SIERRA CLUB
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January 27, 2012

Via Online eFiling Portal

Ms. Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E., Room 1A
Washington, D.C. 20426

Re: Environmental Assessment - Sabine Pass Liquefaction Project
Docket No. CP11-72-000

Dear Ms. Bose:

Enclosed please find the following documents submitted by Sierra Club in FERC docket CP11-72-000:

- Sierra Club's Motion to Intervene and Comments on the Environmental Assessment for the Sabine Pass Liquefaction Project
- Exhibits 1-9 to Sierra Club's Comments

All information contained in the documents submitted as part of this filing is designated public information. If you have any questions regarding this filing, please do not hesitate to contact me at (415) 977-5695.

Respectfully Submitted,

/s/ Nathan Matthews________
Nathan Matthews
Attorney for Sierra Club

UNITED STATES DEPARTMENT OF ENERGY

BEFORE THE DEPARTMENT OF ENERGY
FEDERAL ENERGY REGULATORY COMMISSION

In the Matter of: Sabine Pass Liquefaction, LLC and Sabine Pass LNG, L.P	FERC Docket Nos. CP11-72-000, PF10-24

SIERRA CLUB'S NOTICE OF INTERVENTION, MOTION TO INTERVENE, and COMMENT on THE DECEMBER 28, 2011 SABINE PASS LIQUEFACTION PROJECT ENVIRONMENTAL ASSESSMENT

January 27, 2012

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UNITED STATES DEPARTMENT OF ENERGY

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I. Background and Motion to Intervene

Pursuant to Rule 214 of the U.S. Department of Energy's Rules of Practice and Procedure the Sierra Club hereby moves to intervene in the above-captioned docket. [1] Sierra Club's principal place of business is 85 Second St., Second Floor, San Francisco, CA 94105. Service in this proceeding may be made upon counsel for Sierra Club designated below.

Sierra Club is a national, non-profit environmental and conservation organization with more than 600,000 members nationwide. Through its Natural Gas Reform campaign, Sierra Club members work to ensure that the natural gas industry is subject to strong national and state safeguards that protect our air, water, and communities. The Sierra Club's work includes submitting comments in numerous state and federal agency energy-related proceedings and rulemakings,

[1] 18 C.F.R. § 385.214(a)(3), (b)(1), (b)(2)(iii).

pursuing energy-related litigation, attending and speaking at public hearings, speaking to students and civic and other organizations, and holding seminars and symposia – all in support of policies to limit fossil fuels' impacts to human health, climate change and the environment and to promote clean energy alternatives and energy efficiency.

On January 31, 2011, Sabine Pass LNG, L.P. and Sabine Pass Liquefaction, LLC (collectively "Sabine Pass") filed an application with the Federal Energy Regulatory Commission ("FERC") under Section 3(a) of the Natural Gas Act[2] to construct and operate liquefaction and export facilities at the existing LNG import facility in Cameron Parish, Louisiana.[3] This application is docketed as FERC Docket No. CP11-72-000.

The construction/operation application follows earlier applications before the Department of Energy's Office of Fossil Energy ("DOE FE") requesting authority to export LNG to free-trade-agreement[4] and non-free-trade-agreement[5] countries. DOE has granted both applications, although the application for export to non-free-trade-agreement countries is conditioned on completion of FERC's National Environmental Policy Act[6] ("NEPA") review of the construction/operation application.

As a result of the separate construction/operation and export applications, there are effectively two dockets in this case. The construction/operation docket is

[2] 15 U.S.C. § 717b.
[3] FERC Docket No. CP11-72
[4] Application filed August 11, 2010, FE Docket No. 10-85-LNG. Application granted Sept. 7, 2010.
[5] Application filed Sept. 7, 2010, FE Docket No. 10-111-LNG. Application conditionally granted May 20, 2011, pending completion of National Environmental Policy Act analysis.
[6] 42 U.S.C. § 4321.

FERC Docket No. CP11-72-000, while FERC previously opened a "pre-filing" docket in connection with the DOE FE export applications, FERC Docket No. PF10-24. The environmental assessment was filed in CP11-72-000, with notice of the filing lodged in PF10-24. No separate environmental assessment will be filed in PF10-24.

Sierra Club has a direct interest in these dockets because the environmental, climate and human health effects of exports and the siting, construction, and operation of this export facility are potentially significant. Accordingly, an environmental impact statement must be prepared under NEPA and DOE's NEPA regulations at 10 CFR Part 1021. These effects are articulated below, together with other concerns regarding the application. The Sierra Club's interests in this proceeding are not represented by any current party to the proceeding. Sierra Club's participation will advance the public interest in full disclosure and assessment of environmental effects associated with the Sabine Pass application.[7]

II. Comments on The EA

a. The EA Unlawfully Looks Only at The Impacts of Construction and Operation of the Export Facilities, Ignoring The Effects of Export Itself and Failing to Take A Hard Look at Whether LNG Export Is in The Public Interest

Section 3(a) of the Natural Gas Act requires the Secretary of Energy to deny an export application if he finds that the proposed exportation "will not be consistent with the public interest." The public interest includes environmental effects in addition to effects on natural gas markets. Here, in DOE FE's order

[7] 18 C.F.R. § 385.214 (a)(3), (b)(2)(iii).

conditionally granting Sabine Pass's application for export authority, DOE FE acknowledged that the public interest assessment "the domestic need for the natural gas proposed to be exported; whether the proposed exports pose a threat to the security of domestic natural gas supplies; and *any other issue determined to be appropriate*."[8] These other issues include environmental impacts. The open-ended requirement to assess the public interest, interpreted in light of the policies and obligations imposed by NEPA, requires "DOE to give appropriate consideration to the environmental effects of its proposed decisions."[9]

Under the FERC and DOE FE's proposed framework, the instant environmental assessment provides the sole opportunity to examine environmental effects of exports themselves or of construction, operation, and siting of export facilities. DOE FE is relying on FERC: DOE FE's authorization of exports was "conditioned on the satisfactory completion of the environmental review process in FERC Docket No. PF10-24-000 and on issuance by DOE/FE of a finding of no significant impact or a record of decision pursuant to NEPA."[10] PF10-24 is FERC's "pre-filing" docket for this matter. The EA at issue here is docketed in CP11-72-000 and referred to in PF10-24.[11]

Although environmental review of export itself was deferred until this EA, the EA wrongly limits its scope to solely the siting, construction and operation of the

[8] NFTA Export Order at 29 (emphasis added)
[9] *Id.* The NFTA order further cited DOE FE Order No. 1473, *Phillips Alaska Natural Gas Corporation and Marathon Oil Company*, 2 FE ¶ 70,317 and DOE Delegation Order No. 0204-111 for the proposition that DOE must regulate exports "based on a consideration of the domestic need for the gas to be exported and such other matters as the Administrator finds in the circumstances of a particular case to be appropriate."
[10] NFTA order at 41 (citing 10 CFR § 590.402)
[11] *See* FERC filing of Oct. 29, 2010 in PF10-24 (explaining FERC's NEPA process), FERC filing of Dec. 16, 2011 in PF10-24 (notice of availability of EA in CP11-72-00)

liquefaction and loading facilities, ignoring the impacts of export itself. This cabined review violates NEPA. NEPA's implementing regulations require agencies to consider the effects of their actions, and do not allow consideration of a subset of the action. NEPA also requires that all environmental analyses be conducted at "the earliest possible time" and to the "the fullest extent possible."[12] NEPA requires that an "assessment of all 'reasonably foreseeable' impacts must occur at the earliest practicable point, and must take place before an 'irretrievable commitment of resources' is made."[13]

Export of LNG will induce additional shale gas extraction, increase domestic gas prices, induce additional coal consumption for electricity generation, and increase greenhouse gas emissions and global warming. Each of these effects should have been analyzed in the EA but were omitted from discussion. Furthermore, these effects bear on the question of whether export is in the public interest, and must be factored into the DOE FE's forthcoming final assessment of the public interest pursuant to the Natural Gas Act.

i. Export Will Induce Additional Shale Gas Extraction, but The EA Does Not Examine The Impacts of This Extraction

The stated purpose of the export and associated facilities is to "provide a market solution to allow further development of unconventional (particularly shale

[12] *See N.M. ex rel. Richardson v. BLM*, 565 F.3d 683, 718 (10th Cir. 2009)

[13] *Id.* (citing 42 U.S.C. § 4332(2)(C)(v); *Pennaco Energy, Inc. v. U.S. Dept. of Interior*, 377 F.3d 1147, 1160 (10th Cir. 2004); 40 C.F.R. §§ 1501.2, 1502.2240 C.F.R. § 1501.2)), *see also Kern v. U.S. Bureau of Land Mgmt.*, 284 F.3d 1062, 1072 (9th Cir. 2002) ("NEPA is not designed to postpone analysis of an environmental consequence to the last possible moment. Rather, it is designed to require such analysis as soon as it can reasonably be done.").

gas-bearing formation) sources in the United States."[14] Despite this explicit recognition that the project will encourage additional shale gas extraction, the EA contains no analysis of the impacts of such extraction. This violates NEPA's command to consider both direct and indirect impacts of the proposed action.[15]

As a threshold matter, the EA's prediction that exports will "facilitate" shale gas extraction appears well-founded. The Energy Information Administration ("EIA") recently concluded that "natural gas markets in the United States balance in response to increased natural gas exports largely through increased natural gas production," and that in most foreseeable scenarios, "about three-quarters of this increased production is from shale sources."[16]

Shale gas is typically extracted through a combination of horizontal drilling and hydraulic fracturing techniques. These techniques, and their health and environmental consequences, were recently summarized by the Natural Gas Subcommittee of the Secretary of Energy Advisory Board,[17] other government agencies,[18] and in expert reports submitted by the Sierra Club and other groups in a variety of regulatory proceedings.[19] We summarize this process and these impacts

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[14] EA 1-10

[15] 40 CFR § 1508.8 (indirect effects defined as those "caused by an action and [that] are later in time or farther removed in distance, but are still reasonably foreseeable")

[16] Exhibit 1, Energy Information Administration, Effects of Increased Natural Gas Exports on Domestic Energy Markets, 6 (January 2012) available at http://www.eia.gov/analysis/requests/fe/pdf/fe_lng.pdf

[17] Exhibit 2, Natural Gas Subcommittee, *90-day interim report*, (August 18, 2011), *available at* http://www.shalegas.energy.gov/resources/081811_90_day_report_final.pdf, Exhibit 3, *180-day interim report* (Nov. 18, 2011) *available at* http://www.shalegas.energy.gov/resources/111811_final_report.pdf.

[18] While it would be infeasible to include every such assessment here, a recent and notable example is the New York Department of Environmental Conservation's *Revised Draft Supplemental General Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program* (September 2011), *available at* http://www.dec.ny.gov/data/dmn/rdsgeisfull0911.pdf and attached here as Exhibit 4.

[19] The Sierra Club and other organizations have also provided extensive expert analysis of the impacts of hydraulic fracturing. For analysis of water impacts, *see* Natural Resources Defense Council, Earthjustice, and Sierra Club,

here. Hydraulic fracturing involves injecting water, sand, and various fracturing chemicals into the gas-bearing formation at high pressures to fracture the rock and release additional gas. Thus, the first step in the process requires procurement of large quantities of water and sand, often in areas with limited water resources. These materials must then be transported to the well site, imposing significant transportation impacts. The fracturing process then poses a risk to groundwater resources, as fractures in the formation and failure of the well casing can lead to contamination of groundwater. Contaminants may include chemicals introduced into the well, such as fracturing fluid and drilling muds, as well as naturally occurring substances previously isolated from the ground water sources, such as methane, salts, and naturally occurring radioactive material. On the surface, the fracturing fluid, drilling mud, and produced water must be stored and disposed of. The storage facilities for these substances can fail, introducing environmental and erosion hazards into the surrounding environment. Disposal of produced water is a challenge because of, *inter alia*, its volume, salinity, and unusual contaminants. Thus, publicly owned water treatment works are often incapable of processing hydraulic fracturing produced water. After the initial fracturing, gas from the well is often vented or flared as the initial "flowback" is cleared from the well. Because of this flaring or venting process, fractured wells typically have air emissions much higher than those of traditional wells.

Comments [to EPA] on Permitting Guidance for Oil and Gas Hydraulic Fracturing Activities Using Diesel Fuels (June 29, 2011), attached here as Exhibit 5. For a discussion of the air impacts of natural gas extraction, with a focus on hydraulic fracturing, *see* Sierra Club, et al., *Comments on New Source Performance Standards: Oil and Natural Gas Sector; Review and Proposed Rule for Subpart OOOO,* Docket No. EPA-HQ-OAR-2010-0505 (Nov. 30, 2011), attached here as Exhibit 6. We further submitted extensive technical reports on the NY RDSGEIS, attached here as Exhibits 7 and 8

In light of the stated purpose of the project and the Energy Information Administration's predictions, an increase in shale gas extraction (and concomitant environmental effects) is indisputably an effect likely to be "caused by" the project, 40 CFR § 1508.8. NEPA requires analysis of the effects of increased driling. The EA's failure to address these effects is unlawfully deficient.

ii. Export Will Increase Domestic Gas Prices

The EIA recently concluded that LNG export will increase domestic gas prices.[20] This rebuts conclusions reached by DOE FE in the order conditionally granting authority to export to non-free-trade-agreement countries.[21] Specifically, the DOE FE's public interest determination explicitly rested on the conclusion that export would minimally affect domestic gas prices. *Id.* Although some commenters had argued to the contrary, DOE FE rejected these comments as lacking scientific foundation. The EIA report provides the missing foundation. At a minimum, the EA must revisit this issue in light of the EIA report, and consider the effects that increased domestic gas prices would entail.

iii. The EA Fails to Examine the Effect LNG Export Will Have on Domestic Electricity Production and the Consequences Associated with These Effects

As noted above, the Energy Information Administration concluded that exports will increase domestic natural gas prices. These higher prices will cause "the electric power sector primarily [to] shift[] to coal-fired generation, and

[20] Exhibit 1, Energy Information Administration, *Effects of Increased Natural Gas Exports on Domestic Energy Markets*, 6 (January 2012) *available at* http://www.eia.gov/analysis/requests/fe/pdf/fe_lng.pdf
[21] DOE FE NFTA Order at 30.

secondarily of renewable resources."[22] The increase in domestic coal consumption for purposes to electricity generation is therefore an indirect effect caused by LNG export. Because coal burning power plants emit more hazardous pollutants than natural gas fired plants, this shift will negatively affect human health and the environment. The EA should have analyzed this impact.

iv. The EA Unlawfully Failed to Take A Hard Look at Impacts on Global Warming, Because It Improperly Concluded That The Export Facility's GHG Emissions Were Insignificant and Improperly Failed to Indirect Effects on Greenhouse Gas Emissions

The EA acknowledges that the liquefaction facility will emit greenhouse gasses ("GHGs")[23], and that direct emissions of the liquefaction project will amount to 3.9 million tons per year of carbon dioxide equivalent.[24] This will increase Louisiana's total GHG emissions by 2% on a CO2-equivalent basis.[25] Sabine Pass completed a GHG Best Available Control Technology analysis as part of its Clean Air Act Prevention of Significant Deterioration permit application with the Environmental Protection Agency. The EA summarizes this analysis, explaining that carbon capture and sequestration technology is infeasible because of the distance to carbon dioxide pipelines.[26] The EA then states:

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[22] Exhibit 1, Energy Information Administration, *Effects of Increased Natural Gas Exports on Domestic Energy Markets*, 6 (January 2012) *available at* http://www.eia.gov/analysis/requests/fe/pdf/fe_lng.pdf
[23] EA 2-57
[24] *Id.*
[25] EA 2-99
[26] *Id.*

> Currently there is no standard methodology to determine how the Project's incremental contribution to GHGs would translate into physical effects on the global environment. However, the emissions would increase the atmospheric concentration of GHGs, in combination with past and future emissions from all other sources, and contribute incrementally to climate change that produces the impacts previously described. Because we cannot determine the Project's incremental physical impacts due to climate change on the environment, we cannot determine whether the Project would result in significant impacts related to climate change.[27]

This analysis is inadequate for several reasons. First, the claimed inability to identify incremental physical impacts is not sufficient to support a finding of insignificance. The Supreme Court has explained that global warming is a problem that will be addressed one piece at a time.[28] Here, GHG emissions are over an order of magnitude greater than the threshold EPA set for identifying major sources of GHG emissions. Accordingly, the claimed inability to quantify incremental impacts does not render the impacts insignificant.

Second, the EA fails to account for indirect GHG emissions. LNG has higher lifecycle greenhouse gas emissions than traditional natural gas.[29] Liquefying natural gas is an energy intensive process. The EA includes the emissions directy attributable to the liquefaction process, although as described in the previous paragraph, the EA fails to take a hard look at the effects of those emissions. Liquefaction, however, is only one part of the gas lifecycle. Once liquefied, LNG

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[27] EA 2-99 – 2-100

[28] *Massachusetts v. EPA*, 549 U.S. 497, 524 (2007) (describing GHG emissions from the US transportation sector as a "meaningful contribution" to global emissions)

[29] Exhibit 9, Jamarillo, et al., *Comparative Life Cycle Carbon Emissions of LNG Versus Coal and Gas for Electricity Generation* (Oct. 12, 2005) *available at* http://www.ce.cmu.edu/~gdrg/readings/2005/10/12/Jaramillo_LifeCycleCarbonEmissionsFromLNG.pdf.

must be transported by truck or tanker, with inherent transportation emissions. [30] It is then regassified, typically using equipment that runs of natural gas and entails further emissions.[31] When these additional steps are considered, LNG has lifecycle greenhouse gas emissions that rival or even exceed those of coal in terms of electricity generation on a per-kilowatt-hour basis.[32] Furthermore, as explained above, GHG emissions from shale gas are higher than those for traditional gas, in part because of the gasses released during the completion process. As noted, the export project is likely to induce further shale gas drilling. All of these additional GHG emissions are indirect effects of the project, yet none of these are included in the EA.

b. The EA Uses The Wrong Baseline for Ship Traffic

The EA states that "The number of ships utilizing the [Sabine Pass Natural Gas] Terminal would not increase as a result of the project. Sabine Pass is currently permitted for a maximum of 400 ships that could call on the terminal per year. Because loading rates proposed for the Project are the same as the unloading rates for the [existing] Terminal, no increase in ship traffic is anticipated."[33]

Rather than comparing anticipated ship traffic with existing *permit*, the EA should have compared anticipated traffic with existing *practice*. The EA does not indicate how the current level of *actual* ship traffic. In light of existing natural gas market conditions, with US prices lower than international prices, it is unlikely

[30] *Id.* at 10.
[31] *Id.* at 10.
[32] *Id.* at 13.
[33] EA 1-9

that the terminal is being used to its full permitted import capacity. Indeed, it is likely that the terminal has *never* been used at this capacity, as the construction of the terminal coincided with the shale gas boom and accompanying change in the domestic gas market. Thus, it is likely that construction of export facilities and authorization of exports will increase the number of ships actually calling on the terminal.

At least one state supreme court has explicitly considered such a scenario in interpreting a state NEPA analogue, holding that when actual practice has lesser impacts than allowed by existing permits, meaningful environmental review requires measurement against the actual practice.[34] There, a refinery had licenses to operate four boilers, each specifying a maximum operating level.[35] Although these licenses in principle authorized all four boilers to simultaneously operate at maximum capacity, this never occurred in practice.[36] Instead, no boiler operated at the maximum level unless one or more other boilers had been shut down for maintenance.[37] The state Environmental Impact Report used the legally authorized but never realized limit, rather than actual practice, as the environmental baseline. The Court overturned this report. "An approach using hypothetical allowable conditions as the baseline results in 'illusory' comparisons that 'can only mislead the public as to the reality of the impacts and subvert full consideration of the actual environmental impacts,' a result at direct odds with [the state environmental

[34] *Cmtys. for a Better Env't v. S. Coast Air Quality Mgmt. Dist.*, 48 Cal.4th 310, 328, 106 Cal.Rptr.3d 502, 226 P.3d 985 (2010).
[35] *Id.*, 48 Cal.4th at 322, 106 Cal.Rptr.3d 502, 226 P.3d 985
[36] *Id.*
[37] *Id.*

review statute's] intent."[38] This reasoning is equally applicable to NEPA and to the facts here.

c. The EA Fails To Take A Hard Look at Water Requirements

The project will require 3,500 gallons per minute ("gpm") of water, but the EA only describes the provision of 2,300 to 2,400 gpm of supply. Failure to identify the remaining supply renders the EA deficient.

Sabine Pass proposes to construct four liquefaction trains. The EA states that "[o]peration of all four liquefaction trains would require a water supply of approximately 3,500 gpm."[39] This demand exceeds existing on-site supply, which provides only 100 to 200 gpm.[40] Sabine Pass (the company) proposes to augment this supply by constructing a pipe to Sabine Pass, Texas (the town).[41] This "12-inch diameter, 1.2-mile water supply line" is designed to supply "approximately 2,200" gpm.[42]

The EA provides no discussion of how the remaining 1,100 to 1,200 gpm of water will be supplied, or what consequences will arise if the water is unavailable. Instead, the EA merely states that if additional water supplies are needed, Sabine Pass will "consult with the appropriate state and federal resource agencies to obtain or update its existing permits or authorizations."[43] As explained above, NEPA requires that all environmental analyses be conducted at "the earliest possible time"

[38] *Id.*
[39] EA 2-15
[40] *Id* EA 1-10
[41] *Id*
[42] *Id*
[43] *Id*

and to the "the fullest extent possible."[44] Postponing inquiry into to the satisfaction of known water needs violates this obligation.

d. The EA Relies on Methods to Remedy Identified Deficiencies in Particulate Management without Addressing Whether These Methods Will Be Effective

The EA determined that construction of the facilities will cause significant particulate emissions in the form of fugitive dust, included 658 tons per year (tpy) of PM10 and 99 tpy of PM2.5 across the multi-year construction period. EA 2-52. Sabine Pass proposes to limit these emissions by spraying water and/or applying calcium chloride or other dust suppressants. EA 2-54. The EA assumes that these techniques will have a "control factor" of 50%. The EA properly concludes that these measures are therefore insufficient to ensure adequate mitigation of fugitive dust emissions. The EA therefore recommends requiring Sabine Pass to file a "Fugitive Dust Control Plan" that identifies "precautions" and "additional mitigation measures" to control fugitive dust emissions. EA 2-54. These measures may include "measures to limit track-out onto the roads," a speed limit on unsurfaced roads, and "covering open-bodied haul trucks." EA 2-55. Absent from the EA is any assessment of the efficacy of these measures in this context. Without knowing how effective these measures can be, the EAs' conclusion that these measures will render fugitive dust emissions insignificant is arbitrary and capricious.

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[44] *See N.M. ex rel. Richardson v. BLM*, 565 F.3d 683, 718 (10th Cir. 2009)

e. Hydrogen Sulfide

The proposed project includes facilities to remove carbon dioxide and hydrogen sulfide from natural gas prior to liquefaction. This removed hydrogen sulfide will periodically be vented to the atmosphere. EA 2-69. Such venting will emit concentrations of hydrogen sulfide as high as 0.1%. Id. The EA includes a cursory discussion of the placement of hydrogen sulfide detectors, but includes no discussion of whether these emissions will pose a threat to human health or the environment. Absent such a discussion, FERC cannot conclude that these effects are insignificant.

f. An Environmental Impact Statement Is Required

The authorization to export LNG and to construct and operate LNG export facilities merits an Environmental Impact Statement ("EIS") under NEPA because both aspects of the project will have significant effects on the human environment. Under NEPA, an agency must prepare an EIS when there is a major Federal action that significantly affects the quality of the human environment.[45]

FERC's own regulations identify export of natural gas as an activity that will ordinarily require an EIS.[46] Specifically, FERC's regulations provide that an EIS is "generally" required for "authorizations to . . . export natural gas under section 3 of the Natural Gas Act involving construction of . . . liquefied natural gas terminals and regasification or storage facilities[] or significant expansions and modifications

[45] 42 U.S.C. §4332(C)
[46] 10 C.F.R. § 1021 app. D ("Classes of Actions that Normally Require EISs")

of existing pipelines or related facilities."[47] An EIS is also generally required for "Approvals or disapprovals of authorizations to import or export natural gas under section 3 of the Natural Gas Act involving major operational changes (*such as a major increase in the quantity of liquefied natural gas imported or exported*)."[48] The export proposals before FERC and DOE FE appear to fall into both categories. Although the agencies may argue that the regulation only states that an EIS is "generally" required, before departing from this general rule, the EA must at the very least explain why a departure is warranted. Here, however, the EA includes no discussion of the regulation or regarding why these "general" rules are inapplicable here, nor does there appear to be any other such discussion in the docket.

Even absent FERC's own regulations, NEPA and the statute's general implementing regulations demonstrate that an EIS is required. Many of the project's impacts cross the threshold of "significance" and thereby trigger the EIS requirement. In determining whether or not the effects will be "significant," or whether substantial questions exist as to the significance of the effects, NEPA's implementing regulations require FERC to consider the "context" and "intensity" of the likely impacts. "Context" means "that the significance of an action must be analyzed in several contexts such as society as a whole (human, national), the affected region, the affected interests, and the locality."[49] Also, "[b]oth short- and

[47] *Id at D8*
[48] *Id*. at D9 (emphasis added)
[49] 40 C.F.R. § 1508.27(b)

long-term effects are relevant" for context.[50] "Intensity" means the "severity of impact" and is to be judged according to several criteria.[51]

Finally, the failure to consider many pertinent impacts in the EA warrants completion of an EIS. As explained above, the EA wholly fails to consider many of the impacts associated with the proposal. When an agency gives a "cursory and inconsistent treatment" of an issue, or no references or defense of a statement is given, an agency must prepare an EIS.[52]

III. Conclusion

As explained above, the EA violates NEPA by failing to take a hard look at the effects of the proposed action. The EA wholly ignores indirect effects resulting from export, considering only construction and operation of the facility itself. This exclusion of indirect effects violates NEPA and is incompatible with DOE FE's decision to rely on FERC to assess the impacts of export authorization. The EA further falls short in its evaluation with regard to several of the factors it did consider. In light of these reasons, as well as FERC's general guidelines, FERC must prepare an EIS for the action.

In order to continue to assert the above arguments, and to generally advocate the public interest in the environment in these proceedings, the Sierra Club respectfully requests to intervene.

[50] *Id*
[51] *Id*
[52] *Blue Mountains Biodiversity Project v. Blackwood*, 161 F.3d 1208, 1213-14 (9th Cir. 1998)

Dated: January 27, 2012

Respectfully Submitted,

_/s Nathan Matthews_____________________

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UNITED STATES DEPARTMENT OF ENERGY

BEFORE THE DEPARTMENT OF ENERGY
FEDERAL ENERGY REGULATORY COMMISSION

In the Matter of: Sabine Pass Liquefaction, LLC and Sabine Pass LNG, L.P	FERC Docket Nos. CP11-72-000, PF10-24

SIERRA CLUB'S COMMENTS on THE DECEMBER 28, 2011 SABINE PASS LIQUEFACTION PROJECT ENVIRONMENTAL ASSESSMENT

Exhibit 1

Energy Information Administration, *Effects of Increased Natural Gas Exports on Domestic Energy Markets,* 6 (January 2012)

January 27, 2012

Independent Statistics & Analysis
U.S. Energy Information Administration

Effect of Increased Natural Gas Exports on Domestic Energy Markets

as requested by the Office of Fossil Energy

January 2012

Contacts

The Office of Energy Analysis prepared this report under the guidance of John Conti, Assistant Administrator for Energy Analysis. General questions concerning the report can be directed to Michael Schaal (michael.schaal@eia.gov, 202/586-5590), Director, Office of Petroleum, Natural Gas and Biofuels Analysis; and Angelina LaRose, Team Lead, Natural Gas Markets Team (angelina.larose@eia.gov, 202/586-6135).

Technical information concerning the content of the report may be obtained from Joe Benneche (joseph.benneche@eia.gov, 202/586-6132).

Preface

The U.S. Energy Information Administration (EIA) is the statistical and analytical agency within the U.S. Department of Energy. EIA collects, analyzes, and disseminates independent and impartial energy information to promote sound policymaking, efficient markets, and public understanding of energy and its interaction with the economy and the environment. By law, EIA's data, analyses, and forecasts are independent of approval by any other officer or employee of the U.S. Government. The views in this report, therefore, should not be construed as representing those of the Department of Energy or other Federal agencies.

The projections in this report are not statements of what *will* happen but of what *might* happen, given the assumptions and methodologies used. The Reference case in this report is a business-as-usual trend estimate, reflecting known technology and technological and demographic trends, and current laws and regulations. Thus, it provides a policy-neutral starting point that can be used to analyze policy initiatives. EIA does not propose, advocate, or speculate on future legislative and regulatory changes.

Contents

Tables

Figures

Introduction

This report responds to an August 2011 request from the Department of Energy's Office of Fossil Energy (DOE/FE) for an analysis of "the impact of increased domestic natural gas demand, as exports." Appendix A provides a copy of the DOE/FE request letter. Specifically, DOE/FE asked the U.S. Energy Information Administration (EIA) to assess how specified scenarios of increased natural gas exports could affect domestic energy markets, focusing on consumption, production, and prices.

DOE/FE provided four scenarios of export-related increases in natural gas demand (Figure 1) to be considered:

- 6 billion cubic feet per day (Bcf/d), phased in at a rate of 1 Bcf/d per year (low/slow scenario),
- 6 Bcf/d phased in at a rate of 3 Bcf/d per year (low/rapid scenario),
- 12 Bcf/d phased in at a rate of 1 Bcf/d per year (high/slow scenario), and
- 12 Bcf/d phased in at a rate of 3 Bcf/d per year (high/rapid scenario).

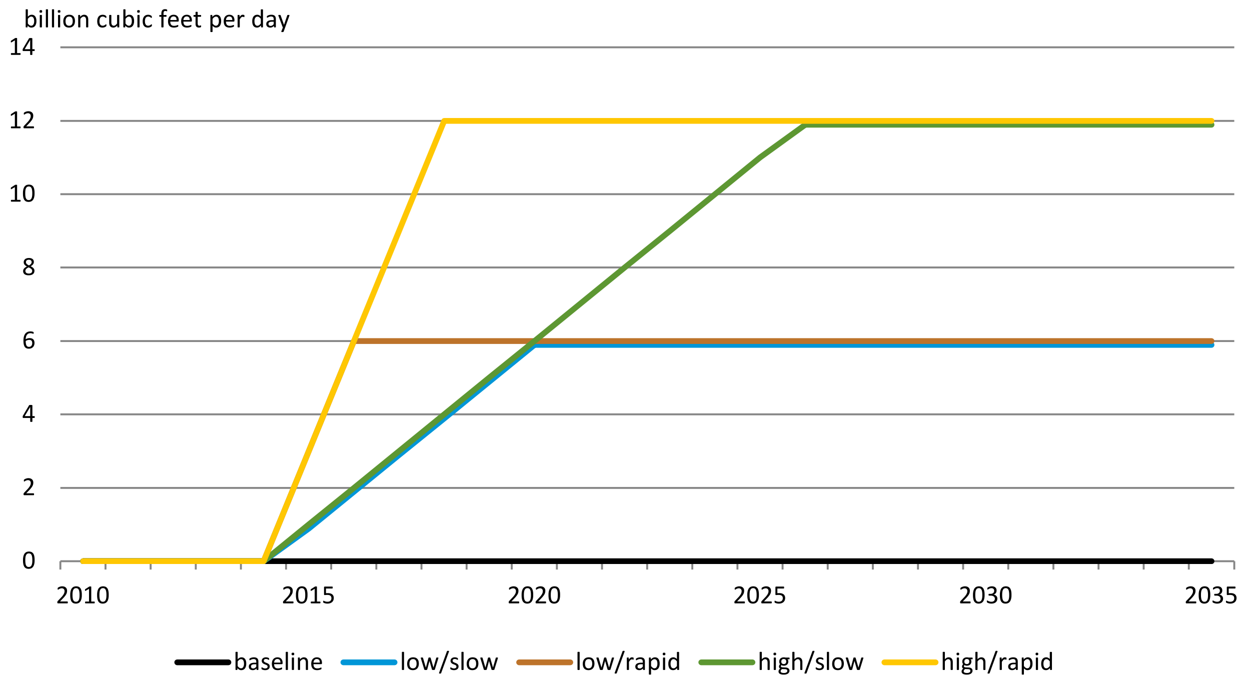
Total marketed natural gas production in 2011 was about 66 Bcf/d. The two ultimate levels of increased natural gas demand due to additional exports in the DOE/FE scenarios represent roughly 9 percent or 18 percent of current production.

DOE/FE requested that EIA consider the four scenarios of increased natural gas exports in the context of four cases from the EIA's *2011 Annual Energy Outlook* (*AEO2011*) that reflect varying perspectives on the domestic natural gas supply situation and the growth rate of the U.S. economy. These are:

- the *AEO2011* Reference case,
- the High Shale Estimated Ultimate Recovery (EUR) case (reflecting more optimistic assumptions about domestic natural gas supply prospects, with the EUR per shale gas well for new, undrilled wells assumed to be 50 percent higher than in the Reference case),
- the Low Shale EUR case (reflecting less optimistic assumptions about domestic natural gas supply prospects, with the EUR per shale gas well for new, undrilled wells assumed to be 50 percent lower than in the Reference case), and
- the High Economic Growth case (assuming the U.S. gross domestic product will grow at an average annual rate of 3.2 percent from 2009 to 2035, compared to 2.7 percent in the Reference case, which increases domestic energy demand).

DOE/FE requested this study as one input to their assessment of the potential impact of current and possible future applications to export domestically produced natural gas. Under Section 3 of the Natural Gas Act (NGA) (15 U.S.C. § 717b), DOE must evaluate applications to import and export natural gas and liquefied natural gas (LNG) to or from the United States. The NGA requires DOE to grant a permit unless it finds that such action is not consistent with the public interest. As a practical matter, the need for DOE to make a public interest judgment applies only to trade involving countries that have not entered into a free trade agreement (FTA) with the United States requiring the national treatment for trade in natural gas and LNG. The NGA provides that applications involving imports from or exports to an FTA country are deemed to be in the public interest and shall be granted without modification or delay. Key countries with FTAs include Canada and Mexico, which engage in significant natural gas trade with the United States via pipeline. A FTA with South Korea, currently the world's second largest importer of LNG, which does not currently receive domestically produced natural gas from the United States, has been ratified by both the U.S. and South Korean legislatures, but had not yet entered into force as of the writing of this report.

Figure 1. Four scenarios of increased natural gas exports specified in the analysis request



Source: U.S. Energy Information Administration based on DOE Office of Fossil Energy request letter

Analysis approach

EIA used the *AEO2011* Reference case issued in April 2011 as the starting point for its analysis and made several changes to the model to accommodate increased exports. EIA exogenously specified additional natural gas exports from the United States in the National Energy Modeling System (NEMS), as the current version of NEMS does not generate an endogenous projection of LNG exports. EIA assigned these additional exports to the West South Central Census Division.[1] Any additional natural gas consumed during the liquefaction process is counted within the total additional export volumes specified in the DOE/FE scenarios. Therefore the net volumes of LNG produced for export are roughly 10 percent below the gross volumes considered in each export scenario.

Other changes in modeled flows of gas into and out of the lower-48 United States were necessary to analyze the increased export scenarios. U.S. natural gas exports to Canada and U.S. natural gas imports from Mexico are exogenously specified in all of the *AEO2011* cases. U.S. imports of natural gas from

[1] This effectively assumes that incremental LNG exports would be shipped out of the Gulf Coast States of Texas or Louisiana.

Canada are endogenously set in the model and continue to be so for this study. However, U.S. natural gas exports to Mexico and U.S. LNG imports that are normally determined endogenously within the model were set to the levels projected in the associated *AEO2011* cases for this study. Additionally, EIA assumed that an Alaska pipeline, which would transport Alaskan produced natural gas into the lower-48 United States, would not be built during the forecast period in any of the cases in order to isolate the lower-48 United States supply response. Due to this restriction, both the *AEO2011* High Economic Growth and Low Shale EUR cases were rerun, as those cases had the Alaska pipeline entering service during the projection period in the published *AEO2011*.

Caveats regarding interpretation of the analysis results

EIA recognizes that projections of energy markets over a 25-year period are highly uncertain and subject to many events that cannot be foreseen, such as supply disruptions, policy changes, and technological breakthroughs. This is particularly true in projecting the effects of exporting significant natural gas volumes from the United States due to the following factors:

- NEMS is not a world energy model and does not address the interaction between the potential for additional U.S. natural gas exports and developments in world natural gas markets.
- Global natural gas markets are not integrated and their nature could change substantially in response to significant changes in natural gas trading patterns. Future opportunities to profitably export natural gas from the United States depend on the future of global natural gas markets, the inclusion of relevant terms in specific contracts to export natural gas, as well as on the assumptions in the various cases analyzed.
- Macroeconomic results have not been included in the analysis because the links between the energy and macroeconomic modules in NEMS do not include energy exports.
- NEMS domestic focus makes it unable to account for all interactions between energy prices and supply/demand in energy-intensive industries that are globally competitive. Most of the domestic industrial activity impacts in NEMS are due to changes in the composition of final demands rather than changes in energy prices. Given its domestic focus, NEMS does not account for the impact of energy price changes on the global utilization pattern for existing capacity or the siting of new capacity inside or outside of the United States in energy-intensive industries.

Representation of natural gas markets

Unlike the oil market, current natural gas markets are not integrated globally. In today's markets, natural gas prices span a range from $0.75 per million British thermal units (MMBtu) in Saudi Arabia to $4 per MMBtu in the United States and $16 per MMBtu in Asian markets that rely on LNG imports. Prices in European markets, which reflect a mix of spot prices and contract prices with some indexation to oil, fall between U.S and Asian prices. Spot market prices at the U.K. National Balancing Point averaged $9.21 per MMBtu during November 2011.

Liquefaction projects typically take four or more years to permit and build and are planned to run for at least 20 years. As a result, expectations of future competitive conditions over the lifetime of a project play a critical role in investment decisions. The current large disparity in natural gas prices across major world regions, a major driver of U.S. producers' interest in possible liquefaction projects to increase natural gas exports, is likely to narrow as natural gas markets become more globally integrated. Key questions remain regarding how quickly convergence might occur and to what extent it will involve all or only some global regions. In particular, it is unclear how far converged prices may reflect purely "gas on gas" competition, a continuing relationship between natural gas and oil prices as in Asia (and to a lesser extent in Europe), or some intermediate outcome. As an example of the dynamic quality of global gas markets, recent regulatory changes combined with abundant supplies and muted demands appear to have put pressure on Europe's oil-linked contract gas prices.

U.S. market conditions are also quite variable, as monthly average Henry Hub spot prices have ranged from over $12 to under $3 per MMBtu over the past five years. Furthermore, while projected Henry Hub prices in the *AEO2011* Reference case reach $7.07 per MMBtu in 2035, in the High and Low Shale EUR cases prices in 2035 range from $5.35 per MMBtu to $9.26 per MMBtu.[2] 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.

The prospects for U.S. LNG exports depend greatly on the cost-competitiveness of liquefaction projects in the United States relative to those at other locations. The investment to add liquefaction capacity to an existing regasification terminal in the United States is significant, typically several times the original cost of a regasification-only terminal. However, the ability to make use of existing infrastructure, including natural gas processing plants, pipelines, and storage and loading facilities means that U.S. regasification terminals can reduce costs relative to those that would be incurred by a "greenfield" LNG facility. Many of the currently proposed LNG supply projects elsewhere in the world are integrated standalone projects that would produce, liquefy, and export stranded natural gas. These projects would require much more new infrastructure, entailing not only the construction of the liquefaction plant from the ground up, but also storage, loading, and production facilities, as well pipelines and natural gas processing facilities.

While the additional infrastructure for integrated standalone projects adds considerably to their cost, such projects can be sited at locations where they can make use of inexpensive or stranded natural gas resources that would have minimal value independent of the project. Also, while these projects may require processing facilities to remove impurities and liquids from the gas, the value of the separated liquids can improve the overall project economics. On the other hand, liquefaction projects proposed for the lower-48 United States plan to use pipeline gas drawn from the largest and most liquid natural gas market in the world. Natural gas in the U.S. pipeline system has a much greater inherent value than stranded natural gas, and most of the valuable natural gas liquids have already been removed.

Future exports of U.S. LNG depend on other factors as well. Potential buyers may place additional value on the greater diversity of supply that North American liquefaction projects provide. Also, the degree of regulatory and other risks are much lower for projects proposed in countries like the United States,

[2] All prices in this report are in 2009 dollars unless otherwise noted. For the Low Shale EUR case used in this study the Henry Hub price in 2035 is $9.75 per MMBtu, slightly higher than in the AEO2011 case with the Alaska pipeline projected to be built towards the end of the projection period.

Canada, and Australia than for those proposed in countries like Iran, Venezuela, and Nigeria. However, due to relatively high shipping costs, LNG from the United States may have an added cost disadvantage in competing against countries closer to key markets, such as in Asia. Finally, LNG projects in the United States would frequently compete not just against other LNG projects, but against other natural gas supply projects aimed at similar markets, such as pipeline projects from traditional natural gas sources or projects to develop shale gas in Asia or Europe.

Macroeconomic considerations related to energy exports and global competition in energy-intensive industries

Macroeconomic results have not been included in the analysis because energy exports are not explicitly represented in the NEMS macroeconomic module. [3] The macroeconomic module takes energy prices, energy production, and energy consumption as inputs (or assumptions) from NEMS energy modules. The macroeconomic module then calculates economic drivers that are passed back as inputs to the NEMS energy modules. Each energy module in NEMS uses different economic inputs; however these economic concepts are encompassed by U.S. gross domestic product (GDP), a summary measure describing the value of goods and services produced in the economy.[4]

The net exports component of GDP in the macroeconomic module, however, does not specifically account for energy exports. As a result, increases in energy exports generated in the NEMS energy modules are not reflected as increases in net exports of goods and services in the macroeconomic module. This results in an underestimation of GDP, all else equal. The components of GDP are calculated based on this underestimated amount as well, and do not reflect the increases in energy exports. This is particularly important in the industrial sector, where the value of its output will not reflect the increased energy exports either.

The value of output in the domestic industrial sector in NEMS depends in general on both domestic and global demand for its products, and on the price of inputs. Differences in these factors between countries will also influence where available production capacity is utilized and where new production capacity is built in globally competitive industries. For energy-intensive industries, the price of energy is particularly important to utilization decisions for existing plants and siting decisions for new ones. Given its domestic focus, however, NEMS does not account for the impact of energy price changes on global utilization pattern of existing capacity or the siting of new capacity inside or outside of the United States in energy-intensive industries. Capturing these linkages requires an international model of the particular industry in question, paired with a global macroeconomic model.

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[3] In the macroeconomic model, energy exports are used in two places: estimating exports of industrial supplies and materials and estimating energy's impact on the overall production of the economy. To assess their impact on overall production, energy exports are included in the residual between energy supply (domestic production plus imports) and energy demand. This residual also includes changes in inventory.

[4] GDP is defined as the sum of consumption, investment, government expenditure and net exports (equal to exports minus imports).

Summary of Results

Increased natural gas exports lead to higher domestic natural gas prices, increased domestic natural gas production, reduced domestic natural gas consumption, and increased natural gas imports from Canada via pipeline.

Impacts overview

- **Increased natural gas exports lead to increased natural gas prices.** Larger export levels lead to larger domestic price increases, while rapid increases in export levels lead to large initial price increases that moderate somewhat in a few years. Slower increases in export levels lead to more gradual price increases but eventually produce higher average prices during the decade between 2025 and 2035.

- **Natural gas markets in the United States balance in response to increased natural gas exports largely through increased natural gas production.** Increased natural gas production satisfies about 60 to 70 percent of the increase in natural gas exports, with a minor additional contribution from increased imports from Canada. Across most cases, about three-quarters of this increased production is from shale sources.

- **The remaining portion is supplied by natural gas that would have been consumed domestically if not for the higher prices.** The electric power sector accounts for the majority of the decrease in delivered natural gas. Due to higher prices, the electric power sector primarily shifts to coal-fired generation, and secondarily to renewable sources, though there is some decrease in total generation due to the higher price of natural gas. There is also a small reduction in natural gas use in all sectors from efficiency improvements and conservation.

- **Even while consuming less, on average, consumers will see an increase in their natural gas and electricity expenditures.** On average, from 2015 to 2035, natural gas bills paid by end-use consumers in the residential, commercial, and industrial sectors combined increase 3 to 9 percent over a comparable baseline case with no exports, depending on the export scenario and case, while increases in electricity bills paid by end-use customers range from 1 to 3 percent. In the rapid growth cases, the increase is notably greater in the early years relative to the later years. The slower export growth cases tend to show natural gas bills increasing more towards the end of the projection period.

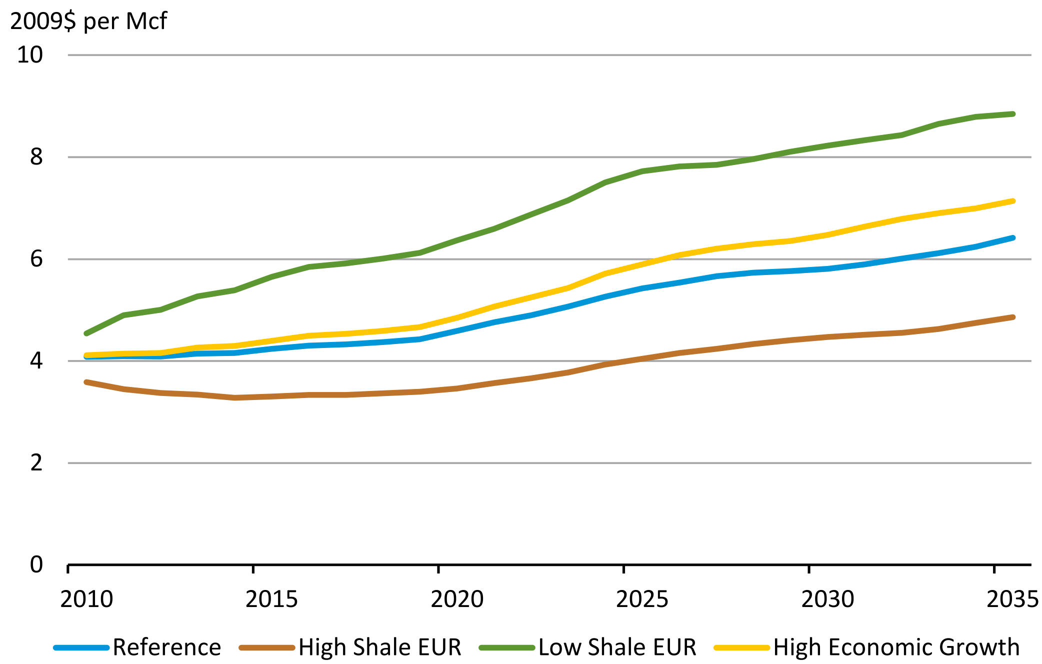
Natural gas prices

Wellhead natural gas prices in the baseline cases (no additional exports)

EIA projects that U.S. natural gas prices are projected to rise over the long run, even before considering the possibility of additional exports (Figure 2). The projected price increase varies considerably, depending on the assumptions one makes about future gas supplies and economic growth. Under the Reference case, domestic wellhead prices rise by about 57 percent between 2010 and 2035. But different assumptions produce different results. Under the more optimistic resource assumptions of the High Shale EUR case, prices actually fall at first and rise by only 36 percent by 2035. In contrast, under the more pessimistic resource assumptions of the Low Shale EUR case, prices nearly double by 2035.

While natural gas prices rise across all four baseline cases (no additional exports) considered in this report, it should be noted that natural gas prices in all of the cases are far lower than the price of crude oil when considered on an energy-equivalent basis. Projected natural gas prices in 2020 range from $3.46 to $6.37 per thousand cubic feet (Mcf) across the four baseline cases, which roughly corresponds to an oil price range of $20 to $36 per barrel in energy-equivalent terms. In 2030, projected baseline natural gas prices range from $4.47 to $8.23 per Mcf in the four baseline cases, which roughly corresponds to an oil price range of $25 to $47 per barrel in energy-equivalent terms.

Figure 2. Natural gas wellhead prices in the baseline cases (no additional exports)



Source: U.S. Energy Information Administration, National Energy Modeling System

Export scenarios—relationship between wellhead and delivered natural gas prices

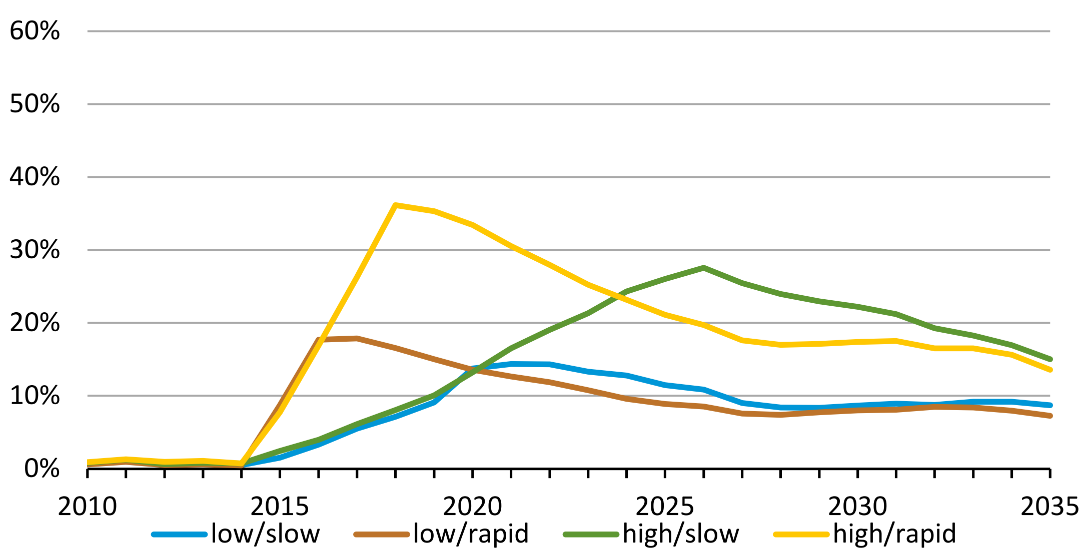
Increases in natural gas prices at the wellhead translate to similar absolute increases in delivered prices to customers under all export scenarios and baseline cases. However, delivered prices include transportation charges (for most customers) and distribution charges (especially for residential and commercial customers). These charges change to much less of a degree than the wellhead price does under different export scenarios. As a result, the percentage change in prices that industrial and electric customers pay tends to be somewhat lower than the change in the wellhead price. The percentage change in prices that residential and commercial customers pay is significantly lower. Summary statistics on delivered prices are provided in Appendix B. More detailed results on delivered prices and other report results can be found in the standard NEMS output tables that are posted online.

Export scenarios – wellhead price changes under the Reference case.

Increased exports of natural gas lead to increased wellhead prices in all cases and scenarios. The basic pattern is evident in considering how prices would change under the Reference case (Figure 3):

- The pattern of price increases reflects both the ultimate level of exports and the rate at which increased exports are phased in. In the low/slow scenario (which phases in 6 Bcf/d of exports over six years), wellhead price impacts peak at about 14% ($0.70/Mcf) in 2022. However, the wellhead price differential falls below 10 percent by about 2026.
- In contrast, rapid increases in export levels lead to large initial price increases that would moderate somewhat in a few years. In the high/rapid scenario (which phases in 12 Bcf/d of exports over four years), wellhead prices are about 36 percent higher ($1.58/Mcf) in 2018 than in the no-additional-exports scenario. But the differential falls below 20 percent by about 2026. The sharp projected price increases during the phase-in period reflect what would be needed to balance the market through changes in production, consumption, and import levels in a compressed timeframe.
- Slower increases in export levels lead to more gradual price increases but eventually produce higher average prices, especially during the decade between 2025 and 2035. The differential between wellhead prices in the high/slow scenario and the no-additional-exports scenario peaks in 2026 at about 28 percent ($1.53/Mcf), and prices remain higher than in the high/rapid scenario. The lower prices in the early years of the scenarios with slow export growth leads to more domestic investment in additional natural gas burning equipment, which increases demand somewhat in later years, relative to rapid export growth scenarios.

Figure 3. Natural gas wellhead price difference from *AEO2011* Reference case with different additional export levels imposed

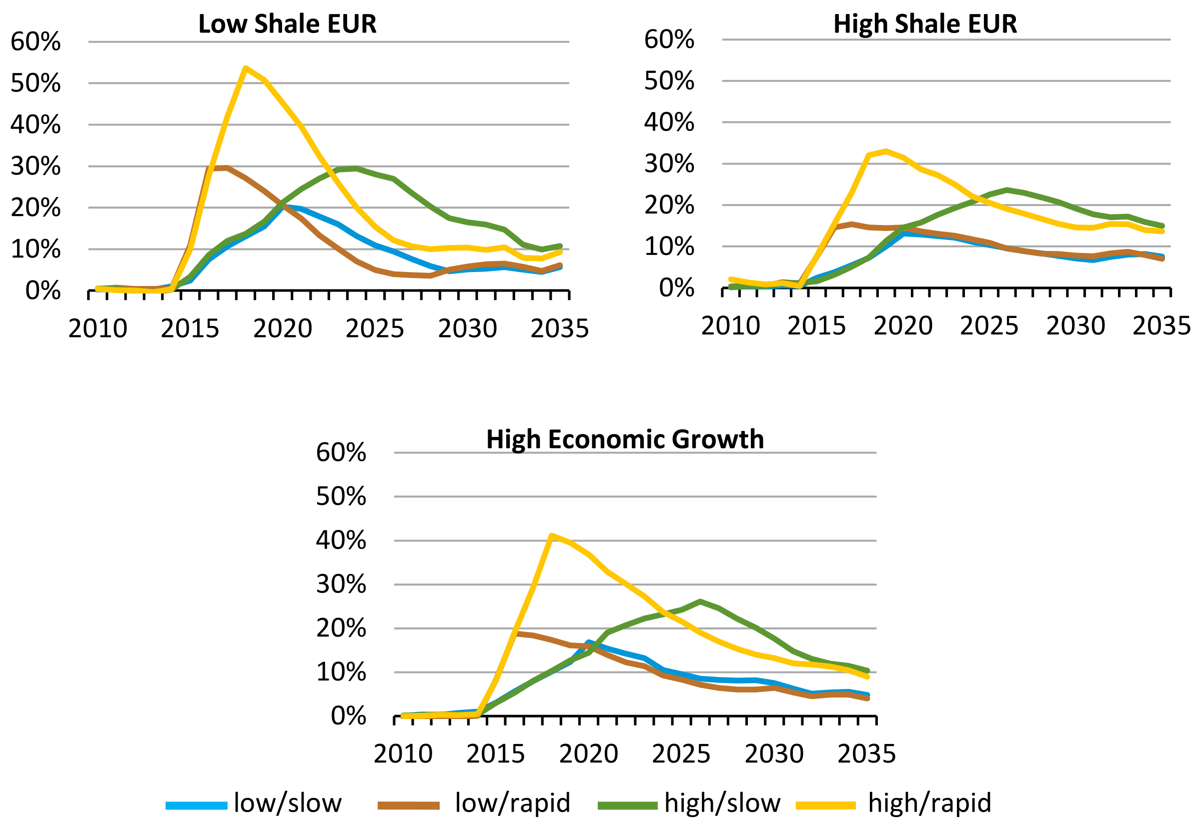


Source: U.S. Energy Information Administration, National Energy Modeling System

Export scenarios—wellhead price changes under alternative baseline cases

The effect of increasing exports on natural gas prices varies somewhat under alternative baseline case assumptions about resource availability and economic growth. However, the basic patterns remain the same: higher export levels would lead to higher prices, rapid increases in exports would lead to sharp price increases, and slower export increases would lead to slower but more lasting price increases. But the relative size of the price increases changes with changing assumptions (Figure 4).

Figure 4. Natural gas wellhead price difference from indicated baseline case (no additional exports) with different additional export levels imposed



Source: U.S. Energy Information Administration, National Energy Modeling System

In particular, with more pessimistic assumptions about the Nation's natural gas resource base (the Low Shale EUR case), wellhead prices in all export scenarios initially increase more in percentage terms over the baseline case (no additional exports) than occurs under Reference case conditions. For example, in the Low Shale EUR case the rapid introduction of 12 Bcf/d of exports results in a 54 percent ($3.23/Mcf) increase in the wellhead price in 2018; whereas under Reference case conditions with the same export scenario the price increases in 2018 by only 36 percent ($1.58/Mcf).[5] But the percentage price increase falls in later years under the Low Shale EUR case, even below the price response under Reference case conditions. Under Low Shale EUR conditions, the addition of exports ultimately results in wellhead prices exceeding the $9 per Mcf threshold, with this occurring as early as 2018 in the high/rapid scenario.

[5] The percentage rise in prices for the low EUR case also represents a larger absolute price increase because it is calculated on the higher baseline price under the same pessimistic resource assumptions.

More robust economic growth shows a similar pattern – higher initial percentage price increases and lower percentage increases in later years. On the other hand, with more optimistic resource assumptions (the High Shale EUR case), the percentage price rise would be slightly smaller than under Reference case conditions, and result in wellhead prices never exceeding the $6 per Mcf threshold.

Natural gas supply and consumption

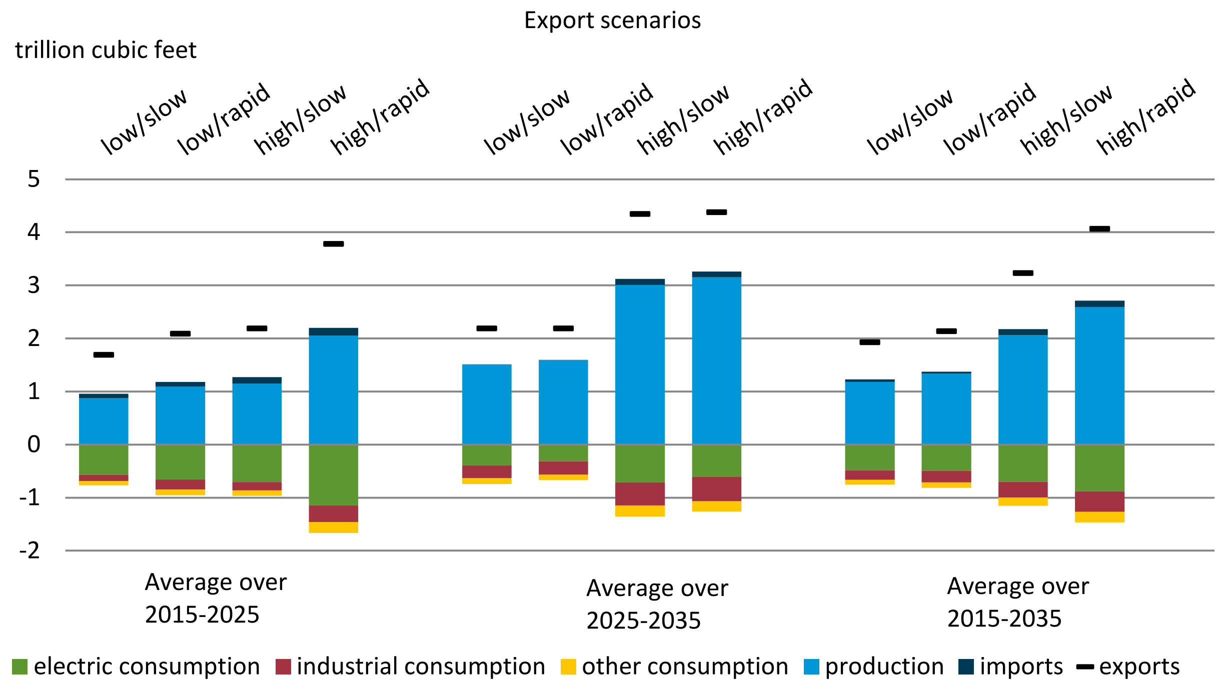
In the AEO2011 Reference case, total domestic natural gas production grows from 22.4 trillion cubic feet (Tcf) in 2015 to 26.3 Tcf in 2035, averaging 24.2 Tcf for the 2015-2035 period. U.S. net imports of natural gas decline from 11 percent of total supply in 2015 to 1 percent in 2035, with lower net imports from Canada and higher net exports to Mexico. The industrial sector consumes an average of 8.1 Tcf of natural gas (34.2% of delivered volumes) between 2015 and 2035, with 7.1 Tcf, 4.8 Tcf, and 3.6 Tcf consumed in the electric power, residential, and commercial sectors respectively.

Under the scenarios specified for this analysis, increased natural gas exports lead to higher domestic natural gas prices, which lead to reduced domestic consumption, and increased domestic production and pipeline imports from Canada (Figure 5). Lower domestic consumption dampens the degree to which supplies must increase to satisfy the additional natural gas exports. Accordingly, in order to accommodate the increased exports in each of the four export scenarios, the mix of production, consumption, and imports changes relative to the associated baseline case. In all of the export scenarios across all four baseline cases, a majority of the additional natural gas needed for export is provided by increased domestic production, with a minor contribution from increased pipeline imports from Canada. The remaining portion of the increased export volumes is offset by decreases in consumption resulting from the higher prices associated with the increased exports.

The absolute value of the sum of changes in consumption (delivered volumes), production, and imports (represented by the total bar in Figure 5) approximately[6] equals the average change in exports. Under Reference case conditions, about 63 percent, on average, of the increase in exports in each of the four scenarios is accounted for by increased production, with most of the remainder from decreased consumption from 2015 to 2035. The percentage of exports accounted for by increased production is slightly lower in the earlier years and slightly higher in the later years. While this same basic relationship between added exports and increased production is similar under the other cases, the percentage of added exports accounted for by increased production is somewhat less under a Low Shale EUR environment and more under a High Economic Growth environment.

[6] The figure displays the changes in delivered volumes of natural gas to residential, commercial, industrial, vehicle transportation, and electric generation customers. There are also some minor differences in natural gas used for lease, plant, and pipeline fuel use which are not included.

Figure 5. Average change in annual natural gas delivered, produced, and imported from *AEO2011* Reference case with different additional export levels imposed



Source: U.S. Energy Information Administration, National Energy Modeling System

One seeming anomaly that can be seen in Figure 5 is in the 2025 to 2035 timeframe: the decrease in consumption is somewhat lower in the rapid export penetration relative to the slow export penetration scenarios. This is largely attributed to slightly lower prices in the later years of the rapid export penetration scenarios relative to the slow penetration scenarios.

Supply

Increases in natural gas production that contribute to additional natural gas exports from the relative baseline scenario come predominately from shale sources. On average, across all cases and export scenarios, the shares of the increase in total domestic production coming from shale gas, tight gas, coalbed, and other sources are 72 percent, 13 percent, 8 percent, and 7 percent, respectively. Most of the export scenarios are also accompanied by a slight increase in pipeline imports from Canada. Under the Low Shale EUR case (which just applies to domestic shale), imports from Canada contribute to a greater degree than in other cases.

Consumption by sector

In general, greater export levels lead to higher domestic prices and larger decreases in consumption, although the price and consumption differences across the scenarios narrow in the later part of the projection period.

Electric power generation

In the AEO2011 Reference case, electric power generation averages 4,692 billion kilowatthours (bkWh) over the 2015-2035 period. Natural gas generation averages 23 percent of total power generation, increasing from 1,000 bkWh in 2015 to 1,288 bkWh in 2035. Coal, nuclear, and renewables provide an average of 43 percent, 19 percent, and 14 percent of generation, respectively, with a minimal contribution from liquids.

In scenarios with increased natural gas exports, most of the decrease in natural gas consumption occurs in the electric power sector (Figure 5). Most of the tradeoff in electric generators' natural gas use is between natural gas and coal, especially in the early years (Figure 6), when there is excess coal-fired capacity to allow for additional generation. Over the projection period, excess coal capacity progressively declines, along with the degree by which coal-fired generation can be increased in response to higher natural gas prices.[7] Increased coal-fired generation accounts for about 65 percent of the decrease in natural gas-fired generation under Reference case conditions.

The increased use of coal for power generation results in an average increase in coal production from 2015 to 2035 over Reference case levels of between 2 and 4 percent across export scenarios. Accordingly, coal prices also increase slightly which, along with higher gas prices, drive up electricity prices. The resulting increase in electricity prices reduces total electricity demand, also offsetting some of the drop in natural gas-fired generation. The decline in total electricity demand tends to be less in the earlier years.

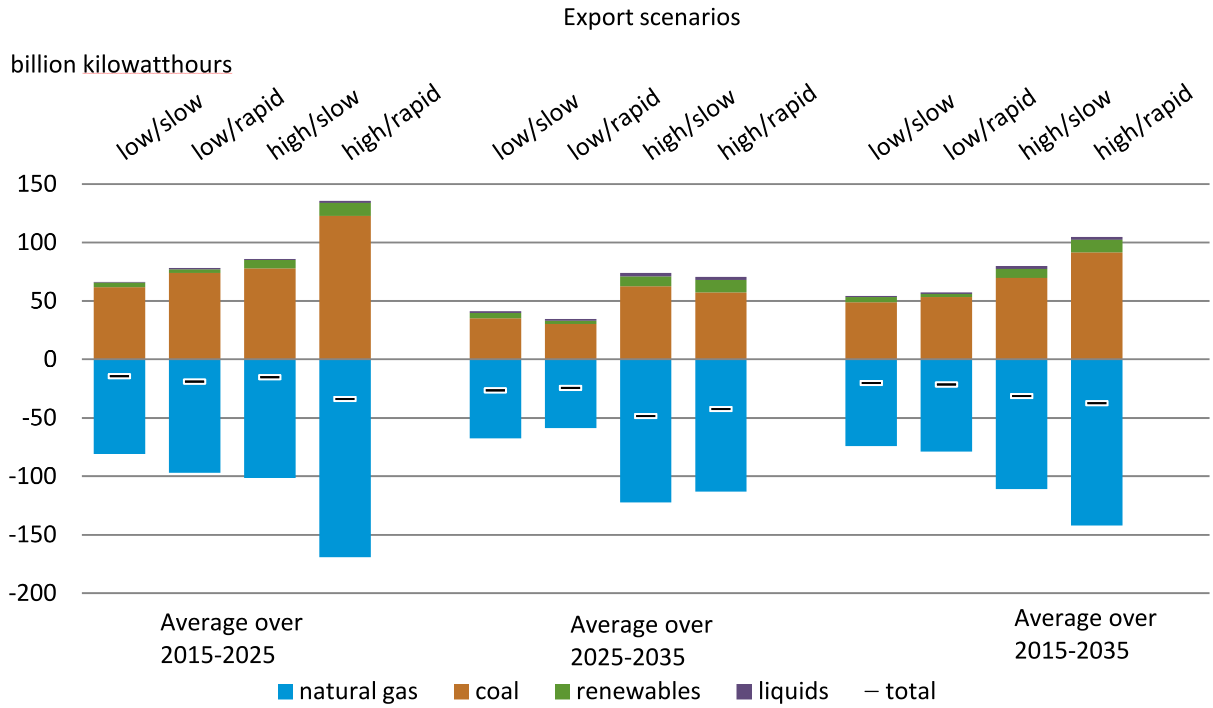
In addition, small increases in renewable generation contribute to reduced natural gas-fired generation. Relatively speaking, the role of renewables is greater in a higher-gas-price environment (i.e., the Low Shale EUR case), when they can more successfully compete with coal, and in a higher-generation environment (i.e., the High Economic Growth case), particularly in the later years.

Industrial sector

Reductions in industrial natural gas consumption in scenarios with increased natural gas exports tend to grow over time. In general, higher gas prices earlier in the projection period in these scenarios provide some disincentive for natural gas-fired equipment purchases (such as natural gas-fired combined heat and power (CHP) capacity) by industrial consumers, which has a lasting impact on their projected use of natural gas.

[7] The degree to which coal might be used in lieu of natural gas depends on what regulations are in-place that might restrict coal use. These scenarios reflect current laws and regulations in place at the time the *AEO2011* was produced.

Figure 6. Average change in annual electric generation from *AEO2011* Reference case with different additional export levels imposed



Source: U.S. Energy Information Administration, National Energy Modeling System
Note: Nucleargeneration levels do not change in the Reference case scenarios.

As noted in the discussion of caveats in the first section of this report, the NEMS model does not explicitly address the linkage between energy prices and the supply/demand of industrial commodities in global industries. To the extent that the location of production is very sensitive to changes in natural gas prices, industrial natural gas demand would be more responsive than shown in this analysis.

Other sectors

Natural gas consumption in the other sectors (residential, commercial, and compressed natural gas vehicles) also decreases in response to the higher gas prices associated with increased exports, although less significantly than in the electric and industrial sectors. Even so, under Reference case conditions residential and commercial consumption decreases from 1 to 2 percent and from 2 to 3 percent, respectively, across the export scenarios, on average from 2015 to 2035. Their use of electricity also declines marginally in response to higher electricity prices. In response to higher natural gas and electricity prices, residential and commercial customers directly cut back their energy usage and/or purchase more efficient equipment.

Exports to Canada and Mexico

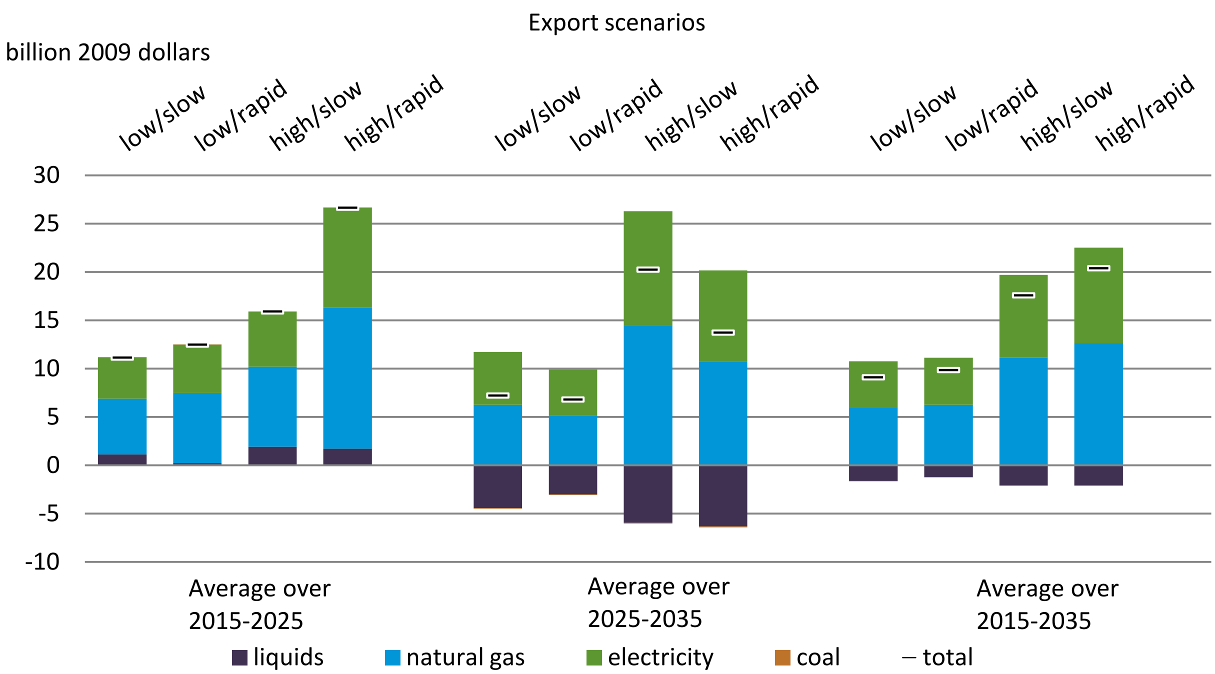
If exports to Canada and Mexico were allowed to vary under these additional export scenarios, they would likely respond similarly to domestic consumption and decrease in response to higher natural gas prices.

End-use energy expenditures

The AEO2011 Reference case projects annual average end-use energy expenditures of $1,490 billion over the 2015-2035 period. Of that, $975 billion per year is spent on liquids, $368 billion on electricity bills, $140 billion on natural gas bills, and $7 billion on coal expenditures.

From an end-user perspective in the scenarios with additional gas exports, consumers will consume less and pay more on both their natural gas and electricity bill, and generally a little less for liquid fuels (Figure 7). Under Reference case conditions, increased end-use expenditures on natural gas as a result of additional exports average about 56 percent of the total additional expenditures for natural gas and electricity combined. For example, under Reference case conditions in the low/slow scenario, end-use consumers together are expected to increase their total energy expenditures by $9 billion per year, or 0.6 percent on average from 2015 to 2035. Under the high/rapid scenarios, consumed total energy expenditures increase by $20 billion per year, or 1.4 percent on average, between 2015 and 2035.

Figure 7. Average change in annual end-use energy expenditures from *AEO2011* Reference case as a result of additional natural gas exports



Source: U.S. Energy Information Administration, National Energy Modeling System

Natural gas expenditures

As discussed earlier, given the lower consumption levels in response to the higher prices from increased exports, the percentage change in the dollars expended by customers for natural gas is less than the percentage change in the delivered prices. In general, the relative pattern of total end-use expenditures across time, export scenarios, and cases, is similar to the relative pattern shown in the wellhead prices in Figures 3 and 4. The higher export volume scenarios result in greater increases in expenditures, while those with rapid export penetration show increases peaking earlier and at higher levels than their slow export penetration counterpart, which show bills increasing more towards the end of the projection period. Under Reference case conditions, the greatest single year increase in total end-use consumer bills is 16 percent, while the lowest single year increase is less than 1 percent. In all but three export scenarios and cases, the higher average increase over the comparable baseline scenario in natural gas bills paid by end-use consumers occurred during the early years. The greatest percentage increase in end-use expenditures over the comparable baseline level in a single year (26 percent) occurs in the high/rapid scenario under the Low Shale EUR case.

On average between 2015 and 2035, total U.S. end-use natural gas expenditures as a result of added exports, under Reference case conditions, increase between $6 billion to $13 billion (between 3 to 9 percent), depending on the export scenario. The Low Shale EUR case shows the greatest average annual increase in end-use natural gas expenditures over the same time period, with increases over the baseline (no additional exports) scenario ranging from $7 billion to $15 billion.

At the sector level, since the natural gas commodity charge represents significantly different portions of each natural gas consuming sector's bill, the degree to which each sector is projected to see their total bill change with added exports varies significantly (Table 1). Natural gas expenditures increase at the highest percentages in the industrial sector, where low transmission and distribution charges constitute a relatively small part of the delivered natural gas price.

Table 1. Change in natural gas expenditures by end use consumers from AEO2011 Reference case with different additional export levels imposed

Sector	Scenario	Average 2015-2025	Average 2025-2035	Average 2015-2035	Maximum Annual Change	Minimum Annual Change
Residential	low/slow	3.2%	3.3%	3.2%	4.7%	0.5%
Residential	low/rapid	4.2%	2.9%	3.6%	5.4%	2.2%
Residential	high/slow	4.4%	7.1%	5.6%	8.9%	0.9%
Residential	high/rapid	8.3%	5.7%	7.0%	10.9%	2.5%
Commercial	low/slow	3.2%	3.2%	3.2%	4.8%	0.6%
Commercial	low/rapid	4.3%	2.7%	3.5%	5.8%	2.0%
Commercial	high/slow	4.6%	6.9%	5.6%	8.9%	0.9%
Commercial	high/rapid	8.3%	5.4%	6.9%	11.4%	2.7%
Industrial	low/slow	7.2%	5.8%	6.4%	11.1%	1.2%
Industrial	low/rapid	9.4%	4.6%	7.1%	14.0%	3.5%
Industrial	high/slow	10.2%	14.7%	12.2%	19.3%	2.0%
Industrial	high/rapid	18.7%	10.4%	14.6%	26.9%	5.2%

Source: U.S. Energy Information Administration, National Energy Modeling System

The results in Table 1 do not reflect changes in natural gas expenditures in the electric power sector. The projected overall decrease in natural gas use by generators is significant enough to result in a decrease in natural gas expenditures for that sector, largely during 2015-2025. However, electric generators will see an increase in their overall costs of power generation that will be reflected in higher electricity bills for consumers.

Electricity expenditures

On average across the projection period, electricity prices under Reference case conditions increase by between 0.14 and 0.29 cents per kilowatthour (kWh) (between 2 and 3 percent) when gas exports are added. The greatest increase in the electricity price occurs in 2019 under the Low Shale EUR case for the high export/rapid growth export scenario, with an increase of 0.85 cents per kWh (9 percent).

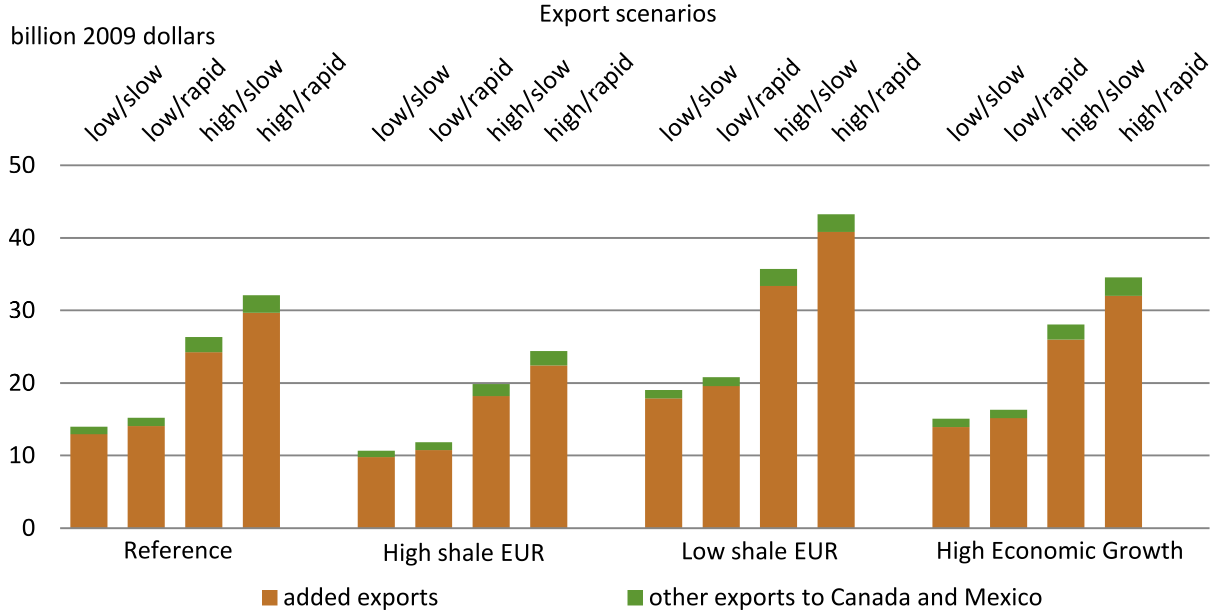
Similar to natural gas, higher electricity prices due to the increased exports reduce end-use consumption making the percentage change in end-use electricity expenditures less than the percentage change in delivered electricity prices; additionally, the percentage increase in end-use electricity expenditures will be lower for the residential and commercial sectors and higher for the industrial sector. Under Reference case conditions, the greatest single year increase in total end-use consumer electricity bills is 4 percent, while the lowest single year increase is negligible. The greatest percentage increase in end-use electricity expenditures over the comparable baseline level in a single year (7 percent) occurs in the high/rapid scenario under the Low Shale EUR case.

On average between 2015 and 2035, total U.S. end-use electricity expenditures as a result of added exports, under Reference case conditions, increase between $5 billion to $10 billion (between 1 to 3 percent), depending on the export scenario. The High Macroeconomic Growth case shows the greatest average annual increase in natural gas expenditures over the same time period, with increases over the baseline (no additional exports) scenario ranging from $6 billion to $12 billion.

Natural gas producer revenues

Total additional natural gas revenues to producers from exports increase on an average annual basis from 2015 to 2035 between $14 billion and $32 billion over the *AEO2011* Reference case, depending on the export scenario (Figure 8). These revenues largely come from the added exports defining the scenarios, as well as other exports to Canada and Mexico in the model that see higher prices under the additional export scenarios, even though the volumes are assumed not to vary. Revenues associated with the added exports reflect dollars spent to purchase and move the natural gas to the export facility, but do not include any revenues associated with the liquefaction and shipping process. The Low Shale EUR case shows the greatest average annual increase in revenues over the 2015 to 2035 time period, with revenues ranging from over $19 billion to $43 billion, due to the relatively high natural gas wellhead prices in that case. These figures represent increased revenues, not profits. A large portion of the additional export revenues will cover the increased costs associated with supplying the increased level of production required when natural gas exports are increased, such as for equipment (e.g., drilling rigs) and labor. In contrast, the additional revenues resulting from the higher price of natural gas that would have been produced and sold to largely domestic customers even in the absence of the additional exports posited in the analysis scenarios would preponderantly reflect increased profits for producers and resource owners.

Figure 8. Average annual increase in domestic natural gas export revenues from indicated baseline case (no additional exports) with different additional export levels imposed, 2015-2035



Source: U.S. Energy Information Administration, National Energy Modeling System

Impacts beyond the natural gas industry

While the natural gas industry would be directly impacted by increased exports, there are indirect impacts on other energy sectors. The electric generation industry shows the largest impact, followed by the coal industry.

As discussed earlier, higher natural gas prices lead electric generators to burn more coal and less natural gas. Coal producers benefit from the increased coal demand. On average, from 2015 to 2035, coal minemouth prices, production, and revenues increase by at most 1.1, 5.5, and 6.2 percent, respectively, across the increased export scenarios applied to all cases.

Domestic petroleum production in the form of lease condensate and natural gas plant liquids also rises due to increased natural gas drilling. For example, under Reference case conditions, in the scenario with the greatest overall response (high/rapid exports), total domestic energy production is 4.13 quadrillion British thermal units (Btu) per year (4.7 percent), which is greater on average from 2015 to 2035 than in the baseline scenario, while total domestic energy consumption is only 0.12 quadrillion Btu (0.1 percent) lower.

Effects on non-energy sectors, other than impacts on their energy expenditures, are generally beyond the scope of this report for reasons described previously.

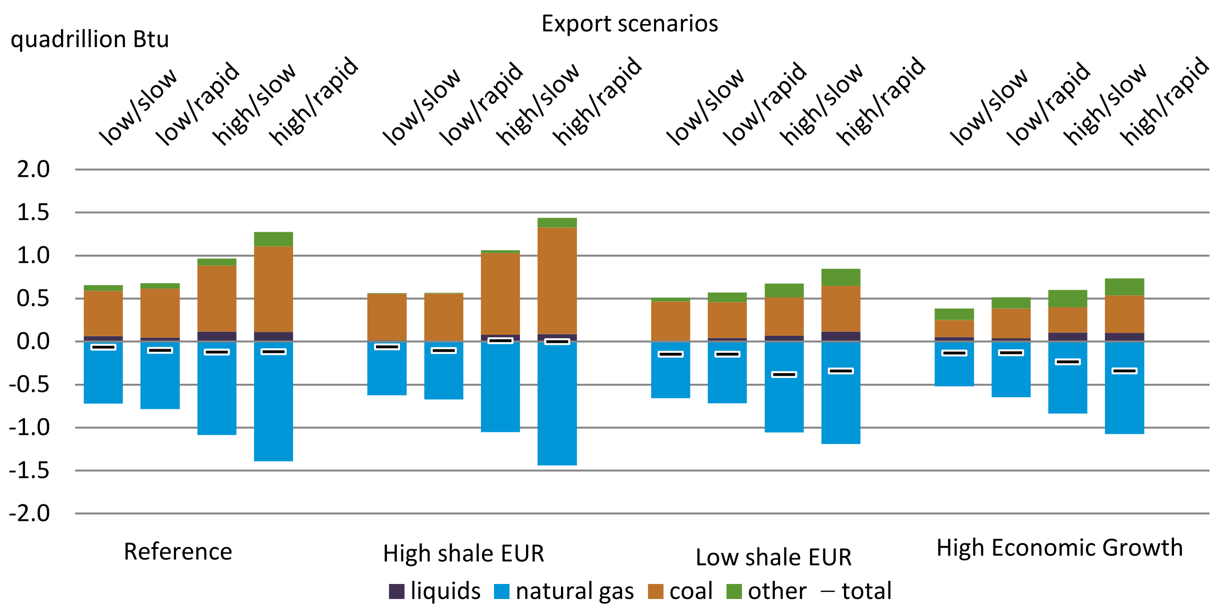
Total energy use and energy-related carbon dioxide emissions

Annual primary energy consumption in the AEO2011 Reference case, measured in Btu, averages 108 quadrillion Btu between 2015 and 2035, with a growth rate of 0.6 percent. Cumulative carbon dioxide (CO_2) emissions total 125,000 million metric tons for that twenty-year period.

The changes in overall energy consumption across scenarios and cases are largely reflective of what occurs in the electric power sector. While additional exports result in decreased natural gas consumption, changes in overall energy consumption are relatively minor as much of the decrease in natural gas consumption is replaced with increased coal consumption (Figure 9). In fact, in some of the earlier years total energy consumption increases with added exports since directly replacing natural gas with coal in electricity generation requires more Btu, as the heat rates (Btu per kWh) for coal generators exceed those for natural gas generators.

On average from 2015 to 2035 under Reference case conditions, decreased natural gas consumption as a result of added exports are countered proportionately by increased coal consumption (72 percent), increased liquid fuel consumption (8 percent), other increased consumption, such as from renewable generation sources (9 percent), and decreases in total consumption (11 percent). In the earlier years, the amount of natural gas to coal switching is greater, and coal plays a more dominant role in replacing the decreased levels of natural gas consumption, which also tend to be greater in the earlier years. Switching from natural gas to coal is less significant in later years, partially as a result of a greater proportion of switching into renewable generation. As a result decreased natural gas consumption from added exports more directly results in decreased total energy consumption via the end-use consumer cutting back energy use in response to higher prices. This basic pattern similarly occurs under the Low Shale EUR and High Economic Growth cases – less switching from natural gas into coal and more into renewable than under Reference case conditions, as well as greater decreases in total energy consumption as a result of added exports.

Figure 9. Average annual change from indicated baseline case (no additional exports) in total primary energy consumed with different additional export levels imposed, 2015-2035



Source: U.S. Energy Information Administration, National Energy Modeling System
Note: Other includes renewable and nuclear generation.

While lower domestic natural gas deliveries resulting from added exports reduce natural gas related CO_2 emissions, the increased use of coal in the electric sector generally results in a net increase in overall

CO_2 emissions. The exceptions occur in environments when renewables are better able to compete against natural gas and coal. However, when also accounting for emissions related to natural gas used in the liquefaction process, additional exports increase CO_2 levels under all cases and export scenarios, particularly in the earlier years of the projection period. Table 2 displays the cumulative CO_2 emissions levels from 2015 to 2035 in all cases and scenarios, with the change relative to the associated baseline case.

Table 2. Cumulative CO_2 emissions from 2015 to 2035 associated with additional natural gas export levels imposed (million metric tons CO_2 and percentage)

Case	no added exports	low/slow	low/rapid	high/slow	high/rapid
Reference					
Cumulative carbon dioxide emissions	125,056	125,699	125,707	126,038	126,283
Change from baseline		643	651	982	1,227
Percentage change from baseline		0.5%	0.5%	0.8%	1.0%
High Shale EUR					
Cumulative carbon dioxide emissions	124,230	124,888	124,883	125,531	125,817
Change from baseline		658	653	1,301	1,587
Percentage change from baseline		0.5%	0.5%	1.0%	1.3%
Low Shale EUR					
Cumulative carbon dioxide emissions	125,162	125,606	125,556	125,497	125,670
Change from baseline		444	394	335	508
Percentage change from baseline		0.4%	0.3%	0.3%	0.4%
High Economic Growth					
Cumulative carbon dioxide emissions	131,675	131,862	132,016	131,957	132,095
Change from baseline		187	341	282	420
Percentage change from baseline		0.1%	0.3%	0.2%	0.3%

Source: U.S. Energy Information Administration, National Energy Modeling System, with emissions related to natural gas assumed to be consumed in the liquefaction process included.

Appendix A. Request Letter

Department of Energy
Washington, DC 20585
August 15, 2011

MEMORANDUM

TO: HOWARD K. GRUENSPECHT
ACTING ADMINISTRATOR
ENERGY INFORMATION ADMINISTRATION

FROM: CHARLES D. MCCONNELL
CHIEF OPERATING OFFICER
OFFICE OF FOSSIL ENERGY

SUBJECT: **ACTION:** Request for EIA to Perform a Domestic Natural Gas Export Case Study

ISSUE: The Department of Energy's (DOE) Office of Fossil Energy (FE) must determine whether exports of liquefied natural gas (LNG) to non-free trade agreement countries are not inconsistent with the public interest. An independent case study analysis of the impact of increased domestic natural gas demand, as exports, under different incremental demand scenarios, performed by the Energy Information Administration (EIA) will be useful to assist DOE/FE in making future public interest determinations.

BACKGROUND: DOE/FE has been delegated the statutory responsibility under section 3 of the Natural Gas Act (NGA) (15 U.S.C. § 717b) to evaluate and approve or deny applications to import and export natural gas and liquefied natural gas to or from the United States. Applications to DOE/FE to export natural gas and LNG to non-free trade agreement countries are reviewed under section 3(a) of the NGA, under which FE must determine if the proposed export arrangements meet the public interest requirements of section 3 of the NGA.

To-date, DOE/FE has received applications for authority to export domestically produced LNG by vessel from three proposed liquefaction facilities, one application to export LNG by ISO containers on cargo carriers, and additional applications could be submitted by others in the future. Applications submitted to DOE/FE total 5.6 billion cubic feet per day (Bcf/day) of natural gas to be exported from the United States, equal to over 8 percent of U.S. natural gas consumption in 2015 compared to the EIA reference case projection of 68.8 Bcf/day in 2015.[1]

Studies and analyses submitted with, and in support of, LNG export applications to DOE/FE evaluated the impact LNG exports could have on domestic natural gas supply,

[1] EIA *Annual Energy Outlook 2011 (AEO2011)*

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demand and market prices. It would be helpful in DOE/FE reviews of these applications, and other potential applications, to understand the implications of additional natural gas demand (as exports) on domestic energy consumption, production, and prices under different scenarios.

Understanding that the domestic natural gas market is sensitive to a number of factors, including those highlighted on page 37 of the *AEO2011*, we request that EIA include sensitivity cases to explore some of these uncertainties, using the modeling analysis presented in the *AEO2011* as a starting point. The results of this study will be beneficial to DOE/FE by providing an independent assessment of how increased natural gas exports could affect domestic markets, and could be used in making future public interest determinations. The specific request of the study is provided in the attachment. We would like to receive the study, along with an analysis and commentary of the results by October 2011, and recognize that the study may be made available on EIA's website.

We are available to further discuss the study with your staff as they begin the study to clarify any issues associated with this request as needed.

RECOMMENDATION: That you approve this request.

APPROVE:_______________ DISAPPROVE: _________________ DATE: _______

ATTACHMENTS:
Impact of Higher Demand for U.S. Natural Gas on Domestic Energy Markets
Background: (15 U.S.C. § 717b)

Impact of Higher Demand for U.S. Natural Gas on Domestic Energy Markets

The Office of Fossil Energy (FE) requests the Energy Information Administration (EIA) to evaluate the impact of increased natural gas demand, reflecting possible exports of U.S. natural gas, on domestic energy markets using the modeling analysis presented in the *Annual Energy Outlook 2011 (AEO2011)* as a starting point. In discussions with EIA we learned that EIA's National Energy Modeling System is not designed to capture the impact of increased export-driven demand for natural gas on economy-wide economic indicators such as gross domestic product and employment, and that it does not include a representation of global natural gas markets. Therefore, EIA should focus its analysis on the implications of additional natural gas demand on domestic energy consumption, production, and prices.

The study should address scenarios reflecting export-related increases in natural gas demand of between 6 billion cubic feet per day (Bcf/d) and 12 Bcf/d that are phased in at rates of between 1 Bcf/d per year and 3 Bcf/d per year starting in 2015. Understanding that the domestic natural gas market is sensitive to a number of factors, including those highlighted on page 37 of the *AEO2011*, we request that EIA include sensitivity cases to explore some of these uncertainties. We are particularly interested in sensitivity cases relating to alternative recovery economics for shale gas resources, as in the *AEO2011 Low and High Shale EUR* cases, and a sensitivity case with increased baseline natural gas demand as in the *AEO2011 High Economic Growth* case.

The study report should review and synthesize the results obtained in the modeling work and include, as needed, discussions of context, caveats, issues and limitations that are relevant to the study. Please include tables or figures that summarize impacts on annual domestic natural gas prices, domestic natural gas production and consumption levels, domestic expenditures for natural gas and other relevant fuels, and revenues associated with the incremental export demand for natural gas. The standard *AEO 2011* reporting tables should also be provided, with the exception of tables reporting information that EIA considers to be spurious or misleading given the limitations of its modeling tools in addressing the study questions.

We would like to receive the completed analysis by October 2011 and recognize that EIA may post the study on its website after providing it to us.

Thank you for your attention to this request. Please do not hesitate to contact me (Charles D. McConnell) or John Anderson at 6-0521, if you have any questions.

Source: http://uscode.house.gov/download/pls/15C15B.txt

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-CITE-
    15 USC Sec. 717b                                          01/07/2011

-EXPCITE-
    TITLE 15 - COMMERCE AND TRADE
    CHAPTER 15B - NATURAL GAS

-HEAD-
    Sec. 717b. Exportation or importation of natural gas; LNG terminals

-STATUTE-
    (a) Mandatory authorization order
      After six months from June 21, 1938, no person shall export any
    natural gas from the United States to a foreign country or import
    any natural gas from a foreign country without first having secured
    an order of the Commission authorizing it to do so. The Commission
    shall issue such order upon application, unless, after opportunity
    for hearing, it finds that the proposed exportation or importation
    will not be consistent with the public interest. The Commission may
    by its order grant such application, in whole or in part, with such
    modification and upon such terms and conditions as the Commission
    may find necessary or appropriate, and may from time to time, after
    opportunity for hearing, and for good cause shown, make such
    supplemental order in the premises as it may find necessary or
    appropriate.
    (b) Free trade agreements
      With respect to natural gas which is imported into the United
    States from a nation with which there is in effect a free trade
    agreement requiring national treatment for trade in natural gas,
    and with respect to liquefied natural gas -
        (1) the importation of such natural gas shall be treated as a
      "first sale" within the meaning of section 3301(21) of this
      title; and
        (2) the Commission shall not, on the basis of national origin,
      treat any such imported natural gas on an unjust, unreasonable,
      unduly discriminatory, or preferential basis.
    (c) Expedited application and approval process
      For purposes of subsection (a) of this section, the importation
    of the natural gas referred to in subsection (b) of this section,
    or the exportation of natural gas to a nation with which there is
    in effect a free trade agreement requiring national treatment for
    trade in natural gas, shall be deemed to be consistent with the
    public interest, and applications for such importation or
    exportation shall be granted without modification or delay.
    (d) Construction with other laws
      Except as specifically provided in this chapter, nothing in this
    chapter affects the rights of States under -
        (1) the Coastal Zone Management Act of 1972 (16 U.S.C. 1451 et
      seq.);
        (2) the Clean Air Act (42 U.S.C. 7401 et seq.); or
        (3) the Federal Water Pollution Control Act (33 U.S.C. 1251 et
      seq.).
    (e) LNG terminals
      (1) The Commission shall have the exclusive authority to approve
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or deny an application for the siting, construction, expansion, or operation of an LNG terminal. Except as specifically provided in this chapter, nothing in this chapter is intended to affect otherwise applicable law related to any Federal agency's authorities or responsibilities related to LNG terminals.

(2) Upon the filing of any application to site, construct, expand, or operate an LNG terminal, the Commission shall -

(A) set the matter for hearing;

(B) give reasonable notice of the hearing to all interested persons, including the State commission of the State in which the LNG terminal is located and, if not the same, the Governor-appointed State agency described in section 717b-1 of this title;

(C) decide the matter in accordance with this subsection; and

(D) issue or deny the appropriate order accordingly.

(3)(A) Except as provided in subparagraph (B), the Commission may approve an application described in paragraph (2), in whole or part, with such modifications and upon such terms and conditions as the Commission find (!1) necessary or appropriate.

(B) Before January 1, 2015, the Commission shall not -

(i) deny an application solely on the basis that the applicant proposes to use the LNG terminal exclusively or partially for gas that the applicant or an affiliate of the applicant will supply to the facility; or

(ii) condition an order on -

(I) a requirement that the LNG terminal offer service to customers other than the applicant, or any affiliate of the applicant, securing the order;

(II) any regulation of the rates, charges, terms, or conditions of service of the LNG terminal; or

(III) a requirement to file with the Commission schedules or contracts related to the rates, charges, terms, or conditions of service of the LNG terminal.

(C) Subparagraph (B) shall cease to have effect on January 1, 2030.

(4) An order issued for an LNG terminal that also offers service to customers on an open access basis shall not result in subsidization of expansion capacity by existing customers, degradation of service to existing customers, or undue discrimination against existing customers as to their terms or conditions of service at the facility, as all of those terms are defined by the Commission.

(f) Military installations

(1) In this subsection, the term "military installation" -

(A) means a base, camp, post, range, station, yard, center, or homeport facility for any ship or other activity under the jurisdiction of the Department of Defense, including any leased facility, that is located within a State, the District of Columbia, or any territory of the United States; and

(B) does not include any facility used primarily for civil works, rivers and harbors projects, or flood control projects, as determined by the Secretary of Defense.

(2) The Commission shall enter into a memorandum of understanding

with the Secretary of Defense for the purpose of ensuring that the Commission coordinate and consult (!2) with the Secretary of Defense on the siting, construction, expansion, or operation of liquefied natural gas facilities that may affect an active military installation.

(3) The Commission shall obtain the concurrence of the Secretary of Defense before authorizing the siting, construction, expansion, or operation of liquefied natural gas facilities affecting the training or activities of an active military installation.

-SOURCE-

(June 21, 1938, ch. 556, Sec. 3, 52 Stat. 822; Pub. L. 102-486, title II, Sec. 201, Oct. 24, 1992, 106 Stat. 2866; Pub. L. 109-58, title III, Sec. 311(c), Aug. 8, 2005, 119 Stat. 685.)

-REFTEXT-

REFERENCES IN TEXT

The Coastal Zone Management Act of 1972, referred to in subsec. (d)(1), is title III of Pub. L. 89-454 as added by Pub. L. 92-583, Oct. 27, 1972, 86 Stat. 1280, as amended, which is classified generally to chapter 33 (Sec. 1451 et seq.) of Title 16, Conservation. For complete classification of this Act to the Code, see Short Title note set out under section 1451 of Title 16 and Tables.

The Clean Air Act, referred to in subsec. (d)(2), is act July 14, 1955, ch. 360, 69 Stat. 322, as amended, which is classified generally to chapter 85 (Sec. 7401 et seq.) of Title 42, The Public Health and Welfare. For complete classification of this Act to the Code, see Short Title note set out under section 7401 of Title 42 and Tables.

The Federal Water Pollution Control Act, referred to in subsec. (d)(3), is act June 30, 1948, ch. 758, as amended generally by Pub. L. 92-500, Sec. 2, Oct. 18, 1972, 86 Stat. 816, which is classified generally to chapter 26 (Sec. 1251 et seq.) of Title 33, Navigation and Navigable Waters. For complete classification of this Act to the Code, see Short Title note set out under section 1251 of Title 33 and Tables.

-MISC1-

AMENDMENTS

2005 - Pub. L. 109-58, Sec. 311(c)(1), inserted "; LNG terminals" after "natural gas" in section catchline.

Subsecs. (d) to (f). Pub. L. 109-58, Sec. 311(c)(2), added subsecs. (d) to (f).

1992 - Pub. L. 102-486 designated existing provisions as subsec. (a) and added subsecs. (b) and (c).

-TRANS-

TRANSFER OF FUNCTIONS

Enforcement functions of Secretary or other official in Department of Energy and Commission, Commissioners, or other official in Federal Energy Regulatory Commission related to compliance with authorizations for importation of natural gas from Alberta as pre-deliveries of Alaskan gas issued under this section with respect to pre-construction, construction, and initial operation of transportation system for Canadian and Alaskan natural gas transferred to the Federal Inspector, Office of Federal Inspector for Alaska Natural Gas Transportation System, until first anniversary of date of initial operation of Alaska Natural Gas Transportation System, see Reorg. Plan No. 1 of 1979, Secs. 102(d), 203(a), 44 F.R. 33663, 33666, 93 Stat. 1373, 1376, effective July 1, 1979, set out under section 719e of this title. Office of Federal Inspector for the Alaska Natural Gas Transportation System abolished and functions and authority vested in Inspector transferred to Secretary of Energy by section 3012(b) of Pub. L. 102-486, set out as an Abolition of Office of Federal Inspector note under section 719e of this title. Functions and authority vested in Secretary of Energy subsequently transferred to Federal Coordinator for Alaska Natural Gas Transportation Projects by section 720d(f) of this title.

DELEGATION OF FUNCTIONS

Functions of President respecting certain facilities constructed and maintained on United States borders delegated to Secretary of State, see Ex. Ord. No. 11423, Aug. 16, 1968, 33 F.R. 11741, set out as a note under section 301 of Title 3, The President.

-EXEC-

EX. ORD. NO. 10485. PERFORMANCE OF FUNCTIONS RESPECTING ELECTRIC POWER AND NATURAL GAS FACILITIES LOCATED ON UNITED STATES BORDERS

Ex. Ord. No. 10485. Sept. 3, 1953, 18 F.R. 5397, as amended by Ex. Ord. No. 12038, Feb. 3, 1978, 43 F.R. 4957, provided:

Section 1. (a) The Secretary of Energy is hereby designated and empowered to perform the following-described functions:

(1) To receive all applications for permits for the construction, operation, maintenance, or connection, at the borders of the United States, of facilities for the transmission of electric energy between the United States and a foreign country.

(2) To receive all applications for permits for the construction, operation, maintenance, or connection, at the borders of the United States, of facilities for the exportation or importation of natural gas to or from a foreign country.

(3) Upon finding the issuance of the permit to be consistent with the public interest, and, after obtaining the favorable recommendations of the Secretary of State and the Secretary of Defense thereon, to issue to the applicant, as appropriate, a permit for such construction, operation, maintenance, or connection. The Secretary of Energy shall have the power to attach to the issuance of the permit and to the exercise of the rights granted thereunder such conditions as the public interest may in its judgment require.

(b) In any case wherein the Secretary of Energy, the Secretary of State, and the Secretary of Defense cannot agree as to whether or not a permit should be issued, the Secretary of Energy shall submit to the President for approval or disapproval the application for a permit with the respective views of the Secretary of Energy, the Secretary of State and the Secretary of Defense.

Sec. 2. [Deleted.]

Sec. 3. The Secretary of Energy is authorized to issue such rules and regulations, and to prescribe such procedures, as it may from time to time deem necessary or desirable for the exercise of the authority delegated to it by this order.

Sec. 4. All Presidential Permits heretofore issued pursuant to Executive Order No. 8202 of July 13, 1939, and in force at the time of the issuance of this order, and all permits issued hereunder, shall remain in full force and effect until modified or revoked by the President or by the Secretary of Energy.

Sec. 5. Executive Order No. 8202 of July 13, 1939, is hereby revoked.

-FOOTNOTE-

(!1) So in original. Probably should be "finds".

(!2) So in original. Probably should be "coordinates and consults".

-End-

Appendix B. Summary Tables

Table B1. U.S. Annual Average Values from 2015 to 2025

	Reference					High Shale EUR					Low Shale EUR					High Macroeconomic Growth				
	baseline	low/ slow	low/ rapid	high/ slow	high/ rapid	baseline	low/ slow	low/ rapid	high/ slow	high/ rapid	baseline	low/ slow	low/ rapid	high/ slow	high/ rapid	baseline	low/ slow	low/ rapid	high/ slow	high/ rapid
NATURAL GAS VOLUMES (Tcf)																				
Net Exports	(1.90)	(0.29)	0.11	0.17	1.74	(1.32)	0.32	0.70	0.79	2.35	(2.72)	(1.17)	(0.88)	(0.73)	0.66	(2.00)	(0.38)	0.01	0.07	1.64
gross imports	3.62	3.70	3.70	3.74	3.76	3.19	3.25	3.26	3.27	3.31	4.27	4.42	4.53	4.48	4.68	3.70	3.78	3.79	3.82	3.85
gross exports	1.72	3.41	3.81	3.91	5.50	1.87	3.56	3.96	4.06	5.65	1.56	3.25	3.65	3.75	5.34	1.70	3.39	3.79	3.89	5.49
Dry Production	23.27	24.15	24.37	24.42	25.33	26.24	27.28	27.51	27.57	28.41	19.80	20.72	20.78	20.99	21.83	23.85	24.90	25.10	25.22	26.20
shale gas	8.34	8.96	9.17	9.13	9.90	11.90	12.66	12.87	12.89	13.64	3.88	4.42	4.63	4.53	5.22	8.73	9.49	9.70	9.69	10.51
other	14.93	15.18	15.20	15.29	15.43	14.34	14.61	14.65	14.68	14.77	15.91	16.30	16.15	16.45	16.62	15.12	15.41	15.39	15.53	15.70
Delivered Volumes (1)	23.34	22.57	22.38	22.37	21.68	25.58	24.94	24.79	24.75	24.00	20.82	20.13	19.90	19.94	19.35	23.99	23.37	23.17	23.22	22.60
electric generators	6.81	6.25	6.16	6.11	5.67	8.35	7.94	7.88	7.80	7.30	5.07	4.66	4.55	4.54	4.23	6.99	6.63	6.53	6.54	6.21
industrial	8.14	8.01	7.95	7.98	7.83	8.55	8.40	8.34	8.37	8.19	7.74	7.58	7.51	7.56	7.38	8.50	8.34	8.27	8.30	8.12
residential	4.83	4.80	4.79	4.79	4.75	4.94	4.92	4.90	4.91	4.87	4.68	4.63	4.61	4.62	4.57	4.90	4.86	4.85	4.85	4.81
commercial	3.48	3.44	3.42	3.42	3.37	3.65	3.61	3.59	3.60	3.55	3.27	3.20	3.17	3.18	3.11	3.52	3.46	3.45	3.45	3.39
NATURAL GAS END-USE PRICES (2009$/Mcf)																				
residential	11.19	11.63	11.77	11.81	12.33	9.92	10.24	10.37	10.36	10.72	13.23	14.05	14.27	14.42	15.10	11.56	12.09	12.21	12.29	12.87
commercial	9.23	9.66	9.79	9.83	10.34	7.97	8.28	8.40	8.39	8.74	11.27	12.09	12.31	12.46	13.16	9.60	10.12	10.24	10.31	10.88
industrial	5.59	6.10	6.25	6.32	6.91	4.41	4.80	4.95	4.94	5.41	7.50	8.40	8.62	8.83	9.59	5.89	6.49	6.63	6.73	7.41
OTHER PRICES																				
Natural Gas Wellhead Price (2009$/Mcf)	4.70	5.17	5.30	5.37	5.91	3.56	3.90	4.02	4.03	4.42	6.52	7.41	7.63	7.84	8.64	4.99	5.54	5.66	5.77	6.39
Henry Hub Price (2009$/MMBtu)	5.17	5.69	5.83	5.91	6.51	3.92	4.29	4.43	4.43	4.87	7.18	8.16	8.41	8.64	9.51	5.49	6.10	6.23	6.35	7.04
Coal Minemouth Price (2009$/short-ton)	32.67	32.76	32.89	32.89	32.89	32.33	32.69	32.52	32.59	32.77	32.91	33.15	33.10	32.97	33.04	33.23	33.18	33.06	33.33	33.28
End-Use Electricity Price (2009 cents/KWh)	8.85	8.98	9.00	9.02	9.17	8.56	8.62	8.67	8.64	8.70	9.44	9.64	9.71	9.78	9.97	9.08	9.26	9.27	9.32	9.46
NATURAL GAS REVENUES (B 2009$)																				
Export Revenues (2)	9.47	20.64	23.25	25.10	37.74	7.51	16.01	18.17	19.27	28.89	12.83	29.03	32.72	36.09	53.91	10.04	22.11	24.82	26.97	40.81
Domestic Supply Revenues (3)	160.19	175.25	179.33	181.70	199.21	147.33	159.55	163.65	164.23	177.50	177.88	201.92	206.65	213.21	236.34	171.34	190.13	193.88	197.79	218.78
production revenues (4)	109.53	125.29	129.41	132.23	150.47	93.68	106.70	111.00	111.90	126.30	129.24	154.00	158.75	165.84	189.27	119.39	138.71	142.53	146.83	168.64
delivery revenues (5)	50.65	49.97	49.92	49.46	48.74	53.65	52.85	52.65	52.33	51.20	48.64	47.92	47.91	47.37	47.07	51.94	51.41	51.36	50.96	50.14
Import Revenues (6)	17.44	19.22	19.72	19.92	21.97	12.09	13.35	13.86	13.83	15.35	28.00	31.62	33.03	33.32	36.58	18.96	21.07	21.66	21.94	24.19
END-USE ENERGY EXPENDITURES (B 2009$)	1,398.11	1,409.25	1,410.59	1,414.03	1,424.75	1,368.25	1,375.50	1,377.65	1,379.69	1,386.87	1,448.36	1,465.24	1,469.02	1,473.83	1,482.50	1,485.34	1,498.28	1,499.67	1,504.03	1,514.65
liquids	913.43	914.55	913.66	915.34	915.15	908.98	909.65	908.67	911.23	911.57	920.92	921.56	921.21	920.98	916.83	971.80	971.63	971.22	972.09	970.98
natural gas	128.00	133.77	135.27	136.30	142.58	113.26	117.51	119.11	119.24	123.94	151.16	161.03	163.24	165.90	173.42	136.49	143.47	144.71	146.37	153.61
electricity	349.77	354.03	354.76	355.46	360.10	339.21	341.51	343.06	342.39	344.53	369.28	375.68	377.60	379.98	385.31	369.58	375.70	376.28	378.08	382.59
coal	6.90	6.91	6.91	6.93	6.92	6.80	6.82	6.81	6.83	6.83	6.99	6.98	6.97	6.97	6.94	7.47	7.49	7.46	7.49	7.46
END-USE ENERGY CONSUMPTION (quadrillion Btu)	67.88	67.68	67.59	67.67	67.37	68.58	68.40	68.28	68.37	68.11	66.93	66.63	66.49	66.54	66.20	70.23	70.02	69.89	69.98	69.64
liquids	36.71	36.74	36.74	36.78	36.78	36.67	36.71	36.71	36.74	36.75	36.71	36.72	36.71	36.74	36.73	38.13	38.18	38.16	38.20	38.20
natural gas	16.04	15.85	15.76	15.81	15.55	16.76	16.55	16.45	16.49	16.23	15.22	14.97	14.86	14.91	14.65	16.49	16.26	16.16	16.21	15.92
electricity	13.44	13.41	13.41	13.41	13.37	13.48	13.47	13.46	13.48	13.47	13.32	13.26	13.24	13.22	13.16	13.84	13.81	13.80	13.79	13.75
coal	1.68	1.68	1.68	1.68	1.67	1.67	1.67	1.67	1.67	1.67	1.68	1.68	1.68	1.68	1.67	1.77	1.77	1.77	1.77	1.76
ELECTRIC GENERATION (billion kWh)	4,456.38	4,441.98	4,437.47	4,441.10	4,422.62	4,492.78	4,484.65	4,477.63	4,483.35	4,471.75	4,391.20	4,369.32	4,360.19	4,356.29	4,329.07	4,594.62	4,577.41	4,572.19	4,572.39	4,552.42
coal	1,921.25	1,982.85	1,995.33	1,999.09	2,044.09	1,756.51	1,808.90	1,813.78	1,828.74	1,885.58	2,093.76	2,132.35	2,134.49	2,123.82	2,139.82	2,004.09	2,036.83	2,052.54	2,043.09	2,073.78
gas	999.19	918.42	902.15	898.01	829.83	1,232.25	1,170.15	1,158.31	1,147.99	1,070.38	733.83	671.33	653.23	655.42	608.52	1,036.47	978.19	959.84	964.71	909.63
nuclear	866.34	866.34	866.34	866.34	866.34	850.50	850.50	850.50	851.17	855.05	866.34	866.34	866.34	866.34	866.34	866.34	866.34	866.34	866.34	866.34
renewables	610.16	614.27	613.17	617.16	621.29	593.01	594.47	595.24	594.57	599.35	636.27	638.25	645.09	648.70	651.89	626.90	634.74	632.26	636.59	641.06
other	59.43	60.11	60.48	60.50	61.08	60.51	60.63	59.80	60.87	61.39	61.00	61.04	61.03	62.00	62.50	60.83	61.30	61.21	61.65	61.61
PRIMARY ENERGY (quadrillion Btu)																				
Consumption	104.89	104.90	104.87	104.98	104.91	105.24	105.25	105.14	105.32	105.27	104.34	104.16	104.07	104.06	103.75	108.35	108.31	108.25	108.36	108.12
Imports	28.62	28.75	28.72	28.78	28.90	27.69	27.73	27.77	27.87	27.94	29.78	29.83	29.92	29.98	30.08	30.06	30.22	30.21	30.24	30.28
Exports	7.06	8.76	9.15	9.26	10.86	7.20	8.92	9.32	9.43	11.03	6.85	8.54	8.93	9.01	10.60	7.10	8.80	9.20	9.30	10.90
Production	83.14	84.73	85.12	85.28	86.71	84.63	86.34	86.60	86.79	88.26	81.15	82.63	82.84	82.86	84.05	85.16	86.66	87.01	87.18	88.52
ENERGY RELATED CO_2 EMISSIONS (including liquefaction)(million metric tons)	5,793.73	5,832.23	5,837.67	5,846.39	5,869.62	5,754.36	5,787.50	5,787.31	5,804.76	5,833.35	5,832.09	5,853.23	5,846.94	5,841.58	5,843.35	6,017.09	6,037.23	6,043.12	6,043.12	6,055.08

Table B2. Differential from Base in U.S. Average Annual Values from 2015 to 2025 when Exports are Added

	Reference				High Shale EUR				Low Shale EUR				High Macroeconomic Growth			
	low/ slow	low/ rapid	high/ slow	high/ rapid	low/ slow	low/ rapid	high/ slow	high/ rapid	low/ slow	low/ rapid	high/ slow	high/ rapid	low/ slow	low/ rapid	high/ slow	high/ rapid
NATURAL GAS VOLUMES (Tcf)																
Net Exports	1.61	2.00	2.07	3.64	1.64	2.02	2.11	3.67	1.55	1.84	1.99	3.38	1.62	2.01	2.07	3.64
gross imports	0.08	0.09	0.12	0.15	0.05	0.07	0.08	0.12	0.14	0.25	0.20	0.41	0.07	0.08	0.12	0.14
gross exports	1.69	2.09	2.19	3.78	1.69	2.09	2.19	3.78	1.69	2.09	2.19	3.78	1.69	2.09	2.19	3.78
Dry Production	0.87	1.09	1.15	2.05	1.04	1.28	1.33	2.17	0.92	0.98	1.19	2.04	1.05	1.24	1.37	2.35
shale gas	0.62	0.82	0.79	1.55	0.77	0.97	0.99	1.74	0.53	0.75	0.65	1.33	0.76	0.97	0.96	1.78
other	0.25	0.27	0.36	0.50	0.27	0.31	0.34	0.43	0.39	0.24	0.54	0.71	0.29	0.27	0.41	0.57
Delivered Volumes (1)	(0.77)	(0.95)	(0.97)	(1.66)	(0.64)	(0.80)	(0.84)	(1.59)	(0.69)	(0.91)	(0.88)	(1.46)	(0.62)	(0.82)	(0.77)	(1.39)
electric generators	(0.57)	(0.66)	(0.71)	(1.15)	(0.42)	(0.47)	(0.55)	(1.05)	(0.41)	(0.52)	(0.53)	(0.84)	(0.36)	(0.46)	(0.45)	(0.78)
industrial	(0.13)	(0.19)	(0.16)	(0.32)	(0.15)	(0.22)	(0.19)	(0.36)	(0.15)	(0.23)	(0.18)	(0.35)	(0.16)	(0.23)	(0.20)	(0.38)
residential	(0.03)	(0.04)	(0.04)	(0.08)	(0.03)	(0.04)	(0.04)	(0.07)	(0.05)	(0.07)	(0.07)	(0.11)	(0.04)	(0.05)	(0.05)	(0.09)
commercial	(0.05)	(0.06)	(0.06)	(0.11)	(0.04)	(0.06)	(0.05)	(0.10)	(0.07)	(0.09)	(0.09)	(0.15)	(0.05)	(0.07)	(0.07)	(0.13)
NATURAL GAS END-USE PRICES (2009$/Mcf)																
residential	0.44	0.58	0.62	1.14	0.32	0.45	0.44	0.80	0.81	1.03	1.18	1.87	0.53	0.65	0.72	1.31
commercial	0.43	0.57	0.61	1.12	0.31	0.43	0.42	0.76	0.82	1.04	1.19	1.89	0.52	0.64	0.71	1.28
industrial	0.51	0.66	0.73	1.32	0.39	0.54	0.54	1.00	0.90	1.13	1.33	2.09	0.61	0.74	0.85	1.52
OTHER PRICES																
Natural Gas Wellhead Price (2009$/Mcf)	0.47	0.60	0.68	1.21	0.33	0.46	0.47	0.86	0.88	1.11	1.32	2.11	0.55	0.67	0.77	1.40
Henry Hub Price (2009$/MMBtu)	0.52	0.66	0.74	1.34	0.37	0.51	0.51	0.95	0.97	1.22	1.46	2.33	0.60	0.74	0.85	1.54
Coal Minemouth Price (2009$/short-ton)	0.09	0.21	0.22	0.22	0.36	0.19	0.26	0.44	0.24	0.19	0.06	0.13	(0.05)	(0.17)	0.11	0.06
End-Use Electricity Price (2009 cents/KWh)	0.13	0.15	0.17	0.31	0.06	0.11	0.08	0.14	0.20	0.27	0.34	0.53	0.17	0.19	0.24	0.38
NATURAL GAS REVENUES (B 2009$)																
Export Revenues (2)	11.17	13.77	15.63	28.26	8.50	10.65	11.75	21.38	16.20	19.89	23.25	41.08	12.07	14.79	16.93	30.78
Domestic Supply Revenues (3)	15.07	19.14	21.51	39.02	12.22	16.32	16.91	30.17	24.04	28.77	35.33	58.46	18.79	22.55	26.46	47.44
production revenues (4)	15.75	19.88	22.70	40.93	13.02	17.31	18.22	32.62	24.76	29.51	36.60	60.03	19.32	23.13	27.44	49.24
delivery revenues (5)	(0.68)	(0.74)	(1.19)	(1.91)	(0.80)	(0.99)	(1.32)	(2.45)	(0.72)	(0.74)	(1.28)	(1.58)	(0.53)	(0.59)	(0.98)	(1.80)
Import Revenues (6)	1.78	2.28	2.48	4.53	1.26	1.77	1.74	3.26	3.62	5.03	5.32	8.58	2.12	2.70	2.99	5.24
END-USE ENERGY EXPENDITURES (B 2009$)	11.15	12.49	15.92	26.65	7.26	9.40	11.44	18.63	16.89	20.67	25.47	34.14	12.94	14.33	18.69	29.31
liquids	1.12	0.22	1.91	1.72	0.68	(0.30)	2.26	2.60	0.64	0.29	0.05	(4.09)	(0.18)	(0.59)	0.29	(0.82)
natural gas	5.76	7.26	8.30	14.58	4.26	5.85	5.98	10.68	9.86	12.07	14.73	22.25	6.98	8.22	9.88	17.12
electricity	4.26	4.99	5.69	10.32	2.31	3.85	3.18	5.32	6.39	8.31	10.70	16.02	6.12	6.70	8.50	13.01
coal	0.01	0.01	0.03	0.02	0.02	0.00	0.03	0.03	(0.00)	(0.01)	(0.01)	(0.04)	0.02	(0.01)	0.02	(0.00)
END-USE ENERGY CONSUMPTION (quadrillion Btu)	(0.20)	(0.29)	(0.21)	(0.50)	(0.18)	(0.30)	(0.21)	(0.47)	(0.30)	(0.44)	(0.38)	(0.73)	(0.22)	(0.34)	(0.26)	(0.60)
liquids	0.03	0.03	0.06	0.06	0.04	0.04	0.07	0.08	0.01	(0.00)	0.03	0.02	0.05	0.03	0.07	0.07
natural gas	(0.19)	(0.28)	(0.23)	(0.49)	(0.22)	(0.32)	(0.27)	(0.53)	(0.25)	(0.36)	(0.31)	(0.57)	(0.24)	(0.34)	(0.28)	(0.57)
electricity	(0.03)	(0.04)	(0.04)	(0.08)	(0.00)	(0.02)	(0.00)	(0.01)	(0.06)	(0.08)	(0.09)	(0.16)	(0.03)	(0.04)	(0.05)	(0.09)
coal	(0.00)	(0.00)	0.00	(0.00)	(0.00)	(0.00)	0.00	(0.00)	(0.00)	(0.01)	(0.00)	(0.01)	(0.00)	(0.00)	0.00	(0.01)
ELECTRIC GENERATION (billion kWh)	(14.39)	(18.91)	(15.27)	(33.75)	(8.13)	(15.15)	(9.43)	(21.02)	(21.89)	(31.02)	(34.92)	(62.13)	(17.21)	(22.43)	(22.23)	(42.20)
coal	61.59	74.07	77.84	122.84	52.39	57.26	72.23	129.07	38.59	40.73	30.06	46.06	32.74	48.46	39.01	69.70
gas	(80.76)	(97.03)	(101.17)	(169.36)	(62.10)	(73.94)	(84.25)	(161.86)	(62.50)	(80.59)	(78.41)	(125.31)	(58.28)	(76.63)	(71.76)	(126.84)
nuclear	-	-	-	-	0.00	0.00	0.67	4.55	(0.00)	-	-	(0.00)	-	-	-	-
renewables	4.10	3.00	7.00	11.12	1.46	2.24	1.57	6.35	1.98	8.82	12.43	15.61	7.85	5.36	9.70	14.17
other	0.67	1.04	1.07	1.64	0.11	(0.71)	0.36	0.88	0.04	0.03	1.00	1.50	0.47	0.38	0.82	0.78
PRIMARY ENERGY (quadrillion Btu)																
Consumption	0.02	(0.02)	0.09	0.02	0.01	(0.09)	0.08	0.03	(0.18)	(0.27)	(0.28)	(0.59)	(0.03)	(0.10)	0.01	(0.23)
Imports	0.13	0.10	0.16	0.28	0.04	0.08	0.18	0.26	0.05	0.14	0.20	0.30	0.16	0.15	0.18	0.22
Exports	1.70	2.09	2.20	3.79	1.72	2.12	2.23	3.83	1.69	2.08	2.16	3.75	1.70	2.10	2.20	3.80
Production	1.59	1.98	2.14	3.58	1.71	1.96	2.16	3.63	1.47	1.69	1.71	2.90	1.50	1.85	2.02	3.36
ENERGY RELATED CO_2 EMISSIONS (including liquefaction)(million metric tons)	38.50	43.94	52.67	75.90	33.14	32.94	50.39	78.99	21.14	14.85	9.48	11.26	20.14	26.03	26.03	37.99

Table B3. U.S. Annual Average Values from 2025 to 2035

	Reference					High Shale EUR					Low Shale EUR					High Macroeconomic Growth				
	baseline	low/ slow	low/ rapid	high/ slow	high/ rapid	baseline	low/ slow	low/ rapid	high/ slow	high/ rapid	baseline	low/ slow	low/ rapid	high/ slow	high/ rapid	baseline	low/ slow	low/ rapid	high/ slow	high/ rapid
NATURAL GAS VOLUMES (Tcf)																				
Net Exports	(0.71)	1.48	1.48	3.52	3.57	0.10	2.16	2.15	4.19	4.20	(2.09)	(0.21)	(0.33)	1.83	1.76	(0.88)	1.29	1.29	3.21	3.38
gross imports	2.98	2.99	2.98	3.10	3.09	2.47	2.60	2.61	2.73	2.75	3.99	4.30	4.42	4.41	4.52	3.09	3.11	3.11	3.35	3.21
gross exports	2.28	4.47	4.47	6.62	6.66	2.57	4.76	4.76	6.91	6.95	1.90	4.09	4.09	6.25	6.28	2.21	4.40	4.40	6.56	6.59
Dry Production	25.07	26.58	26.66	28.08	28.23	28.73	30.16	30.21	31.50	31.51	20.98	22.22	22.24	23.61	23.89	26.84	28.59	28.55	29.99	30.31
shale gas	10.96	12.08	12.10	13.10	13.27	15.51	16.70	16.75	17.75	17.74	5.22	6.06	6.13	6.78	6.97	12.19	13.49	13.47	14.49	14.75
other	14.12	14.49	14.56	14.98	14.96	13.21	13.46	13.47	13.75	13.77	15.76	16.16	16.11	16.83	16.91	14.65	15.10	15.08	15.50	15.56
Delivered Volumes (1)	23.96	23.22	23.29	22.60	22.70	26.63	25.94	26.00	25.19	25.19	21.41	20.69	20.82	19.97	20.27	25.80	25.29	25.26	24.72	24.85
electric generators	7.27	6.87	6.95	6.56	6.66	8.89	8.55	8.65	8.11	8.20	5.78	5.28	5.41	4.82	5.08	8.21	8.04	8.03	7.77	7.93
industrial	8.06	7.82	7.81	7.62	7.60	8.68	8.45	8.42	8.25	8.16	7.47	7.34	7.32	7.20	7.19	8.68	8.43	8.40	8.22	8.18
residential	4.82	4.78	4.78	4.73	4.74	4.95	4.91	4.91	4.88	4.88	4.64	4.61	4.61	4.56	4.58	5.01	4.97	4.97	4.93	4.94
commercial	3.68	3.62	3.62	3.56	3.57	3.91	3.85	3.85	3.80	3.80	3.40	3.36	3.37	3.29	3.32	3.75	3.70	3.71	3.66	3.66
NATURAL GAS END-USE PRICES (2009$/Mcf)																				
residential	12.90	13.45	13.39	14.05	13.85	11.31	11.66	11.68	12.10	11.98	15.49	15.96	15.83	16.76	16.27	13.70	14.13	14.06	14.67	14.51
commercial	10.61	11.15	11.09	11.73	11.54	9.01	9.34	9.36	9.75	9.63	13.24	13.71	13.58	14.53	14.02	11.39	11.80	11.73	12.32	12.15
industrial	6.82	7.43	7.36	8.26	7.98	5.39	5.86	5.88	6.46	6.32	9.30	9.79	9.66	10.69	10.09	7.50	8.05	7.96	8.82	8.59
OTHER PRICES																				
Natural Gas Wellhead Price (2009$/Mcf)	5.88	6.42	6.35	7.14	6.88	4.45	4.82	4.83	5.31	5.17	8.25	8.77	8.68	9.69	9.10	6.52	6.98	6.90	7.67	7.43
Henry Hub Price (2009$/MMBtu)	6.47	7.06	6.99	7.86	7.58	4.90	5.30	5.31	5.85	5.69	9.08	9.66	9.56	10.67	10.02	7.18	7.68	7.60	8.45	8.18
Coal Minemouth Price (2009$/short-ton)	33.46	33.51	33.43	33.68	33.43	33.20	33.45	33.21	33.42	33.25	33.77	34.11	33.89	33.76	33.85	34.30	34.01	33.95	33.99	34.16
End-Use Electricity Price (2009 cents/KWh)	9.02	9.17	9.15	9.36	9.28	8.57	8.65	8.67	8.75	8.69	9.86	9.98	9.94	10.25	10.06	9.50	9.67	9.63	9.90	9.78
NATURAL GAS REVENUES (B 2009$)																				
Export Revenues (2)	12.81	29.82	29.50	50.58	48.98	10.46	23.42	23.49	38.88	38.06	17.38	39.57	38.98	66.69	62.90	14.21	32.48	32.11	54.16	52.87
Domestic Supply Revenues (3)	199.45	221.98	220.95	249.66	244.39	184.30	200.41	201.19	220.08	216.08	222.71	243.85	242.19	276.77	266.61	230.96	254.64	252.33	282.66	278.95
production revenues (4)	147.54	170.77	169.47	200.63	194.52	128.09	145.41	146.06	167.45	162.93	173.25	194.92	193.13	228.66	217.47	175.63	199.91	197.44	230.19	225.48
delivery revenues (5)	51.91	51.21	51.48	49.03	49.87	56.21	55.00	55.13	52.63	53.14	49.47	48.94	49.06	48.11	49.13	55.33	54.74	54.89	52.47	53.47
Import Revenues (6)	18.06	19.89	19.65	22.97	22.09	11.69	13.64	13.75	16.04	15.80	33.87	37.50	37.30	41.19	39.73	20.96	22.75	22.52	26.35	24.99
END-USE ENERGY EXPENDITURES (B 2009$)	1,582.70	1,589.93	1,589.52	1,602.94	1,596.44	1,543.37	1,552.01	1,553.43	1,559.62	1,552.40	1,648.34	1,658.55	1,651.04	1,673.64	1,651.53	1,766.94	1,773.78	1,770.57	1,786.74	1,777.53
liquids	1,036.91	1,032.47	1,033.91	1,030.97	1,030.61	1,032.78	1,033.84	1,034.44	1,031.39	1,028.44	1,044.39	1,046.22	1,041.53	1,044.12	1,034.65	1,156.40	1,151.96	1,151.22	1,149.05	1,147.03
natural gas	152.47	158.71	157.65	166.94	163.18	136.00	140.12	140.18	146.00	143.37	180.36	184.84	183.01	194.25	187.01	172.16	177.27	175.86	185.15	181.63
electricity	386.65	392.12	391.36	398.45	396.09	368.01	371.51	372.27	375.68	374.08	416.91	420.84	419.85	428.68	423.29	430.75	436.99	435.94	445.06	441.40
coal	6.67	6.62	6.61	6.59	6.56	6.57	6.54	6.53	6.54	6.51	6.68	6.64	6.65	6.59	6.58	7.63	7.55	7.54	7.48	7.46
END-USE ENERGY CONSUMPTION (quadrillion Btu)	70.29	69.92	69.90	69.59	69.57	71.26	70.89	70.87	70.66	70.61	68.84	68.56	68.64	68.25	68.43	74.98	74.60	74.59	74.25	74.26
liquids	37.85	37.84	37.82	37.84	37.83	37.75	37.74	37.75	37.81	37.80	37.74	37.71	37.77	37.73	37.81	40.67	40.66	40.65	40.64	40.64
natural gas	16.26	15.95	15.94	15.69	15.66	17.32	16.97	16.93	16.66	16.58	15.13	14.92	14.92	14.71	14.73	17.13	16.83	16.81	16.58	16.53
electricity	14.59	14.55	14.56	14.48	14.52	14.61	14.62	14.62	14.61	14.66	14.39	14.35	14.38	14.25	14.32	15.43	15.39	15.41	15.31	15.37
coal	1.59	1.58	1.58	1.57	1.57	1.58	1.57	1.57	1.57	1.57	1.58	1.57	1.57	1.56	1.56	1.74	1.73	1.73	1.72	1.72
ELECTRIC GENERATION (billion kWh)	4,926.27	4,899.77	4,902.00	4,877.85	4,883.87	4,985.61	4,970.39	4,968.96	4,955.47	4,962.16	4,805.29	4,785.02	4,792.39	4,749.29	4,771.60	5,218.96	5,192.01	5,194.85	5,161.80	5,172.17
coal	2,142.71	2,177.86	2,173.08	2,205.23	2,199.91	1,965.65	2,017.08	2,010.40	2,076.04	2,072.01	2,250.96	2,299.95	2,288.43	2,318.37	2,307.93	2,230.53	2,234.24	2,247.81	2,248.95	2,243.60
gas	1,143.09	1,075.44	1,084.20	1,020.61	1,029.93	1,418.58	1,349.39	1,356.51	1,272.85	1,275.05	878.08	797.50	812.65	731.17	762.84	1,317.28	1,273.98	1,266.15	1,220.40	1,234.87
nuclear	876.67	876.67	876.67	876.67	876.67	858.29	858.29	858.29	858.29	863.83	876.67	878.22	878.27	879.99	878.26	876.67	877.25	876.67	877.38	876.67
renewables	702.87	707.59	705.79	711.29	713.75	681.48	683.24	681.93	685.54	688.71	734.07	743.56	747.72	752.68	756.76	730.61	742.46	740.48	748.18	750.94
other	60.93	62.21	62.25	64.05	63.60	61.62	62.40	61.82	62.74	62.56	65.51	65.81	65.32	67.09	65.81	63.87	64.07	63.73	66.89	66.09
PRIMARY ENERGY (quadrillion Btu)																				
Consumption	111.05	110.88	110.85	110.69	110.76	111.50	111.37	111.37	111.45	111.46	109.71	109.57	109.69	109.18	109.59	117.72	117.47	117.54	117.22	117.23
Imports	27.93	27.63	27.67	27.60	27.46	26.80	26.78	26.86	27.04	26.99	29.22	29.38	29.42	29.45	29.40	30.26	30.04	29.97	30.09	29.72
Exports	7.91	10.13	10.13	12.29	12.32	8.18	10.39	10.40	12.58	12.62	7.54	9.74	9.72	11.88	11.94	7.97	10.17	10.18	12.32	12.36
Production	90.96	93.37	93.26	95.38	95.65	92.89	95.05	94.99	97.21	97.27	87.86	89.79	89.86	91.50	92.04	95.31	97.52	97.67	99.38	99.80
ENERGY RELATED CO_2 EMISSIONS (including liquefaction)(million metric tons)	6,114.82	6,136.49	6,131.49	6,155.61	6,152.88	6,074.00	6,103.94	6,102.31	6,151.52	6,146.61	6,084.64	6,103.94	6,106.49	6,104.89	6,120.61	6,521.09	6,517.76	6,525.31	6,521.52	6,520.16

Table B4. Differential from Base in U.S. Average Annual Values from 2025 to 2035 when Exports are Added

	Reference				High Shale EUR				Low Shale EUR				High Macroeconomic Growth			
	low/ slow	low/ rapid	high/ slow	high/ rapid	low/ slow	low/ rapid	high/ slow	high/ rapid	low/ slow	low/ rapid	high/ slow	high/ rapid	low/ slow	low/ rapid	high/ slow	high/ rapid
NATURAL GAS VOLUMES (Tcf)																
Net Exports	2.18	2.19	4.23	4.28	2.06	2.05	4.09	4.10	1.88	1.76	3.93	3.85	2.17	2.17	4.09	4.26
gross imports	0.01	0.00	0.12	0.10	0.13	0.14	0.26	0.28	0.31	0.43	0.42	0.53	0.02	0.02	0.26	0.12
gross exports	2.19	2.19	4.35	4.38	2.19	2.19	4.35	4.38	2.19	2.19	4.35	4.38	2.19	2.19	4.35	4.38
Dry Production	1.51	1.59	3.00	3.15	1.43	1.49	2.77	2.78	1.24	1.25	2.62	2.90	1.74	1.71	3.15	3.47
shale gas	1.13	1.15	2.14	2.31	1.18	1.23	2.24	2.23	0.84	0.91	1.55	1.75	1.29	1.28	2.30	2.56
other	0.38	0.44	0.86	0.84	0.25	0.25	0.53	0.55	0.40	0.35	1.07	1.16	0.45	0.43	0.85	0.91
Delivered Volumes (1)	(0.75)	(0.67)	(1.36)	(1.26)	(0.69)	(0.63)	(1.43)	(1.43)	(0.72)	(0.59)	(1.44)	(1.13)	(0.51)	(0.54)	(1.08)	(0.95)
electric generators	(0.40)	(0.32)	(0.71)	(0.61)	(0.35)	(0.25)	(0.79)	(0.70)	(0.50)	(0.37)	(0.96)	(0.69)	(0.17)	(0.19)	(0.45)	(0.28)
industrial	(0.24)	(0.25)	(0.44)	(0.46)	(0.24)	(0.27)	(0.43)	(0.53)	(0.13)	(0.15)	(0.27)	(0.28)	(0.25)	(0.27)	(0.46)	(0.49)
residential	(0.04)	(0.04)	(0.08)	(0.08)	(0.03)	(0.03)	(0.07)	(0.06)	(0.03)	(0.03)	(0.08)	(0.06)	(0.04)	(0.03)	(0.07)	(0.07)
commercial	(0.06)	(0.06)	(0.12)	(0.11)	(0.05)	(0.06)	(0.11)	(0.10)	(0.05)	(0.04)	(0.11)	(0.08)	(0.05)	(0.04)	(0.10)	(0.09)
NATURAL GAS END-USE PRICES (2009$/Mcf)																
residential	0.55	0.48	1.15	0.95	0.35	0.37	0.79	0.67	0.46	0.33	1.27	0.78	0.43	0.35	0.97	0.81
commercial	0.54	0.48	1.12	0.92	0.33	0.34	0.73	0.61	0.47	0.34	1.29	0.78	0.41	0.34	0.93	0.76
industrial	0.62	0.54	1.44	1.16	0.46	0.48	1.07	0.92	0.49	0.36	1.39	0.78	0.55	0.46	1.32	1.09
OTHER PRICES																
Natural Gas Wellhead Price (2009$/Mcf)	0.54	0.47	1.27	1.01	0.36	0.38	0.86	0.71	0.52	0.43	1.44	0.85	0.45	0.38	1.15	0.90
Henry Hub Price (2009$/MMBtu)	0.60	0.52	1.39	1.11	0.40	0.41	0.95	0.79	0.57	0.47	1.59	0.94	0.50	0.42	1.26	1.00
Coal Minemouth Price (2009$/short-ton)	0.05	(0.03)	0.22	(0.03)	0.25	0.01	0.22	0.05	0.34	0.12	(0.01)	0.08	(0.29)	(0.35)	(0.30)	(0.14)
End-Use Electricity Price (2009 cents/KWh)	0.16	0.13	0.35	0.27	0.08	0.10	0.18	0.12	0.12	0.08	0.38	0.20	0.17	0.13	0.40	0.28
NATURAL GAS REVENUES (B 2009$)																
Export Revenues (2)	17.01	16.69	37.77	36.17	12.96	13.03	28.42	27.60	22.19	21.60	49.31	45.52	18.27	17.90	39.95	38.66
Domestic Supply Revenues (3)	22.53	21.50	50.21	44.94	16.11	16.89	35.77	31.78	21.14	19.48	54.05	43.89	23.68	21.37	51.70	47.99
production revenues (4)	23.23	21.93	53.09	46.98	17.31	17.97	39.36	34.84	21.67	19.88	55.41	44.23	24.28	21.81	54.56	49.85
delivery revenues (5)	(0.71)	(0.44)	(2.88)	(2.04)	(1.21)	(1.08)	(3.58)	(3.06)	(0.53)	(0.40)	(1.36)	(0.33)	(0.60)	(0.44)	(2.86)	(1.87)
Import Revenues (6)	1.82	1.59	4.91	4.02	1.95	2.06	4.35	4.11	3.63	3.43	7.32	5.87	1.79	1.56	5.39	4.03
END-USE ENERGY EXPENDITURES (B 2009$)	7.22	6.81	20.24	13.73	8.64	10.06	16.25	9.03	10.21	2.71	25.31	3.19	6.84	3.63	19.81	10.59
liquids	(4.45)	(3.01)	(5.94)	(6.31)	1.05	1.66	(1.39)	(4.34)	1.83	(2.86)	(0.27)	(9.74)	(4.43)	(5.17)	(7.34)	(9.37)
natural gas	6.25	5.18	14.47	10.71	4.12	4.18	10.00	7.37	4.49	2.65	13.90	6.65	5.12	3.70	12.99	9.47
electricity	5.47	4.71	11.80	9.44	3.50	4.26	7.68	6.07	3.94	2.94	11.78	6.39	6.24	5.19	14.31	10.65
coal	(0.05)	(0.07)	(0.08)	(0.11)	(0.03)	(0.04)	(0.03)	(0.06)	(0.04)	(0.03)	(0.09)	(0.11)	(0.08)	(0.09)	(0.15)	(0.16)
END-USE ENERGY CONSUMPTION (quadrillion Btu)	(0.37)	(0.38)	(0.70)	(0.71)	(0.37)	(0.39)	(0.60)	(0.65)	(0.28)	(0.20)	(0.60)	(0.42)	(0.38)	(0.39)	(0.73)	(0.72)
liquids	(0.00)	(0.02)	(0.01)	(0.02)	(0.01)	0.00	0.06	0.06	(0.03)	0.03	(0.01)	0.07	(0.02)	(0.03)	(0.03)	(0.03)
natural gas	(0.31)	(0.32)	(0.57)	(0.60)	(0.35)	(0.39)	(0.65)	(0.74)	(0.21)	(0.21)	(0.42)	(0.40)	(0.30)	(0.32)	(0.54)	(0.60)
electricity	(0.04)	(0.03)	(0.11)	(0.07)	0.00	0.01	(0.00)	0.04	(0.04)	(0.01)	(0.14)	(0.07)	(0.05)	(0.02)	(0.13)	(0.07)
coal	(0.01)	(0.01)	(0.02)	(0.02)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.02)	(0.02)	(0.01)	(0.01)	(0.02)	(0.03)
ELECTRIC GENERATION (billion kWh)	(26.50)	(24.27)	(48.42)	(42.40)	(15.22)	(16.66)	(30.14)	(23.45)	(20.26)	(12.90)	(55.99)	(33.69)	(26.95)	(24.11)	(57.15)	(46.78)
coal	35.15	30.37	62.53	57.20	51.43	44.76	110.39	106.36	48.98	37.46	67.41	56.97	3.71	17.28	18.42	13.07
gas	(67.65)	(58.89)	(122.48)	(113.16)	(69.19)	(62.06)	(145.72)	(143.53)	(80.58)	(65.43)	(146.91)	(115.24)	(43.30)	(51.13)	(96.88)	(82.41)
nuclear	-	(0.00)	-	-	0.00	0.00	0.00	5.55	1.54	1.60	3.32	1.59	0.58	0.00	0.71	0.00
renewables	4.72	2.92	8.41	10.87	1.76	0.46	4.07	7.23	9.49	13.65	18.61	22.69	11.85	9.87	17.57	20.33
other	1.28	1.33	3.12	2.68	0.77	0.19	1.12	0.94	0.30	(0.19)	1.58	0.31	0.20	(0.13)	3.02	2.22
PRIMARY ENERGY (quadrillion Btu)																
Consumption	(0.16)	(0.20)	(0.35)	(0.29)	(0.13)	(0.13)	(0.05)	(0.04)	(0.13)	(0.02)	(0.53)	(0.12)	(0.25)	(0.18)	(0.50)	(0.49)
Imports	(0.30)	(0.26)	(0.33)	(0.47)	(0.03)	0.05	0.23	0.19	0.16	0.20	0.23	0.18	(0.22)	(0.30)	(0.17)	(0.54)
Exports	2.21	2.21	4.37	4.41	2.21	2.22	4.40	4.43	2.20	2.19	4.35	4.41	2.20	2.21	4.35	4.39
Production	2.41	2.30	4.42	4.69	2.16	2.10	4.32	4.38	1.93	2.00	3.65	4.18	2.20	2.36	4.07	4.49
ENERGY RELATED CO_2 EMISSIONS (including liquefaction)(million metric tons)	21.67	16.67	40.79	38.07	29.94	28.31	77.52	72.61	19.31	21.85	20.25	35.98	(3.33)	4.21	0.43	(0.93)

Table B5. U.S. Annual Average Values from 2015 to 2035

	Reference					High Shale EUR					Low Shale EUR					High Macroeconomic Growth				
	baseline	low/ slow	low/ rapid	high/ slow	high/ rapid	baseline	low/ slow	low/ rapid	high/ slow	high/ rapid	baseline	low/ slow	low/ rapid	high/ slow	high/ rapid	baseline	low/ slow	low/ rapid	high/ slow	high/ rapid
NATURAL GAS VOLUMES (Tcf)																				
Net Exports	(1.31)	0.57	0.78	1.81	2.63	(0.63)	1.21	1.41	2.44	3.24	(2.40)	(0.70)	(0.60)	0.52	1.21	(1.45)	0.44	0.64	1.60	2.49
gross imports	3.31	3.35	3.35	3.42	3.43	2.84	2.94	2.95	3.01	3.04	4.13	4.36	4.46	4.44	4.59	3.40	3.45	3.45	3.59	3.53
gross exports	2.00	3.93	4.13	5.23	6.06	2.22	4.15	4.35	5.45	6.28	1.73	3.66	3.86	4.96	5.79	1.95	3.88	4.09	5.19	6.02
Dry Production	24.18	25.37	25.52	26.24	26.78	27.48	28.71	28.86	29.52	29.95	20.40	21.47	21.51	22.28	22.86	25.37	26.75	26.83	27.60	28.26
shale gas	9.65	10.51	10.63	11.10	11.56	13.70	14.67	14.79	15.30	15.67	4.56	5.23	5.37	5.64	6.08	10.47	11.48	11.58	12.08	12.62
other	14.54	14.85	14.89	15.15	15.21	13.78	14.04	14.06	14.22	14.28	15.84	16.24	16.14	16.64	16.78	14.90	15.27	15.25	15.53	15.65
Delivered Volumes (1)	23.67	22.91	22.85	22.52	22.20	26.12	25.46	25.41	25.00	24.61	21.12	20.42	20.36	19.97	19.81	24.92	24.35	24.23	24.01	23.75
electric generators	7.06	6.58	6.57	6.36	6.18	8.64	8.26	8.28	7.98	7.77	5.44	4.97	4.98	4.69	4.66	7.63	7.36	7.29	7.18	7.09
industrial	8.10	7.92	7.88	7.81	7.72	8.62	8.42	8.38	8.31	8.18	7.60	7.46	7.42	7.38	7.29	8.59	8.39	8.34	8.27	8.16
residential	4.82	4.79	4.78	4.76	4.75	4.94	4.91	4.91	4.89	4.88	4.66	4.62	4.61	4.59	4.57	4.95	4.92	4.91	4.90	4.87
commercial	3.58	3.53	3.52	3.49	3.47	3.78	3.73	3.72	3.70	3.68	3.34	3.28	3.27	3.24	3.22	3.64	3.59	3.58	3.56	3.53
NATURAL GAS END-USE PRICES (2009$/Mcf)																				
residential	12.04	12.53	12.57	12.91	13.08	10.61	10.95	11.02	11.22	11.35	14.35	14.98	15.06	15.55	15.69	12.63	13.10	13.13	13.45	13.68
commercial	9.91	10.39	10.44	10.76	10.93	8.49	8.80	8.88	9.06	9.18	12.24	12.88	12.95	13.46	13.60	10.49	10.95	10.98	11.29	11.50
industrial	6.20	6.76	6.80	7.26	7.44	4.90	5.32	5.41	5.69	5.86	8.38	9.07	9.15	9.71	9.84	6.69	7.26	7.29	7.75	7.99
OTHER PRICES																				
Natural Gas Wellhead Price (2009$/Mcf)	5.28	5.78	5.82	6.23	6.39	4.01	4.35	4.42	4.66	4.79	7.37	8.06	8.16	8.71	8.87	5.75	6.25	6.28	6.69	6.90
Henry Hub Price (2009$/MMBtu)	5.81	6.36	6.41	6.86	7.03	4.41	4.79	4.87	5.12	5.27	8.12	8.88	8.98	9.60	9.77	6.33	6.88	6.91	7.36	7.60
Coal Minemouth Price (2009$/short-ton)	33.06	33.12	33.15	33.29	33.18	32.77	33.07	32.87	32.99	33.00	33.34	33.64	33.50	33.38	33.46	33.74	33.60	33.52	33.66	33.72
End-Use Electricity Price (2009 cents/KWh)	8.94	9.08	9.08	9.19	9.22	8.56	8.63	8.67	8.70	8.70	9.65	9.81	9.83	10.00	10.02	9.29	9.46	9.45	9.60	9.62
NATURAL GAS REVENUES (B 2009$)																				
Export Revenues (2)	11.13	25.11	26.34	37.49	43.23	8.98	19.64	20.80	28.85	33.39	15.07	34.12	35.85	50.80	58.30	12.11	27.19	28.43	40.19	46.69
Domestic Supply Revenues (3)	179.79	198.43	200.12	215.08	221.64	165.83	179.88	182.38	191.82	196.70	200.15	222.46	224.55	243.87	251.43	201.24	222.30	223.13	239.62	248.66
production revenues (4)	128.46	147.79	149.40	165.76	172.31	110.87	125.92	128.47	139.27	144.50	151.06	173.98	176.05	196.01	203.32	147.54	169.19	169.97	187.82	196.82
delivery revenues (5)	51.32	50.64	50.72	49.32	49.33	54.96	53.96	53.92	52.55	52.21	49.09	48.48	48.50	47.86	48.12	53.70	53.12	53.16	51.79	51.84
Import Revenues (6)	17.77	19.53	19.69	21.37	22.03	11.92	13.52	13.84	14.94	15.61	30.84	34.49	35.15	37.10	38.16	19.97	21.90	22.09	24.07	24.58
END-USE ENERGY EXPENDITURES (B 2009$)	1,489.93	1,499.04	1,499.79	1,507.51	1,510.31	1,455.15	1,463.17	1,465.18	1,469.08	1,469.35	1,547.09	1,561.08	1,559.57	1,572.52	1,567.30	1,625.45	1,635.66	1,634.71	1,644.67	1,646.03
liquids	974.71	973.09	973.49	972.64	972.64	970.30	971.23	971.23	970.91	969.68	981.60	983.31	980.57	982.05	975.74	1,063.35	1,061.47	1,060.75	1,060.30	1,058.97
natural gas	140.16	146.09	146.41	151.27	152.79	124.61	128.76	129.62	132.45	133.62	165.55	172.70	173.21	179.55	180.30	154.27	160.27	160.24	165.41	167.51
electricity	368.28	373.10	373.13	376.85	378.14	353.56	356.51	357.67	359.05	359.38	393.11	398.26	398.98	404.14	404.50	400.29	406.41	406.21	411.48	412.09
coal	6.78	6.76	6.75	6.75	6.74	6.68	6.68	6.67	6.68	6.67	6.83	6.81	6.81	6.78	6.76	7.54	7.51	7.50	7.48	7.46
END-USE ENERGY CONSUMPTION (quadrillion Btu)	69.09	68.81	68.75	68.64	68.49	69.93	69.65	69.59	69.52	69.37	67.90	67.61	67.58	67.42	67.33	72.62	72.33	72.26	72.14	71.97
liquids	37.29	37.30	37.29	37.31	37.31	37.21	37.23	37.24	37.28	37.28	37.24	37.23	37.25	37.25	37.28	39.42	39.43	39.42	39.43	39.44
natural gas	16.15	15.90	15.85	15.76	15.61	17.04	16.76	16.69	16.58	16.41	15.18	14.95	14.89	14.82	14.69	16.81	16.55	16.49	16.41	16.23
electricity	14.02	13.98	13.98	13.95	13.95	14.05	14.05	14.04	14.04	14.06	13.85	13.81	13.81	13.74	13.74	14.64	14.60	14.61	14.55	14.56
coal	1.63	1.63	1.63	1.63	1.62	1.62	1.62	1.62	1.62	1.62	1.63	1.62	1.62	1.62	1.61	1.76	1.75	1.75	1.74	1.74
ELECTRIC GENERATION (billion kWh)	4,691.78	4,671.70	4,670.36	4,660.47	4,654.31	4,740.10	4,728.42	4,724.32	4,720.03	4,717.90	4,599.04	4,578.46	4,576.69	4,554.90	4,551.26	4,907.86	4,886.10	4,884.89	4,868.85	4,864.09
coal	2,030.24	2,078.96	2,083.33	2,100.15	2,121.75	1,860.54	1,912.06	1,912.09	1,949.35	1,977.66	2,171.63	2,216.91	2,212.07	2,221.68	2,224.94	2,114.85	2,134.13	2,149.63	2,144.11	2,158.39
gas	1,074.40	1,000.10	995.54	963.40	932.18	1,328.06	1,262.83	1,259.57	1,215.21	1,175.80	808.02	735.39	733.01	695.09	685.68	1,181.25	1,129.59	1,115.49	1,096.96	1,074.83
nuclear	871.23	871.23	871.23	871.23	871.23	854.18	854.18	854.18	854.53	859.21	871.23	872.04	872.07	872.97	872.07	871.23	871.54	871.23	871.61	871.23
renewables	655.74	660.26	658.89	663.43	666.81	636.24	637.87	637.72	639.17	643.29	684.94	690.77	696.38	700.70	704.42	678.14	688.13	686.04	691.94	695.77
other	60.17	61.15	61.37	62.26	62.34	61.08	61.49	60.76	61.77	61.93	63.21	63.35	63.16	64.47	64.16	62.38	62.71	62.50	64.24	63.86
PRIMARY ENERGY (quadrillion Btu)																				
Consumption	107.97	107.90	107.87	107.85	107.85	108.38	108.31	108.27	108.38	108.37	107.04	106.89	106.89	106.66	106.70	113.05	112.91	112.92	112.81	112.71
Imports	28.28	28.20	28.21	28.18	28.19	27.27	27.28	27.34	27.47	27.49	29.50	29.62	29.68	29.71	29.75	30.17	30.14	30.09	30.17	30.02
Exports	7.48	9.43	9.63	10.73	11.57	7.69	9.64	9.86	10.96	11.81	7.19	9.12	9.32	10.41	11.25	7.53	9.47	9.68	10.77	11.61
Production	87.04	89.04	89.18	90.30	91.17	88.73	90.66	90.77	91.94	92.73	84.52	86.20	86.35	87.18	88.04	90.24	92.09	92.35	93.26	94.16
ENERGY RELATED CO_2 EMISSIONS (including liquefaction)(million metric tons)	5,955.05	5,985.66	5,986.04	6,001.82	6,013.46	5,915.71	5,947.04	5,946.80	5,977.68	5,991.27	5,960.10	5,981.23	5,978.85	5,976.06	5,984.27	6,270.24	6,279.14	6,286.47	6,283.68	6,290.23

Table B6. Differential from Base in U.S. Average Annual Values from 2015 to 2035 when Exports are Added

	Reference				High Shale EUR				Low Shale EUR				High Macroeconomic Growth			
	low/ slow	low/ rapid	high/ slow	high/ rapid	low/ slow	low/ rapid	high/ slow	high/ rapid	low/ slow	low/ rapid	high/ slow	high/ rapid	low/ slow	low/ rapid	high/ slow	high/ rapid
NATURAL GAS VOLUMES (Tcf)																
Net Exports	1.89	2.10	3.12	3.95	1.84	2.03	3.06	3.87	1.70	1.81	2.92	3.61	1.89	2.09	3.05	3.94
gross imports	0.04	0.04	0.11	0.12	0.09	0.10	0.17	0.20	0.23	0.33	0.31	0.46	0.04	0.05	0.19	0.13
gross exports	1.93	2.14	3.23	4.07	1.93	2.14	3.23	4.07	1.93	2.14	3.23	4.07	1.93	2.14	3.23	4.07
Dry Production	1.18	1.33	2.06	2.59	1.23	1.38	2.04	2.47	1.06	1.11	1.88	2.45	1.38	1.46	2.23	2.89
shale gas	0.86	0.98	1.45	1.91	0.97	1.09	1.60	1.97	0.67	0.81	1.08	1.52	1.01	1.11	1.61	2.15
other	0.32	0.35	0.61	0.68	0.26	0.28	0.44	0.50	0.40	0.30	0.80	0.93	0.37	0.35	0.62	0.74
Delivered Volumes (1)	(0.76)	(0.82)	(1.15)	(1.47)	(0.66)	(0.71)	(1.12)	(1.51)	(0.71)	(0.77)	(1.15)	(1.31)	(0.57)	(0.69)	(0.91)	(1.17)
electric generators	(0.48)	(0.49)	(0.70)	(0.88)	(0.38)	(0.36)	(0.66)	(0.87)	(0.46)	(0.46)	(0.75)	(0.78)	(0.27)	(0.34)	(0.45)	(0.54)
industrial	(0.18)	(0.22)	(0.29)	(0.38)	(0.19)	(0.24)	(0.31)	(0.44)	(0.14)	(0.19)	(0.22)	(0.32)	(0.20)	(0.25)	(0.32)	(0.43)
residential	(0.04)	(0.04)	(0.06)	(0.08)	(0.03)	(0.04)	(0.05)	(0.06)	(0.04)	(0.05)	(0.07)	(0.09)	(0.04)	(0.04)	(0.06)	(0.08)
commercial	(0.05)	(0.06)	(0.09)	(0.11)	(0.05)	(0.06)	(0.08)	(0.10)	(0.06)	(0.07)	(0.10)	(0.12)	(0.05)	(0.06)	(0.08)	(0.11)
NATURAL GAS END-USE PRICES (2009$/Mcf)																
residential	0.49	0.53	0.87	1.04	0.33	0.41	0.60	0.73	0.64	0.71	1.20	1.34	0.47	0.50	0.82	1.05
commercial	0.48	0.52	0.84	1.02	0.31	0.39	0.57	0.69	0.64	0.71	1.22	1.35	0.46	0.49	0.80	1.02
industrial	0.56	0.60	1.07	1.24	0.42	0.51	0.79	0.96	0.69	0.77	1.33	1.46	0.57	0.60	1.06	1.30
OTHER PRICES																
Natural Gas Wellhead Price (2009$/Mcf)	0.50	0.54	0.95	1.11	0.34	0.42	0.65	0.79	0.69	0.79	1.34	1.50	0.50	0.52	0.94	1.15
Henry Hub Price (2009$/MMBtu)	0.55	0.59	1.05	1.22	0.38	0.46	0.72	0.87	0.77	0.87	1.48	1.65	0.55	0.58	1.03	1.26
Coal Minemouth Price (2009$/short-ton)	0.06	0.09	0.22	0.12	0.30	0.11	0.22	0.24	0.29	0.16	0.04	0.12	(0.14)	(0.22)	(0.08)	(0.02)
End-Use Electricity Price (2009 cents/KWh)	0.14	0.14	0.25	0.29	0.07	0.10	0.13	0.13	0.16	0.18	0.35	0.37	0.17	0.16	0.31	0.33
NATURAL GAS REVENUES (B 2009$)																
Export Revenues (2)	13.99	15.22	26.36	32.10	10.66	11.82	19.87	24.41	19.05	20.78	35.73	43.23	15.08	16.32	28.08	34.57
Domestic Supply Revenues (3)	18.64	20.34	35.29	41.85	14.05	16.55	25.99	30.88	22.30	24.39	43.72	51.28	21.06	21.88	38.37	47.42
production revenues (4)	19.33	20.94	37.29	43.84	15.05	17.60	28.40	33.63	22.92	24.98	44.95	52.25	21.64	22.43	40.28	49.28
delivery revenues (5)	(0.69)	(0.60)	(2.00)	(1.99)	(1.00)	(1.04)	(2.41)	(2.75)	(0.61)	(0.59)	(1.23)	(0.97)	(0.58)	(0.54)	(1.91)	(1.86)
Import Revenues (6)	1.76	1.93	3.60	4.26	1.60	1.92	3.02	3.69	3.65	4.31	6.26	7.31	1.93	2.12	4.11	4.61
END-USE ENERGY EXPENDITURES (B 2009$)	9.11	9.86	17.59	20.39	8.02	10.03	13.93	14.19	13.98	12.47	25.42	20.21	10.22	9.26	19.22	20.58
liquids	(1.63)	(1.22)	(2.07)	(2.07)	0.92	0.92	0.61	(0.62)	1.70	(1.04)	0.45	(5.86)	(1.88)	(2.60)	(3.05)	(4.38)
natural gas	5.94	6.26	11.12	12.63	4.15	5.01	7.84	9.01	7.15	7.66	14.00	14.75	6.00	5.98	11.14	13.24
electricity	4.82	4.86	8.57	9.87	2.95	4.11	5.49	5.82	5.15	5.87	11.03	11.39	6.12	5.92	11.19	11.80
coal	(0.02)	(0.03)	(0.03)	(0.04)	(0.01)	(0.02)	(0.00)	(0.02)	(0.02)	(0.02)	(0.05)	(0.07)	(0.03)	(0.04)	(0.06)	(0.08)
END-USE ENERGY CONSUMPTION (quadrillion Btu)	(0.28)	(0.34)	(0.45)	(0.60)	(0.27)	(0.34)	(0.41)	(0.55)	(0.29)	(0.32)	(0.48)	(0.57)	(0.30)	(0.36)	(0.49)	(0.65)
liquids	0.01	0.00	0.03	0.03	0.02	0.02	0.06	0.07	(0.01)	0.02	0.01	0.04	0.02	0.00	0.02	0.02
natural gas	(0.25)	(0.30)	(0.40)	(0.54)	(0.28)	(0.35)	(0.46)	(0.63)	(0.23)	(0.29)	(0.36)	(0.49)	(0.27)	(0.33)	(0.41)	(0.58)
electricity	(0.04)	(0.03)	(0.07)	(0.07)	(0.00)	(0.00)	(0.00)	0.02	(0.05)	(0.05)	(0.11)	(0.11)	(0.04)	(0.03)	(0.09)	(0.08)
coal	(0.00)	(0.01)	(0.01)	(0.01)	(0.00)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.02)	(0.01)	(0.01)	(0.01)	(0.02)
ELECTRIC GENERATION (billion kWh)	(20.08)	(21.43)	(31.31)	(37.47)	(11.67)	(15.77)	(20.07)	(22.20)	(20.58)	(22.35)	(44.13)	(47.78)	(21.76)	(22.98)	(39.01)	(43.78)
coal	48.72	53.09	69.91	91.51	51.52	51.55	88.82	117.12	45.28	40.44	50.04	53.31	19.28	34.78	29.25	43.53
gas	(74.30)	(78.86)	(111.00)	(142.22)	(65.24)	(68.49)	(112.86)	(152.26)	(72.63)	(75.01)	(112.93)	(122.34)	(51.66)	(65.76)	(84.29)	(106.42)
nuclear	-	(0.00)	-	-	0.00	0.00	0.35	5.02	0.81	0.84	1.74	0.83	0.30	0.00	0.37	0.00
renewables	4.52	3.15	7.69	11.07	1.63	1.48	2.94	7.06	5.84	11.44	15.76	19.48	9.99	7.89	13.80	17.63
other	0.98	1.20	2.09	2.17	0.41	(0.32)	0.69	0.86	0.13	(0.06)	1.25	0.94	0.33	0.11	1.86	1.48
PRIMARY ENERGY (quadrillion Btu)																
Consumption	(0.07)	(0.10)	(0.12)	(0.12)	(0.06)	(0.11)	0.01	(0.00)	(0.15)	(0.15)	(0.38)	(0.34)	(0.13)	(0.13)	(0.24)	(0.34)
Imports	(0.09)	(0.08)	(0.10)	(0.10)	0.01	0.07	0.20	0.22	0.12	0.18	0.21	0.25	(0.03)	(0.07)	0.00	(0.15)
Exports	1.94	2.15	3.25	4.09	1.96	2.17	3.28	4.12	1.93	2.13	3.22	4.06	1.94	2.15	3.24	4.08
Production	2.00	2.14	3.26	4.13	1.93	2.03	3.20	4.00	1.68	1.83	2.66	3.52	1.85	2.11	3.02	3.92
ENERGY RELATED CO_2 EMISSIONS (including liquefaction)(million metric tons)	30.62	30.99	46.77	58.42	31.33	31.09	61.96	75.56	21.14	18.75	15.96	24.18	8.90	16.23	13.44	19.99

FOOTNOTES

(1) total includes components below plus deliveries to the transportation sector

(2) export volumes added for this study times the Henry Hub price plus an assumed transport fee to the liquefaction facility of 20 cents per Mcf, plus sum of all other export volumes (i.e., to Canada and Mexico) times the associated price at the border

(3) represents producer revenues at the wellhead plus other revenues extracted before final gas delivery.

(4) dry gas production times average wellhead or first-purchase price

(5) represented revenues extracted as gas moves from the first-purchase wellhead price to final delivery

(6) import volumes times the associated price at the border

Projections: EIA, Annual Energy Outlook 2011 National Energy Modeling system runs ref2011.d020911a, rflexslw.d090911a, rflexrpd.d090911a, rfhexslw.d090911a, rfhesrpd.d090911a, hshleur.d020911a, helexslw.d090911a, helexrpd.d090911a, hehexslw.d090911a, hehexrpd.d090911a, feleur.d090811a, lelexslw.d090911a, lelexrpd.d090911a, lehexslw.d090911a, lehexrpd.d090911a, fehdem.d090811a, hmlexslw.d090911a, hmlexrpd.d090911a, hmhexslw.d090911a, hmhexrpd.d090911a

UNITED STATES DEPARTMENT OF ENERGY

BEFORE THE DEPARTMENT OF ENERGY
FEDERAL ENERGY REGULATORY COMMISSION

In the Matter of: Sabine Pass Liquefaction, LLC and Sabine Pass LNG, L.P	FERC Docket Nos. CP11-72-000, PF10-24

SIERRA CLUB'S COMMENTS on THE DECEMBER 28, 2011 SABINE PASS LIQUEFACTION PROJECT ENVIRONMENTAL ASSESSMENT

Exhibit 2

Natural Gas Subcommittee, *90-day interim report*, (August 18, 2011)

January 27, 2012

Secretary of Energy Advisory Board

Source: U.S. Energy Information Administration based on data from various published studies. Canada and Mexico plays from ARI.
Updated: May 9, 2011

Shale Gas Production Subcommittee 90-Day Report

August 18, 2011

U.S. DEPARTMENT OF ENERGY

The SEAB Shale Gas Production Subcommittee

Ninety-Day Report – August 18, 2011

Executive Summary

The Shale Gas Subcommittee of the Secretary of Energy Advisory Board is charged with identifying measures that can be taken to reduce the environmental impact and improve the safety of shale gas production.

Natural gas is a cornerstone of the U.S. economy, providing a quarter of the country's total energy. Owing to breakthroughs in technology, production from shale formations has gone from a negligible amount just a few years ago to being almost 30 percent of total U.S. natural gas production. This has brought lower prices, domestic jobs, and the prospect of enhanced national security due to the potential of substantial production growth. But the growth has also brought questions about whether both current and future production can be done in an environmentally sound fashion that meets the needs of public trust.

This 90-day report presents recommendations that if implemented will reduce the environmental impacts from shale gas production. The Subcommittee stresses the importance of a process of continuous improvement in the various aspects of shale gas production that relies on best practices and is tied to measurement and disclosure. While many companies are following such a process, much-broader and more extensive adoption is warranted. The approach benefits all parties in shale gas production: regulators will have more complete and accurate information; industry will achieve more efficient operations; and the public will see continuous, measurable improvement in shale gas activities.

A list of the Subcommittee's findings and recommendations follows.

- Improve public information about shale gas operations: Create a portal for access to a wide range of public information on shale gas development, to include current data available from state and federal regulatory agencies. The portal should be open to the public for use to study and analyze shale gas operations and results.

- Improve communication among state and federal regulators: Provide continuing annual support to STRONGER (the State Review of Oil and Natural Gas Environmental Regulation) and to the Ground Water Protection Council for expansion of the *Risk Based Data Management System* and similar projects that can be extended to all phases of shale gas development.

- Improve air quality: Measures should be taken to reduce emissions of air pollutants, ozone precursors, and methane as quickly as practicable. The Subcommittee supports adoption of rigorous standards for new and existing sources of methane, air toxics, ozone precursors and other air pollutants from shale gas operations. The Subcommittee recommends:

  (1) Enlisting a subset of producers in different basins to design and rapidly implement measurement systems to collect comprehensive methane and other air emissions data from shale gas operations and make these data publically available;

  (2) Immediately launching a federal interagency planning effort to acquire data and analyze the overall greenhouse gas footprint of shale gas operations through out the lifecycle of natural gas use in comparison to other fuels; and

  (3) Encouraging shale-gas production companies and regulators to expand immediately efforts to reduce air emissions using proven technologies and practices.

- Protection of water quality: The Subcommittee urges adoption of a systems approach to water management based on consistent measurement and public disclosure of the flow and composition of water at every stage of the shale gas production process. The Subcommittee recommends the following actions by shale gas companies and regulators – to the extent that such actions have not already been undertaken by particular companies and regulatory agencies:

  (1) Measure and publicly report the composition of water stocks and flow throughout the fracturing and clean-up process.

  (2) Manifest all transfers of water among different locations.

  (3) Adopt best practices in well development and construction, especially casing, cementing, and pressure management. Pressure testing of cemented casing and state-of-the-art cement bond logs should be used to confirm formation isolation. Microseismic surveys should be carried out to assure that hydraulic fracture growth is limited to the gas producing formations. Regulations and inspections are needed to confirm that operators

have taken prompt action to repair defective cementing jobs. The regulation of shale gas development should include inspections at safety-critical stages of well construction and hydraulic fracturing.

(4) Additional field studies on possible methane leakage from shale gas wells to water reservoirs.

(5) Adopt requirements for background water quality measurements (e.g., existing methane levels in nearby water wells prior to drilling for gas) and report in advance of shale gas production activity.

(6) Agencies should review field experience and modernize rules and enforcement practices to ensure protection of drinking and surface waters.

- Disclosure of fracturing fluid composition: The Subcommittee shares the prevailing view that the risk of fracturing fluid leakage into drinking water sources through fractures made in deep shale reservoirs is remote. Nevertheless the Subcommittee believes there is no economic or technical reason to prevent public disclosure of all chemicals in fracturing fluids, with an exception for genuinely proprietary information. While companies and regulators are moving in this direction, progress needs to be accelerated in light of public concern.

- Reduction in the use of diesel fuel: The Subcommittee believes there is no technical or economic reason to use diesel in shale gas production and recommends reducing the use of diesel engines for surface power in favor of natural gas engines or electricity where available.

- Managing short-term and cumulative impacts on communities, land use, wildlife, and ecologies. Each relevant jurisdiction should pay greater attention to the combination of impacts from multiple drilling, production and delivery activities (e.g., impacts on air quality, traffic on roads, noise, visual pollution), and make efforts to plan for shale development impacts on a regional scale. Possible mechanisms include:

  (1) Use of multi-well drilling pads to minimize transport traffic and need for new road construction.

  (2) Evaluation of water use at the scale of affected watersheds.

  (3) Formal notification by regulated entities of anticipated environmental and community impacts.

(4) Preservation of unique and/or sensitive areas as off-limits to drilling and support infrastructure as determined through an appropriate science-based process.

(5) Undertaking science-based characterization of important landscapes, habitats and corridors to inform planning, prevention, mitigation and reclamation of surface impacts.

(6) Establishment of effective field monitoring and enforcement to inform on-going assessment of cumulative community and land use impacts.

The process for addressing these issues must afford opportunities for affected communities to participate and respect for the rights of surface and mineral rights owners.

- <u>Organizing for best practice:</u> The Subcommittee believes the creation of a shale gas industry production organization dedicated to continuous improvement of best practice, defined as improvements in techniques and methods that rely on measurement and field experience, is needed to improve operational and environmental outcomes. The Subcommittee favors a national approach including regional mechanisms that recognize differences in geology, land use, water resources, and regulation. The Subcommittee is aware that several different models for such efforts are under discussion and the Subcommittee will monitor progress during its next ninety days. The Subcommittee has identified several activities that deserve priority attention for developing best practices:

  <u>Air</u>: (a) Reduction of pollutants and methane emissions from all shale gas production/delivery activity. (b) Establishment of an emission measurement and reporting system at various points in the production chain.

  <u>Water</u>: (a) Well completion – casing and cementing including use of cement bond and other completion logging tools. (b) Minimizing water use and limiting vertical fracture growth.

- <u>Research and Development needs</u>. The public should expect significant technical advances associated with shale gas production that will significantly improve the efficiency of shale gas production and that will reduce environmental impact. The move from single well to multiple-well pad drilling is one clear example. Given the economic incentive for technical advances, much of the R&D will be performed by the oil and gas industry. Nevertheless the federal government has a role especially in basic R&D, environment protection, and safety. The current level of federal support for unconventional gas R&D is small, and the Subcommittee recommends that the Administration and the Congress set an appropriate mission for R&D and level funding.

The Subcommittee believes that these recommendations, combined with a continuing focus on and clear commitment to measurable progress in implementation of best practices based on technical innovation and field experience, represent important steps toward meeting public concerns and ensuring that the nation's resources are responsibly being responsibly developed.

Introduction

On March 31, 2011, President Barack Obama declared that "recent innovations have given us the opportunity to tap large reserves – perhaps a century's worth" of shale gas. In order to facilitate this development, ensure environmental protection, and meet public concerns, he instructed Secretary of Energy Steven Chu to form a subcommittee of the Secretary of Energy Advisory Board (SEAB) to make recommendations to address the safety and environmental performance of shale gas production.[1] The Secretary's charge to the Subcommittee, included in Annex A, requested that:

> Within 90 days of its first meeting, the Subcommittee will report to SEAB on the "immediate steps that can be taken to improve the safety and environmental performance of fracturing.

This is the 90-day report submitted by the Subcommittee to SEAB in fulfillment of its charge. There will be a second report of the Subcommittee after 180 days. Members of the Subcommittee are given in Annex B.

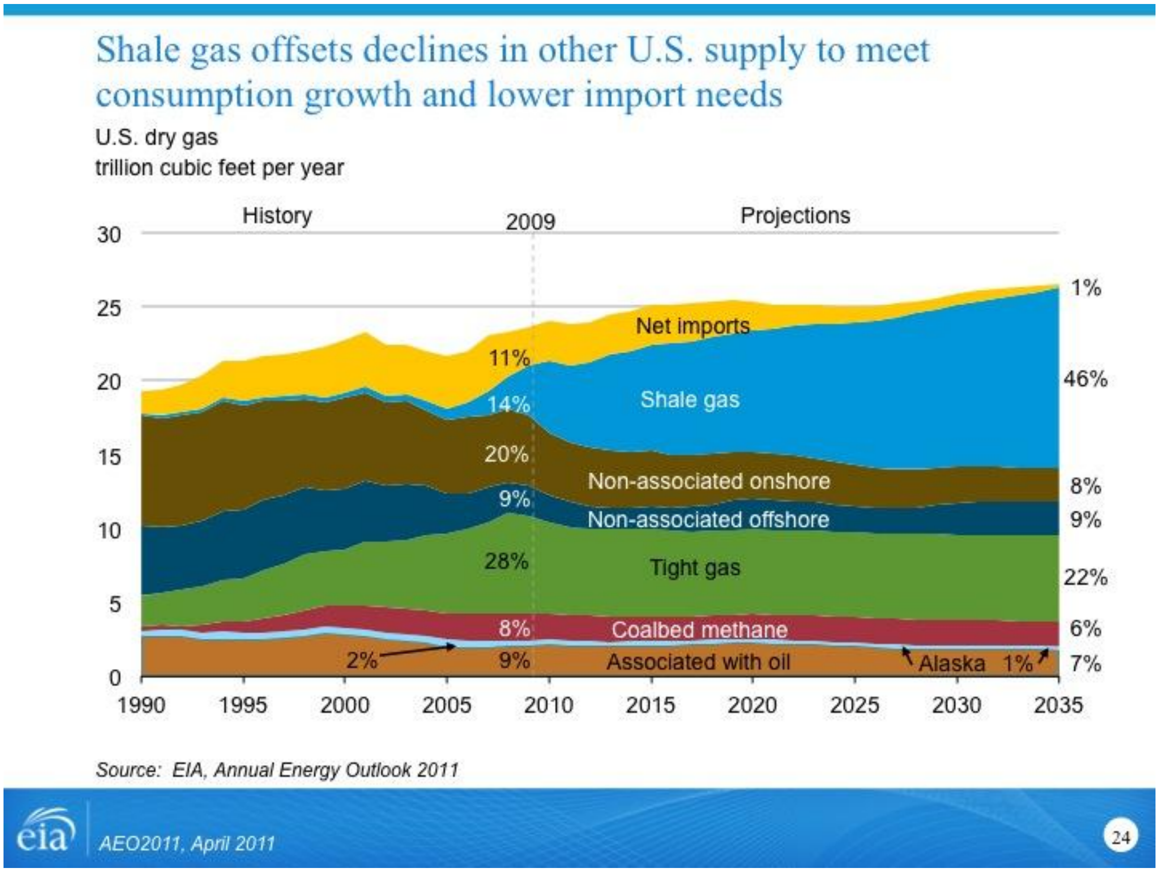
Context for the Subcommittee's deliberations

The Subcommittee believes that the U.S. shale gas resource has enormous potential to provide economic and environmental benefits for the county. Shale gas is a widely distributed resource in North America that can be relatively cheaply produced, creating jobs across the country. Natural gas – if properly produced and transported – also offers climate change advantages because of its low carbon content compared to coal.

Source: U.S. Energy Information Administration based on data from various published studies. Canada and Mexico plays from ARI.
Updated: May 9, 2011

Domestic production of shale gas also has the potential over time to reduce dependence on imported oil for the United States. International shale gas production will increase the diversity of supply for other nations. Both these developments offer important national security benefits.[2]

The development of shale gas in the United States has been very rapid. Natural gas from all sources is one of America's major fuels, providing about 25 percent of total U.S. energy. Shale gas, in turn, was less than two percent of total U.S. natural gas production in 2001. Today, it is approaching 30 percent.[3] But it was only around 2008 that the significance of shale gas began to be widely recognized. Since then, output has increased four-fold. It has brought new regions into the supply mix. Output from the Haynesville shale, mostly in Louisiana, for example, was negligible in 2008; today, the Haynesville shale alone produces eight percent of total U.S. natural gas output. According to the U.S. Energy Information Administration (EIA), the rapid expansion of shale gas production is expected to continue in the future. The EIA projects shale gas to be 46 percent of domestic production by 2035. The following figure shows the stunning change.



The economic significance is potentially very large. While estimates vary, well over 200,000 of jobs (direct, indirect, and induced) have been created over the last several years by the development of domestic production of shale gas, and tens of thousands more will be created in the future.[4] As late as 2007, before the impact of the shale gas revolution, it was assumed that the United States would be importing large amounts of liquefied natural gas from the Middle East and other areas. Today, the United States is essentially self-sufficient in natural gas, with the only notable imports being from Canada, and expected to remain so for many decades. The price of natural gas has fallen by more than a factor of two since 2008, benefiting consumers in the lower cost of home heating and electricity.

The rapid expansion of production is rooted in change in applications of technology and field practice. It had long been recognized that substantial supplies of natural gas were embedded in shale rock. But it was only in 2002 and 2003 that the combination of two technologies working together – hydraulic fracturing and horizontal drilling – made shale gas commercial.

These factors have brought new regions into the supply mix. Parts of the country, such as regions of the Appalachian mountain states where the Marcellus Shale is located, which have not experienced significant oil and gas development for decades, are now undergoing significant development pressure. Pennsylvania, for example, which produced only one percent of total dry gas production in 2009, is one of the most active new areas of development. Even states with a history of oil and gas development, such as Wyoming and Colorado, have experienced significant development pressures in new areas of the state where unconventional gas is now technically and economically accessible due to changes in drilling and development technologies.

The urgency of addressing environmental consequences

As with all energy use, shale gas must be produced in a manner that prevents, minimizes and mitigates environmental damage and the risk of accidents and protects public health and safety. Public concern and debate about the production of shale gas has grown as shale gas output has expanded.

The Subcommittee identifies four major areas of concern: (1) Possible pollution of drinking water from methane and chemicals used in fracturing fluids; (2) Air pollution; (3) Community disruption during shale gas production; and (4) Cumulative adverse impacts that intensive shale production can have on communities and ecosystems.

There are serious environmental impacts underlying these concerns and these adverse environmental impacts need to be prevented, reduced and, where possible, eliminated as soon as possible. Absent effective control, public opposition will grow, thus putting continued production at risk. Moreover, with anticipated increase in U.S. hydraulically fractured wells, if effective environmental action is not taken today, the potential environmental consequences will grow to a point that the country will be faced a more serious problem. Effective action requires both strong regulation and a shale gas industry in which all participating companies are committed to continuous improvement.

The rapid expansion of production and rapid change in technology and field practice, requires federal and state agencies to adapt and evolve their regulations. Industry's pursuit of more efficient operations often has environmental as well as economic benefits, including waste minimization, greater gas recovery, less water usage, and a reduced operating footprint. So there are many reasons to be optimistic that continuous improvement of shale gas production in reducing existing and potential undesirable impacts can be a cooperative effort among the public, companies in the industry, and regulators.

Subcommittee scope, procedure and outline of this report

Scope: The Subcommittee has focused exclusively on production of natural gas (and some liquid hydrocarbons) from shale formations with hydraulic fracturing stimulation in either vertical or horizontal wells. The Subcommittee is aware that some of the observations and recommendations in this report could lead to extension of its findings to other oil and gas operations, but our intention is to focus singularly on issues related to shale gas development. We caution against applying our findings to other areas, because the Subcommittee has not considered the different development practices and other types of geology, technology, regulation and industry practice.

These shale plays in different basins have different geological characteristics and occur in areas with very different water resources. In the Eagle Ford, in Texas, there is almost no flow-back water from an operating well following hydraulic fracturing, while in the Marcellus, primarily in Ohio, New York, Pennsylvania and West Virginia, the flow-back water is between 20 and 40 percent of the injected volume. This geological diversity means that engineering practice and regulatory oversight will differ widely among regions of the country.

The Subcommittee describes in this report a comprehensive and collaborative approach to managing risk in shale gas production. The Subcommittee believes that a more systematic commitment to a process of *continuous improvement* to identify and implement best practices is needed, and should be embraced by all companies in the shale gas industry. Many companies already demonstrate their commitment to the kind of process we describe here, but the public should be confident that this is the practice across the industry.

This process should involve discussions and other collaborative efforts among companies involved in shale gas production (including service companies), state and federal regulators, and affected communities and public interests groups. The process should identify best practices that evolve as operational experience increases, knowledge of environmental effects and effective mitigation grows, and know-how and technology changes. It should also be supported by technology peer reviews that report on individual companies' performance and should be seen as a compliment to, not a substitute for, strong regulation and effective enforcement. There will be three benefits:

- For industry: As all firms move to adopt identified best practices, continuous improvement has the potential to both enhance production efficiency and reduce environmental impacts over time.
- For regulators: Sharing data and best practices will better inform regulators and help them craft policies and regulations that will lead to sounder and more efficient environmental practices than are now in place.
- For the public: Continuous improvement coupled with rigorous regulatory oversight can provide confidence that processes are in place that will result in improved safety and less environmental and community impact.

The realities of regional diversity of shale gas resources and rapid change in production practices and technology mean that a single best engineering practice cannot set for all locations and for all time. Rather, the appropriate starting point is to understand what are regarded as "best practices" today, how the current regulatory system works in the context of those operating in different parts of the country, and establishing a culture of continuous improvement.

The Subcommittee has considered the safety and environmental impact of all steps in shale gas production, not just hydraulic fracturing.[5] Shale gas production consists of several steps, from well design and surface preparation, to drilling and cementing steel casing at multiple stages of well construction, to well completion. The various steps include perforation, water and fracturing fluid preparation, multistage hydraulic fracturing, collection and handling of flow-back and produced water, gas collection, processing and pipeline transmission, and site remediation.[6] Each of these activities has safety and environmental risks that are addressed by operators and by regulators in different ways according to location. In light of these processes, the Subcommittee interprets its charge to assess this entire system, rather than just hydraulic fracturing.

The Subcommittee's charge is not to assess the balance of the benefits of shale gas use against these environmental costs. Rather, the Subcommittee's charge is to identify steps that can be taken to reduce the environmental and safety risks associated with shale gas development and, importantly, give the public concrete reason to believe that environmental impacts will be reduced and well managed on an ongoing basis, and that problems will be mitigated and rapidly corrected, if and when they occur.

It is not within the scope of the Subcommittee's 90-day report to make recommendations about the proper regulatory roles for state and federal governments. However, the Subcommittee emphasizes that effective and capable regulation is essential to protect the public interest. The challenges of protecting human health and the environment in light of the anticipated rapid expansion of shale gas production require the joint efforts of state and federal regulators. This means that resources dedicated to oversight of the industry must be sufficient to do the job and that there is adequate regulatory staff at the state and federal level with the technical expertise to issue, inspect, and enforce regulations. Fees, royalty payments and severance taxes are appropriate sources of funds to finance these needed regulatory activities.

The nation has important work to do in strengthening the design of a regulatory system that sets the policy and technical foundation to provide for continuous improvement in the protection of human health and the environment. While many states and several federal agencies regulate aspects of these operations, the efficacy of the regulations is far from clear. Raw statistics about enforcement actions and compliance are not sufficient to draw conclusions about regulatory effectiveness. Informed conclusions about the state of shale gas operations require analysis of the vast amount of data that is publically available, but there are surprisingly few published studies of this publically available data. Benchmarking is needed for the efficacy of existing regulations and consideration of additional mechanisms for assuring compliance such as disclosure of company performance and enforcement history, and operator certification of performance subject to stringent fines, if violated.

Subcommittee Procedure: In the ninety days since its first meeting, the Subcommittee met with representatives of industry, the environmental community, state regulators, officials of the Environmental Protection Agency, the Department of Energy, the Department of the Interior, both the United States Geologic Survey (USGS) and the Bureau of Land Management (BLM), which has responsibility for public land regulation,[7] and a number of individuals from industry and not-for-profit groups with relevant expertise and interest. The Subcommittee held a public meeting attended by over four hundred citizens in Washington Country, PA, and visited several Marcellus shale gas sites. The Subcommittee strove to hold all of its meeting in public although the Subcommittee held several private working sessions to review what it had learned and to deliberate on its course of action. A website is available that contains the Subcommittee meeting agendas, material presented to the Subcommittee, and numerous public comments.[8]

Outline of this report: The Subcommittee findings and recommendations are organized in four sections:

- Making information about shale gas production operations more accessible to the public – an immediate action.
- Immediate and longer term actions to reduce environmental and safety risks of shale gas operations
- Creation of a Shale Gas Industry Operation organization, on national and/or regional basis, committed to continuous improvement of best operating practices.
- R&D needs to improve safety and environmental performance – immediate and long term opportunities for government and industry.

The common thread in all these recommendations is that measurement and disclosure are fundamental elements of good practice and policy for all parties. Data enables companies to identify changes that improve efficiency and environmental performance and to benchmark against the performance of different companies. Disclosure of data permits regulators to identify cost/effective regulatory measures that better protect the environment and public safety, and disclosure gives the public a way to measure progress on reducing risks.

Making shale gas information available to the public

The Subcommittee has been struck by the enormous difference in perception about the consequences of shale gas activities. Advocates state that fracturing has been performed safety without significant incident for over 60 years, although modern shale gas fracturing of two mile long laterals has only been done for something less than a decade. Opponents point to failures and accidents and other environmental impacts, but these incidents are typically unrelated to hydraulic fracturing *per se* and sometimes lack supporting data about the relationship of shale gas development to incidence and consequences.[9] An industry response that hydraulic fracturing has been performed safely for decades rather than engaging the range of issues concerning the public will not succeed.

Some of this difference in perception can be attributed to communication issues. Many in the concerned public use the word “fracking” to describe all activities associated with shale gas development, rather than just the hydraulic fracturing process itself. Public concerns extend to accidents and failures associated with poor well construction and operation, surface spills, leaks at pits and impoundments, truck traffic, and the cumulative impacts of air pollution, land disturbance and community disruption.

The Subcommittee believes there is great merit to creating a national database to link as many sources of public information as possible with respect to shale gas development and production. Much information has been generated over the past ten years by state and federal regulatory agencies. Providing ways to link various databases and, where possible, assemble data in a comparable format, which are now in perhaps a hundred different locations, would permit easier access to data sets by interested parties.

Members of the public would be able to assess the current state of environmental protection and safety and inform the public of these trends. Regulatory bodies would be better able to assess and monitor the trends in enforcement activities. Industry would be able to analyze data on production trends and comparative performance in order to identify effective practices.

The Subcommittee recommends creation of this national database. A rough estimate for the initial cost is $20 million to structure and construct the linkages necessary for assembling this virtual database, and about $5 million annual cost to maintain it. This recommendation is not aimed at establishing new reporting requirements. Rather, it focuses on creating linkages among information and data that is currently collected and technically and legally capable of being made available to the public. What analysis of the data should be done is left entirely for users to decide.[10]

There are other important mechanisms for improving the availability and usefulness of shale gas information among various constituencies. The Subcommittee believes two such mechanisms to be exceptionally meritorious (and would be relatively inexpensive to expand).

The first is an existing organization known as STRONGER – the State Review of Oil and Natural Gas Environmental Regulation. STRONGER is a not-for-profit organization whose purpose is to accomplish genuine peer review of state regulatory activities. The peer reviews (conducted by a panel of state regulators, industry representatives, and environmental organization representatives with respect to the processes and policies of the state under review) are published publicly, and provide a means to share information about environmental protection strategies, techniques, regulations, and measures for program improvement. Too few states participate in STRONGER's voluntary review of state regulatory programs. The reviews allow for learning to be shared by states and the expansion of the STRONGER process should be encouraged. The Department of Energy, the Environmental Protection Agency, and the American Petroleum Institute have supported STRONGER over time.[11]

The second is the Ground Water Protection Council's project to extend and expand the *Risk Based Data Management System, which* allows states to exchange information about defined parameters of importance to hydraulic fracturing operations.[12]

The Subcommittee recommends that these two activities be funded at the level of $5 million per year beginning in FY2012. Encouraging these multi-stakeholder mechanisms will help provide greater information to the public, enhancing regulation and improving the efficiency of shale gas production. It will also provide support for STRONGER to expand its activities into other areas such as air quality, something that the Subcommittee encourages the states to do as part of the scope of STRONGER peer reviews.

Recommendations for immediate and longer term actions to reduce environmental and safety risks of shale gas operations

1. Improvement in air quality by reducing emissions of regulated pollutants and methane.

Shale gas production, including exploration, drilling, venting/flaring, equipment operation, gathering, accompanying vehicular traffic, results in the emission of ozone precursors (volatile organic compounds (VOCs), and nitrogen oxides), particulates from diesel exhaust, toxic air pollutants and greenhouse gases (GHG), such as methane.

As shale gas operations expand across the nation these air emissions have become an increasing matter of concern at the local, regional and national level. Significant air quality impacts from oil and gas operations in Wyoming, Colorado, Utah and Texas are well documented, and air quality issues are of increasing concern in the Marcellus region (in parts of Ohio, Pennsylvania, West Virginia and New York).[13]

The Environmental Protection Agency has the responsibility to regulate air emissions and in many cases delegate its authority to states. On July 28, 2011, EPA proposed amendments to its regulations for air emissions for oil and gas operations. If finalized and fully implemented, its proposal will reduce emissions of VOCs, air toxics and, collaterally, methane. EPA's proposal does not address many existing types of sources in the natural gas production sector, with the notable exception of hydraulically fractured well re-completions, at which "green" completions must be used. ("Green" completions use equipment that will capture methane and other air contaminants, avoiding its release.) EPA is under court order to take final action on these clean air measures in 2012. In addition, a number of states – notably, Wyoming and Colorado – have taken proactive steps to address air emissions from oil and gas activities.

The Subcommittee supports adoption of emission standards for both new and existing sources for methane, air toxics, ozone-forming pollutants, and other major airborne contaminants resulting from natural gas exploration, production, transportation and distribution activities. The Subcommittee also believes that companies should be required, as soon as practicable, to measure and disclose air pollution emissions, including greenhouse gases, air toxics, ozone precursors and other pollutants. Such disclosure should include direct measurements wherever feasible; include characterization of chemical composition of the natural gas measured; and be reported on a publically accessible website that allows for searching and aggregating by pollutant, company, production activity and geography.

Methane emissions from shale gas drilling, production, gas processing, transmission and storage are of particular concern because methane is a potent greenhouse gas: 25 to 72 times greater warming potential than carbon dioxide on 100-year and 20-year time scales respectively.[14] Currently, there is great uncertainty about the scale of methane emissions.

The Subcommittee recommends three actions to address the air emissions issue.

First, inadequate data are available about how much methane and other air pollutants are emitted by the consolidated production activities of a shale gas operator in a given area, with such activities encompassing drilling, fracturing, production, gathering, processing of gas and liquids, flaring, storage, and dispatch into the pipeline transmission and distribution network. Industry reporting of greenhouse gas emissions in 2012 pursuant to EPA's reporting rule will provide new insights, but will not eliminate key uncertainties about the actual amount and variability in emissions.

The Subcommittee recommends enlisting a subset of producers in different basins, on a voluntary basis, to immediately launch projects to design and rapidly implement measurement systems to collect comprehensive methane and other air emissions data.

These pioneering data sets will be useful to regulators and industry in setting benchmarks for air emissions from this category of oil and gas production, identifying cost-effective procedures and equipment changes that will reduce emissions; and guiding practical regulation and potentially avoid burdensome and contentious regulatory procedures. Each project should be conducted in a transparent manner and the results should be publicly disclosed.

There needs to be common definitions of the emissions and other parameters that should be measured and measurement techniques, so that comparison is possible between the data collected from the various projects. Provision should be made for an independent technical review of the methodology and results to establish their credibility. The Subcommittee will report progress on this proposal during its next phase.

The second recommendation regarding air emissions concerns the need for a thorough assessment of the greenhouse gas footprint for cradle-to-grave use of natural gas. This effort is important in light of the expectation that natural gas use will expand and substitute for other fuels. There have been relatively few analyses done of the question of the greenhouse gas footprint over the entire fuel-cycle of natural gas production, delivery and use, and little data are available that bear on the question. A recent peer-reviewed article reaches a pessimistic conclusion about the greenhouse gas footprint of shale gas production and use – a conclusion not widely accepted.[15] DOE's National Energy Technology Laboratory has given an alternative analysis.[16] Work has also been done for electric power, where natural gas is anticipated increasingly to substitute for coal generation, reaching a more favorable conclusion that natural gas results in about one-half the equivalent carbon dioxide emissions.[17]

The Subcommittee believes that additional work is needed to establish the extent of the footprint of the natural gas fuel cycle in comparison to other fuels used for electric power and transportation because it is an important factor that will be considered when formulating policies and regulations affecting shale gas development. These data will help answer key policy questions such as the time scale on which natural gas fuel switching strategies would produce real climate benefits through the full fuel cycle and the level of methane emission reductions that may be necessary to ensure such climate benefits are meaningful.

The greenhouse footprint of the natural gas fuel cycle can be either estimated indirectly by using surrogate measures or preferably by collecting actual data where it is practicable to do so. In the selection of methods to determine actual emissions, preference should be given to direct measurement wherever feasible, augmented by emissions factors that have been empirically validated. Designing and executing a comprehensive greenhouse gas footprint study based on actual data – the Subcommittee's recommended approach -- is a major project. It requires agreement on measurement equipment, measurement protocols, tools for integrating and analyzing data from different regions, over a multiyear period. Since producer, transmission and distribution pipelines, end-use storage and natural gas many different companies will necessarily be involved. A project of this scale will be expensive. Much of the cost will be borne by firms in the natural gas enterprise that are or will be required to collect and report air emissions. These measurements should be made as rapidly as practicable. Aggregating, assuring quality control and analyzing these data is a substantial task involving significant costs that should be underwritten by the federal government.

It is not clear which government agency would be best equipped to manage such a project. The Subcommittee recommends that planning for this project should begin immediately and that the Office of Science and Technology Policy, should be asked to coordinate an interagency effort to identify sources of funding and lead agency responsibility. This is a pressing question so a clear blueprint and project timetable should be produced within a year.

Third, the Subcommittee recommends that industry and regulators immediately expand efforts to reduce air emissions using proven technologies and practices. Both methane and ozone precursors are of concern. Methane leakage and uncontrolled venting of methane and other air contaminants in the shale gas production should be eliminated except in cases where operators demonstrate capture is technically infeasible, or where venting is necessary for safety reasons and where there is no alternative for capturing emissions. When methane emissions cannot be captured, they should be flared whenever volumes are sufficient to do so.

Ozone precursors should be reduced by using cleaner engine fuel, deploying vapor recovery and other control technologies effective on relevant equipment." Wyoming's emissions rules represent a good starting point for establishing regulatory frameworks and for encouraging industry best practices.

2. Protecting water supply and water quality.

The public understandably wants implementation of standards to ensure shale gas production does not risk polluting drinking water or lakes and streams. The challenge to proper understanding and regulation of the water impacts of shale production is the great diversity of water use in different regional shale gas plays and the different pattern of state and federal regulation of water resources across the country. The U.S. EPA has certain authorities to regulate water resources and it is currently undertaking a two-year study under congressional direction to investigate the potential impacts of hydraulic fracturing on drinking water resources.[18]

Water use in shale gas production passes through the following stages: (1) water acquisition, (2) drilling and hydraulic fracturing (surface formulation of water, fracturing chemicals and sand followed by injection into the shale producing formation at various locations), (3) collection of return water, (4) water storage and processing, and (5) water treatment and disposal.

The Subcommittee offers the following observations with regard to these water issues:

(1) Hydraulic fracturing stimulation of a shale gas well requires between 1 and 5 million gallons of water. While water availability varies across the country, in most regions water used in hydraulic fracturing represents a small fraction of total water consumption. Nonetheless, in some regions and localities there are significant concerns about consumptive water use for shale gas development.[19] There is considerable debate about the water intensity of natural gas compared to other fuels for particular applications such as electric power production.[20]

    One of the commonly perceived risks from hydraulic fracturing is the possibility of leakage of fracturing fluid through fractures into drinking water. Regulators and geophysical experts agree that the likelihood of properly injected fracturing fluid reaching drinking water through fractures is remote where there is a large depth separation between drinking water sources and the producing zone. In the great majority of regions where shale gas is being produced, such separation exists and there are few, if any, documented examples of such migration. An improperly executed fracturing fluid injection can, of course, lead to surface spills and leakage into surrounding shallow drinking water formations. Similarly, a well with poorly cemented casing could potentially leak, regardless of whether the well has been hydraulically fractured.

With respect to stopping surface spills and leakage of contaminated water, the Subcommittee observes that extra measures are now being taken by some operators and regulators to address the public's concern that water be protected. The use of mats, catchments and groundwater monitors as well as the establishment of buffers around surface water resources help ensure against water pollution and should be adopted.

Methane leakage from producing wells into surrounding drinking water wells, exploratory wells, production wells, abandoned wells, underground mines, and natural migration is a greater source of concern. The presence of methane in wells surrounding a shale gas production site is not *ipso facto* evidence of methane leakage from the fractured producing well since methane may be present in surrounding shallow methane deposits or the result of past conventional drilling activity.

However, a recent, credible, peer-reviewed study documented the higher concentration of methane originating in shale gas deposits (through isotopic abundance of C-13 and the presence of trace amounts of higher hydrocarbons) into wells surrounding a producing shale production site in northern Pennsylvania.[21] <u>The Subcommittee recommends several studies be commissioned to confirm the validity of this study and the extent of methane migration that may take place in this and other regions</u>.

(2) Industry experts believe that methane migration from shale gas production, when it occurs, is due to one or another factors: drilling a well in a geological unstable location; <u>loss of well integrity as a result of poor well completion (cementing or casing) or poor production pressure management</u>. Best practice can reduce the risk of this failure mechanism (as discussed in the following section). Pressure tests of the casing and state-of-the-art cement bond logs should be performed to confirm that the methods being used achieve the desired degree of

formation isolation. Similarly, frequent microseismic surveys should be carried out to assure operators and service companies that hydraulic fracture growth is limited to the gas-producing formations. Regulations and inspections are needed to confirm that operators have taken prompt action to repair defective cementing (squeeze jobs).

(3) A producing shale gas well yields flow-back and other produced water. The flow-back water is returned fracturing water that occurs in the early life of the well (up to a few months) and includes residual fracturing fluid as well as some solid material from the formation. Produced water is the water displaced from the formation and therefore contains substances that are found in the formation, and may include brine, gases (e.g. methane, ethane), trace metals, naturally occurring radioactive elements (e.g. radium, uranium) and organic compounds. Both the amount and the composition of the flow-back and produced water vary substantially among shale gas plays – for example, in the Eagle Ford area, there is very little returned water after hydraulic fracturing whereas, in the Marcellus, 20 to 40 percent of the fracturing fluid is produced as flow-back water. In the Barnett, there can significant amounts of saline water produced with shale gas if hydraulic fractures propagate downward into the Ellenburger formation.

(4) The return water (flow-back + produced) is collected (frequently from more than a single well), processed to remove commercially viable gas and stored in tanks or an impoundment pond (lined or unlined). For pond storage evaporation will change the composition. Full evaporation would ultimately leave precipitated solids that must be disposed in a landfill. <u>Measurement of the composition of the stored return water should be a routine industry practice</u>.

(5) There are four possibilities for disposal of return water: <u>reuse</u> as fracturing fluid in a new well (several companies, operating in the Marcellus are recycling over 90 percent of the return water); <u>underground injection into disposal wells</u> (this mode of disposal is regulated by the EPA); <u>waste water treatment</u> to produce clean water (though at present, most waste water treatment plants are not equipped with the capability to treat many of the contaminants associated with shale gas waste water); and <u>surface runoff</u> which is forbidden.

Currently, the approach to water management by regulators and industry is not on a "systems basis" where all aspect of activities involving water use is planned, analyzed, and managed on an integrated basis. The difference in water use and regulation in different shale plays means that there will not be a single water management integrated system applicable in all locations. Nevertheless, the Subcommittee believes certain common principles should guide the development of integrated water management and identifies three that are especially important:

- Adoption of a life cycle approach to water management from the beginning of the production process (acquisition) to the end (disposal): all water flows should be tracked and reported quantitatively throughout the process.
- Measurement and public reporting of the composition of water stocks and flow throughout the process (for example, flow-back and produced water, in water ponds and collection tanks).
- Manifesting of all transfers of water among locations.

Early case studies of integrated water management are desirable so as to provide better bases for understanding water use and disposition and opportunities for reduction of risks related to water use. The Subcommittee supports EPA's retrospective and prospective case studies that will be part of the EPA study of hydraulic fracturing impacts on drinking water resources, but these case studies focus on identification of possible consequences rather than the definition of an integrated water management system, including the measurement needs to support it. The Subcommittee believes that development and use of an integrated water management system has the potential for greatly reducing the environmental footprint and risk of water use in shale gas production and recommends that regulators begin working with industry and other stakeholders to develop and implement such systems in their jurisdictions and regionally.

Additionally, agencies should review field experience and modernize rules and enforcement practices – especially regarding well construction/operation, management of flow back and produced water, and prevention of blowouts and surface spills – to ensure robust protection of drinking and surface waters. Specific best practice matters that should receive priority attention from regulators and industry are described below.

3. Background water quality measurements.

At present there are widely different practices for measuring the water quality of wells in the vicinity of a shale gas production site. Availability of measurements in advance of drilling would provide an objective baseline for determining if the drilling and hydraulic fracturing activity introduced any contaminants in surrounding drinking water wells.

The Subcommittee is aware there is great variation among states with respect to their statutory authority to require measurement of water quality of private wells, and that the process of adopting practical regulations that would be broadly acceptable to the public would be difficult. Nevertheless, the value of these measurements for reassuring communities about the impact of drilling on their community water supplies leads <u>the Subcommittee to recommend that states and localities adopt systems for measurement and reporting of background water quality in advance of shale gas production activity</u>. These baseline measurements should be publicly disclosed, while protecting landowner’s privacy.

4. Disclosure of the composition of fracturing fluids.

There has been considerable debate about requirements for reporting all chemicals (both composition and concentrations) used in fracturing fluids. Fracturing fluid refers to the slurry prepared from water, sand, and some added chemicals for high pressure injection into a formation in order to create fractures that open a pathway for release of the oil and gases in the shale. Some states (such as Wyoming, Arkansas and Texas) have adopted disclosure regulations for the chemicals that are added to fracturing fluid, and the U.S. Department of Interior has recently indicated an interest in requiring disclosure for fracturing fluids used on federal lands.

The DOE has supported the establishment and maintenance of a relatively new website, FracFocus.org (operated jointly by the Ground Water Protection Council and the Interstate Oil and Gas Compact Commission) to serve as a voluntary chemical registry for individual companies to report all chemicals that would appear on Material Safety Data Sheets (MSDS) subject to certain provisions to protect “trade secrets.” While FracFocus is off to a good start with voluntary reporting growing rapidly, the restriction to MSDS data means that a large universe of chemicals frequently used in hydraulic fracturing treatments goes unreported. MSDS only report chemicals that have been deemed to be hazardous in an occupational setting under standards adopted by OSHA (the Occupational Safety and Health Administration); MSDA reporting does not include other chemicals that might be hazardous if human exposure occurs through environmental pathways. Another limitation of FracFocus is that the information is not maintained as a database. As a result, the ability to search for data is limited and there are no tools for aggregating data.

The Subcommittee believes that the high level of public concern about the nature of fracturing chemicals suggests that the benefit of immediate and complete disclosure of all chemical components and composition of fracturing fluid completely outweighs the restriction on company action, the cost of reporting, and any intellectual property value of proprietary chemicals. The Subcommittee believes that public confidence in the safety of fracturing would be significantly improved by complete disclosure and that the barrier to shield chemicals based on trade secret should be set very high. <u>Therefore the Subcommittee recommends that regulatory entities immediately develop rules to require disclosure of all chemicals used in hydraulic fracturing fluids on both public and private lands.</u> Disclosure should include all chemicals, not just those that appear on MSDS. It should be reported on a well-by-well basis and posted on a publicly available website that includes tools for searching and aggregating data by chemical, well, by company, and by geography.

5. Reducing the use of diesel in shale gas development

<u>Replacing diesel with natural gas or electric power for oil field equipment</u> will decrease harmful air emissions and improve air quality. Although fuel substitution will likely happen over time because of the lower cost of natural gas compared diesel and because of likely future emission restrictions, <u>the Subcommittee recommends conversion from diesel to natural gas for equipment fuel or to electric power where available, as soon as practicable</u>. The process of conversion may be slowed because manufacturers of compression ignition or spark ignition engines may not have certified the engine operating with natural gas fuel for off-road use as required by EPA air emission regulations.[22]

Eliminating the use of diesel as an additive to hydraulic fracturing fluid**.** The Subcommittee believes there is no technical or economic reason to use diesel as a stimulating fluid. Diesel is a refinery product that consists of several components possibly including some toxic impurities such as benzene and other aromatics. (EPA is currently considering permitting restrictions of the use of diesel fuels in hydraulic fracturing under Safe Drinking Water Act (SDWA) Underground Injection Control (UIC) Class II.) Diesel is convenient to use in the oil field because it is present for use fuel for generators and compressors.

Diesel has two uses in hydraulic fracturing and stimulation. In modest quantities diesel is used to solubilize other fracturing chemical such as guar. Mineral oil (a synthetic mixture of C-10 to C-40 hydrocarbons) is as effective at comparable cost. Infrequently, diesel is use as a fracturing fluid in water sensitive clay and shale reservoirs. In these cases, light crude oil that is free of aromatic impurities picked up in the refining process, can be used as a substitute of equal effectiveness and lower cost compared to diesel, as a non-aqueous fracturing fluid.

6. Managing short-term and cumulative impacts on communities, land use, wildlife and ecologies.

Intensive shale gas development can potentially have serious impacts on public health, the environment and quality of life – even when individual operators conduct their activities in ways that meet and exceed regulatory requirements. The combination of impacts from multiple drilling and production operations, support infrastructure (pipelines, road networks, etc.) and related activities can overwhelm ecosystems and communities.

The Subcommittee believes that federal, regional, state and local jurisdictions need to place greater effort on examining these cumulative impacts in a more holistic manner; discrete permitting activity that focuses narrowly on individual activities does not reach to these issues. Rather than suggesting a simple prescription that every jurisdiction should follow to assure adequate consideration of these impacts, the Subcommittee believes that each relevant jurisdiction should develop and implement processes for community engagement and for preventing, mitigating and remediating surface impacts and community impacts from production activities. There are a number of threshold mechanisms that should be considered:

- Optimize use of multi-well drilling pads to minimize transport traffic and needs for new road construction.
- Evaluate water use at the scale of affected watersheds.
- Provide formal notification by regulated entities of anticipated environmental and community impacts.
- Declare unique and/or sensitive areas off-limits to drilling and support infrastructure as determined through an appropriate science-based process.
- Undertake science-based characterization of important landscapes, habitats and corridors to inform planning, prevention, mitigation and reclamation of surface impacts.
- Establish effective field monitoring and enforcement to inform on-going assessment of cumulative community and land use impacts.
- Mitigate noise, air and visual pollution.

The process for addressing these issues must afford opportunities for affected communities to participate and respect for the rights of mineral rights owners.

Organizing for continuous improvement of "best practice"

In this report, the term "Best Practice" refers to industry techniques or methods that have proven over time to accomplish given tasks and objectives in a manner that most acceptably balances desired outcomes and avoids undesirable consequences. Continuous best practice in an industry refers to the evolution of best practice by adopting process improvements as they are identified, thus progressively improving the level and narrowing the distribution of performance of firms in the industry. Best practice is a particularly helpful management approach in a field that is growing rapidly, where technology is changing rapidly, and involves many firms of different size and technical capacity.

Best practice does not necessarily imply a single process or procedure; it allows for a range of practice that is believed to be equally effective at achieving desired out comes. This flexibility is important because it acknowledges the possibility that different operators in different regions will select different solutions.

The Subcommittee believes the creation of a shale gas industry production organization dedicated to continuous improvement of best practice through development of standards, diffusion of these standards, and assessing compliance among its members can be an important mechanism for improving shale gas companies' commitment to safety and environmental protection as it carries out its business. The Subcommittee envisions that the industry organization would be governed by a board of directors composed of member companies, on a rotating basis, along with external members, for example from non-governmental organizations and academic institutions, as determined by the board.

Strong regulations and robust enforcement resources and practices are a prerequisite to protecting health, safety and the environment, but the job is easier where companies are motivated and committed to adopting best engineering and environmental practice. Companies have economic incentives to adopt best practice, because it improves operational efficiency and, if done properly, improves safety and environmental protection.

Achievement of best practice requires management commitment, adoption and dissemination of standards that are widely disseminated and periodically updated on the basis of field experience and measurements. A trained work force, motivated to adopt best practice, is also necessary. Creation of an industry organization dedicated to excellence in shale gas operations intended to advance knowledge about best practice and improve the interactions among companies, regulators and the public would be a major step forward.

The Subcommittee is aware that shale gas producers and other groups recognize the value of a best practice management approach and that industry is considering creating a mechanism for encouraging best practice. The design of such a mechanism involves many considerations including the differences in the shale production and regulations in different basins, making most effective use of mechanisms that are currently in place, and respecting the different capabilities of large and smaller operators. The Subcommittee will monitor progress on this important matter and continue to make its views known about the characteristics that such a mechanism and supporting organization should possess to maximize its effectiveness.

It should be stressed that any industry best practice mechanism would need to comply with anti-trust laws and would not replace any existing state or federal regulatory authority.

Priority best practice topics

Air

- Measurement and disclosure of air emissions including VOCs, methane, air toxics, and other pollutants.
- Reduction of methane emission from all shale gas operations

Water

- Integrated water management systems
- Well completion – casing and cementing
- Characterization and disclosure of flow back and other produced water

The Subcommittee has identified a number of promising best practice opportunities. Five examples are given in the call-out box. Two examples are discussed below to give a sense of the opportunities that presented by best practice focus.

Well integrity: an example. Well integrity is an example of the potential power of best practice for shale gas production. Well integrity encompasses the planning, design and execution of a well completion (cementing, casing and well head placement). It is fundamental to good outcomes in drilling oil and gas wells.

Methane leakage to water reservoirs is widely believed to be due to poor well completion, especially poor casing and cementing. Casing and cementing programs should be designed to provide optimal isolation of the gas-producing zone from overlaying formations. The number of cemented casings and the depth ranges covered will depend on local geologic and hydrologic conditions. However, there need to be multiple engineered barriers to prevent communication between hydrocarbons and potable aquifers. In addition, the casing program needs to be designed to optimize the potential success of cementing operations. Poorly cemented cased wells offer pathways for leakage; properly cemented and cased wells do not.

Well integrity is an ideal example of where a best practice approach, adopted by the industry, can stress best practice and collect data to validate continuous improvement. The American Petroleum Institute, for example, has focused on well completion in its standards activity for shale gas production.[23]

At present, however, there is a wide range in procedures followed in the field with regard to casing placement and cementing for shale gas drilling. There are different practices with regard to completion testing and different regulations for monitoring possible gas leakage from the annulus at the wellhead. In some jurisdictions, regulators insist that gas leakage can be vented; others insist on containment with periodic pressure testing. There are no common leakage criteria for intervention in a well that exhibits damage or on the nature of the intervention. It is very likely that over time a focus on best practice in well completion will result in safer operations and greater environmental protection. The best practice will also avoid costly interruptions to normal operations. The regulation of shale gas development should also include inspections at safety-critical stages of well construction and hydraulic fracturing.

<u>Limiting water use by controlling vertical fracture growth</u>: – a second example. While the vertical growth of hydraulic fractures does not appear to have been a causative factor in reported cases where methane from shale gas formations has migrated to the near surface, it is in the best interest of operators and the public to limit the vertical extent of hydraulic fractures to the gas bearing shale formation being exploited. By improving the efficiency of hydraulic fractures, more gas will be produced using less water for fracturing – which has economic value to operators and environmental value for the public.

The vertical propagation of hydraulic fractures results from the variation of earth stress with depth and the pumping pressure during fracturing. The variation of earth stress with depth is difficult to predict, but easy to measure in advance of hydraulic fracturing operations. Operators and service companies should assure that through periodic direct measurement of earth stresses and microseismic monitoring of hydraulic fracturing operations, everything possible is being done to limit the amount of water and additives used in hydraulic fracturing operations.

<u>Evolving best practices must be accompanied by metrics that permit tracking of the progress in improving shale gas operations performance and environmental impacts</u>. The Subcommittee has the impression that the current standard- setting processes do not utilize metrics. Without such metrics and the collection of relevant measured data,

operators lack the ability to track objectively the progress of the extensive process of setting and updating standards.

Research and development needs

The profitability, rapid expansion, and the growing recognition of the scale of the resource mean that oil and gas companies will mount significant R&D efforts to improve performance and lower cost of shale gas exploration and production. In general the oil and gas industry is a technology-focused and technology-driven industry, and it is safe to assume that there will be a steady advance of technology over the coming years.

In these circumstances the federal government has a limited role in supporting R&D. The proper focus should be on sponsoring R&D and analytic studies that address topics that benefit the public or the industry but which do not permit individual firms to attain a proprietary position. Examples are environmental and safety studies, risk assessments, resource assessments, and longer-term R&D (such as research on methane hydrates). Across many administrations, the Office of Management and Budget (OMB) has been skeptical of any federal support for oil and gas R&D, and many Presidents' budget have not included any request for R&D for oil and gas. Nonetheless Congress has typically put money into the budget for oil & gas R&D.

The following table summarizes the R&D outlays of the DOE, EPA, and USGS for unconventional gas:

Unconventional Gas R&D Outlays for Various Federal Agencies ($ millions)					
	FY2008	**FY2009**	**FY2010**	**FY2011**	**FY2012 request**
DOE Unconventional Gas					
EPAct Section 999 Program Funds					
RPSEA Administered	$14	$14	$14	$14	0
NETL Complementary	$9	$9	$9	$4	0
Annual Appropriated Program Funds					
Environmental	$2	$4	$2	0	0
Unconventional Fossil Energy	0	0	$6	0	0
Methane Hydrate projects	$15	$15	$15	$5	$10
Total Department of Energy	$40	$42	$46	$23	$10
Environmental Protection Agency	$0	$0	$1.9	$4.3	$6.1
USGS	$4.5	$4.6	$5.9	$7.4	$7.6
Total Federal R&D	**$44.5**	**$46.6**	**$53.8**	**$34.7**	**$23.7**

Near Term Actions:

The Subcommittee believes that given the scale and rapid growth of the shale gas resource in the nation's energy mix, the federal government should sponsor some R&D for unconventional gas, focusing on areas that have public and industry wide benefit and addresses public concern. The Subcommittee, at this point, is only in a position to offer some initial recommendations, not funding levels or to assignment of responsibility to particular government agencies. The DOE, EPA, the USGS, and DOI Bureau of Land Management all have mission responsibility that justify a continuing, tailored, federal R&D effort.

RPSEA is the Research Partnership to Secure Energy for America, a public/private research partnership authorized by the 2005 Energy Policy Act at a level of $50 million from offshore royalties. Since 2007, the RPSEA program has focused on unconventional gas. The Subcommittee strongly supports the RPSEA program at its authorized level.[24]

The Subcommittee recommends that the relevant agencies, the Office of Science and Technology Policy (OSTP), and OMB discuss and agree on an appropriate mission and level of funding for unconventional natural gas R&D. If requested, the Subcommittee, in the second phase of its work, could consider this matter in greater detail and make recommendations for the Administration's consideration.

In addition to the studies mentioned in the body of the report, the Subcommittee mentions several additional R&D projects where results could reduce safety risk and environmental damage for shale gas operations:

1. Basic research on the relationship of fracturing and micro-seismic signaling.

2. Determination of the chemical interactions between fracturing fluids and different shale rocks – both experimental and predictive.

3. Understanding induced seismicity triggered by hydraulic fracturing and injection well disposal.[25]

4. Development of "green" drilling and fracturing fluids.

5. Development of improved cement evaluation and pressure testing wireline tools assuring casing and cementing integrity.

Longer term prospects for technical advance

The public should expect significant technical advance on shale gas production that will substantially improve the efficiency of shale gas production and that will in turn reduce environmental impact. The expectation of significant production expansion in the future offers a tremendous incentive for companies to undertake R&D to improve efficiency and profitability. The history of the oil and gas industry supports such innovation, in particular greater extraction of the oil and gas in place and reduction in the unit cost of drilling and production.

The original innovations of directional drilling and formation fracturing plausibly will be extended by much more accurate placement of fracturing fluid guided by improved interpretation of micro-seismic signals and improved techniques of reservoir testing. As an example, oil services firms are already offering services that provide near-real-time monitoring to avoid excessive vertical fracturing growth, thus affording better control of fracturing fluid placement. Members of the Subcommittee estimate that an improvement in in efficiency of water use could be between a factor of two and four. There will be countless other innovations as well.

There has already been a major technical innovation – the switch from single well to pad-based drilling and production of multiple wells (up to twenty wells per pad have been drilled). The multi-well pad system allows for enhanced efficiency because of repeating operations at the same site and a much smaller footprint (e.g. concentrated gas gathering systems; many fewer truck trips associated with drilling and completion, especially related to equipment transport; decreased needs for road and pipeline constructions, etc.). It is worth noting that these efficiencies may require pooling acreage into large blocks.

Conclusion

The public deserves assurance that the full economic, environmental and energy security benefits of shale gas development will be realized without sacrificing public health, environmental protection and safety. Nonetheless, accidents and incidents have occurred with shale gas development, and uncertainties about impacts need to be quantified and clarified. Therefore the Subcommittee has highlighted important steps for more thorough information, implementation of best practices that make use of technical innovation and field experience, regulatory enhancement, and focused R&D, to ensure that shale operations proceed in the safest way possible, with enhanced efficiency and minimized adverse impact. If implemented these measures will give the public reason to believe that the nation's considerable shale gas resources are being developed in a way that is most beneficial to the nation.

ANNEX A – CHARGE TO THE SUBCOMMITTEE

From: Secretary Chu

To: William J. Perry, Chairman, Secretary's Energy Advisory Board (SEAB)

On March 30, 2011, President Obama announced a plan for U.S. energy security, in which he instructed me to work with other agencies, the natural gas industry, states, and environmental experts to improve the safety of shale gas development. The President also issued the Blueprint for a Secure Energy Future ("Energy Blueprint"), which included the following charge:

> **"Setting the Bar for Safety and Responsibility:** To provide recommendations from a range of independent experts, the Secretary of Energy, in consultation with the EPA Administrator and Secretary of Interior, should task the Secretary of Energy Advisory Board (SEAB) with establishing a subcommittee to examine fracking issues. The subcommittee will be supported by DOE, EPA and DOI, and its membership will extend beyond SEAB members to include leaders from industry, the environmental community, and states. The subcommittee will work to identify, within 90 days, any immediate steps that can be taken to improve the safety and environmental performance of fracking and to develop, within six months, consensus recommended advice to the agencies on practices for shale extraction to ensure the protection of public health and the environment." *Energy Blueprint (page 13).*

The President has charged us with a complex and urgent responsibility. I have asked SEAB and the Natural Gas Subcommittee, specifically, to begin work on this assignment immediately and to give it the highest priority.

This memorandum defines the task before the Subcommittee and the process to be used.

Membership:

In January of 2011, the SEAB created a Natural Gas Subcommittee to evaluate what role natural gas might play in the clean energy economy of the future. Members of the Subcommittee include John Deutch (chair), Susan Tierney, and Dan Yergin. Following consultation with the Environmental Protection Agency and the Department of the Interior, I have appointed the following additional members to the Subcommittee: Stephen Holditch, Fred Krupp, Kathleen McGinty, and Mark Zoback.

The varied backgrounds of these members satisfies the President's charge to include individuals with industry, environmental community, and state expertise. To facilitate an expeditious start, the Subcommittee will consist of this small group, but additional members may be added as appropriate.

Consultation with other Agencies:

The President has instructed DOE to work in consultation with EPA and DOI, and has instructed all three agencies to provide support and expertise to the Subcommittee. Both agencies have independent regulatory authority over certain aspects of natural gas production, and considerable expertise that can inform the Subcommittee's work.

- The Secretary and Department staff will manage an interagency working group to be available to consult and provide information upon request of the Subcommittee.
- The Subcommittee will ensure that opportunities are available for EPA and DOI to present information to the Subcommittee.
- The Subcommittee should identify and request any resources or expertise that lies within the agencies that is needed to support its work.
- The Subcommittee's work should at all times remain independent and based on sound science and other expertise held from members of the Subcommittee.
- The Subcommittee's deliberations will involve only the members of the Subcommittee.
- The Subcommittee will present its final report/recommendations to the full SEAB Committee.

Public input:

In arriving at its recommendations, the Subcommittee will seek timely expert and other advice from industry, state and federal regulators, environmental groups, and other stakeholders.

- To assist the Subcommittee, DOE's Office of Fossil Energy will create a website to describe the initiative and to solicit public input on the subject.
- The Subcommittee will meet with representatives from state and federal regulatory agencies to receive expert information on subjects as the Subcommittee deems necessary.
- The Subcommittee or the DOE (in conjunction with the other agencies) may hold one or more public meetings when appropriate to gather input on the subject.

Scope of work of the Subcommittee:

The Subcommittee will provide the SEAB with recommendations as to actions that can be taken to improve the safety and environmental performance of shale gas extraction processes, and other steps to ensure protection of public health and safety, on topics such as:

- well design, siting, construction and completion;
- controls for field scale development;
- operational approaches related to drilling and hydraulic fracturing;
- risk management approaches;
- well sealing and closure;
- surface operations;
- waste water reuse and disposal, water quality impacts, and storm water runoff;

- protocols for transparent public disclosure of hydraulic fracturing chemicals and other information of interest to local communities;
- optimum environmentally sound composition of hydraulic fracturing chemicals, reduced water consumption, reduced waste generation, and lower greenhouse gas emissions;
- emergency management and response systems;
- metrics for performance assessment; and
- mechanisms to assess performance relating to safety, public health and the environment.

The Subcommittee should identify, at a high level, the best practices and additional steps that could enhance companies' safety and environmental performance with respect to a variety of aspects of natural gas extraction. Such steps may include, but not be limited to principles to assure best practices by the industry, including companies' adherence to these best practices. Additionally, the Subcommittee may identify high-priority research and technological issues to support prudent shale gas development.

Delivery of Recommendations and Advice:

- Within 90 days of its first meeting, the Subcommittee will report to SEAB on the "immediate steps that can be taken to improve the safety and environmental performance of fracking."
- Within 180 days of its first meeting, the Subcommittee will report to SEAB "consensus recommended advice to the agencies on practices for shale extraction to ensure the protection of public health and the environment."
- At each stage, the Subcommittee will report its findings to the full Committee and the SEAB will review the findings.
- The Secretary will consult with the Administrator of EPA and the Secretary of the Interior, regarding the recommendations from SEAB.

Other:

- The Department will provide staff support to the Subcommittee for the purposes of meeting the requirements of the Subcommittee charge. The Department will also engage the services of other agency Federal employees or contractors to provide staff services to the Subcommittee, as it may request.
- DOE has identified $700k from the Office of Fossil Energy to fund this effort, which will support relevant studies or assessments, report writing, and other costs related to the Subcommittee's process.
- The Subcommittee will avoid activity that creates or gives the impression of giving undue influence or financial advantage or disadvantage for particular companies involved in shale gas exploration and development.
- The President's request specifically recognizes the unique technical expertise and scientific role of the Department and the SEAB. As an agency not engaged in regulating this activity, DOE is expected to provide a sound, highly credible evaluation of the best practices and best ideas for employing these practices safely that can be made available to companies and relevant regulators for appropriate action. Our task does not include making decisions about regulatory policy.

ANNEX B – MEMBERS OF THE SUBCOMMITTEE

John Deutch, Institute Professor at MIT (Chair) **-** John Deutch served as Director of Energy Research, Acting Assistant Secretary for Energy Technology and Under Secretary of Energy for the U.S. Department of Energy in the Carter Administration and Undersecretary of Acquisition & Technology, Deputy Secretary of Defense and Director of Central Intelligence during the first Clinton Administration. Dr. Deutch also currently serves on the Board of Directors of Raytheon and Cheniere Energy and is a past director of Citigroup, Cummins Engine Company and Schlumberger. A chemist who has published more than 140 technical papers in physical chemistry, he has been a member of the MIT faculty since 1970, and has served as Chairman of the Department of Chemistry, Dean of Science and Provost. He is a member of the Secretary of Energy Advisory Board.

Stephen Holditch, Head of the Department of Petroleum Engineering at Texas A&M University and has been on the faculty since 1976 - Stephen Holditch, who is a member of the National Academy of Engineering, serves on the Boards of Directors of Triangle Petroleum Corporation and Matador Resources Corporation. In 1977, Dr. Holditch founded S.A. Holditch & Associates, a petroleum engineering consulting firm that specialized in the analysis of unconventional gas reservoirs. Dr. Holditch was the 2002 President of the Society of Petroleum Engineers. He was the Editor of an SPE Monograph on hydraulic fracturing treatments, and he has taught short courses for 30 years on the design of hydraulic fracturing treatments and the analyses of unconventional gas reservoirs. Dr. Holditch worked for Shell Oil Company prior to joining the faculty at Texas A&M University.

Fred Krupp, President, Environmental Defense Fund **-** Fred Krupp has overseen the growth of EDF into a recognized worldwide leader in the environmental movement. Krupp is widely acknowledged as the foremost champion of harnessing market forces for environmental ends. He also helped launch a corporate coalition, the U.S. Climate Action Partnership, whose Fortune 500 members - Alcoa, GE, DuPont and dozens more - have called for strict limits on global warming pollution. Mr. Krupp is coauthor, with Miriam Horn, of New York Times Best Seller, *Earth: The Sequel*. Educated at Yale and the University of Michigan Law School, Krupp was among 16 people named as America's Best Leaders by U.S. News and World Report in 2007.

Kathleen McGinty, Kathleen McGinty is a respected environmental leader, having served as President Clinton's Chair of the White House Council on Environmental Quality and Legislative Assistant and Environment Advisor to then-Senator Al Gore.

More recently, she served as Secretary of the Pennsylvania Department of Environmental Protection. Ms. McGinty also has a strong background in energy. She is Senior Vice President of Weston Solutions where she leads the company's clean energy development business. She also is an Operating Partner at Element Partners, an investor in efficiency and renewables. Previously, Ms. McGinty was Chair of the Pennsylvania Energy Development Authority, and currently she is a Director at NRG Energy and Iberdrola USA.

Susan Tierney, Managing Principal, Analysis Group **-** Susan Tierney is a consultant on energy and environmental issues to public agencies, energy companies, environmental organizations, energy consumers, and tribes. She chairs the Board of the Energy Foundation, and serves on the Boards of Directors of the World Resources Institute, the Clean Air Task Force, among others. She recently, co-chaired the National Commission on Energy Policy, and chairs the Policy Subgroup of the National Petroleum Council's study of North American natural gas and oil resources. Dr. Tierney served as Assistant Secretary for Policy at the U.S. Department of Energy during the Clinton Administration. In Massachusetts, she served as Secretary of Environmental Affairs, Chair of the Board of the Massachusetts Water Resources Agency, Commissioner of the Massachusetts Department of Public Utilities and executive director of the Massachusetts Energy Facilities Siting Council.

Daniel Yergin, Chairman, IHS Cambridge Energy Research Associates **-** Daniel Yergin is the co-founder and chairman of IHS Cambridge Energy Research Associates. He is a member of the U.S. Secretary of Energy Advisory Board, a board member of the Board of the United States Energy Association and a member of the U.S. National Petroleum Council. He was vice chair of the 2007 National Petroleum Council study, *Hard Truths* and is vice chair of the new National Petroleum Council study of North American natural gas and oil resources. He chaired the U.S. Department of Energy's Task Force on Strategic Energy Research and Development. Dr. Yergin currently chairs the Energy Security Roundtable at the Brookings Institution, where he is a trustee, and is member of the advisory board of the MIT Energy Initiative. Dr. Yergin is also CNBC's Global Energy Expert. He is the author of the Pulitzer Prize-winning book, *The Prize: The Epic Quest for Oil, Money and Power.* His new book – *The Quest: Energy, Security, and the Remaking of the Modern World* – will be published in September 2011..

Mark Zoback, Professor of Geophysics, Stanford University - Mark Zoback is the Benjamin M. Page Professor of Geophysics at Stanford University. He is the author of a textbook, *Reservoir Geomechanics*, and author or co-author of over 300 technical research papers. He was co-principal investigator of the San Andreas Fault Observatory at Depth project (SAFOD) and has been serving on a National Academy of Engineering committee investigating the Deepwater Horizon accident. He was the chairman and co-founder of GeoMechanics International and serves as a senior adviser to Baker Hughes, Inc. Prior to joining Stanford University, he served as chief of the Tectonophysics Branch of the U.S. Geological Survey Earthquake Hazards Reduction Program.

ENDNOTES

[1] http://www.whitehouse.gov/sites/default/files/blueprint_secure_energy_future.pdf

[2] The James Baker III Institute for Public Policy at Rice University has recently released a report on *Shale Gas and U.S. National Security,* Available at: http://bakerinstitute.org/publications/EF-pub-DOEShaleGas-07192011.pdf.

[3] As a shale of total dry gas production in the “lower ’48”, shale gas was 6 percent in 2006, 8 percent in 2007, at which time its share began to grow rapidly – reaching 12 percent in 2008, 16 percent in 2009, and 24 percent in 2010. In June 2011, it reached 29 percent. Source: Energy Information Adminstration and Lippman Consulting.

[4] Timothy Considine, Robert W. Watson, and Nicholas B. Considine, “The Economy Opportunities of Shale Energy Development,” Manhattan Institute, May 2011, Table 2, page 6.

[5] Essentially all fracturing currently uses water at the working fluid. The possibility exists of using other fluids, such as nitrogen, carbon dioxide or foams as the working fluid.

[6] The Department of Energy has a shale gas technology primer available on the web at: http://www.netl.doe.gov/technologies/oil-gas/publications/brochures/Shale_Gas_March_2011.pdf

[7] See the Bureau of Land Management *Gold Book* for a summary description of the DOI’s approach: http://www.blm.gov/pgdata/etc/medialib/blm/wo/MINERALS__REALTY__AND_RESOURCE_PROTECTION_/energy/oil_and_gas.Par.18714.File.dat/OILgas.pdf

[8] http://www.shalegas.energy.gov/

[9] The 2011 *MIT Study on the Future of Natural Gas,* gives an estimate of about 50 widely reported incidents between 2005 and 2009 involving groundwater contamination, surface spills, off-site disposal issues, water issues, air quality and blow outs, Table 2.3 and Appendix 2E. http://web.mit.edu/mitei/research/studies/naturalgas.html

[10] The Ground Water Protection Council and the Interstate Oil and Gas Compact Commission are considering a project to create a *National Oil and Gas Data Portal* with similar a objective, but broader scope to encompass all oil and gas activities.

[11] Information about STRONGER can be found at: http://www.strongerinc.org/

[12] The RBMS project is supported by the DOE Office of Fossil Energy, DOE grant #DE-FE0000880 at a cost of $1.029 million. The project is described at: http://www.netl.doe.gov/technologies/oil-gas/publications/ENVreports/FE0000880_GWPC_Kickoff.pdf

[13] See, for example: John Corra, “Emissions from Hydrofracking Operations and General Oversight Information for Wyoming,” presented to the U.S. Department of Energy Natural Gas Subcommittee of the Secretary of Energy Advisory Board, July 13, 2011; Al Armendariz, “Emissions from Natural Gas Production in the Barnett Shale Area and Opportunities for Cost-Effective Improvements,” Southern Methodist University, January 2009; Colorado Air Quality Control Commission, “Denver Metro Area & North Front Range Ozone Action Plan,” December 12, 2008; Utah Department of Environmental Quality, “2005 Uintah Basin Oil and Gas Emissions Inventory,” 2005.

[14] IPCC 2007 –The Physical Science Basis, Section 2.10.2).

[15] Robert W. Howarth, Renee Santoro, and Anthony Ingraffea, *Methane and the greenhouse-gas*

footprint of natural gas from shale formations, Climate Change, The online version of this article (doi:10.1007/s10584-011-0061-5) contains supplementary material.

[16] Timothy J. Skone, *Life Cycle Greenhouse Gas Analysis of Natural Gas Extraction & Delivery in the United States,* DOE, NETL, May 2011, available at: http://www.netl.doe.gov/energy-analyses/pubs/NG_LC_GHG_PRES_12MAY11.pdf

[17] Paulina Jaramillo, W. Michael Griffin, and H. Scott Mathews, *Comparative Life-Cycle Air Emissions of Coal, Domestic Natural Gas, LNG, and SNG for Electricity Generation*, Environmental Science & Technology, 41, 6290-6296 (2007).

[18] The EPA draft hydraulic fracturing study plan is available along with other information about EPA hydraulic fracturing activity at: http://water.epa.gov/type/groundwater/uic/class2/hydraulicfracturing/index.cfm

[19] See, for example, “South Texas worries over gas industry’s water use during drought,” Platts, July 5, 2011, found at: http://www.platts.com/RSSFeedDetailedNews/RSSFeed/NaturalGas/3555776; “Railroad Commission, Halliburton officials say amount of water used for fracking is problematic,” Abeline Reporter News, July 15, 2011, found at: http://www.reporternews.com/news/2011/jul/15/railroad-commission-halliburton-officials-say-of/?print=1; “Water Use in the Barnett Shale,” Texas Railroad Commission Website, updated January 24, 2011, found at: http://www.rrc.state.tx.us/barnettshale/wateruse_barnettshale.php.

[20] See, for example, *Energy Demands on Water Resources, DOE Report to Congress,* Dec 2006, http://www.sandia.gov/energy-water/docs/121-RptToCongress-EWwEIAcomments-FINAL.pdf

[21] Stephen G. Osborna, Avner Vengoshb, Nathaniel R. Warnerb, and Robert B. Jackson, *Methane contamination of drinking water accompanying gas-well drilling and hydraulic fracturing*, Proceedings of the National Academy of Science, 108, 8172-8176, (2011).

[22] See EPA Certification Guidance for Engines Regulated Under: 40 CFR Part 86 (On-Highway Heavy-Duty Engines) and 40 CFR Part 89 (Nonroad CI Engines); available at: http://www.epa.gov/oms/regs/nonroad/equip-hd/420b98002.pdf

[23] API standards documents addressing hydraulic fracturing are: API HF1, Hydraulic Fracturing Operations-Well Construction and Integrity Guidelines, First Edition/October 2009, API HF2, Water Management Associated with Hydraulic Fracturing, First Edition/June 2010, API HF3, Practices for Mitigating Surface Impacts Associated with Hydraulic Fracturing, First Edition/January 2011, available at: http://www.api.org/policy/exploration/hydraulicfracturing/index.cfm

[24] Professor Steven Holditch, one of the Subcommittee members, is chair of the RPSEA governing committee.

[25] Extremely small microearthquakes are triggered as an integral part of shale gas development. While essentially all of these earthquakes are so small as to pose no hazard to the public or facilities (they release energy roughly equivalent to a gallon of milk falling of a kitchen counter), earthquakes of larger (but still small) magnitude have been triggered during hydraulic fracturing operations and by the injection of flow-back water after hydraulic fracturing. It is important to develop a hazard assessment and remediation protocol for triggered earthquakes to allow operators and regulators to know what steps need to be taken to assess risk and modify, as required, planned field operations.

UNITED STATES DEPARTMENT OF ENERGY

BEFORE THE DEPARTMENT OF ENERGY
FEDERAL ENERGY REGULATORY COMMISSION

In the Matter of: Sabine Pass Liquefaction, LLC and Sabine Pass LNG, L.P	FERC Docket Nos. CP11-72-000, PF10-24

SIERRA CLUB'S COMMENTS on THE DECEMBER 28, 2011 SABINE PASS LIQUEFACTION PROJECT ENVIRONMENTAL ASSESSMENT

Exhibit 3

Natural Gas Subcommittee, *180-day interim report*, (Nov. 18, 2011)

January 27, 2012

Secretary of Energy Advisory Board

Source: U.S. Energy Information Administration based on data from various published studies. Canada and Mexico plays from ARI.
Updated: May 9, 2011

Shale Gas Production Subcommittee Second Ninety Day Report

November 18, 2011

U.S. DEPARTMENT OF ENERGY

The SEAB Shale Gas Production Subcommittee Second Ninety Day Report – November 18, 2011

Executive Summary

The Shale Gas Subcommittee of the Secretary of Energy Advisory Board is charged with identifying measures that can be taken to reduce the environmental impact and to help assure the safety of shale gas production. Shale gas has become an important part of the nation's energy mix. It has grown rapidly from almost nothing at the beginning of the century to near 30 percent of natural gas production. Americans deserve assurance that the full economic, environmental and energy security benefits of shale gas development will be realized without sacrificing public health, environmental protection and safety. On August 18, 2011 the Subcommittee presented its initial Ninety-Day Report[1] including twenty recommendations that the Subcommittee believes, if implemented, would assure that the nation's considerable shale gas resources are being developed responsibly, in a way that protects human health and the environment and is most beneficial to the nation. The Secretary of Energy's charge to the Subcommittee is included in Annex A and members of the Subcommittee are given in Annex B.

In this report the Subcommittee focuses on implementation of the twenty recommendations presented in its Ninety-day report. The Executive Summary of these recommendations is presented in Annex C.

The Second Ninety-Day Report

The Subcommittee recommendations in its initial report were presented without indicating priority or how each recommendation might be implemented. Progress in achieving the Subcommittee's objective of continuous improvement in reducing the environmental impact of shale gas production depends upon implementation of the Subcommittee recommendation; hence this final report focuses on implementation. On October 31, 2011, the Subcommittee held a public meeting at DOE headquarters in Washington, D.C., to learn the views of the Department of Interior, the Environmental Protection Agency, and the Department of Energy about progress and barriers to implementation of the Subcommittee recommendations.

The Subcommittee is mindful that state and federal regulators and companies are already deeply involved in environmental management. Implementing the twenty Subcommittee recommendations will require a great deal of effort, and regulators, public officials, and companies need to decide how to allocate scarce human and financial resources to each recommendation, potentially shifting effort from other valuable existing activities. All of the Subcommittee recommendations in its Ninety-Day report involve actions by one or more parties: federal officials, state officials, and public and private sector entities.

Two criteria are important in deciding on the allocation: the importance and ease of implementation. Early success in implementing some recommendations may stimulate greater effort on other recommendations, which require greater time and effort for progress. Decisions about when, how and whether to proceed with our recommendations are the responsibility of the public and private participants in the process – not the Subcommittee. But, the Subcommittee can be helpful at identifying those recommendations that seem particularly important and particularly amendable to early action. Accordingly this report classifies the twenty recommendations into three categories:

(1) Recommendations ready for implementation, primarily by federal agencies;

(2) Recommendations ready for implementation, primarily by states;

(3) Recommendations that require new partnerships and mechanisms for success.

<u>The Subcommittee recognizes that successful implementation of each of its recommendations will require cooperation among and leadership by federal, state and local entities. In its initial report, the Subcommittee called for a process of continuous improvement and said: "This process should involve discussions and other collaborative efforts among companies involved in shale gas production (including service companies), state and federal regulators, and affected communities and public interest groups."</u>

The Subcommittee also believes it has a responsibility to assess and report progress in implementing the recommendations in its initial report. Too often advisory committee recommendations are ignored, not because of disagreement with substance, but because the implementation path is unclear or because of the press of more immediate matters on dedicated individuals who are over extended. The Subcommittee does not wish to see this happen to its recommendation, because it believes citizens expect prompt action. Absent action there will be little credible progress in toward reducing in the environmental impact of shale gas production, placing at risk the future of the enormous potential benefits of this domestic energy resource. At this early stage, it is reasonable to assess if initial, constructive, steps are underway; there is no expectation that any of the recommendations could be completely implemented in the three months since the Subcommittee issued its initial report.

(1) Recommendations for implementation, primarily by federal agencies.

The Subcommittee has identified nine recommendations where federal agencies have primary responsibility and that are ready for implementation; these are presented in Table I.

Recommendation #2 Two existing non-profit organizations – the State Review of Oil and Natural Gas Environmental Regulations (STONGER) and the Ground Water Protection Council (GWPC) are two existing organizations that work to share information to improve the quality of regulatory policy and practice in the states. The budgets for these organizations are small, and merit public support. Previously, federal agencies (DOE and EPA) provided funding for STRONGER and GWPC, but federal funding is currently not provided. To maintain credibility to have an ability to set their own agenda these organizations cannot rely exclusively on funding provided by companies of the regulated industry. The Subcommittee has recommended that $5 million per year would provide the resources to STRONGER and the GWCPC needed to strengthen and broaden its activities as discussed in the Subcommittees previous report, for example, updating hydraulic fracturing guidelines and well construction guidelines, and developing guidelines for water supply, air emissions and cumulative impacts. Additionally, DOE and/or EPA should consider making grants to those states that volunteer to have their regulations and practices peer-reviewed by STRONGER, as an incentive for states to undergo updated reviews and to implement recommended actions.

Table 1. Recommendations ready for immediate implementation		
Rec.#	**Recommendation**	**Comment & Status**
1.	Improve public information about shale gas operations	Federal responsibility to begin planning for public website. Some discussion between DOE and White House offices about possible hosting sites but no firm plan. States should also consider establishing sites.
2.	Improve communication among federal and state regulators and provide federal funding for STRONGER and the Ground Water Protection Council	Federal funding at $5m/y will allow state regulators/NGOs/industry to plan activities. Possible minor DOE FY2012 funding; no multi-year commitment. See discussion below.
3	Measures should be taken to reduce emissions of air pollutants, ozone precursors, and methane as quickly as practicable.	We encourage EPA to complete its current rule making as it applies to shale gas production quickly, and explicitly include methane, a greenhouse gas, and controls from existing shale gas production sources. Additionally, some states have taken action in this area, and others could do so as well. See discussion below.
4	Enlisting a subset of producers in different basins to design and field a system to collect air emissions data.	Industry initiative in advance of regulation. Several companies have shown interest. Possible start in Marcellus and Eagle Ford. See discussion below.
5	Immediately launching a federal interagency planning effort to acquire data and analyze the overall greenhouse gas footprint of natural gas use.	OSTP has not committed to leading an interagency effort, but the Administration is taking steps to collect additional data, including through the EPA air emissions rulemaking.
6	Encouraging shale-gas production companies and regulators to expand immediately efforts to reduce air emissions using proven technologies and practices.	A general statement of the importance the Subcommittee places on reducing air emissions. Federal funding at $5m/y for state regulators/NGOs/industry will encourage planning. Some states have taken action in this area, and others could do so as well.
11	Launch addition field studies on possible methane migration from shale gas wells to water reservoirs.	No new studies launched; funding required from fed agencies or from states.[2]
14	Disclosure of Fracturing fluid composition	DOI has announced its intent to propose requirement. Industry appears ready to agree to mandatory stricter disclosure. See discussion below.
15	Elimination of diesel use in fracturing fluids	EPA is developing permitting guidance under the UIC program. The Subcommittee reiterates its recommendation that diesel fuel should be eliminated in hydraulic fracturing fluids.
20	R&D needs	OMB/OSTP must define proper limits for unconventional gas R&D and budget levels for DOE, EPA, and USGS. See discussion below.

Funding for the GWPC would allow the association to extend and expand its *Risk Based Data Management System,* which helps states collected and publicly share data associated with their oil and gas regulatory programs – for example, sampling and monitoring programs for surface waters, water wells, sediments and isotopic activity in and around areas of shale gas operations. Likewise, funding could go toward integrating the RBDMS into the national data portal discussed in Recommendation #1. Funding would also allow GWPC to upgrade its fracturing fluid chemical disclosure registry, *Frac Focus*, so that information can be searched, sorted and aggregated by chemical, by well, by company and by geography – as recommended by the Subcommittee in its 90-Day report.

Recommendation #3 On July 28th the U.S. EPA proposed New Source Performance Standards and National Emissions Standards for Hazardous Air Pollutants (NSPS/NESHAPs) for the oil and natural gas sector. The proposed rules, which are currently under comment and review, are scheduled to be finalized by April 3, 2012, represent a critical step forward in reducing emissions of smog-forming pollutants and air toxics. The Subcommittee commends EPA for taking this important step and encourages timely implementation. However, the proposed rules fall short of the recommendations made in the Subcommittee's Ninety-Day Report because the rules do not directly control methane emissions and the NSPS rules as proposed do not cover existing shale gas sources except for fractured or re-fractured existing gas wells.

Additionally, in its Ninety-Day report the Subcommittee recommended that companies be required to measure and disclose air emissions from shale gas sources. Recently, in response to a challenge, the EPA took two final actions that compromise the ability to get accurate emissions data from the oil and gas sector under the Greenhouse Gas Reporting Rule.[3] The Subcommittee reiterates its recommendation that the federal government or state agencies require companies to measure and disclose air emissions from shale gas sources.

Recommendation #4 The Subcommittee is aware that operating companies are considering projects to collect and disclose air emissions data from shale gas production sites. Discussions are underway to define the data to be collected, appropriate instrumentation, and subsequent analysis and disclosure of the data. The Subcommittee welcomes this development and underscores its earlier recommendation for disclosure, including independent technical review of the methodology.

Recommendation #14 The Subcommittee welcomes the announcement of the DOI of its intent to require disclosure of fracturing fluid composition on federal lands. The Subcommittee was pleased to learn from the DOI at its October 31, 2011 public hearing that the agency intends to follow the disclosure recommendations in its Ninety-Day Report that disclosure should include all chemicals, not just those that appear on

Material Safety Data Sheets, and that chemicals should be reported on a well-by-well basis and posted on a publicly available website that includes tools for searching and aggregating data by chemical, by well, by company and by geography. The Subcommittee recognized the need for protection of legitimate trade secrets but believes that the bar for trade secret protection should be high. The Subcommittee believes the DOI disclosure policy should meet the Subcommittee's criteria and that it can serve as a model for the states. The Ground Water Protection Council and the Interstate Oil and Gas Compact Commission have taken an important step in announcing their intent to require disclosure of all chemicals by operators who utilize their voluntary chemical disclosure registry, FracFocus. The Subcommittee welcomes this progress and encourages those organizations to continue their work toward upgrading FracFocus to meet the Subcommittee's recommended disclosure criteria.

Recommendation #20 As set out in its Ninety-day report, the Subcommittee believes there is a legitimate role for the federal government in supporting R&D on shale gas, arguably the country's most important domestic energy resource. To be effective such an R&D program must be pursued for several years, at a relatively modest level. The Subcommittee is aware that discussions have taken place between OMB and the involved agencies, DOI/USGS, DOE, and EPA about funding for unconventional gas R&D. The Subcommittee understands that agreement has been reached that the administration will seek funding for "priority items" for FY2012 in its discussions with Congress, but the "priority items" and the level of this funding is not decided. The Subcommittee welcomes the agencies effort to coordinate their planned out-year research effort for FY2013 and beyond, as described by DOI, DOE, and EPA at its public meeting on October 31, 2011. But, as yet, there has been no agreement with OMB on the scale and composition of a continuing unconventional gas R&D program. Failure to provide adequate funding for R&D would be deleterious and undermine achieving the policy objectives articulated by the President.

Note: after the Subcommittee completed its deliberations the Office of Management and Budget sent a letter setting forth the efforts underway to find funding for the Subcommittee recommendations; **see Annex D**. While the letter does not settle the matter, it is an important and welcome, positive step.

(2) Recommendations ready for implementation, primarily by states.

The Subcommittee has identified four recommendations in this category; all address water quality related issues.

Table 2. Recommendations requiring cooperation between regulators and industry		
Rec.#	**Recommendation**	**Comment & Status**
8	Measure and publicly report the composition of water stocks and flow throughout the fracturing and cleanup process.	Awaits EPA's study underway on the Impacts of hydraulic fracturing on drinking water resources. See discussion below. States should also determine a way forward to measure and record data from flow back operations as many issues will be local issues.
9	Manifest all transfers of water among different locations	
10	Adopt best practices in well development and construction, especially casing, cementing, and pressure management	Widely recognized as a key practice by companies and regulators but no indication of a special initiative on field measurement and reporting.
12	Adopt requirements for background water quality measurements	The value of background measurements is recognized. Jurisdiction for access to private wells differs widely

Recommendation #8 and 9 EPA has a number of regulatory actions in process. On October 20, 2011 EPA announced a schedule setting waste water discharge standards that will affect some shale gas production activities.[4] Further water quality regulatory developments will benefit from the results of EPA's study on the impact of hydraulic fracturing on drinking water that will not be complete until 2014 and will likely initiate significant negotiation between EPA and state regulators on the scope and responsibility for water regulations. The Subcommittee observes that there will be a tremendous amount of activity in the field before EPA completes its study (and any potential regulatory actions that flow from it) and urges the EPA to take action as appropriate during the course of its process.

Recommendation #12 In its initial report, the Subcommittee called for background water measurements at wells surrounding planned production sites to establish an objective benchmark to assess potential damage to water resources. All stakeholders agree that such measurements can be helpful in establishing facts and verifying disputed contamination claims. The lack of a clear pattern of state, local, and federal authority for access to private water wells to make such measurements is an impediment to policy development.

(3) Recommendations that require new partnerships or mechanisms for success

The following recommendations require development of new partnerships or mechanisms and hence the implementation challenge can be quite significant. These recommendations do, however, signal significant concerns shared by members of the Subcommittee that are noted in Table 3. The challenge is to devise new mechanisms for addressing these significant environmental problems.

Table 3. Recommendations that require new mechanisms for success

Rec.#	Recommendation	Comment & Status
7	Protection of water quality through a systems approach.	At present neither EPA or the states are engaged in developing a systems/lifecycle approach to water management.
13	Agencies should review field experience and modernize rules and enforcement practices to ensure protection of drinking and surface waters.	Reflects Subcommittee unease that the present arrangement of shared federal and state responsibility for cradle-to-grave water quality is not working smoothly or as well as it should.
16	Managing short-term and cumulative impacts on communities, land use, wildlife, and ecologies.	No new studies launched; funding required from federal agencies or from states. See discussion below.
17	Organizing for best practice.	Industry intends to establish 'centers of excellence' regionally, that involve public interest groups, state and local regulatory and local colleges and universities.
18	Air	
19	Water	

Recommendation #16 Shale gas production brings both benefits and cost of economic development to a community, often rapidly and in a region that it is unfamiliar with oil and gas operations. Short and long term community impact range from traffic, noise, land use, disruption of wildlife and habitat, with little or no allowance for planning or effective mechanisms to bring companies, regulators, and citizens to deliberate about how best to deal with near term and cumulative impacts. The Subcommittee does not believe that these issues will solve themselves or be solved by prescriptive regulation or in the courts. State and local governments should take the lead in experimenting with different mechanisms for engaging these issues in a constructive way, seeking to be beyond discussion to practical mitigation. Successful models should be disseminated.

The U.S. Department of Interior, however, is somewhat unique in having tools at its disposal that could be used to address cumulative and community impacts. For example, Master Leasing and Development Plans, a relatively new tool, might help improve planning for production on federal lands through requirements for phased leasing and development, multi-well pad drilling, limitations on surface disturbance, centralization of infrastructure, land and roadway reclamation, etc.

Recommendation 17, 18 & 19 Industry has always been interested in best practices. The Subcommittee has called for industry to increase their best practices process for field engineering and environmental control activities by adopting the objective of continuous improvement, validated by measurement and disclosure of key operating metrics.[5] Leadership for this initiative lies with industry but also involves regulators and public interest groups. Best practices involves the entire range of shale gas operations including: (a) well design and siting, (b) drilling and well completion, including importantly casing and cementing, (c) hydraulic fracturing, (d) surface operations, (e) collection and distribution of gas and land liquids, (f) well abandonment and sealing, and (g) emergency response. Developing reliable metrics for best practices is a major task and must take into account regional differences of geology and regulatory practice. A properly trained work force is an important element in achieving best practice. Thus, organizing for best practice should include better mechanisms for training of oil field workers. Such training should utilize local community college and vocational education resources.

Industry is taking a regional approach to best practice, building on local organizations, such as the Marcellus Shale Coalition. Shale companies understand the importance of involving non-industry stakeholders in their efforts and are beginning to take initiatives that engage the public in a meaningful way. Industry is showing increased interest in engineering practice as indicated by the recent workshop on hydraulic fracturing sponsored by the American Petroleum Institute on October 4 and 5, 2011 in Pittsburgh PA.[6] The Subcommittee urges leading companies to adopt a more visible commitment to using quantitative measures as a means of achieving best practice and demonstrating to the public that there is continuous improvement in reducing the environmental impact of shale gas production.

Concluding remarks

The Subcommittee was gratified with the generally favorable, but not universally favorable, response to its initial report. In particular there was overwhelming agreement on two points: (1) If the country is to enjoy the economic and other benefits of shale gas production over the coming years disciplined attention must be devoted to reducing the environmental impact that accompanies this development, and (2) a prudent balance between development and environmental protection is best struck by establishing a strong foundation of regulation and enforcement, and adopting a policy and practice that measures, discloses, and continuously improves shale gas operations.

The Subcommittee believes that if action is not taken to reduce the environmental impact accompanying the very considerable expansion of shale gas production expected across the country – perhaps as many as 100,000 wells over the next several decades – there is a real risk of serious environmental consequences causing a loss of public confidence that could delay or stop this activity. Thus, the Subcommittee has an interest in assessing and reporting on, the progress that is being made on implementing its recommendations or some sensible variations of these recommendations.

The Subcommittee has the impression that its initial report stimulated interest in taking action to reduce the environmental impact of shale gas production by the administration, state governments, industry, and public interest groups. However, the progress to date is less than the Subcommittee hoped and it is not clear how to catalyze action at a time when everyone's attention is focused on economic issues, the press of daily business, and an upcoming election. The Subcommittee cautions that whether its approach is followed or not, some concerted and sustained action is needed to avoid excessive environmental impacts of shale gas production and the consequent risk of public opposition to its continuation and expansion.

ANNEX A – CHARGE TO THE SUBCOMMITTEE

From: Secretary Chu

To: William J. Perry, Chairman, Secretary's Energy Advisory Board (SEAB)

On March 30, 2011, President Obama announced a plan for U.S. energy security, in which he instructed me to work with other agencies, the natural gas industry, states, and environmental experts to improve the safety of shale gas development. The President also issued the Blueprint for a Secure Energy Future ("Energy Blueprint"), which included the following charge:

> **"Setting the Bar for Safety and Responsibility:** To provide recommendations from a range of independent experts, the Secretary of Energy, in consultation with the EPA Administrator and Secretary of Interior, should task the Secretary of Energy Advisory Board (SEAB) with establishing a subcommittee to examine fracking issues. The subcommittee will be supported by DOE, EPA and DOI, and its membership will extend beyond SEAB members to include leaders from industry, the environmental community, and states. The subcommittee will work to identify, within 90 days, any immediate steps that can be taken to improve the safety and environmental performance of fracking and to develop, within six months, consensus recommended advice to the agencies on practices for shale extraction to ensure the protection of public health and the environment." *Energy Blueprint (page 13).*

The President has charged us with a complex and urgent responsibility. I have asked SEAB and the Natural Gas Subcommittee, specifically, to begin work on this assignment immediately and to give it the highest priority.

This memorandum defines the task before the Subcommittee and the process to be used.

Membership:

In January of 2011, the SEAB created a Natural Gas Subcommittee to evaluate what role natural gas might play in the clean energy economy of the future. Members of the Subcommittee include John Deutch (chair), Susan Tierney, and Dan Yergin. Following consultation with the Environmental Protection Agency and the Department of the Interior, I have appointed the following additional members to the Subcommittee: Stephen Holditch, Fred Krupp, Kathleen McGinty, and Mark Zoback.

The varied backgrounds of these members satisfies the President's charge to include individuals with industry, environmental community, and state expertise. To facilitate an expeditious start, the Subcommittee will consist of this small group, but additional members may be added as appropriate.

Consultation with other Agencies:

The President has instructed DOE to work in consultation with EPA and DOI, and has instructed all three agencies to provide support and expertise to the Subcommittee. Both agencies have independent regulatory authority over certain aspects of natural gas production, and considerable expertise that can inform the Subcommittee's work.

- The Secretary and Department staff will manage an interagency working group to be available to consult and provide information upon request of the Subcommittee.
- The Subcommittee will ensure that opportunities are available for EPA and DOI to present information to the Subcommittee.
- The Subcommittee should identify and request any resources or expertise that lies within the agencies that is needed to support its work.
- The Subcommittee's work should at all times remain independent and based on sound science and other expertise held from members of the Subcommittee.
- The Subcommittee's deliberations will involve only the members of the Subcommittee.
- The Subcommittee will present its final report/recommendations to the full SEAB Committee.

Public input:

In arriving at its recommendations, the Subcommittee will seek timely expert and other advice from industry, state and federal regulators, environmental groups, and other stakeholders.

- To assist the Subcommittee, DOE's Office of Fossil Energy will create a website to describe the initiative and to solicit public input on the subject.
- The Subcommittee will meet with representatives from state and federal regulatory agencies to receive expert information on subjects as the Subcommittee deems necessary.
- The Subcommittee or the DOE (in conjunction with the other agencies) may hold one or more public meetings when appropriate to gather input on the subject.

Scope of work of the Subcommittee:

The Subcommittee will provide the SEAB with recommendations as to actions that can be taken to improve the safety and environmental performance of shale gas extraction processes, and other steps to ensure protection of public health and safety, on topics such as:

- well design, siting, construction and completion;
- controls for field scale development;
- operational approaches related to drilling and hydraulic fracturing;
- risk management approaches;
- well sealing and closure;
- surface operations;
- waste water reuse and disposal, water quality impacts, and storm water runoff;
- protocols for transparent public disclosure of hydraulic fracturing chemicals and other information of interest to local communities;
- optimum environmentally sound composition of hydraulic fracturing chemicals, reduced water consumption, reduced waste generation, and lower greenhouse gas emissions;

- emergency management and response systems;
- metrics for performance assessment; and
- mechanisms to assess performance relating to safety, public health and the environment.

The Subcommittee should identify, at a high level, the best practices and additional steps that could enhance companies' safety and environmental performance with respect to a variety of aspects of natural gas extraction. Such steps may include, but not be limited to principles to assure best practices by the industry, including companies' adherence to these best practices. Additionally, the Subcommittee may identify high-priority research and technological issues to support prudent shale gas development.

Delivery of Recommendations and Advice:

- Within 90 days of its first meeting, the Subcommittee will report to SEAB on the "immediate steps that can be taken to improve the safety and environmental performance of fracking."
- Within 180 days of its first meeting, the Subcommittee will report to SEAB "consensus recommended advice to the agencies on practices for shale extraction to ensure the protection of public health and the environment."
- At each stage, the Subcommittee will report its findings to the full Committee and the SEAB will review the findings.
- The Secretary will consult with the Administrator of EPA and the Secretary of the Interior, regarding the recommendations from SEAB.

Other:

- The Department will provide staff support to the Subcommittee for the purposes of meeting the requirements of the Subcommittee charge. The Department will also engage the services of other agency Federal employees or contractors to provide staff services to the Subcommittee, as it may request.
- DOE has identified $700k from the Office of Fossil Energy to fund this effort, which will support relevant studies or assessments, report writing, and other costs related to the Subcommittee's process.
- The Subcommittee will avoid activity that creates or gives the impression of giving undue influence or financial advantage or disadvantage for particular companies involved in shale gas exploration and development.
- The President's request specifically recognizes the unique technical expertise and scientific role of the Department and the SEAB. As an agency not engaged in regulating this activity, DOE is expected to provide a sound, highly credible evaluation of the best practices and best ideas for employing these practices safely that can be made available to companies and relevant regulators for appropriate action. Our task does not include making decisions about regulatory policy.

ANNEX B – MEMBERS OF THE SUBCOMMITTEE

John Deutch, Institute Professor at MIT (Chair) **-** John Deutch served as Director of Energy Research, Acting Assistant Secretary for Energy Technology and Under Secretary of Energy for the U.S. Department of Energy in the Carter Administration and Undersecretary of Acquisition & Technology, Deputy Secretary of Defense and Director of Central Intelligence during the first Clinton Administration. Dr. Deutch also currently serves on the Board of Directors of Raytheon and Cheniere Energy and is a past director of Citigroup, Cummins Engine Company and Schlumberger. A chemist who has published more than 140 technical papers in physical chemistry, he has been a member of the MIT faculty since 1970, and has served as Chairman of the Department of Chemistry, Dean of Science and Provost. He is a member of the Secretary of Energy Advisory Board.

Stephen Holditch, Head of the Department of Petroleum Engineering at Texas A&M University and has been on the faculty since 1976 - Stephen Holditch, who is a member of the National Academy of Engineering, serves on the Boards of Directors of Triangle Petroleum Corporation and Matador Resources Corporation. In 1977, Dr. Holditch founded S.A. Holditch & Associates, a petroleum engineering consulting firm that specialized in the analysis of unconventional gas reservoirs. Dr. Holditch was the 2002 President of the Society of Petroleum Engineers. He was the Editor of an SPE Monograph on hydraulic fracturing treatments, and he has taught short courses for 30 years on the design of hydraulic fracturing treatments and the analyses of unconventional gas reservoirs. Dr. Holditch worked for Shell Oil Company prior to joining the faculty at Texas A&M University.

Fred Krupp, President, Environmental Defense Fund **-** Fred Krupp has overseen the growth of EDF into a recognized worldwide leader in the environmental movement. Krupp is widely acknowledged as the foremost champion of harnessing market forces for environmental ends. He also helped launch a corporate coalition, the U.S. Climate Action Partnership, whose Fortune 500 members - Alcoa, GE, DuPont and dozens more - have called for strict limits on global warming pollution. Mr. Krupp is coauthor, with Miriam Horn, of New York Times Best Seller, *Earth: The Sequel*. Educated at Yale and the University of Michigan Law School, Krupp was among 16 people named as America's Best Leaders by U.S. News and World Report in 2007.

Kathleen McGinty, Kathleen McGinty is a respected environmental leader, having served as President Clinton's Chair of the White House Council on Environmental Quality and Legislative Assistant and Environment Advisor to then-Senator Al Gore. More recently, she served as Secretary of the Pennsylvania Department of Environmental Protection. Ms. McGinty also has a strong background in energy. She is Senior Vice President of Weston Solutions where she leads the company's clean energy development business. She also is an Operating Partner at Element Partners, an investor in efficiency and renewables. Previously, Ms. McGinty was Chair of the Pennsylvania Energy Development Authority, and currently she is a Director at NRG Energy and Iberdrola USA.

Susan Tierney, Managing Principal, Analysis Group **-** Susan Tierney is a consultant on energy and environmental issues to public agencies, energy companies, environmental organizations, energy consumers, and tribes. She chairs the Board of the Energy Foundation, and serves on the Boards of Directors of the World Resources Institute, the Clean Air Task Force, among others. She recently, co-chaired the National Commission on Energy Policy, and chairs the Policy Subgroup of the National Petroleum Council's study of North American natural gas and oil resources. Dr. Tierney served as Assistant Secretary for Policy at the U.S. Department of Energy during the Clinton Administration. In Massachusetts, she served as Secretary of Environmental Affairs, Chair of the Board of the Massachusetts Water Resources Agency, Commissioner of the Massachusetts Department of Public Utilities and executive director of the Massachusetts Energy Facilities Siting Council.

Daniel Yergin, Chairman, IHS Cambridge Energy Research Associates **-** Daniel Yergin is the co-founder and chairman of IHS Cambridge Energy Research Associates. He is a member of the U.S. Secretary of Energy Advisory Board, a board member of the Board of the United States Energy Association and a member of the U.S. National Petroleum Council. He was vice chair of the 2007 National Petroleum Council study, *Hard Truths* and is vice chair of the new National Petroleum Council study of North American natural gas and oil resources. He chaired the U.S. Department of Energy's Task Force on Strategic Energy Research and Development. Dr. Yergin currently chairs the Energy Security Roundtable at the Brookings Institution, where he is a trustee, and is member of the advisory board of the MIT Energy Initiative. Dr. Yergin is also CNBC's Global Energy Expert. He is the author of the Pulitzer Prize-winning book, *The Prize: The Epic Quest for Oil, Money and Power.* His new book – *The Quest: Energy, Security, and the Remaking of the Modern World* – will be published in September 2011..

Mark Zoback, Professor of Geophysics, Stanford University - Mark Zoback is the Benjamin M. Page Professor of Geophysics at Stanford University. He is the author of a textbook, *Reservoir Geomechanics*, and author or co-author of over 300 technical research papers. He was co-principal investigator of the San Andreas Fault Observatory at Depth project (SAFOD) and has been serving on a National Academy of Engineering committee investigating the Deepwater Horizon accident. He was the chairman and co-founder of GeoMechanics International and serves as a senior adviser to Baker Hughes, Inc. Prior to joining Stanford University, he served as chief of the Tectonophysics Branch of the U.S. Geological Survey Earthquake Hazards Reduction Program.

Annex C – Subcommittee Recommendations

A list of the Subcommittee's findings and recommendations follows.

1. Improve public information about shale gas operations: Create a portal for access to a wide range of public information on shale gas development, to include current data available from state and federal regulatory agencies. The portal should be open to the public for use to study and analyze shale gas operations and results.

2. Improve communication among state and federal regulators: Provide continuing annual support to STRONGER (the State Review of Oil and Natural Gas Environmental Regulation) and to the Ground Water Protection Council for expansion of the *Risk Based Data Management System* and similar projects that can be extended to all phases of shale gas development.

3. Improve air quality: Measures should be taken to reduce emissions of air pollutants, ozone precursors, and methane as quickly as practicable. The Subcommittee supports adoption of rigorous standards for new and existing sources of methane, air toxics, ozone precursors and other air pollutants from shale gas operations. The Subcommittee recommends:

    4. Enlisting a subset of producers in different basins to design and rapidly implement measurement systems to collect comprehensive methane and other air emissions data from shale gas operations and make these data publically available;

    5. Immediately launching a federal interagency planning effort to acquire data and analyze the overall greenhouse gas footprint of shale gas operations throughout the lifecycle of natural gas use in comparison to other fuels; and

    6. Encouraging shale-gas production companies and regulators to expand immediately efforts to reduce air emissions using proven technologies and practices.

7. Protection of water quality: The Subcommittee urges adoption of a systems approach to water management based on consistent measurement and public disclosure of the flow and composition of water at every stage of the shale gas production process. The Subcommittee recommends the following actions by shale gas companies and regulators – to the extent that such actions have not already been undertaken by particular companies and regulatory agencies:

    8. Measure and publicly report the composition of water stocks and flow throughout the fracturing and clean-up process.

    9. Manifest all transfers of water among different locations.

    10. Adopt best practices in well development and construction, especially casing, cementing, and pressure management. Pressure testing of cemented casing and state-of-the-art cement bond logs should be used to confirm formation isolation. Microseismic surveys should be carried out to assure that

hydraulic fracture growth is limited to the gas producing formations. Regulations and inspections are needed to confirm that operators have taken prompt action to repair defective cementing jobs. The regulation of shale gas development should include inspections at safety-critical stages of well construction and hydraulic fracturing.

11. Additional field studies on possible methane leakage from shale gas wells to water reservoirs.

12. Adopt requirements for background water quality measurements (e.g., existing methane levels in nearby water wells prior to drilling for gas) and report in advance of shale gas production activity.

13. Agencies should review field experience and modernize rules and enforcement practices to ensure protection of drinking and surface waters.

14. <u>Disclosure of fracturing fluid composition</u>: The Subcommittee shares the prevailing view that the risk of fracturing fluid leakage into drinking water sources through fractures made in deep shale reservoirs is remote.[7] Nevertheless the Subcommittee believes there is no economic or technical reason to prevent public disclosure of all chemicals in fracturing fluids, with an exception for genuinely proprietary information. While companies and regulators are moving in this direction, progress needs to be accelerated in light of public concern.

15. <u>Reduction in the use of diesel fuel</u>: The Subcommittee believes there is no technical or economic reason to use diesel in shale gas production and recommends reducing the use of diesel engines for surface power in favor of natural gas engines or electricity where available.

16. <u>Managing short-term and cumulative impacts on communities, land use, wildlife, and ecologies</u>. Each relevant jurisdiction should pay greater attention to the combination of impacts from multiple drilling, production and delivery activities (e.g., impacts on air quality, traffic on roads, noise, visual pollution), and make efforts to plan for shale development impacts on a regional scale. Possible mechanisms include:

(1) Use of multi-well drilling pads to minimize transport traffic and need for new road construction.

(2) Evaluation of water use at the scale of affected watersheds.

(3) Formal notification by regulated entities of anticipated environmental and community impacts.

(4) Preservation of unique and/or sensitive areas as off-limits to drilling and support infrastructure as determined through an appropriate science-based process.

(5) Undertaking science-based characterization of important landscapes, habitats and corridors to inform planning, prevention, mitigation and reclamation of surface impacts.

(6) Establishment of effective field monitoring and enforcement to inform on-going assessment of cumulative community and land use impacts.

The process for addressing these issues must afford opportunities for affected communities to participate and respect for the rights of surface and mineral rights owners.

17. Organizing for best practice: The Subcommittee believes the creation of a shale gas industry production organization dedicated to continuous improvement of best practice, defined as improvements in techniques and methods that rely on measurement and field experience, is needed to improve operational and environmental outcomes. The Subcommittee favors a national approach including regional mechanisms that recognize differences in geology, land use, water resources, and regulation. The Subcommittee is aware that several different models for such efforts are under discussion and the Subcommittee will monitor progress during its next ninety days. The Subcommittee has identified several activities that deserve priority attention for developing best practices:

    18. Air: (a) Reduction of pollutants and methane emissions from all shale gas production/delivery activity. (b) Establishment of an emission measurement and reporting system at various points in the production chain.

    19. Water: (a) Well completion – casing and cementing including use of cement bond and other completion logging tools. (b) Minimizing water use and limiting vertical fracture growth.

20. Research and Development needs. The public should expect significant technical advances associated with shale gas production that will significantly improve the efficiency of shale gas production and that will reduce environmental impact. The move from single well to multiple-well pad drilling is one clear example. Given the economic incentive for technical advances, much of the R&D will be performed by the oil and gas industry. Nevertheless the federal government has a role especially in basic R&D, environment protection, and safety. The current level of federal support for unconventional gas R&D is small, and the Subcommittee recommends that the Administration and the Congress set an appropriate mission for R&D and level funding.

Annex D Letter from the Office of Management and Budget

EXECUTIVE OFFICE OF THE PRESIDENT
OFFICE OF MANAGEMENT AND BUDGET
WASHINGTON, D.C. 20503

THE DIRECTOR

November 8, 2011

Dr. John Deutch
Chairman
Secretary of Energy Advisory Board on Natural Gas
Washington, DC 20585

Dear John:

Thank you for your letter on Tuesday, November 1 about the Subcommittee of the Secretary of Energy Advisory Board on Natural Gas (SEAB). I am sorry that I could not attend the SEAB meeting earlier this week. Your work on this issue has been very helpful and it is a high priority of the Administration.

As you are aware, the Office of Management and Budget (OMB) is running an interagency working group to coordinate the research budget proposals on hydraulic fracturing and has received some preliminary suggestions from the agencies for FY 2013 activities. Over the course of the next few weeks, the interagency budget working group will review agencies' research proposals taking into consideration core competencies, which I understand was discussed with you on Monday, October 31. We will be looking carefully at the research and development (R&D) recommendations of the SEAB report as we put together the President's FY 2013 Budget.

As you know, all discretionary funding is capped in FY 2012 and FY 2013. Hydraulic fracturing R&D is a priority that we are seeking to fund as we make tough choices within these constraints. As your report acknowledges, the industry has a strong incentive to fund and carry out production-related R&D. To the degree that environmental constraints could impede continued growth, industry also has an interest in R&D to improve environmental performance and safety. Thus, finding the correct balance between public and private investment, within the broader Federal budget constraints is challenging, but important. As part of the R&D budget review, we are identifying existing programs across the government to avoid redundancies and to optimize budgetary resources. As a general matter, OMB does not announce budget decisions prior to the full presentation to the Congress in February of each year.

I am concerned there has been some confusion around OMB's position on funding this research. The Administration has opposed subsidies for conventional fossil energy exploration and production, just as the Bush Administration did. But hydraulic fracturing R&D that adheres to the framework set forth in the SEAB 90-day interim report – for air, water, induced seismicity or other public information needed to set appropriate regulatory boundaries – we strongly support, and we agree that the Environmental Protection Agency, Department of the Interior, and Department of Energy all have roles to play. However, we need to carefully articulate those roles and structure the President's Budget to most efficiently deliver the R&D funding needed to address environmental and safety concerns.

The SEAB 90-day interim report supports the existing Ultradeepwater and Unconventional Natural Gas and Other Petroleum Research Program (Sec. 999) which is funded through mandatory appropriations authorized by the Energy Policy Act of 2005. On this point, we disagree. Mandatory R&D funding from Sec. 999 is too inflexible a mechanism to adequately address environmental and safety concerns in the dynamic and rapidly evolving hydraulic fracturing space, and the President's Budgets have proposed eliminating this mandatory R&D program. Absent Congressional action to repeal Sec. 999, the Administration has sought to refocus this funding to support R&D with significant potential public benefits, including activities consistent with the SEAB recommendations.

Thank you again for reaching out to me on this important issue. Please do not assume that because we are busy, that this issue is not important to the Administration, and feel free to be in touch moving forward.

Hope all is well with you and would look forward to catching up.

Best regards,

Jack

Jacob J. Lew

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To: Jack Lew, Director Office of Management and Budget

Dear Jack,

November 1, 2011

In March, President Obama directed Steve Chu to establish a Subcommittee of the Secretary of Energy Advisory Board on Hydraulic Fracturing tasked to identify steps that should be taken to reduce the environmental impact of shale gas production. I am the chair of this Subcommittee, which released its initial report on August 18, 2011.

One of the Subcommittee's twenty recommendations called on the administration to adopt a unconventional gas R&D program to perform R&D that merits public funding such as environmental studies on methane leakage, assessing the relative greenhouse gas foot print of natural gas production, seismicity, inventing new techniques for real time monitoring and control of hydraulic fluid injection, and development of environmentally friendly stimulation fluids. The Subcommittee did not ask for "new" money, or suggest a particular level of funding, or how responsibilities should be distributed between the DOE, EPA, and the USGS.

On October 5, 2011, I wrote to you requesting that you or a designated representative come and speak with the Subcommittee (in open or closed session) about this matter. You designated Sally Ericsson, Associate Director for Natural Resources, who I understand participated in an interagency meeting on this subject and agreed to attend the Subcommittee's October 31 meeting. Unfortunately, Ms Ericsson had to cancel her attendance, inevitably leaving the Subcommittee, as it prepares its second and final report, with the impression that the administration has not yet been able to formulate a position on the level of distribution of federal support for unconventional gas R&D, arguably the most important near term domestic energy supply option for the country. The Subcommittee did learn that the administration will seek funds for "priority" items for FY2012 in its discussions with Congress and that EPA, DOE, and DOI are coordinating their research plans, but evidently an effective R&D program requires consistent multi-year funding.

I know that you are totally consumed by the budget deficit and countless other matters. Nevertheless, I urge you to devote a few minutes to resolving the issue of federal support for R&D on unconventional gas. President Obama in his *Blue Print for Secure Energy Future* recognized that realizing the enormous economic benefits of shale case requires improving the environmental performance of shale gas production and the *Blue Print* explicitly identified a role for federally sponsored research. It will be a shame if the administration does not take the initial steps necessary to establish a modest, but steady R&D effort by the participating agencies.

Sincerely

John Deutch

John Deutch

Cc: Steven Chu,
Heather Zichal,
Michael Froman

ENDNOTES

[1] The Subcommittee report is available at:
http://www.shalegas.energy.gov/resources/081811_90_day_report_final.pdf

[2] Duke University has launched a follow-on study effort to its initial methane migration study. NETL, in cooperation with other federal agencies and with PA state agencies, Penn State, and major producers is launching a study limited to two wells. More needs to be done by federal agencies.

[3] First, EPA has finalized a deferral that will prevent the agency from collecting inputs to emissions equations data until 2015 for Subpart W sources. These inputs are critical to verify emissions information calculated using emission equations. Second, EPA has finalized a rule allowing more widespread use of Best Available Monitoring Methods ("BAMM") in 2011 and beyond. This action allows reporters to use more relaxed, non-standard methods when monitoring under Subpart W.
See: Change to the Reporting Date for Certain Data Elements Required Under the Mandatory Reporting of Greenhouse Gases Rule, 76 Fed. Reg. 53,057 (Aug. 25, 2011); and Mandatory Reporting of Greenhouse Gases: Petroleum and Natural Gas Systems: Revisions to Best Available Monitoring Method Provisions, 76 Fed. Reg. 59,533 (Sept. 27, 2011).

[4] The EPA announcement of the schedule to Develop Natural Gas Wastewater Standards can be found on the EPA home web site: http://www.epa.gov/newsroom/. It states:

> **Shale Gas Standards:**Currently, wastewater associated with shale gas extraction is prohibited from being directly discharged to waterways and other waters of the U.S. While some of the wastewater from shale gas extraction is reused or re-injected, a significant amount still requires disposal. As a result, some shale gas wastewater is transported to treatment plants, many of which are not properly equipped to treat this type of wastewater. EPA will consider standards based on demonstrated, economically achievable technologies, for shale gas wastewater that must be met before going to a treatment facility.

[5] Since the release of the Subcommittee's Ninety-Day Report, the National Petroleum Council issued its "Prudent Development" report on September 15, 2011, with its recommendation that:

> "Natural gas and oil companies should establish regionally focused council(s) of excellence in effective environmental, health, and safety practices. These councils should be forums in which companies could identify and disseminate effective environmental, health, and safety practices and technologies that are appropriate to the particular region. These may include operational risk management approaches, better environmental management techniques, and methods for measuring environmental performance. The governance structures, participation processes, and transparency should be designed to: promote engagement of industry and other interested parties; and enhance the credibility of a council's products and the likelihood they can be relied upon by regulators at the state and federal level."

NPC, "Prudent Development: Realizing the Potential of North America's Abundant Natural Gas and Oil Resources," Executive Summary Section II.A.1.

[6] See: http://www.energyfromshale.org/commitment-excellence-hydraulic-fracturing-workshop

[7] An interesting Society of Petroleum Engineers paper sheds light on this point:
Hydraulic Fracture-Height Growth: Real Data, Kevin Fisher and Norm Warpinski, SPE 145949 available at:
http://www.spe.org/atce/2011/pages/schedule/tech_program/documents/spe145949%201.pdf .