18	500
White River Hub	Jan-18	500
Wyoming Interstate (Kanda Lat)	Jan-18	400
Kern River (CA)	Jan-20	500
Kern River (Mainline)	Jan-20	500
KM Border Pipeline	Jan-20	300
KM Mexico	Jan-20	425
KM Texas Pipeline (AguaDulce)	Jan-20	250
Mojave (Mojave-Kern Common)	Jan-20	200
Tennessee (Z0 Alamo)	Jan-20	215
Tennessee (Z0 Rio Bravo)	Jan-20	315
Tennessee (Z6 East MA)	Jan-20	285
Tennessee (Z6 West MA)	Jan-20	306
Texas Eastern (S TX Hidalgo)	Jan-20	315
Texas Eastern (S TX Rcpt)	Jan-20	300
Wyoming Interstate (Mainline)	Jan-20	500
Cypress Pipeline	May-20	500
Rockies Express (Z1: Mkr-Wam)	Jan-23	500
Rockies Express (Z1: Wam-Chey)	Jan-23	500
White River Hub	Jan-23	500
Kern River (Opal-Muddy Crk)	Jan-25	440
KM Border Pipeline	Jan-25	300
Transwestern (Topock-Calpine)	Jan-25	80
Alaska (ANGTS / Denali)	Jul-25	4500

[1] Ramps from 90 to 500 from April 2011 to April 2015

Capacity units in MMcfd

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Appendix B: Natural Gas Consumption Tables

U.S. Natural Gas Consumption by End Use (Bcfd) – *GHG As-Is Case*[13]							
Year	Lease & Plant Fuel	Pipeline & Distribu-tion Use	Res/ Comm	Industrial	Vehicle Fuel	Electric Power	Total Consump-tion
2010	3.1	1.9	22.2	16.7	0.1	18.0	**62.0**
2011	3.1	1.8	21.7	17.1	0.1	16.7	**60.6**
2012	3.1	1.8	21.6	17.9	0.1	15.6	**60.2**
2013	3.1	1.8	21.7	18.6	0.1	13.8	**59.2**
2014	3.2	1.8	21.8	19.0	0.1	13.3	**59.2**
2015	3.2	1.8	21.9	18.9	0.1	14.2	**60.2**
2016	3.2	1.8	22.1	19.0	0.2	14.3	**60.6**
2017	3.2	1.8	22.1	19.0	0.2	14.7	**61.1**
2018	3.2	1.8	22.2	19.2	0.2	14.9	**61.5**
2019	3.2	1.8	22.3	19.3	0.2	15.2	**62.0**
2020	3.2	1.8	22.5	19.3	0.2	15.5	**62.5**
2021	3.2	1.8	22.6	19.2	0.2	15.4	**62.4**
2022	3.2	1.8	22.6	19.1	0.3	15.6	**62.7**
2023	3.2	1.8	22.7	19.0	0.3	16.1	**63.2**
2024	3.4	1.8	22.9	19.1	0.3	17.1	**64.5**
2025	3.6	1.9	23.0	19.0	0.3	17.2	**64.9**
2026	3.7	1.9	23.0	18.8	0.3	18.0	**65.7**
2027	3.7	1.9	23.2	18.8	0.3	18.3	**66.3**
2028	3.7	1.9	23.3	18.7	0.4	18.8	**66.8**
2029	3.7	2.0	23.3	18.6	0.4	19.2	**67.1**
2030	3.7	2.0	23.2	18.5	0.4	19.3	**67.1**
2031	3.7	2.0	23.3	18.5	0.4	19.5	**67.4**
2032	3.7	2.0	23.4	18.4	0.5	19.8	**67.8**
2033	3.7	2.0	23.5	18.6	0.5	20.1	**68.4**
2034	3.7	2.0	23.7	18.5	0.5	20.4	**68.7**
2035	3.7	2.0	23.8	18.6	0.5	20.4	**68.9**

[13] In the GHG As-Is Case, the sectoral demand in Navigant Consulting's Spring 2010 Forecast was backed out and a demand based on the EIA's Annual Energy Outlook was substituted. Due to technical reasons, the EIA-based figures above do not tie-out exactly to the EIA source numbers due to model calibration tolerances.

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U.S. Natural Gas Consumption by End Use (Bcfd) – *GHG As-Is, Moderate Export Case*							
Year	**Lease & Plant Fuel**	**Pipeline & Distribu-tion Use**	**Res/ Comm**	**Industrial**	**Vehicle Fuel**	**Electric Power**	**Total Consump-tion**
2010	3.1	1.9	22.2	16.7	0.1	18.0	**62.0**
2011	3.1	1.8	21.7	17.1	0.1	16.7	**60.6**
2012	3.1	1.8	21.6	17.9	0.1	15.6	**60.2**
2013	3.1	1.8	21.7	18.6	0.1	13.8	**59.2**
2014	3.2	1.8	21.8	19.0	0.1	13.3	**59.1**
2015	3.2	1.9	21.8	18.8	0.1	14.2	**60.1**
2016	3.2	1.9	21.9	18.9	0.2	14.3	**60.4**
2017	3.2	1.9	22.0	19.0	0.2	14.7	**61.0**
2018	3.2	1.9	22.1	19.1	0.2	14.9	**61.5**
2019	3.2	1.9	22.2	19.2	0.2	15.2	**62.0**
2020	3.3	1.9	22.4	19.3	0.2	15.5	**62.6**
2021	3.2	1.9	22.5	19.2	0.2	15.4	**62.4**
2022	3.2	1.9	22.5	19.1	0.3	15.6	**62.7**
2023	3.3	1.9	22.6	19.0	0.3	16.1	**63.2**
2024	3.4	2.0	22.8	19.1	0.3	17.1	**64.6**
2025	3.6	2.0	22.9	19.0	0.3	17.2	**65.0**
2026	3.7	2.0	23.0	18.8	0.3	18.0	**65.8**
2027	3.7	2.0	23.1	18.8	0.3	18.3	**66.3**
2028	3.7	2.1	23.2	18.6	0.4	18.8	**66.8**
2029	3.7	2.1	23.2	18.6	0.4	19.2	**67.1**
2030	3.7	2.1	23.2	18.5	0.4	19.3	**67.2**
2031	3.7	2.1	23.2	18.5	0.4	19.5	**67.5**
2032	3.7	2.1	23.4	18.4	0.5	19.8	**67.8**
2033	3.7	2.1	23.4	18.6	0.5	20.1	**68.4**
2034	3.7	2.1	23.6	18.5	0.5	20.4	**68.7**
2035	3.7	2.1	23.7	18.5	0.5	20.4	**68.9**

U.S. Natural Gas Consumption by End Use (Bcfd) – *GHG As-Is, High Export Case*							
Year	**Lease & Plant Fuel**	**Pipeline & Distribu-tion Use**	**Res/ Comm**	**Industrial**	**Vehicle Fuel**	**Electric Power**	**Total Consump-tion**
2010	3.1	1.9	22.2	16.7	0.1	18.0	**62.0**
2011	3.1	1.8	21.7	17.1	0.1	16.7	**60.6**
2012	3.1	1.8	21.6	17.9	0.1	15.6	**60.2**
2013	3.1	1.8	21.7	18.6	0.1	13.8	**59.2**
2014	3.2	1.8	21.8	18.9	0.1	13.3	**59.1**
2015	3.2	2.0	21.7	18.8	0.1	14.2	**60.1**
2016	3.3	2.0	21.8	18.9	0.2	14.3	**60.4**
2017	3.2	2.0	21.9	19.0	0.2	14.7	**61.0**
2018	3.2	2.0	22.0	19.1	0.2	14.9	**61.5**
2019	3.3	2.0	22.1	19.2	0.2	15.2	**62.0**
2020	3.3	2.0	22.3	19.2	0.2	15.5	**62.6**
2021	3.3	2.0	22.4	19.2	0.2	15.4	**62.4**
2022	3.3	2.0	22.4	19.1	0.3	15.6	**62.7**
2023	3.3	2.0	22.6	19.0	0.3	16.1	**63.2**
2024	3.4	2.1	22.7	19.0	0.3	17.1	**64.6**
2025	3.6	2.1	22.8	19.0	0.3	17.2	**65.0**
2026	3.7	2.1	22.9	18.8	0.3	18.0	**65.8**
2027	3.8	2.1	23.0	18.7	0.3	18.3	**66.3**
2028	3.8	2.2	23.1	18.6	0.4	18.8	**66.8**
2029	3.7	2.2	23.1	18.6	0.4	19.2	**67.1**
2030	3.7	2.2	23.1	18.5	0.4	19.3	**67.2**
2031	3.7	2.2	23.2	18.5	0.4	19.5	**67.5**
2032	3.7	2.2	23.3	18.4	0.5	19.8	**67.8**
2033	3.7	2.2	23.4	18.6	0.5	20.1	**68.4**
2034	3.7	2.2	23.5	18.4	0.5	20.4	**68.8**
2035	3.7	2.2	23.6	18.5	0.5	20.4	**69.0**

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U.S. Natural Gas Consumption by End Use (Bcfd) – *GHG Plus Case*							
Year	**Lease & Plant Fuel**	**Pipeline & Distribu-tion Use**	**Res/ Comm**	**Industrial**	**Vehicle Fuel**	**Electric Power**	**Total Consump-tion**
2010	3.2	2.0	22.6	18.2	0.1	18.8	**64.8**
2011	3.3	1.9	22.9	18.3	0.1	19.0	**65.5**
2012	3.3	1.9	23.0	18.3	0.1	19.2	**65.7**
2013	3.3	1.9	23.1	18.3	0.1	19.5	**66.3**
2014	3.3	1.9	23.2	18.3	0.2	19.9	**66.7**
2015	3.4	1.9	23.3	18.2	0.2	20.5	**67.5**
2016	3.4	1.9	23.4	18.2	0.2	21.1	**68.2**
2017	3.4	1.9	23.4	17.9	0.3	21.8	**68.7**
2018	3.4	2.0	23.5	17.8	0.4	22.4	**69.5**
2019	3.4	2.0	23.5	17.8	0.6	23.1	**70.3**
2020	3.4	2.0	23.5	17.7	0.7	23.6	**70.9**
2021	3.4	2.0	23.5	17.7	0.9	24.3	**71.9**
2022	3.4	2.0	23.4	17.6	1.2	25.0	**72.7**
2023	3.5	2.1	23.3	17.6	1.5	25.7	**73.6**
2024	3.6	2.1	23.2	17.5	1.8	26.3	**74.4**
2025	3.8	2.1	23.2	17.5	2.1	27.0	**75.8**
2026	4.0	2.1	23.2	17.5	2.5	27.7	**77.0**
2027	4.1	2.2	23.1	17.4	2.8	28.4	**77.9**
2028	4.0	2.2	23.0	17.3	3.1	29.0	**78.7**
2029	4.1	2.3	22.9	17.3	3.4	29.8	**79.8**
2030	4.1	2.3	22.8	17.3	3.7	30.5	**80.6**
2031	4.1	2.3	22.7	17.2	3.9	31.1	**81.4**
2032	4.1	2.3	22.6	17.0	4.1	31.8	**81.9**
2033	4.1	2.3	22.6	16.8	4.3	32.4	**82.5**
2034	4.1	2.3	22.4	16.3	4.5	33.0	**82.7**
2035	4.1	2.3	22.4	16.2	4.7	33.5	**83.1**

U.S. Natural Gas Consumption by End Use (Bcfd) – *GHG Plus, High Export Case*							
Year	**Lease & Plant Fuel**	**Pipeline & Distribu-tion Use**	**Res/ Comm**	**Industrial**	**Vehicle Fuel**	**Electric Power**	**Total Consump-tion**
2010	3.2	2.0	22.6	18.2	0.1	18.8	**64.8**
2011	3.3	1.9	22.9	18.3	0.1	19.0	**65.5**
2012	3.3	1.9	23.0	18.3	0.1	19.2	**65.7**
2013	3.3	1.9	23.1	18.3	0.1	19.5	**66.3**
2014	3.3	1.9	23.2	18.3	0.2	19.9	**66.7**
2015	3.4	2.1	23.0	18.1	0.2	20.5	**67.3**
2016	3.4	2.1	23.0	18.1	0.2	21.1	**68.0**
2017	3.4	2.2	23.2	17.8	0.3	21.8	**68.6**
2018	3.4	2.2	23.3	17.8	0.4	22.4	**69.4**
2019	3.4	2.2	23.3	17.7	0.6	23.0	**70.2**
2020	3.4	2.2	23.2	17.6	0.7	23.6	**70.9**
2021	3.5	2.2	23.2	17.6	0.9	24.3	**71.8**
2022	3.5	2.2	23.1	17.6	1.2	25.0	**72.6**
2023	3.5	2.3	23.1	17.5	1.5	25.6	**73.6**
2024	3.7	2.3	23.0	17.4	1.8	26.3	**74.4**
2025	3.9	2.3	22.9	17.4	2.1	27.0	**75.7**
2026	4.1	2.4	22.9	17.4	2.5	27.7	**76.9**
2027	4.1	2.4	22.8	17.3	2.8	28.4	**77.9**
2028	4.1	2.4	22.8	17.2	3.1	29.0	**78.7**
2029	4.1	2.5	22.7	17.2	3.4	29.8	**79.6**
2030	4.1	2.5	22.6	17.1	3.7	30.5	**80.5**
2031	4.1	2.5	22.5	16.9	3.9	31.1	**81.0**
2032	4.1	2.5	22.4	16.6	4.1	31.7	**81.4**
2033	4.1	2.5	22.3	16.2	4.3	32.3	**81.8**
2034	4.1	2.5	22.2	16.1	4.5	32.7	**82.2**
2035	4.1	2.5	22.2	16.1	4.7	33.2	**82.7**

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Appendix C: U.S. Supply Disposition Tables

U.S. Supply Disposition (Bcfd) – *GHG As-Is Case*

Year	Dry Production	NET IMPORTS			Net Storage	Balancing Item	Total Disposition [14]
		Net Pipeline Imports	Net LNG Imports	Total Net Imports			
2010	56.0	5.3	1.5	6.8	0.0	-0.9	**62.0**
2011	55.8	3.5	1.1	4.6	0.3	0.0	**60.6**
2012	56.6	3.0	0.6	3.6	0.1	0.0	**60.2**
2013	56.9	2.2	0.2	2.4	-0.1	0.0	**59.2**
2014	57.7	1.4	0.2	1.5	-0.1	0.0	**59.2**
2015	58.9	1.1	0.2	1.2	0.1	0.0	**60.2**
2016	59.6	0.9	0.2	1.1	0.0	0.0	**60.6**
2017	60.1	0.7	0.2	1.0	0.0	0.0	**61.1**
2018	60.6	0.7	0.2	0.9	0.0	0.0	**61.5**
2019	61.1	0.7	0.3	1.0	0.0	0.0	**62.0**
2020	61.8	0.2	0.4	0.6	0.1	0.0	**62.5**
2021	61.9	0.1	0.5	0.6	-0.1	0.0	**62.4**
2022	62.2	-0.1	0.6	0.5	0.0	0.0	**62.7**
2023	62.5	-0.2	1.0	0.8	-0.1	0.0	**63.2**
2024	63.0	-0.4	1.8	1.4	0.1	0.0	**64.5**
2025	63.3	-0.4	2.0	1.7	0.0	0.0	**64.9**
2026	63.9	-0.5	2.4	1.9	0.0	0.0	**65.7**
2027	64.5	-0.8	2.7	1.9	0.0	0.0	**66.3**
2028	65.0	-1.1	2.9	1.8	0.1	0.0	**66.8**
2029	65.3	-1.3	3.0	1.8	0.0	0.0	**67.1**
2030	65.4	-1.3	3.1	1.9	-0.1	0.0	**67.1**
2031	65.5	-1.2	3.2	2.0	-0.1	0.0	**67.4**
2032	65.5	-1.0	3.3	2.3	0.0	0.0	**67.8**
2033	65.8	-0.9	3.4	2.6	0.0	0.0	**68.4**
2034	66.0	-0.9	3.5	2.7	0.1	0.0	**68.7**
2035	66.2	-0.6	3.7	3.0	-0.2	0.0	**68.9**

[14] In EIA tables, this column is labeled "Consumption."

U.S. Supply Disposition (Bcfd) – *GHG As-Is, Moderate Export Case*							
		NET IMPORTS					
Year	Dry Production	Net Pipeline Imports	Net LNG Imports	Total Net Imports	Net Storage	Balancing Item	Total Disposition [15]
2010	56.0	5.3	1.5	6.8	0.0	-0.9	**62.0**
2011	55.8	3.5	1.1	4.6	0.3	0.0	**60.6**
2012	56.6	3.0	0.6	3.6	0.1	0.0	**60.2**
2013	56.9	2.2	0.2	2.4	-0.1	0.0	**59.2**
2014	57.8	1.4	0.2	1.6	-0.2	-0.1	**59.1**
2015	59.5	1.3	-0.7	0.6	0.2	0.0	**60.1**
2016	60.1	1.0	-0.7	0.4	0.0	0.0	**60.4**
2017	60.7	0.9	-0.6	0.3	0.0	0.0	**61.0**
2018	61.2	0.9	-0.6	0.3	0.0	0.0	**61.5**
2019	61.7	0.9	-0.5	0.4	0.0	0.0	**62.0**
2020	62.2	0.4	-0.2	0.3	0.1	0.0	**62.6**
2021	62.4	0.3	-0.1	0.2	-0.1	0.0	**62.4**
2022	62.6	0.0	0.1	0.1	0.0	0.0	**62.7**
2023	62.9	-0.1	0.5	0.4	-0.1	0.0	**63.2**
2024	63.5	-0.2	1.2	1.0	0.1	0.0	**64.6**
2025	63.7	-0.1	1.4	1.3	0.0	0.0	**65.0**
2026	64.4	-0.3	1.7	1.4	0.0	0.0	**65.8**
2027	65.0	-0.7	2.0	1.3	0.0	0.0	**66.3**
2028	65.6	-0.9	2.1	1.2	0.0	0.0	**66.8**
2029	66.0	-1.0	2.2	1.1	0.0	0.0	**67.1**
2030	66.1	-1.0	2.2	1.2	-0.1	0.0	**67.2**
2031	66.2	-0.9	2.3	1.4	-0.1	0.0	**67.5**
2032	66.2	-0.8	2.4	1.6	0.0	0.0	**67.8**
2033	66.6	-0.7	2.6	1.9	0.0	0.0	**68.4**
2034	66.7	-0.7	2.7	2.0	0.1	0.0	**68.7**
2035	66.9	-0.5	2.8	2.3	-0.2	-0.1	**68.9**

[15] In EIA tables, this column is labeled "Consumption."

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U.S. Supply Disposition (Bcfd) – *GHG As-Is, High Export Case*							
Year	Dry Production	NET IMPORTS			Net Storage	Balancing Item	Total Disposition [16]
		Net Pipeline Imports	Net LNG Imports	Total Net Imports			
2010	56.0	5.3	1.5	6.8	0.0	-0.9	**62.0**
2011	55.8	3.5	1.1	4.6	0.3	0.0	**60.6**
2012	56.6	3.0	0.6	3.6	0.1	0.0	**60.2**
2013	56.9	2.2	0.2	2.4	-0.1	0.0	**59.2**
2014	57.8	1.4	0.2	1.6	-0.3	-0.1	**59.1**
2015	59.8	1.4	-1.4	0.0	0.3	0.0	**60.1**
2016	60.5	1.2	-1.3	-0.1	0.0	0.0	**60.4**
2017	61.1	1.1	-1.2	-0.1	0.0	0.0	**61.0**
2018	61.7	1.0	-1.2	-0.1	0.0	0.0	**61.5**
2019	62.1	1.0	-1.1	0.0	-0.1	0.0	**62.0**
2020	62.6	0.6	-0.7	-0.1	0.1	0.0	**62.6**
2021	62.8	0.5	-0.7	-0.2	-0.1	0.0	**62.4**
2022	63.0	0.1	-0.4	-0.3	0.0	0.0	**62.7**
2023	63.3	0.1	0.0	0.0	-0.1	0.0	**63.2**
2024	63.9	-0.1	0.7	0.6	0.1	0.0	**64.6**
2025	64.2	0.0	0.9	0.9	0.0	0.0	**65.0**
2026	64.9	-0.1	1.0	0.9	0.0	0.0	**65.8**
2027	65.6	-0.4	1.1	0.7	0.0	0.0	**66.3**
2028	66.2	-0.6	1.2	0.5	0.0	0.0	**66.8**
2029	66.6	-0.8	1.3	0.5	0.0	0.0	**67.1**
2030	66.7	-0.7	1.4	0.6	-0.1	0.0	**67.2**
2031	66.9	-0.7	1.5	0.7	-0.1	0.0	**67.5**
2032	66.9	-0.6	1.6	1.0	0.0	0.0	**67.8**
2033	67.3	-0.5	1.7	1.2	0.0	0.0	**68.4**
2034	67.4	-0.5	1.8	1.3	0.1	0.0	**68.8**
2035	67.6	-0.3	2.0	1.6	-0.2	-0.1	**69.0**

[16] In EIA tables, this column is labeled "Consumption."

U.S. Supply Disposition (Bcfd) – *GHG Plus Case*							
		NET IMPORTS					
Year	Dry Production	Net Pipeline Imports	Net LNG Imports	Total Net Imports	Net Storage	Balancing Item	Total Disposition [17]
2010	57.9	6.4	1.6	7.9	-0.2	-0.9	**64.8**
2011	58.4	5.0	1.7	6.7	0.4	-0.1	**65.5**
2012	59.4	4.4	2.0	6.4	0.0	0.0	**65.7**
2013	60.1	3.6	2.5	6.2	0.0	-0.1	**66.3**
2014	61.2	2.8	2.8	5.6	0.0	-0.1	**66.7**
2015	62.1	2.5	2.9	5.4	0.0	-0.1	**67.5**
2016	62.9	2.3	3.0	5.3	0.0	0.0	**68.2**
2017	63.5	2.1	3.1	5.2	0.0	0.0	**68.7**
2018	64.2	2.1	3.2	5.3	0.0	0.0	**69.5**
2019	64.9	2.2	3.3	5.5	0.0	0.0	**70.3**
2020	65.5	2.1	3.4	5.5	0.0	0.0	**70.9**
2021	66.3	2.1	3.5	5.6	0.0	0.0	**71.9**
2022	67.1	1.9	3.7	5.6	0.0	0.0	**72.7**
2023	67.9	1.9	3.8	5.7	0.0	0.0	**73.6**
2024	68.7	1.7	4.0	5.8	0.0	0.0	**74.4**
2025	69.5	2.1	4.2	6.3	0.0	-0.1	**75.8**
2026	70.7	2.0	4.3	6.3	0.0	-0.1	**77.0**
2027	71.8	1.7	4.5	6.2	0.0	-0.1	**77.9**
2028	72.7	1.5	4.6	6.1	0.0	-0.1	**78.7**
2029	73.7	1.3	4.8	6.1	0.0	0.0	**79.8**
2030	74.4	1.4	5.0	6.3	-0.1	-0.1	**80.6**
2031	75.0	1.4	5.1	6.5	-0.1	0.1	**81.4**
2032	75.2	1.5	5.2	6.7	0.0	0.0	**81.9**
2033	75.5	1.6	5.5	7.1	0.0	0.0	**82.5**
2034	75.4	1.6	5.7	7.3	0.1	0.0	**82.7**
2035	75.2	2.1	5.9	8.0	-0.1	0.0	**83.1**

[17] In EIA tables, this column is labeled "Consumption."

NAVIGANT CONSULTING

U.S. Supply Disposition (Bcfd) – *GHG Plus, High Export Case*							
Year	Dry Production	NET IMPORTS			Net Storage	Balancing Item	Total Disposition [18]
		Net Pipeline Imports	Net LNG Imports	Total Net Imports			
2010	57.9	6.4	1.6	7.9	-0.2	-0.9	**64.8**
2011	58.4	5.0	1.7	6.7	0.4	-0.1	**65.5**
2012	59.4	4.4	2.0	6.4	0.0	0.0	**65.7**
2013	60.1	3.6	2.5	6.2	0.0	-0.1	**66.3**
2014	61.3	2.9	2.8	5.6	-0.2	-0.1	**66.7**
2015	63.1	2.9	1.2	4.1	0.2	-0.1	**67.3**
2016	63.9	2.7	1.3	4.1	0.0	0.0	**68.0**
2017	64.6	2.7	1.4	4.0	0.0	-0.1	**68.6**
2018	65.3	2.7	1.4	4.1	0.0	0.0	**69.4**
2019	66.0	2.7	1.6	4.3	0.0	0.0	**70.2**
2020	66.6	2.6	1.7	4.3	0.0	0.0	**70.9**
2021	67.4	2.6	1.8	4.4	0.0	0.0	**71.8**
2022	68.3	2.4	2.0	4.4	0.0	0.0	**72.6**
2023	69.1	2.3	2.2	4.5	0.0	0.0	**73.6**
2024	69.9	2.1	2.4	4.5	0.0	0.0	**74.4**
2025	70.8	2.5	2.5	5.0	0.0	-0.1	**75.7**
2026	72.0	2.4	2.6	5.0	0.0	-0.1	**76.9**
2027	73.1	2.0	2.8	4.8	0.0	-0.1	**77.9**
2028	74.0	1.8	2.9	4.7	0.0	-0.1	**78.7**
2029	75.0	1.6	3.1	4.7	0.0	-0.1	**79.6**
2030	75.7	1.7	3.2	4.9	-0.1	-0.1	**80.5**
2031	76.0	1.7	3.5	5.1	-0.1	0.0	**81.0**
2032	76.0	1.8	3.6	5.4	0.0	0.0	**81.4**
2033	75.9	2.0	3.9	5.9	0.0	0.0	**81.8**
2034	75.8	2.3	4.1	6.4	0.1	0.0	**82.2**
2035	75.6	3.0	4.3	7.3	-0.1	0.0	**82.7**

[18] In EIA tables, this column is labeled "Consumption."

Appendix D: Henry Hub Price Forecast Comparison Table

Henry Hub Price Forecast Comparison (2009$/MMBtu)					
Year	**GHG As-Is**	**GHG As-Is, Moderate Export**	**GHG As-Is, High Export**	**GHG Plus**	**GHG Plus, High Export**
2010	$4.68	$4.68	$4.68	$4.68	$4.68
2011	$5.03	$5.03	$5.03	$5.03	$5.03
2012	$5.12	$5.12	$5.12	$5.23	$5.23
2013	$3.50	$3.50	$3.50	$4.62	$4.62
2014	$3.10	$3.12	$3.14	$4.49	$4.55
2015	$3.29	$3.49	$3.64	$4.50	$5.02
2016	$3.33	$3.54	$3.69	$4.51	$5.04
2017	$3.45	$3.65	$3.80	$4.58	$5.10
2018	$3.50	$3.70	$3.85	$4.65	$5.14
2019	$3.62	$3.79	$3.95	$4.79	$5.26
2020	$3.85	$3.98	$4.10	$4.99	$5.44
2021	$3.91	$4.04	$4.17	$5.27	$5.72
2022	$4.05	$4.19	$4.30	$5.58	$6.05
2023	$4.23	$4.35	$4.47	$5.90	$6.39
2024	$4.47	$4.60	$4.72	$6.27	$6.77
2025	$4.60	$4.72	$4.87	$6.59	$7.09
2026	$4.76	$4.89	$5.06	$6.90	$7.42
2027	$4.93	$5.08	$5.28	$7.24	$7.81
2028	$5.09	$5.28	$5.49	$7.56	$8.16
2029	$5.33	$5.52	$5.73	$8.02	$8.69
2030	$5.55	$5.74	$5.94	$8.50	$9.24
2031	$5.81	$5.99	$6.21	$9.02	$9.83
2032	$6.04	$6.26	$6.49	$9.54	$10.39
2033	$6.38	$6.60	$6.83	$10.18	$11.01
2034	$6.65	$6.88	$7.12	$10.86	$11.67
2035	$6.97	$7.20	$7.46	$11.43	$12.33