



Addendum to Impact Assessment of Mandatory GHG Control Legislation on the Refining and Upstream Segments of the U.S. Petroleum Industry

Lieberman/Warner Climate Security Act of 2007, S.2191

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ACRONYMS

AEO	Annual Energy Outlook
AGR	Acid Gas Removal
Bbbls	Billion Barrels
Bbls	Barrels
Bcf	Billion cubic feet
Bmt	Billion metric tonnes
BOE	BOE
CCS	Carbon Capture and Storage
CEM	Continuous emission monitoring
CH ₄	Methane
CO ₂	Carbon Dioxide
CO ₂ e	Carbon Dioxide equivalent
DOE	Department of Energy
EIA	Energy Information Administration
EOR	Enhanced oil recovery
E&P	Exploration and Production
EPA	Environmental Protection Agency
EU	European Union
EU-ETs	European Union Emissions Trading System
EUR	Estimated Ultimate Recovery
FCC	Fluid Catalytic cracker
GHG	Greenhouse Gas(es)
GWP	Global Warming Potential
H ₂	Hydrogen
HCR	Hydrocracking unit
HDS	Hydrodesulfurization unit
HSM	Hydrocarbon Supply Model
IFO	Intermediate Fuel Oil
IGCC	Integrated Gasification Combined Cycle
LNG	Liquefied Natural Gas
Mb/d	Thousand barrels per day
Mcf/d	Thousand cubic feet per day
MDO	Marine diesel oil
MGO	Marine gas oil
MM	Million (s)
MMb/d	Million barrels per day
MMtCO ₂ e	Million metric tons of carbon dioxide equivalent
MW	Megawatts
NCEP	National Commission on Energy Policy
NGLs	Natural Gas Liquids
N ₂ O	Nitrous Oxide
NPC	National Petroleum Council
O&M	Operation and Maintenance
PADD	Petroleum Administration for Defense District
RFO	Refinery Fuel

SECA	SOx Emission Control Area
TAP	Technology Accelerator Payment
Tcf	Trillion Cubic Feet
TCO ₂ e	Metric Tonne of CO ₂ equivalent
Tonne	Metric ton
WORLD®	World Oil Refining, Logistics, and Demand Model

EXECUTIVE SUMMARY

OVERVIEW

This study estimates the impacts of the Lieberman/Warner *Climate Security Act of 2007*¹ on U.S. oil and gas operations and the potential impacts on U.S. energy supplies. Extending the analysis in the preceding report, *Impact Assessment of Mandatory GHG Control Legislation on the Refining and Upstream Segments of the U.S. Petroleum Industry*, this study used detailed models of the U.S. oil and natural gas production, natural gas processing, and the U.S. and global refining sectors to estimate impacts on new oil and gas drilling, the potential shutdown of existing wells, increased costs on natural gas processing plants, investment in refining capacity in the global refining market, and refinery throughput. The results presented herein raise questions about the broader implications of the impact of the Lieberman/Warner bill on U.S. energy supplies.

This report does not take into account how the cost of consumer emission allowances to natural gas processors under the Lieberman-Warner bill could affect natural gas supply. To the extent that any of the consumer allowance costs are borne by natural gas producers and/or processors, the adverse impact on U.S. natural gas supplies would be greater than estimated in this report. Additionally, this study estimates the cost to producers due to the Lieberman/Warner bill but it does not attempt to estimate how these costs and other costs imposed by the bill might impact overall energy markets including supply, demand and market prices.

Requirements for the Oil and Gas Sector:

The Lieberman/Warner bill as passed by the Senate Environment and Public Works Committee² would require:

- Exploration and production activities to obtain allowances for facility greenhouse gas emissions (GHG). Under a rulemaking required by the bill, E&P activities also may be required to obtain allowances for “consumer emissions” (emissions from consumer use of natural gas) for any gas not sent to a natural gas processing plant;
- Natural gas processing plants to obtain allowances for facility GHG emissions and emissions from consumer use of natural gas and NGLs delivered to the market;
- Refineries to obtain allowances for facility GHG emissions and emissions from consumer use of petroleum products. Similarly, importers of refined petroleum products have the same obligations.

Key Assumptions & Caveats

- GHG Emission Allowance Costs:
 - The assumed costs of GHG emission allowances are comparable to or below estimated allowance costs found in recent studies of the Lieberman/Warner bill.
 - The potential impacts of the low carbon fuels standard in the Lieberman/Warner bill were not evaluated.
- Baseline & Mitigation Technologies:

¹ *Lieberman/Warner Climate Security Act of 2007*, S. 2191

² The wording in the bill requires some interpretation and coverage of emissions related to natural gas will depend on a required EPA rulemaking to be completed within two years of the bill becoming law. While not addressed in this analysis, importers of finished petroleum products and natural gas would be responsible for any facility emissions as well as consumer emissions from the use of those products.

- Based on experience under the EPA Natural Gas STAR program, improved technologies are expected to result in lower methane emissions per well in coming years. For example, methane emissions per onshore natural gas well are expected to decline by 27% between 2012 and 2020 in the base case. The potential for additional methane emission reductions under Lieberman/Warner has been estimated using the large database created through the Gas STAR program.
- The refining base case incorporates recent fuel quality requirements such as the introduction of Ultra Low-Sulfur Diesel fuels. Additionally, the base case assumes that by 2012 and 2020, a series of Sulfur Dioxide (SO_x) Emission Control Areas (SECAs) will be established requiring significant reductions in the sulfur content of marine bunker fuels. Despite these increasingly stringent fuel specification requirements, expected investments in the base case results in CO₂ emissions per unit of refinery throughput that are estimated to be 4% lower in 2020 than in 2012. Lacking a data base comparable to that of the Gas STAR program, robust estimates of refinery mitigation potential and cost could not be developed.
- Allowances for Facility Emissions and Consumer Emissions:
 - The estimated cost of allowances for facility emissions are assumed to be fully absorbed by the facility and lead to the estimated impacts. The cost of allowances for emissions from consumer use of fuels delivered to the market is estimated and reported but not integrated into facility operating cost estimates or the overall operation of energy markets.
 - It is critical to note that the estimated required allowances for consumer emissions are many times that for facility emissions – more than 20 times (about \$39 billion) for natural gas processing plants and roughly 9 times (about \$90 billion) for refineries in 2012. A fully-integrated assessment of the Lieberman/Warner bill requires a detailed full-market assessment of:
 - potential impacts of allowance costs on domestic energy supplies – covering facility allowances as well as consumer allowance costs;
 - potential impacts of allowance costs on energy consumers and demand-side responses;
 - the integration of these supply- and demand-side initial impacts and subsequent market responses within the broader functioning of the complex US economy.
 - Thus far, no major analysis of the impact of climate bills on the overall US economy has investigated in-depth the potential supply-side impacts on US oil and gas supplies. The ICF study is the first study to do so. While the analysis is “static” and does not attempt to evaluate potential impacts on consumers, overall energy demand, market prices for fuels, or the overall economy, it provides a basis for beginning to integrate oil & gas energy supply considerations into a broader analysis of climate bills.

Impacts on the Nation’s Energy Supplies

○ Reduction in Natural Gas Supplies

- The cost of GHG emission allowances is estimated to raise the cost of drilling new wells somewhat but result in a substantial increase in the cost of operating wells. Even though methane emissions from the E&P sector are small relative to the nation’s overall GHG emissions (about 1%), the impact on investment in new wells would be substantial because the estimated cost of allowances is high relative to the cost of operating gas wells.
 - Compared to an estimated average gas well operating cost of around \$25,000/year, the increased operating costs associated with Lieberman/Warner

are estimated at about \$12,500 in 2012 and \$25,600 in 2030, or roughly 50% and 100% increases in operating costs.

- Additionally, obtaining allowances for natural gas processor facility emissions is estimated to increase the cost of operations by an estimated \$0.13 per Mcf processed in 2012, \$0.18 per Mcf processed in 2020, and \$0.27 per Mcf processed in 2030.
- Higher costs would reduce the incentive to drill for natural gas and it is estimated that natural gas drilling would decline, relative to the base case and depending on assumptions about potential additional mitigation efforts, by about 18% to 22% over 2012-2020 and about 31% to 40% over 2021-2030.
- Taking into account the estimated allowance costs incurred for upstream facility emissions but not any allowance costs associated with consumer emissions from the use of natural gas, overall US natural gas production is estimated to be reduced from base case projections about 3-4% in 2012, about 5% to over 6% in 2020, and 7% to over 12% in 2030 depending on mitigation assumptions. Over the entire 2012-2030 period, lost natural gas production is estimated at 20.4 TCF to 30.8 TCF which is roughly equal to one to one and one-half years worth of production. This assumes that drilling reductions occur mostly on marginal fields – those with the lowest expected new production. The lower impact estimate reflects additional methane emission mitigation efforts beyond the 27% reduction in emissions per well already incorporated in the base case. U.S. oil production also is estimated to be adversely impacted but by smaller amounts.
- These estimated production impacts were estimated based on the impact of allowance costs from facility emissions only and do not consider the potential impacts of the much larger consumer emissions or any broader market supply & demand impacts that are likely to occur under the economy-wide implementation of Lieberman/Warner.
- **Increased Dependence on Imported Refined Petroleum Products**
 - Because U.S. refineries would be required to obtain allowances for facility emissions while most foreign refineries would not, U.S. refineries would become increasingly disadvantaged as estimated allowance costs increased. Investment in U.S. refinery facilities is estimated to drop over \$3 billion/year in 2012 from the base case and about \$11.5 billion/year in 2020. As refinery throughput moved overseas, U.S. jobs would be lost but global refinery GHG emissions are estimated as unchanged.
 - U.S. refinery throughput is estimated to decline by about 3 million barrels a day off a base case level of about 18.5 million barrel/day in 2020. Total U.S. imports of crude oil plus refined petroleum products are estimated to shift from about 15% refined petroleum products in the 2020 base case to about 29% under Lieberman/Warner.
- **Increase Cost of Producing Energy for the Nation**
 - The estimated reductions in output under Lieberman/Warner are driven by the allowance costs requirement for facility emissions. Additionally, covered facilities also must obtain allowances for emissions from consumer use of natural gas and petroleum products. The estimated cost of allowances for consumer emissions vastly outweighs the estimated cost of allowances for facility emissions as summarized in the table below.
 - For natural gas, the estimated costs of allowances for facility and consumer emissions are equivalent to about \$2.28 per MCF of natural gas in 2012, and about \$3.14 per MCF in 2020.
 - For refining, the estimated costs of allowances for facility and consumer emissions are equivalent to about 43 cents per gallon of petroleum product in 2012 and about 61 cents per gallon in 2020.

ES-1: Summary of Estimated Allowance Costs under Lieberman/Warner

	Units	2012 L/W	2020 L/W
Allowance Cost	2006\$/tCO₂e	\$41.21	\$57.31
<u>Exploration, Production & Processing</u>			
Exploration & Production:			
GHG Emissions After Mitigation	Million tCO ₂ e	121	121
Direct emission allowance cost	Million 2006\$	\$4,986	\$6,935
Natural Gas Processing:			
Gas production in cases with mitigation	Bcf per year	21,302	21,997
Natural gas processing throughput	Bcf per year	18,213	19,797
GHG emissions per unit of gas processed	tCO ₂ e/MMcf/day	629	685
Facility direct emissions after mitigation	Million tCO ₂ e	45.0	39.3
Facility direct emissions allowance cost	Million 2006\$	\$1,855	\$2,195
Consumer emissions after mitigation *	Million tCO ₂ e	961.4	1045.0
Allowance cost of consumer emissions	Million 2006\$	\$39,620	\$59,891
Total cost of direct and consumer allowances	Million 2006\$	\$41,476	\$62,086
Direct plus consumer allowance cost per Mcf	2006\$ per Mcf	\$2.28	\$3.14
* Consumer GHG emissions shown are only those resulting from gas processing operations. This excludes produced gas that does not require processing, imported gas from Canada, and imported LNG.			
<u>Refining</u>			
Refinery throughput	Million Bbls/day	15.79	15.54
Refinery throughput	Million Gal/yr	242,060	238,230
Non-feedstock products assuming they are 95% of total	Million Gal/yr	229,960	226,320
Refinery direct CO ₂ emissions	Million tCO ₂ e	251.72	237.18
Total allowance cost for direct emissions	Million 2006\$	\$10,373	\$13,593
Direct emission allowance cost	Cents/gal. throughput	4.51	6.01
Consumer emissions from petroleum products **	Million tCO ₂ e	2,189	2,154
Cost of allowances for consumer emissions	Million 2006\$	\$90,209	\$123,446
Consumer emission allowance cost	Cents/gal. throughput	39.2	54.6
Total refinery allowance cost	Million 2006\$	\$100,582	\$137,039
Allowance cost per gallon (refinery plus consumer emissions)	Cents/gal	43.7	60.6
** Allowance requirements for imported finished petroleum products are not included in this table.			

BACKGROUND

The U.S. Congress was active in the 2007 session in considering mandatory controls of greenhouse gas emissions³. At the time the original study⁴ for API began at least thirteen bills were under consideration in the Congress, of which at least four were economy wide. One of these latter bills, the Lieberman/Warner⁵ is examined in detail in this study.

A number of studies have assessed the economic impacts of comprehensive climate legislation including analysis by the Energy Information Administration (EIA), the U.S. Environmental Protection Agency (EPA), and the Massachusetts Institute of Technology (MIT). These studies focused on energy consumption and related macroeconomic impacts on the overall economy.

The main study and this addendum are the first to look in detail at the direct primary impacts and related costs on oil and gas production, natural gas processing, and refining.⁶ Since the bill under consideration is economy wide, the market value of the allowances resulting from this bill would be determined on an economy wide basis. That being the case, ICF utilized estimates from the macroeconomic studies cited above to value the GHG allowances.

For the main study a Base Case was developed based upon official government statistics and peer reviewed reports under which no GHG controls were in place in the United States. Each GHG control bill was then imposed on the Base Case under two assumptions: 1) no greenhouse gas mitigation options other than those already currently being implemented in the Base Case were available (the Base Case includes technology improvements resulting in more than a 25% reduction in methane emissions per onshore gas well between 2012 and 2020), and 2) various potential mitigation activities were available. This approach allows for the estimation of impacts of the bills under varying assumptions regarding the availability of mitigation options. This same Base Case was used in this study.

The results, even assuming mitigation options, reveal that oil and gas production would likely decline in the United States particularly across marginal properties. In the downstream sector, refinery utilization (and crude oil imports) would likely fall relative to the baseline, but product imports would likely increase.

The remainder of this Executive Summary summarizes this report. The details of the Base Case and the development of emissions estimates for the different sectors of the industry are discussed at length in Volume I and Volume II of the main study and are not repeated here except for a brief summary.

BASE CASE

Two detailed ICF and EnSys models were used for this analysis, the ICF *Hydrocarbon Supply Model* (HSM), and EnSys Energy & Systems' *World Oil Refining, Logistics and Demand Model* (WORLD®). Additionally, an ICF natural gas processing model was used for analysis of that sector. Using these models, the Base Cases were created for 2012 and 2020 tied to EIA's *Annual Energy*

³ Many states have also moved forward with a variety of laws and regulations requiring reductions in greenhouse gas (GHG) emissions by electric utilities and other emitters.

⁴ ICF International, *Impact Assessment of Mandatory GHG Control Legislation on the Refining and Upstream Segments of the U.S. Petroleum Industry, Volume I: Report*, December 2007

⁵ *Lieberman/Warner Climate Security Act of 2007*, S. 2191

⁶ It was beyond the scope of this study to address the wider issue of secondary and indirect costs. That would require the integration of a macroeconomic model with the detailed industry models that were used in this study.

Outlook 2006 (AEO06). A detailed discussion of the models and the Base Cases can be found in Chapter 1 of the main report and in the Volume II Appendices.

A major parameter for the study was the estimation of the costs of the GHG allowances. For the main study ICF adapted the output from publicly available, reputable, and analytically robust results from large scale energy and macroeconomic models. Since the EIA and EPA analyses were not available when this study began, results from a major MIT⁷ study were selected.

However, as the amended bill was only referred out of the full Committee in early December, there has not been time for any substantive, publicly available analysis to be undertaken. There are a number of reports on the allowance costs under the original Lieberman/Warner bill. However, the amendments constitute some major differences. CRA⁸, the Nicholas Project from Duke⁹ and MIT¹⁰ have conducted analyses of the original bill. EIA is undertaking an analysis of the amended bill but a report was not available as this analysis was undertaken.

ICF therefore used the following approach to establishing an estimate of the allowance costs. Exhibit ES-2 based on the range of scenarios in the analyses mentioned above, shows the estimated range of costs of the CO₂e allowances over time, and also indicates the cumulative total quantity of the allowances over the 2012-2050 time frames for each projection. The amended Lieberman/Warner bill has a cumulative total of 146.4 billion tonnes (bmt) of allowances. In this respect it falls between the old version of the bill (132 bmt) and the most stringent of the MIT Core Scenarios (167 bmt), the cost estimates of which were used for the Lieberman/McCain analysis in the original report. At the same time, the GHG emission coverage of the amended Lieberman/Warner bill is somewhat more extensive than the old version of the bill complicating this comparison.

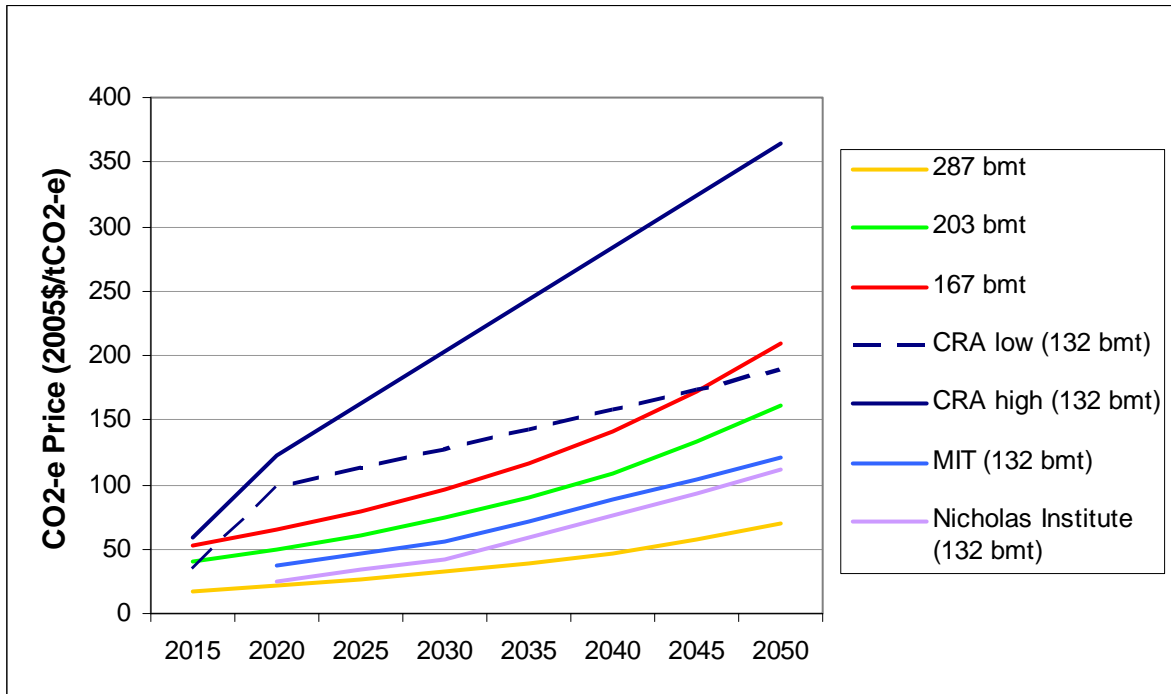
⁷ Massachusetts Institute of Technology, *Assessment of U.S. Cap-and-Trade Proposals*, April 2007

⁸ CRA International, *Economic Impacts of Proposed House/Senate Energy Legislation on the U.S. Economy*, November 2007

⁹ Murray, Brian C., Ross, Martin T., *The Lieberman/Warner America's Climate Security Act: A preliminary Assessment of Potential Economic Impacts*, October 2007

¹⁰ Massachusetts Institute of Technology, *op. cit.*, "Appendix D: Analysis of the Cap and Trade Features of the Lieberman-Warner Climate Security Act (S. 2192)", February 2008

Exhibit ES-2: Carbon Values by Cumulative Allowance Scenario



One of the major differences between the MIT 167 bmt Core Case and the Lieberman/Warner analysis relates to international offsets. The MIT Core Scenarios do not allow international trading, a factor that we know from the various studies drives up the cost of the allowances. Under Lieberman/Warner international allowances are allowed up to 15 percent of a facility’s obligation. The delta between the 167 bmt case and the MIT and Nicholas Institute 132 bmt cases represents an estimate of the impact of international offset assumptions.

However, the terms of the international offsets in Lieberman/Warner are onerous (they are the same in both the original and the amended bill). International offsets will only be accepted from countries that 1) impose on themselves mandatory absolute tonnage limits on GHG emissions, and 2) have a program as stringent as that proposed in this bill. ICF believes that these requirements will substantially reduce the availability of the offsets.

RECOMMENDED ESTIMATE SELECTION

Therefore, the exhibit below was constructed by discounting the offset premium by 30 percent and then adding the residual to the values for the MIT 132 bmt case, resulting in an estimated allowance cost scenario between the MIT 132 bmt case and the MIT 167 bmt case. Values were then extrapolated to generate annual costs for the time period 2012 to 2030. Values were then converted to 2006 real dollars as shown in Exhibit ES-3.

Clearly these values are estimates only but using these estimates gives a sense of the likely impact on the oil and gas sectors of the economy.

Exhibit ES-3: Estimated GHG Emission Allowance Values, \$2006/tCO₂e

Year	MIT (132 bmt) Adjusted
2012	41.21
2013	42.94
2014	44.67
2015	46.40
2016	48.58
2017	50.76
2018	52.94
2019	55.12
2020	57.31
2021	59.84
2022	62.37
2023	64.91
2024	67.45
2025	69.98
2026	72.95
2027	75.92
2028	78.89
2029	81.86
2030	84.82

ESTIMATED IMPACT OF THE LIEBERMAN/WARNER BILL ON THE U.S. OIL AND GAS INDUSTRY

Overview of the Bill: Lieberman/Warner

The Lieberman/Warner proposed bill initially was in many ways similar to the Lieberman/McCain bill, although more stringent. However, the amended bill that emerged from the Senate's Environment and Public Works Committee had some major changes, particularly in the definition of covered facilities. There are some anomalies in the bill, and, in addition, a great deal is left to the discretion of the EPA Administrator. Consequently, many assumptions needed to be made for the modeling effort.

Looking at the available public discussions on the amended bill combined with what ICF has been able to discern from talking to personnel on the Hill, it is clear that the overall intention of the amendments is to capture oil and gas facility GHG emissions, and impose allowance costs for emissions from consumer use of fuels at the "upstream" point: that is the processing plant for natural gas and NGLs and the refinery for petroleum products. All natural gas and petroleum product imports are also captured.

Covered Facilities

The amended bill contains five definitions of covered entities¹¹:

1. Any facility using > 5,000 short tons of coal per annum would be covered. This definition would cover essentially all of the coal used by power generation plants and industrial facilities.

¹¹ Sec.4, DEFINITIONS(7) of Lieberman/Warner.

2. Any facility that is a natural gas processing plant, that produces natural gas in Alaska, or imports natural gas either by pipeline or as LNG. While this misses domestically produced non-associated natural gas that bypasses the processing plants, the language in the Section 1204 required rulemaking presumably would cover that non-associated gas.
3. Any facility that produces petroleum- or coal-based liquid or gaseous fuels, the combustion of which would emit GHGs. Also covered would be any entity that imports the same. Petroleum and coal based products that are used as feedstocks to produce products that do not generate GHG emissions are exempt.
4. Any facility that produces for sale or distribution or imports > 10,000 tCO₂e of GHG chemicals. While the word “chemicals” is believed to target perfluorocarbons (PFCs), the way the section is written has been interpreted by some as covering methane emissions as well.
5. Any facility that emits > 10,000 tCO₂e of hydrofluorocarbons (HFCs) as a byproduct of hydrochlorofluorcarbon (HCFC) production

All of the above assume that there is no destruction or capture and sequestration of the GHG.

Compliance Obligations¹²

Assuming no capture or sequestration all covered facilities will need an allowance for each tCO₂e that:

- a. Was emitted by the use of coal by that facility;
- b. Was emitted from the use of any petroleum – or coal based liquid or gaseous fuel produced or imported by that facility;
- c. Was produced for sale or distribution or imported by that facility;
- d. Was produced as a byproduct of HCFC production by that facility;
- e. Was emitted by the use of natural gas processed or imported by that facility;
- f. Was emitted by the use of NGLs produced by that facility

The “definitions” and “compliance obligations” sections of Lieberman/Warner are somewhat difficult to interpret. For example, under the definition of covered facilities (#2 above) it does appear that production of oil and gas is not covered, with the exception of natural gas in Alaska. If natural gas is re-injected to maintain reservoir pressure then the facility is exempt. On the North Slope some methane is used as lease fuel but much of it is re-injected after the NGLs have been stripped out. The NGLs are then transported through TAPS blended with the crude oil.

However, the bill stresses in several sections that the intention is to cover all emissions from the production and use of natural gas. Section 1204 at the end of Title I was apparently added to clarify coverage of natural gas related emissions, and requires that the coverage of natural gas be expanded by a rulemaking within 2 years after the enactment of the bill to cover all natural gas “emitted or flared during production or processing, or sold for used in the United States”. It appears that the EPA rulemaking is intended to result in coverage of any oil and/or gas production that includes some natural gas. It would also seem to cover the non-associated gas that bypasses gas processing plants and that appears exempt according to how the definitions are written. However, Section 1204 is written so broadly that it may lead to double counting of emissions and double coverage under compliance obligations.

¹² Title I, Subtitle B of Lieberman/Warner.

Turning to refineries (#3 above), combining the definitions and compliance obligation sections, it appears that refineries have a compliance obligation for emissions that come from the use of products of the refinery as well as for the stationary source emissions that come from fuels the refinery has “produced” and “used”. A further consideration to keep in mind is that all of the above does not apply if emissions are destroyed or sequestered, and if fossil fuels are used as feedstocks for products that do not result in CO₂e emissions. This exemption applies to petrochemical feedstocks but apparently not to other products such as asphalt that are not combusted but instead used in road construction.

While an earlier version of Lieberman/Warner generally exempted small emitters (< 10,000 tCO₂e/year), in the amended bill that exemption appears limited to “chemicals” and “HFC” related facilities.

ANALYTICAL APPROACH TO ESTIMATING THE IMPACT ON THE OIL AND GAS SECTORS

Given the problems associated with the bill ICF used the following assumptions for the modeling work. As with the main study indirect costs (i.e., costs of steel, etc.) are not assessed. However, the cost of any purchased electricity or natural gas will include the estimated costs of allowance values paid by the power generator or the natural gas processing plant.

Coverage

ICF used the following modeling assumptions on coverage in the modeling work:

Exploration, Production and Natural Gas Processing Sectors

- Oil and gas production facilities and natural gas processing facilities will be required to obtain allowances for GHG emissions occurring at their facilities. Natural gas producers will be required to obtain allowances for the GHG emissions that come from the use of any natural gas that does not go through a natural gas processing plant.¹³ Given the anomalies in the bill over natural gas coverage and the required Section 1204 EPA rulemaking, ICF assumed that all new and existing gas wells are required to purchase allowances for their greenhouse gas emissions.
- Allowances must be obtained for the GHG emissions from the products of the natural gas processing plants (methane and NGLs) whether used internally or externally by consumers.
- Any purchased electricity or petroleum product would incorporate into their purchase cost the allowance costs paid by the refinery or the power generating plant.

Refineries

- Allowances must be obtained for the GHG emissions from all petroleum based products that are produced and used either in the refinery or outside the refinery. Note that EIA defines still gas as a product.
- The cost of any purchased electricity, natural gas, or NGLs includes the estimated allowance costs paid by the power generating plant or the natural gas processing plant or the producer.
- Petrochemical feedstocks would be exempt.

¹³ Because of data and modeling limitations, the estimated cost of all allowances for emissions from consumer use of natural gas are reported in the tables covering natural gas processing plants.

Low Carbon Fuel Standard

- The low carbon fuel standard (LCFS) in Lieberman/Warner will not be modeled in this study. Any additional costs to refineries of meeting LCFS requirements would be beyond the Lieberman/Warner costs estimated in this study.

Allowance Auctions and Allocations

The bill also allows banking of allowances, borrowing, and a set of requirements covering reporting and verification. The bill sets out a table of the percentage of the allowances that will be allocated free to facilities with compliance obligations. In 2012, 34 percent of available allowances are given to those entities with the share falling to 3 percent in 2030. Producers or importers of petroleum based fuels receive 2 percent of all allowances in 2012 and natural gas producers receive no free allowances.

Auctioned allowances constitute direct costs to the covered entity and free allocated allowances may be treated as an “opportunity cost” by the covered entity. Many economists believe that these costs may be passed through to consumers depending on market circumstances. If the allowances are allocated directly then the cost implications could be quite different. In this study the assumption has been made that all allowances will be auctioned.

ESTIMATED IMPACT OF THE BILL ON THE INDUSTRY

The modeling results discussed below indicate the likely impact of the bill on the relevant sectors and show trends as a function of the estimated allowance values. However, it should at all times be kept in mind that the modeling is limited to the likely direct impacts of the bills on the sectors, and does not reflect the *indirect* impacts and costs (except for electricity, where costs to producers, processors, and refiners were adjusted in the impact cases).

In an economy as complex, large, and sophisticated as that of the United States there are both direct and indirect interrelationships between the various economic sectors and they are not always transparent. An economy wide bill will affect a wide assortment of sectors. The oil and gas industry, as an emitter of GHGs will be directly affected, but also will experience indirect impacts. The industry uses (among many inputs) steel, cement, chemicals, catalysts, nickel, and other metals. All of these are sectors that are also emitters of GHGs and thus subject to the allowance costs. Therefore the industry will have to contend with both the impact of the allowance costs on its plants and products, and the impact of the allowance costs on its inputs.

EXPLORATION AND PRODUCTION SECTOR

Under Lieberman/Warner, assuming no mitigation actions, gas wells drilled would likely decline by an estimated 21.8 percent compared to the Base Case, between 2012 and 2020 and by an estimated 41.0 percent between 2021 and 2030. The likely declines in oil well drilling relative to the Base Case are smaller: 1.9 percent in the earlier period and 4.3 percent in the later period.

The estimated production decline is likely smaller than the drilling decline; the low yield wells are the ones more likely to become uneconomic with the addition of allowance costs. Oil production likely falls an estimated 0.6 percent in 2012-20 and 0.8 percent in the later period, while gas production likely falls 4.5 percent in 2012-20 and 10.9 percent in the later period. The decline in oil production is less than that for natural gas because methane emissions, and therefore allowance costs, are greater for natural gas production than oil production.

Exhibit ES-4 shows the changes in GHG emissions under the bill assuming no mitigation actions beyond those already incorporated in the Base Case. A major contributing factor to the lower Base Case emissions in 2020 than in 2012 is improvements in technology – methane emissions per onshore gas well in 2020 are more than 25% less than in 2012. Exhibit ES-5 summarizes the impacts of the Lieberman/Warner bill after mitigation efforts have been undertaken by the upstream sector. As the exhibits show, there is still a likely negative impact on wells drilled and production, but the impact has been softened.

In Lieberman/Warner with the assumed mitigation options (Exhibit ES-5), gas well drilling likely declines 17.6 percent relative to the Base Case in the early period and 30.6 percent in the later period. In terms of gas production, there is an estimated decline of 3.3 percent relative to the Base Case in the 2012-2020 period and 6.8 percent in the 2021-2030 period.

Exhibit ES-4: Graphical Summary of Estimated Upstream Emissions Results: Cases with No Mitigation

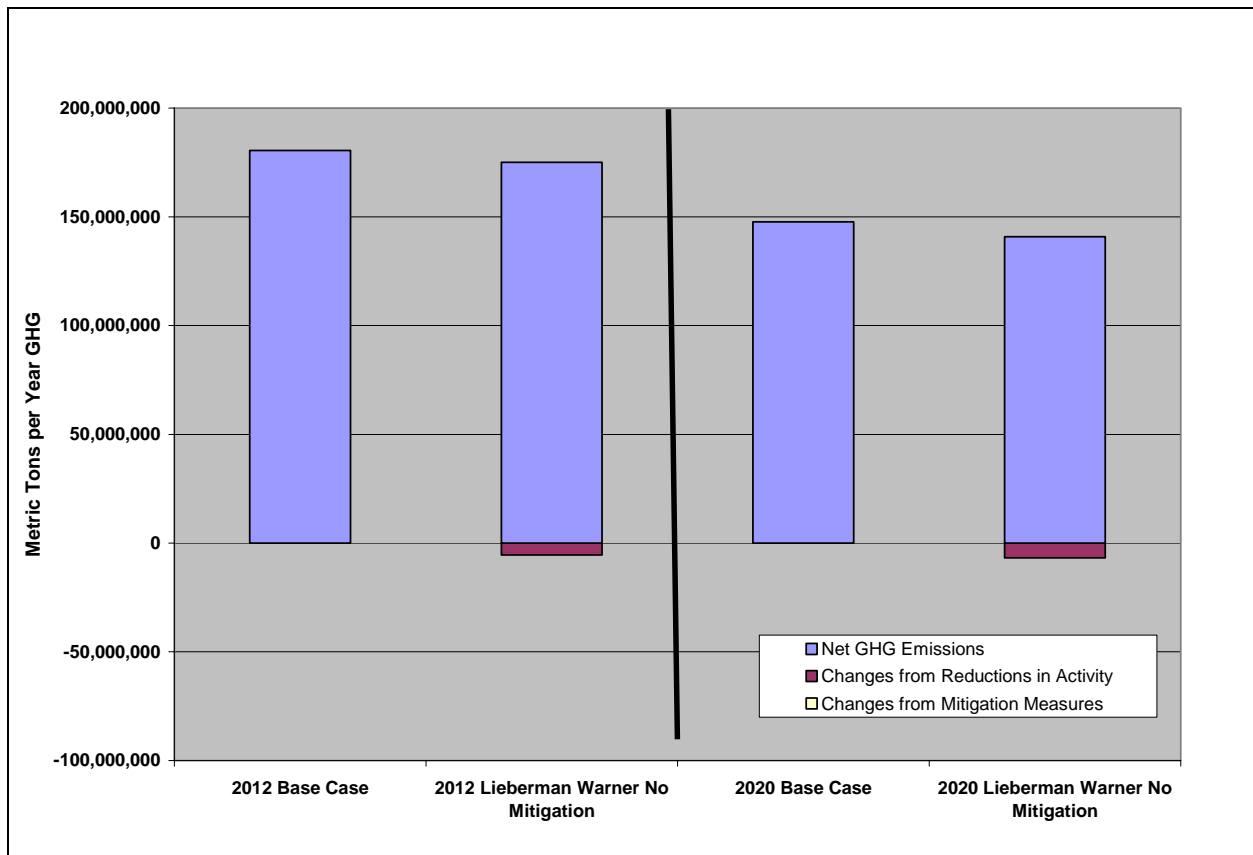
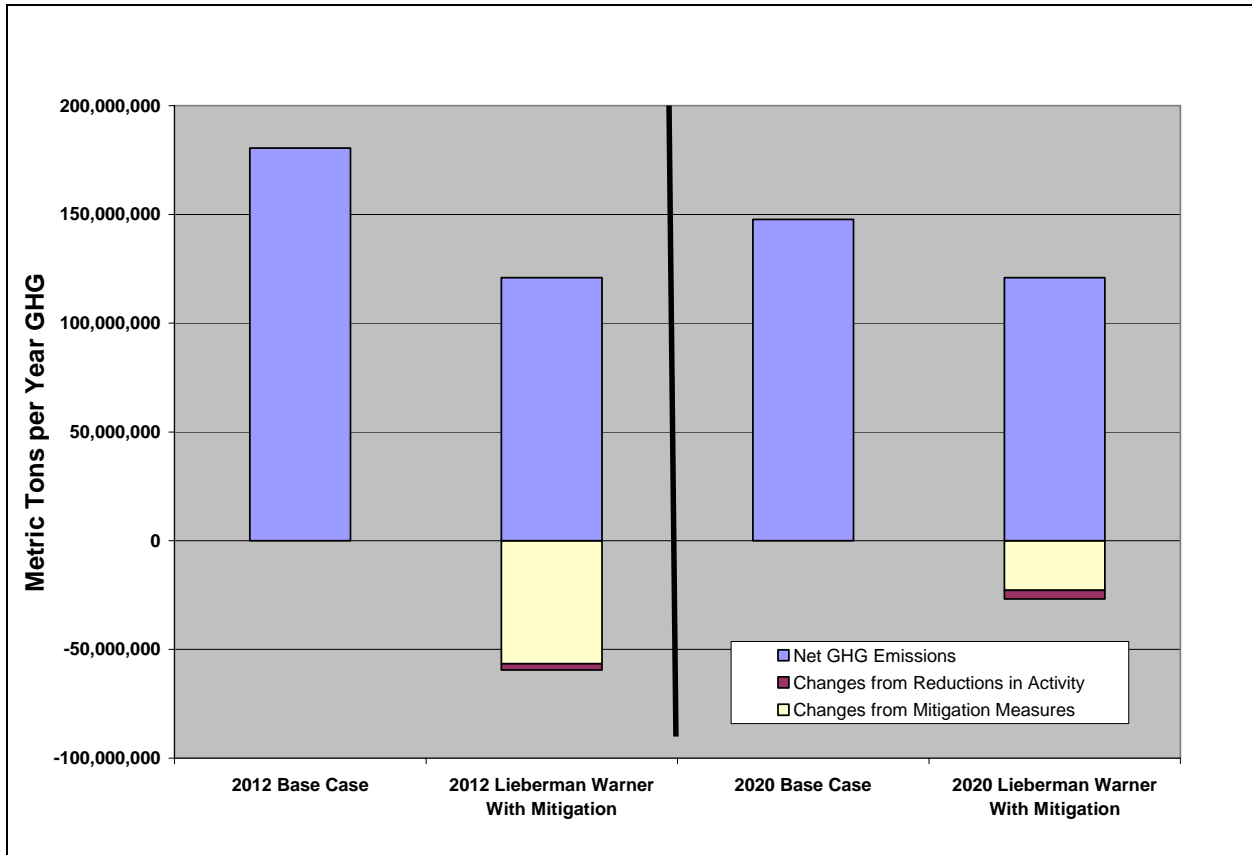


Exhibit ES-5: Estimated Impact of Lieberman/Warner on Drilling and Production after Mitigation

	2012	2020	2030	Cumulative 2012-2020	Cumulative 2021-2030	Cumulative 2012-2030
Base						
Oil Wells Drilled	11,404	10,852	10,502	98,922	105,834	204,756
Gas Wells Drilled	19,436	15,578	18,627	148,796	162,906	311,702
All Wells Drilled	38,732	34,803	40,220	317,705	366,624	684,329
Oil Production MMB	1,698	1,672	1,375	15,198	15,165	30,363
Gas Production BCF	21,518	20,957	20,273	191,108	205,087	396,195
Lieberman/Warner (adjusted for existing well impacts)						
Oil Wells Drilled	11,205	10,814	10,195	97,472	103,033	200,505
Gas Wells Drilled	18,668	10,766	11,186	122,536	113,060	235,596
All Wells Drilled	37,564	29,031	31,310	284,180	306,026	590,206
Oil Production MMB	1,683	1,665	1,364	15,118	15,087	30,204
Gas Production BCF	20,872	19,987	18,872	184,765	191,069	375,834

Exhibit ES-6 presents the estimated emissions results for the cases with mitigation. Exploration and production sector emissions with Lieberman/Warner in 2012 are approximately 121.1 million tonnes and 121.4 million tonnes in 2020. The blue columns indicate the annual CO₂ emission level. The reductions are shown in red or yellow at the base of each column. The red indicates likely reductions resulting from lower activity. Yellow indicates likely reductions resulting from mitigation measures.

Exhibit ES-6: Graphical Summary of Estimated Upstream Emissions: Cases with Mitigation



NATURAL GAS PROCESSING SECTOR

Gas processing costs likely would go up because gas processors would have to buy allowances to cover methane and carbon dioxide emissions from their operations and to high costs for purchased electricity. For 2012, the higher processing costs are estimated at \$0.13/Mcf processed. For 2020 and 2030, these estimates higher costs are estimated at \$0.18 and \$0.27 per Mcf processed, respectively.

Exhibit ES-7 shows the results of the gas processing sector CO₂ emissions analysis without mitigation. Base Case emissions in 2012 are approximately 57 million tonnes of CO₂ and in 2020 are 43 million tonnes, reflecting the expected reductions in Base Case emissions with investments in improved technology for gas processing. Without mitigation the Lieberman/Warner case results in likely reductions in emissions to approximately 55 million tonnes in 2012 and 41 million tonnes in 2020.

Exhibit ES-8 shows the results of the gas processing emissions analysis with mitigation. Base Case emissions in 2012 are 57 million tonnes of CO₂ and in 2020 are 43 million tonnes. The Lieberman/Warner case results in likely reductions in emissions to an estimated 45 million tonnes in 2012 and 38 million tonnes in 2020.

Exhibit ES-7: Graphical Summary of Gas Processing Estimated Emissions Results without Mitigation

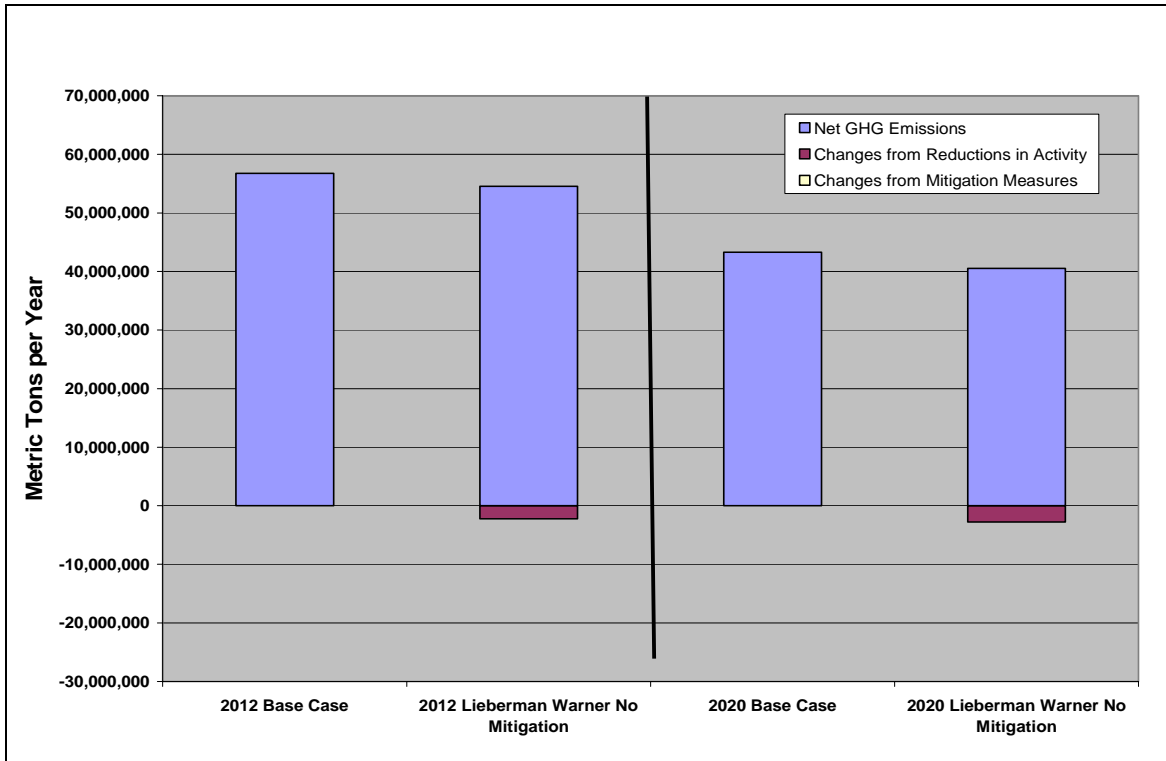
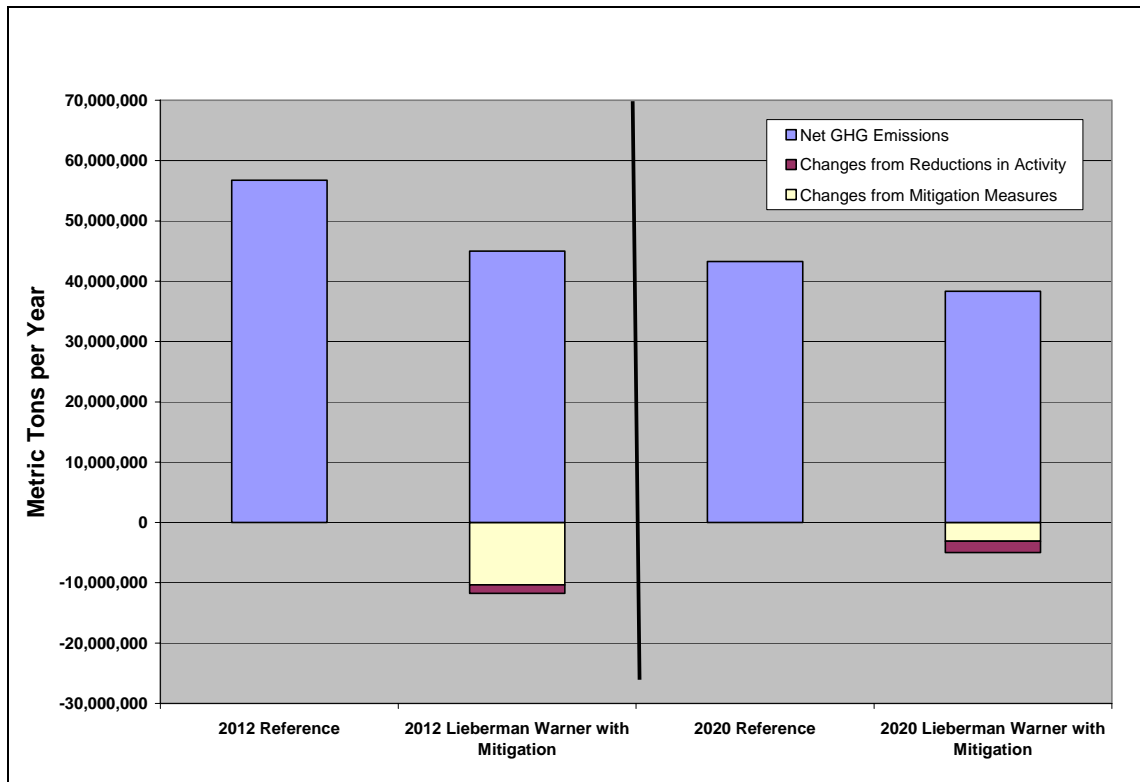


Exhibit ES-8: Graphical Summary of Gas Processing Estimated Emissions Results with Mitigation



DOWNSTREAM SECTOR

Unlike the upstream (exploration, production and natural gas processing) cases, modeling of the impacts of the bills on the downstream sector was undertaken assuming no mitigation. There is a substantial body of well documented data, largely from EPA's Gas STAR program, detailing the technologies and costs of methane reduction technologies that are currently being installed in the upstream sector. Unfortunately, there is no comparable data for the downstream sector. Therefore a mitigation case was not modeled for the downstream sector.

Exhibit ES-9 shows the estimated refinery investment levels for the Base Case and for the Lieberman/Warner impact case for the United States and the rest of the world. In the Base Case rest of world (ROW) investments are estimated to be approximately \$92 billion (in 2006\$) in 2012 and \$166.3 billion in 2020. In the United States Base Case refinery investment is estimated at about \$36.1 billion in 2012 and \$47.3 billion in 2020. U.S. investments are estimated to fall to \$32.9 billion in 2012 and \$35.8 billion in 2020 under Lieberman/Warner.

Looking at investment levels by PADD in Exhibit ES-9 one point to note is that in both 2012 and 2020 investment levels in PADD 5 (the West Coast) are expected to rise when compared to the Base Case. This is driven by substantial investment in hydrocracking. PADD 5, driven in part by high demand for jet fuel and by the uniqueness of California's clean fuel specifications, is expected to be constrained by a shortage of middle distillates and thus required to make the investments.

Investments in the rest of the world are estimated to increase steadily as other countries make up the investments lost in the United States, with a resulting shift in refinery capacity away from the United States to other countries without comparable emission allowance costs on refinery activity.

With the shifting investment patterns, U.S. refinery throughput drops.

- Under Lieberman/Warner, U.S. refinery throughput is estimated to drop from the Base Case level of 17.02 million barrels/day in 2012 to 15.8 million barrels/day and shows reduction from 18.5 million barrels/day to 15.5 million barrels/day in 2020.
- Matching this decline in investment and throughputs U.S. refinery utilization when compared to the Base Case falls from 91% to 85.3% in 2012 and from 92.7% to 83.1% in 2020.
- With the reduced investment and refinery throughput, the U.S. would become more dependent on imports of refined petroleum products. While this shift in imports from crude oil to refined product imports may raise logistical issues and costs, they were not investigated in this assessment.

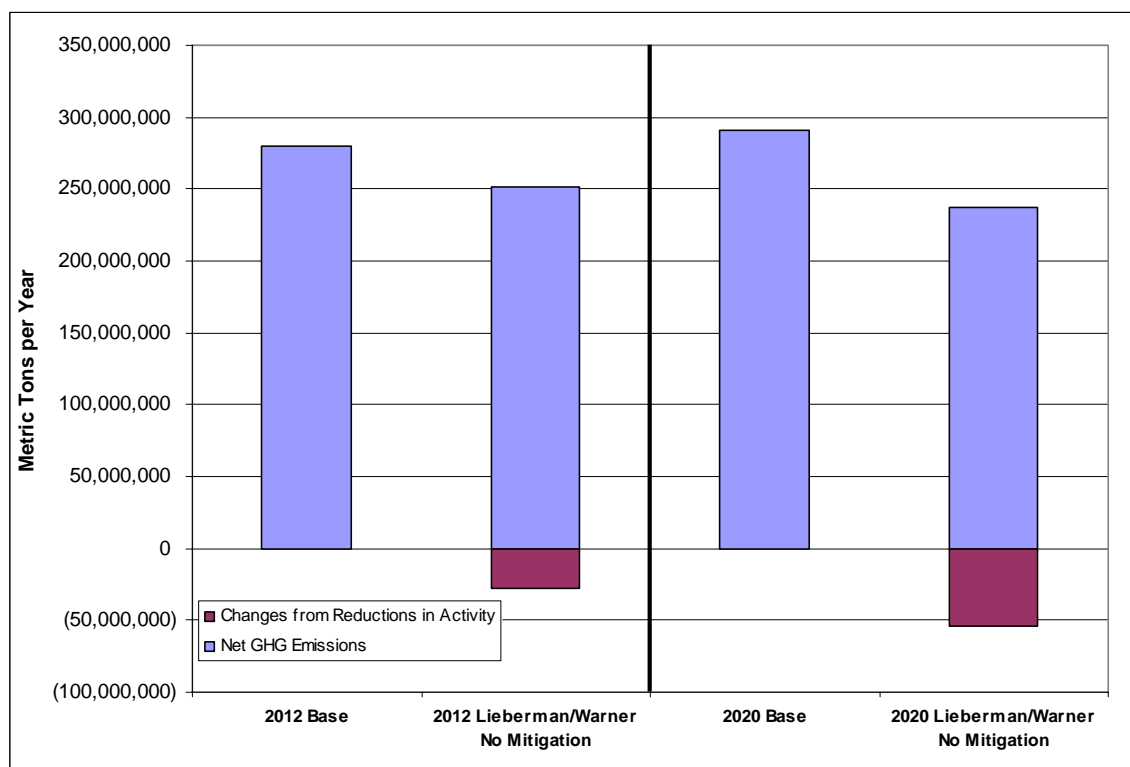
Exhibit ES-10 shows the impact of the bill on emissions from the U.S. refining sector. However, it must be remembered that this is without any mitigation activities.

Exhibit ES-9: Estimated Investment Levels, Throughput, and Utilization by PADD for the 2012 and 2020 Base Case and the Lieberman/Warner Case

	TOTAL	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5	USA	ROW
TOTAL INVESTMENTS								
Base Case 2012	132.10	2.85	11.11	13.71	3.35	5.06	36.08	92.02
Lieberman/Warner 2012	160.14	2.60	9.90	10.44	3.20	6.74	32.88	127.26
Base Case 2020	213.60	3.93	11.24	18.66	2.91	10.51	47.288	166.34
Lieberman/Warner 2020	258.22	2.71	8.88	9.178	2.59	12.42	35.77	222.45
TOTAL THROUGHPUTS								
Base Case 2012	78.84	1.43	3.87	8.16	0.60	2.95	17.02	61.82
Lieberman/Warner 2012	78.49	1.31	3.87	7.21	0.59	2.81	15.79	62.70
Base Case 2020	86.85	1.70	4.15	8.81	0.59	3.20	18.46	68.40
Lieberman/Warner 2020	86.43	1.35	3.99	6.67	0.57	2.96	15.54	70.89
UTILIZATION								
Base Case 2012	84.8%	88.7%	93.0%	90.8%	93.1%	89.9%	91.0%	83.2%
Lieberman/Warner 2012	83.8	82.6%	93.0%	81.3%	92.3%	86.2%	85.3%	83.5%
Base Case 2020	86.1%	96.0%	93.0%	92.3%	93.1%	91.5%	92.7%	84.4%
Lieberman/Warner 2020	84.5%	84.8%	93.0%	75.8%	89.9%	87.2.6%	83.1%	84.8%

Note: Investments are in billions 2006\$. Throughputs are in MMB/d.

Exhibit ES-10: Summary of Estimated Refining Results: Cases without Mitigation



In summary:

- In the upstream sector, it is likely that fewer wells are drilled or existing low yield wells are shut in resulting in less U.S. production.
- In the downstream sector, it is likely that all U.S. refineries are adversely affected, but especially those in PADD 3 (Gulf Coast) and PADD 1 (East Coast).

In addition, what the modeling of the downstream sector shows, despite the caveats, is that when controls are imposed on refiners in only one part of the world -- in this case, the United States -- resulting in additional costs, the tendency is likely to be for additional investment in refining capacity to be diverted outside of the United States. The likely impact on the United States would be the attendant costs of lost jobs, and revenues as well as increased product imports.

GHG ALLOWANCE COSTS AND “CONSUMER EMISSIONS”

While this report focuses on the operational impacts on oil and gas facilities, an important aspect of this bill (and others) is the varied approach taken towards so-called “consumer emissions.” The term “consumer emissions” -- some times called “tailpipe emissions” -- refers to the emissions that come from the use of a product rather than from the production or processing of the product.

EXPLORATION, PRODUCTION AND NATURAL GAS PROCESSING SECTOR ALLOWANCE COSTS

To put consumer emissions into perspective, Exhibit ES-11 summarizes estimated GHG allowance requirements that arise because of emissions at oil and gas sector operations as well as emissions from consumer use of fuels. Required allowances for direct exploration and production emissions are estimated at \$5.0 billion and \$6.9 billion for 2012 and 2020, respectively. Lieberman/Warner does not require exploration and production operations to obtain allowances for emissions from consumer use of fuels. Those emissions are addressed at natural gas processing plants and refineries in the bill.

Natural gas processing plants under Lieberman/Warner are required to obtain allowances for their own facility emissions as well the emissions that will come from natural gas delivered to the market. As with the exploration and production sector, the assumed Lieberman/Warner allowance costs are evaluated to provide a full range of impact sensitivity and summarized in Exhibit ES-11. Note that the allowance costs in the table apply only to that volume of natural gas that moves through a natural gas processing plant.

- Under Lieberman/Warner, and after mitigation efforts, natural gas processing plants in 2012 would likely have an allowance cost of about \$1.9 billion dollars for facility emissions. The allowances needed for “consumer emissions” from processed natural gas would be about \$40 billion. In 2020, the corresponding annual allowances costs would be about \$2.2 billion and \$60 billion.
- The total allowances costs are equivalent to about \$2.28/MCF and \$3.14/MCF in 2012 and 2020, respectively.

REFINERY ALLOWANCE COSTS

Under Lieberman/Warner refineries must submit GHG allowances for their facility emissions as well as for the GHG emissions that come from the consumer use of the petroleum products produced, other than petrochemical feedstocks.

For this assessment, CO₂ emissions from all petroleum products are estimated based on an average CO₂ content (20.9859 lbs of CO₂ per gallon) and refinery throughput as reported in Chapter 4, and the simplifying assumption that 95 percent of petroleum products are non-feedstock products. Since this assessment is focusing on refineries, allowance requirements associated with imported petroleum products are not included. The detailed results are outlined in Exhibit ES-11.

- Under Lieberman/Warner in 2012 allowances for the refinery emissions would likely cost \$10.4 billion (in 2006\$). Allowance costs for the emissions from consumer use of products are estimated to be \$90.2 billion, for a total estimated cost of \$100.6 billion in 2012.
- In 2020, refinery allowance costs would likely be \$13.6 billion. Transportation fuels allowance costs are estimated to be \$123.5 billion, for a total estimated allowance obligation of \$137.0 billion.
- Total estimated allowances costs are equivalent to almost 44 cents/gallon in 2012 and over 60 cents/gallon in 2020.

ES-11: Summary of Estimated Upstream, Midstream, and Downstream Emission Allowance Costs for the Lieberman/Warner Bill

	Units	2012 L/W	2020 L/W
Allowance Cost	2006\$/tCO2e	\$41.21	\$57.31
<u>Exploration, Production & Processing</u>			
Exploration & Production:			
GHG Emissions After Mitigation	Million tCO2e	121	121
Direct emission allowance cost	Million 2006\$	\$4,986	\$6,935
Natural Gas Processing:			
Gas production in cases with mitigation	Bcf per year	21,302	21,997
Natural gas processing throughput	Bcf per year	18,213	19,797
GHG emissions per unit of gas processed	tCO2e/MMcf/day	629	685
Facility direct emissions after mitigation	Million tCO2e	45.0	39.3
Facility direct emissions allowance cost	Million 2006\$	\$1,855	\$2,195
Consumer emissions after mitigation *	Million tCO2e	961.4	1045.0
Allowance cost of consumer emissions	Million 2006\$	\$39,620	\$59,891
Total cost of direct and consumer allowances	Million 2006\$	\$41,476	\$62,086
Direct plus consumer allowance cost per Mcf	2006\$ per Mcf	\$2.28	\$3.14
* Consumer GHG emissions shown are only those resulting from gas processing operations. This excludes produced gas that does not require processing, imported gas from Canada, and imported LNG.			
<u>Refining</u>			
Refinery throughput	Million Bbls/day	15.79	15.54
Refinery throughput	Million Gal/yr	242,060	238,230
Non-feedstock products assuming they are 95% of total	Million Gal/yr	229,960	226,320
Refinery direct CO2 emissions	Million tCO2e	251.72	237.18
Total allowance cost for direct emissions	Million 2006\$	\$10,373	\$13,593
Direct emission allowance cost	Cents/gal. throughput	4.51	6.01
Consumer emissions from petroleum products **	Million tCO2e	2,189	2,154
Cost of allowances for consumer emissions	Million 2006\$	\$90,209	\$123,446
Consumer emission allowance cost	Cents/gal. throughput	39.2	54.6
Total refinery allowance cost	Million 2006\$	\$100,582	\$137,039
Allowance cost per gallon (refinery plus consumer emissions)	Cents/gal	43.7	60.6
** Allowance requirements for imported finished petroleum products are not included in this table.			

1 INTRODUCTION

OVERVIEW

In 2007 ICF International (ICF), and its subcontractor EnSys Energy & Systems (EnSys), were retained by API to estimate the likely impact on the U.S. oil and natural gas sectors of the selected proposed bills in the U.S. Congress that would regulate and control the emissions of greenhouse gases (GHG). The proposed bills varied in their complexity and coverage, all of them covering the electrical power sector, but only some them covering the economy as a whole.

The focus of the original study¹⁴ was on two economy wide bills, the *Climate Stewardship and Innovation Act of 2007*, S. 280, sponsored by Senators Lieberman and McCain, and the *Low Carbon Economy Act of 2007*, S. 1766, sponsored by Senators Bingaman and Specter.

These two bills were selected because:

- They appeared to cover a wider spectrum of the economy than the other bills,
- The two bills spanned much of the range between the most and the least stringent of the economy wide bills,
- The Bingaman/Specter bill had a safety valve that prevented allowance costs rising above a certain level, and
- Both bills (or roughly equivalent proposals) had been analyzed by external groups such as the Massachusetts Institute of Technology (MIT) or the Energy Information Administration (EIA).

This additional work is to evaluate the impact on the same industrial sectors of another economy wide bill, the *Lieberman/Warner Climate Security Act of 2007*, S. 2191, as amended in December 2007 by the full Senate Environment and Public Works Committee.

ANALYTICAL APPROACH

The same analytical approach used to evaluate the impact of the two previous bills on the oil and gas sector is used for the analysis of the Lieberman/Warner bill. It is a combination of scenario modeling using ICF's Hydrocarbon Supply Model (HSM) to represent the upstream sectors and EnSys' World Oil Refining, Logistics and Demand Model (WORLD®) to represent the downstream sectors of the industry. Both of these models, which are central to the analysis, contain extensive detail about facility operations in the upstream (exploration and production) and downstream (refining) sectors of the oil and gas industry. Additionally, an ICF natural gas processing model was used for analysis of that sector.

In addition to these two models, a set of spreadsheet models were created that calculated the emissions for the upstream and midstream sectors which then provided input to the HSM. Finally, for the economy wide market clearing cost of allowances, ICF adapted the output from publicly available, reputable, and analytically robust results from large scale energy and macroeconomic models as discussed below. The same approach is followed in this analysis.

¹⁴ ICF International, *Impact Assessment of Mandatory GHG Control Legislation on the Refining and Upstream Segments of the U.S. Petroleum Industry, Volume I: Report*, December 2007

The Base year in both models is drawn from the Energy Information Administration's (EIA) *Annual Energy Outlook 2006* (AEO06), Base Case. The two years examined were 2012 and 2020, with some additional evaluation of the impacts in 2030 for the upstream sectors. All costs were estimated in 2006 dollars.

For this additional modeling work the ICF Team used the same Base Cases that were generated for the previous report. Other than a few summary references we are not presenting again the assumptions and the analysis that underlay the Base Cases. These can be found in the original report in Chapters 2 and 3 of Volume I. The original report also contained substantial details on GHG emissions from the three sectors of the industry and information on the technologies that could be used for mitigation. This too is not being repeated but can be found in Chapters 2, 3, and 5 of Volume I and in Appendix E of Volume II.

ESTIMATED MARKET COST OF CO₂E ALLOWANCES

The two bills examined previously and the one under examination in this addendum involve an economy wide tradable permits system with mandatory emissions targets and a market-based system for meeting the targets. A critical parameter of the analysis of the impacts is the market value of the CO₂e allowances. The proposed cap-and-trade policies are economy wide¹⁵. Consequently, the market clearing cost of allowances is determined on an economy wide basis.

PUBLICLY AVAILABLE EVALUATIONS OF THE BILLS

As the amended bill was only referred out of the full Committee in early December, there has not been time for any substantive, publicly available analysis to be undertaken. There are a number of reports on the allowance costs under the original Lieberman/Warner bill. However, the amendments constitute some major differences. CRA¹⁶, the Nicholas Project from Duke¹⁷ and MIT¹⁸ have conducted analyses of the original bill. EIA is undertaking an analysis of the amended bill but they are currently occupied with the new AEO and do not expect to have a report published until March or April.

ICF therefore used the following approach to establishing an estimate of the allowance costs. The exhibit below, based on the range of scenarios in the analyses mentioned above, shows the estimated range of costs of the CO₂e allowances over time, and also indicates the cumulative total of the allowances over the 2012-2050 time frames for each projection. The amended Lieberman/Warner bill has a cumulative total of 146.4 billion tonnes (bmt) of allowances. In this respect it falls between the old version of the bill (132 bmt) and the most stringent of the MIT Core Scenarios (167 bmt), the prices of which were used for the Lieberman/McCain analysis in the original report. At the same time, the GHG emission coverage of the amended Lieberman/Warner bill is somewhat more extensive than the old version of the bill complicating this comparison.

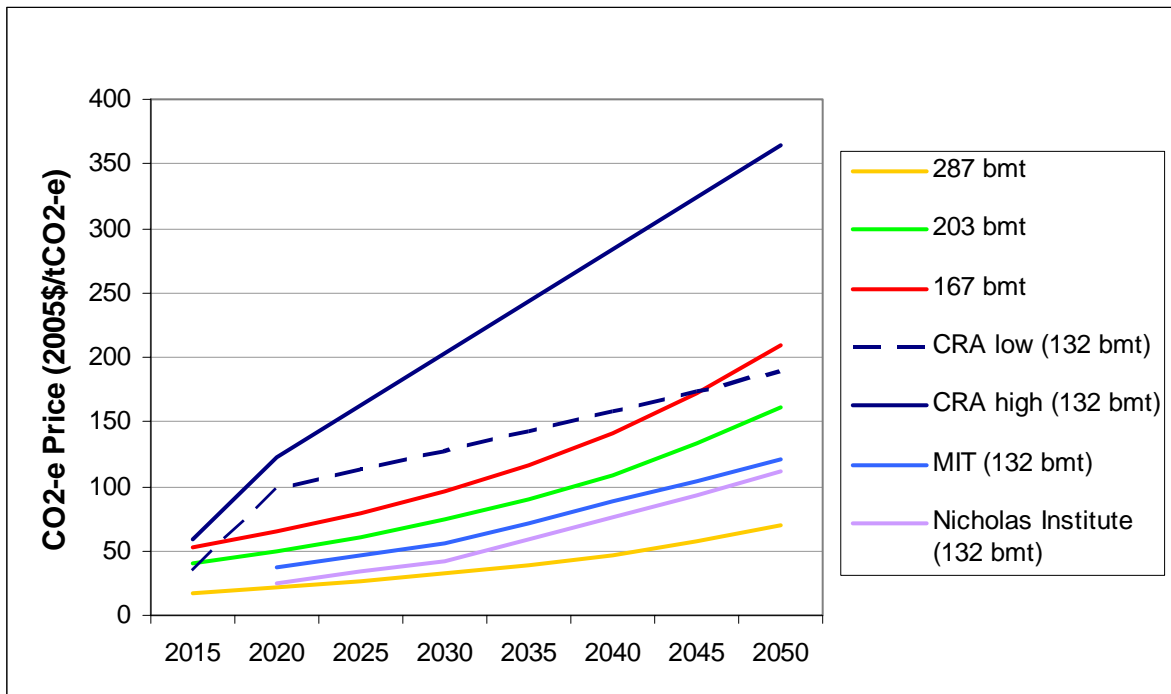
¹⁵ This is not literally true. Depending on the bill, agriculture and forestry, and in some cases other sectors, are excluded as are small emitters. However, it is close enough to be described as "economy wide".

¹⁶ CRA International, *Economic Impacts of Proposed House/Senate Energy Legislation on the U.S. Economy*, November 2007

¹⁷ Murray, Brian C., Ross, Martin T., *The Lieberman/Warner America's Climate Security Act: A preliminary Assessment of Potential Economic Impacts*, October 2007

¹⁸ Massachusetts Institute of Technology, *Assessment of U.S. Cap-and-Trade Proposals, April 2007*, "Appendix D: Analysis of the Cap and Trade Features of the Lieberman-Warner Climate Security Act (S.2191)", February 2008

Exhibit 1-1: Carbon Values by Cumulative Allowance Scenario



One of the major differences between the MIT 167 bmt Core Case and the Lieberman/Warner analysis relates to international offsets. The MIT Core Scenarios do not allow international trading, a factor that we know from the various studies drives up the cost of the allowances. Under Lieberman/Warner international allowances are allowed up to 15 percent of a faculty's obligation. The delta between the 167 bmt case and the MIT and Nicholas Institute 132 bmt cases represents the premium allocated to international offsets.

However, the terms of the international offsets in Lieberman/Warner are onerous (they are the same in both the original and the amended bill). International offsets will only be accepted from countries that 1) impose on themselves mandatory absolute tonnage limits on GHG emissions, and 2) have a program as stringent as that proposed in this bill. ICF believes that these requirements will substantially reduce the availability of the offsets.

RECOMMENDED ESTIMATE SELECTION

Therefore, the exhibit below was constructed by discounting the premium by 30 percent and then adding the residue to the values for the MIT 132 bmt case, resulting in an allowance cost scenario between the MIT 132 bmt case and the MIT 167 bmt case. Values were then extrapolated to generate annual costs for the time period 2012 to 2050. Values were then converted to 2006 real dollars as shown in Exhibit 1-2.

Clearly these values are estimates only and one can argue about the methodological approach and about the discount rate that was applied to the premium. Nevertheless, using these estimates gives a sense of the likely impact on the oil and gas sectors of the economy.

Exhibit 1-2: Estimated GHG Emission Allowance Values, \$2006/tCO₂e

Year	MIT (132 bmt) Adjusted
2012	41.21
2013	42.94
2014	44.67
2015	46.40
2016	48.58
2017	50.76
2018	52.94
2019	55.12
2020	57.31
2021	59.84
2022	62.37
2023	64.91
2024	67.45
2025	69.98
2026	72.95
2027	75.92
2028	78.89
2029	81.86
2030	84.82

CAVEATS

The original study, the first of its kind, looked in detail at the potential impacts of specific GHG emissions control bills on the operation of the upstream, midstream and downstream sectors of the U.S. oil and gas industry. It was not the intent of the study to assess the potential impacts of these bills on the broader U.S. economy. A number of other studies have addressed economy wide impacts but their assessments focus on energy consumption and not on the supply side of the oil and gas industry.

The bills examined are economy-wide with some exceptions which vary depending on the specific bill. As discussed in the section above, the values of the allowances are being drawn from studies that include the use of a general equilibrium model that represents the entire economy. In that regard, there is already some useful linkage between this analysis and models that look at economy wide impacts. However, when considering the results that will be laid out in the following chapters the reader has to keep the following facts in mind.

- Given one of the findings of this study – that the bills being considered could result in less domestic production of natural gas -- and the importance of domestic energy supplies to the U.S. economy, it may be valuable in the future to attempt a closer integration of analysis between economy wide models focusing on energy consumption and much more detailed models focusing on domestic energy supplies.
- The modeling of the direct allowance costs to the oil and gas sector does not reflect the complexity, the interrelationships, and the unexpected impacts that occur in an economy as

complex, sophisticated, and large as that of the United States, particularly as energy is at the core of an industrialized economy and feeds through to all sectors.

The costs of purchased electricity as well as purchased natural gas are increased in the modeling to reflect estimated allowance costs as the power sector and natural gas processors will be impacted by the bills. However, costs will likely be even higher for the oil and gas industry because also impacted would be the steel industry, petrochemicals, the catalyst industry, and other metallurgy sectors, all sectors that provide inputs to the various parts of the oil and gas sector. On the other hand, just as the models used do not represent the cost increases from the sectors mentioned above, they do not represent other factors that might lower costs. Additionally, most of the bills contain offset provisions and set some limit on the percentage of obligations that an impacted entity can offset. While these offsets may be drawn from non-impacted domestic sectors or from foreign sectors, available information on the potential availability and cost is not regarded as robust. To fully evaluate all the myriad of direct and indirect costs, a general macroeconomic model closely linked to models incorporating the level of detail about individual industry sectors like that used in this study would be required.

STRUCTURE OF THE REPORT

The rest of the report is structured as follows.

- Chapter 2 briefly summarizes the Base Cases for 2012 and 2020 that were developed for the original report for the upstream (production), the midstream (natural gas processing), and the downstream (refining) sectors of the industry.
- Chapter 3 discusses the details of the Lieberman/Warner bill and examines the impact of the bill on the three sectors of the industry under the assumption that no mitigation efforts would be undertaken.
- Chapter 4 takes the impacts identified in Chapter 3 and examines the changes that would occur if mitigation actions were undertaken.
- Chapter 5 summarizes the conclusions.

2 BASE CASES FOR 2012 AND 2020

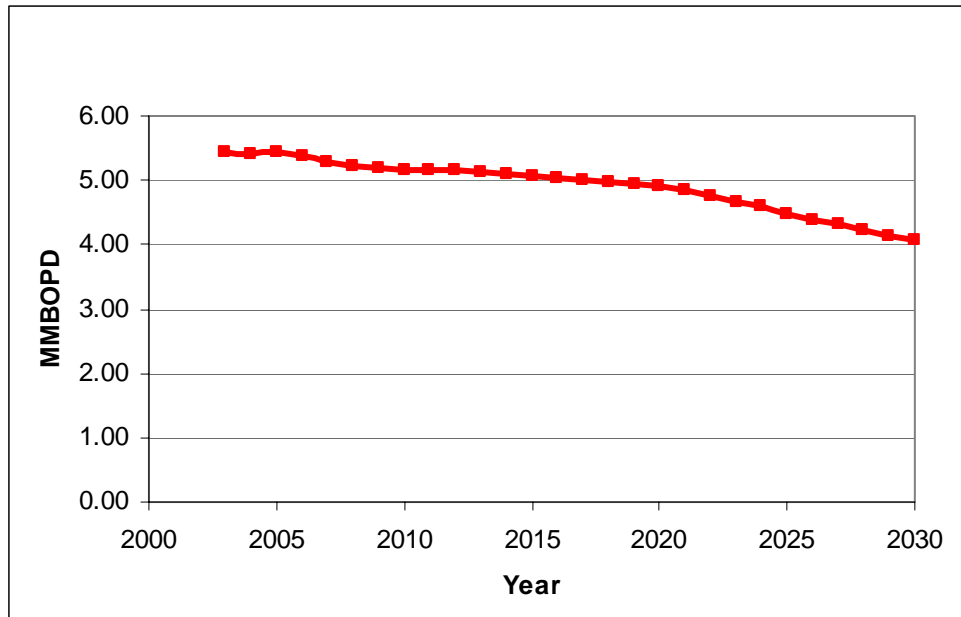
BASE CASE RESULTS FOR THE UPSTREAM SECTOR

The upstream impact analyses on new well drilling and production were conducted using the ICF Hydrocarbon Supply Model (HSM). Analyses of existing wells were conducted using the ICF Oil Well Operating Cost Model and the ICF Gas Well Operating Cost Model. A “Base Case” was prepared with these models to provide a basis for comparison to the “impact cases.” A total of two impact cases were prepared based on the Lieberman/Warner legislative proposal distinguished by whether or not mitigation measures were considered.

The cost impacts on the gas processing sector were developed using the ICF Gas Processing Database and Cost Model. Calculations made with this tool were fed into the other models as cost inputs. Details on the models may be found in Appendix B in Volume II of the original report.

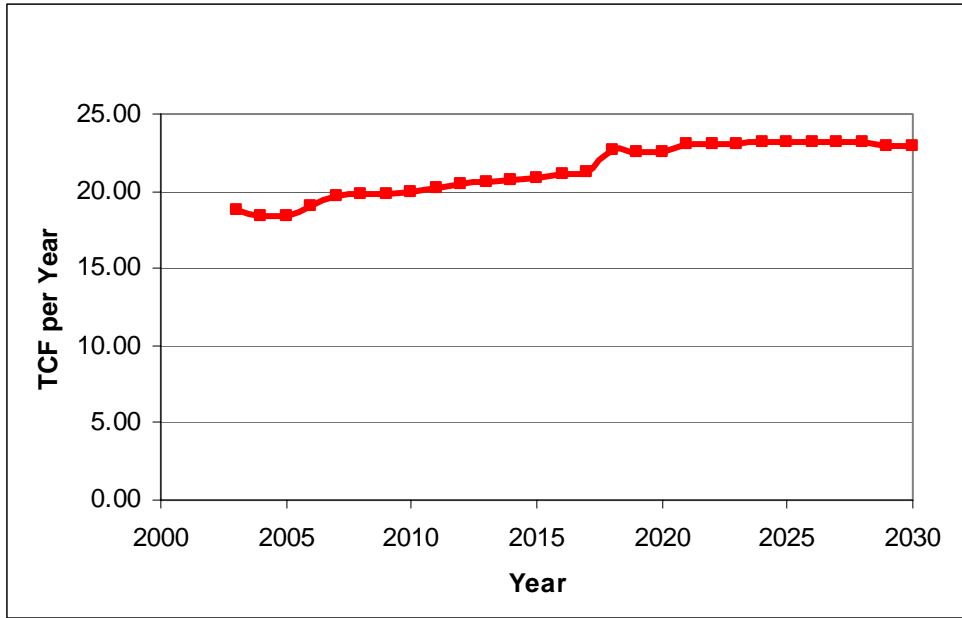
Exhibit 2-1 through Exhibit 2-4 show the Base Case results for the upstream forecast. A detailed analysis of the Base Case may be found in Chapter 2 of Volume I of the original report.

Exhibit 2-1: Total U.S. Oil Production Forecast



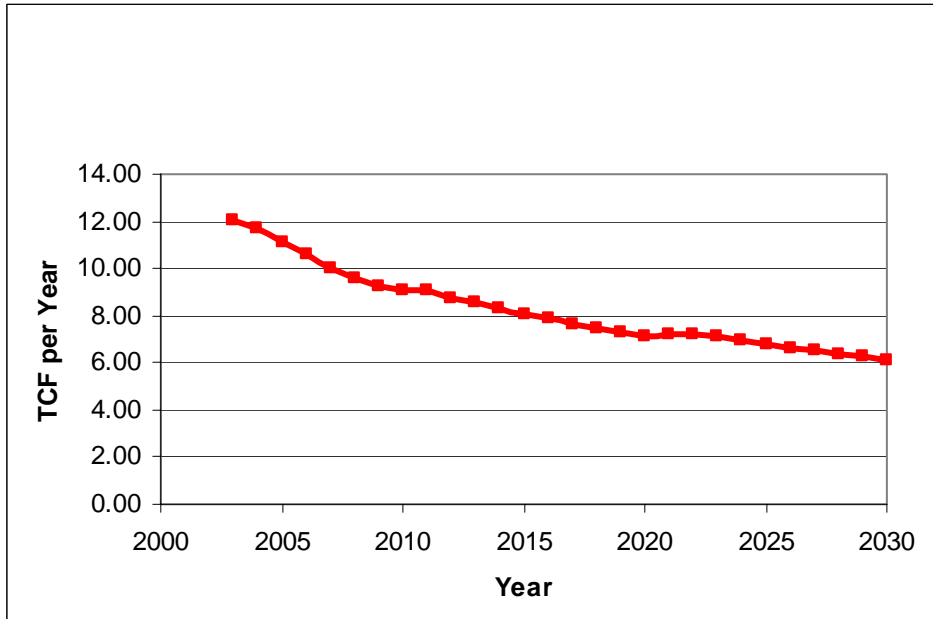
Source: ICF, Hydrocarbon Supply Model runs

Exhibit 2-2: Total U.S. Gas Production Forecast



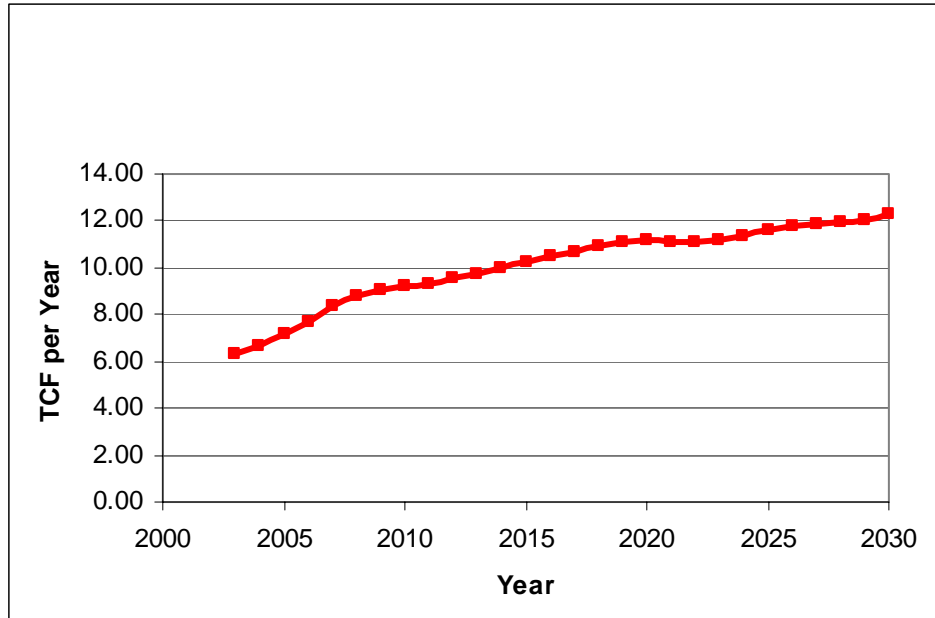
Source: ICF, Hydrocarbon Supply Model runs

Exhibit 2-3: Lower-48 Conventional Gas Production



Source: ICF, Hydrocarbon Supply Model runs

Exhibit 2-4: Lower-48 Non-Conventional Gas Production



Source: ICF, Hydrocarbon Supply Model runs

Regional oil and gas production data can be found in Appendix B of Volume II of the original report.

EMISSIONS FROM THE UPSTREAM AND NATURAL GAS PROCESSING SECTORS

The methodology used to estimate carbon dioxide (CO₂), methane (CH₄), and nitrous oxide (N₂O) emissions from oil and natural gas production and natural gas processing is discussed in detail in Volume I of the original report and in Appendix D of Volume II.

Based on this GHG emissions methodology, Exhibit 2-5 indicates that the estimated oil and natural gas production carbon dioxide emissions are almost one and half times larger than the natural gas processing carbon dioxide emissions. The oil and natural gas production sector dominates the estimated methane emissions with more than 107 million tonnes of carbon dioxide equivalent (MMtCO₂e) of emission from all sources. Both sectors have relatively small nitrous oxide emissions compared to the other greenhouse gases, totaling about 0.54 MMtCO₂e. Overall, the oil and natural gas production and the natural gas processing sector account for an estimated 236.29 MMtCO₂e of greenhouse gas emissions, including indirect emissions from purchased electricity.

Exhibit 2-5: Estimated 2005 Greenhouse Gas Emissions Summary (Million Tonnes CO₂e)

Sector	CO₂	CH₄	N₂O	Total MMtCO₂e
Production – Direct Emissions	51.40	107.80	0.36	159.56
Production – Indirect Emissions	16.32	0.00		16.32
Processing – Direct- Emissions	31.22	11.69	0.18	43.09
Processing – Indirect Emissions	17.32	0.00		17.32
Total	116.26	119.49	0.54	236.29

On a CO₂ equivalent basis, within the exploration and processing sectors, the production sector is responsible for an estimated 74.4 percent of emissions and the natural gas processing sector is responsible for 25.6 percent of emissions.

SUMMARY OF EMISSIONS FROM ALL THREE SECTORS

Exhibit 2-6 and Exhibit 2-7 summarize the GHG emissions from the upstream and midstream sectors of the oil and gas industry disaggregated by PADD level and with the offshore broken out.

Exhibit 2-6: 2005 Estimated Oil and Natural Gas Production Emissions (MMtCO₂e)

PADD	Direct CO₂	Indirect CO₂	CH₄¹⁹	N₂O	Total MMtCO₂e
PADD I	1.51	1.64	9.17	0.01	12.33
PADD II	3.62	4.13	30.83	0.07	38.65
PADD III	19.18	7.51	37.85	0.18	64.72
PADD IV	5.49	2.63	16.98	0.03	25.13
PADD V	18.59	0.41	8.20	0.05	27.25
Offshore	3.00		4.77	0.02	7.79
Total	51.39	16.32	107.80	0.36	175.88

¹⁹ Indirect and direct CH₄ emissions included; indirect CH₄ emissions are negligible compared to direct CH₄ emissions.

Exhibit 2-7: 2005 Estimated Natural Gas Processing Emissions (MMtCO₂e)

PADD	Direct CO₂	Indirect CO₂	CH₄²⁰	N₂O	Total MMtCO₂e
PADD I	0.20	0.25	0.13	0.00	0.58
PADD II	3.25	3.93	1.71	0.02	8.91
PADD III	20.72	11.18	6.51	0.11	38.51
PADD IV	3.87	1.67	1.46	0.02	7.02
PADD V	3.20	0.29	1.88	0.02	5.38
Total	31.24	17.23	11.69	0.18	60.41

BASE CASE RESULTS FOR THE DOWNSTREAM SECTOR

As WORLD® is a global market model both U.S. and global assumptions had to be developed for the 2012 and the 2020 Base cases. A detailed discussion of the assumptions can be found in Chapter 3 of Volume I of the original report.

Exhibit 2-8 and Exhibit 2-9 show the estimated throughputs and utilizations for the 2012 and 2020 Base Cases at the PADD, national, and global level. The two exhibits also report on total estimated investment. There are substantial regional variations among the PADDs that are reflected in the estimates. Over time PADD 1 shows potential increases in all three categories while PADD 2 shows a slight potential increase in investment with a similar pattern in throughput and utilization. PADDs 3 and 5 show substantial potential increases in investment with lesser increases in throughput and utilization. PADD 4, the Rockies, shows a decline in investment between 2012 and 2020 with a similar decline in throughput.

Exhibit 2-8: Estimated Investment Levels and Utilization by PADD for the 2012 Base Case

	Total	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5	USA TOTAL	Rest of World
TOTAL INVESTMENTS	132.10	2.85	11.11	13.71	3.35	5.06	36.08	96.02
TOTAL THROUGHPUT 2012	78.84	1.43	3.87	8.16	0.60	2.95	17.02	61.82
Utilizations	84.8%	88.7%	93.0%	90.8%	93.1%	89.9%	91.0%	83.2%

Note: Investments are in billions of 2006\$. Throughputs are in MMB/d

Exhibit 2-9: Estimated Investment Levels and Utilization by PADD for the 2020 Base Case

	Total	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5	USA TOTAL	Rest of World
TOTAL INVESTMENTS	213.60	3.93	11.24	18.66	2.91	10.51	47.26	166.34
TOTAL THROUGHPUT 2020	86.85	1.70	4.15	8.81	0.59	3.20	18.46	68.40
Utilizations	86.1%	96.0%	93.0%	92.3%	93.1%	91.5%	92.7%	84.4%

Note: Investments are in billions of 2006\$. Throughputs are in MMB/d

²⁰ Indirect and direct CH₄ emissions included; indirect CH₄ emissions are negligible compared to direct CH₄ emissions.

Comparing the changes between the 2012 Base Case and that of 2020, in the United States as a whole and the rest of the world there appear to be similar trends. Investment is estimated to increase in both regions; the United States by 31 percent and the rest of the world by 73 percent. This difference, likewise in refinery throughputs, is not surprising since the majority of the growth in petroleum demand is found in the Asia Pacific region and other regions outside the OECD in general and the United States in particular.

EMISSIONS FROM THE DOWNSTREAM SECTOR

Refineries generate large volumes of emissions of CO₂ and much lesser volumes of emissions of CH₄ and N₂O. The WORLD® model computes CO₂ emissions as a function of the fuel consumed in refineries, including from FCC catalyst regeneration, from Hydrogen Plant CO₂ yield and from sulfur plant tail gas and flare losses. Emissions from flares are captured by a factor that represents the gas lost as a function of crude oil charged. This factor matches that in the *API Compendium*.

Indirect GHG emissions from purchased electricity are not explicitly included in WORLD®. However, the model calculates and identifies electricity purchases. It also incorporates self generated electricity in the form of refinery fuel burned for steam and electricity generation. To capture the CO₂ emissions impacts of changes in U.S. refinery electric power consumption, the levels of purchased power were set constant so that all the changes in consumption were captured via variations in the level of internal refinery power generation which, in the model, has directly associated CO₂ emissions.

BASE CASE EMISSIONS

Exhibit 2-10 shows the 2012 and the 2020 case greenhouse gas emissions results for all U.S. refinery groups (i.e. all U.S. refineries evaluated in the WORLD® model). Consistent with EIA and EPA reports, the ICF Team assumed that CH₄ and N₂O emissions are a *de minimis* fraction of CO₂ emissions for refineries; this is not the case for upstream and midstream gas processing. Results are totaled into CO₂ equivalents (CO₂e).

**Exhibit 2-10: 2012 and 2020 Base Case Estimated Greenhouse Gas Emissions Summary
U.S. Refineries, Million Tonnes per Annum**

Activity	CO ₂	CH ₄	N ₂ O	Total CO ₂ e
Combustion and venting - 2012	279.44	N/A	N/A	279.44
Combustion and Venting - 2020	291.31	N/A	N/A	291.31

WORLD® model outputs,

On a CO₂e basis, the oil refining sector estimate totals 279.44 million tonnes in 2012 and 291.31 tonnes in 2020.

EMISSION SUMMARY

Exhibit 2-11 and Exhibit 2-12 show WORLD® emissions projections for each PADD for the 2012 and 2020 Base Cases.

Exhibit 2-11: 2012 Base Case Greenhouse Gas Emissions Summary by PADD, Million tonnes

Process Units	U.S. Total	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5
PRIMARY UNITS						
From H₂ plant	27.74	0.85	5.35	13.99	0.35	7.20
From Refinery Fuel Oil	241.50	20.59	52.39	118.44	8.10	41.98
From Flare/Loss	9.45	0.80	2.15	4.53	0.34	1.64
From Sulfur Plant Tail Gas	0.75	0.03	0.13	0.45	0.01	0.12
Total	279.44	22.27	60.02	137.41	8.80	50.93

Source: Output from WORLD® model runs

Exhibit 2-12: 2020 Base Case Greenhouse Gas Emission Summary by PADD, Million tonnes

Process Units	U.S. Total	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5
PRIMARY UNITS						
From H₂ Plant	30.83	1.20	5.57	16.57	0.40	7.10
From Refinery Fuel Oil	249.36	22.22	54.52	122.52	7.23	42.87
From Flare/Loss	10.25	0.94	2.31	4.89	0.33	1.78
From Sulfur Plant Tail Gas	0.86	0.05	0.15	0.49	0.01	0.16
Total	291.31	24.41	62.54	144.48	7.97	51.91

Source: Output from WORLD® Model runs

With the exception of hydrogen production by steam-methane reforming, all estimated emissions are a result of combusted sources, which means that mitigation options for the refinery cases will focus on capturing combustion byproducts, fuel switching, or energy efficiency. Reflecting an indicated decline in refinery activity in PADD 4 between 2012 and 2020, the region's emissions totals also decline between 2012 and 2020. As expected, emissions grow in all other PADDs between 2012 and 2020.

3 IMPACT OF THE LIEBERMAN/WARNER BILL ON THE INDUSTRY WITHOUT MITIGATION ACTIONS

OVERVIEW OF THE LIEBERMAN/WARNER BILL

The Lieberman/Warner proposed bill initially was in many ways similar to the Lieberman/McCain bill, although more stringent. However, the amended bill that emerged from the Senate's Environment and Public Works Committee had some major changes, particularly in the definition of covered facilities. There are some anomalies in the bill, and, in addition, a great deal is left to the discretion of the EPA Administrator, requiring a number of assumptions to be made for the modeling effort.

Looking at the available public discussions on the amended bill combined with what ICF has been able to find out from talking to personnel on the Hill, it is clear that the overall intention of the amendments is to capture oil and gas emissions, and thus impose allowance costs at the "upstream" point: that is the processing plant for natural gas and NGLs and the refinery for petroleum products. All natural gas and petroleum product imports are also captured.

Covered Facilities

The amended bill contains five definitions of covered entities²¹:

1. Any facility using > 5,000 short tons of coal per annum would be covered. This definition would cover essentially all of the coal using power generation plants and industrial facilities.
2. Any facility that is a natural gas processing plant, that produces natural gas in Alaska, or imports natural gas either by pipeline or as LNG. While this misses domestically produced non-associated natural gas that bypasses the processing plants, the language in the Section 1204 required rulemaking presumably would cover that non-associated gas.
3. Any facility that produces petroleum- or coal-based liquid or gaseous fuels, the combustion of which would emit GHGs. Also covered would be any entity that imports the same. Petroleum and coal based products that are used as feedstocks to produce products that do not generate GHG emissions are exempt.
4. Any facility that produces for sale or distribution or imports > 10,000 tCO₂e of GHG chemicals. While the word "chemicals" is believed to target perfluorocarbons (PFCs), the way the section is written has been interpreted by some as covering methane emissions as well.
5. Any facility that emits > 10,000 tCO₂e of hydrofluorocarbons (HFCs) as a byproduct of hydrochlorofluorcarbon (HCFC) production

All of the above assume that there is no destruction or capture and sequestration of the GHG.

Compliance Obligations²²

Assuming no capture or sequestration all covered facilities will need an allowance for each tCO₂e that

- a. Was emitted by the use of coal by that facility

²¹ Sec.4, DEFINITIONS(7) of Lieberman/Warner.

²² Title I, Subtitle B of Lieberman/Warner.

- b. Was emitted from the use of any petroleum – or coal based liquid or gaseous fuel produced or imported by that facility
- c. Was produced for sale or distribution or imported by that facility
- d. Was produced as a byproduct of HCFC production by that facility
- e. Was emitted by the use of natural gas processed or imported by that facility
- f. Was emitted by the use of NGLs produced by that facility

The “definitions” and “compliance obligations” sections of Lieberman/Warner are somewhat difficult to interpret. For example, under the definition of covered facilities (#2 above) it does appear that production of oil and gas is not covered, with the exception of natural gas in Alaska. If natural gas is re-injected to maintain reservoir pressure then the facility is exempt. On the North Slope some methane is used as lease fuel but much of it is re-injected after the NGLs have been stripped out. The NGLs are then transported through TAPS blended with the crude oil.

However, the bill stresses in several sections that the intention is to cover all emissions from the production and use of natural gas. Section 1204 at the end of Title I was apparently added to clarify coverage of natural gas related emissions, requires that the coverage of natural gas be expanded by a rulemaking within 2 years after the enactment of the bill to cover all natural gas “emitted or flared during production or processing, or sold for used in the United States”. It appears that the EPA rulemaking is intended to result in coverage of any oil and/or gas production that includes some methane. It would also seem to cover the non-associated gas that bypasses gas processing plants and that appears exempt according to how the definitions are written. However, Section 1204 is written so broadly that it may lead to double counting of emissions and double coverage under compliance obligations.

Turning to refineries (#3 above), combining the definitions and compliance obligation sections, it appears that refineries have a compliance obligation for emissions that come from the use of products of the refinery as well as for the stationary source emissions that come from fuels the refinery has “produced” and “used”. A further consideration to keep in mind is that all of the above does not apply if emissions are destroyed or sequestered, and if fossil fuels are used as feedstocks for products that do not result in CO₂e emissions. This exemption applies to petrochemical feedstocks but apparently not to other products such as asphalt that are not combusted but instead used in road construction.

While an earlier version of Lieberman/Warner generally exempted small emitters (< 10,000 tCO₂e/year, in the amended bill that exemption appears limited to “chemicals” and “HFC” related facilities.

ANALYTICAL APPROACH TO ESTIMATING THE IMPACT ON THE OIL AND GAS SECTORS

Given the problems associated with the bill ICF used the following assumptions for the modeling work. As with the main study indirect costs (i.e., costs of steel, etc.) are not assessed, with two exceptions. Any electricity purchased or natural gas purchased will incorporate into their costs the allowance values paid by the power generator or the natural gas processing plant.

Coverage

ICF used the following modeling assumptions on coverage in the modeling work:

Exploration, Production and Natural Gas Processing Sector

- Oil and gas production facilities and natural gas processing facilities will be required to obtain allowances for GHG emissions occurring at their facilities. Natural gas producers will be required to obtain allowances for the GHG emissions that come from the use of any natural gas that does not go through a natural gas processing plant.²³ Given the anomalies in the bill over natural gas coverage and the required Section 1204 EPA rulemaking, ICF is assuming that all new and existing gas wells are required to purchase allowances for their greenhouse gas emissions.
- Allowances must be obtained for the GHG emissions from the products of the natural gas processing plants (methane and NGLs) whether used internally or externally by consumers.
- Any purchased electricity or petroleum product would incorporate into their purchase cost the allowance costs paid by the refinery or the power generating plant.

Refineries

- Allowances must be obtained for the GHG emissions from all petroleum based products that are used either in the refinery or outside the refinery. Note that EIA defines still gas as a product.
- Any purchased electricity, natural gas, or NGLs would incorporate into their purchase cost the allowance costs paid by the power generating plant or the natural gas processing plant or the producer.
- Petrochemical feedstocks would be exempt.

Low Carbon Fuel Standard

- The low carbon fuel standard will not be modeled in this study. Any costs to refineries of meeting LCFS requirements would be beyond the Lieberman/Warner costs estimated in this study.

Allowance Auctions and Allocations

The bill also allows banking of allowances, borrowing, and a set of requirements covering reporting and verification. The bill sets out a table of the percentage of the allowances that will be allocated free to facilities with compliance obligations. In 2012, 34 percent of available allowances are given to those entities with the share falling to 3 percent in 2030. Producers or importers of petroleum based fuels receive 2 percent of all allowances in 2012 and natural gas producers receive no free allowances.

Auctioned allowances constitute direct costs to the covered entity and free allocated allowances may be treated as an “opportunity cost” by the covered entity. Many economists believe that these costs may be passed through to consumers depending on market circumstances. If the allowances are allocated directly then the cost implications are quite different. In this study the assumption has been made that all allowances will be auctioned.

The market clearing value of allowances under the Lieberman/Warner proposal used in this modeling exercise is shown below in Exhibit 3-1. It is drawn from Exhibit 1-2.

²³ Because of data and modeling limitations, the estimated cost of all allowances for emissions from consumer use of natural gas are reported in the tables covering natural gas processing plants.

Exhibit 3-1: Estimated GHG Allowance Values, \$2006/tCO₂e

Year	MIT (132 bmt) Adjusted
2012	41.21
2013	42.94
2014	44.67
2015	46.40
2016	48.58
2017	50.76
2018	52.94
2019	55.12
2020	57.31
2021	59.84
2022	62.37
2023	64.91
2024	67.45
2025	69.98
2026	72.95
2027	75.92
2028	78.89
2029	81.86
2030	84.82

RESULTS OF THE MODELING OF THE EXPLORATION, PRODUCTION AND NATURAL GAS PROCESSING SECTORS

The Hydrocarbon Supply Model was run to simulate the impacts on the level of future drilling and related production that might be expected from the Lieberman/Warner bill. The Base Case scenario inputs were kept the same in the impacts cases with three exceptions for estimated costs:

- Oil and gas well operating costs were increased to account for the estimated cost of the allowances that would be needed to cover GHG emissions from oil and gas production operations,
- Capital costs for new wells were increased to reflect the estimated allowance cost for fuel used to drill new wells, and
- Costs for processing natural gas were increased to reflect the estimated allowance costs for operating natural gas processing plants.

For the “No Mitigation” impact cases, the emission factors used to estimate those extra allowance costs are the Base Case factors and do not reflect potential cost-effective mitigation steps the industry could take - beyond the steps already taken in the Base Case - to further reduce GHG emissions in the face of the allowance costs. Assumptions for how mitigation could reduce the overall costs of complying with GHG regulations are included in a second set of “With Mitigation” HSM runs in the next chapter.

Similarly, an economic analysis was conducted for wells that are expected to be in production before the start of the regulatory regime in 2012. This analysis was carried out using the ICF Oil Well Operating Cost Model and the ICF Gas Well Operating Cost Model. The purpose was to see how much the operating cost of these existing wells would change, how many would be rendered uneconomic and consequently the amount of oil and gas production that might be expected to be lost.

It is important to note that upstream impacts were modeled in terms of “direct” or “first order” impacts only and ignore secondary impacts such as increases in cost of steel or other non-fuel inputs to oil and gas operations, changes to quantity of oil gas demanded in the market or changes to the wellhead prices for oil and gas. Another important point to note is the HSM runs were made assuming that all new and existing oil and gas wells would be subject to GHG regulations and would be required to obtain allowances for their GHG emissions

MODELING INPUTS

Each of the major estimated cost impacts of GHG legislation on upstream and midstream operations is discussed in this section.

Estimated Increases in Well Operating Costs

Exhibit 3-2 shows the assumed increases expected in average onshore wells that would be caused by the Lieberman/Warner proposal. These include the allowance cost for methane and carbon dioxide emissions and the higher cost of any electricity used on the lease.

- For gas wells under Lieberman/Warner, the additional operating costs would likely rise from about \$12,496 in 2012 to \$25,578 in 2030. The Lieberman/Warner impact thus would be about a 50 to 100 percent increase in average onshore gas well operating costs for 2012 and 2030 respectively.
- The expected increase in the operating costs for onshore oil wells from Lieberman/Warner is lower than for gas wells because of the lower emission factors for methane and CO₂. The oil well operating costs are expected to go up by an estimate of about \$4,540 in 2012 and by \$8,311 in 2030. This would be about 18 to 34 percent increases in average onshore oil well operating costs for 2012 and 2030 respectively.

To put these changes into context Exhibits 3-4, 3-5, and 3-6 show the well operating costs for oil and gas wells from the Base Case.

Exhibit 3-2: Lieberman Warner Estimated Impact on Onshore Well Operating Cost without Mitigation

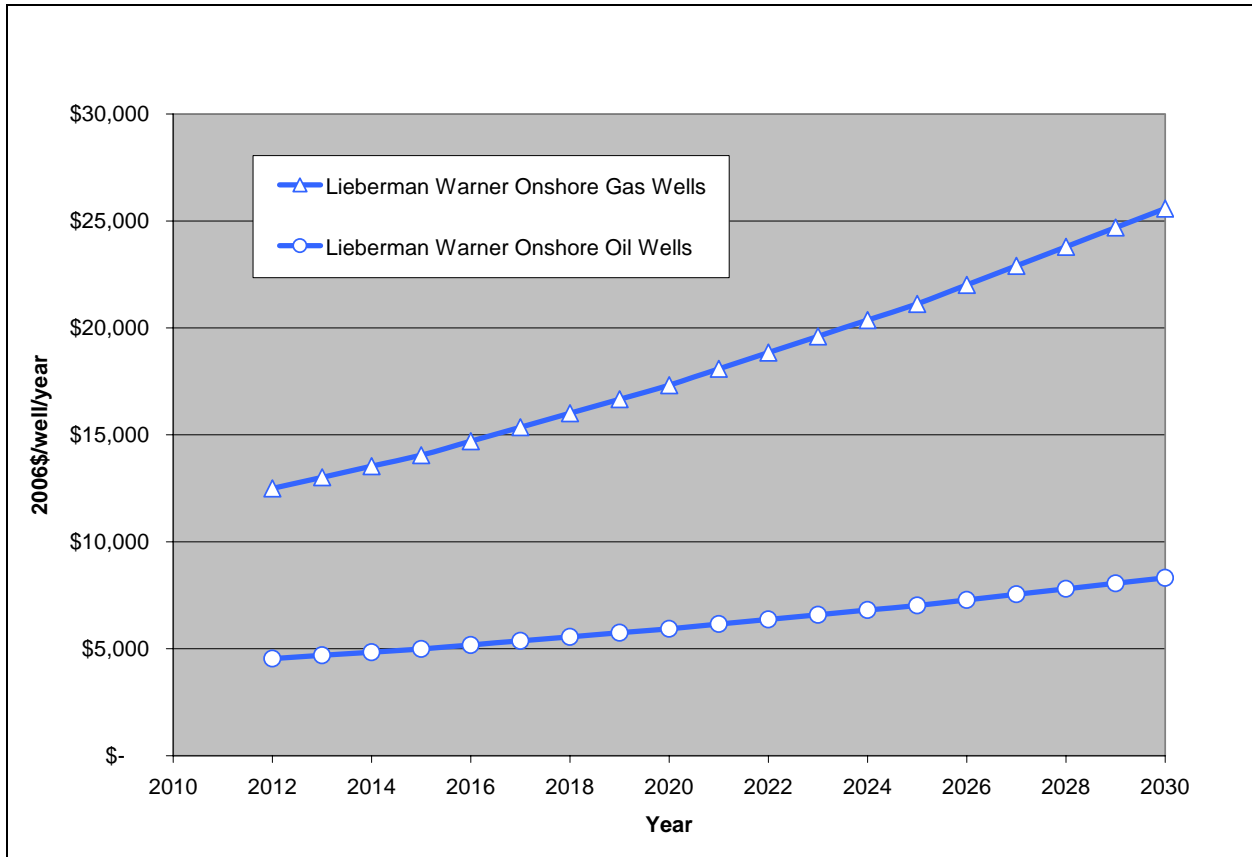
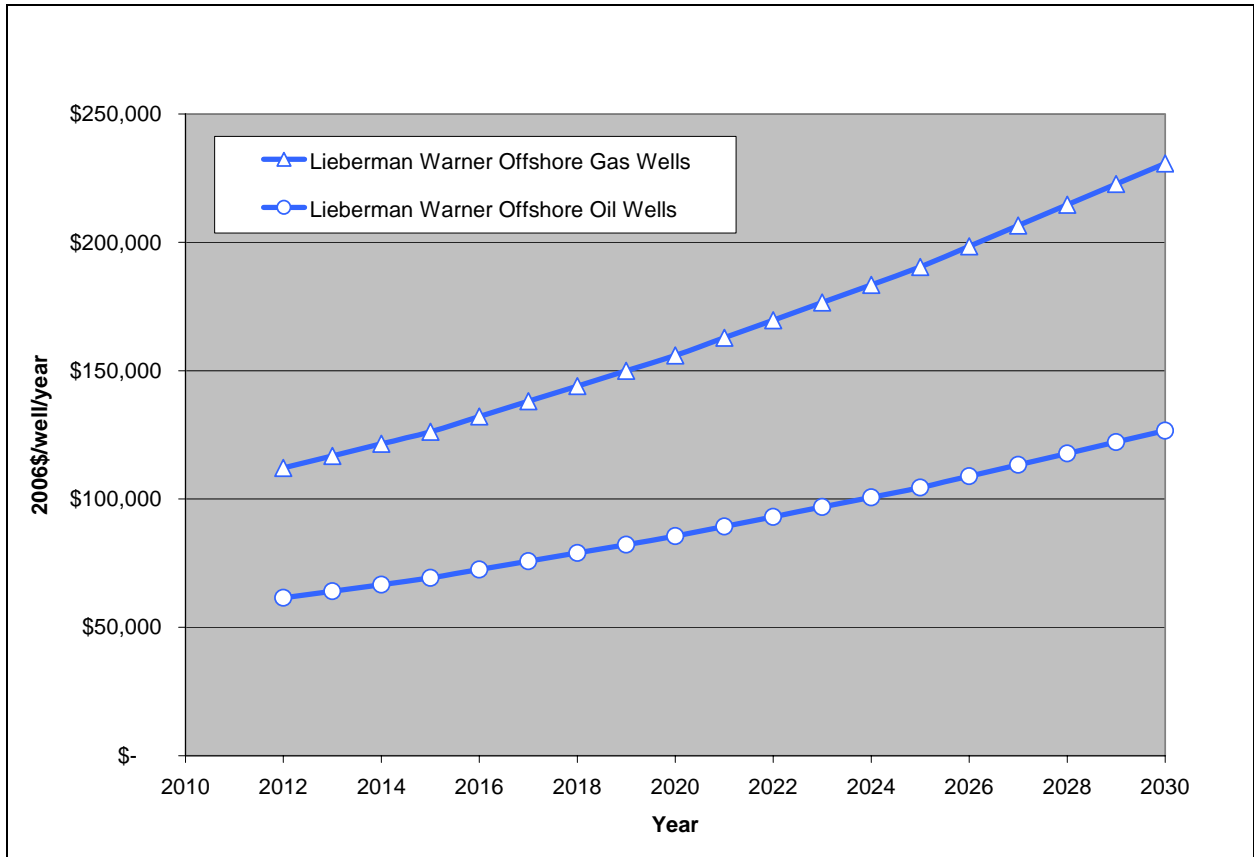


Exhibit 3-3 shows the assumed operating cost increases for average offshore wells that would be expected from the Lieberman/Warner proposal. The production rates from offshore wells are much higher than onshore wells and the GHG emissions per well are also much larger. For this reason the estimated cost of GHG allowances per well are more than 10 times greater. However, because the Base Case operating costs for offshore wells (\$350,000 or more per well) are higher than onshore wells, the estimated increase in operating costs on a percentage basis is similar to or slightly lower than onshore wells.

Exhibit 3-3: Lieberman/Warner Estimated Impact on Offshore Well Operating Cost without Mitigation



**Exhibit 3-4: Onshore Gas Well Operating Costs
Base Case**

(2006 Dollars per Year per Well)					
Well Depth:	2,000 ft	4,000 ft	8,000 ft	12,000 ft	16,000 ft
50 Thousand Cubic Feet per Day					
Mid-Continent	\$13,700	\$16,000			
North Louisiana	\$13,200				
South Louisiana	\$13,200	\$15,600			
Rocky Mountains	\$16,000	\$18,700			
South Texas	\$14,500	\$17,000			
West Texas	\$11,500	\$14,400	\$18,800		
250 Thousand Cubic Feet per Day					
Mid-Continent	\$18,700	\$25,400	\$40,100	\$49,300	
North Louisiana	\$16,000	\$22,900	\$39,700		
South Louisiana	\$16,000	\$22,800	\$39,200		
Rocky Mountains	\$18,800	\$31,400	\$43,500	\$53,500	
South Texas	\$17,200	\$23,500	\$39,900		
West Texas	\$14,200	\$20,500	\$35,000	\$44,600	
500 Thousand Cubic Feet per Day					
Mid-Continent		\$23,800	\$32,200	\$38,800	\$42,600
North Louisiana		\$22,400	\$32,200	\$36,700	
South Louisiana			\$32,700	\$38,000	\$41,700
Rocky Mountains		\$32,300	\$36,600	\$44,200	
South Texas			\$31,700	\$39,900	
West Texas			\$25,700	\$32,600	\$38,500
1 Million Cubic Feet per Day					
Mid-Continent				\$52,000	\$55,100
North Louisiana				\$49,100	\$56,000
South Louisiana			\$42,900	\$50,900	\$55,400
Rocky Mountains				\$56,300	
South Texas			\$49,000	\$48,000	
West Texas				\$43,400	\$48,100
5 Million Cubic Feet per Day					
Mid-Continent					\$60,800
North Louisiana					\$64,400
South Louisiana				\$49,200	\$63,100
Rocky Mountains					
South Texas				\$53,400	
West Texas					\$57,500

Source: DOE/EIA Costs and Indices for Domestic Oil and Gas Field Equipment and Production Operations 1987 through 2005, converted to 2006 dollars.

**Exhibit 3-5: Offshore Well Operating Costs, Base Case
2006\$/well/year**

Water Depth	100 Foot	300 Foot	600 Foot
12-Slot Platform	\$573,332	\$595,582	
18-Slot Platform	\$465,241	\$482,700	\$514,020

Source: DOE/EIA *Costs and Indices for Domestic Oil and Gas Field Equipment and Production Operations, 1987 through 2005*, converted to 2006 dollars

**Exhibit 3-6: Onshore Oil Well Operating Costs
Base Case**

(2006 Dollars per Year per Well)				
Well Depth:	2,000 ft	4,000 ft	8,000 ft	12,000 ft
Primary Production				
California	\$21,392	\$28,260	\$48,821	\$71,966
Oklahoma	\$20,213	\$24,047	\$42,005	\$51,681
South Louisiana	\$23,954	\$35,660	\$42,251	\$61,296
South Texas	\$24,446	\$31,663	\$40,139	\$61,695
West Texas	\$18,317	\$21,976	\$31,745	\$48,760
Rocky Mountains	\$20,890	\$23,462	\$31,919	\$43,153
Secondary Production				
California				
Oklahoma				
South Louisiana				
South Texas				
West Texas	\$39,155	\$52,911	\$74,118	
Rocky Mountains				

Source: DOE/EIA *Costs and Indices for Domestic Oil and Gas Field Equipment and Production Operations 1987 through 2005*, converted to 2006 dollars.

Estimated Increases in Well Drilling Costs

The second impact of GHG regulation modeled in the HSM is the effect of allowance costs for the fuel used to drill new wells. The estimated impact on the cost of new wells is summarized in Exhibit 3-7 which shows the estimated impact of the Lieberman/Warner bill. The first three rows in the table show the amount of fuel estimated to be used to drill new wells. The first four columns of the table represent four drilling depth intervals for onshore areas (0 to 5,000 feet, 5,000 to 10,000 feet, etc.). More fuel is used for deeper wells because larger rigs are employed and because the number of days needed to drill a well goes up exponentially with depth. The last two columns represent shallow water and deep water offshore drilling. The deep water fuel consumption is high because dynamically-positioned, floating drilling vessels are typically used.

For each case shown in Exhibit 3-7 the added cost to drill a well is the tonnes of CO₂ accounted for by fuel use (for rig and support vehicles, vessels and equipment) times the assumed allowance cost for a given legislative case and year. For example, an onshore well drilled to 5,000 to 10,000 feet would use about 13,543 gallons of fuel, the combustion of which would result in approximately 138 metric tonnes of CO₂.

- The Lieberman/Warner case in 2012 is estimated to have an allowance value of about \$41.21 per metric tonne of CO₂ equivalent and would likely lead to an additional cost of about \$5,666 to drill such as a well. The Base Case cost for such a well in 2012 is estimated to be about \$845,000 so this additional cost represents a 0.6 percent increase. By 2030 the cost impact would be about 1.4 percent of Base Case costs.

Exhibit 3-7: Lieberman/Warner Estimated Impact on New Well Costs

	0 to 5,000 ft Onshore Wells	5,000 to 10,000 ft Onshore Wells	10,000 to 15,000 ft Onshore Wells	>15,000 ft Onshore Wells	Offshore Shallow Water	Offshore Deep Water
Gallons of diesel fuel per well						
Rig Mobilization and Support	493	2,709	14,158	43,089	32,994	78,792
Drilling Operations	1,970	10,834	56,632	172,357	131,977	315,168
Total Fuel Gallons	2,463	13,543	70,790	215,446	164,971	393,960
Metric Tons CO2 per Well	25	138	719	2,187	1,675	4,000
Added Cost per Well 2012	\$1,030	\$5,666	\$29,619	\$90,144	\$69,025	\$164,836
Added Cost per Well 2020	\$1,433	\$7,880	\$41,190	\$125,358	\$95,989	\$229,228
Added Cost per Well 2030	\$2,121	\$11,663	\$60,967	\$185,551	\$142,080	\$339,294
Illustrative Base Case Estimated Costs (2006\$/well before added cost)						
2012	241,000	845,000	2,232,000	5,192,000	8,794,000	24,624,000
2020	240,000	844,000	2,246,000	5,256,000	9,071,000	25,399,000
2030	244,000	857,000	2,302,000	5,450,000	9,698,000	27,155,000

Estimated Increases in Gas Processing Costs

Gas processing costs likely would go up as gas processors would have to buy and retire allowances to cover the emissions of methane and carbon dioxide from their operations and higher costs for purchased electricity. These added costs are shown in Exhibit 3-8, the estimated Lieberman/Warner impact on dollar per Mcf of marketed gas basis. (Note that the table relates only to the gas processing operation itself and does not reflect the allowances that would have to be retired for the dry natural gas and natural gas liquids sold as fuel.) These extra costs are reflected in the HSM for the estimated impact cases as additions to the model's Base Case gas processing costs.

Exhibit 3-8: Lieberman/Warner Estimated Impact on Gas Processing Costs

	2012	2020	2030
Average \$/Mcf Cost Increase	\$0.13	\$0.18	\$0.27

RESULTS OF IMPACT CASE FOR NEW WELLS

The estimated higher well operating costs, well drilling costs and gas processing costs described above for the Lieberman/Warner case were input into the HSM to estimate their impact on drilling activity and production from new wells. For this run, no mitigation measures by producers to reduce GHG emissions beyond those in the Base Case were assumed. The estimated GHG-related costs were added for wells drilled starting in 2012 and were escalated based on the assumed trajectory of allowance values for each legislative case. Other assumptions for the HSM such as resource base, land access, technology, drilling costs (other than for fuel-related GHG allowance costs), equipment costs, wellhead prices for oil and gas and financial parameters were unchanged from the Base Case.

The resulting estimated impacts for the Lieberman/Warner are shown in summary form in Exhibit 3-9. The left-hand part of the table summarizes results for the nine-year period, 2012 to 2020, while the right-hand side shows results for the ten years of 2021 to 2030. Values are shown in terms of declines in the number of new wells drilled and oil and gas production over those two periods. Also shown are the percentage declines in values relative to the Base Case.

- For the Lieberman/Warner case in the early period gas wells drilled are estimated to decline by about 21.8 percent while gas production from new wells are estimated to fall 4.5 percent relative to the Base Case. In the period of 2021 to 2030 the estimated cost impacts are likely to increase along with the assumed GHG allowance values and the decline in new gas wells drilled is about 41 percent and the decline in gas production is about 10.9 percent.

The percent reduction in the number of wells drilled is likely to be greater than the percentage loss of production because it is the low-productivity wells that are more likely to be rendered uneconomic due to the higher costs.

- Even so, over the entire nineteen years from 2012 to 2030 U.S. gas production would likely be approximately 30.9 trillion cubic feet lower in the Lieberman/Warner case.²⁴

Exhibit 3-9: Lieberman/Warner Estimated Impact on New Well Drilling and Production

	2012-2020		2021-2030	
	Delta	% Delta	Delta	% Delta
Oil Wells Drilled	-1,910	-1.9%	-4,525	-4.3%
Gas Wells Drilled	-32,430	-21.8%	-66,810	-41.0%
All Wells Drilled	-41,594	-13.1%	-84,213	-23.0%
Oil Production MMB	-96	-0.6%	-126	-0.8%
Gas Production Bcf	-8,531	-4.5%	-22,324	-10.9%

Note: Values are summed over 9- and 10-year periods. "All wells" include dry holes in addition to oil and gas wells.

The percentage decline expected in oil well drilling and oil production from new wells is likely to be lower than for natural gas because the per-well operating cost increases are substantially lower.

²⁴ Such a large loss in natural gas production would tend to raise natural gas prices and stimulate some additional U.S. drilling (as well as encourage greater imports of LNG). Since our cases were constructed assuming that the AEO 2006 natural gas and oil prices prevail in both the Base Case and impact cases, this feedback effect that would somewhat moderate the production loss is not included.

- Under the Lieberman/Warner case assumptions, oil well drilling will likely decline about 1.9 percent versus the Base Case and production will likely fall by 0.6 percent from 2012 through 2020. For the 2021 to 2030 period oil well drilling will likely be about 4.3 percent lower than the base case and production will be about 0.8 percent lower.

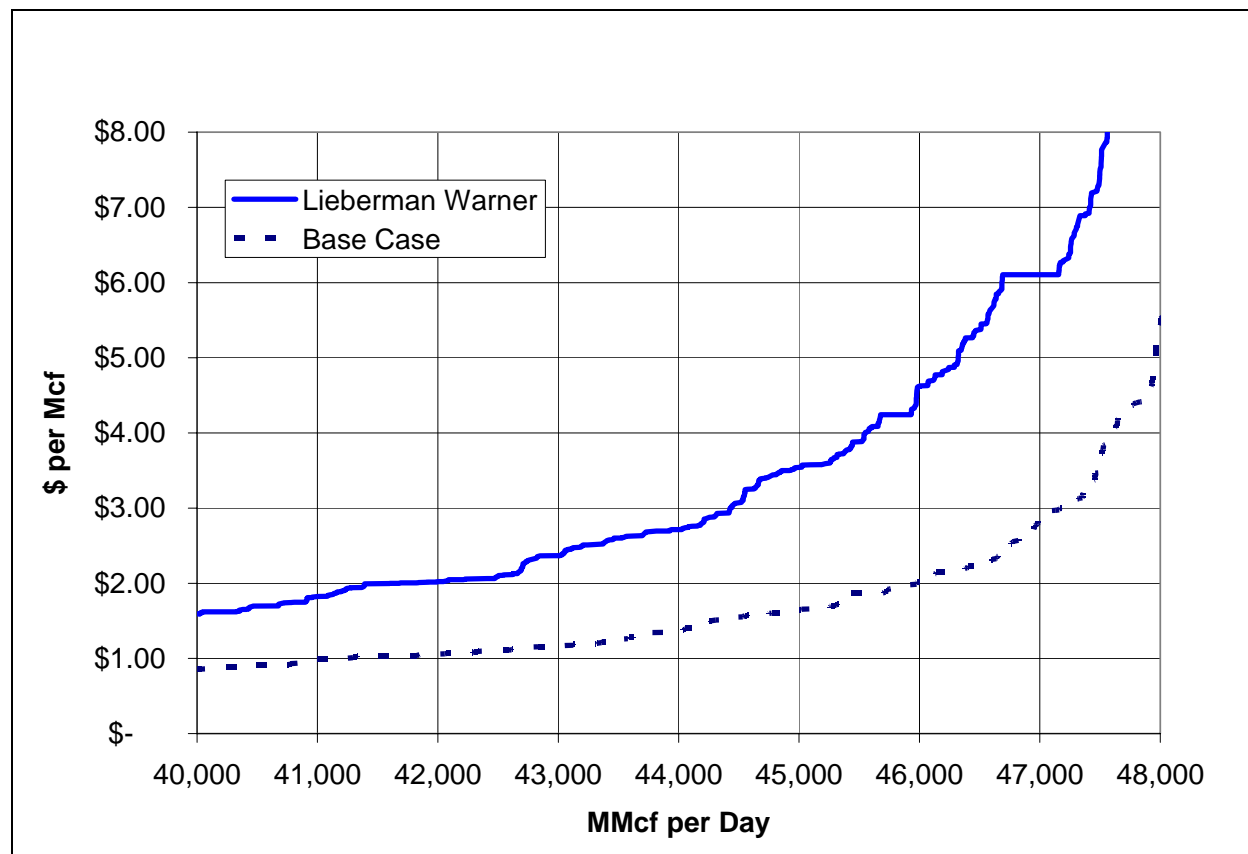
RESULTS OF IMPACT CASE FOR EXISTING WELLS

The estimated operating cost increases discussed above also would apply to existing wells at the time the GHG regulation begins. Those higher operating costs could lead to premature shutdown of existing wells with a loss of production and reserves. The ICF Oil Well Operating Cost Model and the ICF Gas Well Operating Cost Model were run for wells expected to be in existence at the beginning of 2012 to investigate this possibility. One case was run with Base Case operating costs alone and another was run for each of the scenarios adding the 2012 operating costs and gas processing cost factors.

The results for gas wells under the Lieberman/Warner case are shown in Exhibit 3-10.

- At the wellhead prices expected to be prevailing in 2012 in the 2006 AEO, about 2.23 bcf per day of production (or 4.6 percent) could be in danger of being prematurely abandoned. This loss would take place soon after the regulations began and would be in addition to the loss discussed above related to fewer new gas wells being drilled. The expected cumulative production that would have otherwise come from the prematurely abandoned wells from 2012 through 2030 would be roughly 4.0 Tcf.

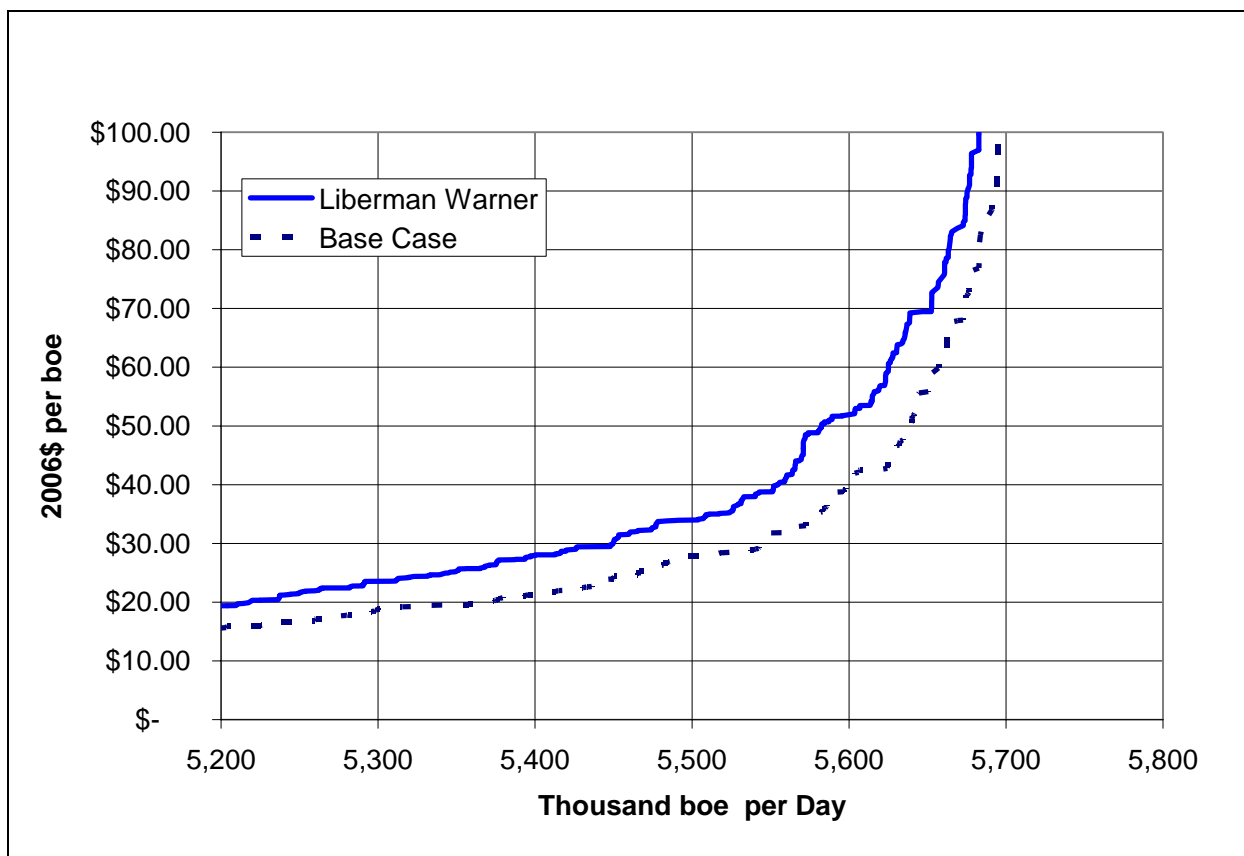
Exhibit 3-10: Lieberman/Warner Estimated Impact on Existing L-48 Gas Wells



The results for existing oil wells are shown in Exhibit 3-11 for the Lieberman/Warner legislative scenario without mitigation. Volumes are in barrels of oil equivalent and include crude oil and associated/dissolved gas.

- At the wellhead oil prices estimated to be prevailing in 2012 in the AEO06, about 58,000 barrels-equivalent per day of crude oil and associated-dissolved gas production (or one percent) could be in danger of being prematurely abandoned. This loss would likely take place soon after the regulations began and would be in addition to the production losses discussed above related to fewer new oil wells being drilled. The estimated cumulative production that would have otherwise come from the prematurely abandoned oil wells from 2012 through 2030 would be roughly 104 million BOE.

Exhibit 3-11: Lieberman/Warner Estimated Impact on Existing L-48 Oil Wells



IMPACT ON POSSIBLE CARBON CAPTURE, GEOSEQUESTRATION AND CO₂ EOR

One of the possible impacts of GHG regulation might be to encourage permanent underground storage (geosequestration) of CO₂. Some of this geosequestration could be done as part of enhanced oil recovery (EOR) efforts.

Current EOR production in the U.S. is approximately 650,000 barrels per day.²⁵ This represents 14 percent of total U.S. production of 4.74 million barrels per day and 17 percent of Lower-48 oil

²⁵ *Oil & Gas Journal*, April 17, 2006.

production of 3.89 million barrels per day. Chapter 4 of Volume I of the main report contains a detailed examination of EOR, carbon capture and geosequestration in the United States.

To illustrate the potential importance of geosequestration, ICF has created a scenario for CCS and EOR that is roughly consistent with the AEO oil price forecast, DOE’s CO₂ EOR potential shown in Chapter 4 of the main report, and with the level of GHG allowance values assumed for the Lieberman/Warner case. The total amount of CCS assumed to take place by year and the portion of that going into EOR under Lieberman/Warner is presented in Exhibit 3-12. The resulting annual production of incremental crude oil is shown in Exhibit 3-13. This scenario assumes that under a GHG regulator regime the traditional EOR practices will be changed as more CO₂ will be injected (and permanently stored). While the DOE resource estimate is based on approximately 4.3 Mcf of purchased CO₂ per incremental barrel (0.14 metric tons CO₂ per barrel of crude) the scenario shown here assumes 10.6 Mcf of purchased CO₂ per incremental barrel of crude oil (0.34 tonnes CO₂ per barrel of crude).²⁶

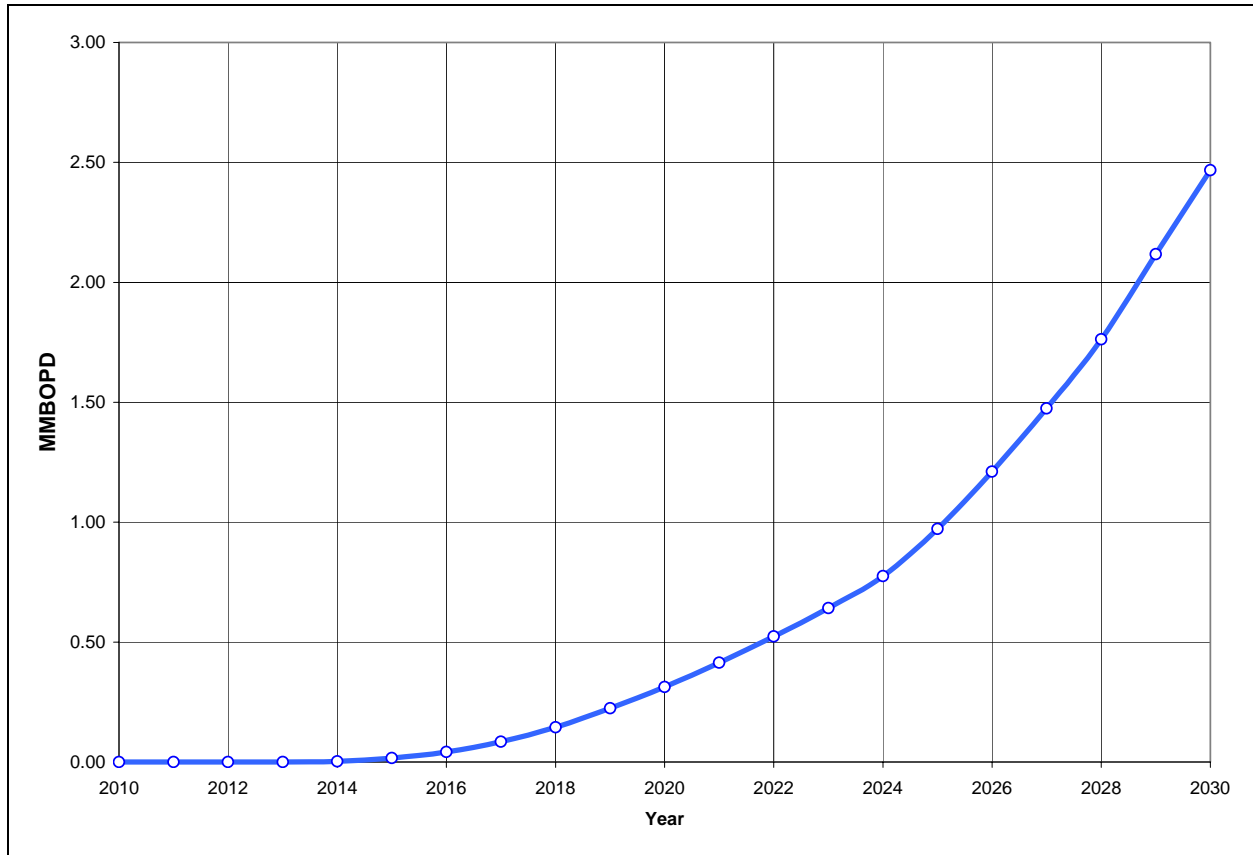
Of the 77 billion barrels of lower-48 EOR potential estimated by DOE, this scenario by 2030 develops EOR project that over their lives would produce an incremental 25 billion barrels. Production in 2030 reaches 2.47 million barrels of crude per day and cumulative incremental production through 2030 is 4.8 billion barrels.

Exhibit 3-12: Possible CCS and EOR Scenario for the Lieberman/Warner Case

Year	Annual CCS Plants Built	Cumulative MW Sequestered	Million Metric tons CCS per Year	Fraction going to EOR	Million Metric tons CO ₂ to EOR per Year	Million bbl CO ₂ to EOR per Year	New Project million bbl oil EOR (over 33 years)	Cumulative EOR mmb Projects
2010	0.00	-	0	50.0%	0	-		
2011	0.00	-	0	50.0%	0	-		
2012	1.16	582	3	50.0%	2	12	161	161
2013	1.16	1,164	7	50.0%	3	24	161	321
2014	2.33	2,327	13	49.0%	6	48	308	630
2015	2.56	3,607	20	49.0%	10	74	346	976
2016	3.84	5,527	31	48.0%	15	111	490	1,466
2017	4.19	7,622	43	47.1%	20	150	515	1,981
2018	5.59	10,415	59	46.1%	27	201	672	2,653
2019	6.05	13,440	76	45.2%	34	254	702	3,355
2020	7.56	17,222	97	44.3%	43	319	858	4,213
2021	7.56	21,004	119	43.4%	52	381	822	5,035
2022	16.29	29,149	165	42.5%	70	519	1,813	6,848
2023	16.29	37,295	211	41.7%	88	650	1,738	8,586
2024	17.45	46,022	260	40.9%	106	787	1,797	10,383
2025	17.45	54,750	310	40.0%	124	917	1,722	12,105
2026	27.93	68,714	388	39.2%	152	1,128	2,784	14,889
2027	27.93	82,678	467	38.5%	180	1,330	2,667	17,556
2028	27.93	96,641	546	37.7%	206	1,524	2,555	20,111
2029	29.26	111,270	629	36.9%	232	1,719	2,581	22,692
2030	29.26	125,899	712	36.2%	258	1,906	2,470	25,162

²⁶ Since some of the CO₂ is produced with the oil and then recompressed and re-injected back into the reservoir, the volume of “injected” CO₂ is about three times the amount “purchased.”

Exhibit 3-13: Possible CO₂ EOR Production Scenario for the Lieberman/Warner Case



As discussed in more detail in the main report, there are obstacles to achieving this level of CO₂ enhanced oil recovery. Briefly, some of the key issues include:

- An uncertain regulatory environment in the United States for GHG emission limits and the resulting allowance values;
- A high level of uncertainty regarding integration of power generation with capture technology;
- Technology, environmental and economic uncertainties on integrating power generation with capture and long-term storage on the required scale;
- Lack of State and Federal regulatory regimes needed for permitting, building, operating, monitoring, and closing geosequestration sites;
- Lack of a liability regime for CCS project operation and long-term responsibility for closed sites;
- Lack of a legal framework for ownership of underground pore space needed for CCS projects; and
- Potential public opposition to large scale infrastructure needed for CCS pipelines and storage sites.

RESULTS OF THE MODELING OF THE DOWNSTREAM SECTOR

The downstream sector modeling looks at the years 2012 and 2020. The carbon cases are run off the Base cases discussed in Chapter 2. The modeling captured the impacts of the bill in WORLD® by applying incremental costs in two areas of the model. Restrictions on CO₂e emissions are represented as impacts in WORLD® by applying estimated emission costs to refinery fuels and to the production and transportation of all refined products with the exception of petrochemical feedstocks.

The assumed allowance costs for refiners' CO₂ emissions from fuel consumption, hydrogen plant CO₂ yield and other sources were applied as costs directly on related model activities. The methodology for capturing allowance costs on finished products was to attach these costs to transport costs for those products from the source regions. The estimated costs apply both for products produced in and those imported into the United States. Thus, since they apply to all source regions, they represent a "level playing field".²⁷

The same is not true for regions such as the United States that – in addition - have allowance costs on their own refinery CO₂ emissions. Source regions that do not have their own CO₂ fuel emissions regulations would, of course, not be subject to the incremental costs on CO₂ from refinery fuel. CO₂ emissions costs were applied to the refining systems in the EU and Canada to represent both the EU's Emissions Trading (EU-ETs) system now in existence and the GHG emission control legislation that Canada is now considering. This was discussed in Chapter 4 of Volume I of the original report.

The estimated CO₂e allowance costs (shown in Exhibit 1-2 and at the beginning of this chapter) were added to the refinery U.S. CO₂ emissions, namely to the emissions from:

- The Hydrogen (H₂) plant
- Refinery fuel
- FCC coke, and
- Sulfur plant tail gas, and
- Flare loss

These same CO₂e costs, based on CO₂ content, were added to all finished products production/movements from all refineries (domestic and foreign) into the various U.S. demand regions (petrochemical feedstocks were exempt).

Within the United States itself both natural gas and electric power prices were adjusted to reflect the allowance impact on these two sectors.

IMPACTS OF THE LIEBERMAN/WARNER PROPOSED BILL

Exhibit 3-14 shows the global results for 2012 and 2020 from the Lieberman/Warner runs. Exhibit 3-15 shows global capacity additions and investments for 2012 and 2020. These exhibits compare the carbon case outcome to those of the corresponding Base Cases. On a global scale, estimated refining investments rise by about \$28 billion to \$45 billion, refinery utilizations drop slightly, and

²⁷ The main impact of the application of carbon allowance costs to finished products likely would be to raise their total supply costs and reduce demand through price elasticity effects. As explained later, such effects were not adjusted for. Separately, while imposition of carbon allowance costs would be expected to raise equipment capital costs for refiners, cost escalation factors were not adjusted in the WORLD® carbon case runs.

capacity additions show increases in hydro-cracking, catalytic reforming and particularly sulfur recovery as clean fuels production increases in regions outside the United States to compensate for reductions in output from U.S. refineries. There is also a slight increase in hydrogen plant as the global system rebalances to the existence of carbon costs on U.S. refinery CO₂ emissions. As discussed further below, the global view masks the regional impacts which are greater than might be gleaned from looking at the global results alone.

Exhibit 3-16 shows the model results for changes in product manufacturing supply costs between the 2012 and 2020 Base and the Lieberman/Warner cases for the U.S. East Coast, Gulf Coast and West Coast. Largely reflecting the imposition of the carbon allowance costs, the estimated manufacturing costs rise by about 27 to just over 40 percent in 2012 and by about 36 to almost 60 percent in 2020²⁸. The large rise in cost over the Base Case for 2020 as compared to 2012 is because the carbon allowance cost increases substantially over the period.

However, one caveat to the results is that in these runs, although most estimated production costs increased significantly, product demands were not adjusted down. Adjusting demand would have required not only an adjustment based on price and income elasticities but also adjustments to projections of likely requirements for mandated biofuels and estimates of the penetration levels of hybrid and electric cars, as well as a wide range of macroeconomic considerations beyond the scope of this study.

²⁸ The estimated dollar per barrel costs for the heavy transport products rise the most percentage wise, and vice versa. This is because the carbon allowance costs are expressed as dollars per tonne of CO₂e and heavy products, such as marine IFO bunker fuel, contain more mass and thus more carbon per barrel.

Exhibit 3-14: Estimated Global Results of the Lieberman/Warner Case for 2012 and 2020

WORLD Model Results						
Case	G14	L14	L14-B14	G22	L22	L22-B22
Year	2012	2012	2012	2020	2020	2020
Type	Base	CO2		Base	CO2	
Pass	3rd	Lieberman / Warner		3rd	Lieberman / Warner	
SUPPLY						
SUPPLY - CRUDES (INCLUDES SYNCRUDES & CONDENSATES)	MMBPD	MMBPD		MMBPD	MMBPD	
Crude gross production	79.840	79.489	-0.35	87.650	87.223	(0.43)
of which						
Crude Direct Use	0.554	0.554	0.00	0.459	0.459	0.00
Crude Direct Loss Total	0.270	0.270	0.00	0.141	0.141	0.00
Crude net to refs before TRLOS	79.016	78.665	-0.35	87.050	86.622	(0.43)
SUPPLY - NON CRUDES						
NGL ETHANE	1.556	1.556	0.00	1.762	1.762	0.00
NGLs C3+	5.642	5.642	0.00	6.446	6.446	0.00
PETCHEM RETURNS	0.710	0.710	0.00	0.797	0.797	0.00
BIOMASS	1.527	1.527	0.00	1.867	1.867	0.00
METHANOL (EX NGS)	0.110	0.105	0.00	0.112	0.105	(0.01)
GTL LIQUIDS (EX NGS)	0.535	0.535	0.00	1.008	1.008	0.00
CTL LIQUIDS (EX COAL)	0.488	0.488	0.00	0.891	0.891	0.00
HYDROGEN (EX NGS)	0.768	0.796	0.03	1.003	1.072	0.07
TOTAL	11.335	11.359	0.02	13.886	13.948	0.06
PROCESS GAIN & LOSSES						
REFINERY PROCESS GAIN	2.655	2.433	-0.22	2.889	2.648	(0.24)
DEMAND						
EXTERNAL DEMANDS - FINISHED PRODUCTS NON SOLIDS						
ETHANE	1.556	1.556	0.00	1.762	1.762	0.00
LPG	7.877	7.877	0.00	8.564	8.564	0.00
NAPHTHA	5.927	5.927	0.00	7.077	7.077	0.00
GASOLINE	23.584	23.584	0.00	25.502	25.502	0.00
JET/KERO	7.557	7.557	0.00	8.308	8.308	0.00
DISTILLATE (NON BUNKERS)	25.323	25.323	0.00	29.127	29.127	0.00
DISTILLATE (BUNKERS)	1.961	1.961	0.00	2.268	2.268	0.00
DISTILLATE (TOTAL)	27.284	27.284	0.00	31.395	31.395	0.00
RESIDUAL (NON BUNKERS)	5.361	5.361	0.00	4.890	4.890	0.00
RESIDUAL (IFO BUNKERS)	5.168	5.168	0.00	6.402	6.402	0.00
RESIDUAL FUEL (TOTAL)	10.529	10.529	0.00	11.292	11.292	0.00
OTHER PRODUCTS (excl coke,sulphur)	3.848	3.848	0.00	4.470	4.470	0.00
CRUDE DIRECT USE	0.554	0.554	0.00	0.459	0.459	0.00
TOTAL	88.716	88.716	0.00	98.829	98.829	0.00
EXTERNAL DEMANDS - FINISHED PRODUCTS SOLIDS						
PETR COKE TOTAL MMBPD	1.028	0.776	(0.25)	1.173	0.854	(0.32)
ELEMENTAL SULPHUR MMBPD	0.188	0.190	0.00	0.226	0.225	(0.00)
TOTAL	1.216	0.966	(0.25)	1.399	1.079	(0.32)
INTERNAL DEMANDS/CONSUMPTION						
REFINERY FUEL - CRUDE BASED STREAMS						
PROCESS GAS	2.220	2.092	(0.13)	2.254	2.161	(0.09)
FCC CATALYST COKE	0.538	0.551	0.01	0.581	0.609	0.03
MINOR STREAMS	0.001	0.001	(0.00)	0.000	0.001	0.00
RESIDUAL FUEL	1.288	1.288	0.00	1.679	1.679	0.00
TOTAL CRUDE BASED STREAMS	4.046	3.931	(0.11)	4.513	4.450	(0.06)
NATURAL GAS TO RFO	1.877	1.925	0.05	2.098	2.109	0.01
TOTAL INCL NATURAL GAS	5.923	5.856	(0.07)	6.611	6.559	(0.05)
RFO INCL NGS AS PCT OF CRUDE TO REFS	7.5%	7.5%	0.00	7.6%	7.6%	(0.00)
OTHER LOSSES	0.162	0.162		0.085	0.085	0.00
TOTAL INTERNAL CONS & LOSS EXCL NAT GAS	4.214	4.098		4.604	4.542	(0.06)
TRANSPORT LOSS TOTAL	0.240	0.241		0.274	0.275	0.00

**Exhibit 3-15: Estimated Global Capacity Additions and Investments for the
Lieberman/Warner Case in 2012 and 2020
Billions 2006\$**

WORLD Model Results						
Case	G14	L14	L14-B14	G22	L22	L22-B22
Year	2012	2012	2012	2020	2020	2020
Type	Base	CO2		Base	CO2	
Pass	3rd	Lieberman / Warner		3rd	Lieberman / Warner	
Bunkers Demand Basis						
CAPACITY ADDITIONS & INVESTMENTS						
	cap+constr	cap+constr		cap+constr	cap+constr	
REVAMP	\$ 7.3	\$ 7.1	\$ (0.3)	\$ 7.6	\$ 8.0	\$ 0.4
DEBOTTLENECKING	\$ 1.0	\$ 1.0	\$ (0.0)	\$ 2.4	\$ 2.0	\$ (0.4)
MAJOR NEW UNITS	\$ 123.8	\$ 152.1	\$ 28.3	\$ 203.7	\$ 248.3	\$ 44.6
TOTAL REFINING	\$ 132.1	\$ 160.1	\$ 28.0	\$ 213.6	\$ 258.2	\$ 44.6
MERCHANT						
MAJOR NEW UNITS						
TOTAL REFINING + MERCHANT	\$ 132.1	\$ 160.1	\$ 28.0	\$ 213.6	\$ 258.2	\$ 44.6
Percent Increase versus Base						
CRUDE DISTILLATION BASE CAPACITY & ADDITIONS						
BASE CAPACITY	85.18	85.18	0.00	85.18	85.18	0.00
FIRM CONSTRUCTION	3.45	3.45	0.00	3.71	3.71	0.00
DEBOTTLENECKING ADDITIONS	0.89	0.68	(0.21)	2.30	1.50	(0.81)
MAJOR NEW UNIT ADDITIONS	3.47	4.32	0.85	9.72	11.91	2.19
TOTAL ADDITIONS OVER BASE	7.82	8.46	0.64	15.74	17.12	1.38
TOTAL BASE + ADDITIONS	93.00	93.64	0.64	100.91	102.30	1.38
REFINERY UTILIZATION	84.8%	83.8%	(0.01)	86.1%	84.5%	(0.02)
TOTAL CRUDE CAP USED	78.84	78.49	(0.35)	86.85	86.43	(0.43)
SECONDARY PROCESSING ADDITIONS						
VACUUM DISTILLATION	2.16	3.09	0.93	4.17	6.59	2.42
COKING	0.09	0.25	0.15	0.16	0.82	0.66
VISBREAKING	0.08	0.20	0.12	0.20	0.32	0.12
CATALYTIC CRACKING	0.19	0.25	0.06	0.44	0.52	0.07
HYDRO-CRACKING (TOTAL)	1.65	2.88	1.23	3.87	6.00	2.13
- Gasoil Mild/FCC Feed	0.04	0.00	(0.04)	0.00	0.00	0.00
- Gasoil Conventional	0.04	0.02	(0.02)	0.11	0.04	(0.08)
- Gasoil ULS	0.98	1.31	0.32	2.22	3.21	1.00
- Resid LS	0.32	0.80	0.48	0.87	1.40	0.53
- Resid MS	0.25	0.75	0.50	0.67	1.35	0.68
- Resid HS	0.00	0.00	0.00	0.00	0.00	0.00
CATALYTIC REFORMING - New	1.34	1.39	0.05	1.89	2.22	0.33
CATALYTIC REFORMING - Revamp	0.72	0.60	(0.12)	0.56	0.80	0.24
DESULPHURIZATION (TOTAL)	11.28	11.49	0.20	15.37	14.98	(0.40)
- GASOLINE - ULS	2.69	2.78	0.09	3.85	3.74	(0.11)
- DISTILLATE ULS - NEW	2.40	2.28	(0.12)	4.39	4.20	(0.20)
- DISTILLATE ULS - REVAMP	5.56	5.61	0.05	5.67	5.42	(0.26)
- DISTILLATE CONV/LS	0.41	0.33	(0.08)	0.82	0.84	0.02
- VGO/RESID	0.22	0.48	0.26	0.64	0.78	0.15
HYDROGEN (MMBFOED)	0.52	0.56	0.05	0.84	0.95	0.11
SULPHUR PLANT (TPD)	8240	8740	500.00	17100	24420	7320.00

**Exhibit 3-16: Summary of the Estimated Cost Impacts of the Lieberman/Warner
Proposal for 2012 and 2020 in Three U.S. Region**

WORLD Model Results						
Case	G14	L14	L14-B14	G22	L22	L22-B22
Year	2012	2012	2012	2020	2020	2020
Type	Base	CO2		Base	CO2	
Pass	3rd	Lieberman / Warner		3rd	Lieberman / Warner	
COSTS AND DIFFERENTIALS						
CRUDE COSTS (FOB)						
			% change			% change
SAUDI LIGHT (input marker crude price)			0.0%			0.0%
WEST TEXAS INTERMEDIATE			0.7%			-0.3%
BRENT			0.3%			-0.4%
DUBAI			-0.4%			-0.4%
SAUDI HEAVY			-1.5%			-0.7%
MAYAN			-3.3%			-2.2%
PRODUCT COSTS TO THE CONSUMER						
			% change			% change
USEC						
LPG			7.5%			5.7%
PETCHEM NAPHTHA			2.2%			1.2%
CG - ULS PREMIUM			27.6%			36.0%
CG - ULS REGULAR			28.8%			36.9%
RFG - PREMIUM (0/5.7/10% ETOH)			27.6%			37.0%
RFG - REGULAR (0/5.7/10% ETOH)			29.7%			38.7%
KERO/JET JTA/A1			29.9%			38.2%
DSL NO2 ULSD (50 - 10 PPM)			29.6%			38.2%
NO2 HEATING OIL (US)			32.7%			42.5%
RESID .3-1.0%			40.1%			54.7%
MGO DMA			33.9%			48.2%
MDO HS DMC			35.5%			52.1%
MDO LS DMB			33.9%			47.1%
IFO380 LS			40.3%			55.3%
IFO380 HS			39.7%			60.4%
USGC						
LPG			8.8%			6.8%
PETCHEM NAPHTHA			3.0%			1.8%
CG - ULS PREMIUM			27.4%			36.4%
CG - ULS REGULAR			29.3%			38.0%
RFG - PREMIUM (0/5.7/10% ETOH)			28.2%			37.8%
RFG - REGULAR (0/5.7/10% ETOH)			30.4%			39.6%
KERO/JET JTA/A1			30.5%			39.5%
DSL NO2 ULSD (50 - 10 PPM)			30.3%			39.4%
RESID .3-1.0%			43.3%			55.6%
MGO NO2			0.0%			0.0%
MDO HS DMC			31.7%			43.8%
MDO LS DMB			32.5%			46.0%
IFO380 LS			31.7%			42.5%
IFO380 HS			42.1%			56.6%
			41.2%			60.8%
USWC						
LPG			4.6%			4.8%
PETCHEM NAPHTHA			2.0%			3.2%
CG - ULS PREMIUM			26.3%			35.0%
CG - ULS REGULAR			27.5%			35.8%
CARB RFG PREMIUM (0/5.7% ETOH)			26.3%			36.0%
CARB RFG REGULAR (0/5.7% ETOH)			27.6%			36.4%
KERO/JET JTA/A1			28.7%			37.6%
DSL NO2 ULSD (50 - 10 PPM)			29.4%			39.1%
DSL NO2 RFD / CARB			29.5%			39.2%
RESID .3-1.0%			41.0%			53.8%
MGO NO2			0.0%			0.0%
MDO HS DMC			32.1%			44.6%
MDO LS DMB			35.1%			51.9%
IFO380 LS			32.6%			48.3%
IFO380 HS			41.4%			56.8%
			44.3%			59.5%

U.S. Refining Sector – Estimated Output Impacts under Lieberman/Warner

Keeping in mind that these cases are run without an assessment of mitigation options because of lack of needed data, the main impact on the U.S. refining sector stems from the effect of the allowance costs on the refineries themselves. Exhibit 3-16 showed the estimated impact of the regulations on refining products.

The impacts on the U.S. refining sector are estimated as a combination of reduced investments, throughputs, and utilizations vis-à-vis the Base Case. Exhibit 3-17 and Exhibit 3-18 show the estimated changes in these three parameters at the global, national, and PADD levels for 2012 and 2020. The main driver of these effects is the existence of the costs on CO₂ emissions from U.S. located refining that are not imposed on most overseas refineries. Higher U.S. refining costs are projected to result in reduced domestic refinery output and increased imports of, and reliance on, refined products. Consistent with the estimated shift overseas of U.S. refinery investments, activity and (potentially) jobs, CO₂ emissions are also likely effectively relocated overseas, as further discussed below.

Exhibit 3-19 compares the changes in throughputs and utilization to the Base Case on the U.S. national level. By 2020 there is estimated to be a 2.92 MMB/d decline in throughputs compared to the Base Case and a decline in overall U.S. refinery utilization of about 9.6 percent. There is estimated to be an almost mirror image reverse effect in the rest of the world with throughputs increasing 2.49 MMB/d by 2020 although utilization decreases by about 0.4 percent.

Exhibit 3-17: 2012 Estimated Investments, Throughputs and Utilization by PADD Level under the Lieberman/Warner Bill

	Total	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5	USA TOTAL	Rest of World
TOTAL INVESTMENTS	160.14	2.60	9.90	10.44	3.20	6.74	32.88	127.26
TOTAL THROUGHPUT 2012	78.49	1.31	3.87	7.21	0.59	2.81	15.79	62.70
Utilizations	83.8%	82.6%	93.0%	81.3%	92.3%	86.2%	85.3%	83.5%

Note: Investments are in Billions of 2006\$. Throughputs are in MMB/d

Exhibit 3-18: 2020 Estimated Investments, Throughputs and Utilization by PADD Level under the Lieberman/Warner Bill

	Total	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5	USA TOTAL	Rest of World
TOTAL INVESTMENTS	258.22	2.71	8.88	9.17	2.59	12.42	35.77	222.45
TOTAL THROUGHPUT 2020	86.43	1.35	3.99	6.67	0.57	2.96	15.54	70.89
Utilizations	84.5%	84.8%	93.0%	75.8%	89.9%	87.2%	83.1%	84.8%

Note: Investments are in Billions of 2006\$. Throughputs are in MMB/d

Exhibit 3-19: U.S. Estimated Throughputs and Utilization under the Lieberman/Warner Bill as Opposed to the Base Case

	Base Case 2012	Lieberman/Warner 2012	Base Case 2020	Lieberman/Warner 2020
Throughput MMB/d	17.02	15.79	18.46	15.54
Utilization Percentage	91.0%	85.3%	92.7%	83.1%

Exhibit 3-20 shows changes in throughput and utilization as compared to the Base Cases at the PADD level. As can be seen, the likely major impacts are among the refineries in PADDs 1, 3, and 5, the coastal regions.

- WORLD® results show that within the PADDs among the refinery groups those most affected are small refineries and those categorized as heavy crude/sour crude deep conversion refineries. Data on the refinery groups within PADDs can be found in Appendix C of Volume II of the original report and in Appendix A of this report.

Exhibit 3-20: Estimated Changes in PADD Level Throughputs and Utilization under the Lieberman/Warner Bill as Opposed to the Base Case

Region	Throughputs (MMb/d)				Utilization (Percentage)			
	Base 2012	L/W 2012	Base 2020	L/W 2020	Base 2012	L/W 2012	Base 2020	L/W 2020
PADD 1	1.43	1.31	1.70	1.35	88.7	82.6	96.0	84.8
PADD 2	3.87	3.87	4.15	3.99	93.0	93.0	93.0	93.0
PADD 3	8.16	7.21	8.81	6.67	90.8	81.3	92.3	75.8
PADD 4	0.60	0.59	0.59	0.57	93.1	92.3	93.1	89.9
PADD 5	2.95	2.81	3.20	2.96	89.9	86.2	91.5	87.2

With the estimated reductions in throughputs, investments, and utilization come associated estimated impacts on U.S. refining.

- Because of the higher estimated cost of natural gas, purchased power, and allowance costs associated with refinery fuel and hydrogen, throughput cuts are likely focused on units that are energy or hydrogen intensive, particularly hydrocracking (HCR), hydrodesulfurization (HDS) and the hydrogen plant itself.
- Consequently, U.S. refinery CO₂ emissions are projected to decline, but on the global stage these are likely largely offset by increases elsewhere.

Exhibit 3-21 shows the estimated impact of the Lieberman/Warner proposal on refinery investments. Note that these investments shown in the exhibit are for first time new plant (capacity expansions) and do not include ongoing replacement which will also likely decline. The same pattern appears in this exhibit as in the throughput exhibit. Investments are estimated to decline in the United States but they are estimated to increase in the rest of the world²⁹, essentially offsetting the U.S. decline. The refining industry outside of the United States, and outside of those areas that ICF has assumed have GHG emission controls, will be faced with growing demand from the emerging market countries and with demand in the United States that U.S. refineries will be unable to meet, and thus will likely invest in new plants and capacity.

Exhibit 3-22 compares investment levels at the PADD levels. With a couple of exceptions for 2012 (as PADDs 1 and 5 adjust configurations), investments likely drop broadly across U.S. refining regions versus the corresponding Base Cases. The region most severely affected is likely PADD 3, with investment reductions versus the Base Case of about 24 percent in 2012 and about 51 percent in 2020. This in part stems from the concentration in PADD 3 of high complexity, deep conversion refineries that have associated high processing fuel and hydrogen intensities. The geographical isolation of the PADD 5 high complexity refineries would appear to provide them with a measure of protection.

²⁹ Note that in the WORLD® cases as run, regional and global product demands were not changed under the carbon regimes: therefore declines in output from U.S. refineries need to be offset by increases from refineries in other regions.

Exhibit 3-21: Estimated Capacity Expansion Refining Investment under the Lieberman/Warner bill compared to the Base Case – Billions of \$2006

	Base Case 2012	Lieberman/Warner – 2012	Base Case 2020	Lieberman/Warner 2020
United States	36.08	32.88	47.26	35.77
Non-U.S.	96.02	127.26	166.34	222.45
Global Total	132.10	160.14	213.60	258.22

Exhibit 3-22: Estimated New Plant Refining Investment under the Lieberman/Warner Bill Compared to the Base Case – Billions of \$2006

Region	Base 2012	L/W 2012	Base 2020	L/W 2020
PADD 1	2.35	2.60	3.93	2.71
PADD 2	11.11	9.90	11.24	8.88
PADD 3	13.71	10.44	18.66	9.17
PADD 4	3.35	3.20	2.91	2.59
PADD 5	5.06	6.74	10.51	12.42

Exhibit 3-23 shows the estimated impact of the Lieberman/Warner proposal on emissions from U.S. refineries.

- A critical finding is that, while the estimated impact of Lieberman/Warner is to reduce U.S. refinery CO₂ emissions by about 54 million tonnes per year (18 percent) by 2020, these reductions are likely largely offset by projected increases of 57 million tonnes per year in other world regions. Put another way, the primary emissions effect is likely to relocate CO₂ emissions rather than reduce them.
- Overall emissions increase globally in 2020 reflecting the rapid growth of refinery capacity in those parts of the world that do not control CO₂ emissions.

Exhibit 3-23: Estimated Impact of Lieberman/Warner on Refinery CO₂ Emissions Compared to the Base Case – Million tonnes per year

	Base Case 2012	Lieberman/Warner 2012	Base Case 2020	Lieberman/Warner 2020
United States	279.44	251.72	291.0	237.18
Non-U.S.	722.23	744.28	850.12	906.62
Global Total	1001.67	996.0	1141.12	1143.80

Since all refineries are subject to the U.S. allowance cost on moving finished products into the various U.S. demand regions, these costs are estimated to have little competitive effect in the wider global market. Canadian and EU refineries are subject to their own stationary source allowance costs which, as for the United States, reduce their competitiveness relative to the regions that have no CO₂ stationary source costs.

Exhibit 3-24 through Exhibit 3-27 show the movements of crude and products on the world stage drawn from the WORLD® model runs.

- Crude oil imports into North America are estimated to decline by about 0.97 MMB/d in 2012 and by about 2.16 MMB/d in 2020 under the Lieberman/Warner proposal. Imports in 2012 are likely to decline from Latin America falling by about 2.03 MMB/d in 2020 as compared to the Base Case. Imports from the Middle East are estimated to rise slightly, by 0.79 MMB/d compared to the Base Case.
- Refined product Imports are estimated to increase under the Lieberman/Warner proposal, particularly in 2020 when they are estimated to jump by about 1.80 MMB/d. A large part of this increase comes from Latin America which in the modeling does not have allowance costs on stationary source GHG emissions.

Exhibit 3-28 directly compares both North American crude oil consumption and refined product production under the Base Case and the Lieberman/Warner case. Thus, the indicated impact of Lieberman/Warner is both to exacerbate the decline of U.S. crude oil production and to lower U.S. overall dependency on crude oil imports (particularly from Latin America) but to increase crude oil dependency on the Middle East. Production of refined products declines in North America and exports of some products increase particularly to those regions that do not have CO₂ controls. Overall, Lieberman/Warner likely reduces U.S. dependency on crude oil imports but increases dependency on imported products.

Exhibit 3-24: Estimated Global Crude Oil Movements 2012 under the Lieberman/Warner Bill, Million Barrels per Day

CONSUMING REGIONS									
	Total Exports	Total Local + Exports							
Region			USA&Canada	Latin America	Africa	Europe	FSU	Middle East	Asia/Pacific
USA&Canada	0.46	9.11	8.65	0.00	0.00	0.00	0.00	0.00	0.46
Latin America	3.12	11.29	2.52	8.17	0.00	0.60	0.00	0.00	0.00
Africa	8.46	10.98	3.14	0.00	2.52	3.70	0.00	0.00	1.62
Europe	0.26	4.63	0.26	0.00	0.00	4.37	0.00	0.00	0.00
Former FSU	6.08	12.56	0.31	0.10	0.18	4.20	6.48	0.10	1.19
Middle East	16.99	23.73	2.80	0.21	0.65	0.00	0.00	6.75	13.33
Asia	0.00	6.19	0.00	0.00	0.00	0.00	0.00	0.00	6.19
Total Imports	35.37		9.03	0.31	0.83	8.50	0.00	0.10	16.60
Total Local+Imports		78.49	17.68	8.48	3.36	12.87	6.48	6.85	22.78

Exhibit 3-25: Estimated Global Refined Products (Including Sulfur and Coke) Movements 2012 under the Lieberman/Warner Bill, Million Barrels per Day

CONSUMING REGIONS									
	Total Exports	Total Local + Exports							
Region			USA&Canada	Latin America	Africa	Europe	FSU	Middle East	Asia/Pacific
USA&Canada	1.85	20.88	19.03	1.10	0.03	0.05	0.00	0.00	0.67
Latin America	2.18	8.90	1.77	6.72	0.00	0.40	0.00	0.00	0.00
Africa	0.60	3.36	0.08	0.07	2.77	0.37	0.00	0.00	0.08
Europe	1.70	13.46	0.73	0.33	0.54	11.77	0.00	0.09	0.01
Former FSU	2.31	6.41	0.02	0.00	0.06	2.08	4.10	0.00	0.15
Middle East	1.61	6.98	0.00	0.00	0.08	0.00	0.00	5.37	1.53
Asia	0.00	24.50	0.00	0.00	0.00	0.00	0.00	0.00	24.50
Total Imports	10.24		2.61	1.49	0.71	2.90	0.00	0.09	2.44
Total Local+Imports		84.49	21.64	8.22	3.47	14.67	4.10	5.46	26.94
Total Exports			1.85	2.18	0.60	1.70	2.31	1.61	0.00
Total Local + Imports- Exports			19.80	6.04	2.87	12.97	1.79	3.84	26.94

Exhibit 3-26: Estimated Global Crude Oil Movements 2020 under the Lieberman/Warner Bill, Million Barrels per Day

CONSUMING REGIONS									
	Total Exports	Total Local + Exports							
Region			USA&Canada	Latin America	Africa	Europe	FSU	Middle East	Asia/Pacific
USA&Canada	1.04	9.13	8.09	0.00	0.00	0.00	0.00	0.00	1.04
Latin America	3.59	13.58	2.86	9.99	0.00	0.73	0.00	0.00	0.00
Africa	10.19	12.76	2.28	0.88	2.57	4.23	0.00	0.00	2.80
Europe	0.56	4.18	0.44	0.00	0.00	3.62	0.00	0.00	0.12
Former FSU	8.24	15.22	0.36	0.10	0.32	4.91	6.98	0.10	2.45
Middle East	18.66	25.88	3.54	0.10	0.56	0.00	0.00	7.22	14.46
Asia	0.00	5.67	0.00	0.00	0.00	0.00	0.00	0.00	5.67
Total Imports	42.27		9.47	1.08	0.87	9.87	0.00	0.10	20.88
Total Local+Imports		86.43	17.56	11.07	3.45	13.49	6.98	7.32	26.55

Exhibit 3-27: Estimated Global Refined Products (Including Sulfur and Coke) Movements 2020 under the Lieberman/Warner Bill, Million Barrels per Day

CONSUMING REGIONS									
	Total Exports	Total Local + Exports							
Region			USA&Canada	Latin America	Africa	Europe	FSU	Middle East	Asia/Pacific
USA&Canada	1.49	20.99	19.50	0.84	0.03	0.05	0.00	0.00	0.57
Latin America	3.64	12.12	2.69	8.48	0.01	0.73	0.00	0.00	0.21
Africa	0.52	3.61	0.07	0.11	3.09	0.30	0.00	0.00	0.03
Europe	1.86	14.05	0.90	0.23	0.59	12.20	0.00	0.12	0.02
Former FSU	2.49	6.94	0.08	0.00	0.19	1.81	4.45	0.00	0.41
Middle East	1.66	7.60	0.00	0.00	0.11	0.00	0.00	5.94	1.55
Asia	0.19	29.02	0.11	0.00	0.00	0.00	0.00	0.08	28.83
Total Imports	11.85		3.84	1.19	0.92	2.90	0.00	0.20	2.80
Total Local+Imports		94.33	23.34	9.66	4.01	15.09	4.45	6.15	31.62
Total Exports			1.49	3.64	0.52	1.86	2.49	1.66	0.19
Total Local + Imports- Exports			21.85	6.02	3.49	13.24	1.95	4.49	31.43

Exhibit 3-28: A Comparison of Crude Oil Consumption and Refined Products Production in North America under the Base Case and under the Lieberman/Warner Bill, Million Barrels per Day

Million Barrels per Day								
	Crude Oil Processed -		Refined Product Production -		Crude Oil Processed - Showing		Refined Product Production -	
	Base 2012	L/W	Base 2012	L/W	Base 2020	L/W	Base 2020	L/W
Region	USA/Canada	USA/Canada	USA/Canada	USA/Canada	USA/Canada	USA/Canada	USA/Canada	USA/Canada
USA&Canada	8.81	8.65	21.10	19.03	8.84	8.09	22.88	19.50
	imports from		exports to		imports from		exports to	
Latin America	3.27	2.52	0.64	1.10	4.89	2.86	0.51	0.84
Africa	3.11	3.14	0.00	0.03	3.18	2.28	0.02	0.03
Europe	0.53	0.26	0.00	0.05	0.47	0.44	0.00	0.05
Former FSU	0.45	0.31	0.00	0.00	0.33	0.36	0.00	0.00
Middle East	2.63	2.80	0.00	0.00	2.75	3.54	0.00	0.00
Asia	0.00	0.00	0.25	0.67	0.00	0.00	0.26	0.57
Total Supply / Production	18.80	17.68	22.00	20.88	20.47	17.56	23.67	20.99

4 ESTIMATED IMPACT OF THE LIEBERMAN/WARNER BILL ON THE INDUSTRY WITH POTENTIAL MITIGATION ACTIONS

Chapter 3 examined the potential impact of the bill on the oil and gas sectors but did not factor in any potential mitigation efforts – beyond improvements in efficiency that occur in the base case - that could lower the volume of emissions and thus the cost of the allowances. This chapter looks at the potential impact of the bill assuming that certain mitigation options are economically viable and undertaken.

The approach taken to the upstream and midstream sectors is different from that taken to the downstream sector. Examining Exhibit 4-1 it is clear that the main emission from the upstream sector is methane while that from the midstream and downstream is CO₂. Methane is a product of considerable value in the market so there is a strong economic incentive to capture as much of the methane emissions as makes economic sense, particularly in an era of high fuel prices. It should be noted here that the Base Case scenario reflects this economic incentive even without a legislated cost to methane emissions and estimates more than a 25 percent reduction in methane emissions per onshore natural gas well between 2012 and 2020.

**Exhibit 4-1: Estimated Total 2005 GHG Emissions from the Oil and Gas Sectors
MMtCO₂e**

United States	CO₂	CH₄	N₂O	Total MMtCO₂e
Upstream	67.71	107.80	0.36	175.88
Midstream	48.47	11.69	0.18	60.14
Downstream	238.46	N/A	N/A	238.46

The approach taken in modeling mitigation efforts in the upstream and midstream sectors under the Lieberman/Warner proposal is the same as the approach taken in modeling the Lieberman/McCain and the Bingaman/Specter bills. Much of the mitigation efforts revolve around the role played by the USEPA’s voluntary Gas STAR program.

In Chapter 5 of Volume I of the original report there is an extensive discussion of the Gas STAR program, the mitigation technologies associated with it and what proportion of the U.S. industry participates in the program. Appendix E in Volume II also contains substantive discussions of the mitigation options for the upstream and midstream sectors of the industry. Also discussed was the incorporation of Gas STAR technologies in the Base Case (i.e., technologies that are economic with a carbon allowance value set at zero). This discussion is not being repeated in this addendum.

ESTIMATED IMPACT OF POTENTIAL MITIGATION ACTIONS ON THE UPSTREAM AND MIDSTREAM SECTORS OF THE INDUSTRY UNDER LIEBERMAN/WARNER

This chapter discusses which mitigation measures have the potential to be implemented cost-effectively in the upstream and gas processing (midstream) sectors of the oil and gas industry under the Lieberman/Warner legislative scenario for GHGs. The chapter presents the potential effect of these mitigation measures in terms of expected total expenditures the industry would have to bear, expected reductions in GHG emissions and the effect on oil and gas drilling and production as

estimated by the Hydrocarbon Supply Model. The estimated effects on oil and gas drilling and production come about from the higher capital and operating costs stemming from the mitigation efforts and the cost of buying allowances for the GHG emissions that cannot be cost-effectively mitigated.

NATURAL GAS AND OIL PRODUCTION MITIGATION METHODOLOGY AND ASSUMPTIONS

Under the Lieberman/Warner legislative scenario, estimated carbon allowance values would be placed on GHG emissions putting pressure on the industry to reduce emissions wherever possible and most economic. The economic mitigation options are those for which the estimated capital and net operating costs per tonne of reduction are less than the cost of buying a tonne of carbon allowances under the proposed legislation. The analyses to be presented here include estimates of total emission reductions, annualized capital costs, operating costs and the market value of any natural gas that is recovered by the mitigation option.

NATURAL GAS AND OIL PRODUCTION MITIGATION ASSUMPTIONS FOR IMPACT CASES

ICF has assumed that all outstanding emissions, after voluntary emission reductions (from the Natural Gas STAR Program extrapolated to include non-Partners) have been subtracted, are subject to reductions through the application of the potential mitigation options detailed below. Since methane has an economic value and a 21 multiplier in global warming potential (GWP) methane mitigation projects usually will be more cost effective than carbon dioxide (GWP of 1) mitigation opportunities.

It is assumed that the requirement to either retire carbon allowances or to apply the mitigation options will apply to all wells under the bill regardless of well production volume, because there is no basis to differentiate well productivity by producing company size in a future year.

- In this way we can estimate an upper bound on emission reductions that are achievable under the two bills as well as an upper bound on cost required to implement these technologies.

LIEBERMAN/WARNER IMPACT CASE

Under the Lieberman/Warner bill natural gas production and processing facilities must purchase carbon allowance credits to offset emissions.

- For modeling purposes, mitigation options will be applied to the entire natural gas and oil production sector.

2012 Production Emission Mitigation under Lieberman/Warner

The estimated carbon allowance value in 2012 under the Lieberman/Warner legislation is about \$41.21/tCO₂e (in 2006\$) which means that companies are assumed to implement mitigation technologies and practices that can reduce emissions at a net cost that is smaller than the carbon allowance value.

Exhibit 4-2 lists the more significant mitigation options relevant to the production sector that likely fall below the 2012 carbon allowance value.

**Exhibit 4-2: Estimated Production Sector Potential Mitigation Options in 2012 –
Lieberman/Warner (2006\$)**

Emission Reduction Opportunities	One Time Cost (\$/tCO₂e)¹	Operating and Maintenance Cost (\$/tCO₂e)	Aggregate Cost (Including Gas Savings) (\$/tCO₂e)²
Reduced Emissions (Green) Completions	\$8.85	\$0.38	(\$2.96)
Plunger Lifts	\$0.18	\$0.21	(\$11.80)
Vapor Recovery Units	\$0.44	\$0.60	(\$11.15)
Replace High Bleed Pneumatic Controls	\$0.94	\$0.00	(\$11.25)
Install Smart Automation on Well Venting	\$4.79	\$1.54	(\$5.86)
Install Instrument Air Systems (at sites w/electric power)	\$1.00	\$2.36	(\$8.84)
Install Instrument Air Systems (at sites w/o electric power)	\$2.35	\$2.36	(\$7.48)
Install Solenoid Valve Actuators (at sites w/ electric power) ³	\$18.54	\$7.13	\$13.48
Install Solar Powered Glycol Circulation Pump	\$6.49	\$4.32	(\$1.38)

All costs in 2006 dollars. One-time costs are annualized with a discount factor of 0.13.
² Aggregate cost includes additional revenue from natural gas savings. Based on EIA's *Annual Energy Outlook* natural gas prices are estimated at \$4.96/Mcf in 2012 under the Lieberman/Warner impact case.
³ Solenoid control valves are considered not to be commercially available until 2020.

The estimated aggregate cost per tonne of carbon reduced is negative for many of these technologies when the revenue from natural gas savings is considered. This means that each of these technologies is “cost effective” at a zero carbon allowance value.

- Note that “cost effective” does not imply that these technologies are the most profitable way for companies to use their limited manpower. Both Gas STAR Partner and non-Partner companies are retrofitting some, but not all of these applications where the payback (generally under one year) and technical difficulty justifies their personnel’s attention.
- In general, new construction includes the lower emissions technologies. Applying these technologies across the natural gas and oil production sector in 2012 will reduce emissions substantially. Several assumptions were used to estimate the actual implementation of these technologies and their effect on overall emissions.

Introduction to Production Mitigation Analysis Tables

All of the emissions impact analysis below is based upon the drilling and completion levels of the Base Case. The estimated reduced emissions from the Lieberman/Warner case shown here are the result of mitigation assuming Base Case drilling activity. **This excludes the impact of the reduced drilling and production activity that would result from the increased costs to industry in the Lieberman/Warner case.** These impacts on well completions and production are discussed in a later section of this chapter.

To state it another way, the emission mitigation impacts shown here represent the effects of applying the economic mitigation strategies only. This is intended to document the technology effect component separately from the impact of reduced drilling and production activity. Each table that is based upon Base Case drilling and production is labeled as such in its title.

2012 Estimated Production Emission Mitigation Results under Lieberman/Warner

Using the above assumptions, each mitigation option was applied across the natural gas and oil production sector to estimate the total impact on GHG emissions in 2012. Exhibit 4-3 estimates the total emission reductions achieved through the application of these options.

Exhibit 4-3: Estimated Production Sector Estimated Mitigation Potential under Lieberman/Warner Allowance Costs in 2012 (Base Case Activity)¹

Production Type	GHG Emissions BEFORE Mitigation (tCO₂e)	GHG Emissions BEFORE Mitigation (tCO₂e/Well)	GHG Emissions AFTER Mitigation (tCO₂e)	GHG Emissions AFTER Mitigation (tCO₂e/Well)
Natural Gas Production				
Onshore	117,020,168	236	74,225,879	150
Offshore ²	7,642,875	4,859	4,847,875	3,082
Gas Total	124,663,043		79,073,754	
Oil Production				
Onshore	38,573,244	77	30,891,174	61
Offshore ²	17,221,602	11,926	13,791,826	9,551
Oil Total	55,794,846		44,683,000	
Upstream Total	180,457,889		123,756,754	

¹ Mitigation options were applied to emissions from direct emission sources. Indirect emissions are not shown in Exhibit 5-3. Indirect emission increases are reflected as an increase in electricity price.
² Numbers are in tCO₂e/platform rather than tCO₂e/well.

Voluntary emission reductions under the Natural Gas STAR Program extrapolated to include non-Partner companies are included under the “GHG Emissions BEFORE Mitigation” column in Exhibit 4-3. These base case reductions total over 23 million tCO₂e for the natural gas and oil production sector in 2012. Emission reductions achieved through the application of further mitigation options total an additional 56.7 million tCO₂e in the natural gas and oil production sector in 2012. The costs associated with achieving these reductions are shown in Exhibit 4-4. The total production sector costs associated to applying mitigation options under the Lieberman/Warner bill are shown in Exhibit 4-5.

Exhibit 4-4: Estimated Production Sector Costs Associated with GHG Emission Reductions in 2012 – Lieberman/Warner

Production Type	Capital Cost For GHG Reductions (2006\$/Well)	O&M Cost for GHG Reductions (2006\$/Well)	Gas Savings from GHG Reductions (2006\$/Well)	Aggregate Cost for GHG Reductions (2006\$/Well)
Natural Gas Production ¹	\$284.83	\$164.30	\$1,052.19	(\$603.06)
Oil Production ²	\$26.28	\$32.10	\$186.23	(\$127.85)

¹ National average costs per non-associated gas well.
² National average costs per oil well.

Exhibit 4-5: Estimated Production Sector Costs Associated with GHG Emission Reductions in 2012 – Lieberman/Warner

Production Type	Capital Cost For GHG Reductions (2006\$)	O&M Cost for GHG Reductions (2006\$)	Gas Savings from GHG Reductions (2006\$)	Aggregate Cost for GHG Reductions (2006\$)
Natural Gas Production	\$141,303,231	\$81,509,915	\$521,988,268	(\$299,175,123)
Oil Production	\$13,218,066	\$16,142,222	\$93,658,316	(\$64,298,028)

2020 Production Emission Mitigation under Lieberman/Warner

Under the Lieberman/Warner legislation, the carbon allowance value will likely rise over time reflecting the stricter caps on GHG emissions. The estimated carbon allowance value rises to about \$57.31/tCO₂e in the year 2020. This rise in carbon allowance value will likely cause companies to seek additional emissions mitigation technologies that were not previously sufficiently cost effective to further reduce GHG emission rather than paying the allowance value. Exhibit 4-6 displays mitigation technologies that are likely to be cost effective in 2020 under the assumptions used here.

These technologies are assumed to be installed throughout the production sector to further reduce emissions that were not captured in 2012. Installing electric compressor drivers is not estimated to be economic under the \$57.31/tCO₂e carbon allowance values at the 2020 AEO wellhead natural gas price. In addition to these technologies, incremental emissions from new production after 2012 will also be included in the GHG reductions in 2020. It is assumed that all new production operations that come on-line after 2012 will employ the cost-effective technologies listed in Exhibit 4-6 at those facilities. The following assumptions were used in addition to those listed for 2012 to estimate the total level of GHG emission reductions in 2020.

Exhibit 4-6: Estimated Production Sector Potential Mitigation Options in 2020 – Lieberman/Warner (2006\$)

Emission Reduction Opportunities	One Time Cost (\$/tCO₂e)	Operating and Maintenance Cost (\$/tCO₂e)	Aggregate Cost (Including Gas Savings) (\$/tCO₂e)¹
Reduced Emissions (Green) Completions	\$8.85	\$0.38	(\$3.43)
Plunger Lifts	\$0.18	\$0.21	(\$12.26)
Vapor Recovery Units	\$0.44	\$0.60	(\$11.62)
Replace High Bleed Pneumatic Controls	\$0.94	\$0.00	(\$11.72)
Install Smart Automation on Well Venting	\$4.79	\$1.54	(\$6.33)
Install Instrument Air Systems (at sites w/electric power)	\$1.00	\$2.51	(\$9.15)
Install Instrument Air Systems (at sites w/o electric power)	\$2.35	\$2.51	(\$7.80)
Install Solenoid Valve Actuators (at sites w/ electric power) ²	\$18.54	\$7.13	\$13.02
Install Solar Powered Glycol Circulation Pump	\$6.49	\$4.32	(\$1.84)

¹ Aggregate cost includes additional revenue from natural gas savings. Gas prices are estimated at \$5.15/Mcf in 2020 under the Lieberman/McCain impact case.
² Solenoid control valves are considered not to be commercially available until 2020.

2020 Production Emissions Mitigation Results under Lieberman/Warner

The total emission reductions estimated to be achieved by new technology installations in 2020 are summarized in Exhibit 4-7.

Exhibit 4-7: Production Sector Estimated Mitigation Potential under Lieberman/Warner Allowance Costs in 2020 (Base Case Activity)¹

Production Type	GHG Emissions BEFORE Mitigation (tCO₂e)	GHG Emissions BEFORE Mitigation (tCO₂e/Well)	GHG Emissions AFTER Mitigation (tCO₂e)	GHG Emissions AFTER Mitigation (tCO₂e/Well)
Natural Gas Production				
Onshore	96,337,045	173	77,166,797	139
Offshore ²	4,650,445	3,090	3,725,046	2,475
Gas Total	100,987,489		80,891,843	
Oil Production				
Onshore	32,868,238	67	30,953,233	63
Offshore ²	13,823,113	9,832	13,017,735	9,259
Oil Total	46,691,351		43,970,968	
Upstream Total	147,678,840		124,862,811	

¹ Mitigation options were applied to emissions from direct emission sources. Indirect emissions are not shown in Exhibit 5-7.
² Numbers are in tCO₂e/platform rather than tCO₂e/well.

Voluntary emission reductions under the Natural Gas STAR Program and other industry activities are included under the GHG Emissions BEFORE Mitigation column in Exhibit 4-7.

- These reductions total over 26 million tCO₂e for the natural gas and oil production sector in 2020.

Emission reductions achieved through the application of further mitigation options total an additional approximate 22 million tCO₂e in the natural gas and oil production sector in 2020. The estimated decrease in the rate of emissions per well in the natural gas systems in spite of an increase in natural gas production is due to the continuous application of cost effective mitigation technology, not currently in place, to all new production. The estimated costs associated with achieving these incremental reductions over the 2012 efforts are displayed in Exhibit 4-8. Likely high costs associated with solenoid valve actuators have increased the total cost to reduce GHG emissions in 2020.

Exhibit 4-8: Estimated Production Sector Costs Associated with GHG Emission Reductions in 2020 – Lieberman/Warner (2006\$)

Production Type	Capital Cost For GHG Reductions (\$/Well)	O&M Cost for GHG Reductions (\$/Well)	Gas Savings from GHG Reductions (\$/Well)	Aggregate Cost for GHG Reductions (\$/Well)
Natural Gas Production ¹	\$389.48	\$151.60	\$435.81	\$105.26
Oil Production ²	\$72.79	\$28.00	\$49.69	\$51.09

¹ National average costs per non-associated gas well.
² National average costs per oil well.

The estimated total production sector costs associated to applying mitigation options under the Lieberman/McCain bill in 2020 are shown in Exhibit 4-9.

Exhibit 4-9: Estimated Production Sector Costs Associated with GHG Emission Reductions in 2020 – Lieberman/Warner

Production Type	Capital Cost For GHG Reductions (2006\$)	O&M Cost for GHG Reductions (2006\$)	Gas Savings from GHG Reductions (2006\$)	Aggregate Cost for GHG Reductions (2006\$)
Natural Gas Production	\$216,900,824	\$84,425,865	\$242,704,633	\$58,622,057
Oil Production	\$35,509,479	\$13,657,492	\$24,241,735	\$24,925,236

NATURAL GAS PROCESSING SECTOR MITIGATION ASSUMPTIONS FOR IMPACT CASES

LIEBERMAN/WARNER IMPACT CASE

For simplicity, this study assumes that all of the natural gas processing plants will reduce emissions if the new bill is enacted.

2012 Gas Processing Emission Mitigation under Lieberman/Warner

This study assumes the implementation of methane mitigation options from the Natural Gas STAR Program that reduce overall plant fugitives and fugitive emissions from centrifugal compressors. In 2012, it is estimated that the Lieberman/Warner bill's carbon allowance value will be \$41.21 tCO₂e. Exhibit 4-10 shows the mitigation options proven to reduce significant amounts of carbon dioxide and methane emissions at natural gas processing plants that are more cost effective to perform than paying the carbon allowance value under the 2012 Lieberman/Warner impact case.

Exhibit 4-10: Estimated Processing Sector Potential Mitigation Options in 2012 – Lieberman/Warner

Emission Reduction Opportunities	One Time Cost Per tCO₂e Reduced	O&M Cost Per tCO₂e Reduced	Aggregate Cost Per tCO₂e Reduced
Directed Inspection & Maintenance	\$0.41	\$0.00	(\$11.85)
Replace Centrifugal Compressor Wet Seals with Dry Seals	\$0.60	\$1.49	(\$10.17)
Recover Carbon Dioxide for EOR Operations ¹	\$3.15	\$10.98	\$14.13
¹ CO ₂ Capture Project. <i>A Study of Very Large Scale Post Combustion CO₂ Capture at a Refining & Petrochemical Complex</i> . Available online at < http://www.co2captureproject.org/news/documents/GHGT%206%20CCP%20Post%20Combustion%20Refinery.pdf >.			

The cost estimates for these technologies and practices have been estimated using a 2012 natural gas price of \$4.96 per thousand cubic feet. The estimated aggregate cost per tonne of carbon reduced is negative for two of these technologies when the additional revenue from natural gas savings is considered. This means that each of these two technologies is cost effective at a zero carbon allowance value under these assumptions.

2012 Estimated Gas Processing Emissions Mitigation under Lieberman/Warner

Exhibit 4-11, Exhibit 4-12, and Exhibit 4-13 below show the estimated carbon dioxide equivalent emissions and the capital, operational & maintenance, and aggregate estimated costs for the natural gas processing sector in 2012 under the Lieberman/Warner case.

Exhibit 4-11 estimates that implementing the assumed potential emission mitigation options following the enactment of Lieberman/Warner bill in 2012 could reduce carbon dioxide equivalent emissions from these facilities by as much as 43 percent.

Exhibit 4-11: Natural Gas Processing Sector Estimated Mitigation Potential under Lieberman/Warner Allowance Costs in 2012 (Base Case Activity)

	GHG emissions BEFORE Mitigation (tCO₂e)	GHG Emissions BEFORE Mitigation (tCO₂e/MMcfd Throughput)	GHG emissions AFTER Mitigation (tCO₂e)	GHG Emissions AFTER Mitigation (tCO₂e/MMcfd Throughput)
Sector Total				
Natural Gas Processing	56,767,394	1,104	32,324,042	629

Exhibit 4-12 displays the estimated costs per unit of gas processed associated with applying the assumed mitigation options under the Lieberman/Warner case in 2012.

Exhibit 4-12: Estimated Processing Sector Costs per MMcfd Throughput Associated with GHG Emission Reductions in 2012 – Lieberman/Warner (2006\$)

	Capital Cost For GHG Reductions (\$/MMcfd throughput)	Operational + Maintenance Cost for GHG Reductions (\$/MMcfd throughput)	Gas Savings from GHG Reductions (\$/MMcfd throughput)	Aggregate Cost for GHG Reductions (\$/MMcfd throughput)
Sector Total				
Natural Gas Processing	\$889	\$3,065	\$547	\$3,407

Exhibit 4-13 shows estimated capital and O&M costs topping \$203 million for the processing sector as a whole. The net cost for implementing the bill will likely be about \$175 million after natural gas savings are realized.

Exhibit 4-13: Estimated Processing Sector Costs Associated with GHG Emission Reductions in 2012 – Lieberman/Warner (2006\$)

	Capital Cost For GHG Reductions (\$)	Operational + Maintenance Cost for GHG Reductions (\$)	Gas Savings from GHG Reductions (\$)	Aggregate Cost for GHG Reductions (\$)
Sector Total				
Natural Gas Processing	\$45,713,919	\$157,561,561	\$28,128,799	\$175,146,681

2020 Gas Processing Emission Mitigation under Lieberman/Warner

In 2020, it is estimated that the Lieberman/Warner bill’s carbon allowance value will be \$57.31/tCO₂e. Exhibit 4-14 shows the mitigation options with potential to reduce significant amounts of carbon dioxide and methane emissions at natural gas processing plants that are more cost effective to perform than paying the carbon allowance value under the 2020 Lieberman/Warner impact case.

Exhibit 4-14: Estimated Processing Sector Potential Mitigation Options in 2020 – Lieberman/Warner

Emission Reduction Opportunities	One Time Cost Per tCO₂e Reduced	O&M Cost Per tCO₂e Reduced	Aggregate Cost Per tCO₂e Reduced
Directed Inspection & Maintenance	\$0.41	\$0.00	(\$12.32)
Replace Centrifugal Compressor Wet Seals with Dry Seals	\$0.60	\$1.49	(\$10.64)
Recover Carbon Dioxide for EOR Operations	\$3.15	\$11.50	\$14.65

The cost estimates for these technologies and practices have been estimated using a 2020 natural gas price of \$5.15 per thousand cubic feet. Installing electric compressor drivers is not economic under the \$57.31/tCO₂e carbon allowance values at the 2020 AEO wellhead natural gas price.

Exhibit 4-15, Exhibit 4-16, and Exhibit 4-17 below show the estimated carbon dioxide equivalent emissions and the capital, operational & maintenance, and aggregate costs for the natural gas processing sector in 2020 under the Lieberman/McCain case.

Exhibit 4-15: Natural Gas Processing Sector Estimated Mitigation Potential under Lieberman/Warner Allowance Costs in 2020 (Base Case Activity)

	GHG emissions BEFORE Mitigation (tCO₂e)	GHG Emissions BEFORE Mitigation (tCO₂e/MMcfd Throughput)	GHG emissions AFTER Mitigation (tCO₂e)	GHG Emissions AFTER Mitigation (tCO₂e/MMcfd Throughput)
Sector Total				
Natural Gas Processing	43,298,830	765	38,788,041	685

Exhibit 4-15 indicates that mitigation action taken in response to the Lieberman/Warner bill in 2020 might reduce carbon dioxide equivalent emissions by over 10 per cent. It should be noted that the decrease in the rate of emissions per throughput in the natural gas processing systems in spite of an increase in natural gas throughput is due to the continuous application of cost effective mitigation technologies in the “before mitigation” scenario to all new processing facility throughput.

Exhibit 4-16: Processing Sector Estimated Costs per MMcfd Throughput Associated with GHG Emission Reductions in 2020 – Lieberman/Warner (2006\$)

	Capital Cost For GHG Reductions (\$/MMcfd throughput)	Operational + Maintenance Cost for GHG Reductions (\$/MMcfd throughput)	Gas Savings from GHG Reductions (\$/MMcfd throughput)	Aggregate Cost for GHG Reductions (\$/MMcfd throughput)
Sector Total				
Natural Gas Processing	\$176	\$636	\$89	\$724

Exhibit 4-16 displays the estimated costs per unit of gas processed associated with applying the economic mitigation options under the Lieberman/Warner case in 2020.

Exhibit 4-17: Processing Sector Estimated Costs Associated with GHG Emission Reductions in 2020 – Lieberman/Warner (2006\$)

	Capital Cost For GHG Reductions (\$)	Operational + Maintenance Cost for GHG Reductions (\$)	Gas Savings from GHG Reductions (\$)	Aggregate Cost for GHG Reductions (\$)
Sector Total				
Natural Gas Processing	\$9,974,226	\$35,997,755	\$5,016,872	\$40,955,108

Exhibit 4-17 shows an estimated capital and O&M costs over \$45 million for the processing sector as a whole. The net cost for implementing the bill will be about \$41 million after natural gas savings are realized.

IMPACTS ON OIL AND GAS DRILLING AND PRODUCTION WITH POTENTIAL MITIGATION OPTIONS

- The Hydrocarbon Supply Model was run to simulate the impacts on the level of future drilling and related production that might be expected from the Lieberman/Warner proposal assuming that costs to producers could be reduced through measures to mitigate GHG emissions in the upstream and gas processing sectors

For the “No Mitigation” impact cases, the emission factors used to calculate the estimated extra allowance costs are the Base Case factors and do not reflect potential cost-effective mitigation steps the industry could take to further reduce GHG emissions in the face of the allowance costs. In contrast, the GHG emission factors for the “With Mitigation” HSM runs use the lower emission factors presented in this Chapter.

The estimated total, net capital and operating costs associated with the mitigation measures are also reflected in the HSM. Where the net costs are negative because the savings in methane pays the extra capital and operating expenses under the assumptions used in the analysis, the net costs (not accounting for the purchase of allowances) are modeled as zero.

- As a caveat, because the mitigation assumptions used are based on average costs instead of marginal costs, the analysis is likely to overstate emission reduction potential because it includes mitigation circumstances that have above average net costs.

In addition to analyzing wells the model estimate will be drilling in the post-2012 period, an economic analysis also was conducted for wells that are expected to be in production before the start of the regulatory regime in 2012. This analysis was carried out using the ICF Oil Well Operating Cost Model and the ICF Gas Well Operating Cost Model. The purpose was to see how much the estimated operating cost of these existing wells would likely change under the GHG proposals assuming mitigation, how many would be rendered uneconomic and consequently the amount of oil and gas production that might be expected to be lost.

- It is important to remember that upstream impacts “With Mitigation” just as “Without Mitigation” were modeled in terms of “direct” or “first order” impacts only and ignore secondary impacts such as increases in cost of steel or other non-fuel inputs to oil and gas operations, changes to quantity of oil gas demanded in the market or changes to the wellhead prices for oil and gas.
- Another important point to note is the HSM runs were made assuming that all new and existing oil and gas wells would be subject to GHG regulations and would need to obtain allowances for their GHG emissions.

UPSTREAM IMPACTS WITH ASSUMED MITIGATION OPTIONS

The net operating cost assumptions with mitigation are shown in Exhibit 4-18 for onshore wells for Lieberman/Warner proposal. These estimated added costs include the allowance cost for methane and carbon dioxide emissions that are not mitigated, the higher cost of electricity used on the lease and the net costs for mitigation measures. Because the net mitigation costs for the assumed mitigation options (including the value of captured methane) are very low or negative, the “With Mitigation” case has operating costs that are reduced from the “Without Mitigation” case in the same approximate proportion that GHG emission are reduced by mitigation.

Exhibit 4-18: Estimated Onshore Well Operating Costs Impacts with Assumed Mitigation Options

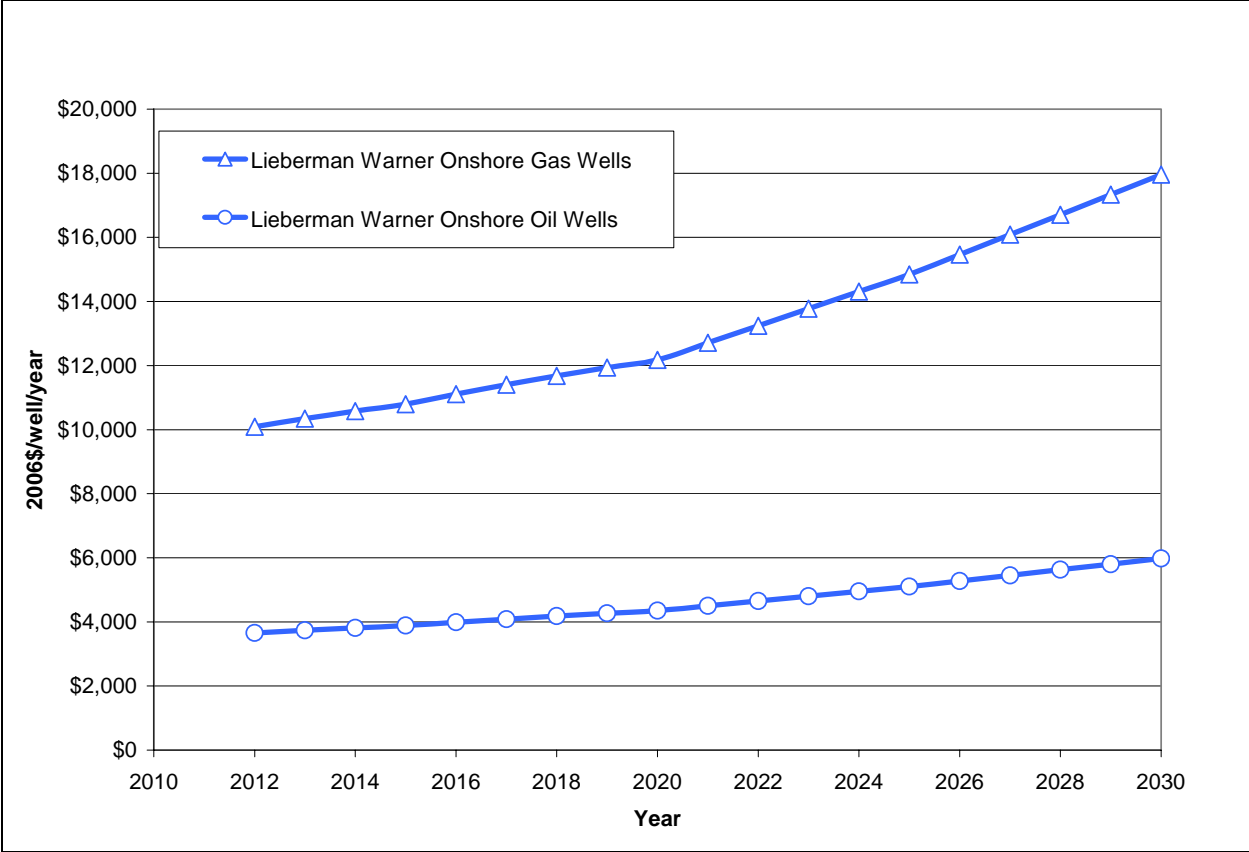
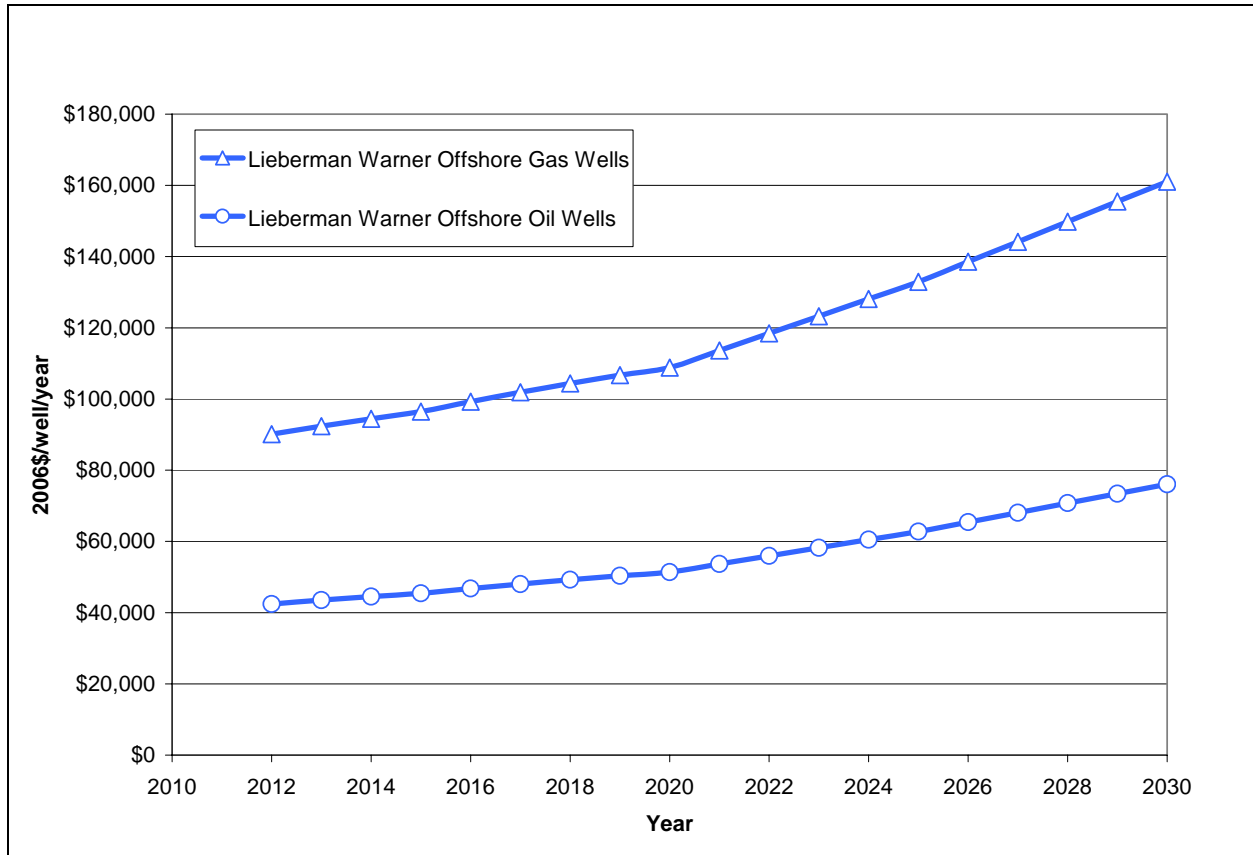


Exhibit 4-19 shows the estimated operating cost increases for average offshore wells that would be expected from the Lieberman/Warner proposal. The production rates from offshore wells are much higher than onshore wells and the GHG emissions per well are also much larger. For this reason the expected cost of GHG allowances per well are more than 10 times greater. However, because the Base Case operating costs for offshore wells are higher than onshore wells (about \$250,000 to \$350,000 per well versus about \$25,000 for onshore wells), the estimated increase in operating costs on a percentage basis is similar to or slightly lower than onshore wells.

Exhibit 4-19: Estimated Offshore Well Operating Costs Impacts with Assumed Mitigation Options



Another component in the impact cases is likely changes to gas processing costs coming from the need of gas processors to buy allowances to cover their own emissions and higher electricity prices for purchased power. These extra costs are reflected in the HSM for the estimated impact cases as additions to the model’s Base Case gas processing costs. The amount of these estimated cost increases is shown in Exhibit 4-20 for the Lieberman/Warner impact case. (Note that the table relates only to the gas processing operation itself and does not reflect the allowances that would have to be retired for the dry natural gas and natural gas liquids sold as fuel.) Before factoring in GHG allowance costs, the net capital and operating cost of the assumed mitigation options including the value of captured methane is taken into account.

Exhibit 4-20: Estimated Gas Processing Cost Impact with Assumed Mitigation Options (2006\$)

	2012	2020	2030
Average \$/Mcf Cost Increase Lieberman/Warner	\$0.10	\$0.14	\$0.20

Upstream Model Results for New Wells of “With Mitigation” Cases

The higher estimated well operating costs, well drilling costs and gas processing costs described above for the Lieberman/Warner case were input into the HSM to estimate the impacts on drilling activity and production from new wells compared to the Base Case. For these “With Mitigation” impact cases, mitigation measures by producers to reduce GHG emissions beyond those in the Base

Case were assumed. The GHG-related costs were added for wells drilled starting in 2012 and were escalated based on the assumed trajectory of allowance values for the respective legislative case. Other assumptions for the HSM such as resource base, land access, technology, drilling costs (other than for fuel-related GHG allowance costs), equipment costs, wellhead prices for oil and gas and financial parameters were unchanged from the Base Case.

The resulting estimated impacts for the Lieberman/Warner are shown in summary form in Exhibit 4-21. The left-hand part of the table summarizes results for the nine-year period, 2012 to 2020, while the right-hand side shows results for the ten years of 2021 to 2030. Values are shown in terms of declines and percentage declines relative to the Base Case number of new wells drilled and oil and gas production over those two periods.

In the early period gas well counts are estimated to decline by about 17.6 percent while gas production from new wells falls about 3.3 percent relative to the Base Case. In the period of 2021 to 2030 the cost impacts are estimated to increase along with the assumed GHG allowance values and the decline in new gas wells drilled is estimated at about 30.6 percent and the decline in gas production is about 6.8 percent. The percent reduction in the number of wells drilled is greater than the percentage loss of production because it is the low-productivity wells that are more likely to be rendered uneconomic due to the likely higher costs.

- Even so, over the entire nineteen years from 2012 to 2030 U.S. gas production is estimated to be approximately 24.8 trillion cubic feet lower in the Lieberman/Warner case.³⁰ This compares to about 30.9 Tcf lost from new wells in the corresponding “Without Mitigation” case presented in Chapter 3.

The percentage decline expected in oil well drilling and oil production from new wells is lower than for natural gas because the per-well operating cost increases are substantially lower. Under the Lieberman/Warner case assumptions, oil well drilling is estimated to decline about 1.5 percent versus the Base Case and production falls by about 0.51 percent from 2012 through 2020. For the 2021 to 2030 period oil well drilling is estimated at about 2.6 percent lower than the base case and production is about 0.5 percent lower. The oil production loss from new wells from 2012 to 2030 comes to about 127 million BOE compared to 222 million BOE in the corresponding “Without Mitigation” Lieberman/Warner case presented in Chapter 3.

³⁰ Such a large loss in natural gas production would tend to raise natural gas prices and stimulate some additional U.S. drilling (as well as encourage greater imports of LNG). Since our cases were constructed assuming that the AEO 2006 natural gas and oil prices prevail in both the Base Case and impact cases, this feedback effect that could somewhat moderate the production loss is not included.

Exhibit 4-21: Lower 48 Estimated U.S. Impacts on New Wells: Lieberman/Warner with Mitigation

	2012-20			2021-30	
	Delta	% Delta		Delta	% Delta
Oil Wells Drilled	-1,450	-1.5%		-2,801	-2.6%
Gas Wells Drilled	-26,260	-17.6%		-49,846	-30.6%
All Wells Drilled	-33,525	-10.6%		-60,598	-16.5%
Oil Production (million barrels)	-80	-0.5%		-78	-0.5%
Gas Production (billion cubic feet)	-6,343	-3.3%		-14,018	-6.8%
Note: values are summed over 9- and 10-year periods. "All wells" include dry holes in addition to oil and gas wells.					

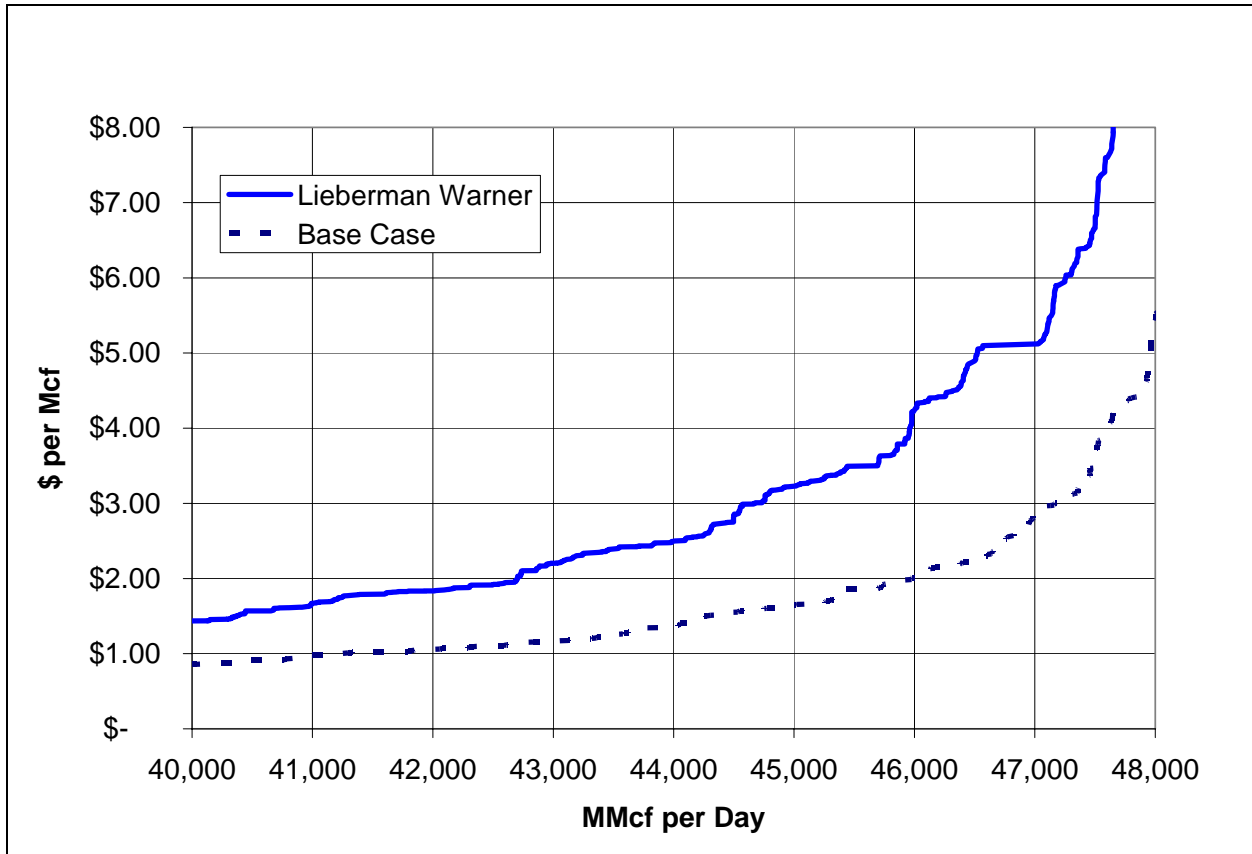
Results of "With Mitigation" Impact Cases for Existing Wells

The operating cost increases discussed above for the With Mitigation cases also would apply to existing wells at the time the GHG regulation begins. Those higher estimated operating costs could lead to premature abandonment of existing wells with a loss of production and reserves. To investigate this possibility we ran the ICF Oil Well Operating Cost Model and the ICF Gas Well Operating Cost Model for wells expected to be in existence at the beginning of 2012. A case was run with Base Case operating costs alone and other cases were run adding the 2012 GHG-related operating costs and gas processing cost factors.

The results for gas wells are shown in Exhibit 4-22 for the Lieberman/Warner case.

- At the wellhead prices expected to be prevailing in 2012 in the 2006 AEO, about 1.69 bcf per day of production (or 3.5 percent) could be in danger of being prematurely abandoned for the Lieberman/Warner case. This loss could start taking place soon after the regulations began and would be in addition to the production loss discussed above related to fewer new gas wells being drilled. The expected cumulative production that would have otherwise come from the prematurely abandoned wells from 2012 through 2030 would be roughly 3.0 Tcf. This compares to an estimated 4.0 Tcf lost from existing wells in the "Without Mitigation" Lieberman/Warner case.

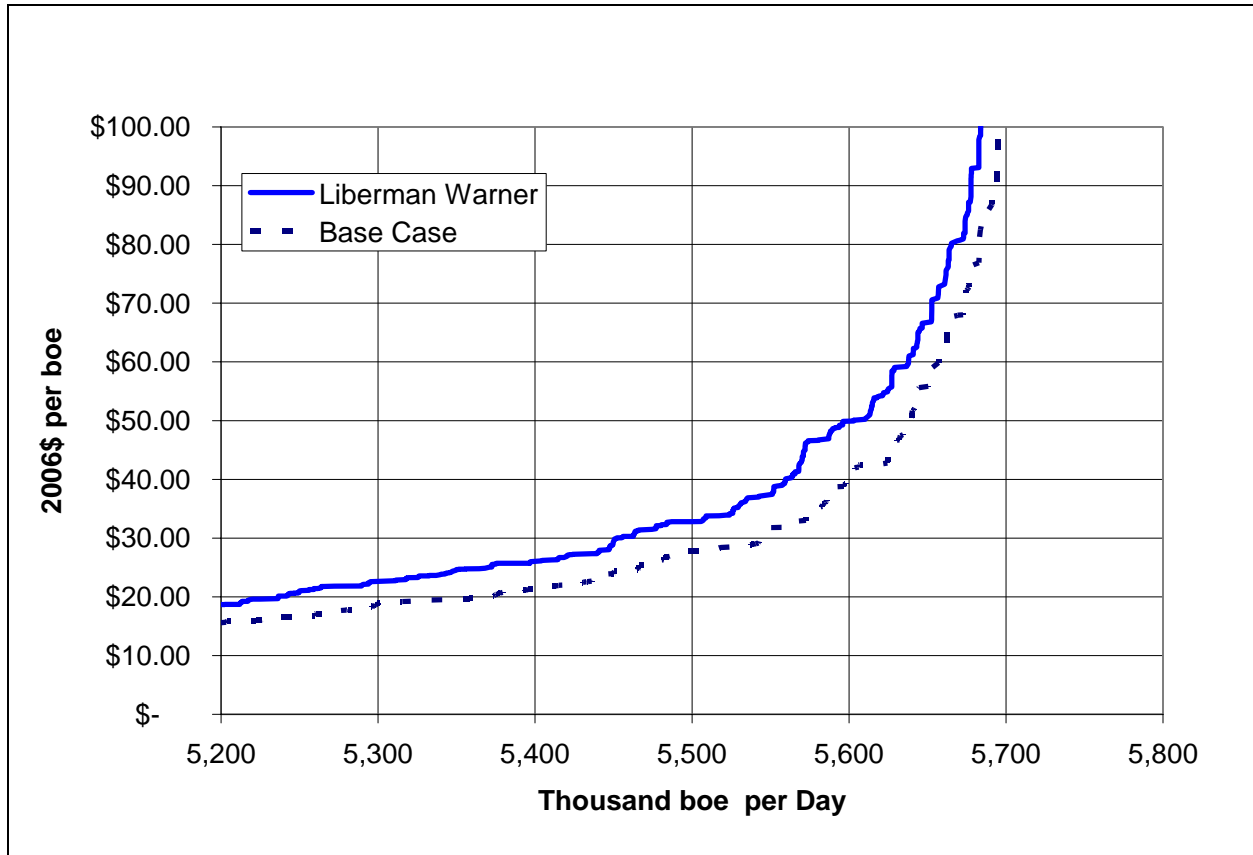
Exhibit 4-22: Estimated Impact on Existing L-48 Gas Wells with Mitigation



The results for existing oil wells are shown in Exhibit 4-23 for the Lieberman/Warner legislative scenario with mitigation.

- At the wellhead oil prices expected to be prevailing in 2012 in the 2006 AEO, about 53,000 barrels-equivalent per day of crude oil and associated-dissolved gas production (or 0.9 percent) could be in danger of being prematurely abandoned under Lieberman/Warner. The expected cumulative production that would have otherwise come from the prematurely abandoned oil wells from 2012 through 2030 would be roughly 95 million BOE. This compares to an estimated cumulative 104 million BOE loss in the “Without Mitigation” case for existing oil wells for Lieberman/Warner.

Exhibit 4-23: Estimated Impacts on Existing L-48 Oil Wells with Mitigation



Impact on Carbon Capture, Geosequestration and CO₂ EOR

One of the possible impacts of GHG regulation might be to encourage permanent underground storage (geosequestration) of CO₂. Some of this geosequestration could be done as part of enhanced oil recovery (EOR) efforts. In Chapter 3 we presented possible scenarios for geosequestration and related EOR for the Lieberman/Warner case.

Since most of the sequestered CO₂ is expected to come from electric power plants, we do not expect much difference in EOR between the “Without Mitigation” and the “With Mitigation” cases for upstream and midstream sectors. The only impact might be that additional recovery of CO₂ at gas processing plants assumed under the “With Mitigation” case might make the EOR scenarios somewhat easier to achieve since the CO₂ would be available in greater quantities and in more locations.

SUMMARY OF THE ESTIMATED EMISSIONS IMPACTS INCLUDING BOTH MITIGATION AND ACTIVITY EFFECTS

The emissions impact tables presented earlier in this chapter are based upon Base Case activity levels. As stated previously, the higher costs imposed by the Lieberman/Warner bill likely would result in reduced drilling and production levels. Thus the net greenhouse gas emissions logically would be lower than those in the previous tables. Exhibit 4-24 summarizes the net GHG emissions

including the activity effect for the upstream sector and Exhibit 4-25 summarizes the emissions for the midstream sector.

Exhibit 4-24: Summary of Estimated Upstream GHG Emissions Impacts Showing Additional Impact of Reduced Activity

	2012 Base Case (tCO2e)	2012 Lieberman Warner (tCO2e)	2020 Base Case (tCO2e)	2020 Lieberman Warner (tCO2e)
Base Case	180,457,889		147,678,840	
Without Mitigation				
Mitigation Effect		0		0
GHG - Mitigation Only		180,457,889		147,678,840
Reduced Activity Effect		-5,426,989		-6,783,641
NET GHG Emissions		175,030,900		140,895,199
With Mitigation				
Mitigation Effect		-56,701,135		-22,816,029
GHG - Mitigation Only		123,756,754		124,862,811
Reduced Activity Effect		-2,768,629		-3,928,188
NET GHG Emissions		120,988,125		120,934,623

Exhibit 4-25: Summary of Estimated Gas Processing Emissions Impacts Showing Effects of Reduced Future Gas Production

	2012 Base Case (tCO2e)	2012 Lieberman Warner (tCO2e)	2020 Base Case (tCO2e)	2020 Lieberman Warner (tCO2e)
Base Case	56,767,394		43,298,830	
Without Mitigation				
Mitigation Effect		0		0
GHG - Mitigation Only		56,767,394		43,298,830
Reduced Activity Effect		-2,231,862		-2,776,811
NET GHG Emissions		54,535,532		40,522,019
With Mitigation				
Mitigation Effect		-10,353,409		-3,101,795
GHG - Mitigation Only		46,413,985		40,197,035
Reduced Activity Effect		-1,393,412		-1,860,530
NET GHG Emissions		45,020,573		38,336,505

ESTIMATED IMPACT OF MITIGATION ACTIONS ON THE DOWNSTREAM SECTOR OF THE INDUSTRY UNDER LIEBERMAN/WARNER

Unlike the upstream sector with its Natural Gas STAR program, there is no large, well documented, publicly available body of literature on the on-going efforts of the downstream sector to reduce emissions.

Reducing energy losses will reduce fuel consumption which will in turn reduce emissions, both direct and indirect: refinery purchased natural gas in the case of direct emissions, and refinery purchased electricity in the case of indirect emissions. One can say unequivocally, that if refineries are required to buy allowances and the economics of operating change energy efficiency is one area that the industry will continue to focus on. However, a sound basis for quantifying potential refinery mitigation actions in response to proposals like Lieberman/Warner is simply not available at this time.

5 CONCLUSIONS

This report examines the potential impact of one of the proposed bills in Congress aimed at controlling GHG emissions on a relatively economy wide basis. While some studies have assessed impacts on the economy as a whole, this is the first study that has looked in-depth at potential impacts on oil and gas sector operational impacts. Two models were used, the Hydrocarbon Supply Model for the upstream and midstream sectors and the World Oil Refining, Logistics and Demand Model for the downstream sector. Both models represent the sectors in detail but they do not model interactions with sectors other than reflecting the higher cost of purchased electricity associated with estimated allowance costs. An additional ICF model was used to assess potential impacts on the natural gas processing sector.

An allowance value for the Lieberman/Warner impacts was constructed from a number of studies of the original bill, there being no analysis of the amended bill available when this study was initiated.

The modeling results indicate the likely impact of the bill on the relevant sectors and show trends as a function of the allowance values. However, it should at all times be kept in mind that the modeling reflects the direct impacts of the bills on the sectors, and does not reflect the indirect impacts and costs.

In an economy as complex, large, and sophisticated as that of the United States there are both direct and indirect interrelationships between the various economic sectors and they are not always transparent. An economy wide bill will likely affect a wide assortment of sectors. The oil and gas industry, as an emitter of GHGs will be affected both directly and indirectly. The industry uses (among many inputs) steel, cement, chemicals, catalysts, power, nickel, and other metals, all sectors that are also emitters of GHGs and thus subject to the allowance costs. Therefore the industry will have to contend with both the impact of the allowance costs on its plants and products, and the impact of the allowance costs on its inputs.

To fully evaluate all the direct and indirect costs that will affect the industry, a general macroeconomic model that also incorporated all the details of the industry that the HSM and WORLD® possess would be required. A key factor that must be borne in mind is that the study as conducted did not incorporate the impacts of higher product costs on demand. Such an analysis would require integration with macroeconomic modeling. These caveats must be kept in mind when evaluating the results of this study.

ESTIMATED IMPACTS OF LIEBERMAN/WARNER ON THE OIL AND GAS INDUSTRY

UPSTREAM SECTOR – EXPLORATION AND PRODUCTION

Exhibit 5-1 through Exhibit 5-3 show the estimated impacts of the Lieberman/Warner bill on the upstream sectors of the oil and gas industry prior to assumed mitigation efforts.

- It should be noted that the analysis shown here includes an adjustment for the existing well impacts in both legislative cases. This is because the higher operating costs relative to the Base Case would result in premature abandonment of some currently existing wells.

Under Lieberman/Warner (Exhibit 5-1), gas wells drilled decline by an estimated 21.8 percent compared to the Base Case, between 2012 and 2020 and by about 41.0 percent between 2021 and 2030. The estimated declines in oil well drilling relative to the Base Case are smaller: about 1.9 percent in the earlier period and about 4.3 percent in the later period.

Exhibit 5-1: Estimated Lieberman/Warner Impacts on Drilling and Production – No Assumed Mitigation

	2012	2020	2030	Cumulative 2012-2020	Cumulative 2021-2030	Cumulative 2012-2030
Base						
Oil Wells Drilled	11,404	10,852	10,502	98,922	105,834	204,756
Gas Wells Drilled	19,436	15,578	18,627	148,796	162,906	311,702
All Wells Drilled	38,732	34,803	40,220	317,705	366,624	684,329
Oil Production MMB	1,698	1,672	1,375	15,198	15,165	30,363
Gas Production BCF	21,518	20,957	20,273	191,108	205,087	396,195
Lieberman/Warner (adjusted for existing well impacts)						
Oil Wells Drilled	11,203	10,739	10,085	97,012	101,309	198,321
Gas Wells Drilled	18,467	9,377	10,233	116,366	96,096	212,462
All Wells Drilled	37,331	27,238	29,830	276,111	282,411	558,522
Oil Production MMB	1,682	1,661	1,358	15,102	15,039	30,141
Gas Production BCF	20,672	19,613	17,771	182,577	182,763	365,340

The estimated production decline is smaller than the estimated drilling decline because the assumption is that the low yield wells are the ones more likely to become uneconomic with the addition of allowance costs. Oil production falls about 0.6 percent in 2012-20 and about 0.8 percent in the later period, while gas production falls about 4.5 percent in 2012-20 and about 10.9 percent in the later period.

Exhibit 5-2 presents the estimated emissions results of the no-mitigation case. Exhibit 5-3 presents the results graphically.

As shown in

Exhibit 5-2, Base Case emissions of CO₂e in 2012 are an estimated 180 million tonnes and in 2020 are 148 billion tonnes. The Lieberman/Warner –No Mitigation case results in estimated reductions to 175 million tonnes and 141 million tonnes, respectively.

In Exhibit 5-3 the blue columns show the annual CO₂ emissions. Reductions are shown in red at the base of each column. The red indicates reductions resulting from lower industry activity. There is no mitigation related reduction in these cases.

Exhibit 5-2: Summary of Estimated Upstream Emissions Results: Cases with No Assumed Mitigation

	2012 Base Case (tCO ₂ e)	2012 Lieberman Warner (tCO ₂ e)	2020 Base Case (tCO ₂ e)	2020 Lieberman Warner (tCO ₂ e)
Base Case	180,457,889		147,678,840	
Without Mitigation				
Mitigation Effect			0	0
Reduced Activity Effect		-5,426,989		-6,783,641
NET GHG Emissions		175,030,900		140,895,199

Exhibit 5-3: Graphical Summary of Estimated Upstream Emissions Results: Cases with No Assumed Mitigation

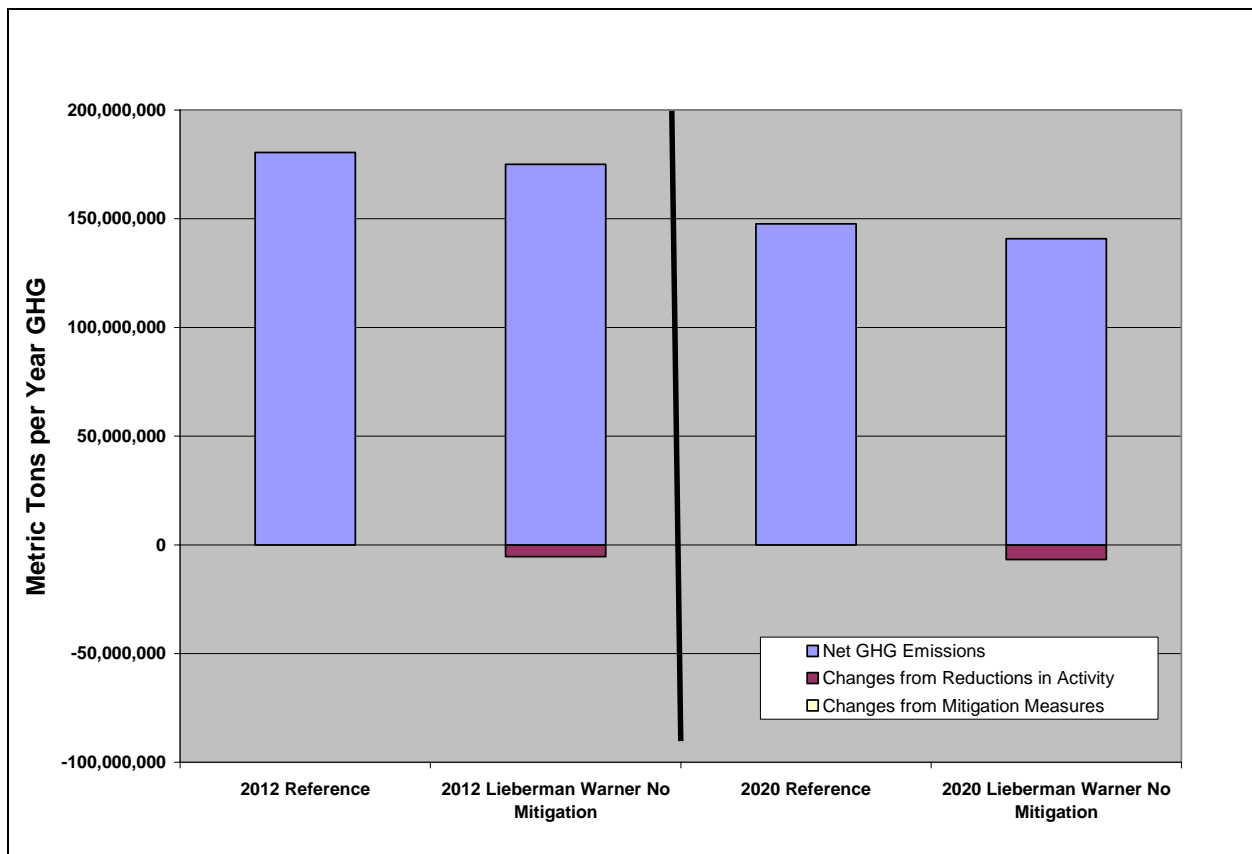


Exhibit 5-4 through 5-6 summarize the estimated impacts of the Lieberman/Warner bill after assumed mitigation efforts have been undertaken by the upstream sector. As the exhibits show, there is still likely to be an impact on wells drilled and production, but the impact has been softened. For example, without assumed mitigation, U.S. natural gas production over 2021-2030 is estimated at about 10.9 percent lower than the Base Case under Lieberman/Warner. However, with assumed mitigation, natural gas production over 2021-2030 is an estimated about 6.8 percent lower than the Base Case under Lieberman/Warner.

In Lieberman/Warner with assumed mitigation (Exhibit 5-4), gas well drilling declines about 17.7 percent relative to the Base Case in the early period and about 30.1 percent in the later period. In terms of gas production, there is a decline of about 3.3 percent relative to the Base Case in the earlier period and about 6.8 percent in the later period.

Exhibit 5-4: Estimated Lieberman/Warner Impacts on Drilling and Production: Cases with Assumed Mitigation

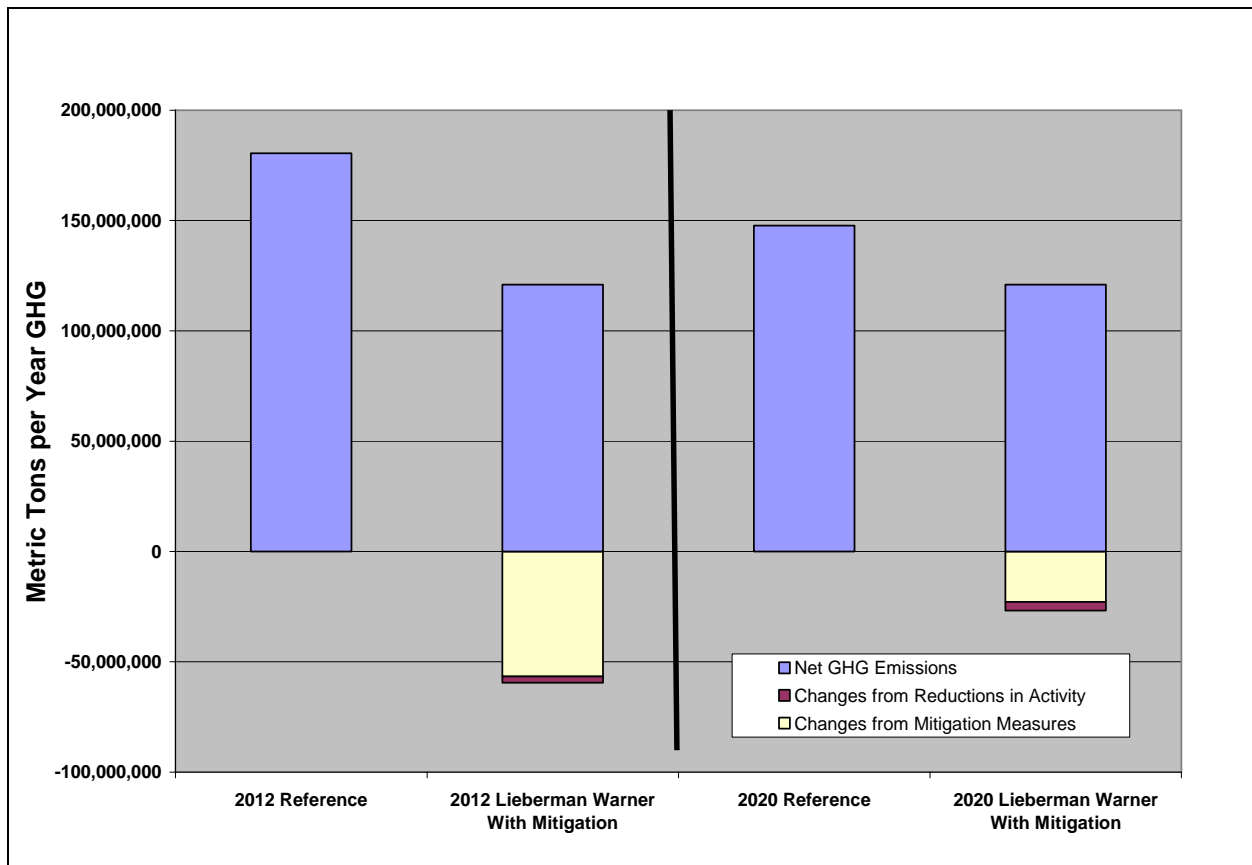
	2012	2020	2030	Cumulative 2012-2020	Cumulative 2021-2030	Cumulative 2012-2030
Base						
Oil Wells Drilled	11,404	10,852	10,502	98,922	105,834	204,756
Gas Wells Drilled	19,436	15,578	18,627	148,796	162,906	311,702
All Wells Drilled	38,732	34,803	40,220	317,705	366,624	684,329
Oil Production MMB	1,698	1,672	1,375	15,198	15,165	30,363
Gas Production BCF	21,518	20,957	20,273	191,108	205,087	396,195
Lieberman/Warner (adjusted for existing well impacts)						
Oil Wells Drilled	11,205	10,814	10,195	97,472	103,033	200,505
Gas Wells Drilled	18,668	10,766	11,186	122,536	113,060	235,596
All Wells Drilled	37,564	29,031	31,310	284,180	306,026	590,206
Oil Production MMB	1,683	1,665	1,364	15,118	15,087	30,204
Gas Production BCF	20,872	19,987	18,872	184,765	191,069	375,834

Exhibit 5-5 and Exhibit 5-6 present the results of the emissions results for the cases with assumed mitigation. Upstream emissions with Lieberman/Warner in 2012 are estimated at 120.9 million tonnes and in 2020 are about 120.9 million tonnes. Exhibit 5-6 presents the emissions results graphically. The blue columns indicate the annual CO₂ emission level. The reductions are shown in red or yellow at the base of each column. The red indicates reductions resulting from lower activity. Yellow indicates reductions resulting from mitigation measures.

Exhibit 5-5: Summary of Estimated Upstream Emissions Results: Cases with Assumed Mitigation

	2012 Base Case (MtCO ₂ e)	2012 Lieberman Warner (MtCO ₂ e)	2020 Base Case (MtCO ₂ e)	2020 Lieberman Warner (MtCO ₂ e)
Base Case	180,457,889		147,678,840	
With Mitigation				
Mitigation Effect		-56,701,135		-22,816,029
GHG - Mitigation Only		123,756,754		124,862,811
Reduced Activity Effect		-2,768,629		-3,928,188
NET GHG Emissions		120,988,125		120,934,623

Exhibit 5-6: Graphical Summary of Estimated Upstream Emissions Results: Cases with Assumed Mitigation



UPSTREAM SECTOR – NATURAL GAS PROCESSING

Exhibit 5-7 and Exhibit 5-8 show the estimated results of the gas processing sector CO₂ emissions analysis without mitigation. Base Case emissions are estimated at 57 million tonnes

of CO₂ in 2012 and 43 million tonnes in 2020. The Lieberman/Warner case results in reductions to about 55 million tonnes in 2012 and about 41 million tonnes in 2020.

Exhibit 5-7: Estimated Gas Processing Emissions Results: Cases without Assumed Mitigation

	2012 Base Case (tCO ₂ e)	2012 Lieberman Warner No Mitigation (tCO ₂ e)	2020 Base Case (tCO ₂ e)	2020 Lieberman Warner No Mitigation (tCO ₂ e)
Net GHG Emissions	56,767,394	54,535,532	43,298,830	40,522,019
Changes from Reductions in Activity		-2,231,862		-2,776,811
Changes from Mitigation Measures		0		0

Exhibit 5-8: Graphical Summary of Gas Processing Estimated Emissions: Cases without Assumed Mitigation

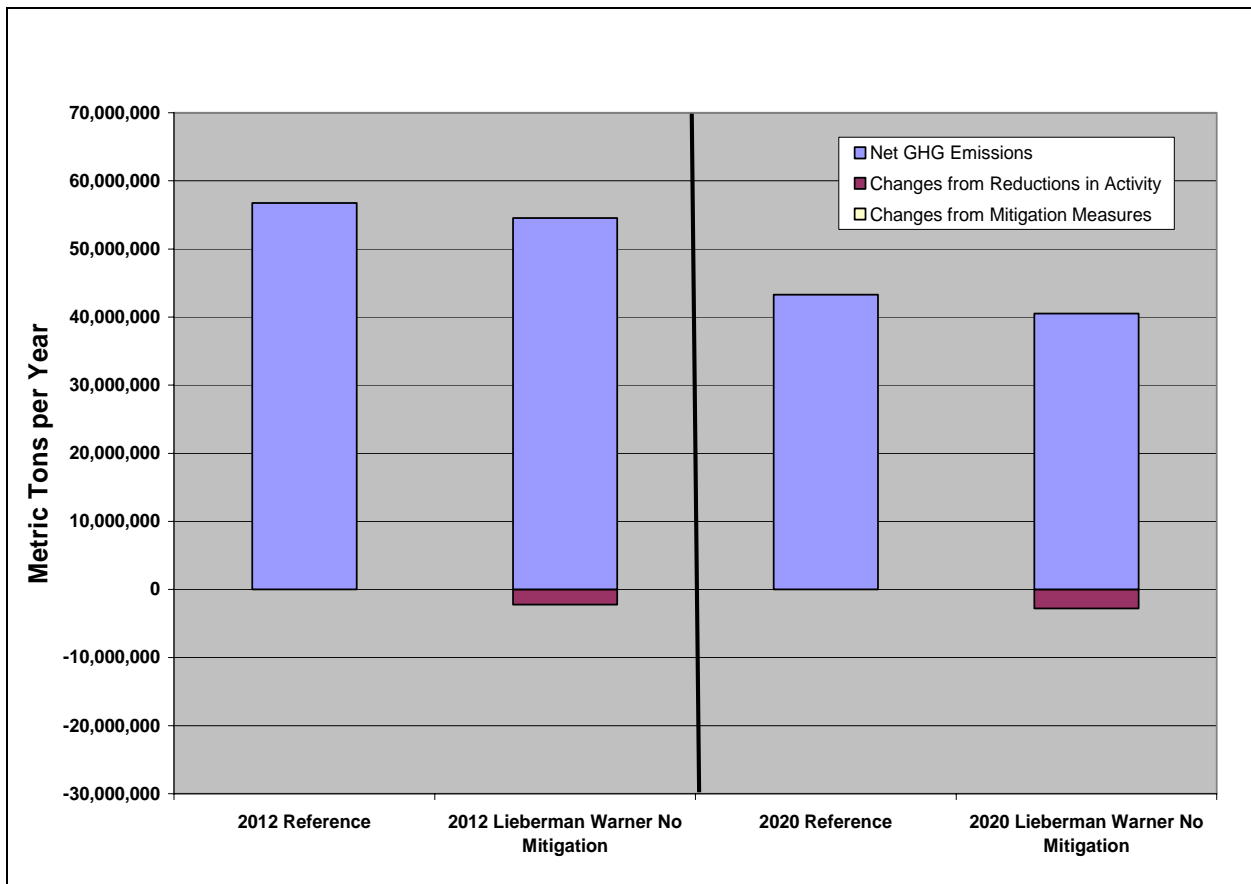
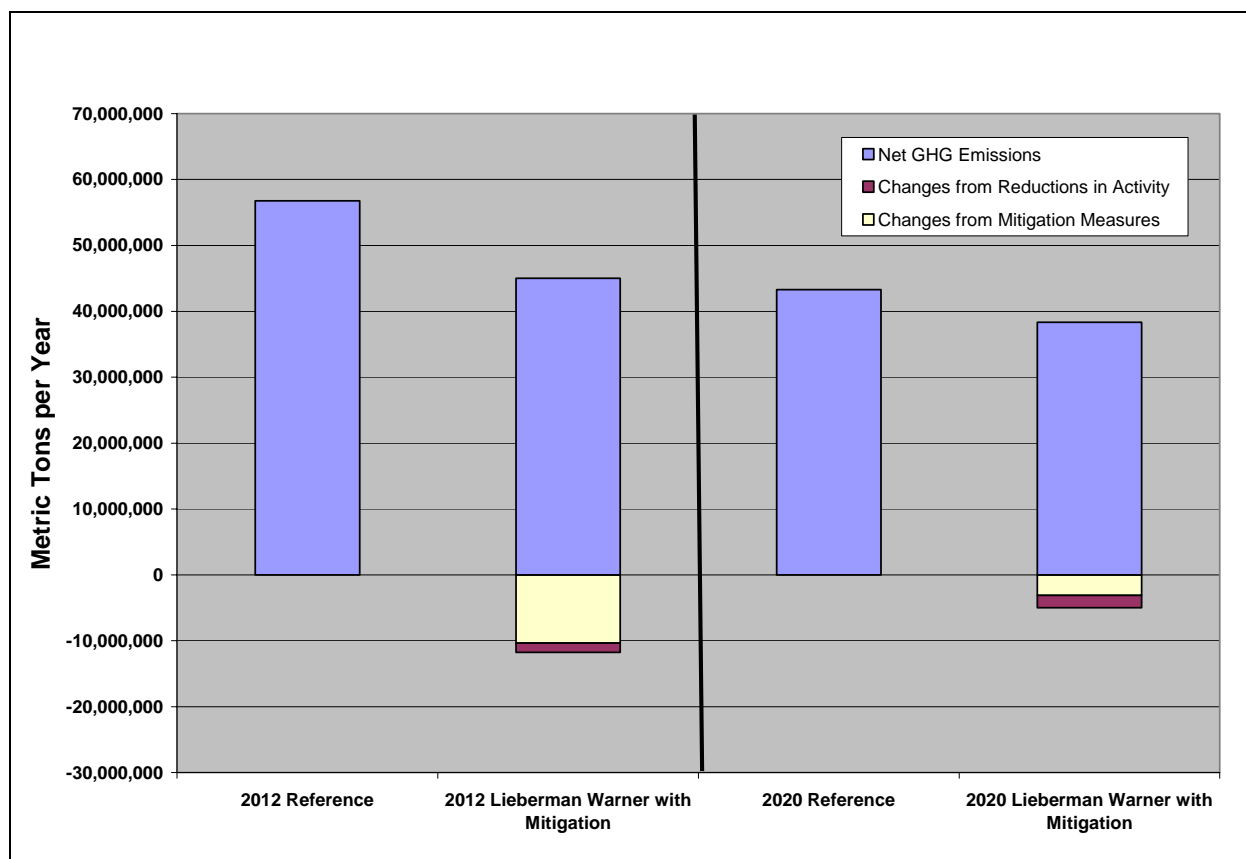


Exhibit 5-9 and Exhibit 5-10 show the estimated results of the gas processing emissions analysis with assumed mitigation. Base Case emissions in 2012 are estimated at 57 million tonnes of CO₂ and in 2020 are 43 million tonnes. The Lieberman/Warner case results in reductions to about 45 million tonnes in 2012 and about 38 million tonnes in 2020

Exhibit 5-9: Gas Processing Estimated Emissions Results: Cases with Assumed Mitigation

	2012 Base Case (tCO ₂ e)	2012 Lieberman Warner with Mitigation (tCO ₂ e)	2020 Base Case (tCO ₂ e)	2020 Lieberman Warner with Mitigation (tCO ₂ e)
Net GHG Emissions	56,767,394	45,020,573	43,298,830	38,336,505
Changes from Reductions in Activity		-1,393,412		-1,860,530
Changes from Mitigation Measures		-10,353,409		-3,101,795

Exhibit 5-10: Graphical Summary of Gas Processing Estimated Emissions Results: Cases with Assumed Mitigation



DOWNSTREAM SECTOR

A somewhat similar pattern can be observed in the downstream sector. One caveat to keep in mind when considering the impacts on the downstream sector is that there were no iterations made to estimate the impact on demand and how the price and income elasticities might affect the demand for different products. Keeping that in mind, with demand kept constant and costs increasing, the

estimated general trend is for domestic refinery throughput to fall so crude oil imports likely decline, but product imports likely increase.

Exhibit 5-11 shows the results of the modeling by PADD level. Total investments, throughputs and utilization are shown for the Base Case and the Lieberman/Warner case. What the investment and the throughput numbers show is that the global refining industry is likely to continue to expand outside the United States (and Canada and the EU).

As Chapter 3 showed the roughly 54 million tonne drop in U.S. refinery CO₂ emissions in 2020 under Lieberman/Warner is offset by a roughly 57 million tonne increase in non-U.S. refinery emissions, yielding a slight increase in global refinery CO₂ emissions.

Exhibit 5-12 and

Exhibit 5-13 show more detailed information on estimated GHG emissions from U.S. refineries.

The lowered utilization estimated in the United States is an indication of the possible closing of some refineries.

In the assumptions that were discussed at the beginning of Chapter 3, ICF noted that outside of the United States only the EU and Canada were assumed to have substantial or stringent greenhouse gas emission controls. Consequently, the modeling indicates that plants (or plant capacity) are likely to migrate to the areas where costs are less; that is, where there are either no GHG emission controls or only superficial ones. The differential would be the cost of the allowances as refineries, wherever sited, would have to make the technology investments to meet the product specifications that apply in the United States.

Overall, based on the detailed oil and gas well information in the Hydrocarbon Supply Model and the refinery specific information contained in the WORLD model, it is estimated that:

- In the upstream sector, fewer wells are drilled or existing low yield wells are shut in resulting in less U.S. production.
- In the downstream sector, all U.S. refineries but especially the less efficient or more processing/energy intensive ones are adversely affected.

In addition, what the modeling of the downstream sector shows, despite all the caveats, is that in dealing with a global market when fairly stringent controls are imposed on plants in only one part of the world – in this case, the United States – resulting in additional costs, the tendency is for those plants to migrate overseas. The likely impact on the United States would be the attendant costs of lost jobs and revenues as well as increased product imports.

Exhibit 5-11: Estimated Investment Levels, Throughput, and Utilization by PADD for the 2012 and 2020 Base Case and the Lieberman/McCain Case

	TOTAL	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5	USA	ROW
TOTAL INVESTMENTS								
Base Case 2012	132.10	2.85	11.11	13.71	3.35	5.06	36.08	92.02
Lieberman/Warner 2012	160.14	2.60	9.90	10.44	3.20	6.74	32.88	127.26
Base Case 2020	213.60	3.93	11.24	18.66	2.91	10.51	47.288	166.34
Lieberman/Warner 2020	258.22	2.71	8.88	9.178	2.59	12.42	35.77	222.45
TOTAL THROUGHPUTS								
Base Case 2012	78.84	1.43	3.87	8.16	0.60	2.95	17.02	61.82
Lieberman/Warner 2012	78.49	1.31	3.87	7.21	0.59	2.81	15.79	62.70
Base Case 2020	86.85	1.70	4.15	8.81	0.59	3.20	18.46	68.40
Lieberman/Warner 2020	86.43	1.35	3.99	6.67	0.57	2.96	15.54	70.89
UTILIZATION								
Base Case 2012	84.8%	88.7%	93.0%	90.8%	93.1%	89.9%	91.0%	83.2%
Lieberman/Warner2012	83.8	82.6%	93.0%	81.3%	92.3%	86.2%	85.3%	83.5%
Base Case 2020	86.1%	96.0%	93.0%	92.3%	93.1%	91.5%	92.7%	84.4%
Lieberman/Warner 2020	84.5%	84.8%	93.0%	75.8%	89.9%	87.2.6%	83.1%	84.8%

Note: Investments are in billions 2006\$. Throughputs are in MMB/d.

Exhibit 5-12: Estimated Refinery CO2 Emissions in 2012 and 2020 for the Base Case and the Lieberman/Warner Case

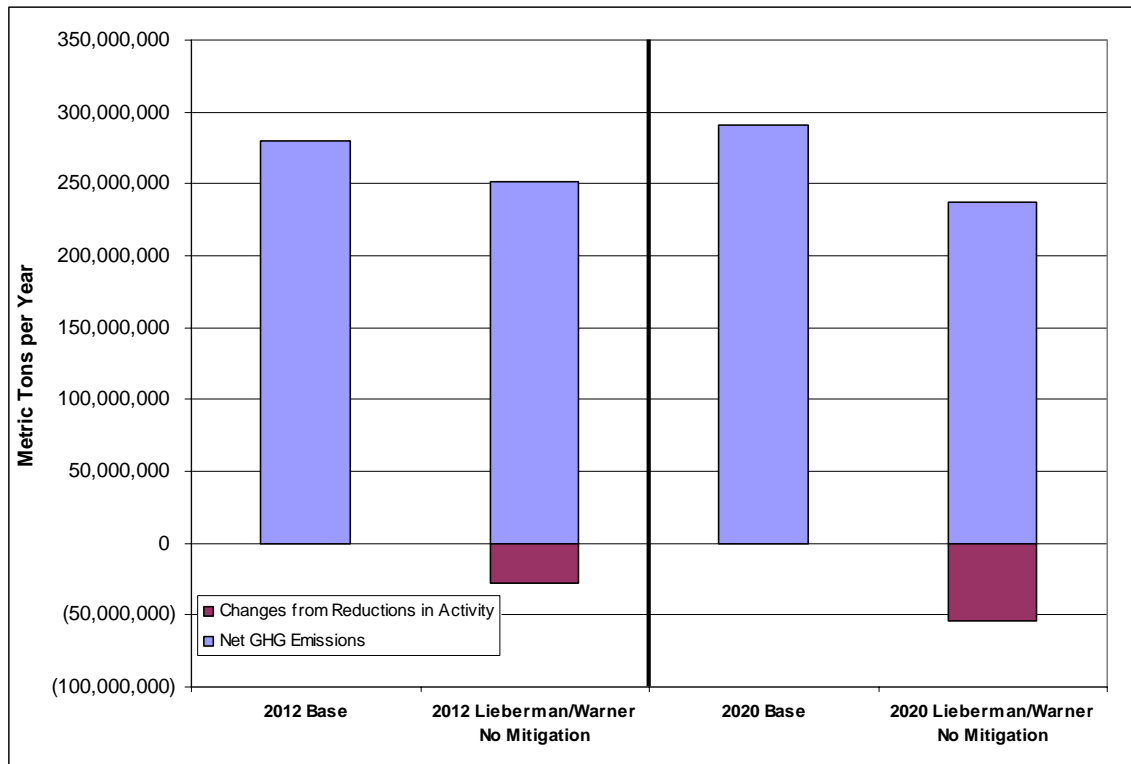
BASE CASE 2012						
CO2 Emissions - million tonnes per year	US Total	PADD-1	PADD-2	PADD-3	PADD-4	PADD-5
- from H2 plant	27.74	0.85	5.35	13.99	0.35	7.20
- from Refinery Fuel Oil	241.50	20.59	52.39	118.44	8.10	41.98
- from Flare/Loss	9.45	0.80	2.15	4.53	0.34	1.64
- from Sulfur Plant Tail Gas	0.75	0.03	0.13	0.45	0.01	0.12
Total	279.44	22.27	60.02	137.41	8.80	50.93

L-W 2012						
CO2 Emissions - million tonnes per year	US Total	PADD-1	PADD-2	PADD-3	PADD-4	PADD-5
- from H2 plant	22.17	0.93	4.50	9.75	0.33	6.66
- from Refinery Fuel Oil	220.16	18.21	51.87	103.45	7.57	39.06
- from Flare/Loss	8.77	0.73	2.15	4.00	0.33	1.56
- from Sulfur Plant Tail Gas	0.63	0.04	0.12	0.34	0.01	0.12
Total	251.72	19.91	58.65	117.54	8.24	47.40

BASE CASE 2020						
CO2 Emissions - million tonnes per year	US Total	PADD-1	PADD-2	PADD-3	PADD-4	PADD-5
- from H2 plant	30.83	1.20	5.57	16.57	0.40	7.10
- from Refinery Fuel Oil	249.36	22.22	54.52	122.52	7.23	42.87
- from Flare/Loss	10.25	0.94	2.31	4.89	0.33	1.78
- from Sulfur Plant Tail Gas	0.86	0.05	0.15	0.49	0.01	0.16
Total	291.31	24.41	62.54	144.48	7.97	51.91

L-W 2020						
CO2 Emissions - million tonnes per year	US Total	PADD-1	PADD-2	PADD-3	PADD-4	PADD-5
- from H2 plant	20.94	0.90	4.03	8.43	0.33	7.26
- from Refinery Fuel Oil	207.02	18.99	51.81	90.38	7.12	38.72
- from Flare/Loss	8.63	0.75	2.22	3.70	0.32	1.64
- from Sulfur Plant Tail Gas	0.59	0.04	0.10	0.32	0.01	0.13
Total	237.18	20.67	58.16	102.82	7.77	47.75

Exhibit 5-13: Summary of Refining Results: Estimated GHG Emissions without Mitigation



GHG ALLOWANCE COSTS AND “CONSUMER EMISSIONS”

Consumer Emission Allowances

While this report focuses on the likely operational impacts on oil and gas facilities of the proposed bills in Congress, an important aspect of the many economy wide bills is the varied approach they take towards so-called “consumer emissions.” The term “consumer emissions” – some times called “tailpipe emissions” when referring to vehicles -- refers to the emissions that come from the actual use of a product rather than from the production or processing of the product.

Under Lieberman/Warner, natural gas processing plants would be responsible for acquiring allowances for CO₂ emissions that will come from the future consumer use of the natural gas processed at the plant (as it is prepared for pipeline shipment) even though the CO₂ emissions actually occur only when that natural gas is used by home owners and businesses. Similarly under Lieberman/Warner, for all petroleum products delivered to the market, refineries would be responsible for acquiring allowances for the CO₂ emissions that will occur when the products are used by home owners, vehicle owners, and other businesses, with the exception of petrochemical feedstocks.

To put consumer emissions into perspective, this section compares the GHG allowance requirements that arise because of emissions at oil and gas sector operations to the much larger allowance requirements associated with consumer emissions.

UPSTREAM SECTOR ALLOWANCE COSTS – EXPLORATION AND PRODUCTION

Exhibit 5-14 summarizes the allowance requirements under Lieberman/Warner to put upstream allowance requirements in perspective. Briefly:

- Under Lieberman/Warner compliance obligations of upstream oil and gas facilities would depend on an EPA rulemaking required under Section 1204. Consumer emissions from the use of oil and gas produced at upstream facilities are addressed at refineries and natural gas plants. Also, refineries and natural gas plants would need to acquire allowances for their facility emissions. Because of that general approach in Lieberman/Warner and the expansive language in Section 1204, this study evaluates potential impacts on upstream facilities at the assumed Lieberman/Warner allowance costs. Under these assumptions, exploration and production sector allowance costs are estimated to range from about \$4.99 billion in 2012 to \$6.94 billion in 2020.

Exhibit 5-14: Estimated E&P Sector Allowance Costs – After Mitigation and Adjusted for Reduced Activity

	Units	2012 L/W.	2020 L/W.
Allowance Cost	2006\$/tCO ₂ e	\$41.21	\$57.31
GHG Emissions After Mitigation	Million tCO ₂ e	121.0	121.0
Direct Emission Allowance Cost	Million 2006\$	\$4,986	\$6,935

UPSTREAM SECTOR ALLOWANCE COSTS -- NATURAL GAS PROCESSING PLANTS

Natural gas processing plants under Lieberman/Warner are required to obtain allowances for their own facility emissions as well the emissions that will come from consumer use of natural gas delivered to the market.

- Under Lieberman/Warner and after assumed mitigation efforts, facility GHG emissions in 2012 are estimated at about 45.02 million tCO₂e but consumer emissions from the natural gas processed at natural gas processing plants are estimated about 961 million tCO₂e. Under Lieberman/Warner, natural gas processing plants would have an allowance cost of about \$1.855 billion dollars for facility emissions plus the allowances for “consumer emissions” from natural gas use that would cost an additional \$39.6 billion. In 2020, the corresponding emissions would be about 38.3 million tCO₂e, and the corresponding allowances costs would be about \$2.197 billion and \$59.9 billion.

Exhibit 5-15: Estimated Natural Gas Processing Plant Allowance Costs – After Mitigation and Adjusted for Reduced Gas Production

	Units	2012 L/W	2020 L/W
Allowance cost	2006\$/tCO ₂ e	\$41.21	\$57.31
GHG Emissions After Mitigation	Million tCO ₂ e	45.02	38.34
Facility Direct Emission Allowance Cost	Million 2006\$	\$1,855	\$2,197
Natural Gas Throughput	Bcf	18,213	19,797
Consumer Emissions	Million tCO ₂ e	961	1,045
Cost of Nat. Gas Plant Allowances For Consumer Emissions	Million 2006\$	\$39,620	\$59,891
Total Allowance Cost (Facility + Consumer)	Million 2006\$	\$41,476	\$62,086

REFINERY ALLOWANCE COSTS

Under Lieberman/Warner refineries must submit GHG allowances for their facility GHG emissions and they must also submit allowances for GHG emissions that will come from consumer use of *all* petroleum products produced with the exception of petrochemical feedstocks.

For this assessment, CO₂ emissions of all petroleum products are estimated based on an average CO₂ content (20.9859 lbs of CO₂ per gallon) and refinery throughput as reported in Chapter 3. Since this assessment is focusing on refineries, allowance requirements associated with imported petroleum products are not included. The detailed results are outlined in Exhibit 5-16.

- Under Lieberman/Warner, 2012 refinery CO₂ emissions are estimated at 251.72 million tCO₂e with an associated allowance cost of about \$10.4 billion. The consumer emissions requirement under Lieberman/Warner, however, covers emissions from consumer use of all petroleum fuels except petrochemical feedstocks. Emissions from these fuels are estimated at about 2,189 million tCO₂e and the associated allowances would cost refineries about \$90.21 billion in 2012. For 2012, refineries would thus have to obtain allowances worth about \$100.58 billion to meet their obligations. The estimated allowance cost is equivalent to almost 44 cents/gallon of throughput.

In 2020, the models indicate that refinery CO₂ emissions would total about 237.18 million tCO₂e and allowance costs would be about \$13.59 billion. Consumer emissions, however, would total 2,154 million tCO₂e and the allowances for these emissions would cost about \$123.45 billion. In 2020, the total refinery allowance requirement would total about \$137.04 billion. The estimated allowance cost is equivalent to almost 61 cents/gallon of throughput.

**Exhibit 5-16: Refining Sector Estimated Allowance Costs
(Excludes Product Imports)**

	<u>2012</u> L/W	<u>2020</u> L/W
CO2 Allowance Cost (2006\$/tCO2e)	\$41.21	\$57.31
Refinery Throughput (Mill B/d)	15.79	15.54
Refinery Throughput (Mill gal/Yr)	242,060	238,230
Non-Feedstocks (Million gal/Yr) assuming 95% are not exempt feedstocks	229,260	226,320
Refinery Direct CO2 Emissions (Mill tCO2e/yr)	251.72	237.18
Total Allowance Cost for Direct Emissions (2006\$ Million)	\$10,373	\$13,593
Direct Emission Allowance cost: <u>Cents per gal/non-feedstocksthroughput</u>	4.51	5.71
Consumer Emissions of Petroleum Products (Mill. tCO2e) (Assuming 20.9859 lbs CO2 per gallon product)	2,189	2,154
Cost of Allowances for Consumer Emissions (2006\$ Million)	\$90,209	\$123,450
Consumer Emission Allowance cost:		
Cents per gal/covered throughput	39.2	54.6
Total Refinery Allowance Cost (refinery + consumer emission, 2006\$ Million)	\$100,582	\$137,043
Allowance cost: cents/gallon (Refinery emissions + consumer emissions)	43.7	60.6