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UNITED STATES OF AMERICA
BEFORE THE DEPARTMENT OF ENERGY
OFFICE OF FOSSIL ENERGY

In the Matter of	]	
	]	**FE Docket No. 11-128- LNG**
DOMINION COVE POINT LNG, LP	]	

RESPONSE OF DOMINION COVE POINT LNG, LP TO MOTIONS TO INTERVENE, COMMENTS, AND PROTESTS

Pursuant to Section 590.303(e) of the Department of Energy's ("DOE") regulations, 1/ and the Notice of Application published in the Federal Register on December 8, 2011, 2/ Dominion Cove Point LNG, LP ("DCP") hereby submits this answer ("Answer") to comments and protests submitted in this proceeding on February 6, 2012 by: (1) the Sierra Club, (2) certain individuals affiliated with various "Riverkeeper" organizations, (3) the American Public Gas Association ("APGA"), and (4) the West Virginia State Building and Construction Trades Council, AFL-CIO and its division the Affiliated Construction Trades Foundation (the "Trades Council"). The protests concern DCP's proposal to export domestically produced natural gas as liquefied natural gas ("LNG") from the existing LNG terminal (the "Cove Point LNG Terminal" or "Terminal") located in Calvert County, Maryland.

The protests focus largely on matters that are well beyond the scope of the issues to be resolved by the Office of Fossil Energy of the Department of Energy ("DOE/FE") in this proceeding. In particular, the Sierra Club and the Riverkeepers devote much of their lengthy protests to a detailed attack on the development of shale gas, particularly in the Marcellus Shale region. With respect to issues that are relevant here, the protesting parties (1) challenge DCP's showing that its proposed project will create significant new jobs and other

1/ 10 C.F.R. § 590.303(e) (2010).
2/ 76 Fed. Reg. 76698 (2011).

economic benefits and (2) claim that exports of LNG will increase domestic natural gas prices significantly. As detailed below, the protests fall far short of overcoming the presumption that exports of LNG like those proposed by DCP are in the public interest.

I. Legal Background

Section 3(a) of the Natural Gas Act ("NGA") establishes a rebuttal presumption that a proposed export of natural gas is in the public interest. 3/ Moreover, the DOE/FE has explained that opponents of an export application must make an affirmative showing of inconsistency with the public interest in order to overcome the rebuttable presumption favoring export applications. 4/ In implementing NGA Section 3, the DOE issued policy guidelines explaining the approach that it will employ in evaluating applications for natural gas imports. 5/ The Policy Guidelines were "designed to establish natural gas trade on a market-competitive basis and to provide immediate as well as long-term benefits to the American economy from this trade." 6/

The Policy Guidelines

> establish a regulatory framework for buyers and sellers to negotiate contracts based on traditional competitive and market considerations, with minimal regulatory constraints and conditions. The government, while ensuring that the public interest is adequately protected, should not interfere with buyers' and sellers' negotiation of the commercial aspects of import [export]

3/ *E.g.*, *Sabine Pass Liquefaction, LLC*, DOE/FE Order No. 2961 at 28, FE10-111-LNG, (May 20, 2011; *Conoco Phillips Alaska Natural Gas Corp. and Marathon Oil Co.*, FE07-02-LNG, Order No. 2500 at 43 (June 3, 2008); *Phillips Alaska*, FE96-99-LNG, Order No. 1473 at 13 (April 2, 1999).

4/ *Sabine Pass*, Order No. 2961, at 28 & note 38; *ConocoPhillips*, Order No. 2500; *Phillips Alaska Natural Gas Corp. and Marathon Oil Co.*, FE96-99-LNG DOE/FE Opinion and Order No. 1473, 2 FE ¶ 70,317 (April 2, 1999); *Panhandle Producers and Royalty Owners Assoc. v. ERA*, 822 F.2d 1105, 1111 (D.C. Cir. 1987).

5/ "New Policy Guidelines and Delegation Orders Relating to the Regulation of Natural Gas," 49 Fed. Reg. 6684-01 (Feb. 22, 1984)(hereinafter the "Policy Guidelines"). DOE/FE has repeatedly reaffirmed the continued applicability of the guidelines and has consistently held that they apply equally to export applications (though written to apply to imports). *Yukon Pacific*, Order No. 350; *Phillips Alaska*, Order No. 1479; *ConocoPhillips Alaska*, Order No. 2500, *Sabine Pass*, Order No. 2961.

6/ Policy Guidelines at 6684.

> arrangements. The thrust of this policy is to allow the commercial parties to structure more freely their trade arrangements, tailoring them to the markets served. Thus, with the presumption that commercial parties will develop competitive arrangements, parties opposing an import [export] will bear the burden of demonstrating that the import [export] arrangement is not consistent with the public interest. 7/

Section 3(c) of the NGA requires that applications for export of natural gas, including LNG, to countries with which the United States has a free trade agreement ("FTA") requiring the national treatment for trade in natural gas are deemed to be in the public interest and must be granted without modification or delay.

For applications for authority to export LNG to countries that do not have a FTA requiring national treatment for trade in natural gas, DOE conducts a full public interest review. DOE/FE has explained that its public interest review focuses on "the domestic need for the gas; whether the proposed exports pose a threat to the security of domestic natural gas supplies; and any other issue determined to be appropriate, including whether the arrangement is consistent with DOE's policy of promoting competition in the marketplace by allowing commercial parties to freely negotiate their own trade arrangements." 8/

The DOE/FE has granted authorization for one applicant for the export of domestic gas to non-FTA countries. *Sabine Pass Liquefaction, LLC*, DOE/FE Order No. 2961 (FE Docket No. 10-111-LNG)(May 20, 2011). It has also granted a series of applications to export LNG to FTA countries.

7/ *Id.* at 6685. The parenthetical references to exports are added to reflect the applicability of the Policy Guidelines to exports.

8/ *Sabine Pass*, Order No. 2961 at 29. This approach is consistent with DOE Delegation Order No. 0204-111, which previously guided DOE/FE decisions on export applications but is no longer in effect. *Id. See also, e.g., ConocoPhillips Alaska*, Decision No. 2500 at 44-45; *Phillips Alaska*, Order No. 1473 at 13-14.

II. **Procedural Background and DCP's Application**

On October 3, 2011, DCP filed with DOE/FE its application ("Application") for the export from the Cove Point LNG Terminal of up to 7.82 million metric tons per annum or 365 billion cubic feet ("BCF") per year of domestically produced gas as LNG to any country with which the United States does not prohibit trade but also does not have a FTA requiring the national treatment for trade in natural gas. In the Application, DCP requested multi-contract authorization to export LNG over a twenty-five year term commencing on the date of the first export or six years from the date that the authorization is issued, whichever is sooner. DOE/FE has already granted the similar authority for DCP to export those identical volumes of LNG to countries with which the U.S. has entered into (or in the future will enter into) a FTA providing for national treatment of natural gas. 9/

In each case, DCP requested authorization to act as agent on behalf of other entities that will hold title to natural gas liquefied and exported as LNG from the Cove Point LNG Terminal. As explained in the Application, DCP's customers will be responsible for procuring their own gas supplies and delivering it to the Cove Point LNG Terminal for liquefaction and export as LNG. For this purpose, the customers may enter into long-term gas supply contracts or procure spot supplies in the very large and liquid U.S. gas market. As DCP explained, its Terminal is ideally located to provide access to a wide range of domestic supply sources through the connected interstate pipeline grid, allowing gas to be sourced from a variety of geographic regions and both conventional and non-conventional production. DCP added that its project is especially well positioned to export gas production from the nearby Marcellus Shale, one of the

9/ *Dominion Cove Point LNG, LP*, DOE/FE Order No. 3019 (FE Docket No. 11-115-LNG)(Oct. 7, 2011).

largest shale plays with among the lowest development costs, and the very promising Utica Shale.

In its Application, DCP explained that granting the requested authorization will be consistent with, and indeed advance, the public interest. Allowing DCP and its customers to freely negotiate contracts to respond to market conditions and utilize the Cove Point LNG Terminal for exports when warranted by prices will be consistent with the pro-competition focus of the Policy Guidelines. And North American gas reserves are more than adequate to satisfy U.S. demand, even under the most aggressive demand scenarios, including a domestic LNG export industry. The exports proposed by DCP, of only up to 1 Bcf-equivalent per day, could not possibly pose a threat to domestic gas supply security. Indeed, by providing a steady, incremental demand for gas, LNG exports from the Cove Point LNG Terminal will help support ongoing supply development and, thereby, help keep U.S. gas prices stable. DCP also explained numerous other ways that approval of the requested authorization will promote the public interest, which were detailed in the "Economic Benefits Study" prepared by ICF International ("ICF") that was included as Appendix C of the Application.

DCP also included with its Application two studies prepared by Navigant Consulting, Inc. ("Navigant") to address the issues of adequacy of supply for LNG exports, and possible price effects. The "Navigant Supply Report" included as Appendix A of the Application demonstrated that domestic gas resources are more than adequate to satisfy domestic demand, including the incremental demand associated with DCP's export project. The "Navigant Pricing Report," included as Appendix B of the Application, conservatively projected the possible price effects of DCP's proposed LNG exports under a variety of scenarios and demonstrated that any possible price increases would be modest.

DCP also explained in its Application that it was engaged in Preliminary Front End Engineering Design studies for its liquefaction project, as well as in commercial negotiations with potential customers. DCP stated that, accordingly, it has not yet determined the particular facilities to be constructed. DCP explained that, as its project further develops, it will commence the mandatory pre-filing process under the National Environmental Policy Act ("NEPA") with the Federal Energy Regulatory Commission ("FERC") and subsequently file an application for the necessary FERC authorization for the construction and operation of the needed facilities. 10/ DCP requested, consistent with prior orders by DOE/FE, that the authorization requested here be conditioned on DCP's receipt of all necessary FERC authorizations, including the related NEPA review, for the facilities needed for the export of LNG.

Following the approval and construction of the liquefaction and export facilities, the Cove Point LNG Terminal will be operated as a bi-directional facility. The Terminal will retain the capability to import LNG and vaporize it into natural gas for delivery into the U.S. interstate pipeline network, and add the capability of liquefying domestic natural gas to export as LNG to foreign markets. Following completion of its project, the Cove Point LNG Terminal can be responsive to competitive market forces. Domestic gas can be liquefied and exported from the Terminal when U.S. gas prices are low compared to prices in other countries, as they are now. In contrast, if prices of LNG in other parts of the world fall below the U.S. prices, DCP's customers may utilize the Terminal to import LNG and supply the regasified natural gas to the domestic market.

10/ Although DOE/FE has authority to regulate the export (and import) of natural gas including LNG, Section 3(e) of the NGA provides that the FERC has the exclusive authority to approve or deny an application for the siting, construction, expansion or operation of an LNG terminal.

DOE/FE published its notice of DCP's application in the Federal Register on December 8, 2011. 76 Fed. Reg. 76698. The notice established that interventions and written comments concerning the Application were to be filed by no later than February 6, 2012.

III. The Protestors Have Not Demonstrated Particular Interests Here

DOE regulations require any person who seeks to become a party to a proceeding to file a motion to intervene "which sets out clearly and concisely the facts upon which the petitioner's claim of interest is based." 11/ Only two of the protesting parties – APGA and the Sierra Club – made any effort to comply with this procedural requirement. APGA explained that its members, publicly-owned natural gas distribution systems, have an interest in securing natural gas 12/ and in its protests expresses concern that the DCP project will increase natural gas prices. The Sierra Club maintains that its members have interests in the economic and environmental consequences of LNG exports. Riverkeepers did not include any explanation of its interests here; but, based on its comments, likely would echo the Sierra Club claims. The Trades Council also did not explain its interest here, but it represents construction workers in West Virginia and expresses interest in the increased use of natural gas and, in particular, the harnessing of natural gas from the Marcellus and Utica Shale plays.

Nothing in any of the interests expressed in the protests specifically relates to the DCP project, other than the Sierra Club's statement that its "Maryland Chapter has a long history of engagement with the Cove Point facility in particular." 13/ DCP indeed has a long history with the Maryland Chapter of the Sierra Club, and it has been a cooperative and constructive one. DCP hopes and expects that this relationship will continue with its LNG export project. The

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11/ 10 C.F.R. § 590.303(e) (2011).

12/ APGA Protest at 2.

13/ Sierra Club Protest at 3.

issues raised in the Sierra Club's protest, however, are not specific to DCP's particular project, but rather focus on generic policy issues associated with the export of LNG, as well as shale gas development.

DCP does not know if the interests (expressed or inferred) of the protestors here satisfy the DOE requirements for a cognizable interest. It would appear that any interest group, or gas consumer, could intervene and express comments if these protestors may legitimately do so. Nevertheless, DCP will respond to the protests in case the DOE/FE decides to consider them in the interest of facilitating a complete record for its decision-making.

IV. The Protests Do Not Undermine DCP's Showing of Economic Benefits

Three of the protesting parties – Sierra Club, Riverkeepers, and the Trades Council – challenge DCP's showing that its proposed liquefaction project will convey large economic benefits. Before responding to those challenges, DCP will summarize again the benefits of its project as detailed in its Application and the Economic Benefits Study analysis prepared by the independent consultant, ICF International, filed with the Application.

As further detailed there, the economic benefits of the DCP liquefaction project include the following:

- Job Creation: At its peak of construction activity, the short-term economic impacts from the DCP liquefaction project would support between 3,700 and 4,400 "job years" in the State of Maryland, and an additional 3,850 to 4,820 jobs in the rest of the Nation. During operations from 2018 through 2040, the economic activity at the Cove Point LNG Terminal and (much more significantly) economic activity associated with the long-term upstream supply of natural gas for the LNG exports would result in an average of over 18,000 new jobs annually. 14/
- Direct Economic Stimulus: The DCP liquefaction project is estimated to create at its peak in 2015, between $183 and $230 million in "value added" (meaning the contribution to Gross Domestic Product, calculated as the difference between the

14/ *See* Economic Benefits Study at 24, Table 7 "U.S. Upstream Natural Gas Sector Annual Job-years Resulting from LNG Exports from Cove Point (Job-years)."

output generated from expenditures and the expenditures for intermediate goods and services) within Calvert County and an additional $80 to $100 million in the rest of Maryland. Annual activities during operations from 2018 through 2040 are expected to generate an additional $22 million in value added annually for Calvert County, Maryland, and over $47 million for the U.S. in total. 15/

- Indirect Economic Stimulus: In aggregate, $44 billion in total value added is projected to result from upstream expenditures of $32 billion needed to supply the LNG exports over the 25-year period. 16/
- Promote domestic production of petroleum and liquid hydrocarbons: Incremental production of natural gas liquids ("NGLs") from 2016 through 2040 associated with LNG exports by DCP is estimated at 8.5 million barrels per year, with an average projected market value of $1.2 billion per year. 17/
- Improvement in the U.S. Balance of Trade: LNG exports, along with associated NGL production, will help realign the U.S. balance of trade by a range of $2.8 billion to nearly $7.1 billion per year, 18/ reducing the total U.S. trade deficit (compared to the 2010 deficit) by an estimated 0.6 and 1.4 percent. 19/
- Increased Tax and Royalty Revenues: Estimated tax revenues generated as a result of the construction phase of the DCP liquefaction project peak in 2014 with a total of $130-$163 million nationally. 20/ Total U.S. taxes are estimated to increase by nearly $11 million per year from 2018 through 2040, not including income taxes, property taxes, or gross receipt taxes. 21/ The long-term operation of the Terminal is expected to produce up to $40 million per year of property tax revenues. 22/ In addition, upstream economic activity associated with gas production to support the incremental LNG exports is associated with $25 billion in government royalty and tax revenues to federal, state, and local governments over the 25-year period, with an average of approximately $1 billion in annual

15/ *See id.* at 16, Table 3 "Annual Value Added Impacts, Facility Construction/Operation (2011$)."

16/ *Id.* at 20. *See also id.* at 26, Table 8 "U.S. Output from Upstream O&G Expenditures Associated with LNG Exports from Cove Point (2011$)" and 28, Table 9 "U.S. Value Added from Upstream O&G Expenditures Associated with LNG Exports from Cove Point (2011$)."

17/ *See id.* at 38, Table 16 "U.S. Volume, Value, and Economic Impact of Incremental Hydrocarbon Liquids Associated with LNG Export from Cove Point."

18/ *See id.* at 41-42 and Table 19 "Range of Annual Positive Effect of LNG Export from Cove Point on U.S. Balance of Trade."

19/ *Id.* at 2.

20/ *Id.* at 17, Figure 9 "Total Tax Revenue Trends, 2011-2018, Facility Construction/Operation (2011$)."

21/ *Id.* at 19, Table 5 "Tax Impacts, 2011-2018, Facility Construction/Operations (2011$)."

22/ This property tax estimate was internally generated by DCP, and is not based on the Economic Benefits Study.

revenues. 23/ Another $9.8 billion in royalty income over the 25 years will be provided to landowners in the form of mineral leases. 24/

- Environmental Benefits: To the extent that LNG exported from the Cove Point LNG Terminal is used as substitute for coal and fuel oil in other countries (which seems likely), it will reduce global greenhouse gas emissions significantly over the requested 25-year export term.

Speaking much more generally, Secretary of Energy Steven Chu recently recognized the benefits of LNG exports. Speaking at Houston Community College, the Secretary reportedly stated that "Exporting natural gas means wealth comes into the country." He explained further: "We have a choice. When all these things become cost-competitive, do you want to buy or do you want to sell? If we are buying, that is wealth out of the country. If we are selling, that's wealth into the country." 25/

None of the protesting parties presented any alternative analysis of the benefits of the DCP export project. The Sierra Club does criticize DCP's quantification of the projected benefits. The Sierra Club charges that the "IMPLAN" model used by ICF is a "fairly mechanical system" that "does not consider counter-factuals and foregone opportunities" or "chart what the future would have looked like under different conditions." 26/ This criticism cannot be regarded as a serious challenge to the findings of the ICF Economic Benefits Study. The fact that the ICF study did not, somehow, envision and model all hypothetical "counter-factual" alternative scenarios, does not undermine its conclusions about the benefits of DCP's project.

The IMPLAN methodology used by ICF is explained in detail in Section 6 of the Economic Benefits Study. IMPLAN is a well-established input-output model. Input-output

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23/ Economic Benefits Study at 32, Table 11 "U.S. Taxes and Royalties from Upstream Oil and Gas Expenditures and Production Associated with LNG Exports from Cove Point (2011$)."

24/ Economic Benefits Study at 21.

25/ "Energy Secretary backs natural gas exports," by Simone Sebastian, *Houston Chronicle*, Feb. 2, 2012, available at: http://www.chron.com/business/article/Energy-secretary-backs-natural-gas-exports-2973215.php

26/ Sierra Club Protest at 10 and 11.

analysis is a basic and widely-used method of quantitative economics that portrays macroeconomic activity as a system of interrelated goods and services. In particular, the technique observes various economic sectors as a series of inputs of source materials (or services) and outputs of finished or semi-finished goods (or services). The IMPLAN model is based on a matrix that incorporates economic flows for hundreds of industries. By tracing purchases between sectors, the model provides an estimate of the impact of an industry's output (*e.g.*, the goods and services purchased by the oil and gas upstream sector) to impacts on related industries. From the changes in industry spending, the IMPLAN model generates estimates of direct, indirect, and induced economic impacts.

The Sierra Club argues that DOE/FE must "undertake its own independent analysis of the costs and benefits" of DCP's proposed exports. 27/ The office has publicly announced that it has commissioned a study by a private contractor to address the impact of LNG exports on the U.S. economy, including the effect on gross domestic product, jobs creating, the balance of trade, and other factors. DCP is confident that this study (which is expected to be completed in the first quarter of this year) will corroborate DCP's views of the economic benefits of LNG exports.

The bulk of the argument by the Sierra Club and the Riverkeepers against DCP's showing of the benefits of its export project are based on their belief that – in a phrase used by both protestors – "booms in resource extraction industry are far more of a mixed bag than DCP acknowledges." 28/ Both the environmental groups apparently are discontent with the recent phenomena of shale gas development and seem generally opposed to increased natural gas production. They not only raise a series of environmental concerns opposing increased gas

27/ Sierra Club Protest at 16-17.

28/ Sierra Club Protest at 10; Riverkeepers Protest at 16.

production (as discussed further below), but even question whether the increased production of natural gas and NGLs is an economic benefit.

Thus, Sierra Club questions whether increased gas production actually creates many jobs, argues that the "boom-bust cycle inherent in gas extraction makes employment benefits tenuous," complains that "[s]ome people will prosper and some will not during the resultant disruption," worries that communities must "confront a panoply of development issues," as well as about the "consequences of transforming an entire region of the country, converting it from a largely rural swath of small towns, farms and forests into an industrial gas extraction zone." 29/ Similarly, Riverkeepers tout the "resource curse phenomena" and the "Boom and Bust cycle," claim that increased gas production may negatively impact the communities where it occurs, and emphasize the "short-term" nature of some jobs related to gas extraction. 30/

Of course, DOE/FE need not establish in this case definite views of the pros and cons of the development of shale gas. The economic stimulus, job creation, tax benefits, balance of trade improvements, and other benefits of the DCP project help demonstrate that granting the requested export authorization is consistent with the public interest. The protestors' suggestions that the development of shale gas is actually a bad thing surely do not satisfy their burden of making an affirmative showing that exports would be inconsistent with the public interest.

In any event, the environmentalist groups' disparaging of the benefits of increased gas production are well outside the mainstream, and contrary to established governmental policies. In this year's State of the Union Address, President Obama stated: "We have a supply of natural gas that can last America nearly 100 years. And my administration will take every possible action to safely develop this energy. Experts believe this will support more than 600,000 jobs by

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29/ Sierra Club Protest at 12-15.

30/ Riverkeepers Protest at 14-18.

the end of the decade…. The development of natural gas will create jobs and power trucks and factories that are cleaner and cheaper, proving that we don't have to choose between our environment and our economy." 31/ Secretary of Energy Chu, in a recent speech in Pittsburgh, highlighted the President's remarks and echoed the call for the development of the Nation's abundant natural gas resource so as to create new jobs for American workers. 32/ While the particular "experts" relied upon by President Obama and Secretary Chu for their job creation estimates were not identified, a recent study by IHS Global found that just shale gas production supported more than 650,000 jobs in 2010 and projected that number to grow to nearly 870,000 by 2015. 33/

The greatest benefit of the shale gas bonanza, of course, has been decreased natural gas prices, with the resulting tremendous savings for American consumers. The dramatic decrease in gas prices since around mid-2008 has been remarkable. 34/ Prices in 2010 averaged $4.52 per Mcf, about 38 percent lower than the 5-year average from 2005 through 2010 of $7.77 per MMBtu, and just over half the average price for 2008 of $8.86 per MMBtu. 35/ And gas prices have continued to drop even more since 2010: a recent press release by the Energy Information Administration ("EIA") noted that natural gas prices are now near 10-year lows, with average

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31/ Jan. 24, 2012 State of the Union by President Obama, available at: http://www.whitehouse.gov/the-press-office/2011/01/25/remarks-president-state-union-address

32/ DOE news release, "Chu in Pittsburgh: 'We Need an All-Out, All-of-the-Above Strategy that Develops Every Available Source of American Energy," available at: http://www.fossil.energy.gov/news/techlines/2012/12005-Secretary_Chu_Visits_NETL.html. Just like the President's remarks, the DOE release states that "the safe development of America's nearly 100-year supply of natural gas will support more than 600,000 jobs by the end of the decade."

33/ IHS Global Insight, "The Economic and Employment Contributions of Shale Gas in the United States," issued Dec. 6, 2011, available at: http://www.ihs.com/info/ecc/a/shale-gas-jobs-report.aspx

34/ *See, e.g.*, Application Appendix A, Navigant Supply Report at 7 & Figure 7 (graphing Henry Hub monthly settlement prices from Jan. 2002 through Jan. 2011).

35/ EIA, Natural Gas Year-in-Review with Data for 2010, released Dec. 9, 2011, at pp. 1 & 2, available at: www.eia.gov/naturalgas/review/print_version.cfm spot prices in January 2012 of just $2.68 per MMBtu. 36/ The suggestion that facilitating further gas production to continue this trend is not in the public interest strains credulity.

As DCP explained in its Application, LNG exports will encourage and support increased domestic production of natural gas, and associated NGLs, by providing a new, steady, market demand that will underpin future supply development, and help keep domestic gas prices stable. 37/ The steady demand for natural gas to export will allow domestic gas that might otherwise not be produced as a result of supply in excess market demand to be available for sale into the global LNG market, and will spur the development of new natural gas resources that might not otherwise be developed. This conclusion has been strengthened by events occurring since DCP filed its Application, as the very low current prices have led major producers to announce cut-backs in their drilling plans. 38/ A study released by Wood Mackenzie just this month explained that the combination of reduced drilling and delaying completion in response to low gas prices during the first half of 2012 will stem the rising tide of U.S. production growth. 39/ Incremental demand like that associated with LNG exports is sorely needed in the currently over-supplied gas market.

36/ EIA, "Today in Energy" dated Feb. 1, 2012, "Natural gas spot prices near 10-year lows amid warm weather and robust supplies," available at: www.eia.gov/todayinenergy/detail.cfm?id=4810

37/ Application at 3 & 17; Navigant Pricing Report at 9.

38/ *See, e.g.*, Sharon Epperson, *Production Shut-Ins Fuel Nat Gas Spike*, CNBC.com, Jan. 25 2012, http://www.cnbc.com/id/46133729/Production_Shut_Ins_Fuel_Nat_Gas_Spike (citing recent natural gas well shut-in announcements by Chesapeake Energy, Occidental Petroleum, and Conoco Phillips); *Progress Energy to shut in natural gas production*, Rueters.com, Feb. 8, 2012, http://www.reuters.com/article/2012/02/08/progressenergy-idUSL2E8D86SS20120208 ("Progress Energy Resources Corp . . . will cut spending on developing its natural gas reserves and shut in 10 percent of its gas production until prices recover.").

39/ "Short-term drilling and production: how much response to low gas prices?" issued to its clients by Wood Mackenzie North American Gas Service, dated Feb. 2012.

The Trades Council approaches these issues from a very different perspective from the environmental groups. It questions DCP's plan to "take a portion of a key natural resource from the State of West Virginia and surrounding states and export that resource" and questions the benefits of export "particularly when compared to potential domestic processing and use." 40/ Dominion Resources, Inc., DCP's parent company, is a strong supporter of developing the gas resources of West Virginia and the surrounding states. It is making large investments in infrastructure projects in West Virginia, including gas gathering lines, a new processing and fractionation plant, and interstate transportation pipelines to move new supplies to market. Those investments, and the resulting jobs, are created by increased production, regardless of whether the gas heads out of the country or just out of state. By creating an incremental market for those supplies, the DCP liquefaction project will support increased production and associated jobs, consistent with the claimed goals of the Trades Council.

V. LNG Exports Will Have Only A Modest Impact On Gas Prices

The Nation's policy, as reflected in the Policy Guidelines, is that markets, and not the government, should allocate resources and set prices, and that free trade in natural gas on a market-competitive basis benefits consumers and promotes the public interest. 41/ Nevertheless, as part of its public interest analysis of LNG export proposals, DOE/FE is evaluating the potential impact of LNG exports on domestic gas prices. In the *Sabine Pass* non-FTA order,

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40/ Trades Council Protest at 1.

41/ The general benefits of free trade are well-established and need not be detailed here. In addition to providing direct benefits, exports will provide other countries with cheaper energy , which will not only lower the prices of products we import but also promote economic development in other countries that, in turn, can import more American-made goods.

DOE/FE concluded that the export authorization would result in "a modest increase" in domestic gas prices that would not be inconsistent with the public interest. 42/

As Appendix B of its Application, DCP filed the Navigant Pricing Report to provide a detailed analysis of the possible effect under a variety of scenarios on gas prices of LNG exports in general, and from the Cove Point LNG Terminal in particular. As DCP explained in the Application, the Navigant projections likely overstate the price effect of LNG exports. To begin with, the modeling included very conservative assumptions about the supply response to incremental demand: assuming the addition of no new gas supply basins beyond those already identified, estimating the production capacity for each shale play based only on then publicly available empirical production data (and, therefore, not including any U.S. Utica Shale volumes), and strictly limiting the additions of new infrastructure. Furthermore, the model features a constant balance between supply and demand and then adds the LNG demand in a block, resulting in seemingly large price jumps. Yet, in reality unlike this economic modeling, given the long lead time associated with an LNG liquefaction project, as well as the current ability of shale production to increase if demand is added, producers may plan in advance and add incremental supply to coincide with onset of LNG export operations – minimizing the initial price increase associated with new LNG exports.

Notwithstanding this conservative approach, the price effects projected by Navigant are properly viewed as "modest" and certainly insufficient to overcome the presumption that LNG exports are in the public interest. DCP will not repeat the detailed results here, but will summarize a few highlights for context. In the basic scenario of adding DCP's proposed exports to its Reference Case, Navigant calculated that DCP exports would increase Henry Hub prices by 5.7 percent in 2020, 4.1 percent in 2030, and 6.0 percent in 2040, and Dominion South Point

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42/ *Sabine Pass*, Order No. 2961 at 29 & Appendix A.

prices by 6.2 percent in 2020, 3.6 percent in 2030, and 2.7 percent in 2040. Put another way, while Navigant's Reference Case projects that Henry Hub prices will again exceed $6.00 per MMBtu only in 2029, that price level would instead be reached in 2027 if DCP exports are added. In contrast, the average price over the five years 2005 through 2009 was $7.07 per MMBtu. 43/ Thus, prices need to increase much more significantly than is projected to result from LNG exports before they would return to levels that were normal a few years ago (much less approach the much higher levels that were then predicted for the future).

Navigant showed the greatest conceivable price effects with its "Extreme Demand" scenario, which assumed a total of 7.1 Bcf per day of LNG exports as well as significant new demand for natural gas vehicle use. In this scenario, U.S. gas demand increases from the 2011 level of 65.6 Bcf/d to 74.5 Bcf/d in 2020, 83.4 Bcf/d in 2030, and 90.1 Bcf/d in 2040. With this demand, the model projects Henry Hub price increases of 5.4 percent in 2020, 17.4 percent in 2030, and 16.2 percent in 2040. The price increases at Dominion South Point (near the prolific Marcellus supplies) are much less pronounced in the later years: increasing by the same 5.4 percent in 2020, but 11.9 percent in 2030, and just 4.8 percent in 2040. Again, all these price effects are likely significantly overstated as a result of Navigant's intentionally conservative assumptions about the available supply. Moreover, little of the price increases in this high demand scenario would be caused by the relatively small incremental demand from the DCP export volumes: the elimination of Cove Point exports from this scenario would decrease the Henry Hub prices by 5.2 percent in 2020 but by only 1.7 percent in 2040.

The protesting parties attempt to portray the price effects of LNG exports as much more significant, and rely for support on: (1) the "Effect of Increased Natural Gas Exports on

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43/ EIA, Natural Gas Year-in-Review with Data for 2010, released Dec. 9, 2011, at p. 2, available at: www.eia.gov/naturalgas/review/print_version.cfm

Domestic Energy Markets" issued in January 2012 by EIA at the request of DOE/FE (the "Jan. 2012 EIA Study") and (2) EIA's Early Release Overview of its Annual Energy Outlook 2012 (the "AEO2012 Overview" or "AEO2012"). Properly understood, both these EIA releases are fully consistent with DCP's conclusion that the effect of LNG exports on gas prices are expected to be modest.

A. EIA Modeling of The Price Impact of Exports

The Jan. 2012 EIA Study provided four scenarios of LNG-export increases in gas demand: 6 Bcf per day phased in over 6 or 2 years and 12 Bcf per day phased in over 12 or 4 years. To put these export levels into perspective, the world's largest LNG exporting country, Qatar, exported about 7.33 Bcf per day in 2010 while the second largest exporting country, Indonesia, exported just over 3 Bcf per day. 44/ Moreover, Qatar began exporting LNG in 1997, and its growth to the current levels is considered very rapid. 45/ Thus, under *all* the scenarios modeled by EIA, the U.S. is assumed to become either the largest or second largest LNG exporting country in the world in an astonishing short period of time.

APGA claims that the scenario of adding 12 Bcf per day of exports over just 4 years is the "most realistic scenario" modeled by EIA, given the number of export applications filed with DOE/FE. 46/ Other protestors similarly note the large number of recent applications. In reality, EIA's "high/rapid" scenario is the stuff of fantasy. Just because a project has filed an application

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44/ BP Statistical Review 2011, Natural Gas Section at p. 28, "Natural Gas Trade Movements 2010, available at: http://www.bp.com/liveassets/bp_internet/globalbp/globalbp_uk_english/reports_and_publications/statistical_energy_review_2011/STAGING/local_assets/pdf/natural_gas_section_2011.pdf
The data in billion cubic meters per year has been converted to Bcf per day by multiplying by 35.3145 (to convert from cubic meters to cubic feet) and dividing by 365 to calculate a daily amount.

45/ *See* EIA, Today in Energy, dated Feb. 25, 2011, "Qatar accounts for a growing share of LNG exports," available at: www.eia.gov/todayinenergy/detail.cfm?id=50

46/ APGA Protest at 11.

with DOE/FE does not mean that it will find customers, obtain financing, and be constructed. DCP believes that EIA's "low/slow" scenario of adding 6 Bcf per day over 6 years is actually quite bullish on the near-term prospects of U.S. LNG exports.

Even with all its very aggressive scenarios for LNG exports, EIA still found fairly modest price impacts when applied to its Reference case. The calculated average increase in gas expenditures by residential consumers over the years 2015-2035 ranged from 3.2 percent in the scenario of adding 6 Bcf per day of demand in 6 years (the *relatively* "low/slow" scenario) to 7.0 percent in the astonishing "high/rapid" scenario of adding 12 Bcf per day over just 4 years. 47/ Price impacts on commercial customers are very similar, while the effect on industrial customers are slightly higher. 48/ These projected price impacts are properly characterized as modest, especially because they focus on increases from the *very low* present prices.

The protesting parties highlight much larger projected increases taken from the Jan. 2012 EIA Study, particularly the attention-grabbing figure of a 54 percent increase in *wellhead prices* in 2018 projected for the "high/rapid" LNG export scenario coupled with "Low Shale EUR" conditions. 49/ Yet, the study itself alludes to the presumably obvious fact that higher LNG exports would not actually occur in a low shale environment, explaining that "for purposes of this study, the scenarios of additional exports posited by DOE/FE in their request do not vary across the different baseline cases that are considered. In reality, given available prices in export markets, lower or higher U.S. natural gas prices would tend to make any given volume of additional exports more or less likely." 50/ Moreover, the referenced 2018 price increase reflects

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47/ Jan. 2012 EIA Study at 15 & Table 1.

48/ *Id.*

49/ This extreme scenario is referenced in the Jan. 2012 EIA Study at 9, and is cited in the Sierra Club Protest at 20, Riverkeepers Protest at 6, and the APGA Protest at 11.

50/ Jan. 2012 EIA Study at 4.

the greatest snap-shot impact in a single year: the average wellhead price change from 2015 through 2035 for this extreme and counter-intuitive combination of low shale and high/rapid exports is 20 percent. Somewhat more realistically, if 6 Bcf per day were added over 6 years in the low shale conditions, the report reflects an average wellhead price increase from 2015 through 2035 of 9 percent. The price impact on end-use consumers is considerably less than these wellhead price effects.

Importantly, the Jan. 2012 EIA Study is (like Navigant's report) a static model that essentially assumes a fixed supply at any given time and, thereby, tends to overestimate the price impact of demand change. In the model, increases in demand (whether for LNG exports, increased gas-fired generation, or anything else) cannot be anticipated and, thus, result in an overstated increase in prices. In reality, producers anticipate future demand (like that associated with LNG exports) and incorporate it in their production decisions, adding supply and reducing the price effect.

A recent report prepared by the Deloitte Center for Energy Solutions and Deloitte MarketPoint ("Deloitte") entitled "Made in America: The Economic Impact of LNG Exports from the United States" uses a more dynamic model under which producer decisions regarding when and how much reserves to add reflect knowledge of anticipated forward prices. Unlike EIA's model (and Navigant's), Deloitte's "World Gas Model" also reflects developments outside the U.S., which obviously can influence U.S. prices. 51/ DCP has included a copy of this publicly available report with this Answer, for ease of reference.

Consistent with a point made by DCP in its Application, Deloitte explains at page 2 of its report:

51/ The failure of its model to reflect world markets was one of four important "caveats" noted in the Jan. 2012 EIA report, at page 4.

> If exports can be anticipated, and clearly they can with the public application process and long lead time required to construct a LNG liquefaction plant, then producers, midstream players, and consumers can act to mitigate the price impact. Producers will bring more supplies online, flows will be adjusted, and consumers will react to price changes from LNG exports.

Deloitte used its dynamic World Gas Model to estimate the expected price impact of LNG exports of 6 Bcf per day (assumed all to come from the Gulf Coast). It concluded that those exports would increase average city-gate prices by $0.12 per MMBtu from 2016 to 2035, an increase of just 1.7 percent. The projected price impact is slightly higher at the Henry Hub (near the point of all the assumed exports) and less farther away from the Gulf Coast. The Deloitte study also responds to some possible concerns about LNG exports and strongly supports the public interest benefits of exports. This independent study provides additional support for DCP's Application and DCP hereby incorporates it in the record for that purpose.

B. The AEO2012 Early Release Overview

The AEO2012 Overview is very supportive of the case for LNG exports. The protesting parties ignore this fundamental fact and focus on one point in the release: EIA's significant decrease in its estimate of the technically recoverable resource for the Marcellus Shale.

The most important conclusions of the AEO2012 Overview are the continued recognition of increasing production, driven by shale development, and falling prices, along with recognition of the coming exports of LNG. Cumulative gas production from 2010 through 2035 in the AEO2012 reference case is 7 percent higher than estimated in the AEO2011, primarily as a result of increased shale gas production. 52/ The share of total production related to shale plays is projected in the AEO2012 to increase from 23 percent in 2010 to 49 percent in 2035. 53/ Projected gas prices are significantly lower in the near term compared to projections in

52/ AEO2012 Overview at 9.

53/ *Id.* at 1 & Figure 2.

AEO2011 (consistent with recent market conditions), while reaching similar levels as predicted last year for further in the future. Specifically, AEO2012 projects wellhead prices to be $5.23 in 2025 and $6.52 in 2035 54/ -- still very low compared to the actual prices from a few years ago.

The AEO2012 reference case shows the U.S. becoming a net exporter of LNG in 2016, and a net exporter of natural gas generally in 2021. 55/ The exports of LNG are assumed to start with 1.1 Bcf per day in 2016 with another 1.1 Bcf per day increase in 2019. 56/ These levels of exports apparently had very little effect on the prices projected in the AEO2012.

Three of the protesting parties highlight the reduction in the AEO2012 of the estimated technically recoverable resource base for the Marcellus Shale from 410 Tcf to 141 Tcf. 57/ Notably, Acting EIA Administrator Howard Gruenspecht told a Senate Committee that EIA's reduction in the resource base is not material to its 25 year projections, explaining "Whether the US has 100 years of total recoverable resources at current rates or 90 years of total recoverable resources estimated at current rates, I just don't think it has much of an effect." 58/ EIA's projections of increased production over time despite the reduction in its estimated recoverable resources confirms this view.

Furthermore, the reasons for EIA's reduction in its estimate of Marcellus reserves are not yet clear, nor is the accuracy of the change. Notably, Terry Engelder of Penn State, one of the closest and most knowledgeable followers of Marcellus development, has questioned EIA's

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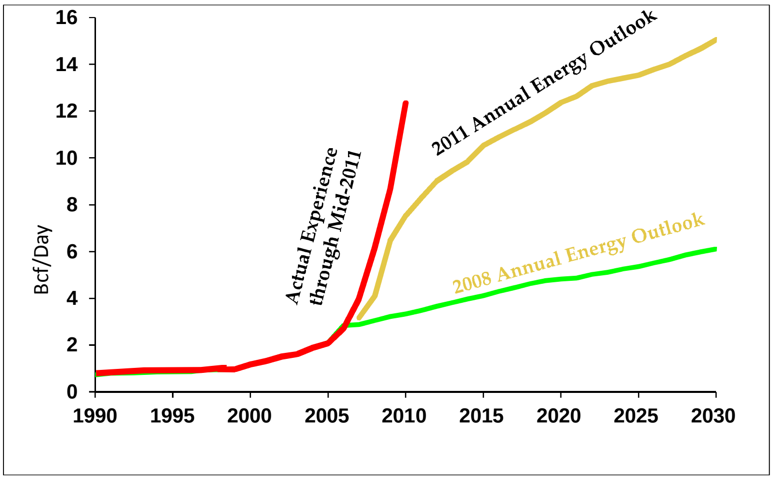
54/ *Id.* at 13 & Table 1.
55/ *Id.* at 9.
56/ *Id.*
57/ *Id.* at 9, cited in the Riverkeepers Protest at 7, APGA Protest at 3, and Trade Council Protest at 3.
58/ As quoted in "EIA downplays Marcellus reserve revision," by Conway Irwin, Interfax Energy, dated Feb. 1, 2012, available at: http://interfaxenergy.com/natural-gas-news-analysis/energy-news-analysis/marcellus-reserve-revision-not-the-issue-for-us-gas/

change and stands by his Marcellus reserve estimate of more than 500 Tcf. 59/ Moreover, the combined Marcellus reserve estimates provided to investors by Range Resources and Chesapeake Energy alone is roughly equal to the amount that EIA now estimates can be found in the entire region. 60/ While Range and Chesapeake are leading producers in the region, their combined acreage holdings are just a small fraction of the entire play.

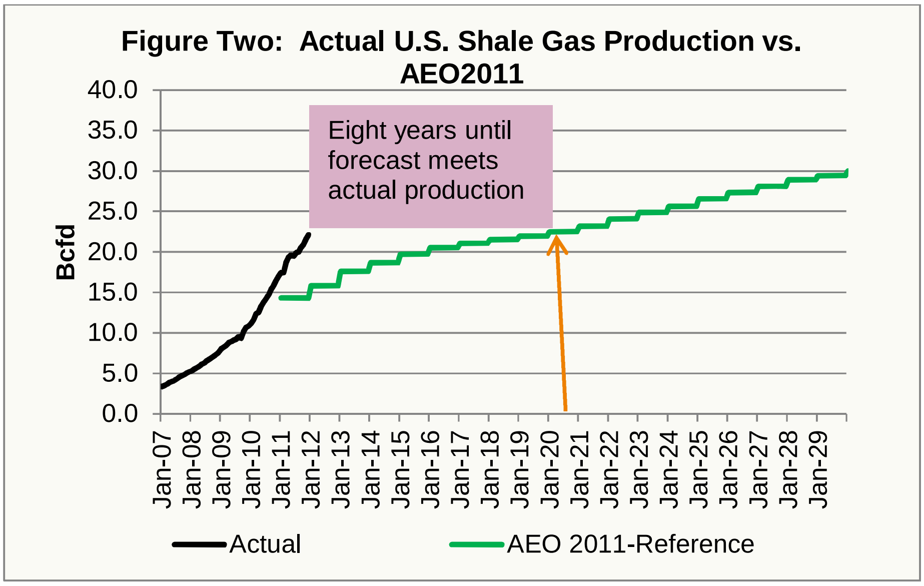
Moreover, DCP must note (as it did in the Application) that EIA historically has consistently underestimated shale development and the rapidly growing production levels. This fact is graphically illustrated in the three figures below, which compare various EIA estimates over time to the actual shale production levels:

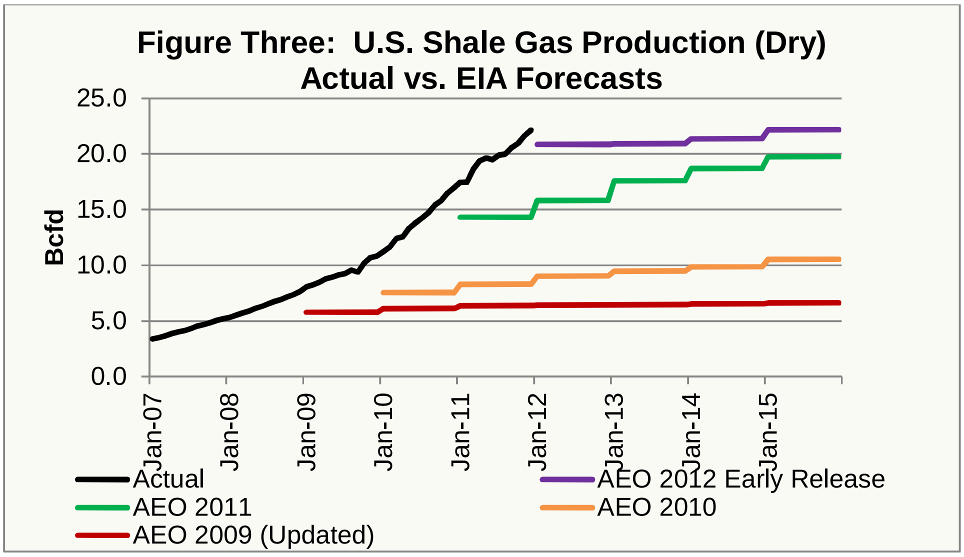
Figure One: EIA's Shale Gas Outlook versus Actual



59/ *See Inside FERC*, Feb. 6, 2012 , at 3-4, "Industry officials raise questions about EIA's newly reduced shale gas estimates"; "New Report by Agency Lowers Estimates of Natural Gas in U.S.," by Ian Urbina, New York Times, Jan. 29, 2012, available at: http://www.nytimes.com/2012/01/29/us/new-data-not-so-sunny-on-us-natural-gas-supply.html?_r=1&pagewanted=all

60/ *Id.*





In any case, even if EIA's reduction in the Marcellus resource base is accepted uncritically, that estimate would still recognize Marcellus as one of the largest gas fields in the world. Moreover, AEO2012 also took note, for the first time, of the Utica Shale that underlies the Marcellus, and included technically recoverable resources of 16 Tcf for the Utica while noting that it is still relatively unexplored. 61/ Industry activity in the Utica suggests that the

61/ AEO2012 Overview at 9.

production may be much greater. 62/ And the Ohio Department of Natural Resources has estimated a recoverable Utica Shale potential for that State alone of between 1.3 and 5.5 billion barrels of oil and between 3.8 and 15.7 trillion cubic feet of natural gas. 63/

Notwithstanding the protestors' suggestions, the proximity of the Cove Point LNG Terminal to the Marcellus and Utica Shale regions is a key advantage of DCP's project. If these prolific gas reserves are to have access to world markets, the logical (and probably only feasible) gateway is the Cove Point LNG Terminal. DCP's project, however, is not dependent on those particular supply areas: its customers may obtain gas for export from anywhere in the large and liquid U.S. gas market.

VI. NEPA Arguments Against Shale Development Are Irrelevant Here

The Sierra Club and Riverkeepers devote much of their protests to allegations about the environmental effects of hydraulic fracturing and attacks on the development of Marcellus Shale. They urge the DOE/FE to conduct an extensive analysis of Marcellus development under NEPA. DCP certainly disagrees with the environmental groups' views on these issues, but it need not engage in that debate because the issues are plainly not relevant here.

The FERC has exclusive jurisdiction over the siting, construction, expansion or operation of an LNG terminal and, thus, over the facilities that will comprise DCP's liquefaction project.

62/ *See, e.g., Utica shale development gets major boost*, UPI.com, Nov. 4, 2011, http://www.upi.com/Business_News/Energy-Resources/2011/11/04/Utica-shale-development-gets-major-boost/UPI-64161320409195/ (noting that Chesapeake Energy holds 1.25 million acres in the Utica shale field and that the company estimates the Utica shale deposits may hold as much as 25 billion barrels of oil equivalent and could be worth between $15-20 billion.); Mikaila Adams, *JV streak continues as Chesapeake completes US$2.32B Utica Shale deal with Total*, Oil & Gas Financial Journal, Jan. 4, 2012), http://www.ogfj.com/articles/2012/01/chesapeake-utica-jv.html (describing a $2.3 billion joint venture between a subsidiary of Total SA and Chesapeake Energy Corp. for the development of Utica shale resources).

63/ http://www.sooga.org/downloads/Larry%20Wickstrom%20-%20SOOGA%202011%20Trade%20Show%20-%20Utica%20Presentation.pdf

As the agency responsible for the physical siting, FERC is the lead agency charged with conducting any environmental analysis required by NEPA. DCP anticipates commencing the FERC pre-filing process that will begin the NEPA process this summer. DOE/FE presumably will participate in the NEPA review process as a cooperating agency.

DCP requested in its Application that DOE/FE issue a conditional order authorizing the export of LNG, conditioned on completion of the environmental review by FERC. Such a conditional order is consistent with the agency's regulations, 10 C.F.R. § 590.402 (2011). This is also the approach taken by DOE/FE with its non-FTA authorization for Sabine Pass, and in other cases.

Accordingly, the scope of NEPA review for DCP's project will not be determined in this proceeding. So, the purported environmental concerns raised by Riverkeepers and Sierra Club are not within the DOE/FE's authority and are beyond the scope of this proceeding. Moreover, their request for environmental analysis is premature since the specific facilities to be constructed have not yet even been identified.

That said, a detailed NEPA analysis of issues associated with Marcellus Shale production – which *might* be liquefied by DCP's project -- is not appropriate in the environmental review of DCP's project. The FERC considered this very issue in detail in its recent orders related to a pipeline project to transport Marcellus supplies, *Central New York Oil and Gas Company, LLC*. 64/

In that case, environmental interveners presented many of the same concerns regarding the effects of natural gas development in the Marcellus Shale formation. In response, FERC found that the Marcellus Shale development and its associated potential environmental impacts

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64/ *Central New York Oil and Gas Company, LLC*, 137 FERC ¶ 61,121 (2011), *reh'g*, 138 FERC ¶ 61,104 (2012).

are not sufficiently causally-related to the pipeline project to warrant the more comprehensive analysis that commenters sought. In particular, FERC held that the development of the Marcellus Shale could occur regardless of whether the pipeline project proceeded and, conversely, that the development of the project was not necessarily dependent on the expansion of Marcellus drilling activity. Relatedly, no particular Marcellus Shale development activity could be attributed to the project. FERC further reasoned that it had no jurisdiction over Marcellus drilling, and that such activity was solely within the purview of state authorities. It noted that the Supreme Court has found that if an agency has no ability to prevent a certain effect due to limited statutory authority over the relevant actions, the agency cannot be considered a legally relevant cause of the effect. Finally, FERC concluded that the impacts of Marcellus Shale drilling activities were not "reasonably foreseeable," so such an analysis would amount to little more than speculation on the nature and scope of future development of the shale play.

Each of these considerations is equally applicable to DCP's project. Therefore, the FERC almost certainly will not undertake a comprehensive review of Marcellus Shale drilling impacts as part of its NEPA review of DCP's export facilities. That decision, however, is for another agency and another day, and need not be resolved by DOE/FE here.

The reality is that the environmental groups protesting here are unhappy with the on-going development of shale gas and what they perceive to be inadequate environmental regulation of that activity. That is an issue almost entirely within the ambit of state regulatory authorities. And consideration and formulation of the appropriate regulation of shale development is an active, on-going matter at the State legislatures and State agencies with relevant jurisdiction. The protesting parties apparently do not approve of how at least certain states are handling the issue: notably, Riverkeepers charge that Pennsylvania has a "pock-marked record infamous for ad hoc regulation of natural gas resource extraction." 65/ Accordingly, they are searching for a forum in which to present their claims about problems they perceive with shale gas development. They need to keep searching, because this is not the place or time for such a debate.

Relatedly, the Sierra Club also presents arguments related to DCP's need to comply with the Endangered Species Act and the National Historical Preservation Act. 66/ DCP's project, of course, will have to comply with these statutes and a variety of others as well. Contrary to the Sierra Club's suggestions, however, DOE/FE has no jurisdiction in these areas. Those issues too are well outside the scope of this proceeding.

VII. The Competitive Viability Of The Project Will Be Determined in the Market

Finally, the APGA argues that DCP's "export plans will eventually prove uneconomical." 67/ It contends that domestic gas prices will increase and international prices will decrease, making LNG exports from the U.S. not viable in the long run. 68/ This theory is not supported by any economic analysis, and is contrary to the conclusions of the studies done by Navigant and Deloitte.

More importantly, these decisions will be made by market participants willing to invest billions of dollars in the LNG export projects. DCP will make such an investment in its liquefaction project only based on financial commitments by customers willing to pay it billions of dollars over the term of long-term, binding contracts. Based on its discussions with a number of sophisticated global energy companies, DCP anticipates that it will obtain such contracts.

Moreover, Dominion Resources, Inc. has ample financial resources and capability to

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65/ Riverkeepers Protest at 10.

66/ Sierra Club Protest at 8-9.

67/ APGA Protest at 19.

68/ *Id.* at 19-21.

develop the project, along with the technical expertise and proven track-record of successful large projects at Cove Point and elsewhere. Some applicants for LNG export authorizations may very well not have economic or viable projects, but APGA's worries in that regard with respect to DCP's proposal are misplaced.

VIII. Conclusion

In the event that DOE/FE grants the interventions of the protesting parties and considers their views, DCP requests that the agency consider this Answer as well. In addition, DCP requests that DOE/FE consider the Deloitte study provided as an attachment here as part of its analysis of the possible price effect of LNG exports.

Furthermore, for all the reasons set forth in its Application and in this Answer, DCP submits that its proposal to export LNG to any country with which the U.S. does not prohibit trade but also does not have an FTA requiring the national treatment for trade in natural gas is consistent with the public interest. Accordingly, DCP respectfully renews its requests that the DOE/FE grant the requested authority as expeditiously as possible, and by no later than June 1, 2012.

Respectfully submitted,

/s/ J. Patrick Nevins

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February 21, 2012

UNITED STATES OF AMERICA
BEFORE THE DEPARTMENT OF ENERGY
OFFICE OF FOSSIL ENERGY

In the Matter of	**]**	
	]	**FE Docket No. 11-128- LNG**
DOMINION COVE POINT LNG, LP	**]**	

CERTIFICATED STATEMENT OF AUTHORIZED REPRESENTATIVE

Pursuant to Section 590.103(b) of the Department of Energy's (DOE) regulations, 10 C.F.R. § 590.303(e) (2011), I, J. Patrick Nevins, hereby certify that I am a duly authorized representative of Dominion Cove Point LNG, LP, and that I am authorized to sign and file with the Office of Fossil Energy of the Department of Energy, on behalf of Dominion Cove Point LNG, LP, the foregoing document in the above-captioned proceeding.

Filed and dated in Washington, D.C., on this 21st day of February, 2012.

Respectfully submitted,

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Deloitte.

Made in America
The economic impact of LNG exports from the United States

A report by the Deloitte Center for Energy Solutions and Deloitte MarketPoint LLC

Deloitte Center for Energy Solutions

Contents

Deloitte MarketPoint applied its integrated North American Power, Coal, and World Gas Model to analyze the price and quantity impacts of LNG exports on the U.S. gas market. Given the model's assumptions, the World Gas Model projects a weighted-average price impact of $0.12/MMBtu on U.S. prices from 2016 to 2035 as a result of the 6 Bcfd of LNG exports. The $0.12/MMBtu increase represents a 1.7% increase in the projected average U.S. citygate gas price of $7.09/MMBtu over this time period. The projected impact on Henry Hub price is $0.22/MMBtu, significantly higher than the national average because of its close proximity to the prospective export terminals. The projected price impacts diminish with distance away from the Gulf. Distant market areas' projected price impacts are less than $0.10/MMBtu. Focusing solely on the Henry Hub or regional prices around the export terminals will greatly overstate the total impact on U.S. consumers.

The results show that the North American gas market is dynamic. If exports can be anticipated, then producers, midstream players, and consumers can act to mitigate the price impact. Producers will bring more supplies online, flows will be adjusted, and consumers will react to price change resulting from LNG exports.

Executive summary

Deloitte MarketPoint LLC ("DMP") is pleased to provide an independent assessment of the potential economic impacts of LNG exports from the United States. Exporters might benefit from selling to foreign buyers, but how would such exports adversely impact domestic consumers of natural gas? Increased competition for supplies and accelerated resource depletion will likely raise domestic prices, but by how much? Will the level of exports being considered raise prices enough to cause economic damage as some objectors contend? After all, natural gas is a depletable resource, and what is exported is made unavailable to domestic uses. Under the assumptions outlined in this paper, we shall see that the magnitude of domestic price increase that results from export of natural gas in the form of LNG is likely quite small.

Deloitte MarketPoint applied its integrated North American Power, Coal, and World Gas Model to analyze the price and quantity impacts of LNG exports on the U.S. gas market.

Some arguments in support of or objecting to LNG exports center around whether there are adequate resources to meet both domestic consumption and export volumes. That is, does the U.S. need the gas for its own consumption or does the U.S. possess sufficiently abundant gas volumes to provide for both domestic consumption and exports? In our view, this question only begins to address the export issue because simple comparisons of total available domestic resources to projected future consumption are insufficient to adequately analyze the economic impact of LNG exports. We believe the real issue is not only one of volume, but more of price impact. *If price is not significantly affected, then scarcity and shortage of supply are not significant issues.*

DMP applied its integrated North American Power, Coal, and World Gas Model ("WGM" or "Model") to analyze the price and quantity impacts of LNG exports on the U.S. gas market.[1] The WGM projects monthly prices and quantities over a 30-year time horizon based on rigorous adherence to accepted microeconomic theories. It includes disaggregated representations of North America, Europe, and other major global markets. The WGM computes prices and quantities simultaneously across multiple markets and across multiple time points. Unlike many other models which compute prices and quantities assuming all parties work together to achieve a single global objective, the WGM applies fundamental economic theories to represent self-interested decisions made by each market "agent" along every stage of the supply chain. More information can be obtained from DMP.

Vital to this analysis, the WGM represents fundamental producer decisions regarding when and how much reserves to add given the producer's resource endowments and anticipated forward prices. This supply-demand dynamic is particularly important in analyzing the impact of demand changes (e.g., LNG exports) because without it, the answer will likely greatly overestimate the impact of demand changes by not adequately considering supply dynamics. Indeed, producers will anticipate the export volumes and resulting increased prices to make production decisions accordingly. LNG exporters might back up their multibillion dollar projects with long-term domestic supply contracts, but even if they do not, producers will anticipate and incorporate the demand growth in their production decisions. Missing this supply-demand dynamic is tantamount to assuming the market will be surprised and unprepared for the volume of exports and have to ration fixed supplies to meet the required volumes. Static models assume a fixed supply volume (i.e., productive capacity) during each time period and therefore are prone to overestimate the price impact of a demand change. Typically, users have to override this lack of supply response by manually adjusting supply to meet demand. Instead, the WGM uses sophisticated depletable resource logic in which today's drilling decisions affect tomorrow's price, and tomorrow's price affects today's drilling decisions. It captures the market dynamics between suppliers and consumers.

[1] In this document, "LNG exports" refers to the volume of exports from the three Gulf Coast terminals that have applied for a license to export LNG.

Shale gas production has grown tremendously over the past several years. However, there is considerable debate as to how long this trend will continue and how much will be produced out of each shale gas basin. Rather than simply extrapolating past trends, the WGM projects production-based resource volumes and cost, future gas demand, particularly for power generation, and competition among various sources in each market area. It computes incremental sources to meet a change in demand and the resulting impact on price.

Based on our existing model and assumptions, which we will call the "Reference Case," we developed a second case, which we will call the LNG Export Case, to assess the impact of LNG exports. Both cases are identical except for the LNG export volumes. In the LNG Export Case we represented 6 billion cubic feet per day ("Bcfd") of LNG exports, approximately equal to the total volume of the three LNG export applications at Sabine Pass, Freeport, and Lake Charles LNG terminals. Since the WGM already represented these import LNG terminals, we only had to represent exports as incremental demands, each with a constant of 2 Bcfd demand, near each of the terminals. Comparing results of this second case to the Reference Case, we projected how much the exports would increase domestic prices and affect production and flows.

Given the model's assumptions, the WGM projects a weighted-average price impact of $0.12 per million British thermal units (MMBtu) on U.S. prices from 2016 to 2035 as a result of the 6 Bcfd of LNG exports. The $0.12/MMBtu increase represents a 1.7% increase in the projected average U.S. citygate gas price of $7.09/MMBtu over this time period. The projected impact on Henry Hub price is $0.22/MMBtu, significantly higher than the national average because of its close proximity to the prospective export terminals. The projected price impacts diminish with distance away from the Gulf. Distant market areas' projected price impacts are less than $0.10/MMBtu, such as the New York and Chicago areas. Focusing solely on the Henry Hub or regional prices around the export terminals will greatly overstate the total impact on the U.S. consumers.

The results show that the North American gas market is dynamic. If exports can be anticipated, and clearly they can with the public application process and long lead time required to construct a LNG liquefaction plant, then producers, midstream players, and consumers can act to mitigate the price impact. Producers will bring more supplies online, flows will be adjusted, and consumers will react to price change resulting from LNG exports.

Given the model's assumptions, the WGM projects a weighted-average price impact of $0.12/MMBtu on U.S. prices from 2016 to 2035.

Gas prices in the Eastern U.S., historically the highest priced region in North America, could be dampened by incremental shale gas production within the region. Eastern bases to Henry Hub are projected to sink under the weight of surging gas production from the Marcellus Shale. The Marcellus Shale is projected to dominate the Mid-Atlantic natural gas market, including New York, New Jersey, and Pennsylvania, meeting most of the regional demand and pushing gas through to New England and even to South Atlantic markets. Pipelines built to transport gas supplies from distant producing regions — such as the Rockies and the Gulf Coast — to Northeastern U.S. gas markets may face stiff competition. The expected result is displacement of volumes from the Gulf which would depress prices in the Gulf region. Combined with the growing shale gas production out of Haynesville and Eagle Ford, the Gulf region is projected to continue to have plentiful production and remain one of the lowest cost regions in North America.

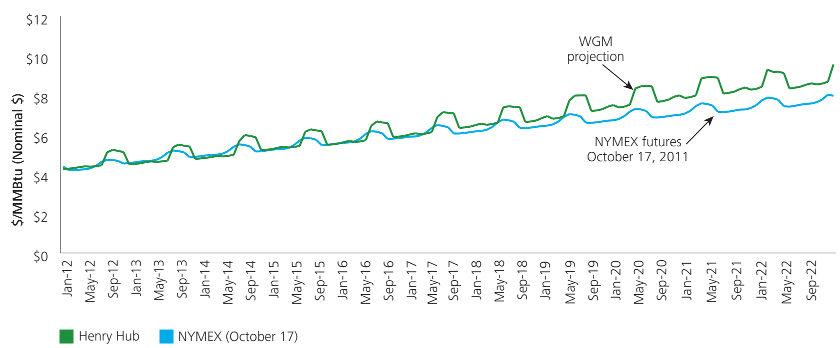
Overview of Deloitte MarketPoint Reference Case

The WGM Reference Case assumes a "business as usual" scenario including no new CO_2 emission regulations for power plants and no new regulations for hydrofracking operations in shale gas production. U.S. gas demand growth rates are consistent with the U.S. Energy Information Administration's ("EIA") Annual Energy Outlook ("AEO") 2011 projection, except for power generation which is based on the DMP electricity model. (There is no intended advocacy or prediction of any events. Rather, we use these assumptions as a frame of reference. The impact of LNG exports could easily be tested against other scenarios, but the overall results would be rather similar for reasons articulated later in this document.)

In the Reference Case, natural gas prices are projected to rebound from current levels and continue to strengthen over the next two decades, although nominal prices do not return to the peak levels of the mid-to-late 2000s until after 2020. In real terms (i.e., constant 2011 dollars), benchmark U.S. Henry Hub spot prices increase from an annual average of $4.15 per MMBtu in 2011 to $6.00 per MMBtu in 2020, before rising to $7.16 per MMBtu in 2030 in the Reference Case. Our Henry Hub price forecast for 2011-2035 averages $6.23. Bear in mind that this is the Reference Case which includes no LNG exports.

Escalating real prices by an annual inflation rate (estimated at 2.0%[2]), yields nominal prices which can be compared to NYMEX futures prices. The WGM projection of monthly Henry Hub prices is compared to NYMEX futures prices as of October 17, 2011 in Figure 1. Prices are shown in nominal terms (i.e., dollars of the day including inflation). Near-term projections are fairly consistent, but in the longer term, projected prices from the WGM rise significantly higher than the NYMEX futures prices. On an annual average, the projected prices are a dollar higher than the NYMEX futures prices in the longer term.

Figure 1. Comparison between projected Henry Hub and NYMEX futures prices



[2] Average consumer price index over the past 10 years according to the Bureau of Labor Statistics.

The WGM projects the U.S. power sector to increase by about 50% over the next decade, accounting for nearly all of the projected future growth. Based on assumptions in the WGM, gas will become the fuel of choice for power generation.

One possible reason why the WGM forecasts prices higher than market expectation (i.e., NYMEX futures) is because the WGM's forecast of gas demand for power generation is considerably higher than the publicly available EIA forecast. Based on our electricity model projections, we forecast natural gas consumption for electricity generation to drive North American natural gas demand higher during the next two decades.

As shown in Figure 2, the DMP projected gas demand for U.S. power generation is far greater than the demand predicted by EIA's AEO 2011, which essentially forecasts no change. The WGM projects the U.S. power sector to increase by about 50% (approximately 10 Bcfd) over the next decade, accounting for nearly all of the projected future growth. Based upon assumptions in the WGM, gas will become the fuel of choice for power generation for a variety of reasons, including: tightening application of existing environmental regulations for mercury, NOx, and SOx; expectations of ample domestic gas supply at competitive gas prices; and the need to back up intermittent renewable sources such as wind and solar to ensure reliability. Like the EIA's AEO, our projection does not assume any new carbon legislation in the Reference Case.

Our electricity model, fully integrated with our WGM and coal model, contains a detailed representation of the North American electricity system including environmental emissions for key pollutants (CO_2, SOx, NOx, and mercury). The integrated structure of the models is shown in Figure 3. The electricity model projects electric generation capacity addition, dispatch and fuel burn based on competition among different types of power generators given a host of factors including plant capacities, fuel price, heat rates, variable costs, and environmental emissions costs. This integration captures global linkages and also inter-commodity linkages. Integrating gas and electricity is vitally important because U.S. natural gas demand growth is expected to be driven almost entirely by the electricity sector, which is predicted to grow at substantial rates. Hence, the WGM projection will be less favorable to the question of LNG export than if we had assumed a lower gas demand. The higher gas demand will push projection of price and quantity impacts of LNG export to be more "conservative." However, the real issue is not the absolute price of exported gas, but rather the price impact resulting from the LNG exports.

Figure 2. Diverse projections of the U.S. gas demand for power generation

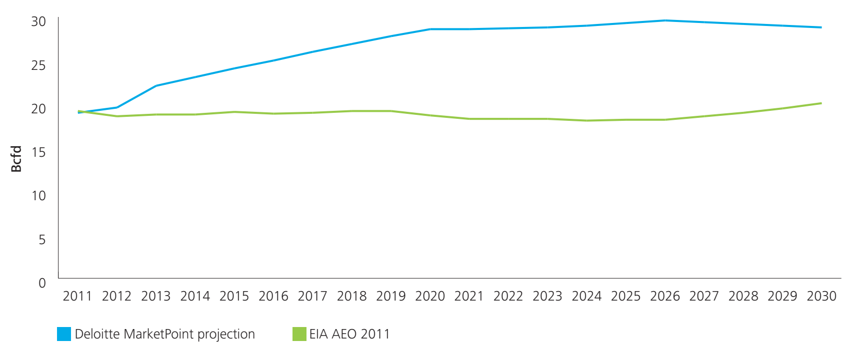
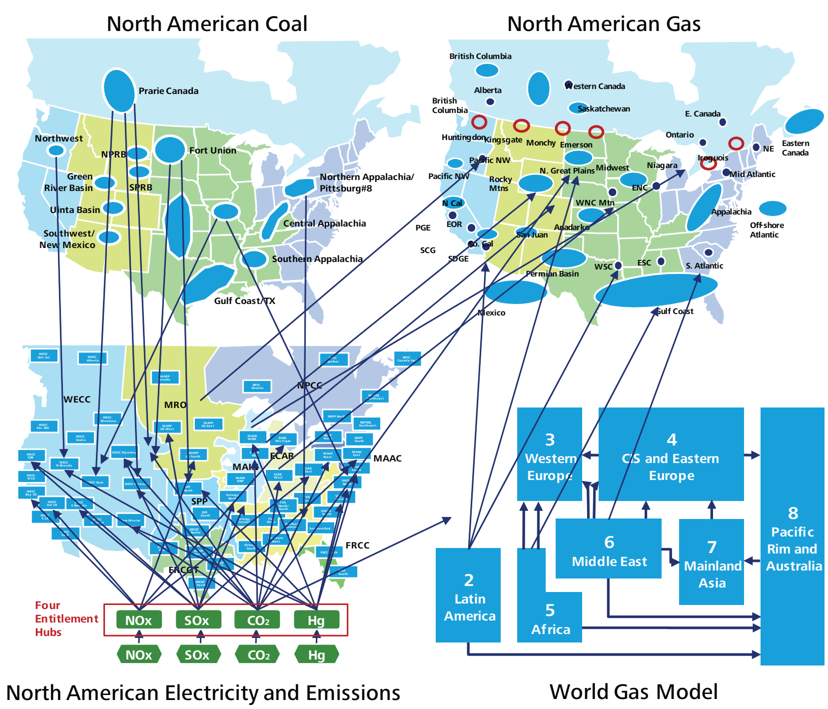


Figure 3. DMP North American representation



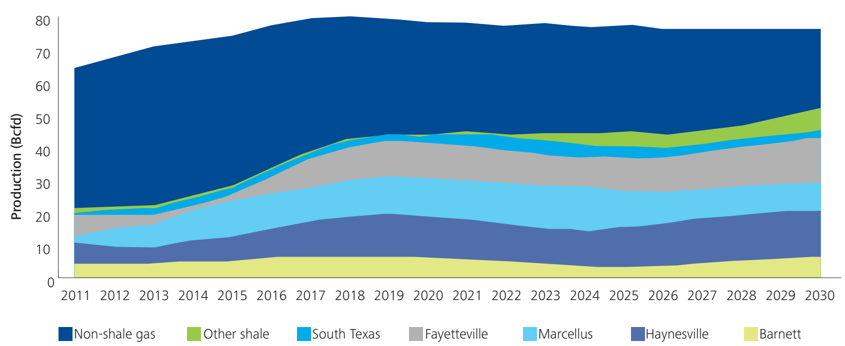
Buffering the price impact of LNG exports is the large domestic resource base, particularly shale gas, which we project to be an increasingly important component of domestic supply. As shown in Figure 4, the Reference Case projects shale gas production, particularly in the Marcellus Shale in Appalachia and the Haynesville Shale in Texas and Louisiana, to grow and eventually become the largest component of domestic gas supply. Increasing U.S. shale gas output bolsters total domestic gas production, which grows from about 64 Bcfd in 2011 to almost 80 Bcfd in 2018 before tapering off.

The projected growth in production from a large domestic resource base is a crucially important point. Many upstream gas industry observers today believe that there is a very large quantity of gas available to be produced in the shale regions of North America at a more or less constant price. This would imply that they also believe that natural gas supply is highly "elastic," i.e., the supply curve is very flat.

Gas production in Canada is projected to decline over the next several years, reducing exports to the U.S. and continuing the recent slide in production out of the Western Canadian Sedimentary Basin. However, Canadian production is projected to ramp up in the later part of this decade with increased production out of the Horn River and Montney shale gas plays in Western Canada. Further into the future, the Mackenzie Delta pipeline may begin making available supplies from Northern Canada. Increased Canadian production makes more gas available for export to the U.S. The North American natural gas system is highly integrated so Canadian supplies can generally access U.S. markets when economic. This increase in available gas for export to the U.S. could be supplemented even more if the Alaskan Gas Pipeline were to penetrate Alberta, but that would likely not happen within the time horizon of this scenario and is thus not considered.

Increasing production from major shale gas plays, many of which are not located in traditional gas-producing areas, is projected to transform historical basis relationships during the next two decades. Varying rates of regional gas demand growth, the advent of new natural gas infrastructure, and evolving gas flows may also contribute to changes in regional basis, though to a lesser degree. This is a very important point as well. If LNG is exported from

Figure 4. U.S. gas production by type



one particular geographic point, the entire eastern part of the United States reorients production and flows and basis differentials change substantially. Basis differentials are not fixed and invariant to LNG exports or other demand changes. On the contrary, basis differentials adjust to LNG volumes and help ensure economically efficient backfill and efficient prices. The advent of large quantities of shale gas in heretofore nonproducing areas will cause the basis to those areas to fall. The increased supply also will make more gas available for export and help mitigate the price increases due to exports.

Most notably, gas prices in the Eastern U.S., historically the highest priced region in North America, could be dampened by incremental shale gas production within the region. Eastern bases to Henry Hub are projected to sink under the weight of surging gas production from the Marcellus Shale. The Marcellus Shale is projected to dominate the Mid-Atlantic natural gas market, including New York, New Jersey, and Pennsylvania, meeting most of the regional demand and pushing gas through to New England and even to South Atlantic markets. Pipelines built to transport gas supplies from distant producing regions — such as the Rockies and the Gulf Coast — to Northeastern U.S. gas markets may face stiff competition. The expected result is displacement of volumes from the Gulf which would depress prices in the Gulf region. Combined with the growing shale gas production out of Haynesville and Eagle Ford, the Gulf region is projected to continue to have plentiful production and remain one of the lowest cost regions in North America.

Given our basic assumptions, the WGM projects LNG exports will cause a volume weighted-average price impact of $0.12/MMBtu on U.S. citygate prices from 2016 to 2035 as a result of the assumed 6 Bcfd of LNG exports out of the three Gulf Coast terminals. The $0.12/MMBtu increase represents a 1.7% increase in the projected average U.S. citygate gas price of $7.09/MMBtu over this time period. The projected increase in Henry Hub gas price is $0.22/MMBtu during this period. It is important to note the variation in price impact by location. The WGM projects that the impact at the Henry Hub will be much greater than the impact in other markets more distant from export terminals.

Potential impact of LNG exports

Given our basic assumptions, the WGM projects LNG exports will cause a volume weighted-average price impact of $0.12/MMBtu on U.S. citygate prices from 2016 to 2035 as a result of the assumed 6 Bcfd of LNG exports out of the three Gulf Coast terminals. The $0.12/MMBtu increase represents a 1.7% increase in the projected average U.S. citygate gas price of $7.09/MMBtu over this time period. The projected increase in Henry Hub gas price is $0.22/MMBtu during this period. It is important to note the variation in price impact by location. The WGM projects that the impact at the Henry Hub will be much greater than the impact in other markets more distant from export terminals.

To put the impact in perspective, Figure 5 shows the price impact on top of projected Reference Case U.S. average citygate prices over a 20-year period. The height of both bars represents the projected price with LNG exports.

The WGM's projected price impact might not be as large as some might expect because that is not what they observe in the short term. For example, even a 1 Bcfd increase in demand during a peak winter day can cause spot prices to shoot up.

However, in this analysis we are considering long-term impacts, when changes in supply and demand can be anticipated. Unlike short-term markets, in which supply and demand are both largely fixed, both supply and demand are far more elastic in the long term. Producers can develop more reserves in anticipation of demand growth, such as LNG exports. Indeed, LNG export projects will likely be backed by long-term supply contracts, as well as long-term contracts with buyers. There will be ample notice and time in advance of the exports to make supplies available. The price impact is then determined by how supply costs will change as a result of more rapid depletion of domestic resources.

As previously stated, the projected impact of LNG exports on price varies by location, as shown in Figure 6. The price impact attenuates with distance from the LNG export terminals. The impact is greatest at the Henry Hub, situated near all of the export terminals, about $0.22/MMBtu on average from 2016 to 2035. The impact at the Houston Ship Channel is nearly as much, about $0.20/MMBtu.

By the time you move to downstream markets, such as Illinois, New York, and California, the projected price impact is generally about $0.10/MMBtu or less. If we weight the price impact in each market by the volume of gas demand, we can compute a weighted average price impact for the U.S. of $0.12/MMBtu.

This analysis illustrates the interconnectivity of the North American system and the need to analyze not only Henry Hub and other price points near export terminals, but prices throughout the U.S. in order to fairly gauge the impacts from LNG exports. Analyses that focus just on Henry Hub prices will likely overstate the impact.

Figure 5: Impact of LNG exports on average U.S. citygate gas prices

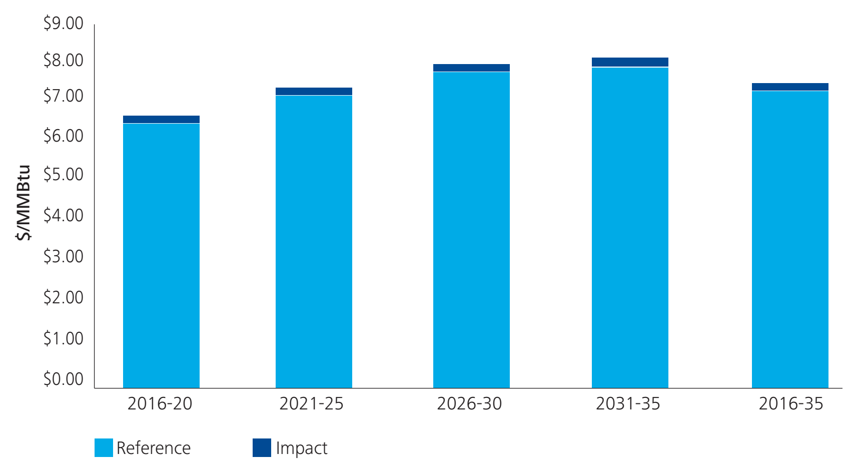


Figure 6: Price impact varies by location (average 2016-35)

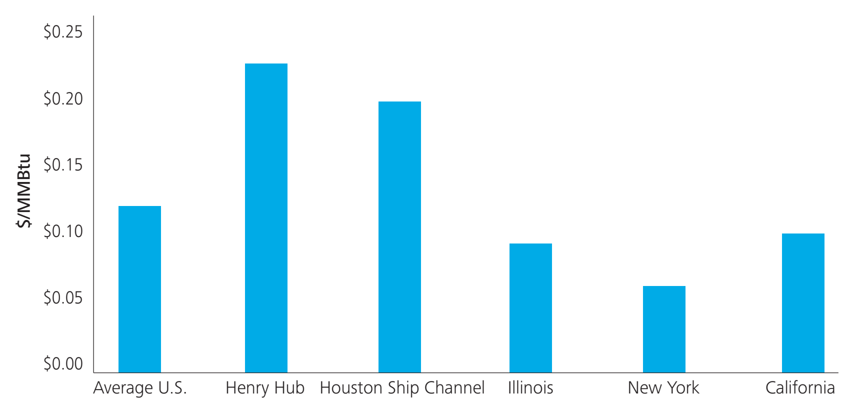


Figure 7 shows the aggregate U.S. supply curve, including Alaska and all types of gas formations, assumed in the WGM. It plots the volumes of reserve additions available at different all-in marginal capital costs, including financing, return on equity, and taxes. The marginal capital cost is equivalent to the wellhead price necessary to induce a level of investment required to bring the estimated volumes on line. The WGM includes over 100 different supply nodes representing the geographic and geologic diversity of domestic supply basins. The supply data is based on publicly available documents and discussions with credible sources such as the United States Geological Survey, National Petroleum Council, Potential Gas Committee, and the Department of Energy's EIA.

The area of the supply curve that matters most is the section below $6/MMBtu of capital cost because wellhead prices are projected to fall under this level during most of the time horizon considered. These are the volumes that are projected to be produced over the next couple of decades. The Reference Case estimates about 1,200 trillion cubic feet (Tcf) available at wellhead prices below $6/MMBtu. To put the LNG export volumes into proper perspective, it will accelerate depletion of the domestic resource base, estimated to include about 1,200 Tcf at prices below $6/MMBtu in all-in capital cost, by 2.2 Tcf per year (equivalent to 6 Bcfd). Alternatively, the 2.2 Tcf represents an increase in demand of about 8% to the projected demand of 26 Tcf by the time exports are assumed to commence in 2016. The point is not to downplay the export volume, but to put exports into perspective versus the overall available supply base. The results of this analysis demonstrate that the magnitude of the assumed total LNG exports is substantial on its own, but not very significant relative to the entire U.S. resource base or total U.S. demand.

In the WGM, supply and price are inextricably linked. With regard to the potential impact of LNG exports, the absolute price is not the driving factor but rather the shape of the aggregate supply curve which determines the price impact. Figure 8 depicts how demand increase affects price. Incremental demand pushes out the demand curve, causing it to intersect the supply curve at a higher point. Since the supply curve is fairly flat in the area of demand, the price impact is fairly small. The massive shale gas resources have flattened the U.S. supply curve. It is the shape of the aggregate supply curve that really matters.

Figure 7. Aggregate U.S. natural gas supply curve

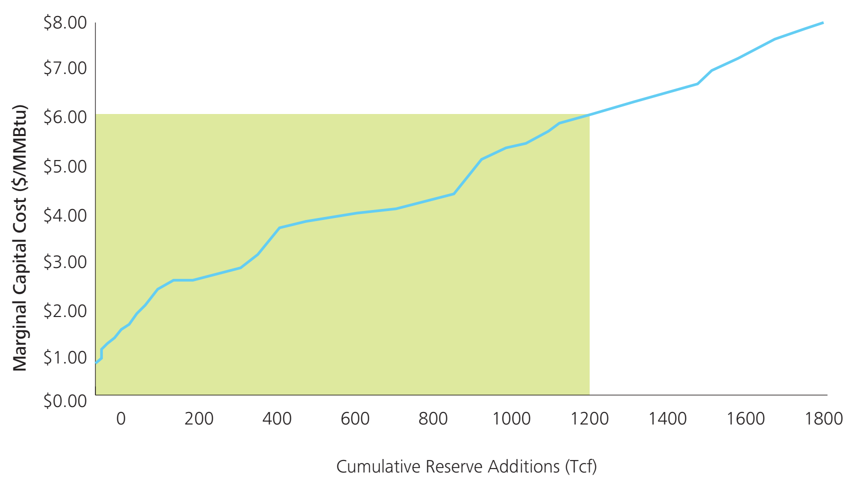
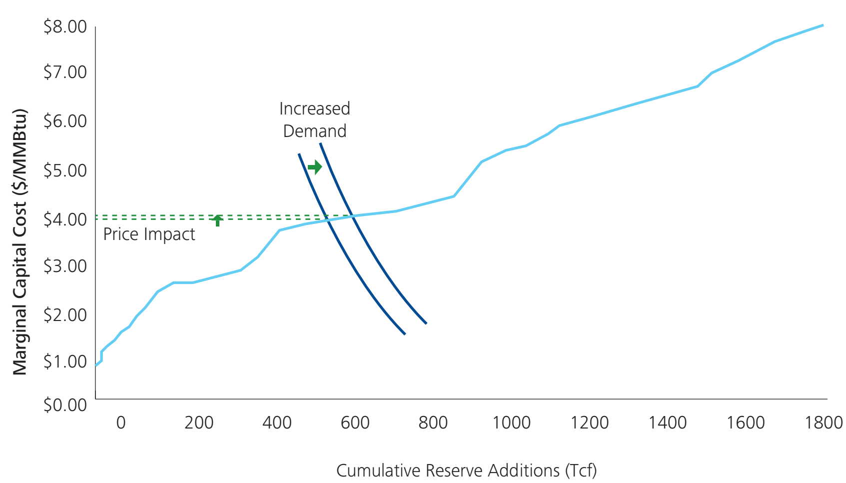


Figure 8: Impact of higher demand on price



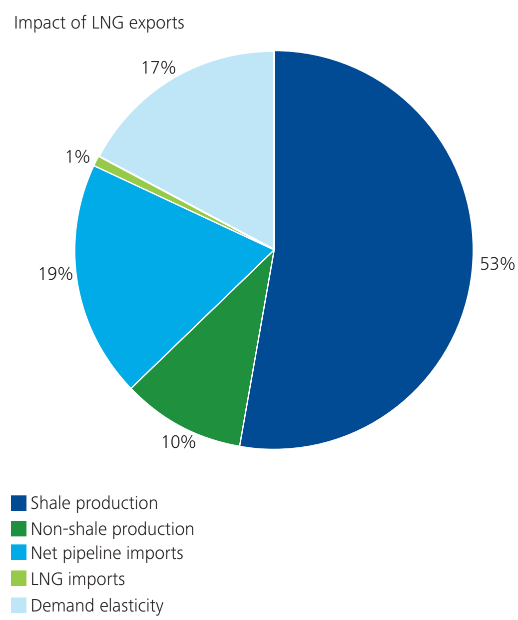
If that is the case, leftward and rightward movements in the demand curve (where such leftward and rightward movements would be volumes of LNG export) cut through the supply curve at pretty much the same price. Flat, elastic supply means that the price of domestic natural gas is increasingly and continually determined by supply issues (e.g., production cost). Given that there is a significant quantity of domestic gas available at modest production costs, the export of 6 Bcfd of LNG should not significantly increase the price of domestic gas because it should not dramatically increase the production cost of domestic gas.

The projected sources of incremental supply used to meet the assumed export volumes come from multiple sources, including domestic resources (both shale gas and non-shale gas), import volumes, and demand elasticity. As shown in Figure 9, the bulk of the incremental volumes come from shale gas production. Including non-shale gas production, the domestic production contributes 63% of the total incremental volume. Net pipeline imports, comprised mostly of imports from Canada, contribute another 19%. Higher U.S. prices would be expected to induce greater Canadian production, primarily from Horn River and Montney shale gas resources, making gas available for export to the U.S. The U.S. net exports to Mexico decline slightly as higher cost of U.S. supplies will prompt more Mexican production and reduce the need for U.S. exports to Mexico. Higher gas prices are also projected to trigger demand elasticity so less gas is consumed, representing about 17% of the incremental volume. Most of the reduction in gas consumption comes from the power sector as higher gas prices incentivize greater utilization of generators burning other types of fuels.

Finally, there is a small increment, 1%, coming from LNG imports. Having both LNG imports and exports is not necessarily contradictory since there is variation in price by terminal (e.g., Everett terminal near Boston historically has much higher prices than the Gulf terminals) and by time. The WGM projects seasonal arbitrage of global LNG flows. U.S. LNG imports are expected to be higher during summer periods as LNG shippers take advantage of plentiful storage capacity and large summer load for power generation in the U.S. and weaken during the winter when European and Asian demands peak.

An important point to bear in mind is that the North American natural gas market is highly integrated and all segments will work together to mitigate price impacts of demand changes.

Figure 9: Projected sources of incremental volume



Responses to raised concerns about LNG exports

In response to LNG export applications to the DOE made by several entities to date, some concerns have been raised regarding the viability of exports and the impact they may have on the U.S. gas market. The opposing arguments to LNG exports center around two main points: (i) allowing exports will cause U.S. gas prices to rise to levels equal to world gas prices, and (ii) exports should be prohibited in order to suppress domestic prices because suppressing domestic prices is good for employment and the U.S. economy. These two main points have prompted parties to raise more specific concerns and questions which we will address one at a time. Based on the WGM analysis conducted and based on our knowledge and experience, DMP provides the following observations in response to these concerns.

Concern: Contribution of shale gas to U.S. market could be grossly overestimated.

DMP Analysis: Abundant shale gas resources and commitment by energy majors to develop those reserves will likely ensure strong future growth of shale gas production.

Despite the rapid growth in shale gas production during the past several years, there is still some degree of skepticism about how long the trend will continue. The EIA forecasts shale gas will comprise 47% of total U.S. production in 2035, more than double the 23 percent share in 2011.[3] Our Reference Case forecasts that shale gas will become the dominant domestic source, hitting 50% as early as 2020. There is little debate over the massive volumes of shale gas. The debate is really over the production cost of shale gas. Some have estimated massive volumes to be available at very low prices (under $4/MMBtu). The shale gas supply curves in the WGM are less optimistic and represent diversity of shale gas plays, including some in "sweet spots" with very low production costs, but more in higher cost areas. The WGM supply curves were developed based on best available data and talking with leading supply experts from industry and governmental agencies.

The price forecast from the WGM based on the various assumptions reflects the long-run marginal cost of domestic supplies and is higher in the long term than the current forward price curves. Regardless of the exact share of total production, many expect shale gas to be an important component of domestic supply and prices will reflect production costs. Higher shale gas production cost estimates do not necessarily mean that shale gas will not be produced because prices will tend to rise in order to sustain their development.

Another factor that will help maintain the growth in shale gas development is the huge amount of capital that companies, particularly the majors, have poured into acquiring shale gas acreage and developing fields. The capital expenditures represent sunk costs and lower the marginal cost of future production. That is, the incremental cost of production is lower because part of the total cost has already been paid. Some examples of major expenditures are:

- ExxonMobil paid $34.9 billion to acquire XTO, which specialized in shale gas development, and later purchased two small shale gas exploration companies (Bloomberg, June 9, 2011).
- Chevron acquired Atlas Energy Inc. and its 622,000 acres in the Marcellus Shale for $3.58 billion and subsequently purchased additional acreage from smaller operators (Bloomberg, May 4, 2011).
- Shell acquired East Resources for $4.7 billion to double its reserves of shale gas (Bloomberg, May 28, 2010).
- Statoil signed deals with Chesapeake and Talisman for shares in jointed development of shale gas plays with these companies (Reuters, October 10, 2010).

Not only are these investments large, but the arrival of majors signals a new era in the development of shale gas. Unlike in the past when smaller independent companies worked shale gas fields in response to high prices, energy majors have the resources to remain committed to development through the vacillations of gas prices. They have staying power. Furthermore, they have the resources to invest in continued improvements of shale gas technologies and procedures. Their involvement will likely continue to drive down the cost of shale gas production, making more volumes available economically.

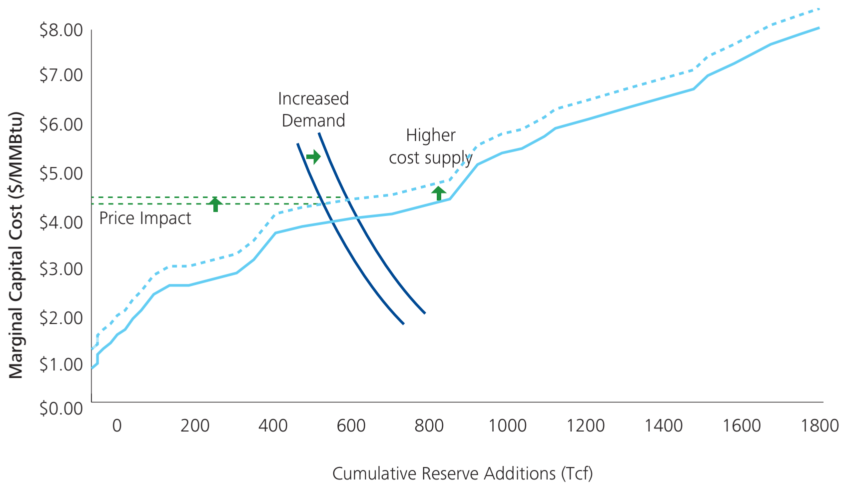
[3] EIA Annual Energy Outlook 2011 with Projections to 2035, p.2.

Even if shale gas production does not reach the projected levels because costs turn out to be higher than estimated, it does not necessarily mean that the impact of LNG exports would be much higher. Lower shale gas production would likely be the result of the discovery of another, more economic, source of supply. Very important, it is the shape of the supply curve, rather than the absolute cost level, that determines the price impact. Figure 10 illustrates that simply having a higher supply cost estimate (i.e., shifting the supply curve up) does not necessarily imply a greater price impact from a demand change.

Concern: High level of uncertainty that shale gas can be produced as modeled due to concerns including regulatory issues, access issues, and environmental issues.

DMP Analysis: Regulations will likely push best practices already adopted by leading companies and restrict fracking in only the most sensitive areas.

Figure 10: Impact of higher cost supply curve



The U.S. EPA and a few states, primarily those without past history of large scale gas production, are examining hydraulic fracturing ("fracking") practices and considering new regulations designed to ensure safe operations. Improvements to fracking technology and its combined use with horizontal drilling helped drive down the cost of shale gas production and turn it into an economic resource. Fracking involves drilling a well and propagating fractures in the shale source rock by injecting large amounts of fluid. The fluid is primarily water mixed with sand and a small amount of chemicals. While most fracking operations have been performed without incident, some fear that accidental leakage of waste water or uncontrolled fracturing might contaminate groundwater aquifers. Potential regulations might drive up the cost of hydrofracking or restrict areas for drilling.

Although tighter regulations might impose additional cost to shale gas development, it is unlikely that they would kill shale gas growth. The fracking process includes installing multiple layers of cement and casing to protect against leakage into groundwater and subsurface. Furthermore, groundwater aquifers are typically located at much shallower depths than the production zone.

When employing best practices, hydrofracking operations have demonstrated to be safe and reliable. More stringent regulations will most likely enforce adoption of best practices in hydrofracking operations. As such, they would not be expected to impose significant added cost to those already employing best practices. If a ban on fracking is imposed, it is likely to be restricted to highly sensitive areas, such as near sources of drinking water or population centers. For example, New York's Department of Environmental Conservation recently lifted a fracking ban on all but the most sensitive areas, leaving 85% of the state's Marcellus Shale open to drilling.[4]

Furthermore, fracking regulations may likely be imposed at a state level. Some major shale gas producing states, including Texas and Louisiana, have a long history of oil and gas production and may be unlikely to impose new regulations on hydrofracking. These states have experienced an economic boom due to rapid growth in shale gas production in the Barnett, Haynesville, and Eagle Ford basins located in their states and are unlikely to restrict future prospects with additional regulations. Therefore, most shale gas operations are unlikely to be greatly affected by new fracking regulations.

[4] http://money.cnn.com/2011/07/01/news/economy/fracking_new_york/index.htm

Finally, additional costs imposed by new fracking regulations will be partly borne by producers and partly passed on to consumers in the form of higher prices. Shale gas is a vital resource, and prices will reflect a level necessary to support their production. Therefore, new fracking regulations are unlikely to drive up costs to the point of making shale gas uneconomic to produce.

Concern: Exporting gas will result in a significant increase in the price of gas for U.S. industry, causing them to be uncompetitive in global markets, leading to a loss of jobs.

DMP Analysis: The modest price impact from proposed export volumes is unlikely to cause the U.S. to be uncompetitive in global markets.

The WGM results indicate that U.S. prices will not significantly increase due to LNG export. The projected change in the average U.S. price is a rather modest $0.12/MMBtu, a 1.7% increase over the Reference Case without LNG exports. The projected impact is greatest near the export terminals but dissipates with distance away from the Gulf region. The price impact is less than $0.10/MMBtu in most downstream markets. Given the projected price impact, it is highly unlikely that it would cause U.S. industry to be uncompetitive in global markets and lead to a loss of jobs. The U.S. has lower gas prices than most industrialized countries and is projected to continue to have lower gas prices, in part due to continued growth in shale gas production. An increase in gas price of less than 2% is unlikely to change the U.S. competitiveness in global markets.

Furthermore, even with exports, U.S. prices will be lower than those in the importing countries. Otherwise, export would be uneconomic. The high cost of constructing a liquefaction plant plus the high transportation cost of a LNG tanker is estimated to require a spread of at least $3.00/MMBtu to Europe and over $4.00/MMBtu to Asia in order to make LNG export economic to those regions. Exporting LNG from the U.S. is being considered now because the price spreads from the U.S. Gulf to Europe and Asia are well above those levels. However, the key point is that even with LNG exports, the U.S. has a built-in cost advantage for natural gas because of the cost differential to get LNG to European and Asian markets. LNG exports alone cannot elevate U.S. prices to European and Asian price levels because of the cost differential.

To illustrate this point, consider the Gulf to the Mid-Atlantic regions which are connected by major pipelines. However, Mid-Atlantic prices are still substantially higher than Gulf prices because of the transportation costs. At specific market hubs, such as New York City, prices can skyrocket during extreme peak demand days because of deliverability constraints on the pipeline system. Even though markets are connected, deliverability constraints can and will decouple their prices during peak periods. The total European gas demand is nearly as large as the U.S. demand. The LNG export volume being considered represents a small fraction of European demand, as well as U.S. supply. The proposed LNG export volumes are inadequate to bring these markets to parity because of transportation costs and capacity constraints.

Concern: Exporting gas will result in a significant increase in the price of electricity for U.S. consumers and industry, causing them to be uncompetitive in global markets, leading to a loss of jobs.

DMP Analysis: The projected impact on electricity prices is projected to be even smaller than the projected impact on gas prices.

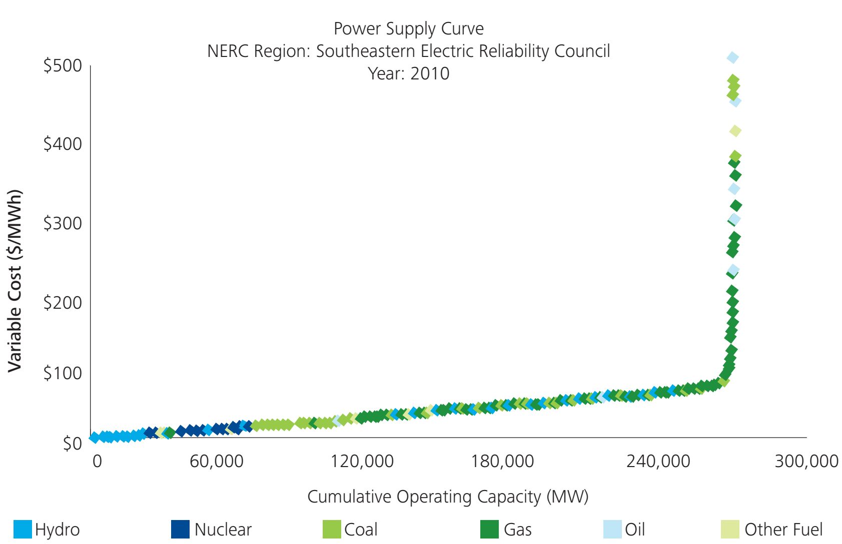
DMP's electricity model is integrated with the WGM so we can also estimate the impact of LNG exports on electricity prices, as natural gas is also a fuel for generating electricity. Since our integrated models represent the geographic linkages between the electricity and natural gas systems, we can compute the impact of the LNG exports in local markets where the impact would be the greatest.

Comparison of electricity prices with and without LNG exports shows that projected electricity prices increase by 1.2% in Louisiana where most of the LNG exports are assumed to occur. The impact is far less than the projected 3.3% Louisiana gas price impact. In power markets in other regions, the impact is projected to be much less because the gas price impact is much less. For example, Midwest gas prices increase by less than 1.0% and result in electricity prices increasing by much less than 1.0%.

A key reason why the electricity price impact is less is that gas price will impact electricity price only if gas-fired generation is at the margin. When gas-fired generation is lower cost than the marginal source, then a small increase in gas price will only impact electricity price if it is sufficient to drive it to the margin. If it is higher cost than the marginal source, then increasing gas price will have no impact because it still would not be utilized. If gas-fired generation is the marginal source, then electricity prices will increase with gas price but only up to the point where some other source can displace it as the marginal source. Every power region has numerous competing generation plants burning different fuel types which will mitigate the price impact of increase in any one fuel.

Figure 11 shows the 2010 power supply curve for the SERC Reliability Corporation (SERC) region which includes Louisiana. The curve plots the variable cost of generation and capacity by fuel type. Depending on where the demand curve intersects the supply curve, a particular fuel type will set the electricity price. During extremely low demand periods, hydro, nuclear, or coal plants will likely set the price. An increase in gas price during these periods would not impact electricity price in this region because gas-fired plants are typically not utilized during these periods. During moderate or moderately high demand periods, coal or gas could be the marginal fuel type. If it is gas on the margin, price can rise only up to the cost of the next marginal fuel type (e.g., coal plant). If gas remains on margin, then the following calculation demonstrates the expected electricity price impact. At the projected gas price impact of $0.22/MMBtu, a typical gas plant with a heat rate of 7,500 would cost an additional $1.65/MWh (=$0.22/MMBtu x 7500 Btu/MWh x 1 MMBtu/1000 Btu). Remember, that is the most that the gas price increase could elevate electricity price. Power load fluctuates greatly during a day, typically peaking during midafternoon and falling during the night. That implies that the marginal fuel type will also vary and gas will be at the margin only part of the time.

Figure 11: Power supply curve for SERC region



Concern: LNG exports will cause U.S. gas prices to trade at global price levels.

DMP Analysis: The volume of LNG exports, as well as the high cost of LNG exports, is inadequate to cause U.S. prices to trade at global price levels.

Based on our analysis, it is unlikely that a limited amount of LNG exports would cause U.S. gas price to be set at global price levels. For one thing, there is no world gas price, in contrast to the oil market in which there is a world oil price. Natural gas, unlike oil, is highly unlikely to ever have a world price. The cost of transportation, on a unitized energy basis, is much higher for gas than it is for oil. Therefore, global gas markets will remain partially interconnected regional markets with prices within each region determined by regional supply and demand balances.

Furthermore, even if there were a global gas market, having a fixed export capacity would not necessarily mean that domestic prices would rise to global price levels. For example, the current European prices (e.g., Zeebrugge, Belgium) are more than double the current Henry Hub price. Exporting 6 Bcfd to Europe would not mean that Henry Hub price would rise to the level of European prices minus the transportation costs differential. Limited transportation capacity would prevent prices from coupling. The same phenomena occur in the U.S. during peak winter days when there are often huge differences between Henry Hub and New York City prices. The basis differential between Henry and New York can rise to many times greater than the transportation cost between the regions. Transportation bottlenecks along the route from the Gulf to New York City prevent Henry prices from rising along with New York City prices and cause these basis blowouts.

As stated previously, even with exports, U.S. prices will be lower than those in the importing countries. Otherwise, export would be uneconomic. The high cost of constructing a liquefaction plant plus the high transportation cost of a LNG tanker would require a spread of at least $3.00/MMBtu to Europe and over $4.00/MMBtu to Asia in order to make LNG export economic to those regions. Exporting LNG from the U.S. is being considered now because the spreads to Europe and Asia are well above those levels. However, the key point is that even with LNG exports, the U.S. has a built-in cost advantage for natural gas. LNG exports alone cannot elevate U.S. prices to European and Asian price levels because of the cost differential.

Concern: Exporting gas will make U.S. prices more volatile as it will link them to global oil markets.
DMP Analysis: The relatively low volume of LNG exports is unlikely to cause significant change in U.S. price volatility.

Whether exports will increase U.S. price volatility involves close examination of seasonal, deliverability, supply contracts, and storage operations. Europe, which along with Asia are expected to be the primary targets for LNG exports, has a highly seasonal demand and little storage capacity relative to the U.S. which translates to highly seasonal prices.

We believe a better question to consider is whether U.S. prices could be pulled up by LNG exports to prices in global markets during peak periods. The price volatility in foreign markets might then be transmitted to U.S. prices.

An examination of historical prices reveals that European prices are no more volatile than U.S. prices. There is a misconception by some that European gas prices are more volatile because they are higher than U.S. prices. This is not true. In fact, during most of the past 20 years, the U.S. had the most volatile prices of all major gas consuming countries.[5] One reason for this is because European countries have long-term supply contracts to meet most of their peak loads and their markets are far more regulated than the U.S. market. Japanese prices are the least volatile because most of their supplies are from long-term contracts that have price smoothing mechanisms (e.g., three-month rolling average price) designed to reduce sharp price swings. Furthermore, the Japanese gas demand is primarily for power generation, which is not highly seasonal.

[5] Natural Gas Price Volatility: Lessons from Other Markets; Report for the American Clean Skies Foundation. Austin F. Whitman, M.J. Bradley & Associates LLC, 2011.

Nevertheless, could connecting to other countries increase the price volatility in the U.S.? For many of the same reasons described in the previous sections, limited LNG exports are unlikely to cause U.S. prices to be more volatile. The volume of exports is relatively small compared to the entire size of the U.S. supply and small relative to the entire European market. If demand increased with a concomitant increase in supply, price and volatility could increase. However, LNG exports will be anticipated by producers and supplies will be made available when they are needed. In fact, prospective LNG exporters are already lining up potential gas suppliers to provide gas for liquefaction.

The concern that LNG exports will increase volatility may be based on observations of price spikes when demand surges during peak days. Temporal supply demand balance can cause short-term price volatility. When the balance is tight, prices tend to rise, and when the balance is slack, prices tend to fall. However, it is an entirely different matter to say that well-anticipated demand growth will cause a tighter market that is more prone to price run-ups during peak periods. Short-term price volatility arises from short-term inelasticities in supply and demand. For example, when demand spikes suddenly, more gas supplies cannot immediately be produced. Productive capacity is fairly fixed in the short term. There is a long lead time before reserves can be added and produced. However, when new demand is well anticipated, productive capacity will rise to meet it.

Hence, the absolute level of demand has little bearing on price volatility. As an example, consider the price volatility of this year, when U.S. demand is trending towards a historical high, compared to the volatility in 2008, when demand was lower. Price volatility this year has been far lower than in 2008 which saw huge gyrations in price. This demonstrates that gas price volatility is not a simple function of absolute gas demand level because gas productive capacity will be developed to match the anticipated demand level.

Some point to the volatility in world oil prices, which translates to volatility in domestic oil and gasoline prices, as a reason for not exporting LNG. However, this is a poor comparison. The cost of transportation, on a unitized energy basis, is much higher for gas than it is for oil. Therefore, global gas markets will remain partially interconnected regional markets with prices within each region determined by regional supply and demand balances.

It is possible that LNG exports might actually work to decrease, not increase, U.S. price volatility. This is counterintuitive but quite possible because LNG exports, with their well-known export capacities, will prompt incremental supplies that could be utilized to meet peak domestic demand. During peak periods when domestic prices shoot up, it might be more advantageous for LNG exporters to not export but rather keep the supplies in the U.S.

Finally, arguments against LNG exports purely on the grounds of increased prices or volatility could just as well be made against any type of domestic demand. After all, a given volume of demand increase, whether it is for domestic consumption or export, will have the same impact on price.

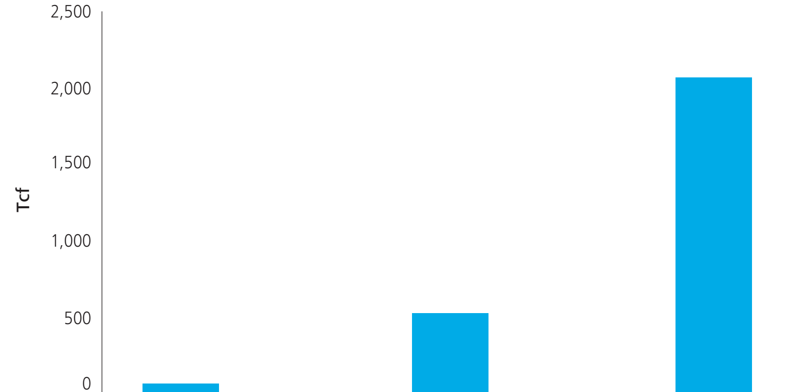
Concern: Exporting gas decreases U.S. energy security.
DMP Analysis: The assumed volume of exports is insignificant compared to total U.S. resource potential.

The energy security issue is based on the fear that exporting LNG will deplete domestic resources, leaving the U.S. dependent on foreign suppliers in the future and vulnerable to price manipulation or supply curtailment. However, the incremental 2.2 Tcf (6 Bcf/day x 365 days/year) of LNG annual exports are fairly insignificant compared to over 2,170 Tcf of technically recoverable gas in the U.S. as estimated by the Potential Gas Committee.[6] (The EIA's latest estimate is even higher: 2,587 Tcf of technically recoverable gas in the U.S.)

Figure 12 illustrates the relative magnitudes of LNG export volumes and U.S. demand for a 20-year period compared to the technically recoverable gas resources in the U.S. This comparison demonstrates that export volumes pale in comparison to both total demand and total domestic supply.

Of course, this simple calculation does not tell the whole story because it ignores the impact on supply cost. However, it underscores the point that economics, not security, is the concern. The volume of LNG exports and projected price impact based on the various assumptions in the WGM are inadequate to pose a security issue. Unless the U.S. is able to convert oil usage to natural gas (i.e., automobiles) to reduce dependence on foreign oil, the issue becomes more one of economics rather than one of energy security.

Figure 12: Comparison of volumes



	LNG Exports (2.2 Tcf/year)	U.S. Demand (26 Tcf/year)	Technically Recoverable Gas (PGC)
Volume	44	520	2,170

[6] Potential Gas Committee press release, April 27, 2011.

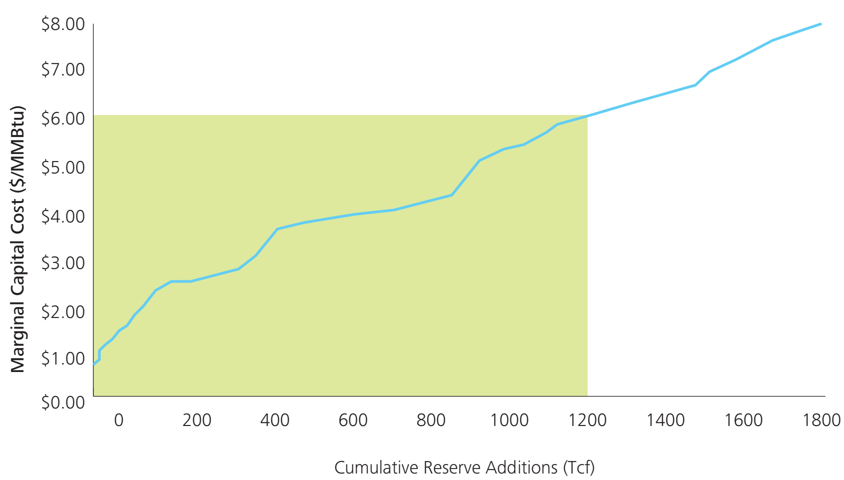
Concern: There are insufficient reserves to allow exports to continue without impacting the market over the term of those exports.

DMP Analysis: The projected volume of LNG exports is insignificant compared to total U.S. resource potential.

As we described in previous sections, the impact of LNG exports would be fairly small to domestic gas markets and almost imperceptible to the power market. The domestic gas resource base, represented by the supply curve in Figure 13, is estimated to be adequate to supply projected demand levels for at least 50 years at moderate prices. The volume of LNG exports represents a relatively small increment to the total demand.

Furthermore, technological advancements will likely continue to drive down production costs, thereby reducing the high cost end of the supply curve. Some of the largest energy supermajors have committed to shale gas development and improving technologies and procedures to drive down their costs. This implies more economically recoverable gas and a prolonged period of relatively low gas prices with or without LNG exports.

Figure 13. U.S. supply curve



It is important to note that the volume of "reserves" is not the issue but rather the volume of "resources." Reserves are volumes of resource that have been "proved up" and ready for production. Resources, on the other hand, are the total volumes that are in the ground, most of which have yet to be proved up or even discovered, but can be reasonably estimated based on geological and other factors.

Concern: LNG exports are inconsistent with the U.S. policy of energy independence.

DMP Analysis: Large domestic gas supplies will maintain natural gas independence even with exports.

There is a frequently expressed desire for energy independence in the U.S., but there is no official U.S. policy for energy independence. The U.S. is largely independent of non-North American natural gas supplies. The energy dependency that the general public has in mind usually relates to oil imports and the resulting export of dollars to the oil-exporting countries. Perhaps the thought is that gas can displace the oil imports and help alleviate U.S. dependence on foreign oil. If this is the goal, then it would require retrofit of millions of vehicles and thousands of refueling stations. This has been much discussed but never done because of the tremendous costs involved. Due to the high density of oil, it is a near perfect fuel for transportation. Natural gas, although much cheaper and domestically available, lacks the desired properties of oil and therefore is unlikely to capture a significant share of the transportation market.

Furthermore, natural gas is not a substitute for oil to a significant degree in any other sector. There are very few oil-fired power plants, and those generally have low utilization rates. Very few industrial boilers burn oil because of its high cost and emissions. Indeed there is very limited oil-gas substitutable demand. Therefore, at present, there is little that natural gas can do to alleviate the country's dependence on oil imports.

Finally, energy exports from the U.S. are not without precedent. The U.S. has been exporting coal for years, as well as exporting LNG from Alaska. The U.S. also exports gas to Mexico. The attention on LNG exports on security grounds seems inconsistent with these other examples.

Concern: Exporting gas will reduce U.S. ability to maximize use of gas domestically.

DMP Analysis: There are sufficient volumes of domestic natural gas for both domestic consumption and LNG exports.

As we discussed earlier, there are sufficient volumes for both domestic use and exports. As stated previously, the domestic gas resource base is estimated to be adequate to supply projected demand levels for at least 50 years at moderate prices. The volume of LNG exports represents a relatively small increment to the total demand. This concern would be more relevant if the U.S. did not possess the abundant shale gas resources that it does, but then again, there would be no talk about LNG exports if that was the case.

One could argue that allowing export of LNG is making maximal use of domestic gas because producers are finding a market for gas that would otherwise not be produced.

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