THE EUROPEAN WIND ENERGY ASSOCIATION

Wind in power

2013 European statistics

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Contents

Data collection and analysis

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Data sources

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Executive summary

2013 annual installations

- 11,159 MW of wind power capacity (worth between €13 bn and €18 bn) was installed in the EU-28 during 2013, a decrease of 8% compared to 2012 installations.
- EU wind power installations for 2013 show the negative impact of market, regulatory and political uncertainty sweeping across Europe. Destabilised legislative frameworks for wind energy are undermining investments.
- Wind power is the technology which installed the most in 2013: 32% of total 2013 power capacity installations - five percentage points higher than during the previous year.
- Renewable power installations accounted for 72% of new installations during 2013: 25 GW of a total 35 GW of new power capacity, up from 70% the previous year.

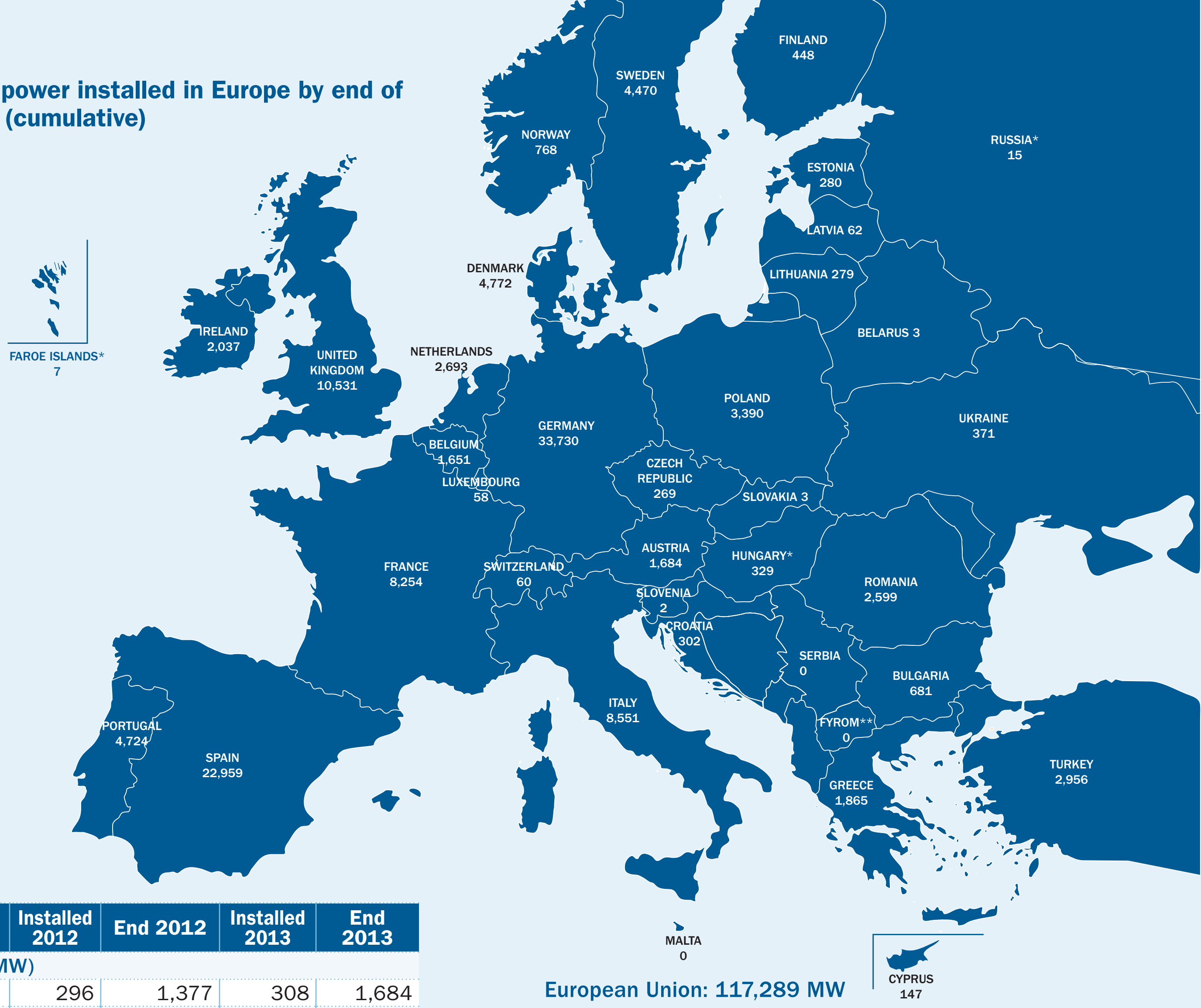
Trends and cumulative installations

- There are now 117.3 GW of installed wind energy capacity in the EU: 110.7 GW onshore and 6.6 GW offshore.
- The EU's total installed power capacity increased by 13 GW net to 900 GW, with wind power increasing by 11.2 GW and reaching a share of total installed generation capacity of 13%, up one percentage point compared to the previous year.
- Since 2000, over 28% of new capacity installed has been wind power, 55% renewables and 92% renewables and gas combined.
- The EU power sector continues its move away from fuel oil and coal with each technology continuing to decommission more than it installs.

Wind power installations

- Annual installations of wind power have increased over the last 13 years, from 3.2 GW in 2000 to 11.2 GW in 2013, a compound annual growth rate of 10%.
- A total of 117.3 GW is now installed in the European Union, an increase in installed cumulative capacity of 10% compared to the previous year.
- Germany remains the EU country with the largest installed capacity followed by Spain, the UK and Italy. Fifteen EU countries have more than 1 GW of installed capacity, including two newer EU countries (Poland and Romania), and eight EU countries have more than 4 GW of installed capacity.
- The volatility across Europe has contributed to 46% of all new installations in 2013 being in just two countries (Germany and the UK), a significant concentration compared to the trend of previous years whereby installations were increasingly spread across healthy European Markets. This is a level of concentration that has not been seen in the EU's wind power market since 2007 when the three wind energy pioneering countries (Denmark, Germany and Spain) together represented 58% of all new installations that year.
- A number of previously healthy markets such as Spain, Italy and France have seen their rate of wind energy installations decrease significantly in 2013, by 84%, 65% and 24% respectively.
- Offshore saw a record growth in 2013 (+1.6 GW); the outlook for 2014 and 2015 is stable, but not growing.
- The wind power capacity installed by the end of 2013 would, in a normal wind year, produce 257 TWh of electricity, enough to cover 8% of the EU's electricity consumption – up from 7% the year before.

Wind power installed in Europe by end of 2013 (cumulative)



European Union: 117,289 MW
Candidate Countries: 2,956 MW
EFTA: 830 MW
Total Europe: 121,474 MW

	Installed 2012	End 2012	Installed 2013	End 2013
EU Capacity (MW)				
Austria	296	1,377	308	1,684
Belgium	297	1,375	276	1,651
Bulgaria	158	674	7.1	681
Croatia	48	180	122	302
Cyprus	13	147	0	147
Czech Republic	44	260	9	269
Denmark	220	4,162	657	4,772
Estonia	86	269	11	280
Finland	89	288	162	448
France	814	7,623	631	8,254
Germany	2,297	30,989	3,238	33,730
Greece	117	1,749	116	1,865
Hungary*	0	329	0	329
Ireland	121	1,749	288	2,037
Italy	1,239	8,118	444	8,551
Latvia	12	60	2	62
Lithuania	60	263	16	279
Luxembourg	14	58	0	58
Malta	0	0	0	0
Netherlands	119	2,391	303	2,693
Poland	880	2,496	894	3,390
Portugal	155	4,529	196	4,724
Romania	923	1,905	695	2,599
Slovakia	0	3	0	3
Slovenia	0	0	2	2
Spain	1,110	22,784	175	22,959
Sweden	846	3,582	724	4,470
United Kingdom	2,064	8,649	1,883	10,531
Total EU-28	**12,102**	**106,454**	**11,159**	**117,289**
Total EU-15	**9,879**	**99,868**	**9,402**	**108,946**
Total EU-13	**2,224**	**6,586**	**1,757**	**8,343**

	Installed 2012	End 2012	Installed 2013	End 2013
Candidate Countries (MW)				
FYROM**	0	0	0	0
Serbia	0	0	0	0
Turkey	506	2,312	646	2,956
Total	**506**	**2,312**	**646**	**2,956**
EFTA (MW)				
Iceland	0	0	1,8	1,8
Liechtenstein	0	0	0	0
Norway	166	703	110	768
Switzerland	4	50	13	60
Total	**170**	**753**	**125**	**830**
Other (MW)				
Belarus	0	3	0	3
Faroe Islands	2	2	5	7
Ukraine	125	276	95	371
Russia*	0	15	0	15
Total	**127**	**297**	**100**	**397**
Total Europe	**12,906**	**109,816**	**120,030**	**121,474**

* Provisional data or estimate.
** Former Yugoslav Republic of Macedonia
Note: due to previous year adjustments, 372 MW of project de-commissioning, re-powering and rounding of figures, the total 2013 end-of-year cumulative capacity is not exactly equivalent to the sum of the 2012 end-of-year total plus the 2013 additions.

2013 annual installations

Wind power capacity installations

During 2013, 12,030 MW of wind power was installed across Europe, of which 11.159 MW was in the European Union, 8% less than the previous year.

Of the 11,159 MW installed in the EU, 9,592 MW was onshore and 1,567 MW offshore. In 2013, the onshore market decreased in the EU by 12%, whilst offshore installations grew by 34%. Overall, the wind energy market decreased by 8% compared to 2012 installations.

Investment in EU wind farms was between €13 billion (bn) and €18 bn. Onshore wind farms attracted around €8 bn to €12 bn, while offshore wind farms accounted for €4.6 bn to €6.4 bn.

In terms of annual installations, Germany was the largest market in 2013, installing 3,238 MW of new capacity, 240 MW of which (7%) offshore. The UK came in second with 1,883 MW, 733 MW of which (39%) offshore, followed by Poland with 894 MW, Sweden (724 MW), Romania (695 MW), Denmark (657 MW), France (631 MW) and Italy (444 MW).

The emerging markets of central and eastern Europe, including Croatia, installed 1,755 MW, 16% of total installations. In 2013, these countries represent a slightly smaller share of the total EU market than in 2012 (18%).

Moreover, 46% of all new EU installations in 2013 were in just two countries (Germany and the Uk), a significant concentration compared to the trend of previous years when installations were increasingly spread across Europe. This is a level of concentration that has not been seen in the EU's wind power market since 2007 when the three wind energy pioneering countries (Denmark, Germany and Spain) together represented 58% of all new installations that year.

A number of previously large markets such as Spain, Italy and France have seen their rate of wind energy installations decrease significantly in 2013, by 84%, 65%, 24% respectively.

Offshore accounted for almost 14% of total EU wind power installations in 2013, four percentage points more than in 2012, further confirming the high level of concentration in annual installations during 2013.

FIGURE 1.1: EU MEMBER STATE MARKET SHARES FOR NEW CAPACITY INSTALLED DURING 2013 IN MW. TOTAL 11,159 MW

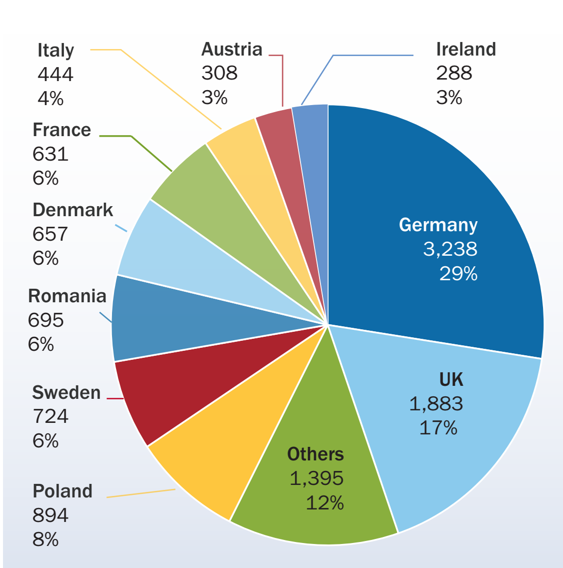


Photo: Kay Ludwig

Power capacity installations

Overall, during 2013, 35 GW of new power generating capacity was installed in the EU, 10 GW less than in 2012.

Wind power accounted for 32% (11.2 GW) of new installations in 2013. Followed by solar PV (31%, 11 GW) and gas (21%, 7.5 GW).

No other technologies compare to wind, PV and gas in terms of new installations. Coal installed 1.9 GW (5% of total installations), biomass 1.4 GW (4%), hydro 1.2 GW (4%), CSP 419 MW (1%), fuel oil 220 MW, waste 180 MW, nuclear 120 MW, geothermal 10 MW and ocean 1 MW.

During 2013, 10 GW of gas capacity was decommissioned, as were 7.7 GW of coal, 2.7 GW of fuel oil and 750 MW of biomass capacity.

FIGURE 1.2: SHARE OF NEW POWER CAPACITY INSTALLATIONS IN EU, TOTAL 35,181 MW

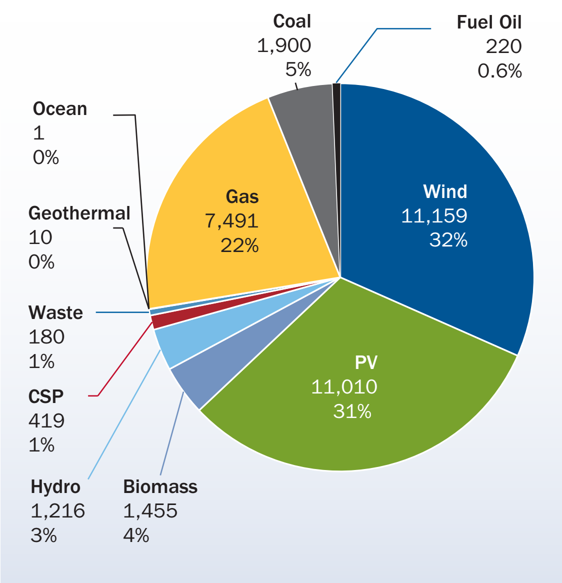


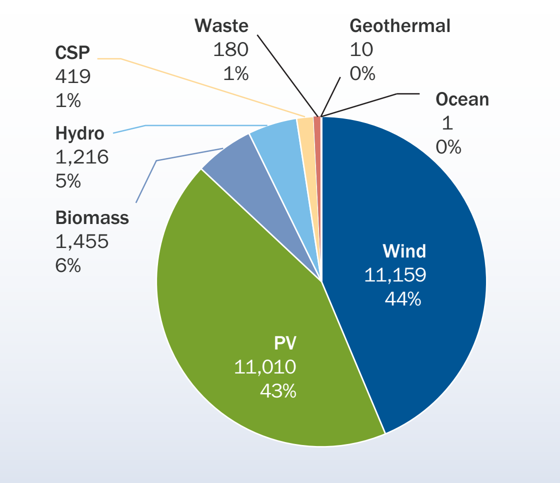
FIGURE 1.3: NEW INSTALLED POWER CAPACITY AND DECOMMISSIONED POWER CAPACITY IN MW

(1) Provisional data.

Renewable power capacity installations

In 2013, a total of 25.4 GW of renewable power capacity installations were installed. Over 72% of all new installed capacity in the EU was renewable. It was, furthermore, the sixth year running that over 55% of all new power capacity in the EU was renewable.

FIGURE 1.4: 2013 SHARE OF NEW RENEWABLE POWER CAPACITY INSTALLATIONS IN MW, TOTAL 25,450 MW



Trends & cumulative installations

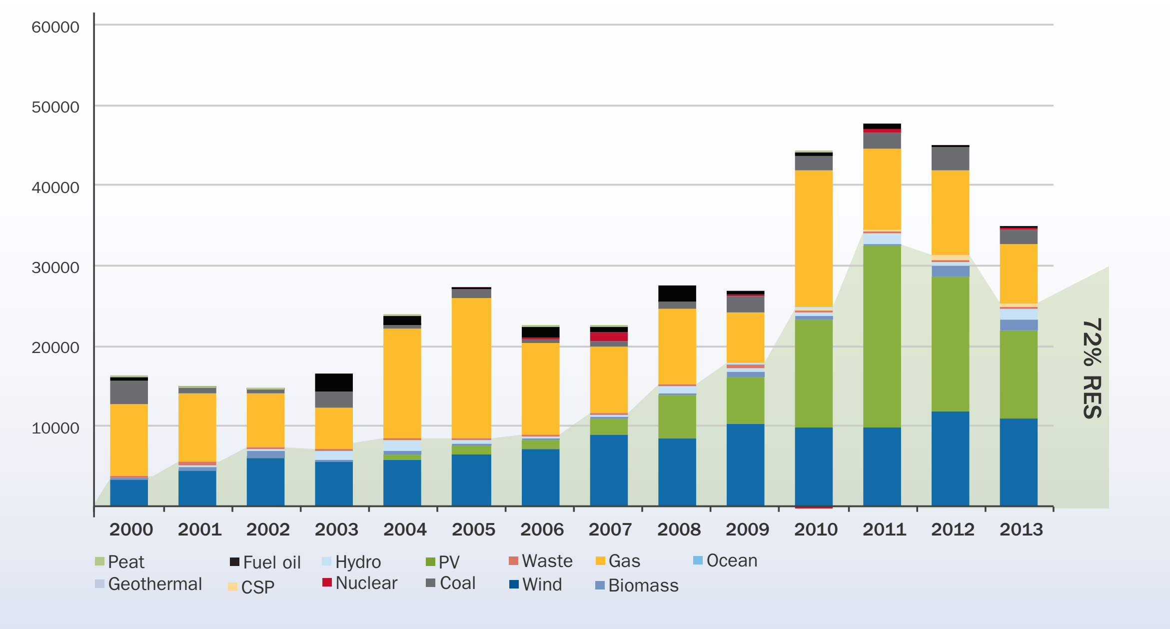
Renewable power capacity installations

In 2000, new renewable power capacity installations totalled a mere 3.6 GW. Since 2010, annual renewable capacity additions have been between 24.7 GW and 35.2 GW, eight to ten times higher than in 2000.

The share of renewables in total new power capacity additions has also grown. In 2000, the 3.6 GW represented 22.4% of new power capacity installations, increasing to 25 GW representing 72% in 2013.

385 GW of new power capacity has been installed in the EU since 2000. Of this, over 28% has been wind power, 55% renewables and 92% renewables and gas combined.

FIGURE 2.1: INSTALLED POWER GENERATING CAPACITY PER YEAR IN MW AND RENEWABLE ENERGY SHARE (%)

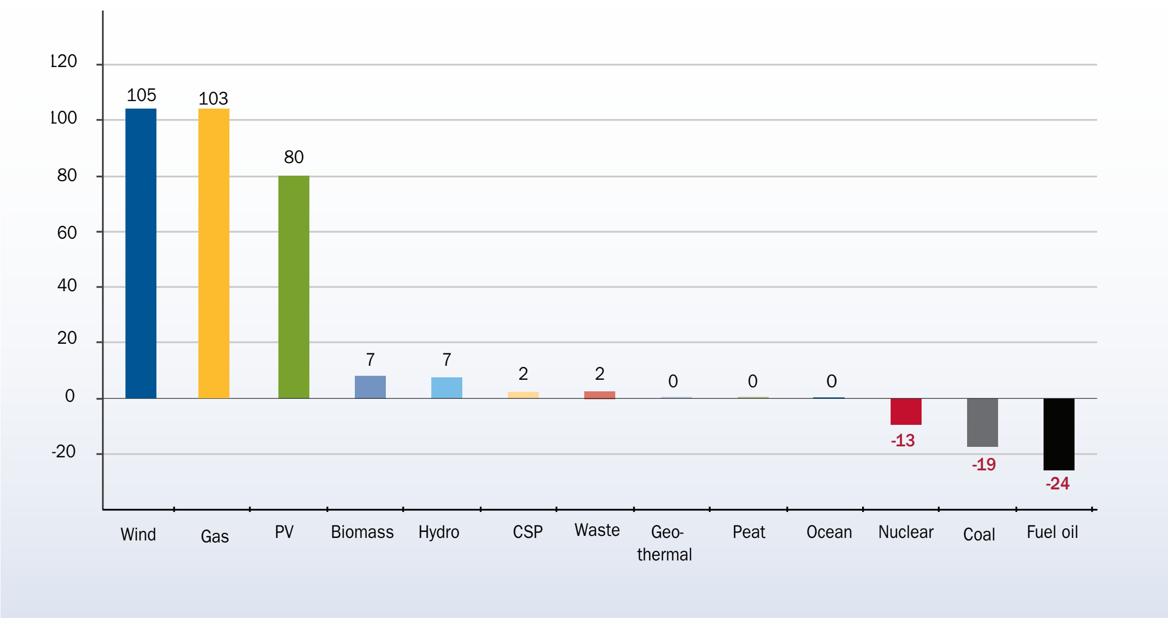


Net changes in EU installed power capacity 2000-2013

The net growth since 2000 of gas power (131.7 GW), wind (115.4 GW) and solar PV (80 GW) was at the expense of fuel oil (down 28.7 GW), coal (down 19 GW) and nuclear (down 9.5 GW). The other renewable technologies (hydro, biomass, waste, CSP, geothermal and ocean energies) have also been increasing their installed capacity over the past 13 years, albeit more slowly than wind and solar PV.

The EU's power sector continues to move away from fuel oil, coal and nuclear while increasing its total installed generating capacity with gas, wind, solar PV and other renewables.

FIGURE 2.2: NET ELECTRICITY GENERATING INSTALLATIONS IN THE EU 2000-2013 (GW)



Total installed power capacity

Wind power's share of total installed power capacity has increased five-fold since 2000; from 2.4% in 2000 to 13% in 2013. Over the same period, renewable capacity increased by 61% from 24.5% of total power capacity in 2000 to 39.6% in 2013.

FIGURE 2.3: EU POWER MIX 2000

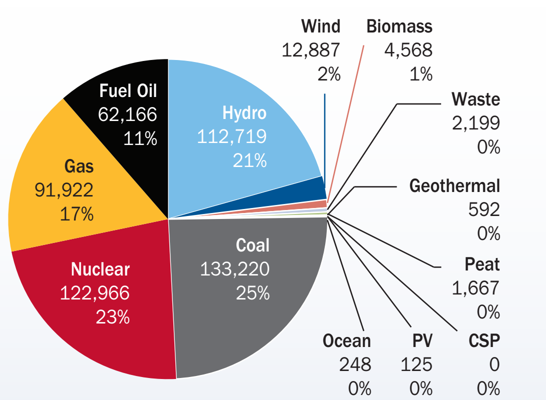
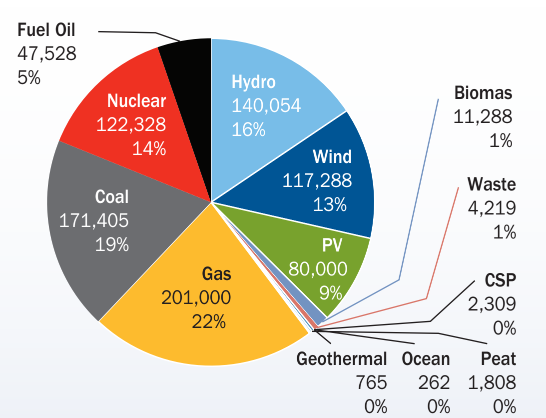


FIGURE 2.4: EU POWER MIX 2013



A closer look at wind power installations

Total installed power capacity

Annual wind power installations in the EU have increased steadily over the past 13 years from 3.2 GW in 2000 to 11 GW in 2013, a compound annual growth rate of over 10%.

FIGURE 3.1: ANNUAL WIND POWER INSTALLATIONS IN EU (GW)

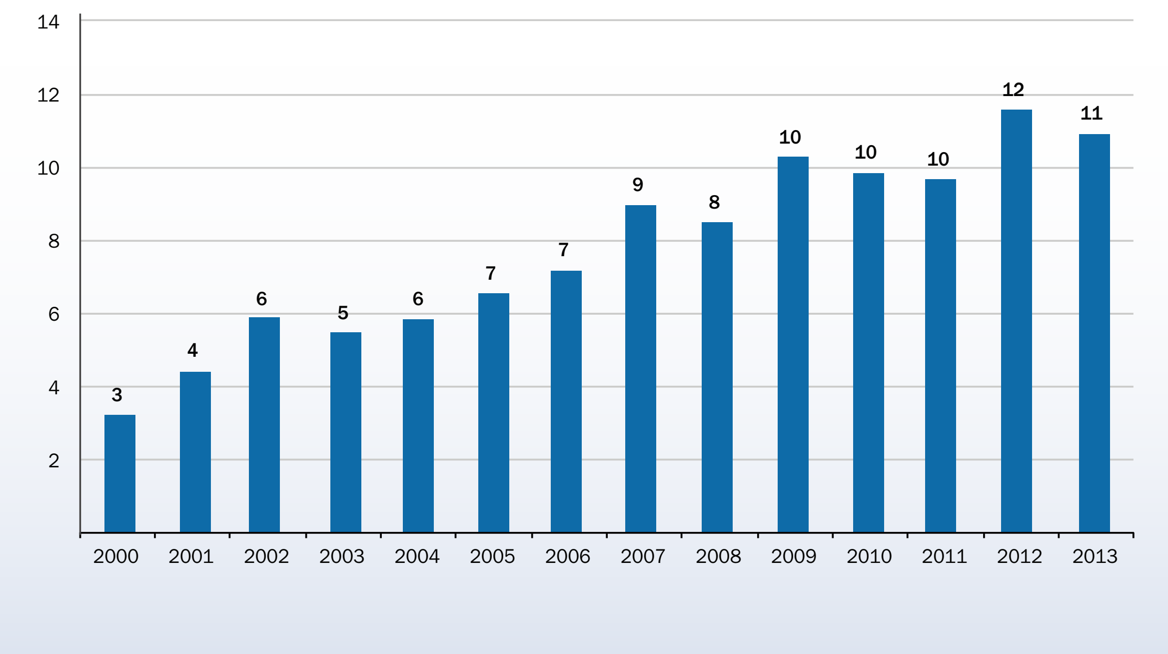


Photo: Joan Sullivan

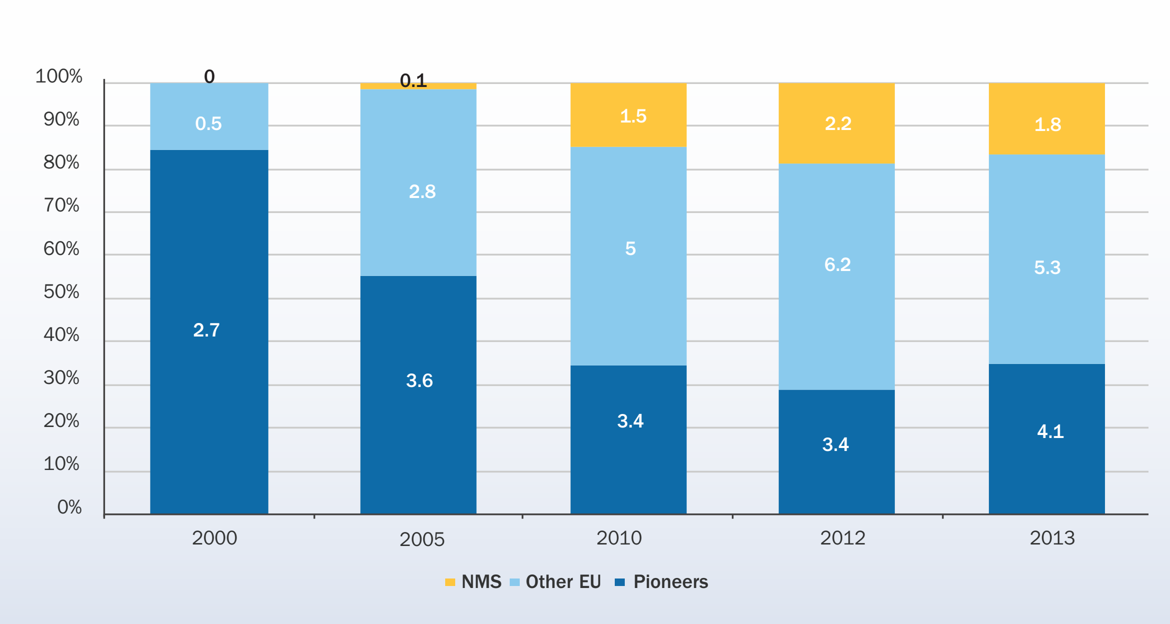
National breakdown of wind power installations

In 2000, the annual wind power installations of the three pioneering countries – Denmark, Germany and Spain – represented 85% of all EU wind capacity additions. By 2012, they represented only 29% of total installations. In 2013, although the Spanish market contracted significantly compared to the previous year (-84%), the German market grew by 36% and installations in the three pioneering countries together represented 36% of the EU market.

Moreover, in 2000, the countries that make up, today, the 13[1] newer EU Member States, had no wind energy, in 2013, they reached 16% of the EU's total market. However, 90% of those installations were in just two countries, Poland and Romania.

This indicates that the renewables policy instability that has affected numerous countries in the EU is leading to increased concentration of wind energy installation in a handful of countries.

FIGURE 3.2 SHARE OF EU WIND POWER MARKET, PIONEERING COUNTRIES, NEWER MEMBER STATES, AND REST OF EU (GW)



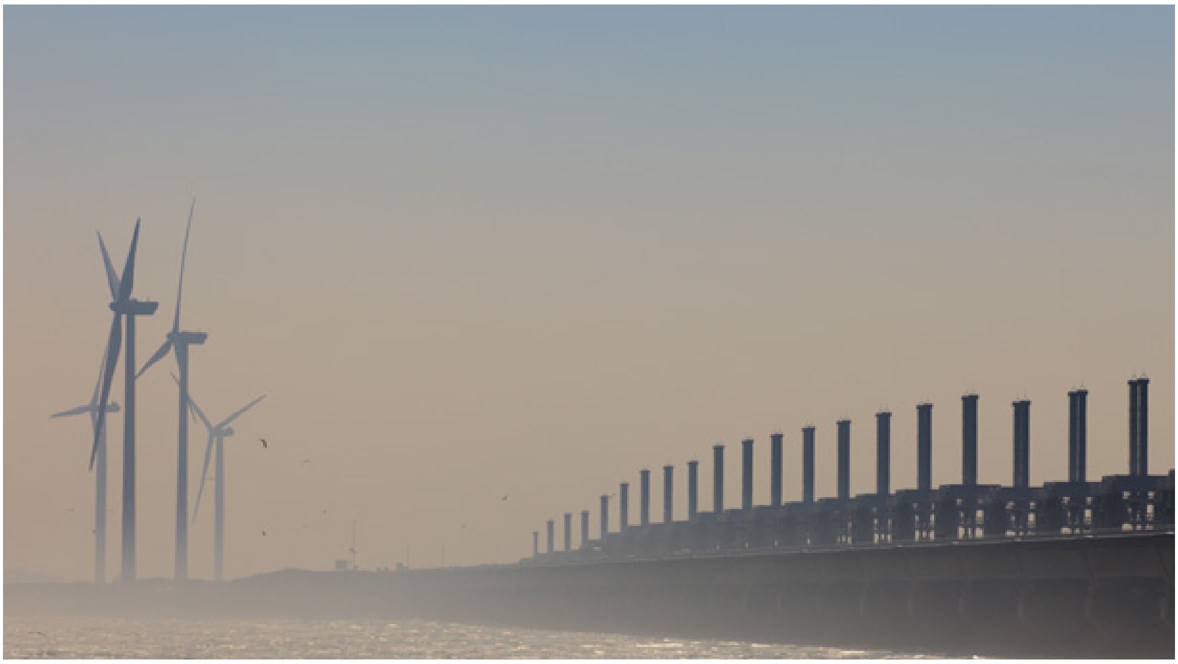


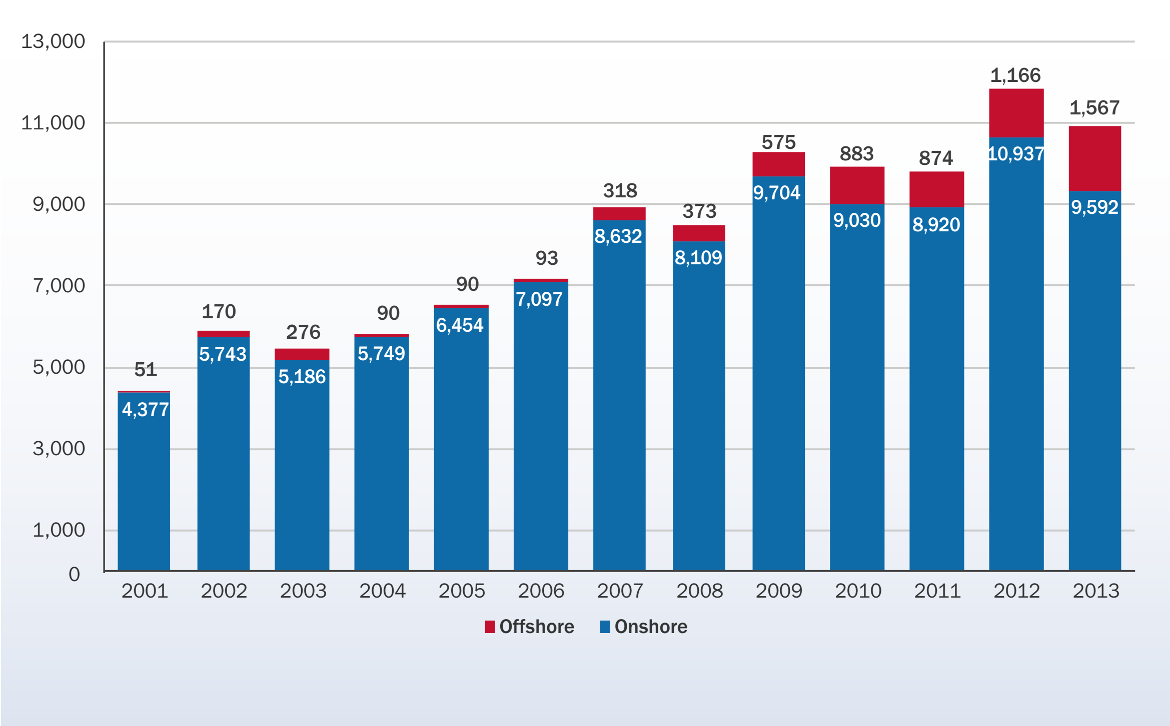
Photo: Arjan de Jager

[1] Bulgaria, Croatia Cyprus, Czech Republic, Estonia, Hungary, Latvia, Lithuania, Malta, Poland, Romania, Slovakia, Slovenia.

Onshore and offshore annual markets

2013 was a record year for offshore installations, with 1,567 MW of new capacity grid connected. Offshore wind power installations represent over 14% of the annual EU wind energy market, up from 10% in 2012.

FIGURE 3.3: ANNUAL ONSHORE AND OFFSHORE INSTALLATIONS (MW)

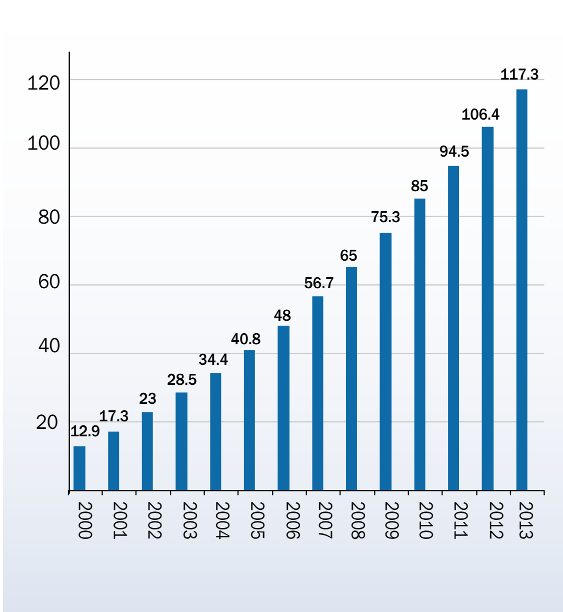


Cumulative wind power installations

A total of 117 GW is now installed in the European Union, a growth of 10% on the previous year and lower to the growth recorded in 2012 (+12% compared to 2011). Germany remains the EU country with the largest installed capacity, followed by Spain, the UK, Italy and France. Eleven other EU countries have over 1 GW of installed capacity: Austria, Belgium, Denmark, France, Greece, Ireland, The Netherlands, Poland, Portugal, Romania and Sweden.

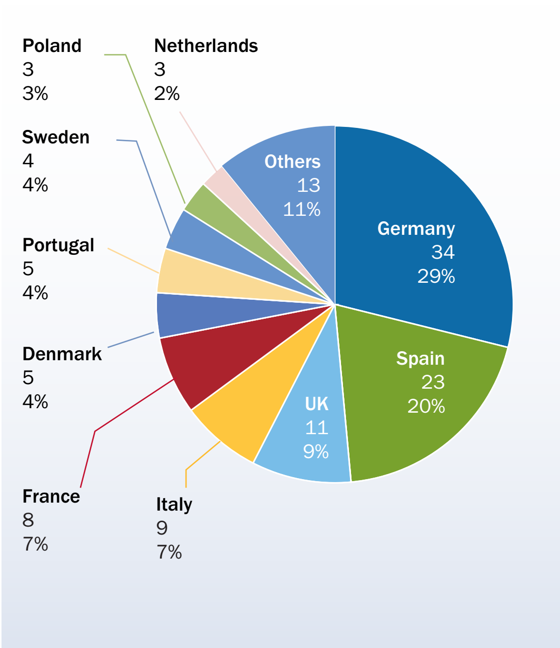
Eight of the latter (Denmark, France, Germany, Italy, Portugal, Spain, Sweden, United Kingdom), have more than 4 GW of installed wind energy capacity.

FIGURE 3.4: CUMULATIVE WIND POWER INSTALLATIONS IN THE EU (GW)



Germany (34.3 GW) and Spain (23 GW) have the largest cumulative installed wind energy capacity in Europe. Together they represent 49% of total EU capacity. The UK, Italy and France follow with, respectively, 10.5 GW (9% of total EU capacity), 8.6 GW (7%) and 8.3 GW (7%). Amongst the newer Member States, Poland, with 3.4 GW (2.9%) of cumulative capacity, is now in the top 10, in front of the Netherlands (2.7 GW, 2%), and Romania is 11th with 2.6 GW (2%).

FIGURE 3.5: EU MEMBER STATE MARKET SHARES FOR TOTAL INSTALLED CAPACITY (TOTAL 118 GW)



Estimated wind energy production

The wind energy capacity currently installed in the EU would produce in an average wind year 257 TWh of electricity, enough to cover the 8% of the EU's total electricity consumption.

TABLE 1: WIND ENERGY SHARE OF EU ELECTRICITY CONSUMPTION[2]

Total EU electricity consumption	Onshore wind energy production	Offshore wind energy production	Share of EU consumption met by onshore wind	Share of EU consumption met by offshore wind	Share of EU consumption met by wind
3,280 TWh	233 TWh	24 TWh	7.1%	0.7%	7.8%

[2] Wind energy penetration levels are calculated using average capacity factors onshore and offshore and Eurostat electricity consumption figures (2011). Consequently, table 1 indicates approximate share of consumption met by the installed wind energy capacity at end 2013. The figure does not represent real wind energy production over a calendar year.

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Comparative Life-Cycle Air Emissions of Coal, Domestic Natural Gas, LNG, and SNG for Electricity Generation

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The U.S. Department of Energy (DOE) estimates that in the coming decades the United States' natural gas (NG) demand for electricity generation will increase. Estimates also suggest that NG supply will increasingly come from imported liquefied natural gas (LNG). Additional supplies of NG could come domestically from the production of synthetic natural gas (SNG) via coal gasification−methanation. The objective of this study is to compare greenhouse gas (GHG), SO_x, and NO_x life-cycle emissions of electricity generated with NG/LNG/SNG and coal. This life-cycle comparison of air emissions from different fuels can help us better understand the advantages and disadvantages of using coal versus globally sourced NG for electricity generation. Our estimates suggest that with the current fleet of power plants, a mix of domestic NG, LNG, and SNG would have lower GHG emissions than coal. If advanced technologies with carbon capture and sequestration (CCS) are used, however, coal and a mix of domestic NG, LNG, and SNG would have very similar life-cycle GHG emissions. For SO_x and NO_x we find there are significant emissions in the upstream stages of the NG/LNG life-cycles, which contribute to a larger range in SO_x and NO_x emissions for NG/LNG than for coal and SNG.

1. Introduction

Natural gas currently provides 24% of the energy used by United States homes (*1*). It is an important feedstock for the chemical and fertilizer industry. Low wellhead gas prices (less than \$3/thousand cubic feet (Mcf) (*2*)) spurred a surge in construction of natural-gas-fired power plants: between 1992 and 2003, while coal-fired capacity increased only from 309 to 313 GW, natural-gas-fired capacity more than tripled, from 60 to 208 GW (*3*). Adding to this was the Energy Information Agency's (EIA) prediction of continued low natural gas prices (around \$4/Mcf) through 2020 (*4*), lower capital costs, shorter construction times, and generally lower air emissions for natural-gas-fired plants that allowed power generators to meet the clean air standards (*5*). However, instead of remaining near projected levels, the average wellhead price of natural gas peaked at \$11/Mcf in October 2005 (*6*). This price increase made natural gas uneconomical as a feedstock, so most natural-gas-fired plants are operating below capacity (*7*). Despite these trends, natural gas consumption is expected to increase by 20% of 2003 levels by 2030. Demand from electricity generators is projected to grow the fastest. At the same time, natural gas production in the United States and pipeline imports from Canada and Mexico are expected to remain fairly constant (*8*). The gap between North American supply and U.S. demand can only be met with alternative sources of natural gas, such as imported liquefied natural gas (LNG) or synthetic natural gas (SNG) produced from coal. Current projections by EIA estimate that LNG imports will increase to 16% of the total U.S. natural gas supply by 2030 (*8*). Alternatively, Rosenberg et al. call for congress to promote gasification technologies that use coal to produce SNG. This National Gasification Strategy calls for the United States to produce 1.5 trillion cubic feet (tcf) of synthetic natural gas per year within the next 10 years (*7*), equivalent to 5% of expected 2030 demand.

The natural gas system is one of the largest sources of greenhouse gas emissions in the United States, generating around 132 million tons of CO_2 equivalents annually (*1*). Significant emissions of criteria air pollutants also come from upstream combustion life-cycle stages of the gas. Emissions from the emerging LNG life-cycle stages or from the production of SNG have not been studied in detail. If larger percentages of the U.S. supply of natural gas will come from these alternative sources, then LNG or SNG supply chain emissions become an important part of understanding overall natural gas life-cycle emissions. Also, comparisons between coal and natural gas that concentrate only on the emissions at the utility plant may not be adequate. The objective of this study is to perform a life-cycle analysis (*9*, *10*) of natural gas, LNG, and SNG. Direct air emissions from the processes during the life-cycle will be considered, as well as air emissions from the combustion of fuels and electricity used to run the process. A comparison with coal life-cycle air emissions will be presented, in order to have a better understanding of the advantages and disadvantages of using coal versus natural gas for electricity generation.

2. Fuel Life-Cycles

The natural gas life-cycle starts with the production of natural gas and ends at the combustion plant. Natural gas is extracted from wells and sent to processing plants where water, carbon dioxide, sulfur, and other hydrocarbons are removed. The produced natural gas then enters the transmission system. The U.S. transmission system also includes some storage of natural gas in underground facilities such as reconditioned depleted gas reservoirs, aquifers, or salt caverns to meet seasonal and/or sudden short-term demand. From the transmission and storage system, some natural gas goes directly to large-scale consumers, like electric power generators, which is modeled here. The rest goes into local distribution systems that deliver it to residential and commercial consumers via low-pressure, small-diameter pipelines.

The use of liquefied natural gas (LNG) adds three additional life-cycle stages to the natural gas life-cycle described above. Natural gas is produced and processed to remove contaminants and transported by pipeline relatively short distances to be liquefied. In the liquefaction process, natural gas is cooled and pressurized (*11*). Liquefaction plants are generally located in coastal areas of LNG exporting countries and dedicated LNG ocean tankers transport LNG

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to the United States. Upon arriving, the LNG tankers offload their cargo and the LNG is regasified. At this point the regasified LNG enters the U.S. natural gas transmission system.

The coal life-cycle is conceptually simpler than the natural gas life-cycle, consisting of three major steps: coal mining and processing, transportation, and use/combustion.

U.S. coal is produced from surface mines (67%), or underground mines (33%) (*1*). Mined coal is processed to remove impurities. Coal is then transported from the mines to the consumers via rail (84%), barge (11%), and trucks (5%) (*12*). More than 90% of the coal used in the United States is used by the electric power sector, which is modeled here (*8*).

The life-cycle of SNG is a combination of some stages from the coal life-cycle and some stages of the natural gas life-cycle. Coal is mined, processed, and transported, as in the coal life-cycle, to the SNG production plant. At this plant, syngas, a mixture of carbon monoxide (CO) and hydrogen (H_2), is produced by gasification and converted, via methanation, to methane and water. The SNG is then sent to the natural gas transmission system, described above, and on to the electric power generator.

3. Methods for Calculating Life-Cycle Air Emissions

In our study we investigate the life-cycle air emissions from coal, natural gas, LNG, and SNG use. All fossil fuel options are used to produce electricity and combustion emissions are included as a component of the each life-cycle. For GHG, the emissions factors at power plants used are 120 lb CO_2 equiv/MMBtu of natural gas and 205 lb CO_2 equiv/MMBtu of coal. The SO_x and NO_x emissions at power plants are presented in the results section and in the Supporting Information

3.1. Life-Cycle Air Emissions from Natural Gas produced in North America. In 2003, the total consumption of natural gas in the United States was over 27 trillion cubic feet (tcf). Of this, 26.5 tcf were produced in North America (U.S., Canada, and Mexico) (*13*). According to the Environmental Protection Agency (EPA), 1.07% of the natural gas produced is lost in its production, processing, transmission, and storage (*14*). Total methane emissions were calculated using the percentage of natural gas lost. It was also assumed that natural gas has an average heat content of 1030 Btu/ft^3 (*13*), and that 96% of the natural gas lost is methane, which has a density of 0.0424 lb/ ft^3 (*14*).

In 1993 the U.S. EPA established the Natural Gas STAR program to reduce methane emissions from the natural gas industry. Data from this program for the reductions in methane lost in the natural gas system, as described in the Supporting Information, were combined with the data described above to develop a range of methane emissions factors for the North American natural gas life-cycle stages.

Carbon dioxide emissions are produced from the combustion of natural gas used during various life-cycle stages and from the production of electricity consumed during transport. EIA provides annual estimates of the amount of natural gas used for the production, processing, and transport of natural gas. In 2003, approximately 1900 billion cubic feet of natural gas were consumed during these stages of the natural gas life-cycle (*13*). Total carbon dioxide emissions were calculated using a carbon content in natural gas of 31.90 lb C/MMBtu and an oxidation fraction of 0.995 (*1*). According to the Transportation Energy Data Book, 3 billion kWh were used for natural gas pipeline transport in 2003 (*15*). The average GHG emission factor from the generation of this electricity is 1400 lb CO_2 equiv/MWh (*16*). These CO_2 emissions were added to methane emissions to obtain the upstream combustion GHG emission factors for North American natural gas.

SO_x and NO_x emissions from the natural gas upstream stages of the life-cycle come from the combustion of the fuels used to produce the energy that runs the system, as given in the Supporting Information. Total emissions from flared gas were calculated using the AP 42 Emission Factors for natural gas boilers (*17*). A range of emissions from the combustion of the natural gas used during the upstream stages of the life-cycle was developed using the AP 42 Emissions Factors for reciprocating engines and for natural gas turbines (*17*). Emissions from generating the electricity used during natural gas pipeline operations were estimated using the most current average emission factors given by EGRID: 6.04 lb SO_2/MWh and 2.96 lb NO_x/MWh (*16*). Note that EGRID reports emissions of SO_2 only. Other references used in this paper report total SO_x emission. For this paper, sulfur emission will be reported in terms of SO_x emissions.

In addition to emissions from the energy used during the life-cycle of natural gas, SO_x emissions are produced in the processing stage of the life-cycle, when hydrogen sulfide (H_2S) is removed from the sour natural gas to meet pipeline requirements. A range of SO_x emissions from this processing of natural gas was developed using the AP 42 emissions factors for natural gas processing and for sulfur recovery (*17*). To use the AP 42 emission factors for sulfur recovery, we found that in 2003 1945 thousand tons of sulfur were recovered from 14.7 trillion cubic feet of natural gas resulting in a calculated average natural gas H_2S mole percentage of 0.0226. This was then used with the AP 42 emission factors for natural gas processing.

3.2. Air Emissions from the LNG Life-Cycle. In 2003, 500 billion cubic feet of natural gas were imported in the form of LNG (*13*). In 2003, 75% of the LNG imported to the United States came from Trinidad and Tobago, but this percentage is expected to decrease as more imports come from Russia, the Middle East, and Southeast Asia (*13*). According to EIA, the LNG tanker world fleet capacity should have reached 890 million cubic feet of liquid (equivalent to 527 billion cubic feet of natural gas) by the end of 2006 (*18*). There are currently 5 LNG terminals in operation in the United States, with a combined base load capacity of 5.3 billion cubic feet per day (about 2 trillion cubic feet per year). In addition to these terminals, there are 45 proposed facilities in North America, 18 of which have already been approved by the Federal Energy Regulatory Commission (FERC) (*19*).

Due to unavailability of data for emissions from natural gas production in other countries, it is assumed that natural gas imported to the United States in the form of LNG produces the same emissions from the production and processing life-cycle stages as North American natural gas. Those stages are incorporated for LNG. Most of the natural gas converted to LNG is produced from modern fields developed and operated by multinational oil and gas companies, so they are assumed to be operated in a similar way to those in the United States.

It is expected that transportation of natural gas from the production field to the liquefaction plant would have emissions similar to those of pipeline transport of domestic natural gas. But the emission factor for the U.S. system (which is included in the LNG life-cycle) is based on total pipeline distances of over 200 000 miles (*20*). Because LNG facilities are closely paired with gas fields, it is expected that the average distance from production field to a LNG facility would be much smaller than 200 000 miles. Also, because there were no reliable data for the myriad of fields and facilities and suspected impact on the overall life cycle would be minimal, this transport from the fields to the liquefaction terminals was ignored. This would slightly underestimate the emissions from the LNG life cycle.

Additional emission factors were developed for the liquefaction, transport, and regasification life-cycle stages of LNG. Tamura et al. have reported emission factors for the liquefaction stage in the range of 11−31 lb CO_2 equiv/MMBtu (*21*). The sources of these emissions are outlined in the Supporting Information.

LNG is shipped to the United States via LNG tankers. LNG tankers are the last ship type to use steam turbine technology in their engines. This technology allows for easy use of boil-off gas (BOG) in a gas boiler. Boil-off rates in LNG tankers range between 0.15% and 0.25% per day when loaded (*22*, *23*). When there is not enough BOG available, a fuel oil boiler is used to produce the steam. In addition to this benefit, steam turbines require less maintenance than diesel engines, which is beneficial to these tankers that have to be readily available to leave a terminal in case of emergency (*22*).

Most LNG tankers currently in operation have a capacity to carry between 4.2 and 5.3 million cubic feet of LNG (2.6 and 3.2 billion cubic feet of gas). There are smaller tankers available, but they are not widely used for transoceanic transport. There is also discussion about building larger tankers (8.8 million cubic feet), however none of the current U.S. terminals can handle tankers of this size (*18*).

The rated power of the LNG tankers ranges between 20 and 30 MW, and they operate under this capacity around 75% of the time during a trip (*24*, *25*). The energy required to power this engine is 11.6 MMBtu/MWh (*26*). As previously mentioned, some of this energy is provided by BOG and the rest is provided by fuel oil. A loaded tanker with a rated power of 20 MW, and 0.12% daily boil-off rate would consume 3.88 million cubic feet of gas per day and 4.4 tons of fuel oil per day. The same tanker would consume 115 tons of fuel oil per day on they way back to the exporting country operating under ballast conditions. A loaded tanker with a rated power of 30 MW, and a 0.25% daily boil-off rate would get all its energy from the BOG, with some excess gas being combusted to reduce risks of explosion (*22*). Under ballast conditions, the same tanker would consume 172 tons of fuel oil per day.

For LNG imported in 2003 the average travel distance to the Everett, MA LNG terminal was 2700 nautical miles (*13*, *27*). In the future LNG could travel as far as far as 11 700 nautical miles (the distance between Australia and the Lake Charles, LA LNG terminal (*27*)). This range of distances is representative of distances from LNG countries to U.S. terminals that could be located on either the East or West coasts. To estimate the number of days LNG would travel (at a tanker speed of 20 knots (*22*)), these distances were used. This trip length can then be multiplied by the fuel consumption of the tanker to estimate total trip fuel consumption and emissions, and these can then be divided by the average tanker capacity to obtain a range of emission factors for LNG tanker transport between 2 and 17 lb CO_2 equiv/MMBtu.

Regasification emissions were reported by Tamura et al. to be 0.85 lb CO_2 equiv/MMBtu (*21*). Ruether et al. report an emission factor of 3.75 lb of CO_2 equiv/MMBtu for this stage of the LNG life-cycle by assuming that 3% of the gas is used to run the regasification equipment (*28*). The emission reported by Tamura et al. differs because they assumed only 0.15% of the gas is used to run the regasification terminal, while electricity, which may be generated with cleaner energy sources, provides the additional energy requirements. These values were used as lower and upper bounds of the range of emissions from regasification of LNG.

As done for the carbon emissions, natural gas produced in other countries and imported to the United States in the form of LNG is assumed to have the same SO_x and NO_x emissions in the production, processing, and transmission stages of the life-cycle as for natural gas produced in North America. Emission ranges for the liquefaction and regasification of natural gas were calculated using the AP 42 emission factors for reciprocating engines and natural gas turbines (*17*). It is assumed that 8.8% of natural gas is used in the liquefaction plant (*21*) and 3% is used in the regasification plants (*28*). Emissions of SO_x, and NO_x from transporting the LNG via tanker were calculated using the AP 42 emission factor for natural gas boilers and diesel boilers, as well as the tanker fuel consumption previously described.

3.3. Air Emissions from the Coal Life-Cycle. Greenhouse gas emissions from the mining life-cycle stage were developed from methane releases and from combustion of fuels used at the mines. EPA estimates that methane emissions from coal mines in 1997 were 75 million tons of CO_2 equivalents, of which 63 million tons came from underground mines and 12 million tons came from surface mines (*1*). CO_2 is also emitted from mines through the combustion of the fuels that provide the energy for operation. The U.S. Census Bureau provides fuel consumption data for mines in 1997 (*29*). These data are available in the Supporting Information. Fuel consumption data were converted to GHG emissions using the carbon content and heat content of each fuel and an oxidation fraction given in EPA's Inventory of U.S. Greenhouse Gas Emissions Sources and Sinks (*1*) (see Supporting Information). Emissions from the generation of the electricity consumed were calculated using an average 1997 emission factor of 1400 lb CO_2 equiv/MWh (*16*). These total emissions were then converted to an emission factor using the amount of coal produced in 1997 and the average heat content of this coal.

Emissions from the transportation of coal were calculated using the EIO-LCA tool developed at Carnegie Mellon University (*30*). To use this tool, economic values for coal transportation were needed. In 1997, the latest year for which the EIO-LCA tool has data, 84% of coal was transported via rail, 11% via barge, and 5% via truck. The cost for rail transport, barge, and truck transport was 13.9, 9.5, and 142.7 mills/ton-mile respectively (*12*). For a million ton-miles of coal transported, EIO-LCA estimates that 43.6 tons of CO_2 equivalents are emitted from rail transportation, 5.89 tons of CO_2 equivalents from water transportation, and 69 tons of CO_2 equivalents from truck transportation (*30*). These emissions were then converted to an emission factor by using the average travel distance of coal in each mode (796, 337, and 38 miles by rail, barge, and truck, respectively), the weighted average U.S. coal heat content of 10 520 Btu/lb (*31*) and the coal production data for 1997 (see Supporting Information).

The energy consumption data used to develop carbon emissions from the mining life-cycle stage were used to develop SO_x and NO_x emission factors for coal. AP 42 emissions factors for off-road vehicles, natural gas turbines, reciprocating engines, light duty gasoline trucks, large stationary diesel engines, and gasoline engines were used to develop this range of emission factors (*17*, *32*). In addition, the average emission factors from electricity generation in 1997 (3.92 lb NO_x/MWh and 7.86 lb SO_2/MWh (*16*)) were used to include the emissions from the electricity used in mines.

SO_x and NO_x emissions for coal transportation were again calculated using EIO-LCA (*30*). EIO-LCA estimates that a million ton-miles of coal transported via rail results in emissions of 0.02 tons of SO_x and 0.4 tons of NO_x. A million ton-miles of coal transported via water would emit 0.07 tons of SO_x, and 0.36 tons of NO_x. Finally, a million ton-miles of coal transported via truck would emit 0.06 tons of SO_x, and 1.42 tons of NO_x (*30*). These data were added to emissions from mines to find the total SO_x and NO_x emission factors for the upstream stages of the coal life-cycle.

3.4. Air Emissions from the SNG Life-Cycle. Performance characteristics for two SNG plants are given in the Supporting Information. These plants have a higher heating value efficiency between 57% and 60% (*33*, *34*). Using these efficiencies, emissions from coal mining, processing, and

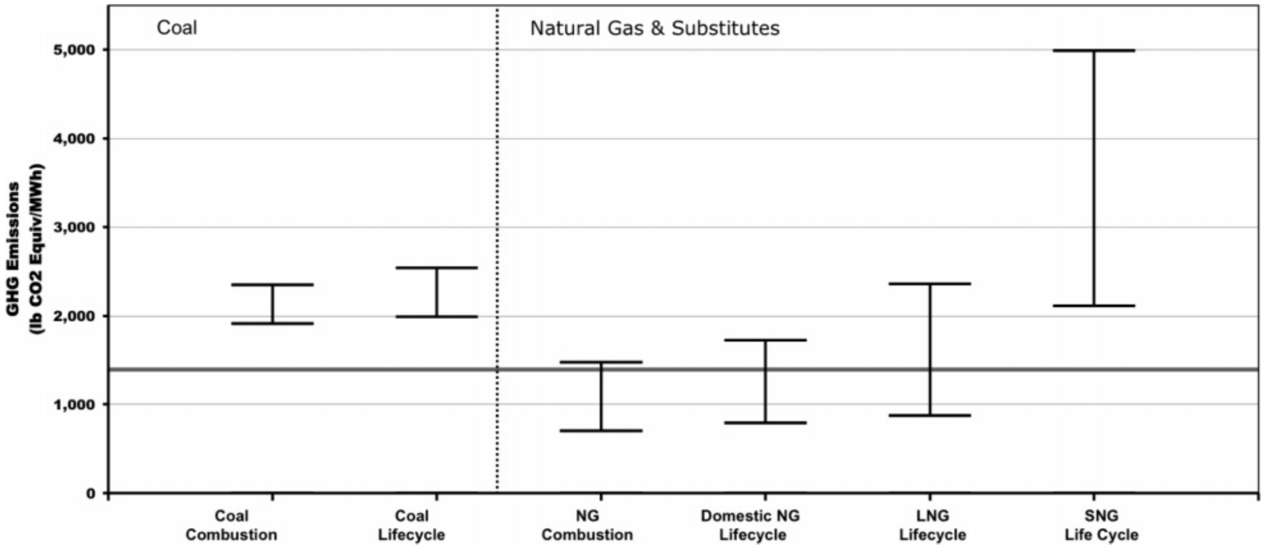

FIGURE 1. Fuel Combustion and Life-Cycle GHG Emissions for Current Power Plants.

transportation previously obtained were converted to pounds of CO_2 equiv/MMBtu of SNG. The data were also used to calculate the emissions at the gasification−methanation plant using a coal carbon content of 0.029 tons/MMBtu and a calculated SNG storage fraction of 37% (*1*). Finally, the emissions from transmission, storage, distribution, and combustion of SNG are the same as those for all other natural gas.

To develop the SO_x and NO_x emissions from the life-cycle of SNG, the emissions from coal mining and transport developed in the previous section in pounds per MMBtu of coal were converted to pounds per MMBtu of SNG using the efficiencies previously discussed. In addition, the emissions from natural gas transmission and storage were assumed to represent emissions from these life-cycle stages of SNG. The emissions from the gasification−methanation plant were taken from emission data for an Integrated Coal Gasification Combine Cycle (IGCC) plant, which operates with a similar process. Bergerson (*35*) reports SO_x emissions factors from IGCC between 0.023 and 0.15 lb/MMBtu coal (0.026−0.17 lb/MMBtu of coal if there is carbon capture), and a NO_x emission factor of 0.0226 lb/MMBtu coal (0.0228 lb/MMBtu of coal if there is carbon capture). These were converted to lb/MMBtu of SNG using the same coal-to-SNG efficiencies previously described.

4. Results

4.1. Comparing Fuel Life-Cycle Emissions for Fuels Used at Currently Operating Power Plants. Emission factors for the fuel life-cycles were calculated as pounds of pollutants per MMBtu of fuel produced, as presented in the Supporting Information. Since coal and natural gas power plants have different efficiencies, 1 MMBtu of coal does not generate the same amount of electricity as 1 MMBtu of natural gas/LNG/SNG. For this reason, emission factors given in Table 10S and Table 11S in the Supporting Information were converted to pounds of pollutant per MWh of electricity generated. This conversion is done using the efficiency of natural gas and coal power plants. According to the U.S. Department of Energy (DOE), currently operating coal power plants have efficiencies ranging from 30% to 37%, while currently operating natural gas power plants have efficiencies ranging from 28% to 58% (*36*). The life-cycle GHG emissions factors of natural gas, LNG, coal, and SNG described in the Supporting Information were converted to a lower and upper bound emission factor from coal and natural gas power plants using these efficiency ranges. Figure 1 shows the final bounds for the emission factors for each fuel cycle. The life-cycle for each fuel use includes fuel combustion at a power plant. The combustion-only emissions for each fuel are shown for comparison. The solid horizontal line shown represents the current average GHG emission factor for U.S. electricity generation: 1400 lb CO_2 equiv/MWh (*16*). Note that in this graph no carbon capture and storage (CCS) is performed at any stage of the life-cycle. CCS is a process by which carbon emissions are separated from other combustion products and injected into underground geologic formations such as saline formations or depleted oil/gas fields. A scenario in which CCS is performed at power plants as well as in gasification−methanation plants will be discussed in the following section.

It can be seen that combustion emissions from coal-fired power plants are higher than those from natural gas: the midpoint between the lower and upper bound emission factors for coal combustion is approximately 2100 lb CO_2 equiv/MWh, while the midpoint for natural gas combustions is approximately 1100 lb CO_2 equiv/MWh. This reflects the known environmental advantages from combustion of natural gas over coal. Figure 1 also shows that the life-cycle GHG emissions of electricity generated with coal are dominated by combustion, and adding the upstream life-cycle stages does not change the emission factor significantly, with the midpoint between the lower and upper bound life-cycle emission factors being 2270 lb CO_2 equiv/MWh. For natural-gas-fired power plants the emissions from the upstream stages of the natural gas life-cycle are more significant, especially if the natural gas used is synthetically produced from coal (SNG). The midpoint life-cycle emission factor for domestic natural gas is 1250 lb CO_2 equiv/MWh; for LNG and SNG it is 1600 lb CO_2 equiv/MWh and 3550 lb CO_2 equiv/MWh, respectively. SNG has much higher emission factors than the other fuels because of efficiency losses throughout the system. It is also interesting to note that the range of life-cycle GHG emissions of electricity generated with LNG is significantly closer to the range of emissions from coal than the life-cycle emissions of natural gas produced in North America. The upper bound life-cycle emission factor for LNG is 2400 lb CO_2 equiv/MWh, while the upper bound life-cycle emission factor for coal is 2550 lb CO_2 equiv/MWh.

To compare emissions of SO_x and NO_x from all life-cycles, the upstream emission factors and the power plant efficiencies from the Supporting Information are used. Emissions of these pollutants from coal and natural gas power plants in operation in 2003 were obtained from EGRID (*37*). Table 1

TABLE 1. SO_x and NO_x Combustion and Life-Cycle Emission Factors for Current Power Plants

fuel		SO_x (lb/MWh)		NO_x (lb/MWh)	
		min	max	min	max
current electricity mix		6.04		2.96	
coal	combustion	1.54	25.5	2.56	9.08
	life-cycle	1.60	25.8	2.83	9.69
natural gas	combustion	0.00	1.13	0.12	5.20
	life-cycle	0.04	1.49	0.17	9.40
LNG	life-cycle	0.094	2.93	0.25	15.4
SNG	life-cycle	0.30	3.88	0.65	8.08

shows life-cycle emissions for each fuel obtained by adding the combustion emissions from EGRID to the transformed upstream emissions. The current average SO_x and NO_x emission factors for electricity generated in the United States are also shown (*16*).

It can be seen that coal has significantly larger SO_x emissions than natural gas, LNG, or SNG. This is expected since the sulfur content of coal is much higher than the sulfur content of other fuels. SNG, which is produced from coal, does not have high sulfur emissions because the sulfur from coal must be removed before the methanation process.

For NO_x, it can be seen that the upstream stages of domestic natural gas, LNG, and even SNG make a significant contribution to the total life-cycle emissions. These upstream NO_x emissions come from the combustion of fuels used to run the natural gas system: for domestic natural gas, production is the largest contributor to these emissions; for LNG most NO_x upstream emissions come from the liquefaction plant; finally, for SNG most upstream NO_x emissions come from the gasification−methanation plant.

4.2. Comparing Fuel Life-Cycle Emissions for Fuels Used with Advanced Technologies. According to the DOE, by 2025 65 GW of inefficient facilities will be retired, while 347 GW of new capacity will be installed (*8*). Advanced pulverized coal (PC), integrated coal gasification combined cycle (IGCC), and natural gas combined cycle (NGCC) power plants could be installed. PC, IGCC, and NGCC plants are generally more efficient (average efficiencies of 39%, 38%, and 50%, respectively (*38*)) than the current fleet of power plants. In addition, CCS could be performed with these newer technologies. Experts believe that sequestration of 90% of the carbon will be technologically and economically feasible in the next 20 years (*5*, *38*). Having CCS at PC, IGCC, and NGCC plants decreases the efficiency of the plants to average of 30%, 33%, and 43%, respectively (*38*).

Figure 2 was developed using the revised efficiencies for advanced technologies and the GHG emission factors (in lb/MMBtu) described in the Supporting Information. This figure represents total life-cycle emissions for electricity generated with each fuel. Notice that emissions are shown with and without CCS. In the case of SNG with CCS, capture is performed at both the gasification−methanation plant and at the power plant. The solid horizontal line shown represents the current average GHG emission factor for electricity generation in the United States (1400 lb CO_2 equiv/MWh) (*16*). The upper and lower bound emissions in this figure are closer together than the upper and lower bounds in Figure 1, because only one power plant efficiency value is used, while for Figure 1 the upper and lower bound efficiency from all currently operating power plants was used (this is especially obvious for the domestic natural gas (NGCC) cases). It can be seen that, in general, life-cycle GHG emissions of electricity generated with the fuels without CCS would decrease slightly compared to emissions from current power plants that use the same fuel (due to efficiency gains). The most efficient natural gas plant currently in operation, however, could have slightly lower emissions than the lower bound for NGCC, LNGG, and SNGCC, due to efficiency differences. Three of the cases, however (PC, IGCC, and SNGCC), would still have higher emissions than the current average emissions from power plants. If CCS were used, however, there would be a significant reduction in emissions for all cases. In addition the midpoints between upper and lower bound emissions from all fuels are closer together, as can be seen in Figure 3. This figure also shows how the upstream from combustion emissions of fuels become significant contributors to the life-cycle emission factors when CCS is used.

Table 2 was developed using the upstream SO_x and NO_x emission factors obtained in this study and the combustion emissions reported by Bergerson (*35*) for PC and IGCC plants and by Rubin et al. for NGCC plants (*38*). These reported combustion emissions can be seen in the Table 12S in the Supporting Information.

As can be seen from Table 2, if advanced technologies are used there could be a significant reduction of NO_x and SO_x emissions, even if CCS is not available. It is interesting also to note that a PC plant with CCS could have lower life-cycle emissions than an IGCC plant with CCS. In the PC case all sulfur is removed through flue gas desulfurization. The removed sulfur compounds are then solidified and disposed of or sold as gypsum. In an IGCC plant with CCS, sulfur is removed from the syngas before combustion. In these plants, however, instead of solidifying the sulfur compounds removed and disposing them, the elemental sulfur is recovered in a process that generates some additional SO_x emissions (*35*). For NO_x, only LNG has higher life-cycle emissions than the average generated at current power plants.

5. Discussion

Natural gas is an important energy source for the residential, commercial, and industrial sectors. In the 1990s, the surge in demand by electricity generators and relatively constant natural gas production in North America caused prices to increase, so that in 2005 these sectors paid 58 billion dollars more than they would have paid if 2000 prices remained constant. Cumulative additional costs of higher natural gas prices for residential, commercial, and industrial consumers between 2000 and 2005 were calculated to be around 120 billion dollars. LNG has been identified as a source of natural gas that might help reduce prices, but even with an increasing supply of LNG, EIA still projects average delivered natural gas prices above $6.5/Mcf in the next 25 years. This is higher than the $4.5 /Mcf average projected price in earlier reports before the natural-gas-fired plant construction boom (*4*).

In addition to LNG, SNG has been proposed as an alternative source to add to the natural gas mix. The decision to follow the path of increased LNG imports or SNG production should be examined in light of more than just economic considerations. In this paper, we analyzed the effects of the additional air emissions from the LNG/SNG life-cycle on the overall emissions from electricity generation in the United States. We found that with current electricity generation technologies, natural gas life-cycle GHG emissions are generally lower than coal life-cycle emissions, even when increased LNG imports are included. However LNG imports decrease the difference between GHG emissions from coal and natural gas. SNG has higher life-cycle GHG emission than coal, domestic natural gas, or LNG. It is also important to note that upstream GHG emissions of NG/LNG/SNG have a higher impact in the total life-cycle emissions than upstream coal emissions. This is a significant point when considering a carbon-constrained future in which combustion emissions are reduced.

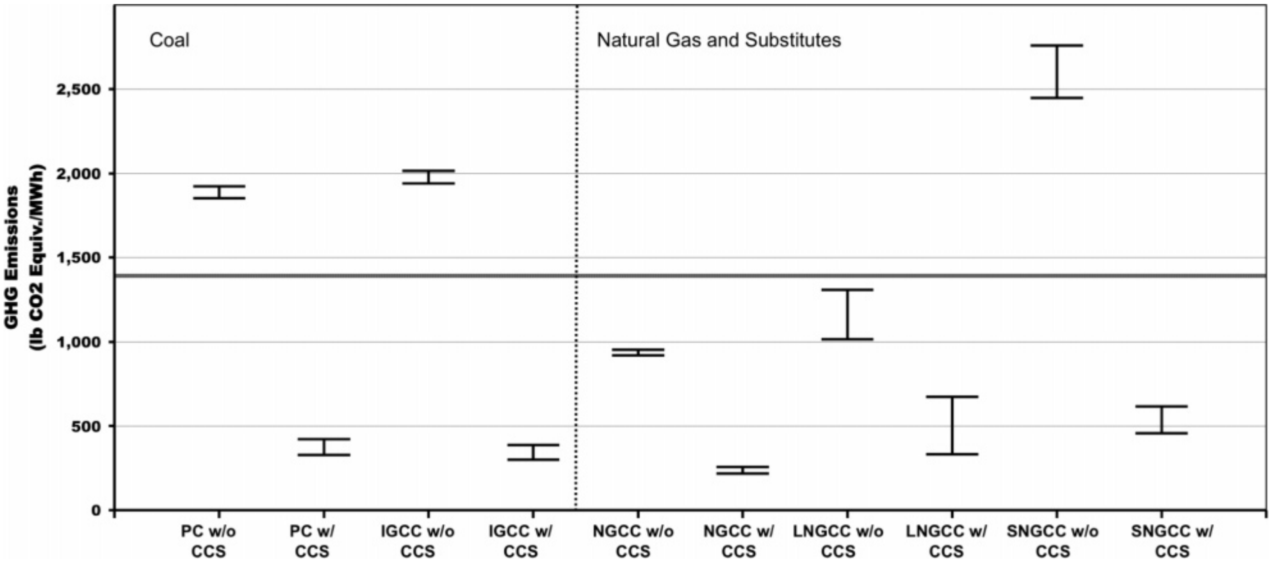

FIGURE 2. Fuel GHG Life-Cycle Emissions Using Advanced Technologies.

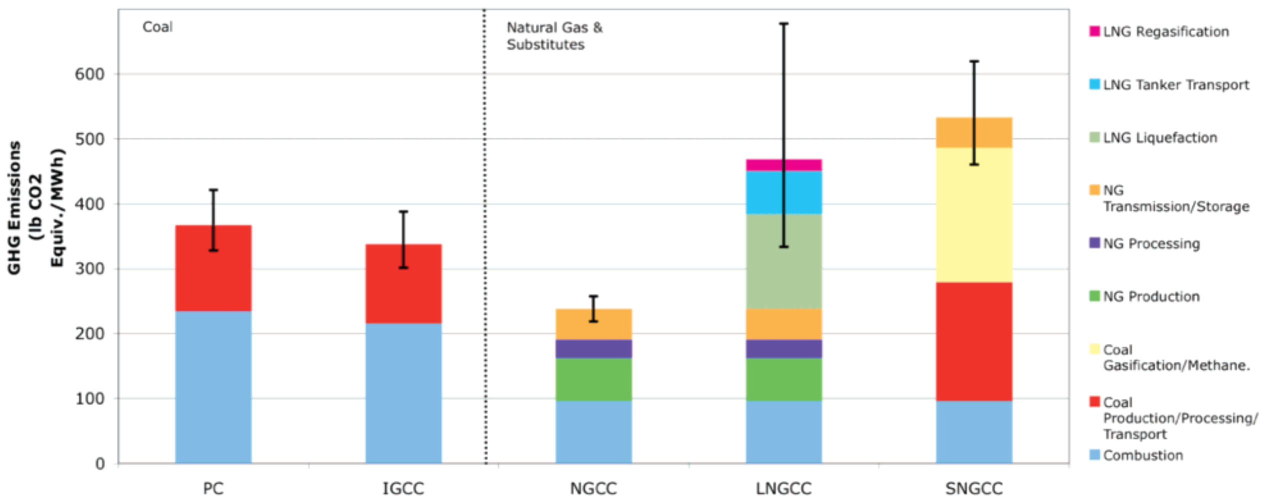

FIGURE 3. Midpoint Life-Cycle GHG Emissions Using Advanced Technologies with CCS.

TABLE 2. SO_x and NO_x Life-Cycle Emission Factors for Advanced Technologies

fuel		SO_x (lb/MWh)		NO_x (lb/MWh)	
		min	max	min	max
current electricity mix		6.04		2.96	
coal	PC w/o CCS	0.24	1.54	1.42	2.46
	PC w/ CCS	0.08	0.34	1.90	3.61
	IGCC w/o CCS	0.27	1.57	0.47	0.70
	IGCC w/ CCS	0.32	1.83	0.54	0.78
natural gas	NGCC w/o CCS	0.04	0.20	0.30	2.57
	NGCC w/ CCS	0.05	0.24	0.36	3.01
LNG	NGCC w/o CCS	0.25	1.04	0.39	5.89
	NGCC w/ CCS	0.30	1.23	0.46	6.91
SNG	NGCC w/o CCS	0.35	2.15	0.88	1.85
	NGCC w/ CCS	0.45	2.80	1.03	2.18

For emissions of SO_x, we found that with current electricity generation technologies, coal has significantly higher life-cycle emissions than any other fuel due to very high emissions at current power plants. For NO_x, however, this pattern is different. We find that with current electricity generation technologies, LNG could have the highest life-cycle NO_x emissions (since emissions from liquefaction and regasification are significant), and that even natural gas produced in North America could have life-cycle NO_x emissions very similar to those of coal. It is important to note that while GHG emissions contribute to a global problem, SO_x and NO_x are local pollutants and U.S. policy makers may not give much weight to emissions of these pollutants in other countries.

In the future, as newer generation technologies and CCS are installed, the overall life-cycle GHG emissions from electricity generated with coal, domestic natural gas, LNG, or SNG could be similar. Most important is that all fuels with advanced combustion technologies and CCS have lower life-cycle GHG emission factors than the current average emission factor from electricity generation. For SO_x we found that coal and SNG would have the largest life-cycle emissions, but all fuels have lower life-cycle SO_x emissions than the current average emissions from electricity generation. For NO_x, LNG would have the highest life-cycle emissions and would be the only fuel that could have higher emissions than the current average emission factor from electricity generation, even with advanced power plant design.

We suggest that advanced technologies are important and should be taken into account when examining the possibility of doing major investments in LNG or SNG infrastructure. Power generators hope that the price of natural gas will decrease as alternative sources of natural gas are added to the U.S. mix, so they can recover the investment made in natural gas plants that are currently producing well under capacity. We suggest that these investments should be viewed as sunk costs. Thus, it is important to re-evaluate whether investing billions of dollars in LNG/SNG infrastructure will lock us into an undesirable energy path that could make future energy decisions costlier than ever expected and increase the environmental burden from our energy infrastructure.

Acknowledgments

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Supporting Information Available

Graphical representation of the fuel life-cycles, emissions calculation information, summary of emissions from fuel life-cycles, power plant efficiency information, emissions from advanced technologies, and references, This material is available free of charge via the Internet at http://pubs.acs.org.

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Comparative Life-cycle Air Emissions of Coal, Domestic Natural Gas, LNG, and SNG for Electricity Generation

Supporting Information

1. Graphical Representation of the Fuel Life-cycles

Figure 1S and Figure 2S below, show the life-cycle stages on natural gas used by electric power generators, including the stages from the LNG life-cycle. Notice that local distribution of natural gas falls outside our analysis boundary.

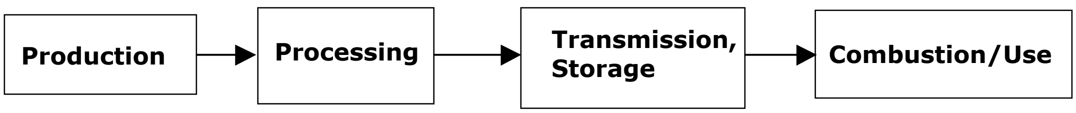

Figure 1S: Domestic Natural Gas Life-cycle.

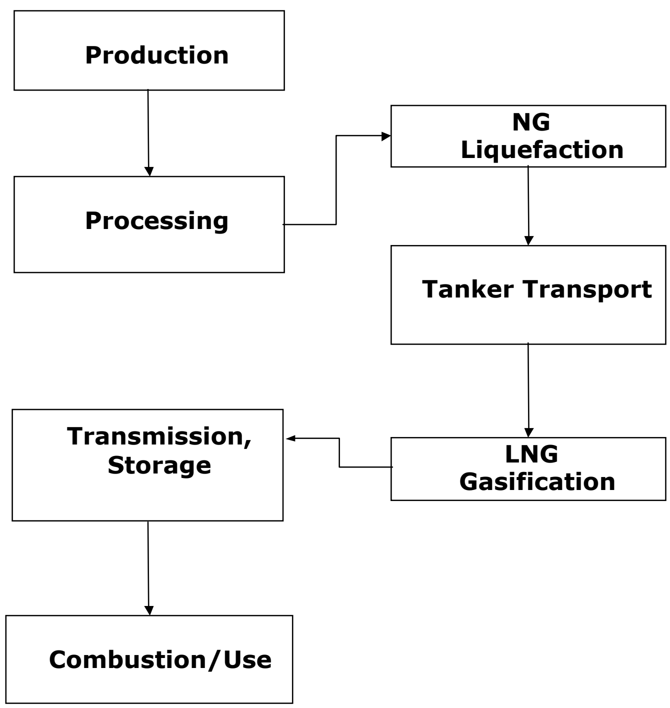

Figure 2S: LNG Life-cycle.

Figure 3S and Figure 4S show the life-cycle of coal and synthetic natural gas (SNG) derived from coal.

Figure 3S: Coal Life-cycle.

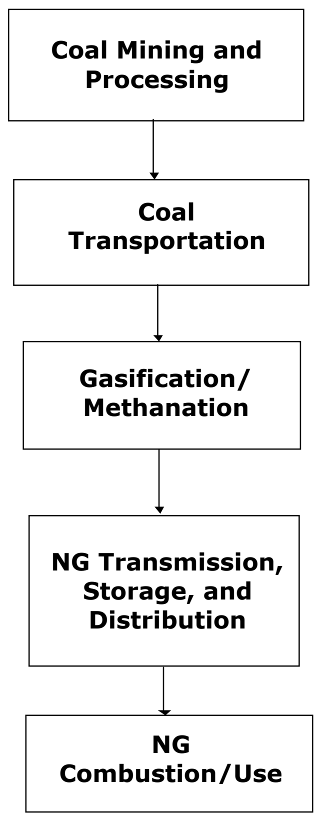

Figure 4S: SNG Life-cycle.

2. Calculating Emissions from the Domestic Natural Gas Life-cycle

During the late 1980s and early 1990s the U.S. Environmental Protection Agency (EPA) conducted a study to determine methane emissions from the natural gas industry (1). This comprehensive study developed hundreds of activity and emissions factors from all areas of the natural gas industry. These factors were developed using data collected from different sectors of the industry as well as from data collected in field measurements. Methane emissions from the U.S. natural gas system given as a percentage of natural gas produced can be seen in Table 1S. This data was used to develop methane emission factors, as described in the main document. Notice, that Table 1S includes an estimate for natural gas losses in the local distribution system. This estimate is given here for reference, but it was not included in our calculation of emissions of natural gas used to generate electricity.

In addition data from the EPA Natural Gas STAR program was used. The program is a voluntary partnership with the goal of encouraging the natural gas industry to adopt practices that increase efficiency and reduce emissions (for example by reducing natural gas leaks in the pipeline system). Consequently, since 1993, a cumulative total of 338 billion cubic feet of methane emissions have been eliminated. In 2003 alone, 52,900 million cubic feet of methane emissions were eliminated, a 9% reduction over projected emissions for that year without improved practices (2).

Table 1S: Methane Emissions from North American Gas Life-cycle as a Percentage of Natural Gas Produced (1).

Lifecycle Segment	**Emissions as a Percentage of Gas Produced**
Production	0.38%
Processing	0.16%
Transmission and Storage	0.53%
Distribution	0.35%

Carbon dioxide emissions from the different natural gas life-cycle stages were also calculated. These emissions were calculated using data on the amount of natural gas used to run the processes, as given in Table 2S, as well as an estimated 3 billion KWh of electricity used for pipeline transport. These data were also used to calculate SO_x and NO_x emissions from the life-cycle, as described in the main document. It should be mentioned that the pipeline fuel presented in Table 2S includes fuel used by the transmission system and the local distribution system. As previously described, natural gas used by electricity generators is bought directly from the transmission system, so that emissions from the distribution system are not included in our analysis. Due to data limitations, we were not able to disaggregate pipeline fuel and electricity consumption between the two systems. To deal with this issue, we use a range of emissions. The minimum value assumes that none of this fuel is consumed in the transmission system and the maximum value assumes that all is consumed in the transmission system.

Table 2S: Natural Gas Used During the Natural Gas Life-cycle. (3).

Use (as defined by EIA)	NG Life-cycle Stage	Amount (million ft^3)
Flared Gas	Production	98,000
Lease Fuel	Production	760,000
Pipeline Use	Transmission/Distribution	665,000
Plant Fuel	Processing	365,000

3. Calculating Emissions from the LNG Life-cycle

As mentioned in the main paper, Tamura et al (4) provide GHG emissions for liquefaction plants. Table 3S presents the sources of these emissions.

Table 3S: Liquefaction Emission Factors (Adapted from Tamura et al (4)).

Liquefaction	Emission Factors (lb CO_2 Equivalent/MMBtu)		
	Minimum	Average	Maximum
CO_2 from fuel combustion	11	12	13
CO_2 from flare combustion	0.00	0.77	1.5
CH_4 from vent	0.09	1.3	9.8
CO_2 in raw gas	0.09	4.0	6.6

Table 4S provides the distance from LNG exporting countries to two U.S. LNG terminals and the amount of LNG brought from each country in 2003. These two terminals were chosen because they are two of the largest terminals in the United States and they represent longest and shortest tanker travel distances for which route information is available. In addition, the range of distances provided is also representative of distances LNG would have to travel if a LNG terminal was located in the U.S. West Coast. Figure 5S shows the emission factors for LNG Tanker transport from each country to each of these terminals, obtained using the tanker information given in the main document. Emissions from tanker transport range between 2 and 17 pounds of CO_2 Equivalent per MMBtu of natural gas. These data was also used to calculate the SO_x and NO_x emission factors for tanker transport.

Table 4S: LNG Exporting Countries in 2003.

Exporting Country	Distance to Lake Charles Facility (nautical miles) (5)	Distance to Everett, MA Facility (nautical miles) (5)	2003 US Imports (million cubic feet NG) (3)
Algeria	5,000	3,300	53,000
Australia	12,000	11,000	0
Brunei	12,000	11,000	0
Indonesia	12,000	11,000	0
Malaysia	12,000	11,000	2,700
Nigeria	6,100	5,000	50,000
Oman	8,900	7,500	8,600
Qatar	9,700	8,000	14,000
Trinidad	2,200	2,000	380,000
UAE	9,600	7,959	0
Russia	9,600	11,000	0

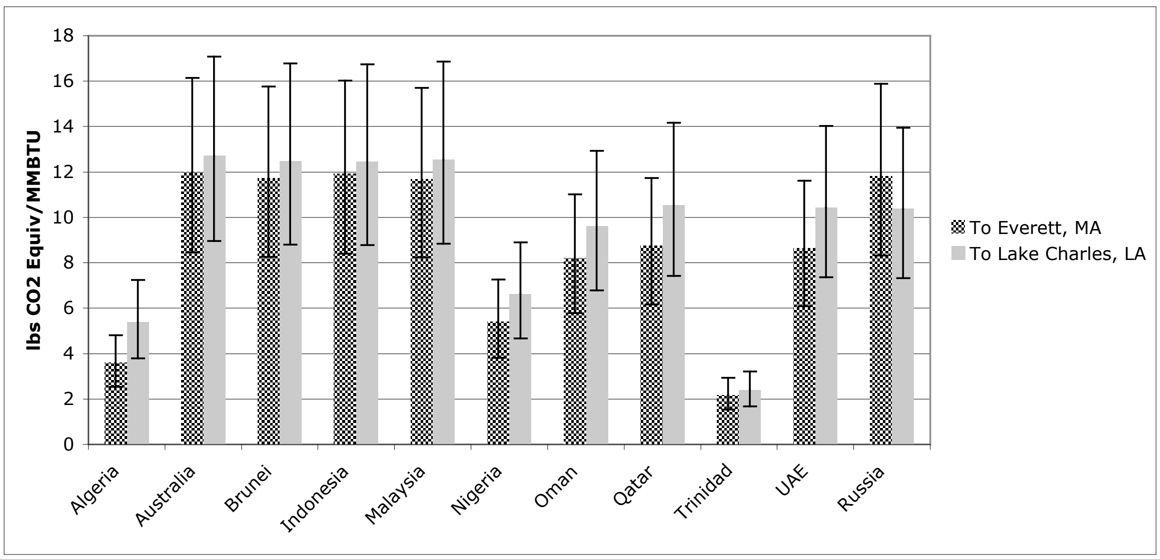

Figure 5S: Tanker Emission Factors from Each Country.

4. Calculating Emissions from the Coal Life-cycle

Table 5S presents fuel consumption data for coal mines in the U.S., and Table 6S presents carbon content, heat content of these fuels. These data was used to calculate GHG emissions factors for coal mines.

Table 5S: 1997 Fuel Consumption at Coal Mines (6)

Mine Type	Fuel Oil (1000 bbl)			Gas (10^9 ft^3)	Gasoline (10^6 gal)	Electricity (10^6 KWh)
	Total	Distillate	Residual			
Surface	8,280	7,524	756	0.7	30	42,474
Underground	801	656	145	0.5	4	7,123

Table 6S: Carbon Content, and Heat Content of Different Fuels (7).

Fuel Type	Carbon Content of Fuel lb/MMBtu Fuel	Heat Content of Fuel (MMBtu/bbl - MMBtu/MMcf)	Fraction Oxidized
Distillate	43.98	5.825	0.99
Residual	47.38	6.287	0.99
Gas	31.90	1,030	0.995
Gasoline	42.66	5.253	0.99

Table 7S: 1997 Coal Production Data (8).

Mine Type	Coal Produced (1000 tons)	Heat Content of Coal (BTU/lb)
Surface	669,273	9,626
Underground	420,657	11,944
Total	1,089,930	10,520

As described in the main document, EIO-LCA was used to estimate emission factors from coal transportation. Table 8S summarizes the emissions resulting from transporting one million ton-miles of coal via each transportation mode.

Table 8S: EIO-LCA GHG Emission Data for a Million Ton-Miles of Coal Transported (9).

Sector	Total GHG Emissions (tons CO_2 Equivalent)	Total SO_x Emissions (tons SO_x)	Total NO_x Emissions (tons NO_x)
Rail Transportation	43.6	0.02	0.40
Water Transportation	5.89	0.07	0.36
Truck Transportation	69.0	0.06	1.42

5. Calculating Emissions from the SNG Life-cycle

In order to calculate air emissions from the SNG life-cycle, the emissions from coal production, processing and transport were converted from pounds per MMBtu of coal used to pounds per MMBtu of SNG produced using the performance characteristics of two SNG plants given in Table 9S. The emissions from SNG transport, storage and use are the same as those from natural gas. The efficiency for the CCS case was obtained assuming an energy penalty of 16% as described for and IGCC plant by Rubin et al (10).

Table 9S: SNG Plant Performance Characteristics

	Case 1 (11)	Case 2 (12)
SNG Output (1. mcf/day and 2. MMBtu/hr)	250	1,739
Efficiency without CCS (HHV)	57%	60%
Efficiency with CCS (HHV)	50%	52%

6. Summary of Emissions from Fuel Life-cycles

Table 10S summarizes GHG emission factors for all fuels. The emission factors presented in this section are the average emission rate relative to units of fuel produced, without considering the efficiency of using these fuels. These emission factors can later be used to develop total inventories of GHG emissions from the annual consumption of each fuel. Allocation of these emissions for each life-cycle stage can be seen in Figure 6S through Figure 8S. Note that there are two different emission factors for SNG. In one case, no carbon capture and sequestration (CCS) is performed at the gasification-methanation stage. When CCS is performed at the gasification-methanation plant, an energy penalty is incurred. It was assumed that the energy penalty observed at IGCC plants with CCS (16%) is representative of the energy penalty at the SNG gasification-methanation plant (10). CCS could also be performed at power plants, as discussed in the main document.

It is also very important to note that the emission factors shown in Table 10**S** (and the emission factors given in Table 11S) are not comparable to each other, since one Btu of coal does not generate the same amount of electricity as one Btu of natural gas or SNG. These emission factors can be transformed to comparable units, namely lbs/MWh of electricity produced, by taking into consideration the efficiency of electricity generation.

Table 10S: Life-cycle GHG Emission Factors

(units: lbs/MMBtu of Fuel Produced)

Life-cycle Stages	North American NG		LNG		Coal		SNG (No CCS at Gasif./Methan. Plant)		SNG (CCS at Gasif./Methan. Plant)	
	Min	Max	Min	Max	Min	Max	Min	Max	Min	Max
Upstream	15.3	20.1	29.6	72.3	8.2	16.4	240	286	45.2	65.2
Combustion (no CCS)	120	120	120	120	205	205	120	120	120	120
Combustion (with CCS)	12	12	12	12	20.5	20.5	12	12	12	12

SO_x and NO_x emission factors for the upstream stages of electricity generation for the fuel life-cycles can be seen in Table 11S. SO_x and NO_x emissions from the combustion of fuel at power plants are very dependent on specific plant characteristics, so it was not possible to transform these power plant emissions (given in lbs/MWh) to the same units as the emissions from the upstream stages of the life-cycle (lbs/MMBtu) by simply using the efficiency of the power plants.

Table 11S: Upstream SO_x and NO_x Emission Factors (units: lbs/MMBtu of Fuel Produced)

Pollutant	North American Natural Gas		LNG		Coal		SNG (No CCS at Gasif./Methan. Plant)		SNG (CCS at Gasif./Methan. Plant)	
	Min	Max	Min	Max	Min	Max	Min	Max	Min	Max
SO_x	0.006	0.030	0.016	0.145	0.007	0.029	0.051	0.316	0.064	0.400
NO_x	0.009	0.342	0.022	0.831	0.030	0.535	0.090	0.234	0.104	0.253

7. GHG Emissions Allocated to Fuel Life-cycle Stages

Figure 6S through Figure 8S show how the GHG emissions reported in Table 10S are allocated among the different life-cycle stages.

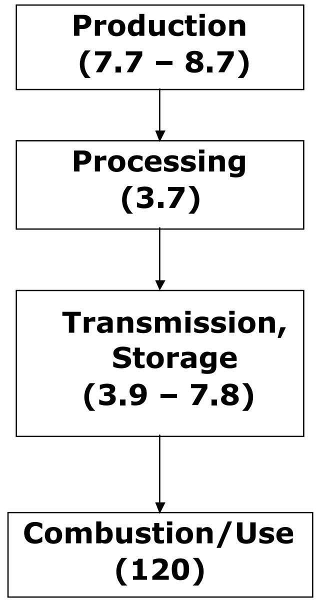

Figure 6S: North American Gas Life-cycle GHG Emission Factors (Units: lbs CO_2 Equivalent/MMBtu).

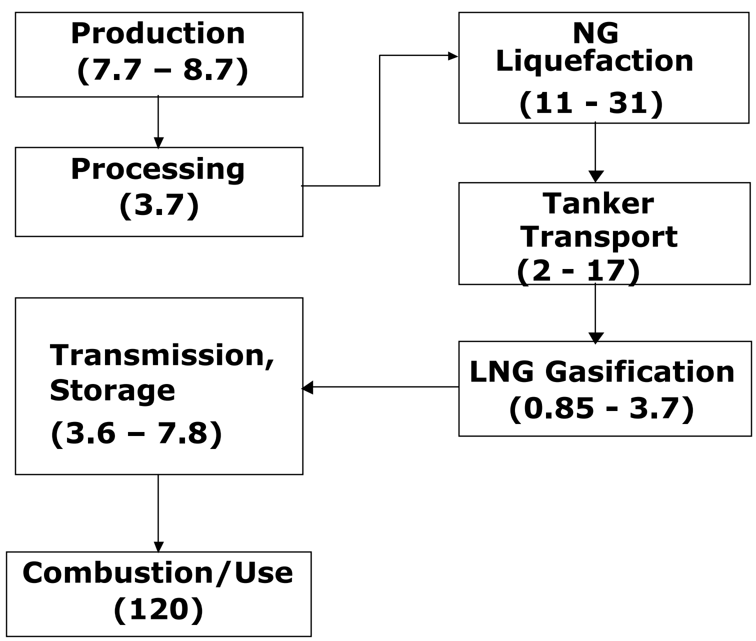

Figure 7S: LNG Life-cycle GHG Emission Factors (Units: lbs CO_2 Equivalent/MMBtu).

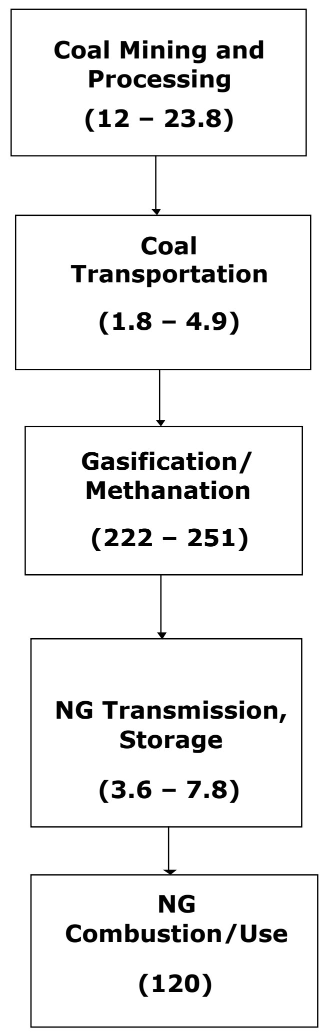

Figure 8S: SNG Life-cycle GHG Emission Factors (Units: lbs CO_2 Equivalent/MMBtu).

8. Efficiencies of Currently Operating Power Plants

Figure 9S shows the distribution of the efficiencies of currently operating power plants, obtained using the cumulative distribution function of EIA 2003 electricity generation data for all utility plants (13). As illustrated in Figure 9S, the median efficiency for natural gas plants is higher than the median efficiency for coal plants. These efficiencies were used to convert the emission factors previously presented (in lbs/ MMBtu of fuel) to lbs/MWh.

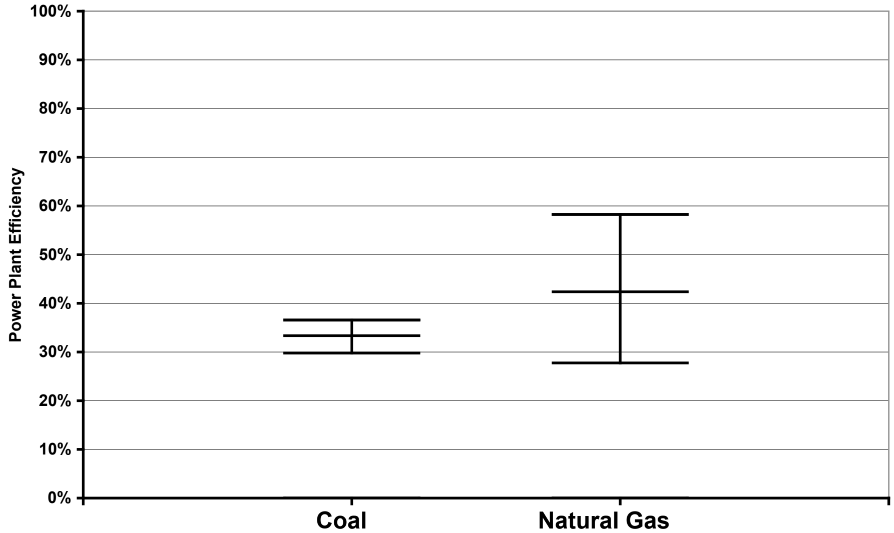

Figure 9S: Efficiencies of Natural Gas and Coal Plants (13).

9. Combustion Emissions from Advance Technologies

Table 12S reports combustion emissions from advanced power plant technologies. The emission factors from PC and IGCC plants were reported Bergerson (14) for PC and IGCC plants. Rubin et al reported the emissions for NGCC plants (10).

Table 12S: Combustion Emissions from Advanced Power Plants.

Fuel/Pollutant	SO_x (lbs/MWh)		NO_x (lbs/MWh)	
	Min	Max	Min	Max
PC w/o CCS	0.17	1.28	1.16	2.00
PC w/ CCS	0.00	0.01	1.56	3.00
IGCC w/o CCS	0.20	1.30	0.20	0.20
IGCC w/ CCS	0.24	1.52	0.20	0.20
NGCC w/o CCS	0.00	0.00	0.24	0.24
NGCC w/ CCS	0.00	0.00	0.29	0.29

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Comparative Life Cycle Carbon Emissions of LNG Versus Coal and Gas for Electricity Generation

Paulina Jaramillo, W. Michael Griffin, H. Scott Matthews

Introduction

Natural gas currently provides 24% of the energy used by homes and businesses in the US (1). It is also an important feedstock for the chemical and fertilizer industry. In the early 1990's the price of natural gas was low (around \$3/1000 ft^3) and as a result there was a surge in construction of natural gas plants (2). Today, the Henry Hub price of natural gas is around \$15/1000 ft^3 (3), and most of these plants are operating below capacity. However, natural gas consumption is expected to increase 41% by 2025 (to 30 trillion cubic feet), with demand from electricity generators growing the fastest (increasing 90% by 2025). At the same time natural gas production in North America is expected to remain fairly constant at around 24 trillion cubic feet, so that demand of imported liquefied natural gas (LNG) will increase to around 6 trillion cubic feet or 20% of the total supply by 2025 (3).

The natural gas system is the second largest source of greenhouse gas emissions in the US, generating around 132 million tons of CO_2 Equivalents (1). Several studies have performed emission inventories for the natural gas lifecycle from production to distribution. Usually these analyses have been performed for domestic natural gas, so that emissions from the LNG lifecycle stages have been ignored. If, as the DOE estimates suggest, larger percentages of the supply of natural gas will come from these imports, emissions from these steps in the lifecycle could influence the total natural gas lifecycle emissions. Thus, comparisons between coal and natural gas that concentrate only on the emissions at the utility plant may not be adequate. The objective of this study is to perform an analysis of the natural gas lifecycle greenhouse gas emissions taking the emissions from LNG into consideration. Different scenarios for the percentage of natural gas as LNG are analyzed. Moreover, a comparison with the coal fuel cycle greenhouse gas emissions will be presented, in order to have a better understanding of the advantages and disadvantages of using coal versus natural gas for electricity generation.

The Natural Gas Life Cycle

The natural gas life cycle starts with the production of natural gas and ends at the combustion plant. NaturalGas.org has a very detailed description of this life cycle. Readers are encouraged to visit this website if they need more information about the topic.

Geological surveys and seismic studies are used to determine the location of natural gas deposits. After these sites have been identified, wells are constructed. There are two types of well for the extraction of natural gas: oil wells and natural gas wells. Oil wells are drilled primarily to extract oil, but natural gas can also be obtained. Natural gas wells are specifically drilled to extract natural gas.

After natural gas is extracted through the wells, it has to be processed to meet the characteristics of the natural gas used by consumers. Consumer natural gas is composed primarily of methane. However, when natural gas is extracted, it exists with other hydrocarbons such as propane and ethane. In addition, the extracted natural gas contains impurities such as water vapor and carbon dioxide that must be removed. Natural gas processing plants are usually constructed in gas producing regions. The natural gas is transported from the extraction sites to these plants through a system of low-diameter, low-pressure pipelines. At the plant, water vapor is first removed from the gas by using absorption or adsorption methods. Glycol Dehydration is an example of absorption, in which glycol, which has a chemical affinity to water, is used to absorb the vapor. Solid-Desiccant Dehydration is an example of adsorption. In this process the natural gas passes through towers that contain activated alumina or other solid desiccants. As the gas is passed through these towers, the water particles are retained on the surface of the solids.

As previously mentioned, natural gas is extracted with other hydrocarbons that must be removed. The removal of these hydrocarbons, called Natural Gas Liquids (NGL), is done with the absorption method or the cryogenic expander process. The absorption method is similar to the water absorption method, but instead of glycol, absorbing oil is used. The cryogenic expansion method consists of dropping the temperatures of the gas causing the hydrocarbons to condense so that they can be separated from the natural gas. The absorption method is used to remove heavier hydrocarbons, while lighter hydrocarbons are removed using the cryogenic expansion process.

The final step in the processing of natural gas is the removal of sulfur and carbon dioxide. Often, natural gas from the wells contains high amounts of these two compounds, and it is called sour gas. Sulfur must be removed from the gas because it is a potentially lethal chemical if breathed. In addition, sour gas can be corrosive for the transmissions and distribution pipelines. The process of removing sulfur and carbon dioxide from the gas is similar to the absorption processes previously described.

After the natural gas is processed it enters the transmission system. In the US, this transmission system is the interstate natural gas pipeline network, which consists of thousands of miles of high-pressure pipelines that transport the gas from producing areas to high demand areas. In addition to the pipes, this pipeline system has compressor stations along the way, usually placed in 40 to 100 mile intervals. These compressor stations use a turbine or an engine to compress the natural gas and maintain the high pressure required in the pipeline. The turbines and engines generally run with a small amount of the gas from the pipeline. In addition to compressor stations, metering stations are also placed along the system to allow companies to better monitor and manage the natural gas in the pipes. Moreover valves can be found through the entire length of the pipelines to regulate flow.

Natural gas can be stored to meet seasonal demand increases or to meet sudden, short-term demand increases. Natural gas is usually stored in underground facilities. Such facilities could be built in reconditioned depleted gas reservoirs, aquifers or salt caverns. According to the Energy Information Administration (EIA), in 2003 the total storage capacity in the United States was 8.2 billion cubic feet. 82% of this capacity was in depleted gas fields, 15% in depleted aquifers, and 3% in salt caverns. Moreover during that year, withdrawals from storage added to 3.1 billion cubic feet while injections totaled 3.3 billion cubic feet (4). It is important to note that some gas injected into underground storage becomes physically unrecoverable gas. This gas is known as base gas.

Distribution is the final step before natural gas is delivered to consumers. Local Distribution Companies transport natural gas from delivery points along the transmission system to local consumers via a low-pressure, small-diameter pipeline system. Natural gas that arrives to a city gate through the transmission system is depressurized, and filtered to remove any moisture or particulate content. In addition, Mercaptan is added to the gas to create the distinctive smell that allows leaks to be detected. Small compressors are used in the distribution system to maintain the pressure required.

When Liquefied Natural Gas (LNG) is added to the mix of natural gas, three additional lifecycle stages are created: liquefaction, tanker transport, and regasification. Figure 1 shows the total life cycle of natural gas including the LNG stages.

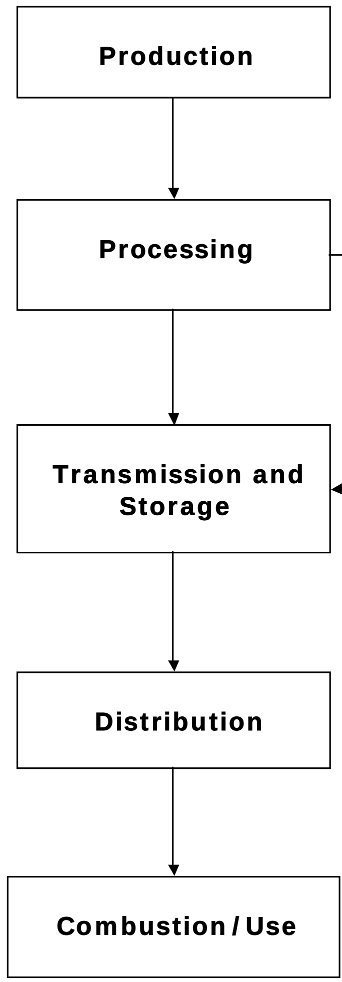

Figure 1: Natural Gas Life Cycle Including LNG.

In the liquefaction process, natural gas is cooled and pressurized to convert it to liquid form, reducing its volume by a factor of 610 (5). These liquefaction plants are generally located in coastal areas of LNG export countries. Currently 75% of the LNG imported to the US comes from Trinidad, but this percentage is expected to decrease as more imports come from Russia, the middle east, and southeast Asia (4). LNG tankers bring this gas to the US. According to EIA, there were 151 LNG tankers in operation worldwide as of October 2003. The majority of these tankers have the capacity to carry more than 120,000 cubic meters of liquefied natural gas (equivalent to 2.59 billion cubic feet of natural gas, enough gas to supply an average of 31,500 residences for a year (4)) and the total fleet capacity is 17.4 million cubic meters of liquid (equivalent to 366 billion cubic feet of natural gas). There are currently fifty-five ships under construction that will increase total fleet capacity to 25.1 million cubic meters of liquid (equivalent to 527 billion cubic feet of natural gas) in 2006 (6).

Regasification facilities are the last step LNG must pass through before going into the US pipeline system. Regasification facilities are LNG marine terminals where LNG tankers unload their gas. These facilities consist of storage tanks and vaporization equipment that warms the LNG to return it to the gaseous state. There are currently 5 LNG terminals in operation in the US: Lake Charles, Louisiana; Elba Island, Georgia; Cove Point, Maryland; Everett, Massachusetts; and a recently opened offshore terminal in the Gulf of Mexico. These terminals have a combined base load capacity of 3.05 billion cubic feet per day (about 1 trillion cubic feet per year). In addition to these there are over fifty proposed facilities for a total proposed capacity of 62 billion cubic feet per day (23 trillion cubic feet per year). Figure 2 shows the proposed location of these facilities (6).

As shown in Figure 1, natural gas combustion is the last stage in the natural gas lifecycle. In the US, natural gas is used for electricity generation, heating, and several industrial processes. Approximately 24% of the electricity generated comes from natural gas (1). Natural gas plants have heat rates that range from 5,800 BTU/kWh to 12,300 BTU/kWh (7).

US Natural Gas Industry in 2003

In 2003, the total supply of natural gas in the US was over 27 trillion cubic feet. Of this, 26.5 trillion cubic feet were produced in North America (US, Canada, and Mexico), and 0.5 trillion cubic feet were imported in the form of LNG. 75% of LNG came from Trinidad and Tobago. Other exporting countries included Algeria, Malaysia, Nigeria, Qatar, and Oman (4). Table 1 shows more detailed statistics about the state of the US natural gas industry in 2003. Numbers may not add up due to rounding.

Table 1: 2003 Natural Gas Industry Statistics (All units in million cubic feet) (4)

Gross Withdrawals	24,000,000
Total Dry Production	19,000,000
Total Supply	27,000,000
Total Consumption	22,500,000
Total Imports	4,000,000
Pipeline Imports	3,500,000
LNG Imports	505,000

Greenhouse gas emissions from Natural Gas produced in North America

During the late 1980's and early 1990's the US Environmental Protection Agency (EPA) conducted a study to determine methane emissions from the natural gas industry. This very comprehensive study developed hundreds of activity and emissions factors from all the areas of the natural industry. These factors were developed using data collected from the different sectors of the industry as well as from data collected in field measurements. Table 2 presents the percentage of produced natural gas that is emitted to the atmosphere during the lifecycle according to the results of the previously described study, as well as the source of these emissions.

Table 2: Methane Emissions from North American Gas Life Cycle as a Percentage of Natural Gas Produced (8).

<table>
<tr><th>Lifecycle Segment</th><th>Emission Sources</th><th>Emissions as a Percentage of Gas Produced</th></tr>
<tr><td rowspan="6">Production</td><td>Pneumatic Devices</td><td rowspan="6">0.38%</td></tr>
<tr><td>Fugitive Emissions</td></tr>
<tr><td>Underground Pipeline Leaks</td></tr>
<tr><td>Blow and Purge</td></tr>
<tr><td>Compressor</td></tr>
<tr><td>Glycol Dehydrator</td></tr>
<tr><td rowspan="3">Processing</td><td>Fugitive Emissions</td><td rowspan="3">0.16%</td></tr>
<tr><td>Compressor</td></tr>
<tr><td>Blow and Purge</td></tr>
<tr><td rowspan="4">Transmission and Storage</td><td>Fugitive Emissions</td><td rowspan="4">0.53%</td></tr>
<tr><td>Blow and Purge</td></tr>
<tr><td>Pneumatic Devices</td></tr>
<tr><td>Compressor</td></tr>
<tr><td rowspan="3">Distribution</td><td>Underground Pipeline Leaks</td><td rowspan="3">0.35%</td></tr>
<tr><td>Meter and Pressure Stations</td></tr>
<tr><td>Costumer Meter</td></tr>
</table>

Based on the statistics presented in Table 1, 26.5 billion cubic feet of natural gas were produced in North America in 2003. Using the percentages of natural gas emitted, an average heat content of 1,030 BTU/ft^3, and the assumption that 100% of the natural gas lost is methane (density 19.23 gr/ ft^3) which may result in a slight overestimate of emissions given that the real percentage of methane in natural gas varies between 94% and 98%; total methane emission were calculated to develop the emission factors shown in Figure 4.

In addition to methane, carbon dioxide emissions are produced from the combustion of natural gas used during the lifecycle stages previously described. The Energy Information Administration maintains records of the amount of natural gas used during the production, processing, transmission, storage, and distribution of natural gas. This data for 2003 can be seen in Table 3. Assuming that 100% of this gas is methane, total carbon dioxide emissions were found using thermodynamic calculations. These emissions were then added to methane emissions to obtain the total emission factors shown in Figure 3.

Table 3: Natural Gas Used During Natural Gas Life Cycle. (All units in million cubic feet) (4).

Flared Gas	98,000
Lease Fuel	760,000
Pipeline and Distribution Use	665,000
Plant Fuel	365,000

In 1993 the Natural Gas STAR program was established by the EPA to reduce methane emissions from the natural gas industry. The program is a voluntary partnership with the goal of encouraging industries to adopt practices that increase efficiency and reduce emissions. Since 1993, 338 billion cubic feet of methane have been eliminated. In 2003, 52,900 million cubic feet of methane emissions were eliminated, a 9% reduction over projected emissions for that year without improved practices (9). This data was used to develop a range of emission factors for the North American natural gas industry. Figure 2 shows the total range of emission factors for the North American natural gas lifecycle. It can be seen that total lifecycle emission for natural gas produced in North America are approximately 140 lbs CO_2/MMBTU, an amount dominated by combustion emissions for natural gas plants currently in operation in the US of an average 120 lbs CO_2/MMBTU (10)

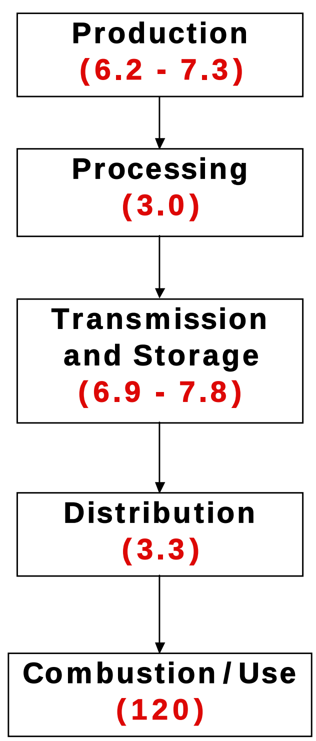

Figure 2: Carbon Dioxide Equivalent Emission Factors from North American Gas Lifecycle (All Units in lbs CO_2/MMBTU).

Greenhouse gas emissions from LNG lifecycle

As shown in Figure 1, the addition of liquefied natural gas (LNG) into the North American gas system introduces three additional stages into the lifecycle of natural gas: liquefaction, tanker transport, and regasification. It is assumed that natural gas produced in other countries and imported to the US in the form of LNG produces the same emissions in the production, processing, transmission, and distribution stages of the lifecycle as if the natural gas were produced in North America. Additional emission factors needed to be developed for the three additional lifecycle stages of LNG. Tamura et-al (11) has reported emission factors for the liquefaction stage in the range of 1.32 to 3,67 gr-C/MJ. Using these results, the emission factors for liquefaction were found in units of pounds of CO_2 per million BTUs, as shown in Table 4.

Table 4: Liquefaction Emission Factors.

Liquefaction	Emission Factors (lb CO_2/MMBTU)		
	Min	**Average**	**Max**
CO_2 from fuel combustion	11	12	13
CO_2 from flare combustion	0.00	0.77	1.5
CH_4 from vent	0.09	1.3	9.8
CO_2 in raw gas	0.09	4.0	6.6

Emissions from tanker transport of LNG were calculated using Equation 1.

$$EmissionFactor = \frac{(EF)\sum_x \left[\left(2 \times roundup\left(\frac{LNG_x}{TC}\right)\right) \times \frac{D_x}{TS} \times FC \times \frac{1}{24}\right]}{LNG_T}$$

Equation 1: Tanker Emission Factor.

Where EF is the tanker emission factor of 3,200 kg CO_2/ ton of fuel consumed; 2 is the number of trips each tanker does for every load (one bringing the LNG and one going back empty); LNG_x is the amount of natural gas (in cubic feet) brought from each country; TC is the tanker capacity in cubic feet of natural gas, assumed to be 120,000 cubic meters of LNG (1 m^3 LNG = 21,537 ft^3 NG); Dx is the distance from each country to US LNG facilities; TS is the tanker speed of 14 Knots; FC is a fuel consumption of 41 tons of fuel per day; and 24 is hours per day (12).

Exporting countries, their distances to the LNG facilities at Lake Charles, LA and Everett, MA, and the 2003 US imports can be seen in Table 5.

Table 5: LNG Exporting Countries in 2003 (4).

Exporting Country	Distance to Lake Charles Facility (nautical miles)	Distance to Everett, MA Facility (nautical miles)	2003 US Imports (million cubic feet NG)
Algeria	5,000	3,300	53,000
Australia	12,000	11,000	0
Brunei	12,000	11,000	0
Indonesia	12,000	11,000	0
Malaysia	12,000	11,000	2,700
Nigeria	6,100	5,000	50,000
Oman	8,900	7,500	8,600
Qatar	9,700	8,000	14,000
Trinidad	2,200	2,000	380,000
UAE	9,600	7,959	0
Russia	9,600	11,000	0

Emission factors for tanker transport from each country to both US facilities can be seen in Figure 3.

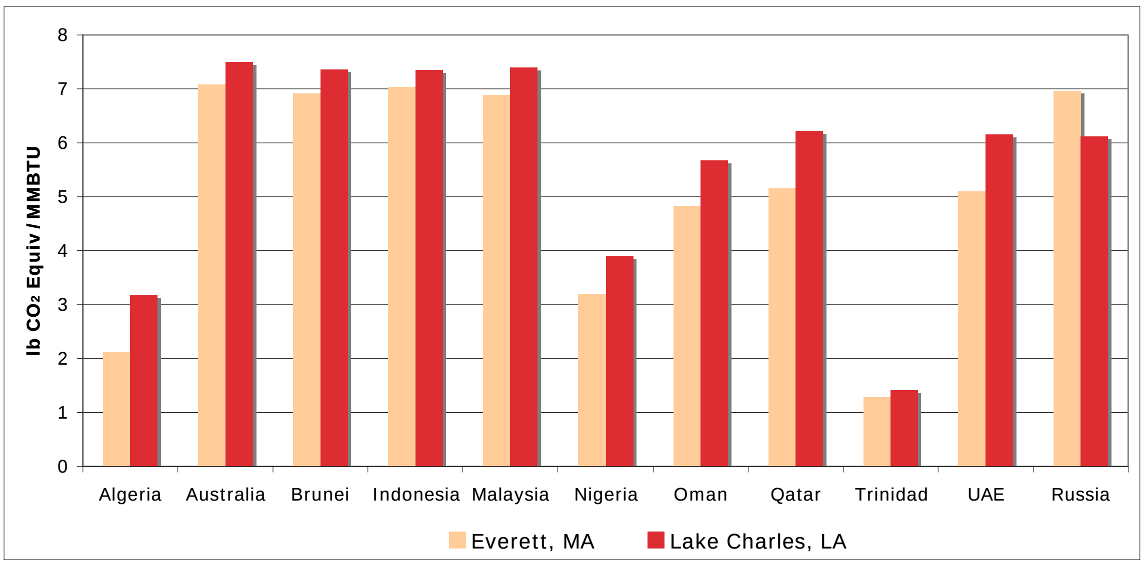

Figure 3: Tanker Emission Factors from Each Country

Since most of the LNG in 2003 was brought from Trinidad, the weighted average emission factor calculated for trips from each country to the Everett, MA facility is considered to be the a lower bound. An upper bound was obtained by assuming that all LNG was brought from Indonesia to the Lake Charles facility, and an average was obtained assuming all LNG was brought from Oman to the Lake Charles, LA facility. These resulting numbers can be seen in Table 6.

Table 6: Tanker Transport Emission Factors.

Emission Factors (lb CO_2/MMBTU)	
Min	1.8
Average	5.7
Max	7.3

Regasification emissions were reported by Tamura et-al to be 0.1 gr C/ MJ (0.85 lb CO_2/MMBTU) (11). Ruether et-al reports an emission factor of 1.6 gr CO_2/MJ (3.75 lb CO_2/MMBTU) for this stage of the LNG lifecycle by assuming that 3% of the gas is used to run the regasification equipment (13). These values were used as the lower and upper bounds of the range of emission from regasification of LNG. Total LNG lifecycle emissions are shown in Figure 4. They range between 154 and 184 lbs CO_2/MMBTU

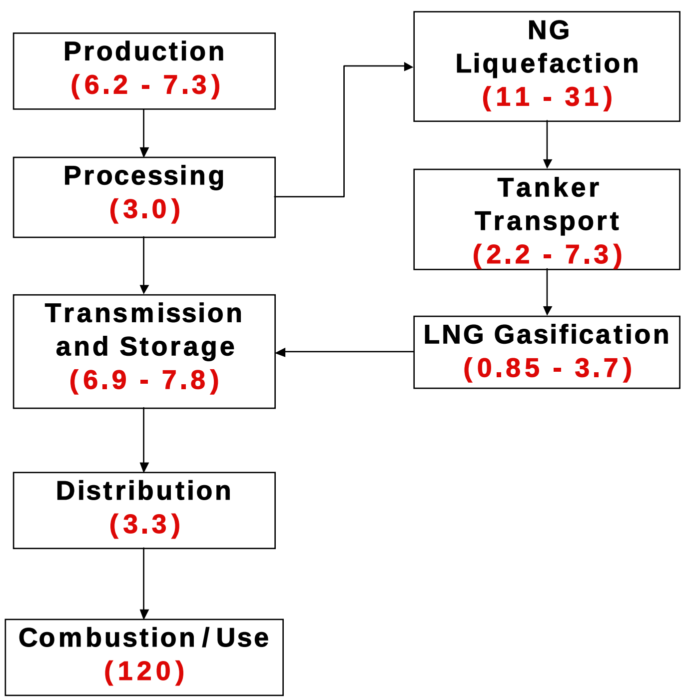

Figure 4: LNG Lifecycle Emission Factors (All Units in lbs CO_2/MMBTU).

Coal Lifecycle and its Greenhouse Gas Emissions for Electricity Generation

The coal lifecycle is conceptually simpler than the natural gas lifecycle, consisting of only three steps, as shown in Figure 5.

Figure 5: Coal Lifecycle.

In the US, 67% of the coal produced is mined in surface mines, while the remaining 33% is extracted from underground mines (1). Mined coal is then processed to remove impurities. Coal is then transported from the mines to the consumers via rail (84%), barge (11%), and trucks (5%) (14). Emissions from these lifecycle steps were calculated using the EIO-LCA tool developed at Carnegie Mellon University. In order to use this tool, economic values for each step of the lifecycle were necessary. In 1997, the year for which the EIO-LCA tool has data, the price of coal was $18.14/ton (15). Moreover, the cost for rail transport, barge, and truck transport was $11.06/ton, $3.2/ton, and $5.47/ton respectively (14). For a million tons of coal the following emission information was obtained using EIO-LCA.

Table 7: EIO-LCA Emission Data for Coal Lifecycle (16).

Sector	Total GHG Emissions (MT CO_2 Equiv)
Mining	75,000
Rail Transportation	36,000
Water Transportation	3,700
Truck Transportation	5,000

Using a weighted average US coal heat content of 10,266 BTU/lb (17) and the data previously discussed, it was found that the average emission factor for coal mining and transport is 11 lb CO_2/MMBTU.

In 1999, the National Renewable Energy Lab published a report on lifecycle emissions for power generation from coal (18). Upstream coal emissions (including transportation) from underground mines are reported to be 15 lbs CO_2/MMBTU, while upstream coal emissions from surface mines is 9.9 lbs CO_2/MMBTU. As previously mentioned, 67% of coal is currently mines in surface mines, while 33% is mined in underground mines (1). Using this information, the current coal upstream emissions average 12 lbs CO_2/MMBTU, which is very close to the emission factor obtained using EIO-LCA. In the future, the distribution of US mines could change, affecting the average emission factor. For this reason, the range of coal upstream emissions from underground and surface mines described above is used for this paper. Moreover, the average emission factors for coal combustion at utility plants used is 205 lb CO_2/MMBTU (10).

Comparing Natural Gas and Coal Lifecycle Emissions

Emissions factors for the natural gas lifecycle and the coal lifecycle were previously reported in pounds of CO_2 per MMBTU of fuel. Coal and natural gas power plants have different efficiencies; thus one million BTU of coal does not generate the same amount of electricity as one million BTU of natural gas. For this reason, emission factors must be converted to units of pounds of CO_2 per kWh of electricity generated. This conversion was done using the heat rates of natural gas and coal plants. Figure 6 shows the distribution of these heat rates, and Figure 7 shows the resulting emission factor distribution for coal and natural gas. These distributions were obtained using the cumulative distribution function of EIA electricity generation data for all utility plants in 2003 (7). The minimum value represents the heat rate at which 5% of the electricity generated with the specific fuel is seen. Similarly the mean and maximum values are the heat rates at which 50% and 95% of the electricity has been generated with each fuel. As seen in Figure 6, the average heat rate for natural gas plants is lower than the average heat rate for coal plants, however the upper range of heat rates for natural gas plants surpasses the heat rates for coal plants.

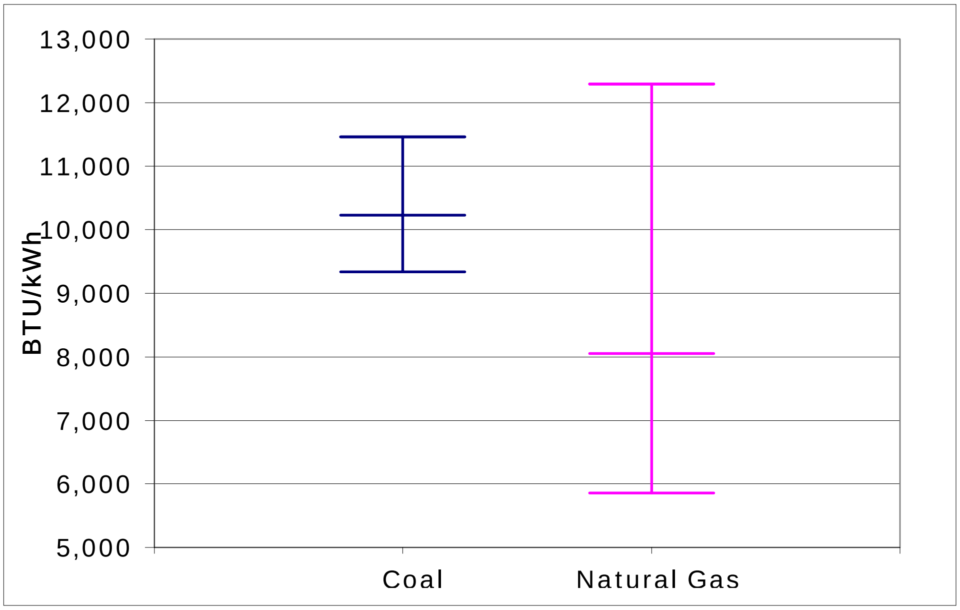

Figure 6: Natural Gas and Coal Plant Heat Rates (7).

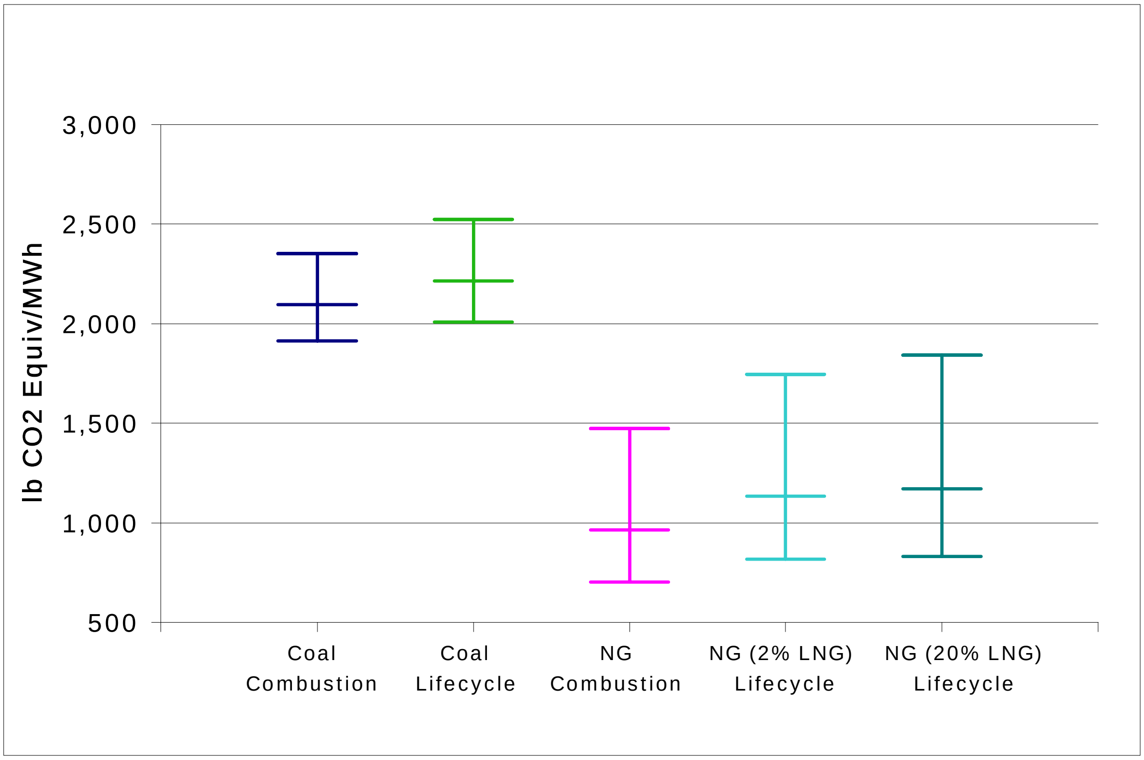

Figure 7: Emission Factors for Coal and Natural Gas Lifecycles.

Note that the average emission factor for coal combustion is higher than the emission factor for natural gas combustion. This does not change too much when the whole lifecycle is considered. More important seems to be the effect that including upstream emissions have in the range of emission factors for natural gas. While the average emission factor for the total coal lifecycle only increases by 5% compared to combustion emissions, the average emission factor for a natural gas mix with 20% LNG is 21% higher than the combustion emissions. Moreover, the maximum emission factor of the natural gas lifecycle gets closer to the minimum coal lifecycle emission factor. These results imply that if emissions at the combustion stage of the lifecycle could be controlled, natural gas would not be a much better alternative to coal in terms of greenhouse gas emissions.

New Generation Capacity

According to the DOE, by 2025 43 GW of inefficient gas and oil fired facilities will be retired, while 281 GW of new capacity will be installed (3). IGGC and NGCC power plants will probably be installed. These plants are generally more efficient than current technologies (average HHV Efficiencies are 37.5% and 50.2% respectively) (19) and thus have lower carbon emissions at the combustion stage. In addition, carbon capture and sequestration (CCS) can be performed more easily with these newer technologies. CCS is a process by which carbon emissions at the power plant are separated from other combustion products, captured and injected into underground geologic formations such as saline formations and depleted oil/gas fields. Experts believe that 90% CCS will be technologically and economically feasible in the future. Having CCS at IGCC and NGCC plants decreases the efficiency of the plants to average HHV efficiencies of 32.4% and 42.8% respectively (19) but overall lifecycle emissions would be greatly reduced and would be essentially the same for coal and natural gas (with 20% LNG). However, the major contributor for coal emissions would be at the combustion stage, while for natural gas the majority of the emissions would come from upstream processes. Figure 8, shows total emissions with CCS for IGCC and NGCC plants using average upstream emission factors of 11.6 lbs CO_2 Equiv/MMBTU and 25.6 lbs CO_2 Equiv/MMBTU for coal and natural gas respectively

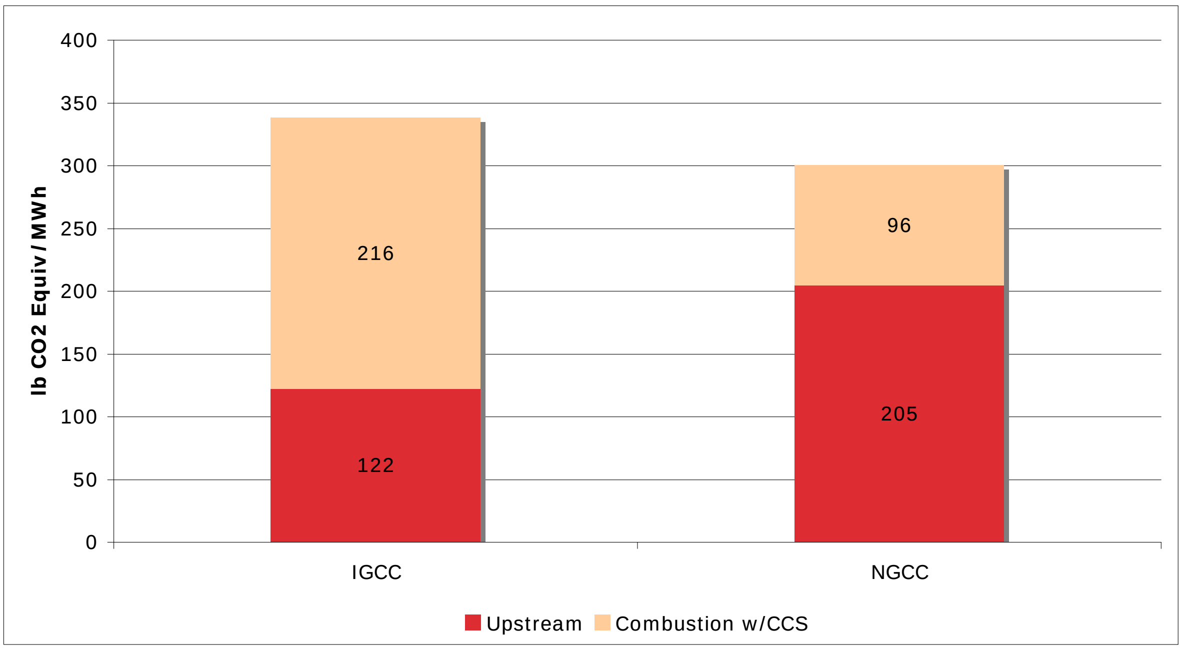

Figure 8: Lifecycle Emission Factors for IGCC and NGCC plants w/ CCS.

Discussion

It has been shown that there is high uncertainty about overall lifecycle carbon emissions for coal and LNG. In the future, as newer generation technologies and CCS are installed, overall emissions from electricity generated with coal and electricity generated with natural gas could be surprisingly similar. There is push right now from power generator to increase import of LNG. They seem to hope that the price of natural gas will decrease with these imports and they will be able to recover the investment they made in natural gas plants that are currently producing under capacity. These investments should be considered sunk costs and it is important to revaluate whether investing billions of dollars in LNG infrastructure will lead us into an energy path that cannot be easily changed as it will be harder to consider these investments as sunk costs once the expected environmental benefits are not achieved.

The analysis presented here only includes carbon emission, and no consideration was given to issues like energy security. Increasingly, LNG will come from areas of the world that are politically unstable. Policymakers should evaluate this increased dependence on foreign fuel before making decisions about future energy investments. In addition, the analysis presented only considers the use of natural gas for electricity generation. Natural gas is an indispensable fuel for many sectors of the US economy. As demand for natural gas from the electric utilities increases, these other sectors will probably be affected by higher natural gas prices. It is important to analyze whether these other sectors constitute a better use for natural gas than electricity generation, which has alternative fuels at its disposal.

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TESTIMONY OF JAMES BRADBURY

SENIOR ASSOCIATE, CLIMATE AND ENERGY PROGRAM
WORLD RESOURCES INSTITUTE

HEARING BEFORE THE U.S. HOUSE OF REPRESENTATIVES ENERGY AND COMMERCE SUBCOMMITTEE ON ENERGY AND POWER:
"U.S. ENERGY ABUNDANCE:
EXPORTS AND THE CHANGING GLOBAL ENERGY LANDSCAPE"

May 7, 2013

Summary of Key Points:

Liquefied natural gas (LNG) exports present both opportunities and risks. Producing and delivering natural gas to customers is highly energy- and emissions-intensive, particularly when LNG is involved. Research by the World Resources Institute has found that cuts in upstream methane leakage from natural gas systems are among the most important steps the U.S. can take toward meeting our greenhouse gas (GHG) emissions reduction goals by 2020 and beyond.

This testimony focuses on fugitive methane emissions and the many cost-effective solutions available for reducing them. It appears very likely that LNG exports from U.S. terminals would result in increased domestic GHG emissions from both upstream and downstream sources. Policymakers should more actively work to help achieve reductions in GHG emissions from throughout the natural gas value chain, if this valuable fuel and LNG are to be part of the solution to the climate change problem. Taking these actions offer economic, environmental, and geopolitical benefits, both in the U.S. and internationally. To this end, I offer the following policy recommendations:

- Expand applied technology research programs at the U.S. Department of Energy to help reduce the cost of leak-detection and emissions measurement technologies, and to develop new and lower-cost emission reduction strategies.
- Update emissions factors for natural gas systems using robust measurement protocols, public reporting by industry, and independent verification.
- Authorize and appropriate funding for the organization STRONGER (State Review of Oil and Natural Gas Environmental Regulations) to help states with timely development and evaluation of their environmental regulations.
- Support voluntary programs at the U.S. Environmental Protection Agency (EPA), including Natural Gas STAR and other programs which recognize companies that demonstrate a commitment to best practices.
- Support EPA's efforts to provide technical and regulatory assistance to states with expanding oil and natural gas development, including through the Ozone Advance Program.
- Enact policies to support clean energy and address climate change. A clean energy standard or putting a price on carbon would provide clear signals to energy markets that energy providers and users need to recognize the environmental and social costs as well as the direct economic costs of energy resources.

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May 7, 2013

Good morning, and thank you for the opportunity to contribute to the deliberations of this Subcommittee. My name is James Bradbury, and I am a senior associate in the Climate and Energy Program at the World Resources Institute (WRI). WRI is a non-profit, non-partisan think tank that focuses on the intersection of the environment and socio-economic development. We go beyond research to put ideas into action, working globally with governments, business, and civil society to build transformative solutions that protect the earth and improve people's lives. We operate globally because today's problems know no boundaries. We provide innovative paths to a sustainable planet through work that is accurate, fair, and independent.

Summary

I am pleased to be here today to offer WRI's perspective on the climate implications of U.S. liquefied natural gas (LNG) exports. I encourage this committee to weigh a complete consideration of the associated economic and geopolitical opportunities next to the potential risks, neither of which have been fully considered in the public debate. In particular, it appears very likely that LNG exports from U.S. terminals would result in increased domestic greenhouse

gas (GHG) emissions. For example, analysis by the Energy Information Administration (EIA)[1] concluded that any scenario of LNG exports would trigger an increase in domestic carbon dioxide (CO_2) emissions, due to an increase in coal-fired electricity and use of natural gas for the energy-intensive liquefaction process at LNG terminals. The EIA also projected an increase in natural gas production from shale wells. Though not considered in the EIA study, an inevitable consequence would be greater upstream air emissions from natural gas infrastructure – that is, emissions that occur prior to fuel combustion – including fugitive methane, which is a potent global warming pollutant. While LNG exports from the U.S. are widely expected to marginally reduce global CO_2 emissions, modeling to date suggests that the scale of these reductions is less than ten percent of the total levels of global fugitive methane emissions from natural gas and oil systems.

These facts should raise the bar for policymakers and advocates for LNG exports to more actively work to achieve continuous improvement in GHG emissions from all life cycle stages (from extraction to use), if natural gas and LNG are to be part of the solution to our climate change problem. Furthermore, to the extent that substantial LNG exports from the U.S. move forward, our national policy objectives should be broader than simply improving our balance of trade vis-à-vis fossil fuel exports to increase our economic and geopolitical standing. We also have an important – indeed urgent – opportunity to improve our economic and geopolitical standing by showing leadership in addressing global climate change. We can do through policies

[1] See: http://www.fossil.energy.gov/programs/gasregulation/reports/fe_eia_lng.pdf

that promote the development, deployment, and export of low-carbon products and services[2] to help enable global GHG emissions reductions from all sectors, including through technologies and practices that allow the cleaner production and more efficient end-use of natural gas.

Today I will focus in particular on fugitive methane emissions[3] and the cost-effective solutions available for reducing them.[4] The case for policy action is particularly strong considering that recent research shows that climate change is happening faster than expected. In addition, the projected expansion in domestic oil and natural gas production increases the risk of higher GHG emissions if proper protections are not in place.

- Methane is the primary component of natural gas and also a potent greenhouse gas. Methane leaked from natural gas systems (i.e., fugitive methane) represent lost product and reduced revenue for companies and governments, with negative consequences for air quality and the environment.
- Fugitive methane emissions from natural gas systems represent roughly 3 percent of global warming pollution in the U.S. Reductions in methane emissions are urgently needed as part of the broader effort to slow the rate of global temperature rise.
- Although natural gas burns much cleaner than coal or oil, fugitive methane emissions significantly reduce this relative advantage, from a climate standpoint; therefore, cutting

[2] For more information on low-carbon market opportunities, see Jennifer Morgan's testimony, here: http://www.wri.org/publication/testimony-american-energy-security-and-innovation-assessment-of-energy-resources

[3] While this testimony focuses on greenhouse gas emissions – and methane emissions from natural gas systems, in particular – WRI is committed to minimizing the full scope of impacts cause by energy production and use. It is critical for U.S. energy policies to be developed with consideration to a broad range of risks and benefits.

[4] For more detailed analysis and discussion of this topic, see WRI's recent working paper, "Clearing the Air: Reducing Upstream Greenhouse Gas Emissions from U.S. Natural Gas Systems." Available at: http://www.wri.org/publication/clearing-the-air

fugitive emissions from natural gas systems would ensure that the climate impacts of natural gas are much lower than coal or diesel fuel over any time horizon.

- Recent emissions standards from the U.S. Environmental Protection Agency (EPA) will substantially reduce leakage from natural gas systems, but to help slow the rate of global warming pollution and improve air quality, further action by states and federal agencies should directly address fugitive methane from new and existing wells and equipment.
- Fortunately, most strategies for reducing fugitive methane emissions are cost-effective, with payback periods of three years or less. A recent WRI report found that cuts in methane leakage from natural gas systems are among the most important steps the U.S. can take toward meeting our GHG emissions reduction goals.[5]
- The process of liquefaction, transport, and regasification of LNG is highly emissions-intensive, increasing by 15 percent the total life cycle GHG emissions associated with exported U.S. natural gas, compared to natural gas that is produced and consumed domestically. These added upstream emissions also significantly reduce the relative advantage that natural gas would have over higher-emitting fuels, like coal and oil.
- The following policy actions by Congress would help reduce methane emissions as cost-effectively and quickly as possible:
    - Expand applied technology research programs at the U.S. Department of Energy (DOE) to help reduce the cost of leak-detection and emissions measurement technologies, and to develop new and lower-cost emission reduction strategies.

[5] See: "Can the U.S. Get There from Here? Using Existing Federal Laws and State Actions to Reduce Greenhouse Gas Emissions," available at: http://www.wri.org/publication/can-us-get-there-from-here.

  - Update emissions factors for natural gas systems using robust measurement protocols, public reporting by industry, and independent verification.
  - Authorize and appropriate funding for the organization STRONGER (State Review of Oil and Natural Gas Environmental Regulations) to help states with timely development and evaluation of their environmental regulations.
  - Support voluntary programs at EPA, including Natural Gas STAR and other programs which recognize companies that demonstrate a commitment to best practices.
  - Support EPA's efforts to provide technical and regulatory assistance to states with expanding oil and natural gas development, including through the Ozone Advance Program.
- Broader action on policies supporting clean energy and addressing climate change should also be on the table. A clean energy standard or putting a price on carbon would provide clear signals to energy markets that energy providers and users need to recognize the environmental and social costs as well as the direct economic costs of energy resources.

Finally, every day that we take no policy action on climate change, we make the policy choice to let climate change run its course. This ignores the overwhelming consensus of climate scientists who have been warning for decades that rising GHG emissions will cause the planet to warm, sea levels to rise, and weather to become more extreme. It is indisputable that these climate changes are happening today, in many cases much more quickly than expected. Action is urgently needed.

LNG Exports, the Public Interest, and Climate Change

When reviewing grant applications for LNG export authorizations, DOE is required to determine if proposed exports "will not be consistent with the public interest." In making this finding, DOE is considering a range of factors, including economic, energy security, and environmental impacts.[6] The climate change implications of LNG exports touches on each of these factors and therefore deserves more careful consideration by Congress and DOE.

The January 2012 study by EIA included a useful but limited assessment of the climate change implications of LNG exports, while the NERA Economic Consulting report (December 2012) was more narrowly focused on macroeconomic considerations.[7] This testimony focuses particular attention to how LNG exports – and increased production of natural gas more broadly – could affect domestic and international GHG emissions, which is clearly a question of relevance to the public interest.

There is no doubt that our climate is already changing in ways that are increasingly risky, difficult to manage, and harmful to public health and the environment.[8] Recent science assessments – including by the U.S. National Academy of Sciences and the U.S. Global Change Research Program[9] – agree that GHG emissions are very likely causing higher global temperatures, rising sea levels, and more frequent extreme weather events. National science

[6] See: http://www.fossil.energy.gov/programs/gasregulation/LNGStudy.html
[7] Both reports are available here: http://www.fossil.energy.gov/programs/gasregulation/LNGStudy.html
[8] National Academies, Committee on Climate Choices, Final Report, 2011. http://dels.nas.edu/Report/America-Climate-Choices-2011/12781
[9] http://ncadac.globalchange.gov/download/NCAJan11-2013-publicreviewdraft-fulldraft.pdf

academies from over a dozen countries, including the U.S., have expressly urged governments to take urgent action to curb these harmful emissions.[10]

The current U.S. commitment to the international community is to reduce GHG emissions below 2005 levels by 17 percent in 2020 and 83 percent in 2050.[11] While a shift in electric generation to natural gas from coal has played a significant role in recent reductions in U.S. carbon dioxide emissions, this market-driven trend in the power sector has reversed somewhat in recent months, as natural gas prices have been increasing.[12] Furthermore, GHG emissions from all major sources will need to be addressed for the U.S. to help achieve climate stabilization at 2° Celsius, which the international community has agreed to be an appropriate and relatively safe target. A recent report by the World Bank[13] found that the world is on track for at least a 4° Celsius increase in global temperatures, which would be extremely damaging to global development goals and be "marked by extreme heat-waves, declining global food stocks, loss of ecosystems and biodiversity, and life-threatening sea level rise." However, the World Bank also concluded that there is still time to enact policies that would help avoid this outcome.

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[10] G8+5 Academies' joint statement: Climate change and the transformation of energy technologies for a low carbon future. http://www.nationalacademies.org/includes/G8+5energy-climate09.pdf

[11] See: http://unfccc.int/files/meetings/cop_15/copenhagen_accord/application/pdf/unitedstatescphaccord_app.1.pdf

[12] See: http://insights.wri.org/news/2013/03/new-data-reveals-rising-coal-use

[13] See: http://climatechange.worldbank.org/content/climate-change-report-warns-dramatically-warmer-world-century

Concerns about the environmental impacts of shale gas development

Natural gas production in the United States has increased rapidly in recent years, growing by 23 percent from 2007 to 2012.[14] This development has significantly changed projections of the future energy mix in the U.S. The shale gas phenomenon has also helped reduce energy prices, directly and indirectly supporting growth for many sectors of the U.S. economy, including manufacturing. The EIA projects that the United States will begin exporting LNG within 5 years and that the country will be a net natural gas exporter by the year 2020.[15]

Shale gas development has also triggered divisive debates over the near- and long-term environmental implications of developing and using these resources, including concerns about water resources, air quality, and land and community impacts.[16] Like all forms of energy, including conventional natural gas, there are public health and environmental risks associated with shale gas development. Chief among public concerns are drinking water contamination resulting from improper wastewater management, chemical spills, and underground methane migration into groundwater. There are also concerns regarding air emissions, and land-related impacts including habitat fragmentation and soil erosion. Other common concerns involve community impacts related to industrial development and extensive truck traffic. In 2011, the Secretary of Energy Advisory Board's Natural Gas Subcommittee warned[17] that "disciplined attention must be devoted to reducing the environmental impact" of shale gas development in the

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[14] See: http://www.eia.gov/forecasts/aeo/index.cfm

[15] ibid

[16] For more detailed discussions of the broader environmental impacts of natural gas development, see: http://www.gao.gov/products/GAO-12-732; and http://www.rff.org/Documents/RFF-Rpt-PathwaystoDialogue_FullReport.pdf

[17] http://www.shalegas.energy.gov/resources/111811_final_report.pdf

face of its expected continued rapid growth, with as many as 100,000 more wells expected over the next few decades.

Of particular concern are the air emissions and climate change implications of shale gas development, including fugitive methane emissions, which reduce the net climate benefits of using lower-carbon natural gas as a substitute for coal and oil for electricity generation and transportation, respectively. Other air emissions from the natural gas sector include CO_2, volatile organic compounds (VOCs, which are chemicals that contribute to ground-level ozone and smog), and hazardous air pollutants (HAPs). In 2012, EPA finalized air pollution standards for VOCs and HAPs from the oil and natural gas sector. These rules will improve air quality and have the co-benefit of reducing methane emissions. As discussed below (see p. 18, "Progress is Being Made but There is More Work to Be Done"), these standards should be complemented by additional actions to further reduce methane emissions, which will help slow the rate of global temperature rise in the coming decades.

From the standpoint of CO_2 emissions, shale gas development and lower natural gas prices have contributed to recent emissions reductions in the U.S. However, GHG emissions are projected to rise, and market forces and voluntary actions alone will not enable an effective response to climate change. Thus broad policy action will be needed. For example, analysis by the International Energy Agency (IEA)[18] found that a significant global increase in use of natural gas over the coming decades could have some net climate benefits compared to scenarios in which oil and coal play more prominent roles. However, the IEA's "Golden Rules Case" scenario

[18] International Energy Agency, "Golden Rules for a Golden Age of Gas." Available at: http://www.worldenergyoutlook.org/media/weowebsite/2012/goldenrules/weo2012_goldenrulesreport.pdf

would result in CO_2 concentrations in the atmosphere of 650 parts per million (ppm) and a global temperature rise of 3.5° Celsius, almost twice the internationally accepted 2° Celsius target. Economic modeling conducted by researchers at MIT[19] and Resources for the Future[20] have also found that while greater use of natural gas may offer some climate benefits, climate and energy policies will be needed to reduce CO_2 emissions by anywhere near our 83 percent target by mid-century. While natural gas will likely play an essential bridging role in this transition, this will require both reducing the upstream GHGs produced during the extraction process, and ─ if gas-fired power plants are to be a part of a longer-term energy future ─ using carbon capture and storage (CCS) technology.

Why Focus on Methane Emissions?

Though methane accounted for only 10 percent of the U.S. greenhouse gas emissions inventory in 2010 (Figure 1),[21] it represents one of the most important opportunities for reducing GHG emissions in the U.S.[22] In addition to the scale and cost-effectiveness of the reduction opportunities, climate research scientists have concluded that cutting methane emissions in the near term could slow the rate of global temperature rise over the next several decades.[23]

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[19] See: http://globalchange.mit.edu/research/publications/2229

[20] See: http://www.rff.org/RFF/Documents/RFF-IB-09-11.pdf

[21] Note: all GHG inventory numbers referred to in this testimony were adjusted to reflect a more current global warming potential (GWP) for methane of 25 (IPCC 2007). This is necessary because when EPA converts methane to carbon dioxide equivalents they use an out-of-date GWP for methane of 21 (IPCC 1995), for the sake of consistency with UNFCCC reporting guidelines.

[22] See: "Can the U.S. Get There from Here? Using Existing Federal Laws and State Actions to Reduce Greenhouse Gas Emissions," available at: http://www.wri.org/publication/can-us-get-there-from-here.

[23] National Research Council, 2011. "Climate Stabilization Targets: Emissions, Concentrations, and Impacts over Decades to Millennia," ISBN: 0-309-15177-5, 298 pages. http://www.nap.edu/catalog/12877.html

Rising methane concentrations in the atmosphere have a potent, near-term warming effect because this greenhouse gas has a relatively high global warming potential and short atmospheric lifetime (IPCC 2007). Global warming potential (GWP) is a measure of the total energy that a gas absorbs over a particular period of time (usually 100 years), compared to carbon dioxide. Key factors affecting the GWP of any given gas include its average atmospheric lifetime and the ability of that molecule to trap heat. By mass, the same amount of methane emissions is 25 times more potent than carbon dioxide emissions over a 100-year time horizon (IPCC 2007). In the 20-year time frame, studies estimate that methane's GWP is at least 72 times greater than that of carbon dioxide.

Scientists at the National Research Council of the U.S. National Academy of Sciences have concluded that global CO_2 emissions need to be reduced in the coming decades by at least 80 percent to stabilize atmospheric CO_2 concentrations and thereby avoid the worst impacts of global climate change.[24] However, given the slow pace of progress in the U.S. in this regard, it is valuable and important for policymakers to consider cost-effective mitigation strategies – such as cutting methane emissions – that would have a disproportionate short-term impact.

How Emissions-Intensive is U.S. Natural Gas?

EPA estimates that total emissions from the development, transmission, and use of natural gas in the U.S. made up roughly a quarter of the total U.S. GHG inventory in 2011.[25] While natural gas emits about half as much carbon dioxide as coal at the point of combustion, the picture is more

[24] Ibid.
[25] Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2011 (April 2013). http://www.epa.gov/climatechange/ghgemissions/usinventoryreport.html

complicated from a life cycle perspective. Three percent of the U.S. inventory is the result of fugitive methane emissions from natural gas systems[26] – i.e., natural gas lost to the atmosphere through venting and systemic leaks, prior to the point of combustion. To put this in perspective, in 2011, these methane leaks resulted in more GHG emissions[27] than all of the direct and indirect GHG emissions from U.S. iron and steel, cement, and aluminum manufacturing combined.[28]

EPA's 2013 GHG inventory implies a methane leakage rate of less than 2 percent of total natural gas production. Meanwhile, recent research[29] has shown that at less than a 3 percent leakage rate, natural gas produces fewer GHG emissions than coal over any time horizon. Additionally, reducing the methane leakage rate to below 1 percent would ensure that heavy-duty vehicles fueled by natural gas, like buses and long-haul trucks, would provide an immediate climate benefit over similar vehicles fueled by diesel. Thus, reducing total methane leakage to less than 1 percent of natural gas production is a sensible performance standard for the sector; an achievable benchmark that has not yet been reached.

Accurate estimates of the total leakage rate from the natural gas sector require reliable data for a broad range of industry activities and emissions factors associated with those activities. While EPA has recently updated industry activity data, most of the emissions factors rely on assumed emissions factors – as opposed to direct measurements, which are generally rare and often

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[26] The GHG inventory estimates 6.9 million metric tons of fugitive methane from natural gas systems in 2011.
[27] This estimate is based on an assumed global warming potential for methane of 25, which is the convention when considering the climate implications of methane compared to carbon dioxide, integrated over a 100-year time frame (IPCC, 2007).
[28] See: http://www.energetics.com/resourcecenter/products/roadmaps/Pages/USManufacturingEnergyUseandGreenhouseGasEmissionsAnalysis.aspx
[29] See: http:// www.pnas.org/content/109/17/6435

outdated. Some recently published research suggests that emissions levels may be higher than EPA estimates; this, coupled with high ground-level ozone levels in Colorado and Texas and rural parts of Utah and Wyoming (i.e., smog that is attributed to shale gas production activities), suggests that the emissions problem may be worse than we think, and certainly subject to regional variations.[30]

With hundreds of thousands of wells and thousands of natural gas producers operating in the U.S., the data quality issue will likely remain an active debate, even as forthcoming data from EPA and other sources in the coming months aims to clarify these questions.[31] In its November 2011 final report, the Secretary of Energy Advisory Board recommended that natural gas companies measure and disclose air emissions from shale wells.[32] Indeed, what remains lacking is a valid system for direct measurement and independent verification of emissions data reported by this sector.[33]

Nevertheless, while uncertainties remain regarding exact methane leakage rates, the weight of evidence suggests that significant leakage occurs during every life cycle stage of U.S. natural gas systems and much more can be done to reduce these emissions cost-effectively. A recent expert

[30] Recent research based on field measurements of ambient air near natural gas well-fields in Colorado and Utah suggest that more than 4 percent of well production may be leaking into the atmosphere at some production-stage operations. For more discussion of questions regarding the quality and availability of methane emissions data, see Appendix 3 of "Clearing the Air," here: http://www.wri.org/publication/clearing-the-air.

[31] For example, independent researchers at the University of Texas at Austin are teaming up with the Environmental Defense Fund and several industry partners to directly measure methane emissions from several key sources. When results are published in 2013 and 2014, these data will provide valuable points of reference to help inform this important discussion.

[32] See: http://www.shalegas.energy.gov/

[33] Such systems and protocols have been developed for tracking emissions from other sources. For example, see: http://www.epa.gov/etv/vt-ams.html

survey by Resources for the Future[34] identified methane emissions as a "consensus environmental risk" that should be addressed through government and industry actions.

How Will LNG Exports Affect Greenhouse Gas Emissions?

To the extent that it is displacing higher-carbon fuels such as coal and oil, natural gas has the potential to help reduce total greenhouse gas emissions. This is particularly true as long as upstream emissions associated with natural gas are minimized and ideally methane leakage is kept below 1 percent of total production, as discussed above.

That said, the potential for LNG exports raises three primary concerns from a climate perspective.

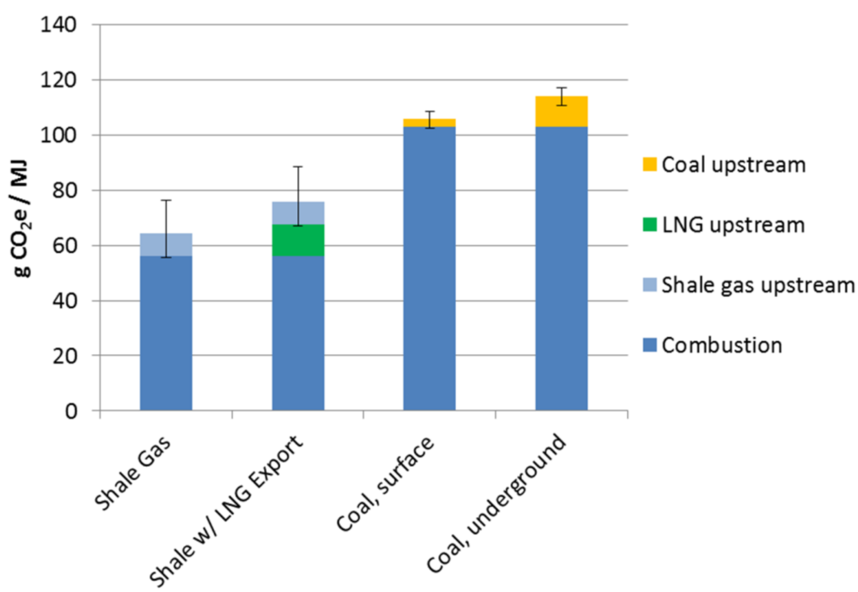
1) The first area of concern involves upstream GHG emissions associated with increased onshore natural gas production. EIA projects that LNG exports would result in increased domestic production of natural gas, with roughly three quarters of this from shale sources. As shown in Figure 1, there are significant upstream GHG emissions (both CO_2 and methane) associated with shale gas production in the U.S. Given continued uncertainty around the actual level of methane emissions over the lifetime of both conventional and unconventional gas wells,[35] this projected market response could result in substantially higher levels of GHG emissions from throughout U.S. natural gas systems. The good news is that there are many ways to cost-effectively reduce upstream methane emissions; we encourage government and industry to do more to realize this

[34] See: http://www.rff.org/Documents/RFF-Rpt-PathwaystoDialogue_FullReport.pdf

[35] Most studies estimate that upstream GHG emissions from conventional and unconventional gas sources are roughly comparable, within the margin of error.

opportunity (see p. 20 below, "Further Potential to Reduce Fugitive Methane Emissions").

Figure 1: Estimated Life Cycle Greenhouse Gas Emissions from U.S. Shale Gas, LNG Exports, and Coal



Sources: Bradbury et al. 2013; Weber and Clavin, 2012; NETL, 2012; Burnham et al. 2011

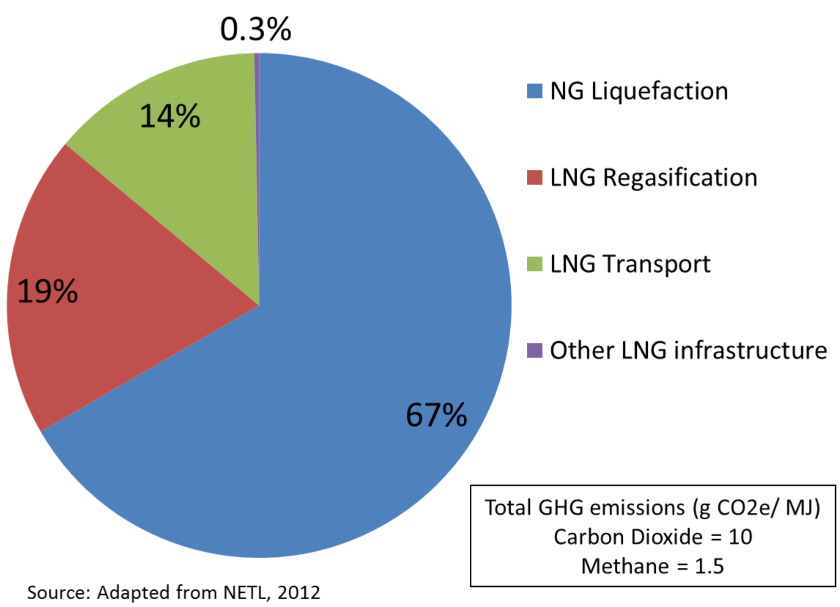
2) The second area of concern is with respect to the liquefaction, transport, and regasification of LNG exports. According to a 2012 Natural Gas Technology Assessment by the National Energy Technology Lab (NETL),[36] these energy- and emissions-intensive processes would add roughly 15 percent[37] to total life cycle GHG emissions associated with U.S. onshore natural gas production (see Figure 1, above, "LNG upstream"). These added upstream emissions significantly reduce the relative advantage that natural gas

[36] NETL (National Energy Technology Laboratory). 2012. Role of Alternative Energy Sources: Natural Gas Technology Assessment. National Energy Technology Laboratory, U.S. Department of Energy. Available at: http://www.netl.doe.gov/energy-analyses/refshelf/PubDetails.aspx?Action=View&PubId=435

[37] Based on data provided in Appendix B of the NETL (2012) report, we calculate 11.5 grams of CO_2 equivalent per megajoule (g CO2e/MJ) of natural gas exported, which we added to estimated life cycle emissions associated with shale gas production, after the recent EPA rule takes effect (8.25 g CO2e/MJ), and typical estimate of final combustion of natural gas (56 g CO2e/MJ).

would have over higher-emitting fuels like coal.[38] The chart below illustrates the relative contributions of each process to total GHGs associated with LNG exports; liquefaction is the most emissions-intensive process, followed by regasification and transport. It is also worth noting that natural gas liquefaction emissions would occur at domestic LNG terminals, adding to total U.S. GHG emissions.

Figure 2: Life Cycle GHG Emissions from LNG Terminals, Transport, and Infrastructure



3) The third area of concern is the indirect domestic and international energy market implications of U.S. LNG exports. EIA's 2012 report to DOE found that LNG exports would raise domestic prices for natural gas, making natural gas relatively less competitive compared to other energy sources in the U.S., resulting in greater use of coal

[38] Note that the data presented in Figure 1 show life cycle emissions estimates for the domestic production of natural gas and coal, with upstream LNG numbers assuming LNG exported from Trinidad and Tobago and imported in Louisiana. Ideally, this figure would offer a direct comparison between life cycle emissions from domestic shale gas production and export versus coal or fuel oil in the country of import. However, such data are not readily available at this time.

and higher levels of GHG emissions under all LNG export scenarios.[39] The global GHG implications of LNG exports from the U.S. is harder to assess, but the basic picture is that more gas would be sold into international markets, which would help reduce carbon dioxide emissions as long as it displaced higher-carbon fuel sources. Given the extensive scale of planned coal-fired power plants around the world[40] and accounting for the prevalence of energy-efficient technologies available for natural gas combustion,[41] this is a reasonable assumption. On the other hand, a greater abundance of lower-priced natural gas in global energy markets (supported by U.S. LNG exports) is also expected to increase total energy use and displace some lower-carbon renewable and nuclear energy sources, which will increase GHG emissions in markets where lower-carbon technologies have become relatively cost-effective. Taking all of these factors into consideration, IEA projections[42, 43] find that greater supplies of natural gas would lead to net annual reductions in global CO_2 emissions of 0.5 percent by 2035.[44] The report concludes that "while a greater role for natural gas in the global energy mix does bring environmental benefits where it substitutes for other fossil fuels, natural gas cannot on its own provide the answer to the challenge of climate change."

[39] The EIA estimates increases in U.S. CO_2 emissions between 9 and 75 MMt per year, from 2015 to 2035.
[40] See: http://www.wri.org/publication/global-coal-risk-assessment
[41] See: http://www.c2es.org/technology/factsheet/natural-gas
[42] See: http://www.worldenergyoutlook.org/goldenageofgas/
[43] See: http://www.worldenergyoutlook.org/media/weowebsite/2011/WEO2011_GoldenAgeofGasReport.pdf
[44] In their 2011 special report on natural gas, the IEA estimated that the GAS Scenario would lead to 35.3 gigatonnes (Gt) energy-related CO_2 emissions in 2035, with annual reduction of 160 million metric tons (MMt), in that year (compared to their "New Policies Scenario"). In their 2012 special report, the IEA reached a similar conclusion, estimating 184 MMt of annual reductions in global energy-related CO_2 emissions in 2035 with their "Golden Rules Case" (compared to a baseline), with global emissions rising to 36.8 gigatonnes (Gt) in the same year.

In summary, available evidence suggests that LNG exports from the U.S. would marginally reduce global CO_2 emissions, although the scale of these estimated GHG emissions savings is an order of magnitude lower than the total projected levels of global methane emissions from natural gas and oil systems.[45] Meanwhile, it appears very likely that LNG exports from U.S. terminals would result in increased domestic GHG emissions from both upstream and downstream sources.

These expected outcomes should raise the bar for policymakers and industry to more actively work to achieve continuous improvement in GHG emissions from all life cycle stages of natural gas development and use. Our research shows that reducing fugitive methane can be highly cost-effective – beneficial to customers and companies alike – and it is necessary if natural gas and LNG exports are to be part of the solution to our climate change problem, both in the U.S. and internationally.

Progress is Being Made but There is More Work to Be Done

Now for the good news. Increased attention to the air emissions issue has resulted in significant recent progress toward reducing air pollution from natural gas systems.

In April 2012 EPA finalized regulations for New Source Performance Standards (NSPS) and National Emissions Standards for Hazardous Air Pollutants (NESHAP) that primarily target

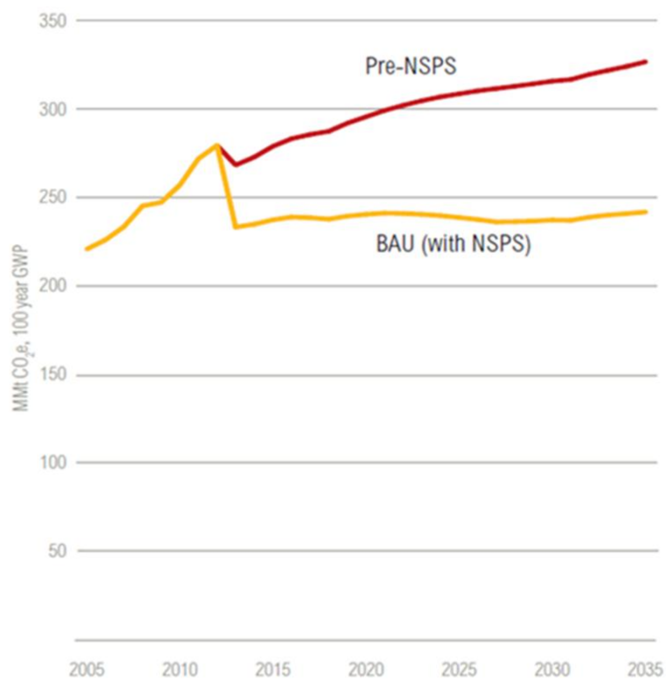
[45] By way of comparison, the EPA estimates that global annual fugitive methane emissions from natural gas and oil systems in 2030 will exceed 2,500 MMT carbon dioxide equivalent (CO_2e), assuming a GWP of 25, over a 100 year time frame (see: http://www.epa.gov/climatechange/EPAactivities/economics/nonco2projections.html). The U.S. GHG inventory estimates that fugitive methane emissions from U.S. natural gas systems in 2011 were just over 170 MMT CO2e.

VOCs and air toxics emissions but will have the co-benefit of reducing methane emissions. The new EPA rules require "green completions," which reduce emissions during the flow-back stage of all hydraulic fracturing operations at new and re-stimulated natural gas wells. The rules will also reduce leakage rates for compressors, controllers, and storage tanks.

EPA should be applauded for establishing these public health protections. Minimum federal standards for environmental performance are a necessary and appropriate framework for addressing cross-boundary pollution issues like air emissions. Federal Clean Air Act regulations are generally developed in close consultation with industry and state regulators and are often implemented by states. This framework allows adequate flexibility to enable state policy leadership and continuous improvement in environmental protection over time.

In our recent working paper, WRI estimated that these new rules will reduce methane emissions enough to cut all upstream GHG emissions from natural gas systems (including shale gas) by 13 percent in 2015 and 25 percent by 2035. As can be seen in Figure 3 below, the NSPS/NESHAP rules will make a big difference by helping to avoid a rise in upstream GHG emissions that would otherwise be likely given the projected growth in domestic natural gas production. The figure also shows that upstream carbon dioxide and methane emissions will remain a significant problem without further action.

Figure 3: Upstream GHG Emissions from All Natural Gas Systems, 2006 to 2035



Notes: Upstream GHG emissions before and after application of the EPA NSPS rule, for all natural gas systems

Source: Bradbury et al., 2013 (WRI)

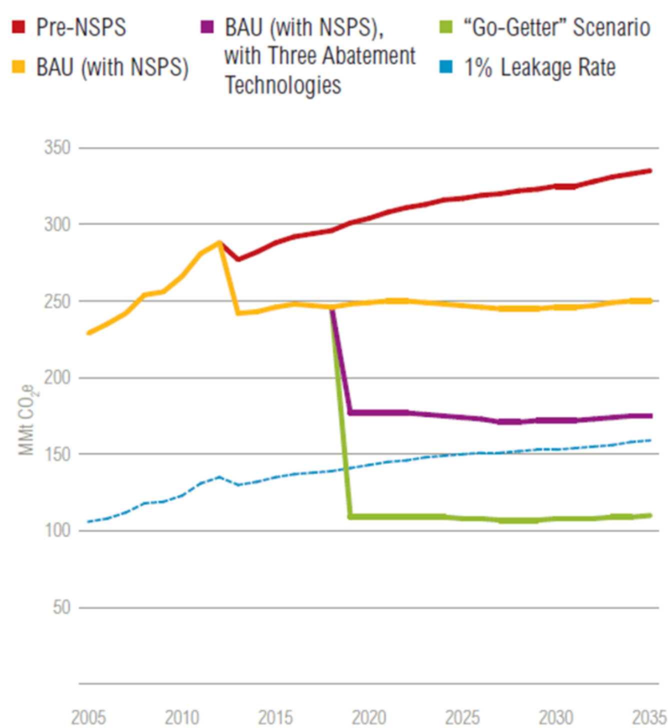
Further Potential to Reduce Fugitive Methane Emissions

WRI estimates that by implementing just three technologies that capture or avoid fugitive methane emissions, upstream methane emissions across all natural gas systems could be cost-effectively cut by up to an additional 30 percent (see Figure 4, below). The technologies include (a) fugitive methane leak monitoring and repair at new and existing well sites, processing plants, and compressor stations; (b) replacing existing high-bleed pneumatic devices with low-bleed equivalents throughout natural gas systems; and (c) use of plunger lift systems[46] at new and existing wells during liquids unloading operations. By our estimation, these three steps would

[46] Note: new data from the most recent EPA emissions inventory suggests that these technologies are much more widely used than previously thought. See: http://insights.wri.org/news/2013/05/5-reasons-why-its-still-important-reduce-fugitive-methane-emissions

bring down the total life cycle leakage rate across all natural gas systems to just above 1 percent of total production. Through adoption of five additional abatement measures that each address smaller emissions sources (i.e., a "Go-Getter" Scenario), the 1 percent goal would be readily achieved. All eight of these technologies could be implemented cost-effectively with payback periods of three years or less.

Figure 4: Upstream GHG Emissions from All Natural Gas Systems; with Additional Abatement Scenarios



Source: Bradbury et al., 2013

Policy Recommendations

New public policies will be needed to reduce methane emissions from both new and existing equipment throughout U.S. natural gas systems. WRI research has found that market conditions alone are not sufficient to compel industry to adequately or quickly adopt available best practices. To the members of this committee, I recommend the following actions to help EPA and states cost-effectively reduce air emissions from natural gas systems.

Expand applied technology research. Efforts to reduce upstream GHG emissions from natural gas systems could be aided by applied technology research at DOE. Such research should be expanded, with a focus on advancement of technologies to reduce the cost of leak detection, improve emissions measurements, and develop new and lower-cost methane emission reduction strategies.

Update emissions factors for key processes. To help resolve questions regarding the scale of methane emissions from U.S. natural gas infrastructure and operations – and to inform critical domestic and international climate and energy policy decisions – the oil and gas sector should be required to directly measure and report their emissions, with results subject to independent verification and public disclosure.

Assist with environmental regulations. With more funding, the organization STRONGER (State Review of Oil and Natural Gas Environmental Regulations) could provide more states with timely assistance in developing and evaluating environmental regulations, including (but not limited to) those designed to reduce air pollution.

Support best practices. With more funding, EPA could do more through Natural Gas STAR and other programs to recognize companies that demonstrate a commitment to best practices. This program could further encourage voluntary industry actions by maintaining a clearinghouse for technologies and practices that reduce all types of air emissions from the oil and natural gas sector.[47]

Provide technical and regulatory assistance. Recognizing the central role of state governments in achieving federal National Ambient Air Quality Standards, with more funding EPA could provide targeted technical and regulatory assistance to states with expanding oil and natural gas development. One example of a successful model that could be expanded is EPA's Ozone Advance Program. States concerned about smog and other air quality problems associated with oil and gas development voluntarily engage with this program, resulting in the co-benefit of reduced methane emissions.

Reduce carbon dioxide emissions. Broader action is also needed on policies supporting clean energy and addressing climate change. A clean energy standard or putting a price on carbon would provide clear signals to energy markets that energy providers and users need to recognize the environmental and social costs as well as the direct economic costs of energy resources.

Conclusions

Some advocate for a free-market approach to managing energy production, transmission, and use. While I agree with the general virtues of free markets, I would also caution that there is no free lunch. The National Research Council has identified very significant costs associated with

[47] An example of one existing clearinghouse can be found here: http://cfpub.epa.gov/RBLC/

fossil energy use that are hidden to most U.S. consumers.[48] Society pays when our health-care premiums rise due to harmful health effects caused by high ozone levels and other air pollution; taxpayers pick up the tab for climate change when the frequency and intensity of extreme weather events causes increasing damage to our communities and critical infrastructure.

Others highlight the energy and national security benefits of natural gas exports, which may reduce the political and economic influence of countries that do not share common interests with the U.S. and our allies. While such geopolitical benefits may be realized, LNG exports will do little to help avoid dangerous levels of climate change. We could also improve our geopolitical standing by demonstrating leadership in achieving greenhouse gas emissions reductions, much of which can be accomplished cost-effectively and with net benefits to the economy – starting with the policy actions recommended above. Meanwhile, the more we invest in fossil energy resources and infrastructure while delaying policy actions to significantly reduce GHG pollution, the more we expose ourselves and our allies to the destabilizing effects of climate change. In its 2010 Quadrennial Defense Review, the Department of Defense found that "climate change could have significant geopolitical impacts around the world." The same report concludes that climate change could further weaken fragile governments and contribute to food scarcity, spread of disease, and mass migration. Meanwhile, 30 military installations already face elevated risk from sea-level rise.

[48] NRC (National Research Council). 2010."Hidden Costs of Energy: Unpriced Consequences of Energy Production and Use." Washington, DC: The National Academies Press. Available at: http://www.nap.edu/catalog.php?record_id=12794.

Every day that we take no policy action on climate change, we make the policy choice to let climate change run its course. This ignores the overwhelming consensus of climate scientists who have been warning for decades that rising GHG emissions will cause the planet to warm, sea levels to rise, and weather to become more extreme. It is indisputable that these climate changes are happening today, and in many cases much more quickly than expected. Action is urgently needed.

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LETTER

Coal to gas: the influence of methane leakage

Tom M. L. Wigley

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Abstract Carbon dioxide (CO_2) emissions from fossil fuel combustion may be reduced by using natural gas rather than coal to produce energy. Gas produces approximately half the amount of CO_2 per unit of primary energy compared with coal. Here we consider a scenario where a fraction of coal usage is replaced by natural gas (i.e., methane, CH_4) over a given time period, and where a percentage of the gas production is assumed to leak into the atmosphere. The additional CH_4 from leakage adds to the radiative forcing of the climate system, offsetting the reduction in CO_2 forcing that accompanies the transition from coal to gas. We also consider the effects of: methane leakage from coal mining; changes in radiative forcing due to changes in the emissions of sulfur dioxide and carbonaceous aerosols; and differences in the efficiency of electricity production between coal- and gas-fired power generation. On balance, these factors more than offset the reduction in warming due to reduced CO_2 emissions. When gas replaces coal there is additional warming out to 2,050 with an assumed leakage rate of 0%, and out to 2,140 if the leakage rate is as high as 10%. The overall effects on global-mean temperature over the 21st century, however, are small.

Hayhoe et al. (2002) have comprehensively assessed the coal-to-gas issue. What has changed since then is the possibility of substantial methane production by high volume hydraulic fracturing of shale beds ("fracking") and/or exploitation of methane reservoirs in near-shore ocean sediments. Fracking, in particular, may be associated with an increase in the amount of attendant gas leakage compared with other means of gas production (Howarth et al. 2011). In Hayhoe et al., the direct effects on global-mean temperature of differential gas leakage between coal and gas production are very small (see their Fig. 4). Their estimates of gas

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leakage, however, are less than more recent estimates. Here, we extend and update the analysis of Hayhoe et al. to examine the potential effects of gas leakage on the climate, and on uncertainties arising from uncertainties in leakage percentages.

We begin with a standard "no-climate-policy" baseline emissions scenario, viz. the MiniCAM Reference scenario (MINREF below) from the CCSP2.1a report (Clarke et al. 2007). (Hayhoe et al. used the MiniCAM A1B scenario, Nakićenović and Swart 2000.) We chose MINREF partly because it is a more recent "no-policy" scenario, but also because there is an extended version of MINREF that runs beyond 2,100 out to 2,300 (Wigley et al. 2009). The longer time horizon is important because of the long timescales involved in the carbon cycle where changes to CO_2 emissions made in the 21st century can have effects extending well into the 22nd century. (A second baseline scenario, the MERGE Reference scenario from the CCSP2.1a report, is considered in the Electronic Supplementary Material).

In MINREF, coal combustion provides from 38% (in 2010) to 51% (in 2100) of the emissions of CO_2 from fossil fuels. (The corresponding percentages for gas are 19 to 21%, and for oil are 43 to 28%.) For our coal-to-gas scenario we start with their contributions to energy. It is important here to distinguish between primary energy (i.e., the energy content of the resource) and final energy (the amount of energy delivered to the user at the point of production). For a transition from coal to gas, we assume that there is no change in final energy. As electricity generation from gas is more efficient than coal-fired generation, the increase in primary energy from gas will be less than the decrease in primary energy from coal — the differential depends on the relative efficiencies with which energy is produced.

To calculate the change in fossil CO_2 emissions for any transition scenario we use the following relationship relating CO_2 emissions to primary energy (P)…

$$\mathrm{ECO2} = \mathrm{A\ Pcoal} + \mathrm{B\ Poil} + \mathrm{C\ Pgas} \tag{1}$$

where A, B and C are representative emissions factors (emissions per unit of primary energy) for coal, oil and gas. The emissions factors relative to coal that we use are 0.75 for oil and 0.56 for gas, based on information in EPA's AP-42 Report (EPA 2005). Using the MINREF emissions for CO_2 and the published primary energy data give a best fit emissions factor for coal of 0.027 GtC/exajoule, well within the uncertainty range for this term.

To determine the change in CO_2 emissions in moving from coal to gas under the constraint of no change in final energy we use the equivalent of Eq. (1) expressed in terms of final energy (F). This requires knowing the efficiencies for energy production from coal, oil and gas (i.e., final energy/primary energy). If F=P×(efficiency), then we have

$$\mathrm{ECO2} = (\mathrm{A/a})\mathrm{Fcoal} + (\mathrm{B/b})\mathrm{Foil} + (\mathrm{C/c})\mathrm{Fgas} \tag{2}$$

where a, b and c are the efficiencies for energy production from coal, oil and gas. For changes in final energy (ΔF) in the coal-to-gas case, ΔFoil is necessarily zero. To keep final energy unchanged, therefore, we must have ΔFgas = −ΔFcoal. Hence, from Eq. (2) …

$$\Delta\mathrm{ECO2} = (\Delta\mathrm{Fcoal})(\mathrm{A/a} - \mathrm{C/c}) \tag{3}$$

or …

$$\Delta\mathrm{ECO2} = \mathrm{A}\ \Delta\mathrm{Pcoal}[1 - (\mathrm{C/A})/(\mathrm{c/a})] \tag{4}$$

As ΔPcoal is negative, the first term here is the reduction in CO_2 emissions from the reduction in coal use, while the second term is the partially compensating increase in CO_2

emissions from the increase in gas use. Our best-fit value for A is 0.027 GtC/exajoule, and C/A=0.56. To apply Eq. (4) we need to determine a reasonable value for the relative gas-to-coal efficiency ratio (c/a), which we assume does not change appreciably over time. For electricity generation, the primary sector for coal-to-gas substitution, Hayhoe et al. (2002, Table 2) give representative efficiencies of 32% for coal and 60% for gas. Using these values, Eq. (4) becomes …

$$\Delta ECO2 = 0.027\ \Delta Pcoal[1 - 0.299] \tag{5}$$

for ΔECO2 in GtC and ΔP in exajoules. Thus, for a unit reduction in coal emissions, there is an increase in emissions from gas combustion of about 0.3 units.

To complete our calculations, we need to estimate the changes in methane, sulfur dioxide and black carbon emissions that would follow the coal-to-gas conversion. Consider methane first. Methane is emitted to the atmosphere as a by-product of coal mining and gas production. Although these fugitive emissions are relatively small, they are important because methane is a far more powerful forcing agent per unit mass than CO_2.

For coal mining we use information from Spath et al. (1999; Figs. C1 and C4). A typical US coal-fired power plant emits 1,100 gCO2/kWh, with an attendant release of methane of 2.18 gCH4/kWh, almost entirely from mining. Thus, for each GtC of CO_2 emitted from a coal-fired power plant, 7.27 TgCH4 are emitted from mining. Spath et al. give other information that can used to check the above result. They give values of 1.91 gCH4 released per ton of coal mined from surface mines, and 4.23 gCH4 per ton from deep mines. As 65% of coal comes from deep mines, the weighted average release is 3.42 gCH4/ton. Since 1 ton of coal, when burned, typically produces 1.83 kgCO2, the amount of fugitive methane per GtC of CO_2 emissions from coal-fired power plants is 6.85 TgCH4/GtC, consistent with the previous result. For our calculations we use the average of these two results, 7.06 TgCH4/GtC; i.e., if CO_2 emissions from coal-fired power generation are reduced by 1 GtC, we assume a concomitant decrease in CH_4 emissions of 7.06 TgCH4. We assume that this value for the USA is applicable for other countries.

For leakage associated with gas extraction and transport we note that every kg of gas burned produces 12/16 kgC of CO_2. If the leakage rate is "p" percent, then, for any given increase in CO_2 emissions from gas combustion, the amount of fugitive methane released is (p/100) (16/12) 1000=13.33 (p) TgCH4/GtC. For a leakage rate of 2.5%, for example (roughly the present leakage rate for conventional gas extraction), this is 33.3 TgCH4/GtC. Because the CO_2 emissions change from gas combustion is much less than that for coal (about 30%; see Eq. (5)), for the 2.5% leakage case this would make the coal mining and gas leakage effects on CH_4 quite similar (but of opposite sign), in accord with Hayhoe et al. (2002, Table 1).

SO_2 emissions are important because coal combustion produces substantial SO_2, whereas SO_2 emissions from gas combustion are negligible. Reducing energy production from coal has compensating effects — reduced CO_2 emissions leads to reduced warming in the long term, but this is offset by the effects of reduced SO_2 emissions which lead to lower aerosol loadings in the atmosphere and an attendant warming (Wigley 1991). For CO_2 and SO_2, emissions factors for coal (from Hayhoe et al. 2002, Table 1) are 25 kgC/GJ and 0.24 kgS/GJ. For each GtC of CO_2 produced from coal combustion, therefore, there will be 19.2 TgS of SO_2 emitted. We can check this using emissions factors from Spath et al. (1999, Figs. C1 and C2). For a typical coal-fired power plant these are 7.3 gSO2/kWh and 1,100 gCO2/kWh. Hence, for each GtC of CO_2 produced from coal combustion, SO_2 emissions will be 12.17 TgS. Effective global emissions factors can also be obtained from published emissions scenarios. For example, for changes over 2000 to 2010 in the MINREF scenario, the emissions factor for coal combustion is approximately 11.6 TgS/GtC.

From these different estimates it is clear that there is considerable uncertainty in the SO_2 emissions factor, echoing in part the widely varying sulfur contents in coal. Furthermore, for future emissions from coal combustion the SO_2 emissions factor is likely to decrease markedly due to the imposition of SO_2 pollution controls (as explained, for example, in Nakićenović and Swart 2000). It is difficult to quantify this effect, a difficulty highlighted, for example, by the fact that, in the second half of the 21st century, many published scenarios show increasing CO_2 emissions, but decreasing SO_2 emissions — with large differences between scenarios in the relative changes.

For the coal-to-gas transition, it is not at all clear how to account for the effects that SO_2 pollution controls, that will likely go on in parallel with any transition from coal to gas, will have on the SO_2 emissions factor. However, future coal-fired plants will certainly employ such controls, so emissions factors for SO_2 will decrease over time. To account for this we assume a value of 12 TgS/GtC for the present (2010) declining linearly to 2 TgS/GtC by 2,060 and remaining at this level thereafter. This limit and the attainment date are consistent with the fact that many of the SRES scenarios tend to stabilize SO_2 emissions at a finite, non-zero value at around this time.

For black carbon (BC) aerosol emissions we use the relationship between BC and SO_2 emissions noted by Hayhoe et al. (2002, p. 125) and make BC forcing proportional to SO_2 emissions. Using best-estimate forcings from the IPCC Fourth Assessment Report, this means that the increase in sulfate aerosol forcing changes due to SO_2 emissions reductions are reduced by approximately 30% by the attendant changes in BC emissions. This is a larger BC effect than in Hayhoe et al. However, compared with the large overall uncertainty in aerosol forcing, the difference between what we obtain here and the results of Hayhoe et al. are relatively small.

For our coal-to-gas emissions scenario we assume that primary energy from coal is reduced linearly (in percentage terms) by 50% over 2010 to 2050 (1.25%/yr), and that the reduction in final energy is made up by extra energy from gas combustion. (A second, more extreme scenario is considered in the Electronic Supplementary Material). In this way, there are no differences in final energy between the MINREF baseline scenario and the coal-to-gas perturbation scenario. Hayhoe et al. consider scenarios where coal production reduces by 0.4, 1.0 and 2.0%/yr over 2000 to 2025. After 2050 we assume no further percentage reduction in coal-based energy (i.e., the reduction in emissions from coal relative to the baseline scenario remains at 50%). This is an idealized scenario, but it is sufficiently realistic to be able to assess the relative importance of different gas leakage rates. We consider leakage rates of zero to 10%,

Baseline and perturbed (coal to gas) primary energy scenarios for coal and gas are shown in Fig. 1, together with the corresponding fossil-fuel CO_2 emissions. The changes in primary energy breakdown are large: e.g., in 2100, primary energy from coal is 37% more than from gas in the baseline case, but 50% less than gas in the perturbed case. The corresponding reduction in emissions is less striking. In the perturbed case, 2100 emissions are reduced only by 19%. (Cases where there are larger emissions reductions are considered in the Electronic Supplementary Material).

To determine the consequences of the coal-to-gas scenario we use the MAGICC coupled gas-cycle/upwelling-diffusion climate model (Wigley et al. 2009; Meinshausen et al. 2011). These are full calculations from emissions through concentrations and radiative forcing to global-mean temperature consequences. We do not make use of Global Warming Potentials (as in Howarth et al. 2011, for example), which are a poor substitute for a full calculation

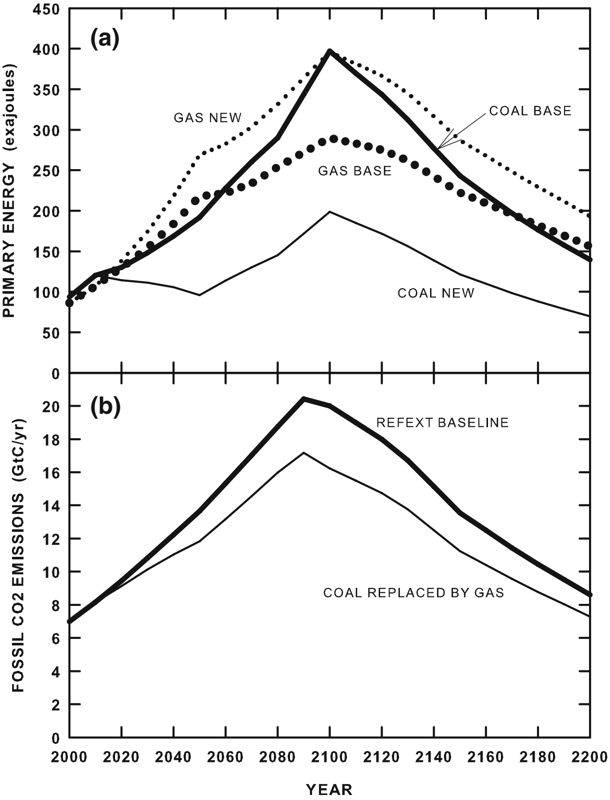

Fig. 1 **a** Primary energy scenarios. Baseline data to 2100 are from the CCSP2.1a MiniCAM Reference scenario. After 2100, baseline primary energy data have been constructed to be consistent with emissions data in the extended MiniCAM Reference scenario (Wigley et al. 2009 — REFEXT). Full lines are for coal, dotted lines are for gas. "NEW" data correspond to the coal-to-gas scenario. Under the final energy constraint that ΔFgas = −ΔFcoal, ΔPgas = −(a/c) ΔPcoal = −0.533 ΔPcoal. **b** Corresponding fossil CO_2 emissions data

(see, e,g., Smith and Wigley 2000a, b). MAGICC considers all important radiative forcing factors, and has a carbon cycle model that includes climate feedbacks on the carbon cycle. Methane lifetime is affected by atmospheric loadings on methane, carbon monoxide, nitrogen oxides (NOx) and volatile organic compounds. The effects of methane on tropospheric ozone and stratospheric water vapor are considered directly. For component forcing values we use central estimates as given in the IPCC Fourth Assessment Report (IPCC 2007, p.4). We also assume a central value for the climate sensitivity of 3°C equilibrium warming for a CO_2 doubling. (A second case using a higher sensitivity is considered in the Electronic Supplementary Material).

Figure 2 shows the relative and total effects of the coal-to-gas transition for a leakage rate of 5%. This is within the estimated leakage rate range (1.7–6.0%; Howarth et al. 2011) for conventional methane production (the effects of well site leakage, liquid uploading and gas processing, and transport, storage and processing). For methane from shale, Howarth et al. estimate an additional leakage of 1.9% (their Table 2) with a range of 0.6–3.2% (their Table 1). The zero to 10.0% leakage rate range considered here spans these estimates — although we note that the high estimates of Howarth et al. have been criticized (Ridley 2011, p. 30).

The top panel of Fig. 2 shows that the effects of CH_4 leakage and reduced aerosol loadings that go with the transition from coal to gas can appreciably offset the effect of reduced CO_2 concentrations, potentially (see Fig. 3) until well into the 22nd century. For the leakage rate ranges considered here, however, the overall effects of the coal to gas transition on global-mean temperature are very small throughout the 21st century, both in absolute and relative terms (see Fig. 2a). This is primarily due to the relatively small reduction in CO_2 emissions that is effected by the transition away from coal (see Fig. 1b). Cases where the CO_2 emissions reductions are larger (due to a more extreme substitution scenario, or a different baseline) are considered in the Electronic Supplementary Material. The relative contributions to temperature change are similar, but the magnitudes of temperature change scale roughly with the overall reduction in CO_2 emissions.

Figure 3 shows the sensitivity of the temperature differential to the assumed leakage rate. The CO_2 and aerosol terms are independent of the assumed leakage rate, so we only show the methane and total-effect results. These results are qualitatively similar to those of Hayhoe et al. who considered only a single leakage rate case (corresponding approximately to our 2.5% leakage case). For leakage rates of more than 2%, the methane leakage contribution is positive (i.e., replacing coal by gas produces higher methane concentrations) — see the "CH4 COMPONENT" curves in Fig. 3. Depending on leakage rate, replacing coal by gas leads, not to cooling, but to additional warming out to between 2,050 and 2,140. Initially, this is due mainly to the influence of SO_2 emissions changes, with the effects of CH_4 leakage becoming more important over time. Even with zero leakage from gas production, however, the cooling that eventually arises from the coal-to-gas transition is only a few tenths of a degC (greater for greater climate sensitivity — see Electronic Supplementary Material). Using climate amelioration as an argument for the

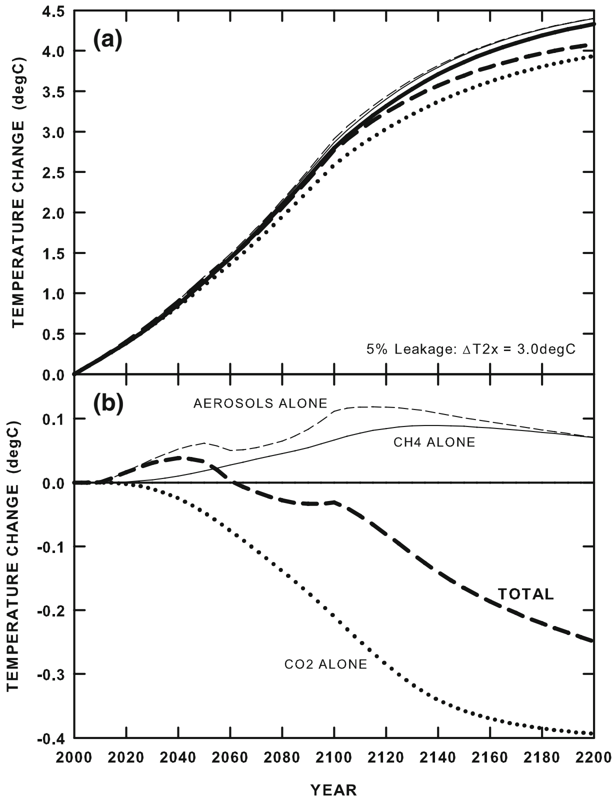

Fig. 2 **a** Baseline global-mean warming (*solid bold line*) from the extended CCSP2.1a Mini-CAM reference scenario together with the individual and total contributions due to reduced CO_2 concentrations, reduced aerosol loadings and increased methane emissions for the case of 5% methane leakage. The *bold dashed line* gives the result for all three components, the *dotted line* shows the effect of CO_2 alone. The *top two thin lines* show the CH_4 and aerosol components. **b** Detail showing differences from the baseline

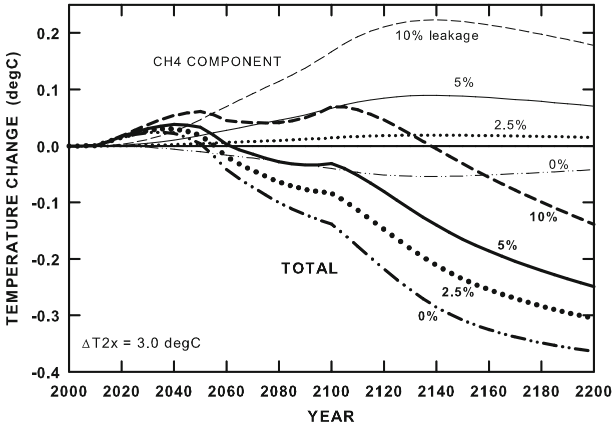

Fig. 3 The effects of different methane leakage rates on global-mean temperature. The *top four curves* (CH4 COMPONENT) show the effects of methane concentration changes, while the *bottom four curves* (TOTAL) show the total effects of methane changes, aerosol changes and CO_2 concentration changes. The latter two effects are independent of the leakage rate, and are shown in Fig. 2. Results here are for a climate sensitivity of 3.0°C

transition is, at best, a very weak argument, as noted by Hayhoe et al. (2002), Howarth et al. (2011) and others.

In summary, our results show that the substitution of gas for coal as an energy source results in increased rather than decreased global warming for many decades — out to the mid 22nd century for the 10% leakage case. This is in accord with Hayhoe et al. (2002) and with the less well established claims of Howarth et al. (2011) who base their analysis on Global Warming Potentials rather than direct modeling of the climate. Our results are critically sensitive to the assumed leakage rate. In our analysis, the warming results from two effects: the reduction in SO_2 emissions that occurs due to reduced coal combustion; and the potentially greater leakage of methane that accompanies new gas production relative to coal. The first effect is in accord with Hayhoe et al. In Hayhoe et al., however, the methane effect is in the opposite direction to our result (albeit very small). This is because our analyses use more recent information on gas leakage from coal mines and gas production, with greater leakage from the latter. The effect of methane leakage from gas production in our analyses is, nevertheless, small and less than implied by Howarth et al.

Our coal-to-gas scenario assumes a linear decrease in coal use from zero in 2010 to 50% reduction in 2050, continuing at 50% after that. Hayhoe et al. consider linear decreases from zero in 2000 to 10, 25 and 50% reductions in 2025. If these authors assumed constant reduction percentages after 2025, then their high scenario is very similar to our scenario.

In our analyses, the temperature differences between the baseline and coal-to-gas scenarios are small (less than 0.1°C) out to at least 2100. The most important result, however, in accord with the above authors, is that, unless leakage rates for new methane can be kept below 2%, substituting gas for coal is not an effective means for reducing the magnitude of future climate change. This is contrary to claims such as that by Ridley (2011) who states (p. 5), with regard to the exploitation of shale gas, that it will "accelerate the decarbonisation of the world economy". The key point here is that it is not decarbonisation *per se* that is the goal, but the attendant reduction of climate change. Indeed, the shorter-term effects are in the opposite direction. Given the small climate differences between the baseline and the coal-to-gas scenarios, decisions regarding further exploitation of gas reserves should be based on resource availability (both gas and water), the economics of extraction, and environmental impacts unrelated to climate change.

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Greenhouse gases, climate change and the transition from coal to low-carbon electricity

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Greenhouse gases, climate change and the transition from coal to low-carbon electricity

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Abstract
A transition from the global system of coal-based electricity generation to low-greenhouse-gas-emission energy technologies is required to mitigate climate change in the long term. The use of current infrastructure to build this new low-emission system necessitates additional emissions of greenhouse gases, and the coal-based infrastructure will continue to emit substantial amounts of greenhouse gases as it is phased out. Furthermore, ocean thermal inertia delays the climate benefits of emissions reductions. By constructing a quantitative model of energy system transitions that includes life-cycle emissions and the central physics of greenhouse warming, we estimate the global warming expected to occur as a result of build-outs of new energy technologies ranging from 100 GW_e to 10 TW_e in size and 1–100 yr in duration. We show that rapid deployment of low-emission energy systems can do little to diminish the climate impacts in the first half of this century. Conservation, wind, solar, nuclear power, and possibly carbon capture and storage appear to be able to achieve substantial climate benefits in the second half of this century; however, natural gas cannot.

Keywords: climate change, bulk electricity supply, central-station greenhouse gas emissions, electricity, climate

S Online supplementary data available from stacks.iop.org/ERL/7/014019/mmedia

1. Introduction

Hoffert *et al* [1] estimated that if economic growth continues as it has in the past, 10–30 TW of carbon-neutral primary power must be deployed by 2050 to meet global energy demand while stabilizing CO_2 concentrations at 450 ppmv, and that even more rapid deployment of new technologies would need to occur in the second half of this century. Pacala and Socolow [2] have suggested that a broad portfolio of existing technologies could put us on a trajectory toward stabilization in the first half of this century. No previous study, however, has predicted the climate effects of energy system transitions.

Fossil fuels, such as coal and natural gas, emit greenhouse gases when burned in conventional power plants. Concern about climate change has motivated the deployment of lower-GHG-emission (LGE) power plants, including wind, solar photovoltaics (PV), nuclear, solar thermal, hydroelectric, carbon capture and storage, natural gas and other energy technologies with low GHG emissions. Electricity generation accounts for approximately 39% of anthropogenic carbon dioxide emissions [3, 4].

Because LGE power plants have lower operating emissions, cumulative emissions over the lifetime of the plants are lower than for conventional fossil-fueled plants of equivalent capacity. LGE power plants typically require greater upfront emissions to build, however. Consequently, rapid deployment of a fleet of LGE power plants could initially increase cumulative emissions and global mean surface temperatures over what would occur if the same net electrical output were generated by conventional coal-fired plants. Our results show that most of the climate benefit of a transition to LGE energy systems will appear only after the transition is complete. This substantial delay has implications for policy aimed at moderating climate impacts of the electricity generation sector.

2. Models of LGE energy system build-outs

To make our assumptions clear and explicit, we used simple mathematical models to investigate the transient effects of energy system transitions on GHG concentrations, radiative forcing and global mean temperature changes. We represent an electric power plant's life in two phases: construction and operation. Our model assumes that each plant produces a constant annual rate of GHG emissions as it is constructed and a different constant emission rate as it operates. Emission rates were taken from the literature (see table S1 in the supplementary online material (SOM) available at stacks.iop.org/ERL/7/014019/mmedia). IPCC-published formulas for the atmospheric lifetime of GHGs [5] are used to model increases in atmospheric GHG concentrations that result from the construction and operation of each power plant (see SOM text SE1 for details). Radiative forcing as a function of time, $\Delta F(t)$, follows directly from GHG concentration using expressions from the IPCC [5].

We estimated the change in surface temperature, ΔT by using a simple energy-balance model. The radiative forcing ΔF supplies additional energy into the system. Radiative losses to space are determined by a climate feedback parameter, λ. We used $\lambda = 1.25$ W m^2 K^{-1} [6–8], which yields an equilibrium warming of 3.18 K resulting from the radiative forcing that follows a doubling of atmospheric CO_2 from 280 to 560 ppmv. The approach to equilibrium warming is delayed by the thermal inertia of the oceans. We represented the oceans as a 4 km thick, diffusive slab with a vertical thermal diffusivity $k_v = 10^{-4}$ m^2 s^{-1} [8]. Other parameter choices are possible, but variations within reason would not change our qualitative results, and this approach is supported by recent tests with three-dimensional models of the global climate response to periodic forcing [9]. Our simple climate model treats direct thermal heating in the same way as radiative heating; heat either mixes downward into the ocean or radiates outward to space. To isolate the effects of a transition to LGE energy systems, we consider GHG emissions from only the power plant transition studied. Initial, steady-state atmospheric GHG concentrations are set to $P_{CO_2} = 400$ ppmv, $P_{CH_4} = 1800$ ppbv, and $P_{N_2O} = 320$ ppbv, at which $\Delta F = \Delta T = 0$. (Use of other background concentrations for GHGs would not alter our qualitative results (SOM text SE1.3 available at stacks.iop.org/ERL/7/014019/mmedia)).

Although life-cycle estimates of emissions from individual power plants (SOM table S1 available at stacks.iop.org/ERL/7/014019/mmedia) vary, they show a consistent pattern at both the low and high ends of the range, as seen in figures 1(A) and (B). For renewable plants, peak emissions occur during plant construction. For fossil-fueled plants, in contrast, operating emissions dominate; typically $<1\%$ of lifetime plant emissions are attributable to construction. For nuclear plants, both construction and fueling for ongoing operation make substantial contributions to lifetime GHG emissions, although these emissions are far lower than the emissions from coal-fired power plants. The primary GHG emission from hydroelectric plants is methane (CH_4) produced by anaerobic decay of organic matter that is inundated as the reservoir fills [10–12]; the amount emitted varies with local conditions.

To provide a stable supply of electricity, a new power plant must be built as each old power plant nears the end of its useful life. As shown in figures 1(C) and (D), fossil-fueled plants produce a comparatively smooth increase in atmospheric GHG concentrations because emissions during construction are small compared to those from operations. In contrast, the larger contribution during construction of nuclear and renewable power plants produces increased emissions each time a plant of this kind is replaced, yielding a sawtooth trend in atmospheric GHG concentrations for a constant output of electricity.

Construction and operation of a new power plant of any technology modeled here will produce higher atmospheric CO_2 concentrations than would have occurred if no new generating capacity were added. Carbon dioxide poses a special concern because of its long lifetime in the atmosphere. With the exception of dams, carbon dioxide emissions dominate the GHG radiative forcing from power plants. Radiative forcing due to CH_4 and N_2O at any point in time accounts for $<1\%$ of the total GHG forcing from wind, solar and nuclear power plants; $<5\%$ for coal-fired plants; and $<10\%$ for natural gas plants. CH_4 dominates only in the case of hydroelectric power, for which it contributes $\sim$95% of the radiative forcing in the first 20 yr, declining monotonically to $\sim$50% at 70 yr after construction.

We contrasted LGE energy technologies with a high-GHG-emission (HGE) energy technology, namely conventional coal-based electricity production. We define 'HGE warming' to mean the increase in global mean surface temperature that would have been produced by the continued operation of the coal-based HGE energy system. This warming is additional to any temperature increases occurring as a result of past or concurrent emissions from outside the 1 TW_e energy system considered here.

To illustrate the consequences of rapid deployments of new energy systems, we considered emissions from a variety of linear energy system transitions, each of which replaces 1 TW_e of coal-based electricity by bringing new LGE power plants online at a constant rate over a 40 yr period. (1 TW_e is the order of magnitude of the global electrical output currently generated from coal [10].) Existing coal-fired generators were assumed to be new at the onset of the transition, to be replaced with equivalent plants at the end of their lifetime, and to be retired at the rate of new plant additions in order to maintain constant annual output of electricity. Lifetimes

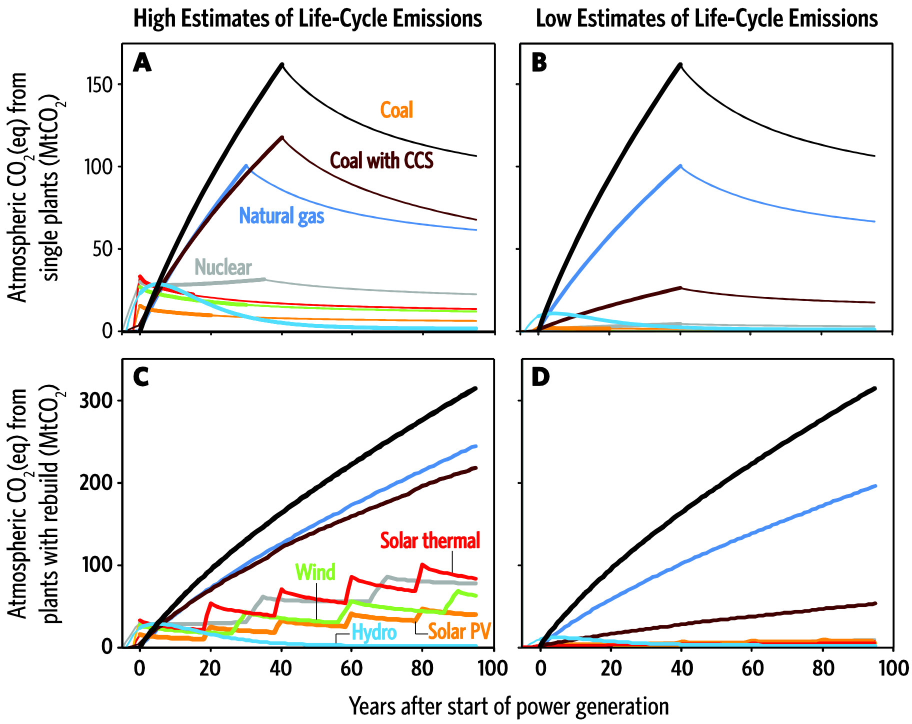

Figure 1. The time evolution of atmospheric CO_2(eq) concentrations resulting from the construction and operation of a 1 GW_e electric power plant varies widely depending on the type of plant. (A), (B) Atmospheric CO_2(eq) concentrations from single power plants of different types based on high (A) and low (B) estimates of life-cycle power plant emissions. Renewable technologies have higher emissions in the construction phase (thin lines prior to year zero); conventional fossil technologies have higher emissions while operating (thick lines); emitted gases persist in the atmosphere even after cessation of operation (thin lines after year zero). The operating life of plants varies by plant type. (C), (D) Atmospheric CO_2(eq) concentrations from the construction of series of power plants built to maintain 1 GW_e output. For high estimates of life-cycle emissions, periodic replacement of aging plants produces pulses of emissions resulting in substantial, step-like change in atmospheric concentrations. However, in all cases except hydroelectric, continued electricity production results in increasing trends of atmospheric CO_2(eq) concentrations.

and thermal efficiencies of the coal plants were taken from the life-cycle analysis (LCA) literature, as were the additional emissions associated with constructing power plants (SOM table S1 available at stacks.iop.org/ERL/7/014019/mmedia). Using GHG emission data from this literature, we calculated time series for emissions, radiative forcing, and temperature for build-outs of eight LGE energy technologies, for a range of rollout durations (SOM text SN3 available at stacks.iop.org/ERL/7/014019/mmedia) including, as a lower bound, the unrealistic case in which all plants are built simultaneously in a single year. Climate consequences of a portfolio of technologies can be approximated by a linear combination of our results for each technology taken individually. For each technology, we examine low and high emission estimates from the LCA literature, and label these ‘Low’ and ‘High’. The time evolution of emissions and temperature increases resulting from an example transition, from coal to natural gas, is illustrated in SOM table S4 (available at stacks.iop.org/ERL/7/014019/mmedia).

We investigated transitions from an HGE energy system to various LGE options for a wide range of transition rates (figure 4). Building on previous life-cycle analyses (SOM table S1 available at stacks.iop.org/ERL/7/014019/mmedia), we estimated the magnitude of most direct and indirect GHG emissions from the construction and operation of the power plants, including GHG emissions associated with long-distance electricity transmission and thermal emissions attributable to power generation and use (SOM text SN2 available at stacks.iop.org/ERL/7/014019/mmedia). During this transition, GHG emissions attributed to the fleet include both those due to construction or operation of the new technology and those due to coal-fired generators that have not yet been replaced. Various energy system transitions could be imagined. Delaying the transition delays long-term climate benefits of LGE energy. Accelerating the transition decreases total fleet emissions from burning coal, but increases the rate of emissions produced by new construction (figure 4(C)). Qualitatively similar results hold for exponential and logistic growth trajectories (SOM text SD1 and figures S10–12 available at stacks.iop.org/ERL/7/014019/mmedia).

3. Delayed benefits from energy system transitions

By the time any new power plant begins generating electricity, it has incurred an ‘emissions debt’ equal to the GHGs released to the atmosphere during its construction. The size of this debt varies from one LGE technology to another, as does the operating time required to reach a break-even point at which emissions avoided by displacing power from an HGE plant equal the emissions debt. All transitions from coal to other energy technologies thus show higher GHG concentrations

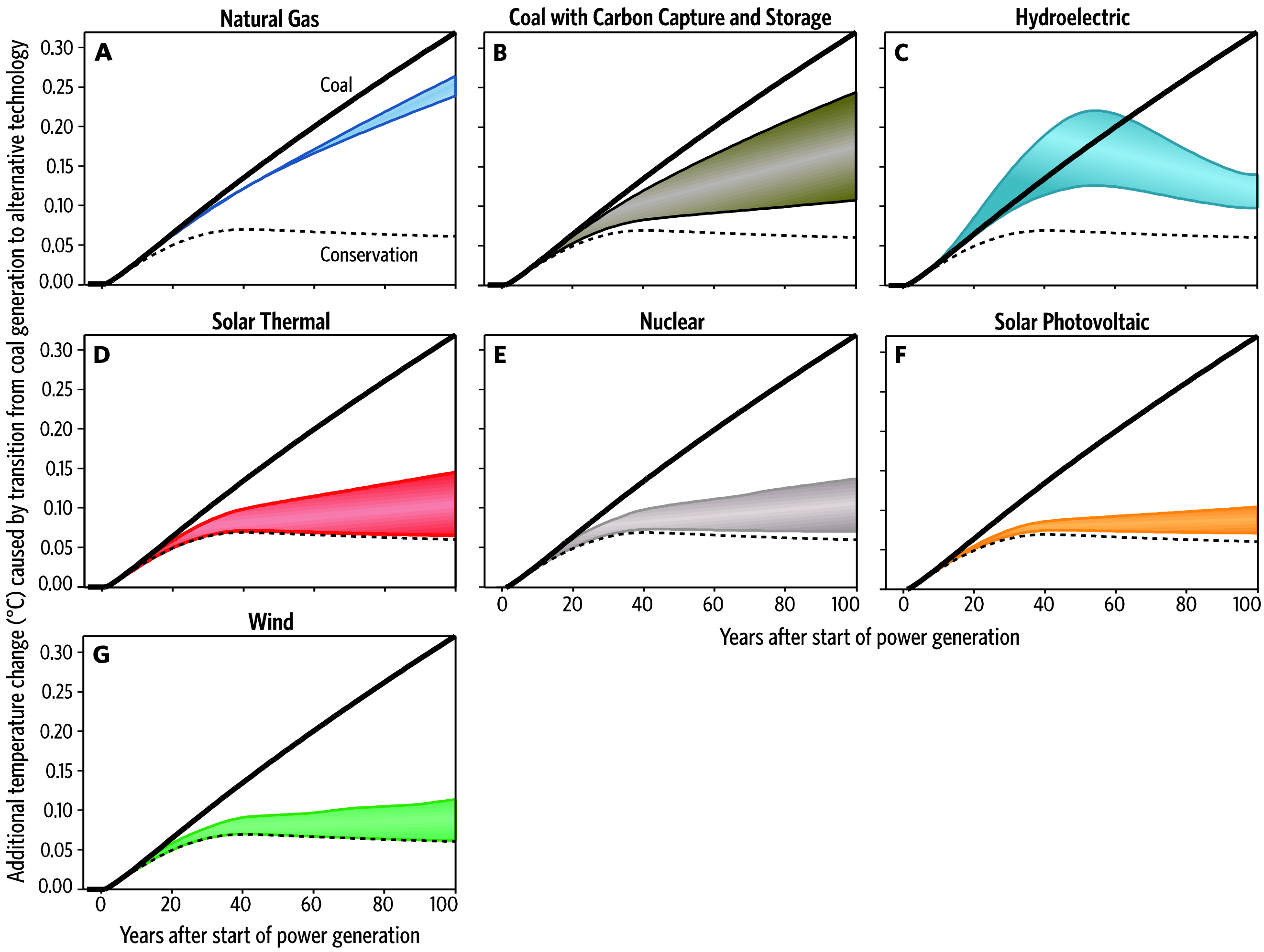

Figure 2. Many decades may pass before a transition from coal-based electricity to alternative generation technologies yields substantial temperature benefits. Panels above show the temperature increases predicted to occur during a 40 yr transition of 1 TW_e of generating capacity. Warming resulting from continued coal use with no alternative technology sets an upper bound (solid black lines), and the temperature increase predicted to occur even if coal were replaced by idealized conservation with zero CO_2 emissions (dashed lines) represents a lower bound. The colored bands represent the range of warming outcomes spanned by high and low life-cycle estimates for the energy technologies illustrated: (A) natural gas, (B) coal with carbon capture and storage, (C) hydroelectric, (D) solar thermal, (E) nuclear, (F) solar photovoltaic and (G) wind.

and temperatures at the outset than would have occurred in the absence of a transition to a new energy system. We calculated, for each technology, the number of years following the start of electricity generation until the transition starts reducing HGE warming, as well as the times at which the transition has reduced HGE warming by 25% or 50%.

Our results (figure 2 and SOM tables S3 and S4 available at stacks.iop.org/ERL/7/014019/mmedia) illustrate the general finding that emerges from our results: energy system transitions cause reductions in HGE warming only once they are well underway, and it takes much longer still for any new system to deliver substantial climate benefits over a conventional coal-based system. It is instructive to examine idealized energy conservation, considered here as a technology that produces electricity with zero GHG emissions. Conservation is thus equivalent to phasing out 1 TW_e of coal power over 40 yr without any replacement technology. Even in this case, GHGs (particularly CO_2) emitted by coal during the phaseout linger in the atmosphere for many years; in addition, ocean thermal inertia causes temperature changes to lag radiative forcing changes. Consequently, conservation takes 20 yr to achieve a 25% reduction in HGE warming and 40 yr to achieve a 50% reduction.

This idealized rollout of conservation that displaces 1 TW_e of conventional coal power sets a lower bound to the temperature reductions attainable by any technology that does not actively withdraw GHGs from the atmosphere. This lower bound is approached most closely by wind, solar thermal, solar PV and nuclear, using the low LCA estimates; these cases yield temperature increases that exceed the idealized conservation case by only a fraction of a degree, and the time to a 50% reduction in HGE warming is delayed by only a few years. Differences among these same technologies appear, however, if high LCA estimates are used (figure 3). When using the complete range of LCA estimates, for example, our model projects that a 40 yr, linear transition from coal to solar PV would cause a 1.4–6.9 yr period with greater warming than

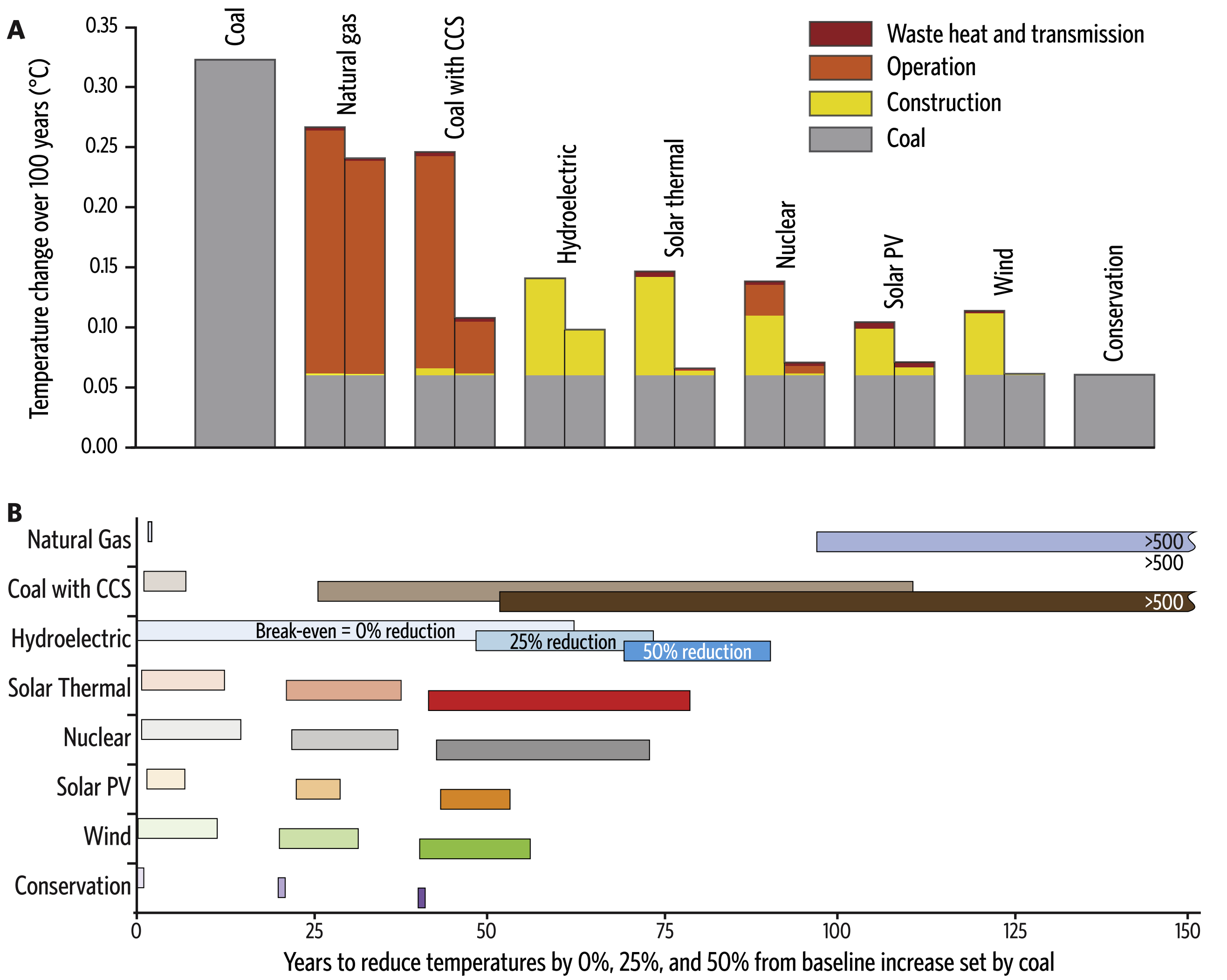

Figure 3. Transitions of 1 TW_e of coal-based electricity generation to lower-emitting energy technologies produces modest reductions in the amount of global warming from GHG emissions; if the transition takes 40 yr to complete, only the lowest-emission technologies can offset more than half of the coal-induced warming in less than a century. (A) Increases in global mean surface temperature attributable to the 1 TW_e energy system 100 yr after the start of a 40 yr transition to the alternative technology. Even if the coal-based system were phased out without being replaced by new power plants of any kind, GHGs released by the existing coal-fired plants during the phaseout would continue to add to global warming (rightmost column). Split columns reflect temperature changes calculated using both high and low emissions estimates from a range of life-cycle analyses, as described in the text and SOM text SN2 (available at stacks.iop.org/ERL/7/014019/mmedia). (B) Time required from the start of power generation by an alternative technology to achieve break-even, warming equal to what would have occurred without the transition from coal (lightest shading); a 25% reduction in warming (medium shading); and a reduction by half (darkest shading) as a result of the transition. The bars span the range between results derived using the lowest and highest LCA estimates of emissions. For numeric values, see SOM table S3 (available at stacks.iop.org/ERL/7/014019/mmedia).

had the transition not been undertaken, and that the transition would take 23–29 yr to produce a 25% reduction in HGE warming and 43–53 yr to avoid half of the HGE warming.

Natural gas plants emit about half the GHGs emitted by coal plants of the same capacity, yet a transition to natural gas would require a century or longer to attain even a 25% reduction in HGE warming (SOM table S3 available at stacks.iop.org/ERL/7/014019/mmedia). Natural gas substitution thus may not be as beneficial in the near or medium term as extrapolation from 'raw' annual GHG emissions might suggest.

Carbon capture and storage (CCS) also slows HGE warming only very gradually. Although CCS systems are estimated to have raw GHG emissions of ∼17%–∼27% that of unmodified coal plants, replacement of a fleet of conventional coal plants by coal-fired CCS plants reduces HGE warming by 25% only after 26–110 yr. This transition delivers a 50% reduction in 52 years under optimistic assumptions and several centuries or more under pessimistic assumptions.

More generally, any electricity-generating technology that reduces GHG emissions versus coal plants by only a factor of two to five appears to require century-long times to accrue substantial temperature reductions. Comparison of 1 TW_e, 40 yr transitions from coal to a wide range of LGE energy technologies reveals little difference in warming produced by the various technologies until the transition is complete (figures 2(A)–(G)). Although it takes many decades

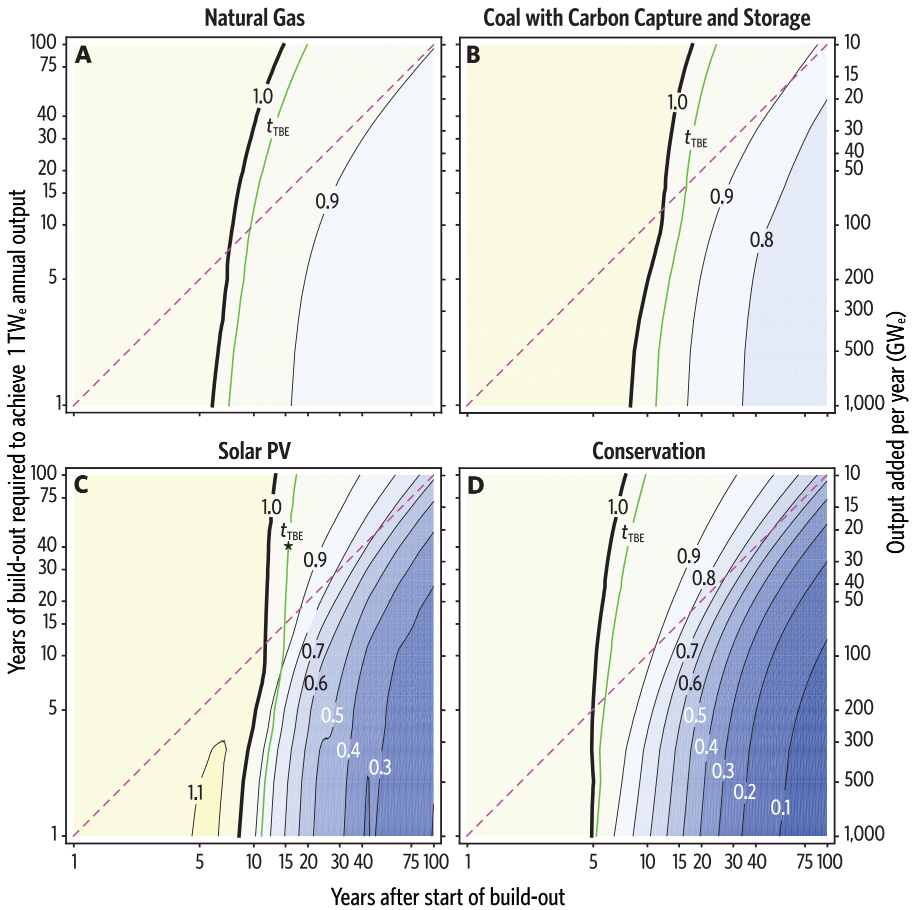

Figure 4. Analysis of a wide range of energy transition rates, scales, and technologies finds that replacement of coal-fired power plants requires many years to deliver climate benefits. For a given alternative energy technology and transition scale, the range of simulation results can be summarized by a contour plot; those above show results for 1 TW_e, linear transitions to (A) natural gas, (B) coal with CCS, (C) solar PV and (D) conservation; high emission estimates from LCA studies were used in each case. For plots of other technologies, transition scales, and build-out trajectories, see SOM figures S10 and S11 (available at stacks.iop.org/ERL/7/014019/mmedia). In these plots, the vertical axis represents the duration of the build-out; results span build-out durations from 1 to 100 yr, which corresponds to annual additions of output ranging from 10 to 1000 GW_e. Contour lines plot the ratio $\Delta T_{new}/\Delta T_{coal}$, where ΔT_{new} is the increase in global mean surface temperature projected to result from the transition to the lower-emission technology. Contour lines thus represent the time to achieve reductions in warming ranging from 10% (a ratio of 0.9) to 90% (a ratio of 0.1). Whereas the progress of the build-out (horizontal axis) is measured from the start of power generation in figure 3, here time is measured from the start of construction, which we assume lasts five years before each new plant begins generating. (For ease of comparison, conservation is treated similarly.) Dashed magenta lines indicate the completion of construction of the last plant in the build-outs. The instantaneous break-even point at which $\Delta T_{new} = \Delta T_{coal}$ is indicated by thick black curves. A better metric of the break-even time, however, is where the time-averaged integral of ΔT_{new} equals that of ΔT_{coal} (t_{TBE}, green curves). A 40 yr deployment of 1 TW_e of solar PV, for example, would not reach t_{TBE} until year 15 of the build-out (asterisked point).

to achieve substantial benefits from a phaseout of coal-based power plants, instantaneously turning coal plants off without replacing the generating capacity would yield a 50% reduction in HGE warming in 11 yr, as shown in figure 4(D), which plots the reduction in temperature increases to be expected in any given year from elimination of 1 TW_e of coal capacity by build-outs ranging in duration from 1 to 100 yr.

We selected coal-fired plants as the basis for comparison because this energy technology emits the most GHGs per unit electricity generated; replacing plants of this kind thus delivers the greatest climate benefits. If the new technology were instead to replace natural gas plants, then even less CO_2 emission would be avoided, and the times to achieve reductions in warming relative to a natural gas baseline would be even longer than projected here.

4. Effects of scale, duration, technological improvement and bootstrapping

Although we focus here on 40 yr, linear transitions of a 1 TW_e energy system, we examined a far broader range of cases; none of these cases altered our central conclusions. Figure 4, for example, illustrates the HGE warming caused by transitions to several LGE energy technologies that range in duration from 1 to 100 yr. We have simulated transitions ranging from 0.1 to 10 TW_e. In addition to the linear transition presented here, we examined exponential and logistic transitions (SOM texts SD1–SD3 and figures S8, S11–S14 available at stacks.iop.org/ERL/7/014019/mmedia). We also analyzed plausible effects of technological improvement by reducing the emission per unit energy generation over time by various exponential rates, an approach that effectively forces each technology under study to approach the zero emission case of conservation asymptotically (SOM text SD3 and figure S14 available at stacks.iop.org/ERL/7/014019/mmedia). The analysis reveals that the long timescale required for energy system transitions to reduce temperatures substantially is not sensitive to technological improvement. High rates of technological improvement could alter, however, the relative rank of energy technologies in their abilities to mitigate future warming.

Finally, we examined 'bootstrapping' transitions. The exponential, linear and logistic models all assume that generated electricity is used to displace coal and thus lower emissions. A very different strategy is to use a low-GHG-emitting technology to bootstrap itself. This strategy is particularly interesting for wind and solar PV because each of them require substantial amounts of electricity in the manufacturing of key components.

A bootstrapping transition uses electricity from the first plant built to manufacture more plants of the same kind, which in turn provide energy to build new plants, and so on exponentially (SOM text SD2 and figure S13 available at stacks.iop.org/ERL/7/014019/mmedia). In this approach, however, no electricity is turned over to the grid—and thus no coal is replaced—until the build-out goal has been installed and brought online, at which point the coal is displaced all at once. The effect of bootstrapping is thus equivalent to distributing the electrons from PV systems and using coal-generated electrons to construct the PV arrays.

Emissions estimates from the LCA studies we use in our principal analysis, in contrast, assume carbon intensities lower than that of coal-based electricity and thus lower emissions than would occur with either bootstrapping or coal as the source of energy for new plant construction. For both wind and solar, bootstrapping produces higher temperatures during the first 70–100 yr than would occur if the plants were constructed using power from the existing grid. For transitions lasting longer than 100 yr, bootstrapping does yield lower GHG emissions for plant construction and, eventually, lower temperatures than grid-connected build-outs. On this extended time scale, however, emissions for grid-connected models are likely to fall substantially as well, due to changes in the mix of electricity generation.

Figure 3(A) shows that, for fossil fuel plants, emissions from plant operation are the predominant source of life-cycle emissions, and they are responsible for the majority of the global temperature increase produced. Conservation yields the largest temperature reductions. In transitions to wind, solar, and nuclear technologies, temperature increases caused by emissions during plant construction exceed those due to plant operation; the resulting temperature increases are dwarfed, however, by those caused by emissions from coal plants as they are being phased out.

Temperature increases due to transmission and waste heat are small but can amount to a substantial fraction of the total temperature increase associated with the lowest emission technologies.

5. Sources of uncertainty

Our central result is that transitions from coal to energy technologies having lower carbon emissions will not substantially influence global climate until more than half a century passes, and that even large transitions are likely to produce modest reductions in future temperatures. These fundamental qualitative conclusions are robust, but our quantitative calculations incorporate important sources of uncertainty in representations of both the energy system and the physical climate system.

We characterize uncertainty in energy system properties by presenting both high and low estimates from life-cycle analyses (e.g., figures 1–3). Our model of the physical climate system is affected by uncertainties both in the relationship between greenhouse gas emissions and atmospheric concentrations and in the relationship between atmospheric concentrations and the resulting climate change. The IPCC [5] states that equilibrium climate sensitivity to a doubling of atmospheric CO_2 content 'is likely to lie between 2 and 4.5 °C with a most likely value of approximately 3 °C.' Our model yields a climate sensitivity of 3.18 °C per CO_2-doubling. Physical climate system uncertainties could thus potentially halve or double our quantitative results. The impact of most of these uncertainties would apply equally to all technologies, however, so relative amounts of warming resulting from different technology choices are likely to be insensitive to uncertainties about the climate system.

6. Conclusions

Here, we have examined energy system transitions on the scale of the existing electricity sector, which generates $\sim$1 TW_e primarily from approximately 3 TW thermal energy from fossil fuels [3]. It has been estimated, however, that 10–30 TW of carbon-neutral thermal energy must be provisioned by mid-century to meet global demand on a trajectory that stabilizes the climate with continued economic growth [1].

It appears that there is no quick fix; energy system transitions are intrinsically slow [13]. During a transition, energy is used both to create new infrastructure and to satisfy other energy demands, resulting in additional emissions. These emissions have a long legacy due to the long lifetime of CO_2 in the atmosphere and the thermal inertia of the oceans. Despite the lengthy time lags involved, delaying rollouts of low-carbon-emission energy technologies risks even greater environmental harm in the second half of this century and beyond. This underscores the urgency in developing realistic plans for the rapid deployment of the lowest-GHG-emission electricity generation technologies. Technologies that offer only modest reductions in emissions, such as natural gas and—if the highest estimates from the life-cycle analyses (SOM table S1 available at stacks.iop.org/ERL/7/014019/mmedia) are correct—carbon capture storage, cannot yield substantial temperature reductions this century. Achieving substantial reductions in temperatures relative to the coal-based system will take the better part of a century, and will depend on rapid and massive deployment of some mix of conservation, wind, solar, and nuclear, and possibly carbon capture and storage.

Acknowledgments

The authors are grateful to W Gibbs, L Wood and A Modoran for helpful comments on the manuscript.

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Japan's Kansai to buy U.S. Cameron LNG from Mitsui

TOKYO, April 1 Mon Mar 31, 2014 9:23pm EDT

(Reuters) - Japan's second-biggest utility, Kansai Electric Power Co, said it had signed a 20-year contract to buy 400,000 tonnes per year of U.S. Cameron liquefied natural gas (LNG) from trader Mitsui & Co at U.S. Henry Hub-linked prices.

The Osaka-based firm said it would buy for 20 years from the project's planned launch, scheduled for late 2017.

LNG imports by Japan, the world's top buyer of the super-cooled fuel, have jumped since the Fukushima nuclear disaster, with utilities looking to boost supplies from North America to diversify supply sources and lower prices.

The deal marks Kansai's second purchase of U.S. shale gas. It has agreed to buy 800,000 tonnes per year from the U.S. Cove Point export plant in Maryland.

The U.S. Energy Department in February approved exports from Sempra Energy's Cameron LNG project as the Obama administration moves forward with its goal of expanding the global market for the fuel. (Reporting by Osamu Tsukimori; Editing by Joseph Radford)

- **UPDATE 4-Pipe explodes at Williams LNG facility in Washington state**
  | *31 Mar*

30-Year Fixed Jumbo	4.75%	4.35%

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Cheniere Energy, Inc.
700 Milam Street, Suite 800
Houston, Texas 77002
phone: 713.375.5000
fax: 713.375.6000

March 20, 2014

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

Re: Sabine Pass LNG, L.P. and Sabine Pass Liquefaction, LLC
Monthly Construction Progress Report for Sabine Pass Liquefaction Project
Docket Nos. CP11-72-000 & CP13-2-000

Dear Ms. Bose:

On April 16, 2012, the Federal Energy Regulatory Commission ("FERC") issued an Order Granting Authorization under Section 3(a) of the Natural Gas Act ("April 16 Order") in the above-captioned docket. The Order authorizes Sabine Pass LNG, L.P. and Sabine Pass Liquefaction, LLC ("Sabine Pass") to site, construct, and operate the Sabine Pass Liquefaction Project at the Sabine Pass LNG Terminal, located in Cameron Parish, Louisiana. On August 2, 2013, the FERC issued an Order Amending Section 3 Authorization ("August 2 Order") for the Sabine Pass Modification Project.

Pursuant to Condition 7 in Appendix D of the April 16 Order, and Condition 7 of the August 2 Order, Sabine Pass is herein submitting its monthly construction progress report for February 2014.

Should you have any questions about this filing, please feel free to contact the undersigned at (713) 375-5000.

Thank you,

/s/ *Karri Mahmoud*

Karri Mahmoud
Sabine Pass LNG, L.P.
Sabine Pass Liquefaction, LLC

cc: Ms. Sentho White, Federal Energy Regulatory Commission
Ms. Karla Bathrick, Federal Energy Regulatory Commission
Ms. Magdalene Suter, Federal Energy Regulatory Commission
Mr. Stephen Kusy, Federal Energy Regulatory Commission

SABINE PASS LIQUEFACTION PROJECT

Cameron Parish, Louisiana

Monthly Progress Report

February 2014

Table of Contents

1.0 Executive Summary

This report covers activities of the SPL Stage 1 and SPL Stage 2 projects occurring during the month of February 2014. Stage 1 Engineering is 94.4% complete, Procurement is 91.4%, and Subcontract and direct hire Construction work are 37.1% and 18.6% complete, respectively, for the period. Stage 1 overall project completion is 60.8% against the plan of 63.6%.

Stage 2 Engineering is now 48.1% complete, Procurement is 38.1%, and Subcontract and direct hire Construction work are 12.0% and 0.4% complete, respectively. Overall project completion for Stage 2 is 23.3% against the plan of 22.3%.

Actual project progress and current recovery plans continues to support the achievement of the scheduled Substantial Completion Dates for Trains 1 and 2, which remain as February 2016 and June 2016, respectively. Trains 3 and 4 Substantial Completion Dates are April 2017 and August 2017.

2.0 Project Highlights

In February, Stage 1 engineering is complete and is in punch list mode. For Stage 2, engineering completed the IFC of all Train 3 ISOs.

The Train 1 heavy wall vessels and the propane substation building have arrived at Site. The 1st set of refrigeration compressors are in transit and will arrive in March, as will the BOG compressors and the first shipments of air coolers for the Train 1 cryo rack. First structural steel for Train 3 was delivered to site in February. Procurement continues to support construction activities at the jobsite through delivery of piping and structural items.

During the month of February, Subcontracts managed the following major subcontracts for Trains 1 and 2: soil improvement, field erected tanks, onsite concrete batch plant, offsite equipment insulation, permanent telecommunications, and fire/gas detection. The electric heat tracing subcontract was awarded. For Trains 3 and 4, Subcontracts managed efforts for pile fabrication and installation, field erected tanks, and busing.

Construction in Train 1 continued in structural and paving concrete, structural steel erection, and installation of underground and aboveground piping, electrical grounding, cable tray and mechanical equipment. Train 2 work continued in structural and paving concrete, structural steel erection, electrical grounding, and installation of underground and aboveground pipe. Construction in the OSBL area continued with structural and paving concrete, structural steel erection, electrical grounding, installation of underground and aboveground pipe, and mechanical equipment installation. The Revamp area continued in structural concrete, structural steel erection, underground and aboveground piping, and electrical cable.

Construction in Train 3 continues with concrete works in area 233N01 and Train 3 underground piping. Seal slabs have been poured in area 233A01 and 233D01 and excavation was done for the hot oil sump.

3.0 Environmental, Safety & Health Progress

During the month of February, the project had 34 first aid, 18 near misses, and 1 OSHA recordable.

	Near Miss Cases		First Aid		OSHA Cases		LWDC Cases	
	Month	ITD[1]	Month	ITD[1]	Month	ITD[1]	Month	ITD[1]
Bechtel	18	106	34	267	1	8	0	0
Subcontractors	0	26	0	20	0	5	0	0
Total	**18**	**132**	**34**	**287**	**1**	**13**	**0**	**0**

[1.] ITD = Project totals reflect inception to date and are combined for Stage 1 & 2.

4.0 Schedule

Overall, Train 1 & 2 project progress is 60.8% complete against a plan of 63.6%. Overall Train 3 & 4 project progress is 23.3% complete against a plan of 22.3% complete.

5.0 Construction

Area	Comments	Planned Work for Next Reporting Period
Liquefaction Stage 1 Area – Train 1	• Continued constructing foundations, erecting structural steel and installing above ground and underground piping. • Continued installing mechanical equipment. • Continued installing electrical cable tray in the propane condenser rack.	• Continue activities to support Train 1 construction.
Liquefaction Stage 1 Area – Train 2	• Continued constructing foundations, erecting structural steel and installing above ground and underground piping. • Installing mechanical equipment	• Continue activities to support Train 2 construction.
Liquefaction Stage 2 Area – Train 3	• Placement of the seal slab in the Train 3 propane Area. • Train 3 piles reached substantial completion. • Started placement of structural concrete. • Started excavation for the hot oil sump. • Started underground piping installation in the Train 3 area.	• Continue soil stabilization. • Continue pile driving. • Continue activities to support Train 3 construction.
Liquefaction Stage 2 Area – Trains 4	• Soil Stabilization • Continue pile driving activities within Train 4 and OSBL.	• Continue soil stabilization. • Continue pile driving.

Area	Comments	Planned Work for Next Reporting Period
OSBL	• Constructing pipe racks in the LNG Tank 3 and 5 areas. • Constructing the marine flare. • Continued constructing foundations and erecting structural steel.	• Continue activities to support OSBL construction.
Support Buildings Area	• Continued construction of the warehouse and control room. • Continued constructing pipe racks in the Tank 3 and 5 areas. • Continued constructing the marine flare.	• Continue warehouse and control room work.
Access Roads, Waterline	• Water trucks were operated for dust control, as necessary.	• Dust control will continue.
Laydown, Staging Areas	• Continued mixing for soil stabilization and began laying rock in the area north of Trains 3 and 4.	• Contractors will continue to mobilize personnel and equipment.
Construction Dock (Ro-Ro)	• Received and offload pile barges at the construction dock. • Receiving and offloading heavy equipment at the Ro-Ro. • Dredging occurred this period.	• Continue to receive pile barges.

6.0 Permitting and Environmental

None.

Summary of Problems, Non-Compliances, and Corrective Actions.

Date	Description
None.	

Agency Contacts/Inspections

Agency	Name	Date	Location/Activity

Proposed Changes to Schedule or Scope:
None.

7.0 Progress Pictures

Train 1 131G02 (inlet gas-seal slab for paving) (24-Feb-2014)

Train 1 131K01 (dehydration mercury removal) (24-Feb-2014)

Train 1 131N01 (propane rack accumulator set) (20-Feb-2014)

Train 1 131N02 (propane substation) (24-Feb-2014)

Train 1 131N01 (set accumulator) (24-Feb-2014)

Train 2 132A01 (compressor methane tabletop) (27-Feb-2014)

Train 2 132A02 (compressor substation) (27-Feb-2014)

Train 2 132B01 (amine storage area and thermal oxidizer) (24-Feb-2014)

Train 2 131M01 (heavies removal unit paving) (13-Feb-2014)

OSBL 135F01 (water treatment area) (24-Feb-2014)

Certificate of Service

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Houston, Texas this 20th day of March 2014.

/s/ *Karri Mahmoud*
Karri Mahmoud
Sabine Pass LNG, L.P.
Sabine Pass Liquefaction, LLC

Document Content(s)

DOE approves Dominion Cove Point LNG exports to non-FTA countries

WASHINGTON, DC, Sept. 11
09/11/2013
By Nick Snow
OGJ Washington Editor

The US Department of Energy approved Dominion Cove Point LP's application to export LNG from its terminal in Calvert County, Md., to countries that do not have a free-trade agreement with the US.

Subject to environmental review and final regulatory approval, the facility on Chesapeake Bay received conditional authorization to export as much as 0.77 bcfd for of 20 years, DOE said on Sept. 11. The installation previously received clearance to export LNG to non-FTA countries on Oct. 7, 2011, it noted.

"We agree with DOE's decision that exports are expected to bring economic benefits to the country," said Thomas F. Farrell II, chief executive of parent Dominion Resources Inc. "It is good news on many fronts, including the thousands of jobs that will be created, the boost in government revenues that will result, and the support it provides to allied nations."

Dominion Cove Point's proposed liquefaction and export operations are expected to cost $3.4-3.8 billion. The company sought approval for them in March from the US Federal Energy Regulatory Commission. Pending receipt of regulatory approval and permits, construction is scheduled to begin in 2014, with a 2017 in-service date.

The installation already has robust infrastructure, including connections to the pipeline grid, LNG storage capacity, and an updated pier. Construction will chiefly entail adding liquefaction capability, Dominion said.

It said the facility's capacity is fully subscribed, with signed 20-year terminal service agreements. Pacific Summit Energy LLC, a US affiliate of Japanese trading company Sumitomo Corp., and GAIL Global (USA) LNG LLC, a US affiliate of GAIL (India) Ltd., each have contracted for half of the marketed capacity.

Under amendments to the 1920 Natural Gas Act, DOE is required to determine if an applicant's request to export LNG to a non-FTA country is in the national interest. In Dominion Cove Point's case, it said it considered the economic, energy security, and environmental impacts, as well as public comments for and against the application and nearly 200,000 public comments related to the associated analysis of the cumulative impacts of increased LNG exports.

Dominion Cove Point is the fourth US LNG terminal to gain DOE approval of exports to non-FTA nations. Sabine Pass Liquefaction LLC, Freeport LNG Expansion LLC, and Lake Charles Exports LLC's applications were approved earlier. DOE has another 19 non-FTA LNG export applications under review.

Contact Nick Snow at nicks@pennwell.com.

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FACTBOX-North America natural gas export plans

Fri, Mar 14 2014

March 14 (Reuters) - Freeport LNG's proposed liquefied natural gas export terminal in Texas inched closer to approval by the Federal Energy Regulatory Commission with the release of a draft report on Friday finding the project would not cause significant environmental harm.

Companies need approval from both the U.S. Department of Energy, which determines whether the proposed exports would be in the public interest, and FERC, which assesses safety and environmental effects of the projects' construction and operation.

Freeport is one of four companies waiting for a decision from FERC after receiving permission from the DOE for exports to countries without free trade agreements with the United States.

Cheniere Energy Inc's Sabine Pass project in Louisiana is the only terminal that has received permission from both agencies so far.

FERC typically sets a schedule for carrying out its environmental review of each project, with decisions on licenses usually issued 30 to 90 days after the assessments are completed.

Below is a table showing the proposed and potential LNG export plants in North America according to FERC and the release dates set for the commission's environmental reviews so far. Capacity is in billion cubic feet per day (*indicates project has received DOE, non-free trade agreement approval).

Approved by FERC

Project	State	Company	Start Up	Capacity
*Sabine Pass	Louisiana	Cheniere Energy	2015	2.6

Proposed to FERC

Project	State	Company	Start Up	Capacity
*Freeport LNG	Texas	Freeport LNG/FLNG Liquefaction	2015	1.8
*Lake Charles	Louisiana	Southern Union-Trunkline LNG	TBD	2
*Cove Point	Maryland	Dominion	2016	0.77
*Hackberry	Louisiana	Sempra-Cameron LNG	2018	1.7
Coos Bay	Oregon	Jordan Cove Energy Project	2017	0.9
Elba Island	Georgia	Southern LNG Company	TBD	0.35
Lavaca LNG	Texas	Excelerate Liquefaction	2017	1.38
Magnolia LNG	Louisiana	LNG Limited	2017	1.07
Sabine Pass, TX	Texas	ExxonMobil-Golden Pass	2018	2.1
Corpus Christi	Texas	Cheniere Energy	2017	2.1
Plaquemines Parish	Louisiana	CE FLNG	2018	1.07
Astoria	Oregon	Oregon LNG	2017	1.3
Sabine Pass, LA	Louisiana	Sabine Pass Liquefaction (expansion)	2017	1.3

Final environmental reviews scheduled by FERC

Freeport LNG	June 16, 2014
Cove Point	May 15, 2014
Hackberry (Cameron LNG)	April 30, 2014
Corpus Christi	Oct. 8, 2014

Potential U.S. Project Sites

Project	State	Company	Start-up	Capacity
Cameron Parish	Louisiana	Gasfin Development	TBD	0.2
Brownsville	Texas	Gulf Coast LNG Export	TBD	2.8
Pascagoula	Mississippi	Gulf LNG Liquefaction	TBD	1.5

Cameron Parish	Louisiana	Venture Global	TBD	0.7
Cameron Parish	Louisiana	Waller LNG Services	TBD	0.16
Ingleside	Texas	Pangea LNG	2018	1.09

Proposed Canadian Sites

Kitimat	British Columbia	Apache Canada	2015	0.7
Douglas Island	British Columbia	BC LNG Export Cooperative	2014	0.25
Kitimat	British Columbia	LNG Canada	2020	3.2

Potential Canadian Project Sites

Prince Rupert Island	British Columbia	BG Group	2021	4.2
Goldboro LNG	Nova Scotia	Pieridae Energy Canada	2020	0.7
Melford	Nova Scotia	H-Energy	2020	1.8
Prince Rupert Island	British Columbia	Pacific Northwest LNG	TBD	2.5
Prince Rupert Island	British Columbia	ExxonMobil-Imperial	TBD	3.8
Squamish	British Columbia	Woodfibre LNG Export	TBD	0.3

(Reporting by Ayesha Rascoe; Editing by Marguerita Choy)

MAGNOLIA LNG fact sheet

PROJECT

Magnolia LNG, LLC, proposes to construct, own and operate a mid-scale liquefied natural gas (LNG) export facility that will use a thermally efficient LNG process technology.

LOCATION

108 acres of industrial land on Industrial Canal South Shore (PLC Tract 475), through a long-term lease with the Lake Charles Harbor and Terminal District (Port of Lake Charles).

The Project site is located on an existing LNG shipping channel and the facility will be accessible by road, near the intersection of Henry Pugh Boulevard and Big Lake Road (Conceptual Layout and Site Map on reverse side).

PROCESS

It is proposed that the Project will receive natural gas via an existing pipeline. The natural gas will be treated, liquefied, and stored onsite. The LNG will be loaded onto LNG vessels for delivery to domestic and export markets and into trucks for domestic distribution in Louisiana and surrounding states.

CAPACITY

At full plant capacity, the Project will consist of four LNG trains (gas liquefaction units), each with a nominal LNG production capacity of 2 million tonnes per annum (mtpa).

TECHNOLOGY

Optimized Single Mixed Refrigerant (OSMR®) liquefaction process has the following main features, which contribute to its high efficiency and 30% less emissions:

- Aeroderivative gas turbines and efficient compressors.
- Combined heat and power plant, which minimizes plant fuel gas use.
- Steam-driven ammonia refrigeration system.

OSMR® is 100% developed and owned by Magnolia LNG, LLC's parent company, Liquefied Natural Gas Limited.

OWNER

Magnolia LNG, LLC, a wholly owned subsidiary of Liquefied Natural Gas Limited (www.lnglimited.com.au), GPO Box 920, West Perth WA 6872 Australia

INITIAL INVESTMENT

$2.2 billion, for Phase 1 of the Project comprising two LNG Trains, each of 2 mtpa LNG production capacity.

JOBS

Based on estimates by Magnolia LNG, LLC and the Louisiana Department of Economic Development Phase 1 of the Project will generate approximately 1,000 construction jobs, 45 permanent direct jobs and an additional 175 indirect jobs, and provide significant economic benefits for the State of Louisiana and the United States of America.

SCHEDULE

Magnolia LNG, LLC, is targeting commencement of construction in 2015 and initial start-up of operations in late 2017.

CONTACT

Ernie Megginson
VP–Project Management
Magnolia LNG, LLC

Email: emegginson@lnglimited.com.au

616 Broad Street | Lake Charles, LA 70601


MAGNOLIA
LNG
G
L
MAGNOLIA LNG PROJECT
CONCEPTUAL LAYOUT - 8 MTPA

MAGNOLIA LNG

PROJECT OVERVIEW

Total Capital Cost (Phase 1)
US$ 2.2 Billion

Estimated Construction Jobs 1,000

Estimated Direct Employment 45

Estimated Indirect Employment 175

Phase 1 (4 mtpa) focused on Domestic and FTA Markets

Construction Start
Mid-2015

Operations Start
Late 2017

MAGNOLIA**LNG**.COM

MAGNOLIA LNG

FREQUENTLY ASKED QUESTIONS

What is LNG?

- Liquefied natural gas (LNG) is natural gas in its liquid form.
- Cooled to –260°F, LNG is a clear, colorless, odorless, non-corrosive, non-toxic liquid.
- Primarily methane, with low concentrations of other hydrocarbons, water, carbon dioxide, nitrogen and some sulphur compounds.
- Sometimes confused with LPG (liquefied petroleum gas), which is used for domestic and commercial applications. LPG is kept liquid by confining under high pressure; LNG is kept liquid at normal atmospheric pressure by maintaining a very low temperature.

How is LNG used?

- Before LNG can be used, it must be converted back into a gas (regasification).
- After regasification, supplied to households, power stations and other industrial consumers through pipelines.
- LNG in liquid form used as cleaner alternative transportation fuel.

Why use LNG?

- Natural gas is the cleanest-burning fossil fuel, producing less emissions and pollutants than coal or oil.
- Occupies only 1/600th of the volume of natural gas; more economical to transport; can be stored in larger quantities.

How is LNG stored?

- Stored in large insulated tanks consisting of an inner tank and outer tank, with a special insulating layer between.

How is LNG transported?

- Transported in double-hulled ships designed specifically to handle the low temperature of LNG.
- LNG weighs less than half the weight of water so it will float if spilled on water, quickly boiling off and dissipating into the atmosphere, leaving no residue. No environmental clean-up is needed for an LNG spill on water.

Is LNG flammable?

- As a liquid, LNG is not flammable. Vaporized LNG is only flammable if its concentration is within 5%–15% natural gas with air.

Is LNG explosive?

- As a liquid, LNG is not explosive. LNG vapors (methane) mixed with air are not explosive in an unconfined environment. LNG vapor will explode only if in a confined space, and only if within the flammable range of 5% to 15% natural gas with air.

How safe are LNG ships and LNG terminals?

- The LNG industry has an excellent safety record thanks to the safe properties of LNG and the stringent enforcement of standards, codes and guidelines applying to LNG.
- To date there have been more than 50,000 transported shipments by LNG tankers, covering more than 70 million nautical miles, without a single significant accident or safety problem, neither in a port nor at sea.

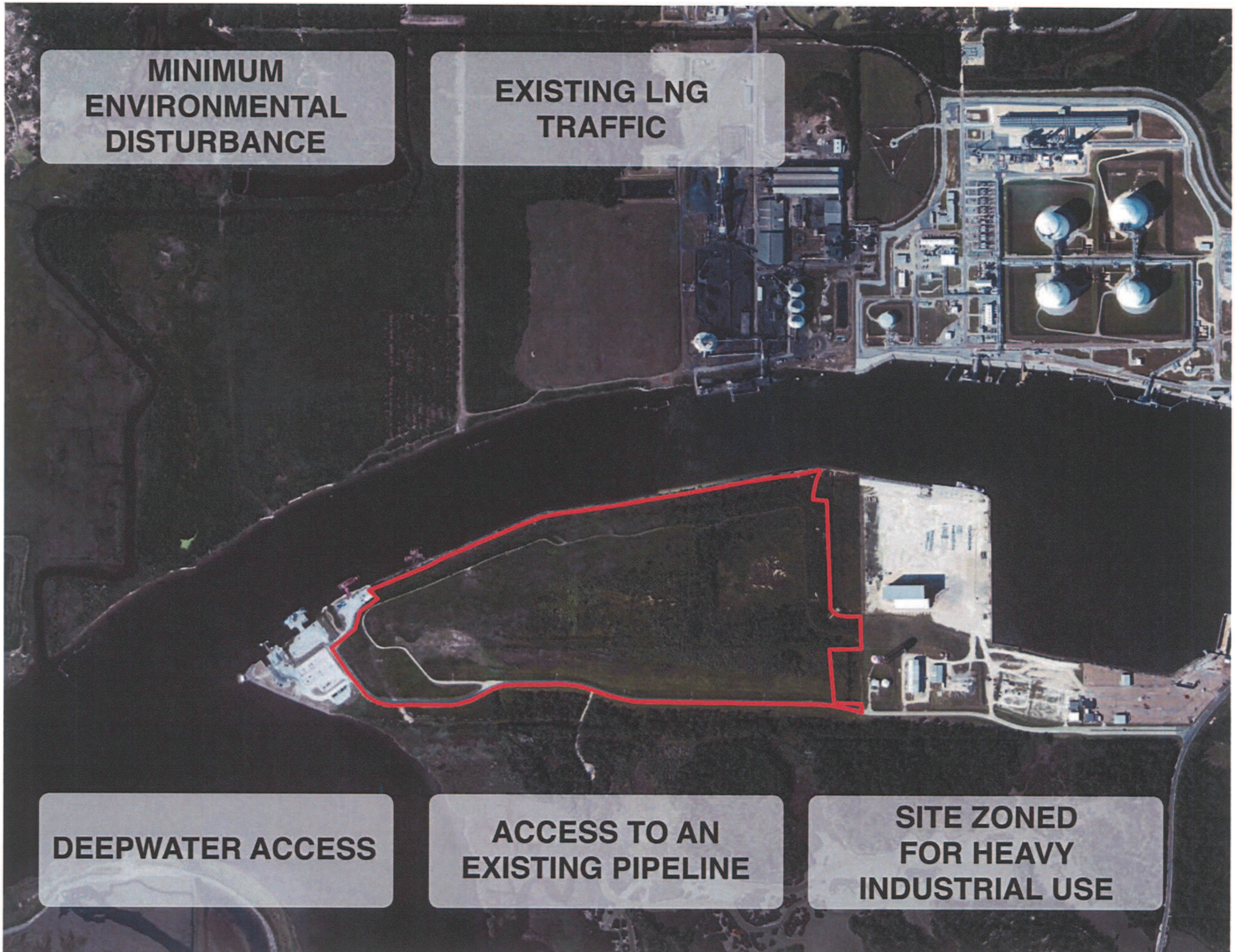
How secure are LNG ships and LNG facilities?

- The LNG industry adheres to stringent security procedures for its ships and facilities. The industry carefully follows requirements set forth by the International Maritime Organization, Federal Energy Regulatory Commission, Department of Transportation, and the U.S. Coast Guard and works closely with the Department of Homeland Security to ensure that its operations are safe and secure.

Source: www.LNGFacts.org

The LNG Industry in General

- This industry has an excellent safety record spanning many decades.
- LNG terminals (export and import) are located all over the world.
- There are over 80 LNG reception terminals and approximately 30 LNG liquefaction plants in operation worldwide, with over 40 planned new and expanded LNG terminals, and more than 30 planned liquefaction plants and expansions.


MINIMUM ENVIRONMENTAL DISTURBANCE
EXISTING LNG TRAFFIC
DEEPWATER ACCESS
ACCESS TO AN EXISTING PIPELINE
SITE ZONED FOR HEAVY INDUSTRIAL USE

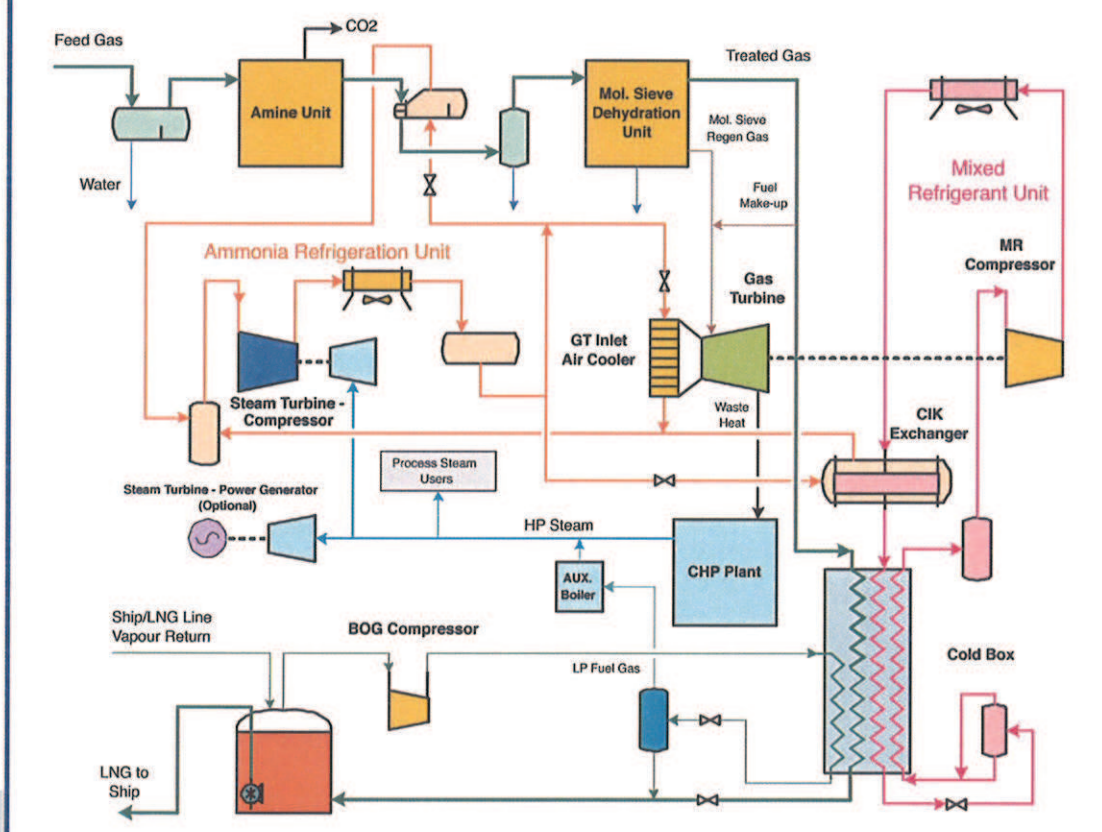
LIQUEFACTION TECHNOLOGIES

Large Scale Liquefaction Technology
(>3 mtpa)
ConocoPhillips – Cascade Process
API – C3MR Process
Shell – Dual MR

Medium Scale Liquefaction Technology (1-3 mpta)
LNG Limited – OSMR® Process

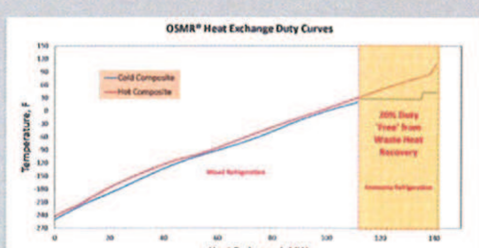
Small Scale Liquefaction Technology
(< 1 mtpa)
Black & Veatch – PRICO – SMR Process
Hamworthy – N2 Expansion

OSMR® PROCESS SCHEMATIC



MAGNOLIA LNG

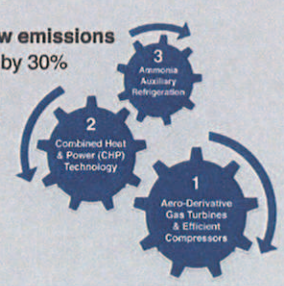
OSMR® COOLING CURVE



OSMR® BENEFITS

Simplicity in design, construction and operation
- Faster construction
- Proven technology
- Reduced capital requirement
- Location flexibility
- Less footprint required
- Simple start-up & operation
- Low turndown

High efficiency and low emissions
- Improved efficiency by 30%
- Better economics
- Reduced emissions



MAGNOLIA LNG

PARTIAL LIST OF SUBJECTS IN ENVIRONMENTAL STUDY

AIR EMISSIONS

WATER DISCHARGES

WATER USE

WATER QUALITY

STORM WATER RUN OFF

WETLANDS IMPACTS

DREDGING AND SPOIL PLACEMENT

WILDLIFE AND PROTECTED SPECIES

FISHERIES

LAND USE, RECREATION, AND AESTHETICS

CULTURAL RESOURCES AND HISTORIC PRESERVATION

SOCIAL AND SOCIOECONOMIC IMPACTS

SOILS AND GEOLOGY

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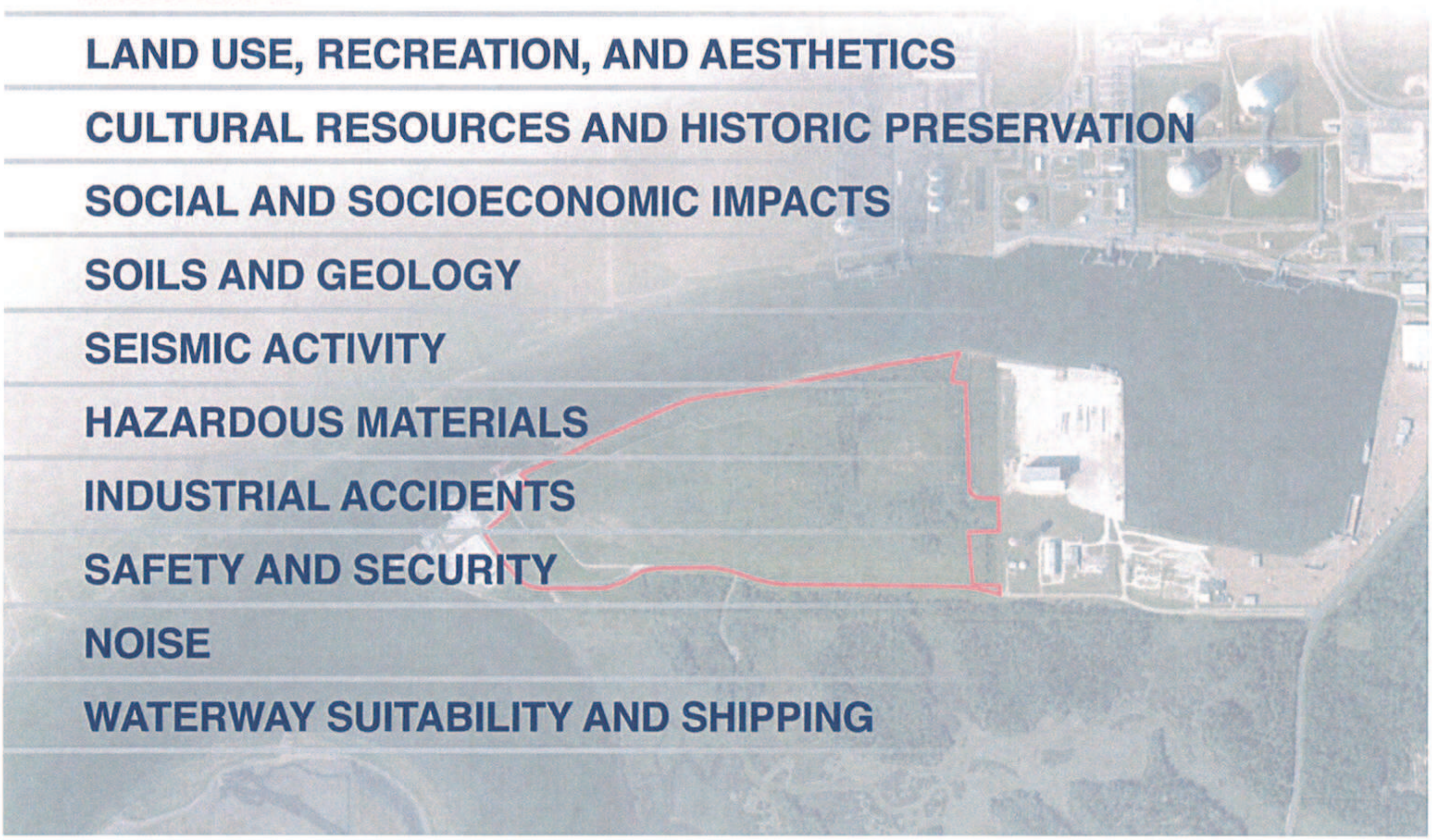
NOISE

WATERWAY SUITABILITY AND SHIPPING



MAGNOLIA LNG

MAJOR AGENCY ROLES IN ENVIRONMENTAL AND SAFETY REVIEW

FEDERAL AGENCIES

Federal Energy Regulatory Commission
Order Granting Section 3 Authorization

National Oceanic & Atmospheric Administration: National Marine Fisheries Service
Consultation on essential fish habitat, sea turtles in the water, marine mammals, marine fisheries and other protected marine species under agency jurisdiction

U.S. Army Corps of Engineers
Section 10/404 Dredge and Fill Permit

U.S. Coast Guard
Letter of Recommendation for suitability of waterway for LNG marine traffic

U.S. Department of Interior, Fish and Wildlife Service
Consultation on migratory birds, bald and golden eagles, sea turtles on the beach, and other protected species under agency jurisdiction

U.S. Department of Transportation: Pipeline and Hazardous Materials Safety Administration
Applies and enforces federal safety regulations related to LNG facilities

STATE AGENCIES

Louisiana Department of Environmental Quality
Process air emissions permits, water discharge permits, storm water control permits

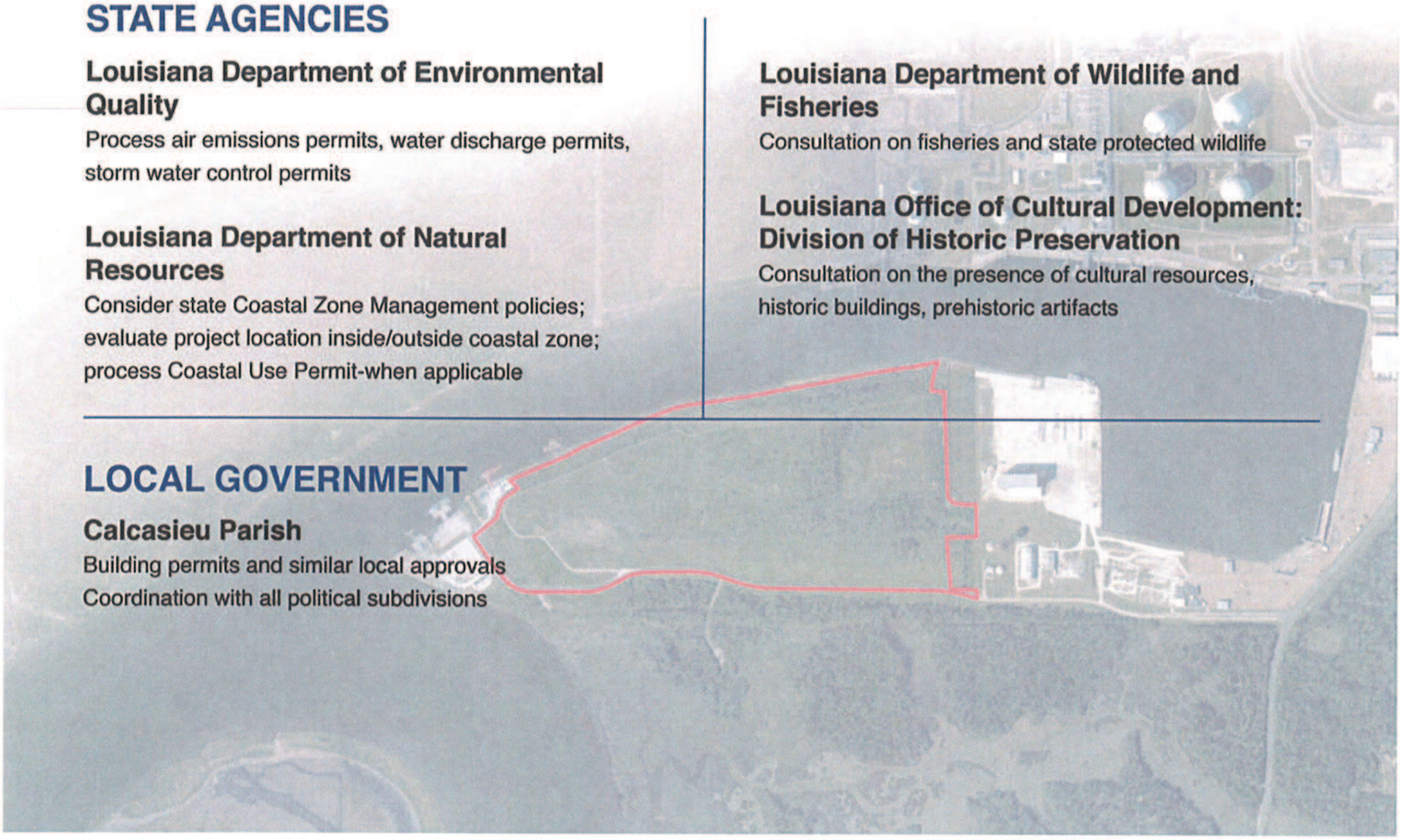
Louisiana Department of Natural Resources
Consider state Coastal Zone Management policies; evaluate project location inside/outside coastal zone; process Coastal Use Permit-when applicable

Louisiana Department of Wildlife and Fisheries
Consultation on fisheries and state protected wildlife

Louisiana Office of Cultural Development: Division of Historic Preservation
Consultation on the presence of cultural resources, historic buildings, prehistoric artifacts

LOCAL GOVERNMENT

Calcasieu Parish
Building permits and similar local approvals
Coordination with all political subdivisions



Endesa Buys More LNG from Cheniere

Posted on Apr 8th, 2014 with tags Buys, Cheniere, Endesa, LNG, News .

Cheniere Energy's unit Corpus Christi Liquefaction has entered into an LNG sale and purchase agreement with Endesa under which the Spanish company has agreed to purchase approximately 0.75 million tonnes per annum of LNG. The SPA is in addition to the previously signed SPA under which Endesa will purchase approximately 1.5 mtpa of LNG, bringing the total quantity of LNG sold to Endesa under the two agreements to approximately 2.25 mtpa.

The Corpus Christi Liquefaction project is being designed and permitted for up to three trains, with aggregate design production capacity of 13.5 mtpa of LNG.

Under the SPA, Endesa will purchase LNG on an FOB basis for a purchase price indexed to the monthly Henry Hub price plus a fixed component. LNG will be loaded onto Endesa's vessels. The SPA has a term of twenty years commencing upon the date of first commercial delivery and an extension option of up to ten years. Deliveries are expected to occur as early as 2018.

"Endesa has agreed to purchase an additional 0.75 mtpa from the Corpus Christi Liquefaction Project for use by their Italian parent company Enel," said **Charif Souki, Chairman and CEO.** "*We have now entered into a total of approximately 3 mtpa of SPAs at the project, completing the SPAs for Train 1. We continue to work towards finalizing additional agreements and expect*

to complete all necessary steps to reach a final investment decision and begin construction by early 2015."

Press Release, April 08, 2014; Image: Cheniere

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THE GLOBE AND MAIL

March 24, 2014

U.S. approves Veresen's LNG project in Oregon

By BRENT JANG

Terminal in Oregon will be supplied with Canadian natural gas to ship to Asia

The U.S. Department of Energy has approved an application to export liquefied natural gas from a proposed Oregon terminal that would tap into resources that originate in Canada.

The Jordan Cove LNG project, owned by an arm of Calgary-based Veresen Inc., will rely heavily on natural gas supplies to be transported through an existing pipeline network from Western Canada to Oregon.

Plans also call for building the 370-kilometre Pacific Connector feeder pipeline, co-owned by Veresen and Williams Companies Inc. of Tulsa, Okla., in an effort to bring in natural gas from suppliers in Wyoming and Colorado.

Veresen wants to export LNG to Asian customers in a fierce energy race on North America's West Coast. Rivals include one other U.S. Pacific Northwest project, Oregon LNG Marketing Co. LLC, and at least 14 B.C. LNG proposals. There is also global competition to export LNG to Asia, including from Qatar, Australia and Nigeria.

So far, Cheniere Energy Inc.'s Sabine Pass LNG project in Louisiana is the only LNG export project under construction in North America. Jordan Cove and five other U.S. proposals are awaiting approval from the U.S. Federal Energy Regulatory Commission.

Several B.C. LNG projects have been spending millions of dollars on site preparation and other costly preliminary planning, but none of the proponents have made final investment decisions.

Environmentalists and local residents oppose the Jordan Cove project in southern Oregon, but its backers point to economic benefits. Veresen chief executive officer Don Althoff said Monday that Jordan Cove will generate much-needed jobs and provide tax revenue to the Oregon government.

Last month, Canada's National Energy Board approved Jordan Cove's 25-year licence application to export up to 1.55 billion cubic feet a day of natural gas from Western Canada to the U.S.

Veresen said the Canadian natural gas will help supply the Oregon terminal to be constructed at Coos Bay. The LNG production launch is slated for early 2019.

The U.S. Department of Energy's 20-year authorization allows Jordan Cove to export nearly six million tonnes annually of LNG, subject to final regulatory approval. The department said it "considered the economic, energy security and environmental impacts" before giving its blessing Monday for Jordan Cove to export LNG to countries that do not have free-trade agreements with the United States. Jordan Cove needs to secure Asian customers to take delivery of LNG.

Lake Charles LNG export project partners file FERC application

HOUSTON, Mar. 26
03/26/2014
By OGJ editors

Trunkline LNG Co. LLC and Trunkline LNG Export LLC, both wholly owned subsidiaries of Energy Transfer Equity LP and Energy Transfer Partners LP, have submitted an application with the US Federal Energy Regulatory Commission seeking its authorization for the siting, construction, ownership, and operation of the proposed Lake Charles LNG export project.

The FERC filing represents the culmination of significant front-end engineering and design (FEED) work and pre-filing consultations with FERC and other federal, state, and local agencies that have been under way since mid-2012, said BG Group, which will oversee the construction and operation of the proposed facility under a long-term agreement with Energy Transfer.

Pending final investment decisions and the receipt of all necessary approvals expected in 2015, construction is planned to start shortly afterwards, with first LNG exports expected in second-quarter 2019.

The US Department of Energy in August 2013 conditionally granted authorization to export as much as 2 bcfd of LNG from the existing Trunkline LNG import terminal to non-free trade agreement nations (OGJ Online, Aug. 8, 2013).

The proposed project will include the construction of three liquefaction trains and use the existing LNG storage and marine berthing facilities owned by Trunkline LNG Co. LLC. Energy Transfer has secured all property rights required for the site of the proposed liquefaction facility.

Energy Transfer will own and finance the proposed facility while BG Group will be responsible for the offtake. Trunkline Gas will provide pipeline transportation services to supply gas to the proposed facility.

RELATED ARTICLES

AMP files FERC request for abandonment of Midla Pipeline

04/03/2014 American Midstream Partners LP (AMP) has filed a request with the US Federal Energy Regulatory Commission to abandon use of its 1920s vintage Midla...

Cheniere, Endesa sign Corpus Christi LNG deal

04/02/2014 Corpus Christi Liquefaction LLC, a subsidiary of Cheniere Energy Inc., has signed an LNG sale and purchase agreement (SPA) with Spanish multination...

Senate Republicans introduce energy amendment to jobs bill

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(713) 621-9720

Dominion Cove Point LNG, LP
701 East Cary Street, Richmond, VA 23219

Dominion

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OCT 3 2011

October 3, 2011

Mr. John Anderson
U.S. Department of Energy
Office of Fossil Energy
Docket Room 3F-056, FE-50
Forrestal Building
1000 Independence Avenue, S.W.
Washington, D.C. 20585

Re: Dominion Cove Point LNG, LP
FE Docket No. 11-128-LNG
Application for Long-Term Authorization to Export LNG
To Non-Free Trade Agreement Countries

Dear Mr. Anderson:

Dominion Cove Point LNG, LP (DCP) hereby submits for filing, with the U.S. Department of Energy, Office of Fossil Energy (DOE/FE), one original and three copies of its application for long-term authorization to export liquefied natural gas (LNG). DCP is seeking long-term, multi-contract authority to export domestically produced LNG of up to the equivalent of approximately 1 billion cubic feet of natural gas per day or approximately 7.82 million metric tons per annum at its Cove Point LNG Terminal located in Calvert County, Maryland over a twenty-five year period. The requested export authority would permit DCP as an agent for others to export LNG to any country which has or in the future develops the capacity to import LNG via ocean-going carrier with which the United States does not prohibit trade but also does not have a Free Trade Agreement.

As stipulated by 10 C.F.R. § 590.207, a check for the filing fee in the amount of $50.00 is enclosed. Pursuant to 10 C.F.R. § 590.103(b), a certified statement that the signatory is a duly authorized representative is attached in Appendix D.

If you have any questions, please contact Amanda Prestage at 804-771-4416.

Respectfully submitted,

/s/ Matthew R. Bley

Matthew R. Bley
Authorized Representative of
Dominion Cove Point LNG Company, LLC,
The General Partner of Dominion Cove Point LNG, LP
Tel: (804) 771-4399
Fax: (804) 771-4804

\\\DC - 063803/000134 - 3306810 v1

Dominion Cove Point LNG, LP
701 East Cary Street, Richmond, VA 23219

Dominion

October 4, 2011

Mr. John Anderson
U.S. Department of Energy
Office of Fossil Energy
Docket Room 3F-056, FE-50
Forrestal Building
1000 Independence Avenue, S.W.
Washington, D.C. 20585

Re: Dominion Cove Point LNG, LP
FE Docket No. 11-128-LNG
Application for Long-Term Authorization to Export LNG
To Non-Free Trade Agreement Countries – Resubmitting of Appendices

Dear Mr. Anderson:

On October 3, 2011, Dominion Cove Point LNG, LP (DCP) submitted for filing with the U.S. Department of Energy, Office of Fossil Energy (DOE/FE), its application (Application) for long-term authorization to export liquefied natural gas (LNG) to countries with which the United States does not prohibit trade but also does not have a Free Trade Agreement at its Cove Point LNG Terminal located in Calvert County, Maryland.

DCP hereby requests to withdraw and replace Appendix B (Navigant Price Report) and Appendix C (ICF Economic Benefit Study) of the Application. DCP proposes to withdraw and replace these two appendices to correct minor errors on three pages of Appendix B and one page of Appendix C, so as to ensure that the most accurate and complete information is filed on the record under this docket. This supplemental filing does not affect the Application itself, or Appendices A, D, and E.

For ease of administration, we have enclosed an original and three bound copies of the Application as a whole, including the corrected versions of Appendices B and C. If you have any questions, please contact Amanda Prestage at 804-771-4416.

Respectfully submitted,

/s/ Matthew R. Bley

Matthew R. Bley
Authorized Representative of
Dominion Cove Point LNG Company, LLC,
The General Partner of Dominion Cove Point LNG, LP
Tel: (804) 771-4399
Fax: (804) 771-4804

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

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

APPLICATION OF DOMINION COVE POINT LNG, LP FOR
LONG-TERM AUTHORIZATION TO
EXPORT LIQUEFIED NATURAL GAS

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Kyle.Simpson@hoganlovells.com

Filed: October 3, 2011

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

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

APPLICATION OF DOMINION COVE POINT LNG, LP FOR LONG-TERM AUTHORIZATION TO EXPORT LIQUEFIED NATURAL GAS

Pursuant to Section 3 of the Natural Gas Act (NGA) 1/ and Part 590 of the Department of Energy's (DOE) regulations, 2/ Dominion Cove Point LNG, LP (DCP) hereby files this application (Application) with the DOE, Office of Fossil Energy (DOE/FE) for long-term, multi-contract authorization to engage in exports of domestically produced liquefied natural gas (LNG) of up to the equivalent of 1 billion cubic feet of natural gas per day, or approximately 7.82 million metric tons per annum. DCP proposes to export the LNG from its existing LNG terminal ("Cove Point LNG Terminal" or "Terminal") located in Calvert County, Maryland, over a twenty-five year term commencing on the date of the first LNG export or six years from the date that the authorization is issued, whichever is sooner. DCP requests authorization herein to export the LNG to any country that has or in the future develops the capacity to import LNG via ocean-going carrier and with which the United States (U.S.) does not prohibit trade but also does not have a Free Trade Agreement (FTA) requiring the national treatment for trade in natural gas.

1/ 15 U.S.C. § 717 (b).

2/ 10 C.F.R. Part 590 (2011).

DCP is requesting this authorization to act as agent on behalf of other entities who themselves hold title to the LNG, after registering each such entity with DOE/FE.

This Application represents the second part of DCP's two part request for authorization to export domestic natural gas in the form of LNG from its Terminal. On September 1, 2011, DCP filed in FE Docket No. 11-115-LNG its application requesting long-term, multi-contract authorization to export domestically produced LNG to any country (1) with which the United States has, or in the future enters into, an FTA requiring national treatment for trade in natural gas and (2) which has or in the future develops the capacity to import LNG via ocean-going carrier. Through the combination of the two applications, DCP requests authorization to export domestic natural gas as LNG to any country with which trade is not prohibited by U.S. law or policy.

In support of this Application, DCP respectfully shows as follows:

I. DESCRIPTION OF THE APPLICANT

The exact legal name of DCP is Dominion Cove Point LNG, LP. DCP is a limited partnership organized and existing under the laws of the State of Delaware with its principal place of business at 2100 Cove Point Road, Lusby, Maryland, 20657, and offices at 701 East Cary Street, Richmond, Virginia, 23219. DCP is a subsidiary of Dominion Resources, Inc. ("DRI"), one of the Nation's largest producers and transporters of energy. DRI is a corporation organized and existing under the laws of the Commonwealth of Virginia with its principal place of business at 100 Tredegar Street, Richmond, Virginia, 23219.

DCP owns the Cove Point LNG Terminal, as well as an 88-mile gas pipeline connecting the Terminal to the interstate pipeline grid. The construction and operation of the Cove Point LNG Terminal and pipeline was initially authorized in 1972 as part of a project to import LNG from Algeria and transport natural gas to U.S. markets. 3/ Shipments of LNG to the Terminal began in March 1978, but ceased in December 1980. In 2001, the FERC authorized the reactivation of the Terminal and the construction of new facilities to recommence LNG imports. 4/ In 2006, the FERC authorized the Cove Point Expansion project, which nearly doubled the size of the Terminal, expanded the capacity of the Cove Point pipeline, and provided for new downstream pipeline and storage facilities. 5/ In 2009, FERC authorized DCP to upgrade, modify, and expand its existing off-shore pier at the Terminal to accommodate the docking of larger LNG vessels. 6/

The Cove Point LNG Terminal currently has peak daily send-out capacity of 1.8 billion cubic feet (Bcf) and on-site LNG storage capacity of the equivalent of 14.6 Bcf (or 678,900 cubic meters of LNG). DCP's 88-mile gas pipeline, which has firm transportation capacity of 1.8 Bcf, connects the Terminal to the major Mid-Atlantic gas transmission systems of Transcontinental Gas Pipe Line Company, LLC ("Transco"), Columbia Gas Transmission, LLC ("Columbia") and Dominion Transmission, Inc. ("DTI"). DTI is an interstate gas transmission business unit of DRI.

DCP has experienced a significant decline in the level of LNG imports at the Terminal, especially since mid-2010. The decline in imports has been largely driven by the development of large quantities of shale gas in the U.S., together with the consistent demand for LNG (and higher gas prices) in other countries. In light of the plentiful, inexpensive supplies of domestic

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3/ The Federal Energy Regulatory Commission ("FERC") granted the original certificate for the Cove Point facilities in *Columbia LNG Corp. and Consolidated System LNG Co.*, 47 FPC 1624, *aff'd and modified*, 48 FPC 723 (1972).

4/ *Cove Point LNG LP*, 97 FERC ¶ 61,043, *reh'g*, 97 FERC ¶ 61,276 (2001), *reh'g*, 98 FERC ¶ 61,270 (2002).

5/ *Dominion Cove Point LNG, LP*, 115 FERC ¶ 61,37 (2006), *reh'g*, 118 FERC ¶ 61,007 (2007), *remanded sub nom. Washington Gas Light Co. v. FERC*, 532 F.3d 928 (D.C. Cir. 2008), *order on remand*, 125 FERC ¶ 61,018 (2008), *reh'g*, 126 FERC ¶ 61,036 (2009).

6/ *Dominion Cove Point LNG, LP*, 128 FERC ¶ 61,037, *reh'g*, 129 FERC ¶ 61,137 (2009).

gas in the U.S., LNG cargos have been more profitably delivered to other markets around the world, rather than to the U.S. This market dynamic has led DCP, like certain other existing LNG import terminals, 7/ to plan to export domestic natural gas.

II. COMMUNICATIONS AND CORRESPONDENCE

The names, titles and mailing addresses of the persons to whom correspondence and communications concerning this Application, including all service of pleadings and notices, are to be addressed are:

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These persons are designated to receive service and should be placed on the official service list for this proceeding.

7/ See *Sabine Pass Liquefaction, LLC*, FE10-111-LNG, DOE Order No. 2961 (May 20, 2011); *Sabine Pass Liquefaction, LLC*, FE10-85-LNG, DOE Opinion and Order No. 2833 (Sept. 7, 2010); *Freeport LNG Expansion, L.P. and FLNG Liquefaction, LLC*, FE10-160-LNG, DOE Opinion and Order No. 2913 (Feb. 10, 2011); *Lake Charles Exports, LLC*, FE11-59-LNG, DOE Opinion and Order 2987 (July 22, 2011).

III. EXECUTIVE SUMMARY

DCP plans to construct new facilities at its existing Terminal to provide gas liquefaction and LNG export services to customers that will provide their own gas supply. The Cove Point LNG Terminal is well positioned to provide the export customers with access to abundant and diverse domestic gas supply, and particularly well-situated to export gas production from the prolific Marcellus Shale. LNG exports will provide an additional outlet for growing gas supplies, and promote the continued development of the Nation's energy resources.

Following the construction of its liquefaction project, the Cove Point LNG Terminal will be operated as a bi-directional facility. The Terminal then can be used both to export LNG when domestic natural gas prices are low compared to prices elsewhere in the world (as they are now), and to import LNG to supplement domestic supply if supported by market conditions. This flexibility to respond to market conditions comports with DOE policy favoring the trade of natural gas on a market-competitive basis.

In recent years, the American gas market has experienced a tremendous boom, driven by the development of shale gas. North American gas reserves now are more than sufficient to satisfy domestic demand as it grows over time, as well as the export of LNG. The relatively small amount of LNG exports proposed by DCP could not possibly pose any threat to the security of domestic natural gas supply. Moreover, the DCP liquefaction project will result in a host of benefits to the public interest including: supporting the continued development of domestic natural gas and liquid hydrocarbons, the creation of thousands of new jobs, providing a huge economic stimulus, increasing tax revenues, and improving the U.S. balance of trade.

For these reasons, and as fully explained below and in the studies provided in the appendices attached to the Application, authorization of DCP's Application for the export of LNG is "not inconsistent with the public interest." To the contrary, authorization of the Application will advance the public interest significantly. Accordingly, DCP respectfully requests that the DOE/FE authorize the export, as proposed in the Application, by June 1, 2012. Granting the authorization in this time frame will facilitate DCP's contracting with its potential customers, and enable it to place its project in-service by the end of 2016 in response to market needs.

IV. DESCRIPTION OF PROPOSAL AND REQUESTED AUTHORIZATION

DCP's request for authorization here is part of its plan to develop, own and operate facilities at its existing Terminal to liquefy domestically produced natural gas and to load the resulting LNG onto tankers for export to foreign markets. DCP anticipates placing its liquefaction project in service by the end of 2016. DCP is currently engaged in Preliminary Front End Engineering Design ("Pre-FEED") studies for its liquefaction project. DCP also is in the process of conducting commercial negotiations with potential customers, and has received significant interest in its project. Long-term authorization by DOE/FE to export LNG is required at this time to facilitate the execution of the anticipated long-term agreements with customers.

DCP's liquefaction project will be integrated with some existing facilities at its Terminal. Domestic gas can be delivered to the Terminal through DCP's existing pipeline, which is bi-directional allowing gas to flow both away from and toward the Terminal. In addition, much of the existing facilities at the Terminal will be used as part of the liquefaction project. Existing facilities that may be utilized include the off-shore pier (with two berths), insulated LNG and gas piping from the pier to the on-shore Terminal and within the Terminal facility, the seven LNG storage tanks, on-site power generation, and control systems. In addition, DCP will construct new facilities to liquefy the natural gas delivered to the Terminal through the Cove Point pipeline. The new liquefaction facilities will be located on land already owned by DCP (which encompasses more than 1,000 acres).

DCP requests long-term, multi-contract authorization for the exportation of domestically produced LNG for a term of twenty-five years commencing on the date of the first LNG export or six years from the date that the authorization is issued, whichever is sooner. 8/ DCP proposes to export LNG of up to the equivalent of 1 Bcf of natural gas per day (Bcf/d), or approximately 7.82 million metric tons per annum (mtpa) of LNG. 9/ DCP previously requested, in FE Docket No. 11-115-LNG, similar export authorization limited to any country that has or in the future develops the capacity to import LNG via ocean-going carrier and with which the U.S. has, or in the future enters into, an FTA. By this Application, DCP requests authorization for export to the countries with which the U.S. does not have an FTA but with which trade is not prohibited by U.S. law or policy.

DCP anticipates entering into one or more long-term (likely of twenty years duration) 10/ contractual agreements with customers for natural gas liquefaction and LNG export services on a date that is closer to the start of export operations. These contracts will

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8/ DCP anticipates commencing exports by the end of 2016, but proposes that the requested authorization commence within six years of the date of authorization to allow for some potential delay in that schedule. In its prior order approving LNG exports to non-FTA countries for Sabine Pass, DOE/FE authorized the exports to commence on the earlier of the date of first export or five years from the date of issuance of the authorization. *Sabine Pass*, DOE Order No. 2961. In prior orders approving LNG exports to FTA countries, DOE/FE provided for the authorization to commence on the date of first exports not to exceed ten years (Sabine Pass and Lake Charles) or five years (Freeport) from the date that authorization is issued. *Sabine Pass*, Order No. 2833; *Freeport*, Order No. 2913; *Lake Charles*, Order No. 2987.

9/ Section 590.202(b)(1) of the DOE's regulations requires that applications for export or import authority set forth "the volumes of natural gas involved, expressed either in Mcf or Bcf and their Bcf equivalents." In recent orders authorizing LNG exports, DOE/FE has authorized levels set forth in Bcf of natural gas. *Freeport LNG Expansion, L.P. and FLNG Liquefaction, LLC*, Order No. 2913; *Lake Charles,* Order No. 2987 (July 22, 2011). DCP similarly requests authorization for the amount of natural gas of up to 1 Bcf per day. For purposes of LNG measurement, DCP has utilized here a conversion factor of 46.675 Bcf per metric ton of LNG but the actual conversion factor will depend on the composition of the natural gas.

10/ DCP requests export authorization for twenty-five years, even though it anticipates contracts of twenty years duration. The additional length of the export authorization will allow leeway needed because not all contracts will necessarily start on the date that the authorization will begin – *i.e.*, the sooner of (a) six years from authorization or (b) the date of first exports. The request for twenty-five years authorization is intended to ensure that the authorization will remain in place for all initial contracts of twenty years duration, even if they start sometime later.

provide for DCP to provide a service to its customers of liquefying natural gas and loading it onto LNG tankers at the Terminal for export, and may also include rights for the customers to import LNG for vaporization and send-out as regasified LNG into the domestic market, when desired by the customers.

The specific terms of DCP's future contracts with its customers for LNG exports – including, but not limited to, commencement and termination dates, pricing, volumes, and export destinations – will be determined by market conditions and negotiations between the parties. The countries of destination may not be specified in the contracts, so as to allow maximum flexibility to the LNG owner; but, in such instances, the contract will expressly provide that the export destination must be consistent with the export authorizations issued for DCP by DOE/FE and shall be reported on a monthly basis. This approach is consistent with the terms recently approved by DOE/FE for a similar LNG export authorization. 11/

DCP's customers will be responsible for procuring their own gas supplies and holding title to the gas that they will deliver to DCP for liquefaction and the LNG to be exported from the Cove Point LNG Terminal. For this purpose, the customers may enter into long-term gas supply contracts or procure spot supplies in the very large and liquid U.S. gas market. The gas will be delivered to DCP from the interstate pipeline grid and may be sourced from both conventional and non-conventional production. The Cove Point LNG Terminal is ideally located to provide access to a wide range of domestic supply sources.

The Terminal's connection through DCP's own pipeline with the interstate pipeline systems of Transco, Columbia and DTI provide access for DCP's customers to abundant and diverse domestic supplies. These major interstate pipelines connected to DCP are, in turn,

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11/ *Sabine Pass,* Order No. 2961.

interconnected with the pipeline grid, allowing gas to be sourced from a wide variety of regions. The DTI pipeline system, for instance, provides direct access to Appalachian (including Marcellus Shale) supply as well as connections to major pipelines transporting gas from the Gulf of Mexico area, the mid-continent, the Rockies and Canada. DTI also operates the largest underground natural gas storage system in the country, as well as a very liquid trading hub: Dominion South Point.

DCP is especially well positioned to export gas production from the Marcellus Shale, one of the largest shale plays with among the lowest development costs, as well as the very promising Utica Shale – as discussed in Section V.B.1. below. The pipeline industry in the Marcellus area has recently experienced a surge in pipeline expansions as the gas producers look for ways to get their gas to markets. With export authorization, DCP would be able to provide an additional outlet for these growing domestic gas supplies. In addition, LNG exports will increase the opportunities for more robust development of energy resources, not only natural gas but also natural gas liquids (NGL) and oil resources that are also found in the shale formations. These new NGL and oil resources can increase domestic liquids production, improve the balance of trade, benefit the American petrochemical industry, and reduce the need to import oil.

DCP does not intend to hold title to gas delivered to it for liquefaction or the LNG to be exported, and is requesting authorization to act as agent on behalf of its customers that will hold title to the gas and LNG. Consistent with the terms for an LNG terminal operator receiving export authorization in its role as agent for others established by DOE/FE in *Freeport LNG Development, LP*, FE 11-51-LNG, DOE/FE Order No. 2986 (July 19, 2011), DCP will register each LNG title holder for whom DCP seeks to export LNG with DOE/FE. Consistent with that order, the registration will include a written statement by the title holder acknowledging and agreeing to comply with all applicable requirements included in DCP's export authorization and to include those requirements in any subsequent purchase or sale agreement entered into for the exported LNG by that title holder. As DOE/FE has recognized, this registration process is responsive to current LNG markets and provides an expedited process by which companies seeking to export LNG can so do. 12/

DCP also will file under seal with DOE/FE any relevant long-term commercial agreements that it enters into with LNG title holders on whose behalf the exports will be performed, once the agreements are executed. DOE/FE has previously held that the commitment to file contracts once they are executed conforms with the requirement of 10 C.F.R. § 590.202(b) to supply transaction specific information "to the extent practicable." 13/

DCP has not at this time determined the particular facilities to be constructed, or the amount of liquefaction capacity of those facilities because its pre-FEED studies have not been completed. Depending on the outcome of those studies and its negotiations with customers, DCP anticipates constructing one to three liquefaction trains, offering liquefaction capability sufficient to allow the export of the equivalent of up to 1 Bcf/d. Given that DCP has not finalized its facility planning but needs to proceed with obtaining authorization for LNG exports for purposes of customer contracting, DCP requests here authorization to export up to 1 Bcf/d, which is the maximum volume it contemplates exporting at this time.

Once DCP has further developed its plans concerning the facilities to be constructed for its liquefaction project, DCP will request permission to commence the FERC's mandatory pre-filing process under the National Environmental Policy Act (NEPA) and subsequently file an

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12/ *Sabine Pass,* Order No. 2961 at 39-40; *Freeport,* Order No. 2986 at pages 7-8; *see also Freeport,* Order No. 2913 at pages 7-8. Of course, the entities that hold title to the LNG are not required to use the agency rights issued to the terminal and could choose to submit an export application for their own separate authorization. *Id.*

13/ *Yukon Pacific Corp*., ERA Docket No. 87-68-LNG, Order No. 350 (Nov. 16, 1989); Distrigas Corp., FE95-100-LNG, Order No. 1115 (Nov. 7, 1995); *Sabine Pass*, Order No. 2961 at 41.

application for the necessary FERC authorization for the construction and operation of the facilities to liquefy gas and provide for the exportation of domestically produced LNG from the Cove Point LNG Terminal. The authorization requested here, as a practical matter, will not be actionable until the FERC grants DCP authorization for the needed facilities. DCP does not anticipate receiving FERC authorization within the timeframe during which DOE/FE will act on this Application. Accordingly, consistent with prior orders by DOE/FE, the authorization requested here should be conditioned on DCP's receipt of all necessary FERC authorizations of the facilities needed for the export of LNG. 14/ In this way, the effective level of export authorization will be limited to the amount possible using the facilities approved by FERC and actually constructed, not to exceed 1 Bcf/d.

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

14/ *E.g., Sempra LNG Marketing, LLC*, FE10-110-LNG, DOE Opinion and Order No. 2885 at page 6 (Dec. 3, 2010).

V. CONSISTENCY WITH THE PUBLIC INTEREST

A. The Applicable Legal Standard

Section 3(a) of the NGA, 15 USC 717b(a), sets forth the following statutory standard for the review of this LNG export Application:

> [N]o person shall export natural gas from the United States to a foreign country or import any natural gas from a foreign country without first having secured an order of the [Secretary of Energy 15/] authorizing it to do so. The [Secretary] shall issue such order upon application, unless after opportunity for hearing, [he] finds that the proposed exportation or importation will not be consistent with the public interest. The [Secretary] may by [the Secretary's] order grant such application, in whole or in part, with such modification and upon such terms and conditions as the [Secretary] may find necessary or appropriate.

Section 3(a) establishes a rebuttal presumption that a proposed export of natural gas is in the public interest, and DOE must grant an export application unless opposing parties (if any) overcome that presumption. 16/ Moreover, DOE/FE has explained that opponents of an export application must make an affirmative showing of inconsistency with the public interest in order to overcome the rebuttable presumption favoring export applications. 17/

In implementing Section 3 of the NGA, the DOE issued policy guidelines explaining the approach that it will employ in evaluating applications for natural gas imports. 18/ DOE/FE has repeatedly reaffirmed the continued applicability of the guidelines and has consistently held that

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15/ The Secretary's authority was established by the DOE Organization Act of 1977, which transferred jurisdiction over gas import and export authorizations from the Federal Power Commission.

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

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

18/ "New Policy Guidelines and Delegation Orders Relating to the Regulation of Natural Gas," 49 Fed. Reg. 6684-01 (Feb. 22, 1984)(hereinafter the "Policy Guidelines").

they apply equally to export applications (though written to apply to imports). 19/ The Policy Guidelines were "designed to establish natural gas trade on a market-competitive basis and to provide immediate as well as long-term benefits to the American economy from this trade." 20/ The Guidelines provide that:

> The market, not government, should determine the price and other contract terms of imported [or exported] gas. U.S. buyers [sellers] should have full freedom – along with the responsibility – for negotiating the terms of trade arrangements with foreign sellers [buyers]. The federal government's primary responsibility in authorizing imports [exports] should be to evaluate the need for the gas and whether the import arrangement will provide the gas on a competitively priced basis for the duration of the contract while minimizing regulatory impediments to a freely operating market….
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> [T]he guidelines establish a regulatory framework for buyers and sellers to negotiate contracts based on traditional competitive and market considerations, with minimal regulatory constraints and conditions. The government, while ensuring that the public interest is adequately protected, should not interfere with buyers' and sellers' negotiation of the commercial aspects of import [export] arrangements. The thrust of this policy is to allow the commercial parties to structure more freely their trade arrangements, tailoring them to the markets served. Thus, with the presumption that commercial parties will develop competitive arrangements, parties opposing an import [export] will bear the burden of demonstrating that the import [export] arrangement is not consistent with the public interest. 21/

The Policy Guidelines further explain:

> The policy cornerstone of the public interest standard [of NGA Section 3] is competition. Competitive import [export] arrangements are an essential element of the public interest, and natural gas imported [exported] under arrangements that provide

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19/ *Yukon Pacific*, Order No. 350; *Phillips Alaska*, Order No. 1479; *ConocoPhillips Alaska*, Order No. 2500, *Sabine Pass*, Order No. 2961.

20/ Policy Guidelines at 6684.

21/ *Id.* at 6685. The parenthetical references to exports are added to reflect the applicability of the Policy Guidelines to exports. *See* note 19, *supra*.

> for the sale of gas in volumes and at prices responsive to market demands largely meets the public interest test….
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> This policy approach presumes that buyers and sellers, if allowed to negotiate free of constraining governmental limits, will construct competitive import [export] agreements that will be responsive to market forces over time. The specific commercial terms and conditions of a particular arrangement should be negotiated by the parties pursuant to discrete requirements of the buyer's [and seller's] market and not directed by government regulators. 22/

In addition to following the Policy Guidelines, DOE/FE has explained that its review of export applications under its delegated authority focuses on "the domestic need for the gas; whether the proposed exports pose a threat to the security of domestic natural gas supplies; and any other issue determined to be appropriate, including whether the arrangement is consistent with DOE's policy of promoting competition in the marketplace by allowing commercial parties to freely negotiate their own trade arrangements." 23/

B. Exports From Cove Point Will Promote the Public Interest

Granting DCP's requested authorization to allow LNG exports will be consistent with, and indeed advance, the public interest. Allowing DCP and its customers to freely negotiate contracts to respond to market conditions and utilize the Cove Point LNG Terminal for exports when warranted by prices will be consistent with the pro-competition focus of the Policy Guidelines. And North American gas reserves are more than adequate to satisfy U.S. demand, even under the most aggressive demand scenarios, including a domestic LNG export industry. The exports proposed by DCP, of only up to 1 Bcf-equivalent per day, could not possibly pose a threat to domestic gas supply security. Indeed, by providing a steady, incremental demand for

22/ *Id.* at 6687.

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

gas, LNG exports from the Cove Point LNG Terminal will help support ongoing supply development and, thereby, help keep U.S. gas prices stable. Moreover, approval of the requested authorization will promote the public interest in numerous other ways.

To help demonstrate that its liquefaction and LNG export project is consistent with the public interest, DCP commissioned and provides here three studies by independent, expert consultants. The first study, prepared by Navigant Consulting, Inc. ("Navigant") is the "North American Gas Supply Overview and Outlook To 2040," attached as Appendix A ("Navigant Supply Report"). The Navigant Supply Report builds on Navigant's most recent forecast of the North American gas market (its Spring 2011 Reference Case) 24/ to evaluate the adequacy of supply to satisfy domestic demand as well as proposed LNG exports. The Navigant Supply Report also provides benchmark comparisons to other publicly available supply forecasts, including the 2011 Annual Energy Outlook (AEO) issued by the Energy Information Administration (EIA). The second study, also prepared by Navigant, is the "North American Gas System Model to 2040" attached as Appendix B ("Navigant Pricing Report"). The Navigant Pricing Report (which is to be read in conjunction with the Navigant Supply Report) analyzes the possible price effects of proposed LNG exports. The modeling conservatively projects the price effects of DCP's proposed LNG exports under a variety of scenarios and concludes that any possible price increases would be modest. Third, ICF International prepared an "Economic Benefits Study" quantifying the economic benefits associated with the export of LNG by DCP, which is attached as Appendix C.

24/ As part of its internal integrated energy modeling process for natural gas and electricity, Navigant develops a forecast of the North American natural gas market in the spring and fall of each year. The Supply Report provided here builds on Navigant's Spring 2011 Reference case forecast and Navigant's ongoing market resource. Navigant Supply Report, "Summary of Assignment."

The benefits of DCP's proposal, as detailed in the Economic Benefits Study, include the following:

- Direct and Indirect Job Creation: At its peak of construction activity, the short-term economic impacts from construction and operation of the DCP liquefaction project have the potential to support between 2,700 and 3,400 "job years" 25/ in Calvert County, Maryland, as well as approximately 1,000 additional jobs in the rest of the State of Maryland. Moreover, the significant inter-linkage between various economic sectors provides the potential to support an additional 3,850 to 4,820 jobs in the rest of the Nation during peak construction. During operations from 2018 through 2040, the economic activity at the Cove Point LNG Terminal is estimated to result in 320 jobs across the Nation. 26/ Moreover, economic activity associated with the long-term upstream supply of natural gas for exports from the Terminal would result in an average of over 18,000 new jobs annually. 27/
- Economic Stimulus From Construction: The DCP liquefaction project has the potential to create significant short-term economic activity in the region and throughout the state during the construction phase. In 2015, the DCP facility will create between $183 and $230 million in "value added" (meaning the contribution to Gross Domestic Product, calculated as the difference between the

25/ In the Economic Benefits Study, ICF calculates the employment impact in terms of a "job-years", which is defined as the amount of work performed by one full-time individual in one year (typically 2,080 hours). Economic Benefits Study at 1. For ease of presentation, ICF's results in "job-years" are referred to in this Application simply as jobs.

26/ All these employment results are detailed in the Economic Benefits Study at 11, Table 2 "Annual Job-Year Impacts, Facility Construction/Operation (Job-years)."

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

output generated from expenditures and the expenditures for intermediate goods and services) within Calvert County and an additional $80 to $100 million in the rest of Maryland. Annual activities during operations from 2018 through 2040 are expected to generate an additional $22 million in value added annually for Calvert County, Maryland, and over $47 million for the U.S. in total. 28/

- Indirect Economic Stimulus: In aggregate, $44 billion in total value added is projected to result from upstream expenditures of $32 billion needed to supply the LNG exports over the 25-year period. 29/ The top sectors, as a function of total value added, include real estate and equipment rentals; oil and gas support activities; educational, medical, hotel, food, and other services; wholesale and retail trade; and IT, scientific, environmental, and waste management services.
- Promote domestic production of petroleum and liquid hydrocarbons: Incremental production of hydrocarbon liquids from 2016 through 2040 associated with LNG exports by DCP is estimated at 8.5 million barrels per year, with an average projected market value of $1.2 billion per year. 30/ This domestic production of NGLs will help reduce reliance on foreign sources of oil and help U.S. industry, particularly the petrochemical industry.
- Improvement in the U.S. Balance of Trade: LNG exports, along with associated NGL production, will help realign the U.S. balance of trade by a range of $2.8

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

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

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

billion to nearly $7.1 billion per year. 31/ The value of the exports is estimated to reduce the total U.S. trade deficit (compared to the 2010 deficit) by between 0.6 and 1.4 percent. 32/

- Increased Tax and Royalty Revenues: Estimated tax revenues generated as a result of the construction phase of the DCP liquefaction project peak in 2014 with a total of $130-$163 million nationally. 33/ Total U.S. taxes are estimated to increase by nearly $11 million per year from 2018-40, not including income taxes, property taxes, or gross receipt taxes. 34/ In addition, the long-term operation of the Terminal is expected to produce up to $40 million per year of property tax revenues. 35/ In addition, upstream economic activity associated with gas production to support the incremental LNG exports is associated with $25 billion in government royalty and tax revenues to federal, state, and local governments over the 25-year period, with an average of approximately $1 billion in annual revenues. 36/ Another $9.8 billion in royalty income over the 25 years will be provided to landowners in the form of mineral leases. 37/

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

32/ *Id.* at 2.

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

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

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

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

37/ Economic Benefits Study at 21.

- Environmental Benefits: As the cleanest-burning fossil fuel, natural gas significantly reduces total greenhouse gas emissions when used as a substitute for coal or fuel oil. To the extent that the up to 1 Bcf/d of LNG exported from the Cove Point LNG Terminal is used as substitute for coal and fuel oil in other countries, it will reduce global greenhouse gas emissions significantly over the requested 25-year export term.

1. Projected Gas Supplies

The main focus of the DOE/FE's public interest analysis for gas export authorizations has been the projected domestic need for the gas. DOE has historically determined whether there is a domestic need for the gas proposed for export by comparing the total volume of natural gas reserves expected to be available to produce with the expected gas demands during the proposed period of exports. 38/ In light of the dramatic recent successes of domestic gas production, such an analysis clearly demonstrates that the sufficient reserves now exist to satisfy domestic demand as well as the proposed LNG exports.

The most recent estimate by the EIA of dry natural gas reserves in the United States is 2,543 trillion cubic feet ("Tcf"). 39/ This latest EIA reserve estimate compares to EIA's 2005 reserve estimate of about 1,600 Tcf. 40/ The dramatic increase of nearly sixty percent in just six years has been driven by the phenomena of domestic shale gas, resulting from the refinement and improvement in drilling technologies. EIA's 2011 estimate of technically

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38/ *Yukon Pacific*, Order No. 350; *Phillips Alaska*, Order No. 1473; *ConocoPhillips Alaska*, Order No. 2500.

39/ Newell, EIA, *Shale Gas and the Outlook for U.S. Natural Gas Markets and Global Gas Resources*, presentation to the Organization for Economic Cooperation and Development (OECD), June 21, 2011, available at http://www.eia.gov/pressroom/presentations/newell_06212011.pdf. See also US EIA, 2011 AEO, http://www.eia.doe.gov/forecasts/aeo/pdf/0383(2011).pdf

40/ *See* Newell presentation, *supra.* at 13.

recoverable reserves includes 827 Tcf of shale reserves, compared to the 347 Tcf of shale reserves included in its AEO just one year before and the less than 100 Tcf included as recently as 2006. 41/ Similarly, in 2009, the Potential Gas Committee of the Colorado School of Mines estimated that the recoverable natural gas resource in North America is 2,170 Tcf (an increase of 89 Tcf over their previous evaluation), including 687 Tcf of shale gas. 42/

The increase in reserves has mirrored the dramatically increased production levels in recent years, also driven by shale gas. U.S. natural gas production increased from about 50.5 Bcf/d in May 2005 to about 60.9 Bcf/d in May 2011. 43/ Shale gas production from eight major basins under development in North American grew from 3 Bcf/d in the first quarter of 2007 to 16.5 Bcf/d in first quarter of 2011, an increase of more than 525 percent in just over four years. 44/ Total U.S. shale production in the first quarter of 2011 was approximately 18 Bcf/d. 45/

Navigant projects gas production to continue to grow steadily. In its Reference Case, Navigant projects North American produced supply to reach 105 Bcf/d by 2040, with U.S. production of more than 81 Bcf/d. 46/ Navigant expects more than half of the 2040 U.S. production of over 29.5 Tcf to be from shale gas plays. EIA also projects shale gas production to continue to increase strongly through 2035 in its 2011 AEO reference case, growing almost fourfold from 2009 to 2035. EIA's reference case forecasts total domestic natural gas production to grow from 21.0 Tcf in 2009 to 26.3 Tcf in 2035, with shale gas production

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41/ *See* Newell presentation, *supra.* at 13, and the 2011, 2010, and 2006 editions of EIA's AEO.

42/ Potential Gas Committee press release, April 27, 2011, http://potentialgas.org/

43/ Navigant Supply Report at 8 & Figure 4.

44/ *Id.* at 9 & Figure 6.

45/ Id. at 15.

46/ *Id.* at 4-5, Figures 1 and 2.

growing to 12.2 Tcf in 2035, amounting to 47 percent of total U.S. production -- compared to its 16-percent share in 2009. 47/

As explained in the Navigant Supply Report (at page 15, Figure 10 & Table 1), EIA has historically been conservative when adding into its projections the latest information about the domestic shale gas resource. As recently as the 2010 AEO, EIA projected shale production **for 2035** of about 16.5 Bcf/d – less than the actual production this year. The 2011 AEO now projects shale production in 2035 of about 33.5 Bcf/d (more than twice what it predicted the prior year). Yet, the current shale production levels (of 18 Bcf/d) have already outpaced the forecast for 2011 in EIA's 2011 AEO of 15 Bcf/d. In contrast, the Navigant Supply Report forecasts shale production of more than 46 Bcf/d in 2035. Navigant projects more shale gas to be brought on by 2020 than EIA does in its 2011 AEO; after 2020, the growth rates projected by Navigant and EIA are roughly the same. 48/

One particularly important shale play is the Marcellus Shale formation, which is located in Appalachia near the Cove Point LNG Terminal 49/ and essentially underlies the DTI system which interconnects with the Cove Point pipeline. Marcellus production has increased from almost nothing in mid-2008 to over 2.5 Bcf per day in June 2011. 50/ Just this run-up in initial Marcellus production dwarfs the amount of LNG that DCP proposes to export. More significantly, a recent study conducted by Penn State University estimates that Marcellus

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47/ US EIA, 2011 AEO, Executive Summary, http://www.eia.doe.gov/forecasts/aeo/pdf/0383(2011).pdf

48/ Navigant Supply Report at 14-15, Figure 10.

49/ *See* Navigant Supply Report at 10-11.

50/ Navigant Supply Study at 30, Figure 16. *See also The Pennsylvania Marcellus Shale Natural Gas Industry: Status, Economic Impacts and Future Potential*, Penn State University, July 20, 2011, Executive Summary (graphing the increase in Marcellus gas, and NGL production, from Q1 2009 to Q4 2010).

production will grow from 327 MMcf/d during 2009 to 13.5 Bcf/d by 2020. 51/ According to this study, the Marcellus Shale has the potential to be the second largest natural gas field in the world (behind only the South Pars/Asalouyeh field shared between the nations of Iran and Qatar) and its gas, when converted to British Thermal Units (BTUs), could be equivalent to the energy content of 87 billion barrels of oil, enough to meet the demand of the entire world for nearly three years. 52/ Similarly, Dr. Terry Engelder of Penn State has estimated that the Marcellus Shale alone has a 50 percent chance of containing 489 Tcf of recoverable gas. 53/ In 2010, the U.S. consumed about 24 Tcf, or less than 5 percent of the Marcellus potential. 54/ The recent estimate by the U.S. Geological Survey ("USGS") of the "mean undiscovered natural gas resource base" for the Marcellus of 84 Tcf is not (contrary to some press reports) inconsistent with larger reserves estimates by EIA and others: indeed, the USGS estimate seems to be *additive* to the EIA estimate. 55/

Other new shale resource plays are being identified at a high rate. EIA's 2011 map of shale gas plays included several shale plays (including the Niobrara, Heath, Tuscaloosa, Excello-Mulky and Monterey) that were not included on the 2010 version, and enlarged significantly the

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

52/ *Id.*

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

54/ Navigant Supply Report at 11.

55/ *Id.* at 28. *See also* Marcellus Shale Coalition press release, "Myth vs. Fact: USGS/EIA Marcellus Data" (Aug. 30, 2011), available at http://marcelluscoalition.org/2011/08/myth-vs-fact-usgseia-marcellus-data/

areal extent of other plays (notably the Eagle Ford). 56/ As Navigant concludes, "North America is clearly in the early phases of discovery for this resources." 57/

Nevertheless, Navigant's forecast conservatively assumes the addition of no new gas supply basins (shale or otherwise) beyond those already identified. Moreover, Navigant's estimate of the production capacity for each shale play is based on currently available empirical production data. 58/ This approach has the effect of under-estimating the production of shale plays that are now in the early phase of development. A key example of significant importance to the export of LNG from the Cove Point LNG Terminal is the Utica Shale, which is well-situated (very near the DTI system) to provide supply to DCP's customers.

Navigant assumes in its Pricing Study that the Utica Shale will produce only 0.9 Bcf/d in 2040 (from its Canadian portion, with no production at all in the U.S.), while noting that "it is arguable that the Utica Shale could be producing many multiples of that number by that date, given the rapid run-up of development of other liquids-rich shales such as the Eagle Ford." 59/ Public statements by production companies active in developing the Utica support the view that it will be a significant addition to future production. Numerous projects have been announced in recent weeks that reflect burgeoning interest in the development of the Utica Shale. 60/ Chesapeake Energy Corporation ("Chesapeake") has leased 125 million acres of the Utica in

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56/ Navigant Supply Report at 10 & Figure 7.

57/ *Id.* at 10.

58/ Navigant Pricing Report at 7. The Pricing Report does assume the addition of some new supply in the Aggregate Export and Extreme Demand scenarios (described below), but only from existing, quantified reserves.

59/ Navigant Pricing Report at 5 and 8. *See also* "Utica Shale – The Natural Gas Giant Below the Marcellus?", available at http://geology.com/articles/utica-shale/

60/ Navigant Supply Report at 28-29. The report notes, in addition to the Chesapeake announcement, that (1) CONSOL Energy and Hess Corporation have agreed to form a joint venture that will develop nearly 200,000 acres in the Utica Shale and (2) Petroleum Development Corporation has executed agreements to acquire up to 100,000 acres in the wet gas and oil phases of the Utica Shale.

eastern Ohio and has five rigs operating in a liquids-focused effort that is likely to produce natural gas as well; Chesapeake indicates it may have 40 rigs in the Utica by 2014. Chesapeake's CEO recently announced that the Utica Shale could be worth $500 billion, that he expects around ten companies to compete in the play, and that Chesapeake alone plans to drill as many as 12,500 wells in the Utica. 61/ Moreover, an economic impact study recently released by the Ohio Oil & Gas Energy Education Program estimated that by 2015 development of Ohio's Utica formation will create more than 204,000 jobs, increase economic output by over $22 billion, wages by over $12 billion, and local government tax revenues by $240 million. 62/ If these projections are even close to correct, the Utica formation will be another significant source of supply for LNG exports by DCP, which is not included in the Navigant analyses. And providing a market demand for gas to help support development of the Utica Shale will be another benefit of DCP's export project.

2. Projected Gas Demand

U.S. gas demand in 2011 was approximately 65.6 Bcf/d. Navigant projects demand to increase steadily in the future, with the overwhelming majority of the growth expected to come from electric generation. 63/ Navigant expects electric generation gas demand to increase at an annual rate of 4.9 percent through 2015, and at an annual rate of 2.1 percent through 2040. In contrast, Navigant projects North American gas industrial demand to grow annually by an

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61/ "McClendon Values Utica Shale at Half a Trillion Dollars, NGI Reports," Sept. 21, 2011, available at http://www.businesswire.com/news/home/20110921006942/en/McClendon-Values-Utica-Shale-Trillion-Dollars-NGI

62/ "Ohio's Natural Gas and Crude Exploration and Production Industry and the Emerging Utica Gas Formation, Economic Impact Study, Ohio Oil & Gas Energy Education Program (Sept. 2011), available at http://www.oogeep.org/downloads/file/Economic%20Impact%20Study/Ohio%20Natural%20Gas%20and%20Crude%20Oil%20Industry%20Economic%20Impact%20Study%20September%202011.pdf

63/ Navigant Supply Report at 15-16.

average rate of 0.5 percent, and residential, commercial and vehicle demand for gas to grow at just 0.2 percent per year.

Navigant's sector-by-sector outlook for gas demand is explained in the Navigant Supply Report at pages 16-17 and illustrated in its Figure 11. In total, Navigant projects U.S. consumption (in its Reference Case) to increase to approximately 30.7 Tcf by 2040, compared to about 24 Tcf this year. Supply and demand are two parts of a single dynamic, with reliable demand a key to underpinning the growth of reliable supply and a sustainable gas market. Navigant concludes that LNG exports from the U.S. have the potential to provide a steady, reliable baseload market that will underpin on-going supply development, and help keep domestic gas prices stable. 64/ In the coming years, LNG exports should provide a new market in the currently oversupplied natural gas market in the U.S., in which the slow development of new markets for natural gas is the only thing currently restricting even more gas resource development. 65/ An example is the current situation with Marcellus supply, where producers are searching for new markets for their gas (as evidenced by the surge in pipeline expansions in the area). With LNG export authorization, DCP would be able to provide an additional outlet for these growing domestic gas supplies, encouraging further development.

Navigant also evaluated the potential concern that exporting LNG from North America will tend to bring overseas LNG pricing, which has historically been linked to higher-priced oil, into the North American gas market. 66/ The U.S. is likely to remain the most liquid market for natural gas in the world, supported by its superior infrastructure (particularly storage) and dependable demand. Given the level of North American gas reserves compared to any

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64/ *Id.* at 3 & 17; Navigant Pricing Report at 9.

65/ Navigant Supply Report at 17.

66/ Navigant Pricing Report at 9.

reasonable expectation of demand (discussed below), Navigant concludes that domestic consumers will not be exposed to overseas LNG prices. Navigant's modeling and market research indicates that it is very unlikely that the projected levels of LNG exports will increase the need for significant amounts of imported LNG. It is more likely that spot LNG cargos from overseas will land from time to time in the U.S. and accept U.S. domestic pricing, as overseas LNG production capacity is projected to grow. DOE/FE itself reached a similar conclusion in its recent *Sabine Pass* order. 67/

3. Supply Is More Than Sufficient to Satisfy Demand, Including LNG Exports

EIA's current estimate of reserves of 2,543 Tcf represents more than 100 years of supply at current usage rates of approximately 24 Tcf per year. Even at the 2040 rate of consumption estimated by Navigant of 30.7 Tcf per year, these current reserves represent 83 years of supply. Navigant's "Extreme Demand Case" (which, as discussed below, includes 7.1 Bcf/d of LNG exports, greenhouse gas regulation, and dramatically increased use of natural gas vehicles) projects 2040 demand of 32.7 Tcf. Even this aggressive demand estimate for 2040 would represent just 1.3 percent of EIA's current estimate of reserves, leaving about 77 years of supply to meet demands at that level. This result also assumes very conservatively, and unrealistically, that the amount of reserves will not increase by 2040 over EIA's current estimate.

This showing of the comparative balance between supply reserves and demand, including for the proposed gas exports, convincingly demonstrates that the requested authorization is consistent with the public interest. DOE/FE historically has focused on this issue of the adequacy of reserves compared to expected demand, and authorized exports based

67/ *Sabine Pass*, Order No. 2961 at 34.

on much less robust supply scenarios. 68/ For instance, in 1989, DOE/FE authorized the export of LNG from the North Slope of Alaska of up to 14 mmta in the face of forecasts claiming that proved reserves would be entirely depleted by the end of the next decade, reasoning that new reserves would be added over time. 69/ Just this year, of course, DOE/FE authorized the export of LNG from Sabine Pass based on "substantial evidence showing an existing and projected future supply of domestic natural gas sufficient to simultaneously support the proposed export and domestic natural gas demand both currently and over the 20-year term of the requested authorization." 70/

All available evidence and projections show that current gas reserves are ample to support all expected demand, including LNG exports, at least through 2040. Accordingly, there is no "domestic need" for the gas that DCP proposes to export. And the exports do not pose any possible threat to the security of domestic natural gas supplies. Therefore, the proposed exports are consistent with the public interest.

4. Any Effect of LNG Exports From DCP On Domestic Prices Would Be Minor

The Policy Guidelines (as reflected in the quotations in Section V.A above) establish that the federal government's policy is not to manipulate energy prices by approving or disapproving import or export applications. Rather, the Nation's policy is that markets, and not the government, should allocate resources and set prices, and that free trade in natural gas on a market-competitive basis benefits consumers and promotes the public interest.

Although concern about possible price levels appears arguably outside the scope of the Policy Guidelines, DOE/FE evaluated in its recent order authorizing exports from Sabine Pass the

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68/ *See Yukon Pacific*, Order No. 350; *Phillips Alaska*, Order No. 1473.

69/ *Yukon Pacific*, Order No. 350 at 19-22.

70/ *Sabine Pass*, Order No. 2961 at 29.

projected impact of LNG exports on domestic gas prices. In that order, DOE/FE concluded that the export authorization would result in "a modest increase" in domestic gas prices reflecting the increasing marginal costs of additional domestic production for the LNG exports. 71/ This modest projected increase was viewed as not inconsistent with the public interest.

The attached Navigant Pricing Report provides a detailed analysis of the possible effect on prices of LNG exports in general, and from the Cove Point LNG Terminal in particular. The price forecasts build on Navigant's Spring 2011 Reference Case and the Navigant Supply Report previously described. Thus, the pricing forecasts incorporate Navigant's approach of conservatively assuming the addition of no new gas supply basins beyond those already identified, and estimating the production capacity for each shale play based only on available empirical production data. As a result, the forecasted price effects likely overstate the impact on prices, since additional new reserves and production will almost certainly be added over time. In addition, Navigant does not introduce any currently unannounced infrastructure projects into its model and limits infrastructure expansion to instances where existing pipelines become constrained, then adding only sufficient capacity to relieve the constraint. 72/ This conservative approach ignores the possibility of major new infrastructure that can restrain possible future price increases by transporting growing supplies to areas of high demand.

The Navigant Pricing Report models four scenarios: (1) a Reference Case, (2) the Cove Point Export Case, (3) the Aggregate Export Case, and (4) the Extreme Demand Case. In all scenarios, Navigant studied price impacts over time through 2040 at Dominion South Point (a major, active trading hub on the DTI system) to focus on the potential price effect on the key

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

72/ Navigant Pricing Report at 9-10.

market in the vicinity of the Cove Point LNG Terminal, as well as the Henry Hub (the underlying physical location of the natural gas NYMEX futures contract). Information on the types of supply and sectors of demand over time is detailed for each scenario. All prices in the report (and referenced in this summary of the results) are adjusted for assumed future inflation and shown in constant 2010 dollars.

The Reference Case reflects Navigant's Spring 2011 modeling with steadily increasing demand, as previously described. This case also assumes the operation of two North American LNG export facilities – Sabine Pass in Louisiana and Kitimat in British Columbia – beginning in 2015. The Cove Point Export Case adds 1 Bcf/d of additional LNG exports from the Cove Point LNG Terminal. The Aggregate Export Case adds another 3.4 Bcf/d of LNG exports, to reflect proposals by the Lake Charles LNG facility in Louisiana and the Freeport LNG facility in Texas, with all the capacity assumed to be added between 2017 and mid-2019. Finally, the Extreme Demand Case further increases demand to reflect both increased natural gas vehicle demand (taken from an EIA 2011 AEO scenario) and higher electric generation gas demand resulting from greenhouse gas reduction legislation. Navigant also modeled variations of the Aggregate Export Case and the Extreme Demand Case with no LNG exports from Cove Point, to isolate the possible price impact of approval of this Application.

In its beginning Reference Case, 73/ Navigant projects average annual prices at the Henry Hub to remain below $5.00 per MMBtu through 2020, to remain below $6.00 per MMBtu until 2029, and to reach $8.64 per MMBtu in 2040. These prices reflect assumptions of steadily increasing demand, with consumption rising from about 24 Tcf in 2011 to 30.7 Tcf in 2040. Prices at Dominion South Point are projected to be slightly lower in 2015 than in 2011, then to

73/ See Navigant Pricing Report at 14-16.

rise more slowly than the Henry Hub prices throughout the forecast period, as the abundant Marcellus Shale supply increasingly becomes the dominant supply in the region. The projected Dominion South Point prices reach only $6.01 per MMBtu in 2040, significantly lower than the Henry Hub price. The negative basis at Dominion South Point is expected to develop due to the supply strength and ramping up of Marcellus production resulting in Dominion South Point prices that are increasingly lower over time than Henry Hub prices that are influenced by broader market factors. 74/

These relatively low projected prices (as well as all the prices detailed below) should be contrasted with actual market prices, as well as expectations for the future, just a few years ago. Annual average Henry Hub spot prices per MMBtu, prior to the recent shale gas boom, were $7.91 in 2005, $6.62 in 2006, $6.20 in 2007, and $8.25 in 2008. 75/ Even more dramatically, the EIA as recently as its 2009 AEO reference case projected that prices would be $6.96 in 2010, $7.77 in 2020, and $9.68 in 2030 (adjusted to 2010 dollars for purposes of comparison). 76/ In contrast, Navigant's Cove Point Export Case projects prices in 2030 to be $6.61 – much less than was projected in the 2009 AEO reference case. Even in the Extreme Demand Case, the 2030 prices projected by Navigant are less than EIA's projection in 2009.

In the Cove Point Export Case, Navigant added 1 Bcf/d of exports from Cove Point to the Reference Case starting in 2016, with no other changes in the model. 77/ This small

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74/ *Id. at 5.*

75/ *Platt's Inside FERC*.

76/ Annual Energy Outlook 2009 with Projections to 2030, Table 13, U.S. Energy Information Administration, available at http://www.eia.gov/oiaf/archive/aeo07/aeoref_tab.html, cited in Navigant Pricing Report at 5-6 & Table 2.

77/ *See* Navigant Pricing Report at 17-20. The primary Cove Point Export Case assumes the Cove Point LNG Terminal is bi-directional, allowing both exports and imports as warranted by market prices and customer decisions. Navigant also modeled an Alternative Case for the Cove Point Export Case, under which Cove Point is assumed to increase in demand -- adding 1 Bcf/d to the 2011 demand of 65.6 Bcf/d and projected 2040 demand of 84 Bcf/d in the Reference Case – results in a small projected increase in prices. In this scenario, Henry Hub prices exceed $6.00 per MMBtu (still a relatively low price compared to recent years prior to the shale boom) for the first time in 2027 – two years earlier than in the Reference Case. Compared to the Reference Case, Henry Hub prices with the Cove Point exports added are projected to be 5.7 percent higher in 2020, 4.1 percent higher in 2030, and 6 percent higher in 2040. For Dominion South Point, the projected prices increases are larger initially but smaller over time, as Marcellus supplies dwarf the exports: 6.2 percent in 2020, 3.6 percent in 2030, and 2.7 percent in 2040. These percentage increases are compared to historically low gas prices.

DCP believes that the projections likely overstate the price effect resulting from LNG exports from the Cove Point LNG Terminal, both at the outset and longer term. To begin with, the new demand is added in a block, upsetting an existing supply/demand balance in the model, resulting in seemingly large price jumps. Yet, in reality unlike economic modeling, given the long lead time associated with an LNG liquefaction project like DCP's, as well as the current ability of shale production to increase if demand is added, producers may plan in advance and add incremental supply to coincide with onset of LNG export operations – minimizing the initial price increase associated with new LNG export demand projected by Navigant. 78/ Producers presumably will have long-term contracts to supply natural gas to DCP's export customers and, therefore, will be obligated to match production to export related demand. More fundamentally, Navigant's conservative assumptions noted above about supply (essentially no

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operate only as an export facility, with no LNG imports at the Terminal. No significant differences in supply, demand or prices resulted from this changed assumption. *Id.*

78/ Navigant itself makes this point in its Pricing Report at 7.

new supply over time) and infrastructure (no unannounced projects added) inherently overstate the price effect, especially in the longer run. Accordingly, the price impacts forecast in the Navigant model should be considered the maximum possible impacts.

Navigant's third scenario, the Aggregate Export Case, assumes that the export projects proposed by Lake Charles LNG facility in Louisiana and the Freeport LNG facility in Texas also are built and added into demand between 2017 and mid-2019. 79/ This scenario makes no judgment about whether any of the proposed facilities will be approved, supported by customers, financed and constructed, but rather conservatively assumes that they all will come on-line. Moreover, Navigant assumes (conservatively for purposes of modeling the price effects) that all the export facilities will operate at 90 percent of capacity – a very high utilization rate since customers likely would not take advantage of contractual rights to export as much as operationally possible at all times. The model projects increases, above the Cove Point Export Case, in Henry Hub prices of 11 percent in 2020, 3.5 percent in 2030 and 5.3 percent in 2040. The projected price effects at Dominion South Point are 9.9 percent in 2020, 6.5 percent in 2030, and 5.6 percent in 2040. The near-term price effect, again, is likely overstated as it reflects the sudden addition, into a model of equalized supply and demand, of significant new demand from North American LNG exports (here, a total of 7.1 Bcf/d) in a very short period of time. Increased production to meet the LNG exports as they come on-line would reduce the near-term (2020) effect. And, again, new supply conservatively omitted from the model would reduce the price effect in later years.

Navigant also modified its Aggregate Export Case to eliminate any LNG exports from Cove Point – to allow a comparison of what portion of the projected price increase is

79/ See Navigant Pricing Report at 21-25.

attributable the LNG export projects other than DCP. 80/ The "Aggregate Export Without Cove Point Case" also may be compared to the "Cove Point Export Case" to compare the scenario of adding to the Reference Case either (a) just Cove Point exports and (b) just the Freeport and Lake Charles projects. The Henry Hub prices are notably lower in all years with Cove Point exports compared to the scenario with the other export projects and not Cove Point; the Dominion South Point price is lower in 2020, but higher in 2030 and 2040, with just Cove Point exports compared to with the other export projects but not Cove Point. These results logically show that exports from DCP affect prices at Dominion South Point more than exports from the Gulf Coast would. Of course, projected Dominion South Point prices are lower than Henry Hub over time as a result of access to the nearby Marcellus Shale, while the Henry Hub prices are more affected by the assumption of three Gulf coast export projects.

For the fourth scenario, Navigant included an Extreme Demand Case showing the highest projected prices, with assumed significant new gas demand as a result of greenhouse gas regulation and dramatically increased natural gas vehicle usage. 81/ In this scenario, U.S. gas demand increases from the 2011 level of 65.6 Bcf/d to 74.5 Bcf/d in 2020, 83.4 Bcf/d in 2030, and 90.1 Bcf/d in 2040. As a result, Henry Hub prices increase by another 5.4 percent in 2020, 17.4 percent by 2030, and 16.2 percent by 2040. The price increases at Dominion South Point are much less pronounced in the later years: increasing by the same 5.4 percent in 2020, but 11.9 percent in 2030, and just 4.8 percent in 2040. Navigant's approach of adding no new, not currently known, supply in this scenario again inflates the results and seems particularly conservative, and unrealistic, in the assumed world of much greater demand for gas.

80/ *Id.* at 24-25.

81/ *Id.* at 26-30.

Furthermore, the competitive market will determine the level of LNG exports and imports to the U.S. and, thereby, provide a restraining mechanism on domestic gas prices. If domestic prices rise significantly with increased demand, they could exceed prices available around the world. In that event, LNG would once again be imported into the U.S., rather than exported.

Finally, Navigant modified the Extreme Demand scenario to eliminate any LNG exports from Cove Point, in order to isolate the predicted portion of these increased prices that would relate to the exports proposed here. 82/ Compared to the unaltered Extreme Demand scenario, the elimination of Cove Point exports would decrease Henry Hub prices by 5.2 percent in 2020 but by only 1.7 percent in 2040. In other words, while Henry Hub prices are projected to be quite high in 2040 under the Extreme Demand Case assumptions, very little of the price increase would be attributable to LNG exports from Cove Point. This conclusion, of course, is logical, since the 1 Bcf/d of DCP exports would be a very small portion of the assumed increase in demand from 2011 to 2040 of nearly 25 Bcf/d.

In summary, DCP submits that the conclusion from all of the extensive Navigant pricing analysis is that, even with very conservative assumptions, LNG exports from the Cove Point LNG Terminal will have no more than a very modest impact on domestic gas prices. Therefore, any price effect would not render the proposed exports contrary to the public interest.

5. Benefits of LNG Exports From DCP

The requested export authorization also is in the public interest because it will benefit the national, regional and local economies and create jobs for Americans. The benefits of the exports are detailed in the ICF Economic Benefits Study (Appendix C) and summarized here. ICF assessed the national and regional impacts of the new DCP facility, quantifying the direct

82/ *Id.* at 29-30.

and secondary benefits of the project. The Economic Benefits Study discusses the results in the creation of new jobs and the impact on the existing economy (in terms of income, wages, taxes, etc.). The Economic Benefits Study also details the macro-level, national and international implications of the DCP project, including the impact on the U.S. balance of trade and the economic impact of upstream expenditures due to the significant new demand for the gas to be exported. The Economic Benefits Study is premised on a project with inlet capacity of 0.75 Bcf/d, assumed to be operated at a 90 percent of capacity. 83/ To the extent that DCP constructs a larger project – consistent with the requested export authorization for up to 1 Bcf/d – the economic benefits will be even greater. These benefits overwhelm any perceived detriment of modestly increased domestic natural gas prices.

The most basic benefit of the proposed LNG exports will be to encourage and support increased domestic production of natural gas, and NGLs. The DCP liquefaction project would allow domestic natural gas that might otherwise be shut-in as a result of a lack of market demand to be available for sale into the global LNG market. The steady new demand associated with LNG exports can spur the development of new natural gas resources that might not otherwise be developed. In the recent order authorizing LNG exports from Sabine Pass, DOE/FE concluded that it was "persuaded that directionally, natural gas production associated with exports… will result in increased production that could be used for domestic requirements if market conditions warrant such use. Overall, this will tend to enhance U.S. domestic energy security." 84/ Navigant reached the same conclusion, as previously noted.

83/ Economic Benefits Study at 1, note 1.

84/ *Sabine Pass*, Order No. 2961 at 35.

Moreover, the development of the gas resources for export by DCP will also result in the increased production of NGLs. 85/ In its *Sabine Pass* order, DOE/FE found that the applicant demonstrated that the production of domestic natural gas will yield NGLs which will, in part, offset the need to import oil. 86/ NGLs are used as home heating fuels, refinery blending and agricultural crop drying, and the U.S. petrochemical industry uses ethane in particular as a feedstock in numerous applications. New supplies of NGLs from shale production (including the Marcellus, and Utica) create a new competitive advantage for the industry that presents a tremendous opportunity to strengthen U.S. manufacturing, boost economic output and create jobs. 87/ Indeed, the recent development of shale gas has already lead the U.S. petrochemical industry to announce significant expansions of petrochemical capacity, reversing a decades long decline. 88/ The DCP liquefaction project will further this trend by supporting further shale development, particularly in the Marcellus and Utica Shales. ICF estimates that LNG exports from the Cove Point LNG Terminal will result in the incremental production of approximately 8.5 million barrels of hydrocarbon liquids per year, with a market value of approximately $1.2 billion per year (in real 2011 dollars). 89/

Of particular importance in the current economic climate, the DCP liquefaction project also will result in new jobs for American workers, consistent with the Administration's 2010

85/ *See* Economic Benefits Study at 38-39.

86/ *Sabine Pass*, Order No. 2961 at 36.

87/ *See* American Chemistry Council (ACC). "Shale Gas and new Petrochemicals Investment: Benefits for the Economy, Jobs, and U.S. Manufacturing." Economics and Statistics, ACC, March 2011, available at http://www.americanchemistry.com/ACC-Shale-Report.

88/ *Id.*

89/ Economic Benefits Study at 38, Table 16 "U.S. Volume, Value, and Economic Impact of Incremental Hydrocarbon Liquids Associated with LNG Export from Cove Point."

National Export Initiative ("NEI"). 90/ The NEI is intended "to improve conditions that directly affect the private sector's ability to export. The NEI will help meet [the] Administration's goal of doubling exports over the next 5 years by working to remove trade barriers abroad, by helping firms -- especially small businesses -- overcome the hurdles to entering new export markets, by assisting with financing, and in general by pursuing a Government-wide approach to export advocacy abroad, among other steps." 91/ In announcing the NEI, President Obama explained:

> Creating jobs in the United States and ensuring a return to sustainable economic growth is the top priority for my Administration. A critical component of stimulating economic growth in the United States is ensuring that U.S. businesses can actively participate in international markets by increasing their exports of goods, services, and agricultural products. Improved export performance will, in turn, create good high-paying jobs. 92/

The President returned to the theme of increasing exports to create jobs in the 2011 State of the Union Address, explaining:

> To help businesses sell more products abroad, we set a goal of doubling our exports by 2014 – because the more we export, the more jobs we create here at home. Already, our exports are up. Recently, we signed agreements with India and China that will support more than 250,000 jobs here in the United States. And last month, we finalized a trade agreement with South Korea that will support at least 70,000 American jobs. This agreement has unprecedented support from business and labor, Democrats and Republicans -- and I ask this Congress to pass it as soon as possible. 93/

90/ NEI, Executive Order No. 13534, 75 Fed. Reg. 12433 (March 11, 2010).

91/ NEI, Section 1.

92/ *Id.*

93/ President Barack Obama, State of the Union Address (Jan. 25, 2011), transcript available at http://www.whitehouse.gov/the-press-office/2011/01/25/remarks-president-state-union-address

Still more recently, when introducing the American Jobs Act to a Joint Session of Congress, the President explained:

> Now it's time to clear the way for a series of trade agreements that would make it easier for American companies to sell their products in Panama and Colombia and South Korea – while also helping the workers whose jobs have been affected by global competition. If Americans can buy Kias and Hyundais, I want to see folks in South Korea driving Fords and Chevys and Chryslers. I want to see more products sold around the world stamped with the three proud words: "Made in America." That's what we need to get done. 94/

Approval of DCP's LNG export authorization is a concrete step to advance the NEI by making possible the sale of natural gas that is "made in America" around the world, creating American jobs in the process.

In order to export LNG from the Cove Point LNG Terminal, DCP will need to make a significant capital investment with additional annual expenditures to operate the new facility over the life of the exports. ICF concludes that DCP's project has the potential to create significant short-term economic activity in Maryland and the broader region during the construction phase, as well as during operations. ICF estimates that industry output impacts in 2015 will be between $355 million and $443 million in Calvert County, with an additional $130 million to $163 million throughout the rest Maryland. 95/ Furthermore, the DCP project will support the region by creating between $183 million and $230 million in value added (*i.e.*, the difference between the output of long-term expenditures and the expenditures for intermediate goods and services) within Calvert County and an additional $80 million to $100 million in the

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94/ President Barack Obama, Address to a Joint Session of Congress (Sept. 08, 2011), transcript available at http://www.whitehouse.gov/the-press-office/2011/09/08/address-president-joint-session-congress

95/ See Economic Benefits Study at 16, Table 4 "Annual Industry Output, Facility Construction/Operation (2011$)."

rest of Maryland. 96/ Annual operations are expected to generate an additional $22 million in value added annually in the local economy from 2018 through 2040. 97/ More generally, ICF calculates $44 billion in industry value added associated with upstream expenditures of $32 billion to support LNG exports over a 25-year term. 98/

The economic value associated with the DCP project, along with the economic activity associated with the natural gas production supporting the LNG exports, will create thousands of new jobs. While many people may have a misperception that natural gas production benefits only major energy companies, the associated economic activity benefits the many smaller companies doing the work and hiring the needed employees.

In its Economic Benefits Study, ICF calculates that the short-term economic impacts from construction and operation of the DCP export project has the potential to support between 2,700 and 3,400 jobs in Calvert County, Maryland at its peak of construction activity (roughly equivalent to 12 percent of the county's total employment). 99/ Moreover, these activities could support over an additional thousand jobs in the rest of the State of Maryland. Furthermore, ICF estimates that thousands of more jobs would be added across the Nation, as the significant inter-linkages between various economic sectors provide a short-run boost to support employment not just in the localized region but across the entire country. 100/ For the period of operations from 2018-2040, ICF estimates that economic activity associated with

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96/ See Economic Benefits Study at 16, Table 3 "Annual Value Added Impacts, Facility Construction/Operation (2011$)."

97/ *Id.*

98/ See *id.* at 28, Table 9 "U.S. Value Added from Upstream O&G Expenditures Associated with LNG Exports from Cove Point (2011$)."

99/ *Id.* at 11, Table 2 "Annual Job-Year Impacts, Facility Construction/Operation (Job-years).".

100/ *Id.*

DCP's liquefaction project will result in the addition of 320 jobs across the Nation. 101/ ICF's study also shows that economic activity associated with the long-term upstream supply of natural gas for the LNG exports proposed by DCP will support an estimated 18,000 jobs annually over the life of the project. 102/

Significant tax revenue also will be generated as a result of the construction phase of the DCP project, and subsequent operations. ICF projects tax revenues for federal, state and local governments will peak in 2014 with a total of $130-163 million. 103/ The state and local taxes, which account for roughly 38 percent of the total tax revenues, include taxes generated in both Maryland and other states, because goods and services purchased in other states are used to supply the direct expenditures in Calvert County. ICF estimates an annual average of increased tax revenue from 2018-2040 for the U.S. as a whole of nearly $11 million. 104/ In addition to the taxes calculated by ICF, DCP estimates that the long-term operation of the Terminal will produce up to $40 million per year of property tax revenues.

In addition, upstream economic activity to support the incremental LNG exports is expected by ICF to lead to over $25 billion in increased government royalty and tax revenues to federal, state, and local governments over the 25-year period, with an average of approximately

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101/ *Id.*

102/ *Id.* at 24, Table 7 "U.S. Upstream Natural Gas Sector Annual Job-years Resulting from LNG Exports from Cove Point (Job-years)."

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

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

$1 billion in annual revenues. 105/ In addition, another $9.8 billion in royalty income over 25 years is expected for landowners in the form of mineral leases. 106/

Furthermore, granting DCP's requested export authorization also will help realign the U.S. balance of trade. 107/ The U.S. has experienced large balance of trade deficits for more than decade (although the rise in U.S. exports after the economic crisis somewhat realigned the trade balance). In 2010, the U.S. trade deficit in goods and services was $497.8 billion, up from $374.9 billion in 2009. 108/ More than half of the total trade deficit, over $265 billion, resulted from a negative balance in trade of petroleum products. 109/ Authorizing the export of LNG will help redress this balance, by allowing the U.S. to export some of its abundant natural gas. In a variation on the President's recent remarks: If Americans can buy Hondas and Kias, and fuel them with Middle Eastern oil, folks in Japan and South Korea should be able to burn American natural gas.

In its Economic Benefits Study, ICF calculates that DCP's proposed exports of LNG and associated NGLs can improve the U.S. balance of trade in a range from $2.8 billion to $7.1 billion per year over the 25-year forecast period. 110/ The expected value of the exports is estimated to reduce the U.S. trade deficit by between 0.6 percent and 1.4 percent, based on

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105/ *Id.* at 32, Table 11 "U.S. Taxes and Royalties from Upstream Oil and Gas Expenditures and Production Associated with LNG Exports from Cove Point (2011$ million)."

106/ *Id.*

107/ *Id.* at 41-42.

108/ Bureau of Economic Analysis, U.S. Dept. of Commerce, *U.S. International Trade in Goods and Services* (Feb. 11, 2011), available at http://www.bea.gov/newsreleases/international/trade/2011/pdf/trad1210.pdf at page 3.

109/ *Id.* at page 16.

110/ Economic Benefits Study at 41-42 and Table 19 "Range of Annual Positive Effect of LNG Export from Cove Point on U.S. Balance of Trade."

the 2010 deficit. 111/ In authorizing previous gas export applications, DOE/FE has recognized the positive role that LNG exports can have on the balance of trade with the destination countries. 112/ DOE/FE also acknowledge this benefit (and rejected countervailing arguments) in its recent order approving exports from Sabine Pass. 113/

Authorization of the DCP project also will result in international impacts that will benefit the U.S. in several ways. The following conclusions of DOE/FE when authorizing LNG exports from Sabine Pass order are equally applicable here:

> First, the export of natural gas produced in the United States will help to promote new international markets for natural gas, thereby encouraging the development of additional productive resources in this country (as discussed above) and internationally. Second, augmentation of global natural gas supplies will support efforts by overseas electric power generators to switch away from oil or coal, both more carbon intensive and environmentally damaging than natural gas. Third, an improvement in natural gas supplies internationally will help certain countries that currently have limited sources of natural gas supplies to broaden and diversify their supply base. This will contribute to greater overall transparency, efficiency, and liquidity of international natural gas markets, encouraging a liberalized global natural gas trade and a greater diversification of global natural gas supplies. Fourth, these developments may encourage the decoupling of international natural gas prices from oil prices in some international natural gas markets and may exert downward pressure on natural gas market prices in relation to oil prices in those markets. 114/

The international benefits of increased domestic gas production – which will be fostered by LNG exports – are further explained in the recent report by the James A. Baker III Institute

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111/ *Id.* at 2.

112/ *E.g.*, *ConocoPhillips*, Order No. 2731 at 10; *Freeport*, Order No. 2644 at 12; *Cheniere Marketing, inc.*, FE Docket No. 08-77-LNG, Order No. 2651 at 14 (June 8, 2009).

113/ *Sabine Pass*, Order No. 2961 at 35-36.

114/ *Id.* at 37.

for Public Policy at Rice University. 115/ That report highlights the broad effects that new shale discoveries are having on our Nation's energy security, and explains the added security and stability that increased American natural gas reserves will bring around the world, lessening the many thorny entanglements that our dependence on foreign energy sources brings. The report also details the numerous benefits that shale gas will have on a global scale, from eliminating demand for imports of foreign LNG to the U.S., to reducing the possibility of a natural gas "OPEC," weakening the energy stranglehold held by certain countries, and helping curb America's dependence on Middle East oil.

This section summarizes the many benefits of authorizing LNG exports from the Cove Point LNG Terminal. All of these benefits demonstrate that granting DCP’s requested export authorization will not be inconsistent with (indeed, will benefit) the public interest.

VI. DOE’S CONTINUING DUTY TO PROTECT THE PUBLIC INTEREST

In its recent *Sabine Pass* order, DOE/FE noted that the present and currently projected gas supply and demand conditions may not continue over the duration of a long-term export authorization. 116/ Furthermore, DOE/FE noted its statutory authority, “after opportunity for a hearing and for good cause shown, to make a supplemental order as necessary or appropriate to protest the public interest,” as well as “to perform any and all acts and to prescribe, issue, make, amend or rescind such orders, rules, and regulations as it may find necessary or appropriate” to carry out its responsibilities. 117/

115/ "Shale Gas and U.S. National Security," Medlock, Myers Jaffe, and Hartley, published by the James A. Baker III Institute for Public Policy (July 19, 2011).

116/ *Sabine Pass*, Order No. 2961 at 31-33.

117/ *Id.* at 32-33 & note 45.

DCP recognizes the uncertainty of the future and the agency's statutory authority, but respectfully submits that the prospect of future changes in export authorization may present risks that will undermine the needed investment in LNG export projects. DCP anticipates making a significant capital investment in its liquefaction project, and its customers likely will be making their own billions of dollars of investments in the related gas supply. Moreover, the destination markets will depend on the anticipated LNG supply from the U.S. to meet their future needs. All of these investments will be made in reliance upon an authorization issued by DOE/FE. If terminal developers like DCP, and their customers, cannot rely on an export authorization issued by DOE/FE, the needed investments may not be made. In that event, the great benefits of exports of the Nation's abundant natural gas supplies will be lost.

Accordingly, DCP urges DOE/FE to ensure the sanctity of its export authorizations once issued, so that investments can be made with greater certainty. At a minimum, DOE/FE should clarify the following points concerning any future modifications of the authorization to be issued here. First, in its consideration of any future modification of the authorization, DOE/FE will fully recognize the significant and reasonable reliance of DCP and its customers on its export authorization. Second, any change in the authorization would require a showing that continuation of the existing authorization would be contrary to the public interest (consistent with the statutory standard). Third, a change in the existing authorization will be made only if this showing is proven by clear and convincing evidence, meaning that the threat to the public interest must be highly and substantially more probable to be true than not and DOE/FE must have a firm belief or conviction in the existence of a true threat to the public interest. Finally, the burden of proof will be on an advocate of a change in the authorization (and DOE/FE) to satisfy this showing and justify the change in its previously issued authorization.

DCP respectfully submits that these clarifications likely reflect DOE/FE's intent with respect to possible future modification of its LNG export authorization. Yet, the clarifications are necessary to reassure the parties investing in such projects and allow them to properly assess the risk of a future change in export authorizations. Lack of clarity on this issue (or the appearance of too cavalier an attitude about the possibility of modifying or rescinding export authorizations relied upon by parties) will chill the prospect of beneficial export projects and creation of new American jobs at a time when they are desperately needed.

VII. ENVIRONMENTAL IMPACT

As previously noted, in order to accommodate the proposed export activities, construction of new facilities at the Cove Point LNG Terminal will be required. The facilities will be designed to minimize or mitigate any environmental or other adverse impacts. Therefore, the proposal does not constitute a major federal action significantly affecting the quality of the human environment, within the meaning of the National Environmental Policy Act (NEPA) of 1969 (42 U.S.C. 4321, *et seq*.).

DCP plans to file an application with the FERC for the necessary authorizations for facilities to allow for the liquefaction of domestically produced natural gas and export of LNG from the Cove Point LNG Terminal. An environmental review under NEPA will be completed by FERC prior to granting DCP authorization. The authorization requested here, as a practical matter, will not be actionable until the FERC grants DCP authorization. DCP requests that DOE/FE issue a conditional order authorizing the export of LNG, conditioned on completion of the environmental review by FERC.

VIII. APPENDICES

The following appendices are attached hereto and incorporated by reference herein:

Appendix A: Navigant Supply Report

Appendix B: Navigant Price Report

Appendix C: ICF Economic Benefits Study

Appendix D: Verification

Appendix E: Opinion of Counsel

IX. CONCLUSION

Based on the reasons set forth above, DCP respectfully requests that the DOE/FE grant DCP authority for its proposal to engage in long-term, multi-contract exports of LNG that was domestically produced for a term of twenty-five years, commencing on the date of the first LNG export or six years from the date that the authorization is issued whichever is sooner, for the equivalent of up to 1 Bcf of natural gas per day (or approximately to 7.82 million mtpa) to any country which has or in the future develops the capacity to import LNG via ocean-going carrier and with which the U.S. does not prohibit trade but also does not have an FTA requiring the national treatment for trade in natural gas. DCP respectfully requests that the DOE/FE grant such authority as expeditiously as possible, and by no later than June 1, 2012.

Respectfully submitted,

/s/ Matthew R. Bley

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Dated: October 3, 2011

Appendix A

Navigant Supply Report

NAVIGANT

North American Gas Supply Overview and Outlook to 2040

Prepared for:

Dominion Cove Point LNG, LP

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September 19, 2011

Disclaimer: This report was prepared by Navigant Consulting, Inc. for the benefit of Dominion Cove Point LNG, LP. This work product involves forecasts of future natural gas demand, supply, and prices. Navigant Consulting applied appropriate professional diligence in its preparation, using what it believes to be reasonable assumptions. However, since the report necessarily involves unknowns, no warranty is made, express or implied.

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Summary of Assignment

Dominion Cove Point LNG, LP is considering the manufacture and export of liquefied natural gas (LNG) at the site of its LNG import facility at Cove Point, Maryland. In support of this possible project, Dominion requested Navigant Consulting, Inc. to provide a qualitative outlook for the North American natural gas market to 2040, with an emphasis on supply. It also asked Navigant to model the potential price impacts of its export operations.

This ***North American Gas Supply Overview and Outlook to 2040*** responds to supply issues. The companion report ***North American Gas System Model to 2040*** responds to modeling results and implications. These two reports are designed to be read in conjunction with one another.

As part of its internal integrated energy modeling process for natural gas and electricity, Navigant develops a forecast of the North American natural gas market in the spring and fall of each year. This report for Dominion builds on Navigant's Spring 2011 Reference Case forecast and Navigant's ongoing market research. Where appropriate, the report benchmarks Navigant's supply forecast to the latest U.S. Energy Information Administration's 2011 Annual Energy Outlook forecast as well as other supply forecasts that are publicly available.

Navigant reviews key factors such as:

- Gas drilling trends
- Hydro fracturing – its impact and risk factors
- Infrastructure developments
- The effects and outlook for oil and gas prices
- Gas pricing relative to oil
- Price volatility
- Outlook for economics of gas supply
- Imports (Canada, Mexico, regasification) / exports (LNG, Mexico, Canada)
- Supply balance overview by region
- Frontier gas supply
- Comparative analysis of supply forecasts
- Demand as a factor for gas supply sustainability in a surplus market
- Demand factors affecting gas supply – electric generation (coal, nuclear, renewables, NGVs)

Executive Summary

Domestically available natural gas has become an abundant fuel in North America. In fact, gas supply is surplus to demand.

Before 2008, the general consensus was that domestic gas supplies would be unable to keep pace with growing demand, and that liquefied natural gas (LNG) would have to be imported. That consensus is no longer operative. The situation in North America has reversed from an expectation of domestic supply deficit to an expectation of supply abundance. Prices that were expected to be high and volatile are now expected to be moderate and relatively stable.

The new consensus, which Navigant shares, is that North American gas resources are more than adequate to satisfy domestic demand for the time frame covered by this report, even as demand grows.

It is Navigant's assessment that domestic gas resources are also ample enough to support the creation and ongoing operation of a domestic LNG export industry through the study period to 2040, including the demand added by Dominion's proposed liquefaction facilities at Cove Point.

Several facts support this outlook.

- Dry gas production in the U.S. is up 25 percent, from about 49.5 Bcfd to 62.1 Bcfd, from 2004 through the first seven months of 2011.
- Navigant projects U.S. production to grow to 84 Bcfd in its Reference Case.
- The EIA's most recent estimate of dry natural gas resources in the United States is 2,543 Tcf.[1] This is more than 100 years of supply at current usage rates of approximately 24 Tcf per year. Even at Navigant's projected 2040 rate of consumption of 84 Bcfd (30.7 Tcf per year), this represents 83 years of supply.
- Despite confusion surrounding a recent United States Geological Survey estimate of "undiscovered" reserves in the Marcellus Shale of 84 trillion cubic feet, the Energy Information Agency has not altered its estimate of "undeveloped" Marcellus reserves, which is 410 trillion cubic feet. Based on investigations by Navigant, including direct contact with the personnel involved at the two government agencies, there is a possibility that the two estimates are *additive*. In any case, the EIA has made no changes to its estimate of "undeveloped" Marcellus reserves, reports to the contrary notwithstanding.

[1] Newell, EIA, *Shale Gas and the Outlook for U.S. Natural Gas Markets and Global Gas Resources*, presentation to the Organization for Economic Cooperation and Development (OECD), June 21, 2011, available at http://www.eia.gov/pressroom/presentations/newell_06212011.pdf

An unappreciated fact is that reliable demand is a key to underpinning reliable supply and a sustainable gas market. Demand and supply are two parts of a single dynamic. Domestically manufactured LNG for export can be an integral part of that demand. By providing a steady baseload demand, it can help support ongoing supply development and help keep domestic gas prices stable.

Supply Outlook to 2040

Overall supply growth in the U.S. has been remarkable in the past few years. Due to the vast size of the shale gas resource and the high reliability of shale gas production, the overall supply-demand balance has the potential to be synchronized for the foreseeable future, even as demand grows. The bulk of this change is attributable to prolific supplies of unconventional gas which can now be produced economically. Unconventional gas includes shale gas, tight sands gas, coalbed methane, and gas produced in association with shale oil.

Before the advent of significant unconventional gas production, natural gas development was susceptible to booms and busts. Investment in both production and usage seesawed on the market's perception of future prices. That perception has been driven by uncertainty around the availability of supply to meet demand, both in the short and long terms. The investment cycle for supply was frequently out of phase with demand, due to the uncertainty of the large investment required for exploration or for LNG regasification (on the supply side) and for power plants and other large users (on the demand side).

In between supply and demand are pipelines, another large-scale investment which in individual cases has suffered from underutilization or has become a bottleneck, as a result of the uncoordinated cycles of supply and demand investment.

These factors created a dynamic of price volatility. The volatility itself affected investment decisions, creating a feedback loop of uncertainty.

The dependability of shale gas production has the potential to improve the phase alignment between supply and demand, which will tend to lower price volatility. As long as commodity prices can be sustained at levels that incent drilling and development, yet remain competitive with the price of alternative fuels, the vast size of the shale gas resource will support a much larger demand level than has heretofore been seen in North America.

Navigant expects gas production to continue to grow steadily throughout the forecast period. Our forecast for production, based on our Spring 2011 Reference Case, is shown in ***Figure 1:*** *North American Natural Gas Supply Projection*. Navigant projects that North American-produced supply will be 105 Bcfd by the year 2040. By that year, U.S.-produced supply alone is projected to be a bit more than 81 Bcfd, as shown in ***Figure 2:*** *U.S. Natural Gas Supply Projection*.

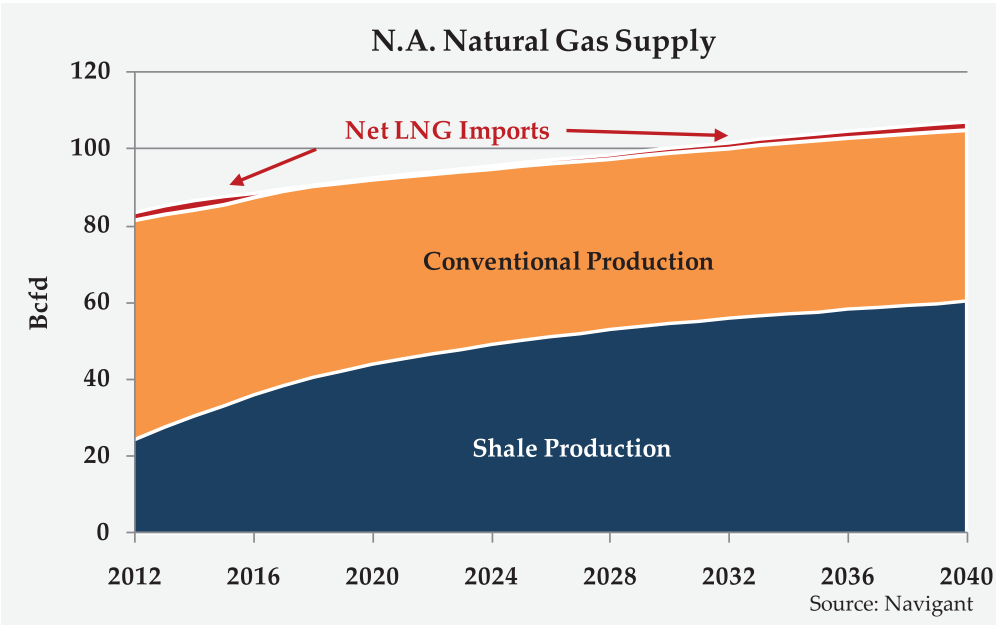

Figure 1: North American Natural Gas Supply Projection

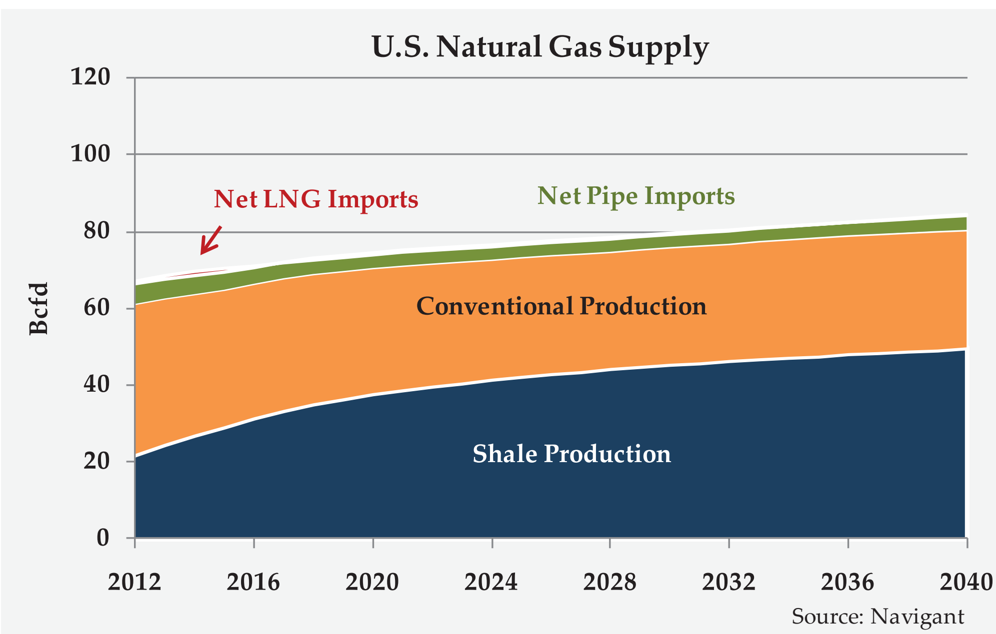

Figure 2: U.S. Natural Gas Supply Projection

With this moderated and controlled supply growth, demand and pipeline investment are expected to grow in a measured fashion, with price volatility relatively limited. This should tend towards creating a healthy, stable, long-term market for natural gas.

This vast majority of production growth is likely to be driven by unconventional gas development, as opposed to conventional gas, which is in decline. Plans to develop frontier gas, such as the Mackenzie Project in Arctic Canada and the Alaska Pipeline Project, are in doubt due to the high cost of those projects relative to unconventional resource development opportunities closer to markets. However, if demand is sufficient, there are scenarios in which these conventional resources may yet play a role in later years.

Factors Underpinning the Forecasted Increase in Gas Supply

In 2008, Navigant first identified the rapidly expanding development of natural gas from shale. While geologists and natural gas production companies had been aware of shale gas resources, (trace amounts of methane were often detected as drillers penetrated shale on the way to a conventional reservoir), such resources were regarded as uneconomic to recover in most instances.

Improvements in Hydraulic Fracturing and Horizontal Drilling

Natural gas prices increased substantially in the first decade of this century, and culminated in significantly higher prices in 2007-2008, as shown in **Figure 3:** *Henry Hub Price History*. These increasing prices induced a boom in LNG import facilities in the late 1990s and 2000s, which was very conspicuous due to the size of the facilities and to the public approval process required for each. As late as 2008, conventional wisdom held that North American gas production would have to be supplemented increasingly by imported LNG.

Far less conspicuously, high prices also supported the development of horizontal drilling and hydraulic fracturing, existing technologies which were refined and systematized in ways that dramatically increased drilling and production efficiencies, reduced costs, and improved the finding and development economics of the industry. In mid-2008, when Navigant released its groundbreaking report,[2] domestic gas production from shale began to overtake imported LNG as the gas supply of choice in North America. The evolution of these cost-effective technologies was the key to unlocking that potential.

[2] North American Natural Gas Supply Assessment, prepared for the American Clean Skies Foundation, July 4, 2008, available at
http://www.navigant.com/~/media/Site/Insights/Energy/NCI_Natural_Gas_Resource_Report.ashx

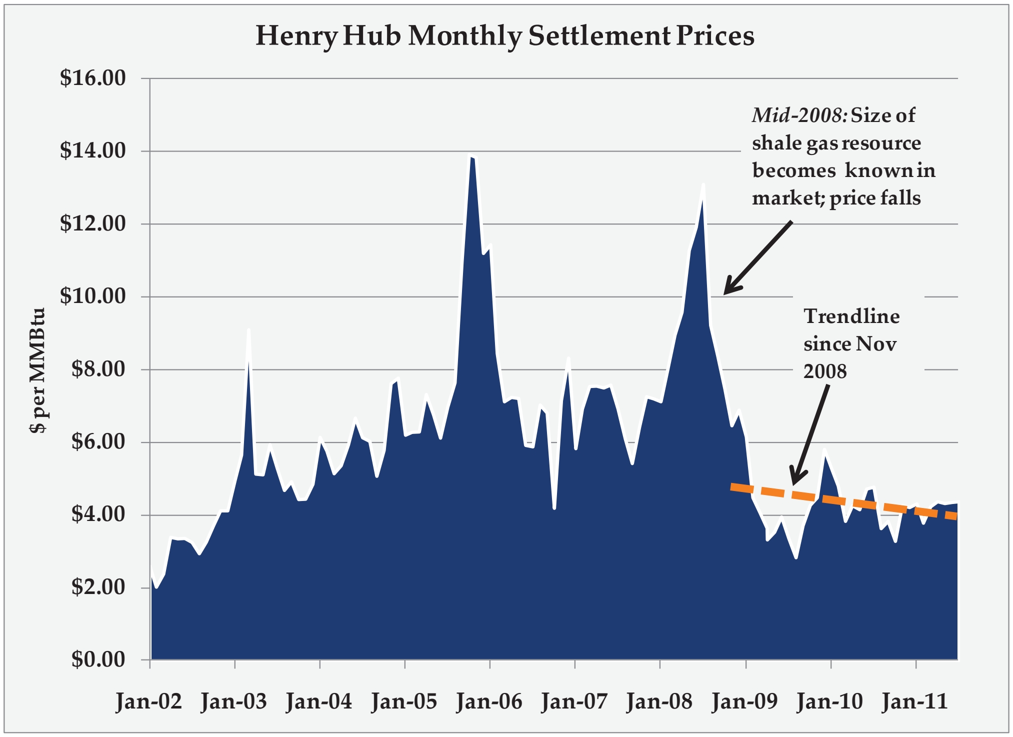

Figure 3: Henry Hub Price History

Shale gas production efficiency has since improved. In many locations, 10 wells can be drilled on the same pad. The lengths of horizontal runs, once limited to several hundred feet, can now reach up to 10,000 feet. The number of fracture zones has increased from four to up to 24.

Improvements continue in other aspects of hydraulic fracturing technology. Much attention is being focused on water usage and disposal. Several states, including Texas and Wyoming, have passed legislation that requires the contents of chemicals used in the hydraulic fracturing process to be disclosed. The U.S. Environmental Protection Agency is investigating the potential impacts of hydraulic fracturing on drinking water resources. Range Resources is pioneering the use of recycled flowback water, and by October 2009 was successfully recycling 100 percent in its core operating area in southwestern Pennsylvania. Range estimates that 60 percent of Marcellus shale operators are recycling some portion of flowback water, noting that such efforts can save significant amounts of money by reducing the need for treatment, trucking, sourcing, and disposal costs.[3] Chesapeake Energy is also actively exploring methods of reducing and reusing water.

These efforts to improve water management will tend to enhance the ability of shale operations to expand.

[3] "Range Answers Questions on Hydraulic Fracturing Process ," Range Resources, http://www.rangeresources.com/Media-Center/Featured-Stories/Range-Answers-Questions-on-Hydraulic-Fracturing-Pr.aspx

Size of the Shale Gas Resource

To illustrate the size of the shale gas resource, its rapid development, and increasing efficiency, consider the following. U.S. natural gas production increased from about 50.5 Bcfd in May 2005 to about 60.9 Bcfd in May 2011, even as overall rig counts fell from 1,170 to 890. This is an increase of 20 percent in six years. The increase in overall gas production has been driven by shale gas, as evidenced by the increase in horizontal drill rig counts and the decrease in vertical (conventional) rig counts. (See **Figure 4:** *U.S. Gas Production and Rig Count History* and ***Figure 5:*** *U.S. Gas Rig Type Shift*.)

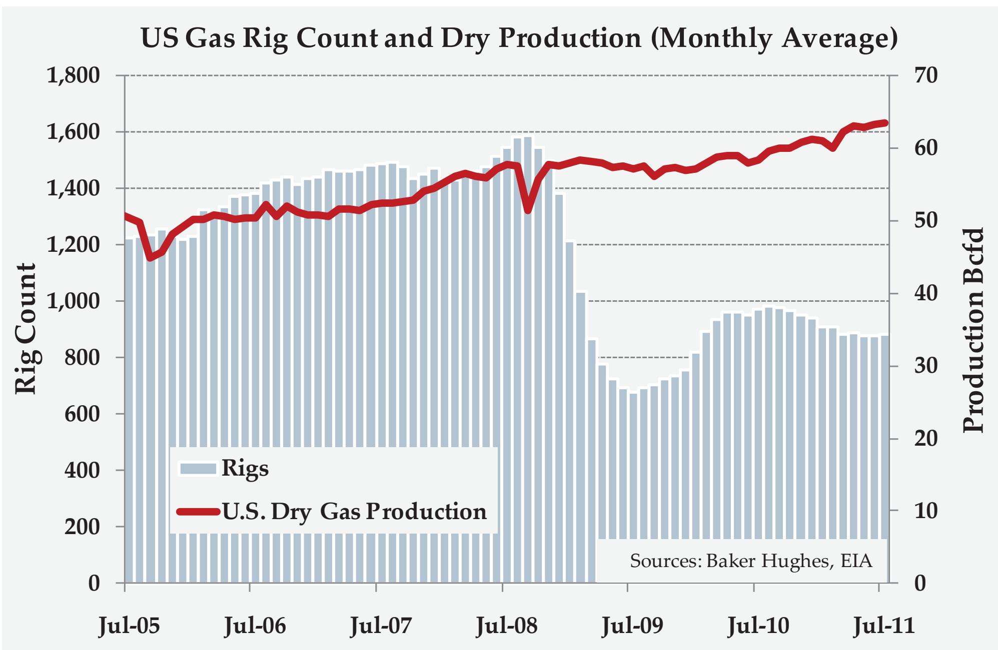

Figure 4: U.S. Gas Production and Rig Count History

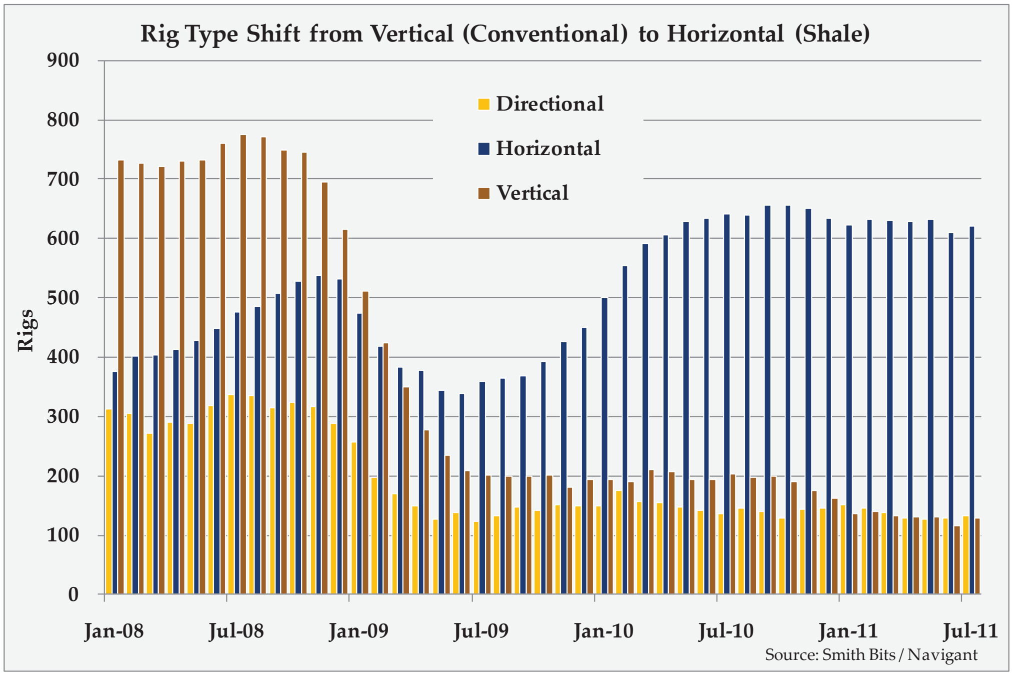

Figure 5: U.S. Gas Rig Type Shift

The growth in shale gas production has been phenomenal, as shown in the graph in **Figure 6:** *Shale Production 2007-2011*. Shale output from eight major basins under development in North America grew from 3.0 Bcfd in the first quarter of 2007 to 16.5 Bcfd in the first quarter of 2011, an increase of almost 525 percent in a little more than four years.

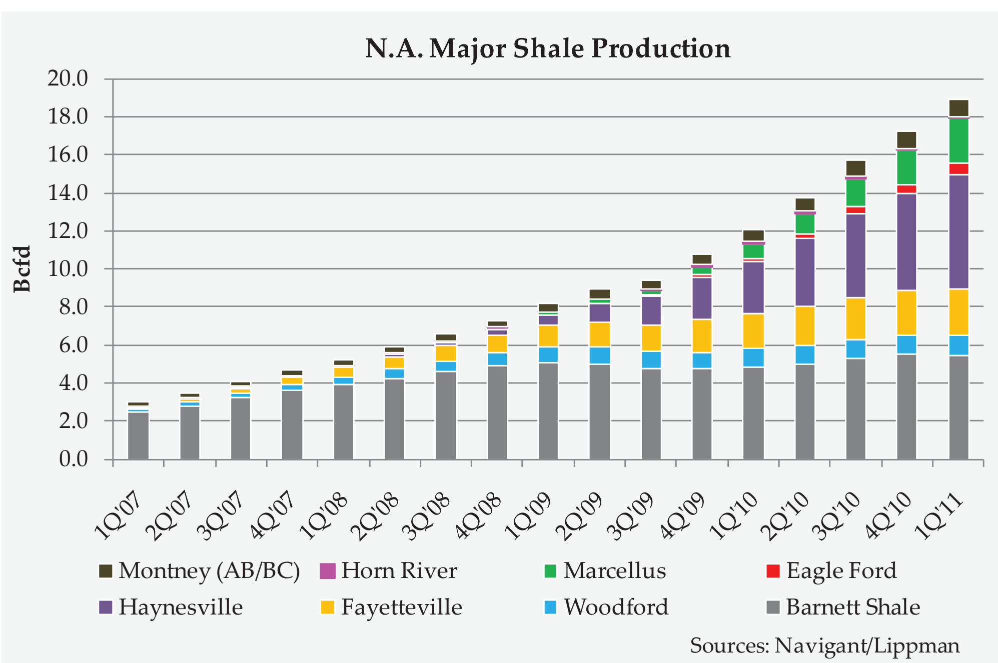

Figure 6: Shale Production 2007-2011

The geographic scope of the U.S.'s shale gas resource can be seen in the map from the Energy Information Administration, shown in **Figure 7:** *EIA Lower-48 Shale Play Map (2011)*. In Navigant's groundbreaking study on the subject of emerging North American shale gas resources, we estimated the maximum recoverable reserves from shale in the U.S. to be 842 trillion cubic feet (Tcf), boosting the maximum recoverable reserves for all of the U.S. to 2,247 Tcf.[4] In its *Annual Energy Outlook 2011*, the EIA's estimate for technically recoverable unproved shale gas resources in the U.S. in its reference case is 827 Tcf.[5]

New shale resource plays are being identified at a high rate. For example, several plays now appear on the 2011 version of the EIA map that did not appear on the 2010 version, including the Niobrara, Heath, Tuscaloosa, Excello-Mulky, and Monterey. The areal extent of others, notably the Eagle Ford, has enlarged significantly. North America is clearly in the early phases of discovery for this resource.

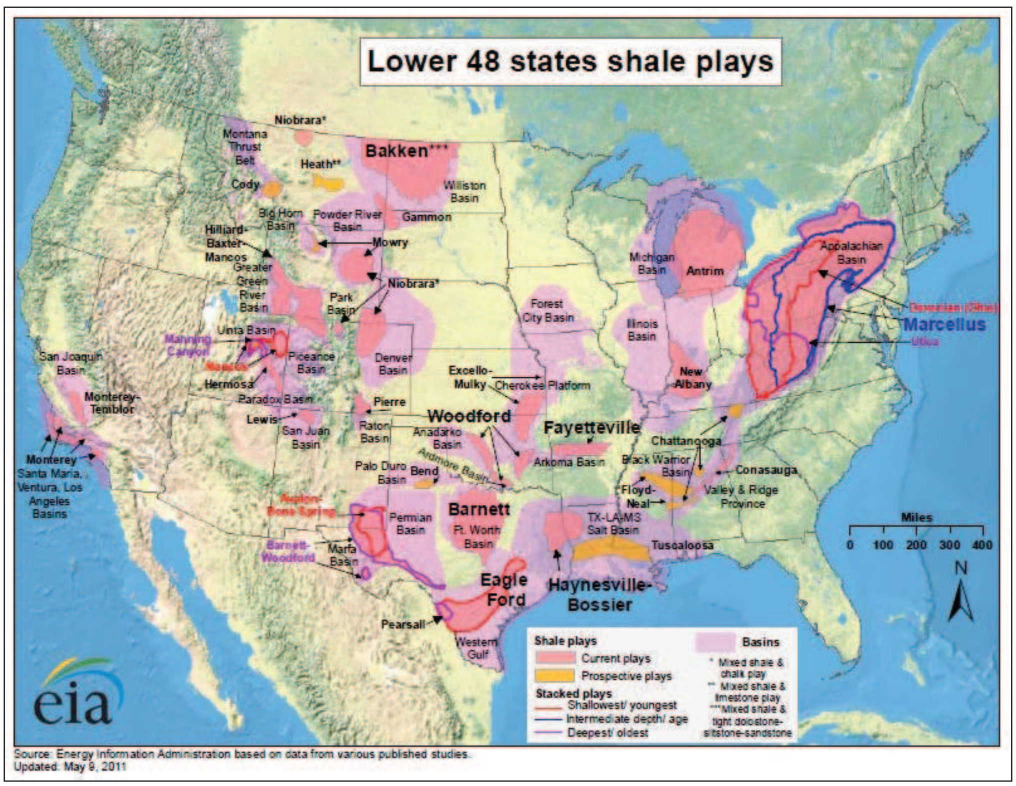

Figure 7: EIA Lower-48 Shale Play Map (2011)

The Marcellus Shale formation is a special case. It is in central Appalachia, the market area of the Cove Point facility. The Marcellus was virtually unheard of in 2007. Dr. Terry Engelder, a professor of geology at Penn State University, has estimated that the Marcellus has a 50 percent chance of

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

[5] *Annual Energy Outlook 2011*, EIA, p. 2.

containing 489 Tcf of recoverable gas.[6] In 2010, the entire United States used about 24 Tcf per year, or less than five percent of the Marcellus's potential production.[7] Another recent study by Penn State estimates that production from the Marcellus will grow from 327 million cubic feet per day during 2009 to 13.5 *billion* cubic feet per day by 2020.[8] (For a discussion of the recent USGS estimate of the Marcellus resources, see ***The Marcellus Shale and Other Key Supply Basins*** on page 27.)

In the final version of its recently published study ***The Future of Natural Gas***, the Massachusetts Institute of Technology stated that "The current mean projection of the recoverable shale gas resource [in the U.S., excluding Canada] is approximately 650 Tcf … approximately 400 Tcf [of which] could be economically developed with a gas price at or below $6/MMBtu at the well-head."[9] In 2009, the Potential Gas Committee of the Colorado School of Mines estimated that the recoverable natural gas resource in North America is 2,170 Tcf, an increase of 89 Tcf over their previous evaluation. This is enough to supply domestic needs at 2010 usage rates (66.1 Bcfd) for 90 years. Of this total, 687 Tcf is shale gas.[10]

The British Columbia Ministry of Energy and Mines and the National Energy Board recently estimated the marketable gas in place in the Horn River Basin alone to be between 61 and 96 trillion cubic feet.[11] This estimate excludes the Montney natural gas play further to the south, resources in the territories to the north such as the Liard Basin and the Cordova Embayment, conventional gas, and any as-yet-to-be-discovered resources.

As indicated by the above, there is little doubt that the shale gas resource in North America is extremely large. In Navigant's estimation, the size of the shale gas resource in North America is more than adequate to serve all forecast domestic demand through the study period to 2040 as well as the demand added by Dominion's proposed liquefaction facilities at Cove Point.

Character of the Shale Gas Resource

The character of the shale gas resource reinforces its future growth potential. Finding economically producible amounts of conventional gas has historically been expensive due largely to geologic risk. Dry or quickly depleted wells are not uncommon in the conventional gas world. Conventional gas is usually trapped in porous rock formations, typically sandstone, under an impermeable layer of cap rock. It is produced by drilling through the cap into the porous formation, liberating the gas. Despite advances in technology, finding and producing conventional gas still involves a significant degree of

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

[7] EIA, Natural Gas Consumption by End Use, annual table, release date 5/31/2011, available at http://www.eia.gov/dnav/ng/ng_cons_sum_dcu_nus_a.htm

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

[9] Massachusetts Institute of Technology, *The Future of Natural Gas*, Ernest J. Moniz, et al, Chapter 1, p. 7, http://web.mit.edu/mitei/research/studies/documents/natural-gas-2011/NaturalGas_Full_Report.pdf.

[10] Potential Gas Committee press release, April 27, 2011, http://potentialgas.org/

[11] *Ultimate Potential for Unconventional Natural Gas in Northeastern British Columbia's Horn River Basin*, May 2011, British Columbia Ministry of Energy and Mines and the National Energy Board, pp 18-24.

risk, with the possibility that a well will be a dry hole or "duster" with no deliverability or production following drilling, and thus no return on investment.

In unconventional shale gas, geologic risk is significantly reduced. Resource plays have become much more certain to be produced in commercial quantities. The reliability of discovery and production has led shale gas development to be likened more to a manufacturing process rather than an exploration process with its attendant risk. This ability to throttle the production of gas by managing the drilling and production process allows supplies to be produced in concert with market demand requirements and economic circumstances.

Gas in a shale formation is entrained in the rock itself. It does not accumulate in pockets under cap rock. It tends to be distributed in relatively consistent quantities over great volumes of the shale. Often, drilling techniques allow a single well-pad to be used to drill multiple horizontal wells up to two miles in length into a given formation, and each bore produces gas. Since the shale formations can be dozens or even hundreds of miles long and often several hundred feet thick and, in many cases, are in existing gas fields wherein the shale was penetrated regularly but not exploited, the risk of not finding a producible formation is much lower compared to some types of conventional gas structures.

The horizontal well, once it is properly located in the target formation, is then enabled to produce volumes large enough to be economic through the use of hydraulic fracturing. Water, sand (or some other proppant to keep the fractures open), and a small amount of chemicals are injected at high pressure to fracture the shale so that it releases the gas. As is the case with most shale wells, initial production (IP) rates are high, but drop off steeply within the first two years. However, once a well has declined to 10-20 percent of initial production, the expectation of many scientists in the industry (which has been supported by experience in shale's brief history to date) is that production will then continue at that lower rate with a very slow decline for many years. The graph below typifies a shale well decline curve. [12]

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

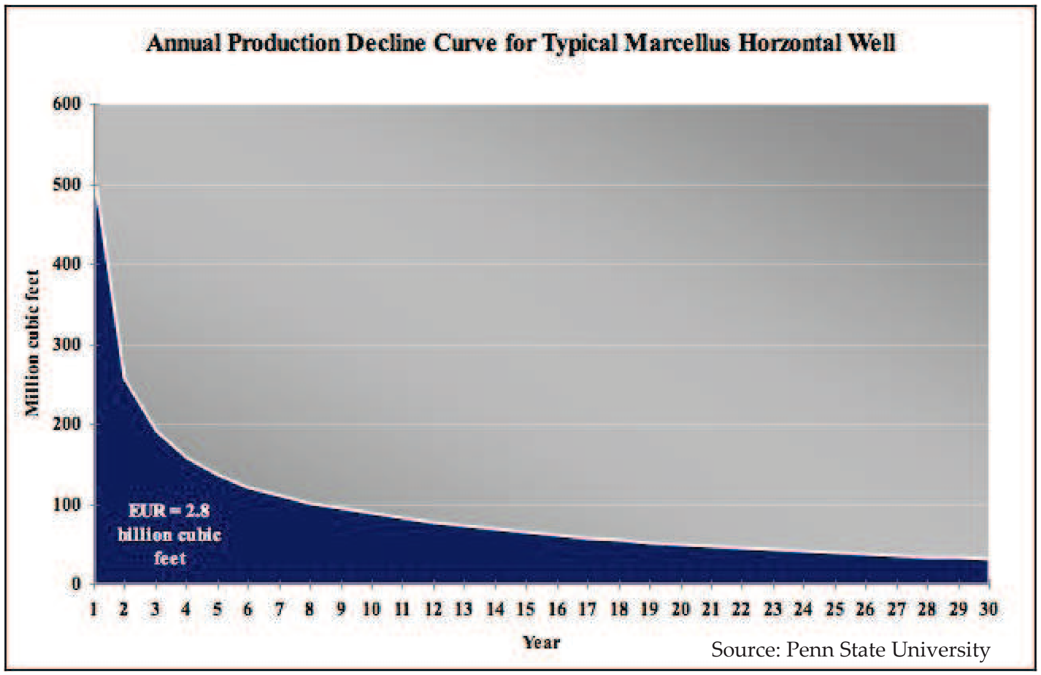

Figure 8: Shale Gas Well Decline Curve[13]

The certainty of production allows shale gas to be managed in response to demand. If demand is growing, additional zones and/or shale wells can be fractured or drilled to meet that demand and mitigate the initial production or IP decline rates from earlier wells. If demand subsides, drilling rates can be reduced or discontinued completely in response to the negative market signal.

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

Similarly, in April 2011, Encana announced the acquisition of liquids-rich Duvernay Shale acreage in Alberta to exploit natural gas liquids in addition to shale gas. Associated gas is generally produced when NGLs are produced. Therefore, gas production is being incented not only by the economics of natural gas itself, but by NGL prices, which tend to follow oil prices. Oil prices can offer a significant premium to natural gas on a per-MMBtu basis, as is currently the case. Oil at $100 per barrel equates to about $17.25 per MMBtu.

Much has been made of the per-play economics of shale gas development. While the cost of producing commercial quantities of gas does vary from play to play, and even within a play, the overall trend is that drilling costs are declining as producers gain experience, develop efficiencies such as the ability to develop multiple fracture zones per well, and leverage investments in drilling

[13] Typo in title is in the original as published by Penn State.

equipment across greater volumes of gas. In some pure gas shale plays, costs have dropped below $4.00 per MMBtu to produce, and continue to drop. Most shale gas plays are expected to be economic in the $4.00 to $6.00 range.

In NGL and crude oil plays such as the Eagle Ford, the cost to produce gas can be thought of as essentially zero, as long as the price of the NGLs and oil supports drilling. As noted above, the price of liquids is several multiples higher than the price of natural gas on a per-MMBtu basis. Navigant expects NGL and crude oil prices to continue to be strong relative to natural gas, based on continued strong demand.

The EIA, in its *International Energy Outlook 2010*, projects worldwide demand for liquid fuels to grow by more than 24 million barrels a day, driven largely by strong economic growth and increasing demand for liquids in the transportation and industrial sectors in Asia, the Middle East, and Central and South America. The EIA also expects oil prices to increase to $130 per barrel by 2035, which will incentivize production.[14] Thus, NGL production will be encouraged in the U.S., along with the production of associated gas.

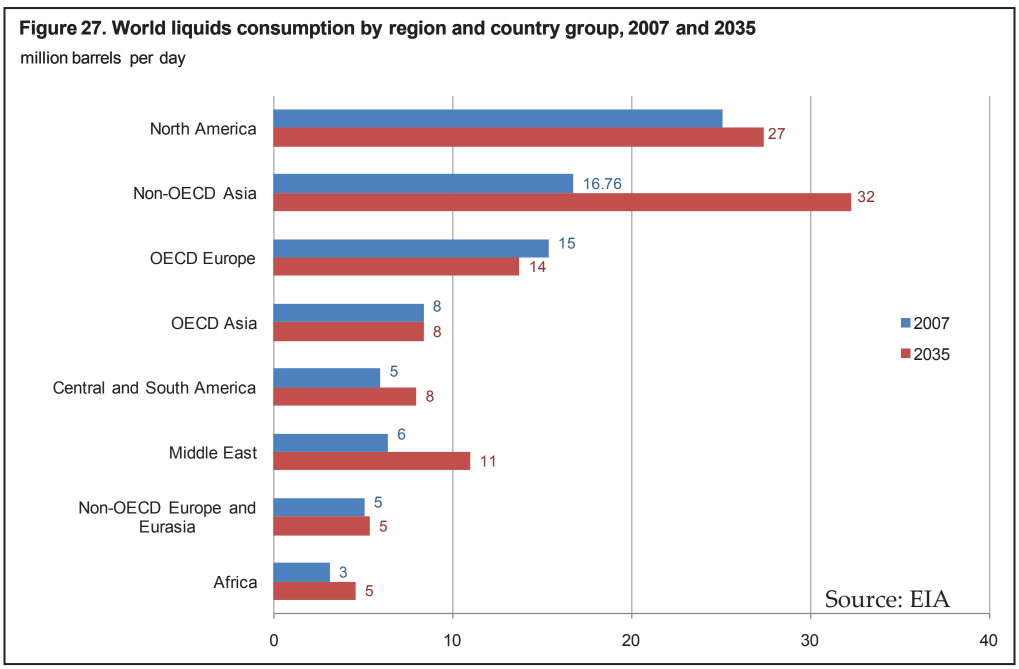

Figure 9: World Liquids Consumption from *EIA International Energy Outlook 2010*

Comparison of Navigant's Supply Outlook to Other Outlooks

In **Figure 10:** *Supply Outlook Comparison: Navigant and EIA*, Navigant's Spring 2011 shale production forecast calls for more gas to be brought on between now and 2020 than does EIA in its *Annual Energy Outlook 2011*. After 2020, the lines of growth are roughly parallel. As the graph also shows, both

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[14] *International Energy Outlook 2010*, EIA, p. 23, available at http://www.eia.gov/oiaf/ieo/liquid_fuels.html

Navigant and EIA increased their estimates for shale production this year compared to 2010, by roughly the same amounts post-2020.

EIA has historically lagged in the recognition of the size of the shale gas resource. As shown in **Figure** *6: Shale Production* 2007-2011, above, shale production in the U.S. in the first quarter of 2011 is 18.0 Bcfd, and on its way to the 20.0 Bcfd in our forecast. EIA's forecast of 15.0 Bcfd for 2011 has already been eclipsed.

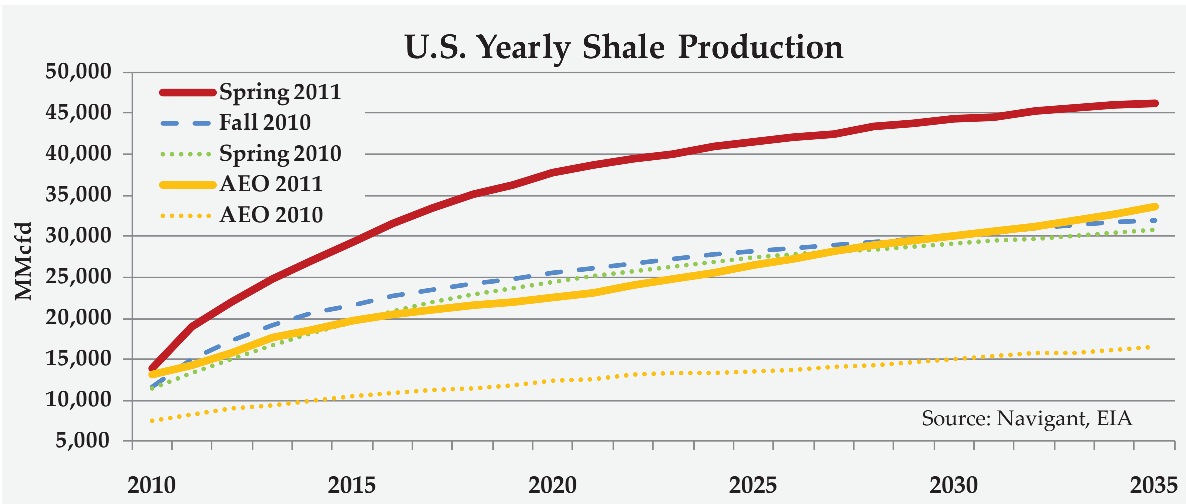

Figure 10: Supply Outlook Comparison: Navigant and EIA

Year	Navigant Spring 2011	Navigant Fall 2010	Navigant Spring 2010	EIA AEO 2011	EIA AEO 2010
2010	**13,976**	11,665	11,478	13,151	7,534
2015	**29,276**	21,659	19,586	19,726	10,548
2020	**37,823**	25,550	24,451	22,493	12,356
2025	**41,521**	28,196	27,328	26,548	13,534
2030	**44,250**	30,049	29,155	29,973	15,068
2035	**46,127**	31,850	30,743	33,562	16,438

Table 1: Supply Outlook Comparison: Navigant and EIA

Demand Is Likely to Increase Steadily

An unappreciated fact is that reliable demand is a key to underpinning reliable supply and a sustainable gas market. Supply is unlikely to be developed unless demand is there to absorb it, and demand will not develop unless supply is there to support it. Demand and supply are two parts of the same dynamic.

In Navigant's view, demand is likely to increase steadily over the coming years. Many factors support this outlook.

The chief driver of steadily growing gas demand is the abundance of reliable and economic supply. With the advent of significant shale gas resources, end-use and pipeline project developers are assured that gas will be available for the indefinite future.

Further, the prospect of steadily growing and reliable supply portends relatively low price volatility. Because of the manufacturing-type profile of shale gas production, production rates can be better matched to demand growth. Low price volatility, like supply growth, is supportive of long-life end-use infrastructure development and pipeline projects.

Demand will also be supported by the existing pipeline network throughout North America. The delivery infrastructure for natural gas is mature and, with the exception of a few highly urban areas such as greater New York City, relatively cost-effective and quick to expand. Since shale resources are so widely dispersed around the continent, Navigant does not foresee the need for another long-line pipeline such as the recently built Ruby, which extends from Opal, Wyoming to markets in California, with the possible exception of the Florida market. Florida produces a negligible amount of gas and may be a possible target for a major pipeline. Such a line would likely transport supplies from the prolific Barnett, Haynesville, and Fayetteville shales in Texas, Louisiana, and Arkansas.

Demand by Sector

Navigant projects that the overwhelming majority of growth in natural gas demand will come from the electric generation (EG) sector of the market. EG is expected to grow at an annual rate of 2.1 percent through the study period, with a higher rate of 4.9 percent through 2015. These expectations are based mainly on expected coal-fired power plant retirements, described later in this report.

Industrial demand in the North America is expected to grow annually by an average 0.5 percent, driven largely by demand from the prolific oil sands development in Alberta and a slowly recovering economy in general.

Residential, commercial, and vehicle demand for natural gas is expected to grow very modestly, at 0.2 percent annually.

The sectoral outlook for natural gas demand is shown in ***Figure 11:*** *North American Natural Gas Demand Projection*.

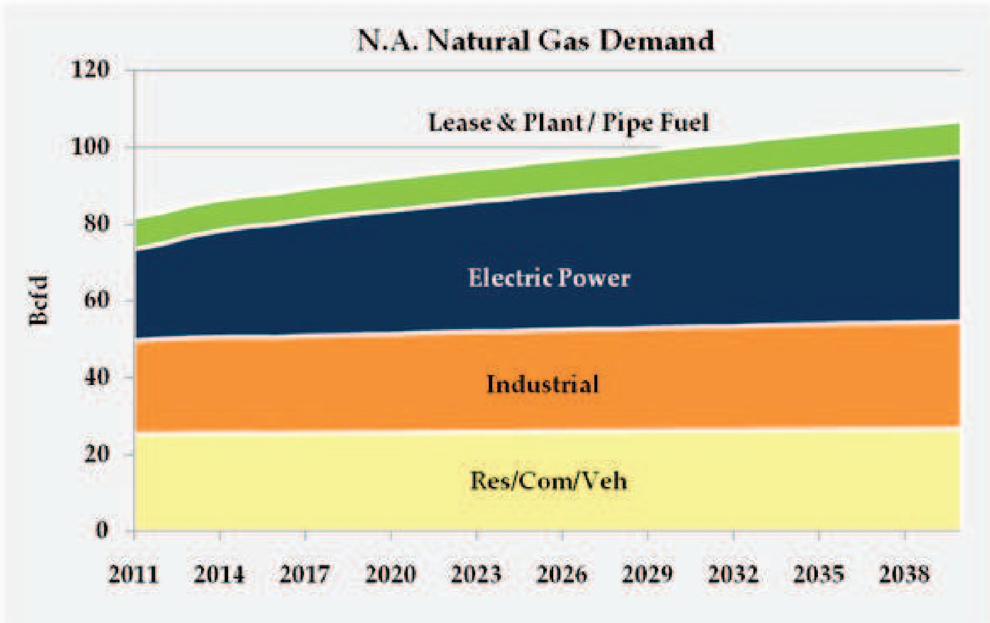

Figure 11: North American Natural Gas Demand Projection

Another recent positive development to the sustainability of the long term gas market is the development of LNG exports. As an artifact of gas shale in North America, four LNG developers, including Cove Point, have now applied for approval to export natural gas from the U.S. In May, Cheniere Energy received U.S. Department of Energy approval for the export of up to 2.0 Bcfd of LNG from their Sabine Pass terminal. Taking advantage of the surplus of natural gas supply, Cheniere has plans to construct a new liquefaction terminal on the same site as their existing import facility.

So far, Cheniere is the only U.S. facility in the Lower 48 to have received DOE approval, but other facilities have applied for export authority or are considering it. LNG export facilities offer the potential for a new baseload market for natural gas and to support ongoing development of the resource through market balancing.

Although Cheniere's Sabine Pass export facility is not scheduled for start-up until 2016 and will not have market impact in 2011, over the mid and long term, emerging LNG exports should provide a new market in the currently oversupplied natural gas market in the U.S. It is becoming increasingly evident that the slow development of new markets for natural gas is the only thing currently restricting even more gas resource development.

Competition from Oil and Other Fuels

As Navigant details in the accompanying report ***North American Gas System Model to 2040***, annual average natural gas prices are projected to remain below $6.61 through 2030 in its Cove Point Case. The Cove Point Case includes LNG exports from Cove Point, Kitimat in British Columbia, and Sabine

Pass in Louisiana. On a per-MMBtu basis, this is expected to be well below oil prices and competitive with coal prices.

Oil

In earlier times, gas and oil competed for some of the same markets, particularly in the electric generation and industrial markets. For the past 20 years, however, oil has become increasingly pushed out of those markets due to gas's lower cost and superior environmental profile. Oil is now used chiefly as a motor fuel and lubricant. The prices of gas and oil are generally acknowledged to have decoupled in North America, as they serve largely separate markets. This is illustrated in the chart at **Figure 12:** *Comparison of Oil and Gas Prices per MMBtu*.

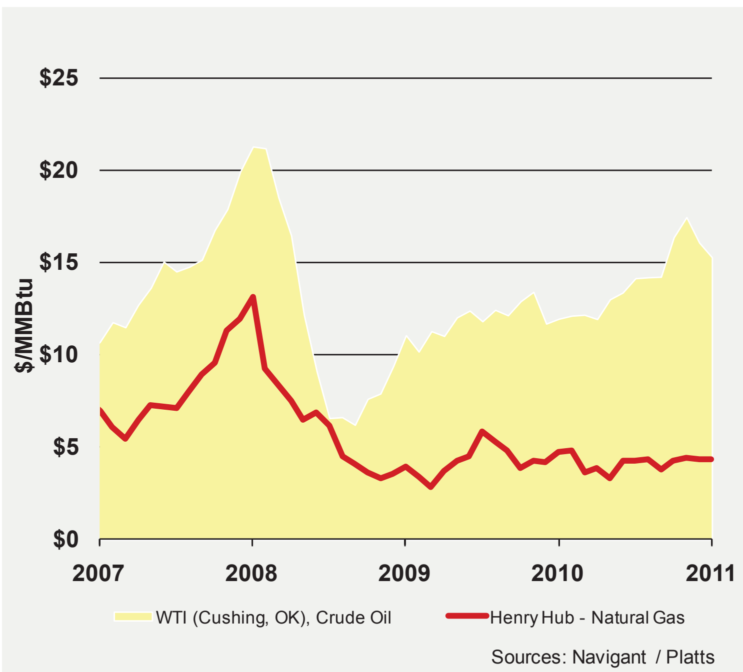

Figure 12: Comparison of Oil and Gas Prices per MMBtu

In any case, the price of oil is likely to continue to be at a significant premium to gas. Gas is domestically plentiful, relative to demand. Oil is not. The United States imports nearly two-thirds of the oil it consumes.[15] Conventional oil resources in the U.S. have largely been identified. Over the last two decades, the motivation to drill for oil in the U.S. has shifted to opportunities around the globe with better returns. It is unlikely that the total oil resource potential in North America has changed recently, especially given restrictions still in place on offshore drilling in the wake of Deepwater Horizon.

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[15] Data from Petroleum Supply Annual, Volume 1, U.S. Energy Information Administration, available at http://www.eia.gov/petroleum/supply/annual/volume1/pdf/table1.pdf

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Large scale export of East Coast Australia natural gas: Unintended consequences

A study of the national interest effects of the structure of the Australian gas industry.

A report to
The Australian Industry Group and the Plastics and Chemicals Industries Association

Prepared by the
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October 2012

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Executive summary

"*One molecule of natural gas is chemically the same as another, but where it is found has enormous implications for global politics.*

The price of gas in the US following the shale drilling boom is now a third of that in western Europe and a fifth of that in Asia."

Financial Times, 17 July 2012

"Gas prices on the eastern seaboard will follow the big rises already hitting downstream industrial users in Western Australia, says Santos chief executive David Knox.

At a Sydney forum on the future of gas, Mr Knox stated that prices in the east of between $3 and $4 a gigajoule would rise to between $6 and $9 for new domestic customers as increasing volumes were exported.

That is the range we are talking about for anyone coming to us now," he said. "We are actively negotiating with a number of buyers … and you are going to see an increase in prices."

Australian Financial Review, 23 August 2012

Natural gas is a fundamental source of energy for power generation, industry, consumers, hospitals and institutions generally. In today's world of transition to greater use of renewable energy it plays an important role in facilitating cost effective peaking power to fill the gaps when renewable supply is not available. It is both an efficient relatively clean fuel source and a critical feedstock for conversion by industry into value-added consumer products. Its value to the domestic economy is very significant as the alternatives are less efficient and, in the case of coal and oil, have significantly higher greenhouse gas emissions.

Many major projects to export Liquefied Natural Gas from Eastern Australia have been approved and will start to operate over the next several years. This will significantly impact the domestic supply of natural gas. In this report we do not argue against the export of LNG but emphasise that the benefits from exporting LNG should be weighed against the benefits of ensuring competitive supply to the domestic gas-dependent manufacturing sector. In a market where there are sufficient reserves of the resource, as appears to be the case in Australia, the typical response would be for additional supply to be made available to meet domestic demand. However, due to the nature of the gas resources, their location, limitations in infrastructure and the way in which we manage these resources, there is a serious risk that this will not be the case. Even a temporary period without secure access to domestic gas would have significant unintended consequences, as would a shift to LNG-linked gas pricing. As such, it is prudent to look at the implications of these developments for consumers and industry.

The National Institute of Economic and Industry Research (NIEIR) has made such an assessment, reviewing the literature and conducting its own assessment of the sectoral and macroeconomic implications of these developments. The findings are concerning.

NIEIR has found that:

- if existing plans proceed, gas exports from eastern Australia will rise from 2 million tonnes in 2015 to 20 million tonnes in 2018, and possibly 24 million tonnes in 2023;

- the current policy framework and market settings for the Australian gas industry favour export of LNG without a subsequent assurance of reliable, competitively priced supplies of gas for domestic industry. Such supplies have historically been a competitive advantage for Australian industry, and gas export revenue is insufficient to compensate Australia for the loss of this advantage;

- natural gas is essential to a range of industries, particularly non-ferrous metals and basic chemicals, but also plastics, pharmaceuticals, paints and cosmetics. Secure local supply at competitive prices is a fundamental requirement for the continuation of a significant part of production and the development of new investment in these industries;

- contracts for the long term supply of gas to domestic industry have ‘evaporated’ as a consequence of export commitments;

- Australia has only a few years before significant economic loss is likely to be felt from the failure to secure an affordable supply of natural gas to domestic users;

- domestic gas users are increasingly being offered “surplus” gas volumes and prices that do not reflect domestic supply, demand or extraction costs, but are instead linked to East Asia’s LNG market – the highest-priced gas in the world. This is a radical reshaping of the domestic gas market, constraining supply (in the near term at least) and driving prices to high (and for many industries uneconomic) levels;

- current gas production and proven reserves will need to expand dramatically in order to support the LNG expansion without significant large scale suppression of gas use on the domestic economy. While the total gas resource is thought to be very large, proving up additional resources and developing them will take time and faces community opposition and other barriers. To ensure gas availability for domestic users, the management of reserves and their supply to market needs attention if domestic needs are not to be overlooked in the rush to export this valuable resource;

- there are important opportunities to expand use of gas in industrial production and electricity generation, but even so domestic consumers cannot make use of the whole gas resource. There are worthwhile benefits to pursue from exporting gas production beyond these needs. But each petajoule of natural gas that is shifted **away** from industrial use **towards** export, whether because of tight supply or uneconomic pricing, means giving up $255 million in lost industrial output for a $12 million gain in export output. That is, for every dollar gained $21 is lost. This increases to $24 when economy-wide impacts are taken into account;

- the dramatic shift in the domestic gas market will have wider impacts well beyond the gas intensive industries:

    - increased operating costs for gas-fired electricity generators due to high gas prices. Such generators would see cost increases three times greater than those currently resulting from the carbon tax. Wholesale electricity prices would thus rise, and the viability of new gas-fired generation would suffer. These plants already play an important role in the electricity market for both peak power and base load. That role is expected to grow to meet emissions reduction targets and provide backup for expanding renewable generation;

- some substitution away from gas towards electricity by business and households, to reduce their exposure to rising gas prices. This would still leave their costs higher than at present, and would raise greenhouse emissions;

- a slow-down of general economic activity resulting from impacts of the tighter gas supply and higher costs for gas and electricity;

- the expected economic response to the East Coast LNG expansion will involve a combination of the adjustments above. As a result, modelling indicates that, by 2040 the gross production benefit for East Coast LNG expansion will be $15 billion annually, in 2009 prices. However, taking into account the negative effects of adjustment on other sectors, annual GDP will be $22 billion lower than it would be with secure and affordable gas. An alternative 'benefit indicator' used for this study, which combines private consumption, tax receipts and net national product, will be reduced by $46 billion;

- under current policy settings and market structures, the unwanted consequences of the significant boom in LNG exports will persist even if, as is likely, adequate natural gas reserves exist and are brought to market; and

- there are substantial further risks that would lead to even greater costs if realised. These risks include:

  (i) LNG prices may be lower than currently expected. While this would reduce the extent of domestic price rises, it would also reduce gross export benefits while leaving domestic supply constrained in the short-to-medium term by contracted export commitments; and

  (ii) industry will likely be unable to grow without secure affordable gas supplies, leading to additional damage.

The rules of thumb developed in this study for these additional effects are:

- for every 1 per cent reduction in the LNG price the economy-wide benefits from LNG exports will be reduced by approximately 2 percentage points. This stems mainly from the fact that tax receipts and domestic profits will be disproportionately impacted. Foreign interest payments and repayment of debt will still have to be paid; and

- for every $1m of existing chemical industry output that is saved by increased natural gas supply there is another $1m of output that can be obtained by using the competitive advantages for domestic natural gas availability in general, and natural gas liquids in particular.

The likely consequences of the current policy and industry settings on natural gas export are serious for both industry and households. There is an urgent need for more recognition of these impacts, and for a debate on how they can be prevented, alleviated or adapted to. LNG export is a positive for Australia as long as it proceeds without significant harm to the domestic sector and with confident assurance of domestic supply.

1. Background and study objective

1.1 Background

Natural gas is an essential input to value creation and productivity in many of Australia's key industries. If the supply of natural gas is threatened or, short of this, confidence in its ready availability at competitive prices is weakened, so too are the industries that use the gas as a raw material or fuel. Current developments in Queensland, focusing on LNG exports, are threatening Eastern Australia's gas-dependent industries by weakening confidence that gas will be available at competitive cost.

In this report we do not argue against the export of LNG but emphasise that the benefits from exporting LNG should be weighed against the benefits of ensuring competitive supply to the domestic gas-dependent manufacturing sector. Our work indicates that the national benefit from the supply of gas to the many industries that are involved is many times the gain due to export of the same quantity of gas.

Taking these benefits into account, from the beginning the Western Australian Government was active in ensuring that domestic use of the offshore North West Shelf gas resource was to be protected. The Government explicitly committed to actively ensuring that this would be the case. The provisions of the original LNG Act drafted in the 1970s to pave the way for Australia's first LNG export project are specific in the way the reserves are to be used for both export and domestic users. Two sections of the Act indicate this.

> *"**Notification of additional reserves of natural gas***
>
> *20. If the Joint Venturers discover reserves of natural gas additional to those required for their commitments contemplated in recitals (c) and (d) of this Agreement during their exploration programme in the offshore Dampier region (carried out under the provision of the Petroleum (Submerged Lands) Acts), which in the opinion of the Joint Venturers are capable of commercial development the Joint Venturers shall –*
>
> *(a) notify the Minister of the extent and nature of such additional reserves;*
>
> *(b) having regard to the State's desire for the petrochemical industry to be established in Western Australia, investigate the processing of all or part of such natural gas for use as petrochemical feedstock; and*
>
> *(c) enter into discussions with the Minister concerning the utilisation of such natural gas."*

> ***"Marketing authorisation***
>
> *42. The State authorises the Joint Venturers and each of them subject to the provisions of this Agreement and pursuant to recital (c) hereof to sell gas to the State Energy Commission and pursuant to such gas agreements with the State Energy Commission –*
>
> *(a) to market gas in the Pilbara to each of their affiliated companies and to major industrial customers who use more than 28 000 cubic metres of gas per day;*

(b) *to sell or supply gas to each of their affiliated companies anywhere in Western Australia;*

(c) *to construct, finance and operate gas transmission pipelines to each of their customers in the Pilbara."*

The benchmark price for domestic sales from the Joint Venture was set with a high weight given to domestic cost levels and competitiveness.

In terms of new fields in this century, the Western Australian Government has imposed a reservation policy where 15 per cent of the natural gas reserves are required to be used for domestic purposes.

The case is very different for Queensland. As of 2012 three major LNG plants are under construction in Gladstone on the Queensland central coast. These projects have been approved to proceed without any conditions or arrangements being put in place to generate supply at competitive prices to domestic gas users, whether they are heavy industrial users, commercial business, electricity generators or households.

With the advent of LNG projects the situation changed quickly for Queensland domestic gas customers and increasingly for large users across the east coast. Previously users were offered long-term contracts with predictable price settings. They could undertake long-term investments underpinned by a secure and cost-stable energy supply.

Currently, long-term contracts have "evaporated" as the first priority of gas producers is to secure supply for their LNG plants. Domestic customers feel the domestic market is now the residual sector, allocated what is surplus to requirements for the LNG plants, a reality which will become obvious once existing gas contracts end. Medium-term, let alone long-term, security of supply is no longer guaranteed. Domestic customers are now faced with the expectation having to pay the "net back" LNG price for natural gas, involving most probably a significant increase in price and, more importantly, the introduction of considerable price uncertainty derived from the unpredictability of the world gas market.

Admittedly, it is difficult to be precise about the calculation of 'net back' prices. Because of the variation in contract arrangements between LNG projects, the concept of a world LNG price is difficult to apply and actual prices will be determined by specific contract provisions. The provisions may or may not relate to LNG prices from other sources, either in Australia or overseas.

However, the concept of a domestic gas price based on a 'net back' price for LNG may not be the only factor leading to increased and more variable prices. Domestic consumers expect that the large impact of LNG demand on reserves will force domestic supply to be sourced from fields with higher extraction costs and, therefore, higher domestic cost. Since the majority of gas reserves are leased by interested parties focussed on LNG, it now appears likely that the domestic customers will be matched to the marginal increment in gross supply costs.

This is an extraordinary state of affairs given the scale of the projects and scale of the impact on the existing Australian identified reserves of natural gas. In the application of the national interest test to the projects which governments are obliged to do as manager of the resource on behalf of the community, it appears unlikely that the impacts of the LNG projects on domestic gas using industries have been considered to any great extent. This has been done in private sector reports, such as "*Carbon Market Economics – The Impact of Liquefied Natural Gas on Queensland Gas markets and Gas Users*", March 2010, with to date little impact in changing arrangements.

Australian natural gas (identified and potential) reserves are owned by the Crown which obliges the government of the day to determine when and how the resources are to be used. In exercising this duty, the government has a responsibility to optimise the benefit which current and future generators obtain from the extraction of the resources. Under the Australian constitution there are Federal/State Government jurisdiction issues as to who is responsible, but the reality is that all areas of Government need to cooperate to solve the problem.

1.2 Study objective

Accordingly, the study objective is to:

(i) outline a framework for testing the national interest benefit of Eastern Australian LNG projects that should be applied by the responsible Governments;

(ii) apply the framework to assess the net benefits that are likely to be obtained from the current projects under the current terms and conditions of their approval; and

(iii) evaluate the impact of alternative terms and conditions, in terms of assessing whether or not the net benefits assessed in (ii) can be significantly increased.

In short, this report complements the *Carbon Market Economics* (CME) report by quantifying the macroeconomic costs of a less than satisfactory (that is deficient) national interest evaluation and appropriate complementary policy design.

1.3 The LNG industry evaluated by this study

The LNG industry evaluated by this national interest evaluation is LNG exports from Queensland. The question at issue is whether Australia will obtain a net benefit from expected exports of LNG from Queensland. The expansion profile assumed in the quantitative analysis of the issue is:

Exports of LNG from Queensland
(million tonnes)

2015	2
2016	15
2017	18
2018	20
2019	20
2020	20
2021	20
2022	20
2023	24

In simple terms, therefore, the study will attempt to answer the question of whether or not Australia will obtain a net benefit from 24 million tonnes per annum of natural gas export from Queensland.

1.4 Why the focus on East Coast LNG?

The focus on East Coast LNG is because:

(i) the Western Australian market is not connected to the integrated gas market of the Eastern Australian states (which for this purpose include South Australia but not the Northern Territory) and

(ii) Western Australia has a domestic reservation policy for natural gas and the eastern states do not.

Because of the inter-connection between the eastern states' markets, the East Coast LNG plants will affect the majority of the Australian economy.

In short, given the conditions under which the Queensland projects were allowed to proceed, it is these projects that are most likely to fail a comprehensive national interest test.

1.5 Construction impacts

This study focuses on the production impacts on the economy. The construction impacts of new capacity required to support the changes is ignored as there is no suggestion that the LNG projects should not proceed but the focus should be on ensuring there is ample gas for the domestic sector.

2. The national interest evaluation framework, indicators and methodology

Under Australian law, Australia's petroleum (including natural gas) resources (and mineral resources) are owned by the Crown, in some cases in the right of the states and territories and in some cases in the right of the Commonwealth. In the words of the Productivity Commission, governments should exercise stewardship over Crown resources, managing them to achieve maximum overall benefits for the community. As the Productivity Commission notes, management should not simply be focussed on economic benefits but should also take into account objectives such as the protection of health, the environment and heritage. In general terms, the governance requirement is expressed as the Government's responsibility to make decisions on:

- how;
- when; and
- on what terms,

the petroleum resources are extracted, in terms of maximising the national interest.

Although the national interest test is required in legislation, for example, for assessing foreign investment proposals, Australian Governments have not explicitly stated what guidelines should be applied in balancing the economic, environment, strategic or social interests that constitute the national interest. While this allows regulatory bodies to operate with maximum flexibility, it also shields their decisions from evaluation in terms of explicit criteria.

2.1 The national interest test

The latest statement on the national interest test was made on behalf of the Australian Government by the Treasurer.[1] The statement applies to foreign investment but would be equally relevant to resource management decisions, and not only for the reason that most resource management decisions have a foreign investment component. The statement runs as follows.

2.1.1 What are the characteristics of investment proposals that are likely to be approved

The Government is making sure investments are not contrary to the national interest. If an investment is contrary to the national interest, the Government will intervene. This occurs infrequently.

What is contrary to the national interest cannot be answered with hard and fast rules. Attempting to do so can prohibit beneficial investments and that is not the intention of our regime. Australia's case-by-case approach maximises investment flows while protecting Australia's national interest.

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[1] The Treasurer of Australia, "*Australian Foreign Investment Policy*", January 2012.

2.1.2 What are the national interest considerations

Assessing the national interest allows the Government to balance potential sensitivities against the benefits of foreign investment.

The Government determines national interest concerns case-by-case. We look at a range of factors and the relative importance of these can vary depending upon the nature of the target enterprise. Investments in enterprises that are large employers or that have significant market share may raise more sensitivities than investments in smaller enterprises. However, investments in small enterprises with unique assets or in sensitive industries may also raise concerns.

The impact of the investment is also a consideration. An investment that enhances economic activity – such as by developing additional productive capacity or new technology – is less likely to be contrary to the national interest.

The Government typically considers the following factors when assessing foreign investment proposals.

National Security

The Government considers the extent to which investments affect Australia's ability to protect its strategic and security interests. The Government relies on advice from the relevant national security agencies for assessments as to whether an investment raises national security issues.

Competition

The Government favours diversity of ownership within Australian industries and sectors to promote healthy competition. The Government considers whether a proposed investment may result in an investor gaining control over market pricing and production of a good or service in Australia. For example, the Government will carefully consider a proposal that involves a customer of a product gaining control over an existing Australian producer of the product, particularly if it involves a significant producer.

The Government may also consider the impact that a proposed investment has on the make-up of the relevant global industry, particularly where concentration could lead to distortions to competitive market outcomes. A particular concern is the extent to which an investment may allow an investor to control the global supply of a product or service.

The Australian Competition and Consumer Commission (ACCC) also examines competition issues in accordance with Australia's competition policy regime. Any such examination is independent of Australia's foreign investment regime.

Other Australian Government Policies (Including Tax)

The Government considers the impact of a foreign investment proposal on Australian tax revenues. Investments must also be consistent with the Government's objectives in relation to matters such as environmental impact.

Impact on the Economy and the Community

The Government considers the impact of the investment on the general economy. The Government will consider the impact of any plans to restructure an Australian enterprise following an acquisition. It also considers the nature of the funding of the acquisition and what level of Australian participation in the enterprise will remain after the foreign investment occurs, as well as the interests of employees, creditors and other stakeholders.

The Government considers the extent to which the investor will develop the project and ensure a fair return for the Australian people. The investment should also be consistent with the Government's aim of ensuring that Australia remains a reliable supplier to all customers in the future.

Though the national interest is defined broadly, possible negative spillover effects of any specific investment on other industries are not explicitly considered.

2.2 A qualification of the national interest test: The guidelines used for this study

(i) Net economic benefit

The project should make a significant net benefit to cumulative economic activity over its life including the construction phase.

(ii) Significant medium-term benefits

In order to ensure that the benefits are not delayed beyond the living spans of a significant proportion of the current living population, at least one third of the net benefits should be achieved within the first 10 years of the life of the operations of the project.

(iii) Strengthening the skill base of the economy

The project should, net, strengthen the skills base of the economy as measured by the skill intensity of demand for labour.

(iv) There is a significant net impact on Government revenues

In order for the benefits of resources to be distributed to the broader community, Governments need a significant revenue base to distribution. Therefore, a necessary requirement would be that the discounted Government revenue from the project be greater than what would be achieved from an expansion in the general economy.

(v) Australia's economic security

One requirement here, in general terms, would be for the economy to be able to withstand negative economic shocks better than would have been the case in the absence of the project. Australia's relatively secure open economy is subject to shocks in the form of sudden and adverse movements in terms of trade (commodity prices) and the exchange rate. It is desirable, therefore, that the project should reduce the economic costs of adverse commodity prices and exchange rates.

(vi) Australian political security is enhanced

It is desirable that the project should not promote economic dependence on any particular trade partner or closely-allied group of partners.

2.3 The national interest evaluation: Its importance in optimising national benefits

The decision to allow an individual LNG project to proceed or not, in terms of the national interest test, would depend on whether or not the expected net economic, environmental and security outcomes are significantly positive. The project would only be allowed to proceed if it was deemed likely to yield greater national benefit compared to denial of approval.

In most cases, however, it will not be a simple case of a go/no go decision. The national interest evaluation process will frequently identify negative outcomes which can be remedied either by changes in the particular project or by more general policy changes, unrelated to the particular project, which will increase the benefits generated by the project. These complementary policies or other changes may change the status of a project from ‘no go’ to a strong positive national interest return, and will frequently include strategies to minimise the costs which the project imposes on other industries. A rigorous national interest evaluation process is therefore in itself an instrument to maximise national benefit.

2.4 The benefit indicator

After the design of the national interest evaluation framework, the next most important decision is the selection of the core indicator for evaluating net benefits. In general terms the benefit indicator selected should measure that part of the flow of production that is available to support expenditures in the national economy that directly contribute to welfare/happiness. In the absence of direct measures of welfare, it is usual to concentrate on the flows of funds available to citizens for expenditure on meeting their needs and wants. We are therefore seeking within the constraints of available data for a benefit indicator of sustainable consumption.

A range of indicators is commonly used when measuring the impact of an investment on economic activity, including:

- gross domestic product;
- gross national product (gross domestic income); and
- net national product (net domestic income).

The bracketed name is what the series is now called in the Australian National Accounts. The original names are retained in this study because they clearly signal that the indicators have the same status as GDP whereas the new names imply a lower status. Gross domestic product is the value added generated in a given jurisdiction, irrespective of where the income is distributed. Gross national product (gross domestic income) is GDP less that part of GDP that is distributed to foreign residents or companies in the form of interest, dividends and undistributed income. Net national product is gross national product less that part of value added that is allocated to depreciation expenses. The last is the most appropriate to use in evaluating the benefits of investments in the gas industry for two reasons.

- high foreign ownership in the industry (one of the three LNG export terminals currently under construction at Gladstone is wholly overseas owned and the other two are joint ventures with substantial overseas participation); and

- very high depreciation charges (the bulk of depreciation expense occurs in the first half of the project life and much of it is returned overseas to repay debt).

Because of overseas ownership and high depreciation, the GDP indicator gives a very misleading indication of the benefits of LNG plants.

Given a regard for national welfare, the benefit indicator on which all national interest evaluations should be based should be either net national product (net disposable income) or direct estimates of sustainable private and public consumption expenditure impacts, which can be approximated by consumption expenditure plus total taxation revenue. Both NNP and consumption plus tax revenue are reasonably good proxies for sustainable consumption. Accordingly, for this study, the benefit indicator is taken to be an average of the two measures, that is, the sum of NNP plus private consumption expenditure plus taxation revenue divided by two.

2.5 A probability approach needs to be built into the evaluation framework

A probability approach is required for this study and for testing the implications of a project's approval by regulators. For this study a range of parameters have to be quantified with values around which there is a great deal of uncertainty not only in terms of current settings but also what the values may be over a 20 to 30 year time horizon.

Regulators are able to assess more accurately current information in regard to particular projects if only for the reason that it will be contained in the supporting documentation required for the approval process. In terms of the future values of required parameters, this will require judgement based on the best available current information. In this case, it would be useful for regulators to adopt a probability approach which requires the explicit setting of the characteristics of the probability distribution around key parameters.

This also fits into the general bottom line reality of assessments. Because of uncertainty, the best that any national interest assessment can conclude is that "*on the balance of probabilities it is concluded that .....*". By specifying probability distributions of the key parameters that determine the overall outcomes, the degree of uncertainty surrounding a decision for a project to proceed or not, or surrounding the conditions imposed on project approval, can be communicated to the general public. This eliminates the need for regulators to have a non-transparent and flexible definition of how the national interest is to be assessed.

Further, it can be more difficult to interrogate modelling results, and minor differences in assumptions can lead to big differences in outcomes. This worry is blunted if a probabilistic framework is adopted since, if results are sensitive to certain parameter specifications, this will be indicated by a high probability distribution range around the bottom line evaluation indicators.

In the present study, all relevant data and relationships used in the calculations for the national interest evaluation are included to readers to cross check the conclusions.

2.6 The quantification of risk – the Trigen distribution

For this study the probability distribution selected to quantify risk is the Trigen distribution. This distribution is selected because its parameters are easily related to the conditions that the probability distribution is describing.

To apply a Trigen probability distribution five parameters have to be specified. They are:

(i) the lower bound of the parameter/indicator;

(ii) the mode value of the parameter/indicator;

(iii) the upper bound value of the parameter/indicator;

(iv) the probability that values less the lower bound values will be taken; and

(v) the probability that values less than the upper bound value will be taken.

The approach will be illustrated for perhaps the most important input indicator for this study which has a high level of uncertainty. This indicator is the total remaining identified and undiscovered reserves of natural gas. As shorthand, these reserves are often referred to as remaining reserves. Chapter 6 below nominates the lower bound and upper bound values based on the estimates of others.

Figure 2.1: Trigen probability distribution for remaining reserves

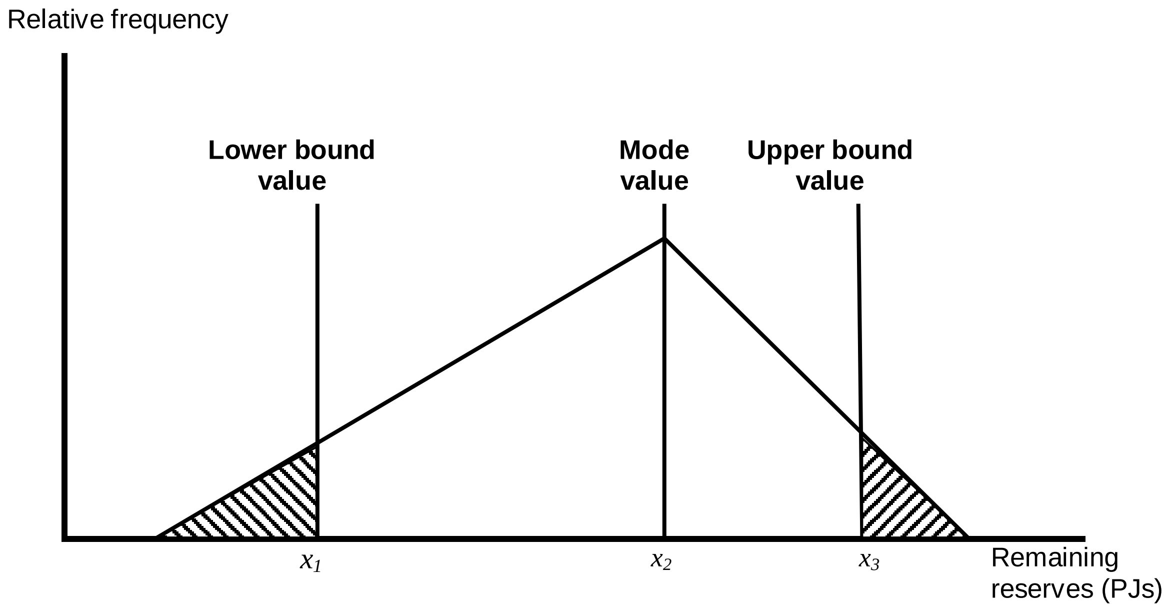


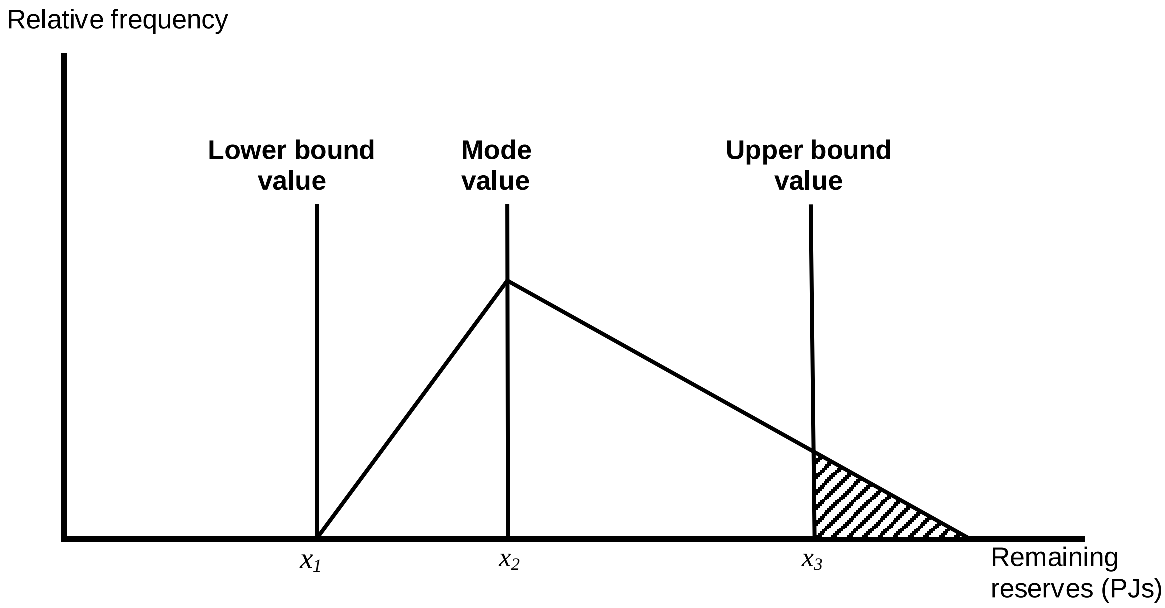
Figure 2.1 illustrates this case. Remaining reserves are measured in petajoules (PJs). The remaining reserves, in terms of lower bound (x_1), mode (x_2) and upper bound values (x_3) are selected on the best available information. If the upper bound probability is set at 100, then there will be no shaded area for the upper bound value. However, if it was considered that the probability of finding more reserves than the upper bound value, then the upper bound probability might be set at 80 per cent with the shaded area in the figure representing a probability of 20 per cent.

The same concepts apply to the lower bound values. For this study the lower bound probability is set at zero, meaning that there is no probability of the lower bound value taking lower values.

The mode can be selected on the basis of whether an upward or downward bias is to be imposed after consideration of upside and downside risks.

Figure 2.2 illustrates the case where the downside risks are considered dominant. Also, the lower bound probability is set at zero.

Figure 2.2: Trigen probability distribution for remaining reserves



2.7 The spillover impacts on other industries

A deficient national interest test would focus on the value of a project with little or no testing of the implications for other industries.

Comprehensive economic national interest testing examines how the project will impact other industries both positively and negatively. Comprehensive national interest testing, therefore, focuses not on the gross benefit of a project but the net impact after taking into account both negative and positive impacts on other industries.

3. LNG export expansion – channels of costs imposed on non-resource industries

LNG expansion can impose costs on other industries. Although a range of transmission channels may be relevant, the costs generally take the form of reductions in the level of output in other industries, sometimes referred to as crowding out. In a fully-employed economy some level of crowding out is inevitable if new projects are to proceed; the question is then whether the benefits from the new project exceed those lost through crowding out. In economies which are less than fully employed opportunities may exist to resource the new project without crowding out, in which case the potential benefits are considerable. However, there is also a possibility that projects will be implemented in ways which cause unnecessary crowding-out.

The discussion here is in qualitative terms and takes LNG expansion as a particular case of resource industry expansion. Although agriculture is also a resource industry, in the context of this chapter the term exclusively applies to the resource extraction industry. In ABS terminology the resource extraction industry is called mining and includes all activities which extract subsurface mineral resources other than water.

3.1 Macroeconomic resource (labour) constraints: Non-resource industry crowding out

Macroeconomic resource constraints apply to any LNG project planned for an economy which would otherwise be operating with full utilisation of resources, or which would reach full resource utilisation in the event of the project proceeding. Full utilisation can apply in both the construction and production phases of the project, and may apply to the economy as a whole or to particular inputs or geographic areas. If the project is to divert inputs from other uses the following tests must return positive answers if the project is to yield net benefits at the national level. (The tests are specified in terms of labour, but can be re-phrased to apply to any other diverted inputs such as office space). The first test is relatively simple: gross product, real wages and Government tax per hour worked by marginal workers transferred into the project are greater than gross product, real wages and taxes per hour worked by marginal workers in the industries from which they are displaced. The second test recognises that labour displacement will be accompanied by a gradual process of capital displacement, particularly during the construction phase, during which capacity-enhancing investment in the non-resource industries will be crowded out by resource project investment. The second test requires that the foregone productivity-enhancing effects of the crowded out investment does not reverse the first test.

Though these tests are conveniently specified in terms of labour, it should be remembered that Australia has a long history of alleviation of labour shortages through increased immigration. The chief concern, therefore, has to be crowded-out investment.

3.2 The drivers of manufacturing expansion

Relative costs are important in the sense that manufacturing will contract if there is too great a gap between domestic and foreign costs of production. However, even if relative costs are comparable and Australian products have a price edge (as when the actual $A/$US exchange rate is below its Purchasing Power Parity level) manufacturing expansion still depends on producers' ability to gain a competitive edge by product differentiation in terms of the design, functionality, durability, etc. of their products. This requires years of lead time in research and development and marketing efforts and also requires time to finance innovation and new capacity involving the latest technology and so on. The efforts of a firm to adopt best practice production technology, innovate via research and development expenditures and develop new markets are all part of either achieving competitive edge product differentiation or identifying opportunities for greater exploitation of existing advantages.

In the typical manufacturing industry the individual producer creates or maintains a market while in the resource extraction industry the producer responds to the market. This is why differentiated product manufacturing is riskier than most other industries. An important aspect of this higher level of risk is that differentiated product manufacturers have to create their own finance for expansion whereas in resource extraction industries this finance is delivered by the market.

At the macroeconomic level the different drivers of the resource extraction industry versus manufacturing expansion can lead to a conflict between manufacturing expansion and equivalent resource extraction industry expansion that is unrelated to issues of national resource availability. This is because the higher terms of trade effect associated with resource extraction industry expansion crowds out manufacturing activity through exchange rate impacts. The converse negative impact on the resource extraction industry from manufacturing expansion is much weaker because manufacturing expansion does not influence the terms of trade.

The most important dynamic is one of cumulative causation. Success in sustained manufacturing expansion depends on an uninterrupted sequence of steps that are resourced adequately and are consistent with market requirements.

Periods of highly over-valued exchange rates associated with elevated resource extraction industry activity intensity are very destructive for manufacturing. This is because high relative costs, in conjunction with already high risks, lead producers to curtail or end new development initiatives. Research and development (R&D) is scaled back and capacity expansion and replacement decisions are postponed, which leads to producers falling further behind their competitors in other countries. When the period of elevated resource extraction investment ends and the exchange rate falls back to cost parity levels domestic competitors are too far behind to restart R&D programs or even, in some cases, to undertake the replacement investment required to ensure long term business sustainability. The same adjustment process occurs, though less severely in terms of the long run negative outcomes, for other trade-exposed industries such as differentiated agriculture, high value business services industries, tourist industries and export-oriented segments of the health and education industries.

In general, a floating exchange rate protects the resource extraction industry in both the expansion and stability phase of the resource price cycle. For manufacturing and other trade exposed industries, positive stimulus to growth mainly comes in periods of low resource prices and hence low exchange rates. However the strength of this positive stimulus to growth is likely to be weak under the following conditions:

(i) if the period of low commodity prices corresponds to a period of relatively low world growth and low expectations of future growth; and

(ii) if a history of high exchange rates during past mining booms has generated expectations of future episodes, leading potential investors to discount the benefits of a current relatively low exchange rate heavily when they calculate the expected future returns on investment. They will not expect the exchange to remain low for very long.

Repeated episodes of resource extraction industry expansion lead to expectations of increasing volatility and the requirement of high short-term returns on investment.

National interest testing of a project's impact on economic security should cover a number of components, including, inter alia trade dependency and resilience to economic shocks.

3.2.1 Economic security: Trade dependency

It is not in an exporting country's national interest to become over-dependent for its exports on any other country. Over-dependence means that if the importing country's economic prospects decline rapidly it will force a significant decline in economic activity on the exporting country. There is also a risk that such trade dependency might be used by the importing country to force political and economic decisions on the exporting country even when they are costly in terms of the latter's national interest.

3.2.2 Economic security and the national interest: Resilience to economic shocks

One of the economic security components of national interest evaluation is the resilience to economic shocks test. If project proceeds, the project should not increase the security risk of the economy to a negative economic shock and, in particular, an exchange rate shock.

The one thing that is certain about any period of strong expansion in resource development is that it will end. More often than not the ending will be characterised by a rapid fall in commodity prices, closely followed by a fall in the exchange rate. This will lead to a widening of the current account deficit which in the Australian case is likely to be unsustainable given that, even with relatively high terms of trade, Australia's current account deficit is likely to be around 5-8 per cent of GDP circa 2016-2020.

The national interest evaluation would require that the following questions be answered.

(i) What is a plausible lower limit for commodity prices at the end of the current resource extraction industry expansion?

(ii) Assuming that the exchange rate falls in proportion to the commodity price fall, what would be the direct impact on:

- domestic inflation rates; and
- the current account deficit?

(iii) How much will national economic activity have to contract to return the inflation rate to desired levels? (The assumption here is that increases in unemployment rates are required to reduce the rate of growth of nominal wages and hence of costs and prices.)

(iv) In terms of (iii), does the project under consideration increase or reduce the contraction in economic activity necessary to bring inflation under control during a period of falling exchange rates?

(v) To what extent are import and export responses to the exchange rate devaluation likely to reduce the initial current account deficit after a reasonable time, say three years? What will be the contribution of the project to these responses?

(vi) Given the outcome of (v), what is the contraction in output required to restore the current account deficit to sustainable levels?

(vii) Given the outcome of (vi) does the go-ahead of the project under evaluation add to or reduce the contraction in economic activity required to restore the current account deficit to acceptable levels?

The national interest test would then compare the calculations from (iv) and (vii). If one or both answers were negative the project would fail the national interest test because it reduced the resilience of the economy to economic shocks. Failure of these tests means that the project could increase the contractions in the level of general economic activity required to achieve satisfactory inflation or balance of payments outcomes during the last phase of an episode of elevated resource expansion, the period of the return to stability.

3.3 Microeconomic resource constraints: Industry crowding out

As distinct from macroeconomic resource constraints, microeconomic resource constraints, resulting from projects proceeding, can impose costs on specific industries by limiting the growth in, or reducing the availability of, key resource inputs which cannot be effectively substituted with other inputs. In this case the industries affected have no option but to reduce actual or planned output in proportion with the actual or expected reduction in key input supply – a process which can easily lead to unemployment of other inputs.

For the case of LNG projects requiring large scale access to natural gas reserves, the impact on the future availability of gas will affect actual and expected investment, output and employment decisions in directly affected industries, especially heavy industry and electricity generation.

The chemical and alumina industries depend on the availability of gas at competitive prices. One or two LNG projects may not undermine confidence in the future availability of gas provided that expected gas reserves are adequate. However, with three and perhaps four additional LNG plants to come online over the next few years, along with projected expansion in the capacity of these plants, it is becoming clear that the combined claims on gas resources may lead to gas supply constraints in the eastern Australian gas market which will almost certainly lead to increasing expectations of real gas cost rises as higher costs of extraction are encountered in exploiting Australia's remaining resources of natural gas. The expectation of rising gas prices will reduce the willingness of producers in the chemical and alumina industries both to maintain the competitiveness of their current plants and to invest in additional capacity. This change in expectations could trigger a long-term decline in these industries which will be accelerated if expectations of gas shortages to domestic users take hold.

Because of the importance of the downstream gas-user industries in Australia's industrial structure and their recent growth performance, the impact of LNG export proposals on domestic users would have to be at the centre of any national interest evaluation for any valid determination of net project benefits. The critical indicator to focus on in this component of the national interest test is the ratio of annual natural gas demand (including all approved LNG plans) to estimated remaining reserves. If this ratio falls below acceptable levels then substantial microeconomic crowding out is likely to eventuate at some point over the project's life.

Microeconomic crowding out is analysed in Chapters 4 to 7 below.

3.4 Electricity price impacts

A further avenue of impact from LNG expansion lies in the implications for wholesale electricity prices that result from greatly elevated natural gas prices. Gas powered generation already plays a significant role in the electricity market, particularly in meeting peak demand, and its role is expected to grow both to provide backup to variable renewable generation and to provide relatively low-emissions base load. At peak times highly responsive Open Cycle Gas Turbines (OCGT) frequently set the wholesale price in the National Electricity Market and increased fuel costs can be expected to flow directly through to higher prices in that market. A 2010 AGL study found a $35 per megawatt hour difference in the marginal running costs of OCGT between a gas price scenario of $3.60 per GJ and one at $6.75.[2] These increases will flow through to almost all consumers, while those businesses who have moved to insulate themselves from rising electricity prices by installing highly efficient gas-fired cogeneration systems in recent years will find themselves subject to the same fuel price pressures.

[2] Paul Simshauser, Tim Nelson and Thao Doan, *The Boomerang Paradox, Part 1* (October 2010) http://www.aglblog.com.au/wp-content/uploads/2010/10/No.17-Boomerang-Paradox-Final-Oct-20101.pdf.

4. The natural gas usage trade-off: Domestic allocation versus export use – the case of natural gas dependent industries

Central to the application of the national interest test will be the direct economic value of a given quantity of natural gas from LNG exports versus the economic value of the same quantity of gas produced from domestic use. The net value of this comparison is a key estimate because:

(i) it indicates the cost of supply shortages if the export of gas has supply preference over domestic users; and

(ii) a high economic value for gas for domestic use entails that it is in the national interest that confidence in the adequacy of future domestic gas supplies at competitive prices ought not to be undermined by inappropriate exports.

The value of the trade-off will be assessed from two perspectives, namely:

(i) gas dependent industries; and

(ii) the non-resource economy excluding agriculture and mining.

The case of natural gas dependent industries is considered in this chapter and the broader economy-wide industry effects will be considered in the next chapter.

Natural gas dependent industries are industries where a large part of total output depends on the availability of natural gas at relatively low prices. These industries are the chemical sector and the non-ferrous basic metals industries (particularly alumina production).

To calculate the net value trade off for a given quantity of natural gas we estimate the value of current output of these industries that, in the long-term, would be curtailed if the supply of natural gas to these industries ended, or alternatively if supply was available only at such prohibitive prices that the industries became uncompetitive and retreated offshore.

4.1 Natural gas dependent industries: The direct value of natural gas availability

The chemical sector consists of the following major industries:

- basic chemicals;
- paints;
- pharmaceuticals;
- soap and detergents;
- cosmetics;
- other chemicals;
- rubber products; and
- plastic products.

There are other industries where the dependency on natural gas is high enough to justify the assumption that a substantial part of these industries, in the current environment, would not exist without reliable supplies of natural gas at competitive prices. These industries include glass and cement. The electricity sector is also becoming dependent on natural gas for peak power generation and increasingly for base load; this dependence will likely increase with the growth of renewables. The concentration of the present study on non-ferrous metals and chemicals to assess the cost of diversion of gas to LNG exports does not imply that other industries are unaffected. As long as the other affected industries have smaller economic values for gas the marginal cost of gas diversion is determined by the analysed industries.

The assumption in this study is that if natural gas was no longer available, the bulk of the basic chemicals industry would cease to operate, not necessarily overnight, but over time. The basic chemical industry was established in Australia before adequate supplies of natural gas became available. However, this was driven by factors including security objectives arising during and from World War II and high levels of tariff protection and subsidies. These no longer exist. More importantly, it was established at a time when other countries with large scale chemical industries also had limited or no supply of natural gas. The widespread availability of natural gas over the last half century has meant that the technological base of the industry has changed radically so that now a world competitive industry perforce relies on natural gas.

Other industries in the chemical sector rely on the presence of a local basic chemicals industry at the head of their supply chain and part of these industries would not exist without the availability of domestic basic chemical products. Accordingly the basic chemical industry generates a supply multiplier through the rest of the chemical sector. The question is how big is this multiplier effect? This multiplier effect was estimated by the following steps:

(i) using input-output table $m flows to calculate the share of product from the basic chemical industry used in the other seven chemical industries listed above as a percentage of output of each industry;

(ii) find the industry with the highest share of basic chemical products and nominate that share of this industry that would not exist in the long-run without the local availability of supply from the basic chemical industry. This nomination is termed the maximum basic chemical industry dependency ratio;

(iii) extend this nomination to the other chemical industries dependent on the basic chemical industry as the maximum basic chemical industry dependency rate multiplied by the basic chemical input share of the industry being estimated, divided by the basic chemical industry input share from (ii), or for that industry with the maximum basic chemical industry dependency ratio;

(iv) divide the results from (ii) for each industry by the basic chemical sector industry; and

(v) sum the results of (iv) across all the chemical industries to give the basic chemical industry multiplier, with a multiplier of unity for the basic chemical industry itself.

Table 4.1 gives the results of the calculation for Australia in 2008-09. The highest input ratio is for the plastics industry and the maximum basic chemical dependency ratio for this industry is nominated at 60 per cent. From this flows the multiplier estimates by industry shown in the second column of the table. The total multiplier value is 1.6.

Table 4.1 The chemical industry basic chemical multiplier	Input from basic chemicals – ratio of output	Basic chemical sector – output multiplier
Basic chemicals	0.12	1.00
Paints	0.05	0.02
Pharmaceutical products	0.01	0.04
Soap and detergents	0.06	0.01
Cosmetics	0.06	0.01
Other chemicals	0.07	0.07
Rubber products	0.02	0.01
Plastic products	0.13	0.44
Total	**–**	**1.60**

4.1.1 The importance of the local supply chain

It may be asserted that Australia's non-basic chemical enterprises would be best served by securing basic chemical inputs from anywhere in the world so long as they are at lowest cost and that a local basic chemicals industry is therefore not important. This view is wrong. The benefits of the local supply chain come from:

(i) just-in-time manufacturing capability;

(ii) manufacture of product that is required by the particular production technologies and product types produced by the local industry (these are not fully available elsewhere in the world);

(iii) security of supply; and

(iv) mutual dependency placing upper limits on price settings.

In this context, the multiplier value of Table 4.1 could be considered as being too low.

4.1.2 The non-ferrous metals industry

The non-ferrous metals industry consists of the alumina, aluminium and other processing industries, such as zinc, nickel, etc. Most certainly the alumina industry would not exist without the availability of natural gas, and almost certainly part of the aluminium industry would not exist without the availability of a strong local supply chain extending from bauxite to alumina and finally to aluminium.

Accordingly, the assumption adopted here is that half the Australian non-ferrous basic metals industry would not exist without the availability of plentiful natural gas supplies at reasonable prices.

4.1.3 Natural gas dependent industries: The direct value estimates

Given the above methodology, Table 4.2 profiles the direct benefit Australia receives from the supply of natural gas to the local gas-dependent industries. The estimates are in terms of $m of output per petajoule (PJ) of natural gas input.

Table 4.2	The direct benefit to Australia per PJ of natural gas – natural gas dependent industries (2008-09)
	$m
Non-ferrous metals	
Output per PJ	476
Adjusted output per PJ	238
Chemical sector ($m per PJ)	
Basic chemicals	168
Paints	3.9
Pharmaceuticals	4.0
Soaps and detergents	6.4
Cosmetics	2.2
Other chemical products	11.6
Rubber products	1.6
Plastic products	73.9
Total	**271.6**
LNG exports	**11.5**

The total value of a PJ of natural gas into the basic chemical industry, given the spillover benefits from the other industries, comes to $271 million per PJ. This is in accordance with the 1.6 multiplier developed above for the chemical sector.

The PJ value for LNG exports over the fiscal years from 2009 to 2011 has averaged $11.5 million. It is extremely important to recognise that this exported gas was sourced without affecting supply to domestic industrial users. The trade-off ratio means that if 1 PJ is instead shifted from local use by gas-dependent industries to export, the result is a direct loss of gross output of (averaging the basic metals and chemical sector estimates) of $255 million, compared to a $12 million gain from export revenues. The direct net loss in Australian value added is $243 million, or a loss/benefit ratio of 21 to 1.

This by itself would justify a national interest evaluation methodology which investigates whether local industry has an adequate supply of gas for the next two to four decades and approves LNG plants only when they can be supplied without affecting supply and price to domestic users. The fact that this evaluation is so compelling suggests that no such evaluation has been applied in national interest assessment to date. However, to be secure in this conclusion a further analysis needs to be undertaken, placing the direct estimates in the context of an input-output framework for the total national economy, incorporating into the analysis parameters reflecting differentials in the depreciation rates, tax rates and foreign ownership rates between industries, and assessing the net impact on the indicators selected as appropriate for national interest evaluations.

4.2 The input-output modelling framework

To evaluate the issue further, it is necessary to adopt a mixed demand-supply constrained input-output framework. This is because the existence of gas dependent industries means that these industries' activity levels are determined not simply by demand, but by whether or not there is an adequate supply of natural gas at reasonable prices to support domestic supply expansion where this is required to accommodate an increase in demand.

Let x_i represent (gross) output of industry i.

The economy consists of n industries, of which m industries are supply constrained by the availability of natural gas. By supply constrained is meant that they cannot automatically respond to demand changes unless the natural gas industry decides to provide the required inputs of (in this case) natural gas without major price increases.

The input-output relationship for the case where no industry is constrained is:

$$
\begin{pmatrix} x_1 \\ \vdots \\ x_m \\ \cdots\cdots \\ x_{m+1} \\ \vdots \\ \vdots \\ \vdots \\ \vdots \\ x_n \end{pmatrix}
=
\begin{pmatrix} a_1 & \cdots & a_{1,m} \\ \vdots & & \vdots \\ a_{m,1} & \cdots & a_{m,n} \\ \cdots\cdots & \cdots\cdots & \cdots\cdots \\ a_{m+1,1} & \cdots & a_{m+1,n} \\ \vdots & & \vdots \\ \vdots & & \vdots \\ \vdots & & \vdots \\ \vdots & & \vdots \\ a_{n,1} & \cdots & a_{m,n} \end{pmatrix}
\begin{pmatrix} x_1 \\ \vdots \\ x_m \\ \\ x_{m+1} \\ \vdots \\ \vdots \\ \vdots \\ \vdots \\ x_n \end{pmatrix}
$$

$$
+
\begin{pmatrix} c_1 & \cdots & c_{1,n} \\ \vdots & & \vdots \\ \vdots & & \vdots \\ c_{m,1} & & c_{m,n} \\ c_{m+1,1} & & c_{m+1,n} \\ \vdots & & \vdots \\ \vdots & & \vdots \\ \vdots & & \vdots \\ \vdots & & \vdots \\ c_{n,1} & \cdots & c_{m,n} \end{pmatrix}
\begin{pmatrix} x_1 \\ \vdots \\ \vdots \\ x_m \\ x_{m+1} \\ \vdots \\ \vdots \\ \vdots \\ \vdots \\ x_n \end{pmatrix}
$$

$$
+
\begin{pmatrix} f_1 \\ \vdots \\ \vdots \\ f_m \\ f_{m+1} \\ \vdots \\ \vdots \\ \vdots \\ \vdots \\ f_n \end{pmatrix}
$$

Given that x_1 to x_m are constrained, the (4.1) can be rewritten as:

$$\begin{pmatrix} x_{m+1} \\ \vdots \\ \vdots \\ \vdots \\ x_n \end{pmatrix} = \begin{pmatrix} a_{m+1,1} & \cdots & a_{m+1,m} \\ \vdots & & \vdots \\ \vdots & & \vdots \\ \vdots & & \vdots \\ a_{n,1} & \cdots & a_{n,m} \end{pmatrix} \begin{pmatrix} x_1 \\ \vdots \\ \vdots \\ \vdots \\ x_m \end{pmatrix}$$

$$+ \begin{pmatrix} a_{n+1,m+1} & \cdots & a_{m+1,m} \\ \vdots & & \vdots \\ \vdots & & \vdots \\ \vdots & & \vdots \\ a_{n,m+1} & \cdots & a_{n,n} \end{pmatrix} \begin{pmatrix} x_{m+1} \\ \vdots \\ \vdots \\ \vdots \\ x_m \end{pmatrix}$$

$$+ \begin{pmatrix} c_{m+1,1} & \cdots & c_{m+1,m} \\ \vdots & & \vdots \\ \vdots & & \vdots \\ \vdots & & \vdots \\ c_{m,1} & \cdots & c_{n,m} \end{pmatrix} \begin{pmatrix} x_1 \\ \vdots \\ \vdots \\ \vdots \\ x_m \end{pmatrix}$$

$$+ \begin{pmatrix} c_{m+1,m+1} & \cdots & c_{m+1,n} \\ \vdots & & \vdots \\ \vdots & & \vdots \\ \vdots & & \vdots \\ c_{n,m+1} & \cdots & c_{n,n} \end{pmatrix} \begin{pmatrix} x_1 \\ \vdots \\ \vdots \\ \vdots \\ x_m \end{pmatrix}$$

$$+ \begin{pmatrix} f_{m+1} \\ \vdots \\ \vdots \\ \vdots \\ f_n \end{pmatrix}$$

Or in matrix form:

$$\boldsymbol{x^u} = \boldsymbol{A^c x^c} + \boldsymbol{C^c x^c} + \boldsymbol{A^u x^u} + \boldsymbol{C^u x^u} + \boldsymbol{f^u}$$

Where:

$$\boldsymbol{x^u} = \begin{pmatrix} x_{m+1} \\ \vdots \\ \vdots \\ \vdots \\ x_n \end{pmatrix}$$

$$\boldsymbol{x^c} = \begin{pmatrix} x_1 \\ \vdots \\ \vdots \\ \vdots \\ x_m \end{pmatrix}$$

$$\boldsymbol{f^u} = \begin{pmatrix} f_{m+1} \\ \vdots \\ \vdots \\ \vdots \\ f_n \end{pmatrix}$$

A^c = $(n - m) * m$ matrix of coefficient of inter-industry input-output coefficients.

A^u = $(n - m) * (n - m)$ coefficients of inter-industry input-output coefficients.

C^c = $(n - m) * m$ matrix of consumption output coefficients for constrained industries.

C^u = $(n - m) * (n - m)$ matrix of consumption output coefficients for unconstrained industries.

Unconstrained industry output is, therefore, given by:

$$\mathbf{x^u = [I - A^u - C^u]^{-1} [A^c + C^c] + [I - A^u - C^u]^{-1} f^u}$$

Other indicators

Other indicators are given by the general form:

$$i_{o,j} = va_j \,.\, i^c_o \, x_j$$

Where:

$i_{o,j}$ = other indicator value (net national product, wage, salaries and mixed income, etc.) for industry j.

va_j = share of value added at factor cost to total gross output for industry j.

i^c_o = ratio of indicator o to value added (or gross surplus) for industry j.

x_j = total gross output for industry j.

The aggregate value across industries is given by:

$$i^t = \sum_{j=1}^{n} i_j$$

The key coefficients, i^c_o, are presented in Appendix B.

4.3 The input-output tables

The direct allocation of imports input-output table used for this study for 2008-09 is given in Appendix B. Other associated tables used are:

(i) the flow table with indirect allocation of imports;

(ii) the indirect tax flow table;

(iii) the import flow table as the difference between the Appendix B table and the indirect import table described in (i).

The key coefficients, tax, income, etc. by industry are also given in the table in Appendix B.

Adjustments are made to the coefficients given in Appendix B to better reflect the East Coast LNG industry as distinct from the offshore Western Australian industry, which is the only LNG industry reflected in the 2008-09 input-output tables. The main adjustment is to employment. The East Coast LNG industry is likely to be more labour intensive in operation due, in part, to its reliance on a land-based, dispersed natural gas collection and distribution system. As a result, the employment to output ratio is set at 0.19 or 60 per cent greater than the Western Australian average. Appropriate adjustments are made to other related parameters.

The foreign ownership ratio is also likely to be lower than for Western Australian projects. The average foreign ownership ratio for Queensland projects is set at 30 per cent.

The other issue is the tax rate. Once the Resource Rent Tax (RRT) becomes operational the ratio of direct tax to gross surplus will approach 50 per cent. However, this will not occur until towards 2030. In the early years, the tax rate will be negligible, rising to around 15 to 20 per cent once company tax rates become applicable. One way to account for this is to adjust the tax rates year by year, requiring all results to be presented in cumulative discounted terms only rather than as yearly average impacts. Accordingly, the tax rate is set at its average project level of around 35 cents in the dollar of gross surplus, which gives a significant upward bias to the benefits of LNG in the first half of a project's life.

4.4 The impact on the economy of LNG exports – a 50 PJ expansion

The model framework developed above will be used to assess the impact on the economy of a 50 PJ (approximately one million tonnes) LNG export expansion supplied at the expense of supply to domestic gas-dependent industries. The construction impacts are not considered.

In 2008-09 dollars, the additional gross output of LNG (and exports) comes to $620 million. Table A.1 indicates that GDP at market prices increases by $729 million, implying a standard multiplier of 1.2. However, the increase in net national product is half the increase in GDP. The increase in the benefit indicator is $401 million annually.

4.5 A 50 PJ contraction in natural gas supply to natural gas dependent industries

The second column in Table A.2 assumes that the 50 PJ expansion allocated to the LNG project is diverted from natural gas dependent industries. The reduction in gross output for the constrained industries given in Table A.2 runs to $12.8 billion in 2009 prices. This follows directly from the calculations given above on the assumption that 25 PJ is withdrawn from the non-ferrous metal industry and 25 PJ from the basic chemicals industry.

In this case the annual average loss in GDP at market prices is $11.0 billion, while total employment falls by 203,000 from what otherwise would have been the case. From column three of Table A.2 the gross negative from the natural gas withdrawal from natural gas dependent industries so overwhelms the positive impacts of LNG expansion that the net change between the two cases is close to the negative impacts of the gas withdrawal case for gas dependant industries.

The net (LNG plus gas dependant industry) cumulative discounted benefit indicator outcome is -$100 billion. The cost benefit ratio for gas withdrawal increases to 24.2 to 1, which may be compared with the preliminary estimate of 21 to 1 calculated in Section 4.1.3 above. Far from reducing the burden, placing the two cases in the broader context of the national economy increases the net cost of shifting gas from gas-dependent industries compared to LNG export expansion.

4.6 Conclusion

When natural gas is reallocated to exports from domestic use in gas-dependent industries, for every $1 of benefit gained from exports $24 of benefits is lost in contraction of the gas-dependent industries. This can be stated in discounted terms. In 2009 140 PJ of natural gas was allocated to Australian gas-dependent industries. It would have taken 3,400 PJ of LNG exports to deliver this benefit. If, at full development, the Australian east coast LNG industry is supplied at the expense of domestic gas-dependent industry, it will deliver less than a third of the benefit required to offset the loss of domestic industry.

On the other hand, the domestic gas using industrial sector does not put a significant claim on the supply options for Australian LNG and thus the growth options for LNG are not significantly constrained by domestic needs at present. However, this will change if large demands are made on gas as a transitional fuel to renewables.

The core issue is whether the large scale export of gas will constrain the ability of the domestic industry to expand or even maintain existing production levels. This will be considered in Chapter 6. In Chapter 5 we generalise the calculations of the present chapter.

5. The net benefits: LNG exports versus domestic gas use – the case of the general economy

One way to assess the impact of switching natural gas from domestic to export sales on the general economy, that is the non-resource sector of the economy, would be to use a large scale multi-sector model of the economy with detailed industry energy demand equations. Energy prices in general and natural gas prices in particular could then be adjusted until domestic natural gas use was reduced to required levels and the impact on the macroeconomic indicators assessed.

NIEIR has such a model and has used it for similar exercises many times. However, the model results are highly sensitive to model closure conditions. The final outcomes depend on which sector bears the cost adjustment for whatever the changed energy capacity arrangements have to be put in place to maintain overall demand/supply balance. From experience, the quantitative impact of the optimum strategy is approximated by a simple approach, which is adopted here.

The approach requires the direct estimation of a production function for the non-resource economy with capital, labour, gas and electricity as factor inputs. The estimated production function coefficients are then used to calculate the elasticity of substitution between gas and electricity. These two fuels are sufficient to specify the production function since, after the adjustment from the oil price shocks of the 1970s and early 1980s, the substitutability between natural gas and oil has been reduced to low levels. Effectively, gas now mainly competes with electricity.

A quantitative estimate of the elasticity of substitution between gas and electricity will enable the calculation of the quantity of electricity that must be supplied to leave economic activity unchanged after the withdrawal of domestic gas.

However, the economic adjustment does not end there. If the additional electricity supply can only be secured at significant additional cost, the additional costs on the economy will have to be taken into account. If these costs are allowed to flow into the industry structure of the economy there will be a whole range of flow-on effects, including loss of exports, increased imports and reduced real incomes. The least cost option (in terms of the fall in economic activity) is to channel the costs into the household sector with the major burden of adjustment being via real household incomes rather than by reduction in investment, exports, employment, and so on.

An alternative strategy would assume that there is no attempt to compensate for the loss of gas supply and non-resource gross product falls in line with the production function coefficient implications. This channel will also be evaluated in this chapter.

There is a third possible approach. This involves suppressing natural gas supply into the electricity sector which would force electricity production to exploit alternative and higher cost sources of supply. This lies outside the production function approach since natural gas input into electricity is included in the electricity input into the general economy.

These three alternative approaches are evaluated in turn.

5.1 The Australian production function

The task is to estimate a production function to determine directly the role of gas and electricity in driving Australia's economic activity. By definition it takes a supply side approach to economic activity.

A general production function can be written in the form:

$$Y \quad = \quad ae^{rt}\,(K, L, E, G) \tag{5.1}$$

Where:

Y = output, which may be defined as gross product of the economy, gross product of the private sector, or gross product of a combination of industries.

L = labour employed.

t = transport or total general government capital stock.

r = rate of exogenous technological change.

If a Cobb-Douglas production function is specified, then (4.1) becomes:

$$ln\,Y \quad = \quad ln\,a + rt + \alpha_1\,ln\,K + \alpha_2\,ln\,L + \alpha_3\,ln\,TE + \alpha_4\,ln\,G \tag{5.2}$$

where ln denotes natural logarithms.

The key estimate is for the a coefficient, or the elasticity of output with respect to gas input.

However, the Cobb-Douglas production function is restrictive in terms of the implied returns to scale for individual factors and the elasticity of substitution between factors. The latter is important for this study because of the requirement to use the elasticity of substitution between gas and electricity to obtain estimates of the costs of gas demand suppression.

To circumvent this, a flexible, that is, unrestricted, transcendental production function is estimated. This takes the form:

$$Y \quad = \quad Ae^{rt}\,ln^{\alpha 1}\,e^{b,L}\,.\,K^{\alpha 2}\,e^{b2K}\,.\,E^{\alpha 3}\,e^{b3E}\,.\,G^{\alpha 4}\,e^{b4G} \tag{5.3}$$

The two estimated coefficients which are of particular interest to this study are α_4 and b^4.

5.1.1 The data

Pooled time series cross section data are used to estimate the coefficients. The data is for the five mainland states. The period of estimation is from 1980 to 2011.

The output variable is state gross non-resource product (total state gross product at factor cost less gross product of agriculture and mining and ownership of dwellings. The annual data over recent years is from the Australian Bureau of Statistics (ABS) "*Australian National Accounts*", Cat. no. 5202.0. These estimates are spliced back to 1980 using estimates by NIEIR.

The labour input variable is total hours of work of the non-resource sector by state obtained from ABS "*Labour Force Australia*", Cat. no. 6203.0.

The methodology of estimating capital stock input by state for business capital stock and transport infrastructure capital stock is outlined in NIEIR's "*Transport Infrastructure Investment: An Instrument for Sustainable Debt Financed Fiscal Policy*", April 2012.

The energy data is taken from the Bureau of Resources and Energy "*Economics – data base for energy consumption by state and industry*". The electricity sector energy input is excluded from the non-resource sector totals for electricity and natural gas.

To remove cyclical effects a five year moving average is passed through the data.

5.1.2 The production function: Coefficient estimates and implications

The estimated coefficients are given in Table 5.1. Ignoring the constraints, non-zero coefficients are of the correct sign and, bar one, strongly significant.

A sensitivity analysis was used to calculate the elasticity of substitution between gas and electricity input and the elasticity of non-resource gross product for the four Eastern Australian mainland states. The elasticity of substitution, as at 2011, was calculated as -0.67. This means that if one PJ of natural gas is withdrawn from Eastern Australian markets, it will require an increase in supply of 0.67 PJ of electricity to maintain a constant level of non-resource gross product.

The elasticity of non-resource gross product at factor cost, with respect to natural gas input for the four Eastern Australian mainland states, was found to be 0.082.

Table 5.1 Estimated coefficients of the transcendental production function

Parameters	Coefficient	t-value
α_1	0.455	9.9
b_1	0.00000015	1.4
α_2	0.483	10.6
b_2	-0.0000067	10.1
α_3	0.011	0.6
b_3	0.103	3.2
α_4	0.0	–
b_4	0.00088	7.6
NSW constant	-0.428	0.8
VIC constant	-0.609	1.1
QLD constant	-0.653	1.2
SA constant	-0.615	1.2
WA constant	-0.803	1.6
$R^2 = 0.985$		

5.2 General economy adjustment to domestic suppression of 50 PJ of natural gas – the electricity substitution case

The three self-contained cases for the adjustment of the general economy to the suppression of 50 PJ of natural gas will be examined in terms of their impact on the economy using the framework applied in the previous chapter.

The elasticity of substitution between natural gas and electricity estimated above suggests that if 50 PJ of natural gas are withdrawn from the domestic market, 34 PJ of electricity will be required to maintain production capacity. The substitution would be partially focussed on space and water heating and process heat involving drying and melting.

Table 5.2 indicates that a considerable cost differential currently exists between electricity and gas, depending on the market and the carbon price. This means that total direct costs of adjustment will depend on the carbon price and a scenario analysis is therefore needed. This will be undertaken in Chapter 7 below. To illustrate the impact on the economy, in terms of the analysis of the previous section, a $50 price of carbon will be assumed. The data in Table 5.2 includes all transmission and distribution costs. The analysis here is for ex-plant costs.

Table 5.2 Current electricity and gas prices in Australia: The impact of carbon prices

	Electricity price	Gas price
No carbon pricing		
Industrial	$100/MWh = $28/GJ	$10/GJ
Residential/commercial	$250/MWh = $69/GJ	$16/GJ
Carbon pricing – $25/t CO_2e		
Industrial	$125/MWh = $35/GJ	$11.8/GJ
Residential/commercial	$275/MWh = $76/GJ	$17.8/GJ
Carbon pricing – $50/t CO_2e		
Industrial	$145/MWh = $40/GJ	$13.3/GJ
Residential/commercial	$295/MWh = $82/GJ	$19.3/GJ

5.2.1 The net cost of electricity substitution

It is critical that the same model framework be used for all evolutions of the possible adjustment paths for gas suppression. The framework developed in the previous section is ideal in terms of transparency and assessing the plausible impact of the contraction in gas dependent industries. For the more general adjustment paths of this chapter, other evaluation approaches are possible, but these would result in unacceptably different methodologies for quantifying impacts. Accordingly, the methodology used for calculating impacts in the electricity substitution case has been designed so that the modelling framework of the previous chapter can be employed. This framework also allows the straightforward introduction of probability analysis. The result is that the shock which is imposed on the model structure becomes a direct adjustment to real household disposable income.

It should be noted that no allowance has been made for the impact on distribution margins. It is assumed that the same total margins have to be recouped to support the distribution infrastructure installed, irrespective of throughput. In any case, the reduction in gas distribution margin would be offset to some extent by the increase in electricity margins.

These preliminaries out of the way, we proceed to model the full electricity substitution case. In the absence of the East Coast LNG plants, the industrial gas price will be taken to be $6/GJ. For each $10 of carbon price the cost of natural gas increases by $0.72/GJ, so the alternative gas price is $9.6/GJ. Therefore, the forgone cost of natural gas will be 9.6 x 50, or $480 million in 2009 prices.

Assuming that between 2012 and the 2020s there is increasing public and international anxiety about the baleful consequences if CO_2 emissions are not curbed, and therefore increasing political and economic pressure to reduce CO_2 emissions, the alternative electricity substitution cost will be taken to be an average of renewable options, for which recent cost estimates range from wind at $110 MWh to solar at over $200 MWh, with other renewables such as geothermal between the two polar cases. The average will be set at $150 MWh. This translates into $42 million additional cost per PJ, or $1.43 billion for the 34 PJ of electricity required.

The net cost is, therefore, 1.43 – 0.48 = $0.95 billion in 2009 prices annually.

To minimise the loss of employment and economic activity, the optimum cost allocation strategy would be to channel the impact into additional cost imposts on the household sector. This would hypothetically be done by:

(i) increasing direct taxes on households to pay for subsidies to shelter industry from the additional energy costs;

(ii) increasing residential electricity prices more than prices for non-household users; and

(iii) increasing the costs of electricity for those commercial sectors that service the household and Government sectors rather than trade-exposed industries.

The results of doing this for the full electricity substitution case are given in Table A.4 to Table A.6.

For the gross product indicators the impact is positive being about two thirds of the LNG overall impact. The combined total impact is a strong $1199m at factor cost. For net national product the increase is much less because of the high depreciation rate for the electricity sector. More importantly private consumption expenditure falls by $810m, or a net $646m if the LNG impact is included. The benefit indicator falls by $423m, more than cancelling out the gain from LNG exports. Full electricity substitution therefore results in no net benefit from LNG exports. The strong response for gross product is due to the fact that the drivers of this growth are dominated by factors (foreign income and depreciation allowances) which cannot be used to support domestic consumption and tax growth.

5.3 General economy adjustment to domestic suppression of 50 PJ of natural gas: The decline in economic activity case

Rather than release gas for export by switching to electricity, it would be possible to release the gas by reducing industrial activity. It is implausible to assume that all the natural gas suppression will involve reductions to industry; part will come from reductions in allocation to households. In the case here it is assumed to be 30 per cent of the total reduction impacts directly on households at a cost similar to the electricity substitution.

This still leaves 35 PJ to be suppressed from the non-resource industries. For the Eastern Australian market this will represent a 7.6 per cent reduction in supply. Using the elasticity estimated above, this will generate a 0.6 per cent reduction in gross non-resource product which translates into a $4.68 billion reduction in non-resource gross product at factor cost for the four Eastern Australian states. Using the relationship between direct reductions in household income and gross product at factor cost (see the model sensitivity results in the previous section) this indicates a direct reduction in household income of $3.58 billion. To this has to be added the reduction in real household incomes due to the transfer of 15 PJ of natural gas from the household sector to exports and its replacement with electricity. Using the full substitution case as the benchmark this will add $0.3 billion, bringing the total to $3.9 billion in 2009 prices.

Table A.4 shows the impact on the general economy for the general reduction in economic activity case. In terms of gross and net product, the decline in activity is six times the LNG benefit. The benefit indicator declines by 17 times the LNG benefit. Even if we make no particular allowance for gas-dependent industries and instead base the calculations on the non-resource sector as a whole, the outcome is decidedly unattractive.

5.4 General economy adjustment to suppression of 50 PJ of natural gas: The electricity sector gas substitution case

We now consider the case where gas is switched from the electricity sector to LNG exports. In this case, before the need for gas suppression, the 50 PJ of gas would have been used in the electricity sector to generate electricity. The scenario is that, in the absence of East Coast LNG exports, large scale gas-fired electricity plants would have been built near major CSM deposits and these exports require that the electricity sector will have to substitute other sources of electricity generation.

The two key determinants of the cost of this response are the cost of electricity generated from natural gas and the cost of the alternatives.

The cost of natural gas derived electricity will be a function of the natural gas price and the carbon price. Table 5.3 indicates a range of responses depending on the gas price and the carbon price. Assessing the effect of the carbon price involves modelling probabilities, because of the range of possibilities both for a given year and across time. This is carried out in Chapter 6 below. To illustrate the impact on the economy that is comparable to the approach taken for other adjustment paths above specific assumptions have to be made. The assumptions are:

- a price per gigajoule of $4; and
- a carbon price of $50.

From Table 5.3 this indicates an electricity price of $78 MWh.

As before, the alternative electricity price will be renewables at an average rate of $150 MWh. To complete the cost estimates it is necessary to know how much electricity can be generated from 1 PJ of natural gas. 1 PJ of electricity is 278 GWh. If a conversion factor of 0.45 is assumed, then 1 PJ of natural gas will generate 125 GWh of electricity. Hence, 50 PJ will generate 6,250 GWh or $489 million. If the alternative 6,250 GWh comes from renewables, then the cost will be 6.25 x 150, or $938 million, giving a net cost of $457 million.

Table 5.3 Natural gas based electricity – cost of supply by input costs

Combinations	Natural gas price ($/GJ)	Carbon price ($/tonne of CO_2)	Long-run marginal cost CCGT ($/MWh)
1	3	0	49
2	4	0	55
3	5	0	61
4	6	0	67
5	3	50	69
6	4	70	83
7	5	80	93
8	6	100	107
Alternative			**150**

Note: CCGT denotes combined cycle gas turbine. Assume 65 per cent capacity factor. For every $10 increase – carbon price a $/tonne of CO_2, the price will increase by $4/MWh. For every $1/GJ increase in the natural gas input price the $/MWh price increases by approximately $6 in 2009 prices.

The impact on the general economy of the gas suppression case is given in Table A.4. This is a low cost case compared to the decline in economic activity case but comes at a higher cost than the full electricity substitution case. For the gross product indicators, the decline is a little under 40 percent of the LNG benefit. However, there is a deterioration compared to the net product indicator with the loss from the gas suppression case almost cancelling out the gain from the LNG expansion. However for the benefit indicator the loss from gas suppression in electricity use is nearly 30 percent more than the LNG benefit.

It should also be noted that the suppression of gas supply to the electricity sector, or if suppression is avoided the increase in gas prices that will result from LNG netback pricing and production from higher-cost reserves, would ultimately have implications for the costs of all existing gas-fired generators. Operating costs for both peaking plants and CCGT would increase, driving higher spot and contract prices in the National Electricity Market.

The electricity sector gas suppression case is a relatively low cost option. Nevertheless the net costs are still significant.

5.5 Conclusion

Analysis which abstracts from the position of the gas-dependent industries concludes that natural gas can be switched from domestic sales to LNG export sales using a number of strategies, the best of which yields little benefit to the economy and the worst substantial net costs. In this worst case, the costs approach those calculated when concentrating on the position of the gas dependant industries. To minimise cost, the following factors would have to be put in place, namely:

(i) the natural gas dependent industries were quarantined from any impact of LNG expansion on available gas supplies and costs;

(ii) the electricity sector would have to plan to carry the full cost of adjustment including higher quantitative targets for renewable energy; and

(iii) the household sector would have to accept that it and not industry would have to directly accept the full costs of adjustment.

Historical experience, the current design of the policy for the introduction of carbon taxes and the political debate over carbon pricing give no grounds for businesses to expect that the minimum cost path would be adopted if it becomes necessary to withdraw domestic natural gas supply to meet export contracts.

How the four options may be combined to determine an overall gas suppression response is outlined in Chapter 7 below.

6. The Australian gas market: Resources, prices and risk of supply shortage by 2040

The prime objective of this chapter is to assess the risks of supply shortages in the Eastern Australian gas market by 2040. This is a critical final step to assessing the likelihood that the costs of natural gas supply withdrawal assessed in the previous two chapters will be realised. The risk of gas supply shortages emerging in turn depends on estimates of natural gas reserves remaining to be discovered.

6.1 The Australian natural gas market: Background

The Australian natural gas industry has three distinct components:

1. the domestic Eastern Australian system;
2. the domestic west/north coast systems; and
3. the LNG export industry (currently only on the west coast fed mainly from off-shore fields, with plants proposed for Eastern Australia based on coal seam methane).

As with electricity, there is no transmission connection between the east and west coasts (Tasmania is connected to the eastern gas and electricity transmission systems).

In 2012-13 total Australian gas production will be about 2,500 PJ, about 35 per cent of which will be exported as LNG. The main producing basins are: in the East, the Gippsland, Cooper-Eromanga and Otway (conventional); and the Bowen and Surat (coal seam gas); and in the West, the Carnarvon, Bonaparte and Browse.

In the domestic markets, east coast demands are about 800 PJs and west/north coast demands 650 PJs. The major domestic markets are for gas-powered electricity generation (GPG), industrial and residential consumption. The GPG market is growing most rapidly but future GPG increases depend significantly on carbon pricing policies.

The current CO_2e price of \$23/t CO_2e is not high enough to stimulate substantial growth in GPG for combined cycle gas turbine (CCGT) base load plants. Gas peaking plants are relatively unaffected by carbon pricing, being mainly responsive to growing summer peak loads where gas plants (open cycle gas turbines, OCGTs) have distinct quick response advantages. Growth in GPG base load will depend on carbon tax levels, gas prices, coal prices and any policy initiatives that directly favour gas (such as the Queensland gas generation policy).

In the industrial sector gas is used for process heat (drying, etc. such as alumina production), water heating, steam raising and for production of petrochemicals (such as ammonia). Metal products, petroleum and chemicals and non-metallic mineral products account for about 85 per cent of industrial gas consumption in Australia.

The alumina industry, a major use of gas for drying (often with cogeneration), is concentrated in south-west Western Australia (Kwinana region) and Gladstone in Queensland. In Western Australia, industrial gas prices have increased substantially (from \$4/GJ to \$8/GJ) due to domestic market supply/demand constraints and reliance (65 per cent) on the North West Shelf project (LNG predominantly) supply. In eastern Australia industrial gas prices are in the \$4 to \$6/GJ range, including network costs as well as wholesale gas costs. At higher prices (>\$10/GJ) some industrial gas users could lose competitiveness to competitors based in gas rich regions, such as the Middle East. Fertiliser and other chemical plants would be at risk, as would alumina.

Over 2011-25 NIEIR estimates (July 2012) growth in industrial gas use will average 2.91 per cent per year, residential 1.48 per cent, commercial 2.4 per cent and electricity generation 4.48 per cent per annum.

The major industrial market is in Western Australia (alumina, direct reduced iron and ammonium nitrate), 55 per cent of national industrial market. The major residential market is in Victoria (space and water heating), 65 per cent of national residential market. GPG is strongest in Queensland and Western Australia.

6.2 Estimates of reserves

Category 1 reserves (commonly referred to as ‘Proven’ or ‘P1’ reserves) include recoverable reserves that have been declared commercially viable. **Category 2** reserves (commonly referred to as “Probable’ or ‘P2’ reserves) comprise estimates of recoverable reserves that have not yet been declared commercially viable, although they have been geologically proved or are awaiting further appraisal. Geoscience Australia (GSA) are now **mainly** using the McKelvey classification of economic and sub-economic demonstrated resources (EDR, SDR), but do not precisely define (for example, $/G) EDR and SDR. In addition, P3 possible/potential reserve estimates are sometimes estimated. Also, inferred resources are mentioned. These arise from recent discoveries and finds that require further appraisal.

While there is always some uncertainty associated with any reserves estimates, GSA’s estimates are often regarded as conservative. These estimates should perhaps be seen as a lower bound estimate of actual reserves. Due to this conservatism, NIEIR formulates its own estimates of reserve levels in the eastern basins by supplementing official data with information recently published by operators and other basin participants. Over the years (1980s on) we have observed significant increases in GSA reserves towards NIEIR estimates.

West Coast (Western Australia/Northern Territory) reserves are mainly in off-shore basins (Carnarvon, Browse, Bonaparte) and amount to about (2009 data, no recent update) 165,000 PJ in P1 and P2 reserves (not including CSM or shale gas). Source: Geoscience Australia, Oil and Gas Resources of Australia 2008.

Eastern Australian reserves, from the same source, P1 and P2 reserves were about 11,000 PJ (excluding CSM and shale reserves); and P3 at 28,000 PJ. CSM reserves (P1, P2) were estimated at 37,000 PJ (P3 at 60,000 PJ).

McKelvey classification reserve estimates are outlined below. Source: Australian Gas Resource Assessment, 2012.

Table 6.1 Australian conventional gas resource represented as McKelvey classification estimates as of 1 January 2011

Conventional gas resources	PJ	tcf
Economic demonstrated resources	113,400	111
Sub-economic demonstrated resources	59,600	53
Inferred resources	11,000	20
Total	**184,000**	**184**

Table 6.2	McKelvey classification estimates by basin as at 1 January 2011		
		Gas	
McKelvey class.	**Basin**	**PJ**	**tcf**
EDR	Carnarvon	74,700	68
EDR	Browse	17,900	16
EDR	Bonaparte	10,100	9
EDR	Gippsland	7,000	6
EDR	Other	3,600	0
Total EDR		**113,400**	**103**
SDR	Carnarvon	26,800	24
SDR	Browse	17,900	16
SDR	Bonaparte	11,900	11
SDR	Gippsland	2,300	2
SDR	Other	1,200	1
Total SDR		**59,600**	**54**
Total (EDR + SDR)		**173,000**	**157**

CSM/G reserve estimates, not included above are presented below.

Table 6.3 CSG resources at January 2011		
CSG resources	**PJ**	**tcf**
Economic demonstrated resources	35,905	33
Sub-economic demonstrated resources	65,529	60
Inferred resources	122,020	111
Total	**223,454**	**203**

Table 6.4	Total Australian gas resources									
Resource category	Conventional gas		Coal seam gas		Tight gas		Shale gas		Total gas	
	PJ	tcf	PJ	tcf	PJ	tcf	PJ	tcf	PJ	tcf
EDR	113,400	103	35,905	33	–	–	–	–	149,305	136
SDR	59,600	54	65,529	60	–	–	2,200	2	127,329	116
Inferred	11,000	10	122,020	111	22,052	20	–	–	155,072	141
All identified resources	**184,000**	**167**	**223,454**	**203**	**22,052**	**20**	**2,200**	**2**	**431,706**	**392**
Potential in ground resource	Unknown	Unknown	258,888	235	Unknown	Unknown	435,600	396	694,488	631
Resources – identified, potential and undiscovered	184,000	167	258,888	235	22,052	20	435,600	396	900,540	819

Note: Conventional gas demonstrated resources as of January 2011; CSG demonstrated resources as of January 2012. Note CSG 2P reserves and 2C resources are used as proxies for EDR and SDR respectively.

Tight gas and shale gas resources

Currently Australia has no proven reserves of tight or shale gas. The in-place resources of tight gas are estimated at around 22,000 PJ (20 tcf) but together with shale gas could be considerably higher. The largest known resources of tight and shale gas are in low permeability sandstone reservoirs in the Perth, Canning, Cooper and Gippsland basins with APPEA's estimates at 440,000 PJ of total possible reserves

6.3 Total Australian reserves (identified, potential and undiscovered)

What is important for this study is not total Australian reserves, but reserves that can supply the integrated Eastern Australian market. This is the market that the East Coast LNG projects will impact. The situation would be different if the Western Australian market was integrated with the Eastern Australian market.

6.3.1 Two estimates of Eastern Australian case reserves

One recent attempt to estimate Eastern Australian reserves was carried out by **Core Energy Group** (COE): gas (Eastern Australian) resource studies, 2012. This study included a section on the distribution of gas reserves by gas production costs (COE page 24).

Core estimated a total of 143,066 PJs potential resource at 1 January 2012 at up to \$6/GJ and about 161,000 PJs at up to \$8/GJ.

In the report (Table 7.1) **conventional** resources were estimated to be 13,000 PJ at up to \$7.37/GJ at a 10 per cent rate of return. In Table 7.2, **coal seam gas** reserves were estimated to be 96,000 PJ at up to \$5.58/GJ at a 10 per cent return. In Table 7.3 estimates for total Eastern Australian **prospective** resources were given as 190,000 PJ at up to \$9.27/GJ at a 10 per cent return.

The study also gave estimates of gas transmission costs as at April 2012. Indicative tariffs for **existing** pipelines are provided in this report in Table 6.4, page 12.

For **new** pipelines estimated tariffs are presented in **Figure 10.4** for a range of pipelines. For example, an estimated tariff of \$0.0018/GJ/km for a 1,000 kilometre hypothetical pipeline would result in a tariff of \$1.8/GJ for the full 1,000 kilometres of gas transmission. Estimated tariffs are also presented in **Figure 10.4** for a range of existing pipelines such as \$0.0014/GJ/km for the Eastern Gas Pipeline. Tariff components (WACC, taxation, etc.) are also provided for several pipelines.

Another study which also estimates remaining gas reserves was by **ACIL Tasman**: draft report, December 2011, Fuel cost projections. This report was prepared for Worley Parsons to provide natural gas and coal outlooks for AEMO modelling.

ACIL Tasman estimated (page 6, Figure 3) that around 90,000 PJ of potential (reserves and resource) could be developed on the East Australian seaboard at up to A\$8/GJ (of which 50,000 PJ is Queensland CSM); and 60,000 PJ (about 40,000 PJ of CSM) at up to \$6/GJ. **Note** that in the same report ACIL Tasman estimated that in addition to these reserve estimates 25,000 PJ of Eastern Australian shale gas could be available at \$9/GJ.

These estimates are much lower than the COE estimates outlined above. The reasons for estimate differences are difficult to discern from the two sets of reports, though COE allows for sales of liquids from gas projects, thus improving project economics.

Potential use of Eastern Australian reserves over 2012-2040 are presented below.

Table 6.5 Potential domestic use of Eastern Australian natural gas reserves

		2015 (NIEIR)	2025 (NIEIR)
Gas (2011, 1,300 PJ)	**Total**	1,400 PJ	2,300 PJ
	GPG use	416 PJ	986 PJ
	Excluding gas for power generation (GPG)	≈ 950 PJ	≈ 1,300 PJ
Electricity consumption	Total in NEM	200,000 GWhs	256,000 GWhs
	Australia	236,000 GWhs	311,000 GWhs

Potential GPG (electricity) use

A 400 MW CCGT	at 90 per cent capacity factor requires about	22 PJ/a
A 10,000 MW CCGT	at 90 per cent capacity factor requires about	550 PJ/a

Potential LNG export use

LNG	4 Mt plant requires	200 PJ/a	1 train
	20 Mt plant requires	1,000 PJ/a	5 trains

28 years (2012-2040) potential use

End use	Approximate average	1,700 PJ/a	= 47,600 PJ
10,000 MW GPG by 2040	Approximate average	300 PJ/a	= 8,400 PJ
LNG (6 trains by 2040)	Approximate average	800 PJ/a	= 22,400 PJ
			78,400 PJ

This suggests adequate availability at up to $8/GJ on the above assumptions: LNG use could be higher but GPG and end-use could be lower. Table 6.5 is the basis for the Eastern Australian market's natural gas projections for the case of no LNG plants outlined below.

6.3.2 Western Australia/Northern Territory

Domestic gas use

In 2012 Western Australia's total gas use is estimated at 617 PJ and Northern Territory at 43 PJ. Western Australia's gas use is dominated by industrial use (442 PJ) and GPG (145 PJ), growing respectively over 2012-25 at 2.65 per cent and 3.44 per cent average per year. Total use in 2025 is estimated to be 905 PJ, the increase mainly through alumina, direct reduced iron, ammonium nitrate and GPG expansion.

In the Northern Territory industrial (24 PJ) and GPG (19 PJ) dominate gas use, growing respectively over 2011-25 at an average per year of 8.4 and 7.0 per cent. Total use in 2025 is projected to be 122 PJ through increases in industrial use (Gove Alumina conversion to gas from fuel oil) and GPG.

Potential domestic use over 2012-2040

At an average annual use in the region (Western Australia/Northern Territory) at the 2025 level of 1,027 PJ, regional gas use over 2012-40 would be about 30,000 PJ. Use could be higher depending on GPG economics (carbon and gas prices) and industrial use (regional competitiveness in global markets).

Potential LNG use over 2012-40

LNG use of gas in the region (Western Australia/Northern Territory) will depend on global demands for LNG and competitiveness of regional LNG plants.

Global LNG demand is projected to increase significantly over the period depending on global climate change policies: aggressive policies could constrain global gas demands. Regional LNG competitiveness could be constrained by high regional costs for new LNG plants and global LNG competition from the Middle East, East Africa, North America and Europe. The strength of this competition will depend considerably on the success of Middle East and Russian gas export strategies and on global shale gas developments. At regional (Western Australia/Northern Territory) average LNG exports over 2012-2040 of 100 Mtpa (about 5,000 PJ per year) LNG exports would total 140,000 PJ.

Total requirements, reserves and prices: Western Australia/Northern Territory

On the basis of the above estimates, 170,000 PJ of regional gas would be consumed (domestic, LNG) over 2012-40, about the current estimates (P1, P2/EDR, SDR) of regional reserves (excluding CSM and shale, which are not yet prominent in the region).

No costs of reserve estimates for the region are available as far as we are aware. Based on net back estimates required for existing and proposed LNG projects, we consider the requirements could be met at <A$8/GJ (ex-processing plant) and <A$10/GJ delivered to customers.

6.4 Proposed LNG plants, 2012-18

Over the period to 2018, 12 LNG plants are proposed: 8 on the west coast (output 70 mtpa) and 4 on the Eastern Australian (30 mtpa). If all proposed plants proceed, gas use by the plants over the period to 2040 would be about 3,400 PJ/a and about 84,000 PJ in total on the west coast; and 1,500 PJ/a and 36,000 PJ in total on the Eastern Australian. (ABARE/BREE, 2010; 5,930 PJ **total** exports in 2029-30.)

Given the prices of gas from LNG in export markets and the cost of liquefaction, transport, regasification and transmission to pricing hubs, to be profitable we judge LNG exporters must be able to access gas at $6-8/GJ (the net back price) for existing and proposed LNG plants.

6.5 Gas prices: weighted average, 2007-08 to 2039-40 – the current view

Gas prices have not been historically transparent whether at the well-head, ex-processing plant or delivered, particularly for large users.

Preliminary estimates for weighted average gas prices (ex-processing plant) are set out below.

Table 6.6 Projection of natural gas prices

Year	Prices (2011-12 $/GJ)	
2007-08	$4	
2011-12	$5	
	Conventional view	**Alternative (optimistic) view**
2019-20	$9	$7
2029-30	$13	$10
2039-40	$15	$11

The alternative optimistic view is based on potential global trends in gas supplies and demands (climate change policies and gas technology improvements for exploration and development).

Traded gas prices, for example those used by ACIL Tasman for the AEMO scenarios, continue to be mainly based on the oil price/gas export price relationship which could be loosened resulting in lower gas prices as global gas competition increases. That is, we believe that despite its continued use in gas trade pricing, there is no longer a logical basis for this concept. Gas and oil are no longer significant substitutes in energy markets for electricity generation, space and water heating, etc. Exploration, development and marketing of the two commodities have diverged over the past 20 years.

6.6 Shale gas: A global gas revolution

The production of gas from low permeability gas rich structures has led to a transformation of the USA gas industry. Gas production from this source in the USA has risen from 4 per cent of total USA gas production in 2004 to 25 per cent in 2011, a total in 2011 of 5,650 PJ (twice Australia's 2011 production) with a reserve estimate (USA EIA) of 4.8 x 10^6 PJs. The flood of shale gas has dropped wholesale gas prices in the USA from >US$10/GJ in 2006 to >US$3/GJ in 2011-12 and stimulated investment in USA LNG export plants.

There is potential for the North American (Canada also has shale gas reserves) experience with shale gas to be repeated elsewhere, but caution is advised as conditions (geologic, development costs, environmental, infrastructure, politics) for shale gas development can vary widely.

In Australia there appears to be significant shale gas potential in the Cooper, Galilee, Perth and Canning Basins.

In North America viable/profitable wellhead prices for shale gas appear to be >US$5/GJ, so the industry is currently not profitable leading to a write-down of shale gas assets by companies (including BHPB). Of the majors, Chevron appears to be shale gas positive with Exxon-Mobil less so.

In a report on Fuel Cost Projections to provide outlooks/inputs for AEMO modelling, ACIL-Tasman in December 2011 estimated an aggregate shale gas resource of 25,000 PJs in eastern Australia at a cost of around A$9/GJ (2012-13 $'s). The report noted that this would tend to limit upward pressures on gas prices. It should be noted, however, that this upper limit, if realised, would still be twice to three times as high as previous wholesale prices.

6.7 The specification of the probability distributions

The above analysis for Eastern Australia needs to be incorporated into the analysis by the specification of probability distributions for two key parameters, namely the remaining reserves and the percentage of remaining gas reserves discovered by 2040.

Table 6.7 gives Trigen probability estimates for the two parameters. The lower bound estimate is the ACIL Tasman estimate. The upper bound estimate is the Core Energy Growth estimate plus the tight and shale gas reserves estimate. There is considerable upside in terms of shale gas availability. This is incorporated into the analysis by setting the upper bound probability relatively low at 85 per cent. This ensures that the maximum upper bound will be higher than the estimate set in the table.

The specification of the estimates of the per cent of remaining reserves at 2011 discovered by 2040 is straightforward and given in Table 6.7.

The reserve production trigger ratio requires explanation. It is one of the most important parameters in the analysis. The central assumption is that there is a minimum identified reserve to production ratio which, if attained, will render prohibitive the risks of investing in gas-intensive projects. This applies equally to new projects as it does to the investment to maintain the competitiveness of existing facilities. This trigger's value will vary from project to project and industry to industry. It is unlikely to be much lower than 15. Below 15 means that the risks are high that there will not be enough gas to feed the gas-using capacity currently installed. For large scale gas-using projects, the realised reserves to production ratio would have to be significantly above 15 given a three year construction period and a 20 to 30 plant life. Hence, the upper boundary is set at a reserve to production ratio of 25 in Table 6.7.

Table 6.7	The specification of the Trigen probability distribution parameters						
		Unit	Lower bound	Mode	Upper bound	Lower bound probability	Upper bound probability
1	Reserves remaining as at 2011	PJ	90,000	163,000	237,000	0	85
2	Per cent of reserves remaining as at 2011 discovered by 2040	Per cent	55	70	80	0	95
3	Reserves – production ratio trigger for suppressing gas demand	No.	15	20	25	0	100

In the model, if Eastern Australia's gas reserve to production ratio falls below the trigger level, the new growth in demand ceases and normal replacement investments are not made, meaning that underlying demand will fall by 2 per cent per annum. The level of demand falls to regain the benchmark reserve to production ratio. If more gas suppression is required gas is suppressed in the electricity sector and finally, in the case of severe restrictions, there will be plant closures.

6.8 The outcomes for the Trigen distribution

Probability estimates from the Trigen distribution parameters specified in Table 6.7 are presented in Table 6.8. The table indicates that the maximum estimate for discovered and undiscovered reserves, as at 2012, is 263,400 PJ. There is a 75 per cent probability that 147,000 PJ will be discovered and a 25 per cent probability that at least 200,000 PJs will be discovered.

The extraction ratio by 2040 of discovered reserves rises from a 5 percentile rate of 60 per cent through a mean of 70 per cent to a 95 percentile level of 80 per cent.

Table 6.8 Reserves and extraction probabilities

	Ultimately recoverable reserves (PJs)	Per cent of reserves discovered by 2040 (%)
Aggregate indicators		
Minimum	91288.86	55.35
Maximum	263437.80	84.62
Mean	173481.80	69.89
Std Deviation	36426.91	6.06
Distribution		
5% Percentile	115200.30	59.67
10% Percentile	125942.10	61.64
15% Percentile	134066.20	63.15
20% Percentile	140810.00	64.43
25% Percentile	146886.90	65.53
30% Percentile	152278.00	66.55
35% Percentile	157293.80	67.46
40% Percentile	161965.70	68.33
45% Percentile	166397.90	69.14
50% Percentile	171161.40	69.90
55% Percentile	176066.50	70.66
60% Percentile	181323.10	71.46
65% Percentile	186829.00	72.32
70% Percentile	192840.70	73.23
75% Percentile	199367.60	74.23
80% Percentile	206442.70	75.32
85% Percentile	214675.40	76.58
90% Percentile	224387.30	78.05
95% Percentile	236890.60	79.99

6.9 The cost of natural gas ex-plant

A price constraint is also inserted into the model. If prices exceed a benchmark level new growth in demand (including replacement demand) will cease. The price formula in the model is given by:

$$Pg \quad = \quad 5 + 0.15 \, . \, RD$$

Where:

Pg = price of gas ex-processing plant.

RD = per cent of reserves extracted as a per cent of remaining reserves, as at 2012.

The schedule has an upper limit of $15/GJ as the extraction ratio of estimated 2012 remaining reserves approaches its upper limit.

6.10 The base case: No Eastern Australian LNG plants

Given the model developed above, the base case will be the case of no Eastern Australian LNG plants to 2040. This will indicate the risk of suppressed demand for gas in the absence of the LNG projects proceeding. The results are given in Table A.7.

If there were no East Coast LNG plants, there is no chance of suppressed demand by 2020.

In the absence of the LNG exports from Queensland, there is only a very small chance, at the 95 percentile level, of the need for gas suppression in the 2020s.

In the 2030s there is a mean risk of the need for natural gas suppression but it is small, at 25 PJ per annum. This is on the basis that between 2025 and 2040 the Eastern Australian domestic natural gas demand grows at 2 per cent per annum for non-electricity sector gas use. The electricity sector case stays constant at the 2025 level to 2040.

6.11 The case of LNG exports

The alternative case is of the impact of 24 million tonnes of East Coast LNG exports on the Eastern Australian demand-supply balance. For the 2012-2020 period there is a mean expected outcome that the Eastern Australian domestic demand will be suppressed by an average of 40 PJ a year. For the 2020s the mean expectation is for a suppression of 600 PJs, with the 25 to 75 per cent probability range being between 165 and 952 PJs. By the 2040s the expectation (that is, the mean) is that there will be a suppression of natural gas equal to 40 per cent of the unconstrained demand case. The 25 to 75 per cent probability range is for a 2040 natural gas suppression rate of between 24 and 58 per cent.

Overall the mean expectation is that a cumulative 15,000 PJs of natural gas demand will be suppressed.

Table A.9 gives the net impact of the East Coast LNG exports on the domestic demand supply balance. As the results in Table A.8 demonstrate, there is little difference between the results in the two tables.

The tables enable readers to apply their own judgement. If one wanted to be optimistic, then the 30 per cent percentile case could be made equal to the expected case. In this case there is still a cumulative shortfall by 2040 of suppressed domestic natural gas demand of 7,640 PJs, with severe supply shortages appearing in the 2020s and the expectation that by 2040 the suppressed demand as a per cent of base case demand is 27 per cent.

6.12 Conclusion

The results are very significant. The results indicate that either the national interest evaluation of the LNG plants was deficient or that confidential knowledge of the gas resources available confirmed that these resources are considerably greater than what is in the public domain. Even if the latter is the case, impacts will not be avoided. There may well be adequate reserves but businesses make decisions on what they know and what they know would indicate that gas is likely to be transferred from domestic to LNG export sales. In this case the net economic cost of the East Coast LNG plants having preferred access to supply will involve very large costs on the economy.

The exact costs will be quantified in the next chapter.

7. The net benefit of East Coast LNG expansion in the context of Eastern Australian demand/supply balance

This chapter takes the results of the last three chapters and assesses the net national benefits and costs of the East Coast LNG expansion. In the event of limited supply to domestic users, the burden of adjustment will be divided between:

- gas dependent industries;
- general economy adjustment – decline in activity;
- general economy adjustment – full electricity substitution; and
- electricity sector gas suppression.

The key task in preparing input to the analysis is to specify the distribution of the burden of adjustment.

7.1 Domestic industrial gas demand suppression in the allocation of the burden of adjustment

The allocation of the share each adjustment path will play is critical in driving the overall net benefits or costs. The reason for this, as Chapter 6 indicated, is that there is a wide range in the net costs of adjustment per channel with the highest being for gas dependent industries and the lowest for the full electricity substitution case.

One approach would simply be to assume the lowest cost outcome. The full electricity substitution case may be appropriate for an efficiently planned state like China which would incorporate the strategy into its five year planning guidelines and more often than not achieve the desired result. In Australia, the mechanism for adjustment is via price changes which, in this case, will have a negative impact on economic activity and real incomes, and increase inflationary pressures via loss of competitiveness.

The fact of the matter is that adopting the full electricity substitution strategy would require a large scale investment in the electricity sector where prices would need to rise to finance it. Given the current reaction to price movements driven by large investments in electricity distribution it would appear that further rises to substitute electricity for gas would be very difficult to achieve.

The second-best course of action, the suppression of gas usage in electricity production, would also be difficult to achieve as it would require increases in the share of renewable production. As the reliance on renewables increases, the stability of the electricity system will decline in that variations in climatic conditions (perhaps aggravated by climate change) will result in greater volatility in supply. The need to have gas fired generating capacity as a back-up supply source can only increase. The reality is that by the 2020s and certainly by the 2030s, there may well be severe constraints on the ability to suppress gas usage in electricity production.

While the costs of a choice to suppress supply to gas-dependent industries are extremely high, this scenario should not be ignored without study. The reality is that it is already happening. Major domestic natural gas users in Queensland (Rio Tinto and Incitec Pivot) are already forecasting natural gas shortages by 2015. This must affect their incentive to expand in Australia and even to maintain their Australian assets at a level that would prevent medium-term closure.

The only way to ensure that gas-dependent industries do not atrophy is to ensure that they have new and guaranteed supply sources for the next three to four decades at prices that can be projected with a degree of confidence. To guarantee supplies to gas-dependent industry will require substantial interventions in the existing regime. However, the need for intervention should be put in perspective: the gas-dependent industries' entire consumption (4 million tonnes a year) is less than the allocation of gas required to keep one LNG train supplied.

Because of the uncertainty surrounding the adjustment paths, a probability approach is adopted. Table 7.1 gives the Trigen probability distribution parameter settings. The burden of the adjustment of the gas-dependent industries is biased downwards compared to their share of overall gas demand. However, the setting of the upper bound probability at 0.85 allows for cases where the burden of adjustment may well be greater.

The resulting distribution of the adjustment share of gas-dependent industries is given in Table 7.2. The mean is a 10 per cent adjustment burden with the 25th percentile at 8 per cent and the 75th percentile at 12 per cent.

For the other channels of adjustment the means are:

- suppression of gas usage in electricity production – 22 per cent; and
- a general fall in economic activity – 16 per cent.

The remaining share would be borne by the residential sector and, at the mean, would be 100 less 22 less 16 less 10, or 52 per cent. This allocation imposes a conservative bias on the analysis, as the above discussion implies that the decline in economic activity should perhaps have a greater weight than it has been accorded.

Table 7.1 Trigen probability distribution parameters – domestic natural gas suppression of the adjustment burden by sector

		Maximum lower bound	Mode	Maximum upper bound	Lower bound probability	Upper bound probability
1	Gas dependent industries – share in gas suppression	0.05	0.09	0.13	0	0.85
2	Electricity gas usage – share in gas suppression	0.15	0.20	0.25	0	1.00
3	General economy – actual decline of electricity substitution – residual given the above three outcomes	0.08	0.15	0.25	0	1.00
4	Carbon price 2040 ($/tonne)	60	100	200	0	0.9
5	Alternative natural gas input price into electricity production ($/GJ)	3	4	5	0	0.9

Table 7.2 Reserves and extraction probabilities		
	Carbon price (2009 $/tonne)	**Share of natural gas dependent industries in total gas suppression (%)**
Aggregate indicators		
Minimum	15.18	5.35
Maximum	219.78	16.35
Mean	119.98	10.22
Std Deviation	44.41	2.42
Distribution		
5% Percentile	45.67	6.54
10% Percentile	59.50	7.13
15% Percentile	71.17	7.65
20% Percentile	79.88	8.05
25% Percentile	88.31	8.42
30% Percentile	95.00	8.74
35% Percentile	102.51	9.03
40% Percentile	108.53	9.33
45% Percentile	114.59	9.65
50% Percentile	119.88	9.96
55% Percentile	125.38	10.33
60% Percentile	131.42	10.65
65% Percentile	137.94	11.08
70% Percentile	144.24	11.48
75% Percentile	151.91	11.93
80% Percentile	159.74	12.39
85% Percentile	168.84	12.99
90% Percentile	179.75	13.66
95% Percentile	194.48	14.57

7.2 The distribution of CO_2 price outcomes

A probability approach was taken for the determination of the CO_2 price with the probability distribution parameters given in Table 7.1. The resulting distribution for the CO_2 price is also given in Table 7.1. The mean over the project period is $120 and the 25 to 75 per cent probability benchmarks are $88 to $152 a tonne.

The operating cost of natural gas for electricity in the absence of East Coast LNG also is determined by a probability distribution with the parameters given in Table 7.1.

7.3 The impact of East Coast LNG exports on the national economy: The expected outcome

Expected outcomes from the mean settings of the various inputs are determined by the probability distributions. This applies whether the input variable is carbon prices or estimates of natural gas reserves to be discovered. The expected results are given in Tables A.11 to A.13.

From Table A.8 there is some risk of gas shortages by 2020, though the risk is not large. What is significant is the inability to secure long-term contracts for gas at competitive rates as gas producers see the opportunity of LNG exports as a windfall, particularly since some LNG plants have yet to secure all their needs. This is the real driver of the crowding out of domestic supply which will have a very significant negative impact on downstream production, jobs and overall economic benefit.

The GDP increase at market prices is initially greater than the direct impact of the LNG exports. Employment increases by 82,000 compared to what would have otherwise been the case. From Table A.8, however, over the 2020s, the expectation is that domestic gas demand will be suppressed by 592 PJ on an average annual basis. This means that by 2020 the positive stimulus from the LNG exports is fully offset by the negative stimulus of the crowding out by gas suppression. All the production series are negative with the greatest decline being for NNP.

The decline continues but at a slower rate in the outcomes for the 2020-2025 period. By 2040 the decline is $22 billion for gross domestic product at market prices, while the net national product is $34 billion lower in 2040 compared to what otherwise would have been the case. The decline by 2040 is 775,000 in employment, while the benefit indicator declines by $46 billion, compared to the disallowance of East Coast LNG exports. This represents about 1.6 to 1.8 per cent below what national baseline GDP would be expected to be by 2040.

The employment loss may appear implausibly large. However, it is likely that the main response to a decline in employment will be via reduction in immigration. The employment loss over 30 years implies a net average annual reduction in immigration of some 35,000. The response to this may be that there is no national loss if the cost is borne by residents who will not be in Australia. The risk is, however, that the decline in employment may be so great that the required level of immigration will fall below the “bedrock” 170,000 to 200,000 level. In this case there will be increases in the effective unemployment rate. There is a limit to the size of a negative shock which can be imposed on the economy without considerable eventual economic pain.

The cumulative decline of the net benefit indicator is $160 billion. If the probability distribution for the expected reserves is near reality, the only strategy to minimise costs is to reduce LNG exports by the amount of the expected supply shortage. By 2040 the expected supply shortage equals the LNG requirement. This is, of course, when the plants are near the end of their expected life. The critical time is in the mid-2020s when the supply shortage is half the LNG demand.

In this context a prudent strategy would have been to perhaps approve one project and delay the approval of other projects until:

(i) the local industry was protected by identified reserves which are allocated to domestic use with a minimum headline reserve to production rate of 20 to 1 by 2040 given expected demand growth; and

(ii) identified available reserves support any new projects over there complete life.

7.4 The range of possible outcomes

Table A.10 shows the distribution of expected outcomes around the mean outcomes for 2020 and 2040. High negative outcomes would result if the ACIL Tasman estimates of remaining natural gas reserves are anywhere near the mark. The low negative and marginally positive outcomes would occur if the alternative estimates of reserves by COE are near the mark, at least in terms of reserves that can be extracted at $10/GJ.

The point about the results is that even if the reserves remaining are at the upper end of the range, the benefit of the East Coast LNG projects are marginal in that costs and benefits are in balance. This is clearly shown in Table A.10 where, if eventually recoverable reserves are near 240,000 PJ, the value of the net benefit indicator in 2040 is $2.4 billion.

7.5 Conclusion

The most important point of all is that even if ultimately recoverable reserves are in fact near the upper range currently assessed, or indeed in excess of the upper range, if these reserves are not identified and they cannot be quickly extracted to meet shortfalls at reasonable costs, the negative consequences in the table are likely to be realised. This is because:

(i) the natural gas dependent industries will not expand and would most likely go into decline;

(ii) gas using electricity plants will not be built; and

(iii) unnecessary costs will be imposed on the economy because businesses and Governments in the main will base demand on realised outcomes with an allowance for future supply security.

To illustrate the issue, assume that the ultimate recoverable reserves are 300,000 PJ. If gas producers continue their practice of allocating resources to export the reserves will not be identified and extracted for domestic use unless Governments force them to do so. The negative results of this analysis would remain, albeit reduced by the additional benefits of another LNG train or two. The only certain way to prevent the negative outcomes of this chapter is the identification and allocation of sufficient reserves for domestic use to cater for their needs for the next 30 to 40 years. In this context the estimates of overall remaining reserves are irrelevant. In any case, given the conservative allocation of weights in this study (that is, biased to low cost options), the benefits of additional potential reserves are likely to be neutralised by increasing the weight towards the higher cost adjustment options.

A related issue is the ownership structure of the enterprises which control the identification of reserves. If their interests are in "just-in-time" identification of reserves, a significant proportion of the negative consequences identified above will still be realised, even if the actual level of eventually recoverable reserves is much greater. Unfortunately, on the estimates presented here, future reserve estimates will affect domestic investment decisions even if they turn out to be too low.

Under the current reserves management practice and with the pipeline infrastructure limitations, Australia does not seem to have enough available reserves of gas to be able to avoid the negative effects of large increases in demand or of falls in the headline reserve/production ratio on business decision making.

8. East Coast LNG expansion: Additional downside risks

Three additional areas could add to the net cost over and above those identified in the previous chapters. These include:

(i) lower prices for LNG than expected;

(ii) higher alternative benefits from the use of the gas domestically; and

(iii) balance of payments adjustment costs to a rapid decline in the terms of trade.

8.1 East Coast LNG expansion: The impact of lower LNG prices

On the world stage, identified recoverable shale gas reserves, together with the extraction of the resource, are now growing strongly, particularly in the United States. United States reserves are large, estimated currently at 865 Tcf with relative low cost investment and production costs at around $4 to $6 per GJ. As a result, shale gas currently constitutes one quarter of United States total gas production and this is expected to increase to 50 per cent by 2035.

Once the United States authorities are satisfied that there is sufficient gas to satisfy domestic requirements for the foreseeable future, large scale LNG exports may be encouraged. Initially this will be done at low cost, converting LNG import infrastructure (currently unused because of the rapid expansion of shale gas production) to LNG export plants.

Given the analysis of the previous section, where the extraction costs are expected to rise to the $7 to $10 per GJ range because of resource depletion, the export of lower cost gas from the United States could force a $2 to $4 reduction in the export LNG price from the East Coast which would be a reduction of between 14 and 28 per cent. Even if LNG prices for East Coast Australia are linked, in part, to the price of oil, downward price pressure will not be avoided. The United States will not allow large scale export of gas until the gas has been fully utilised domestically to maximise the reduction in its dependence on oil imports. Other countries with substantial shale gas resources will also apply the same policies which, combined, will put significant downward pressure on oil prices and hence LNG prices.

If it is assumed that world-wide expansion of shale gas extraction reduces LNG prices by, in real terms, 20 per cent by the latter part of this decade, the effect of the decrease per PJ of output is:

- contribution to gross domestic product reduced by 25 per cent;
- tax receipts down by 66 per cent;
- domestic distributed income reduced by 28 per cent; and
- net national product reduced by 34 per cent.

These are average declines over the first 20 years of the project. The decline in tax revenue occurs because the collection of PRRT revenue is delayed until towards the end of the life of the project.

Table 8.1 shows the economy-wide impact given the above assumed price changes. The base case price is the 2011 level. The alternative case is a 20 per cent reduction in this level.

From the table, the reduction in net benefits is proportional to the reduction in the input parameters. The reduction in the net benefit indicator is $171 million for 50 PJ of exports, or a 43 per cent reduction to $229 million from the base case of $401 million.

This result provides the rule of thumb that:

- **for every 1 per cent reduction in the LNG price the economy-wide benefits from LNG exports will be reduced by approximately 2 percentage points. This stems mainly from the fact that tax receipts and domestic profits will be disproportionately impacted. Interest owed overseas will still have to be paid and debt repaid.**

Table 8.1 The impact of lower LNG prices

		Case study: 50 PJ of natural gas allocated to LNG exports – base case prices	Case study: 50 PJ of natural gas allocated to LNG exports – 20% reduction in base case prices	Net benefit of 50 PJ of LNG exports with 20% reduction in base case prices
Macroeconomic aggregates				
Gross domestic product at factor cost	$2009m	729.56	-186.22	543.34
Gross domestic product at market prices	$2009m	767.76	-198.23	569.53
Gross national product at market prices	$2009m	538.64	-187.21	351.43
Net national product at market prices	$2009m	355.40	-132.73	222.67
Total imports of goods and services	$2009m	75.85	-21.53	54.33
Total employment	**ths.**	**4.28**	**-1.25**	**3.03**
Household activity				
Wages and mixed income	$2009m	170.21	-48.13	122.08
Property income	$2009m	128.49	-54.30	74.20
Direct taxes paid	$2009m	67.21	-23.05	44.16
Household consumption	$2009m	184.68	-63.33	121.36
Government revenue				
Direct taxes on households	$2009m	67.21	-23.05	44.16
Direct taxes on business	$2009m	156.55	-112.19	44.36
Indirect taxes	$2009m	38.21	-12.01	26.19
Total tax revenue	$2009m	261.96	-147.24	114.72
Other indicators				
Income paid overseas	$2009m	229.12	-11.03	218.10
Benefit indicator	$2009m	401.02	-171.65	229.37

8.2 Foregone growth benefits from expansion of the chemicals sector

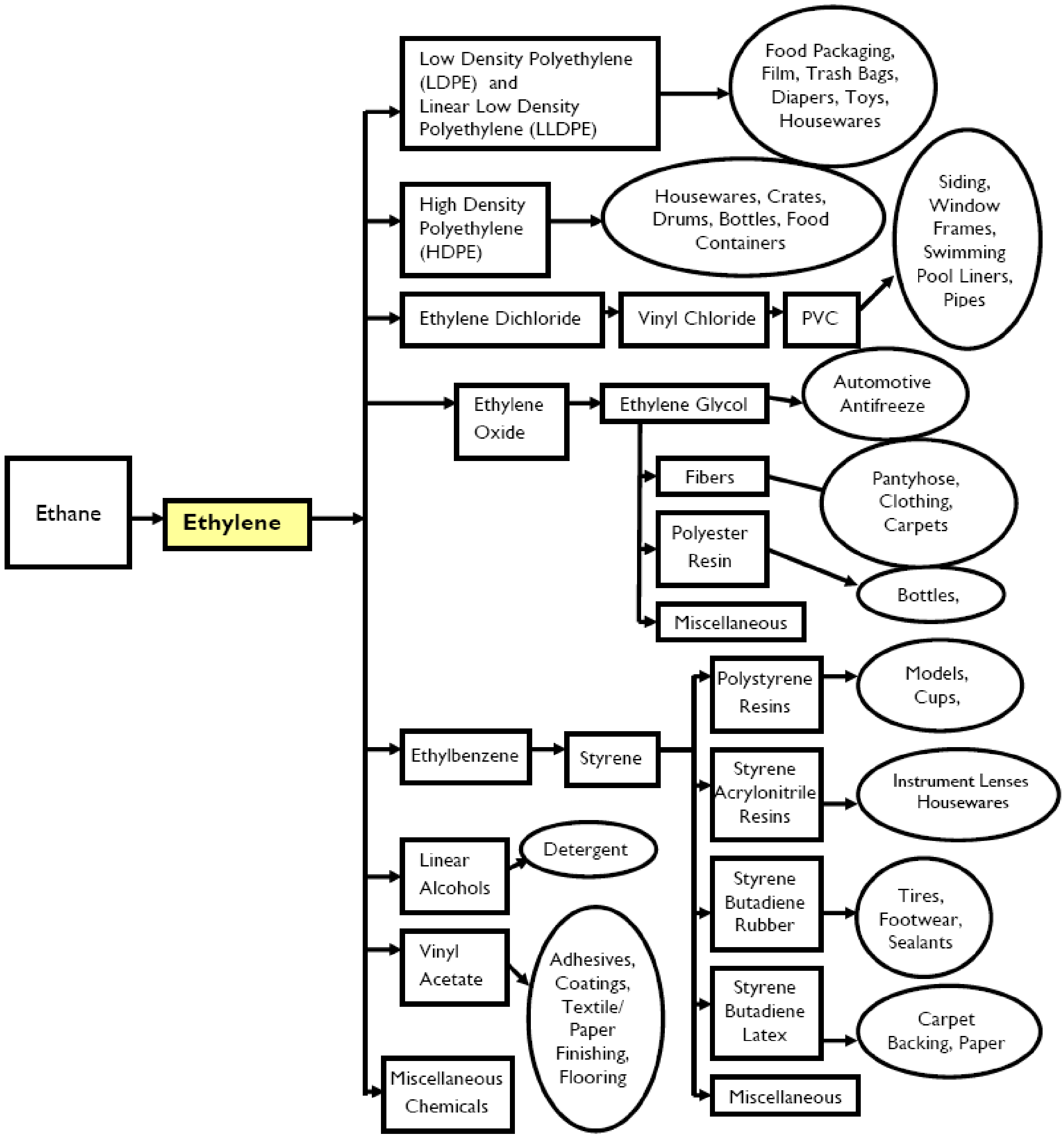
The analysis of Chapters 4 to 7 above were in the context of the existing chemicals sector being crowded out by natural gas shortages. This analysis provided minimum estimates which made no allowance for the foregone ability to grow the chemicals sector as a strategic industry – not only the gas-intensive chemicals industry (fertilizers, explosives) but also that part of the chemicals industry which uses natural gas liquids in general, and ethane in particular. Ethane is the next largest component of natural gas after methane. Its concentration varies from negligible levels to up to 6 per cent of a natural gas deposit. As Figure 8.1 shows, ethane is used to produce ethylene, which is an essential input into a wide range of chemical products.

A 2011 study by the American Chemistry Council (ACC) examined the benefits to the United States of an expansion in the chemicals industry enabled by expanded supply of natural gas. The American study had an indirect (that is inter-industry) effect of $US36 billion from a hypothetical but plausible 25 per cent increase in ethane supply. The ACC study used a completely unconstrained input output framework whereas for this study the chemical sector is treated as a constrained set of industries because of the methodology assuming it is constrained by gas supply. Therefore for this study it was necessary to estimate the indirect inter-industry effect on the rest of the chemical sector by the methodology outlined in developing the data in Table 4.2 which underlies the multiplier of 1.6 for the chemical sector as a whole. The induced multiplier for this study in the context of the Australian economy is of the order of 1.4. This represents the employment income, household consumption expenditure induced plus the non-chemical inter-industry effects which are identical to the Chemical Council study in methodology and concept. Thus if the Australian basic chemical value of $168 million per PJ is multiplied by 1.60 and 1.4 the result is $376 million per PJ which is less than the $415 million per PJ for the American study. The American total multiplier would be expected to be bigger because of the lower import content of the American economy and the greater complexity of the inter-industry supply chains.

Once this adjustment is taken into account the two studies are extremely similar in their quantitative conclusions.

If the investment effects are taken into account an interesting conclusion emerges. While the investment to output ratio for LNG is between 4.0 and 4.5 times the annual value of output, the equivalent ratio for the chemical sector is 0.5 because of the greater value extracted from the chemical sector use of natural gas. The value of output per PJ of natural gas used by the chemicals sector is 2.7 times that for the LNG sector. There is no validity in the argument that LNG should be promoted simply because of its investment intensity.

Figure 8.1: Ethane/Ethylene and the chemical industry flow chart



Source: American Chemistry Council, "*Shale Gas and New Petrochemicals Investment: Benefits for the Economy, Jobs and US Manufacturing*", March 2011.

8.3 The costs of adjustment when the mining boom ends

When the mining boom ends, the terms of trade will decline, the exchange rate will fall and the current account deficit will expand rapidly to double digit levels as a percentage of GDP. The current account deficit circa 2016 to 2020 at least will be around 5 to 6 per cent of GDP with terms of trade near current levels, and given Australia's existing high net international debt any fall in the terms of trade will increase the measured debt and require that the current account deficit be closed rapidly back to the 5 per cent of GDP mark.

Normally the exchange rate decline would be expected to carry some of the burden by facilitating an export expansion/import replacement response to cushion the impact on economic activity. However Australia is destroying capacity in its non-resource trade-exposed industries from a combination of natural gas suppression and the investment-discouraging effects of the loss of competitiveness due to the high exchange rate which has accompanied the boom in mining investment. (Admittedly the iron ore export industry bears major responsibility for the high exchange rate, but LNG exports have played a role.) The high prices for iron ore, coal and other mineral exports are bound to subside, if only because of current investment in expanding capacity in Australia, Africa and elsewhere, and when the high prices fall the Australian dollar exchange rate is likely to fall with them. At this point the loss of capacity in manufacturing, tourism and other trade-exposed industries will have two unpleasant consequences:

(i) the current account deficit will be considerably worse than what would have been the case; and

(ii) most of the adjustment required to bring the current account deficit back to sustainable levels will have to come from demand suppression via contractionary monetary and fiscal policies.

To illustrate, from Table A.11, the expected benefit from East Coast LNG exports would lead to a $6 billion increase in imports. At an average 20 per cent share of imports in GDP to neutralise the impact of the import increase of the balance of payments will require a loss in GDP of $30 billion. However, normal income elasticity effects will reduce this to around $15 billion. This is because imports are highly elastic with respect to GDP change. Even so, it is two to four times the expected GDP loss from Table A.11 from East Coast LNG exports in the 2020s.

Hence, the following rule of thumb.

- **For every $1m of lost GDP from the absence of effective policies to neutralise the impact of domestic gas suppression costs on the economy, at least an additional $2 million will be lost from the current damage being done to the Australian non-resource tradeable industries from the general effects of the currently high exchange rate and potentially from domestic gas suppression.**

This analysis has only been done in terms of the marginal case of Table A.11. The risks for the national economy in the period 2016-2020 appear to require careful analysis. The inference from the above calculations is that a sharp end to the mining boom and a return of the terms of trade to near pre 2005 levels would risk severe economic instability.

9. A review of current policy is urgent

It is not the task of this study to outline the appropriate policy regime. This study goes no further than demonstrating that, unless an appropriate policy regime is put in place, the cost of East Coast LNG exports from Australia is likely to be a net negative for the national economy.

In order to avoid the likelihood of net negative consequences to the economy, a policy review is urgent that considers the impacts and risks discussed in this report and develops policies which gave continuity to existing and potential large scale uses of natural gas in regard to:

(i) adequate supply availability over a 40 year horizon;

(ii) benchmarks for the determination of costs of supply; and

(iii) institutional arrangements which would ensure that domestic customers' long-term interests are protected.

In relation to (iii), the CME study, "*The Impact of Liquefied Natural Gas on Queensland Gas Markets and Gas Users*", March 2010, points to a number of factors which will contribute to negative outcomes from the East Coast LNG exports.

Firstly, as noted in Chapter 1, the interest of gas producers in LNG plants is giving foreign customers first preference in the supply of gas in part because sales on foreign markets are expected to be more profitable than sales to domestic customers. However, as the CME report notes, even if domestic gas sales had higher margins once the LNG plant came into production the domestic sales would become small compared to foreign sales. Higher margins on domestic sales will, therefore, make a small contribution to overall profits.

The drive to secure large scale supply for export markets has driven consolidation in the gas supply industry in Queensland and greatly reduced competition. Second, the control of gas producers over pipelines and, therefore, access is also contributing to a decline in competition. This discourages smaller scale producers from expanding or commencing production. The volume of gas going through pipelines to service export markets will make it easier for pipeline owners to apply for exemptions from pipeline access on the grounds of capacity constraints.

There will indeed be producers who will be willing to supply the local market. However, as the larger producers become increasingly export focussed, these producers are likely to be small scale and, therefore, inefficient and under-capitalised, which will not assist in increasing the confidence of local gas users in long-run prospects.

In this environment the required policy regime to optimise the national interest and to avoid the costs quantified in Chapter 7 is self-evident.

Appendix A: Tables related to chapters of this report

Table A.1 Natural gas dependent industries response to 50 PJ suppression of domestic natural gas demand – macroeconomic implications of different adjustment paths

		Case study: 50 PJ of natural gas allocated to LNG exports	Case study: 50 PJ of natural gas withdrawn from natural gas dependent industries	Net benefit of reallocating 50 PJ of natural gas from natural gas dependent industries to export
Macroeconomic aggregates				
Gross domestic product at factor cost	$2009m	729.56	-11004.69	-10275.13
Gross domestic product at market Prices	$2009m	767.76	-12289.23	-11521.46
Gross national product at market prices	$2009m	538.64	-10994.01	-10455.37
Net national product at market prices	$2009m	355.40	-9112.42	-8757.02
Total imports of goods and services	$2009m	75.85	5680.81	5756.67
Total employment	**ths.**	**4.28**	**-203.34**	**-199.06**
Household activity				
Wages and mixed income	$2009m	170.21	-6441.65	-6271.45
Property income	$2009m	128.49	-2169.01	-2040.51
Direct taxes paid	$2009m	67.21	-1937.40	-1870.19
Household consumption	$2009m	184.68	-5323.87	-5139.19
Government revenue				
Direct taxes on households	$2009m	67.21	-1937.40	-1870.19
Direct taxes on business	$2009m	156.55	-706.87	-550.32
Indirect taxes	$2009m	38.21	-1284.54	-1246.33
Total tax revenue	**$2009m**	**261.96**	**-3928.81**	**-3666.85**
Other indicators				
Income paid overseas	$2009m	229.12	-1295.22	-1066.09
Benefit indicator	$2009m	401.02	-9182.55	-8781.53
Cumulative discounted (at 5%) benefit indicator 2016-2040	$2009m	4629.63	-104509.34	-99879.72

Table A.2 Gross output formation by industry ($2009m)	Case study: 50 PJ of natural gas allocated to LNG exports	Case study: 50 PJ of natural gas withdrawn from natural gas dependent industries	Net benefit of reallocating 50 PJ of natural gas from natural gas dependent industries to export
Constrained industries			
Basic chemicals	0.00	-4202.24	-4202.24
Paints	0.00	-98.17	-98.17
Medicinal and pharmaceutical products, pesticides	0.00	-98.77	-98.77
Soap and detergents	0.00	-159.09	-159.09
Cosmetics and toiletry preparations	0.00	-55.37	-55.37
Other chemical products	0.00	-288.82	-288.82
Rubber products	0.00	-40.00	-40.00
Plastic products	0.00	-1847.01	-1847.01
Basic non-ferrous metal and products	0.00	-5951.61	-5951.61
LNG	620.73	0.00	620.73
Unconstrained industries			
Sheep	0.70	-28.13	-27.43
Grains	1.06	-47.17	-46.11
Beef cattle	1.94	-87.10	-85.15
Dairy cattle	1.08	-33.71	-32.62
Pigs	0.27	-10.67	-10.40
Poultry	0.60	-22.74	-22.14
Other agriculture	3.94	-135.46	-131.52
Services to agriculture, hunting and trapping	0.92	-39.85	-38.94
Forestry and logging	0.50	-23.60	-23.11
Commercial fishing	0.63	-18.96	-18.34
Coal	1.79	-80.86	-79.07
Gas	5.80	-83.10	-77.30
Oil	1.47	-65.27	-63.81
Iron ores	0.20	-5.91	-5.71
Non-ferrous metal ores	0.31	-2448.79	-2448.48
Other mining	0.45	-69.09	-68.64
Services to mining	15.45	-281.93	-266.48
Meat and meat products	4.60	-191.72	-187.12
Dairy products	3.54	-110.34	-106.80
Fruit and vegetable products	1.12	-33.81	-32.69
Oils and fats	0.44	-19.27	-18.83
Flour mill products and cereal foods	1.83	-72.38	-70.55
Bakery products	1.51	-45.15	-43.64
Confectionery	1.15	-35.13	-33.98
Other food products	2.69	-100.96	-98.27

Table A.2 Gross output formation by industry ($2009m) – continued

	Case study: 50 PJ of natural gas allocated to LNG exports	Case study: 50 PJ of natural gas withdrawn from natural gas dependent industries	Net benefit of reallocating 50 PJ of natural gas from natural gas dependent industries to export
Soft drinks, cordials and syrups	1.48	-46.55	-45.07
Beer and malt	1.26	-37.46	-36.20
Wine, spirits and tobacco products (a)	1.44	-45.56	-44.12
Textile fibres, yarns and woven fabrics	0.12	-6.26	-6.14
Textile products	0.37	-11.76	-11.38
Knitting mill products	0.26	-8.45	-8.19
Clothing	0.57	-18.84	-18.27
Footwear	0.12	-3.97	-3.85
Leather and leather products	0.09	-3.46	-3.36
Sawmill products	0.54	-16.20	-15.65
Other wood products	1.09	-38.72	-37.63
Pulp, paper and paperboard	0.30	-13.32	-13.01
Paper containers and products	0.90	-47.09	-46.20
Printing and services to printing	2.88	-101.92	-99.04
Publishing, recorded media, etc.	3.29	-122.30	-119.01
Petroleum and coal products	6.35	-282.82	-276.47
Glass and glass products	0.67	-27.41	-26.74
Ceramic products	0.12	-4.41	-4.30
Cement, lime and concrete slurry	0.83	-29.53	-28.70
Plaster and other concrete products	0.43	-15.83	-15.40
Other non-metallic mineral products	0.23	-7.38	-7.16
Iron and steel	4.24	-122.60	-118.36
Structural metal products	2.92	-73.11	-70.19
Sheet metal products	0.91	-37.26	-36.35
Fabricated metal products	2.23	-73.55	-71.32
Motor vehicles and parts, other transport equipment	4.75	-137.15	-132.41
Ships and boats	0.40	-13.72	-13.31
Railway equipment	1.21	-13.28	-12.06
Aircraft	1.39	-21.41	-20.02
Photographic and scientific equipment	0.91	-27.53	-26.62
Electronic equipment	0.83	-24.03	-23.20
Household appliances	1.37	-38.35	-36.98
Other electrical equipment	1.34	-41.45	-40.12
Agricultural, mining, etc. machinery	1.79	-36.27	-34.49
Other machinery and equipment	1.60	-44.46	-42.87
Prefabricated buildings	0.85	-8.07	-7.22
Furniture	1.26	-36.77	-35.51
Other manufacturing	1.07	-57.35	-56.28

Table A.2 Gross output formation by industry ($2009m) – continued

	Case study: 50 PJ of natural gas allocated to LNG exports	Case study: 50 PJ of natural gas withdrawn from natural gas dependent industries	Net benefit of reallocating 50 PJ of natural gas from natural gas dependent industries to export
Electricity supply	10.97	-460.21	-449.24
Gas supply	1.10	-65.39	-64.29
Water supply, sewerage and drainage services	4.06	-157.67	-153.62
Residential building	1.94	-47.42	-45.48
Other construction	3.52	-78.84	-75.32
Construction trade services	19.47	-418.47	-399.00
Wholesale trade	25.88	-1231.10	-1205.22
Wholesale mechanical repairs	2.89	-22.17	-19.28
Other wholesale repairs	5.51	-111.48	-105.97
Retail trade	32.74	-984.54	-951.80
Retail mechanical repairs	7.63	-229.35	-221.72
Other retail repairs	0.44	-13.03	-12.59
Accommodation, cafes and restaurants	16.97	-515.86	-498.90
Road transport	9.58	-489.81	-480.23
Rail, pipeline and other transport	10.02	-111.10	-101.09
Water transport	1.13	-54.45	-53.32
Air and space transport	4.99	-155.51	-150.52
Services to transport, storage	13.62	-496.68	-483.06
Communication services	15.22	-500.67	-485.44
Finance	47.38	-1319.57	-1272.19
Ownership of dwellings	4.72	-135.99	-131.27
Other property services	31.27	-739.24	-707.97
Scientific research, technical and computer services	11.85	-445.16	-433.31
Legal, accounting, marketing and business management services	18.85	-766.52	-747.67
Other business services	11.10	-478.61	-467.51
Government administration	2.21	-99.62	-97.42
Defence	0.03	-1.39	-1.36
Education	9.51	-282.15	-272.63
Health services	9.29	-271.61	-262.32
Community services	1.16	-33.37	-32.21
Motion picture, radio and television services	4.08	-139.92	-135.84
Libraries, museums and the arts	1.11	-36.41	-35.30
Sport, gambling and recreational services	7.78	-192.15	-184.37
Personal services	3.71	-108.00	-104.28
Other services	3.99	-119.36	-115.37
Total	**1082.81**	**-29840.57**	**-28757.76**

Table A.3 Total employment formation (ths)

	Case study: 50 PJ of natural gas allocated to LNG exports	Case study: 50 PJ of natural gas withdrawn from natural gas dependent industries	Net benefit of reallocating 50 PJ of natural gas from natural gas dependent industries to export
Constrained industries			
Basic chemicals	0.00	-11.20	-11.20
Paints	0.00	-1.00	-1.00
Medicinal and pharmaceutical products, pesticides	0.00	-0.80	-0.80
Soap and detergents	0.00	-0.92	-0.92
Cosmetics and toiletry preparations	0.00	-0.37	-0.37
Other chemical products	0.00	-2.81	-2.81
Rubber products	0.00	-0.35	-0.35
Plastic products	0.00	-16.88	-16.88
Basic non-ferrous metal and products	0.00	-32.47	-32.47
LNG	0.12	0.00	0.12
Unconstrained industries			
Sheep	0.01	-0.47	-0.46
Grains	0.01	-0.41	-0.40
Beef cattle	0.03	-1.24	-1.21
Dairy cattle	0.01	-0.45	-0.43
Pigs	0.01	-0.26	-0.25
Poultry	0.01	-0.20	-0.20
Other agriculture	0.04	-1.28	-1.24
Services to agriculture, hunting and trapping	0.01	-0.29	-0.28
Forestry and logging	0.00	-0.17	-0.16
Commercial fishing	0.00	-0.12	-0.12
Coal	0.00	-0.10	-0.10
Gas	0.00	-0.07	-0.06
Oil	0.00	-0.03	-0.03
Iron ores	0.00	-0.01	-0.01
Non-ferrous metal ores	0.00	-5.15	-5.15
Other mining	0.00	-0.26	-0.25
Services to mining	0.10	-1.88	-1.78
Meat and meat products	0.07	-2.82	-2.75
Dairy products	0.04	-1.17	-1.13
Fruit and vegetable products	0.01	-0.20	-0.19
Oils and fats	0.00	-0.08	-0.08
Flour mill products and cereal foods	0.01	-0.51	-0.50
Bakery products	0.03	-0.97	-0.94
Confectionery	0.01	-0.24	-0.23
Other food products	0.02	-0.63	-0.61

Table A.3 Total employment formation (ths) – continued	Case study: 50 PJ of natural gas allocated to LNG exports	Case study: 50 PJ of natural gas withdrawn from natural gas dependent industries	Net benefit of reallocating 50 PJ of natural gas from natural gas dependent industries to export
Soft drinks, cordials and syrups	0.01	-0.19	-0.18
Beer and malt	0.00	-0.12	-0.11
Wine, spirits and tobacco products (a)	0.01	-0.17	-0.16
Textile fibres, yarns and woven fabrics	0.00	-0.04	-0.04
Textile products	0.01	-0.16	-0.16
Knitting mill products	0.00	-0.07	-0.07
Clothing	0.01	-0.33	-0.32
Footwear	0.00	-0.04	-0.04
Leather and leather products	0.00	-0.02	-0.02
Sawmill products	0.00	-0.12	-0.12
Other wood products	0.02	-0.58	-0.56
Pulp, paper and paperboard	0.00	-0.05	-0.05
Paper containers and products	0.01	-0.35	-0.34
Printing and services to printing	0.03	-1.01	-0.98
Publishing, recorded media, etc.	0.03	-0.94	-0.92
Petroleum and coal products	0.01	-0.64	-0.63
Glass and glass products	0.01	-0.26	-0.25
Ceramic products	0.00	-0.04	-0.03
Cement, lime and concrete slurry	0.00	-0.12	-0.11
Plaster and other concrete products	0.00	-0.08	-0.08
Other non-metallic mineral products	0.00	-0.09	-0.09
Iron and steel	0.04	-1.10	-1.07
Structural metal products	0.02	-0.45	-0.43
Sheet metal products	0.00	-0.17	-0.16
Fabricated metal products	0.02	-0.78	-0.76
Motor vehicles and parts, other transport equipment	0.05	-1.53	-1.48
Ships and boats	0.00	-0.05	-0.05
Railway equipment	0.00	-0.05	-0.05
Aircraft	0.01	-0.09	-0.08
Photographic and scientific equipment	0.01	-0.29	-0.28
Electronic equipment	0.01	-0.26	-0.25
Household appliances	0.01	-0.33	-0.32
Other electrical equipment	0.01	-0.41	-0.40
Agricultural, mining, etc. machinery	0.02	-0.40	-0.38
Other machinery and equipment	0.02	-0.49	-0.47
Prefabricated buildings	0.01	-0.06	-0.05
Furniture	0.03	-0.89	-0.86
Other manufacturing	0.01	-0.71	-0.70

Table A.3 Total employment formation (ths) – continued	Case study: 50 PJ of natural gas allocated to LNG exports	Case study: 50 PJ of natural gas withdrawn from natural gas dependent industries	Net benefit of reallocating 50 PJ of natural gas from natural gas dependent industries to export
Electricity supply	0.03	-1.38	-1.35
Gas supply	0.01	-0.55	-0.54
Water supply, sewerage and drainage services	0.02	-0.68	-0.67
Residential building	0.01	-0.23	-0.22
Other construction	0.02	-0.56	-0.53
Construction trade services	0.29	-6.23	-5.94
Wholesale trade	0.19	-9.03	-8.84
Wholesale mechanical repairs	0.02	-0.15	-0.13
Other wholesale repairs	0.05	-0.94	-0.90
Retail trade	0.56	-16.80	-16.24
Retail mechanical repairs	0.20	-6.06	-5.86
Other retail repairs	0.01	-0.28	-0.27
Accommodation, cafes and restaurants	0.25	-7.51	-7.26
Road transport	0.10	-4.86	-4.77
Rail, pipeline and other transport	0.08	-0.89	-0.81
Water transport	0.01	-0.28	-0.28
Air and space transport	0.04	-1.10	-1.07
Services to transport, storage	0.07	-2.57	-2.50
Communication services	0.09	-3.10	-3.01
Finance	0.19	-5.40	-5.20
Ownership of dwellings	0.00	0.00	0.00
Other property services	0.11	-2.51	-2.41
Scientific research, technical and computer services	0.13	-4.86	-4.73
Legal, accounting, marketing and business management services	0.17	-6.95	-6.78
Other business services	0.08	-3.64	-3.55
Government administration	0.03	-1.18	-1.16
Defence	0.00	-0.01	-0.01
Education	0.12	-3.66	-3.54
Health services	0.11	-3.31	-3.20
Community services	0.02	-0.50	-0.48
Motion picture, radio and television services	0.03	-1.08	-1.05
Libraries, museums and the arts	0.02	-0.77	-0.74
Sport, gambling and recreational services	0.11	-2.77	-2.66
Personal services	0.10	-2.77	-2.68
Other services	0.05	-1.43	-1.38
Total	**4.28**	**-203.34**	**-199.06**

Table A.4 General economy responses to 50 PJ suppression of domestic natural gas demand – macroeconomic implications of different adjustment paths

		Case study: 50 PJ of natural gas allocated to LNG exports	Case study: impact of withdrawing 50 PJ of natural gas – general economy impact full electricity substitution	Net benefit of reallocating 50 PJ of natural gas from natural gas dependent industries to export – full substitution effect	Case study: impact of withdrawing 50 PJ of natural gas – decline in economic activity	Net benefit of reallocating 50 PJ of natural gas from natural gas dependent industries to export – general economy effect – decline in economic activity	Case study: impact of withdrawing 50 PJ of natural gas – gas substitution in electricity production	Net benefit of reallocating 50 PJ of natural gas from natural gas dependent industries to export – general economy effect – gas substitution in electricity production
Macroeconomic aggregates								
Gross domestic product at factor cost	$2009m	729.56	469.54	1199.10	-4658.41	-3928.85	-206.25	523.31
Gross domestic product at market Prices	$2009m	767.76	402.91	1170.67	-5697.53	-4929.77	-282.58	485.18
Gross national product at market prices	$2009m	538.64	211.60	750.23	-5492.32	-4953.68	-296.18	242.45
Net national product at market prices	$2009m	355.40	-3.10	352.30	-4966.96	-4611.56	-307.24	48.16
Total imports of goods and services	$2009m	75.85	-64.14	11.72	-1521.38	-1445.52	-113.45	-37.60
Total employment	**Ths**	**4.28**	**-0.50**	**3.78**	**-92.67**	**-88.39**	**-5.72**	**-1.44**
Household activity								
Wages and mixed income	$2009m	170.21	-1.13	169.07	-3130.00	-2959.80	-209.59	-39.39
Property income	$2009m	128.49	264.86	393.36	-922.44	-793.95	16.41	144.90
Direct taxes paid	$2009m	67.21	59.34	126.55	-911.80	-844.59	-43.47	23.74
Household consumption	$2009m	184.68	-831.59	-646.91	-6410.88	-6226.20	-576.70	-392.02

Table A.4 General economy responses to 50 PJ suppression of domestic natural gas demand – macroeconomic implications of different adjustment paths (continued)

		Case study: 50 PJ of natural gas allocated to LNG exports	Case study: impact of withdrawing 50 PJ of natural gas – general economy impact full electricity substitution	Net benefit of reallocating 50 PJ of natural gas from natural gas dependent industries to export – full substitution effect	Case study: impact of withdrawing 50 PJ of natural gas – decline in economic activity	Net benefit of reallocating 50 PJ of natural gas from natural gas dependent industries to export – general economy effect – decline in economic activity	Case study: impact of withdrawing 50 PJ of natural gas – gas substitution in electricity production	Net benefit of reallocating 50 PJ of natural gas from natural gas dependent industries to export – general economy effect – gas substitution in electricity production
Government revenue								
Direct taxes on households	$2009m	67.21	59.34	126.55	-911.80	-844.59	-43.47	23.74
Direct taxes on business	$2009m	156.55	-4.20	152.34	-248.23	-91.68	-26.12	130.42
Indirect taxes	$2009m	38.21	-66.63	-28.43	-1039.13	-1000.92	-76.33	-38.13
Total tax revenue	**$2009m**	**261.96**	**-11.50**	**250.46**	**-2199.15**	**-1937.19**	**-145.92**	**116.04**
Other indicators								
Income paid overseas	$2009m	229.12	191.31	420.44	-205.21	23.91	13.60	242.73
Benefit indicator	$2009m	401.02	-423.10	-22.07	-6788.50	-6387.47	-514.93	-113.91
Cumulative discounted (at 5%) benefit indicator 2016-2040	$2009m	4629.63	-6154.42	-1524.79	-90767.69	-86138.06	-6995.04	-2365.42

Table A.5 Gross output formation by industry ($2009m)

	Case study: 50 PJ of natural gas allocated to LNG exports	Case study: impact of withdrawing 50 PJ of natural gas – general economy impact full electricity substitution	Net benefit of reallocating 50 PJ of natural gas from natural gas dependent industries to export – full substitution effect	Case study: impact of withdrawing 50 PJ of natural gas – decline in economic activity	Net benefit of reallocating 50 PJ of natural gas from natural gas dependent industries to export – general economy effect – decline in economic activity	Case study: impact of withdrawing 50 PJ of natural gas – gas substitution in electricity production	Net benefit of reallocating 50 PJ of natural gas from natural gas dependent industries to export – general economy effect – gas substitution in electricity production
Constrained industries							
Basic chemicals	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Paints	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Medicinal and pharmaceutical products, pesticides	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Soap and detergents	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cosmetics and toiletry preparations	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other chemical products	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Rubber products	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Plastic products	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Basic non-ferrous metal and products	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LNG	620.73	0.00	620.73	0.00	620.73	0.00	620.73
Unconstrained industries							
Sheep	0.70	-2.63	-1.93	-22.11	-21.41	-1.95	-1.25
Grains	1.06	-4.28	-3.22	-34.66	-33.60	-3.08	-2.03
Beef cattle	1.94	-7.93	-5.98	-64.11	-62.17	-5.70	-3.76
Dairy cattle	1.08	-4.48	-3.40	-36.09	-35.01	-3.21	-2.13
Pigs	0.27	-1.06	-0.79	-8.69	-8.43	-0.77	-0.50
Poultry	0.60	-2.48	-1.88	-19.94	-19.34	-1.77	-1.17
Other agriculture	3.94	-16.22	-12.27	-130.01	-126.06	-11.61	-7.66
Services to agriculture, hunting and trapping	0.92	-3.57	-2.65	-29.49	-28.58	-2.61	-1.70
Forestry and logging	0.50	-0.11	0.39	-5.70	-5.20	-0.50	0.00

Table A.5 Gross output formation by industry ($2009m) – continued

	Case study: 50 PJ of natural gas allocated to LNG exports	Case study: impact of withdrawing 50 PJ of natural gas – general economy impact full electricity substitution	Net benefit of reallocating 50 PJ of natural gas from natural gas dependent industries to export – full substitution effect	Case study: impact of withdrawing 50 PJ of natural gas – decline in economic activity	Net benefit of reallocating 50 PJ of natural gas from natural gas dependent industries to export – general economy effect – decline in economic activity	Case study: impact of withdrawing 50 PJ of natural gas – gas substitution in electricity production	Net benefit of reallocating 50 PJ of natural gas from natural gas dependent industries to export – general economy effect – gas substitution in electricity production
Commercial fishing	0.63	-2.68	-2.06	-21.17	-20.54	-1.89	-1.27
Coal	1.79	127.25	129.04	15.40	17.19	38.71	40.50
Gas	5.80	-129.56	-123.77	-201.86	-196.06	-181.74	-175.94
Oil	1.47	0.52	1.98	-32.29	-30.82	-1.75	-0.28
Iron ores	0.20	0.17	0.37	-1.74	-1.54	-0.12	0.08
Non-ferrous metal ores	0.31	0.32	0.64	-3.73	-3.42	-0.20	0.11
Other mining	0.45	1.11	1.57	-4.96	-4.51	-0.08	0.38
Services to mining	15.45	-0.63	14.82	-13.67	1.78	-9.15	6.30
Meat and meat products	4.60	-18.91	-14.32	-152.31	-147.71	-13.56	-8.96
Dairy products	3.54	-14.68	-11.13	-118.18	-114.63	-10.51	-6.96
Fruit and vegetable products	1.12	-4.74	-3.62	-37.59	-36.47	-3.36	-2.24
Oils and fats	0.44	-1.80	-1.36	-14.62	-14.18	-1.30	-0.85
Flour mill products and cereal foods	1.83	-7.51	-5.68	-60.59	-58.75	-5.39	-3.56
Bakery products	1.51	-6.14	-4.63	-49.72	-48.21	-4.42	-2.91
Confectionery	1.15	-4.77	-3.62	-38.27	-37.12	-3.41	-2.26
Other food products	2.69	-10.64	-7.95	-86.71	-84.02	-7.72	-5.03
Soft drinks, cordials and syrups	1.48	-6.47	-4.99	-50.51	-49.04	-4.53	-3.05
Beer and malt	1.26	-5.01	-3.75	-40.88	-39.62	-3.63	-2.37
Wine, spirits and tobacco products (a)	1.44	-5.69	-4.25	-45.81	-44.37	-4.11	-2.67
Textile fibres, yarns and woven fabrics	0.12	-0.31	-0.19	-3.21	-3.09	-0.27	-0.15
Textile products	0.37	-1.33	-0.96	-11.30	-10.93	-1.00	-0.63
Knitting mill products	0.26	-0.99	-0.73	-8.17	-7.91	-0.73	-0.47
Clothing	0.57	-1.75	-1.18	-16.00	-15.43	-1.40	-0.83
Footwear	0.12	-0.31	-0.19	-3.63	-3.50	-0.29	-0.17

Table A.5 Gross output formation by industry ($2009m) – continued

	Case study: 50 PJ of natural gas allocated to LNG exports	Case study: impact of withdrawing 50 PJ of natural gas – general economy impact full electricity substitution	Net benefit of reallocating 50 PJ of natural gas from natural gas dependent industries to export – full substitution effect	Case study: impact of withdrawing 50 PJ of natural gas – decline in economic activity	Net benefit of reallocating 50 PJ of natural gas from natural gas dependent industries to export – general economy effect – decline in economic activity	Case study: impact of withdrawing 50 PJ of natural gas – gas substitution in electricity production	Net benefit of reallocating 50 PJ of natural gas from natural gas dependent industries to export – general economy effect – gas substitution in electricity production
Leather and leather products	0.09	-0.19	-0.09	-2.23	-2.13	-0.19	-0.09
Sawmill products	0.54	0.69	1.23	-8.10	-7.56	-0.36	0.18
Other wood products	1.09	0.98	2.07	-15.03	-13.94	-0.81	0.28
Pulp, paper and paperboard	0.30	-0.54	-0.23	-7.04	-6.73	-0.57	-0.27
Paper containers and products	0.90	-2.32	-1.42	-25.71	-24.82	-2.09	-1.19
Printing and services to printing	2.88	-4.72	-1.84	-67.72	-64.84	-5.35	-2.47
Publishing, recorded media, etc.	3.29	-10.22	-6.93	-95.69	-92.40	-8.23	-4.94
Petroleum and coal products	6.35	2.25	8.60	-139.89	-133.54	-7.58	-1.23
Glass and glass products	0.67	-1.21	-0.54	-15.11	-14.43	-1.26	-0.59
Ceramic products	0.12	0.45	0.57	-1.83	-1.71	0.01	0.13
Cement, lime and concrete slurry	0.83	5.82	6.65	-6.45	-5.62	1.11	1.94
Plaster and other concrete products	0.43	5.95	6.38	-2.71	-2.28	1.50	1.93
Other non-metallic mineral products	0.23	0.52	0.75	-1.92	-1.69	-0.03	0.20
Iron and steel	4.24	3.06	7.29	-35.80	-31.57	-2.61	1.62
Structural metal products	2.92	4.69	7.60	-17.79	-14.87	-0.77	2.15
Sheet metal products	0.91	-0.80	0.11	-15.64	-14.73	-1.28	-0.37
Fabricated metal products	2.23	2.09	4.31	-19.85	-17.62	-1.26	0.97
Motor vehicles and parts, other transport equipment	4.75	-13.68	-8.93	-127.96	-123.21	-11.19	-6.45
Ships and boats	0.40	-0.91	-0.51	-9.75	-9.34	-0.84	-0.43
Railway equipment	1.21	0.70	1.91	-6.24	-5.03	-0.67	0.55
Aircraft	1.39	-1.44	-0.04	-15.97	-14.57	-1.75	-0.36
Photographic and scientific equipment	0.91	-2.04	-1.13	-23.19	-22.28	-1.92	-1.01
Electronic equipment	0.83	-0.42	0.41	-16.44	-15.61	-1.15	-0.32

Table A.5 Gross output formation by industry ($2009m) – continued

	Case study: 50 PJ of natural gas allocated to LNG exports	Case study: impact of withdrawing 50 PJ of natural gas – general economy impact full electricity substitution	Net benefit of reallocating 50 PJ of natural gas from natural gas dependent industries to export – full substitution effect	Case study: impact of withdrawing 50 PJ of natural gas – decline in economic activity	Net benefit of reallocating 50 PJ of natural gas from natural gas dependent industries to export – general economy effect – decline in economic activity	Case study: impact of withdrawing 50 PJ of natural gas – gas substitution in electricity production	Net benefit of reallocating 50 PJ of natural gas from natural gas dependent industries to export – general economy effect – gas substitution in electricity production
Household appliances	1.37	-4.11	-2.74	-38.44	-37.07	-3.33	-1.96
Other electrical equipment	1.34	16.53	17.87	-17.25	-15.92	3.76	5.10
Agricultural, mining, etc. machinery	1.79	0.47	2.26	-10.42	-8.64	-1.19	0.59
Other machinery and equipment	1.60	0.55	2.15	-14.76	-13.16	-1.21	0.39
Prefabricated buildings	0.85	-0.05	0.80	-1.29	-0.44	-0.53	0.32
Furniture	1.26	-4.00	-2.74	-36.28	-35.03	-3.16	-1.91
Other manufacturing	1.07	-0.92	0.14	-21.80	-20.73	-1.62	-0.55
Electricity supply	10.97	1617.38	1628.35	245.05	256.02	500.12	511.09
Gas supply	1.10	22.25	23.35	-21.68	-20.58	5.50	6.60
Water supply, sewerage and drainage services	4.06	-6.94	-2.89	-106.27	-102.21	-8.00	-3.94
Residential building	1.94	9.08	11.02	-18.08	-16.15	1.11	3.05
Other construction	3.52	12.53	16.05	-30.01	-26.49	0.90	4.42
Construction trade services	19.47	134.00	153.47	-124.52	-105.05	26.28	45.75
Wholesale trade	25.88	-26.98	-1.10	-528.97	-503.09	-40.62	-14.74
Wholesale mechanical repairs	2.89	1.57	4.47	-9.40	-6.51	-1.43	1.47
Other wholesale repairs	5.51	3.25	8.76	-44.94	-39.43	-3.57	1.94
Retail trade	32.74	-133.41	-100.67	-1078.70	-1045.95	-95.95	-63.20
Retail mechanical repairs	7.63	-5.42	2.21	-149.57	-141.94	-10.97	-3.35
Other retail repairs	0.44	-1.49	-1.06	-13.13	-12.69	-1.15	-0.71
Accommodation, cafes and restaurants	16.97	-61.52	-44.56	-533.81	-516.84	-46.52	-29.55
Road transport	9.58	-16.59	-7.00	-228.91	-219.32	-18.20	-8.62
Rail, pipeline and other transport	10.02	6.02	16.03	-52.46	-42.45	-5.45	4.57
Water transport	1.13	0.88	2.01	-13.55	-12.41	-0.82	0.32

Table A.5 Gross output formation by industry ($2009m) – continued

	Case study: 50 PJ of natural gas allocated to LNG exports	Case study: impact of withdrawing 50 PJ of natural gas – general economy impact full electricity substitution	Net benefit of reallocating 50 PJ of natural gas from natural gas dependent industries to export – full substitution effect	Case study: impact of withdrawing 50 PJ of natural gas – decline in economic activity	Net benefit of reallocating 50 PJ of natural gas from natural gas dependent industries to export – general economy effect – decline in economic activity	Case study: impact of withdrawing 50 PJ of natural gas – gas substitution in electricity production	Net benefit of reallocating 50 PJ of natural gas from natural gas dependent industries to export – general economy effect – gas substitution in electricity production
Air and space transport	4.99	-13.85	-8.86	-140.33	-135.34	-11.81	-6.81
Services to transport, storage	13.62	-8.85	4.77	-172.10	-158.48	-16.09	-2.47
Communication services	15.22	-24.74	-9.52	-384.41	-369.19	-29.13	-13.90
Finance	47.38	-42.08	5.30	-1081.89	-1034.51	-75.99	-28.61
Ownership of dwellings	4.72	-21.24	-16.52	-163.75	-159.04	-14.73	-10.01
Other property services	31.27	0.18	31.44	-386.50	-355.23	-30.34	0.92
Scientific research, technical and computer services	11.85	7.43	19.28	-139.34	-127.49	-8.99	2.86
Legal, accounting, marketing and business management services	18.85	-4.21	14.63	-349.65	-330.81	-23.61	-4.76
Other business services	11.10	-1.27	9.83	-207.63	-196.53	-13.59	-2.49
Government administration	2.21	-2.87	-0.66	-41.08	-38.87	-3.50	-1.29
Defence	0.03	-0.03	0.00	-0.51	-0.48	-0.04	-0.01
Education	9.51	-30.06	-20.55	-297.24	-287.73	-24.65	-15.13
Health services	9.29	-41.36	-32.08	-320.54	-311.25	-28.80	-19.51
Community services	1.16	-5.21	-4.05	-40.18	-39.02	-3.61	-2.46
Motion picture, radio and television services	4.08	-8.30	-4.21	-101.00	-96.91	-8.25	-4.17
Libraries, museums and the arts	1.11	-1.05	0.06	-29.01	-27.90	-1.92	-0.82
Sport, gambling and recreational services	7.78	-27.59	-19.80	-216.58	-208.80	-20.18	-12.39
Personal services	3.71	-16.27	-12.56	-127.06	-123.35	-11.39	-7.68
Other services	3.99	-16.76	-12.78	-135.57	-131.58	-11.99	-8.00
Total	**1082.81**	**1156.34**	**2239.14**	**-9213.92**	**-8131.11**	**-344.93**	**737.88**

Table A.6 Total employment formation (ths)

	Case study: 50 PJ of natural gas allocated to LNG exports	Case study: impact of withdrawing 50 PJ of natural gas – general economy impact full electricity substitution	Net benefit of reallocating 50 PJ of natural gas from natural gas dependent industries to export – full substitution effect	Case study: impact of withdrawing 50 PJ of natural gas – decline in economic activity	Net benefit of reallocating 50 PJ of natural gas from natural gas dependent industries to export – general economy effect – decline in economic activity	Case study: impact of withdrawing 50 PJ of natural gas – gas substitution in electricity production	Net benefit of reallocating 50 PJ of natural gas from natural gas dependent industries to export – general economy effect – gas substitution in electricity production
Constrained industries							
Basic chemicals	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Paints	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Medicinal and pharmaceutical products, pesticides	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Soap and detergents	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cosmetics and toiletry preparations	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other chemical products	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Rubber products	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Plastic products	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Basic non-ferrous metal and products	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LNG	0.12	0.00	0.12	0.00	0.12	0.00	0.12
Unconstrained industries							
Sheep	0.01	-0.04	-0.03	-0.37	-0.36	-0.03	-0.02
Grains	0.01	-0.04	-0.03	-0.30	-0.29	-0.03	-0.02
Beef cattle	0.03	-0.11	-0.09	-0.91	-0.89	-0.08	-0.05
Dairy cattle	0.01	-0.06	-0.05	-0.48	-0.46	-0.04	-0.03
Pigs	0.01	-0.03	-0.02	-0.21	-0.20	-0.02	-0.01
Poultry	0.01	-0.02	-0.02	-0.18	-0.17	-0.02	-0.01
Other agriculture	0.04	-0.15	-0.12	-1.23	-1.19	-0.11	-0.07
Services to agriculture, hunting and trapping	0.01	-0.03	-0.02	-0.21	-0.21	-0.02	-0.01
Forestry and logging	0.00	0.00	0.00	-0.04	-0.04	0.00	0.00

Table A.6 Total employment formation (ths) – continued

	Case study: 50 PJ of natural gas allocated to LNG exports	Case study: impact of withdrawing 50 PJ of natural gas – general economy impact full electricity substitution	Net benefit of reallocating 50 PJ of natural gas from natural gas dependent industries to export – full substitution effect	Case study: impact of withdrawing 50 PJ of natural gas – decline in economic activity	Net benefit of reallocating 50 PJ of natural gas from natural gas dependent industries to export – general economy effect – decline in economic activity	Case study: impact of withdrawing 50 PJ of natural gas – gas substitution in electricity production	Net benefit of reallocating 50 PJ of natural gas from natural gas dependent industries to export – general economy effect – gas substitution in electricity production
Commercial fishing	0.00	-0.02	-0.01	-0.14	-0.14	-0.01	-0.01
Coal	0.00	0.16	0.17	0.02	0.02	0.05	0.05
Gas	0.00	-0.11	-0.10	-0.16	-0.16	-0.15	-0.14
Oil	0.00	0.00	0.00	-0.02	-0.01	0.00	0.00
Iron ores	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Non-ferrous metal ores	0.00	0.00	0.00	-0.01	-0.01	0.00	0.00
Other mining	0.00	0.00	0.01	-0.02	-0.02	0.00	0.00
Services to mining	0.10	0.00	0.10	-0.09	0.01	-0.06	0.04
Meat and meat products	0.07	-0.28	-0.21	-2.24	-2.17	-0.20	-0.13
Dairy products	0.04	-0.16	-0.12	-1.25	-1.21	-0.11	-0.07
Fruit and vegetable products	0.01	-0.03	-0.02	-0.22	-0.21	-0.02	-0.01
Oils and fats	0.00	-0.01	-0.01	-0.06	-0.06	-0.01	0.00
Flour mill products and cereal foods	0.01	-0.05	-0.04	-0.43	-0.42	-0.04	-0.03
Bakery products	0.03	-0.13	-0.10	-1.07	-1.03	-0.09	-0.06
Confectionery	0.01	-0.03	-0.02	-0.26	-0.25	-0.02	-0.02
Other food products	0.02	-0.07	-0.05	-0.54	-0.53	-0.05	-0.03
Soft drinks, cordials and syrups	0.01	-0.03	-0.02	-0.20	-0.20	-0.02	-0.01
Beer and malt	0.00	-0.02	-0.01	-0.13	-0.12	-0.01	-0.01
Wine, spirits and tobacco products (a)	0.01	-0.02	-0.02	-0.17	-0.16	-0.02	-0.01
Textile fibres, yarns and woven fabrics	0.00	0.00	0.00	-0.02	-0.02	0.00	0.00
Textile products	0.01	-0.02	-0.01	-0.15	-0.15	-0.01	-0.01
Knitting mill products	0.00	-0.01	-0.01	-0.07	-0.07	-0.01	0.00
Clothing	0.01	-0.03	-0.02	-0.28	-0.27	-0.02	-0.01
Footwear	0.00	0.00	0.00	-0.04	-0.04	0.00	0.00

Table A.6 Total employment formation (ths) – continued

	Case study: 50 PJ of natural gas allocated to LNG exports	Case study: impact of withdrawing 50 PJ of natural gas – general economy impact full electricity substitution	Net benefit of reallocating 50 PJ of natural gas from natural gas dependent industries to export – full substitution effect	Case study: impact of withdrawing 50 PJ of natural gas – decline in economic activity	Net benefit of reallocating 50 PJ of natural gas from natural gas dependent industries to export – general economy effect – decline in economic activity	Case study: impact of withdrawing 50 PJ of natural gas – gas substitution in electricity production	Net benefit of reallocating 50 PJ of natural gas from natural gas dependent industries to export – general economy effect – gas substitution in electricity production
Leather and leather products	0.00	0.00	0.00	-0.01	-0.01	0.00	0.00
Sawmill products	0.00	0.01	0.01	-0.06	-0.06	0.00	0.00
Other wood products	0.02	0.01	0.03	-0.22	-0.21	-0.01	0.00
Pulp, paper and paperboard	0.00	0.00	0.00	-0.02	-0.02	0.00	0.00
Paper containers and products	0.01	-0.02	-0.01	-0.19	-0.18	-0.02	-0.01
Printing and services to printing	0.03	-0.05	-0.02	-0.67	-0.64	-0.05	-0.02
Publishing, recorded media, etc.	0.03	-0.08	-0.05	-0.74	-0.71	-0.06	-0.04
Petroleum and coal products	0.01	0.01	0.02	-0.32	-0.30	-0.02	0.00
Glass and glass products	0.01	-0.01	-0.01	-0.14	-0.14	-0.01	-0.01
Ceramic products	0.00	0.00	0.00	-0.01	-0.01	0.00	0.00
Cement, lime and concrete slurry	0.00	0.02	0.03	-0.03	-0.02	0.00	0.01
Plaster and other concrete products	0.00	0.03	0.03	-0.01	-0.01	0.01	0.01
Other non-metallic mineral products	0.00	0.01	0.01	-0.02	-0.02	0.00	0.00
Iron and steel	0.04	0.03	0.07	-0.32	-0.28	-0.02	0.01
Structural metal products	0.02	0.03	0.05	-0.11	-0.09	0.00	0.01
Sheet metal products	0.00	0.00	0.00	-0.07	-0.07	-0.01	0.00
Fabricated metal products	0.02	0.02	0.05	-0.21	-0.19	-0.01	0.01
Motor vehicles and parts, other transport equipment	0.05	-0.15	-0.10	-1.43	-1.38	-0.12	-0.07
Ships and boats	0.00	0.00	0.00	-0.04	-0.03	0.00	0.00
Railway equipment	0.00	0.00	0.01	-0.03	-0.02	0.00	0.00
Aircraft	0.01	-0.01	0.00	-0.07	-0.06	-0.01	0.00
Photographic and scientific equipment	0.01	-0.02	-0.01	-0.25	-0.24	-0.02	-0.01
Electronic equipment	0.01	0.00	0.00	-0.18	-0.17	-0.01	0.00

Table A.6 Total employment formation (ths) – continued

	Case study: 50 PJ of natural gas allocated to LNG exports	Case study: impact of withdrawing 50 PJ of natural gas – general economy impact full electricity substitution	Net benefit of reallocating 50 PJ of natural gas from natural gas dependent industries to export – full substitution effect	Case study: impact of withdrawing 50 PJ of natural gas – decline in economic activity	Net benefit of reallocating 50 PJ of natural gas from natural gas dependent industries to export – general economy effect – decline in economic activity	Case study: impact of withdrawing 50 PJ of natural gas – gas substitution in electricity production	Net benefit of reallocating 50 PJ of natural gas from natural gas dependent industries to export – general economy effect – gas substitution in electricity production
Household appliances	0.01	-0.04	-0.02	-0.33	-0.32	-0.03	-0.02
Other electrical equipment	0.01	0.16	0.18	-0.17	-0.16	0.04	0.05
Agricultural, mining, etc. machinery	0.02	0.01	0.02	-0.11	-0.09	-0.01	0.01
Other machinery and equipment	0.02	0.01	0.02	-0.16	-0.14	-0.01	0.00
Prefabricated buildings	0.01	0.00	0.01	-0.01	0.00	0.00	0.00
Furniture	0.03	-0.10	-0.07	-0.88	-0.85	-0.08	-0.05
Other manufacturing	0.01	-0.01	0.00	-0.27	-0.26	-0.02	-0.01
Electricity supply	0.03	4.84	4.88	0.73	0.77	1.50	1.53
Gas supply	0.01	0.19	0.20	-0.18	-0.17	0.05	0.06
Water supply, sewerage and drainage services	0.02	-0.03	-0.01	-0.46	-0.44	-0.03	-0.02
Residential building	0.01	0.04	0.05	-0.09	-0.08	0.01	0.02
Other construction	0.02	0.09	0.11	-0.21	-0.19	0.01	0.03
Construction trade services	0.29	1.99	2.28	-1.85	-1.56	0.39	0.68
Wholesale trade	0.19	-0.20	-0.01	-3.88	-3.69	-0.30	-0.11
Wholesale mechanical repairs	0.02	0.01	0.03	-0.06	-0.04	-0.01	0.01
Other wholesale repairs	0.05	0.03	0.07	-0.38	-0.33	-0.03	0.02
Retail trade	0.56	-2.28	-1.72	-18.40	-17.84	-1.64	-1.08
Retail mechanical repairs	0.20	-0.14	0.06	-3.95	-3.75	-0.29	-0.09
Other retail repairs	0.01	-0.03	-0.02	-0.28	-0.27	-0.02	-0.02
Accommodation, cafes and restaurants	0.25	-0.90	-0.65	-7.77	-7.52	-0.68	-0.43
Road transport	0.10	-0.16	-0.07	-2.27	-2.18	-0.18	-0.09
Rail, pipeline and other transport	0.08	0.05	0.13	-0.42	-0.34	-0.04	0.04
Water transport	0.01	0.00	0.01	-0.07	-0.06	0.00	0.00

Table A.6 Total employment formation (ths) – continued

	Case study: 50 PJ of natural gas allocated to LNG exports	Case study: impact of withdrawing 50 PJ of natural gas – general economy impact full electricity substitution	Net benefit of reallocating 50 PJ of natural gas from natural gas dependent industries to export – full substitution effect	Case study: impact of withdrawing 50 PJ of natural gas – decline in economic activity	Net benefit of reallocating 50 PJ of natural gas from natural gas dependent industries to export – general economy effect – decline in economic activity	Case study: impact of withdrawing 50 PJ of natural gas – gas substitution in electricity production	Net benefit of reallocating 50 PJ of natural gas from natural gas dependent industries to export – general economy effect – gas substitution in electricity production
Air and space transport	0.04	-0.10	-0.06	-0.99	-0.96	-0.08	-0.05
Services to transport, storage	0.07	-0.05	0.02	-0.89	-0.82	-0.08	-0.01
Communication services	0.09	-0.15	-0.06	-2.38	-2.29	-0.18	-0.09
Finance	0.19	-0.17	0.02	-4.43	-4.23	-0.31	-0.12
Ownership of dwellings	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other property services	0.11	0.00	0.11	-1.31	-1.21	-0.10	0.00
Scientific research, technical and computer services	0.13	0.08	0.21	-1.52	-1.39	-0.10	0.03
Legal, accounting, marketing and business management services	0.17	-0.04	0.13	-3.17	-3.00	-0.21	-0.04
Other business services	0.08	-0.01	0.07	-1.58	-1.49	-0.10	-0.02
Government administration	0.03	-0.03	-0.01	-0.49	-0.46	-0.04	-0.02
Defence	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Education	0.12	-0.39	-0.27	-3.86	-3.73	-0.32	-0.20
Health services	0.11	-0.50	-0.39	-3.91	-3.79	-0.35	-0.24
Community services	0.02	-0.08	-0.06	-0.60	-0.58	-0.05	-0.04
Motion picture, radio and television services	0.03	-0.06	-0.03	-0.78	-0.75	-0.06	-0.03
Libraries, museums and the arts	0.02	-0.02	0.00	-0.61	-0.59	-0.04	-0.02
Sport, gambling and recreational services	0.11	-0.40	-0.29	-3.12	-3.01	-0.29	-0.18
Personal services	0.10	-0.42	-0.32	-3.26	-3.16	-0.29	-0.20
Other services	0.05	-0.20	-0.15	-1.62	-1.57	-0.14	-0.10
Total	**4.28**	**-0.50**	**3.78**	**-92.67**	**-88.39**	**-5.72**	**-1.44**

Table A.7 Eastern Australian estimates of suppressed gas demand – No East Coast LNG

	Cumulative suppressed gas demand 2011-2040 – petajoules (PJ)	Average annual suppressed gas demand 2011-2020 – petajoules (PJ)	Average annual suppressed gas demand 2021-2030 – petajoules (PJ)	Average annual suppressed gas demand 2031-2040 – petajoules (PJ)	Average annual ex-plant gas cost $2011 per gigajoule 2011-2020 – petajoules ($/GJ)	Average annual ex-plant gas cost $2011 per gigajoule 2021-2030 – petajoules ($/GJ)	Average annual ex-plant gas cost $2011 per gigajoule 2031-2040 – petajoules ($/GJ)	Suppressed demand as per cent of base case domestic Eastern Australian demand (%)
Aggregate indicators								
Minimum	0	0.0	0.0	0.0	5.4	6.4	7.7	0.0
Maximum	16894	0.0	522.3	1167.1	6.0	8.4	11.4	51.6
Mean	1193	0.0	11.6	107.7	5.6	7.0	9.1	9.5
Std Deviation	2269	0.0	49.1	184.0	0.1	0.4	0.8	9.3
Distribution								
5% Percentile	0	0.0	0.0	0.0	5.4	6.5	8.0	0.0
10% Percentile	0	0.0	0.0	0.0	5.4	6.6	8.1	0.0
15% Percentile	0	0.0	0.0	0.0	5.5	6.6	8.2	0.0
20% Percentile	0	0.0	0.0	0.0	5.5	6.7	8.4	0.0
25% Percentile	0	0.0	0.0	0.0	5.5	6.7	8.4	0.0
30% Percentile	86	0.0	0.0	8.6	5.5	6.8	8.5	3.2
35% Percentile	86	0.0	0.0	8.6	5.5	6.8	8.6	3.2
40% Percentile	254	0.0	0.0	25.4	5.5	6.9	8.7	6.3
45% Percentile	254	0.0	0.0	25.4	5.5	6.9	8.8	6.3
50% Percentile	259	0.0	0.0	25.9	5.6	6.9	8.9	6.3
55% Percentile	499	0.0	0.0	49.9	5.6	7.1	9.1	9.3
60% Percentile	499	0.0	0.0	49.9	5.6	7.1	9.2	9.3
65% Percentile	817	0.0	0.0	81.7	5.6	7.2	9.4	12.2
70% Percentile	817	0.0	0.0	81.7	5.7	7.3	9.5	12.2
75% Percentile	1206	0.0	0.0	120.6	5.7	7.3	9.6	15.0
80% Percentile	1432	0.0	0.0	143.2	5.7	7.4	9.8	15.0
85% Percentile	1661	0.0	0.0	166.1	5.7	7.5	9.9	17.7
90% Percentile	3067	0.0	0.0	304.2	5.8	7.7	10.3	21.2
95% Percentile	6403	0.0	77.6	578.6	5.8	7.8	10.5	28.4

Table A.8	Eastern Australian estimates of suppressed gas demand – East Coast LNG							
	Cumulative suppressed gas demand 2011-2040 – petajoules (PJ)	Average annual suppressed gas demand 2011-2020 – petajoules (PJ)	Average annual suppressed gas demand 2021-2030 – petajoules (PJ)	Average annual suppressed gas demand 2031-2040 – petajoules (PJ)	Average annual ex-plant gas cost $2011 per gigajoule 2011-2020 – petajoules ($/GJ)	Average annual ex-plant gas cost $2011 per gigajoule 2021-2030 – petajoules ($/GJ)	Average annual ex-plant gas cost $2011 per gigajoule 2031-2040 – petajoules ($/GJ)	Suppressed demand as per cent of base case domestic Eastern Australian demand (%)
Aggregate indicators								
Minimum	68.9	0.0	0.0	6.9	5.4	6.9	8.9	2.6
Maximum	43585.1	319.9	1752.8	2317.8	6.2	9.2	12.2	94.3
Mean	15170.8	40.2	597.5	883.4	5.7	7.7	10.1	40.8
Std Deviation	10525.2	59.9	450.0	562.1	0.1	0.4	0.6	19.5
Distribution								
5% Percentile	929.1	0.0	0.0	64.1	5.5	7.0	9.2	11.9
10% Percentile	1556.5	0.0	0.0	155.6	5.5	7.2	9.4	15.7
15% Percentile	2148.3	0.0	0.0	187.4	5.5	7.2	9.5	19.3
20% Percentile	2824.3	0.0	52.4	255.5	5.5	7.3	9.6	22.8
25% Percentile	5071.4	0.0	165.3	345.5	5.6	7.4	9.7	24.3
30% Percentile	7641.6	0.0	252.8	494.9	5.6	7.5	9.8	27.0
35% Percentile	9767.5	0.0	361.8	612.4	5.6	7.5	9.9	31.0
40% Percentile	11838.2	0.0	455.0	727.0	5.6	7.6	10.0	33.8
45% Percentile	13520.0	0.0	529.8	811.2	5.6	7.6	10.1	37.2
50% Percentile	15089.4	0.0	609.6	885.4	5.6	7.7	10.1	39.7
55% Percentile	16447.8	8.9	669.9	979.8	5.7	7.7	10.2	42.4
60% Percentile	17998.8	24.6	744.7	1030.2	5.7	7.8	10.3	44.6
65% Percentile	19676.0	38.2	824.7	1112.7	5.7	7.8	10.4	47.6
70% Percentile	21718.6	50.2	888.4	1209.7	5.7	7.9	10.4	51.2
75% Percentile	23340.6	63.7	952.3	1324.2	5.8	8.0	10.5	55.1
80% Percentile	25130.9	82.2	1031.1	1413.9	5.8	8.0	10.6	58.5
85% Percentile	27283.7	110.0	1113.1	1540.5	5.8	8.2	10.7	63.7
90% Percentile	29833.6	136.4	1222.5	1659.1	5.9	8.3	10.9	68.3
95% Percentile	33126.2	169.5	1339.2	1826.5	6.0	8.5	11.2	75.1

Table A.9	Eastern Australian estimates of suppressed gas demand – Impact of East Coast LNG							
	Cumulative suppressed gas demand 2011-2040 – petajoules (PJ)	Average annual suppressed gas demand 2011-2020 – petajoules (PJ)	Average annual suppressed gas demand 2021-2030 – petajoules (PJ)	Average annual suppressed gas demand 2031-2040 – petajoules (PJ)	Average annual ex-plant gas cost $2011 per gigajoule 2011-2020 – petajoules ($/GJ)	Average annual ex-plant gas cost $2011 per gigajoule 2021-2030 – petajoules ($/GJ)	Average annual ex-plant gas cost $2011 per gigajoule 2031-2040 – petajoules ($/GJ)	Suppressed demand as per cent of base case domestic Eastern Australian demand (%)
Aggregate indicators								
Minimum	68.9	0.0	0.0	6.9	0.0	0.5	1.1	2.6
Maximum	26691.3	319.9	1230.5	1150.7	0.2	0.8	0.8	42.7
Mean	13977.5	40.2	585.9	775.7	0.1	0.7	1.1	31.3
Std Deviation	8255.9	59.9	400.9	378.1	0.0	0.0	-0.2	10.2
Distribution								
5% Percentile	929.1	0.0	0.0	64.1	0.0	0.5	1.2	11.9
10% Percentile	1556.5	0.0	0.0	155.6	0.1	0.6	1.3	15.7
15% Percentile	2148.3	0.0	0.0	187.4	0.1	0.6	1.3	19.3
20% Percentile	2824.3	0.0	52.4	255.5	0.1	0.6	1.3	22.8
25% Percentile	5071.4	0.0	165.3	345.5	0.1	0.7	1.3	24.3
30% Percentile	7555.6	0.0	252.8	486.3	0.1	0.7	1.3	23.8
35% Percentile	9681.5	0.0	361.8	603.8	0.1	0.7	1.3	27.8
40% Percentile	11584.7	0.0	455.0	701.7	0.1	0.7	1.3	27.4
45% Percentile	13266.5	0.0	529.8	785.8	0.1	0.7	1.3	30.9
50% Percentile	14830.2	0.0	609.6	859.5	0.1	0.7	1.2	33.4
55% Percentile	15949.2	8.9	669.9	930.0	0.1	0.7	1.1	33.0
60% Percentile	17500.2	24.6	744.7	980.4	0.1	0.7	1.1	35.3
65% Percentile	18858.7	38.2	824.7	1031.0	0.1	0.6	1.0	35.4
70% Percentile	20901.2	50.2	888.4	1128.0	0.1	0.6	0.9	39.0
75% Percentile	22134.6	63.7	952.3	1203.6	0.1	0.6	0.9	40.1
80% Percentile	23698.6	82.2	1031.1	1270.6	0.1	0.6	0.8	43.5
85% Percentile	25622.9	110.0	1113.1	1374.5	0.1	0.7	0.8	46.0
90% Percentile	26767.1	136.4	1222.5	1354.9	0.1	0.6	0.6	47.1
95% Percentile	26723.0	169.5	1261.6	1247.8	0.1	0.7	0.7	46.7

Table A.10 Eastern Australian estimates of suppressed gas demand – No East Coast LNG

	Gross domestic product at market prices (2009 $m) – 2020	Gross domestic product at market prices (2009 $m) – 2040	Total employment (ths) – 2020	Total employment (ths) – 2020	Benefit indicator (2009 $m) – 2020	Benefit indicator (2009 $m) – 2040	Cumulative discounted net benefit indicator (5% rate) (2009 $m) 2012 – 2040	Ultimately recoverable reserves (2009 $m)	Estimates of eventually recoverable reserves as at 2012 (PJ)
Aggregate indicators									
Minimum	-26636	-109626	-672	-2161	-40493	-127105	-797201	94208	91288.9
Maximum	15118	18445	82	103	7744	9647	101184	265838	263437.8
Mean	8339	-33424	-47	-837	-319	-49917	-196062	173479	173481.8
Std Deviation	9292	28332	174	505	10880	31851	212661	36543	36426.9
Distribution									
5% Percentile	-10823	-79109	-391	-1647	-21041	-98005	-561368	115734	115200.3
10% Percentile	-3839	-69326	-279	-1477	-16162	-89901	-492412	125386	125942.1
15% Percentile	-1816	-65155	-243	-1409	-12573	-84793	-433361	133987	134066.2
20% Percentile	-75	-56463	-213	-1263	-10853	-78436	-382385	140845	140810.0
25% Percentile	1720	-52830	-179	-1208	-8621	-73908	-342773	147117	146886.9
30% Percentile	3493	-49945	-131	-1131	-5658	-69629	-313076	151931	152278.0
35% Percentile	5639	-44308	-94	-1038	-3384	-66274	-292924	157163	157293.8
40% Percentile	10072	-41612	-20	-1002	1577	-61076	-263167	161852	161965.7
45% Percentile	13688	-40193	54	-940	5990	-55411	-227867	166430	166397.9
50% Percentile	15118	-35602	82	-869	7744	-52388	-197998	170863	171161.4
55% Percentile	15118	-32403	82	-824	7744	-47911	-168263	176278	176066.5
60% Percentile	15118	-28204	82	-758	7744	-44830	-130813	181130	181323.1
65% Percentile	15118	-21513	82	-637	7744	-37388	-92761	186871	186829.0
70% Percentile	15118	-15515	82	-518	7744	-30791	-39563	192865	192840.7
75% Percentile	15118	-10561	82	-428	7744	-23149	-14712	199282	199367.6
80% Percentile	15118	-5415	82	-331	7744	-18460	25583	206500	206442.7
85% Percentile	15118	593	82	-221	7744	-10114	85246	214882	214675.4
90% Percentile	15118	6777	82	-108	7744	-3718	94371	223848	224387.3
95% Percentile	15118	12600	82	-13	7744	2518	98438	237320	236890.6

Table A.11	Queensland natural gas expansion – the expected net benefit on the national economy (with year benchmarks)						
		2015	**2020**	**2025**	**2030**	**2035**	**2040**
Macroeconomic aggregates							
Gross domestic product at factor cost	$2009m	0.0	14395.9	-3791.9	-6697.9	-8918.8	-22009.2
Gross domestic product at market prices	$2009m	0.0	15117.7	-7326.3	-10834.4	-13496.1	-29253.7
Gross national product at market prices	$2009m	0.0	10544.6	-12045.5	-15406.3	-17962.4	-33181.2
Net national product at market prices	$2009m	0.0	6903.3	-14433.9	-17458.7	-19785.0	-33728.5
Total imports of goods and services	$2009m	0.0	1455.2	6083.9	5781.5	6262.0	9284.3
Total employment	**ths.**	**0.0**	**81.8**	**-375.2**	**-434.3**	**-482.8**	**-774.6**
Household activity							
Wages and mixed income	$2009m	0.0	3275.8	-11437.0	-13396.2	-14975.8	-24450.8
Property income	$2009m	0.0	2528.8	352.4	-179.0	-480.5	-2156.4
Direct taxes paid	$2009m	0.0	1306.0	-2494.0	-3054.4	-3477.7	-5986.6
Household consumption	$2009m	0.0	3436.6	-22827.7	-26451.1	-29099.2	-45299.7
Government revenue							
Direct taxes on households	$2009m	0.0	1306.0	-2494.0	-3054.4	-3477.7	-5986.6
Direct taxes on business	$2009m	0.0	3121.2	2176.4	2004.9	1841.8	860.5
Indirect taxes	$2009m	0.0	721.8	-3534.3	-4136.5	-4577.3	-7244.5
Total tax revenue	**$2009m**	**0.0**	**5149.0**	**-3851.9**	**-5186.0**	**-6213.2**	**-12370.6**
Other indicators							
Income paid overseas	$2009m	0.0	4573.1	4719.2	4571.9	4466.3	3927.6
Benefit indicator	$2009m	0.0	7744.4	-20556.8	-24547.9	-27548.7	-45699.4
Cumulative discounted (at 5%) benefit indicator 2016-2040	$2009m	0.0	0.0	0.0	0.0	0.0	-160043.6

Table A.12 The impact of East Coast LNG exports on the national economy: Gross output formation by industry ($2009m)	2015	2020	2025	2030	2035	2040
Constrained industries						
Basic chemicals	0.0	0.0	-5867.8	-6185.3	-6801.4	-10581.1
Paints	0.0	0.0	-137.1	-144.5	-158.9	-247.2
Medicinal and pharmaceutical products, pesticides	0.0	0.0	-137.9	-145.4	-159.9	-248.7
Soap and detergents	0.0	0.0	-222.1	-234.2	-257.5	-400.6
Cosmetics and toiletry preparations	0.0	0.0	-77.3	-81.5	-89.6	-139.4
Other chemical products	0.0	0.0	-403.3	-425.1	-467.5	-727.2
Rubber products	0.0	0.0	-55.9	-58.9	-64.7	-100.7
Plastic products	0.0	0.0	-2579.1	-2718.6	-2989.4	-4650.7
Basic non-ferrous metal and products	0.0	0.0	-8310.6	-8760.2	-9632.7	-14985.9
LNG	0.0	12414.5	14897.5	14897.5	14897.5	14897.5
Unconstrained industries						
Sheep	0.0	13.0	-89.1	-102.3	-112.7	-176.2
Grains	0.0	19.7	-146.0	-167.0	-183.8	-286.9
Beef cattle	0.0	36.3	-270.2	-308.9	-340.1	-530.7
Dairy cattle	0.0	20.2	-131.1	-151.8	-167.1	-260.7
Pigs	0.0	5.0	-34.8	-40.0	-44.0	-68.8
Poultry	0.0	11.2	-78.2	-89.9	-98.9	-154.4
Other agriculture	0.0	73.7	-491.7	-567.1	-624.4	-974.7
Services to agriculture, hunting and trapping	0.0	17.1	-122.9	-140.7	-154.9	-242.1
Forestry and logging	0.0	9.7	-34.2	-38.7	-43.5	-72.3
Commercial fishing	0.0	11.7	-76.5	-88.5	-97.4	-151.9
Coal	0.0	34.9	1028.6	1061.6	1150.7	1749.2
Gas	0.0	115.1	-2135.4	-2272.8	-2519.9	-4005.1
Oil	0.0	28.0	-117.6	-137.5	-153.1	-246.0
Iron ores	0.0	4.0	-5.8	-7.0	-8.2	-14.9
Non-ferrous metal ores	0.0	6.1	-3417.2	-3603.8	-3963.4	-6168.9
Other mining	0.0	8.8	-87.0	-94.3	-104.6	-167.1

Table A.12 The impact of East Coast LNG exports on the national economy: Gross output formation by industry ($2009m) – continued

	2015	2020	2025	2030	2035	2040
Services to mining	0.0	308.8	-97.0	-125.1	-175.6	-479.9
Meat and meat products	0.0	85.8	-621.9	-712.7	-784.6	-1224.3
Dairy products	0.0	66.1	-429.4	-496.9	-547.1	-853.6
Fruit and vegetable products	0.0	20.9	-135.5	-156.9	-172.7	-269.4
Oils and fats	0.0	8.2	-60.8	-69.5	-76.6	-119.5
Flour mill products and cereal foods	0.0	34.2	-241.8	-277.6	-305.6	-476.9
Bakery products	0.0	28.2	-178.2	-206.5	-227.4	-355.1
Confectionery	0.0	21.5	-138.3	-160.1	-176.3	-275.1
Other food products	0.0	50.3	-340.0	-391.0	-430.7	-673.1
Soft drinks, cordials and syrups	0.0	27.6	-185.1	-214.0	-235.5	-366.9
Beer and malt	0.0	23.5	-146.3	-169.6	-186.8	-291.9
Wine, spirits and tobacco products (a)	0.0	27.0	-168.9	-195.3	-215.2	-336.7
Textile fibres, yarns and woven fabrics	0.0	2.3	-14.9	-17.0	-18.8	-29.6
Textile products	0.0	7.0	-41.4	-47.9	-52.9	-82.9
Knitting mill products	0.0	4.8	-30.3	-35.0	-38.6	-60.4
Clothing	0.0	10.7	-59.7	-69.1	-76.3	-120.3
Footwear	0.0	2.3	-12.6	-14.6	-16.2	-25.4
Leather and leather products	0.0	1.8	-8.7	-10.0	-11.1	-17.8
Sawmill products	0.0	10.6	-20.8	-25.6	-29.1	-49.8
Other wood products	0.0	21.1	-51.5	-61.3	-69.3	-117.1
Pulp, paper and paperboard	0.0	5.8	-30.2	-34.6	-38.4	-61.2
Paper containers and products	0.0	16.9	-115.6	-131.9	-145.5	-228.7
Printing and services to printing	0.0	54.8	-250.9	-291.6	-323.5	-516.7
Publishing, recorded media, etc.	0.0	62.0	-370.7	-427.5	-471.8	-741.9
Petroleum and coal products	0.0	121.2	-509.4	-596.0	-663.2	-1066.0
Glass and glass products	0.0	12.8	-63.2	-72.7	-80.6	-128.8
Ceramic products	0.0	2.2	-3.4	-4.4	-5.1	-8.9
Cement, lime and concrete slurry	0.0	16.3	13.1	9.3	8.0	3.1
Plaster and other concrete products	0.0	8.4	32.1	31.1	32.7	45.6

Table A.12 The impact of East Coast LNG exports on the national economy: Gross output formation by industry ($2009m) – continued	2015	2020	2025	2030	2035	2040
Other non-metallic mineral products	0.0	4.4	-4.8	-6.1	-7.2	-13.7
Iron and steel	0.0	83.3	-124.1	-149.5	-173.2	-314.2
Structural metal products	0.0	57.6	-34.7	-47.5	-58.9	-125.3
Sheet metal products	0.0	17.6	-69.4	-79.8	-89.0	-145.0
Fabricated metal products	0.0	43.7	-75.9	-90.2	-103.8	-184.8
Motor vehicles and parts, other transport equipment	0.0	89.8	-451.6	-525.6	-581.1	-919.4
Ships and boats	0.0	7.7	-37.0	-42.8	-47.4	-75.6
Railway equipment	0.0	24.0	1.2	-2.6	-5.6	-23.1
Aircraft	0.0	27.3	-43.0	-52.5	-60.2	-106.6
Photographic and scientific equipment	0.0	17.3	-80.8	-94.3	-104.4	-166.0
Electronic equipment	0.0	15.9	-51.0	-60.7	-67.8	-110.6
Household appliances	0.0	25.9	-132.9	-154.9	-171.1	-270.0
Other electrical equipment	0.0	25.8	76.9	69.8	73.0	100.4
Agricultural, mining, etc. machinery	0.0	35.3	-28.7	-36.2	-43.8	-88.7
Other machinery and equipment	0.0	31.4	-51.8	-62.0	-71.3	-127.3
Prefabricated buildings	0.0	17.0	3.9	2.7	0.9	-9.9
Furniture	0.0	23.7	-128.0	-148.8	-164.3	-258.8
Other manufacturing	0.0	20.5	-107.0	-121.8	-135.3	-216.7
Electricity supply	0.0	209.5	13710.6	14196.4	15426.2	23620.7
Gas supply	0.0	20.8	78.2	68.7	72.1	103.4
Water supply, sewerage and drainage services	0.0	76.8	-396.4	-460.1	-509.2	-806.9
Residential building	0.0	37.9	16.9	7.0	3.1	-15.5
Other construction	0.0	69.1	12.9	-4.1	-12.7	-57.7
Construction trade services	0.0	382.9	721.2	664.5	677.3	822.6
Wholesale trade	0.0	496.1	-2411.8	-2760.3	-3066.7	-4922.9
Wholesale mechanical repairs	0.0	57.5	25.7	20.0	15.1	-12.7
Other wholesale repairs	0.0	108.4	-97.4	-126.2	-150.3	-292.6
Retail trade	0.0	611.5	-3874.5	-4489.3	-4943.5	-7719.1
Retail mechanical repairs	0.0	146.5	-490.9	-579.9	-647.6	-1054.8

Table A.12 The impact of East Coast LNG exports on the national economy: Gross output formation by industry ($2009m) – continued	2015	2020	2025	2030	2035	2040
Other retail repairs	0.0	8.2	-46.7	-54.2	-59.8	-94.0
Accommodation, cafes and restaurants	0.0	317.8	-1903.2	-2208.5	-2434.2	-3811.9
Road transport	0.0	182.4	-1059.5	-1208.2	-1337.7	-2124.3
Rail, pipeline and other transport	0.0	198.3	7.8	-23.9	-48.9	-194.1
Water transport	0.0	22.1	-70.6	-80.9	-91.0	-152.1
Air and space transport	0.0	94.2	-497.3	-578.4	-639.1	-1008.3
Services to transport, storage	0.0	265.5	-809.1	-929.8	-1045.8	-1747.7
Communication services	0.0	288.8	-1322.0	-1546.7	-1714.2	-2727.7
Finance	0.0	903.3	-3266.8	-3885.7	-4324.4	-6963.1
Ownership of dwellings	0.0	87.8	-583.1	-675.6	-743.3	-1157.1
Other property services	0.0	609.7	-1108.0	-1345.8	-1535.6	-2671.3
Scientific research, technical and computer services	0.0	231.3	-574.5	-671.9	-761.0	-1294.2
Legal, accounting, marketing and business management services	0.0	362.6	-1376.3	-1599.8	-1785.5	-2903.2
Other business services	0.0	213.5	-841.6	-975.7	-1088.4	-1766.6
Government administration	0.0	42.5	-195.3	-222.8	-247.9	-400.1
Defence	0.0	0.5	-2.6	-2.9	-3.2	-5.2
Education	0.0	178.2	-1015.8	-1184.4	-1306.1	-2047.0
Health services	0.0	172.9	-1146.0	-1327.5	-1460.6	-2274.4
Community services	0.0	21.5	-143.1	-165.8	-182.4	-283.9
Motion picture, radio and television services	0.0	77.6	-372.4	-432.5	-479.2	-762.5
Libraries, museums and the arts	0.0	20.9	-91.8	-108.4	-120.2	-191.1
Sport, gambling and recreational services	0.0	147.0	-751.3	-874.5	-966.0	-1525.0
Personal services	0.0	69.1	-453.0	-524.9	-577.6	-899.9
Other services	0.0	74.3	-483.5	-560.5	-616.8	-961.4
Total	**0.000**	**21268**	**-25534**	**-31834**	**-37239**	**-69242**

Table A.13 The impact of East Coast LNG exports on the national economy: Total employment formation (ths)	2015	2020	2025	2030	2035	2040
Constrained industries						
Basic chemicals	0.000	0.000	-15.639	-16.485	-18.127	-28.201
Paints	0.000	0.000	-1.390	-1.465	-1.611	-2.506
Medicinal and pharmaceutical products, pesticides	0.000	0.000	-1.115	-1.175	-1.292	-2.010
Soap and detergents	0.000	0.000	-1.288	-1.358	-1.493	-2.322
Cosmetics and toiletry preparations	0.000	0.000	-0.523	-0.551	-0.606	-0.943
Other chemical products	0.000	0.000	-3.920	-4.133	-4.544	-7.069
Rubber products	0.000	0.000	-0.485	-0.512	-0.563	-0.875
Plastic products	0.000	0.000	-23.566	-24.841	-27.315	-42.495
Basic non-ferrous metal and products	0.000	0.000	-45.336	-47.789	-52.549	-81.751
LNG	0.000	2.359	2.831	2.831	2.831	2.831
Unconstrained industries						
Sheep	0.000	0.217	-1.483	-1.702	-1.875	-2.933
Grains	0.000	0.170	-1.260	-1.441	-1.587	-2.477
Beef cattle	0.000	0.517	-3.850	-4.401	-4.845	-7.561
Dairy cattle	0.000	0.268	-1.740	-2.014	-2.217	-3.460
Pigs	0.000	0.120	-0.834	-0.958	-1.055	-1.648
Poultry	0.000	0.101	-0.704	-0.810	-0.892	-1.391
Other agriculture	0.000	0.697	-4.652	-5.365	-5.907	-9.222
Services to agriculture, hunting and trapping	0.000	0.124	-0.891	-1.019	-1.123	-1.754
Forestry and logging	0.000	0.069	-0.244	-0.276	-0.310	-0.515
Commercial fishing	0.000	0.077	-0.503	-0.582	-0.641	-0.999
Coal	0.000	0.045	1.330	1.373	1.488	2.262
Gas	0.000	0.094	-1.743	-1.855	-2.057	-3.269
Oil	0.000	0.013	-0.055	-0.064	-0.072	-0.115
Iron ores	0.000	0.004	-0.006	-0.007	-0.008	-0.014
Non-ferrous metal ores	0.000	0.013	-7.191	-7.584	-8.340	-12.981
Other mining	0.000	0.033	-0.323	-0.350	-0.388	-0.620

Table A.13 The impact of East Coast LNG exports on the national economy: Total employment formation (ths) – continued

	2015	2020	2025	2030	2035	2040
Services to mining	0.000	2.059	-0.647	-0.834	-1.171	-3.200
Meat and meat products	0.000	1.262	-9.148	-10.484	-11.542	-18.009
Dairy products	0.000	0.701	-4.549	-5.264	-5.796	-9.043
Fruit and vegetable products	0.000	0.120	-0.782	-0.905	-0.996	-1.554
Oils and fats	0.000	0.036	-0.267	-0.306	-0.337	-0.526
Flour mill products and cereal foods	0.000	0.242	-1.712	-1.965	-2.164	-3.377
Bakery products	0.000	0.605	-3.822	-4.429	-4.877	-7.616
Confectionery	0.000	0.146	-0.940	-1.088	-1.198	-1.870
Other food products	0.000	0.315	-2.127	-2.447	-2.695	-4.212
Soft drinks, cordials and syrups	0.000	0.112	-0.750	-0.867	-0.954	-1.486
Beer and malt	0.000	0.074	-0.459	-0.532	-0.586	-0.915
Wine, spirits and tobacco products (a)	0.000	0.100	-0.626	-0.724	-0.798	-1.248
Textile fibres, yarns and woven fabrics	0.000	0.014	-0.089	-0.102	-0.113	-0.178
Textile products	0.000	0.096	-0.565	-0.654	-0.722	-1.133
Knitting mill products	0.000	0.041	-0.256	-0.295	-0.326	-0.510
Clothing	0.000	0.186	-1.036	-1.199	-1.324	-2.087
Footwear	0.000	0.024	-0.130	-0.152	-0.168	-0.264
Leather and leather products	0.000	0.011	-0.051	-0.059	-0.065	-0.104
Sawmill products	0.000	0.081	-0.159	-0.197	-0.224	-0.382
Other wood products	0.000	0.315	-0.766	-0.911	-1.031	-1.742
Pulp, paper and paperboard	0.000	0.020	-0.105	-0.120	-0.133	-0.212
Paper containers and products	0.000	0.126	-0.861	-0.982	-1.084	-1.703
Printing and services to printing	0.000	0.542	-2.480	-2.883	-3.198	-5.107
Publishing, recorded media, etc.	0.000	0.478	-2.861	-3.299	-3.641	-5.726
Petroleum and coal products	0.000	0.275	-1.155	-1.352	-1.504	-2.418
Glass and glass products	0.000	0.121	-0.598	-0.688	-0.763	-1.219
Ceramic products	0.000	0.018	-0.027	-0.036	-0.042	-0.072
Cement, lime and concrete slurry	0.000	0.064	0.052	0.037	0.032	0.012
Plaster and other concrete products	0.000	0.042	0.159	0.155	0.163	0.227

Table A.13 The impact of East Coast LNG exports on the national economy: Total employment formation (ths) – continued	2015	2020	2025	2030	2035	2040
Other non-metallic mineral products	0.000	0.055	-0.060	-0.076	-0.090	-0.170
Iron and steel	0.000	0.749	-1.117	-1.345	-1.559	-2.828
Structural metal products	0.000	0.357	-0.215	-0.294	-0.365	-0.776
Sheet metal products	0.000	0.079	-0.312	-0.359	-0.400	-0.652
Fabricated metal products	0.000	0.463	-0.803	-0.955	-1.099	-1.956
Motor vehicles and parts, other transport equipment	0.000	1.002	-5.043	-5.868	-6.488	-10.266
Ships and boats	0.000	0.028	-0.136	-0.157	-0.174	-0.277
Railway equipment	0.000	0.097	0.005	-0.011	-0.023	-0.093
Aircraft	0.000	0.113	-0.179	-0.219	-0.250	-0.444
Photographic and scientific equipment	0.000	0.186	-0.864	-1.009	-1.117	-1.776
Electronic equipment	0.000	0.174	-0.560	-0.665	-0.744	-1.212
Household appliances	0.000	0.223	-1.146	-1.335	-1.475	-2.329
Other electrical equipment	0.000	0.255	0.761	0.690	0.722	0.992
Agricultural, mining, etc. machinery	0.000	0.387	-0.315	-0.398	-0.480	-0.973
Other machinery and equipment	0.000	0.343	-0.566	-0.678	-0.780	-1.393
Prefabricated buildings	0.000	0.129	0.030	0.020	0.007	-0.075
Furniture	0.000	0.575	-3.104	-3.609	-3.985	-6.276
Other manufacturing	0.000	0.255	-1.333	-1.517	-1.685	-2.700
Electricity supply	0.000	0.627	41.056	42.510	46.193	70.731
Gas supply	0.000	0.175	0.659	0.578	0.607	0.871
Water supply, sewerage and drainage services	0.000	0.333	-1.717	-1.992	-2.205	-3.494
Residential building	0.000	0.187	0.083	0.035	0.016	-0.077
Other construction	0.000	0.489	0.091	-0.029	-0.090	-0.409
Construction trade services	0.000	5.699	10.736	9.891	10.081	12.245
Wholesale trade	0.000	3.638	-17.687	-20.242	-22.490	-36.102
Wholesale mechanical repairs	0.000	0.393	0.176	0.137	0.103	-0.087
Other wholesale repairs	0.000	0.917	-0.824	-1.068	-1.272	-2.476
Retail trade	0.000	10.433	-66.102	-76.590	-84.339	-131.692
Retail mechanical repairs	0.000	3.870	-12.971	-15.323	-17.111	-27.872

Table A.13 The impact of East Coast LNG exports on the national economy: Total employment formation (ths) – continued

	2015	2020	2025	2030	2035	2040
Other retail repairs	0.000	0.178	-1.011	-1.174	-1.295	-2.034
Accommodation, cafes and restaurants	0.000	4.627	-27.705	-32.149	-35.435	-55.489
Road transport	0.000	1.811	-10.521	-11.998	-13.284	-21.095
Rail, pipeline and other transport	0.000	1.595	0.062	-0.192	-0.393	-1.562
Water transport	0.000	0.115	-0.367	-0.420	-0.473	-0.790
Air and space transport	0.000	0.667	-3.522	-4.097	-4.527	-7.142
Services to transport, storage	0.000	1.374	-4.185	-4.810	-5.410	-9.041
Communication services	0.000	1.790	-8.192	-9.585	-10.622	-16.902
Finance	0.000	3.695	-13.364	-15.896	-17.690	-28.485
Ownership of dwellings	0.000	0.000	0.000	0.000	0.000	0.000
Other property services	0.000	2.074	-3.768	-4.577	-5.223	-9.085
Scientific research, technical and computer services	0.000	2.527	-6.278	-7.342	-8.316	-14.143
Legal, accounting, marketing and business management services	0.000	3.290	-12.487	-14.514	-16.199	-26.339
Other business services	0.000	1.622	-6.394	-7.413	-8.270	-13.423
Government administration	0.000	0.504	-2.316	-2.643	-2.941	-4.746
Defence	0.000	0.004	-0.020	-0.022	-0.025	-0.040
Education	0.000	2.312	-13.176	-15.362	-16.941	-26.552
Health services	0.000	2.107	-13.971	-16.184	-17.807	-27.729
Community services	0.000	0.322	-2.138	-2.478	-2.726	-4.243
Motion picture, radio and television services	0.000	0.599	-2.876	-3.341	-3.701	-5.890
Libraries, museums and the arts	0.000	0.441	-1.935	-2.286	-2.534	-4.029
Sport, gambling and recreational services	0.000	2.120	-10.832	-12.609	-13.928	-21.989
Personal services	0.000	1.774	-11.621	-13.467	-14.819	-23.087
Other services	0.000	0.889	-5.786	-6.707	-7.381	-11.505
Total	**0.000**	**81.816**	**-375.199**	**-434.261**	**-482.785**	**-774.619**

Table A.14 East Coast LNG expansion: Gross output formation by industry ($2009m)

	Case study: 50 PJ of natural gas allocated to LNG exports – base case prices	Case study: 50 PJ of natural gas allocated to LNG exports – 20% reduction in base case prices	Net benefit of 50 PJ of LNG exports with 20% reduction in base case prices
Constrained industries			
Basic chemicals	0.00	0.00	0.00
Paints	0.00	0.00	0.00
Medicinal and pharmaceutical products, pesticides	0.00	0.00	0.00
Soap and detergents	0.00	0.00	0.00
Cosmetics and toiletry preparations	0.00	0.00	0.00
Other chemical products	0.00	0.00	0.00
Rubber products	0.00	0.00	0.00
Plastic products	0.00	0.00	0.00
Basic non-ferrous metal and products	0.00	0.00	0.00
LNG	620.73	-124.15	496.58
Unconstrained industries			
Sheep	0.70	-0.23	0.47
Grains	1.06	-0.35	0.70
Beef cattle	1.94	-0.65	1.29
Dairy cattle	1.08	-0.37	0.72
Pigs	0.27	-0.09	0.18
Poultry	0.60	-0.20	0.40
Other agriculture	3.94	-1.32	2.62
Services to agriculture, hunting and trapping	0.92	-0.30	0.61
Forestry and logging	0.50	-0.12	0.37
Commercial fishing	0.63	-0.21	0.41
Coal	1.79	-0.45	1.34
Gas	5.80	-1.24	4.55
Oil	1.47	-0.43	1.03
Iron ores	0.20	-0.05	0.16
Non-ferrous metal ores	0.31	-0.08	0.24
Other mining	0.45	-0.11	0.34
Services to mining	15.45	-3.11	12.34
Meat and meat products	4.60	-1.55	3.05
Dairy products	3.54	-1.20	2.35
Fruit and vegetable products	1.12	-0.38	0.74
Oils and fats	0.44	-0.15	0.29
Flour mill products and cereal foods	1.83	-0.62	1.22
Bakery products	1.51	-0.51	1.00
Confectionery	1.15	-0.39	0.76
Other food products	2.69	-0.90	1.79
Soft drinks, cordials and syrups	1.48	-0.50	0.98
Beer and malt	1.26	-0.42	0.84
Wine, spirits and tobacco products (a)	1.44	-0.48	0.96
Textile fibres, yarns and woven fabrics	0.12	-0.04	0.08
Textile products	0.37	-0.12	0.25
Knitting mill products	0.26	-0.09	0.17

Table A.14 East Coast LNG expansion: Gross output formation by industry ($2009m) – continued

	Case study: 50 PJ of natural gas allocated to LNG exports – base case prices	Case study: 50 PJ of natural gas allocated to LNG exports – 20% reduction in base case prices	Net benefit of 50 PJ of LNG exports with 20% reduction in base case prices
Clothing	0.57	-0.18	0.39
Footwear	0.12	-0.04	0.08
Leather and leather products	0.09	-0.03	0.07
Sawmill products	0.54	-0.14	0.40
Other wood products	1.09	-0.28	0.81
Pulp, paper and paperboard	0.30	-0.09	0.21
Paper containers and products	0.90	-0.29	0.61
Printing and services to printing	2.88	-0.86	2.02
Publishing, recorded media, etc.	3.29	-1.05	2.24
Petroleum and coal products	6.35	-1.87	4.48
Glass and glass products	0.67	-0.20	0.47
Ceramic products	0.12	-0.03	0.08
Cement, lime and concrete slurry	0.83	-0.20	0.63
Plaster and other concrete products	0.43	-0.10	0.33
Other non-metallic mineral products	0.23	-0.05	0.17
Iron and steel	4.24	-1.00	3.24
Structural metal products	2.92	-0.66	2.26
Sheet metal products	0.91	-0.25	0.66
Fabricated metal products	2.23	-0.53	1.70
Motor vehicles and parts, other transport equipment	4.75	-1.48	3.27
Ships and boats	0.40	-0.12	0.28
Railway equipment	1.21	-0.27	0.95
Aircraft	1.39	-0.34	1.05
Photographic and scientific equipment	0.91	-0.28	0.64
Electronic equipment	0.83	-0.23	0.59
Household appliances	1.37	-0.43	0.94
Other electrical equipment	1.34	-0.36	0.98
Agricultural, mining, etc. machinery	1.79	-0.40	1.39
Other machinery and equipment	1.60	-0.38	1.22
Prefabricated buildings	0.85	-0.17	0.68
Furniture	1.26	-0.40	0.86
Other manufacturing	1.07	-0.30	0.76
Electricity supply	10.97	-3.21	7.76
Gas supply	1.10	-0.34	0.76
Water supply, sewerage and drainage services	4.06	-1.26	2.80
Residential building	1.94	-0.47	1.46
Other construction	3.52	-0.84	2.68
Construction trade services	19.47	-4.56	14.91
Wholesale trade	25.88	-7.38	18.50
Wholesale mechanical repairs	2.89	-0.61	2.28
Other wholesale repairs	5.51	-1.29	4.22
Retail trade	32.74	-10.99	21.75

Table A.14 East Coast LNG expansion: Gross output formation by industry ($2009m) – continued

	Case study: 50 PJ of natural gas allocated to LNG exports – base case prices	Case study: 50 PJ of natural gas allocated to LNG exports – 20% reduction in base case prices	Net benefit of 50 PJ of LNG exports with 20% reduction in base case prices
Retail mechanical repairs	7.63	-2.15	5.48
Other retail repairs	0.44	-0.14	0.30
Accommodation, cafes and restaurants	16.97	-5.60	11.37
Road transport	9.58	-2.87	6.72
Rail, pipeline and other transport	10.02	-2.21	7.80
Water transport	1.13	-0.28	0.85
Air and space transport	4.99	-1.58	3.41
Services to transport, storage	13.62	-3.43	10.19
Communication services	15.22	-4.65	10.57
Finance	47.38	-14.02	33.36
Ownership of dwellings	4.72	-1.62	3.10
Other property services	31.27	-7.86	23.41
Scientific research, technical and computer services	11.85	-2.96	8.89
Legal, accounting, marketing and business management services	18.85	-5.24	13.61
Other business services	11.10	-3.10	8.01
Government administration	2.21	-0.61	1.60
Defence	0.03	-0.01	0.02
Education	9.51	-3.13	6.38
Health services	9.29	-3.18	6.11
Community services	1.16	-0.40	0.76
Motion picture, radio and television services	4.08	-1.24	2.85
Libraries, museums and the arts	1.11	-0.34	0.76
Sport, gambling and recreational services	7.78	-2.45	5.34
Personal services	3.71	-1.27	2.45
Other services	3.99	-1.36	2.63
Total	**1082.81**	**-256.45**	**-28757.76**

Table A.15 East Coast LNG expansion: Total employment formation (ths)

	Case study: 50 PJ of natural gas allocated to LNG exports – base case prices	Case study: 50 PJ of natural gas allocated to LNG exports – 20% reduction in base case prices	Net benefit of 50 PJ of LNG exports with 20% reduction in base case prices
Constrained industries			
Basic chemicals	0.00	0.00	0.00
Paints	0.00	0.00	0.00
Medicinal and pharmaceutical products, pesticides	0.00	0.00	0.00
Soap and detergents	0.00	0.00	0.00
Cosmetics and toiletry preparations	0.00	0.00	0.00
Other chemical products	0.00	0.00	0.00
Rubber products	0.00	0.00	0.00
Plastic products	0.00	0.00	0.00
Basic non-ferrous metal and products	0.00	0.00	0.00
LNG	0.12	-0.02	0.09
Unconstrained industries			
Sheep	0.01	0.00	0.01
Grains	0.01	0.00	0.01
Beef cattle	0.03	-0.01	0.02
Dairy cattle	0.01	0.00	0.01
Pigs	0.01	0.00	0.00
Poultry	0.01	0.00	0.00
Other agriculture	0.04	-0.01	0.02
Services to agriculture, hunting and trapping	0.01	0.00	0.00
Forestry and logging	0.00	0.00	0.00
Commercial fishing	0.00	0.00	0.00
Coal	0.00	0.00	0.00
Gas	0.00	0.00	0.00
Oil	0.00	0.00	0.00
Iron ores	0.00	0.00	0.00
Non-ferrous metal ores	0.00	0.00	0.00
Other mining	0.00	0.00	0.00
Services to mining	0.10	-0.02	0.08
Meat and meat products	0.07	-0.02	0.04
Dairy products	0.04	-0.01	0.02
Fruit and vegetable products	0.01	0.00	0.00
Oils and fats	0.00	0.00	0.00
Flour mill products and cereal foods	0.01	0.00	0.01
Bakery products	0.03	-0.01	0.02
Confectionery	0.01	0.00	0.01
Other food products	0.02	-0.01	0.01
Soft drinks, cordials and syrups	0.01	0.00	0.00
Beer and malt	0.00	0.00	0.00
Wine, spirits and tobacco products (a)	0.01	0.00	0.00
Textile fibres, yarns and woven fabrics	0.00	0.00	0.00
Textile products	0.01	0.00	0.00
Knitting mill products	0.00	0.00	0.00

Table A.15 East Coast LNG expansion: Total employment formation (ths) – continued

	Case study: 50 PJ of natural gas allocated to LNG exports – base case prices	Case study: 50 PJ of natural gas allocated to LNG exports – 20% reduction in base case prices	Net benefit of 50 PJ of LNG exports with 20% reduction in base case prices
Clothing	0.01	0.00	0.01
Footwear	0.00	0.00	0.00
Leather and leather products	0.00	0.00	0.00
Sawmill products	0.00	0.00	0.00
Other wood products	0.02	0.00	0.01
Pulp, paper and paperboard	0.00	0.00	0.00
Paper containers and products	0.01	0.00	0.00
Printing and services to printing	0.03	-0.01	0.02
Publishing, recorded media, etc.	0.03	-0.01	0.02
Petroleum and coal products	0.01	0.00	0.01
Glass and glass products	0.01	0.00	0.00
Ceramic products	0.00	0.00	0.00
Cement, lime and concrete slurry	0.00	0.00	0.00
Plaster and other concrete products	0.00	0.00	0.00
Other non-metallic mineral products	0.00	0.00	0.00
Iron and steel	0.04	-0.01	0.03
Structural metal products	0.02	0.00	0.01
Sheet metal products	0.00	0.00	0.00
Fabricated metal products	0.02	-0.01	0.02
Motor vehicles and parts, other transport equipment	0.05	-0.02	0.04
Ships and boats	0.00	0.00	0.00
Railway equipment	0.00	0.00	0.00
Aircraft	0.01	0.00	0.00
Photographic and scientific equipment	0.01	0.00	0.01
Electronic equipment	0.01	0.00	0.01
Household appliances	0.01	0.00	0.01
Other electrical equipment	0.01	0.00	0.01
Agricultural, mining, etc. machinery	0.02	0.00	0.02
Other machinery and equipment	0.02	0.00	0.01
Prefabricated buildings	0.01	0.00	0.01
Furniture	0.03	-0.01	0.02
Other manufacturing	0.01	0.00	0.01
Electricity supply	0.03	-0.01	0.02
Gas supply	0.01	0.00	0.01
Water supply, sewerage and drainage services	0.02	-0.01	0.01
Residential building	0.01	0.00	0.01
Other construction	0.02	-0.01	0.02
Construction trade services	0.29	-0.07	0.22
Wholesale trade	0.19	-0.05	0.14
Wholesale mechanical repairs	0.02	0.00	0.02
Other wholesale repairs	0.05	-0.01	0.04
Retail trade	0.56	-0.19	0.37

Table A.15 East Coast LNG expansion: Total employment formation (ths) – continued			
	Case study: 50 PJ of natural gas allocated to LNG exports – base case prices	**Case study: 50 PJ of natural gas allocated to LNG exports – 20% reduction in base case prices**	**Net benefit of 50 PJ of LNG exports with 20% reduction in base case prices**
Retail mechanical repairs	0.20	-0.06	0.14
Other retail repairs	0.01	0.00	0.01
Accommodation, cafes and restaurants	0.25	-0.08	0.17
Road transport	0.10	-0.03	0.07
Rail, pipeline and other transport	0.08	-0.02	0.06
Water transport	0.01	0.00	0.00
Air and space transport	0.04	-0.01	0.02
Services to transport, storage	0.07	-0.02	0.05
Communication services	0.09	-0.03	0.07
Finance	0.19	-0.06	0.14
Ownership of dwellings	0.00	0.00	0.00
Other property services	0.11	-0.03	0.08
Scientific research, technical and computer services	0.13	-0.03	0.10
Legal, accounting, marketing and business management services	0.17	-0.05	0.12
Other business services	0.08	-0.02	0.06
Government administration	0.03	-0.01	0.02
Defence	0.00	0.00	0.00
Education	0.12	-0.04	0.08
Health services	0.11	-0.04	0.07
Community services	0.02	-0.01	0.01
Motion picture, radio and television services	0.03	-0.01	0.02
Libraries, museums and the arts	0.02	-0.01	0.02
Sport, gambling and recreational services	0.11	-0.04	0.08
Personal services	0.10	-0.03	0.06
Other services	0.05	-0.02	0.03
Total	**4.28**	**-1.25**	**3.03**

Appendix B: Input-output flow table with direct allocation of imports – Australia

Table B.1(a) Australia input-output flow table with direct allocation of imports – $2009m

	Sheep	Grains	Beef cattle	Dairy cattle	Pigs	Poultry	Other agriculture	Services to agriculture, hunting and trapping	Forestry and logging	Commercial fishing
Sheep	2.82	2.66	4.46	1.74	1.64	2.28	2.14	1.15	0.00	0.00
Grains	46.57	1725.26	95.11	50.94	15.51	35.12	29.84	2.74	0.03	0.02
Beef cattle	0.00	0.00	11.30	2.89	0.00	0.00	0.00	0.00	0.00	0.00
Dairy cattle	0.00	0.00	1.19	1.14	0.00	0.00	0.00	0.00	0.00	0.00
Pigs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Poultry	0.00	0.00	0.00	0.00	0.00	13.34	0.00	0.00	0.00	0.00
Other agriculture	161.23	0.34	527.58	122.40	23.88	0.28	359.74	1194.95	4.39	0.07
Services to agriculture, hunting and trapping	555.44	612.63	1295.55	295.68	11.84	46.84	1405.10	32.09	10.57	0.00
Forestry and logging	4.17	0.08	133.48	6.99	0.02	0.07	95.67	0.00	381.55	0.00
Commercial fishing	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal	0.28	0.27	1.10	0.29	0.03	0.03	0.62	0.30	0.02	0.02
Gas	2.56	2.71	4.34	2.23	0.71	6.67	4.98	2.09	1.24	0.28
LNG	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Iron ores	0.03	0.04	0.13	0.03	0.00	0.01	0.06	0.09	0.00	0.01
Non-ferrous metal ores	1.07	0.94	4.01	1.14	0.13	0.07	2.44	0.39	0.06	0.01
Other mining	0.04	0.06	0.08	0.03	0.02	0.03	0.50	0.02	0.00	0.00
Services to mining	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Meat and meat products	1.22	0.78	10.83	16.71	2.77	12.27	11.05	8.39	0.14	4.55
Dairy products	5.76	1.32	47.85	64.06	34.55	25.38	14.81	1.41	0.26	8.64
Fruit and vegetable products	0.49	0.98	1.07	0.74	0.51	0.48	1.25	0.45	0.17	0.46
Oils and fats	1.67	0.35	7.66	6.88	8.39	5.10	4.16	0.31	0.12	1.86
Flour mill products and cereal foods	7.86	2.93	39.92	57.05	25.76	43.30	12.99	1.81	4.31	25.16
Bakery products	0.32	0.91	0.59	0.31	0.05	0.61	1.44	0.41	0.36	0.63
Confectionery	2.47	0.70	20.51	43.20	7.62	30.55	19.36	14.31	0.12	11.03
Other food products	26.80	3.52	199.02	379.30	65.82	275.07	108.87	67.11	0.45	98.05
Soft drinks, cordials and syrups	0.63	2.30	1.04	0.89	0.05	0.11	3.33	0.42	0.04	0.12
Beer and malt	0.40	1.16	0.61	0.51	0.07	0.07	0.51	0.30	0.09	0.17
Wine, spirits and tobacco products	3.90	1.30	34.84	4.61	0.71	0.55	15.33	3.88	2.74	5.34
Textile fibres, yarns and woven fabrics	0.20	0.64	0.45	0.21	0.06	0.09	1.00	0.28	0.13	0.34

Table B.1(a) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Sheep	Grains	Beef cattle	Dairy cattle	Pigs	Poultry	Other agriculture	Services to agriculture, hunting and trapping	Forestry and logging	Commercial fishing
Textile products	0.27	0.57	0.73	0.13	0.03	0.11	0.73	0.17	0.27	1.24
Knitting mill products	0.18	0.49	0.42	0.14	0.04	0.07	0.50	0.16	0.16	0.91
Clothing	0.88	2.27	1.66	1.91	0.13	0.32	2.66	0.81	0.94	1.72
Footwear	0.14	0.36	0.24	0.31	0.04	0.08	0.45	0.16	0.23	0.32
Leather and leather products	0.25	0.57	0.97	1.44	0.24	1.03	1.32	0.24	0.15	0.67
Sawmill products	0.95	0.71	0.94	0.73	0.18	0.12	0.82	0.36	0.22	0.42
Other wood products	1.08	1.61	1.77	0.75	0.47	0.73	1.95	1.13	3.42	9.37
Pulp, paper and paperboard	0.21	0.45	0.40	0.13	0.09	0.29	2.43	0.19	0.18	0.18
Paper containers and products	0.67	1.09	1.08	0.24	0.12	6.29	18.56	0.25	0.21	0.30
Printing and services to printing	1.17	3.55	12.87	0.71	0.34	0.17	10.47	1.24	0.69	0.93
Publishing, recorded media, etc.	2.18	6.47	5.55	1.67	0.20	0.33	6.84	0.78	0.81	0.87
Petroleum and coal products	91.55	138.70	61.52	43.43	3.65	17.52	193.32	8.72	33.48	82.31
Basic chemicals	93.73	263.20	226.97	66.85	4.32	4.86	557.99	63.41	2.47	3.19
Paints	1.15	2.24	4.33	0.66	0.33	0.67	3.91	1.15	0.75	3.30
Medicinal and pharmaceutical products, pesticides	30.50	38.54	81.04	25.36	3.29	6.01	80.92	20.16	6.45	0.52
Soap and detergents	0.59	1.31	0.67	0.14	0.06	0.10	1.57	1.78	0.54	0.28
Cosmetics and toiletry preparations	0.15	0.21	0.35	0.12	0.02	0.04	0.35	0.10	0.05	0.03
Other chemical products	1.95	7.03	12.74	1.73	0.91	0.39	3.21	0.90	2.89	0.85
Rubber products	0.59	2.90	0.85	0.26	0.05	0.10	7.98	0.17	0.16	0.87
Plastic products	2.10	3.07	2.21	2.09	0.27	5.51	26.56	1.32	1.01	10.00
Glass and glass products	0.86	1.28	0.83	0.18	0.03	0.11	1.04	0.25	0.37	0.65
Ceramic products	0.04	0.12	0.08	0.04	0.01	0.02	0.60	0.07	0.24	0.52
Cement, lime and concrete slurry	0.19	0.53	0.35	0.17	0.05	0.11	0.62	0.23	6.75	0.96
Plaster and other concrete products	0.20	0.39	0.37	0.15	0.09	0.14	0.44	0.16	4.24	0.84
Other non-metallic mineral products	0.20	0.72	0.28	0.09	0.02	0.02	2.26	0.09	2.49	1.25
Iron and steel	0.76	1.92	2.51	1.10	0.21	0.46	35.39	0.68	2.21	4.07
Basic non-ferrous metal and products	1.40	3.34	2.60	1.13	0.38	0.94	6.49	1.35	0.95	2.55
Structural metal products	1.39	3.70	4.32	1.92	0.55	2.12	36.34	1.28	6.03	13.18
Sheet metal products	0.71	2.25	1.10	1.35	0.12	0.51	8.94	0.25	0.80	3.05
Fabricated metal products	11.57	9.52	7.27	1.48	0.49	1.62	26.11	0.86	9.47	18.76
Motor vehicles and parts, other transport equipment	3.43	7.64	5.95	2.28	1.34	1.86	7.00	1.97	4.09	10.82
Ships and boats	0.21	0.37	0.40	0.16	0.08	0.14	0.32	0.68	0.35	27.97
Railway equipment	0.10	0.21	0.20	0.09	0.03	0.06	0.20	0.08	0.12	0.29

Table B.1(a) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Sheep	Grains	Beef cattle	Dairy cattle	Pigs	Poultry	Other agriculture	Services to agriculture, hunting and trapping	Forestry and logging	Commercial fishing
Aircraft	0.50	1.63	1.08	0.19	0.03	0.02	0.92	5.86	0.22	0.21
Photographic and scientific equipment	1.38	1.40	3.96	2.47	0.16	0.27	2.74	0.67	0.60	2.83
Electronic equipment	0.93	4.53	2.31	1.29	0.23	0.51	1.84	0.61	1.68	4.20
Household appliances	0.51	1.52	2.49	1.11	0.13	0.23	2.09	0.60	0.58	2.31
Other electrical equipment	1.17	2.31	4.21	1.72	0.44	0.69	4.74	1.07	4.97	9.83
Agricultural, mining, etc. machinery	5.53	44.16	14.67	3.79	0.74	2.85	12.72	1.89	9.33	13.23
Other machinery and equipment	2.04	6.54	4.21	2.07	0.42	0.79	26.54	1.35	11.87	20.01
Prefabricated buildings	0.07	0.21	0.16	0.07	0.01	0.04	0.31	0.09	0.20	0.16
Furniture	0.63	1.41	0.92	0.45	0.11	0.26	2.83	0.70	0.94	3.28
Other manufacturing	2.08	4.30	5.27	6.29	1.12	4.10	11.63	0.90	1.32	6.63
Electricity supply	10.55	21.13	49.89	28.06	4.27	13.19	36.49	3.04	1.14	4.92
Gas supply	1.89	2.12	2.43	1.37	0.65	0.83	2.76	1.46	0.07	0.24
Water supply, sewerage and drainage services	14.08	218.43	132.27	87.66	22.22	24.67	160.91	4.23	0.74	2.34
Residential building	3.14	5.66	12.95	2.90	0.98	1.80	6.26	7.46	0.92	0.78
Other construction	9.67	15.68	34.82	9.65	2.05	4.11	14.92	10.50	1.71	1.06
Construction trade services	70.44	73.77	130.75	41.79	35.60	58.35	60.89	23.77	10.08	10.21
Wholesale trade	244.23	673.79	345.56	163.55	28.07	68.28	658.64	206.46	118.43	193.82
Wholesale mechanical repairs	14.22	47.95	22.30	11.29	1.57	1.78	19.10	0.22	24.73	6.42
Other wholesale repairs	4.70	33.98	15.64	4.75	0.33	2.18	12.51	1.01	2.37	17.89
Retail trade	15.84	42.37	27.49	9.11	1.79	4.53	51.27	14.81	12.29	15.43
Retail mechanical repairs	56.64	54.78	85.84	28.03	1.99	7.60	82.55	3.38	61.81	41.48
Other retail repairs	2.24	1.15	4.09	1.34	1.22	1.87	1.67	0.71	0.00	0.00
Accommodation, cafes and restaurants	19.05	36.23	30.64	12.01	0.21	1.20	38.72	0.82	1.95	6.89
Road transport	119.31	418.02	299.53	173.54	28.86	74.05	280.38	64.63	23.19	36.93
Rail, pipeline and other transport	4.88	18.24	5.65	2.37	0.80	1.44	4.40	1.92	0.30	0.28
Water transport	0.38	0.61	0.08	0.02	0.02	0.02	0.44	0.04	0.13	6.35
Air and space transport	4.38	4.54	11.79	3.01	0.49	0.54	9.35	6.36	0.65	1.46
Services to transport, storage	28.65	233.79	52.43	12.99	2.77	43.73	38.93	0.55	2.37	12.67
Communication services	45.20	45.85	93.11	20.87	5.61	9.36	46.04	4.14	3.88	6.87
Finance	117.26	344.08	258.25	93.21	15.26	43.71	345.73	56.95	39.53	79.69
Ownership of dwellings	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other property services	41.04	100.35	104.40	21.11	4.63	10.92	61.60	96.31	3.89	4.68
Scientific research, technical and computer services	21.93	68.65	109.25	6.27	2.01	2.08	114.97	8.49	0.39	0.84

Table B.1(a) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Sheep	Grains	Beef cattle	Dairy cattle	Pigs	Poultry	Other agriculture	Services to agriculture, hunting and trapping	Forestry and logging	Commercial fishing
Legal, accounting, marketing and business management services	99.12	160.64	212.32	40.35	29.62	28.86	104.69	15.28	1.72	9.14
Other business services	4.14	10.81	41.27	0.04	0.01	0.50	5.69	0.38	1.80	2.88
Government administration	3.75	5.03	3.55	0.41	0.06	0.20	9.21	0.73	1.25	3.69
Defence	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Education	0.40	2.58	2.79	0.53	0.11	0.70	4.09	0.83	0.28	1.90
Health services	1.65	0.01	21.78	8.45	0.61	2.68	0.97	2.43	0.16	1.01
Community services	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Motion picture, radio and television services	0.00	0.00	0.00	0.00	0.00	0.00	0.00	9.55	0.86	0.00
Libraries, museums and the arts	0.57	0.80	12.64	0.07	0.01	0.02	0.31	0.08	7.27	0.12
Sport, gambling and recreational services	14.31	0.09	14.59	7.06	0.86	0.01	0.12	0.01	0.01	0.02
Personal services	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	1.97
Other services	0.06	0.36	0.35	0.02	0.00	0.05	0.12	0.01	0.00	0.00
Total intermediate usage including imports	**2342**	**5978**	**5544**	**2265**	**450**	**1040**	**6109**	**2085**	**1024**	**1250**
Wages and salaries	541	466	914	439	131	163	2168	843	657	326
Gross surplus	1968	3614	4137	1699	390	847	5741	2200	517	560
Indirect taxes on production	185	393	267	179	29	50	407	117	63	114
Total gross output	**5035**	**10451**	**10861**	**4582**	**1000**	**2101**	**14424**	**5244**	**2262**	**2250**
Value added at factor cost to output ratio	0.53	0.43	0.49	0.51	0.55	0.50	0.58	0.60	0.55	0.44
Share of wages and mixed income in value added	0.81	0.76	0.82	0.82	0.84	0.80	0.79	0.77	0.80	0.68
Employment to gross output ratio	16.64	8.63	14.25	13.27	23.95	9.01	9.46	7.25	7.13	6.58
Foreign ownership ratio	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Direct tax rate on surplus	0.01	0.01	0.01	0.01	0.08	0.09	0.02	0.06	0.06	0.06
Indirect tax rate on production	0.06	0.08	0.04	0.07	0.04	0.04	0.04	0.03	0.04	0.11
Foreign income payout ratio	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Replacement depreciation to value added ratio	0.08	0.07	0.18	0.05	0.12	0.13	0.08	0.06	0.13	0.13
Net national product ratio	0.91	0.92	0.81	0.94	0.87	0.86	0.91	0.93	0.86	0.86
Domestic income distribution ratio	0.17	0.20	0.16	0.16	0.14	0.17	0.19	0.20	0.16	0.25

Table B.1(b) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Coal	Gas	LNG	Oil	Iron ores	Non-ferrous metal ores	Other mining	Services to mining	Meat and meat products	Dairy products
Sheep	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1575.79	0.00
Grains	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Beef cattle	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	7479.29	0.00
Dairy cattle	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4062.56
Pigs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	651.23	0.00
Poultry	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1165.84	0.00
Other agriculture	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.08	16.01
Services to agriculture, hunting and trapping	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Forestry and logging	41.01	7.77	2.99	7.53	0.11	60.12	1.00	0.00	0.00	0.00
Commercial fishing	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal	150.92	30.29	11.64	29.36	9.67	19.88	0.52	0.07	0.89	0.79
Gas	12.69	215.70	77.95	49.97	35.18	19.79	1.67	2.00	37.95	58.04
LNG	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Oil	0.00	0.00	0.00	299.82	0.00	0.00	0.00	0.00	0.00	0.00
Iron ores	1.35	0.30	0.12	0.29	804.22	0.74	0.14	0.08	0.15	0.03
Non-ferrous metal ores	16.35	3.22	1.24	3.12	55.08	1108.46	5.87	16.40	0.43	0.08
Other mining	31.61	1.99	0.77	1.93	4.23	6.85	687.19	0.03	0.07	0.01
Services to mining	3243.55	622.23	239.13	603.08	4941.65	4236.04	38.20	147.94	0.00	0.00
Meat and meat products	2.44	0.42	0.16	0.41	1.57	1.97	0.12	0.64	1320.25	13.31
Dairy products	1.81	0.30	0.11	0.29	16.44	1.46	0.10	0.59	13.06	1983.16
Fruit and vegetable products	3.05	0.46	0.18	0.45	1.77	2.79	0.18	0.97	15.34	23.80
Oils and fats	1.20	0.18	0.07	0.18	0.61	1.11	0.06	0.42	3.03	11.30
Flour mill products and cereal foods	2.67	0.43	0.16	0.42	1.66	2.32	0.14	0.73	24.60	25.99
Bakery products	11.19	0.98	0.38	0.95	9.70	7.78	0.55	9.58	17.24	69.52
Confectionery	1.91	0.31	0.12	0.30	1.09	1.67	0.10	0.49	2.43	162.09
Other food products	8.22	1.43	0.55	1.39	8.55	6.93	0.61	2.34	62.32	154.13
Soft drinks, cordials and syrups	0.81	0.17	0.07	0.16	1.46	0.62	0.07	0.14	5.16	9.04
Beer and malt	3.35	0.77	0.30	0.75	6.29	7.01	0.20	0.89	0.75	4.96
Wine, spirits and tobacco products	6.11	2.67	1.03	2.59	6.92	6.10	0.43	1.20	20.50	2.34
Textile fibres, yarns and woven fabrics	3.00	0.45	0.17	0.44	3.36	2.35	0.16	1.02	0.59	2.59
Textile products	4.23	1.05	0.40	1.02	3.09	3.38	0.09	0.74	1.10	7.38
Knitting mill products	1.94	0.40	0.15	0.39	2.73	1.50	0.14	0.29	0.37	0.97
Clothing	12.11	2.01	0.77	1.95	5.19	10.11	0.47	1.35	2.67	6.60

Table B.1(b) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Coal	Gas	LNG	Oil	Iron ores	Non-ferrous metal ores	Other mining	Services to mining	Meat and meat products	Dairy products
Footwear	1.59	0.30	0.12	0.29	1.22	1.31	0.10	0.23	0.51	1.32
Leather and leather products	1.68	0.30	0.11	0.29	1.09	1.49	0.10	0.37	3.18	1.36
Sawmill products	7.21	1.20	0.46	1.16	3.24	3.17	0.15	0.70	0.79	1.60
Other wood products	45.06	9.02	3.47	8.74	38.76	30.52	1.83	4.59	1.76	9.42
Pulp, paper and paperboard	4.62	0.84	0.32	0.82	2.14	3.26	0.13	18.01	15.65	37.75
Paper containers and products	7.43	1.75	0.67	1.70	5.51	5.01	0.31	3.10	97.82	201.03
Printing and services to printing	42.11	10.63	4.09	10.31	16.72	26.74	2.34	24.95	11.38	34.98
Publishing, recorded media, etc.	17.68	5.35	2.06	5.19	6.92	13.45	0.52	9.91	3.64	11.51
Petroleum and coal products	537.32	47.85	18.39	46.38	293.63	524.75	25.50	159.67	13.20	62.35
Basic chemicals	116.48	20.45	7.86	19.82	57.52	140.73	4.45	17.00	8.64	44.15
Paints	7.93	1.46	0.56	1.41	5.00	6.73	0.23	1.05	0.30	1.14
Medicinal and pharmaceutical products, pesticides	13.72	3.09	1.19	2.99	6.13	12.85	0.45	3.45	2.67	6.70
Soap and detergents	5.00	0.64	0.24	0.62	3.72	6.47	0.20	1.37	3.41	11.10
Cosmetics and toiletry preparations	0.59	0.16	0.06	0.15	1.13	0.39	0.05	0.10	0.16	0.45
Other chemical products	259.85	43.36	16.67	42.03	144.63	142.80	10.53	3.50	0.96	4.31
Rubber products	36.17	6.30	2.42	6.10	7.49	29.41	1.01	2.19	0.18	0.46
Plastic products	33.95	6.02	2.31	5.84	16.80	32.65	1.16	10.20	23.31	503.84
Glass and glass products	17.17	2.26	0.87	2.20	13.10	13.08	0.50	4.56	0.43	0.68
Ceramic products	2.14	0.25	0.10	0.24	1.46	4.15	0.15	1.65	0.18	1.47
Cement, lime and concrete slurry	15.39	3.13	1.20	3.04	14.24	31.92	0.80	20.99	0.56	1.62
Plaster and other concrete products	15.00	1.98	0.76	1.92	14.91	18.14	0.28	2.72	0.26	1.13
Other non-metallic mineral products	13.54	4.02	1.54	3.89	15.59	8.21	0.63	4.59	0.17	0.95
Iron and steel	289.72	47.23	18.15	45.77	182.16	156.23	5.20	257.88	1.57	5.78
Basic non-ferrous metal and products	66.79	24.27	9.33	23.53	86.94	78.09	4.24	25.55	3.11	27.85
Structural metal products	223.84	45.85	17.62	44.44	217.37	259.69	8.55	175.22	1.29	3.41
Sheet metal products	48.38	8.77	3.37	8.50	24.99	56.76	1.06	17.95	2.75	134.96
Fabricated metal products	224.89	46.10	17.72	44.68	108.22	159.01	7.40	34.13	5.09	8.81
Motor vehicles and parts, other transport equipment	75.23	16.94	6.51	16.42	47.72	57.85	5.26	18.40	3.39	9.02
Ships and boats	10.01	1.89	0.73	1.83	9.32	6.03	0.38	1.93	1.58	1.00
Railway equipment	13.92	4.83	1.85	4.68	4.55	2.23	0.26	0.26	0.20	0.39
Aircraft	147.12	27.85	10.70	26.99	15.03	8.71	2.38	16.06	0.10	0.69
Photographic and scientific equipment	26.28	5.97	2.29	5.78	14.45	18.45	0.86	3.19	1.28	7.04
Electronic equipment	11.94	5.30	2.04	5.14	16.43	10.19	0.61	8.83	1.41	7.74

Table B.1(b) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Coal	Gas	LNG	Oil	Iron ores	Non-ferrous metal ores	Other mining	Services to mining	Meat and meat products	Dairy products
Household appliances	17.61	5.55	2.13	5.38	7.82	13.58	1.12	4.44	0.81	4.37
Other electrical equipment	58.14	11.45	4.40	11.10	34.89	38.15	3.04	5.61	3.63	21.19
Agricultural, mining, etc. machinery	287.42	51.61	19.84	50.03	118.37	259.25	18.44	11.49	1.56	7.78
Other machinery and equipment	215.63	34.76	13.36	33.69	95.87	196.27	10.31	26.31	8.81	16.57
Prefabricated buildings	132.33	32.96	12.67	31.95	82.80	92.89	8.32	2.66	0.24	0.53
Furniture	21.86	4.28	1.64	4.15	16.11	18.75	0.97	4.09	1.60	5.18
Other manufacturing	38.29	8.53	3.28	8.27	39.40	39.55	1.94	11.30	9.26	29.74
Electricity supply	410.33	79.29	30.47	76.85	224.80	481.93	2.50	4.01	130.75	193.52
Gas supply	6.83	1.50	0.58	1.46	19.79	14.87	0.35	0.03	2.32	4.22
Water supply, sewerage and drainage services	70.33	8.70	3.34	8.43	275.95	179.62	13.38	1.85	28.91	32.02
Residential building	99.82	24.67	9.48	23.91	211.46	77.86	18.28	44.79	4.57	3.00
Other construction	274.01	59.39	22.82	57.56	842.41	194.27	85.23	60.64	6.18	4.05
Construction trade services	1221.53	304.97	117.20	295.59	5167.95	1003.91	192.47	326.54	15.09	49.52
Wholesale trade	1677.97	237.85	91.41	230.53	925.22	1582.16	88.21	468.73	383.49	1162.12
Wholesale mechanical repairs	176.85	95.04	36.53	92.12	138.95	67.05	9.24	246.94	9.08	6.96
Other wholesale repairs	454.67	140.62	54.04	136.29	138.12	100.77	15.69	157.33	25.01	8.61
Retail trade	171.55	30.07	11.56	29.14	107.04	107.94	9.37	45.46	212.50	128.82
Retail mechanical repairs	175.58	86.96	33.42	84.28	103.17	146.53	34.47	113.23	18.62	14.28
Other retail repairs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Accommodation, cafes and restaurants	124.71	33.37	12.83	32.35	89.35	64.64	7.67	113.50	3.50	2.61
Road transport	405.57	65.09	25.02	63.09	152.81	281.41	49.11	92.31	1064.24	483.67
Rail, pipeline and other transport	1926.32	342.66	131.69	332.12	119.70	55.36	0.52	3.80	11.79	15.80
Water transport	45.69	10.00	3.84	9.69	8.07	21.98	1.75	359.92	1.05	3.44
Air and space transport	93.25	17.14	6.59	16.61	86.89	72.95	4.55	89.98	2.22	1.99
Services to transport, storage	1169.62	225.91	86.82	218.96	231.79	173.66	8.91	98.91	93.79	164.35
Communication services	191.90	49.15	18.89	47.64	74.33	367.76	13.30	127.98	44.48	101.62
Finance	1141.70	295.41	113.53	286.32	723.89	952.44	176.74	327.21	80.25	81.10
Ownership of dwellings	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other property services	1721.27	407.16	156.47	394.63	1083.64	533.21	30.22	72.19	338.34	54.20
Scientific research, technical and computer services	165.77	17.00	6.53	16.47	55.03	229.07	3.40	3668.41	39.03	69.18
Legal, accounting, marketing and business management services	1028.24	120.96	46.49	117.24	302.53	844.39	15.18	312.48	41.33	208.89
Other business services	334.76	36.58	14.06	35.45	106.82	545.69	10.51	314.49	128.55	96.96

Table B.1(b) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Coal	Gas	LNG	Oil	Iron ores	Non-ferrous metal ores	Other mining	Services to mining	Meat and meat products	Dairy products
Government administration	121.14	24.00	9.22	23.26	175.98	98.03	6.49	13.19	9.75	3.59
Defence	0.11	0.02	0.01	0.02	0.11	0.08	0.00	1.30	0.14	0.13
Education	67.21	18.04	6.93	17.48	33.97	47.21	4.40	34.85	14.91	34.45
Health services	0.03	0.00	0.00	0.00	0.03	0.02	0.00	1.51	29.60	0.11
Community services	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Motion picture, radio and television services	5.68	2.29	0.88	2.22	20.81	54.46	0.55	18.65	7.15	48.76
Libraries, museums and the arts	0.00	0.00	0.00	0.00	0.05	1.38	0.03	49.17	0.00	0.00
Sport, gambling and recreational services	75.46	52.34	20.11	50.73	8.84	39.30	0.03	94.28	0.00	0.00
Personal services	0.23	0.00	0.00	0.00	0.00	0.00	0.00	6.79	0.00	0.00
Other services	44.27	0.00	0.00	0.00	10.11	11.83	0.11	0.00	3.36	0.38
Total intermediate usage including imports	**23076**	**4822**	**1848**	**4815**	**20960**	**19037**	**1820**	**9326**	**15582**	**11555**
Wages and salaries	4373	1486	211	1225	967	3249	769	5376	3644	1384
Gross surplus	29574	3761	7998	8488	11711	16205	1574	511	134	108
Indirect taxes on production	9	74	28	74	513	599	37	293	451	282
Total gross output	**57032**	**10143**	**10086**	**14601**	**34152**	**39091**	**4200**	**15506**	**19811**	**13329**
Value added at factor cost to output ratio	0.60	0.52	0.82	0.67	0.39	0.51	0.57	0.40	0.21	0.13
Share of wages and mixed income in value added	0.13	0.31	0.05	0.14	0.08	0.17	0.37	0.93	0.92	0.85
Employment to gross output ratio	1.29	0.82	0.19	0.47	0.95	2.10	3.71	6.67	14.71	10.59
Foreign ownership ratio	0.50	0.80	0.70	0.80	0.55	0.60	0.30	0.40	0.45	0.55
Direct tax rate on surplus	0.18	0.21	0.30	0.21	0.25	0.23	0.26	0.22	0.58	0.16
Indirect tax rate on production	-0.01	0.00	0.00	0.00	0.02	0.02	0.01	0.03	0.07	0.09
Foreign income payout ratio	0.36	0.46	0.46	0.50	0.35	0.36	0.15	0.03	0.03	0.07
Replacement depreciation to value added ratio	0.13	0.30	0.24	0.30	0.11	0.26	0.17	0.15	0.13	0.23
Net national product ratio	0.51	0.24	0.29	0.21	0.54	0.38	0.68	0.83	0.84	0.70
Domestic income distribution ratio	0.36	0.11	0.15	0.14	0.28	0.24	0.34	0.04	0.04	0.05

Table B.1(c) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Fruit and vegetable products	Oils and fats	Flour mill products and cereal foods	Bakery products	Confectionery	Other food products	Soft drinks, cordials and syrups	Beer and malt	Wine, spirits and tobacco products	Textile fibres, yarns and woven fabrics
Sheep	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	418.17
Grains	12.80	153.60	1693.59	4.85	13.04	598.87	10.87	522.89	74.14	0.00
Beef cattle	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Dairy cattle	0.00	0.00	0.00	0.00	0.22	0.00	0.00	0.00	0.00	0.00
Pigs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Poultry	0.00	0.00	0.00	12.44	0.00	3.63	0.00	0.00	0.00	0.00
Other agriculture	573.50	22.99	3.66	40.84	49.84	1567.91	214.38	6.88	583.85	0.01
Services to agriculture, hunting and trapping	0.00	7.13	0.00	0.00	0.00	3.20	0.00	0.00	0.00	21.06
Forestry and logging	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Commercial fishing	0.00	25.76	0.63	1.58	0.30	356.64	0.00	0.00	0.00	0.00
Coal	3.55	0.67	4.31	0.56	0.92	8.32	0.04	0.49	0.14	0.38
Gas	21.46	7.47	19.29	15.73	5.25	57.53	26.17	10.15	2.78	0.03
LNG	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Iron ores	0.00	0.00	0.02	0.00	0.00	0.02	0.01	0.00	0.00	0.00
Non-ferrous metal ores	0.01	0.00	0.05	0.01	0.01	0.07	0.02	0.01	0.01	0.00
Other mining	0.01	0.46	0.03	0.29	0.04	169.98	0.00	0.00	0.00	0.00
Services to mining	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Meat and meat products	34.85	70.59	7.46	362.52	5.93	446.80	0.34	0.92	1.07	0.07
Dairy products	34.16	33.63	132.74	235.56	598.75	170.25	7.65	0.27	4.42	0.03
Fruit and vegetable products	128.50	3.73	27.11	35.38	19.77	38.17	1.51	0.78	7.84	0.04
Oils and fats	6.94	82.49	31.14	31.27	7.98	53.45	0.66	0.14	2.59	0.02
Flour mill products and cereal foods	133.22	19.05	1009.40	526.35	110.04	150.15	2.33	2.18	5.51	0.05
Bakery products	3.88	0.51	6.94	59.80	122.06	103.56	0.39	0.24	1.42	0.04
Confectionery	15.34	2.03	90.71	66.75	99.57	75.05	0.55	0.74	1.82	0.04
Other food products	90.65	71.26	166.24	178.23	183.51	570.49	53.45	13.58	26.97	0.15
Soft drinks, cordials and syrups	33.79	3.48	16.07	11.31	25.99	21.26	1.18	2.96	133.27	0.01
Beer and malt	1.82	0.19	2.86	1.78	3.93	15.37	9.99	234.75	6.81	0.01
Wine, spirits and tobacco products	3.23	1.31	4.26	1.79	79.11	6.21	1.61	1.32	244.34	0.07
Textile fibres, yarns and woven fabrics	0.28	0.52	0.63	1.20	0.36	3.79	0.21	0.15	0.45	4.32
Textile products	0.59	0.36	1.38	0.83	1.41	3.50	0.60	1.29	0.84	2.29
Knitting mill products	0.20	0.11	0.43	0.20	0.13	0.72	0.14	0.11	0.14	3.06
Clothing	1.14	0.80	2.01	1.83	1.09	5.33	0.83	0.68	0.85	0.13

Table B.1(c) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Fruit and vegetable products	Oils and fats	Flour mill products and cereal foods	Bakery products	Confectionery	Other food products	Soft drinks, cordials and syrups	Beer and malt	Wine, spirits and tobacco products	Textile fibres, yarns and woven fabrics
Footwear	0.25	0.14	0.46	0.21	0.29	0.77	0.21	0.16	0.19	0.03
Leather and leather products	0.23	0.16	0.26	0.70	0.24	1.67	0.18	0.18	0.18	0.15
Sawmill products	0.38	0.16	0.63	0.26	0.33	1.00	0.28	0.25	0.40	0.04
Other wood products	2.33	1.05	1.34	0.54	0.58	2.09	4.72	1.17	1.36	0.11
Pulp, paper and paperboard	6.84	2.90	7.94	2.35	7.38	11.63	5.87	6.60	7.99	0.04
Paper containers and products	56.92	20.46	60.93	18.29	36.17	123.75	49.01	41.07	67.57	0.04
Printing and services to printing	3.67	1.41	24.82	4.44	4.21	12.32	5.68	4.77	4.52	1.28
Publishing, recorded media, etc.	1.62	0.45	2.86	1.38	3.39	7.49	1.15	1.55	1.56	0.14
Petroleum and coal products	34.01	3.68	18.87	6.87	3.14	34.42	15.63	6.35	5.13	0.39
Basic chemicals	10.15	9.92	11.82	12.47	9.17	45.74	37.50	2.30	3.68	1.83
Paints	0.16	0.06	0.30	0.20	0.14	1.35	0.15	0.09	0.13	0.03
Medicinal and pharmaceutical products, pesticides	1.17	0.62	1.99	1.03	1.59	4.09	1.15	0.88	2.51	0.15
Soap and detergents	0.26	0.10	0.52	0.32	0.41	1.56	0.35	0.19	0.23	0.18
Cosmetics and toiletry preparations	0.21	0.19	0.16	0.21	0.15	0.51	0.31	0.03	0.03	0.01
Other chemical products	0.39	0.27	0.91	0.49	1.02	1.75	0.70	1.59	0.62	0.07
Rubber products	0.15	0.12	0.33	0.12	0.54	0.67	0.09	0.07	0.09	0.02
Plastic products	82.06	44.77	42.29	35.78	34.92	142.44	189.32	6.47	8.94	0.69
Glass and glass products	100.47	0.71	0.29	0.16	1.26	14.66	98.97	35.95	53.67	0.02
Ceramic products	0.08	0.25	0.19	0.11	0.11	0.45	0.07	0.05	0.09	0.01
Cement, lime and concrete slurry	0.41	0.31	0.70	0.33	0.57	2.36	0.28	0.23	0.27	0.05
Plaster and other concrete products	0.17	0.12	0.26	0.12	0.39	0.83	0.15	0.12	0.15	0.02
Other non-metallic mineral products	0.23	0.29	0.58	0.30	1.24	0.86	0.04	0.03	0.08	0.04
Iron and steel	2.35	0.48	1.84	1.12	0.90	7.58	3.15	3.29	0.51	0.10
Basic non-ferrous metal and products	3.74	1.40	3.34	1.91	4.67	24.99	4.23	2.40	1.17	0.55
Structural metal products	6.55	0.31	0.75	0.35	0.71	4.18	6.43	4.59	3.27	0.06
Sheet metal products	89.94	5.36	4.63	0.90	1.05	30.39	176.01	90.57	3.02	0.03
Fabricated metal products	2.46	0.67	1.86	1.14	3.22	5.69	4.11	4.58	1.63	0.11
Motor vehicles and parts, other transport equipment	1.98	1.01	3.14	1.66	3.04	5.26	4.58	1.91	1.87	0.14
Ships and boats	0.18	0.14	0.71	0.26	0.75	2.57	0.91	0.24	0.25	0.01
Railway equipment	0.09	0.03	0.13	0.06	0.28	0.28	0.08	0.05	0.08	0.01
Aircraft	0.03	0.01	0.08	0.05	0.04	0.13	0.07	0.06	0.06	0.00
Photographic and scientific equipment	0.73	0.39	1.25	0.67	0.54	3.24	0.68	0.61	0.56	0.07
Electronic equipment	0.82	0.45	1.38	0.91	1.70	7.70	20.92	1.94	1.40	0.08

Table B.1(c) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Fruit and vegetable products	Oils and fats	Flour mill products and cereal foods	Bakery products	Confectionery	Other food products	Soft drinks, cordials and syrups	Beer and malt	Wine, spirits and tobacco products	Textile fibres, yarns and woven fabrics
Household appliances	0.49	0.26	0.83	0.40	0.47	1.70	0.32	1.00	0.31	0.04
Other electrical equipment	1.11	0.58	2.81	1.67	2.07	5.12	3.02	2.70	2.23	0.11
Agricultural, mining, etc. machinery	1.13	0.44	1.28	0.63	0.61	2.96	1.04	2.24	0.57	0.08
Other machinery and equipment	5.08	1.15	3.64	4.66	3.44	15.66	14.74	2.45	1.17	0.12
Prefabricated buildings	0.11	0.04	0.17	0.07	0.08	0.32	0.07	0.09	0.10	0.01
Furniture	1.11	0.35	1.17	1.33	3.72	2.56	3.45	0.89	0.56	0.16
Other manufacturing	4.51	7.92	10.19	30.80	8.80	39.44	5.72	3.53	3.83	0.83
Electricity supply	25.55	13.35	67.09	22.19	22.46	74.60	14.75	27.84	7.75	4.56
Gas supply	17.52	6.39	16.22	13.33	3.92	44.98	21.97	8.72	1.54	0.05
Water supply, sewerage and drainage services	14.97	3.53	15.91	3.49	7.89	29.42	6.99	26.34	1.87	4.92
Residential building	1.25	0.98	2.70	1.10	2.29	5.53	1.78	0.70	2.27	0.04
Other construction	1.69	1.32	3.65	1.49	3.09	7.35	2.39	0.94	2.99	0.05
Construction trade services	14.06	13.28	28.53	13.61	33.90	32.89	14.25	11.72	13.02	0.84
Wholesale trade	256.71	87.05	352.17	188.32	181.41	663.59	168.97	148.98	180.63	25.90
Wholesale mechanical repairs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other wholesale repairs	0.52	0.84	5.56	36.21	2.09	24.87	11.47	3.89	2.64	1.20
Retail trade	28.66	7.13	74.95	223.70	161.67	269.10	11.64	9.31	53.03	1.73
Retail mechanical repairs	27.40	13.85	52.14	13.81	17.75	72.46	65.97	11.19	3.51	1.05
Other retail repairs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Accommodation, cafes and restaurants	6.22	4.72	15.34	26.09	22.38	66.55	158.16	111.28	80.09	0.34
Road transport	196.62	78.00	379.00	96.47	62.86	535.91	80.28	177.23	67.85	21.73
Rail, pipeline and other transport	8.36	2.12	29.22	5.66	2.17	24.52	7.07	21.73	3.97	2.78
Water transport	1.46	1.97	2.00	0.88	2.02	33.02	1.17	0.53	2.38	0.20
Air and space transport	9.85	5.40	17.88	3.84	5.24	17.40	2.68	2.09	2.97	0.21
Services to transport, storage	15.49	43.50	122.16	42.28	46.19	411.25	133.92	113.20	51.45	1.73
Communication services	12.81	5.59	77.64	13.57	11.80	52.85	26.60	10.13	13.77	1.56
Finance	37.33	29.99	103.52	36.09	19.16	259.28	26.98	129.33	31.77	8.61
Ownership of dwellings	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other property services	6.76	4.37	18.42	22.97	5.11	37.14	24.47	3.29	6.25	0.39
Scientific research, technical and computer services	40.07	2.83	50.28	32.61	11.23	149.39	41.25	1.24	28.04	1.24
Legal, accounting, marketing and business management services	34.60	22.22	175.27	26.56	90.05	220.34	64.42	54.79	54.79	2.01
Other business services	122.36	6.77	42.08	35.94	9.25	120.98	49.70	5.45	62.61	0.75

Table B.1(c) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Fruit and vegetable products	Oils and fats	Flour mill products and cereal foods	Bakery products	Confectionery	Other food products	Soft drinks, cordials and syrups	Beer and malt	Wine, spirits and tobacco products	Textile fibres, yarns and woven fabrics
Government administration	0.78	0.89	9.81	2.34	3.87	36.77	14.61	2.84	2.40	0.03
Defence	0.21	0.02	0.29	0.15	0.03	1.13	0.37	0.00	0.13	0.00
Education	3.94	4.36	8.35	8.00	6.74	12.70	9.58	6.39	3.40	0.10
Health services	0.10	0.06	0.31	0.21	0.42	0.84	0.87	0.14	4.33	0.00
Community services	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Motion picture, radio and television services	9.19	0.00	10.63	5.93	18.76	55.10	24.27	5.85	5.50	0.00
Libraries, museums and the arts	0.00	0.00	0.00	0.00	1.57	0.00	0.00	0.23	0.31	0.00
Sport, gambling and recreational services	0.14	0.01	0.04	0.08	0.06	2.33	0.50	0.36	7.06	0.00
Personal services	0.22	0.14	0.33	0.61	0.27	1.35	1.21	0.13	0.12	0.01
Other services	2.20	0.19	4.75	1.01	1.36	3.26	0.68	0.33	1.17	0.00
Total intermediate usage including imports	**2832**	**1291**	**5581**	**3002**	**2710**	**9080**	**2184**	**2011**	**2229**	**558**
Wages and salaries	440	71	578	1135	948	2329	632	442	1352	405
Gross surplus	776	345	442	364	236	821	1401	1407	2827	109
Indirect taxes on production	96	55	133	124	105	292	94	74	384	144
Total gross output	**4144**	**1762**	**6734**	**4625**	**4000**	**12522**	**4312**	**3933**	**6791**	**1216**
Value added at factor cost to output ratio	0.32	0.27	0.17	0.35	0.32	0.27	0.49	0.49	0.67	0.54
Share of wages and mixed income in value added	0.35	0.17	0.54	0.78	0.78	0.73	0.31	0.24	0.31	0.62
Employment to gross output ratio	5.77	4.40	7.08	21.45	6.80	6.26	4.05	3.14	3.71	5.99
Foreign ownership ratio	0.37	0.42	0.43	0.23	0.32	0.10	0.50	0.29	0.15	0.14
Direct tax rate on surplus	0.02	0.01	0.06	0.09	0.07	0.19	0.15	0.15	0.03	0.02
Indirect tax rate on production	0.05	0.09	0.06	0.06	0.06	0.05	0.03	0.03	0.08	0.27
Foreign income payout ratio	0.22	0.31	0.18	0.05	0.06	0.02	0.28	0.18	0.09	0.04
Replacement depreciation to value added ratio	0.13	0.10	0.17	0.22	0.21	0.14	0.13	0.05	0.11	0.09
Net national product ratio	0.65	0.59	0.66	0.74	0.73	0.84	0.59	0.77	0.80	0.87
Domestic income distribution ratio	0.38	0.42	0.23	0.15	0.13	0.21	0.28	0.43	0.52	0.24

Table B.1(d) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Textile products	Knitting mill products	Clothing	Footwear	Leather and leather products	Sawmill products	Other wood products	Pulp, paper and paperboard	Paper containers and products	Printing and services to printing
Sheep	0.01	0.00	0.08	0.00	41.29	0.00	0.00	0.00	0.00	0.00
Grains	0.02	0.01	0.01	0.02	0.01	0.00	0.00	0.00	0.00	0.00
Beef cattle	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Dairy cattle	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Pigs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Poultry	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other agriculture	1.93	0.07	0.22	0.14	6.11	0.00	0.00	0.00	0.00	0.61
Services to agriculture, hunting and trapping	0.28	8.99	3.91	0.04	42.09	0.00	0.00	0.00	0.00	0.00
Forestry and logging	0.00	0.00	0.00	0.00	0.00	747.20	164.62	74.11	13.12	3.76
Commercial fishing	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal	9.00	0.43	0.01	0.00	0.01	0.21	1.70	2.02	1.50	0.38
Gas	7.69	1.01	0.86	0.42	0.22	12.29	21.49	34.76	39.60	14.18
LNG	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Iron ores	0.00	0.00	0.00	0.00	0.00	0.03	0.04	0.01	0.02	0.08
Non-ferrous metal ores	0.01	0.01	0.01	0.00	0.01	1.12	0.36	0.02	0.07	0.26
Other mining	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.00	0.01	0.03
Services to mining	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Meat and meat products	12.93	0.11	18.95	0.02	325.32	0.27	0.47	0.09	0.21	0.70
Dairy products	0.07	0.07	0.11	0.03	0.05	0.24	0.37	0.06	0.17	0.41
Fruit and vegetable products	0.14	0.09	0.26	0.03	1.71	0.26	0.42	0.08	0.19	0.63
Oils and fats	0.08	0.04	0.06	0.01	0.02	0.13	0.16	0.06	0.07	0.30
Flour mill products and cereal foods	0.10	0.11	0.19	0.04	0.08	0.34	0.51	0.09	0.25	0.78
Bakery products	0.08	0.09	0.16	0.03	0.07	0.24	0.41	0.07	0.18	0.62
Confectionery	0.07	0.08	0.14	0.03	0.06	0.22	0.37	0.06	0.16	0.55
Other food products	0.94	0.25	0.75	0.13	4.19	1.16	2.55	0.37	0.81	2.03
Soft drinks, cordials and syrups	0.08	0.02	0.03	0.01	0.01	0.07	0.10	0.14	0.23	2.15
Beer and malt	0.07	0.06	0.03	0.01	0.01	0.32	0.24	0.04	0.12	0.49
Wine, spirits and tobacco products	0.51	0.43	0.05	0.01	0.02	1.31	1.79	0.31	0.44	4.40
Textile fibres, yarns and woven fabrics	22.20	14.29	20.17	0.65	0.34	0.23	0.71	0.06	1.06	2.29
Textile products	3.07	6.05	11.20	0.22	0.51	0.26	3.53	0.05	1.12	1.55
Knitting mill products	7.17	45.85	39.29	0.14	0.11	0.17	0.24	0.04	1.52	0.86
Clothing	1.38	3.37	37.10	3.23	3.23	0.81	1.49	0.20	0.69	6.20

Table B.1(d) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Textile products	Knitting mill products	Clothing	Footwear	Leather and leather products	Sawmill products	Other wood products	Pulp, paper and paperboard	Paper containers and products	Printing and services to printing
Footwear	0.10	0.12	3.21	11.62	2.69	0.23	0.41	0.04	0.12	0.99
Leather and leather products	2.02	0.58	5.40	8.52	77.73	0.30	0.31	0.06	0.20	0.56
Sawmill products	0.16	0.12	0.18	0.08	0.11	318.93	539.16	25.54	1.34	1.04
Other wood products	1.24	0.34	1.91	0.24	0.39	38.14	397.97	0.68	1.80	15.12
Pulp, paper and paperboard	0.51	0.35	0.61	0.21	0.06	4.88	4.98	5.40	28.76	148.32
Paper containers and products	0.73	2.52	3.16	0.91	0.28	4.85	6.75	1.81	71.55	69.79
Printing and services to printing	23.16	24.62	10.76	0.88	0.74	7.45	17.03	6.35	35.87	373.65
Publishing, recorded media, etc.	0.93	0.84	10.90	0.28	2.44	1.94	10.72	19.85	34.30	43.88
Petroleum and coal products	1.89	0.36	0.60	0.12	0.22	11.84	8.63	5.93	2.31	10.66
Basic chemicals	17.21	25.93	4.83	0.89	5.79	22.06	47.29	15.10	63.39	126.17
Paints	0.19	0.25	0.10	0.04	0.06	1.18	19.87	0.21	1.55	5.27
Medicinal and pharmaceutical products, pesticides	0.95	0.56	0.78	0.58	0.56	4.80	4.15	3.59	3.96	7.58
Soap and detergents	1.34	0.11	0.13	0.05	0.12	2.02	1.68	1.29	2.14	4.85
Cosmetics and toiletry preparations	0.03	0.01	0.02	0.01	0.01	0.13	0.09	0.04	0.09	0.08
Other chemical products	6.00	0.44	0.28	1.50	0.29	6.15	64.21	2.09	13.11	79.28
Rubber products	0.31	0.02	0.10	0.39	0.04	0.16	0.85	0.22	2.03	4.73
Plastic products	14.14	9.45	4.81	1.67	0.93	4.73	26.62	2.35	31.08	265.05
Glass and glass products	1.59	0.07	4.21	1.59	0.55	7.69	15.00	0.08	1.15	3.48
Ceramic products	0.08	0.02	0.18	0.08	0.02	0.17	0.62	0.55	0.86	0.48
Cement, lime and concrete slurry	0.15	0.17	0.18	0.08	0.08	1.74	1.88	0.42	0.98	1.00
Plaster and other concrete products	0.08	0.05	0.10	0.05	0.04	0.92	29.72	0.46	0.79	1.97
Other non-metallic mineral products	0.44	0.21	0.05	0.01	0.01	2.47	5.53	0.72	0.64	0.99
Iron and steel	1.66	0.43	0.29	0.15	0.15	3.93	41.36	2.48	2.66	6.72
Basic non-ferrous metal and products	5.84	2.62	1.34	0.77	0.77	13.21	71.81	2.40	13.28	72.79
Structural metal products	5.47	0.16	0.30	0.06	0.19	1.92	112.06	29.03	0.59	2.47
Sheet metal products	0.42	0.07	0.19	0.06	0.07	0.52	16.76	0.21	1.63	6.76
Fabricated metal products	3.10	7.68	0.51	0.26	0.25	10.98	53.45	6.47	4.73	16.28
Motor vehicles and parts, other transport equipment	0.96	0.39	0.56	0.21	0.23	1.94	9.09	0.54	2.16	8.09
Ships and boats	0.04	0.04	0.05	0.02	0.03	1.20	1.33	0.43	1.29	3.36
Railway equipment	0.02	0.03	0.03	0.01	0.02	0.10	0.17	0.02	0.11	0.25
Aircraft	0.01	0.01	0.02	0.00	0.01	0.03	0.05	0.23	0.18	0.09
Photographic and scientific equipment	0.20	0.14	0.85	0.14	0.18	10.90	12.85	0.34	1.14	12.35
Electronic equipment	0.18	0.20	0.33	0.17	0.20	10.04	11.69	0.34	0.93	8.86

Table B.1(d) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Textile products	Knitting mill products	Clothing	Footwear	Leather and leather products	Sawmill products	Other wood products	Pulp, paper and paperboard	Paper containers and products	Printing and services to printing
Household appliances	0.08	0.09	0.15	0.03	0.07	8.07	9.27	0.09	0.24	6.48
Other electrical equipment	0.43	0.24	0.39	0.09	0.16	10.95	14.51	4.89	4.24	12.69
Agricultural, mining, etc. machinery	0.16	0.17	0.67	0.06	0.14	10.35	13.11	0.16	0.46	8.63
Other machinery and equipment	0.30	0.25	1.18	0.34	0.29	11.64	16.73	4.10	1.10	10.57
Prefabricated buildings	0.14	0.05	0.12	0.04	0.02	0.25	2.36	0.02	0.13	0.30
Furniture	0.79	0.67	1.09	0.31	0.30	0.74	11.01	0.20	0.67	1.60
Other manufacturing	12.83	6.13	37.44	1.00	0.63	5.36	36.53	1.67	11.09	19.99
Electricity supply	10.21	12.10	3.22	1.44	2.02	85.97	130.66	57.67	80.66	109.78
Gas supply	6.23	0.64	0.68	0.12	0.18	6.15	11.92	25.50	31.94	11.61
Water supply, sewerage and drainage services	4.28	11.64	1.12	0.25	1.49	3.29	12.55	11.18	13.54	17.38
Residential building	0.85	0.62	0.18	0.09	0.21	4.79	5.08	0.37	2.70	8.08
Other construction	1.14	0.83	0.24	0.12	0.28	9.05	9.46	0.57	3.90	11.12
Construction trade services	3.57	4.14	2.42	1.29	1.51	63.01	54.18	4.43	14.29	28.23
Wholesale trade	50.85	53.40	98.73	20.51	40.23	226.90	323.00	45.86	117.14	375.61
Wholesale mechanical repairs	0.00	0.00	0.00	0.00	0.00	12.32	8.92	0.70	3.16	0.00
Other wholesale repairs	10.15	3.19	0.82	6.35	4.71	57.68	67.89	6.87	24.56	47.52
Retail trade	9.64	118.90	57.37	2.74	3.24	14.68	25.55	8.39	24.97	69.28
Retail mechanical repairs	15.54	11.50	0.00	8.90	5.31	25.33	14.96	4.27	37.01	147.03
Other retail repairs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Accommodation, cafes and restaurants	8.95	7.55	7.30	0.13	3.10	14.68	20.64	2.06	14.21	84.91
Road transport	20.91	17.58	19.76	13.54	52.95	237.59	128.80	36.86	58.35	126.20
Rail, pipeline and other transport	2.14	16.41	0.25	0.49	0.51	8.73	3.08	6.72	5.98	4.82
Water transport	3.11	1.14	2.58	1.09	0.33	8.66	3.05	9.27	10.32	5.49
Air and space transport	2.70	4.94	7.03	0.40	1.02	2.24	9.69	0.50	5.20	79.96
Services to transport, storage	5.36	3.40	21.75	3.52	3.32	279.77	261.89	26.22	217.09	126.76
Communication services	8.58	6.94	8.93	1.96	1.96	30.36	77.84	3.43	16.84	190.35
Finance	20.83	11.03	12.49	2.42	5.80	45.67	75.02	15.47	33.21	167.58
Ownership of dwellings	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other property services	2.69	1.93	8.64	1.67	4.18	244.87	190.88	2.13	19.76	153.39
Scientific research, technical and computer services	42.99	24.21	8.26	1.44	5.98	27.55	42.09	1.71	28.75	226.54
Legal, accounting, marketing and business management services	37.53	18.85	19.13	5.26	8.00	98.48	170.73	9.10	174.78	425.72
Other business services	6.66	14.71	31.08	7.57	8.61	103.11	154.47	8.98	93.05	409.15

Table B.1(d) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Textile products	Knitting mill products	Clothing	Footwear	Leather and leather products	Sawmill products	Other wood products	Pulp, paper and paperboard	Paper containers and products	Printing and services to printing
Government administration	0.58	0.60	0.07	0.01	0.06	7.82	7.34	1.47	13.86	34.27
Defence	0.08	0.19	0.03	0.01	0.02	0.11	0.13	0.00	0.12	0.42
Education	1.91	1.35	16.06	0.28	0.79	5.13	9.23	1.56	6.27	26.60
Health services	0.02	0.06	5.31	5.53	0.01	4.79	7.61	0.18	1.73	8.84
Community services	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Motion picture, radio and television services	0.72	0.18	1.02	0.19	0.00	1.50	31.55	0.00	0.62	1.51
Libraries, museums and the arts	0.00	0.00	2.00	0.00	0.00	0.00	0.00	0.00	0.76	2.22
Sport, gambling and recreational services	0.03	0.02	0.02	0.00	0.01	0.04	0.06	0.01	0.04	0.25
Personal services	0.39	0.07	0.00	0.00	0.00	0.40	0.32	0.07	0.55	2.26
Other services	0.00	0.00	0.68	0.04	0.20	1.33	1.37	1.75	6.48	9.71
Total intermediate usage including imports	**725**	**740**	**999**	**245**	**728**	**3232**	**4258**	**717**	**2046**	**5934**
Wages and salaries	672	81	732	111	151	448	1626	240	1481	3227
Gross surplus	145	51	418	77	191	768	608	473	610	1743
Indirect taxes on production	51	30	83	16	24	93	120	57	125	251
Total gross output	**1594**	**902**	**2232**	**449**	**1094**	**4542**	**6612**	**1488**	**4262**	**11154**
Value added at factor cost to output ratio	0.54	0.18	0.55	0.45	0.33	0.29	0.36	0.52	0.52	0.47
Share of wages and mixed income in value added	1.01	0.65	0.79	0.64	0.50	0.39	0.87	0.32	0.69	0.69
Employment to gross output ratio	13.65	8.43	17.35	10.39	5.84	7.68	14.87	3.47	7.45	9.88
Foreign ownership ratio	0.03	0.09	0.02	0.15	0.22	0.05	0.15	0.29	0.27	0.05
Direct tax rate on surplus	0.25	0.04	0.08	0.08	0.02	0.06	0.13	0.02	0.03	0.06
Indirect tax rate on production	0.05	0.15	0.06	0.07	0.04	0.04	0.03	0.07	0.05	0.03
Foreign income payout ratio	0.00	0.03	0.00	0.05	0.11	0.02	0.02	0.16	0.08	0.01
Replacement depreciation to value added ratio	0.15	0.09	0.06	0.09	0.06	0.09	0.18	0.54	0.13	0.13
Net national product ratio	0.85	0.89	0.93	0.87	0.83	0.88	0.80	0.29	0.79	0.86
Domestic income distribution ratio	0.00	0.26	0.18	0.27	0.36	0.49	0.10	0.39	0.20	0.27

Table B.1(e) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Publishing, recorded media, etc.	Petroleum and coal products	Basic chemicals	Paints	Medicinal and pharmaceutical products, pesticides	Soap and detergents	Cosmetics and toiletry preparations	Other chemical products	Rubber products	Plastic products
Sheep	0.00	0.00	4.31	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Grains	0.00	0.00	8.95	2.30	90.72	10.00	1.85	5.74	0.01	0.03
Beef cattle	0.00	0.00	23.38	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Dairy cattle	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Pigs	0.00	0.00	2.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Poultry	0.00	0.00	4.34	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other agriculture	1.98	0.00	0.52	0.68	0.05	0.25	0.04	0.20	3.14	55.40
Services to agriculture, hunting and trapping	0.00	0.00	7.66	3.90	0.00	8.89	5.40	2.86	0.00	0.00
Forestry and logging	0.66	0.00	17.31	0.12	10.12	0.00	1.57	9.86	0.00	0.00
Commercial fishing	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal	0.10	316.26	101.18	0.01	0.38	0.01	0.01	0.45	0.01	0.12
Gas	4.58	-4821.55	75.97	0.82	8.15	2.17	0.35	5.61	0.30	14.04
LNG	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Oil	0.00	5844.66	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Iron ores	0.02	0.35	0.03	0.00	0.01	0.00	0.00	0.00	0.00	0.02
Non-ferrous metal ores	0.10	10.72	118.82	1.20	0.05	0.02	0.00	0.09	0.01	0.11
Other mining	0.01	3.98	75.39	0.03	0.03	0.40	0.07	4.16	0.03	0.14
Services to mining	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Meat and meat products	0.20	0.47	104.51	6.50	17.95	103.67	6.38	16.42	0.05	0.77
Dairy products	0.12	0.36	9.41	0.19	5.17	2.10	0.79	1.27	0.03	0.65
Fruit and vegetable products	0.17	0.60	2.05	0.18	1.04	0.48	0.12	0.45	0.04	0.68
Oils and fats	0.07	5.05	12.35	3.36	13.17	6.68	1.07	0.92	0.06	0.35
Flour mill products and cereal foods	0.20	0.57	39.21	1.48	3.03	2.69	0.75	3.45	0.05	0.83
Bakery products	0.16	0.44	1.86	0.06	0.57	0.14	0.04	0.19	0.04	0.66
Confectionery	0.14	0.39	2.13	0.08	0.51	0.14	0.04	0.21	0.03	0.59
Other food products	0.73	2.53	39.63	8.03	23.49	15.11	5.40	15.19	0.14	2.37
Soft drinks, cordials and syrups	0.38	0.40	8.32	0.02	0.97	1.41	0.51	2.57	0.01	0.28
Beer and malt	1.69	0.47	0.47	0.04	0.16	0.07	0.02	0.07	0.02	0.27
Wine, spirits and tobacco products	9.72	2.35	10.79	0.48	2.87	0.53	0.17	0.60	0.18	1.14
Textile fibres, yarns and woven fabrics	1.94	0.67	3.77	0.07	1.81	0.11	0.33	0.58	1.03	5.44
Textile products	0.70	0.44	1.81	0.13	0.33	0.31	0.21	0.34	0.16	2.26
Knitting mill products	0.98	0.54	0.66	0.03	0.26	0.07	0.03	0.09	0.02	2.95
Clothing	3.31	1.43	4.49	0.17	1.66	0.49	0.28	0.69	0.73	5.89

Table B.1(e) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Publishing, recorded media, etc.	Petroleum and coal products	Basic chemicals	Paints	Medicinal and pharmaceutical products, pesticides	Soap and detergents	Cosmetics and toiletry preparations	Other chemical products	Rubber products	Plastic products
Footwear	0.40	0.34	0.74	0.05	0.37	0.12	0.03	0.18	0.10	0.76
Leather and leather products	0.13	0.26	0.73	0.07	0.30	0.13	0.04	0.16	0.21	0.74
Sawmill products	1.24	0.83	1.90	0.07	1.11	0.20	0.09	1.34	0.06	1.87
Other wood products	1.56	6.56	17.79	0.56	3.63	2.08	0.47	3.47	0.71	19.22
Pulp, paper and paperboard	176.63	1.64	2.90	0.15	10.87	2.32	0.45	1.27	0.40	8.86
Paper containers and products	8.72	1.20	22.54	2.66	110.93	19.01	3.94	9.79	0.37	28.04
Printing and services to printing	135.08	5.43	18.01	2.06	16.55	2.52	1.31	4.91	1.15	24.69
Publishing, recorded media, etc.	203.77	10.17	31.72	1.88	34.52	1.73	1.65	16.43	3.43	44.21
Petroleum and coal products	10.34	399.46	200.51	14.46	5.59	3.59	2.39	18.96	6.99	29.97
Basic chemicals	4.97	351.43	1388.08	58.61	58.97	94.98	33.06	172.44	23.88	1102.74
Paints	0.21	4.82	45.64	2.58	1.21	0.95	0.14	2.96	0.13	5.58
Medicinal and pharmaceutical products, pesticides	0.29	4.10	710.67	2.07	98.70	2.47	0.60	6.97	1.29	9.31
Soap and detergents	0.14	10.01	35.63	1.77	2.17	3.16	0.70	5.24	0.39	3.65
Cosmetics and toiletry preparations	0.03	0.91	2.64	0.03	0.44	0.04	0.04	0.19	0.02	0.22
Other chemical products	9.13	26.59	81.52	1.60	6.34	2.93	1.77	102.90	0.74	40.42
Rubber products	1.07	1.48	5.63	0.18	0.61	0.09	0.04	0.70	13.79	18.05
Plastic products	11.49	17.83	133.65	4.36	135.75	72.31	24.31	39.88	5.55	259.92
Glass and glass products	0.51	1.65	5.14	0.11	35.39	8.30	0.28	7.18	0.15	14.59
Ceramic products	0.52	0.63	1.12	0.08	1.95	0.22	0.08	1.25	0.02	1.30
Cement, lime and concrete slurry	0.48	5.42	7.03	0.54	1.98	1.76	0.24	2.30	0.28	2.64
Plaster and other concrete products	0.40	1.30	8.10	0.56	0.71	0.17	0.06	0.50	0.17	5.92
Other non-metallic mineral products	0.59	0.46	3.00	1.14	0.84	0.60	0.21	1.02	0.51	6.18
Iron and steel	1.46	3.13	17.51	0.71	3.82	0.90	0.34	2.84	0.72	9.35
Basic non-ferrous metal and products	4.66	55.07	131.31	6.08	12.95	16.92	1.88	12.09	2.99	185.01
Structural metal products	1.00	1.67	6.04	0.95	3.16	0.77	0.13	1.42	0.19	23.38
Sheet metal products	0.87	7.93	14.61	13.98	35.89	1.83	2.17	9.49	0.12	13.24
Fabricated metal products	16.74	3.46	52.10	2.78	24.60	4.51	1.31	14.62	7.68	29.18
Motor vehicles and parts, other transport equipment	1.30	3.18	5.11	0.37	2.85	0.87	0.33	1.35	0.78	9.03
Ships and boats	6.30	4.66	3.65	0.16	0.44	0.29	0.07	0.43	0.04	0.50
Railway equipment	0.09	0.87	0.30	0.01	0.19	0.03	0.02	0.05	0.04	0.87
Aircraft	0.08	0.34	0.10	0.00	0.05	0.01	0.00	0.01	0.00	0.26
Photographic and scientific equipment	13.22	29.51	6.80	0.11	3.31	0.32	0.11	0.51	0.10	2.45
Electronic equipment	10.98	26.58	5.73	0.12	0.98	0.30	0.09	1.26	0.23	1.97

Table B.1(e) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Publishing, recorded media, etc.	Petroleum and coal products	Basic chemicals	Paints	Medicinal and pharmaceutical products, pesticides	Soap and detergents	Cosmetics and toiletry preparations	Other chemical products	Rubber products	Plastic products
Household appliances	8.72	21.70	4.39	0.08	0.91	0.22	0.05	0.28	0.07	2.13
Other electrical equipment	12.74	28.32	9.02	0.21	2.75	0.55	0.18	0.98	4.86	9.36
Agricultural, mining, etc. machinery	11.02	27.82	9.39	0.15	1.97	0.48	0.12	0.72	0.09	1.70
Other machinery and equipment	11.16	28.36	14.38	0.75	4.46	1.37	0.37	2.85	0.37	6.50
Prefabricated buildings	0.08	0.19	0.36	0.01	0.18	0.04	0.01	0.08	0.01	0.54
Furniture	0.66	0.93	2.94	0.16	1.41	0.29	0.09	0.58	0.27	1.78
Other manufacturing	2.55	5.99	17.62	1.09	11.44	4.27	1.64	7.89	0.52	32.11
Electricity supply	21.64	84.85	164.76	2.61	40.78	6.38	3.07	20.08	7.53	154.35
Gas supply	3.68	24.68	41.45	0.59	6.46	1.60	0.23	4.01	0.10	8.72
Water supply, sewerage and drainage services	5.75	62.36	54.44	0.86	16.99	3.20	3.06	20.94	1.52	10.52
Residential building	5.46	39.76	5.17	0.44	5.70	0.76	0.25	0.91	0.90	5.33
Other construction	7.72	164.87	6.97	0.59	7.68	1.02	0.34	1.23	1.22	7.19
Construction trade services	14.56	735.40	32.56	5.16	21.22	10.55	3.16	11.44	8.01	35.76
Wholesale trade	107.35	606.03	845.70	35.16	385.31	80.88	23.92	111.75	23.11	395.23
Wholesale mechanical repairs	0.00	0.00	1.87	0.53	1.01	1.03	0.31	1.12	0.00	0.00
Other wholesale repairs	94.95	2.84	48.42	3.02	4.31	1.71	0.28	1.05	7.00	78.60
Retail trade	51.50	42.31	69.81	2.81	52.62	11.12	2.38	13.11	2.44	45.36
Retail mechanical repairs	76.80	33.13	72.66	4.04	24.56	7.79	1.82	15.81	0.46	23.16
Other retail repairs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Accommodation, cafes and restaurants	89.46	131.70	63.86	3.18	76.70	7.31	5.36	20.12	0.65	19.13
Road transport	43.72	126.10	363.08	12.71	160.72	41.78	11.39	51.06	8.02	178.81
Rail, pipeline and other transport	4.66	17.14	25.23	0.42	6.58	1.48	0.37	2.49	0.21	66.14
Water transport	5.22	191.07	16.16	0.16	2.17	0.66	0.29	6.16	1.11	9.22
Air and space transport	55.06	17.51	18.53	1.61	17.28	3.68	1.19	3.17	0.65	10.11
Services to transport, storage	356.83	135.90	383.77	7.33	232.04	10.43	2.87	103.22	4.72	67.35
Communication services	170.76	135.89	50.37	8.69	41.24	7.65	2.16	18.39	3.56	65.56
Finance	295.24	77.38	116.25	5.88	101.67	15.98	4.36	16.14	10.52	79.55
Ownership of dwellings	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other property services	553.54	204.32	22.22	5.35	32.66	4.29	2.72	11.95	1.85	42.95
Scientific research, technical and computer services	157.07	23.54	126.68	6.73	340.76	24.98	5.38	14.23	18.84	126.30
Legal, accounting, marketing and business management services	442.18	780.98	317.70	15.51	335.97	10.69	4.32	28.98	21.79	294.02
Other business services	392.91	583.24	134.30	2.75	510.35	38.26	12.74	32.26	109.60	256.18

Table B.1(e) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Publishing, recorded media, etc.	Petroleum and coal products	Basic chemicals	Paints	Medicinal and pharmaceutical products, pesticides	Soap and detergents	Cosmetics and toiletry preparations	Other chemical products	Rubber products	Plastic products
Government administration	114.98	25.43	98.31	5.44	2.85	7.27	1.75	5.60	0.51	9.02
Defence	0.35	0.10	0.77	0.04	1.18	0.09	0.03	0.06	0.10	0.51
Education	8.05	51.17	19.34	2.44	14.48	0.77	1.25	4.75	1.19	14.17
Health services	38.08	1.18	4.83	1.66	76.87	0.16	0.03	0.17	0.10	0.77
Community services	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Motion picture, radio and television services	113.70	14.89	6.54	4.43	32.56	4.13	9.07	0.00	0.05	11.86
Libraries, museums and the arts	51.32	0.00	0.24	1.11	0.00	14.16	1.14	1.82	0.00	0.00
Sport, gambling and recreational services	9.12	0.17	1.77	0.01	0.22	0.83	0.18	0.06	1.76	1.96
Personal services	8.33	0.00	0.75	0.15	0.53	0.11	0.08	0.09	0.22	0.87
Other services	9.41	1.47	4.75	0.15	8.76	0.97	0.37	0.88	0.44	4.86
Total intermediate usage including imports	**5559**	**22850**	**8908**	**462**	**4088**	**1019**	**278**	**1488**	**432**	**5880**
Wages and salaries	3639	618	1642	532	1671	261	164	727	374	1963
Gross surplus	2523	2022	1242	82	711	259	115	145	195	776
Indirect taxes on production	369	364	235	34	173	36	21	53	44	192
Total gross output	**12090**	**25854**	**12027**	**1111**	**6644**	**1575**	**578**	**2413**	**1046**	**8810**
Value added at factor cost to output ratio	0.54	0.12	0.26	0.58	0.38	0.35	0.52	0.38	0.59	0.33
Share of wages and mixed income in value added	0.59	0.24	0.56	0.85	0.68	0.49	0.57	0.82	0.63	0.70
Employment to gross output ratio	7.72	2.27	2.67	10.14	8.08	5.80	6.76	9.72	8.69	9.14
Foreign ownership ratio	0.03	0.80	0.50	0.48	0.65	0.60	0.45	0.28	0.90	0.20
Direct tax rate on surplus	0.04	0.02	0.12	0.06	0.41	0.21	0.21	0.34	0.06	0.13
Indirect tax rate on production	0.05	0.02	0.04	0.05	0.05	0.04	0.06	0.04	0.07	0.04
Foreign income payout ratio	0.01	0.58	0.19	0.07	0.16	0.24	0.16	0.04	0.30	0.05
Replacement depreciation to value added ratio	0.01	0.23	0.24	0.14	0.15	0.13	0.15	0.37	0.09	0.20
Net national product ratio	0.98	0.19	0.58	0.79	0.69	0.63	0.70	0.59	0.61	0.75
Domestic income distribution ratio	0.37	0.15	0.19	0.08	0.09	0.16	0.19	0.11	0.03	0.21

Table B.1(f) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Glass and glass products	Ceramic products	Cement, lime and concrete slurry	Plaster and other concrete products	Other non-metallic mineral products	Iron and steel	Basic non-ferrous metal and products	Structural metal products	Sheet metal products	Fabricated metal products
Sheep	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Grains	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Beef cattle	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Dairy cattle	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Pigs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Poultry	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other agriculture	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.22	0.21	0.14
Services to agriculture, hunting and trapping	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Forestry and logging	0.00	0.00	0.00	0.00	0.00	0.65	8.80	0.00	0.00	0.00
Commercial fishing	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal	0.00	0.00	9.65	0.19	0.00	263.70	8.85	0.54	0.17	3.23
Gas	102.59	97.20	550.65	7.25	22.22	162.42	212.82	8.77	5.21	12.14
LNG	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Iron ores	0.01	0.00	0.04	0.01	0.00	837.81	1.93	30.04	0.03	16.00
Non-ferrous metal ores	0.05	0.00	0.12	72.63	14.97	24.75	25675.69	0.27	0.10	10.53
Other mining	40.68	0.00	683.28	184.78	19.97	582.95	220.53	2.72	0.07	2.67
Services to mining	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Meat and meat products	0.19	0.00	0.46	0.26	0.03	1.58	1.40	1.11	0.42	0.60
Dairy products	0.11	0.00	0.28	0.15	0.02	0.91	1.17	0.63	0.17	0.51
Fruit and vegetable products	0.19	0.00	0.41	0.23	0.03	1.14	1.25	0.93	0.24	0.47
Oils and fats	0.08	0.00	0.17	0.21	0.01	0.58	0.49	0.34	0.11	0.22
Flour mill products and cereal foods	0.20	0.00	0.50	0.30	0.04	1.42	1.50	1.13	0.29	0.59
Bakery products	0.16	0.00	0.40	0.22	0.02	1.23	1.25	0.92	0.23	0.47
Confectionery	0.14	0.00	0.36	0.20	0.02	1.04	1.09	0.81	0.21	0.41
Other food products	0.49	0.00	1.19	1.26	0.10	3.75	3.29	4.52	1.52	2.41
Soft drinks, cordials and syrups	0.06	0.00	0.10	0.06	0.01	0.36	0.28	0.20	0.06	0.11
Beer and malt	0.08	0.00	0.26	0.09	0.01	0.45	0.34	0.31	0.14	0.18
Wine, spirits and tobacco products	1.10	0.00	2.21	0.95	0.13	1.29	0.92	1.17	0.70	0.87
Textile fibres, yarns and woven fabrics	0.20	0.00	0.28	0.51	0.04	2.55	1.05	1.08	0.65	0.83
Textile products	0.46	0.00	0.72	1.17	0.04	2.40	1.74	7.43	0.34	4.98
Knitting mill products	0.10	0.00	0.19	1.54	0.02	0.97	0.64	0.61	1.29	0.39
Clothing	0.59	0.00	1.14	1.10	0.11	4.06	3.51	5.74	1.86	3.39

Table B.1(f) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Glass and glass products	Ceramic products	Cement, lime and concrete slurry	Plaster and other concrete products	Other non-metallic mineral products	Iron and steel	Basic non-ferrous metal and products	Structural metal products	Sheet metal products	Fabricated metal products
Footwear	0.19	0.00	0.30	0.26	0.03	0.76	0.73	0.71	0.27	0.86
Leather and leather products	1.63	0.00	0.46	0.36	0.06	0.44	0.64	1.04	0.19	4.43
Sawmill products	1.05	0.00	0.47	1.75	0.07	7.58	1.81	91.38	2.25	8.48
Other wood products	9.78	0.00	1.34	4.78	0.34	37.23	8.99	48.45	4.54	22.32
Pulp, paper and paperboard	0.85	0.00	5.03	2.30	0.10	1.96	0.79	1.86	0.44	1.56
Paper containers and products	3.83	0.00	52.97	9.97	0.84	4.12	2.47	5.31	1.24	11.82
Printing and services to printing	4.80	0.00	13.08	10.07	1.09	21.59	9.47	34.81	7.19	16.39
Publishing, recorded media, etc.	1.18	0.00	13.15	4.33	0.33	17.26	10.98	56.89	6.85	9.02
Petroleum and coal products	13.83	5.79	196.84	16.09	8.60	116.62	51.87	33.91	15.22	26.73
Basic chemicals	82.80	0.00	5.64	29.24	11.55	51.37	77.78	58.12	13.67	48.82
Paints	3.53	0.00	0.25	0.88	0.22	36.81	1.34	2.98	3.20	5.93
Medicinal and pharmaceutical products, pesticides	2.33	0.00	0.79	1.57	0.36	6.20	5.39	1.96	1.14	3.52
Soap and detergents	4.13	0.00	0.36	2.26	0.50	3.42	2.06	0.54	0.49	2.15
Cosmetics and toiletry preparations	0.38	0.00	0.05	0.08	0.01	0.32	0.21	0.25	0.04	0.09
Other chemical products	3.57	0.00	2.00	5.55	2.40	11.27	3.04	6.60	1.43	8.14
Rubber products	0.20	0.00	0.09	0.48	0.11	1.75	7.01	1.85	1.51	6.76
Plastic products	12.24	0.00	4.58	10.39	3.54	19.14	18.96	47.13	11.77	16.74
Glass and glass products	309.44	0.00	0.90	1.63	0.81	1.67	2.91	170.33	1.84	8.03
Ceramic products	0.90	0.00	74.46	33.96	1.45	6.29	2.23	7.34	0.17	5.99
Cement, lime and concrete slurry	8.55	0.00	1038.10	481.95	18.61	64.79	42.79	8.56	1.61	5.11
Plaster and other concrete products	9.49	0.00	92.16	112.04	9.88	10.25	6.57	19.57	1.24	1.99
Other non-metallic mineral products	22.40	0.00	20.86	13.75	3.54	5.17	6.06	12.31	2.06	9.35
Iron and steel	20.12	0.00	29.12	71.25	3.04	2416.38	237.64	1992.57	334.37	750.88
Basic non-ferrous metal and products	129.53	0.00	8.90	31.74	2.84	2125.18	15296.53	1395.96	1131.20	955.96
Structural metal products	22.62	0.00	8.62	115.15	14.35	65.54	74.88	1299.37	39.11	258.57
Sheet metal products	0.69	0.00	0.31	3.40	1.31	42.47	12.46	60.17	43.16	22.04
Fabricated metal products	5.86	0.00	3.47	12.61	1.71	117.47	47.28	406.52	64.17	153.78
Motor vehicles and parts, other transport equipment	20.52	0.00	4.03	4.74	1.07	21.71	11.71	18.57	8.25	13.76
Ships and boats	0.66	0.00	3.62	0.74	0.08	2.60	1.14	3.99	0.54	1.87
Railway equipment	0.06	0.00	0.12	0.38	0.02	3.32	0.71	0.41	0.22	0.45
Aircraft	0.04	0.00	0.06	0.05	0.00	0.34	0.19	0.11	0.03	0.05
Photographic and scientific equipment	0.34	0.00	0.85	1.08	0.06	6.67	5.93	2.76	0.88	1.69
Electronic equipment	0.90	0.00	1.16	0.82	0.12	5.26	3.13	18.81	1.76	3.31

Table B.1(f) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Glass and glass products	Ceramic products	Cement, lime and concrete slurry	Plaster and other concrete products	Other non-metallic mineral products	Iron and steel	Basic non-ferrous metal and products	Structural metal products	Sheet metal products	Fabricated metal products
Household appliances	2.42	0.00	0.57	0.50	0.06	2.61	1.92	2.39	0.96	1.40
Other electrical equipment	1.67	0.00	2.73	2.75	0.25	18.56	9.25	21.83	8.12	13.51
Agricultural, mining, etc. machinery	0.65	0.00	5.25	6.38	0.21	15.15	14.28	14.24	1.54	19.84
Other machinery and equipment	3.70	0.00	2.94	10.83	0.50	27.15	42.17	22.37	9.54	13.60
Prefabricated buildings	0.11	0.00	0.22	0.93	0.21	1.31	1.30	38.54	0.63	1.34
Furniture	0.86	0.00	0.93	1.44	0.51	11.75	7.69	13.57	2.58	8.53
Other manufacturing	3.79	0.00	2.53	5.40	1.48	71.17	160.88	27.82	6.45	8.91
Electricity supply	80.90	44.40	204.79	33.97	42.42	995.46	529.79	67.54	26.89	80.18
Gas supply	77.97	74.03	431.96	3.31	14.81	104.62	133.25	6.52	4.08	9.14
Water supply, sewerage and drainage services	7.92	0.00	16.50	9.61	0.80	94.92	20.66	6.46	1.71	5.88
Residential building	1.58	0.00	3.88	1.99	0.14	32.21	11.77	8.28	3.11	3.51
Other construction	2.18	0.00	6.11	2.77	0.19	43.55	15.94	11.18	4.20	4.73
Construction trade services	12.25	0.00	17.65	10.16	1.67	133.17	92.10	32.09	14.03	19.06
Wholesale trade	97.80	0.00	238.06	133.43	15.24	735.32	1176.60	551.40	164.68	290.43
Wholesale mechanical repairs	0.17	0.00	12.99	5.60	0.23	6.29	0.80	0.00	0.00	0.00
Other wholesale repairs	13.48	0.00	92.41	11.09	0.38	53.79	4.93	53.51	17.17	21.53
Retail trade	8.84	0.00	35.61	16.07	1.21	87.69	56.82	54.39	19.77	29.19
Retail mechanical repairs	3.44	0.00	24.00	7.02	0.29	15.88	5.30	15.52	6.74	5.24
Other retail repairs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Accommodation, cafes and restaurants	18.38	0.00	36.90	16.33	3.02	48.15	23.82	93.37	25.15	39.18
Road transport	73.46	0.00	564.22	181.37	22.43	620.55	415.74	186.63	48.57	94.16
Rail, pipeline and other transport	27.11	0.00	180.51	4.10	2.20	244.25	307.80	13.20	3.90	9.73
Water transport	2.44	0.00	25.05	5.94	1.51	44.38	220.56	31.51	4.77	8.24
Air and space transport	2.34	0.00	11.48	3.18	0.69	22.74	10.36	20.31	6.55	9.58
Services to transport, storage	30.96	0.00	131.37	56.99	3.37	282.86	148.82	217.46	139.14	130.69
Communication services	17.40	0.00	72.26	63.93	10.18	78.62	23.53	138.63	23.62	69.10
Finance	49.33	0.00	112.88	32.56	7.39	128.52	215.90	129.79	31.38	66.35
Ownership of dwellings	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other property services	15.82	0.00	34.83	11.67	0.73	1530.66	476.80	191.93	60.43	101.44
Scientific research, technical and computer services	45.33	0.00	238.43	32.76	2.47	277.10	114.57	218.39	70.27	63.88
Legal, accounting, marketing and business management services	37.71	0.00	107.18	205.19	11.96	163.92	57.77	235.96	77.37	151.19
Other business services	37.22	0.00	210.38	126.04	2.25	247.53	81.02	312.32	76.43	182.20

Table B.1(f) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Glass and glass products	Ceramic products	Cement, lime and concrete slurry	Plaster and other concrete products	Other non-metallic mineral products	Iron and steel	Basic non-ferrous metal and products	Structural metal products	Sheet metal products	Fabricated metal products
Government administration	2.32	0.00	11.23	3.49	0.18	35.22	3.79	12.85	8.37	6.70
Defence	0.16	0.00	0.53	0.16	0.01	0.50	0.26	1.02	0.47	0.31
Education	5.68	0.00	26.22	9.97	0.46	34.30	16.51	24.02	4.27	7.23
Health services	0.19	0.00	0.78	0.31	0.02	0.70	0.38	0.99	0.22	0.30
Community services	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Motion picture, radio and television services	1.31	0.00	1.22	11.85	0.58	0.94	0.01	9.12	0.29	4.99
Libraries, museums and the arts	0.32	0.00	0.43	0.47	0.00	0.00	0.00	0.00	0.00	0.00
Sport, gambling and recreational services	0.06	0.00	0.11	0.05	0.01	0.14	0.08	0.28	0.07	0.11
Personal services	0.13	0.00	0.33	0.18	0.01	0.94	0.05	0.49	0.32	0.36
Other services	0.52	0.00	2.81	3.09	0.03	2.16	1.07	8.32	2.56	3.51
Total intermediate usage including imports	**2034**	**230**	**6099**	**2622**	**356**	**15381**	**58564**	**10198**	**3063**	**5178**
Wages and salaries	609	507	1330	1254	536	3079	2786	2201	1078	2703
Gross surplus	246	238	483	157	266	2064	3315	1341	464	702
Indirect taxes on production	66	-121	194	83	32	338	945	268	114	195
Total gross output	**2954**	**853**	**8106**	**4115**	**1191**	**20862**	**65611**	**14008**	**4719**	**8777**
Value added at factor cost to output ratio	0.31	0.73	0.25	0.36	0.70	0.26	0.11	0.27	0.35	0.41
Share of wages and mixed income in value added	0.72	0.75	0.71	0.88	0.88	0.61	0.47	0.64	0.74	0.84
Employment to gross output ratio	9.47	8.14	3.93	4.97	12.42	9.00	5.46	6.20	4.50	10.59
Foreign ownership ratio	0.37	0.08	0.42	0.22	0.22	0.25	0.52	0.22	0.32	0.20
Direct tax rate on surplus	0.07	0.14	0.22	0.22	0.05	0.15	0.04	0.18	0.15	0.16
Indirect tax rate on production	0.05	0.07	0.06	0.03	0.03	0.03	0.03	0.04	0.05	0.04
Foreign income payout ratio	0.09	0.02	0.09	0.02	0.03	0.08	0.25	0.07	0.08	0.03
Replacement depreciation to value added ratio	0.27	0.19	0.23	0.14	0.11	0.14	0.32	0.07	0.10	0.08
Net national product ratio	0.63	0.79	0.67	0.84	0.87	0.77	0.43	0.86	0.83	0.89
Domestic income distribution ratio	0.16	0.20	0.13	0.08	0.09	0.25	0.23	0.24	0.16	0.12

Table B.1(g) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Motor vehicles and parts, other transport equipment	Ships and boats	Railway equipment	Aircraft	Photographic and scientific equipment	Electronic equipment	Household appliances	Other electrical equipment	Agricultural, mining, etc. machinery	Other machinery and equipment
Sheep	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Grains	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Beef cattle	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Dairy cattle	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Pigs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Poultry	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other agriculture	0.00	0.00	0.00	0.00	0.25	0.04	0.04	0.17	0.00	0.21
Services to agriculture, hunting and trapping	0.00	0.00	0.00	0.00	0.03	1.11	0.00	6.68	0.00	0.00
Forestry and logging	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Commercial fishing	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal	1.88	0.06	0.01	0.04	0.21	0.35	0.08	0.09	0.07	1.17
Gas	24.14	4.36	1.41	25.75	6.21	3.26	4.51	4.91	9.62	4.83
LNG	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Iron ores	0.54	0.02	0.00	0.01	0.05	0.10	0.01	0.02	0.02	0.03
Non-ferrous metal ores	1.51	0.05	0.24	0.02	0.62	0.29	3.10	38.76	6.98	0.99
Other mining	0.15	0.06	0.03	0.20	0.35	0.05	0.17	1.61	0.10	0.18
Services to mining	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Meat and meat products	4.02	0.58	0.14	1.47	0.74	0.65	1.54	0.74	1.05	0.92
Dairy products	5.17	2.00	0.08	1.68	1.26	0.78	1.01	0.66	0.78	1.05
Fruit and vegetable products	3.65	0.88	0.28	1.68	0.55	0.59	0.76	0.58	0.69	1.58
Oils and fats	1.46	0.40	0.06	0.32	0.21	0.21	0.25	0.21	0.25	0.28
Flour mill products and cereal foods	4.18	0.66	0.16	0.89	0.68	0.72	0.84	0.71	0.84	0.92
Bakery products	3.84	0.75	0.13	0.73	0.59	0.68	0.80	0.67	0.81	1.11
Confectionery	3.65	1.05	0.12	0.82	0.48	0.52	0.60	0.51	0.60	0.66
Other food products	9.71	1.90	0.47	2.26	17.70	1.90	2.60	2.06	3.25	3.42
Soft drinks, cordials and syrups	0.71	0.10	0.03	0.17	0.13	0.11	0.12	0.11	0.12	0.14
Beer and malt	0.95	0.16	0.03	4.17	0.11	0.12	0.16	0.15	0.18	0.23
Wine, spirits and tobacco products	1.51	0.61	0.17	2.83	0.96	0.38	0.63	0.49	0.66	0.88
Textile fibres, yarns and woven fabrics	7.82	1.63	0.42	0.74	1.12	0.53	1.32	0.70	1.53	1.48
Textile products	1.76	2.37	0.41	0.73	1.45	1.47	1.44	3.16	1.57	3.13
Knitting mill products	1.78	0.47	0.07	0.35	0.34	0.27	0.34	0.27	0.32	0.35

Table B.1(g) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Motor vehicles and parts, other transport equipment	Ships and boats	Railway equipment	Aircraft	Photographic and scientific equipment	Electronic equipment	Household appliances	Other electrical equipment	Agricultural, mining, etc. machinery	Other machinery and equipment
Clothing	12.80	1.91	0.66	2.25	2.41	1.85	2.93	2.30	3.87	2.25
Footwear	1.80	0.42	0.16	0.86	0.53	0.32	0.43	0.32	0.40	0.46
Leather and leather products	3.18	0.32	0.29	0.48	1.73	0.37	0.52	0.49	0.70	0.39
Sawmill products	5.86	4.58	0.21	0.70	1.32	1.03	1.38	1.65	1.83	1.54
Other wood products	24.60	97.68	2.72	5.61	4.78	2.07	6.75	3.90	8.07	10.59
Pulp, paper and paperboard	2.41	0.81	0.28	1.08	2.13	0.74	2.16	0.76	0.55	1.67
Paper containers and products	12.95	1.51	0.50	3.04	12.77	4.21	20.71	3.78	3.86	4.82
Printing and services to printing	50.86	7.41	1.20	3.84	12.58	6.04	17.92	16.38	24.78	29.08
Publishing, recorded media, etc.	32.09	4.19	0.63	4.08	6.44	15.20	11.66	10.68	10.68	9.64
Petroleum and coal products	27.81	22.80	4.39	5.92	6.61	3.07	6.01	6.28	15.33	28.85
Basic chemicals	124.74	15.74	4.41	6.05	71.67	10.16	51.58	128.17	6.90	11.55
Paints	57.09	14.75	0.55	3.69	1.29	0.55	8.07	1.94	4.29	5.98
Medicinal and pharmaceutical products, pesticides	6.18	0.82	0.22	1.19	2.44	0.92	1.12	0.96	1.03	1.12
Soap and detergents	2.11	0.26	0.16	0.35	0.88	0.23	0.32	0.45	0.30	0.37
Cosmetics and toiletry preparations	0.40	0.08	0.02	0.11	0.06	0.05	0.10	0.06	0.07	0.08
Other chemical products	9.65	1.75	2.04	2.34	13.39	0.79	3.33	1.63	2.80	3.37
Rubber products	31.70	2.38	1.58	0.30	3.66	1.29	6.95	2.53	3.01	10.66
Plastic products	105.54	5.66	5.41	4.57	83.76	30.27	48.17	32.41	20.32	33.64
Glass and glass products	157.23	16.62	6.72	4.84	3.07	1.31	26.92	9.47	7.08	6.73
Ceramic products	2.46	0.18	0.86	0.99	0.83	0.50	1.79	1.94	2.78	1.62
Cement, lime and concrete slurry	11.86	2.05	1.18	2.50	4.50	1.26	10.13	1.39	6.24	12.87
Plaster and other concrete products	6.48	1.98	1.88	2.08	2.57	0.90	1.44	1.66	2.64	3.81
Other non-metallic mineral products	9.03	6.27	3.14	3.23	6.12	1.53	2.44	1.62	3.96	3.32
Iron and steel	948.29	292.57	84.49	14.28	158.91	35.60	586.40	158.45	731.01	881.53
Basic non-ferrous metal and products	537.71	254.17	27.41	73.46	616.39	124.15	142.68	1588.34	93.03	219.09
Structural metal products	79.40	68.70	139.13	5.66	26.86	12.54	27.47	104.41	117.13	243.02
Sheet metal products	88.41	15.79	6.97	38.12	13.27	4.83	97.24	18.68	58.35	105.25
Fabricated metal products	161.52	49.43	20.71	67.42	26.92	14.68	56.20	49.59	76.60	96.91
Motor vehicles and parts, other transport equipment	1240.96	15.20	6.98	41.18	17.34	6.47	27.51	9.68	45.91	18.04
Ships and boats	6.46	10.35	0.49	3.11	0.71	0.42	0.55	0.82	2.39	1.22
Railway equipment	13.22	0.44	322.99	0.40	0.73	0.94	3.39	2.21	1.44	3.39
Aircraft	1.59	1.70	0.03	489.32	0.05	0.05	0.06	0.07	0.39	0.06

Table B.1(g) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Motor vehicles and parts, other transport equipment	Ships and boats	Railway equipment	Aircraft	Photographic and scientific equipment	Electronic equipment	Household appliances	Other electrical equipment	Agricultural, mining, etc. machinery	Other machinery and equipment
Photographic and scientific equipment	9.98	123.04	1.22	15.01	9.09	7.43	14.52	8.85	11.72	10.24
Electronic equipment	16.57	10.64	3.46	24.05	30.63	50.23	26.67	21.99	17.50	24.86
Household appliances	28.78	9.50	1.18	2.80	3.20	2.57	95.48	5.43	8.45	6.61
Other electrical equipment	33.79	14.76	10.17	16.47	69.07	59.28	230.96	255.74	74.23	114.12
Agricultural, mining, etc. machinery	58.58	87.82	8.11	9.96	4.20	6.41	7.18	9.84	47.25	31.18
Other machinery and equipment	84.61	74.84	14.15	15.36	10.12	14.33	40.88	27.46	71.17	83.36
Prefabricated buildings	1.86	1.38	1.63	0.26	0.31	0.28	0.63	1.51	1.43	2.58
Furniture	10.42	30.87	1.22	2.29	1.61	1.94	2.58	2.89	5.19	5.37
Other manufacturing	28.78	12.29	7.04	5.85	9.58	5.36	19.14	12.26	12.24	22.09
Electricity supply	238.06	32.64	13.41	1.60	27.95	116.63	52.53	54.39	67.84	98.40
Gas supply	16.27	2.36	1.15	18.71	3.55	2.88	3.75	3.93	4.66	3.93
Water supply, sewerage and drainage services	40.68	3.17	0.92	0.00	4.26	7.85	9.31	5.34	12.15	18.66
Residential building	19.38	2.50	1.02	0.07	4.84	1.78	2.94	1.63	2.20	2.46
Other construction	26.22	3.39	1.38	0.10	6.54	2.41	3.97	2.21	2.98	3.33
Construction trade services	62.24	37.43	17.35	7.77	47.69	16.13	26.56	17.54	23.10	29.43
Wholesale trade	1976.45	321.92	77.63	422.63	335.53	352.18	407.21	392.76	411.13	448.39
Wholesale mechanical repairs	129.75	0.00	0.00	0.00	0.09	0.07	0.07	0.22	0.59	0.97
Other wholesale repairs	61.14	7.46	0.83	0.00	5.16	4.54	1.78	5.01	44.00	42.61
Retail trade	208.36	22.50	4.85	31.59	41.52	27.29	27.63	27.87	31.23	31.47
Retail mechanical repairs	13.58	3.96	0.07	0.00	1.39	1.15	1.09	3.43	9.31	15.47
Other retail repairs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Accommodation, cafes and restaurants	81.73	9.50	2.63	0.00	28.36	21.44	17.06	8.30	18.18	17.31
Road transport	186.29	43.54	12.71	30.17	63.53	30.76	90.79	56.60	74.37	87.08
Rail, pipeline and other transport	18.77	1.63	0.55	4.89	4.01	1.69	4.87	2.85	13.80	28.89
Water transport	6.26	0.44	0.38	0.26	3.56	0.70	3.57	3.40	9.43	7.03
Air and space transport	33.98	6.90	0.32	0.99	13.89	10.51	18.55	14.24	30.57	25.43
Services to transport, storage	276.44	61.10	11.35	2.81	18.45	10.63	16.45	25.22	28.25	50.17
Communication services	137.83	31.82	8.41	0.00	60.22	33.99	67.30	60.93	102.34	165.98
Finance	229.53	29.86	13.91	18.11	38.92	40.23	38.08	42.80	55.57	49.08
Ownership of dwellings	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other property services	1179.65	36.93	2.08	13.01	38.31	28.13	20.76	28.56	47.95	70.37
Scientific research, technical and computer services	738.74	19.33	13.09	0.00	155.22	226.63	310.89	165.78	165.05	108.54

Table B.1(g) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Motor vehicles and parts, other transport equipment	Ships and boats	Railway equipment	Aircraft	Photographic and scientific equipment	Electronic equipment	Household appliances	Other electrical equipment	Agricultural, mining, etc. machinery	Other machinery and equipment
Legal, accounting, marketing and business management services	254.06	51.78	7.33	0.00	189.08	33.45	72.99	55.18	93.65	176.05
Other business services	740.23	43.30	1.30	0.00	121.42	87.01	204.31	93.89	197.87	139.98
Government administration	57.69	6.57	0.73	0.00	4.11	1.84	4.91	3.02	6.07	4.29
Defence	0.80	0.03	0.02	0.00	0.30	0.20	0.20	0.10	0.17	0.13
Education	43.85	5.05	1.60	0.00	13.28	12.56	15.67	9.25	17.18	16.36
Health services	29.00	0.65	0.01	0.00	0.36	0.55	0.41	0.40	0.52	0.65
Community services	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Motion picture, radio and television services	178.76	0.00	0.00	0.00	5.41	1.98	17.85	9.19	3.87	1.85
Libraries, museums and the arts	2.39	0.91	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Sport, gambling and recreational services	0.24	0.03	0.01	0.00	0.09	0.06	0.05	0.02	0.05	0.05
Personal services	3.64	1.20	0.01	0.00	2.49	2.51	0.46	0.25	0.31	0.45
Other services	17.45	1.59	0.28	0.00	3.04	1.56	3.41	1.26	2.76	2.68
Total intermediate usage including imports	**14123**	**3107**	**1520**	**2799**	**3590**	**2244**	**4368**	**4814**	**4151**	**5181**
Wages and salaries	3199	1020	642	1196	1637	1614	642	1303	1748	2023
Gross surplus	2743	127	22	-31	60	296	441	649	477	589
Indirect taxes on production	532	94	45	119	104	138	110	159	153	147
Total gross output	**20597**	**4349**	**2229**	**4083**	**5390**	**4293**	**5562**	**6925**	**6529**	**7940**
Value added at factor cost to output ratio	0.31	0.29	0.32	0.31	0.33	0.48	0.21	0.30	0.36	0.35
Share of wages and mixed income in value added	0.54	0.96	1.06	1.09	1.03	0.82	0.59	0.67	0.80	0.80
Employment to gross output ratio	11.17	3.67	4.05	4.16	10.70	10.96	8.62	9.89	10.97	10.94
Foreign ownership ratio	0.50	0.40	0.50	0.50	0.30	0.20	0.18	0.13	0.80	0.42
Direct tax rate on surplus	0.07	0.75	0.75	-0.03	1.98	0.42	0.07	0.15	0.31	0.28
Indirect tax rate on production	0.06	0.05	0.04	0.07	0.03	0.06	0.05	0.05	0.04	0.03
Foreign income payout ratio	0.19	0.01	0.00	0.00	0.00	0.03	0.07	0.04	0.14	0.08
Replacement depreciation to value added ratio	0.24	0.07	0.05	0.27	0.12	0.08	0.09	0.07	0.07	0.08
Net national product ratio	0.57	0.91	0.95	0.73	0.88	0.89	0.85	0.89	0.80	0.85
Domestic income distribution ratio	0.19	0.02	0.00	0.00	0.00	0.12	0.31	0.25	0.03	0.11

Table B.1(h) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Pre-fabricated buildings	Furniture	Other manufacturing	Electricity supply	Gas supply	Water supply, sewerage and drainage services	Residential building	Other construction	Construction trade services	Wholesale trade
Sheep	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	77.64
Grains	0.05	0.05	0.19	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Beef cattle	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	63.83
Dairy cattle	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.00	0.55
Pigs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	36.55
Poultry	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	44.20
Other agriculture	0.17	0.53	19.27	0.88	0.00	6.51	23.93	93.58	15.49	9.17
Services to agriculture, hunting and trapping	0.00	0.25	34.95	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Forestry and logging	0.03	19.34	0.65	1.90	0.00	0.00	1.61	56.86	6.77	0.00
Commercial fishing	0.00	0.00	0.00	0.00	0.00	0.00	0.12	0.18	0.00	0.00
Coal	0.00	0.00	0.00	3017.38	5.90	0.99	2.82	8.51	2.49	10.64
Gas	2.43	7.18	9.06	1797.48	0.00	0.00	2.76	8.63	2.43	3624.98
LNG	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Iron ores	0.00	0.00	0.01	0.93	0.27	0.04	1.22	3.57	1.07	4.06
Non-ferrous metal ores	0.00	0.21	0.03	6.07	0.73	0.60	3.41	11.35	2.98	554.21
Other mining	0.03	0.02	6.24	0.47	0.12	12.02	107.66	336.14	159.21	1.96
Services to mining	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Meat and meat products	0.10	0.56	7.73	0.93	0.11	2.55	7.36	23.41	8.19	222.65
Dairy products	0.26	1.36	1.43	2.33	0.10	10.10	12.03	21.75	6.20	55.82
Fruit and vegetable products	0.08	0.51	0.50	0.93	0.15	0.78	4.60	8.17	4.10	7.00
Oils and fats	0.03	0.21	0.20	0.72	0.10	1.23	2.96	5.12	2.04	5.53
Flour mill products and cereal foods	0.10	0.62	0.61	1.04	0.12	0.80	4.42	7.35	4.66	4.61
Bakery products	0.08	0.48	0.48	2.43	1.40	3.20	3.95	6.56	3.92	11.00
Confectionery	0.08	0.52	0.46	1.18	0.08	2.13	6.61	11.39	4.53	9.06
Other food products	1.15	2.37	5.46	3.61	0.85	3.47	26.15	41.32	16.31	32.21
Soft drinks, cordials and syrups	0.02	0.09	0.13	0.19	0.02	0.14	4.33	6.01	0.86	1.79
Beer and malt	0.02	0.12	0.12	0.20	0.02	0.36	2.63	3.77	1.69	9.00
Wine, spirits and tobacco products	0.24	0.47	1.32	0.45	0.13	3.92	5.44	7.99	3.92	20.32
Textile fibres, yarns and woven fabrics	0.12	10.11	1.78	0.75	0.31	0.96	10.50	19.36	12.88	11.86
Textile products	0.77	7.75	11.13	0.86	0.12	0.47	34.10	55.24	23.28	9.22
Knitting mill products	0.06	7.08	2.85	0.54	0.06	0.28	5.44	8.70	2.74	9.93
Clothing	0.50	3.32	2.82	3.71	0.42	1.70	10.06	18.05	9.97	18.81

Table B.1(h) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Pre-fabricated buildings	Furniture	Other manufacturing	Electricity supply	Gas supply	Water supply, sewerage and drainage services	Residential building	Other construction	Construction trade services	Wholesale trade
Footwear	0.13	0.41	1.44	3.01	0.13	0.51	2.66	7.36	2.98	5.19
Leather and leather products	0.13	5.63	51.53	0.55	0.99	0.42	3.46	7.31	4.71	6.00
Sawmill products	23.87	500.93	44.41	0.81	0.15	1.53	804.82	137.05	742.35	16.37
Other wood products	38.01	351.66	49.68	3.91	0.56	29.34	1664.80	423.85	1350.10	231.96
Pulp, paper and paperboard	0.47	6.60	4.24	1.81	0.09	0.30	35.44	55.15	10.19	34.50
Paper containers and products	0.84	6.38	5.18	12.81	1.32	5.73	126.54	198.98	33.05	244.40
Printing and services to printing	2.31	13.23	18.84	33.90	8.51	14.66	152.72	375.26	55.19	1021.94
Publishing, recorded media, etc.	1.74	6.49	8.76	13.30	2.81	11.55	56.53	116.62	23.66	469.77
Petroleum and coal products	2.16	7.18	8.13	390.97	3.70	188.32	186.34	398.33	360.74	512.03
Basic chemicals	2.73	30.44	55.10	35.94	15.30	96.86	241.00	635.34	404.98	86.63
Paints	1.84	23.84	18.84	8.53	0.93	15.20	112.63	121.71	155.04	11.54
Medicinal and pharmaceutical products, pesticides	0.49	1.71	3.10	6.10	3.36	41.43	10.87	45.50	30.44	44.04
Soap and detergents	0.08	0.90	2.20	3.19	0.98	6.01	2.65	10.35	6.32	23.04
Cosmetics and toiletry preparations	0.03	0.14	0.14	0.17	0.04	0.24	0.90	2.24	1.26	2.61
Other chemical products	1.39	15.09	7.13	4.12	1.07	3.93	82.64	215.26	169.33	28.68
Rubber products	0.23	5.93	10.52	10.85	1.22	1.40	16.05	37.38	16.07	15.23
Plastic products	3.17	68.41	163.38	11.69	29.03	44.59	686.62	910.51	528.20	221.76
Glass and glass products	6.74	34.95	7.38	2.46	0.47	3.09	122.26	143.77	75.18	264.14
Ceramic products	0.42	0.92	0.87	5.61	0.40	5.64	286.71	28.46	183.62	5.26
Cement, lime and concrete slurry	0.77	1.10	3.95	40.19	1.02	85.20	1442.16	2268.57	2051.67	10.39
Plaster and other concrete products	2.14	13.15	4.87	98.02	0.30	4.95	1247.73	776.93	1203.20	22.04
Other non-metallic mineral products	1.17	3.11	6.80	7.12	1.37	8.30	207.53	228.09	230.54	26.17
Iron and steel	104.17	168.01	274.12	30.05	13.26	44.24	837.47	2236.45	1161.22	147.99
Basic non-ferrous metal and products	83.51	249.01	598.38	20.57	6.98	24.57	636.73	492.96	278.11	63.46
Structural metal products	55.00	42.51	93.36	44.35	7.41	84.69	3027.96	3216.94	1450.53	77.75
Sheet metal products	5.96	15.01	22.42	3.73	21.00	7.43	275.29	433.92	189.19	135.96
Fabricated metal products	23.09	63.61	45.23	58.40	36.72	118.84	495.20	1184.73	479.64	123.63
Motor vehicles and parts, other transport equipment	2.80	13.78	55.27	14.92	1.46	11.82	122.76	214.53	155.03	159.31
Ships and boats	0.17	0.32	0.49	1.26	0.39	0.83	72.79	108.94	34.95	80.95
Railway equipment	0.02	0.91	0.87	2.98	0.08	0.22	5.84	9.57	4.07	4.02
Aircraft	0.01	0.03	0.24	0.48	0.02	0.11	14.87	23.23	7.02	121.36
Photographic and scientific equipment	0.24	1.44	3.68	14.80	0.35	4.32	16.23	88.40	20.88	39.01
Electronic equipment	1.42	1.93	4.70	22.15	1.06	9.75	45.82	271.54	137.05	23.66

Table B.1(h) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Pre-fabricated buildings	Furniture	Other manufacturing	Electricity supply	Gas supply	Water supply, sewerage and drainage services	Residential building	Other construction	Construction trade services	Wholesale trade
Household appliances	0.18	1.68	2.85	5.79	0.37	2.12	462.97	263.01	230.32	15.50
Other electrical equipment	1.73	5.10	12.07	399.50	1.61	13.97	170.77	1299.73	401.27	110.60
Agricultural, mining, etc. machinery	0.69	1.35	5.59	22.96	0.92	4.25	72.54	131.66	144.71	36.96
Other machinery and equipment	1.62	7.68	7.79	30.62	5.03	22.57	126.39	444.89	150.03	78.97
Prefabricated buildings	1.03	0.74	0.82	0.43	0.06	0.59	49.86	142.46	36.62	3.93
Furniture	7.00	21.66	3.91	2.42	0.39	14.88	279.97	214.42	231.97	41.11
Other manufacturing	4.20	18.39	35.76	19.02	7.90	10.00	201.35	413.32	364.40	143.34
Electricity supply	1.47	23.17	33.57	4827.31	5.92	282.16	104.04	510.88	83.52	629.05
Gas supply	1.92	5.55	7.33	585.29	0.00	0.99	28.27	6.10	10.87	241.42
Water supply, sewerage and drainage services	0.26	3.91	5.28	97.68	19.28	436.75	304.70	173.35	72.58	251.48
Residential building	0.18	0.68	1.24	160.25	82.17	62.56	1426.15	1976.41	2201.08	271.33
Other construction	0.25	0.91	1.67	230.25	111.09	86.27	2060.11	2681.58	2984.62	434.89
Construction trade services	2.31	6.96	13.39	2220.62	815.06	950.43	11408.93	13437.05	34415.77	1814.01
Wholesale trade	52.88	297.28	306.59	550.84	49.44	449.78	2181.57	3724.59	2502.70	2741.35
Wholesale mechanical repairs	0.09	0.42	0.18	67.54	31.76	36.10	101.58	216.97	59.17	58.03
Other wholesale repairs	4.90	30.34	19.14	147.54	163.60	52.18	130.66	178.25	65.25	579.01
Retail trade	4.94	44.43	94.23	70.91	12.16	39.88	243.68	626.68	275.68	1132.59
Retail mechanical repairs	6.25	24.39	29.37	234.72	47.87	61.64	178.14	502.70	895.85	983.25
Other retail repairs	0.00	0.00	0.00	0.00	0.00	0.00	13.53	22.77	13.07	30.94
Accommodation, cafes and restaurants	4.84	16.71	24.36	122.48	11.67	33.58	38.76	49.67	12.43	579.98
Road transport	13.32	105.45	102.28	164.16	11.44	100.55	947.47	1437.57	1065.81	1141.59
Rail, pipeline and other transport	0.78	3.03	5.29	271.92	2.07	1.07	62.45	115.20	28.30	119.07
Water transport	0.33	1.36	10.01	48.19	13.87	0.29	2.68	6.36	4.19	85.85
Air and space transport	1.47	4.65	5.44	58.93	19.46	29.85	88.59	94.80	23.54	960.80
Services to transport, storage	1.93	20.57	51.35	51.73	2.77	24.67	340.74	3216.56	388.10	9969.41
Communication services	5.48	39.23	76.67	348.59	86.62	143.56	644.46	1482.10	251.68	3116.56
Finance	9.81	43.71	38.38	1313.33	197.77	722.21	3454.88	3401.09	4318.10	3141.12
Ownership of dwellings	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other property services	1.55	18.79	39.26	391.96	312.37	5.11	2745.85	6598.09	2147.70	8405.65
Scientific research, technical and computer services	8.79	25.09	17.42	248.89	51.90	28.04	253.43	6225.46	746.88	1398.42
Legal, accounting, marketing and business management services	3.99	76.50	97.04	316.29	971.67	693.63	1794.49	5040.22	2410.66	5356.98
Other business services	13.98	101.11	74.39	223.77	369.80	101.27	954.49	2917.96	1293.09	1504.10

Table B.1(h) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Pre-fabricated buildings	Furniture	Other manufacturing	Electricity supply	Gas supply	Water supply, sewerage and drainage services	Residential building	Other construction	Construction trade services	Wholesale trade
Government administration	0.43	3.28	2.62	19.07	1.65	38.65	263.71	480.88	83.84	121.97
Defence	0.01	0.07	0.07	0.09	0.00	0.00	0.67	0.73	0.14	8.58
Education	0.48	3.35	3.31	160.64	26.71	25.69	46.29	42.02	10.32	33.03
Health services	0.08	0.27	0.59	1.17	0.00	3.61	0.21	7.13	0.05	12.91
Community services	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Motion picture, radio and television services	1.97	8.26	1.78	13.38	17.43	20.31	46.26	28.59	15.71	285.24
Libraries, museums and the arts	0.50	12.85	1.19	38.49	56.88	50.38	40.11	7.05	0.88	51.48
Sport, gambling and recreational services	0.01	0.05	0.07	0.37	0.03	0.09	227.26	349.43	126.74	158.71
Personal services	0.03	0.60	0.28	0.76	0.00	1.60	15.15	56.23	6.02	18.62
Other services	0.26	1.36	1.26	8.80	0.00	4.59	141.07	448.76	62.11	13.91
Total intermediate usage including imports	**698**	**3597**	**4012**	**20752**	**3980**	**6704**	**48434**	**83660**	**74435**	**62975**
Wages and salaries	194	1447	872	4350	182	3434	4084	13387	21745	30714
Gross surplus	136	485	49	12228	922	6065	7436	19748	17410	18696
Indirect taxes on production	20	125	75	1012	106	20	1053	1768	1902	4578
Total gross output	**1048**	**5654**	**5009**	**38342**	**5189**	**16223**	**61006**	**118564**	**115491**	**116963**
Value added at factor cost to output ratio	0.33	0.36	0.20	0.46	0.23	0.59	0.21	0.29	0.36	0.46
Share of wages and mixed income in value added	0.61	0.94	1.30	0.25	0.16	0.39	0.43	0.48	0.97	0.64
Employment to gross output ratio	7.58	24.25	12.46	2.99	8.42	4.33	4.93	7.08	14.89	7.33
Foreign ownership ratio	0.03	0.05	0.07	0.40	0.30	0.01	0.05	0.15	0.05	0.35
Direct tax rate on surplus	0.16	0.10	0.16	0.01	0.02	0.01	0.07	0.06	0.08	0.23
Indirect tax rate on production	0.03	0.04	0.02	0.04	0.05	-0.01	0.05	0.03	0.02	0.08
Foreign income payout ratio	0.01	0.00	0.00	0.27	0.23	0.01	0.03	0.07	0.00	0.10
Replacement depreciation to value added ratio	0.21	0.08	0.07	0.35	0.35	0.29	0.03	0.02	0.06	0.08
Net national product ratio	0.78	0.92	0.93	0.38	0.42	0.71	0.95	0.91	0.94	0.82
Domestic income distribution ratio	0.32	0.05	0.00	0.41	0.53	0.59	0.49	0.42	0.03	0.19

Table B.1(i) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Wholesale mechanical repairs	Other wholesale repairs	Retail trade	Retail mechanical repairs	Other retail repairs	Accommodation, cafes and restaurants	Road transport	Rail, pipeline and other transport	Water transport	Air and space transport
Sheep	0.00	0.00	502.50	0.00	0.00	181.44	0.00	0.00	0.00	0.00
Grains	0.00	0.00	0.04	0.00	0.00	0.02	0.00	0.00	0.00	0.00
Beef cattle	0.00	0.00	413.05	0.00	0.00	149.45	0.00	0.00	0.00	0.00
Dairy cattle	0.00	0.00	3.59	0.00	0.00	1.31	0.00	0.00	0.00	0.00
Pigs	0.00	0.00	236.53	0.00	0.00	85.58	0.00	0.00	0.00	0.00
Poultry	0.00	0.00	310.29	0.00	0.00	134.42	0.00	0.00	0.00	0.00
Other agriculture	0.00	0.86	318.37	2.96	0.36	482.42	0.77	1.27	0.00	0.00
Services to agriculture, hunting and trapping	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Forestry and logging	0.00	0.00	1.34	0.00	0.00	0.65	3.47	14.34	0.00	0.00
Commercial fishing	0.00	0.00	190.81	0.00	0.00	142.71	0.00	0.00	0.00	0.00
Coal	0.04	1.90	9.97	0.49	0.02	2.40	1.97	9.87	0.99	0.99
Gas	0.84	5.34	115.00	7.57	1.16	167.93	12.48	34.52	0.00	2.86
LNG	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Iron ores	0.02	0.81	1.90	0.21	0.01	1.01	0.56	0.89	0.01	0.29
Non-ferrous metal ores	0.05	2.10	5.64	0.57	0.02	2.99	4.49	25.51	0.33	0.98
Other mining	0.01	0.39	0.46	0.09	0.00	3.67	0.26	0.92	0.00	0.14
Services to mining	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Meat and meat products	0.38	1.56	2613.99	7.05	0.21	1837.30	3.77	1.40	0.05	1.36
Dairy products	1.54	3.07	739.73	13.59	0.92	703.01	6.83	3.32	0.12	6.46
Fruit and vegetable products	0.39	1.69	213.73	3.12	0.20	215.58	3.13	0.32	0.09	1.53
Oils and fats	0.31	0.72	134.36	2.25	0.12	82.00	1.66	0.31	0.03	0.60
Flour mill products and cereal foods	0.44	1.80	719.60	3.72	0.24	383.44	3.73	0.36	0.06	1.62
Bakery products	0.37	1.53	430.33	3.09	0.20	401.24	3.68	1.25	1.50	3.98
Confectionery	0.55	1.65	175.99	4.38	0.28	225.87	3.41	0.73	0.04	1.28
Other food products	1.17	4.30	376.52	9.25	0.60	305.00	13.24	2.35	0.22	7.69
Soft drinks, cordials and syrups	0.07	0.28	423.16	0.55	0.05	99.17	0.86	0.35	0.01	0.33
Beer and malt	0.06	0.62	4.89	1.53	0.19	1550.84	2.28	0.69	0.01	1.84
Wine, spirits and tobacco products	0.10	1.40	5.17	3.09	1.14	902.16	4.61	1.52	0.04	4.36
Textile fibres, yarns and woven fabrics	0.44	1.15	19.88	7.24	0.14	6.36	4.70	0.69	0.08	0.75
Textile products	0.06	0.84	17.71	0.76	0.20	7.75	5.40	0.96	0.13	0.23
Knitting mill products	0.16	0.72	44.33	1.79	0.13	2.02	3.16	0.63	0.03	0.62
Clothing	17.02	5.17	18.56	51.44	1.16	10.84	8.55	2.27	0.20	3.78

Table B.1(i) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Wholesale mechanical repairs	Other wholesale repairs	Retail trade	Retail mechanical repairs	Other retail repairs	Accommodation, cafes and restaurants	Road transport	Rail, pipeline and other transport	Water transport	Air and space transport
Footwear	0.16	4.97	2.76	1.50	1.35	1.62	1.76	0.30	0.03	0.80
Leather and leather products	0.60	1.17	5.20	10.14	0.29	2.08	4.16	0.69	0.29	3.37
Sawmill products	0.29	1.37	28.60	2.43	0.17	2.98	12.12	2.10	0.39	1.82
Other wood products	2.62	3.03	143.12	9.63	0.50	15.76	36.78	5.08	1.17	4.82
Pulp, paper and paperboard	0.08	0.87	21.63	1.17	0.26	24.61	13.86	3.25	1.91	16.27
Paper containers and products	1.10	6.41	192.83	6.22	2.20	93.60	10.62	10.11	1.85	19.39
Printing and services to printing	4.35	6.96	1664.05	36.44	1.56	205.04	44.97	31.26	3.66	13.65
Publishing, recorded media, etc.	3.47	6.39	820.06	28.11	1.31	103.76	22.61	36.72	3.32	12.08
Petroleum and coal products	11.11	81.63	392.69	70.68	16.25	168.35	1466.79	146.92	58.79	2002.78
Basic chemicals	3.31	8.90	49.75	20.90	1.53	56.47	16.54	11.58	0.53	8.51
Paints	4.51	8.94	5.63	19.39	1.20	4.25	1.32	1.09	0.27	0.51
Medicinal and pharmaceutical products, pesticides	0.62	2.20	23.36	5.12	0.34	10.99	5.26	2.02	0.07	2.88
Soap and detergents	0.47	1.49	11.89	2.58	0.27	25.61	4.62	1.44	0.04	0.58
Cosmetics and toiletry preparations	0.06	0.14	1.27	0.37	0.03	0.85	0.31	0.29	0.01	0.13
Other chemical products	1.37	3.91	17.17	4.09	0.82	5.19	4.32	1.38	0.27	3.29
Rubber products	1.38	6.43	4.63	15.69	0.74	4.96	20.27	0.70	0.01	0.22
Plastic products	2.48	11.20	121.51	37.34	1.35	124.50	57.90	12.38	1.88	70.53
Glass and glass products	16.56	2.32	31.70	92.26	0.28	20.45	12.81	5.64	0.02	0.47
Ceramic products	0.06	0.52	5.09	0.63	0.09	1.66	1.34	0.20	0.01	0.21
Cement, lime and concrete slurry	0.34	1.35	22.66	2.14	0.36	1.85	2.43	0.63	0.08	1.05
Plaster and other concrete products	0.33	0.90	9.80	1.59	0.10	3.96	1.36	2.90	0.08	0.51
Other non-metallic mineral products	0.16	0.54	16.12	1.20	0.07	1.74	1.05	0.55	0.02	0.19
Iron and steel	4.78	13.41	75.88	44.09	2.19	9.40	16.60	84.05	0.36	1.62
Basic non-ferrous metal and products	2.97	9.16	90.75	23.58	2.15	30.98	22.03	17.62	0.41	6.80
Structural metal products	10.34	12.96	42.54	42.59	1.01	10.74	18.20	287.25	0.55	2.37
Sheet metal products	2.44	3.40	93.18	21.33	3.15	5.46	181.07	33.52	0.91	4.19
Fabricated metal products	17.19	44.45	137.20	69.57	9.33	36.40	35.98	36.89	1.43	13.74
Motor vehicles and parts, other transport equipment	66.20	18.73	167.17	1582.32	4.39	35.59	680.59	12.00	0.51	6.40
Ships and boats	4.49	1.87	3.41	3.81	0.31	3.28	2.09	1.64	203.12	0.78
Railway equipment	1.55	2.05	4.48	4.53	0.13	1.78	6.04	1156.96	0.04	0.41
Aircraft	0.11	1.49	43.00	2.58	0.35	2.88	0.97	0.55	0.04	1368.70
Photographic and scientific equipment	3.24	27.49	16.77	13.05	2.47	12.76	8.64	4.11	0.79	17.10
Electronic equipment	4.83	101.24	11.21	15.96	5.61	18.32	13.67	4.41	0.81	15.73

Table B.1(i) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Wholesale mechanical repairs	Other wholesale repairs	Retail trade	Retail mechanical repairs	Other retail repairs	Accommodation, cafes and restaurants	Road transport	Rail, pipeline and other transport	Water transport	Air and space transport
Household appliances	4.07	41.41	28.73	17.89	108.99	43.90	16.05	8.17	0.59	12.31
Other electrical equipment	8.63	87.19	57.42	47.66	12.39	27.00	110.44	6.60	0.96	17.51
Agricultural, mining, etc. machinery	54.10	50.63	17.77	162.41	4.48	22.29	11.58	18.75	0.81	16.82
Other machinery and equipment	37.03	128.97	66.75	130.15	12.25	81.40	40.18	16.04	1.72	17.94
Prefabricated buildings	0.10	0.54	3.01	1.15	0.05	1.07	1.47	4.79	0.03	0.40
Furniture	0.89	3.27	39.80	6.32	0.39	38.34	18.10	3.57	0.12	2.86
Other manufacturing	3.69	31.46	136.75	75.26	5.92	85.95	17.01	15.98	0.42	5.53
Electricity supply	38.96	137.13	1018.69	228.00	44.40	780.66	194.40	360.15	52.31	39.47
Gas supply	0.89	3.07	115.31	7.28	1.23	147.08	6.91	12.83	2.96	2.96
Water supply, sewerage and drainage services	17.05	24.71	303.83	76.85	4.96	314.12	309.03	89.19	25.10	20.71
Residential building	10.35	69.98	123.85	21.14	1.12	78.29	46.82	40.52	1.16	14.90
Other construction	14.02	94.38	168.36	28.52	1.52	233.75	72.29	131.16	2.19	21.74
Construction trade services	144.95	185.97	598.79	119.23	16.06	793.76	112.48	781.56	5.83	30.93
Wholesale trade	210.08	913.10	1680.96	1765.04	118.91	1237.11	2245.13	167.52	42.01	1195.34
Wholesale mechanical repairs	1.06	0.00	326.59	0.00	0.00	0.50	34.92	8.08	15.45	0.00
Other wholesale repairs	0.00	0.00	715.52	0.00	0.00	26.65	125.69	32.81	51.54	77.35
Retail trade	13.15	55.31	2399.89	122.04	7.97	2584.89	330.52	43.24	3.03	383.65
Retail mechanical repairs	0.00	81.23	1145.36	0.00	13.68	37.94	3448.50	47.01	58.83	43.87
Other retail repairs	0.00	0.00	56.33	0.00	0.00	19.91	51.45	28.90	21.11	14.70
Accommodation, cafes and restaurants	1.41	9.76	345.67	22.33	4.91	54.01	160.29	15.26	6.35	39.00
Road transport	6.99	63.43	614.95	43.79	19.40	455.43	1310.11	69.91	6.06	223.35
Rail, pipeline and other transport	0.29	2.97	50.96	2.18	0.55	41.98	4.38	5.76	0.05	13.13
Water transport	0.09	3.65	35.73	0.46	0.03	4.95	4.40	0.32	136.02	0.14
Air and space transport	1.50	26.49	188.04	8.40	1.23	38.43	28.04	3.43	2.09	608.78
Services to transport, storage	17.07	28.68	819.74	89.70	7.58	309.37	657.77	55.87	779.88	1687.35
Communication services	59.06	238.08	3093.64	295.78	25.91	673.89	1010.35	54.95	16.80	136.18
Finance	88.29	224.03	2444.20	452.59	35.99	806.72	608.75	268.15	23.86	201.81
Ownership of dwellings	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other property services	16.70	752.39	3732.50	209.30	3.70	1624.62	1239.53	867.32	5.98	586.77
Scientific research, technical and computer services	2.20	15.87	437.73	1.50	0.03	337.05	940.88	52.59	82.82	311.62
Legal, accounting, marketing and business management services	112.86	257.39	6658.34	694.83	54.60	1109.93	2188.96	54.30	63.35	400.34
Other business services	112.29	647.25	3867.83	82.14	1.25	582.84	263.14	83.77	10.10	148.54

Table B.1(i) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Wholesale mechanical repairs	Other wholesale repairs	Retail trade	Retail mechanical repairs	Other retail repairs	Accommodation, cafes and restaurants	Road transport	Rail, pipeline and other transport	Water transport	Air and space transport
Government administration	8.41	8.76	180.14	54.25	2.72	12.60	488.72	16.75	0.91	1.62
Defence	0.00	0.00	2.55	0.00	0.00	3.08	7.92	0.39	0.11	0.67
Education	0.95	2.43	59.27	70.61	0.69	58.23	50.30	18.41	3.38	18.39
Health services	1.02	1.74	15.74	10.36	0.75	5.72	2.52	1.25	0.75	0.21
Community services	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Motion picture, radio and television services	1.33	1.13	1100.24	17.21	0.00	1201.12	63.12	0.82	2.77	18.34
Libraries, museums and the arts	0.00	0.00	74.09	10.96	0.00	176.12	30.36	12.70	17.21	34.47
Sport, gambling and recreational services	0.00	0.03	112.27	9.85	0.01	20.05	3.44	0.05	0.01	3.93
Personal services	0.68	0.58	54.93	4.40	0.00	21.05	0.66	1.29	0.00	0.00
Other services	0.00	0.00	21.74	5.28	0.00	6.74	18.56	0.82	0.00	0.00
Total intermediate usage including imports	**1697**	**6686**	**48333**	**9401**	**801**	**25751**	**22235**	**6070**	**2243**	**11196**
Wages and salaries	385	1445	28804	9540	1126	13483	11377	6018	461	4271
Gross surplus	264	396	18241	334	324	8547	8061	633	1177	894
Indirect taxes on production	77	360	3340	901	102	2747	2711	288	106	1573
Total gross output	**2423**	**8887**	**98718**	**20177**	**2354**	**50528**	**44384**	**13008**	**3987**	**17934**
Value added at factor cost to output ratio	0.30	0.25	0.51	0.53	0.66	0.49	0.50	0.53	0.44	0.38
Share of wages and mixed income in value added	0.60	0.75	0.68	1.05	0.85	0.62	0.72	0.88	0.29	0.66
Employment to gross output ratio	6.83	8.46	17.06	26.42	21.65	14.56	9.93	8.05	5.19	7.08
Foreign ownership ratio	0.15	0.20	0.10	0.04	0.04	0.09	0.20	0.02	0.40	0.38
Direct tax rate on surplus	0.25	0.25	0.13	0.36	0.01	0.04	0.04	0.10	0.04	0.39
Indirect tax rate on production	0.09	0.15	0.06	0.08	0.06	0.11	0.12	0.03	0.05	0.28
Foreign income payout ratio	0.05	0.04	0.03	0.00	0.01	0.03	0.05	0.00	0.26	0.06
Replacement depreciation to value added ratio	0.30	0.32	0.10	0.02	0.01	0.11	0.20	0.43	0.19	0.44
Net national product ratio	0.65	0.64	0.87	0.98	0.99	0.86	0.76	0.57	0.55	0.49
Domestic income distribution ratio	0.26	0.15	0.25	0.00	0.13	0.29	0.18	0.11	0.38	0.10

Table B.1(j) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Services to transport, storage	Commun-ication services	Finance	Ownership of dwellings	Other property services	Scientific research, technical and computer services	Legal, accounting, marketing and business management services	Other business services	Govern-ment admin-istration	Defence
Sheep	0.00	0.00	0.00	0.00	0.00	59.65	0.00	23.61	0.00	0.00
Grains	0.00	0.00	0.00	0.00	0.05	0.02	0.02	0.01	0.04	0.00
Beef cattle	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Dairy cattle	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Pigs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Poultry	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other agriculture	41.78	0.83	4.47	0.00	86.43	44.41	68.76	7.67	68.08	4.92
Services to agriculture, hunting and trapping	0.00	0.00	0.00	0.00	0.00	91.51	0.00	7.89	53.64	16.02
Forestry and logging	1.57	6.24	0.00	0.00	0.00	1.41	0.58	0.64	0.00	0.00
Commercial fishing	0.00	0.00	2.27	0.00	0.00	5.57	0.09	2.60	0.00	0.00
Coal	5.92	4.03	2.26	0.01	26.00	0.95	1.42	2.73	13.81	15.06
Gas	30.22	152.28	7.56	3.62	65.42	30.98	40.38	23.63	62.70	63.74
LNG	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Iron ores	1.71	1.72	0.95	0.00	10.45	0.39	0.60	1.16	1.50	1.11
Non-ferrous metal ores	8.00	4.93	2.66	0.01	40.41	1.23	1.71	3.33	48.55	54.88
Other mining	0.82	0.83	0.45	2.86	7.81	1.27	0.48	0.67	6.06	1.47
Services to mining	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Meat and meat products	3.61	20.06	9.22	1.24	18.22	41.00	34.20	18.85	3.00	10.77
Dairy products	10.03	73.75	10.59	0.38	20.61	108.77	22.56	47.58	3.26	4.28
Fruit and vegetable products	2.18	6.40	0.81	0.30	4.04	5.73	4.01	2.55	1.38	4.48
Oils and fats	1.36	5.27	0.31	0.13	2.46	7.52	4.33	2.08	1.21	1.42
Flour mill products and cereal foods	2.62	4.70	0.75	0.36	3.73	38.66	16.53	15.39	11.35	9.38
Bakery products	3.91	20.25	6.42	0.29	8.16	12.52	13.77	5.21	6.79	24.75
Confectionery	2.41	13.12	0.43	0.26	4.97	12.96	5.45	5.18	2.94	2.44
Other food products	12.08	24.25	6.05	23.29	17.05	57.84	26.92	22.19	25.12	27.46
Soft drinks, cordials and syrups	1.08	1.46	0.87	0.52	3.21	1.80	1.62	0.78	1.30	29.41
Beer and malt	3.44	2.34	3.74	0.62	3.54	3.16	1.96	1.40	5.46	3.25
Wine, spirits and tobacco products	11.14	11.12	32.94	0.80	9.49	5.58	4.03	2.70	84.13	4.39
Textile fibres, yarns and woven fabrics	2.07	12.87	0.69	1.75	4.43	4.17	1.91	1.80	4.73	5.55
Textile products	4.27	5.53	0.47	11.84	5.29	3.17	1.42	1.83	8.21	2.59
Knitting mill products	1.89	4.27	0.21	0.94	4.34	5.88	4.44	2.78	1.43	8.21

Table B.1(j) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Services to transport, storage	Commun-ication services	Finance	Ownership of dwellings	Other property services	Scientific research, technical and computer services	Legal, accounting, marketing and business management services	Other business services	Govern-ment admin-istration	Defence
Clothing	9.52	16.26	0.93	1.02	6.45	12.40	4.74	4.49	3.05	35.82
Footwear	1.51	2.64	0.19	0.30	1.64	1.37	0.87	0.66	0.63	1.94
Leather and leather products	2.03	3.48	0.46	0.57	1.35	1.85	1.90	1.50	1.03	6.63
Sawmill products	26.08	9.54	1.08	7.24	25.89	2.85	3.31	3.23	4.18	3.73
Other wood products	91.54	31.22	1.78	190.07	43.00	7.59	4.61	5.95	81.62	16.29
Pulp, paper and paperboard	3.39	93.68	26.39	1.08	9.07	13.84	37.76	8.81	122.58	4.90
Paper containers and products	7.36	33.88	3.19	0.27	9.45	16.69	10.71	5.55	57.23	6.15
Printing and services to printing	56.28	723.15	158.70	9.28	265.04	599.00	621.08	289.81	588.06	153.25
Publishing, recorded media, etc.	76.99	529.53	71.99	5.69	176.46	360.28	351.41	186.76	215.97	33.12
Petroleum and coal products	385.55	361.19	6.60	10.82	121.06	188.58	271.26	122.12	71.94	156.32
Basic chemicals	23.04	52.08	4.03	32.97	83.42	100.47	40.30	33.50	37.31	52.29
Paints	1.56	2.05	0.42	10.45	12.85	10.61	6.91	3.13	1.89	2.19
Medicinal and pharmaceutical products, pesticides	18.49	8.85	1.25	3.48	40.91	58.48	12.56	13.27	2.88	4.24
Soap and detergents	3.34	5.48	0.48	1.26	18.76	28.24	36.38	12.51	6.75	5.69
Cosmetics and toiletry preparations	0.41	0.61	0.05	0.45	1.60	0.68	0.61	0.35	0.43	0.79
Other chemical products	3.21	15.28	0.82	3.98	19.13	28.34	25.48	12.68	17.23	55.05
Rubber products	6.31	8.79	0.16	1.57	2.32	6.20	1.41	1.76	27.39	48.76
Plastic products	68.24	325.88	3.07	91.85	26.62	42.83	8.80	10.33	53.41	54.74
Glass and glass products	4.92	12.12	4.26	30.51	10.30	5.37	3.28	2.42	11.58	6.16
Ceramic products	1.49	29.17	0.24	3.14	2.52	1.66	0.76	0.82	1.18	0.78
Cement, lime and concrete slurry	2.03	9.98	1.01	56.51	8.93	12.82	2.26	6.57	4.71	3.18
Plaster and other concrete products	1.23	8.79	0.26	23.73	4.21	2.33	1.35	1.22	23.81	3.47
Other non-metallic mineral products	1.72	7.03	0.14	18.96	3.78	2.70	1.89	1.71	3.19	3.72
Iron and steel	7.91	62.75	1.73	163.75	17.20	19.18	5.76	4.50	15.89	31.22
Basic non-ferrous metal and products	20.96	80.45	7.13	141.40	62.12	24.68	20.03	15.81	41.61	41.90
Structural metal products	19.84	36.78	2.23	246.70	50.63	8.12	4.99	6.32	25.64	27.92
Sheet metal products	32.86	281.97	0.98	58.29	21.68	3.92	1.70	2.71	7.85	10.72
Fabricated metal products	19.21	86.39	5.54	67.09	56.49	56.78	17.43	15.96	50.95	117.27
Motor vehicles and parts, other transport equipment	110.92	187.51	7.04	3.82	97.83	46.03	22.23	19.25	21.43	94.20
Ships and boats	10.02	3.32	1.78	1.05	8.77	6.13	2.99	3.04	4.63	2066.14
Railway equipment	2.96	4.74	1.29	1.41	6.03	3.02	1.34	1.06	2.63	2.31
Aircraft	298.89	2.08	0.28	0.95	4.73	6.58	1.93	2.42	1.33	188.16

Table B.1(j) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Services to transport, storage	Commun-ication services	Finance	Ownership of dwellings	Other property services	Scientific research, technical and computer services	Legal, accounting, marketing and business management services	Other business services	Govern-ment admin-istration	Defence
Photographic and scientific equipment	39.36	94.93	3.29	4.12	30.34	60.23	15.50	12.36	18.83	63.41
Electronic equipment	163.18	270.11	5.80	13.46	37.22	84.53	41.60	20.35	15.25	21.59
Household appliances	17.97	20.07	1.76	33.06	19.03	10.29	5.84	4.61	3.65	20.10
Other electrical equipment	91.06	422.30	9.05	21.99	48.75	82.80	28.67	16.35	26.77	28.73
Agricultural, mining, etc. machinery	34.27	38.91	2.61	6.33	35.69	41.03	10.80	9.82	12.33	21.30
Other machinery and equipment	39.20	74.82	3.29	9.41	46.59	81.17	11.87	13.05	22.64	110.05
Prefabricated buildings	1.48	2.50	0.21	2.77	4.98	0.75	0.49	0.69	1.70	11.79
Furniture	10.25	26.68	6.43	30.05	52.66	13.63	14.06	22.13	68.50	40.41
Other manufacturing	24.93	76.65	4.11	13.35	47.34	34.47	20.52	16.07	18.07	32.94
Electricity supply	969.82	451.80	183.87	55.05	494.35	408.86	654.97	375.06	460.26	96.99
Gas supply	25.66	81.30	8.88	4.06	27.96	23.66	40.15	18.86	22.24	3.20
Water supply, sewerage and drainage services	307.59	289.88	89.89	5.36	841.35	667.32	631.30	414.66	283.62	140.94
Residential building	128.46	212.35	94.93	140.75	412.45	132.00	184.91	93.44	124.79	53.29
Other construction	269.60	293.34	127.52	261.56	606.92	181.06	271.50	127.48	273.64	185.80
Construction trade services	607.59	2469.77	68.67	1690.46	850.93	378.13	510.40	239.50	1487.62	1600.03
Wholesale trade	1057.69	2233.56	147.42	181.83	806.31	1215.16	723.43	400.91	571.25	676.30
Wholesale mechanical repairs	36.29	81.26	1.07	0.00	75.27	17.58	1.59	0.22	24.62	0.00
Other wholesale repairs	469.04	840.39	651.14	3.06	328.00	377.22	363.74	297.32	6.88	11.29
Retail trade	208.32	473.28	70.11	22.41	716.91	150.56	153.93	123.81	121.55	80.38
Retail mechanical repairs	712.44	874.32	107.38	0.00	438.44	172.40	288.21	260.05	165.44	68.79
Other retail repairs	23.48	17.85	47.78	1101.68	20.18	23.01	27.66	20.14	42.28	0.00
Accommodation, cafes and restaurants	257.45	415.68	336.40	0.00	20.04	395.60	1429.73	473.40	405.40	58.21
Road transport	467.62	543.43	98.73	53.05	164.38	250.92	294.53	100.70	389.88	144.04
Rail, pipeline and other transport	84.25	124.58	15.40	1.49	129.10	63.48	89.35	39.12	6.89	6.36
Water transport	3.64	102.98	0.15	0.16	31.88	70.46	31.49	32.87	71.57	10.57
Air and space transport	108.71	457.02	146.42	0.07	46.97	265.89	556.02	210.09	299.38	113.48
Services to transport, storage	4279.14	640.42	186.86	6.39	1440.85	546.41	1185.68	865.54	1120.62	481.32
Communication services	1584.87	1385.34	2238.48	16.59	1490.04	1651.04	2679.59	475.14	1822.75	99.93
Finance	971.83	1036.47	38388.03	6387.55	4822.26	889.67	2732.08	895.87	2538.96	287.73
Ownership of dwellings	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other property services	2848.14	3954.93	2035.85	2135.99	25342.34	333.86	4208.77	2557.51	557.73	106.63
Scientific research, technical and computer services	2460.93	691.59	1258.64	28.22	2552.66	7138.12	5398.46	1272.41	2383.55	60.81

Table B.1(j) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Services to transport, storage	Commun- ication services	Finance	Ownership of dwellings	Other property services	Scientific research, technical and computer services	Legal, accounting, marketing and business management services	Other business services	Govern- ment admin- istration	Defence
Legal, accounting, marketing and business management services	1576.41	670.55	3920.44	476.39	5066.07	4302.33	4389.78	1210.08	1815.81	289.37
Other business services	1801.82	585.32	1768.95	3.39	4121.64	2299.34	3114.86	1198.50	843.49	42.06
Government administration	455.92	306.06	82.43	5.28	99.97	425.71	471.22	105.03	1494.19	46.80
Defence	19.57	5.68	6.11	0.02	3.73	9.76	8.29	4.33	14.87	0.28
Education	214.53	48.87	584.44	0.01	209.72	457.66	547.59	295.57	195.85	42.01
Health services	85.43	78.21	20.12	0.01	10.95	13.46	11.36	10.09	43.24	58.02
Community services	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Motion picture, radio and television services	26.85	104.12	344.31	0.00	1294.89	1242.15	1737.30	565.23	113.23	85.69
Libraries, museums and the arts	25.28	43.17	136.21	0.00	119.85	161.10	353.28	88.32	45.67	12.54
Sport, gambling and recreational services	10.25	26.38	102.32	0.00	130.06	178.50	35.02	88.55	65.07	107.23
Personal services	1.05	29.19	3.16	0.06	34.73	53.01	77.10	28.21	2.96	43.93
Other services	30.81	19.58	9.14	0.00	71.63	46.61	58.14	31.34	35.04	26.62
Total intermediate usage including imports	**25567**	**27613**	**54460**	**14516**	**55612**	**31211**	**37774**	**15326**	**21317**	**11306**
Wages and salaries	9376	9636	44477	0	13749	25997	25657	23608	33990	4940
Gross surplus	15355	16546	37406	98384	27291	3241	7478	8761	1185	4547
Indirect taxes on production	1996	1466	4961	10668	2553	1410	3021	934	1170	726
Total gross output	**52294**	**55260**	**141304**	**123568**	**99205**	**61859**	**73930**	**48629**	**57663**	**21519**
Value added at factor cost to output ratio	0.51	0.50	0.61	0.88	0.44	0.50	0.49	0.68	0.63	0.47
Share of wages and mixed income in value added	0.37	0.41	0.55	0.00	0.38	1.01	0.90	0.86	0.95	0.49
Employment to gross output ratio	5.17	6.20	4.09	0.00	3.40	10.93	9.07	7.60	11.86	7.68
Foreign ownership ratio	0.10	0.10	0.20	0.00	0.10	0.15	0.05	0.15	0.00	0.00
Direct tax rate on surplus	0.02	0.12	0.39	0.00	0.09	0.22	0.23	0.09	0.00	0.00
Indirect tax rate on production	0.07	0.04	0.05	0.11	0.04	0.03	0.08	0.02	0.03	0.06
Foreign income payout ratio	0.06	0.04	0.06	0.00	0.05	0.00	0.00	0.02	0.00	0.00
Replacement depreciation to value added ratio	0.23	0.20	0.08	0.00	0.15	0.11	0.07	0.04	0.13	0.13
Net national product ratio	0.72	0.76	0.86	1.00	0.80	0.89	0.93	0.94	0.87	0.87
Domestic income distribution ratio	0.51	0.38	0.24	0.00	0.48	0.00	0.08	0.11	0.00	0.00

Table B.1(k) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Education	Health services	Community services	Motion picture, radio & television services	Libraries, museums & the arts	Sport, gambling & recreational services	Personal services	Other services	Households	Current government expenditure
Sheep	0.00	0.00	9.92	0.00	0.00	0.00	0.00	108.00	7.44	0.00
Grains	0.00	0.09	0.02	0.04	0.02	0.02	0.02	0.04	0.00	0.00
Beef cattle	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	10.60	0.00
Dairy cattle	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Pigs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.44	0.00
Poultry	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	424.46	0.00
Other agriculture	7.71	8.28	6.60	238.60	39.74	500.36	59.22	31.39	5505.94	0.00
Services to agriculture, hunting and trapping	0.00	0.00	5.14	3.01	0.75	2.79	3.37	25.29	45.25	192.25
Forestry and logging	0.00	0.00	0.00	0.63	0.17	0.60	0.10	2.38	27.07	227.93
Commercial fishing	0.00	0.04	0.47	4.39	1.92	5.21	0.06	8.24	1098.56	178.32
Coal	1.30	2.09	0.11	1.92	0.65	2.34	0.45	1.04	16.49	1.69
Gas	54.14	87.14	15.29	9.04	4.34	12.14	7.53	31.40	532.34	4.66
LNG	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Iron ores	0.18	0.45	0.04	0.54	0.19	0.73	0.19	0.41	0.88	0.03
Non-ferrous metal ores	0.72	1.94	0.17	1.53	0.55	2.04	0.53	1.52	2.20	0.10
Other mining	0.08	0.27	0.42	21.25	4.74	24.09	0.87	5.20	2.48	0.02
Services to mining	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	83.87
Meat and meat products	29.90	7.05	4.59	17.28	7.31	86.51	4.62	67.44	6065.47	3.11
Dairy products	116.71	17.76	17.49	6.16	3.89	26.68	2.50	156.79	5107.57	0.01
Fruit and vegetable products	7.80	7.42	1.40	2.05	2.10	5.14	1.04	5.60	2224.83	0.00
Oils and fats	6.96	5.32	1.03	1.97	1.38	4.79	4.42	2.81	719.19	11.60
Flour mill products and cereal foods	11.65	13.66	4.09	26.39	10.80	31.98	5.79	17.95	2013.20	0.01
Bakery products	56.26	20.88	12.34	4.69	2.80	8.82	0.53	8.44	2704.53	0.01
Confectionery	7.96	3.99	1.38	23.82	10.90	126.65	5.50	11.25	1949.20	0.01
Other food products	21.93	41.55	5.37	119.65	56.32	650.60	41.63	33.69	3459.07	29.57
Soft drinks, cordials and syrups	1.52	2.79	2.10	8.34	5.79	12.76	1.09	4.91	3166.43	0.01
Beer and malt	1.94	0.87	0.13	0.45	0.33	0.80	0.15	3.03	1589.55	0.01
Wine, spirits and tobacco products	13.01	1.93	0.16	1.25	0.63	1.04	0.96	5.14	2382.18	0.01
Textile fibres, yarns and woven fabrics	6.63	3.22	0.35	1.39	0.87	1.87	1.07	4.67	128.30	0.01
Textile products	10.70	11.37	0.79	1.95	0.56	7.62	1.99	7.37	741.08	0.00
Knitting mill products	3.00	110.23	5.01	2.46	0.79	2.61	0.40	4.33	445.83	0.01
Clothing	11.88	30.90	4.67	6.43	2.85	19.04	2.82	38.44	981.29	0.01

Table B.1(k) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Education	Health services	Community services	Motion picture, radio & television services	Libraries, museums & the arts	Sport, gambling & recreational services	Personal services	Other services	Households	Current government expenditure
Footwear	1.83	6.48	0.41	1.88	0.79	7.34	0.39	1.83	230.50	0.00
Leather and leather products	1.98	1.77	0.13	3.35	1.42	72.25	0.17	0.71	29.01	0.00
Sawmill products	6.71	3.44	0.24	2.45	1.67	2.67	0.62	1.44	24.72	0.06
Other wood products	162.31	9.69	1.36	48.65	27.34	18.57	3.35	7.65	156.49	0.07
Pulp, paper and paperboard	4.02	9.56	1.04	3.67	17.92	2.57	7.44	28.04	55.88	0.00
Paper containers and products	47.16	258.65	37.46	4.26	3.88	3.53	15.16	20.99	774.17	0.00
Printing and services to printing	507.29	108.59	19.69	145.34	141.13	175.77	132.09	215.34	971.34	3.63
Publishing, recorded media, etc.	1056.02	45.82	7.98	72.59	123.35	59.50	61.94	112.42	4678.66	0.08
Petroleum and coal products	7.94	169.09	11.46	23.17	9.48	39.56	26.97	179.19	6503.08	7.76
Basic chemicals	42.07	428.06	6.93	45.71	8.71	81.11	68.55	62.63	356.94	8.39
Paints	0.87	1.43	0.32	9.53	1.88	9.13	1.25	2.41	34.49	0.01
Medicinal and pharmaceutical products, pesticides	7.74	233.39	16.51	44.78	3.71	106.84	17.68	21.40	1209.88	936.84
Soap and detergents	5.67	16.71	2.20	1.76	1.10	2.01	13.90	14.63	848.87	1.66
Cosmetics and toiletry preparations	0.33	1.18	0.07	0.38	0.07	0.65	2.60	0.37	311.89	2.06
Other chemical products	4.84	8.50	2.16	3.94	1.28	4.94	5.91	27.00	231.08	2.33
Rubber products	2.63	5.27	0.40	1.27	0.36	1.93	1.48	4.65	270.56	0.45
Plastic products	40.92	64.36	3.99	13.83	8.16	14.20	32.09	37.93	785.63	0.37
Glass and glass products	14.80	24.80	1.44	5.14	3.38	5.56	1.83	8.01	386.06	0.01
Ceramic products	4.27	0.98	0.44	1.24	0.39	1.31	0.90	0.85	64.92	0.00
Cement, lime and concrete slurry	3.29	2.92	1.78	1.57	0.63	1.38	6.22	11.25	19.11	0.02
Plaster and other concrete products	6.25	2.39	0.40	2.55	1.16	1.64	3.60	6.61	12.73	0.01
Other non-metallic mineral products	2.41	2.38	0.77	1.78	0.62	1.12	10.99	7.32	17.71	0.00
Iron and steel	34.05	9.28	1.09	8.62	5.19	7.94	5.32	12.43	52.88	1.62
Basic non-ferrous metal and products	33.69	23.78	2.97	22.28	6.91	27.74	29.48	16.44	169.38	4.74
Structural metal products	172.82	6.94	0.65	26.97	24.42	25.70	4.24	6.82	71.77	0.11
Sheet metal products	17.94	20.81	1.08	5.53	2.43	6.22	2.71	3.14	95.25	0.05
Fabricated metal products	55.74	40.89	5.33	72.91	23.16	67.12	12.35	42.52	323.56	0.09
Motor vehicles and parts, other transport equipment	64.74	15.20	2.28	20.91	8.23	18.60	5.69	28.32	7152.68	1.60
Ships and boats	1.64	1.26	0.19	3.32	0.94	2.96	0.32	4.58	563.46	1.61
Railway equipment	0.95	1.67	0.08	0.48	0.21	0.67	0.18	0.63	7.63	2.54
Aircraft	2.58	0.60	0.49	6.81	0.71	4.98	0.09	8.53	25.43	1.01
Photographic and scientific equipment	134.70	639.53	1.78	7.50	2.78	18.16	3.30	24.90	1177.30	4.37
Electronic equipment	51.50	22.98	2.08	31.43	8.05	34.32	2.76	14.57	661.28	0.06

Table B.1(k) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Education	Health services	Community services	Motion picture, radio & television services	Libraries, museums & the arts	Sport, gambling & recreational services	Personal services	Other services	Households	Current government expenditure
Household appliances	9.11	23.71	2.98	31.27	10.20	45.54	1.64	6.54	2477.13	0.04
Other electrical equipment	34.40	24.94	2.69	53.58	15.84	54.09	4.51	27.46	414.90	0.09
Agricultural, mining, etc. machinery	20.20	12.43	1.58	8.41	2.80	9.27	1.72	16.01	250.42	0.07
Other machinery and equipment	33.45	27.54	2.30	15.89	5.82	21.57	6.39	31.96	303.22	0.09
Prefabricated buildings	4.34	0.85	0.07	0.71	0.76	0.78	0.27	0.95	10.27	0.01
Furniture	209.06	7.48	1.02	16.77	21.20	10.98	3.75	9.06	2358.71	0.08
Other manufacturing	75.74	50.92	5.79	37.10	14.08	31.68	10.09	36.58	820.05	0.07
Electricity supply	1299.86	389.10	62.00	181.78	57.23	216.41	104.90	281.62	10480.47	138.55
Gas supply	50.39	64.21	13.29	6.31	2.58	7.30	6.42	13.88	1180.41	38.18
Water supply, sewerage and drainage services	98.26	131.87	21.33	39.17	16.61	41.01	63.45	170.96	5128.88	1600.23
Residential building	12.41	45.81	3.93	27.59	10.09	31.52	16.18	35.71	118.03	15.17
Other construction	20.08	66.88	6.43	37.87	13.90	43.13	21.89	51.81	242.35	4735.46
Construction trade services	59.47	77.87	12.34	18.85	11.43	20.23	14.51	37.41	333.70	17.45
Wholesale trade	1196.80	1751.80	80.23	564.08	199.19	752.74	263.89	558.54	21074.07	285.60
Wholesale mechanical repairs	3.19	0.00	0.00	1.39	0.15	2.21	0.19	2.39	0.00	0.00
Other wholesale repairs	157.38	48.90	22.32	43.25	22.79	47.28	50.38	109.74	307.28	0.00
Retail trade	444.39	260.92	28.03	197.92	81.79	239.43	50.51	158.13	73095.76	3500.41
Retail mechanical repairs	60.68	243.63	14.20	90.81	42.36	147.86	25.82	137.28	6288.31	0.00
Other retail repairs	36.77	20.55	6.62	11.34	4.04	3.20	11.00	17.48	631.97	0.00
Accommodation, cafes and restaurants	173.11	18.00	19.00	171.36	58.26	172.01	45.03	125.15	36929.27	4.17
Road transport	321.95	462.56	18.62	177.54	61.09	428.09	87.28	149.39	9914.19	1350.71
Rail, pipeline and other transport	17.03	18.90	3.59	7.59	3.78	9.21	2.53	10.22	2955.80	7.74
Water transport	11.75	1.13	6.78	32.48	5.16	180.40	6.97	64.02	441.79	0.00
Air and space transport	145.94	49.68	6.33	84.65	27.62	114.93	23.64	47.94	8426.13	0.00
Services to transport, storage	259.32	180.97	12.54	100.92	42.55	111.51	16.38	97.86	1673.46	9283.50
Communication services	1219.91	1063.92	109.79	629.65	222.77	942.51	452.73	1054.68	15865.42	101.13
Finance	1061.16	1532.18	108.37	599.73	271.89	660.91	257.07	367.98	45326.34	9.78
Ownership of dwellings	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	123166.19	-128.08
Other property services	318.30	485.89	51.82	919.47	346.22	1373.38	205.58	408.56	1258.70	71.81
Scientific research, technical and computer services	304.76	209.12	36.87	87.95	151.01	77.98	74.36	611.89	107.10	1763.98
Legal, accounting, marketing and business management services	605.67	1676.57	76.80	768.78	262.84	1049.42	436.74	508.53	3125.06	353.37
Other business services	489.54	1258.27	122.38	529.72	296.62	881.17	462.28	846.64	1286.38	4443.75

Table B.1(k) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Education	Health services	Community services	Motion picture, radio & television services	Libraries, museums & the arts	Sport, gambling & recreational services	Personal services	Other services	Households	Current government expenditure
Government administration	284.70	114.37	13.89	18.88	20.03	16.52	65.08	17.71	1418.87	48922.65
Defence	1.90	0.51	0.20	0.54	0.97	0.49	0.64	4.94	0.00	21228.67
Education	756.21	76.87	15.69	34.67	94.49	21.92	49.31	282.61	20514.94	33273.19
Health services	49.77	480.58	4.55	25.36	2.13	39.81	3.50	34.02	23522.61	48432.90
Community services	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3004.38	13455.31
Motion picture, radio and television services	11.51	14.04	9.46	2681.19	210.13	401.62	69.93	82.99	1907.64	1520.61
Libraries, museums and the arts	606.48	24.18	14.11	215.34	165.80	165.23	0.95	82.08	979.51	3513.40
Sport, gambling and recreational services	189.45	149.63	43.52	523.26	42.74	545.92	15.65	66.45	14871.53	2093.68
Personal services	51.89	559.33	2.41	39.79	6.22	12.62	14.40	9.34	9092.39	175.64
Other services	30.67	62.82	5.10	4.14	1.84	8.49	12.86	16.86	9898.33	14550.98
Total intermediate usage including imports	**15872**	**17842**	**1362**	**11299**	**4110**	**12951**	**4039**	**9231**		
Wages and salaries	43195	47633	11048	2589	2429	4977	4570	13807		
Gross surplus	3582	6524	3721	2428	949	2780	1755	2053		
Indirect taxes on production	1321	1862	333	482	163	567	267	808		
Total gross output	**63970**	**73862**	**16464**	**16798**	**7652**	**21275**	**10630**	**25899**	**590654**	**220243**
Value added at factor cost to output ratio	0.75	0.76	0.92	0.33	0.46	0.39	0.62	0.64		
Share of wages and mixed income in value added	0.94	0.92	0.80	0.54	1.10	0.73	1.23	0.85		
Employment to gross output ratio	12.97	12.19	14.95	7.72	21.08	14.42	25.65	11.97		
Foreign ownership ratio	0.01	0.02	0.01	0.08	0.01	0.05	0.00	0.03		
Direct tax rate on surplus	0.03	0.06	0.01	0.08	0.04	0.18	0.04	0.03		
Indirect tax rate on production	0.02	0.03	0.02	0.07	0.03	0.05	0.03	0.04		
Foreign income payout ratio	0.00	0.00	0.00	0.03	0.00	0.01	0.00	0.00		
Replacement depreciation to value added ratio	0.09	0.06	0.06	0.37	0.06	0.22	0.12	0.08		
Net national product ratio	0.91	0.93	0.93	0.60	0.94	0.77	0.88	0.91		
Domestic income distribution ratio	0.06	0.07	0.19	0.37	0.00	0.22	0.00	0.13		

Table B.1(l) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Construction investment	Equipment investment	Inventories	Exports
Sheep	0.00	367.11	-8.63	1648
Grains	0.00	0.00	-64.03	5317
Beef cattle	0.00	2254.63	-37.56	490
Dairy cattle	0.00	459.16	0.55	52
Pigs	0.00	0.00	-14.40	0
Poultry	0.00	0.00	-19.61	8
Other agriculture	0.00	0.00	-25.27	1108
Services to agriculture, hunting and trapping	0.00	0.00	-48.42	415
Forestry and logging	0.00	0.00	-16.53	111
Commercial fishing	0.00	0.00	0.20	229
Coal	0.00	568.02	142.88	52158
Gas	0.00	3201.73	341.65	0
LNG	0.00	0.00	0.00	10086
Oil	0.00	0.00	0.00	8757
Iron ores	0.00	3.58	1.01	32652
Non-ferrous metal ores	0.00	131.56	-0.94	9501
Other mining	0.00	4.53	2.49	815
Services to mining	0.00	1354.05	0.00	6
Meat and meat products	0.00	46.94	58.23	5538
Dairy products	0.00	24.20	-5.49	2415
Fruit and vegetable products	0.00	37.87	28.69	995
Oils and fats	0.00	12.50	9.13	409
Flour mill products and cereal foods	0.00	42.06	5.52	1049
Bakery products	0.00	34.54	-2.99	383
Confectionery	0.00	29.83	16.29	555
Other food products	0.00	115.58	-18.45	3924
Soft drinks, cordials and syrups	0.00	9.59	-6.64	208
Beer and malt	0.00	10.96	-1.19	386
Wine, spirits and tobacco products	0.00	20.49	-0.94	2593
Textile fibres, yarns and woven fabrics	0.00	49.14	-5.38	342
Textile products	0.00	449.10	10.85	188
Knitting mill products	0.00	14.80	7.10	60
Clothing	0.00	87.42	-2.87	612
Footwear	0.00	18.90	-2.29	79
Leather and leather products	0.00	25.96	7.04	853

Table B.1(l) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Construction investment	Equipment investment	Inventories	Exports
Sawmill products	0.00	33.84	13.24	988
Other wood products	0.00	136.99	14.28	165
Pulp, paper and paperboard	0.00	10.03	23.00	575
Paper containers and products	0.00	18.60	1.81	317
Printing and services to printing	0.00	35.38	-7.12	195
Publishing, recorded media, etc.	0.00	664.14	19.64	337
Petroleum and coal products	0.00	4835.19	91.99	2642
Basic chemicals	0.00	171.26	16.52	2173
Paints	0.00	31.11	2.45	145
Medicinal and pharmaceutical products, pesticides	0.00	55.56	-1.65	2483
Soap and detergents	0.00	13.30	-0.16	264
Cosmetics and toiletry preparations	0.00	4.51	-0.27	277
Other chemical products	0.00	26.95	-4.89	477
Rubber products	0.00	44.93	1.00	256
Plastic products	0.00	495.63	2.16	716
Glass and glass products	0.00	25.24	4.32	285
Ceramic products	0.00	5.96	4.04	95
Cement, lime and concrete slurry	0.00	24.71	17.36	50
Plaster and other concrete products	0.00	31.73	45.95	59
Other non-metallic mineral products	0.00	8.86	16.48	118
Iron and steel	0.00	368.19	-26.72	4081
Basic non-ferrous metal and products	0.00	248.57	-90.04	34003
Structural metal products	0.00	323.32	60.62	278
Sheet metal products	0.00	966.17	11.80	235
Fabricated metal products	0.00	1213.54	14.21	816
Motor vehicles and parts, other transport equipment	0.00	4265.86	-18.35	3037
Ships and boats	0.00	675.16	-3.93	302
Railway equipment	0.00	431.41	-0.53	67
Aircraft	0.00	764.41	-4.96	529
Photographic and scientific equipment	0.00	775.40	1.48	1587
Electronic equipment	0.00	1053.21	-6.66	1075
Household appliances	0.00	776.38	29.04	260
Other electrical equipment	0.00	641.62	-16.43	777
Agricultural, mining, etc. machinery	0.00	3181.43	23.91	1013
Other machinery and equipment	0.00	2497.14	15.09	1612

Table B.1(l) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Construction investment	Equipment investment	Inventories	Exports
Prefabricated buildings	0.00	248.88	0.96	38
Furniture	0.00	1527.52	2.36	156
Other manufacturing	0.00	462.21	32.19	1137
Electricity supply	0.00	5618.74	3.14	65
Gas supply	0.00	872.11	176.07	2
Water supply, sewerage and drainage services	0.00	748.00	0.00	12
Residential building	51612.53	0.00	0.00	131
Other construction	99054.39	0.00	0.00	188
Construction trade services	25627.21	0.00	-0.69	398
Wholesale trade	0.00	20936.44	-31.07	14076
Wholesale mechanical repairs	0.00	0.00	0.00	0
Other wholesale repairs	0.00	0.00	0.00	1
Retail trade	0.00	2495.55	4.31	4076
Retail mechanical repairs	0.00	0.00	0.00	21
Other retail repairs	0.00	0.00	0.00	0
Accommodation, cafes and restaurants	0.00	1.36	0.00	5417
Road transport	0.00	2825.68	-17.96	7703
Rail, pipeline and other transport	0.00	109.78	-0.70	4429
Water transport	0.00	8.45	0.09	976
Air and space transport	0.00	58.65	0.00	4633
Services to transport, storage	0.00	85.99	-0.21	3365
Communication services	0.00	3980.24	0.00	816
Finance	0.00	142.67	0.00	1453
Ownership of dwellings	0.00	0.00	0.00	529
Other property services	0.00	8617.07	0.00	569
Scientific research, technical and computer services	0.00	12231.62	0.00	2652
Legal, accounting, marketing and business management services	0.00	955.75	0.00	2312
Other business services	0.00	0.00	0.00	970
Government administration	0.00	347.48	0.00	41
Defence	0.00	84.50	0.00	84
Education	0.00	64.59	0.00	4788
Health services	0.00	26.80	0.00	612
Community services	0.00	0.00	0.00	4
Motion picture, radio and television services	0.00	565.14	0.00	232

Table B.1(l) Australia input-output flow table with direct allocation of imports – $2009m (continued)

	Construction investment	Equipment investment	Inventories	Exports
Libraries, museums and the arts	0.00	85.63	0.00	162
Sport, gambling and recreational services	0.00	0.00	0.00	596
Personal services	0.00	0.00	0.00	163
Other services	0.00	0.00	0.00	48
Total intermediate usage including imports				
Wages and salaries				
Gross surplus				
Indirect taxes on production				
Total gross output	**176296**	**139197**	**587**	**269081**
Value added at factor cost to output ratio				
Share of wages and mixed income in value added				
Employment to gross output ratio				
Foreign ownership ratio				
Direct tax rate on surplus				
Indirect tax rate on production				
Foreign income payout ratio				
Replacement depreciation to value added ratio				
Net national product ratio				
Domestic income distribution ratio				

Large scale export of East Coast Australia natural gas: Unintended consequences

National Institute of Economic and Industry Research[1]

This note summarizes the major conclusions of the NIEIR study referenced here. Many major projects to export Liquefied Natural Gas from Eastern Australia have been approved and will start to operate over the next several years. This will significantly impact the domestic supply of natural gas. The National Institute of Economic and Industry Research (NIEIR) has done an assessment, reviewing the literature and conducting its own analysis of the sectoral and macroeconomic implications of these developments.

NIEIR has found that:

- If existing plans proceed, gas exports from eastern Australia will rise from 2 million tonnes (0.29 bcf/day) in 2015 to 20 million tonnes (2.9 bcf/day) in 2018, and possibly 24 million tonnes (3.44 bcf/day) in 2023;
- The current policy framework and market settings for the Australian gas industry favor export of LNG without a subsequent assurance of reliable, competitively priced supplies of gas for domestic industry. Such supplies have historically been a competitive advantage for Australian industry, and gas export revenue is insufficient to compensate Australia for the loss of this advantage;
- Natural gas is essential to a range of industries, particularly non-ferrous metals and basic chemicals, but also plastics, pharmaceuticals, paints and cosmetics. Secure local supply at competitive prices is a fundamental requirement for the continuation of a significant part of production and the development of new investment in these industries;
- Contracts for the long term supply of gas to domestic industry have ‘evaporated’ as a consequence of export commitments;
- Australia has only a few years before significant economic loss is likely to be felt from the failure to secure an affordable supply of natural gas to domestic users;
- Domestic gas users are increasingly being offered “surplus” gas volumes and prices that do not reflect domestic supply, demand or extraction costs, but are instead linked to East Asia’s LNG market – the highest-priced gas in the world. This is a radical reshaping of the domestic gas market, constraining supply (in the near term at least) and driving prices to high (and for many industries uneconomic) levels;
- Current gas production and proven reserves will need to expand dramatically in order to support the LNG expansion without significant large scale suppression of gas use on the domestic economy. While the total gas resource is thought to be very large, proving up additional resources and developing them will take time and faces community opposition and other barriers. To ensure gas availability for domestic users, the management of reserves and their supply to market needs attention if domestic needs are not to be overlooked in the rush to export this valuable resource;
- There are important opportunities to expand use of gas in industrial production and electricity generation, but even so domestic consumers cannot make use of the whole gas resource. There are worthwhile benefits to pursue from exporting gas production beyond these needs. But each cubic foot of natural gas that is shifted away from industrial use towards export, whether because of tight supply or uneconomic pricing, means giving up $255 million in lost industrial output for a $12 million gain in export output. That is, for every dollar gained $21 is lost. This increases to $24 when economy-wide impacts are taken into account;
- The dramatic shift in the domestic gas market will have wider impacts well beyond the gas intensive industries:
    - Increased operating costs for gas-fired electricity generators due to high gas prices. Such generators would see cost increases three times greater than those currently resulting from the carbon tax. Wholesale electricity prices would thus rise, and the viability of new gas-fired generation would suffer. These plants already play an important role in the electricity market for both peak power and base load. That role is expected to grow to meet emissions reduction targets and provide backup for expanding renewable generation;

[1] http://www.nieir.com.au

    - Some substitution away from gas towards electricity by business and households, to reduce their exposure to rising gas prices. This would still leave their costs higher than at present, and would raise greenhouse emissions;
    - A slow-down of general economic activity resulting from impacts of the tighter gas supply and higher costs for gas and electricity;
- The expected economic response to the East Coast LNG expansion will involve a combination of the adjustments above. As a result, modeling indicates that, by 2040 the gross production benefit for East Coast LNG expansion will be $15 billion annually, in 2009 prices. However, taking into account the negative effects of adjustment on other sectors, annual GDP will be $22 billion lower than it would be with secure and affordable gas. An alternative 'benefit indicator' used for this study, which combines private consumption, tax receipts and net national product, will be reduced by $46 billion;
- Under current policy settings and market structures, the unwanted consequences of the significant boom in LNG exports will persist even if, as is likely, adequate natural gas reserves exist and are brought to market; and there are substantial further risks that would lead to even greater costs if realized. These risks include:
    - LNG prices may be lower than currently expected. While this would reduce the extent of domestic price rises, it would also reduce gross export benefits while leaving domestic supply constrained in the short-to-medium term by contracted export commitments; and
    - Industry will likely be unable to grow without secure affordable gas supplies, leading to additional damage.

The likely consequences of the current policy and industry settings on natural gas export are serious for both industry and households. LNG export is a positive for Australia as long as it proceeds without significant harm to the domestic sector and with confident assurance of domestic supply.

Reference

National Institute of Economic and Industry Research, "Large scale export of East Coast Australia natural gas: Unintended consequences." A report to the Australian Industry Group and the Plastics and Chemicals Industries Association, October 2012.

Mining the Data: Analyzing the Economic Implications of Mining for Nonmetropolitan Regions

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Extractive industries such as logging and mining are generally expected to bring significant economic benefits to rural regions, but a growing number of findings have now challenged that common expectation. Still, it is not clear whether the findings of less-than-desirable economic outcomes are isolated or representative. In this article, we assemble literally all of the relevant quantitative findings on mining that we have been able to identify in published and/or technical literature from the United States. In the interest of rigor, we limit the assessment to cases in which strictly nonmetropolitan mining regions are compared against other nonmetropolitan regions and/or against those regions' own experiences over time. Overall, 301 findings meet the criteria for inclusion. Contrary to the long-established assumptions, but consistent with more recent critiques, roughly half of all published findings indicate negative economic outcomes in mining communities, with the remaining findings being split roughly evenly between favorable and neutral/indeterminate ones. Positive findings are more likely to be associated with incomes than with poverty or (especially) unemployment rates, and they are more likely to come from the western United States, where much of the mining involves relatively large, new coal strip mines. Over half of all positive findings come from the years prior to 1982. In virtually all other categories, the plurality or majority of findings have been negative. When the patterns of findings are subjected to one-sample means tests, the only way to produce a significantly positive outcome is by combining all neutral/indeterminate findings with the positive ones, while focusing exclusively on incomes; by contrast, in the case of poverty or unemployment rates—as well as for the overall body of findings—the results are consistently and significantly negative, whether the neutral/indeterminate findings are combined with negative ones or omitted from the equations altogether. Until or unless future studies produce dramatically different findings, there appears to be no scientific basis for accepting the widespread, "obvious" assumption that mining will lead to economic improvement.

Both in academic and popular discourse, the common assumption has long been that the potential environmental threats from extractive industries such as logging and mining will be accompanied by economic benefits for the industries' host regions (see, e.g., Imrie 1992; Thompson and Blevins 1983, p. 153; cf. Humphrey et al.1993; see also Lewan 1993). Indeed, particularly for areas that are remote from urban agglomerations and industrial development, the extraction of raw materials from nature is often seen to be the only hope for economic

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development. At least in principle, it would seem reasonable to expect a rich natural resource endowment to translate into increased prosperity, because resource-dependent industries have significantly less locational flexibility than do most other industrial activities. New mines, for example, can only have a realistic opportunity to be profitable in locations where actual mineral deposits are available. In recent years, however, the common assumptions have begun to be undercut by a growing body of findings.

To date, it is not clear whether the findings of less-than-desirable socio-economic outcomes are idiosyncratic or systematic. In this article, accordingly, we seek to provide a comprehensive summary and assessment of the accumulated findings, focusing on mining-dependent communities. We begin with a qualitative review of the existing literature, including known technical reports and other "gray" literature as well as the findings published in peer-reviewed journals. We follow with a quantitative analysis of the key categories of available socioeconomic findings—those on income, unemployment, and poverty rates—that permit "apples to apples" comparisons of the experiences of nonmetropolitan mining regions against those of nonmetropolitan comparison regions and/or against their own experiences over time. The closing section considers this study's implications for future research on natural resource development in nonmetropolitan regions.

Overview of the Literature

Over the past several decades, researchers have begun to question the once-common assumption that mining would bring socioeconomic prosperity to host regions. The questioning appears to have begun outside of the United States, when authors such as Frank (1966, 1967) began to draw attention to "underdevelopment," which was argued to be due in part to unfavorable terms of trade—with raw materials being sent out from extractive regions at relatively low prices, in unequal exchange for finished products that needed to be imported at high prices. In subsequent years, other international studies (see, e.g., Barham and Coomes 1993; Bunker 1985; Repetto 1995; Schurman 1993) have indicated further reasons for concern. Indeed, careful quantitative analyses have found that—even after controlling statistically for other variables, ranging from the openness of a national economy, to the efficiency of national bureaucracy, to the degree of inequality in national income concentration—nations with high rates of natural resource exports have had abnormally low rates of subsequent economic growth (see, e.g., Sachs and Warner 1995; for a careful review of the larger literature on this "resource curse," see especially Ross 1999).

The work of Corden and Neary (1983) helped to draw increased attention to the paradoxical implications of extractive industries in industrialized countries, highlighting what the authors called "Dutch disease": Holland's massive North Sea oil revenues were actually found to be associated with declining rather than improving economic fortunes. At least initially, however, such findings received relatively little attention in U.S. community studies. As many rural community leaders have been quick to point out, after all, jobs in logging and mining tend to pay far higher wages than do service jobs such as cleaning hotel rooms or serving fast-food hamburgers. This point is not simply a widespread belief with no empirical support; instead, the nationwide study by Mills (1995), for example, found that earnings per worker were higher in mining than in many other economic sectors—whether considering metropolitan or nonmetropolitan regions, and whether focusing on the "mining boom time" of 1980 or on the nonboom years of 1970 and 1990. In important respects, accordingly, it has long seemed "obvious" to many commentators that extractive industries should be associated with significantly increased local prosperity. In addition, while examinations of the economic characteristics of mining communities have had a long history in the social sciences (for a review, see Field and Burch 1991), few studies seriously questioned the common assumptions and expectations until the 1980s.

Moreover, in one of the first studies to look at the topic in a broad-brush fashion, Bender et al. (1985) obtained results that were reasonably consistent with the usual expectations. Drawing data largely from the 1980 Census of Population and Housing and using a definition that would later be followed by many other authors—with "mining-dependent" counties being those where 20 percent or more of total labor and proprietor income came from mining—Bender et al. found that mining-dependent counties had higher population growth rates, higher incomes, and fewer people receiving social security than the nonmetropolitan average of the times. The study did note, however, that "the variations among counties . . . were large," and that decreases in demand for fuels and minerals between 1979 and the time of their study in 1985 had "produced income and population declines" that did not show up in their study's quantitative analyses (Bender et al. 1985, p. 9).

The subsequent trends were soon to be documented more systematically. Hady and Ross (1990), both of whom were coauthors on the original Bender et al. study, conducted an update, examining the differences between counties that were mining-dependent by the same definition in 1979 (during the height of the energy crisis and mineral prices) and in 1986 (after both a recession and a drop in mineral prices). In the 7 years between 1979 and 1986, mining employment in the nonmetropolitan United States declined by 14 percent; 50 counties ceased being mining-dependent, while only 19 others became mining-dependent during that period. On average, whether focusing on the counties that were mining-dependent in 1979, 1986, or both, the follow-up study found declining personal incomes and increasing unemployment from 1979 to 1986.

Other researchers soon found evidence that less-than-favorable findings were not limited to a 7-year period. In a more comprehensive review of natural-resource-oriented industries, for example, Weber, Castle, and Shriver (1987) found that, while counties with energy-related mining experienced growth in both employment and earnings during the generally "booming" years of 1969–1985, counties with metal mining experienced declines in both indicators, even during those years.

These kinds of results have raised questions about the degree to which the findings from Bender et al. (1985) may have been influenced by the extraordinary conditions in energy extraction that happened to be approaching their peak around the time period considered in that initial study. One of the points that has become quite clear, for example, is that the areas of the United States having the highest levels of long-term poverty, outside of those having a history of racial inequalities, tend to be found in the very places that were once the site of thriving extractive industries—most notably in Appalachia (Gaventa 1980), but to a lesser extent also in other one-time mining and logging areas such as the "cutover region" of the Upper Midwest (see, e.g., Landis 1938; Lisheron 1991; cf. Schwarzweller and Lean 1993). Perhaps more ominously, the reasons for concern are not limited simply to the implications of ultimate shutdowns or "busts." Several studies have found evidence of problems even while extraction is occurring (e.g., Cook 1995; Drielsma 1984; Elo and Beale 1985; Freudenburg and Gramling 1994; Krannich and Luloff 1991; Peluso et al. 1994; Tickamyer and Tickamyer 1988).

In subsequent years, a number of studies have compared census data from different regions and times. Perhaps the most systematic of these analyses can be found in the work of Nord and Luloff (1993), who offered three kinds of comparisons—comparing data from the 1980 and 1990 censuses, from three regions of the country (the west, the south, and the Great Lakes), and from three different sectors of the mining industry (coal, petroleum, and "other," the last of which includes metal mining and quarrying). These authors' analyses mirrored the findings of Bender et al. in showing that conditions were relatively favorable at the time of the 1980 census, but further analyses showed that the economic implications of mining in all three regions of the country, and in all sectors of the mining industry, had deteriorated since that time. Except in the western region, in fact, unemployment was found to be consistently higher in mining counties than in other nonmetropolitan counties, in each respective region of the country, both in 1980 and in 1990. By 1990, in all but the western region, mining-dependent counties had lower incomes and more persons in poverty than did the nonmining counties. In all regions of the country, including the west, mining-dependent counties experienced greater increases in poverty rates from 1980 to 1990 than did other nonmetropolitan counties. All in all, the only favorable findings associated with mining areas in the 1990 census were found in the western United States—and even there, the findings provided less reason for optimism than had appeared to be the case in 1980.

Other studies have found that local residents' widespread expectations for improved employment may be particularly problematic. In analyzing a decade's worth of data compiled by Weber et al. (1987), for example—a period that included both the "boom years" of extractive industries in the late 1970s and the "agricultural crisis" years of the early 1980s—Krannich and Luloff (1991) found that mining-dependent counties had higher levels of unemployment than did agriculture-dependent counties, in every single year, even during this period. In addition, there is at least suggestive evidence that mining communities' economic problems tend to become increasingly pronounced over time, exacerbated by the volatility of commodity prices, the potential for a cost–price squeeze, and the problem of "flickering" (i.e., the periodic shutting down of extractive operations, as prices fluctuate above and below the costs of operation in specific locations—see Hibbard and Elias 1993). This flickering can contribute to problems of unemployment and poverty, given that laid-off workers will often choose to remain in the area, sometimes for extended periods, in the hope or belief that the high-wage jobs will ultimately return (see, e.g., Freudenburg 1992; Krannich and Luloff 1991).

Perhaps in part because of findings such as the ones being summarized here, there is a potentially telling contrast in two types of studies that have gauged the reactions of local leaders. In regions that are expecting increased mining or just beginning to experience a "boom," it is common to find what Gulliford (1989) calls "euphoria." Unfortunately, in regions that have actually experienced natural resource extraction, local leaders have been found to view their economic prospects less in terms of jubilation than of desperation (e.g., Krannich and Luloff 1991; Freudenburg 1992; Gulliford 1989; Peluso et al. 1994; cf. Cottrell 1951, 1955; Gaventa 1980). Thus, while the largest of the nine working groups established by the Rural Sociological Society's Task Force on Rural Poverty was the one that focused on natural resources, the working group ultimately identified resource extraction not as an antidote to poverty, but as something more like a cause or correlate. In the authors' terminology, they found resource extraction to have a "systematic relationship" with "the impoverization of rural people"—so much so that the bulk of their review was devoted to an effort to identify "social forces at work in resource-dependent rural communities that lead to the creation of relative and/or absolute poverty" (Humphrey et al. 1993, pp. 137–8; see also the responses to this report, including Freudenburg and Gramling 1994; Peluso et al. 1994; Nord and Luloff 1993).

Quantitative Analysis of Available Findings

While even a qualitative literature review can illustrate the need for caution, there is clearly also a need for a more systematic assessment of the relevant evidence. Mining would appear to deserve particularly close attention in that, to repeat, jobs in mining tend to be associated with some of the highest incomes in any economic sector (Mills 1995). In response, we have sought to bring together and analyze the available findings in a way that would be more systematic, and yet that could be reported in a manner that is as straightforward as possible.

As suggested by the foregoing review, there are many differences across the available studies—a fact with a number of important implications. First and most clearly, differences in the units of analysis and the operationalization of variables mean that any comparisons need to be interpreted with caution—as being indicative of overall patterns, rather than as providing definitive or clearcut answers. Second, the available findings are not independent; instead, there are multiple overlaps but also differences across studies. In terms of overlaps, for example, many authors use statistics from the Census and/or the Bureau of Labor Statistics, but at the same time, there are many differences in the time periods and specific sets of counties being considered. In terms of differences, some authors distinguish carefully between "community-level" versus "county-level" data, while others use the terms more or less interchangeably, and some authors focus on officially "rural" communities (those with fewer than 2,500 residents), while many other studies include nonmetropolitan regions more broadly.

Such overlaps and differences would make it inappropriate and potentially misleading to perform extensive statistical transformations or analyses; instead, the more responsible approach is to assess the findings in terms of simple and easy-to-understand categories. In the analyses that follow, accordingly, we have classified the results in terms of a three-way typology—as indicating, in other words, conditions that are more favorable, less favorable, or no different from the conditions prevailing in relevant nonmining areas and/or during earlier time periods. In the effort to avoid the imposition of our own views, we have deferred to the original authors' interpretations of the data whenever such interpretations are available. A "favorable" finding, for example, thus usually reflects the judgement of those who wrote the report or article in question, whether the judgement was based on statistical analyses or on simple comparisons of descriptive data.

It is also important to recognize that the available literature poses still other challenges for an effort that is intended to be both careful and conservative. In particular, while the overall body of literature addressing the economic well-being of mining-dependent areas is vast, the number of studies explicitly offering systematic, quantitative data on the impacts of mining in the rural United States is actually much smaller. In the process of selecting the findings for analysis, accordingly, we needed to proceed in two main steps. The first step was to conduct an extensive search of articles published in peer-reviewed journals, books and chapters, technical reports, and governmental documents and publications. Because of this process, we ultimately identified several hundred reports and publications in all. In the second step, however, we found it necessary to deal with the potentially misleading variations across studies by requiring an appropriate degree of consistency in the studies that were selected for more detailed examination. This process ultimately led to the identification of four relatively stringent criteria that were necessary to permit direct and meaningful comparisons and to the elimination of all studies that were unable to meet the criteria.

The first criterion was the most straightforward. The studies needed to present enough comparative data—whether across locations, across time, or both—to permit a reasonable assessment of net economic impacts for the areas affected. Second, the studies needed to provide quantitative assessments of the impacts of mining activity in nonmetropolitan communities or regions in the United States. This criterion alone was enough to eliminate roughly half of the otherwise "available" studies (e.g., those from other nations), and even in the remaining studies, there were a number of variations in the definitions of "mining" and mining dependency. Most studies have used broad definitions, encompassing the full range of metal, coal, and oil-extraction activities, as well as quarrying, while a smaller number have focused on one type of mineral. Nearly half of the studies defined "mining dependency" according to the criterion used by Bender et al. (1985), including only those counties that received at least 20 percent of their total labor and proprietor income from mining during the period specified. The remaining studies followed one or more mining areas over time, required that a given percentage of local employment be from mining, or relied on measures involving a mixture of income and employment from mining.

The third criterion also requires additional discussion: For purposes of comparability, the data in question needed to present at least one of the three variables most commonly included in such studies—namely, incomes, unemployment rates, and poverty rates—corresponding closely to the three kinds of local economic benefits that are commonly expected to be associated with mining. Even among the studies meeting this criterion, however, there proved to be a number of variations, particularly in the definitions of "poverty" and "income." In the comparisons that follow, accordingly, the "poverty" category will include all findings regarding the percentage of persons in poverty, the percentage of children in poverty, and the percentage of families in poverty, while the "income" category includes studies that provide data on median household income, per capita income, and/or wage and salary earnings. The measures of "unemployment," by contrast, involve fewer variations, usually referring to the percentage of the workforce unemployed at the time of data collection, although a few studies use analyses of unemployment insurance payments.

The fourth and final criterion proved to be particularly conservative. Even after the application of the first three criteria, there were still 363 known, quantitative findings in the available literature. The fourth criterion, however, required the exclusion of all areas that were merely "predominantly" rural or nonmetropolitan, although many people think of predominantly rural states, such as North Dakota, or cultural regions, such as upstate New York or Appalachia, as being "rural." The reason was straightforward: Given that metropolitan areas tend to have significantly stronger economic conditions than do nonmetropolitan areas, important biases might be created by comparing (genuinely) nonmetropolitan mining regions against "control" regions that actually included one or more metropolitan areas (e.g., by comparing the nonmetropolitan mining counties in a given location against the average for the entire region, or for the United States as a whole). The net effect of this fourth criterion was to lower by 51 the number of "adverse" findings on the economic implications of mining, while lowering "positive" findings by only 11. Still, even after the application of this fourth and final criterion, there remained 301 of the "more conservative," quantitative findings, derived from 19 separate studies.

As indicated by Figure 1A, by far the most common findings in the literature are those involving adverse economic outcomes in mining regions. The dashed-line totals indicate that adverse findings constitute an outright majority of the "known" findings (those meeting all but the fourth criterion). Even after the imposition of the fourth and most conservative criterion, just under half of the findings that remain—139 of the remaining 301 findings, in other words, or 46.1 percent of them—indicate the economic conditions in mining regions to be worse than those in the relevant comparison regions. The remaining findings are split roughly evenly between neutral and favorable outcomes, at 74 (24.6%) and 88 (29.2%), respectively. For purposes of clarity, Figure 1B includes only the "more conservative" 301 findings, and in the remainder of this article as well, we will analyze only the 301 findings that meet all four criteria for inclusion. What Figures 1A and 1B show, at least at an overall level, is that favorable or improving economic conditions need to be recognized as being considerably less common in the empirical literature to date than are unfavorable or declining conditions.

Still, to leave the matter there might be too simple. As could be expected on the basis of the preceding literature review, there are a number of variations in the relationships between mining and economic well-being. While the variations among available studies suggest that more detailed analyses should be undertaken only with caution, as noted earlier, there are three types of additional comparisons that are particularly worthy of attention. First are those that focus on the differences that emerge from examining specific indicators of socioeconomic conditions (i.e., incomes, unemployment, and/or poverty rates); second are those that deal with regional variations; and third are those that offer insights into change over time. We will discuss the three in that order. In the interest of conservatism, all of the more detailed comparisons that follow will use only the

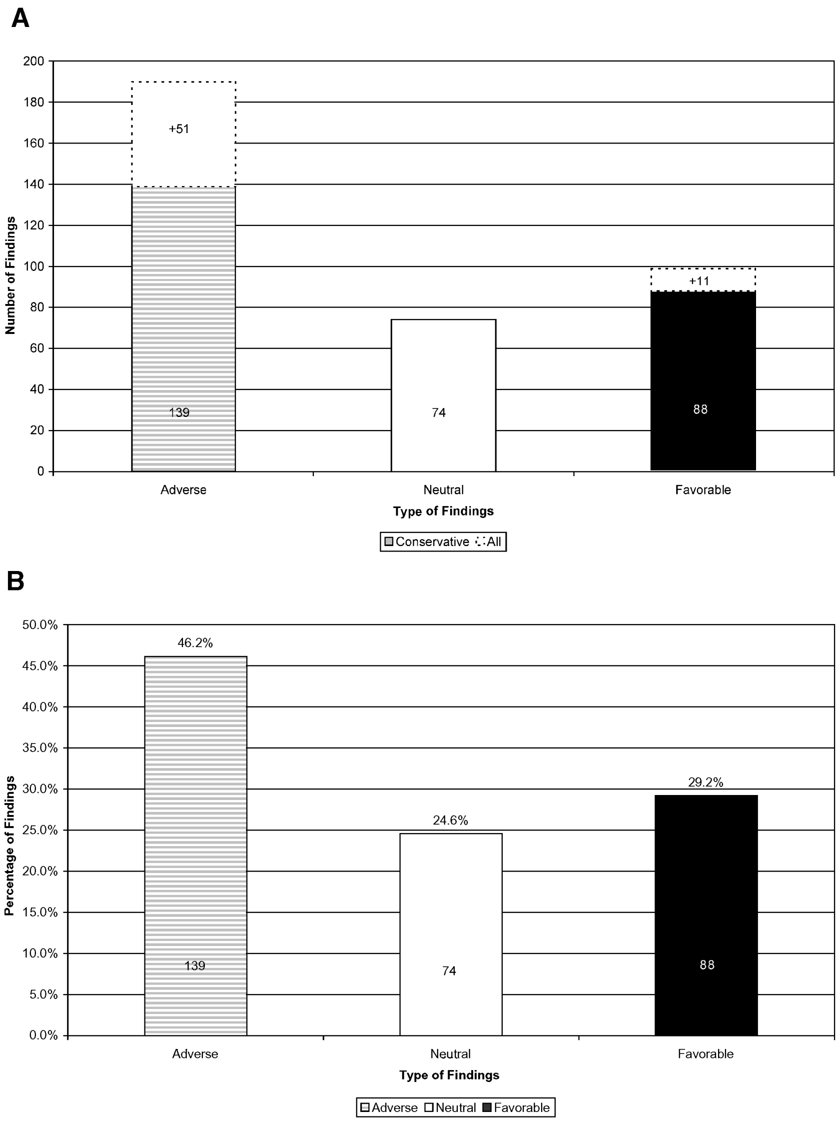

Figure 1

(A) All findings versus "conservative findings." (B) Summary of findings (used in final analysis).

301 findings that meet all four of the criteria for inclusion, and tests of statistical significance will be presented only for the overall totals and for the comparisons involving overall socioeconomic measures or indicators.

Differences across Indicators

The first set of more detailed comparisons involve differences across the three different socioeconomic indicators noted above—income, unemployment rates, and poverty rates. Of the three indicators, the most positive picture emerges from studying incomes, as illustrated in Figure 2. The available studies provide 118 quantitative findings on income differences; in 56 of these cases, or nearly half of the time, mining activity has been associated with higher incomes than in nonmining areas or in previous time periods. Incomes are lower in about one-third of the findings (40, or 33.9%) while the remaining 22 findings (18.6%) indicate a situation that is "no different." Thus, while it may not be literally accurate to describe mining as leading to improved incomes, more findings do fall into the "favorable" category than into the other two, suggesting that mining has indeed been associated with higher income levels in many cases.

A less favorable picture emerges, however, when we consider the fuller range of economic findings. Despite the fact that impoverished rural communities often expect mining to reduce their poverty rates, for example, the findings fail to

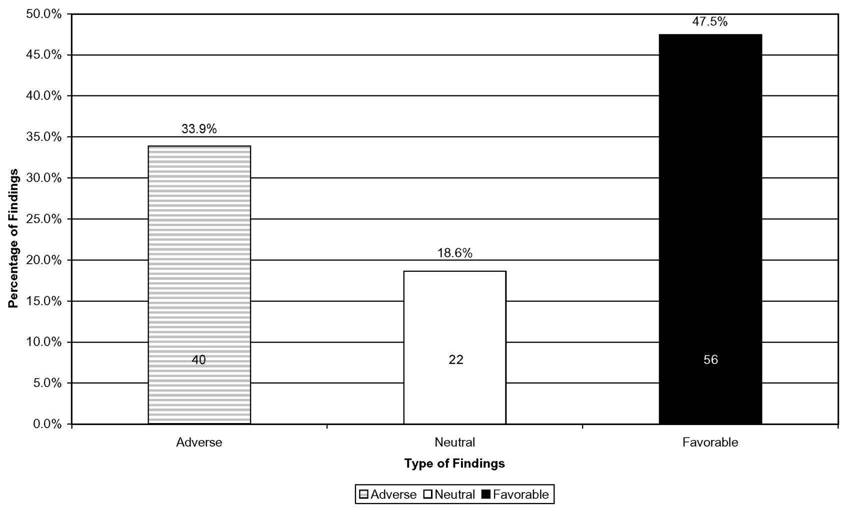

Figure 2
Summary of income findings.

support this common assumption. As can be seen from Figure 3, only about 20 percent of the 59 available findings on the topic indicate mining areas to be associated with lower poverty rates. Instead, more than twice as many findings—26 findings, or 44.1 percent—indicate higher levels of poverty in mining areas, while the remaining 21 findings (35.6%) indicate poverty levels that are neither higher nor lower than in the relevant comparison areas. Likewise, despite the usual assumption that mining will reduce the unemployment problems of rural areas, studies to date have actually tended to find higher levels of unemployment in mining areas than elsewhere. As can be seen from Figure 4, which summarizes the available findings on unemployment rates, a clear majority of the available findings (73 of the 124 findings, or 58.9%) indicate higher levels of unemployment in areas characterized by high levels of mining activity, while another 25 percent of the findings (31) point to conditions that do not differ between mining and comparison areas. Despite the widespread expectation that mining will lower local unemployment rates, actual findings of such favorable conditions prove to be relatively rare, making up the smallest category of all, with just 20 findings (16.1%) suggesting unemployment rates to be lower in mining areas than in comparison areas.

In addition to the graphic presentation of evidence in Figures 1–4, we have provided a quantitative summary and a set of significance tests in Table 1. The

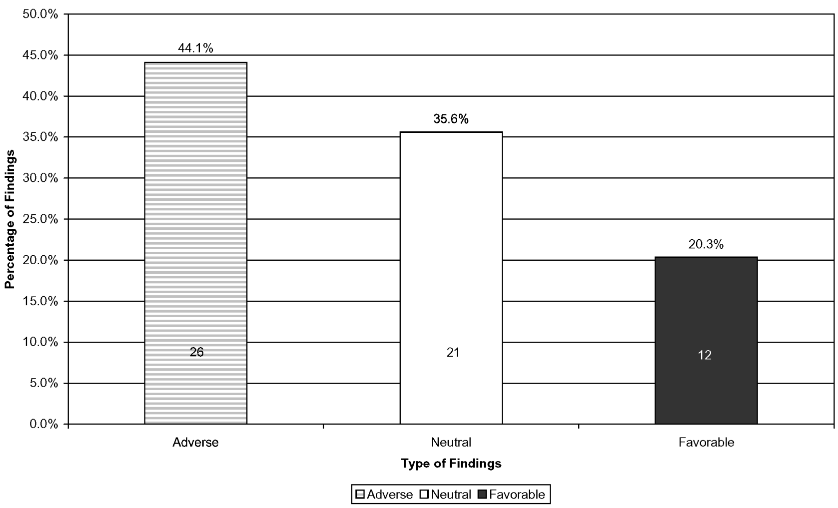

Figure 3
Summary of poverty findings.

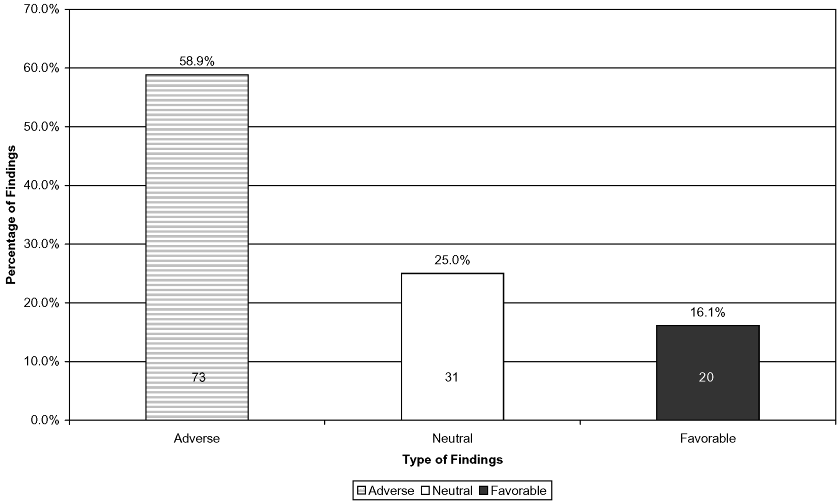

Figure 4
Summary of unemployment findings.

top three lines of the table focus on the overall findings from Figure 1; for the convenience of those who prefer a more detailed examination, the remaining lines of the table summarize the findings in more specific ways. The first column reports the raw number of findings of each type. The second column expresses this number as a percentage of the findings within a given category—that is, as a proportion of all the relevant findings on income, poverty, and unemployment rates—thus repeating the information from Figures 1–4 in tabular form. The final column of the table provides new information, expressing each subcategory of findings (e.g., adverse findings on income, or favorable findings on unemployment rates) as a percentage of the grand or overall total of 301 findings that meet all four of the criteria for inclusion in this analysis.

For each panel of the table, we also present the result of statistical significance tests. Before we turn to the tests themselves, however, four warnings are in order. First, as statistical textbooks routinely note, tests of "statistical significance" should not necessarily be taken as indicating "substantive significance." The tests, instead, are meant to assess the relative consistency of (and hence the degree of statistical confidence that can be placed in) any given pattern. Second, because we are looking at findings from the existing research literature on the three main categories of findings (i.e., incomes, poverty, and unemployment rates), the statistical tests reported here can only be generalized to the research literature addressing these comparative, quantitative results from mining-dependent, nonmetropolitan regions of the United States. Third, given our earlier warning that outcomes reported in the existing literature are often not independent of one another, an important degree of caution is needed in drawing even these inferences; the major advantages of the significance tests have to do with clarifying and systematizing the available findings. Fourth and finally, in keeping with our earlier warning about the need for caution in interpreting the relatively small number of some of the more specific findings, we will perform the statistical tests only for the largest categories of findings, namely, those already noted—the results on incomes, poverty and unemployment rates, and overall patterns.

The simplest possible approach for testing the statistical significance of these findings is to focus on what are technically known as "binomial" outcomes—that is, those that allow for just two possible outcomes. In accordance with the need for caution, the "cost" of this simplicity is that the tests can be carried out in three different ways—with the neutral findings being combined with positive ones, with negative ones, or being omitted altogether.

In Table 1, we present information on statistical significance only for those comparisons that produced significant results. For the overall findings that are summarized in the top panel of Table 1, for example, the binomial tests show adverse findings to be significantly more common than favorable findings according to two of the three possible comparisons—those where the neutral findings are combined with the adverse findings or where they are omitted from the analysis—although not when the neutral findings are combined with positive ones. For the most favorable of the available sets of findings, by contrast—those for incomes—the only way to obtain significantly more favorable findings than negative ones, according to normal standards of statistical significance, is to treat all of the neutral or indeterminate findings as being "favorable" ones, as well. Finally, unlike the case for the income findings, there prove to be significantly more adverse findings than favorable ones in the cases of poverty and unemployment, whether the neutral findings are treated as being negative or are removed from the analysis altogether. In the case of the unemployment findings, in fact, adverse findings prove to be so much more numerous than positive ones that there are significantly more negative than positive findings even if the neutral or indeterminate findings are explicitly treated as positive ones.

In response to reviewer concerns about the extent to which this overall pattern might be shaped by methodological anomalies of one or more studies—whether through shifts in units of analysis or definition of variables, or simply by having one or two studies that contribute a significant fraction of the findings—we have conducted the additional analysis summarized in Figure 5. As can be seen from the dashed horizontal line and the bar at the far right end of this figure, the overall average, across all studies, is for negative findings to be 1.58 times as

Table 1
Percentages of Adverse/Neutral/Favorable Findings, Overall and by Measure

	No. of Findings	% of Category	% of Total
Overall			
Type of Finding			
Adverse	139	NA	46.2
Neutral	74	NA	24.6
Favorable	88	NA	29.2
Total All Findings	301	NA	
"Adverse Findings" are significantly more likely than "Favorable Findings" by two of three tests:			
$t = -7.907$, $p < .000$ when neutral findings are coded as negative.			
$t = -3.466$, $p = .001$ when neutral findings are excluded.			
By Measure			
Income Findings			
Adverse	40	33.9	13.3
Neutral	22	18.6	7.3
Favorable	56	47.5	18.6
Total Income	118	100.0	39.2
"Favorable Findings" are significantly more likely than "Adverse Findings" by one of three tests:			
$t = 3.679$, $p < .000$ when neutral findings are coded as positive.			
Poverty Findings			
Adverse	26	44.1	8.6
Neutral	21	35.6	7.0
Favorable	12	20.3	4.0
Total Poverty	59	100.0	19.6

(continued)

Table 1 *(continued)*

	No. of Findings	% of Category	% of Total
"Adverse Findings" are significantly more likely than "Favorable Findings" by two of three tests:			
$t = -5.612$, $p < .000$ when neutral findings are coded as negative.			
$t = -2.411$, $p = .021$ when neutral findings are excluded.			
Unemployment Findings			
Adverse	73	58.9	24.3
Neutral	31	25.0	10.3
Favorable	20	16.1	6.6
Total Unemployment	124	100.0	41.2
"Adverse Findings" are significantly more likely than "Favorable Findings" by all three tests:			
$t = -1.999$, $p = .048$ when neutral findings are coded as positive.			
$t = -6.652$, $p < .000$ when neutral findings are excluded.			
$t = -10.213$, $p < .000$ when neutral findings are coded as negative.			
Total across Measures	301	NA	100.0

common as positive ones. As can also be seen, however, there are very few cases in which the removal of a study or studies could be said to exert major or undue influences on the overall pattern of results.

The largest change in ratios would come from dropping the study of Mills (1995)—removing this study would increase the overall ratio of negative to positive findings from 1.58:1 to 1.82:1—yet such a change would scarcely be surprising: Mills focuses on incomes, and as noted earlier, incomes provide a consistently more favorable picture of overall socioeconomic outcomes than do

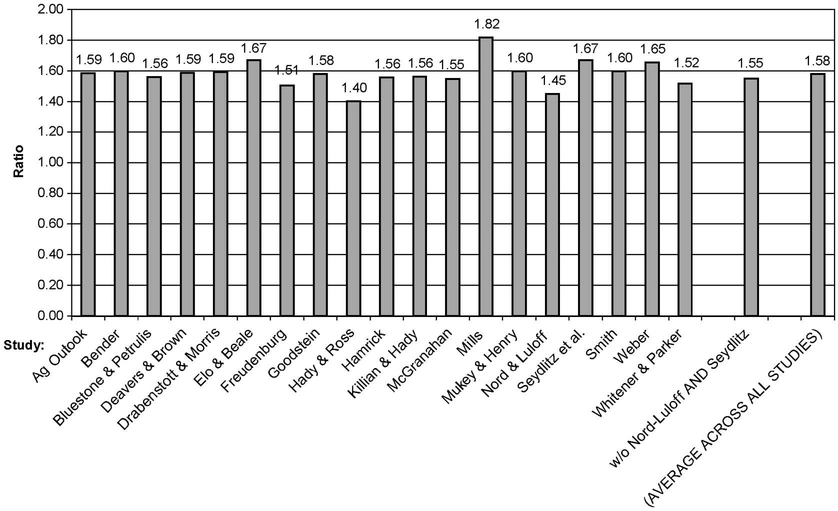

Figure 5

Ratios of adverse to favorable findings without the indicated sources.

poverty or unemployment rates, or for that matter, the overall distributions of findings. The greatest reduction in the overall ratio would come from omitting Hady and Ross (1990); as noted earlier, this study was done as an update to the original report by Bender et al. (1985), and thus it includes a strong emphasis on the years from 1980 onward, when findings have tended to be significantly more negative than in earlier years. Finally, the two studies contributing the largest number of findings are those of Nord and Luloff (1993) and of Seydlitz, Jenkins, and Hampton (1995); these two studies, in combination, provided 141 of the 301 findings just analyzed, but neither of the two studies exerts as much influence in changing the overall total as do Mills (1995) or Hady and Ross (1990), and in combination, the two studies' effects largely counterbalance one another. As can be seen from Figure 5, in other words, the effect of removing the Nord and Luloff findings would be to reduce the overall average from 1.58:1 to 1.45:1, while the effect of removing Seydlitz et al. would be to increase the overall ratio to 1.67:1. As shown by the bar near the extreme right end of the figure, the net effect of removing both studies would be a degree of shift in the overall ratio of negative to positive findings that is remarkably small—a reduction from 1.58:1 to 1.55:1.

Still, in the interest of caution, it should be noted that there would be one clear effect of removing one or both of these studies that is not reflected in Figure 5: Partly because both Nord and Luloff (1993) and Seydlitz et al. (1995) used tests of statistical significance to assess whether findings were positive, negative, or indeterminate, these two studies reported a higher proportion of "indeterminate" outcomes than for the studies that did not use statistical significance tests. Except for these apparently minor variations, however, the simple form of sensitivity analysis presented in Figure 5 shows a considerable degree of robustness in the comparison that is likely to prove most salient to readers, involving the ratio between negative and positive findings. Indeed, there is no other study of the 19 included in the final analysis that has enough of an effect on the overall findings that the removal of that study would shift the overall ratio of negative to positive findings by as much as 0.10; instead, the overall ratio would stay within the range of 1.58 (± 0.10):1.

Variations by Region and Era

Despite the fact that the overall patterns of findings appear to be relatively robust, the existing literature suggests that more finely grained patterns may be present, as well. Given our earlier warnings about the many variations across studies, plus the exploratory nature of any further comparisons, our judgement is that further tests of statistical significance would be inappropriate for these more fine-grained assessments, but there is still a need to ask whether the findings differ systematically in other ways. In particular, given the number of findings that have come from the western "energy boomtowns" of the late 1970s and early 1980s, there is a need to consider whether the available findings differ systematically by region and/or by era.

Regional Variation. As noted by Nord and Luloff (1993), the question of regional differences is particularly relevant in light of the number of mines in the western United States that are new, that use open-pit mining techniques, and that exploit particularly rich deposits of easily accessible coal. As can be seen from Figure 6A, which summarizes the variations in findings across regions, the western mines are indeed associated with the most favorable economic findings. Only in the western United States, in other words, do the available studies provide more favorable findings than adverse ones; in the west, just over half of the 73 available findings are favorable, while 27.4 percent are adverse, and the remaining 20.5 percent are neutral. Findings from the south point to greater economic distress, with 37.2 percent of the findings indicating adverse conditions in mining regions, but only 15.4 percent indicating favorable conditions. The 31 available findings from the Great Lakes region point to even greater distress: Only two of the quantitative findings from this region (6.5%) indicate mining to be associated with favorable economic outcomes; instead, most of the available findings are split into roughly equal numbers of "neutral" and "adverse" outcomes. Finally, the results from "other" regions of the country, or from the nation as a whole, point to conditions in mining areas that are more than twice as likely to be adverse (63.0%) than to be favorable (30.3%), while the remaining 6.7% of the findings show no differences.

Differences across Eras. Figure 6B responds to another need that was pointed out earlier—the need to assess potential changes in the relationships between mining and economic well-being over time. Although the preliminary findings from Bender et al. (1985) were relatively favorable, for example, subsequent studies indicated that those preliminary findings may have reflected the unusually prosperous or "boom" conditions that existed in many mining regions during the mid- to late-1970s.

As any number of authors have noted (see, e.g., Gulliford 1989), the era of "western energy boomtowns" came to an unexpectedly abrupt halt on a date that many residents of the Rocky Mountain region still remember as "Black Sunday"—May 2, 1982—when Exxon shut down its massive oil shale operations near Parachute, Colorado, and the mining-dependent portions of the region suddenly found themselves in a deep bust, with no "next boom" on the horizon. While many oil-extraction regions managed to avoid a serious bust for a few more years, largely because oil prices initially avoided the declines that characterized so many other commodities during the early 1980s, world oil prices ultimately dropped from $24.51 to just $9.39 per barrel in the 6 months between December 1985 and June 1986, bringing the end of the boom for oil regions as well (Freudenburg and Gramling 1998). Findings from the era that ended by the early 1980s, accordingly, might be expected to be quite different from those that have been documented in more recent years—a possibility that will be considered next.

Two main types of temporal comparisons are included in the available studies. The first involves longitudinal analyses—those that assess change over time within a given mining region or locality. The second involves cross-sectional comparisons—that is, between mining counties/communities and a matched or "control" set of counties/communities, at a given point in time. In the interest of simplicity, we use the end of 1982, after the end of "boom times" in most U.S. mining regions, as our cutoff point, comparing the findings from data collected during the years up through 1982 against those from data collected in 1983 or thereafter. Given that the overall conclusions from longitudinal analyses are inherently shaped by the conditions that prevail at the end of the study period, any longitudinal studies that straddle the 1982–1983 cutoff point are classified here with the other studies in the "1983 and thereafter" category, while the longitudinal studies that began and ended before 1982 are analyzed with the other "1982 and earlier" findings.

As shown in Figure 6B, the era of data collection does indeed appear to exert an important influence on the favorability of findings. In the years up through 1982, there were more favorable findings (52 of the 123 findings, or

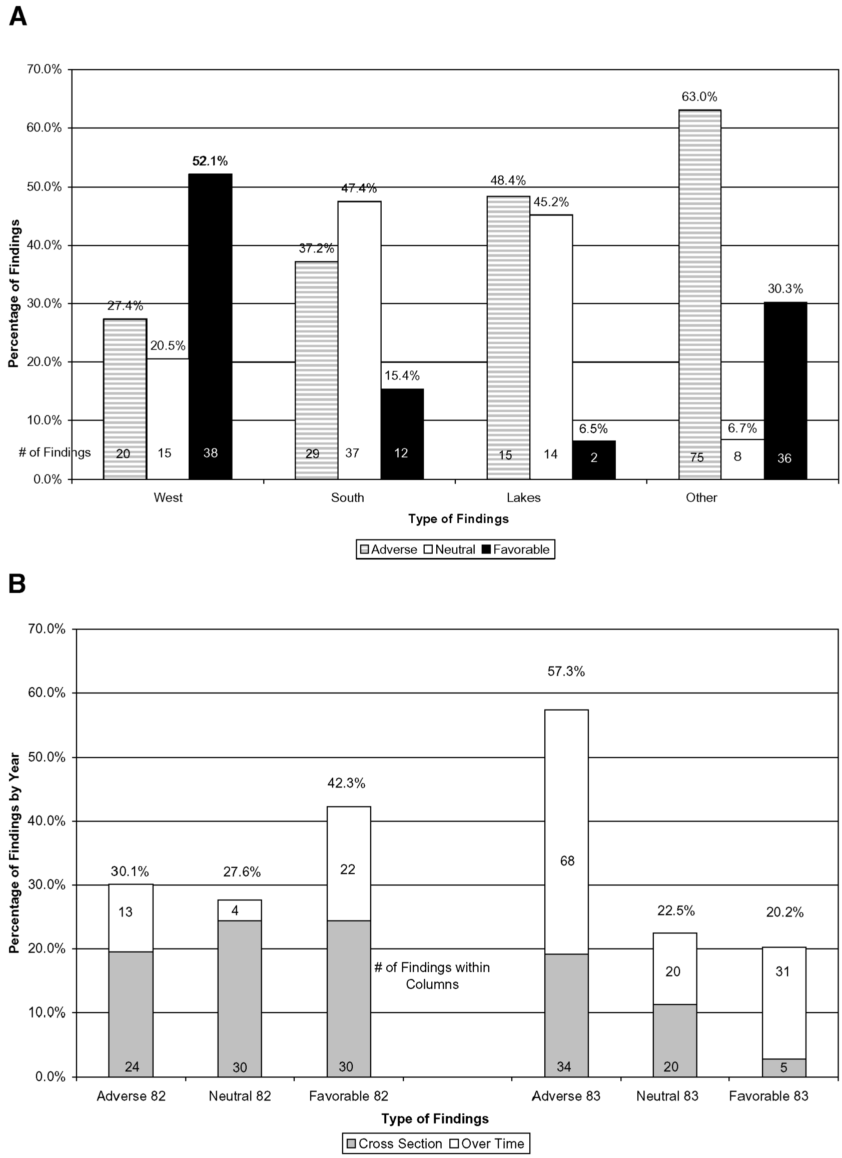

Figure 6
(A) Summary of findings by region. (B) Summary of findings by time.

42.3% of the total) than adverse or neutral ones (37 and 34 findings, or 30.1% and 27.6% of the total, respectively). In the years since then, however, the picture has been much less favorable. An outright majority of the findings since 1982 have been adverse, with 102 adverse findings constituting 57.3 percent of the 178 available findings for the era since 1982. While favorable findings were the most common category for studies that focused on the "boom" conditions that existed up until early 1982, in fact, favorable findings make up the smallest category of the findings since then—just 36 such findings, or 20.2 percent of the total—meaning that there are only about one-third as many favorable findings as adverse ones in studies using data from the years since 1982.

While the cross-sectional findings do not allow us to assess actual change over time in mining areas, a small number of studies have reported "before and after" or longitudinal findings; these findings are reported in the unshaded portions of the bars of Figure 6B, and they do indeed indicate mining to be associated with declining local economic conditions. Intriguingly, save for the fact that the longitudinal studies appear to have produced fewer neutral findings, proportionately, than have the cross-sectional studies (particularly for findings from 1982 and earlier), Figure 6B shows that the overall conclusions suggested by the two different types of methods appear broadly similar to one another, particularly with respect to the dramatic differences between findings from the "boom" era that ended in roughly 1982 and the less "euphoric" times (Gulliford 1989) that have characterized U.S. mining regions ever since. The 68 adverse findings from longitudinal studies, for example, represent 56.2 percent of the 121 longitudinal findings for the period from 1983 to present, while the 34 adverse findings using cross-sectional data represent 57.6 percent of the 59 cross-sectional findings for the same period.

Table 2 presents a summary of the comparisons that are illustrated in Figure 6, doing so in a format that mirrors that of Table 1. As can be seen from a closer examination of the findings from the two tables, most of the more favorable conclusions about economic conditions in mining areas come from a relatively small subset of the available findings—principally those focusing on incomes, in the western United States, before the end of 1982. As shown earlier by Table 1, in other words, only 88 of the 301 findings indicate favorable economic conditions in mining regions, and the clear majority of those findings (56 of the 88, or 63.6% of all favorable findings) involve incomes. Of the greater number of findings that have to do with poverty or unemployment, less than one-fifth—just 32 of the 183 (12+20 of the 59+124), or 17.5 percent—are favorable.

As shown in the top half of Table 2, similarly, it is only in the data from the western United States that favorable outcomes make up as many as one-third of the available findings; across the other regions of the United States as a whole, only 50 of the 228 remaining findings, or 21.9 percent of the total, are favorable, while another 119 findings—52.2 percent, or an actual majority of the remaining 228 findings—point to adverse economic conditions in mining areas. As just noted, finally, the bottom half of Table 2 shows that findings of favorable economic conditions in mining regions have become relatively rare since 1982, making up only about 20 percent of the available findings that come from 1983 and thereafter, while adverse findings make up nearly three times that number, or 57.3 percent of the overall total, for the same era.

Discussion and Conclusions

These analyses strongly support the warnings of those who have expressed skepticism about the socioeconomic benefits of mines. There are clearly more positive than negative findings for incomes, but the only way for this pattern to be statistically significant is for the neutral findings to be treated explicitly as positive ones. By contrast, for the other three main categories of findings—those for poverty, unemployment, and overall—the test results are strongly significant, statistically, in the opposite direction, indicating that adverse economic outcomes are significantly more likely in the accumulated research literature to date than are positive ones. These findings for poverty, unemployment, and overall patterns remain significant when neutral findings are omitted from the analysis, and not just when the neutral findings are treated as negative ones.

Our findings also reinforce the warnings of Nord and Luloff (1993), who note the importance of analyzing the differences in findings across regions and across time; like Nord and Luloff, we find the problems to be particularly severe in the older eastern and nonfuel mining areas. In addition, our findings mirror what Elo and Beale (1985) called a "curious anomaly"—with mining-dependent counties in that study having had higher median incomes, but also higher proportions of households living in poverty. Our results, in other words, also indicate that, even when higher incomes are associated with mining, those incomes do not prove sufficient to alleviate the problems of poverty and unemployment so often associated with mining-dependent regions.

As a reviewer has noted, one partial explanation for the "anomaly" may involve the mechanization that has had particularly strong impacts on mining employment and income inequality in Appalachia. Mechanization has become associated with relatively high wages in most U.S. mining operations today, but only for the smaller number of workers still employed; many other workers once employed in mining have been displaced by the mechanization. This pattern may well be reinforced by the increasing number of "mining workers" whose jobs are professional and/or technical in nature—geologists, engineers, computer specialists, and so forth—such that the traditional blue-collar "mining jobs" are decreasing in proportion as well as in number.

Table 2
Percentages of Adverse/Neutral/Favorable Findings, by Region and Era

	No. of Findings	% of Category	% of Total
Region			
West			
Adverse	20	27.4	6.6
Neutral	15	20.5	5.0
Favorable	38	52.1	100.0
Total West	73	100.0	24.2
South			
Adverse	29	37.2	9.6
Neutral	37	47.4	12.3
Favorable	12	15.4	4.0
Total South	78	100.0	25.9
Lakes			
Adverse	15	48.4	5.0
Neutral	14	45.2	4.7
Favorable	2	6.5	0.7
Total Lakes	31	100.1	10.4
Other/Nation			
Adverse	75	63.0	24.9
Neutral	8	6.7	2.7
Favorable	36	30.3	12.0
Total Other/Nation	119	100	39.6
Total across Regions	301	NA	100.1
Era			
1982 and before			
Adverse	37	30.1	12.3
Neutral	34	27.6	11.3
Favorable	52	42.3	17.3
Total 1982 and before	123	100.0	40.9

(continued)

Table 2 *(continued)*

	No. of Findings	% of Category	% of Total
1983 and after			
Adverse	102	57.3	33.9
Neutral	40	22.5	13.3
Favorable	36	20.2	12.0
Total 1983 and after	178	100.0	59.1
Total across Eras	301	NA	100.0

Another potential factor behind the apparent anomaly may involve methodological variations: Unlike data on poverty and unemployment rates, which are almost always collected at the level of the households and hence in the communities or counties where people actually live, income data are often collected at the level of the firm—that is, where people work, rather than where they live. The potential importance of this distinction is illustrated by the recently closed White Pine Mine of Michigan's Upper Peninsula (see Wilson 2001). Income data coded by place of work show this mine's county (Ontonagon) to have had far higher incomes than those of Michigan's Upper Peninsula as a whole, but income data based on place of residence, taking cross-county commuting into account, show the same county as being at or below the average of the Upper Peninsula. As shown by recent fieldwork by one of the authors of this article, a key reason is that a significant fraction of the mine's workers lived in different counties or even a different state.

When looking toward the future, perhaps the logical starting point is to note again what this article's analyses do not support–namely, the widespread expectation that mining can be expected to increase the prosperity of isolated rural communities. Indeed, this is perhaps the central implication of our analysis, and one that will require additional examination in future research.

To date, sociologists have offered a number of attempts to explain distressed socioeconomic conditions in resource-dependent areas, drawing on theories of segmented economy, underinvestment in human capital, deindustrialization, and changes in the global economy, as well as on more resource-related or "resource contingency" approaches. Given that the findings of the present study show the experiences of mining communities to have differed significantly from the experiences of other rural regions in recent years, there appears to be a particular need for greater attention to be paid to the last of these approaches—analyzing communities' relationships with the characteristics of natural resources themselves and with the specific technologies that are developed to exploit the resources.

As past studies have noted, most nonmetropolitan communities have little direct control over broader social, demographic, and economic trends, which can include industrial restructuring, the aging of the population, and global recessions (see, e.g., Humphrey et al. 1993; Fitchen 1995; Gaventa 1990). Still, a growing body of research indicates that certain characteristics tend to have important effects on how local economies fare within the broader changes (see, e.g., Baum 1987; Drabenstott and Smith 1995; Garkovich 1989; Malecki 1994). What has been noted in previous work on "resource contingency" (see, e.g., Freudenburg 1992; Freudenburg and Gramling 1998), in a line of logic that is reinforced by the present study's findings, is that there is a need for the range of "local characteristics" to be extended, to include the examination of characteristics of the actual natural resources and of the ways in which they are extracted. To be more specific, there appears to be a need to pay greater attention to the dynamics of resource dependency, over time, such as the potential that, as mines age, the costs of production may rise (and/or the incentive to invest in newer and more efficient technologies may drop). Such changing relationships could well contribute to what Hibbard and Elias (1993) have termed "flickering" operations (characterized by shutdowns during periods of low prices) and to what Freudenburg (1992) has termed the "extraction of concessions"—with workers, communities, and regulators being asked to make wage, tax, and/or regulatory concessions to mining operations in the interest of keeping the mines open.

While we believe our assessment is by far the most systematic appraisal ever to become available for the existing body of research, it is important that our findings be kept in perspective; other studies or methods could potentially come up with more (or less) favorable results—and in any case, it is important that the needed future research in fact be carried out. Our findings, in short, should be interpreted with caution. What is abundantly clear, however, is that caution is also in order for a set of conclusions that have rarely been treated with caution in the past—namely, the common conclusion or in some cases even the strongly asserted conviction that mining must be good for local economies. Despite the intensity with which such beliefs are often stated, the present analysis has shown that there is remarkably little evidence to support them; instead, most of the more systematic approaches to the data point instead to the opposite conclusion, often at high levels of statistical significance.

For the future, in short, it is important that more research be done; for the present, what is perhaps more important is to recognize that it can no longer be responsibly asserted that the socioeconomic impacts of mining for rural communities will be favorable ones. Such findings have always been sporadic at best, and at least since 1982, they have become quite rare. To the extent to which past experience is to be our guide, in other words, there is surprisingly little evidence that mining will bring about economic good times, while there is a good deal of evidence for expecting just the opposite.

ENDNOTES

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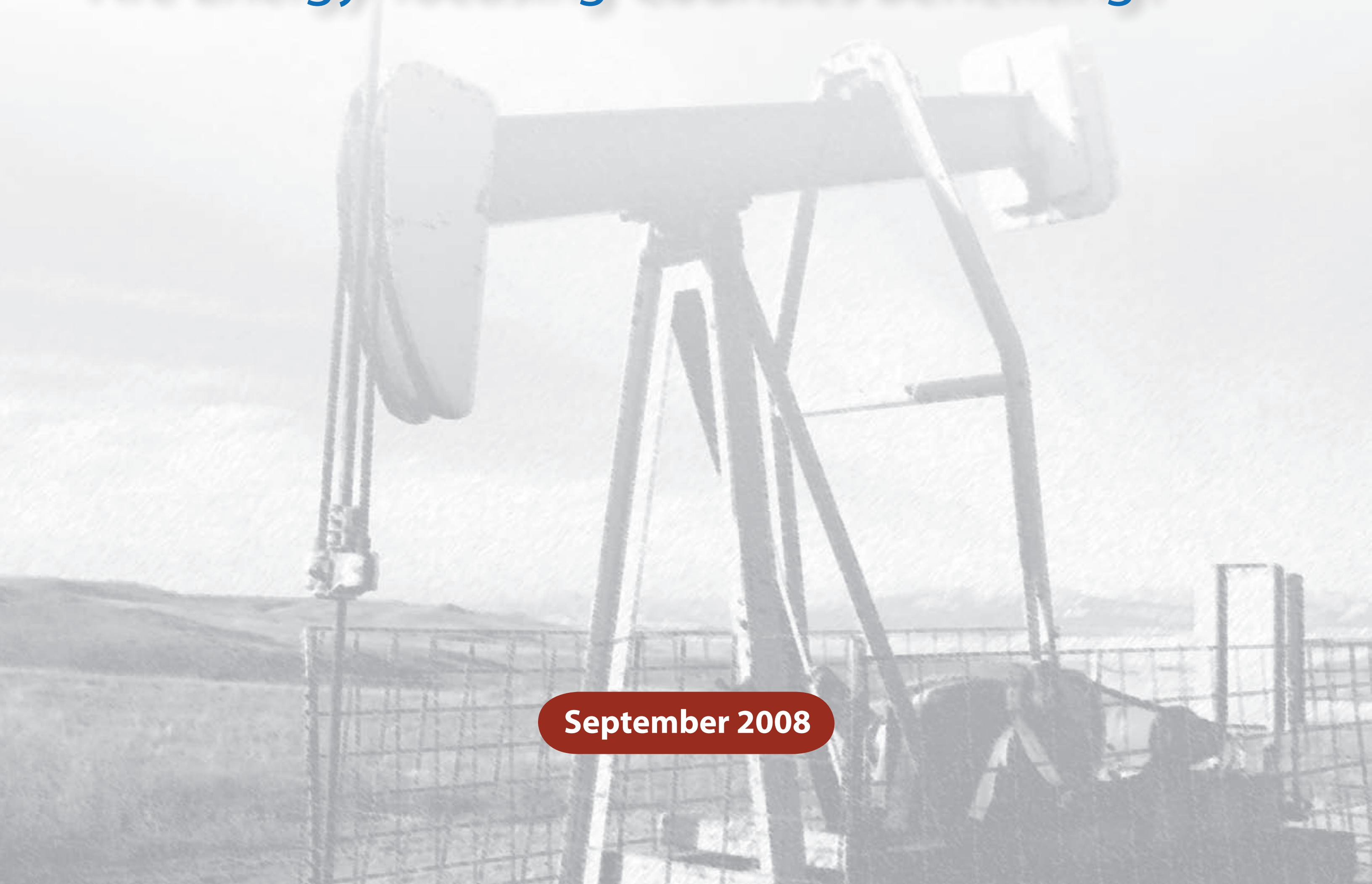
Fossil Fuel Extraction as a County Economic Development Strategy

Are Energy-focusing Counties Benefiting?



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ABOUT HEADWATERS ECONOMICS

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ABOUT THE *ENERGY AND THE WEST* SERIES

This report is the third in a series—*Energy and the West*—published by Headwaters Economics on the topic of energy development. This series is designed to assist the public and public officials in making informed choices about energy development that will benefit the region over the long term.

In forthcoming reports in the *Energy and the West* series, listed below, we cover the policy context for energy development in the West and the resulting impacts to states, counties, and communities viewed from the perspective of economic performance (i.e., jobs, personal income, wages) and fiscal health (i.e., state and county budgets, revenues and expenses). The series also includes state and local area case studies, which highlight benefits and costs in greater detail.

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INTRODUCTION

A rapid rise in the price for oil, natural gas, and coal, and a political climate that has favored energy development on public lands has made it possible for some counties in the West to use energy development as a strategy for economic development.

In this report in our *Energy and the West* series, we examine the consequences of focusing on fossil fuel extraction as an economic development strategy. Has it benefited counties in the long run?

The recent rise in fossil fuel development in the West is happening in the context of an economy that has already made a significant shift, away from a historic dependence on resource extraction, to an economy that today is driven primarily by service industries and knowledge-based occupations, and retirement and investment dollars. As a consequence, the economic role of public lands, where much of today's energy development is taking place, has also shifted.

In the past, the principal economic contribution from Bureau of Land Management (BLM), Forest Service, and state lands in the West came from the raw materials that were extracted and exported from the region. Today, there is an additional economic role for public lands. For many communities, the recreational opportunities and scenery provided by public lands are essential components of the quality of life that attracts and retains people and business, as well as retirees and investment income. The scenery, wildlife, and recreation-oriented lifestyle, in which public lands play a critical role, are now economic assets, and a key component of the West's competitive advantage.

The information provided in this report can help those entrusted with the management of the lands in the West to understand the consequences, and potential tradeoffs, of energy development.

Questions Answered in this Report:

1. Has an economic focus on energy development benefited counties of the West?
2. Is today's energy surge any different from the energy boom of the 1970s?
3. Why do energy-focusing counties underperform relative to their peers?

SUMMARY FINDINGS

Key Term: Energy-focusing

We use the term "energy-focusing," abbreviated "EF" in this report, to refer to the 26 rural counties in the West that concentrate their economic development on the extraction of fossil fuels. These counties have a relatively high proportion of total jobs (7% or more) in the county that are involved in the extraction of fossil fuels (natural gas, oil, and coal). We use the term "peers" to describe the remaining 254 western counties of similar size (57,000 people or less). For a full definition of "energy-focusing" (EF) counties and their "peers" see the Methods section on page 4.

Counties that have focused on energy development are underperforming economically compared to peer counties that have little or no energy development.

It is well documented that counties focused on energy extraction as an economic development strategy have historically gone through periods of boom and bust—that their economies are volatile. What is less well understood is how these counties fare economically in the long term.

In the long run, the economies of energy-focusing (EF) counties grow more slowly than the economies of their peers that are not pursuing energy extraction as an economic development strategy.

From 1990 to 2005, for example, the average rate of growth of real personal income in EF counties was 2.3 percent per year, compared to 2.9 percent in the peers. In terms of employment, the average annual growth of EF counties over the same time period was 1.8 percent, compared to 2.3 percent for their peers.

An energy development surge no longer guarantees strong economic performance.

In the energy boom that began in the 1970s and ended in the early 1980s, counties that were focused on energy development, with a high portion of jobs in fossil fuel development, were some of the top economic performers in the West. In today's energy surge, this is no longer the case.

As measured by average annual job growth, only one of 26 EF counties ranks among the top 30 economic performers in the West, while during the last energy boom half were top performers. In addition, more than half of EF counties are losing population in the midst of today's energy surge.

In EF counties, the share of total jobs in energy-related fields has declined, from 23 percent in 1982 (past energy boom) to 14 percent in 2005 (current energy surge). In recent years, jobs unrelated to energy extraction are growing rapidly and the western economy is much larger than in the past.

A heavy reliance on fossil fuel extraction may point to diminished future competitiveness.

As the West develops its fossil fuel energy resources, an ongoing challenge is increasing the competitiveness of local economies, especially in sectors unrelated to energy development.

Compared to their peers in the West that have not pursued energy development as an economic strategy, EF counties over the long term are characterized by:

- Less economic diversity and resilience
- Lower levels of education in the workforce
- A greater gap between high and low income households
- A growing wage disparity between energy-related workers and all other workers
- Less ability to attract investment and retirement dollars

These long-term indicators suggest that relying on fossil fuel extraction may not be an effective economic development strategy for competing in today's growing and more diverse western economy.

METHODS: THE DEFINITION OF ENERGY-FOCUSING (EF) COUNTIES

We define those counties that concentrate their economic strategy on the development of fossil fuels as "energy-focusing" (EF) counties. These are counties where a relatively high proportion of total jobs in the county are involved in the extraction of fossil fuels (natural gas, oil, and coal). Fossil fuel extraction includes the following codes from the North American Industrial Classification System (NAICS): drilling and extracting oil and gas reserves, extracting coal reserves, and support activities related to these. These NAICS codes are shown in Table 1 and are defined in more detail in the Appendix.[1]

Table 1.Description of Data Used to Show Employment and Personal Income Related to Energy Development, by North American Industrial Classification System (NAICS) Code

Description	NAICS Code
Oil and Gas	
Oil and gas extraction	211
Drilling oil and gas wells	213111
Support activities for oil and gas operations (e.g., contract drilling, surveying, mapping, operating oil and gas fields on a contract basis)	213112
Coal	
Coal mining	2121
Support activities for coal mining (e.g., geophysical surveying, mapping)	213113

We define a county as energy-focusing (EF) if more than 7 percent of total private-sector employment in the county was engaged in energy development—natural gas, oil, and coal—in 2005. The 7 percent cut-off was selected for two reasons: (1) below this threshold, the percent of employment in fossil fuel energy sectors in counties across the West falls off rapidly, and (2) any less energy activity as a share of total employment does not reflect a significant concentration on this single industry.

There are 26 EF counties in the West. Table 2 shows the list of EF counties, and their relative concentration in oil and natural gas versus coal extraction. They are all counties with small populations—fewer than 57,000 people. There is one exception: San Juan County, New Mexico. We eliminated San Juan County, New Mexico from the list because it is more than twice as large as the next largest EF county, and we wanted to compare EF counties, which are overwhelmingly rural, with their rural counterparts in the West.

There are 254 "peer" counties in the West. These are western counties of similar size (57,000 people or less) that do not have significant employment devoted to the extraction of oil, natural gas, and coal (less than 7% of total private employment). EF counties (yellow), along with their non-energy "peers" (blue), are shown in Map 1 (page 6).

Of the 26 EF counties in the West, 12 had between 10 percent and 15 percent of all employment engaged in fossil fuel extraction (light green in Table 2), and another eight had more than 15 percent involved in energy development (dark green in Table 2). Four counties had more than 20 percent of all employment in energy development, and one, Campbell County, Wyoming, had a third of its workforce employed directly in energy development.[2]

We used County Business Patterns data, from the Bureau of the Census, to define EF counties. This data does not include individual proprietors (the self-employed), so the actual number of energy workers in a given county will be larger. The ratio of wage and salary workers to proprietors is fairly consistent across industries, so using wage and salary employment numbers does not significantly alter the overall employment share for each industry.[3]

Definition of Mining

When we use the term "mining" in our *Energy and the West* series, we refer primarily to jobs and income associated with the development and extraction of oil, natural gas, and coal (the fossil fuels). Because of restrictions placed on the level of detail available from the U.S. Department of Commerce and the Bureau of the Census, it is sometimes not possible to separate minerals mining from fossil fuels mining. In the energy-focusing counties analyzed in this report, the bulk (over 80%) of "mining" is in energy development.

Table 2. Energy-focusing Counties in the West, 2005

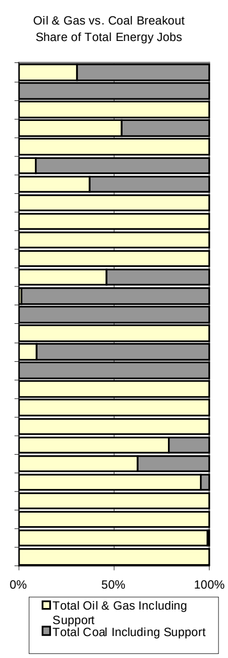
			Oil and Gas Jobs:				Coal Jobs:			
	Energy Jobs in 2005	**Energy Jobs Share of Total Jobs in 2005**	Total Oil & Gas Including Support	Oil and Gas Extraction	Drilling Oil and Gas Wells	Support Activities for Oil and Gas Operations	Total Coal Including Support	Coal Mining	Support Activities for Coal Mining	Population in 2005
Campbell, Wyoming	5,436	**30.0%**	1,656	455	211	990	3,780	3,709	71	37,420
Emery, Utah	668	**24.5%**	2	-	-	2	667	660	7	10,711
Cheyenne, Colorado	99	**21.5%**	99	13	70	15	-	-	-	1,952
Rio Blanco, Colorado	343	**20.9%**	185	49	29	107	158	158	-	6,000
Uinta, Wyoming	1,163	**17.5%**	1,163	247	-	916	-	-	-	19,873
Big Horn, Montana	354	**16.7%**	32	2	-	31	322	322	-	13,076
Converse, Wyoming	610	**16.4%**	227	71	14	142	384	384	-	12,743
Hot Springs, Wyoming	233	**15.4%**	233	36	1	196	-	-	-	4,568
Fallon, Montana	124	**14.9%**	124	72	-	52	-	-	-	2,709
Blaine, Montana	133	**14.1%**	133	-	70	63	-	-	-	6,634
Sublette, Wyoming	309	**14.0%**	309	108	4	197	-	-	-	6,965
Lincoln, Wyoming	639	**13.6%**	294	37	7	250	345	345	-	15,940
Moffat, Colorado	507	**13.5%**	8	2	-	6	499	499	-	13,397
Rosebud, Montana	359	**13.4%**	-	-	-	-	359	359	-	9,279
Lea, New Mexico	2,065	**12.3%**	2,065	447	699	919	-	-	-	56,650
Carbon, Utah	807	**11.5%**	75	44	15	15	733	731	2	19,459
Gunnison, Colorado	689	**11.4%**	-	-	-	-	689	689	-	14,182
Weston, Wyoming	179	**11.2%**	179	87	14	78	-	-	-	6,642
Uintah, Utah	824	**10.9%**	824	195	60	569	-	-	-	27,129
Eddy, New Mexico	1,835	**10.5%**	1,835	798	210	827	-	-	-	51,269
San Juan, New Mexico	3,534	9.5%	2,786	671	500	1,615	748	748	-	125,820
Sweetwater, Wyoming	1,344	**9.0%**	841	217	32	592	502	502	-	38,019
Richland, Montana	317	**8.8%**	303	47	7	249	14	14	-	9,163
Yuma, Colorado	204	**8.4%**	204	17	152	35	-	-	-	9,785
Toole, Montana	124	**7.8%**	124	72	35	17	-	-	-	5,174
Big Horn, Wyoming	175	**7.3%**	174	23	-	150	1	1	-	11,325
Duchesne, Utah	293	**7.0%**	293	99	19	175	-	-	-	15,328

Energy Jobs over 15% of Total

Energy Jobs over 10% of Total

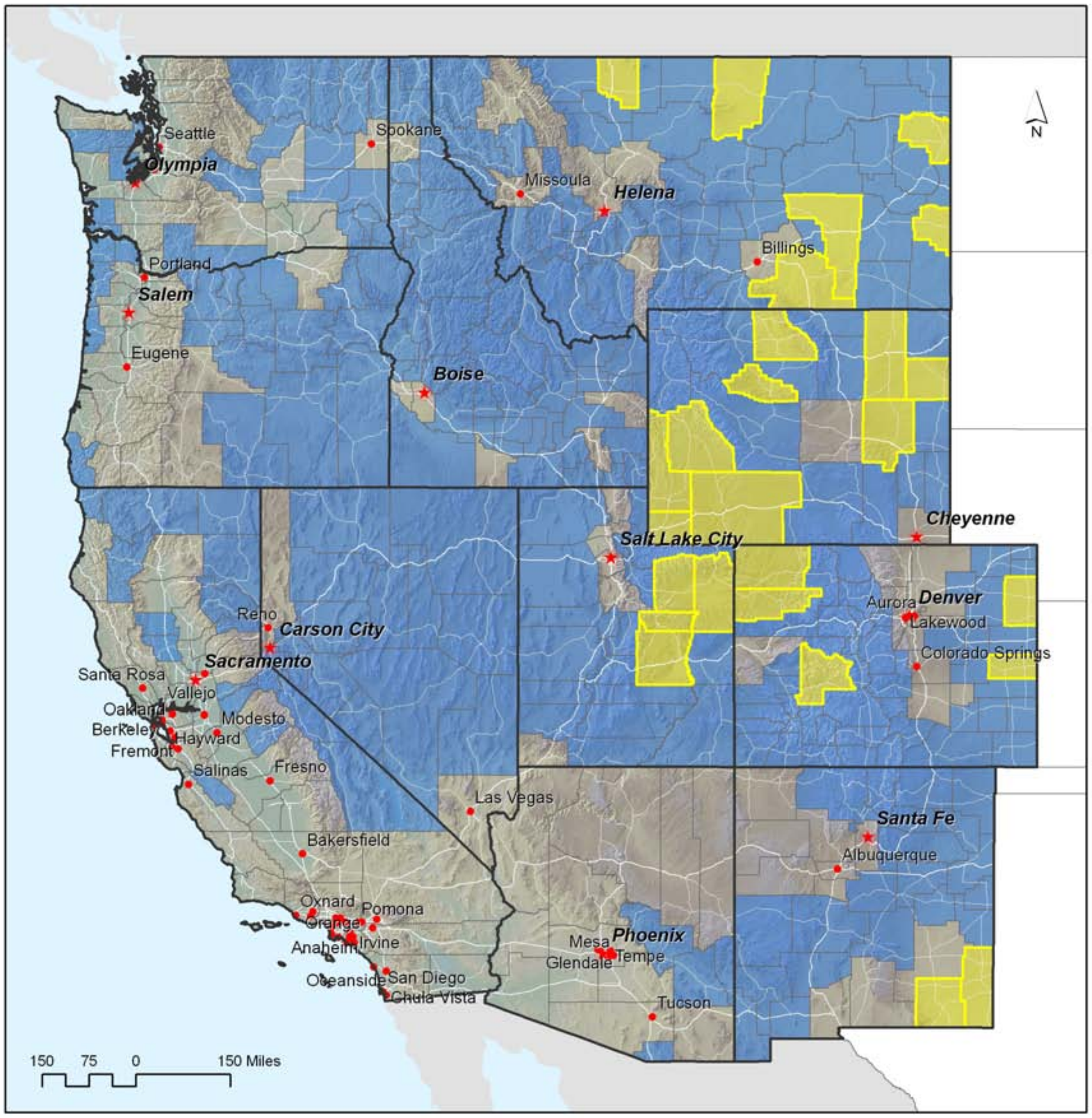
Maximum Population (excl. San Juan) 56,650

San Juan, NM was excluded because population is much larger and we want to focus on small rural communities that are heavily dependent on energy.



EF counties and their peers are shown in Map 1.

Map 1. Energy-focusing Counties and their Rural Peers



Counties
- Energy Focusing Counties
- Peer Counties

Major Cities
- ★ State Capital
- • Population > 100,000

Major Roads
- Limited Access Highway
- Principal Highway

Data Sources: US Census County Business Patterns 2005, US Bureau of Economic Analysis Regional Economic Information System 2005, US Geological Survey

World Mercator Projection

Map Date: 8/7/2008

HAS AN ECONOMIC FOCUS ON ENERGY DEVELOPMENT BENEFITED COUNTIES OF THE WEST?

In order to answer this question, we compared the economic performance of energy-focusing (EF) counties, measured in a variety of ways, to their rural peers.

We use three time periods for analysis:

1970–1982	A period of economic growth, culminating in a national recession. This period also captures an energy development "boom" period in the West.
1982–1990	A period of recovery in the national economy, but decline, or energy "bust" period, for EF counties in the West.
1990–2005	The beginning of a new period of growth in the national economy, dominated by a shift to a service and knowledge-based economy, an increasingly mobile workforce, and the advent of new technology (personal computers, the Internet, telecommunications). This period also captures the most recent energy surge for parts of the West, which began approximately in 2000.

We use these periods for comparison because they frame starkly different economic stages, and highlight differences as well as emerging similarities between EF counties and their peers.

The measures of performance we used to compare EF counties to their rural peers are:

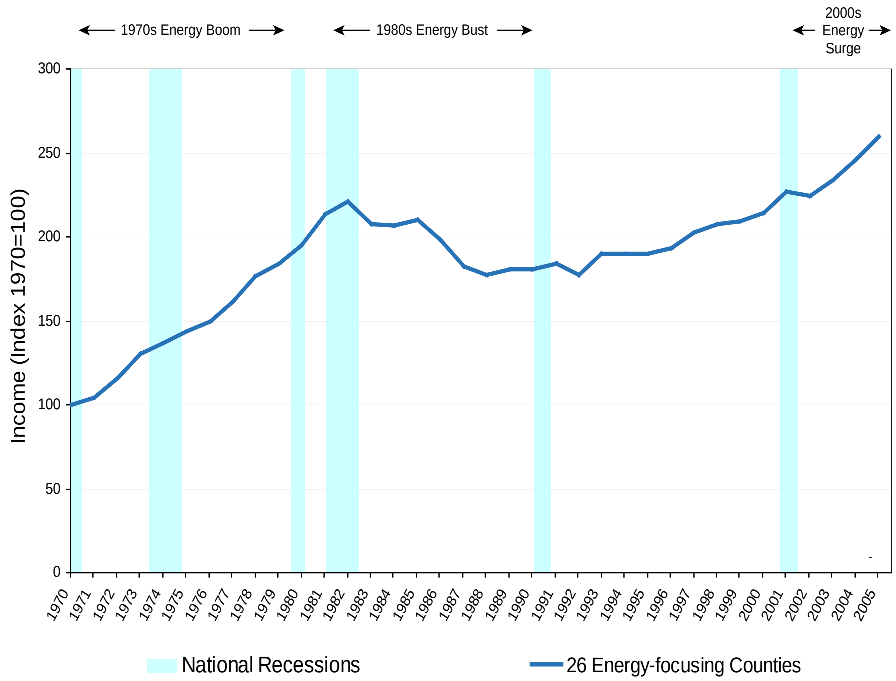
- Total personal income
- Average earnings per job
- Population
- Per capita income
- Employment

Throughout this report all dollars figures are in real terms, i.e., adjusted for inflation.

We begin by looking at the long-term economic history of EF counties. Figure 1 shows the growth and decline of real personal income from 1970 to 2005 in EF counties (in aggregate). Light blue vertical bars illustrate periods of national recession.

The economic history of EF counties is characterized by tremendous volatility. The boom in the 1970s was followed by a bust that lasted a decade in the 1980s. In the 1990s, EF counties recovered. This recovery was fueled by sectors unrelated to energy development, and represents a significant departure from the experience of the 1980s. The steady growth in the 1990s was extended and accelerated in the 2000s, when the current energy surge took root.

Figure 1. Total Personal Income in Energy-focusing (EF) Counties in the West, 1970–2005 (Indexed 1970=100)



Next we examine EF counties as compared to their peers from a historical perspective. Figure 2 shows the trends in personal income, by source (industry and non-labor income sources) from 1970 to 2000, for the aggregate of the 26 EF counties in the West. Figure 3 shows the same information for the aggregate of the 254 rural peer counties in the West.

The differences between the economic experience of EF counties and their peers are starkly evident. While EF counties went through a discernable boom/bust cycle, their peer counties saw a much steadier growth.

From 1970 to 1982, total personal income in EF counties, driven by mining, which includes energy development, grew rapidly. For the rest of the 1980s, mining and energy development contracted severely and brought the rest of the economy down with it. By the 1990s, however, with mining and energy development still declining though beginning to stabilize, the rest of the economy grew—this time independent of the fortunes of mining and energy extraction. Growth in the 1990s was driven by the rise in personal income from people employed in service and professional industries, and the even-faster increase of non-labor income (retirement, investments, government transfer payments, etc.).

For EF counties, the 1990s represented a period of economic diversification. The fact that the economies of EF counties began to diversify, even in the face of rapid declines in the mining (mostly energy development), is an important point. It underscores the economic shift that took place in the rural West between the 1980s and the 1990s, and shows that the context for today's energy surge is an economy that is both larger and more diverse that in the past.

Figure 2. Historical Trends in Personal Income by Source, Energy-focusing (EF) Counties in the West, 1970–2000 [4]

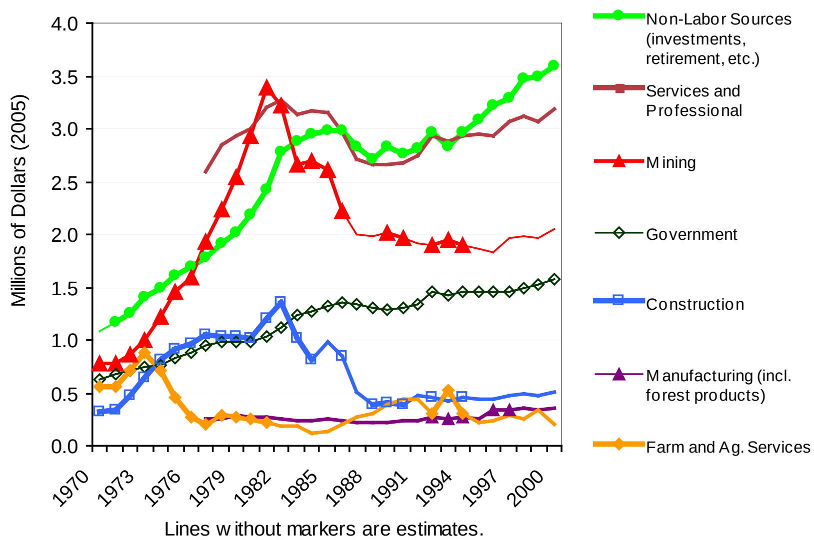
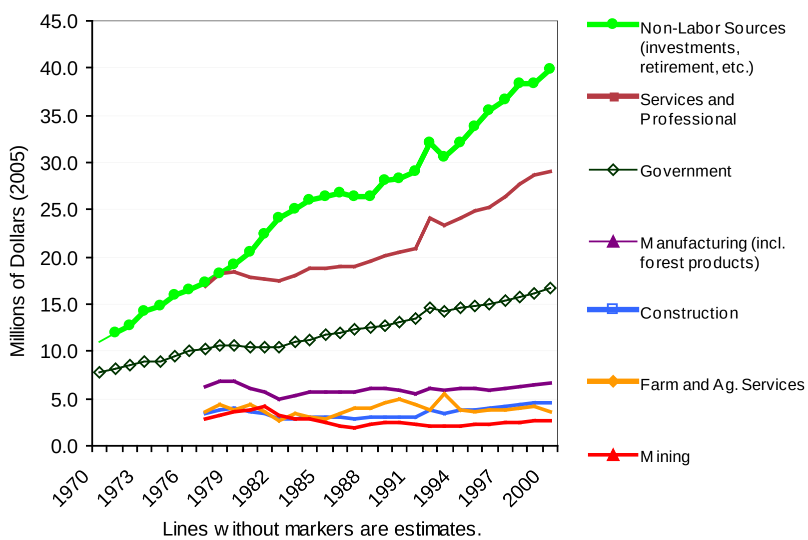


Figure 3: Historical Trends in Personal Income by Source, Peer Counties in the West, 1970–2000 [5]

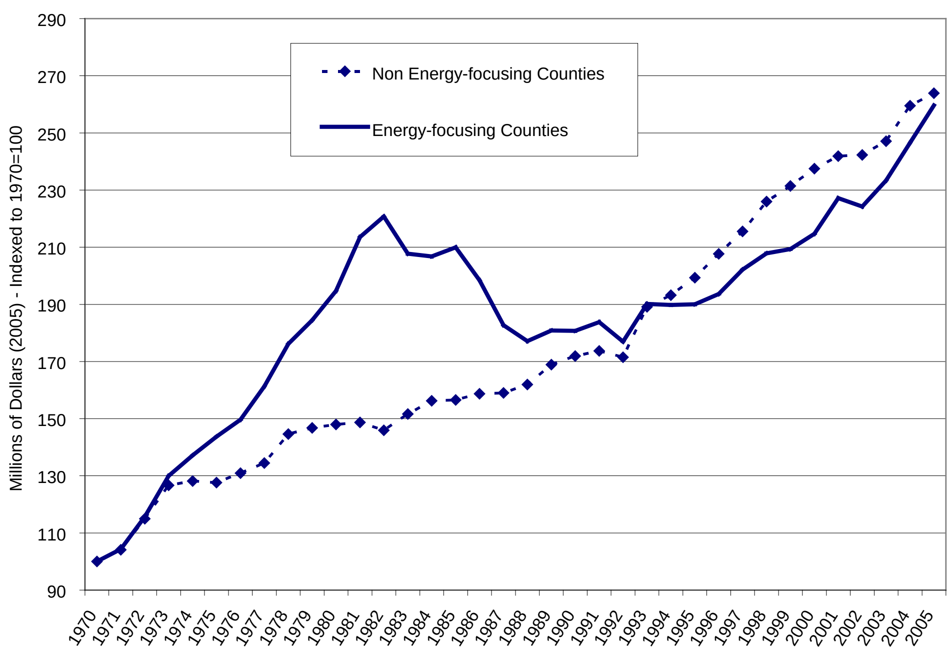


In contrast to EF counties, the non-energy peer counties saw a long and continued growth in real personal income, with no slowdown following the 1982 recession. Traditional industries, ranging from agriculture to manufacturing and construction, were all flat, while service and professional industries, non-labor income, and government enterprises accounted for the growth in personal income.

This tortoise-versus-the-hare comparison shows that it is not necessarily the case that rural counties in the West need to develop energy resources (if they have them) in order to succeed. Both sets of counties—EF counties and their peers—grew their economies at the same rate over the long term. This point is illustrated by Figure 4, which shows the long-term trend in personal income, comparing EF counties to their peer counties. The figure is indexed to 1970 in order to show relative rates of growth.

While the rate of growth in EF counties is characterized by fast acceleration and fast deceleration, the peer counties pursued a steadier expansion, with higher rates of income growth since the early 1990s. From 1990 to 2005, the average rate of real personal income growth in EF counties was 2.3 percent per year, compared to 2.9 percent in the peer counties. For the same time period, the average annual employment growth of EF counties was 1.8 percent, compared to 2.3 percent for the peer counties.[6]

Figure 4. Growth of Total Personal Income, Energy-focusing (EF) Counties versus Peer Counties in the West, Indexed, 1970–2005



These findings show that EF counties have historically gone through periods of boom and bust, outperforming their non-energy peers during the boom, and underperforming during the subsequent bust. They also show that EF counties began to grow and diversify their economies in the 1990s independent of mining and energy development. And, finally, over the last 15 years, EF counties have been falling behind in economic performance compared to their peers.

IS TODAY'S ENERGY SURGE ANY DIFFERENT FROM THE ENERGY BOOM OF THE 1970S?

Figure 5 (page 13) shows measures of economic performance (change in personal income, employment, average earnings per job, population, and per capita income), comparing EF counties to their peers. The vertical bar charts show the difference in growth rates for each measure between the two county types. In the chart, bars above 0.0% (the x-axis) indicate a period when EF counties outperformed the non-EF counties. Bar charts below 0.0% refer to episodes when EF counties underperformed compared to their peers.[7]

During the past energy boom period (1970–1982) EF counties showed fast rates of growth in personal income, employment, average earnings per job, population, and per capita income. This is consistent with Figure 4 that showed a much higher growth rate for EF counties during the 1970s. During the ensuing bust (1982–1990), the reverse occurred, and EF counties saw significant declines in all economic performance indicators relative to their peers.

The most interesting finding of Figure 5 is what occurred from 1990 to 2005, after the last energy bust and before and during the current energy surge, and how different the comparative performance is between the two sets of counties when contrasted with the earlier boom period of the 1970s. Compared to their peer counties in the West, EF counties saw a decline in personal income, employment, and population, and a rise in average earnings per job and per capita income from 1990 to 2005. This means that relative to their peers, EF counties underperformed in terms of the growth of real personal income, employment, and population, and outperformed in terms of the growth in earnings per job and per capita income. In other words, in today's economy there is no guarantee that counties that develop fossil fuel reserves have any significant advantage over those counties without those resources.

What Figure 5 also shows is that economically today's energy surge is different from those of the past. Until 1990, the pattern for EF counties was to do very well during a boom and very poorly during a bust. After 1990, this pattern changed, and it is no longer the case that an energy surge causes those counties with a higher share of economic activity devoted to energy development to outperform their rural peers. In three of the five economic indicators, the EF counties did worse than their peers. For the measures where they outperformed—average earnings per job and per capita income—there was only a modest performance difference (0.6% per year from 1990 to 2005).

The reasons for the difference in relative performance are explored in the next section. In brief, one reason is that the economy of the rural West has grown substantially in the last few decades, and as a result new energy jobs now make up a much smaller percent of total employment than in the past. Figure 6 shows that in EF counties at the peak of the last boom, in 1982, energy-related jobs were 23 percent of total employment (the green line, and right axis in the figure), whereas, in 2005, energy-related jobs in EF counties were 14 percent of total employment.[8] In other words, the relative share of energy jobs in EF counties has declined.

In addition, today's energy surge, driven in part by ready access to public lands, is occurring in a different context. Over the last three decades the economic role of public lands has changed significantly, from a repository of raw materials, to a haven for recreationists, tourists, retirees, and mobile businesses whose owners choose to locate in areas with a high quality of life. The economic transition, from a resource-based economy, to one focused on services, knowledge-based occupations, retirement, and investment dollars, has already taken place.

To put this in perspective, for the West as a whole, service-based occupations and non-labor income constitute 86 percent of the growth in the economy during the last three decades. And today, 45 percent of total personal income comes from wages earned by people employed in service-related occupations, while another 27 percent is from non-labor sources, such as retirement and investments.[9]

Of particular note, given that a new energy development surge started around the beginning of this decade, is the fact that mining, which includes oil, natural gas, and coal development, is still a relatively small component of the economy of the West, providing 1 percent of total personal income in 2005.[10]

The West is the most urbanized part of the U.S., with 90 percent of people living in metropolitan areas. [11] As a result, these trends largely represent urban phenomena. A closer look at the rest of the West—the rural West without metropolitan areas—reveals similar findings.

In the non-metropolitan West, a third of personal income in 2005 was generated by service-related industries. Non-labor income was relatively larger than in the rural West, making up more than 40 percent of total personal income. [12] Mining, including oil and natural gas, constituted less than 5 percent of total personal income and 2 percent of employment.[13]

For a thorough discussion of the economy of the West and the relative role of energy development, please consult another report in our *Energy and the West* series, *Energy Development and the Changing Economy of the West*.

Figure 5. Annual Rates of Growth of Key Economic Indicators, Shown as the Difference in Growth Rates Between Energy-focusing (EF) Counties and their Peers in the Rural West

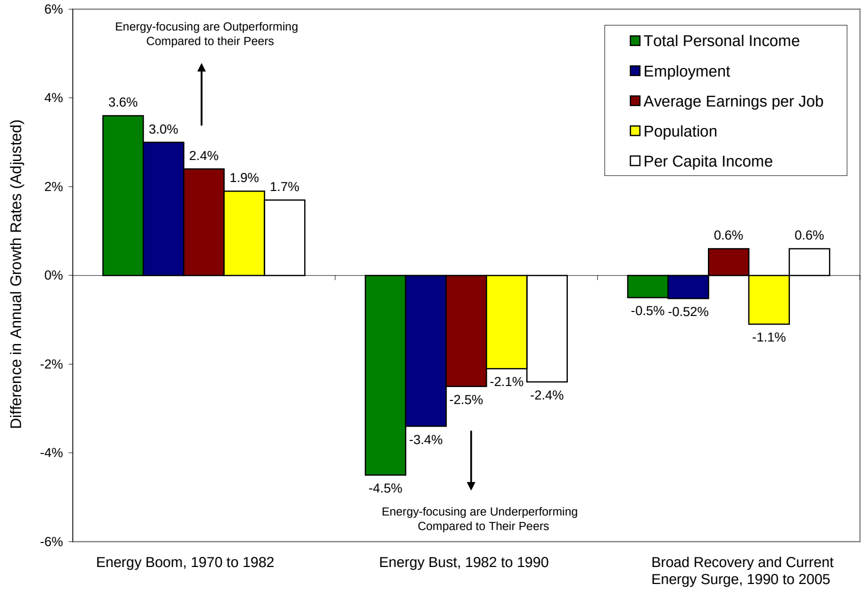
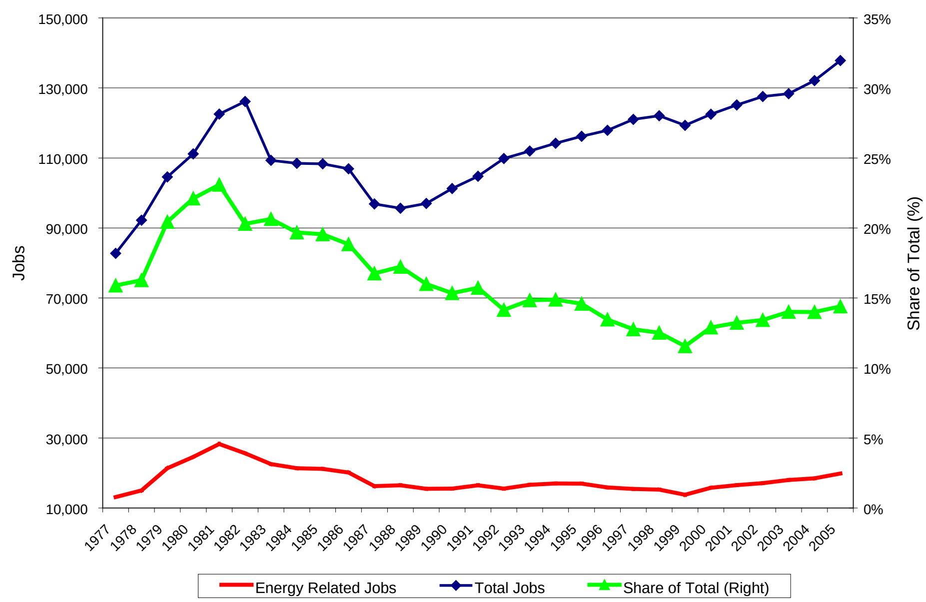


Figure 6. Energy-related Jobs in the Energy-focusing (EF) Counties in the West, as Share of Total, 1977–2005



The scale of the recent economic transition means that it is more difficult today for energy development, by itself, to turn county economies into top economic performers. This is illustrated in Table 3, which ranks EF counties among all counties in the West according to the annual growth of jobs during three time periods. In the energy boom that took place from 1970 to 1982, 10 of the 26 EF counties were in the top 30 counties in the West in terms of job growth (light green). Only one, Toole County, Montana, was among the bottom 30 counties (orange).[14]

During the ensuing bust, from 1982 to 1990, 12 of 26 EF counties ranked among the bottom 30 counties in the West in terms of job growth, and none were top performers. This is consistent with previous figures that showed significant economic decline for EF counties during this period.

The current energy surge has not created a rising tide lifting all EF boats as in the past. Only one county, Sublette County, Wyoming, ranks among the top economic performers in the West, in terms of job growth. Campbell County, Wyoming, the most energy-focusing county in the West, had the third highest rate of growth in the past energy boom, but ranks 85th in overall job growth in the current surge. Emery County, Utah ranked fifth in the past boom, and is 331st in the current surge. Even Sweetwater County, Wyoming, which is in the midst of a boom in natural gas development, ranks 254 out of 411 in terms of job growth during the current energy surge, as compared to fourth in the last boom.

Table 3. Ranking of Energy-focusing Counties Among all Counties in the West, in Terms of Average Annual Job Growth

			Rank among 411 western counties, based on average annual job growth during:		
Sorted by Energy Dependence:	Energy Jobs in 2005	Energy Share of Total (2005)	Old Boom: 1970-1982	Bust: 1982-1990	Recent Boom: 2000-2005
Campbell, Wyoming	5,436	30.0%	3	402	85
Emery, Utah	668	24.5%	5	385	331
Cheyenne, Colorado	99	21.5%	240	327	384
Rio Blanco, Colorado	343	20.9%	31	411	237
Uinta, Wyoming	1,163	17.5%	6	370	139
Big Horn, Montana	354	16.7%	296	348	202
Converse, Wyoming	610	16.4%	14	391	112
Hot Springs, Wyoming	233	15.4%	161	380	304
Fallon, Montana	124	14.9%	280	399	301
Blaine, Montana	133	14.1%	367	270	366
Sublette, Wyoming	309	14.0%	157	326	28
Lincoln, Wyoming	639	13.6%	149	353	110
Moffat, Colorado	507	13.5%	23	358	221
Rosebud, Montana	359	13.4%	7	390	375
Lea, New Mexico	2,065	12.3%	87	403	228
Carbon, Utah	807	11.5%	29	405	327
Gunnison, Colorado	689	11.4%	54	274	36
Weston, Wyoming	179	11.2%	116	382	215
Uintah, Utah	824	10.9%	28	393	88
Eddy, New Mexico	1,835	10.5%	136	351	224
Sweetwater, Wyoming	1,344	9.0%	4	386	254
Richland, Montana	317	8.8%	104	408	321
Yuma, Colorado	204	8.4%	289	131	398
Toole, Montana	124	7.8%	386	299	372
Big Horn, Wyoming	175	7.3%	205	374	278
Duchesne, Utah	293	7.0%	22	375	102

Top 30 (out of 411 Western Counties)
Bottom 30 (out of 411 Western Counties)

In spite of the recent rise in energy development activity, most EF counties are experiencing population losses. Table 4 (page 16) shows that of the 26 EF counties, 10 (38%) have seen an increase in population from 2000 to 2007 (highlighted in green). This includes some of the most heavily energy-focusing counties in Wyoming, Utah, and Colorado. Surprisingly, 16 (62%) of the energy-focusing counties lost population during the same period.[15]

Strangely, six of the counties that lost population at the same time added over 100 new jobs (not counting proprietors), from 2000 to 2005, in energy-related fields. These are: Blaine, Richland, and Rosebud counties, Montana; Eddy and Lea counties, New Mexico; and Uinta County, Wyoming.

Why are these counties losing population in the midst of an energy surge? One possible explanation may be the rising cost of living, which we discuss in more detail in the case study reports. As new jobs are created in the fields of oil, natural gas, and coal mining, workers move in, the cost of labor rises, and with a limited supply of housing, the cost of housing rises along with it. Non-energy workers, unable to compete for housing and a higher cost of living, leave. For example, rental prices in Rock Springs, Wyoming, in Sweetwater County, an EF county that is growing rapidly because of energy development, increased by 100% between 2000 and 2007.[16]

Further Reading

For more detail on the impacts of rapid energy development, see the two reports in the *Energy and the West* series listed below. They are available at: www.headwaterseconomics.org/energy.

Impacts of Energy Development in Colorado, with a Case Study of Mesa and Garfield Counties

Impacts of Energy Development in Wyoming, with a Case Study of Sweetwater County

Another possible explanation is that communities in the midst of an energy surge may displace other residents, retirees for example, who do not wish to live in what is becoming for many former rural towns a fast-paced industrial landscape. There may be other reasons for the loss of population that have nothing to do with energy development, and more to do with the plight of rural communities in general. Regardless of the reasons, there appears to be no guarantee that making a choice to focus economic activity on energy development will stem the loss of population that is so common in the rural West.

Table 4 . Net Migration per Thousand People per Year in Energy-focusing (EF) Counties, 2000–2007

	Migration 2000 to 2007 (People per 1000 per year)
Sublette, Wyoming	36.9
Campbell, Wyoming	14.8
Lincoln, Wyoming	8.0
Uintah, Utah	7.1
Converse, Wyoming	4.6
Duchesne, Utah	4.6
Weston, Wyoming	4.5
Gunnison, Colorado	2.7
Rio Blanco, Colorado	0.5
Lea, New Mexico	-1.8
Moffat, Colorado	-2.0
Sweetwater, Wyoming	-2.2
Big Horn, Wyoming	-2.9
Hot Springs, Wyoming	-4.4
Eddy, New Mexico	-4.7
Yuma, Colorado	-5.6
Uinta, Wyoming	-5.9
Richland, Montana	-6.0
Fallon, Montana	-8.2
Toole, Montana	-9.2
Carbon, Utah	-10.6
Big Horn, Montana	-10.9
Rosebud, Montana	-13.0
Emery, Utah	-15.9
Blaine, Montana	-16.5
Cheyenne, Colorado	-32.6
Unweighted Average	-2.6

These findings show that rural economies focusing on energy development today are very different than in the past. Unlike the past, EF counties are underperforming compared to their rural peers. EF counties are not the West's top economic performers they used to be. Today, only one EF county ranks among the top 30 economic performers in the West, while during the last energy boom half were top performers. Energy development also plays a smaller relative role in EF counties than in the past. The share of total jobs in energy-related fields in EF counties has declined, from a high of 23 percent in 1982 (peak of last energy boom) to 14 percent in 2005 (in the midst of today's energy surge). At the same time, 62 percent of EF counties are losing population in the midst of today's energy surge.

WHY DO ENERGY-FOCUSING COUNTIES UNDERPERFORM RELATIVE TO THEIR PEERS?

In this section, we explore answers to the question of why EF counties underperform economically.

Energy-focusing Counties are Less Economically Diverse

The more diverse the economy of a county, the better it is able to adapt to the constantly changing conditions of the global and national economy.[17]

There are indications that EF counties are diversifying. Figure 2 (page 9), for example, shows a rise in certain sectors of the economy, such as services and non-labor income, despite declines in mining, including energy development. Figure 2 shows that the relative contribution of mining is declining, in part, because the overall non-energy related portion of the economy is growing. In spite of this diversification, by 2000 (the beginning of the current surge) EF counties were still much less diverse economically than their non-EF peers.

To measure economic diversity we developed a specialization index for the aggregate economy of all 26 EF counties and compared that to one developed for the 254 peer counties in the West.[18] This index is commonly used as a measure of industrial specialization in the economy. Counties with a high specialization index are less economically diverse, more susceptible to volatility, and less innovative.[19] The most diverse score possible would be one that exactly emulated the U.S. economy, and would have a score of 0.0.[20]

Our findings show that in 2000, the specialization index for EF counties was 280, compared to a score of 106 for their peer counties. The principal ways EF counties are different from the U.S. are: a heavy reliance on mining and energy development (11.8% of total compared to 0.4% for the U.S.); under-reliance on manufacturing (4.3% compared to 14.1% for the U.S.); and under-reliance on professional scientific and technical services (2.4% compared to 5.9% for the U.S.). The main ways the peer counties in the West differ from the U.S. are: under-reliance on manufacturing (7.9%); over-reliance on agriculture, forestry and fishing (7.2% compared to 1.5% for the U.S.), and over-reliance on accommodation and food services (8.6% compared to 6.1% for the U.S.).[21]

Another way to represent economic diversity is to assess those industries that are growing, and those that are in decline. Table 5 shows the growth of jobs during the current energy surge (2000 to 2005), comparing EF counties to their peers in the West.[22]

In EF counties, the principal growth (indicated in light green when over 5% of new jobs) was in direct energy-related occupations (energy, mining, support activities for oil and natural gas operations) and largely in occupations indirectly associated with energy development (manufacturing, construction, transportation, warehousing, and professional and scientific services). Other sectors, such as retail trade, health care and social assistance, and accommodation and food services also grew.

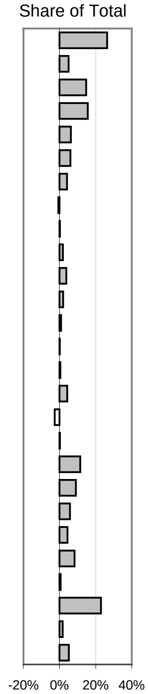
In the peer counties, the bulk of the job growth came from service-related occupations, with the largest growth in health and social assistance, and accommodation and food services. Other areas in which the peer counties grew include construction, transportation and warehousing, retail trade, real estate, and other services. In addition, other data, detailed below, show that peer counties are more successfully attracting investment and retirement dollars, and diversifying their economies with these income streams.[23]

The difference in types of growth can be seen in the column at the far right of Table 5. EF counties are specializing, adding those sectors that are necessary for the exploration, development, extraction, and transportation of fossil fuels. They do not create many new jobs that characterize the broader economic shift in the western economy over the last several decades, namely the development of a service-based and knowledge-based economy.

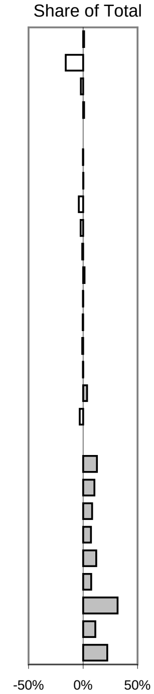
Table 5. New Jobs by Industrial Sector Comparing Energy-focusing Counties to Peer Counties in the West, 2000–2005

	26 Energy-Focusing Counties		254 Non Energy-Focusing Counties	
Industry	New Jobs 2000-2005	New Jobs Share of Total	New Jobs 2000-2005	New Jobs Share of Total
	15,312	100.0%	62,320	100.0%
Energy	4,043	26.4%	643	1.0%
Manufacturing	775	5.1%	(9,873)	-15.8%
Mining	2,249	14.7%	(1,234)	-2.0%
Support Activities for Oil and Gas Operations	2,387	15.6%	599	1.0%
Management of Companies and Enterprises	969	6.3%	103	0.2%
Drilling Oil and Gas Wells	922	6.0%	(7)	0.0%
Oil and Gas Extraction	632	4.1%	170	0.3%
Unclassified	(108)	-0.7%	(2,392)	-3.8%
Forestry, Fishing, Hunting, and Agriculture Support	38	0.3%	(1,440)	-2.3%
Information	284	1.9%	(416)	-0.7%
Other Services (except Public Administration)	567	3.7%	830	1.3%
Utilities	293	1.9%	(60)	-0.1%
Educational Services	131	0.9%	(187)	-0.3%
Wholesale Trade	12	0.1%	(523)	-0.8%
Support Activities for Coal Mining	76	0.5%	(125)	-0.2%
Finance and Insurance	652	4.3%	2,360	3.8%
Auxiliaries, except Corporate, Subsidiary, and Regional M	(412)	-2.7%	(1,930)	-3.1%
Coal Mining	25	0.2%	6	0.0%
Construction	1,756	11.5%	7,969	12.8%
Transportation and Warehousing	1,382	9.0%	6,466	10.4%
Retail Trade	892	5.8%	5,187	8.3%
Administrative and Support and Waste Management and	669	4.4%	4,533	7.3%
Professional, Scientific, and Technical Services	1,261	8.2%	7,484	12.0%
Real Estate and Rental and Leasing	100	0.7%	4,660	7.5%
Health Care and Social Assistance	3,510	22.9%	19,682	31.6%
Arts, Entertainment, and Recreation	262	1.7%	7,026	11.3%
Accommodation and Food Services	789	5.2%	13,778	22.1%

New Jobs Share of Total



New Jobs Share of Total



Green if over 5%, Brown if under -5%.

Overall Wages Have Not Increased at the Same Rate as Energy Industry Wages

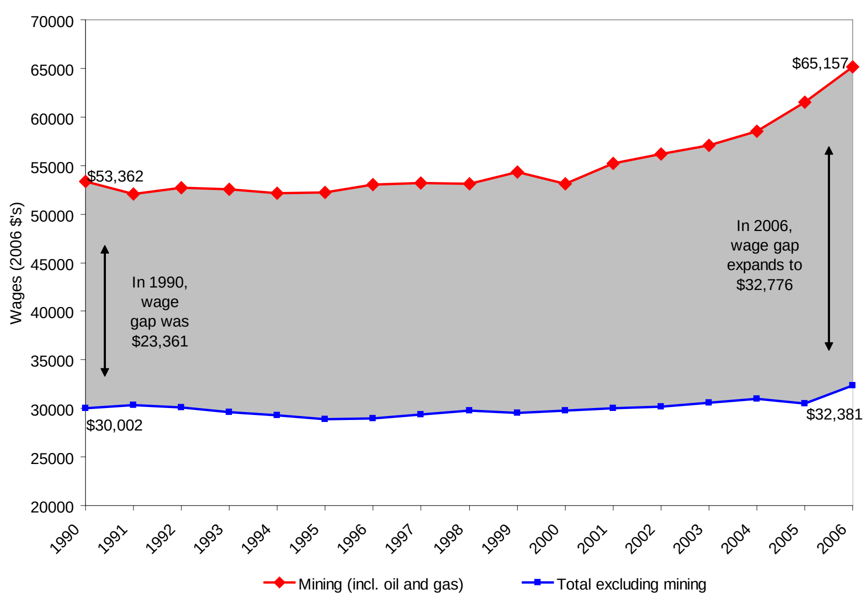
Another possible reason for the relatively lower performance of EF counties is a growing gap between what mine workers earn ("mine" includes energy-related fields in this report) compared to those working in other sectors of the economy.

Figure 7 shows average annual wages of mine workers (primarily oil and natural gas workers) in EF counties, compared to wages in the rest of the economy. In 1990, the wage gap was $23,361; mine workers earned $53,362 per year, on average, while those in other sectors earned, on average, a little over $30,000 per year. Wages in non-mining sectors have not changed much since then. From 1990 to 2006, they grew (in real terms) by 7.9 percent, to $32,381 in 2006. During that time, average annual wages for the mining sector grew by 22 percent, to over $65,000 per year in 2006. The wage gap grew to a difference of $32,776, which is $9,414 more than it was in 1990.[24]

It is possible that the 7.9 percent growth in non-mining wages would not have happened if there weren't any mining activity. From 1990 to 2006, average annual wages in the peer counties grew more slowly, by 6 percent. In 2006, average annual wages in non-mining sectors in the peer counties was $30,555, lower than that of the EF counties, at $32,381.[25]

The growing wage gap in EF counties between mine and all other workers—from $23,361 in 1990 to $32,776 in 2006—is not a healthy sign. The danger is that more people, including teachers, nurses, and farm workers, will be left behind if renewed energy development increases the general cost of living, especially the cost of housing, in a place. We explore this issue in more depth in the case study reports in the *Energy and the West* series.

Figure 7. Average Annual Wages in Mining, including Energy Development, Compared to the Rest of the Economy, in Energy-focusing Counties in the West, 1990-2006



Energy-focusing Counties Have Less Equitable Wealth Distribution

A community where everyone is doing comparatively well stands a higher chance of being able to adapt to change and grow.[26] We measured the gap between "high income" and "low income" by counting the number of households earning more than $150,000 per year ("high income") divided by the number of households earning less than $30,000 per year ("low income") .[27]

At the end of the last energy bust cycle and before EF counties started their economic recovery, in 1990, EF counties had a large gap between high income and low income households: for every household earning over $150,000 per year, there were 108 household earning less than $30,000 per year. By comparison, that same year in the peer counties, for every household earning more than $150,000 per year, there 87 households earning less than $30,000. This means that at the beginning of the recovery period that started in the 1990s, EF counties had a relatively less equitable distribution of wealth; i.e., there were many more "low income" relative to "high income."

Fortunately, by 2000 (at the beginning of the current energy surge, and at the end of the recovery that took place during the 1990s) the high income-low income ratio declined significantly for both county types.[28] In EF counties, for every high income household, there were 27 low income households (a ratio of 1:27; for the peer counties in 2000 the ratio was 1:17).

That EF counties had a larger gap between high income and low income than their peers at the end of a bust period and before embarking on economic recovery (i.e., 1990) is related to the fact that EF counties have not diversified their economies and developed a more mixed suite of service-related industries. By 2000, after a decade of more balanced economic growth, EF counties had improved their earnings distribution, but still lagged behind their peers.

In the current energy surge, EF counties are once again developing an earnings gap among residents. This is attributable to the widening gap between earnings of mine workers and the rest of the economy, a gap that is growing and was over $32,000 in 2006. If cost-of-living factors are considered, it is likely that people on fixed income or earning lower average wages are falling even further behind.

It is premature to estimate what income distribution will look like in EF counties after the current surge, but it is plausible that the gap between the high income and low income households will continue to widen for counties that focus on energy development as a rural development strategy.

Energy-focusing Counties Have Less Educated Workforces

An important condition for economic success in today's U.S. economy is an educated workforce.[29] We look at the percent of the adult population with and without a high school and college education.

At the end of the last energy bust cycle and before EF counties started their economic recovery, in 1990, EF counties had somewhat less educated workforces compared to their peers. In 1990, 24 percent of the adult population in EF counties did not have a high school diploma, which is slightly higher than their peer counties (23%). By 2000, 19 percent of the adult population in the EF counties did not have a high school diploma, an improvement from the previous decade, but still higher than their peers (17%).[30]

In terms of college education, in 1990 the percent of the adult population with a college degree was about equal among the two county types, although slightly less (14% compared to 16%) for EF counties. By 2000, at the end of the 1990s recovery, the percent of the population with a college degree increased slightly for EF counties (to 16%), but remained lower than in the non-EF peers (20%).

These statistics show that counties focused on energy development lag behind their peers in terms of workforce education levels. Even though all counties are experiencing increases in workforce education levels, the proportion of college-educated workers in EF counties at the beginning of this century had been reached by their non-energy peers a decade earlier.

Energy-focusing Counties Attract Fewer Retirement and Investment Dollars

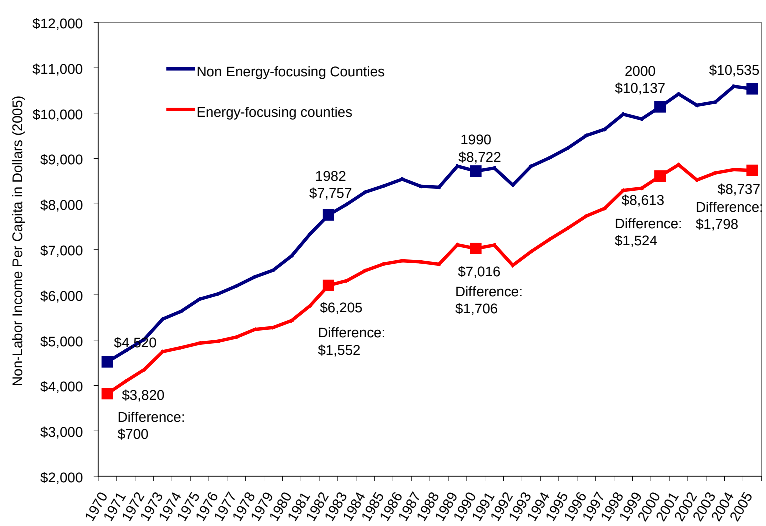
The importance of non-labor sources of income shows no signs of diminishing in the near future. As Americans generate more wealth and our population ages, more people will use their savings, investments, and programs like Social Security to sustain their livelihoods, whether they are still working or retired. By 2005, more than 40 percent of total personal income in the rural West was from non-labor sources, including transfer payments, dividends, interest, and rent.

Non-labor income, when measured on a per capita basis, is a measure of a community's ability to attract and retain this fast-growing segment of the economy.

Figure 8 shows the growth of per capita non-labor income, comparing EF counties to their peers in the West. In 1970, per capita non-labor income was similar between the two county types, with only a $700 difference. By 2005, the difference was $1,798.

These figures show that in the midst of today's energy development surge, counties focusing on energy extraction are less able to attract retirement and investment dollars than their peers.[31]

Figure 8. Growth of Per Capita Non-Labor Income, Energy-focusing Counties Compared to Peers, 1970–2005



These findings show that today's energy surge is different than in the past, and in several important ways EF counties today are less well positioned to compete economically. EF counties are less diverse economically, which makes them less resilient but also means they are less successful at competing for new jobs and income in growing service sectors where most of the West's economic growth has taken place in recent decades. EF counties are also characterized by a greater gap between high and low income households, and between the earnings of mine and energy workers and all other workers. And EF counties are less well educated and attract less investment and retirement income, both important areas for future competiveness.

CONCLUSIONS

In the West today, it is less certain that energy development will bring the prosperity it once did, and reason to be concerned that a concentration on fossil fuel extraction may impair a local economy's ability to grow and compete successfully in today's more diverse economy.

In the past, the pattern of development for counties with fossil fuel reserves was to grow quickly, reach a peak, and then decline sharply—the so-called boom and bust cycle. Beginning in the 1990s, it became clear that the economy in the West was diversifying, with especially rapid job growth occurring in service- and knowledge-based sectors, and that much of the real growth in personal income was associated with this service economy, and an aging population and the influx of retirement and investment dollars.

The implications of these changes—the growth and diversification of the western economy as a whole, including rural areas—is that energy development today does not have the same impact it had in the past. In the 1970s and early 1980s, there were few economic alternatives in rural communities. The discovery and development of oil and natural gas, or coal, created new high-wage jobs where in many cases there had been few or none. By the early 2000s, the West had, with a few exceptions, decoupled from its reliance on resource extraction, and enjoyed a wider range of economic choices than ever before.

The current surge in energy development takes place in this changed economic context. In counties that have pursued energy extraction as an economic development strategy—places we call energy-focusing (EF) in this report—the long-term indicators suggest that relying on fossil fuel extraction is not an effective economic development strategy for competing in today's growing and more diverse western economy.

When compared to their rural peer counties, EF counties suggest an analogy to the fable of the tortoise and the hare. While EF counties race forward and then falter, the non-energy peer counties grow steadily. At the finish line, counties that have focused on broader development choices are better off, with higher rates of growth, more diverse economies, better-educated populations, a smaller gap between high and low income households, and more retirement and investment income.

Economics is the study of how people make choices in a constrained environment. The findings in this report show state and rural leaders, as well as managers of public lands (where much of the energy development is taking place in the West today), that a concentration on fossil fuel development can undercut the competitive position of a regional or local economy.

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APPENDIX

NORTH AMERICAN INDUSTRIAL CLASSIFICATION SYSTEM (NAICS) DEFINITIONS

The language below is copied verbatim from the U.S. Census Bureau's 2002 NAICS Manual
http://www.census.gov/epcd/naics02/index.html

211 Oil and Gas Extraction

Industries in the Oil and Gas Extraction subsector operate and/or develop oil and gas field properties. Such activities may include exploration for crude petroleum and natural gas; drilling, completing, and equipping wells; operating separators, emulsion breakers, desilting equipment, and field gathering lines for crude petroleum and natural gas; and all other activities in the preparation of oil and gas up to the point of shipment from the producing property. This subsector includes the production of crude petroleum, the mining and extraction of oil from oil shale and oil sands, and the production of natural gas, sulfur recovery from natural gas, and recovery of hydrocarbon liquids.

Establishments in this subsector include those that operate oil and gas wells on their own account or for others on a contract or fee basis. Establishments primarily engaged in providing support services, on a fee or contract basis, required for the drilling or operation of oil and gas wells (except geophysical surveying and mapping, mine site preparation, and construction of oil/gas pipelines) are classified in Subsector 213, Support Activities for Mining.

213111 Drilling Oil and Gas Wells

This U.S. industry comprises establishments primarily engaged in drilling oil and gas wells for others on a contract or fee basis. This industry includes contractors that specialize in spudding in, drilling in, redrilling, and directional drilling.

213112 Support Activities for Oil and Gas Operations

This U.S. industry comprises establishments primarily engaged in performing support activities on a contract or fee basis for oil and gas operations (except site preparation and related construction activities). Services included are exploration (except geophysical surveying and mapping); excavating slush pits and cellars, well surveying; running, cutting, and pulling casings, tubes, and rods; cementing wells, shooting wells; perforating well casings; acidizing and chemically treating wells; and cleaning out, bailing, and swabbing wells.

2121 Coal Mining

This industry comprises establishments primarily engaged in one or more of the following: (1) mining bituminous coal, anthracite, and lignite by underground mining, auger mining, strip mining, culm bank mining, and other surface mining; (2) developing coal mine sites; and (3) beneficiating (i.e., preparing) coal (e.g., cleaning, washing, screening, and sizing coal).

213113 Support Activities for Coal Mining

This U.S. industry comprises establishments primarily engaged in providing support activities for coal mining (except site preparation and related construction activities) on a contract or fee basis. Exploration for coal is included in this industry. Exploration includes traditional prospecting methods, such as taking core samples and making geological observations at prospective sites.

ENDNOTES

[1] U.S. Bureau of the Census, North American Industrial Classification System (NAICS): http://www.census.gov/epcd/www/naics.html.

[2] U.S. Bureau of the Census, *County Business Patterns (CBP), 2008*. Washington, D.C.

[3] The data were derived from statistics published by the Bureau of the Census, in their publication *County Business Patterns* (CBP). We used this data sources primarily because it is devoid of disclosure restrictions. Disclosure restrictions are data gaps, where a government agency will not release information to protect the confidentiality of individual firms, and occur most frequently with data in the Regional Economic Information System (REIS) of the U.S. Department of Commerce. The disadvantage of CBP is that, unlike REIS data, it does not include the self-employed or government employment. If a relative measure is used (i.e., percent of total), as we did, the exclusion of the self-employed or proprietors does not make a significant difference. Some mining sectors employ very few single-owner proprietors, so the inclusion of proprietor's data, if it were available, would actually lower the size of mining relative to other sectors. "Coal mining" and "support activities for mining" are both examples of this, where only 8 percent of the industry is made up of proprietors. Other sectors employ more proprietors than average so the inclusion of proprietors would raise their shares. "Oil and gas extraction" is an example of this, where 12 to 14 percent of employment is in proprietors. Our definition of energy includes all three sectors. Together the differences offset each other and the resultant values for energy's share of total are not affected by the exclusion of proprietors. By using a data set that does not count government employment as part of total, our energy share of total calculations are higher than they would otherwise be, especially in some communities that have a lot of government. If we were to calculate energy shares using both proprietors and government, we expect the results would report shares that were the same or lower.

[4] U.S. Department of Commerce, *Regional Economic Information System (REIS)*, *2008*. Bureau of Economic Analysis. Washington, D.C.

[5] Ibid.

[6] CBP 2008.

[7] Data for figure derived from REIS 2008.

[8] Data for figure derived from CBP 2008.

[9] Ibid, REIS 2008. Mining personal income based on estimates. Employment based on non-disclosed data from Bureau of Labor Statistics, *Quarterly Census of Employment and Wages* (QCEW).

[10] Ibid, REIS 2008.

[11] Bureau of the Census 2008. Calculations based on dividing the total number of people living in metropolitan statistical areas (MSAs) by the total population of the West.

[12] Ibid, REIS 2008.

[13] Ibid, REIS 2008. Mining personal income based on estimates. Employment based on non-disclosed data from Bureau of Labor Statistics, QCEW.

[14] Employment data in table from REIS 2008 and CBP 2008.

[15] Figures in table derived from U.S. Bureau of the Census, 2008.

[16] Housing Data, State of WY Dept of Economic Analysis and Info. http://eadiv.state.wy.us/housing.

[17] For a useful review of the academic literature on economic diversity, see Sterling, Andrew. 1998. "On the Economics and Analysis of Diversity." Electronic Working Papers Series, University of Sussex. http://www.sussex.ac.uk/Units/spru/publications/imprint/sewps/sewp28/sewp28.pdf. More narrowly, consult Malizia, E. E. and K. Shanzai. 2006. "The Influence of Economic Diversity on Unemployment and Stability." Journal of Regional Science. 33(2): 221-235.

[18] The specialization index was calculated by summing the squares of the difference between the aggregate (i.e., 26 EF counties, 254 peer counties) and the U.S. economy:

SPECIALit = ∑ ((EMPijt/EMPit)-(EMPusjt/EMPust)) 2 where,
SPECIALit = specialization of economy in county i in year t
EMPijt = employment in industry j in county i in year t
EMPit = total employment in county i in year t
EMPusjt = employment in industry j in U.S. in year t
EMPust = total employment in U.S. in year t
n = number of industries

[19] For an example of the application of a similar specialization index by the Federal Reserve, see Ozcan-Kalemlt S., B.E. Sorensen and O. Yosha. 2000. "Risk-sharing and Industrial Specialization: Regional and International Evidence." RWP 00-06. Kansas City: Federal Reserve Bank of Kansas City.

[20] The data and calculations for the specialization indices can be found on page 23 of the EF and peer profiles, located on: www.headwaterseconomics/energy.

[21] Data from U.S. Bureau of the Census, 2000, File SF#, Table P48.

[22] Data for the table derived from CBP 2008.

[23] REIS 2008.

[24] Data for figure from Bureau of Labor Statistics (BLS). *Quarterly Census of Employment and Wages (QCEW), 2008.* Washington, D.C. The category "mining" consists primarily of workers involved in the development and extraction of oil, natural gas and coal.

[25] Ibid, BLS 2008.

[26] For a review of the academic literature on the relationship between income distribution and economic growth, see: http://micro5.mscc.huji.ac.il/~melchior/html/Income%20Distribution.htm. More narrowly, consult Henry, C.W. 1998. "Income Inequality, Human Capital Accumulation and Economic Performance." *The Economic Journal*. 108 (Jan): 44-59.

[27] Data from the Bureau of the Census, 1990 and 2000 Decennial Census of Population, and Housing.

[28] The improved ratios were not because there were significantly fewer low-income families in 2000. Rather, the number of high-income families, in both sets of counties, increased. In 1990, 0.9% of household in the EF counties were high-income. By 2000, 2.3% were "rich." By comparison, in 1990 1.1% of the households in the peer counties were high-income. By 2000, 5.4% were high-income.

[29] According to the Bureau of Labor Statistics, earnings are higher and the unemployment rate is lower for people who have high levels of education: http://www.bls.gov/opub/ted/2003/oct/wk3/art04.htm. See also Ray, M. and M. Tucker. 1992. *Thinking for a Living: Education and the Wealth of Nations*. Basic Books, New York, New York.

[30] Data from the Bureau of the Census, 1990 and 2000 Decennial Census of Population, and Housing.

[31] REIS 2008.

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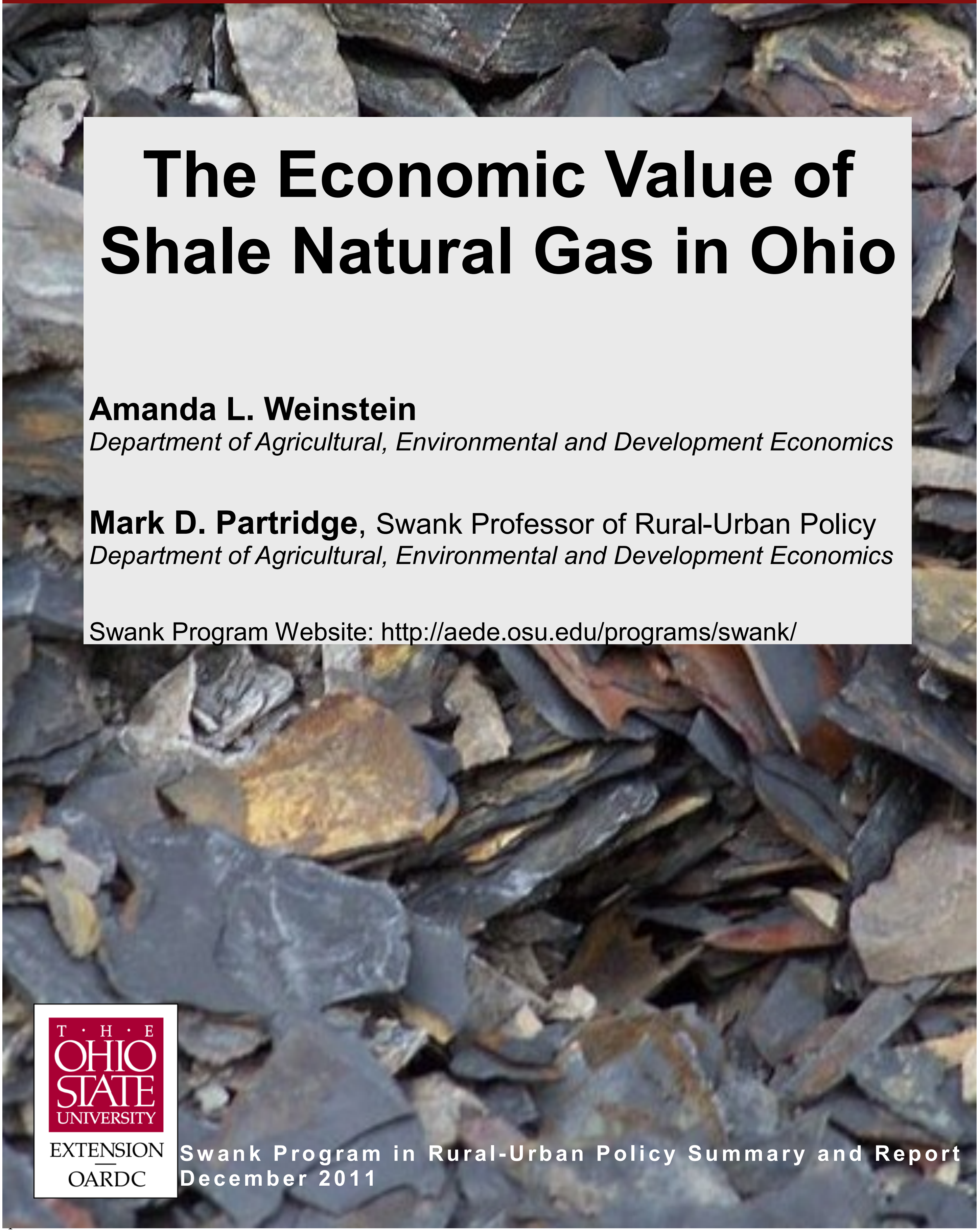

The Economic Value of Shale Natural Gas in Ohio

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Mark D. Partridge, Swank Professor of Rural-Urban Policy
Department of Agricultural, Environmental and Development Economics

Swank Program Website: http://aede.osu.edu/programs/swank/

THE OHIO STATE UNIVERSITY
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Swank Program in Rural-Urban Policy Summary and Report
December 2011

Mark Partridge Short Biography

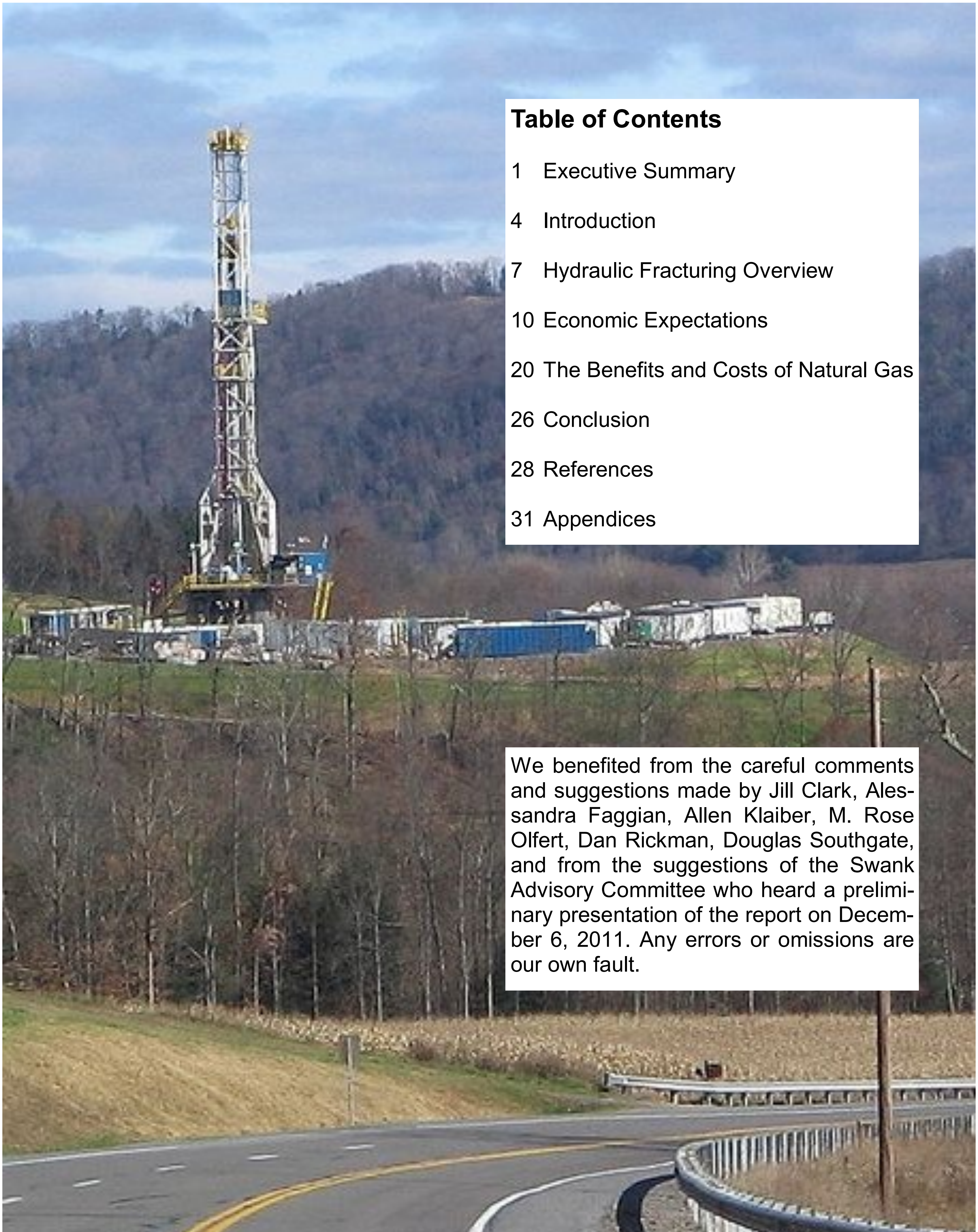
Dr. Mark Partridge is the Swank Chair of Rural-Urban Policy at Ohio State University. He is a Faculty Research Affiliate, City-Region Studies Centre, University of Alberta, an Affiliate of the Martin Prosperity Center at the University of Toronto, and an adjunct professor at the University of Saskatchewan. Professor Partridge is Managing Co-Editor of the *Journal of Regional Science* and is the Co-editor of new the *Springer Briefs in Regional Science* as well as serves on the editorial boards of *Annals of Regional Science, Growth and Change, Letters in Spatial and Resource Sciences, The Review of Regional Studies, and Region et Developpement*. He has published over 100 scholarly papers and coauthored the book *The Geography of American Poverty: Is there a Role for Place-Based Policy?* Dr. Partridge has consulted with OECD, Federal Reserve Bank of Chicago, Federal Reserve Bank of Cleveland, and various governments in the U.S. and Canada, and the European Commission. Professor Partridge has received funding from many sources including the Appalachian Regional Commission, Brookings Institution, European Commission, Infrastructure Canada, Lincoln Institute of Land Policy, U.S. National Science Foundation, U.S. National Oceanic and Atmospheric Administration, and Social Science and Humanities Research Council of Canada. His research includes investigating rural-urban interdependence and regional growth and policy. Dr. Partridge served as President of the Southern Regional Science Association in 2004-05 and is currently on the Executive Council of the Regional Science Association International (the international governing board).

Amanda Weinstein Short Biography

Amanda Weinstein is a PhD student in the Department of Agricultural, Environmental, and Development Economics at The Ohio State University. Her research as the C. William Swank Graduate Research Associate includes policy briefs about the employment effects of energy policies and general regional growth and policy issues. She is an OECD consultant advising on the economic impacts of alternative energy policies on rural communities. Her other research interests include women's role in economic development examining women's effect on regional productivity growth. She was awarded the Coca-Cola Critical Difference for Women Graduate Studies Grant to continue her work on gender issues in economics. She is also conducting research on the skills most valued during a recession and the impact of military service on intergenerational mobility. Before starting her PhD at OSU, she was a commissioned officer in the United States Air Force after graduating from the United States Air Force Academy. As a Scientific Analyst in the Air Force and then as a Sr. Management Analyst for BearingPoint, she advised Air Force leadership on various acquisition and logistics issues. She is currently an adjunct faculty member of Embry-Riddle University and DeVry.

Table of Contents

We benefited from the careful comments and suggestions made by Jill Clark, Alessandra Faggian, Allen Klaiber, M. Rose Olfert, Dan Rickman, Douglas Southgate, and from the suggestions of the Swank Advisory Committee who heard a preliminary presentation of the report on December 6, 2011. Any errors or omissions are our own fault.



Tower for drilling horizontally into the Marcellus Shale Formation for natural gas in Lycoming County, Pennsylvania.

The Economic Value of Shale Natural Gas in Ohio

Executive Summary

Increased production of US natural gas in recent years has helped to meet the growing demands of American customers and has reduced natural gas imports. Natural gas is also a cleaner burning fuel when compared to its most realistic substitute, coal. This substantial increase in production has been attributed in large part due to the development of shale gas through a process called hydraulic fracturing. Hydraulic fracturing has enabled the expansion of natural gas extraction into new undeveloped areas. The Marcellus shale in Pennsylvania has experienced impressive growth in its natural gas industry and neighboring Ohio is beginning down the same path. Proponents argue that among the many purported advantages, natural gas production is associated with significant amounts of new economic activity.

Economists have 150 years of experience in examining energy booms and busts throughout the world to form their expectations of how energy development affects regional economies. Generally, economists find that energy development is associated with small or even negative long-run impacts. They refer to a "natural resources curse" phenomenon associated with the surprisingly poor performance of resource abundant economies. There appears to be more examples like Louisiana, West Virginia, Venezuela, and Nigeria of energy economies seemingly underperforming and few examples of places such as Alberta and Norway of relative over performance. This backdrop needs to be considered in forming good policy in Ohio in order to avoid being in the former group.

In supporting energy development, the natural gas industry has funded its own studies of economic performance. For example, utilizing assumptions derived from Pennsylvania economic impact studies, Kleinhenz & Associates (2011) estimate that the natural gas industry could help "create and support" over 200,000 jobs to Ohio and $14 billion in spending in the next four years. These figures are about the same size as those for Pennsylvania (in industry funded studies). As we outline in this report, impact studies such as those employed by the industry are typically flawed due to the following reasons:

1. Possible double counting economic effects from drilling activities and royalties/lease payments to landowners. Most important, these studies have multipliers well above what independent economists would normally expect.
2. Including unrealistic assumptions about the percentage of spending and hiring that will remain within the state.
3. Ignoring the costs of natural gas extraction on other sectors through higher wages, and land costs that will make them less competitive (e.g., Dutch Disease), as well as environmental damage that limits tourism and other activities. It will also displace coal mining—i.e. more natural gas jobs come at the expense of fewer jobs in coal mining.
4. Often employing out-of-date empirical methodologies that academic economists have long abandoned for better methodologies in terms of evaluation of economic effects.

Many of the same reasons why alternative energy has not been (will not be) a major job creator also applies to natural gas (Weinstein et al., 2010):

1. The energy industry and specifically the natural gas industry's employment share is small and by itself is not a major driver of job growth for an entire state the size of Ohio or Pennsylvania. During the one year span October 2010-October 2011, U.S. Bureau of Labor Statistics data reports that Ohio's unemployment rate fell from 9.7 to 9.0% or 0.7% (without shale development), while Pennsylvania's unemployment rate only fell from 8.5% to 8.1% or 0.4% (with shale development). Ohio also had faster job growth during the span (1.3% versus 1%), showing that shale development by itself is not shaping their growth.
2. It is a capital-intensive industry versus labor-intensive—or a dollar of output is associated with significantly fewer workers.

The costs of natural gas include the effects it has on other industries. Some of these effects include displacement of other forms of economic activity, the effects of pollution that drive out residents who are worried about its effects and the higher wages and land/housing costs that make other sectors less competitive. For example, the tourism industry will likely be adversely affected by fears of pollution and higher wages and costs as other sectors have to compete for workers with the higher paying natural gas sector. In Pennsylvania, for instance, the tourism industry employed approximately 400,000 in 2010 (though a much smaller number is immediately near the shale development) compared to only 26,000 in a broad definition of the natural gas industry (Barth, 2010; BLS). Similar concerns should also apply to Ohio across various sectors of the economy.

Our broad analysis shows the expected employment effects of natural gas are modest in comparison to Ohio's 5.1 million nonfarm employee economy. We show this through (1) an assessment of impact analysis, (2) comparison of drilling counties with similarly matched non-drilling counties in Pennsylvania, (3) statistical regressions on the entire state of Pennsylvania, (4) employment comparisons with North Dakota's Bakkan shale region, and (5) an examination of the employment life cycle effects of natural gas and coal per kilowatt of electricity. Specifically, we estimate that Pennsylvania gained about 20,000 direct, indirect, and induced jobs in the natural gas industry between 2004-2010, which is a far cry fewer than the over 100,000 jobs reported in industry-funded studies (and the 200,000 expected in Ohio by 2015). Given the anticipated size of the boom, Ohio is expected to follow the Pennsylvania's experience. We believe 20,000 jobs would be a more realistic starting point for what to expect in Ohio over the next four years and is in line with what other independent assessments have suggested. However, our 20,000 job estimate does not account for displacement losses in other industries such as tourism, and we also note that local economic effects could appear larger in heavily impacted areas. Moreover, we find that mining counties had considerably faster per-capita income growth than their non-drilling peers, which likely results from royalties/lease payments and the high wages in the industry. Thus, we expect the near-term boom to be associated with frothy increases in income but more temperate job effects.

There are several reasons why the industry-funded studies produce employment results that are considerably different from our estimates. Foremost, impact studies are not viewed as best practice by academic economists and would be rarely used in peer reviewed studies by urban and regional economists. Instead, best practice usually tries to identify a counterfactual of what would have happened <u>without</u> the natural gas industries and compare to what did happen (we adopt two of these approaches). One advantage of identifying the counterfactual is that the estimated effects use actual employment data and are not the estimated outcome of an impact computer model. Yet, like virtually every other economic event, there are winners (e.g., landowners or high-paid rig workers) and losers (e.g., those who can no longer afford the high rents in mining communities and communities dealing with excessive demands on their infrastructure). Moreover, the boom/bust history of the energy economy is that drilling activity usually begins with a wave of drilling and construction in the initial phases, followed by a significant slowdown in jobs as the production phase requires a much smaller number of permanent employees. Indeed Ohio has a long history of energy booms that illustrates that booms too often have few lasting effects. Ohioans need to be aware of this cycle if they are to make prudent decisions and try to gain sustainable gains after the boom has ended. The fundamental problem here is that the time distribution of jobs resulting from a new development is often ignored and it is important. For example it matters whether there are 1,000 jobs distributed as 1,000 for one year and then none, versus 100 additional jobs for 10 consecutive years, or 10 additional jobs for the next 100 years. Yet, 'impact' analysis such as that used by the energy industry typically does not differentiate among these scenarios and the whole topic is usually ignored by the media. Professional economists note that long-term regional economic development requires <u>permanent</u> jobs, and thus independent economists place considerably less weight on the initial construction phase associated with energy development. Policies need to be developed to ensure long-term success.

Natural gas extraction is also associated with potential environmental degradation. Pennsylvania and other areas have reported numerous incidents of water contamination; most notably in Dimock, PA, which was featured in the controversial documentary *Gasland*. Because hydraulic fracturing occurs at levels far below the aquifer level, it is most likely not to blame for contamination, but any contamination is instead likely caused by a casing/tubing failure or other part of the drilling process. Thus, the EPA exempted natural gas extraction using hydraulic fracturing from the Safe Drinking Water Act and Clean Water Act in 2005. However, recognizing increasing concerns over the impact on drinking water and ground water, in 2010 Congress directed the EPA to study the effects of hydraulic fracturing on the environment with results expected by the end of 2012. Until the federal government acts on this issue, state regulations are necessary to ensure natural gas extraction is performed in a safe manner protecting the environment and residents. Yet, coal mining is also associated with high localized environmental costs, indicating that if natural gas mining is not done, there will still be environmental problems that will need to be addressed because more coal mining will be required.

We argue that the focus on whether the industry creates jobs is misguided in assessing its true value and is not how economists typically evaluate the effectiveness of a program or policy. Rather, the focus should be placed on the true costs and benefits of natural gas especially compared to coal (its main substitute in electricity production). *Compared to coal, natural gas is cheaper and emits less carbon and both industries have their own inherent localized environmental costs in their production.* Independent economists would note that neither industry is associated with large numbers of jobs due to their capital-intensive nature. Making a true assessment of the costs and benefits will require qualified independent analysis. Likewise, ensuring that Ohioans benefit long after the energy boom requires innovative planning that unfortunately, most locations that have experienced such booms have failed to do over the last 150 years. These findings also illustrate that Ohio will need to continue to make economic reforms if it is to prosper in the long term because no one industry—in this case energy development—will be its long-term savior.

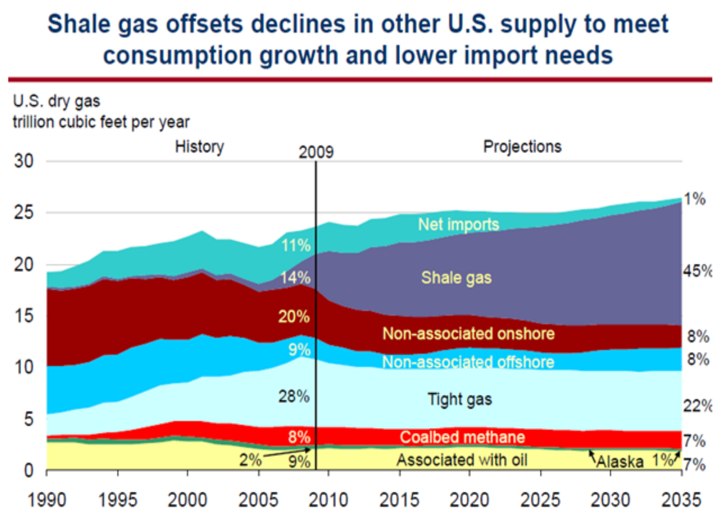
Introduction

With the US economy still struggling to recover from the Great Recession, many are looking for a quick fix to create jobs and generate income. Politicians often turn to the latest economic fad to solve unemployment problems, such as aiming to become the next Silicon Valley or, more recently, the next green energy hub. Employment effects are often overstated to justify various policies rather than having a real conversation about the true benefits and costs of a policy.[1] For example, the job creation benefits of green jobs were optimistically asserted while ignoring the high capital intensity of alternative energy and the displacement effect of jobs no longer needed in the fossil fuels industry, especially coal. In response, the fossil fuels energy industry has now put forward its own solution to unemployment and growing energy demands: natural gas from shale, which also provides its own set of environmental costs and benefits.

In their "Short-Term Energy Outlook," the US Energy Information Administration (EIA) expects that total natural gas consumption will grow by 1.8% in 2011. Despite the increase in consumption, recent increases in natural gas production have met these demands and reduced natural gas imports. Thus, shale gas proponents claim that newly accessible reserves could provide a new level of energy independence for the US. The 2010 EIA "Annual Energy Outlook" found that natural gas production reached its highest levels since 1973 at 21.9 trillion cubic feet (Tcf). This increase in production is mainly attributed to the increase in natural gas extraction from shale resources. From 2009 to 2010 shale gas production more than doubled from 63 billion cubic meters to 137.8 billion cubic meters. This trend in rising natural gas production, especially shale gas production, is likely to continue. Figure 1 below shows the increasing shale gas production the US has experienced, along with future expectations.

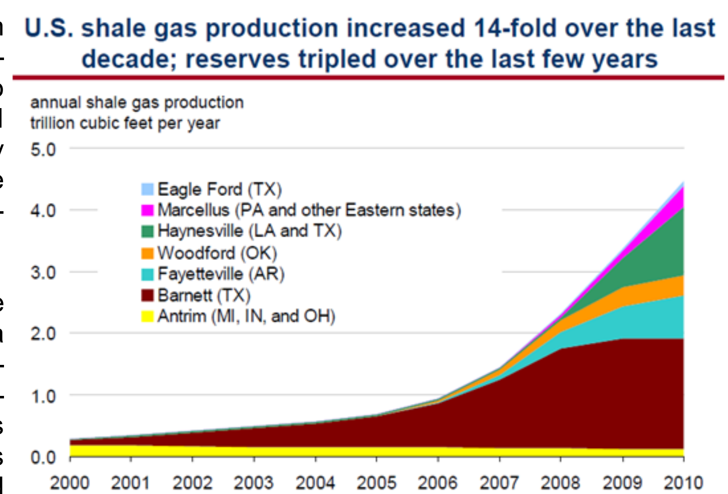
The dramatic increase in shale gas production since 2005 is shown below in Figure 2 separated by the area where shale gas has been developed. Recent technological advancements in a method called hydraulic fracturing, or "fracking", have made extracting natural gas from shale more efficient and cost effective. This has brought natural gas potential to new areas as evidenced by the increased drilling in Pennsylvania. Although still a small percentage compared to Texas, growth in shale gas production in Pennsylvania is growing rapidly and provides a roadmap for how production in Ohio will evolve.

With these innovations, shale gas potential is now growing in neighboring Ohio, which shares the same Marcellus shale with Pennsylvania. Many have already begun to speculate what this could mean in terms of the job benefits to Ohio. An industry-funded study by Kleinhenz & Associates (2011) suggests that new Ohio natural gas production could "create and support" over 200,000 jobs



Source: US EIA Annual Energy Outlook 2011

Figure 1: Shale Gas Prospects



Source: US EIA Annual Energy Outlook 2011

Figure 2: Shale Gas Areas of Production

1. Independent economists have long complained about hyped up numbers from various industry impact reports. For a tongue-in-cheek look see Leach (2011). http://www.theglobeandmail.com/report-on-business/economy/economy-lab/the-economists/who-needs-pipelines-the-oil-bucket-brigade-is-ready/article2268015/

and $14 billion injected into the state economy over the next 4 years (Gearino, 2011).[2] In this manner, Chesapeake Energy CEO Aubrey McClendon stated, "This will be the biggest thing in the state of Ohio since the plow" (Vardon, 2011). Obviously, there is considerable hype surrounding the economic effects of shale oil production

To see if these expectations are realistic, we examine the impacts that natural shale gas has had on Pennsylvania to draw comparisons to Ohio. Many industry funded studies of the economic impacts of the Marcellus shale development in Pennsylvania are consistent with the Kleinhenz & Associates (2011) predictions, which is reasonable in the sense that the early stages of Ohio's development is expected to mimic what happened in Pennsylvania.

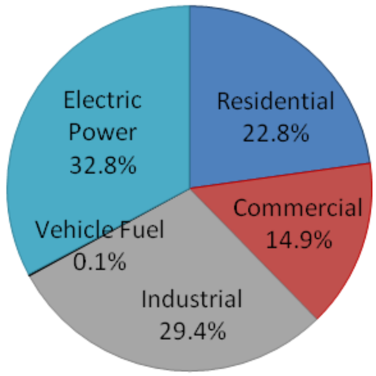
Unlike the industry funded reports, Barth (2010) doubts whether there is any net positive economic impact of drilling in Pennsylvania. She contends that previous industry-funded reports have focused on the benefits while ignoring the costs and risks associated with natural gas extraction. She claims industry funded studies haven't properly accounted for other impacts, including the costs of environmental degradation. Although replacing coal or oil with natural gas can significantly reduce carbon emissions, rising concerns have mounted, most notably in the controversial 2010 documentary *Gasland,* about the potential environmental impacts of natural gas mining on nearby water sources. This has become more of a concern as hydraulic fracturing and natural gas extraction occurs closer to both water sources and population centers in Pennsylvania and Ohio. These concerns have not yet been fully alleviated by the US EPA or the natural gas industry. In 2005, hydraulic fracturing methods were exempted from the Safe Drinking Water Act and Clean Water Act. However, recognizing increasing concerns over the impact on drinking water and ground water, in 2010 Congress directed the U.S. Environmental Protection Agency (EPA) to study the effects of hydraulic fracturing on the environment.

Barth (2010) also argues that previous industry-funded studies have not properly accounted for the impact on infrastructure, property values, and the "displacement" impact pollution can have on other industries such as tourism and fishing. In 2010, tourism employed approximately 400,000 people in Pennsylvania whereas the natural gas industry employed closer to 26,000 (Barth, 2010; BLS). If tourism suffers as a result of the natural gas industry, then a bigger industry could be put at risk from expansion of the natural gas industry, though we note that much of Pennsylvania's tourism industry is not near the mining activity.

Economists have long argued that energy development has limited overall impacts on the economy. There is a longstanding literature that refers to a "natural resources curse" that limits growth from energy development. One reason for the limited effects of energy development is Dutch Disease, which broadly refers to the higher taxes, wages, land rents, and other costs associated with energy development that make other sectors less competitive (including currency appreciation at the national level). These higher costs also reduce the likelihood new businesses will locate in the affected location. Previous research has found evidence of a natural resources curse and Dutch Disease suggesting that a natural resource boom can occur at the cost of other sectors and general long-run economic growth. For example, Papyrakis and Gerlagh (2007) found that US states with a higher degree of reliance on natural resources experience lower economic growth.[3] Kilkenny and Partridge (2009) and James and Aadland (2011) also found evidence of this resource curse at the US county level.

Figure 3 on the next page shows that most natural gas is still used to supply electricity. Thus, with rising electricity demands, increasing natural gas production will lower the need for electricity generation from coal—i.e., we will have more natural gas jobs that are offset by fewer coal jobs. Only 0.1% of natural gas is used as vehicle fuel, which is derived from oil as opposed to coal. Thus, <u>new</u> natural gas will not significantly decrease US reliance on foreign oil unless, as publicly suggested by T. Boone Pickens, the US considers converting more buses, trucks and other vehicles to natural gas. Thus, its effects on "energy security" are rather limited in the foreseeable future as increased electrical demand and the growing reliance on US natural gas will primarily be at the expense of US coal.[4]

2. Kleinhenz & Associates (2011) specify that over 200,000 jobs will be *created* or *supported* but they do not clearly define the difference between "created" and "supported" jobs. In terms of long-term economic development, permanent job creation would be necessary—or does natural gas development create more permanent jobs than what would have happened without the energy development? The latter counterfactual question is not addressed in that report.
3. Dutch Disease refers to natural gas development in the Netherlands in the 1960s and 1970s. The ensuing boom raised costs and appreciated the Dutch currency, rendering Dutch manufacturers less competitive on international markets. After the initial boom settled down, not only were there less employment in the natural gas industry, but Dutch manufactures found it hard to regain their market share on international markets, producing a permanent cost on their economy.
4. The recent expansion of shale development did reduce natural gas imports, but going forward, its main influence will be as a substitute for other sources of electricity, primarily coal.



Source: US EIA

Figure 3: 2010 Natural Gas Consumption by End Use

Even with a significant conversion of vehicles to natural gas, the energy sector as a whole has an employment share that is simply too small to significantly impact the high unemployment rates the US is experiencing. In 2010, the natural gas industry accounted for less than 0.4% of national employment, so even if the sector doubled in size—which is quite a stretch—overall U.S. employment would only be marginally effected (BLS).[5] This is not surprising as natural gas like much of the energy sector (including alternative energy) is quite capital intensive, which reduces the employment effects of natural gas compared to the broader economy.

The pursuit of economic fads is often justified by overpromising jobs while ignoring the displacement effects on other sectors of the economy as well as other costs on the economy. The benefits should be appropriately weighed against the costs, but this requires a better understanding of both the benefits and costs. It should not be based on the overblown hype of either side. Using previous experience from Pennsylvania, we will produce realistic estimates what Ohio should expect from shale gas development over the next four years. We find that although the employment advantages of shale gas have generally been overstated by the industry, there are clear benefits of natural gas production when compared to coal (which has its own environmental risks). The biggest advantages are that natural gas is more cost-effective than coal and can reduce carbon emissions. Coal forms the natural benchmark because in the medium term, natural gas production would displace coal production as the alternative source for electricity.

5. The calculation of total natural gas employees uses the methodology of IHS Global described in more detail in note 7 and we use U.S. Bureau of Labor Statistics Data to derive the employment figures.

Hydraulic Fracturing Overview

Innovations in hydraulic fracturing are the reasons natural gas extraction has recently been developing in the Marcellus shale regions in Pennsylvania and Ohio and now expanding to the Utica shale regions in Ohio. Before investigating the impacts of shale gas development, it is important to understand the hydraulic fracturing method that has made natural gas extraction from shale economically feasible.

Shale is a fine-grained sedimentary rock that can trap petroleum and natural gas well below the surface. Horizontal drilling and hydraulic fracturing now allow the energy industry to extract this trapped gas. Commercial hydraulic fracturing began in 1949, though it took decades of use for innovations to make shale gas extraction more cost effective. Horizontal drilling can cost 3 to 4 times more than conventional drilling, but has the potential of reaching substantially more reserves. Figure 4 from the EIA compares horizontal drilling and hydraulic fracturing to conventional methods of natural gas extraction. Figure 5, further depicts the hydraulic fracturing process.

Horizontal wells and hydraulic fracturing in conjunction with advances in micro-seismic technology aiding both exploration and the drilling process have allowed the energy industry to extract natural gas at greater depths. According to the EPA (Jun., 2010), horizontal wells are drilled to a depth between 8,000 and 10,000 feet. Hydraulic fracturing extracts natural gas from shale using a pressurized injection of fluid composed mostly of water and a small portion of sand and chemical additives that vary by site. This pressure causes the shale to fracture, requiring sand or other propping agents to keep the fissures open and allow gas to escape. Between 15 to 80% of the fluids are recovered from the well before the natural gas is collected. This water called “produced water” can be reused in other wells, but will need to be treated or disposed of at some point.

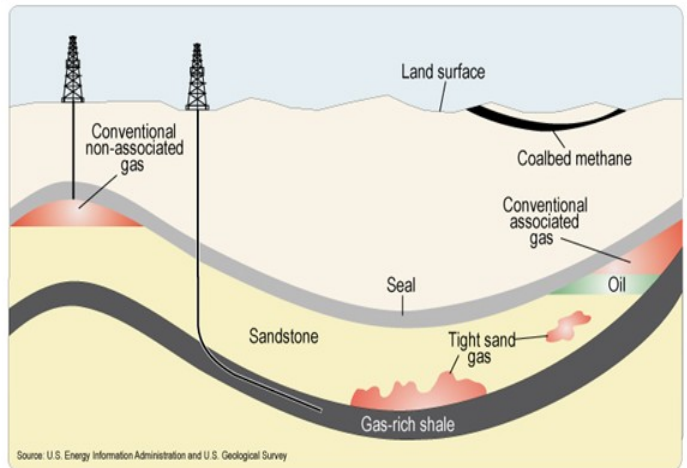
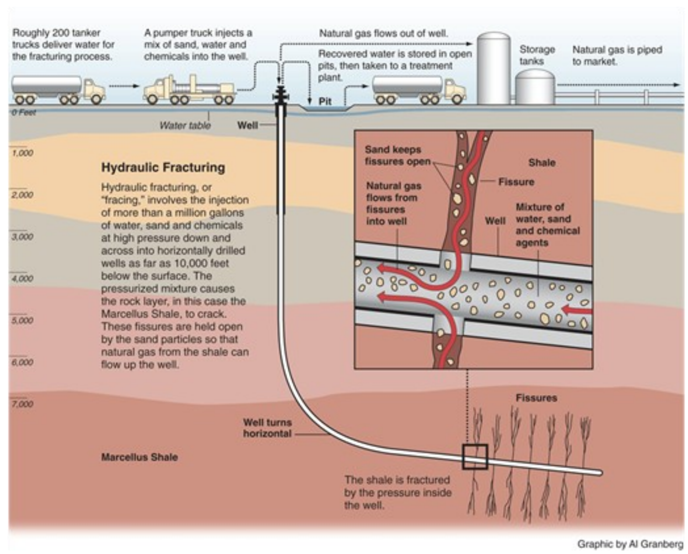


Figure 4: Natural Gas Mining Methods

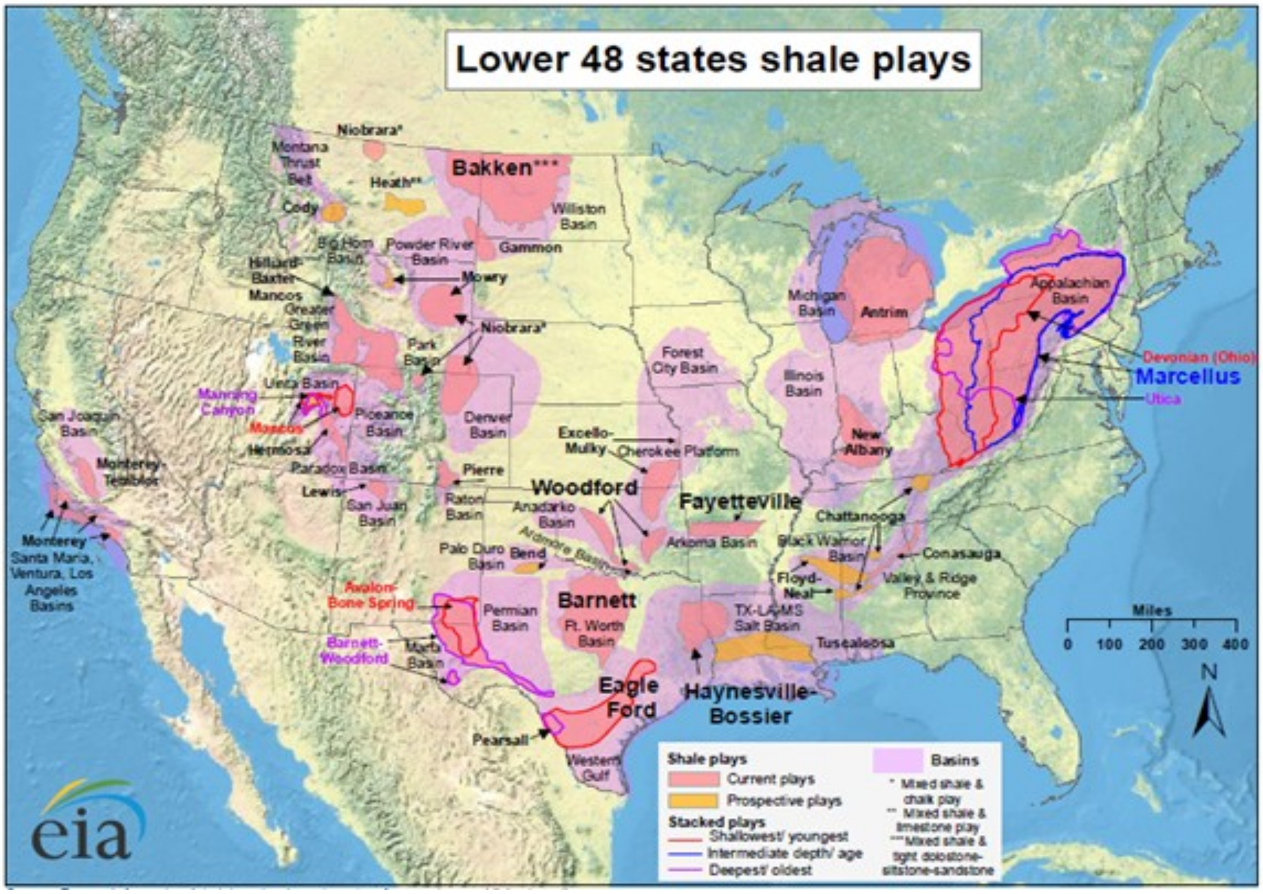


Source: ProPublica

Figure 5: Hydraulic Fracturing

Natural Gas Development in the US:

In the 1980s, the Barnett shale in Texas became the first natural gas producing shale. More than a decade of production from the Barnett shale in Texas has helped improve the hydraulic fracturing process, leading the way for it to be used in other areas such as the Marcellus shale in Pennsylvania and the Utica Shale in Ohio. The Marcellus shale is more than 60 million acres and is significantly larger than the Barnett. The EIA estimates that there are 410 Tcf of recoverable gas in the Marcellus shale alone. Figure 6 on the next page shows the location of US shale plays including the Barnett in Texas and the Marcellus and Utica in Pennsylvania and Ohio. Figure 6 clearly shows that shale natural gas is a national phenomenon that will dramatically alter natural gas availability and pricing nationally. Indeed, EIA data further documents that shale plays are a global phenomenon that will likely reduce world-wide natural gas prices.

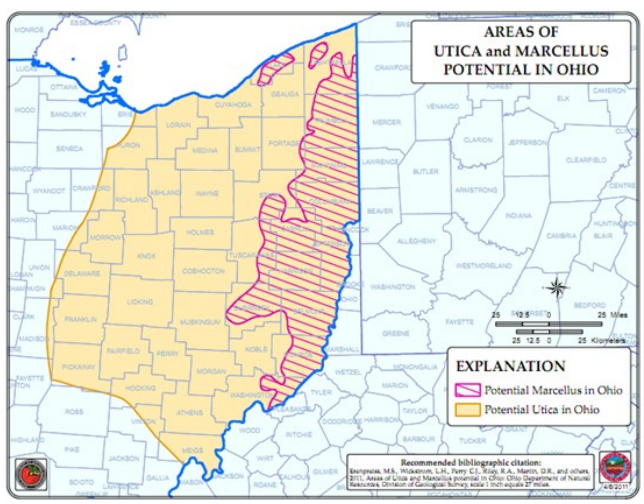


Source: US EIA

Figure 6: US Shale Resources

The large potential of the Marcellus shale, and more recently the Utica shale, has made Pennsylvania and Ohio highly attractive for mining of natural gas reserves. Figure 7 below provides a more detailed look at areas in Ohio that may be directly affected by natural gas resources. In an interview, Douglas Southgate of The Ohio State University's Subsurface Energy Resource Center states that shale resources in Ohio can provide a reliable, cheap, and local source of energy for Ohio. He explains that much of the attention has been on the Marcellus formation, though it is becoming clear that the Utica is more important. In the long term, the latter is expected to supply oil in significant quantities (Dezember and Lefebvre, 2011). It is also an important source of natural gas liquids (NGLs) such as ethane, which is converted into the ethylene used to manufacture a wide array of chemical products (American Chemistry Council, 2011). Thus, Southgate and others argue that shale deposits in and around Ohio are an important source of various hydrocarbons, not just the methane used to heat homes, generate electricity, and so forth.

Ohio shale development is just beginning. Figure 8 on the next page shows specific Marcellus and Utica well activity in Ohio from 2006 through August, 2011. It was recently reported that Chesapeake Energy has its first 4 active Utica shale wells in Ohio producing between 3 and 9.5 million cubic

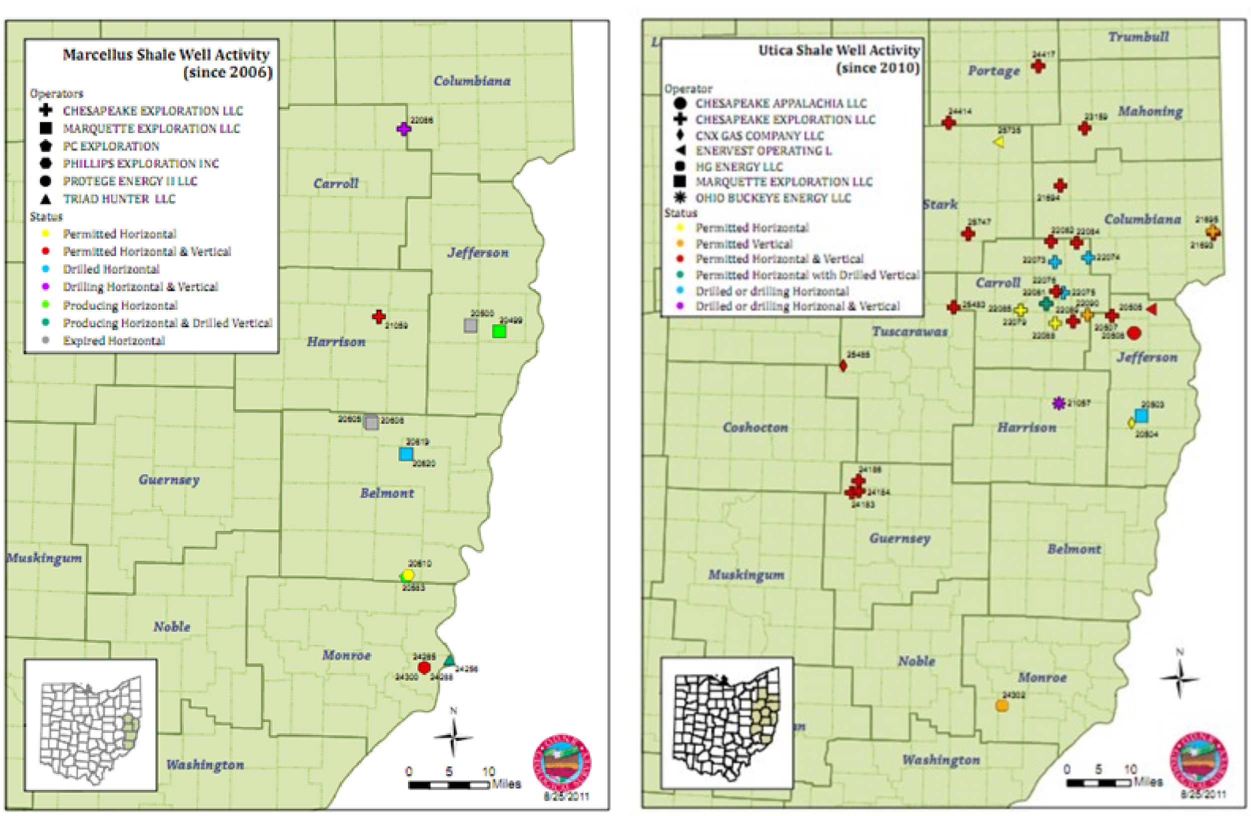


Source: ODNR

Figure 7: Ohio Shale Resources

feet of natural gas per day (Gearnino, 2011). A conventional well might produce between 100,000 and 500,000 cubic feet per day, but the Marcellus and Utica shale wells are expected to produce between 2 to 10 million cubic feet of natural gas per day. Chesapeake plans to increase the number of wells to 20 by the end of 2013.

Although shale development has already begun in Ohio, it is still nascent compared to Pennsylvania. The projected impacts on Ohio are still being debated. For example, Kleinhenz & Associates (2011) projected natural gas development in Ohio would lead to 200,000 jobs and $14 billion in spending. Much of their analysis uses assumptions derived from recent Pennsylvania impact studies such as Considine et al. (2009; 2010; 2011). Kleinhenz & Associates (2011) projected that 4,000 wells will be drilled in Ohio by 2015. Overall, they produced economic results that are similar to the industry-funded estimates for Pennsylvania.



Source: ODNR (Aug, 2011)

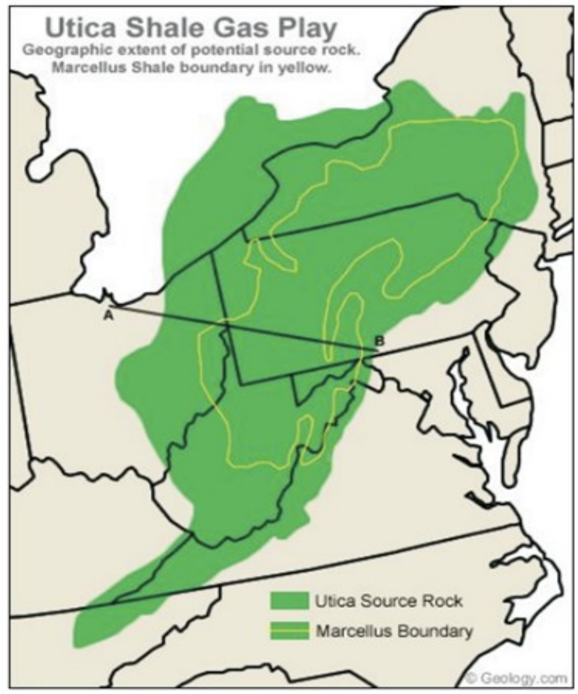
Figure 8: Marcellus and Utica Well Activity in Ohio

Economic Expectations

Pennsylvania is a particularly good gauge to predict what the impacts of shale gas will be on Ohio because they share much of the same natural resources. They are also very proximate and have similar economic structures. Figure 9 shows the Marcellus and Utica shale running through both states. Besides being neighbors, Pennsylvania and Ohio are the 6th and 7th most populous states. For both states, the shale resources are mainly located in rural areas, though there are larger population centers that are affected.

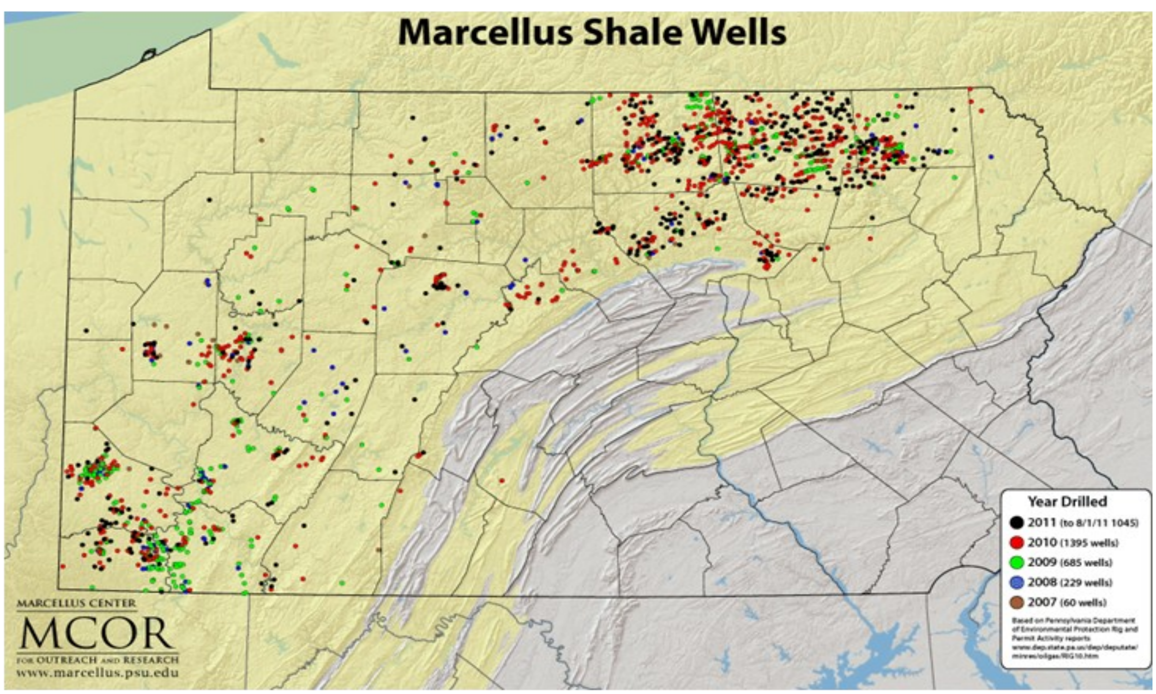
In 2005, the first well in the Marcellus shale in Pennsylvania began producing natural gas. Since then, most of the wells have been located in the northeast and southwest in Pennsylvania. Figure 10 shows the location of wells across the state by year. The number of shale wells drilled grew from 60 in 2007 to 1,395 in 2010. Considine (2010) finds that 36% of the 229 wells drilled in 2008 were horizontal and that percentage is expected to rise.

As the number of wells drilled dramatically increased, so did natural gas production in Pennsylvania, especially in the northeast region. Figure 11 on the next page shows the notable increase in production.



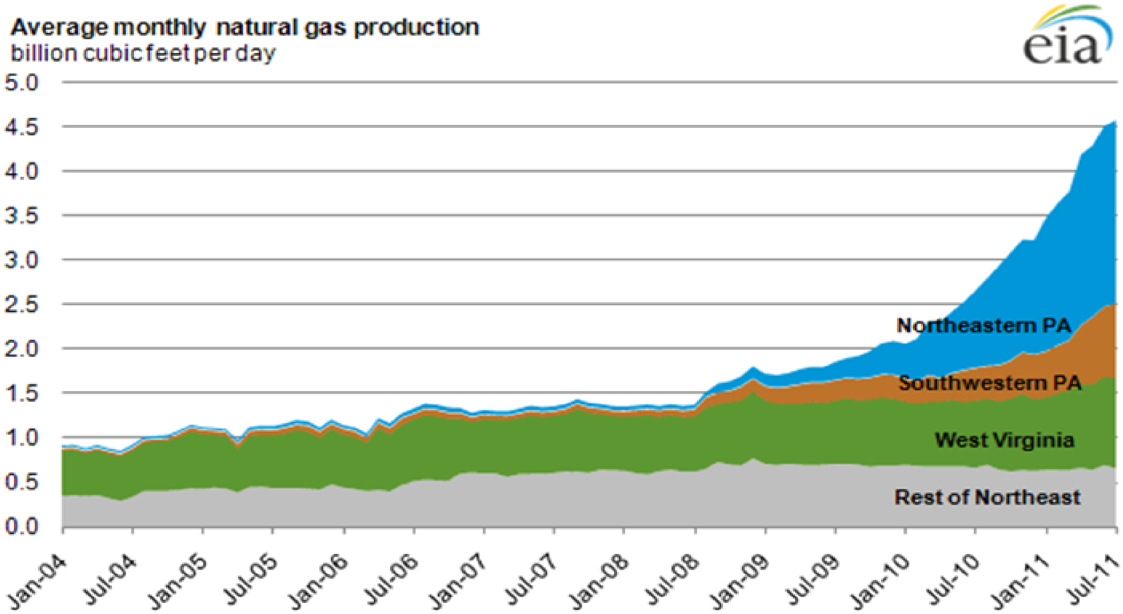
Source: Ohio EPA

Figure 9: Marcellus and Utica Shale Plays



Source: PSU

Figure 10: Marcellus Shale development 2007-2011



Source: US EIA

Figure 11: Northeast Natural Gas Production

Pennsylvania Natural Gas Employment:

Studies of natural gas's role in national and regional economies typically use impact studies (though this is not considered best practice for evaluating economic effects). Impact studies, such as the ones we describe, typically estimate three types of employment effects: (1) direct effects of the jobs directly employed in the activity (in this case natural gas mining); (2) indirect effects that would include inputs to the direct activity (such as pipeline construction); and (3) induced effects due to the added household income (e.g., workers purchasing items in the local economy) (see IMPLAN.com for more details). Summing across the three categories, if done correctly, would produce the total number of jobs "supported" by the industry (not new jobs created). As we describe below, estimating the number of new jobs created would need to assess what would have happened in the absence of natural gas mining—i.e., develop the counterfactual—which is not done in standard impact analysis.

One source of confusion is that impact studies do not produce continuous employment numbers. If an impact study says there are 200,000 jobs, this does not mean 200,000 workers are continuously employed on a permanent basis. For example, there are workers who do site preparation. Then there is another group who do the drilling followed by another group who maintains the well when it is in production. Finally, there is an entirely different group doing pipeline construction, and so on. So, while the public is likely more interested in continuous ongoing employment effects, impact studies are producing total numbers of supported jobs that occur in a more piecemeal fashion.

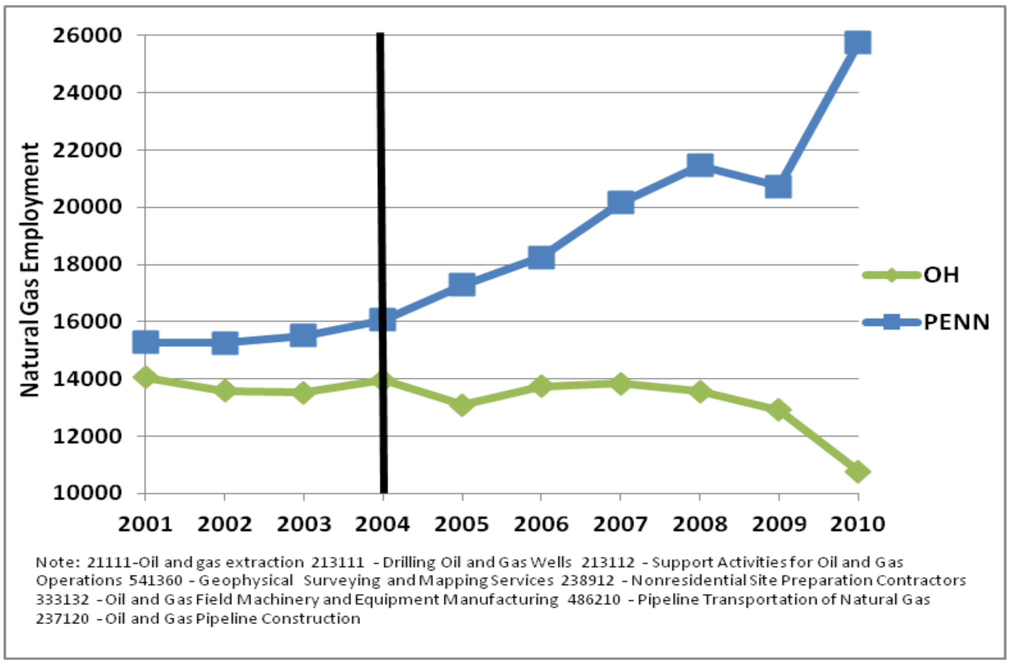
Impact analysis is usually based on an old input-output technology that is typically not used today by economists to estimate actual economic effects. Impact studies do not include various displacement effects and do not reflect the true counterfactual of comparing what would have happened without natural gas drilling. For example, oil and natural gas drilling would lead to higher local wages and land costs, which reduce employment that would have occurred elsewhere in the economy. Likewise, the environmental effects may reduce activity in the tourism sector and other residents may not want to live near such degrading activity. Finally, greater natural gas employment means that there are fewer jobs in coal that would have occurred without the increase in natural gas employment. As described below, best practice economics uses other approaches that try to adjust for displacement effects to derive more accurate estimates of actual effects (see Irwin et al. (2010) for a discussion of the weaknesses of impact studies).

Figure 12 on the next page shows the direct and much of the indirect employment in natural gas and other related sectors in Ohio and Pennsylvania.[6]

6. For the direct effect of natural gas mining, we also include some indirect suppliers that are related to natural gas drilling, which overstates the direct effects. However, not all of the indirect industries are included in Figure 12. When we use a multiplier below, because we already include some indirect effects, we would overstate the total number of supported jobs for the industry.

Since some of the sectors reported in Figure 12 include other sectors—primarily oil—we assume that all of the gain in Pennsylvania employment is due to new natural gas production. Also, we do not include "energy related" sectors in Figure 12 if they showed a large decrease in employment because we believe that would understate the importance of new natural gas production in Pennsylvania (those declines would likely be due to other factors). Thus, if anything, we believe that any measurement "errors" would work to overstate the importance of new gas production employment.[7] From Figure 12, with these assumptions, we assume that from 2004-2010, there was a gain of about 10,000 direct and indirect jobs in the natural gas industry in Pennsylvania.

The typical multiplier would take direct employment and multiply it by the multiplier to arrive at the total effects, including indirect and induced effects. Since the 10,000 number derived above includes some of indirect effects such as pipeline construction, using the standard multiplier would likely lead to an overstatement of the total employment effects of new production. Nonetheless, assuming the standard multiplier of 2 (which is on the high end), the natural gas industries would still have led to about 20,000 direct, indirect, and induced jobs from 2004 to 2010 in Pennsylvania, though this ignores employment losses in other sectors displaced by natural gas.[8] By comparison, Considine et al.'s (2011) industry funded study suggested that natural gas was associated with 140,000 Pennsylvania jobs during 2010.



Source: BLS

Figure 12: Ohio and Pennsylvania Natural Gas Employment[9]

7. IHS Global Insight (2009) notes that employment in these sectors also includes employment in the oil sector and other sectors (not just natural gas). They calculate some national estimates of natural gas's share of overall employment in each sector. For example, they estimate natural gas's employment share for the following industries as follows: (1) 2111-Oil and gas extraction, 213111 - Drilling Oil and Gas Wells, and 213112 - Support Activities for Oil and Gas was 74% in 2008; (2) 237120 - Oil and Gas Pipeline Construction was 68% in 2008; (3) 333132 - Oil and Gas Field Machinery and Equipment Manufacturing was 65% in 2008 and (4) 238912 - Nonresidential Site Preparation Contractors was 16% in 2008). We could have used IHS Global Insight's shares in our calculations, but we believe this would **understate** the increase in the size of the natural gas sector in Pennsylvania because some of the gains would be attributed to other sectors.
8. Academic economists generally use a multiplier of 2 as an upper bound multiplier. For example, Stabler and Olfert (2002) describe a range of employment multipliers in the 1.1 to 1.5 range. Hughes (2003) describes that *output* multipliers above 2.5 are likely very questionable. Likewise, Kelsey et al. (2009) found an output multiplier for natural gas in Pennsylvania to be in the 1.86 to 1.90 range, further showing that our 2.0 multiplier is reasonable. Indeed, as the economy becomes more global, fewer employment gains are on-shore or local, which would reduce employment multiplier effects. Likewise, with outsourcing and increasingly fragmented supply chains, firms are further shifting their purchases outside the firm, which further reduces the amount purchased locally. Further, keep in mind that the energy sector is highly capital intensive which would work to reduce the employment effects and increase the output effects in a multiplier. Thus, we believe our use of an employment multiplier of 2 would be viewed as "generous" by independent academic economists.
9. The direct effects would commonly include the drilling and extraction activities while indirect effects would normally include inputs such as pipeline construction and field equipment manufacturing. Hence, this is why we state that we are already including some of the key inputs as direct employment in Figure 12.

We believe that independent and academic economists in regional and urban economics would view our 20,000 employment estimate as reasonable and some may view it on the high end of actual job creation.[10] For example, Barth (2010) notes that other studies found a multiplier for oil and gas as low as 1.4. She also notes that in similar input-output studies, other industries were found to have higher multipliers than oil and gas, with agriculture having one of the highest multipliers. If shale development adversely effects employment in (say) coal mining, agriculture, and tourism, then those numbers should be subtracted from these numbers to derive the actual employment effects (including any multiplier effects in those sectors). To be sure, we only calculate an impact style estimate to give a feel of the overestimated effects produced by industry consultants (and others who produce impact studies). There are much better approaches than impact studies to calculate actual effects, which we describe below.

One other issue is that proponents of natural gas expansion in Ohio often claim that lower natural gas prices will provide a major stimulus to overall employment, especially in manufacturing. While we will not assess whether natural gas prices are a sufficient share of a typical firm's cost structure to make a tangible difference, we do note that there are reasons to be skeptical of those claims (though we hope we are wrong). Foremost, to make a difference on Ohio's relative competitive edge compared to the rest of the United States and the rest of the world, it would have to be an event that helps Ohio's businesses much more than in the rest of the world. However, as we note in the discussion surrounding Figure 6, shale natural gas is a global phenomenon, meaning that falling natural gas prices will benefit a significant share of Ohio's global competitors. Thus, there is no "edge" given to Ohio's businesses that would make them tangibly more competitive than their national and international competitors.

Economists typically subject their forecasts to "smell tests" by making comparisons to similar events. In our case, comparing energy development around North Dakota's Bakken shale formation in the far northwestern part of the state is good benchmark to assess whether our 20,000 job forecast for Ohio makes sense. Specifically, development of North Dakota's Bakken shale region has been about the same magnitude as the energy development in Pennsylvania and should produce somewhat comparable job effects on both states.[11] During the October 2007-October 2011 period (or a four year period that corresponds to Kleinhenz & Associates' Ohio study), the entire state of North Dakota added about 39,000 jobs. It is highly unlikely that this is all due to energy as high commodity prices (for example) have supported North Dakota's relatively large farm economy. Further, we would expect that the Bismarck metropolitan area (which is relatively close to the mining activity) to be more impacted by the energy boom, while the Fargo and Grand Forks metropolitan areas that are hundreds of miles away on the Minnesota border to be considerably less affected. In this comparison, Bismarck added 4,600 jobs during this four-year period, while Fargo and Grand Forks metropolitan areas respectively added 4,400 and 1,600 jobs. These figures strongly suggest that North Dakota's relative prosperity is more widespread than just an energy boom in the Bakken region. So, even if all 39,000 North Dakota jobs were due to energy (which we have already shown is highly unlikely), this would be a far cry short of the 200,000 jobs that have been forecasted for Pennsylvania and Ohio despite the comparable size of the three states' energy booms.[12] Thus, our forecast of 20,000 jobs over the next four years is further supported as a reasonable forecast based on the North Dakota experience.

Although Pennsylvania's natural gas employment gains are impressive, they still represent just a small share of total state employment. From 2004 to 2010, the employment share of oil and natural gas related sectors shown in Figure 12 increased from 0.30% to 0.48% (see Figure 13). This small employment share is simply not enough to have a significant effect on total jobs and on unemployment for the state.[13] Despite the significant increase in natural gas jobs from 2009 to 2010,

10. For example, there are many factors affecting the actual employment number. If there are workers from out of state, Ohio's employment number would be lower. Conversely, if more landowners are in state compared to Pennsylvania, that would increase the employment number. Other factors are harder to predict such as mining's effect on agriculture and timber.
11. U.S. Bureau of Labor Statistics Data (Current Employment Statistics) suggests that between October 2007 and October 2011, mining employment (which is due to the direct energy production) increased by about 12,000 in both states. The other employment numbers referred to here are from the same source.
12. U.S. Bureau of Labor Statistics Data shows that North Dakota had an October 2011 unemployment rate of 3.5%, which seems quite low compared to the 9.0% national rate. However, North Dakota always has very low unemployment rates due to long-term structural reasons (Partridge and Rickman, 1997a, 1997b). For example, it was an even lower 3.0% in October 2001, well before the energy and commodity price boom of recent years, illustrating that the energy boom is only a partial reason for North Dakota's current low unemployment rate.
13. To give a further feel for the size of the natural gas sector in Pennsylvania, Barth (2010) finds that in January 2010 there were 48,777 Walmart employees in Pennsylvania (almost double that of the natural gas industry broadly defined) and approximately 400,000 jobs in the tourism industry.

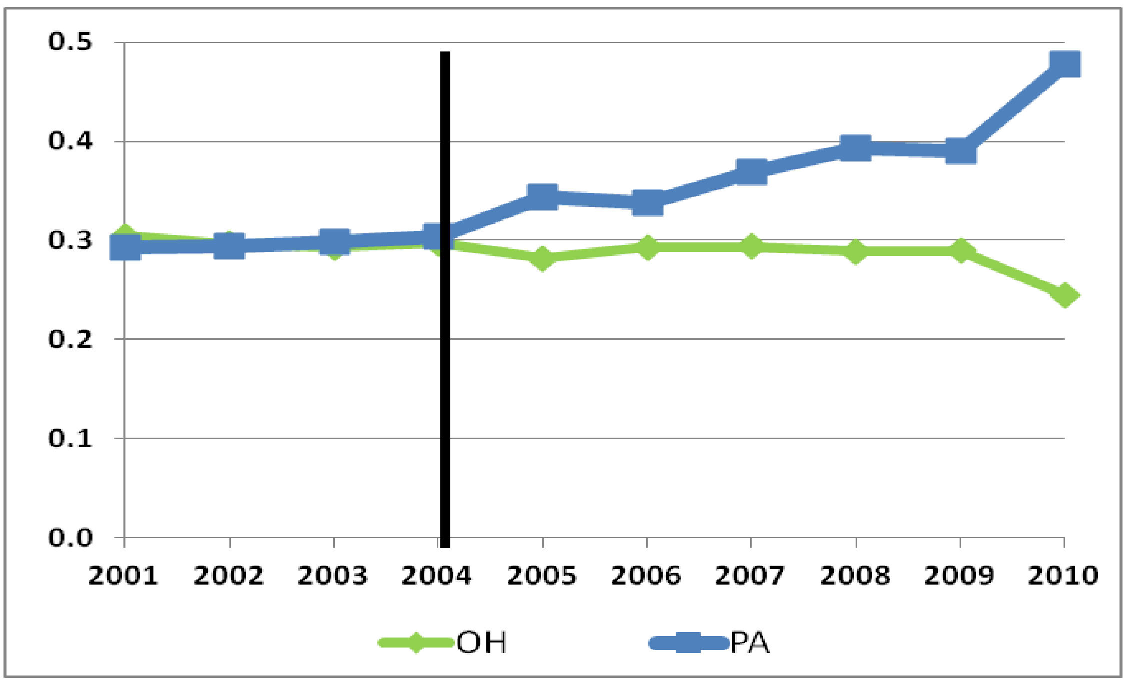
Pennsylvania's unemployment rate still increased from 8.0% to 8.7% during this time (BLS: U.S. Department of Labor, Bureau of Labor Statistics). At most, natural gas employment effects would be localized. Conversely, Ohio's unemployment rate remained unchanged at 10.1% from 2009 to 2010 (BLS) despite a loss in the energy sector jobs in Figure 12, illustrating that natural gas employment is not driving either state's economy.

Concerns with the Economic Impact Studies of Natural Gas Development:

Impact studies are typically associated with overstatements of the employment effects of new development. For example, the Considine et al. (2011) study appears to include indirect and induced jobs before applying the multiplier effect, which double-counts effects and blows up the estimated effects. Direct jobs should include those jobs directly associated with drilling the wells and extracting the natural gas. Indirect jobs include the jobs associated with various inputs required by the industry such as pipelines. Induced jobs should include those jobs and services required by the workers such as restaurants and entertainment.[14] The final two categories should be the outcome of the multiplier process.

Second, Considine et al. assumes that 95% of natural gas industry spending will occur in Pennsylvania. Kleinhenz & Associates assumes a slightly more conservative 90% of all spending will be spent in Ohio. In global economies in which state economies are integrated with national and international economies, such assumptions would not be credible for independent economists. Moreover, because the industry is relatively new and undeveloped, more of the inputs would be brought in from outside of the state, e.g., from Texas.[15]

There are other problems with impact studies because, in reality, more of the money leaks out. For example, Kelsey et al. (2011) found 37% of the Marcellus employment has gone to non-Pennsylvania residents and that landowners save or invest approximately 55% of the money they make from royalties/lease payments rather than spending it in the local economy. They use these



Source: BLS

Figure 13: Ohio and Pennsylvania Natural Gas Employment Shares of Total State Employment

14. Examples of jobs that should not be categorized as direct to natural gas mining are Finance & Insurance, Educational Services, Health, Arts & Entertainment, Hotel & Food Services, etc. By including these jobs as direct jobs, Considine et al. is essentially double counting the employment effects. While we do not have Considine et al.'s programming we believe one source of the double counting derives from how household spending from lease payments/royalties are treated. Even using the job estimates of Considine et al., it is still not a significant portion of the total employment in Pennsylvania.
15. We believe a more reasonable approach would have been to use the default state spending shares from the IMPLAN software (i.e., Considine et al. overruled IMPLAN's default numbers and incorporated 95%). In the absence of detailed and regional I-O data, other shortcuts have been used such as payroll to sales ratios (Oakland et al., 1971; Rioux and Schofield, 1990; Wilson, 1977) or Value-added to gross outlays by industry (Stabler and Olfert, 1994).

	Population 2005	Per Capita Income 2005	Employment Growth Rate 2001-2005	Employment Growth Rate 2005-2009	Income Growth Rate 2001-2005	Income Growth Rate 2005-2009
Non-Drilling Counties	255,508	$32,187	5.3%	-0.4%	12.6%	13.6%
Drilling Counties	124,928	$27,450	1.4%	-0.6%	12.8%	18.2%

Source: BEA

Table 1: Pennsylvania County Descriptive Statistics

more realistic findings to develop a better estimate of the economic impacts of shale development in Pennsylvania. Using IMPLAN, Kelsey et al. (2011) find that in 2009, Marcellus shale development economic impact was over 23,000 jobs and more than $3.1 billion. Our estimate of 20,000 jobs then closely corresponds to Kelsey et al.'s estimates (2011).

Finding Counterfactuals to Assess Growth:

The key problem with impact studies is that they do not estimate the actual number of jobs created by mining because of all of the displacement effects. They are not the true counterfactual and economists have not viewed them as best practice for decades (Irwin et al., 2010). Economists have developed other more credible approaches in developing a counterfactual, such as difference in difference approaches. One of these approaches is to match drilling counties to non-drilling counties that otherwise would have had similar employment patterns if there was no drilling. Thus, the goal is to find counties that would have looked similar to the drilling counties in the absence of drilling. We describe this approach below.

Although natural gas employment does not seem to have had a significant impact on the state as a whole, it may still have a sizeable impact on the specific counties, many of them rural. Table 1 presents data for Pennsylvania counties before and after drilling. Table 1 shows that before 2005, drilling counties are notably struggling more than non-drilling counties. Drilling counties on average are less populated, more rural, have lower per capita income and less employment growth. Natural gas leases also provide an additional source of income for landowners. Landowners that choose to lease their land to natural gas companies generally receive an upfront payment per acre and royalties on the gas produced from the well. Although the payout varies, it can be quite sizeable. From Table 2, it seems natural gas development is positively related to per capita income growth rates for drilling counties.

Table 1 highlights the fact that drilling counties on average look very different than most non-drilling counties. Thus, we look specifically at 3 significant high-drilling counties in the northeast (Tioga, Bradford, and Susquehanna) and 3 in the southwest (Washington, Greene, and Fayette).[16] We then match each of these two sets of mining counties to similar non-mining counties (as of 2009) based on population and similar employment and income dynamics *before* 2005 and the advent of shale drilling.[17] Figure 14 shows the mining and non-mining counties that were chosen. Figure 14 shows that the matches are divided into the Northeast quadrant of the state and the southern part of the state. The appendix provides additional graphs directly comparing each drilling county with its matched

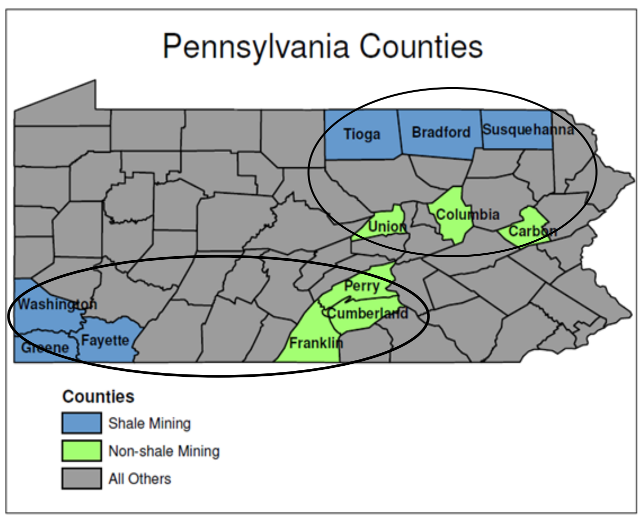


Figure 14: 2009 Matched Drilling and Non-drilling Counties

16. Drilling counties were matched to non-drilling counties on the basis of population and general urbanization as well as region (either north or south).
17. Matching studies can employ other mathematical approaches to finding matches. As will be apparent, our choice of non-drilling counties will appear to be good matches.

non-drilling county.

Using BEA employment and income data, the shale mining counties are compared to the non-mining counties with 2004 marking the point immediately before drilling activities began. One of the key features of the employment and income data is that both mining and non-mining counties are on similar growth paths prior to drilling, suggesting there they are good comparisons (see Figures 15-18 in the next pages). Figure 15 suggests that mining counties may have had faster job growth in the Southern region, but Figure 16 shows that the opposite applies in the Northeastern region. Overall, there are no clear employment effects for heavily drilled counties. We are not saying there are no drilling employment effects, but that they are not large enough to be detected in this commonly used matching approach. One reason may be that many of the new jobs may go to people outside the state who have previous experience in natural gas extraction.[18] Conversely, the positive impacts on incomes are more clear. Figures 17 and 18 show the per capita income impact of natural gas drilling appears to be positive in both Southern and Northeastern regions. While the effects may differ in longer-run periods, our four year window conforms to Kleinhenz & Associates' four year forecast for Ohio.

To be sure, there are many things happening in these county economies, but such efforts to form the true counterfactual are more in line with best economic practice than the impact studies that are often used by economic consultants. In particular, one especially appealing feature is that our approach is based on actual employment and income data and not based on the assumptions of computer software.

For further comprehensive analysis to appraise whether our previous matched results are correct, we now perform a statistical analysis on all counties within Pennsylvania. To control for county-specific effects, we use a difference-in-difference approach to find the impact of drilling on the change in employment after drilling compared to the change in employment before drilling. Details of the difference-in-difference methodology are provided in the appendix, but essentially we are examining whether having more natural gas wells is associated with more job and income growth, but this time we are considering all Pennsylvania counties. This approach accounts for the fact that drilling and non-drilling counties may have systematic differences (fixed effects) for a variety of reasons - and we are adjusting for these differences. Table 2 shows that the number of wells drilled since 2005 has no statistically significant effect on employment.[19] Overall, we believe that there have been modest employment effects in drilling counties, but they are not large enough to statistically ascertain (most likely due to some of the offsetting factors we just described). The upshot is decision makers who are interested in the actual job creation effects of natural gas need to take much more seriously the displacement effects throughout the economy.

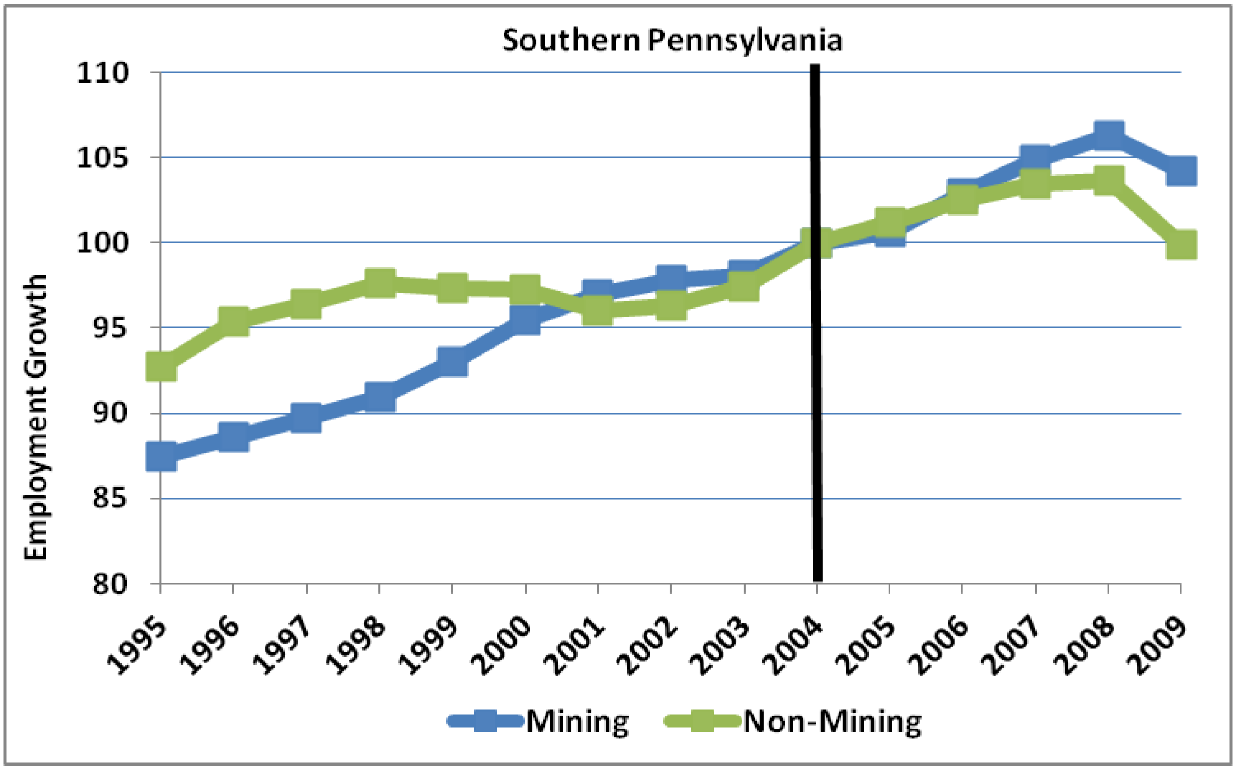
There are many important reasons why we would expect natural gas' impact on employment to be small or insignificant, which explains the findings in Figures 15 and 16 and in Table 2. Besides displacement, one reason is the production technology of natural gas. Like other fossil fuel energy industries, natural gas is rather capital intensive.

	Change in Percent Employment Growth 2005-2009 Compared to 2001-2005	
	Parameter Estimate	t-value
Total Wells 05-09	**1.769E-05**	**1.14**
2001 Log Population	0.023	2.64
2001 Log Per Capita Income	-0.096	-1.55
N	67	
R2	0.118	
Adjusted-R2	0.076	

Source: BEA and Pennsylvania DEP Data. See the appendix for more details.

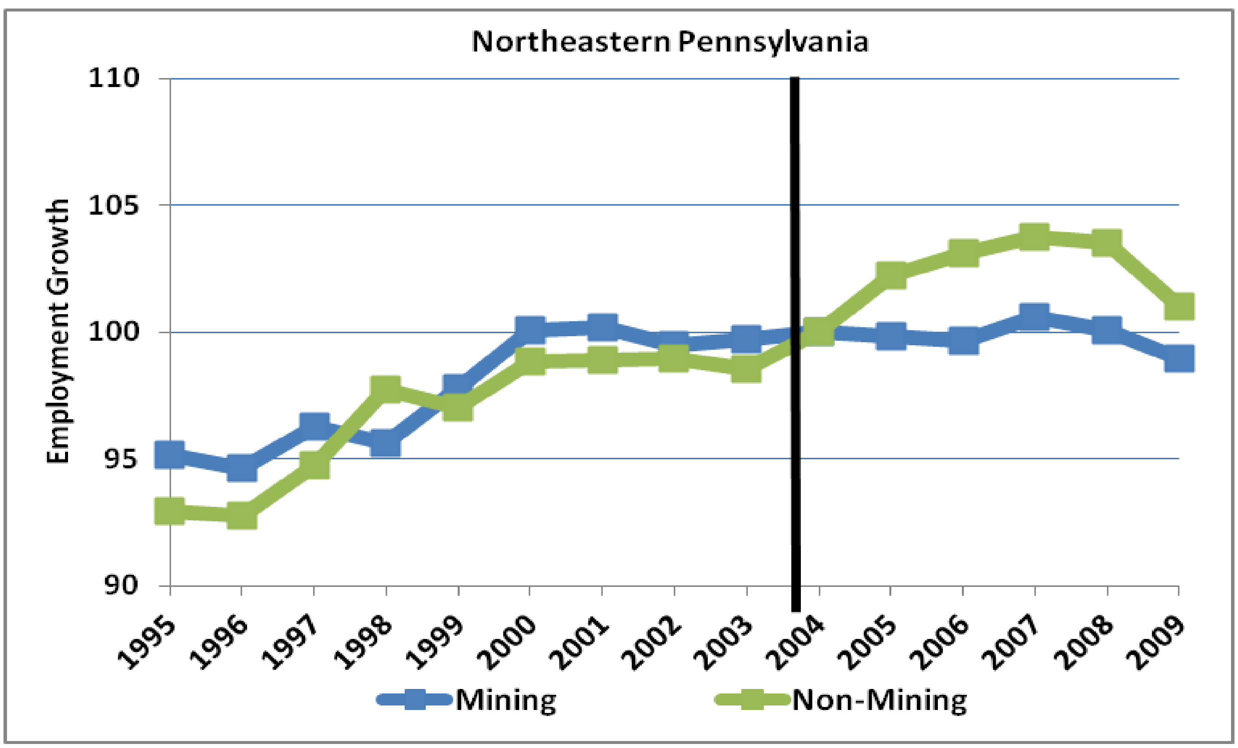
Table 2: Employment Effects of Drilling

18. Pennsylvania and Ohio residents may not have the skills and experience needed to meet the demands of the natural gas industry and royalty/lease monies may not be spent locally. Similarly with natural gas spending, Pennsylvania may not have the services and supply chain the energy industry requires initially. Along with other displacement effects, this may explain the lack of employment response.
19. We also considered that possibility that there are threshold effects (or other nonlinearities) in which drilling does not affect economic growth until a certain number of wells are drilled. We did this by adding a number of wells drilled squared term to the model. This variable's coefficient was negative and statistically insignificant in both the income and employment growth models, suggesting that there are no nonlinear effects. Additionally, these numbers don't account for people switching from part time to full time employment.



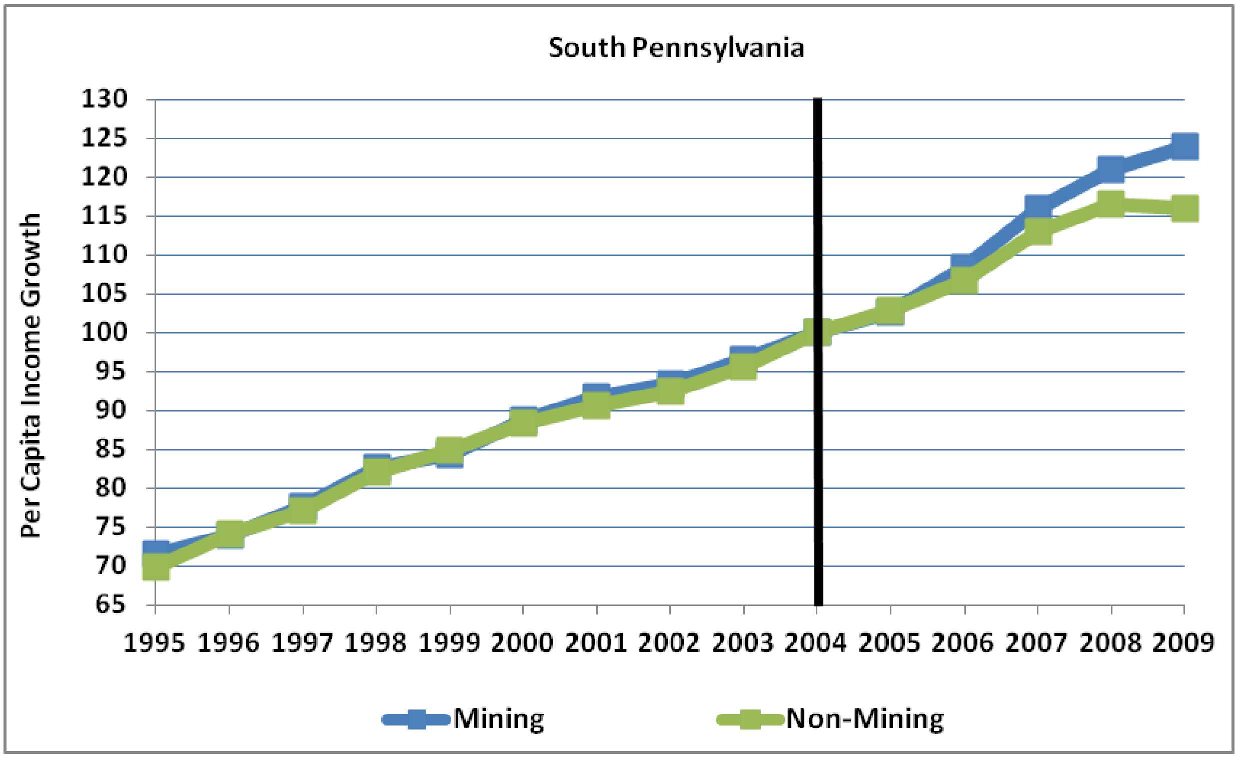
Source: BEA Mining counties (Washington, Greene, and Fayette) Non-mining counties (Perry, Franklin, Cumberland)

Figure 15: Drilling and Non-drilling Employment Comparison (2004=100)



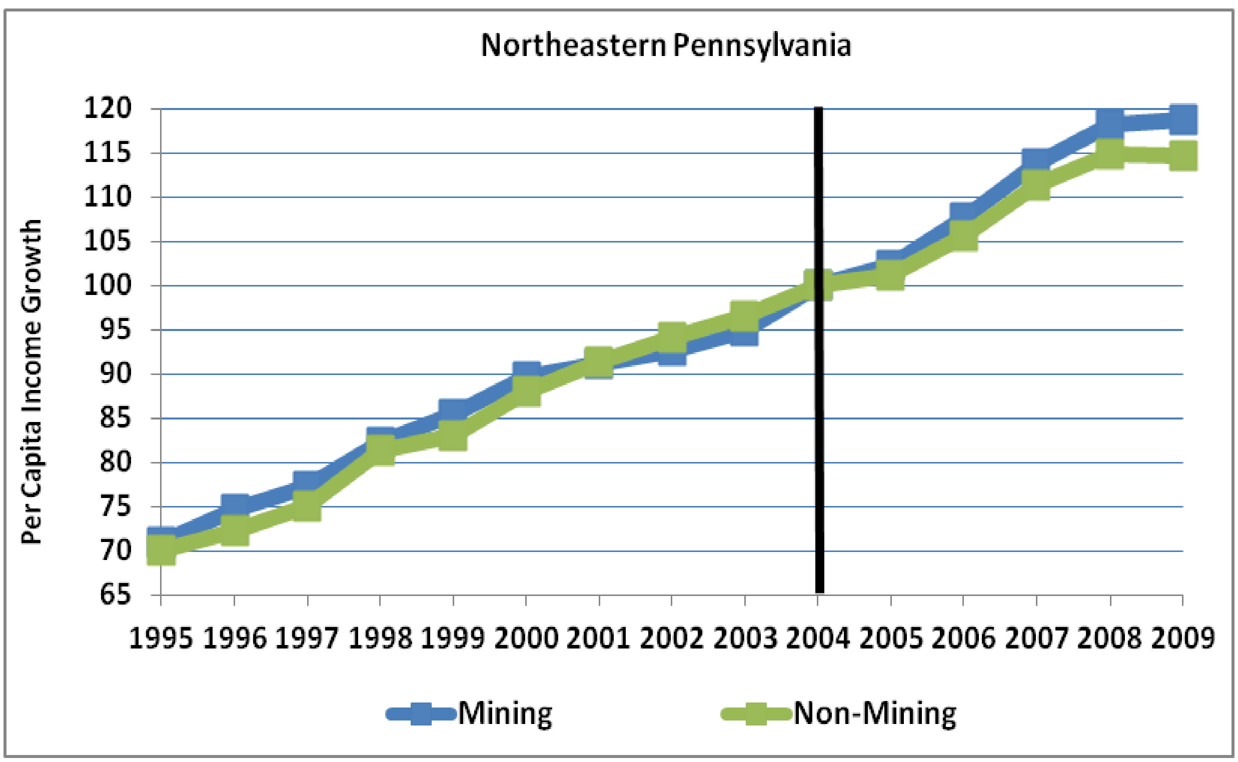
Source: BEA. Mining counties (Tioga, Bradford, and Susquehanna) Non-mining counties (Union, Columbia, Carbon)

Figure 16: Drilling and Non-drilling Employment Comparison (2004=100)



Source: BEA. Mining counties (Washington, Greene, and Fayette) Non-mining counties (Perry, Franklin, Cumberland)

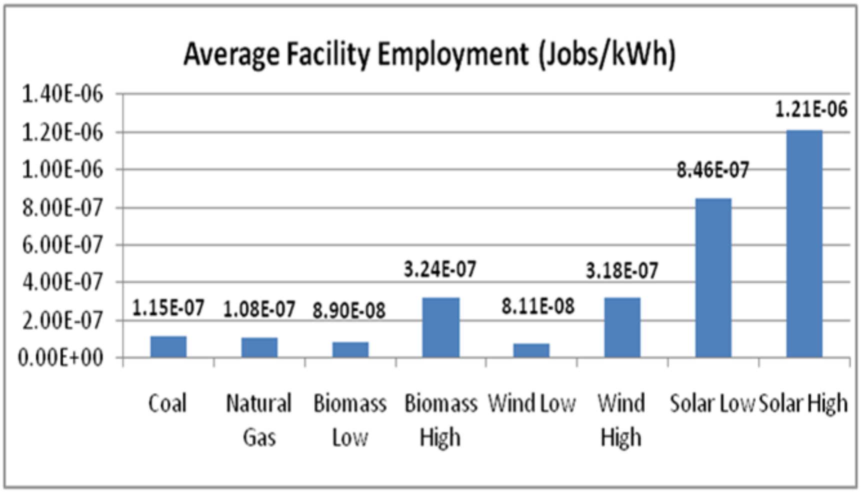
Figure 17: Drilling and Non-drilling Per Capita Income Comparison (2004=100)



Source: BEA. Mining counties (Tioga, Bradford, and Susquehanna) Non-mining counties (Union, Columbia, Carbon)

Figure 18: Drilling and Non-drilling Per Capita Income Comparison (2004=100)

Figure 19 shows the estimated number of jobs required to produce a kWh of electricity. Natural gas actually requires fewer jobs to produce a given amount of electricity than coal. The job requirements for natural gas electricity production are low because it is efficient at producing a kWh. In this case, fewer jobs created is actually a good thing for the overall competitiveness of the economy because that implies low-cost electricity, but it means that natural gas drilling has smaller employment impacts.



Source: Weinstein et al. (2010) chart using data from Kammen et al. (2004)

Figure 19: Jobs Requirements to Produce a kWh by Energy Source

As figure 3 shows, most natural gas resources (32.8%) are used for electricity. When switching from coal to natural gas, there will be significant displacement effects in addition to the effects of natural gas being more productive than coal in producing a kWh. Using the same technique shown in Weinstein et al. (2010), Table 3 shows the approximate employment effects of even large shifts (25% of the kWh produced from coal to kWh generated from natural gas) are rather small. In both cases, there are small employment losses with Ohio having more employment losses due to a higher percentage of electricity being generated from coal.

	Total kWh from Coal 2009	Change in Jobs	Change in Energy Costs (millions)	Change in Emissions (lbs)
Ohio	113,711,997,000	-195	-$491,804	-23,822,663,372
Pennsylvania	105,474,534,000	-181	-$456,177	-22,096,914,873

Source: EIA and Weinstein et al. (2010)

Table 3: Effects of Displacing Coal with Natural Gas

	Change in Percent income Growth	
	Parameter Estimate	t-value
Total Wells 05-09	**2.515E-05**	**2.11**
2001 Log Population	0.084	2.53
2001 Log Employment	-0.086	-2.76
N	67	
R2	0.205	
Adjusted-R2	0.167	

Source: BEA and Pennsylvania DEP Data

Table 4: Income Effects of Drilling

Table 4 shows the regression results for a difference-in-difference for county per-capita income. In this case, the income injected into the economy by the natural gas industry through leases and wages appears to have a significant positive effect on per capita income. These results, along with the employment regression results, verify our previous analysis using matched drilling and non-drilling counties. Drilling seems to have a positive and significant effect on income in drilling counties - but not on employment.

The Benefits and Costs of Natural Gas

Once the realistic expectations of the employment and income effects of shale natural gas development are properly assessed, these impacts can be included when weighing the benefits and costs of shale gas.

The Benefits of Natural Gas:

Other than the income effects and modest employment impacts, additional benefits to natural gas include lower energy prices, natural gas imports, and carbon emissions (especially compared to coal). First, Figure 20 below shows the average levelized cost to produce a kWh. As shown in Table 3, natural gas decreases electricity costs for end users. However, if natural gas prices are too low it will be less economical to pursue shale gas.[20]

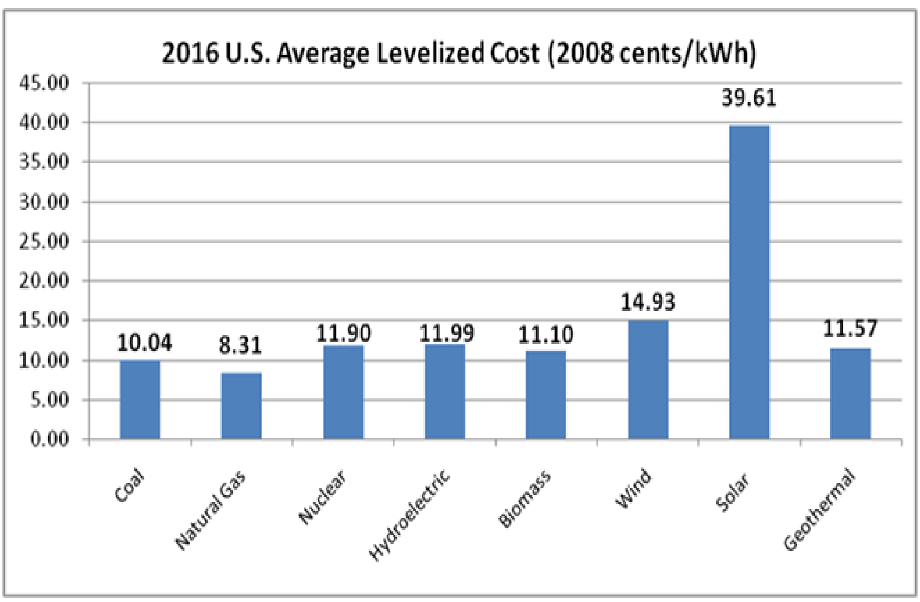
Pennsylvania and Ohio are also good locations to produce natural gas as there is significant natural gas infrastructure in the area and large population and industry centers that require natural gas as shown in Figure 21 on the next page. This proximity further decreases energy costs by reducing transportation costs.

Increasing domestic sources of natural resources are reducing the demand for foreign gas. The EIA reports that 87% of the natural gas consumed in 2009 was produced domestically. Figure 22 on the next page shows that since 2007, natural gas imports have been declining. However, as already noted, future increases in natural gas production will have very little effect on "energy security" as our largest problem relates to oil imports.

The potential benefits of natural gas have been touted by both the industry and the US EIA. However, the ability to supply the country's energy's needs may have been overstated. In the 2011 Annual Energy Outlook, the EIA estimates that 2,543 Tcf of potential natural gas resources could supply the U.S. for approximately 100 years at the 2010 level of annual consumption. However, this does not account for the increasing trends in consumption. Accounting for the trend in consumption from 1974 to 2010, this estimate falls to 65 years. Using a more recent trend from 1986 to 2010, the estimate falls to 52 years. Despite the significant reserves, natural gas energy strategies still suffer from typical fossil fuels problems such as nonrenewability.

The Environmental Benefits and Costs:

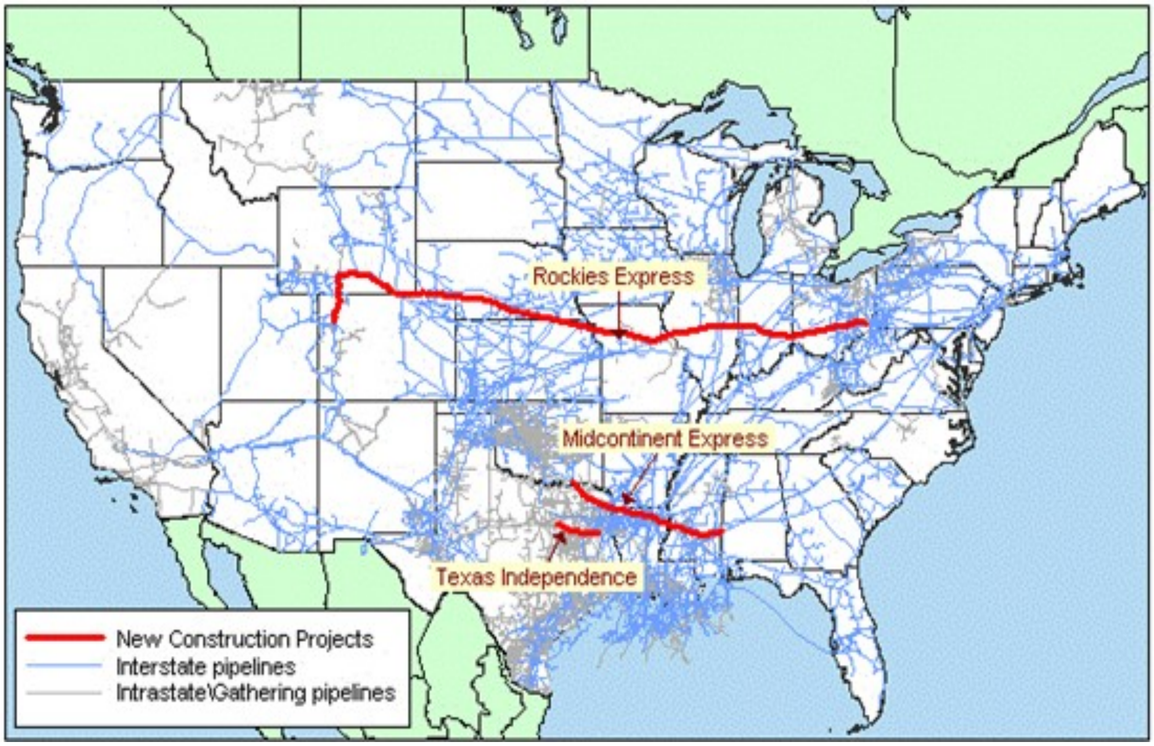
Natural gas is often viewed as a bridge between a reliance on carbon emitting fossil fuels and an energy industry comprised of some mix of alternative energy sources with far less reliance on foreign energy and carbon emitting energy sources. Figure 23 on page 22 shows the life cycle emissions rates for various sources of electricity generation. Although natural gas emits significantly more carbon than nuclear and alternative energy sources, it does emit far less than coal. Thus, as table 3 showed, switching from coal to natural gas will not only save money on energy costs it will also reduce carbon emissions. Natural gas combustion emits lower levels of carbon dioxide, nitrogen oxide, and sulfur dioxide than both coal and oil. Yet,



Source: Weinstein et al. (2010) using data from the EIA

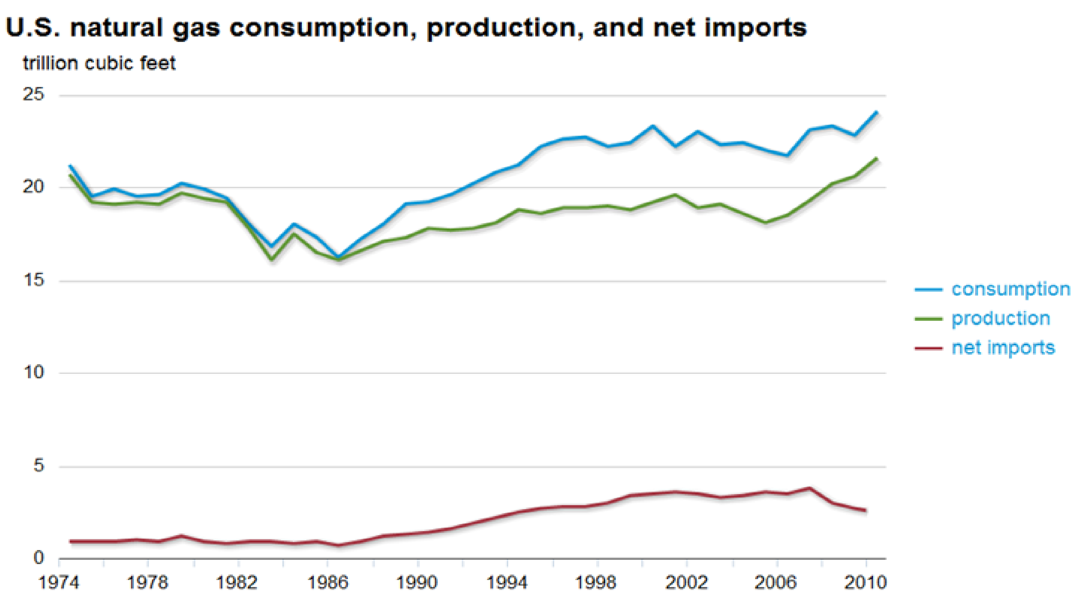
Figure 20: Energy production costs by energy source[21]

20. It should also be noted that a decoupling of natural gas prices from oil prices has realigned markets (Southgate and Daniels, 2011).
21. The average levelized cost is the present value of all costs including building and operating the plants.



Source: EIA, GasTran Natural Gas Transportation Information System.

Figure 21: Natural Gas Infrastructure



Source: EIA

Figure 22: Increasing Production Reduces Imports

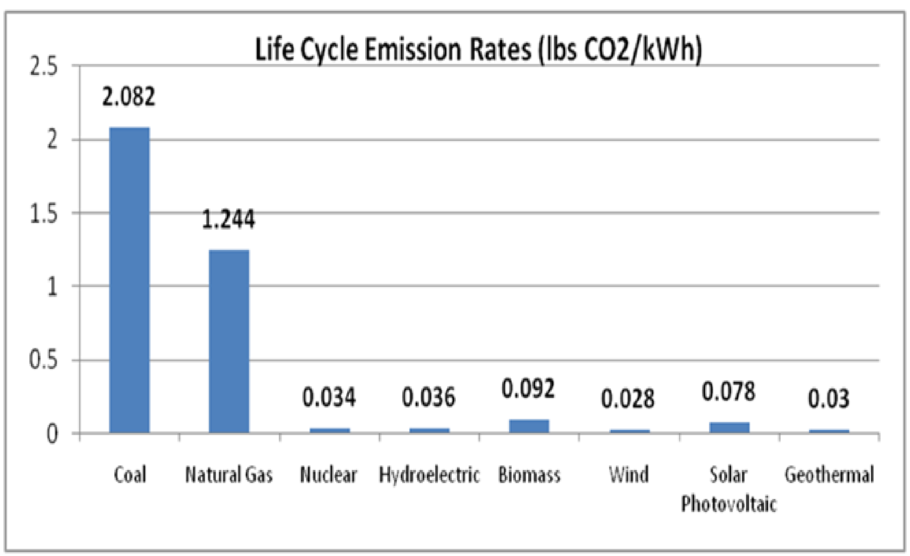
Howarth et al. (2011) find that the carbon emission benefits of natural gas are less when it extracted using hydraulic fracturing compared to conventional methods because of the water and wastewater transportation.

Despite the potential emissions advantages of natural gas, significant concerns have been raised about the environmental impact of natural gas extraction with a Duke University study finding elevated levels of methane in water near drilling sites (Osborn et al., 2011) and the EPA's recent announcement that hydraulic fracturing chemicals polluted water sources in Wyoming (The Associated Press).

The environmental concerns with natural gas have been focused on the hydraulic fracturing process and its impact on water sources. The importance of understanding the hydraulic fracturing process is essential in understanding its potential environmental effects. If cracks aren't able to be controlled or predicted during hydraulic fracturing or somehow disturb the ground, then natural gas or fracturing fluid containing toxic chemicals may shift or migrate to aquifers affecting drinking water. However, hydraulic fracturing typically occurs at depths well below the level of aquifers and drinking water. At thousands of feet below water sources, it is unlikely that hydraulic fracturing would contaminate water sources in Ohio. A 2004 EPA report found that, although fluids migrated unpredictably, hydraulic fracturing did not affect underground drinking water and posed no health risk. Representatives of the natural gas industry have made similar claims that hydraulic fracturing has never contaminated drinking water sources. These claims were used to exempt the natural gas industry from the Clean Water Act and the Safe Drinking Water Act when Congress enacted the 2005 Energy Policy Act.

Although the hydraulic fracturing method of injecting fluids deep below the aquifer level may not be a source of contamination, this level and aquifers themselves must be drilled through. Casing failures in the drilling process may cause fracturing fluids or natural gas to escape and pollute aquifers and local water sources. There are also concerns over spills that can occur during transport or impoundment failures. Thus, whether hydraulic fracturing has contaminated water sources becomes an issue of semantics as to whether the cause is the actual hydraulic fracturing or the drilling, extracting, and spills. Because of the potential impacts on water sources, it is important to be aware of the location of water sources compared to the location of shale resources. Figures 24 and 25 on the next page show the water resources of the US (aquifers are differentiated by various colors). US water resources and shale resources are clearly geographically overlapping though they are at different depths (including in Ohio and Pennsylvania).

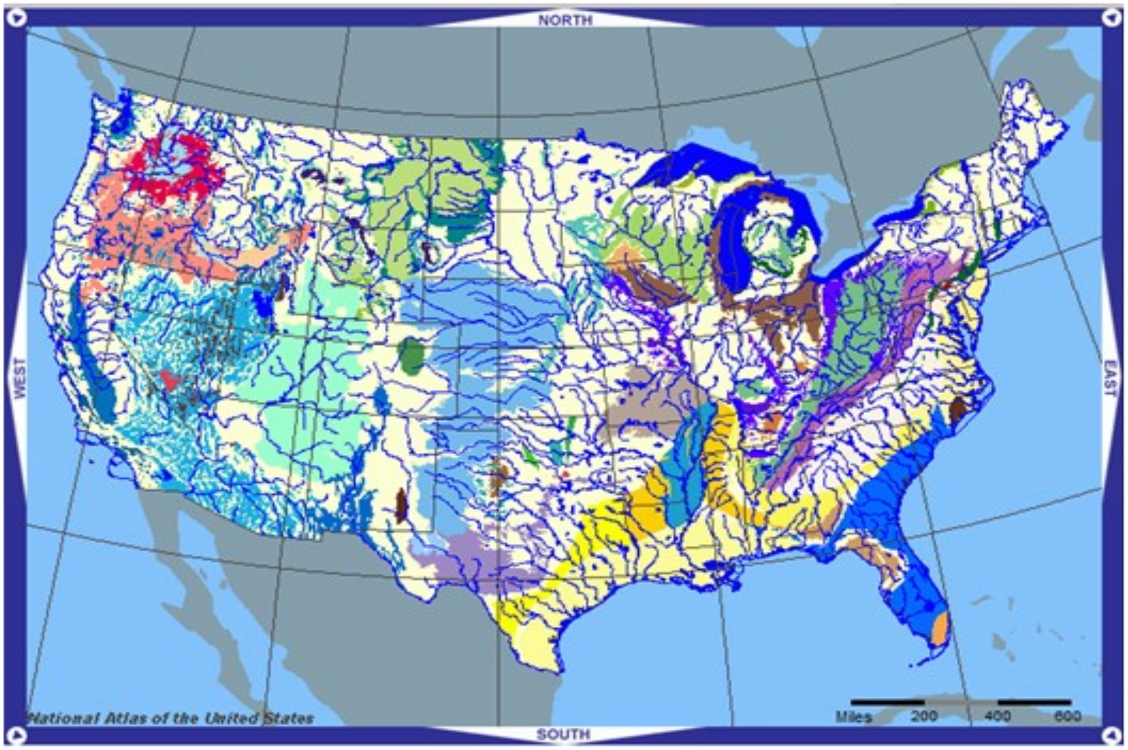
In addition to accidental contamination in the drilling and extraction process, water use and disposal are also concerns. The hydraulic fracturing method requires at least a million gallons of water per well that is combined with chemicals and sand. Sapien (2009) notes that approximately 9 million gallons of wastewater per day were produced from Pennsylvania wells in 2009, and this amount is expected to increase. This water byproduct contains elements and chemicals such as cadmium and benzene that are known to cause cancer. There may be other toxic chemicals in the hydraulic fracturing fluid mix though energy companies have continually refused to disclose these chemicals for proprietary reasons. Water byproducts also contain Total Dissolved Solids (TDS) that can make the water five times as salty as



Source: Weinstein et al. (2010) using data from Meier (2002)

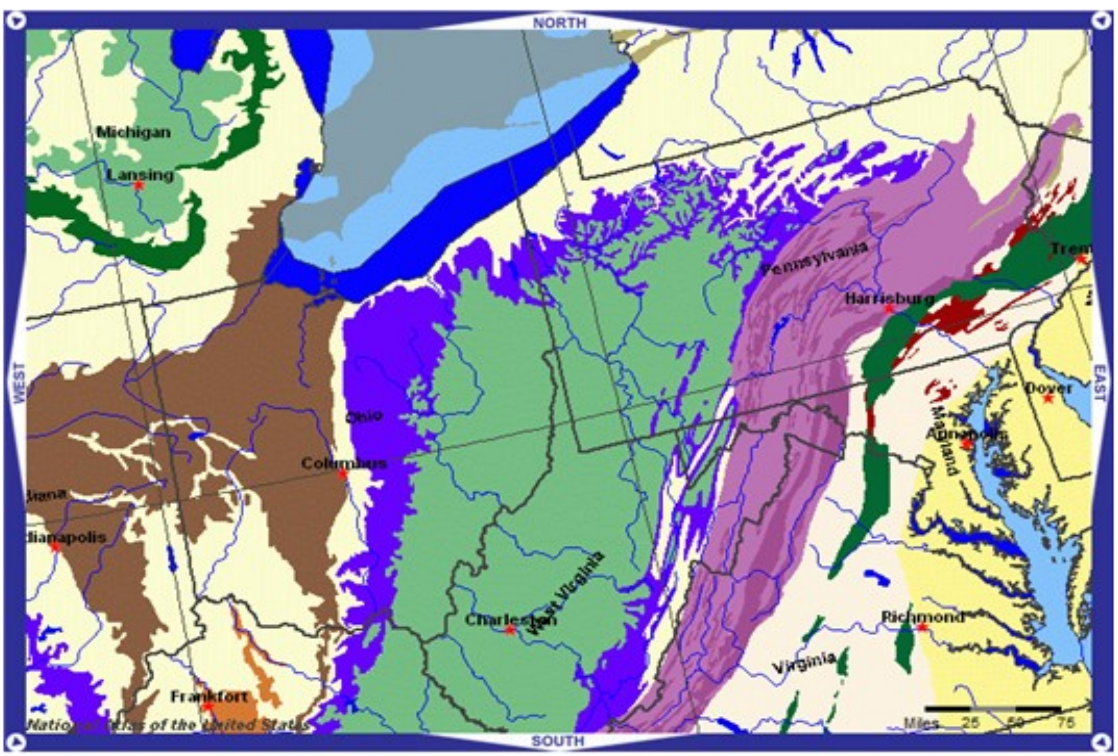
Figure 23: Carbon Emissions by Electricity Source[22]

22. Life cycle emissions rates include the total aggregated carbon emissions over the life cycle of the fuel, including extraction, production, distribution, and use.



Source: NationalAtlas.Gov

Figure 24: US Aquifer, Stream, and Waterbed Resources



Source: NationalAtlas.Gov

Figure 25: Ohio and Pennsylvania Aquifer, Stream, and Waterbed Resources

seawater. Although some of this water is left behind and some can be reused, there is still a significant amount that must be treated and disposed. Water byproducts must be stored in either open wells, closed containment wells, or injected back into the ground. Open wastewater wells can lead to air pollution as it evaporates and water contamination if the lining fails, but this method is less expensive than other methods. There are additional air pollution concerns with the increased traffic resulting from water transportation, flaring, etc.

There are also environmental costs in the form of noise pollution. Ohio residents may simply not want to look at or hear natural gas rigs in their backyard or heavy equipment driving through the countryside. Hydraulic fracturing does limit the number of rigs used compared to conventional methods.

The potential environmental impact of hydraulic fracturing on water in Ohio needs to be accounted for when estimating the economic costs of natural gas. Just as the employment and income effects for Ohio were estimated using Pennsylvania as a case study, the potential environmental impacts of hydraulic fracturing and natural gas drilling on Ohio can be approximated by examining incidents in Pennsylvania. Whether the source of contamination is from the migration of fluids and gas underground, drilling or extraction accidents, or improper disposal of water byproducts, it is important to understand what Pennsylvania residents have experienced. After gaining a better understanding of the environmental impacts, then it is important to determine the source of the contamination, how it can be prevented, and whether new regulations are needed to protect the Ohio environment and its drinking water.

Pennsylvania Environmental Concerns:

In 2008, Lustgarten noted that more than 1,000 cases of suspected contamination have been documented in Colorado, New Mexico, Alabama, Ohio, and Pennsylvania. Incidents of contamination have been most publicized in Dimock, PA. Dimock is located in Susquehanna County in northeastern Pennsylvania where natural gas development is most pronounced. Dimock is a struggling rural area with approximately 1,300 residents and nearly 1 in 7 is unemployed. Residents hoped the natural gas industry would turn their economy around. Instead, the controversial documentary *Gasland* contends it environmentally turned it upside down.[23] The documentary begins and ends in Dimock and includes footage of residents lighting their tap water on fire. After natural gas drilling began in Dimock, Lustgarten notes that several of the residents' wells have exploded. Affected residents now buy water from outside sources. The Pennsylvania Department of Environmental Protection (DEP) believes a casing failure is to blame for the drinking water contamination and is holding Cabot Oil responsible. Cabot Oil has agreed to supply clean water to some of the affected residents and has been required to pay compensation to many residents. In September of 2009, Cabot Oil spilled nearly 8,000 gallons of fracturing fluids that seeped into a nearby creek.

Evidence of fracturing fluid has now been found in drinking water sources including the Monongahela River. In response to these cases and others, the natural gas industry has been quick to label these events as unfortunate but highly unlikely implying that these cases are the result of just a few "bad apples." In some cases they claim methane has always existed in these water sources, but simply went unnoticed until now. Without conducting baseline water testing before drilling, the burden of proof required by the courts in many cases cannot be met to prove otherwise.

The *New York Times* publicized recent peer-reviewed research by Duke University showing an association between drinking water contamination and natural gas extraction. The study by Osborn et al. (2011) conducted research at 68 private water wells in Pennsylvania and New York finding that methane concentrations were 17 times higher for wells near active drilling, with some wells having methane levels requiring "immediate action." However, the study found no evidence of fracturing fluid contamination in these wells. The prevalence and commonality of these incidents, coupled with the devastating impacts, seem to suggest the need for caution. Some chemicals, particularly in the produced water, may be harder for residents to detect than methane, especially when the industry refuses to disclose all of the components of the fracturing fluid mixture. Regardless, it is clear that more information on the environmental impacts of natural gas is needed in deciding any need for further regulations.

Recent EPA Action:

Recognizing the need to further understand the true impacts of natural gas extraction, specifically hydraulic fracturing, Congress directed the EPA to

23. It should be noted that *Gasland* did not undergo the scientific scrutiny of a peer-reviewed journal article and because no baseline testing was conducted in *Gasland* or any research thus far, it is difficult to discern the source of contamination and whether it came from gas industry activity. Hopefully, US EPA research will answer these questions in 2012.

study the impact hydraulic fracturing has on drinking water and groundwater. The EPA (2011) identified seven case studies, three of which are in Pennsylvania, to examine the lifecycle of a well and whether hydraulic fracturing affects drinking water. The EPA will also collect information from computer modeling, laboratories, and other data from the industry, states, and communities. Initial results of this study are expected in late 2012. Hence, it is unlikely that there will be any national regulations in the near future, while Ohio hydraulic fracturing in the Marcellus and Utica has already begun. Until Congress or the EPA acts, the regulation of hydraulic fracturing is left to the states.[24]

Ohio Environmental Protection:

Because the EPA and Congress have essentially relegated any regulatory authority to the states, this increases the importance of the Ohio EPA and the Ohio Division of Mineral Resources Management (ODNR) for environmental regulations. The Ohio EPA (2011) states that ODNR has primary regulatory authority over natural gas drilling, including the treatment and disposal of wastewater in the hydraulic fracturing process. The Ohio EPA also has water quality certification requirements to help preserve wetlands, streams, rivers, and other water sources. The appendix includes a list of the regulatory authority between ODNR and the Ohio EPA.

The Ohio Farm Bureau's Dale Arnold contends that Ohio has better regulatory authority over the oil and gas industry compared to Pennsylvania. Although the Cuyahoga River fire in 1969 in Cleveland, OH was not associated with fracturing, Scott (2009) notes it was a catalyst not only for Ohio environmental regulations, but also the national Clean Water Act in 1972 and the creation of the US EPA (and Ohio EPA). Dale Arnold reckons that even before the Cuyahoga fire, Ohioans had built a "collective consciousness," learning from past oil and gas industry experiences, preparing themselves for future waves.

Ohio's collected experiences and advanced environmental regulations have certainly left the state better prepared to handle the wastewater produced from hydraulic fracturing than Pennsylvania. Much of the wastewater from Pennsylvania comes to Ohio injection wells. Hunt (2011) notes that in June of 2010, Ohio quadrupled out-of-state fees to limit brine coming in from Pennsylvania and other states while anticipating the increased disposal needs of Ohio's own burgeoning natural gas industry. Despite the increased prices, nearly half of the brine in Ohio injection wells came from Pennsylvania after its officials banned 27 treatment plants from dumping brine into streams. This highlights the importance of Ohio properly addressing the issue of wastewater.

Ohio has made strides in environmental regulations through the drilling permitting process. Permits or "frac tickets" are required for gas companies planning on using hydraulic fracturing to extract natural gas. A frac ticket requires that companies disclose the chemicals used in the fracturing fluid. If a spill or casing failure should occur, Ohio will know many of the possible contaminants for testing. Ohio's permitting also allows residents to more easily prove their water has been contaminated with fracturing fluid.

Because many of the residents that will be most affected by shale gas development are farmers, the Ohio Farm Bureau is advising farmers and residents on the leasing process and is recommending that residents establish independent baseline water and soil quality measures that have been so notably missing from Pennsylvania and elsewhere. In addition, it is now standard practice in Ohio for gas companies to do their own baseline testing on all residents' water within 3,000 yards of the drilling site.

Even with better regulations, accidents may happen. Lustgarten (2009) recounts a 2007 incident of a house explosion in Bainbridge, OH. In a later report, ODNR found that a faulty concrete casing failure from a nearby natural gas well caused methane to be pushed into an aquifer during hydraulic fracturing, which then found its way into the plumbing, building up in the basement of the house.

The Cuyahoga fire itself and other serious environmental incidents have a more profound impact than just on the environment. Congressmen Louis Stokes said in regards to the Cuyahoga fire, "It portrayed a totally different image of Cleveland than the image of a productive, progressive city that was making news of a progressive nature" (as quoted in Scott, 2009). The lessons of the Cuyahoga fire resonate for natural gas development. The negative impacts on the environment can affect communities in lasting ways that cannot be exactly quantified but still require consideration.

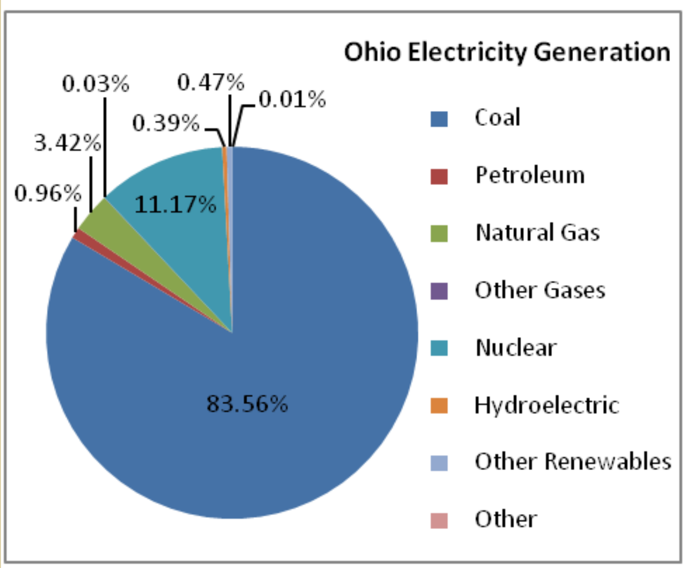
24. In 2009, members of Congress introduced the Fracturing Responsibility and Awareness of Chemicals Act, also called the "Frac Act," to undo the natural gas industry's exemption from the Safe Drinking Water Act and require the industry to disclose the chemicals used in the fracturing process. Though reintroduced in March of 2011, it is not expected to pass.

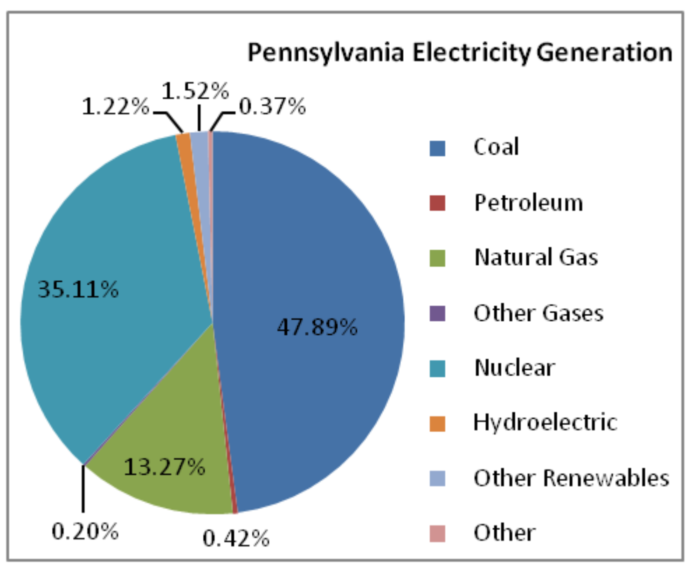
Conclusion

Hydraulic fracturing has made natural gas extraction possible and more productive in shale resources that were previously deemed uneconomical. This has brought a new wave of natural gas extraction to Ohio and other areas. However, recent experiences with hydraulic fracturing have also opened a new debate about the costs and benefits of natural gas extraction. Gary Walzer, Principle Engineer at EMTEC, states that natural gas has the potential to be a substantial source of domestic energy that is cleaner than coal with lower emissions. This has the potential to decrease US reliance on coal. Compared to Pennsylvania, Ohio clearly has a less diversified energy portfolio that relies heavily on carbon emitting coal. Based on electricity generation alone, Ohio is emitting significantly more carbon than Pennsylvania. Natural gas could be a significant first step for Ohio to diversify its energy portfolio and reduce carbon emissions.

Compared to coal, natural gas is not only cleaner but also less expensive to produce electricity. Producing energy in close proximity to where it is needed further lowers energy prices for consumers and industry. Unlike alternative energy, there are market forces pushing for the production of natural gas without the use of inefficient subsidies, though all of the social costs of natural gas (and coal) are not sufficiently priced. Low natural gas prices provide evidence that it is highly efficient for producing electricity. This efficiency is one reason why natural gas is associated with fewer jobs than coal—but the lower costs make the rest of the economy more competitive.

Does all of this also mean that natural gas will create significant numbers of job for Ohioans? Previous studies on the economic impacts of natural gas appear to have widely overstated the economic impacts. This is not surprising, as these studies are typically industry-funded and industry-funded studies are usually not the best sources of information for economic effects (regardless of the industry). One reason for the overstatement is the energy industry is generally very capital intensive. Alan Krueger, Chief Economist and Assistant Secretary for Economic Policy at the US Department of Treasury stated in 2009, “The oil and gas industry is about 10 times more capital intensive than the US economy as a whole… suggesting these tax subsidies are not effective means for domestic job creation” (US Department of Treasury). The energy industry as a whole also does not account for a significant share of employment. Even if the natural gas industry experiences significant job growth, its employment share is too small to have any significant effect on unemployment rates and on the economy (with the exception of remote rural areas such as in rural Western North Dakota). Previous studies on the economic impacts also fail to account for the displacement effects that the natural gas industry will have on other industries. Finally, from a national perspective greater natural gas production will displace other fossil fuels and their workers as they are no longer needed, in





Source: US EIA

Figure 26: 2009 Electricity Generation Profiles

particular coal.

We use Pennsylvania as a case study to estimate the employment effects of drilling that Ohio can realistically expect. Our analysis shows the employment effects of natural gas are modest given the size of the Ohio and Pennsylvania economy. We show this through (1) an assessment of impact analysis, (2) by comparing drilling counties with similarly matched non-drilling counties in Pennsylvania, (3) statistical regressions on the entire state of Pennsylvania, (4) employment comparisons with North Dakota's Bakkan shale region, and (5) an examination of the employment life cycle effects of natural gas and coal per kilowatt of electricity. Our results are not unexpected as the economic literature has long pointed to the adverse effects of natural resource development through phenomenon such as the "natural resources curse" and Dutch Disease. Likewise, a recent Cornell University study found similar overstatements by the oil industry in terms of job forecasts for the Keystone XL pipeline (Cornell University ILR School Global Labor Institute, 2011). On the other hand, our approaches suggest that natural gas activity will increase per-capita income. We expect this is primarily among landholders receiving royalties/lease payments and through higher wages in the industry. Thus, we expect a short-term infusion of income in affected economies.

As Christopherson and Rightor (2011) point out, it is important to realize these are fairly short-term estimates and may still not account for the cycle of the natural resource boom. The initial boom causes competition for labor in the short-term, bidding up wages. This makes the area less competitive and "crowds out" other sectors, especially those that rely on low cost labor such as agriculture and tourism. As housing prices are bid up, this will also further displace low-income workers. In the long-run, the business climate may suffer as there are fewer businesses that are unrelated to the oil and gas industry, which makes the local economy less diverse and more vulnerable to economic shocks. Our advice to counties experiencing drilling activity is to ensure they properly pay for infrastructure needs upfront, place monies in reserves for after the boom, and build up local assets such as schools in order to produce lasting benefits from energy development.

Finally, the environmental costs of natural gas need to be realistically addressed by the industry and regulators. Although natural gas can reduce carbon emissions compared to coal and other fossil fuels, there are concerns about its effect on drinking water. Because Ohio has been able to learn from Pennsylvania's experiences with the oil and gas industry, Ohio seems better prepared to deal with the environmental risks. Nevertheless, a realistic assessment of the environmental costs of natural gas should also include the environmental opportunity cost of natural gas. Natural gas mainly displaces coal, which emits even more carbon and also has additional environmental and safety concerns. A Clean Air Task Force report unequivocally states that "coal irreparably damages the environment." Coal poses significant health risks to both miners and nearby residents. Despite the number of years the US has been extracting coal, there are still significant issues with its waste products. Most recently on Oct. 31, 2011 a bluff collapse caused coal ash to be spilled into Lake Michigan (Jones and Behm, 2011). In 2008, the *New York Times* reported that experts called the Tennessee ash flood that dumped over 1.1 billion gallons of coal ash waste "one of the largest environmental disasters of its kind" (Dewan, 2008). We are not understating the environmental costs of natural gas, but rather putting it into perspective in relation to the environmental costs of coal, which is natural gas's main competitor.

Although we should not expect natural gas to be a big job creator, there are significant benefits to producing natural gas that are getting lost in the hype of job creation. Raising expectations that natural gas will not be able to meet is setting Ohio residents up to be disappointed. The true benefits of natural gas need to be highlighted while putting the costs into perspective. Likewise, Ohio needs to plan today about how to make some of the gains from the energy boom permanent. Among many things, this will require innovative policies and funding models to ensure that infrastructure is paid for today and there is adequate funding to maintain that infrastructure in the future.

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Appendix 1: County Comparison Mining (blue) vs. Non-Mining (green)

See notes to figures 15-18 for more details. Southern drilling counties include Washington, Greene, and Fayette. Southern non-drilling counties include Franklin, Perry, and Cumberland. Northeastern drilling counties include Tioga, Bradford, and Susquehanna. Northeastern non-drilling counties include Union, Columbia, and Carbon.

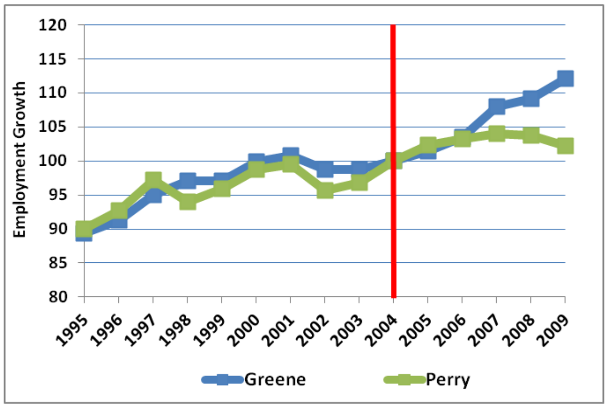

Figure 27: Employment Growth Comparison Greene vs. Perry

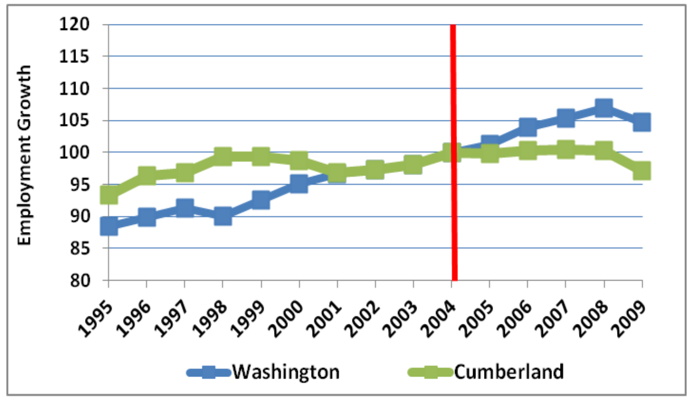

Figure 28: Employment Growth Comparison Washington vs. Cumberland

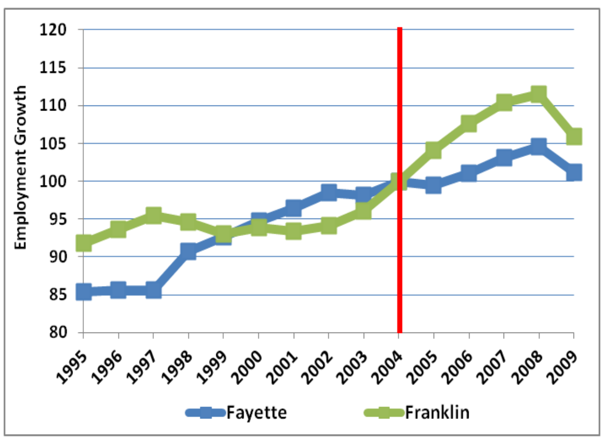

Figure 29: Employment Growth Comparison Fayette vs. Franklin

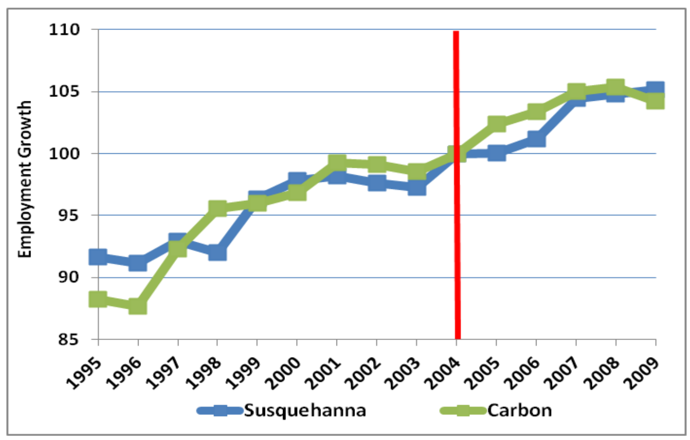

Figure 30: Employment Growth Comparison Susquehanna vs. Carbon

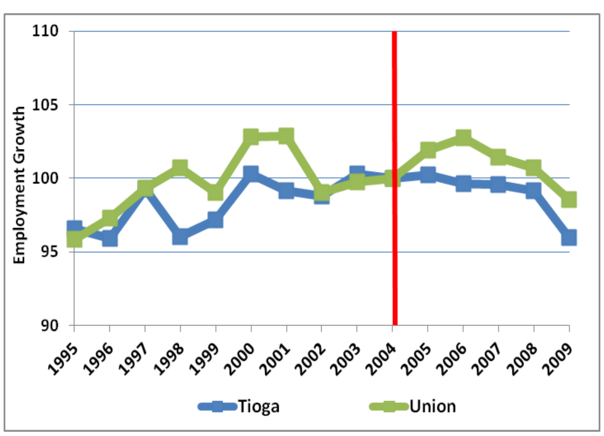

Figure 31: Employment Growth Comparison Tioga vs. Union

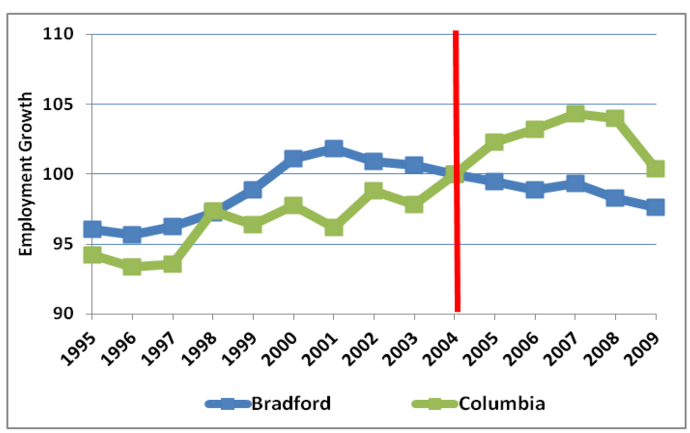

Figure 32: Employment Growth Comparison Bradford vs. Columbia

Appendix 1: County Comparison Mining (blue) vs. Non-Mining (green)

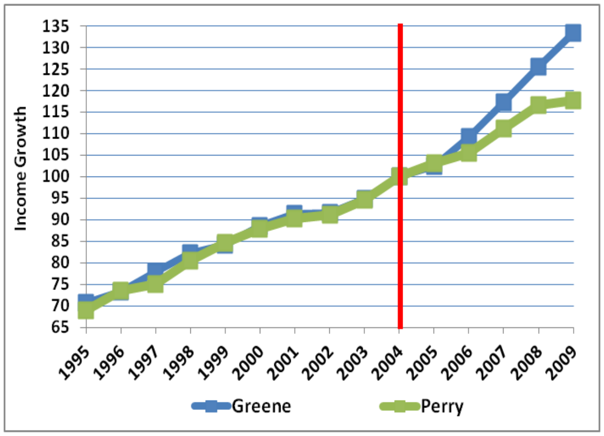

Figure 33: Per Capita Income Growth Comparison
Greene vs. Perry

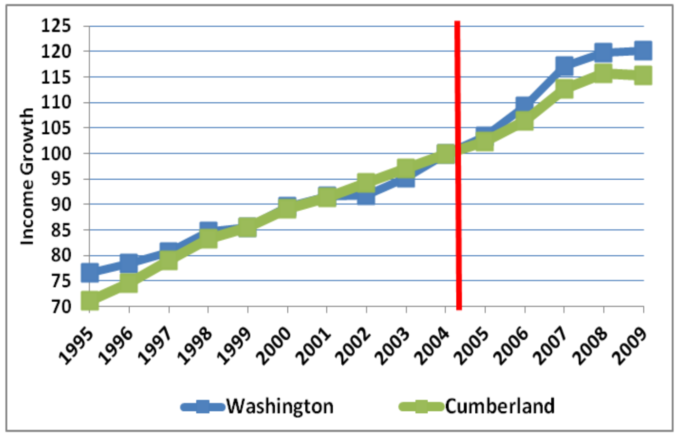

Figure 34: Per Capita Income Growth Comparison
Washington vs. Cumberland

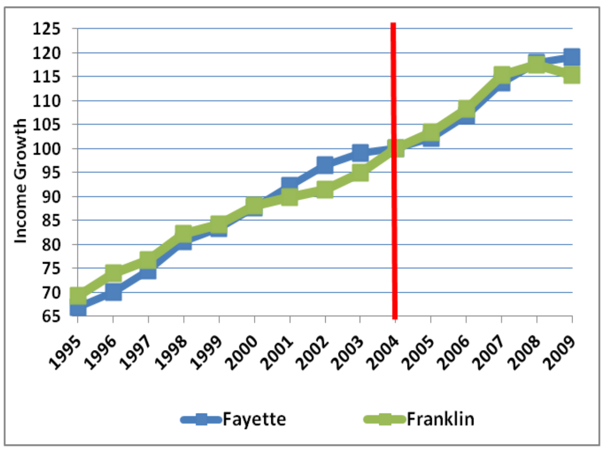

Figure 35: Per Capita Income Growth Comparison
Fayette vs. Franklin

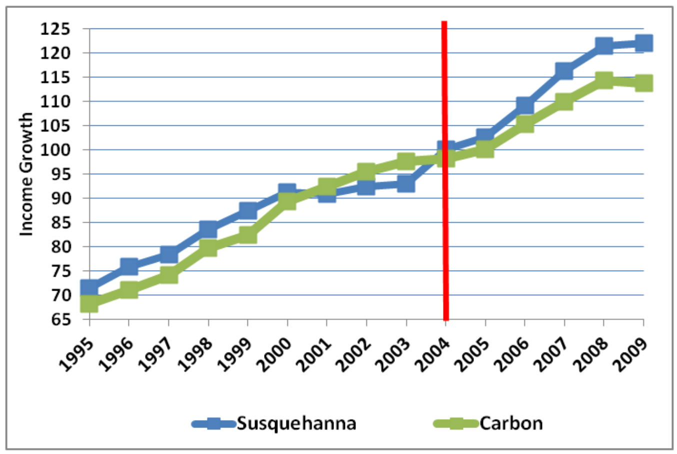

Figure 36: Per Capita Income Growth Comparison
Susquehanna vs. Carbon

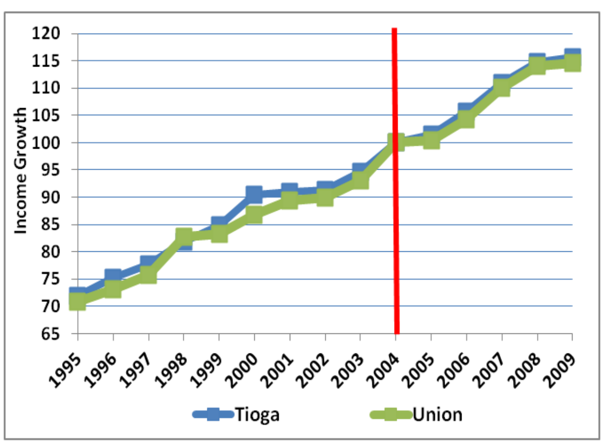

Figure 37: Per Capita Income Growth Comparison
Tioga vs. Union

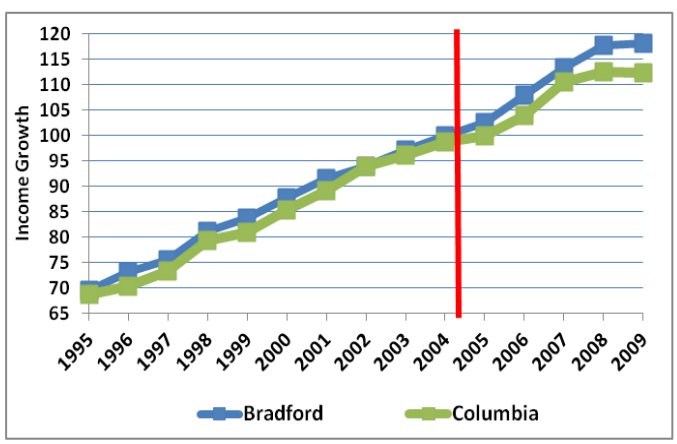

Figure 38: Per Capita Income Growth Comparison
Bradford vs. Columbia

Appendix 2: Statistical Methodology

In 2005, drilling began in Pennsylvania in a number of counties with natural gas potential due to the location of resources in the Marcellus shale. The choice of county to develop shale gas was based on the random occurrence of natural resources and not prior economic conditions. However, there may be other inherent county differences between drilling and non-drilling counties. For example, counties with drilling tend to be rural. Likewise, counties tend to have many factors that influence their economic growth such as the quality of its government, distance to urban centers, and educational and demographic attributes of the population. These factors are either constant or change very slowly. We treat these as county fixed effects on county growth.

We want to measure the economic impacts of drilling. Equation 2 shows the impact of the number of wells on the percent employment growth (Y_{i1}) for county i in period 1 (2005-2009). However, the empirical estimation of this impact would not be able to account for county fixed effects (C_i). This could bias the estimates of the impact of drilling by omitting relevant variables that differentiate drilling counties from non-drilling counties. Thus, equation 3 estimates the impact of drilling since 2005 on the difference in employment growth between period 1 and period 0 (2001-2005). The county fixed effect is differenced out and thus there should not be omitted variable bias.

Table 5 shows the results of this estimation using the total number of well drilled since 2005. We also include additional controls to better account for differences in the way larger or wealthier counties may have reacted to shale development, or more importantly, how wealthier or more urban counties were differentially affected by effects of the housing bubble/bust and the Great Recession. Using the total number of wells parameter estimate, Table 5 shows that drilling has a small and statistically insignificant impact on percent employment growth.

$$Y_{i0} = \beta_0 + \beta_1(\text{Number of Wells})_{i0} + C_i + \varepsilon_{i0} \quad (1)$$
$$Y_{i1} = \beta_0 + \beta_1(\text{Number of Wells})_{i1} + C_i + \varepsilon_{i1} \quad (2)$$
$$Y_{i1} - Y_{i0} = \beta_0 + \beta_1(\Delta \text{ Number of Wells}) + \varepsilon_i \quad (3)$$

A similar method is used to empirically estimate the impact of drilling on per capita income with results presented Table 6. In this case, drilling has a statistically significant impact on percent per capita income growth.

2005-09 Percent Employment Growth Minus 2001-05 Percent Employment Growth	Parameter Estimate	t-value
	Difference in Employment Change	
Total Wells 05-09	**1.769E-05**	**1.14**
2001 Log Population	0.023	2.64
2001 Log Per Capita Income	-0.096	-1.55
N	67	
R2	0.118	
Adjusted-R2	0.076	

Table 5: Impact of drilling on employment

2005-2009 Percent Income Growth Minus 2001-05 Percent Income Growth	Parameter Estimate	t-value
	Difference in Income Change	
Total Wells 05-09	**2.515E-05**	**2.11**
2001 Log Population	0.084	2.53
2001 Log Employment	-0.086	-2.76
N	67	
R2	0.205	
Adjusted-R2	0.167	

Table 6: Impact of drilling on income

Another method to develop a counterfactual to compare how drilling counties would have done if there was no drilling is to use a difference in difference approach. The difference in differences approach treats drilling as a treatment in a natural experiment. The difference in differences estimates the causal effect of the difference between the treatment and control group before and after treatment (drilling). This is shown below in equation 4 where i=0 represents non-drilling counties and i=1 represents drilling counties; t=0 is still the first time period (2001-2005) and t=1 is the second time period (2005-2009).

$$[E(Y_{11})-E(Y_{01})] - [E(Y_{10})-E(Y_{00})] \quad (4)$$

To measure the impact of drilling on the employment growth of county i in time period t (Y_{it}), a control group needs to be established (non-drilling counties). This is further expanded in equation (5). The main effect of the treatment group, β_1 controls for the difference between the treatment and control in period 0. The main effect of the second period, β_2 controls for the difference between the effects of the second period compared to the first period. The parameter of interest, β_3 estimates equation 4: the impact of the number of wells had on counties since drilling began in 2005. Through asymptotics, it can be shown that the probability limit of the estimate of β_3 is equivalent to equation 4.

$$Y_{it} = \beta_0 + \beta_1(\text{Number of Wells}_{it}) + \beta_2 t + \beta_3(t^*\text{Number of Wells}_{it}) + \varepsilon_i \quad (5)$$

Table 7 shows the empirical estimation of equation 4 for employment growth. The results are similar to those in Table 5 with the impact of drilling on employment being small and statistically insignificant. Table 8 reports the estimates of equation 5 for per capita income growth. Similar to Table 6, it shows that drilling appears to have had a positive statistically significant impact on per capita income growth.

Percent Employment Growth	Parameter Estimate	t-value
Time Period*Total Wells	**1.763E-05**	**0.91**
Time Period	-0.05	-4.12
Total Wells	-3.240E-06	-0.23
Log Population	-0.005	-0.85
Log Per Capita Income	0.066	1.69
N	134	
R2	0.125	
Adjusted-R2	0.091	

Table 7: Impact of drilling on employment

Percent Income Growth	Parameter Estimate	t-value
Time Period*Total Wells	**3.119E-05**	**2.52**
Time Period	0.0253	3.51
Total Wells	-3.310E-06	-0.37
Log Population	0.009	0.55
Log Employment	-0.007	-0.43
N	134	
R2	0.205	
Adjusted-R2	0.167	

Table 8: Impact of drilling on income

Appendix 3: Ohio Environmental Regulatory Authority

Summary of ODNR and Ohio EPA regulatory authority over oil/gas drilling and production activities

	Ohio Department of Natural Resources	Ohio Environmental Protection Agency
Drilling in the shale deposits	✓ Issues permits for drilling oil/gas wells in Ohio. ✓ Sets requirements for proper location, design and construction of wells. ✓ Inspects and oversees drilling activity. ✓ Requires controls and procedures to prevent discharges and releases. ✓ Requires that wells no longer used for production are properly plugged. ✓ Requires registration for facility owners with the capacity to withdraw water at a quantity greater than 100,000 gallons per day.	✓ Requires drillers obtain authorization for construction activity where there is an impact to a wetland, stream, river or other water of the state. ✓ Requires drillers obtain an air permit to install and operate (PTIO) for units or activities that have emissions of air pollutants.
Wastewater and drill cutting management at drill sites	✓ Sets design requirements for on-site pits/lagoons used to store drill cuttings and brine/flowback water. ✓ Requires proper closure of on-site pits/lagoons after drilling is completed. ✓ Sets standards for managing drill cuttings and sediments left on-site.	✓ Requires proper management of solid wastes shipped off-site for disposal.
Brine/flowback water disposal	✓ Regulates the disposal of brine and oversees operation of Class II wells used to inject oil/gas-related waste fluids. ✓ Reviews specifications and issues permits for Class II wells. ✓ Sets design/construction requirements for Class II underground injection wells. ✓ Responds to questions/concerns from citizens regard safety of drinking water from private wells from oil/ natural gas drilling.	
Brine/flowback water hauling	✓ Registers transporters hauling brine and oil/gas drilling-related wastewater in Ohio.	
Pumping water to the drill site from a public water supply system		✓ Requires proper containment devices at the point of connection to protect the public water system.

Source: EPA (2011)

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Quality of life

Canadian firm plans fracking campaign that could require 4 billion gallons of Michigan water

25 June 2013

by **Jeff Alexander**
Bridge Magazine contributor

KALKASKA — A Canadian firm has laid out plans to drill 500 new natural gas wells in Northern Michigan, using a technique that could consume more than 4 billion gallons of groundwater — or about as much water as Traverse City uses in two years.

THIRSTY WORK: The Encana Corp.'s Westerman well in Kalkaska County recently used 8.5 million gallons of water to complete a hydraulic fracturing process. (courtesy photo)

The firm, Encana Corp., will rely on hydraulic fracturing or "fracking," a technique cloaked in controversy that requires large amounts of water, mixed with chemicals and other elements, to break down rock formations and release natural gas. Encana, for example, used 8.5 million gallons of groundwater earlier this month to frack a single gas well, the Westerman in Kalkaska County, east of Traverse City.

Because most of the water used in fracking becomes contaminated and is left in geologic formations deep underground, a recent surge in drilling by Encana and other companies has raised concerns that fracking could drain water from some of the state's best rivers.

Encana recently drilled several new wells into the Collingwood shale formation, which lies about two miles underground. That's the first step in a plan to drill 500 more deep shale wells in the region using fracking, according to company records.

The company's plan to drill several new gas wells near Kalkaska will entail pumping about 300 million gallons of water out of the ground, injecting that water into several gas well bores and then leaving nearly all of the contaminated water in the ground when the fracking is completed, according to state records.

The result: A net loss of up to 300 million gallons of groundwater to the North Branch of the Manistee River, a blue-ribbon trout stream fed almost entirely by groundwater. One of Encana's drilling sites is a half-mile from the Manistee River's North Branch, according to company records.

"If the citizens of Michigan knew corporations were destroying hundreds of millions of gallons of Michigan water – water that is supposedly protected by government for use by all of us – they would be opposing this new kind of completion (fracking) technique," said Paul Brady, a fracking watchdog who lives near Kalkaska. "These deep shale, unconventional wells are using massive amounts of water without adequate testing and solid data on aquifer capacity."

Encana spokesman Doug Hock, however, is optimistic: "Can we access the (deep shale gas) and still protect the environment? Absolutely."

State's monitoring questioned, defended

Michigan's Water Withdrawal Assessment Tool, a computer-based program launched in 2006, was supposed to prevent water withdrawals that could harm streams and rivers. The tool is Michigan's first line of defense against excessive water withdrawals, but it was developed before drillers began using large quantities of water when fracking deep shale gas wells here.

Scientists, lawyers and Michigan courts have said the tool and other state estimates of stream flows are deeply flawed. If true, such a problem could result in the state inadvertently approving large water withdrawals that hurt rivers and streams.

Researchers at Michigan State University recently found several sites where the state's water tool over-estimated the volume of water in small headwater streams that feed the Manistee River.

"In some watersheds, we are seeing that the assumed flows (calculated by the state's water tool) are much higher than we measured. In one case the tool was off by a factor of three," said David Hyndman, a hydrogeologist, professor and chairman of MSU's Department of Geological Sciences.

Those findings were significant for three reasons, Hyndman said: Many of the Collingwood shale gas wells are being drilled in the ecologically fragile headwater areas of rivers; headwater streams are critically important to the health of entire river systems; and the state does little monitoring in headwater streams, where rivers originate.

Government and industry officials defended the state's water assessment tool.

State officials who developed the tool "did error analysis to make sure it was working and everywhere they tested, it worked," said Jill VanDyke, a senior geologist with the Michigan Department of Environmental Quality.

The Water Withdrawal Assessment Tool estimates flows in Michigan's 7,000 streams and river segments using data from river gauges and other information, including geology, soil characteristics, drainage area and precipitation. But only 2 percent of all river and stream segments in Michigan, 147 sites, have gauges that measure actual stream flows. That lack of in-stream data forced the DEQ to base much of the water assessment tool on general environmental conditions and mathematical models.

Dave Hamilton, a former DEQ official who helped develop the water assessment tool, said it takes a "very conservative" approach to ensure that large water withdrawals don't cause adverse impacts.

"Ninety percent of the time there is more water in a stream than what the tool is saying," said Hamilton, who is now a senior policy adviser for The Nature Conservancy's Michigan chapter.

Well uses 3 million gallons from village supplies

State law requires using the tool to screen water withdrawals that exceed 100,000 gallons daily. If the tool raises a red flag, state officials conduct a site visit. Those site visits usually lead to permit approvals, according to DEQ officials.

Since 2008, the DEQ has issued 52 permits for large, fracking-related water withdrawals. Another 17 permits are pending, according to state data.

Tanker trucks were used to ship millions of gallons of water from the nearby villages of Kalkaska and Mancelona to a gas and oil well. (courtesy photo)

Fracking critics said recent problems at the Westerman gas well in Kalkaska County — where water wells didn't produce as predicted and drillers had to truck in 3 million of gallons of water from Kalkaska and Mancelona to complete the fracking process — highlighted flaws in the water assessment tool.

Encana's Hock and DEQ officials blamed the problem on "geologic conditions" unrelated to the water assessment tool.

"Everyone wanted to jump to the conclusion that the (water assessment) tool didn't work and there wasn't adequate water," Hock said. "The tool worked well … it was a matter of really tougher rock than we anticipated."

Industry watchdog Brady said the DEQ is trying to gloss over problems with the water assessment tool.

“Obviously the tool declared that the area had ample water and as we unfortunately found out the tool was inaccurate,” said Brady, who has written extensively about fracking on the respectmyplanet.org website.

Concerns about Michigan’s ability to accurately predict stream flows aren’t new.

In 2005, the DEQ planned to issue a permit allowing an oil company to discharge 1.15 million gallons of slightly contaminated groundwater daily into Kolke Creek, the headwaters of the Au Sable River. The DEQ claimed that the index (or average) flow in Kolke Creek was about 6,000 gallons per minute, enough to dilute the oil company’s contaminated water without harming the creek.

As part of a lawsuit challenging the DEQ permit, independent scientists proved that the state’s estimate of Kolke Creek’s index flow was up to 100 times greater than the actual flow.

A state circuit court concluded that the state’s estimate of the flow in Kolke Creek was inaccurate and blocked the proposed discharge of polluted water into creek. The DEQ appealed but the state Court of Appeals upheld the lower court’s ruling.

The prospects for natural gas drilling – and the subsequent need for water supplies for fracking – have waxed and waned in Michigan in recent years.

First came a boom of investment in drilling rights on state property as petroleum firms looked **to extend natural gas exploration from Pennsylvania and Ohio into Michigan**.

By late 2012, though, the pace of exploration in Michigan was still far below drilling rates seen in other Great Lakes states and low natural gas prices were seen **as a potential brake on activity**.

That may soon change.

Encana officials said the oil and gas industry wants to export natural gas extracted from shale formations in Michigan and other states to consumers in Asia. Demand for natural gas in China is strong and prices are double the cost of natural gas in the U.S., industry, watchdogs said.

China’s government-controlled energy company, Sinopec, has already invested $2.5 billion in a joint venture with Oklahoma-based Devon Energy. Devon has permits to drill several Collingwood shale wells in Northern Michigan, according to state records.

And late last week, Michigan Congressman Fred Upton, R-St. Joseph and chairman of the House’s energy panel, touted fracking as an aid in making the **U.S. “energy independent” in natural gas**:

"We're the largest natural gas producer now in the world because of the advances that we've done on hydraulic fracking. … We are so rich in that resource."

Jeff Alexander is owner of J. Alexander Communications LLC and the author of "Pandora's Locks: The Opening of the Great Lakes – St. Lawrence Seaway." A former staff writer for the Muskegon Chronicle, Alexander writes **a blog on the Great Lakes**.

29 comments from Bridge readers.

Bruce McFee

June 25, 2013 at 9:37 am

4 billion gallons is equivalent to about 6 hours of water flowing over Niagara Falls.
While that might seem like a lot of water, it would probably occur over several years. It is not the same impact as in Los Angeles where they have diverted the entire Colorado River for their water use.
The dilemma in all this is that we could continue to import energy from countries that have much less interest in protecting the environment. But this means we need a strong military presence to keep that energy supply safe. Or we just bite the bullet and become energy independent.
One piece of good news is that a break through is right around the corner making desalination of sea water more practical.

Jim Olson

June 25, 2013 at 10:42 am

Ten million gallons over 21 days will most likely harm creeks and wetlands in headwaters areas of our lakes and streams or interfere with adjacent farmer who is irrigating crops or nearby landowners who rely on water wells. What the state and industry have to do is do what every other heavy water user does — conduct a pump yield test and monitor groundwater, wetlands, streams, creeks nearby during the test. Industry will know up front whether there is enough water and DEQ and DNR and citizens will know if there is enough water, that there will be no harm or interference.

Karen Dill-Wilson

June 25, 2013 at 12:53 pm

this example is ridiculous. fracking PERMANENTLY removes that water from the consumable water table and makes it toxic. in MI the flow back water that comes up must be disposed of in class II deep injection wells and the rest stays down hole. it's an industry spin tactic: they want to say they use less water than hydro-electric or agriculture but what they DON'T tell you is that it's PERMANENTLY lost and poisoned, unlike other uses. farmers out west are now competing with gas and oil for water usage…who would you rather have water? someone who grows your food or somebody that will poison your water and leave your well dry?

Russ Klettke

September 9, 2013 at 1:23 pm

Tell us about the desalinization. What is just around the corner and what will it cost — and be sure to include the costs of transport of ocean water to inland fracking wells.
Count me skeptical. Particularly when we already have alternative renewable sources of energy that are technologically developed and increasingly used. Given how solar was first used in the 1950s, we probably could have made use of that a long time ago — but the idea of self-generated energy on the rooftops of homes and businesses cede WAY too much control away from large fossil fuel companies.

Mark Knowles

June 25, 2013 at 9:57 am

June 25, 2013 at 9:57 am

Come on local...and state officials...protect the environment...Don't sell it some Oklahoma based.company and the Chinese. Stop selling your sole and protect your people...the streams and lakes of Michigan are far more important than selling natural gas.

Jim Olson
June 25, 2013 at 10:37 am

Jeff and Center for Michigan. Thanks for publishing and distributing this widely. Citizen organizations, and policy organizations like FLOW **http://www.flowforwater.org** have been calling on MDNR and Natural Resources Commission to investigate and require baseline estimates of water withdrawals, diversions, transfers, and losses from the water cycle for over a year. DNR rejected any talks when approached last year to reform its leasing procedures and lease so that right to use necessary water would not transfer until development plan is submitted to MDNR for approval for areas of the state and state land, with estimates and consideration of water loss and community, farmers, landowners, and environmental impacts. It is the only legal and sensible way to address this issue, and must be done immediately before it is too late. MDEQ must not issue permits until all of this has been done, and effects and alternatives fully considered. The state lands and waters under them and running through them, are held by Michigan through DEQ and DNR as trustees for benefit of citizens, not the oil and gas industry. If fracking is allowed at such a large scale, and the jury is still out on this, it should and can only be done after careful pump tests, hydrogeological monitoring of actual flows and levels of streams, wetlands, lakes, groundwater. There is no other way to know what will happen. And if it is not done, it is plainly reckless.

Caroline B Smith
June 25, 2013 at 12:17 pm

What's another 3 or 4 million gallons? Nestle's is also taking a LOT of ground water out of Michigan and selling it back to us from WalMart and many other outlets. Just remember, "THE ONE WITH THE MOST FRESH WATER WINS."

Jeff Alexander
June 25, 2013 at 2:59 pm

Here's a little perspective: According to state data, Nestle's Ice Mountain water bottling plant near Big Rapids pumped 226 million gallons of groundwater last year. At that rate, it would take Nestle roughly 17 years to withdraw the 4 billion gallons of groundwater that Encana Corp. could withdraw and use at 500 natural gas wells that are hydraulically fractured.
State officials also point out that agricultural operations in Berrien County withdraw 10 million gallons of groundwater daily (averaged over the course of a year). At that rate, all of those farms could pump that amount of water (350 million gallons annually) for 11 years before equaling the amount of groundwater that Encana may use at its hydraulically fractured natural gas wells.
There is one other important point to consider, regardless of whether you think the 4 billion gallons of water that Encana might use is a drop in the bucket or a small lake: The vast majority of water used in fracking is left underground or discarded in deep injection wells because it is contaminated with chemicals. So while Traverse City uses 4 billion gallons of water annually, most of that water remains in the water cycle. It goes back into the ground, surface waters or the air after people use it.
Unless recycled, the water that fracking operations pump out of the ground and use to fracture deep shale is taken out of the local, regional or global water cycle. it's gone forever. Just saying.

Tom Matych
June 30, 2013 at 6:03 am

Good job Jeff. The part where there's enough water in the creek to dilute. Isn't this the same reasoning they used way back when for dumping waste from factories in our lakes and rivers? I don't see anything good from

fracking. My well is 166 feet deep. I have good water. they want to drill around here. I refused to sign the contract, my neighbor did sign. I'm 2 miles from the Muskegon river.

LuAnne Kozma
June 25, 2013 at 12:39 pm

The Committee to Ban Fracking in Michigan is conducting a ballot initiative petition drive to ban horizontal hydraulic fracturing to end this practice in Michigan, and to prevent frack wastes from being dumped here. Donate to the campaign and volunteer to collect signatures at: **http://www.letsbanfracking.org**.
We must protect our state from this threat. The water used in fracking is transformed into industrial waste, which is then "disposed of" in injection wells–back into our ground and eventually contaminating our aquifers.
–LuAnne Kozma, campaign director, Committee to Ban Fracking in Michigan

Neil
June 25, 2013 at 1:02 pm

Is it conceivable and feasible to have a water purification plant to process fracking water back to potable drinking water?

Bill
June 25, 2013 at 1:18 pm

Yes. Frack water could be brought back to an acceptable quality but there must be a disposal method for remaining concentrated effluent. Although the fact does not serve naysayer's purposes, water is an almost endlessly renewable resource if we make reasonable efforts.

Jeff Alexander
June 25, 2013 at 3:02 pm

Not likely. However, the water could be recycled and re-used, thereby reducing use. Encana officials said that fracking operations in the water-starved west and southwest recycle the water used to fracture deep shale deposits.

spudnik
June 25, 2013 at 3:19 pm

No. The process is built around exploiting a ton of water and walking away. This water is nothing you'd want to drink after processing. And once these wells start leaking massive amounts of pollutants into our groundwater, guessing these corporations will go out of business. We as a culture will need to wake up before it's too late, but the greed seems to have the upper hand now.

Nancy Shiffler
June 25, 2013 at 3:21 pm

When you run into problems you didn't "anticipate," it's a pretty good sign that it's time to step back and take a longer, more careful look at what you are doing before you start issuing more permits and drilling more wells. The DEQ isn't doing it's job.

Charles Richards
June 25, 2013 at 3:27 pm

"Encana officials said the oil and gas industry wants to export natural gas extracted from shale formations in Michigan and other states to consumers in Asia. Demand for natural gas in China is strong and prices are double the cost of natural gas in the U.S., industry, watchdogs said" This smacks of autarky, a policy that has been proven throughout history to be inimical to human welfare. If the rest of the article is of similar quality, and I suspect it is, then I don't place much value on it.

Mark L
June 25, 2013 at 5:56 pm

Interesting. A little geometry and one can visualize that the water it took to produce this well is about 1 acre (209 feet square) by 25 feet deep. At around 2.5 feet of precipitation per year in Michigan (NOAA), that would be the entire annual precipitation on 10 acres of land for a year to produce that well. 500 wells then would be 5000 acres or 7.8 square miles worth of annual precipitation out of a watershed to produce? It's not going to dry out the Great lakes, but its a lot of dirty water. The stuff is already toxic after well # 1, and the wells are usually clustered. Why can't it be filtered, reprocessed and re-used in the next hole? "because it's cheaper to inject it" doesn't seem like a very good answer…

Kerry Thompson
June 25, 2013 at 8:08 pm

For a publication that attempts to remain neutral you seem to be in "fear mongering overdrive". We are fracking in several places in Michigan without damage to the environment, We are helping the damaged economy and providing a product for a cost effective price. Benefactors are those land owners that receive dividends every month from the oil companies. Public agencies and charitable organizations are all receiving big dividends from fracking in Michigan. My good friend has a well drilled next to him and the horizontal fracking under him for over a year has not upset his ground water the level of his ponds his fish or his faucet (no gas fumes). The Boy Scout camp down the road has received more revenues from this well than from all of the donors public and private in the last two years combined.
Where are the articles that show the positive benefits of fracking in the state?

David Waymire
June 26, 2013 at 11:46 am

Kerry, the point here isn't that fracking is always bad…it's that it isn't always good, and can have major implications.That is indeed the very definition of neutral reporting, and is far, far from fear mongering.
The massive use of water detailed in this story is a huge change from the "old fracking" that used to consume maybe 100,000 gallons per well. Now we are talking hundreds of millions of gallons from one site, with potential implications for aquifers and small streams and rivers critical to the headwaters of our trout-friendly state. If that kind of withdrawal can be managed, that's one thing. If it is drying up wells, then it needs to be regulated much more strongly. And if it is affecting our blue ribbon trout streams, that needs to stop.

Jim Peters
June 26, 2013 at 2:44 pm

I think it is important to put a few things into perspective. First, it will take EnCana in my estimation 5 – 10 years or longer to drill the 500 wells and mcuh longer to get them completed and producing. More than likely a disposal well will be drilled on each pad or 1 disposal well located to handle several well pads and connected by pipelines eliminating the need to truck the water. Second, this moves EnCana from the explority phase into developement phase where economics of scale become very important. Third, these wells will likely be drilled over a fairly large geographical area (several different counties) on well pads that may contain 6 – 12 wells per pad. If water withdrawal becomes an issue then water recycling I'm sure will be used. EnCana is saying that they are seeing around 25% of the fracturing fluid returned to the surface so even if they recycle 100% of the returned fluid they will still need new water to continue. In Pennsylvania they are currently recycling 90% of the returned fluid. Pennsylvania has drilled now over 6,000 shale wells. Keep in mind that Pennsylvania has a very limited water supply and it's geology does not support deep disposal wells.

Jim Peters

June 26, 2013 at 3:40 pm

Nobody seems to want to discuss the economic impact of drilling 500 shale wells in the somewhat poor, rural areas of northern Michigan. Roughly, 500 wells at around $10 million per well works out to $5 billion dollars invested. Current unemployment rates in these counties range between 10 and 12%. Those rates would drop considerably not just for those counties but for all surrounding counties as well. It won't turn us into North Dakota where some McDonalds pay up to a $1,500.00 sign on bonus if you will stay for at least 2 weeks but the impact will be felt state wide. Local business will florish, families will move in including children for schools, local tax revenues will surge. The economic impact will last for at least a generation. But the water? We are blessed with a significant amount of fresh, clean water. More regulation needed? Possibly, but I believe it can be done in an environmentally safe matter as it is being done every day in Pennsylvania, North Dakota, Texas, Ohio, Colorado, Oklahoma, Arkansas, Louisiana, West Virginia and soon to be California and Illinois.

Brian W
June 30, 2013 at 11:21 pm

I agree with you Jim, There is a very negative spin here. None of the good that comes from this is being pointed out. I know I make a good living…. Most of the people working on these locations are local, EnCana is very conscious about the enviroment and the impact of its operations. Each person has "stop work authority" and are empowered to use it in the event of a safety or environmental concern. EnCana takes this VERY serious. There are wellbore integrity checks at regular intervals to ensure there will not be migration of fluids into the aquifer.
I also feel the protests are necessary… without them the industry would not be evolving to use safer fluids (Halliburton is a pioneer in fluids derived from the food industry). But big oil needs to know they are being watched.

Brian W
June 30, 2013 at 11:25 pm

This weekend was cherry festival too. I feel the tourism has a very profound effect on the environment. I know the garbage on 131 is up this weekend, is an airshow necessary or a waste of fuel? All the idiots on Torch lake, they dont care about the condition they leave the lakes in….

Tracy Davis
July 10, 2013 at 7:50 pm

Jim,
Nobody seems to want to discuss that while they think Fracking is such a horrible thing for our environment, they still keep driving their SUV's, ATV's, Snowmobiles, Boats etc.

acapoz
June 27, 2013 at 8:44 pm

once the drinking water is depleted, then what?
Fracking isn't about energy independence for Americans, its about profits for oil & gas. They will control the supply & demand to maximize profits. The cost Americans will have to pay in the end is the dependence on bottled water. Fracking will take the bottled water industry to the level of oil & gas profits. Once municipal water supply is depleted from fracking then Americans have no other source than bottled water. And you will pay more for water than for energy.

Kris Olsson
July 1, 2013 at 10:01 am

What is the timeline for a fracked well? Do they use the 8 million gallons or so all at once, or is it over the course of several fracking events? So, for a given well, over what period of time is the water consumed. Also, another question – in the state online records for oil and gas, is there a way to distinguish the newer hydro fracking type of drilling from the "regular" oil and gas well permitting/plays?

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trevor mcnamara
November 5, 2013 at 1:21 pm

frack fracking!

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gary Markley
November 14, 2013 at 9:15 am

its a no-brainer. Stop all fracking in the state of Michigan-I can't understand how Michiugan lets money-seeking idiots get away with this. It needs to be illegal.

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barbara
November 27, 2013 at 9:48 am

Hamilton Township in Clare Co. needs help. Besides being fracked recently, DCP Midstream wants to put a gas processing facility tucked right in among homes, farms, and a tourist area of lakes. Our township board says we will be sued if we try to stop this. How can you sue a whole community of people?!!! This facility would be the ruination of our area. Noise, increased traffic (trucks), odors, ground water contamination (everyone here is dependent on well water), an unsightly thing for a tourist area, nearby trout streams, etc. and , of course, air pollution are just a few of our concerns. If this facility has to be it should be away from families and farms. We invite anyone who has the time and the concern to write to our local newspapers. The Clare County Cleaver and The Clare Review accept editorials readily on line. We are a poor community and can not fight this alone. Thank you in advance and God bless……..

The White House

Office of the Press Secretary

For Immediate Release January 24, 2012

Remarks by the President in State of the Union Address

United States Capitol
Washington, D.C.

9:10 P.M. EST

THE PRESIDENT: Mr. Speaker, Mr. Vice President, members of Congress, distinguished guests, and fellow Americans:

Last month, I went to Andrews Air Force Base and welcomed home some of our last troops to serve in Iraq. Together, we offered a final, proud salute to the colors under which more than a million of our fellow citizens fought -- and several thousand gave their lives.

We gather tonight knowing that this generation of heroes has made the United States safer and more respected around the world. (Applause.) For the first time in nine years, there are no Americans fighting in Iraq. (Applause.) For the first time in two decades, Osama bin Laden is not a threat to this country. (Applause.) Most of al Qaeda's top lieutenants have been defeated. The Taliban's momentum has been broken, and some troops in Afghanistan have begun to come home.

These achievements are a testament to the courage, selflessness and teamwork of America's Armed Forces. At a time when too many of our institutions have let us down, they exceed all expectations. They're not consumed with personal ambition. They don't obsess over their differences. They focus on the mission at hand. They work together.

Imagine what we could accomplish if we followed their example. (Applause.) Think about the America within our reach: A country that leads the world in educating its people. An America that attracts a new generation of high-tech manufacturing and high-paying jobs. A future where we're in control of our own energy, and our security and prosperity aren't so tied to unstable parts of the world. An economy built to last, where hard work pays off, and responsibility is rewarded.

We can do this. I know we can, because we've done it before. At the end of World War II, when another generation of heroes returned home from combat, they built the strongest economy and middle class the world has ever known. (Applause.) My grandfather, a veteran of Patton's Army, got the chance to go to college on the GI Bill. My grandmother, who worked on a bomber assembly line, was part of a workforce that turned out the best products on Earth.

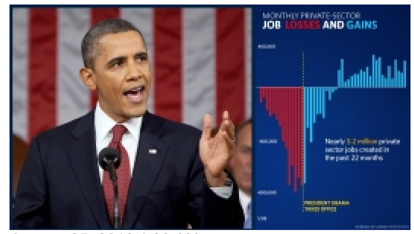
The two of them shared the optimism of a nation that had triumphed over a depression and fascism. They understood they were part of something larger; that they were contributing to a story of success that every American had a chance to share -- the basic American promise that if you worked hard, you could do well enough to raise a family, own a home, send your kids to college, and put a little away for retirement.

The defining issue of our time is how to keep that promise alive. No challenge is more urgent. No debate is more important. We can either settle for a country where a shrinking number of people do really well while a growing number of Americans barely get by, or we can restore an economy where everyone gets a fair shot, and everyone does their fair share, and everyone plays by the same set of rules. (Applause.) What's at stake aren't Democratic values or Republican values, but American values. And we have to reclaim them.

Let's remember how we got here. Long before the recession, jobs and manufacturing began leaving our shores. Technology made businesses more efficient, but also made some jobs obsolete. Folks at the top saw their incomes rise like never before, but most hardworking Americans struggled with costs that were growing, paychecks that weren't, and personal debt that kept piling up.

In 2008, the house of cards collapsed. We learned that mortgages had been sold to people who couldn't afford

WATCH THE VIDEO



January 25, 2012 1:30 AM

2012 State Of The Union Address Enhanced Version

BLOG POSTS ON THIS ISSUE

May 19, 2013 4:33 PM EDT

President Obama Delivers the Commencement Address at Morehouse College

President Obama delivers the commencement address to the 2013 graduates of Morehouse College in Atlanta, GA.

May 18, 2013 7:30 PM EDT

First Lady Delivers Commencement Addresses at Bowie State, Martin Luther King Jr. Magnet High School

First Lady Michelle Obama delivers the commencement addresses at Bowie State University and Martin Luther King Jr. Magnet High School.

May 18, 2013 6:00 AM EDT

Weekly Address: The President Talks About How to Build a Rising, Thriving Middle Class

President Obama talks about his belief that a rising, thriving middle class is the true engine of economic growth, and that to reignite that engine

or understand them. Banks had made huge bets and bonuses with other people's money. Regulators had looked the other way, or didn't have the authority to stop the bad behavior.

It was wrong. It was irresponsible. And it plunged our economy into a crisis that put millions out of work, saddled us with more debt, and left innocent, hardworking Americans holding the bag. In the six months before I took office, we lost nearly 4 million jobs. And we lost another 4 million before our policies were in full effect.

Those are the facts. But so are these: In the last 22 months, businesses have created more than 3 million jobs. (Applause.)

Last year, they created the most jobs since 2005. American manufacturers are hiring again, creating jobs for the first time since the late 1990s. Together, we've agreed to cut the deficit by more than $2 trillion. And we've put in place new rules to hold Wall Street accountable, so a crisis like this never happens again. (Applause.)

The state of our Union is getting stronger. And we've come too far to turn back now. As long as I'm President, I will work with anyone in this chamber to build on this momentum. But I intend to fight obstruction with action, and I will oppose any effort to return to the very same policies that brought on this economic crisis in the first place. (Applause.)

No, we will not go back to an economy weakened by outsourcing, bad debt, and phony financial profits. Tonight, I want to speak about how we move forward, and lay out a blueprint for an economy that's built to last -– an economy built on American manufacturing, American energy, skills for American workers, and a renewal of American values.

Now, this blueprint begins with American manufacturing.

On the day I took office, our auto industry was on the verge of collapse. Some even said we should let it die. With a million jobs at stake, I refused to let that happen. In exchange for help, we demanded responsibility. We got workers and automakers to settle their differences. We got the industry to retool and restructure. Today, General Motors is back on top as the world's number-one automaker. (Applause.) Chrysler has grown faster in the U.S. than any major car company. Ford is investing billions in U.S. plants and factories. And together, the entire industry added nearly 160,000 jobs.

We bet on American workers. We bet on American ingenuity. And tonight, the American auto industry is back. (Applause.)

What's happening in Detroit can happen in other industries. It can happen in Cleveland and Pittsburgh and Raleigh. We can't bring every job back that's left our shore. But right now, it's getting more expensive to do business in places like China. Meanwhile, America is more productive. A few weeks ago, the CEO of Master Lock told me that it now makes business sense for him to bring jobs back home. (Applause.) Today, for the first time in 15 years, Master Lock's unionized plant in Milwaukee is running at full capacity. (Applause.)

So we have a huge opportunity, at this moment, to bring manufacturing back. But we have to seize it. Tonight, my message to business leaders is simple: Ask yourselves what you can do to bring jobs back to your country, and your country will do everything we can to help you succeed. (Applause.)

We should start with our tax code. Right now, companies get tax breaks for moving jobs and profits overseas. Meanwhile, companies that choose to stay in America get hit with one of the highest tax rates in the world. It makes no sense, and everyone knows it. So let's change it.

First, if you're a business that wants to outsource jobs, you shouldn't get a tax deduction for doing it. (Applause.) That money should be used to cover moving expenses for companies like Master Lock that decide to bring jobs home. (Applause.)

Second, no American company should be able to avoid paying its fair share of taxes by moving jobs and profits overseas. (Applause.) From now on, every multinational company should have to pay a basic minimum tax. And every penny should go towards lowering taxes for companies that choose to stay here and hire here in America. (Applause.)

Third, if you're an American manufacturer, you should get a bigger tax cut. If you're a high-tech manufacturer, we should double the tax deduction you get for making your products here. And if you want to relocate in a community that was hit hard when a factory left town, you should get help financing a new plant, equipment, or training for new workers. (Applause.)

So my message is simple. It is time to stop rewarding businesses that ship jobs overseas, and start rewarding companies that create jobs right here in America. Send me these tax reforms, and I will sign them right away. (Applause.)

We're also making it easier for American businesses to sell products all over the world. Two years ago, I set a goal of doubling U.S. exports over five years. With the bipartisan trade agreements we signed into law, we're on track to meet that goal ahead of schedule. (Applause.) And soon, there will be millions of new customers for American goods in Panama, Colombia, and South Korea. Soon, there will be new cars on the streets of Seoul imported from Detroit, and Toledo, and Chicago. (Applause.)

I will go anywhere in the world to open new markets for American products. And I will not stand by when our competitors don't play by the rules. We've brought trade cases against China at nearly twice the rate as the last administration –- and it's made a difference. (Applause.) Over a thousand Americans are working today because we stopped a surge in Chinese tires. But we need to do more. It's not right when another country lets our movies, music, and software be pirated. It's not fair when foreign manufacturers have a leg up on ours only because they're heavily subsidized.

Tonight, I'm announcing the creation of a Trade Enforcement Unit that will be charged with investigating unfair trading practices in countries like China. (Applause.) There will be more inspections to prevent counterfeit or unsafe goods from crossing our borders. And this Congress should make sure that no foreign company has an advantage over American manufacturing when it comes to accessing financing or new markets like Russia. Our workers are the most productive on Earth, and if the playing field is level, I promise you -— America will always win. (Applause.)

I also hear from many business leaders who want to hire in the United States but can't find workers with the right skills. Growing industries in science and technology have twice as many openings as we have workers who can do the job. Think about that –- openings at a time when millions of Americans are looking for work. It's inexcusable. And we know how to fix it.

Jackie Bray is a single mom from North Carolina who was laid off from her job as a mechanic. Then Siemens opened a gas turbine factory in Charlotte, and formed a partnership with Central Piedmont Community College. The company helped the college design courses in laser and robotics training. It paid Jackie's tuition, then hired her to help operate their plant.

I want every American looking for work to have the same opportunity as Jackie did. Join me in a national commitment to train 2 million Americans with skills that will lead directly to a job. (Applause.) My administration has already lined up more companies that want to help. Model partnerships between businesses like Siemens and community colleges in places like Charlotte, and Orlando, and Louisville are up and running. Now you need to give more community colleges the resources they need to become community career centers -— places that teach people skills that businesses are looking for right now, from data management to high-tech manufacturing.

And I want to cut through the maze of confusing training programs, so that from now on, people like Jackie have one program, one website, and one place to go for all the information and help that they need. It is time to turn our unemployment system into a reemployment system that puts people to work. (Applause.)

These reforms will help people get jobs that are open today. But to prepare for the jobs of tomorrow, our commitment to skills and education has to start earlier.

For less than 1 percent of what our nation spends on education each year, we've convinced nearly every state in the country to raise their standards for teaching and learning -- the first time that's happened in a generation.

But challenges remain. And we know how to solve them.

At a time when other countries are doubling down on education, tight budgets have forced states to lay off thousands of teachers. We know a good teacher can increase the lifetime income of a classroom by over $250,000. A great teacher can offer an escape from poverty to the child who dreams beyond his circumstance. Every person in this chamber can point to a teacher who changed the trajectory of their lives. Most teachers work tirelessly, with modest pay, sometimes digging into their own pocket for school supplies -- just to make a difference.

Teachers matter. So instead of bashing them, or defending the status quo, let's offer schools a deal. Give them the resources to keep good teachers on the job, and reward the best ones. (Applause.) And in return, grant schools flexibility: to teach with creativity and passion; to stop teaching to the test; and to replace teachers who just aren't helping kids learn. That's a bargain worth making. (Applause.)

We also know that when students don't walk away from their education, more of them walk the stage to get their diploma. When students are not allowed to drop out, they do better. So tonight, I am proposing that every state -- every state -- requires that all students stay in high school until they graduate or turn 18. (Applause.)

When kids do graduate, the most daunting challenge can be the cost of college. At a time when Americans owe more in tuition debt than credit card debt, this Congress needs to stop the interest rates on student loans from doubling in July. (Applause.)

Extend the tuition tax credit we started that saves millions of middle-class families thousands of dollars, and give more young people the chance to earn their way through college by doubling the number of work-study jobs in the next five years. (Applause.)

Of course, it's not enough for us to increase student aid. We can't just keep subsidizing skyrocketing tuition; we'll run out of money. States also need to do their part, by making higher education a higher priority in their budgets. And colleges and universities have to do their part by working to keep costs down.

Recently, I spoke with a group of college presidents who've done just that. Some schools redesign courses to help students finish more quickly. Some use better technology. The point is, it's possible. So let me put colleges and universities on notice: If you can't stop tuition from going up, the funding you get from taxpayers will go down. (Applause.) Higher education can't be a luxury -– it is an economic imperative that every family in America should be able to afford.

Let's also remember that hundreds of thousands of talented, hardworking students in this country face another challenge: the fact that they aren't yet American citizens. Many were brought here as small children, are American through and through, yet they live every day with the threat of deportation. Others came more recently, to study business and science and engineering, but as soon as they get their degree, we send them home to invent new products and create new jobs somewhere else.

That doesn't make sense.

I believe as strongly as ever that we should take on illegal immigration. That's why my administration has put more boots on the border than ever before. That's why there are fewer illegal crossings than when I took office. The opponents of action are out of excuses. We should be working on comprehensive immigration reform right now. (Applause.)

But if election-year politics keeps Congress from acting on a comprehensive plan, let's at least agree to stop expelling responsible young people who want to staff our labs, start new businesses, defend this country. Send me a law that gives them the chance to earn their citizenship. I will sign it right away. (Applause.)

You see, an economy built to last is one where we encourage the talent and ingenuity of every person in this country. That means women should earn equal pay for equal work. (Applause.) It means we should support everyone who's willing to work, and every risk-taker and entrepreneur who aspires to become the next Steve Jobs.

After all, innovation is what America has always been about. Most new jobs are created in start-ups and small businesses. So let's pass an agenda that helps them succeed. Tear down regulations that prevent aspiring entrepreneurs from getting the financing to grow. (Applause.) Expand tax relief to small businesses that are raising wages and creating good jobs. Both parties agree on these ideas. So put them in a bill, and get it on my desk this year. (Applause.)

Innovation also demands basic research. Today, the discoveries taking place in our federally financed labs and universities could lead to new treatments that kill cancer cells but leave healthy ones untouched. New lightweight vests for cops and soldiers that can stop any bullet. Don't gut these investments in our budget. Don't let other countries win the race for the future. Support the same kind of research and innovation that led to the computer chip and the Internet; to new American jobs and new American industries.

And nowhere is the promise of innovation greater than in American-made energy. Over the last three years, we've opened millions of new acres for oil and gas exploration, and tonight, I'm directing my administration to open more than 75 percent of our potential offshore oil and gas resources. (Applause.) Right now -- right now -- American oil production is the highest that it's been in eight years. That's right -- eight years. Not only that -- last year, we relied less on foreign oil than in any of the past 16 years. (Applause.)

But with only 2 percent of the world's oil reserves, oil isn't enough. This country needs an all-out, all-of-the-above strategy that develops every available source of American energy. (Applause.) A strategy that's cleaner, cheaper, and full of new jobs.

We have a supply of natural gas that can last America nearly 100 years. (Applause.) And my administration will take every possible action to safely develop this energy. Experts believe this will support more than 600,000 jobs by the end of the decade. And I'm requiring all companies that drill for gas on public lands to disclose the chemicals they use. (Applause.) Because America will develop this resource without putting the health and safety of our citizens at risk.

The development of natural gas will create jobs and power trucks and factories that are cleaner and cheaper, proving that we don't have to choose between our environment and our economy. (Applause.) And by the way, it was public research dollars, over the course of 30 years, that helped develop the technologies to extract all this natural gas out of shale rock –- reminding us that government support is critical in helping businesses get new energy ideas off the ground. (Applause.)

Now, what's true for natural gas is just as true for clean energy. In three years, our partnership with the private sector has already positioned America to be the world's leading manufacturer of high-tech batteries. Because of federal investments, renewable energy use has nearly doubled, and thousands of Americans have jobs because of it.

When Bryan Ritterby was laid off from his job making furniture, he said he worried that at 55, no one would give him a second chance. But he found work at Energetx, a wind turbine manufacturer in Michigan. Before the recession, the factory only made luxury yachts. Today, it's hiring workers like Bryan, who said, "I'm proud to be working in the industry of the future."

Our experience with shale gas, our experience with natural gas, shows us that the payoffs on these public investments don't always come right away. Some technologies don't pan out; some companies fail. But I will not walk away from the promise of clean energy. I will not walk away from workers like Bryan. (Applause.) I will not cede the wind or solar or battery industry to China or Germany because we refuse to make the same commitment here.

We've subsidized oil companies for a century. That's long enough. (Applause.) It's time to end the taxpayer giveaways to an industry that rarely has been more profitable, and double-down on a clean energy industry that never has been more promising. Pass clean energy tax credits. Create these jobs. (Applause.)

We can also spur energy innovation with new incentives. The differences in this chamber may be too deep right now to pass a comprehensive plan to fight climate change. But there's no reason why Congress shouldn't at least set a clean energy standard that creates a market for innovation. So far, you haven't acted. Well, tonight, I will. I'm directing my administration to allow the development of clean energy on enough public land to power 3 million homes. And I'm proud to announce that the Department of Defense, working with us, the world's largest consumer of energy, will make one of the largest commitments to clean energy in history -– with the Navy purchasing enough capacity to power a quarter of a million homes a year. (Applause.)

Of course, the easiest way to save money is to waste less energy. So here's a proposal: Help manufacturers eliminate energy waste in their factories and give businesses incentives to upgrade their buildings. Their energy bills will be $100 billion lower over the next decade, and America will have less pollution, more manufacturing, more jobs for construction workers who need them. Send me a bill that creates these jobs. (Applause.)

Building this new energy future should be just one part of a broader agenda to repair America's infrastructure. So much of America needs to be rebuilt. We've got crumbling roads and bridges; a power grid that wastes too much energy; an incomplete high-speed broadband network that prevents a small business owner in rural America from selling her products all over the world.

During the Great Depression, America built the Hoover Dam and the Golden Gate Bridge. After World War II, we connected our states with a system of highways. Democratic and Republican administrations invested in great projects that benefited everybody, from the workers who built them to the businesses that still use them today.

In the next few weeks, I will sign an executive order clearing away the red tape that slows down too many construction projects. But you need to fund these projects. Take the money we're no longer spending at war, use half of it to pay down our debt, and use the rest to do some nation-building right here at home. (Applause.)

There's never been a better time to build, especially since the construction industry was one of the hardest hit when the housing bubble burst. Of course, construction workers weren't the only ones who were hurt. So were millions of innocent Americans who've seen their home values decline. And while government can't fix the problem on its own, responsible homeowners shouldn't have to sit and wait for the housing market to hit bottom to get some relief.

And that's why I'm sending this Congress a plan that gives every responsible homeowner the chance to save about $3,000 a year on their mortgage, by refinancing at historically low rates. (Applause.) No more red tape. No more runaround from the banks. A small fee on the largest financial institutions will ensure that it won't add to the deficit and will give those banks that were rescued by taxpayers a chance to repay a deficit of trust. (Applause.)

Let's never forget: Millions of Americans who work hard and play by the rules every day deserve a government and a financial system that do the same. It's time to apply the same rules from top to bottom. No bailouts, no handouts, and no copouts. An America built to last insists on responsibility from everybody.

We've all paid the price for lenders who sold mortgages to people who couldn't afford them, and buyers who knew they couldn't afford them. That's why we need smart regulations to prevent irresponsible behavior. (Applause.) Rules to prevent financial fraud or toxic dumping or faulty medical devices -- these don't destroy the free market. They make the free market work better.

There's no question that some regulations are outdated, unnecessary, or too costly. In fact, I've approved fewer regulations in the first three years of my presidency than my Republican predecessor did in his. (Applause.) I've ordered every federal agency to eliminate rules that don't make sense. We've already announced over 500 reforms, and just a fraction of them will save business and citizens more than $10 billion over the next five years. We got rid of one rule from 40 years ago that could have forced some dairy farmers to spend $10,000 a year proving that they could contain a spill -- because milk was somehow classified as an oil. With a rule like that, I guess it was worth crying over spilled milk. (Laughter and applause.)

Now, I'm confident a farmer can contain a milk spill without a federal agency looking over his shoulder. (Applause.) Absolutely. But I will not back down from making sure an oil company can contain the kind of oil spill we saw in the Gulf two years ago. (Applause.) I will not back down from protecting our kids from mercury poisoning, or making sure that our food is safe and our water is clean. I will not go back to the days when health insurance companies had unchecked power to cancel your policy, deny your coverage, or charge women differently than men. (Applause.)

And I will not go back to the days when Wall Street was allowed to play by its own set of rules. The new rules we passed restore what should be any financial system's core purpose: Getting funding to entrepreneurs with the best ideas, and getting loans to responsible families who want to buy a home, or start a business, or send their kids to college.

So if you are a big bank or financial institution, you're no longer allowed to make risky bets with your customers' deposits. You're required to write out a "living will" that details exactly how you'll pay the bills if you fail –- because the rest of us are not bailing you out ever again. (Applause.) And if you're a mortgage lender or a payday lender or a credit card company, the days of signing people up for products they can't afford with confusing forms and deceptive practices -- those days are over. Today, American consumers finally have a watchdog in Richard Cordray with one job: To look out for them. (Applause.)

We'll also establish a Financial Crimes Unit of highly trained investigators to crack down on large-scale fraud and protect people's investments. Some financial firms violate major anti-fraud laws because there's no real penalty for being a repeat offender. That's bad for consumers, and it's bad for the vast majority of bankers and financial service professionals who do the right thing. So pass legislation that makes the penalties for fraud count.

And tonight, I'm asking my Attorney General to create a special unit of federal prosecutors and leading state attorney general to expand our investigations into the abusive lending and packaging of risky mortgages that led to the housing crisis. (Applause.) This new unit will hold accountable those who broke the law, speed assistance to homeowners, and help turn the page on an era of recklessness that hurt so many Americans.

Now, a return to the American values of fair play and shared responsibility will help protect our people and our economy. But it should also guide us as we look to pay down our debt and invest in our future.

Right now, our most immediate priority is stopping a tax hike on 160 million working Americans while the recovery is still fragile. (Applause.) People cannot afford losing $40 out of each paycheck this year. There are plenty of ways to get this done. So let's agree right here, right now: No side issues. No drama. Pass the payroll tax cut without delay. Let's get it done. (Applause.)

When it comes to the deficit, we've already agreed to more than $2 trillion in cuts and savings. But we need to do more, and that means making choices. Right now, we're poised to spend nearly $1 trillion more on what was supposed to be a temporary tax break for the wealthiest 2 percent of Americans. Right now, because of loopholes and shelters in the tax code, a quarter of all millionaires pay lower tax rates than millions of middle-class households. Right now, Warren Buffett pays a lower tax rate than his secretary.

Do we want to keep these tax cuts for the wealthiest Americans? Or do we want to keep our investments in everything else –- like education and medical research; a strong military and care for our veterans? Because if we're serious about paying down our debt, we can't do both.

The American people know what the right choice is. So do I. As I told the Speaker this summer, I'm prepared to make more reforms that rein in the long-term costs of Medicare and Medicaid, and strengthen Social Security, so long as those programs remain a guarantee of security for seniors.

But in return, we need to change our tax code so that people like me, and an awful lot of members of Congress, pay our fair share of taxes. (Applause.)

Tax reform should follow the Buffett Rule. If you make more than $1 million a year, you should not pay less than 30 percent in taxes. And my Republican friend Tom Coburn is right: Washington should stop subsidizing millionaires. In fact, if you're earning a million dollars a year, you shouldn't get special tax subsidies or deductions. On the other hand, if you make under $250,000 a year, like 98 percent of American families, your taxes shouldn't go up. (Applause.) You're the ones struggling with rising costs and stagnant wages. You're the ones who need relief.

Now, you can call this class warfare all you want. But asking a billionaire to pay at least as much as his secretary in taxes? Most Americans would call that common sense.

We don't begrudge financial success in this country. We admire it. When Americans talk about folks like me paying my fair share of taxes, it's not because they envy the rich. It's because they understand that when I get a tax break I don't need and the country can't afford, it either adds to the deficit, or somebody else has to make up the difference -- like a senior on a fixed income, or a student trying to get through school, or a family trying to make ends meet. That's not right. Americans know that's not right. They know that this generation's success is only possible because past generations felt a responsibility to each other, and to the future of their country, and they know our way of life will only endure if we feel that same sense of shared responsibility. That's how we'll reduce our deficit. That's an America built to last. (Applause.)

Now, I recognize that people watching tonight have differing views about taxes and debt, energy and health care. But no matter what party they belong to, I bet most Americans are thinking the same thing right about now: Nothing will get done in Washington this year, or next year, or maybe even the year after that, because Washington is broken.

Can you blame them for feeling a little cynical?

The greatest blow to our confidence in our economy last year didn't come from events beyond our control. It came from a debate in Washington over whether the United States would pay its bills or not. Who benefited from that fiasco?

I've talked tonight about the deficit of trust between Main Street and Wall Street. But the divide between this city and the rest of the country is at least as bad -- and it seems to get worse every year.

Some of this has to do with the corrosive influence of money in politics. So together, let's take some steps to fix that. Send me a bill that bans insider trading by members of Congress; I will sign it tomorrow. (Applause.) Let's limit any elected official from owning stocks in industries they impact. Let's make sure people who bundle campaign contributions for Congress can't lobby Congress, and vice versa -- an idea that has bipartisan support, at least outside of Washington.

Some of what's broken has to do with the way Congress does its business these days. A simple majority is no longer enough to get anything -– even routine business –- passed through the Senate. (Applause.) Neither party has been blameless in these tactics. Now both parties should put an end to it. (Applause.) For starters, I ask the Senate to pass a simple rule that all judicial and public service nominations receive a simple up or down vote within 90 days. (Applause.)

The executive branch also needs to change. Too often, it's inefficient, outdated and remote. (Applause.) That's why I've asked this Congress to grant me the authority to consolidate the federal bureaucracy, so that our government is leaner, quicker, and more responsive to the needs of the American people. (Applause.)

Finally, none of this can happen unless we also lower the temperature in this town. We need to end the notion that the two parties must be locked in a perpetual campaign of mutual destruction; that politics is about clinging to rigid ideologies instead of building consensus around common-sense ideas.

I'm a Democrat. But I believe what Republican Abraham Lincoln believed: That government should do for people only what they cannot do better by themselves, and no more. (Applause.) That's why my education reform offers more competition, and more control for schools and states. That's why we're getting rid of regulations that don't work. That's why our health care law relies on a reformed private market, not a government program.

On the other hand, even my Republican friends who complain the most about government spending have supported federally financed roads, and clean energy projects, and federal offices for the folks back home.

The point is, we should all want a smarter, more effective government. And while we may not be able to bridge our biggest philosophical differences this year, we can make real progress. With or without this Congress, I will keep taking actions that help the economy grow. But I can do a whole lot more with your help. Because when we act together, there's nothing the United States of America can't achieve. (Applause.) That's the lesson we've learned from our actions abroad over the last few years.

Ending the Iraq war has allowed us to strike decisive blows against our enemies. From Pakistan to Yemen, the al Qaeda operatives who remain are scrambling, knowing that they can't escape the reach of the United States of America. (Applause.)

From this position of strength, we've begun to wind down the war in Afghanistan. Ten thousand of our troops have come home. Twenty-three thousand more will leave by the end of this summer. This transition to Afghan lead will continue, and we will build an enduring partnership with Afghanistan, so that it is never again a source of attacks against America. (Applause.)

As the tide of war recedes, a wave of change has washed across the Middle East and North Africa, from Tunis to Cairo; from Sana'a to Tripoli. A year ago, Qaddafi was one of the world's longest-serving dictators -– a murderer with American blood on his hands. Today, he is gone. And in Syria, I have no doubt that the Assad regime will soon discover that the forces of change cannot be reversed, and that human dignity cannot be denied. (Applause.)

How this incredible transformation will end remains uncertain. But we have a huge stake in the outcome. And while it's ultimately up to the people of the region to decide their fate, we will advocate for those values that have served our own country so well. We will stand against violence and intimidation. We will stand for the rights and dignity of all human beings –- men and women; Christians, Muslims and Jews. We will support policies that lead to strong and stable democracies and open markets, because tyranny is no match for liberty.

And we will safeguard America's own security against those who threaten our citizens, our friends, and our interests. Look at Iran. Through the power of our diplomacy, a world that was once divided about how to deal with Iran's nuclear program now stands as one. The regime is more isolated than ever before; its leaders are faced with crippling sanctions, and as long as they shirk their responsibilities, this pressure will not relent.

Let there be no doubt: America is determined to prevent Iran from getting a nuclear weapon, and I will take no options off the table to achieve that goal. (Applause.)

But a peaceful resolution of this issue is still possible, and far better, and if Iran changes course and meets its obligations, it can rejoin the community of nations.

The renewal of American leadership can be felt across the globe. Our oldest alliances in Europe and Asia are stronger than ever. Our ties to the Americas are deeper. Our ironclad commitment -- and I mean ironclad -- to Israel's security has meant the closest military cooperation between our two countries in history. (Applause.)

We've made it clear that America is a Pacific power, and a new beginning in Burma has lit a new hope. From the coalitions we've built to secure nuclear materials, to the missions we've led against hunger and disease; from the blows we've dealt to our enemies, to the enduring power of our moral example, America is back.

Anyone who tells you otherwise, anyone who tells you that America is in decline or that our influence has waned, doesn't know what they're talking about. (Applause.)

That's not the message we get from leaders around the world who are eager to work with us. That's not how people feel from Tokyo to Berlin, from Cape Town to Rio, where opinions of America are higher than they've been in years. Yes, the world is changing. No, we can't control every event. But America remains the one indispensable nation in world affairs –- and as long as I'm President, I intend to keep it that way. (Applause.)

That's why, working with our military leaders, I've proposed a new defense strategy that ensures we maintain the finest military in the world, while saving nearly half a trillion dollars in our budget. To stay one step ahead of our adversaries, I've already sent this Congress legislation that will secure our country from the growing dangers of cyber-threats. (Applause.)

Above all, our freedom endures because of the men and women in uniform who defend it. (Applause.) As they come home, we must serve them as well as they've served us. That includes giving them the care and the benefits they have earned –- which is why we've increased annual VA spending every year I've been President. (Applause.) And it means enlisting our veterans in the work of rebuilding our nation.

With the bipartisan support of this Congress, we're providing new tax credits to companies that hire vets. Michelle and Jill Biden have worked with American businesses to secure a pledge of 135,000 jobs for veterans and their families. And tonight, I'm proposing a Veterans Jobs Corps that will help our communities hire veterans as cops and firefighters, so that America is as strong as those who defend her. (Applause.)

Which brings me back to where I began. Those of us who've been sent here to serve can learn a thing or two from the service of our troops. When you put on that uniform, it doesn't matter if you're black or white; Asian, Latino, Native American; conservative, liberal; rich, poor; gay, straight. When you're marching into battle, you look out for the person next to you, or the mission fails. When you're in the thick of the fight, you rise or fall as one unit, serving one nation, leaving no one behind.

One of my proudest possessions is the flag that the SEAL Team took with them on the mission to get bin Laden. On it are each of their names. Some may be Democrats. Some may be Republicans. But that doesn't matter. Just like it didn't matter that day in the Situation Room, when I sat next to Bob Gates -- a man who was George Bush's defense secretary -- and Hillary Clinton -- a woman who ran against me for president.

All that mattered that day was the mission. No one thought about politics. No one thought about themselves. One of the young men involved in the raid later told me that he didn't deserve credit for the mission. It only succeeded, he said, because every single member of that unit did their job -- the pilot who landed the helicopter that spun out of control; the translator who kept others from entering the compound; the troops who separated the women and children from the fight; the SEALs who charged up the stairs. More than that, the mission only succeeded because every member of that unit trusted each other -- because you can't charge up those stairs, into darkness and danger, unless you know that there's somebody behind you, watching your back.

So it is with America. Each time I look at that flag, I'm reminded that our destiny is stitched together like those 50 stars and those 13 stripes. No one built this country on their own. This nation is great because we built it together. This nation is great because we worked as a team. This nation is great because we get each other's backs. And if we hold fast to that truth, in this moment of trial, there is no challenge too great; no mission too hard. As long as we are joined in common purpose, as long as we maintain our common resolve, our journey moves forward, and our future is hopeful, and the state of our Union will always be strong.

Thank you, God bless you, and God bless the United States of America. (Applause.)

END
10:16 P.M. EST

Learn more

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The White House

Office of the Press Secretary

For Immediate Release December 10, 2012

Remarks by the President at the Daimler Detroit Diesel Plant, Redford, MI

Daimler Detroit Diesel Plant
Redford, Michigan

2:29 P.M. EST

THE PRESIDENT: Hello, Redford! (Applause.) It is good to be back in Michigan. (Applause.) How is everybody doing today? (Applause.)

Now, let me just start off by saying we have something in common -- both our teams lost yesterday. (Laughter.) I mean, I would like to come here and talk a little smack about the Bears, but we didn't quite get it done. But it is wonderful to be back. It is good to see everybody in the great state of Michigan. (Applause.)

A few people I want to acknowledge -- first of all, the Mayor of Detroit here -- Dave Bing is in the house. (Applause.) We've got the Redford Supervisor -- Tracey Schultz Kobylarz. (Applause.) We've got some outstanding members of Congress who are here -- please give them a big round of applause. (Applause.)

I want to thank Martin for hosting us. I want to thank Jeff and Gibby for giving me a great tour of the factory. (Applause.) I've got to say I love coming to factories.

AUDIENCE MEMBER: I love you!

THE PRESIDENT: I love you. (Applause.)

So in addition to seeing the best workers in the world -- (applause) -- you've also got all this cool equipment. (Laughter.) I wanted to try out some of the equipment, but Secret Service wouldn't let me. (Laughter.) They said, you're going to drop something on your head, hurt yourself. (Laughter.) They were worried I'd mess something up. And Jeff and Gibby may not admit it, but I think they were pretty happy the Secret Service wouldn't let me touch the equipment. (Laughter.)

Now, it's been a little over a month since the election came to an end. (Applause.) So it's now safe for you to turn your televisions back on. (Laughter.) All those scary political ads are off the air. You can answer your phone again -- nobody is calling you in the middle of dinner asking for your support. But, look, I have to admit there's one part of the campaign that I miss, and that is it is a great excuse for me to get out of Washington and come to towns like this and talk to the people who work so hard every day and are looking out for their families and are in their communities, and just having a conversation about what kind of country do we want to be; what kind of country do we want to leave behind for our kids. Because ultimately, that's what this is about.

And I believe -- and I've been saying this not just for the last six months or the last year, but ever since I got into public office -- I believe America only succeeds and thrives when we've got a strong and growing middle class. (Applause.) That's what I believe. I believe we're at our best when everybody who works hard has a chance to get ahead; that they can get a job that pays the bills; that they've got health care that they can count on; that they can retire with dignity and respect, maybe take a vacation once in a while -- nothing fancy, just being able to pack up the kids and go someplace and enjoy time with people that you love; make sure that your kids can go to a good school; make sure they can aspire to whatever they want to be.

That idea is what built America. That's the idea that built Michigan. That's the idea that's at the heart of the economic plan I've been talking about all year long on the campaign trail. I want to give more Americans the chance to earn the skills that businesses are looking for right now, and give our kids the kind of education they need to succeed in the 21st century. I want to make sure America leads the world in research and technology and clean energy. I want to put people back to work rebuilding our roads and our bridges and our schools. (Applause.) That's how we grow an economy.

WATCH THE VIDEO

December 10, 2012 10:12 PM

President Obama Speaks on the Economy and Middle-Class Tax Cuts

BLOG POSTS ON THIS ISSUE

August 10, 2013 6:22 PM EDT

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The President and First Lady deliver remarks to open the 2013 Disabled American Veterans National Convention in Orlando, FL.

August 10, 2013 6:00 AM EDT

Weekly Address: A Better Bargain for Responsible, Middle Class Homeowners

In this week's address, President Obama says that the housing market is starting to heal, and now it's time to build on that progress by creating a better bargain for responsible, middle-class homeowners.

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I want us to bring down our deficits, but I want to do it in a balanced, responsible way. And I want to reward -- I want a tax code that rewards businesses and manufacturers like Detroit Diesel right here, creating jobs right here in Redford, right here in Michigan, right here in the United States of America. (Applause.) That's where we need to go. That's the country we need to build. And when it comes to bringing manufacturing back to America -- that's why I'm here today.

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Since 1938, Detroit Diesel has been turning out some of the best engines in the world. (Applause.) Over all those years, generations of Redford workers have walked through these doors. Not just to punch a clock. Not just to pick up a paycheck. Not just to build an engine. But to build a middle-class life for their families; to earn a shot at the American Dream.

For seven and a half decades, through good times and bad, through revolutions in technology that sent a lot of good jobs -- manufacturing jobs -- overseas, men and women like you, your parents, maybe even your grandparents, have done your part to build up America's manufacturing strength. That's something you can all be proud of. And now you're writing a new proud chapter to that history. Eight years ago, you started building axles here alongside the engines. That meant more work. That meant more jobs. (Applause.) So you started seeing products -- more products stamped with those three proud words: Made in America.
Today, Daimler is announcing a new $120 million investment into this plant, creating 115 good, new union jobs building transmissions and turbochargers right here in Redford -- (applause) -- 115 good new jobs right here in this plant, making things happen. That is great for the plant. It's great for this community. But it's also good for American manufacturing. Soon, you guys will be building all the key parts that go into powering a heavy-duty truck, all at the same facility. Nobody else in America is doing that. Nobody else in North America is doing that.

And by putting everything together in one place, under one roof, Daimler engineers can design each part so it works better with the others. That means greater fuel efficiency for your trucks. It means greater savings for your customers. That's a big deal. And it's just the latest example of Daimler's leadership on this issue.

Last year, I was proud to have your support when we announced the first-ever national fuel-efficiency standards for commercial trucks, which is going to help save consumers money and reduce our dependence on foreign oil. That's good news. (Applause.)

But here's the other reason why what you guys are doing, what Daimler is doing, is so important. For a long time, companies, they weren't always making those kinds of investments here in the United States. They weren't always investing in American workers. They certainly weren't willing to make them in the U.S. auto industry.

Remember, it was just a few years ago that our auto industry was on the verge of collapse. GM, Chrysler were all on the brink of failure. And if they failed, the suppliers and distributors that get their business from those companies, they would have died off, too. Even Ford could have gone down -- production halted. Factories shuttered. Once proud companies chopped up and sold off for scraps. And all of you -- the men and women who built these companies with your own hands -- would have been hung out to dry. And everybody in this community that depends on you -- restaurant owners, storekeepers, bartenders -- (laughter and applause) -- their livelihoods would have been at stake, too.

So I wasn't about to let that happen. I placed my bet on American workers. We bet on American ingenuity. I'd make that same bet any day of the week. (Applause.) Three and a half years later, that bet is paying off. This industry has added over a quarter of a million new jobs. Assembly lines are humming again. The American auto industry is back.

And companies like Daimler know you're still a smart bet. They could have made their investment somewhere else, but they didn't. And if you ask them whether it was a tough call, they'll tell you it wasn't even close. So the word is going out all around the world: If you want to find the best workers in the world, if you want to find the best factories in the world, if you want to build the best cars or trucks or any other product in the world, you should invest in the United States of America. This is the place to be. (Applause.)

See, you're starting to see the competitive balance is tipping a little bit. Over the past few years, it's become more expensive to do business in countries like China. Our workers have become even more productive. Our energy costs are starting to go down here in the United States. And we still have the largest market. So when you factor in everything, it makes sense to invest here, in America.

And that's one of the reasons why American manufacturing is growing at the fastest pace since the 1990s. And thanks in part to that boost in manufacturing, four years after the worst economic crisis of our lifetimes, our economy is growing again. Our businesses have created more than 5.5 million new jobs over the past 33 months. So we're making progress. (Applause.) We're moving in the right direction. We're going forward.

So what we need to do is simple. We need to keep going. We need to keep going forward. We should do everything we can to keep creating good middle-class jobs that help folks rebuild security for their families. (Applause.) And we should do everything we can to encourage companies like Daimler to keep investing in American workers.

And by the way, what we shouldn't do -- I just got to say this -- what we shouldn't be doing is trying to take away your rights to bargain for better wages and working conditions. (Applause.) We shouldn't be doing that. (Applause.) These so-called "right to work" laws, they don't have to do with economics; they have everything to do with politics. (Applause.) What they're really talking about is giving you the right to work for less money. (Applause.)

You only have to look to Michigan -- where workers were instrumental in reviving the auto industry -- to see how unions have helped build not just a stronger middle class but a stronger America. (Applause.) So folks from our state's capital, all the way to the nation's capital, they should be focused on the same thing. They should be working to make sure companies like this manufacturer is able to make more great products. That's what they should be focused on. (Applause.) We don't want a race to the bottom. We want a race to the top. (Applause.)

America is not going to compete based on low-skill, low-wage, no workers' rights. That's not our competitive advantage. There's always going to be some other country that can treat its workers even worse. Right?

AUDIENCE: Right!

THE PRESIDENT: What's going to make us succeed is we got the best workers -- well trained, reliable, productive, low turnover, healthy. That's what makes us strong. And it also is what allows our workers then to buy the products that we make because they got enough money in their pockets. (Applause.)

So we've got to get past this whole situation where we manufacture crises because of politics. That actually leads to less certainty, more conflict, and we can't all focus on coming together to grow.

AUDIENCE MEMBER: That's right!

THE PRESIDENT: And the same thing -- we're seeing the same thing in Washington. I'm sure you've all heard the talk recently about some big deadlines we're facing in a few weeks when it comes to decisions on jobs and investment and taxes. And that debate is going to have a big impact on all of you. Some of you may know this: If Congress doesn't act soon, meaning in the next few weeks, starting on January 1st, everybody is going to see their income taxes go up.

AUDIENCE: No!

THE PRESIDENT: It's true. You all don't like that.

AUDIENCE: No!

THE PRESIDENT: Typical, middle-class family of four will see an income tax hike of around $2,200. How many of you can afford to pay another $2,200 in taxes? Not you?

AUDIENCE: No!

THE PRESIDENT: I didn't think so. You can't afford to lose that money. That's a hit you can't afford to take. And, by the way, that's not a good hit for businesses, either -- because if Congress lets middle-class taxes go up, economists will tell you that means people will spend nearly $200 billion less than they otherwise would spend. Consumer spending is going to go down. That means you've got less customers. Businesses get fewer profits. They hire fewer workers. You go in a downward spiral. Wrong idea.

Here is the good news: We can solve this problem. All Congress needs to do is pass a law that would prevent a tax hike on the first $250,000 of everybody's income -- everybody. (Applause.) That means 98 percent of Americans -- and probably 100 percent of you -- (laughter) -- 97 percent of small businesses wouldn't see their income taxes go up a single dime. Even the wealthiest Americans would still get a tax cut on the first $250,000 of their income. But when they start making a million, or $10 million, or $20 million you can afford to pay a little bit more. (Applause.) You're not too strapped.

So Congress can do that right now. Everybody says they agree with it. Let's get it done. (Applause.)

So that's the bare minimum. That's the bare minimum we should be doing in order to the grow the economy. But we can do more. We can do more than just extend middle-class tax cuts. I've said I will work with Republicans on a plan for economic growth, job creation, and reducing our deficits. And that has some compromise between Democrats and Republicans. I understand people have a lot of different views. I'm willing to compromise a little bit.

But if we're serious about reducing our deficit, we've also got to be serious about investing in the things that help us grow and make the middle class strong, like education, and research and development, and making sure kids can go to college, and rebuilding our roads and our infrastructure. (Applause.) We've got to do that.

So when you put it all together, what you need is a package that keeps taxes where they are for middle-class families; we make some tough spending cuts on things that we don't need; and then we ask the wealthiest

Americans to pay a slightly higher tax rate. And that's a principle I won't compromise on, because I'm not going to have a situation where the wealthiest among us, including folks like me, get to keep all our tax breaks, and then we're asking students to pay higher student loans. Or suddenly, a school doesn't have schoolbooks because the school district couldn't afford it. Or some family that has a disabled kid isn't getting the help that they need through Medicaid.

We're not going to do that. We're not going to make that tradeoff. That's not going to help us to grow. Our economic success has never come from the top down; it comes from the middle out. It comes from the bottom up. (Applause.) It comes from folks like you working hard, and if you're working hard and you're successful, then you become customers and everybody does well.

Our success as a country in this new century will be defined by how well we educate our kids, how well we train our workers, how well we invent, how well we innovate, how well we build things like cars and engines -- all the things that helped create the greatest middle class the world has ever known. That's how you bring new jobs back to Detroit. That's how you bring good jobs back to America. That's what I'm focused on. That's what I will stay relentlessly focused on going forward. (Applause.)

Because when we focus on these things --- when we stay true to ourselves and our history, there's nothing we can't do. (Applause.) And if you don't believe me, you need to come down to this plant and see all these outstanding workers.

In fact, as I was coming over here, I was hearing about a guy named Willie. (Applause.) Where's Willie? There's Willie right here. There's Willie. (Applause.) Now, in case you haven't heard of him, they actually call him "Pretty Willie." (Laughter.) Now, I got to say you got to be pretty tough to have a nickname like "Pretty Willie." (Laughter.) He's tough.

On Wednesday, Willie will celebrate 60 years working at Detroit Diesel -- 60 years. (Applause.) Willie started back on December 12, 1952. I was not born yet. (Laughter.) Wasn't even close to being born. He made $1.40 an hour. The only time he spent away from this plant was when he was serving our country in the Korean War. (Applause.) So three generations of Willie's family have passed through Detroit Diesel. One of his daughters works here with him right now -- is that right? There she is. (Applause.)

In all his years, Willie has been late to work only once. It was back in 1977. (Laughter.) It's been so long he can't remember why he was late -- (laughter and applause) -- but we're willing to give him a pass.

So Willie believes in hard work. You don't keep a job for 60 years if you don't work hard. Sooner or later, someone is going to fire you if you don't work hard. He takes pride in being part of something bigger than himself. He's committed to family; he's committed to community; he's committed to country. That's how Willie lives his life. That's how all of you live your lives.

And that makes me hopeful about the future, because you're out there fighting every day for a better future for your family and your country. And when you do that, that means you're creating value all across this economy. You're inspiring people. You're being a good example for your kids. That's what makes America great. That's what we have to stay focused on.

And as long as I've got the privilege of serving as your President, I'm going to keep fighting for you. I'm going to keep fighting for your kids. I'm going to keep fighting for an America where anybody, no matter who you are, no matter what you look like, no matter where you come from, you can make it if you try here in America. (Applause.)

Thank you very much, everybody. God bless you. (Applause.)

END
2:51 P.M. EST

Remarks of President Barack Obama – As Prepared for Delivery
Address to Joint Session of Congress
Tuesday, February 24th, 2009

(en español)

Madame Speaker, Mr. Vice President, Members of Congress, and the First Lady of the United States:

I've come here tonight not only to address the distinguished men and women in this great chamber, but to speak frankly and directly to the men and women who sent us here.

I know that for many Americans watching right now, the state of our economy is a concern that rises above all others. And rightly so. If you haven't been personally affected by this recession, you probably know someone who has – a friend; a neighbor; a member of your family. You don't need to hear another list of statistics to know that our economy is in crisis, because you live it every day. It's the worry you wake up with and the source of sleepless nights. It's the job you thought you'd retire from but now have lost; the business you built your dreams upon that's now hanging by a thread; the college acceptance letter your child had to put back in the envelope. The impact of this recession is real, and it is everywhere.

But while our economy may be weakened and our confidence shaken; though we are living through difficult and uncertain times, tonight I want every American to know this:

We will rebuild, we will recover, and the United States of America will emerge stronger than before.

The weight of this crisis will not determine the destiny of this nation. The answers to our problems don't lie beyond our reach. They exist in our laboratories and universities; in our fields and our factories; in the imaginations of our entrepreneurs and the pride of the hardest-working people on Earth. Those qualities that have made America the greatest force of progress and prosperity in human history we still possess in ample measure. What is required now is for this country to pull together, confront boldly the challenges we face, and take responsibility for our future once more.

Now, if we're honest with ourselves, we'll admit that for too long, we have not always met these responsibilities – as a government or as a people. I say this not to lay blame or look backwards, but because it is only by understanding how we arrived at this moment that we'll be able to lift ourselves out of this predicament.

The fact is, our economy did not fall into decline overnight. Nor did all of our problems begin when the housing market collapsed or the stock market sank. We have known for decades that our survival depends on finding new sources of energy. Yet we import more oil today than ever before. The cost of health care eats up more and more of our savings each year, yet we keep delaying reform. Our children will compete for jobs in a global economy that too many of our schools do not prepare them for. And though all these challenges went unsolved, we still managed to spend more money and pile up more debt, both as individuals and through our government, than ever before.

In other words, we have lived through an era where too often, short-term gains were prized over long-term prosperity; where we failed to look beyond the next payment, the next quarter, or the next election. A surplus became an excuse to transfer wealth to the wealthy instead of an opportunity to invest in our future. Regulations were gutted for the sake of a quick profit at the expense of a healthy market. People bought homes they knew they couldn't afford from banks and lenders who pushed those bad loans anyway. And all the while, critical debates and difficult decisions were put off for some other time on some other day.

Well that day of reckoning has arrived, and the time to take charge of our future is here.

Now is the time to act boldly and wisely – to not only revive this economy, but to build a new foundation for lasting prosperity. Now is the time to jumpstart job creation, re-start lending, and invest in areas like energy, health care, and education that will grow our economy, even as we make hard choices to bring our deficit down. That is what my economic agenda is designed to do, and that's what I'd like to talk to you about tonight.

WATCH THE VIDEO

February 24, 2009 4:30 PM

The President Addresses Joint Session of Congress: February 24, 2009

BLOG POSTS ON THIS ISSUE

January 23, 2013 12:45 PM EST

Fireside Hangouts: Vice President Biden Joins a Conversation on Reducing Gun Violence

On Thursday, January 24 at 1:45 p.m. ET, Vice President Biden will host the latest "Fireside Hangout" – a 21st century take on FDR's famous radio addresses – to talk about reducing gun violence.

January 23, 2013 10:40 AM EST

Surprise! President and Mrs. Obama Greet White House Tour (Bo Was There, Too)

The President and First Lady welcomed the guests with handshakes, hugs and even fistbumps, and Bo was treated to a near-constant stream of affectionate pats and petting.

January 21, 2013 3:26 PM EST

Be a Part of the Next Four Years

The President's second term will offer many ways

It's an agenda that begins with jobs.

As soon as I took office, I asked this Congress to send me a recovery plan by President's Day that would put people back to work and put money in their pockets. Not because I believe in bigger government – I don't. Not because I'm not mindful of the massive debt we've inherited – I am. I called for action because the failure to do so would have cost more jobs and caused more hardships. In fact, a failure to act would have worsened our long-term deficit by assuring weak economic growth for years. That's why I pushed for quick action. And tonight, I am grateful that this Congress delivered, and pleased to say that the American Recovery and Reinvestment Act is now law.

Over the next two years, this plan will save or create 3.5 million jobs. More than 90% of these jobs will be in the private sector – jobs rebuilding our roads and bridges; constructing wind turbines and solar panels; laying broadband and expanding mass transit.

Because of this plan, there are teachers who can now keep their jobs and educate our kids. Health care professionals can continue caring for our sick. There are 57 police officers who are still on the streets of Minneapolis tonight because this plan prevented the layoffs their department was about to make.

Because of this plan, 95% of the working households in America will receive a tax cut – a tax cut that you will see in your paychecks beginning on April 1st.

Because of this plan, families who are struggling to pay tuition costs will receive a $2,500 tax credit for all four years of college. And Americans who have lost their jobs in this recession will be able to receive extended unemployment benefits and continued health care coverage to help them weather this storm.

I know there are some in this chamber and watching at home who are skeptical of whether this plan will work. I understand that skepticism. Here in Washington, we've all seen how quickly good intentions can turn into broken promises and wasteful spending. And with a plan of this scale comes enormous responsibility to get it right.

That is why I have asked Vice President Biden to lead a tough, unprecedented oversight effort – because nobody messes with Joe. I have told each member of my Cabinet as well as mayors and governors across the country that they will be held accountable by me and the American people for every dollar they spend. I have appointed a proven and aggressive Inspector General to ferret out any and all cases of waste and fraud. And we have created a new website called recovery.gov so that every American can find out how and where their money is being spent.

So the recovery plan we passed is the first step in getting our economy back on track. But it is just the first step. Because even if we manage this plan flawlessly, there will be no real recovery unless we clean up the credit crisis that has severely weakened our financial system.

I want to speak plainly and candidly about this issue tonight, because every American should know that it directly affects you and your family's well-being. You should also know that the money you've deposited in banks across the country is safe; your insurance is secure; and you can rely on the continued operation of our financial system. That is not the source of concern.

The concern is that if we do not re-start lending in this country, our recovery will be choked off before it even begins.

You see, the flow of credit is the lifeblood of our economy. The ability to get a loan is how you finance the purchase of everything from a home to a car to a college education; how stores stock their shelves, farms buy equipment, and businesses make payroll.

But credit has stopped flowing the way it should. Too many bad loans from the housing crisis have made their way onto the books of too many banks. With so much debt and so little confidence, these banks are now fearful of lending out any more money to households, to businesses, or to each other. When there is no lending, families can't afford to buy homes or cars. So businesses are forced to make layoffs. Our economy suffers even more, and credit dries up even further.

That is why this administration is moving swiftly and aggressively to break this destructive cycle, restore confidence, and re-start lending.

We will do so in several ways. First, we are creating a new lending fund that represents the largest effort ever to help provide auto loans, college loans, and small business loans to the consumers and entrepreneurs who keep this economy running.

Second, we have launched a housing plan that will help responsible families facing the threat of foreclosure lower their monthly payments and re-finance their mortgages. It's a plan that won't help speculators or that neighbor down the street who bought a house he could never hope to afford, but it will help millions of Americans who are struggling with declining home values – Americans who will now be able to take advantage of the lower

for citizens to participate in conversations with the President and his team about the issues that are most important to them.

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interest rates that this plan has already helped bring about. In fact, the average family who re-finances today can save nearly $2000 per year on their mortgage.

Third, we will act with the full force of the federal government to ensure that the major banks that Americans depend on have enough confidence and enough money to lend even in more difficult times. And when we learn that a major bank has serious problems, we will hold accountable those responsible, force the necessary adjustments, provide the support to clean up their balance sheets, and assure the continuity of a strong, viable institution that can serve our people and our economy.

I understand that on any given day, Wall Street may be more comforted by an approach that gives banks bailouts with no strings attached, and that holds nobody accountable for their reckless decisions. But such an approach won't solve the problem. And our goal is to quicken the day when we re-start lending to the American people and American business and end this crisis once and for all.

I intend to hold these banks fully accountable for the assistance they receive, and this time, they will have to clearly demonstrate how taxpayer dollars result in more lending for the American taxpayer. This time, CEOs won't be able to use taxpayer money to pad their paychecks or buy fancy drapes or disappear on a private jet. Those days are over.

Still, this plan will require significant resources from the federal government – and yes, probably more than we've already set aside. But while the cost of action will be great, I can assure you that the cost of inaction will be far greater, for it could result in an economy that sputters along for not months or years, but perhaps a decade. That would be worse for our deficit, worse for business, worse for you, and worse for the next generation. And I refuse to let that happen.

I understand that when the last administration asked this Congress to provide assistance for struggling banks, Democrats and Republicans alike were infuriated by the mismanagement and results that followed. So were the American taxpayers. So was I.

So I know how unpopular it is to be seen as helping banks right now, especially when everyone is suffering in part from their bad decisions. I promise you – I get it.

But I also know that in a time of crisis, we cannot afford to govern out of anger, or yield to the politics of the moment. My job – our job – is to solve the problem. Our job is to govern with a sense of responsibility. I will not spend a single penny for the purpose of rewarding a single Wall Street executive, but I will do whatever it takes to help the small business that can't pay its workers or the family that has saved and still can't get a mortgage.

That's what this is about. It's not about helping banks – it's about helping people. Because when credit is available again, that young family can finally buy a new home. And then some company will hire workers to build it. And then those workers will have money to spend, and if they can get a loan too, maybe they'll finally buy that car, or open their own business. Investors will return to the market, and American families will see their retirement secured once more. Slowly, but surely, confidence will return, and our economy will recover.

So I ask this Congress to join me in doing whatever proves necessary. Because we cannot consign our nation to an open-ended recession. And to ensure that a crisis of this magnitude never happens again, I ask Congress to move quickly on legislation that will finally reform our outdated regulatory system. It is time to put in place tough, new common-sense rules of the road so that our financial market rewards drive and innovation, and punishes short-cuts and abuse.

The recovery plan and the financial stability plan are the immediate steps we're taking to revive our economy in the short-term. But the only way to fully restore America's economic strength is to make the long-term investments that will lead to new jobs, new industries, and a renewed ability to compete with the rest of the world. The only way this century will be another American century is if we confront at last the price of our dependence on oil and the high cost of health care; the schools that aren't preparing our children and the mountain of debt they stand to inherit. That is our responsibility.

In the next few days, I will submit a budget to Congress. So often, we have come to view these documents as simply numbers on a page or laundry lists of programs. I see this document differently. I see it as a vision for America – as a blueprint for our future.

My budget does not attempt to solve every problem or address every issue. It reflects the stark reality of what we've inherited – a trillion dollar deficit, a financial crisis, and a costly recession.

Given these realities, everyone in this chamber – Democrats and Republicans – will have to sacrifice some worthy priorities for which there are no dollars. And that includes me.

But that does not mean we can afford to ignore our long-term challenges. I reject the view that says our problems will simply take care of themselves; that says government has no role in laying the foundation for our common prosperity.

For history tells a different story. History reminds us that at every moment of economic upheaval and transformation, this nation has responded with bold action and big ideas. In the midst of civil war, we laid railroad tracks from one coast to another that spurred commerce and industry. From the turmoil of the Industrial Revolution came a system of public high schools that prepared our citizens for a new age. In the wake of war and depression, the GI Bill sent a generation to college and created the largest middle-class in history. And a twilight struggle for freedom led to a nation of highways, an American on the moon, and an explosion of technology that still shapes our world.

In each case, government didn't supplant private enterprise; it catalyzed private enterprise. It created the conditions for thousands of entrepreneurs and new businesses to adapt and to thrive.

We are a nation that has seen promise amid peril, and claimed opportunity from ordeal. Now we must be that nation again. That is why, even as it cuts back on the programs we don't need, the budget I submit will invest in the three areas that are absolutely critical to our economic future: energy, health care, and education.

It begins with energy.

We know the country that harnesses the power of clean, renewable energy will lead the 21st century. And yet, it is China that has launched the largest effort in history to make their economy energy efficient. We invented solar technology, but we've fallen behind countries like Germany and Japan in producing it. New plug-in hybrids roll off our assembly lines, but they will run on batteries made in Korea.

Well I do not accept a future where the jobs and industries of tomorrow take root beyond our borders – and I know you don't either. It is time for America to lead again.

Thanks to our recovery plan, we will double this nation's supply of renewable energy in the next three years. We have also made the largest investment in basic research funding in American history – an investment that will spur not only new discoveries in energy, but breakthroughs in medicine, science, and technology.

We will soon lay down thousands of miles of power lines that can carry new energy to cities and towns across this country. And we will put Americans to work making our homes and buildings more efficient so that we can save billions of dollars on our energy bills.

But to truly transform our economy, protect our security, and save our planet from the ravages of climate change, we need to ultimately make clean, renewable energy the profitable kind of energy. So I ask this Congress to send me legislation that places a market-based cap on carbon pollution and drives the production of more renewable energy in America. And to support that innovation, we will invest fifteen billion dollars a year to develop technologies like wind power and solar power; advanced biofuels, clean coal, and more fuel-efficient cars and trucks built right here in America.

As for our auto industry, everyone recognizes that years of bad decision-making and a global recession have pushed our automakers to the brink. We should not, and will not, protect them from their own bad practices. But we are committed to the goal of a re-tooled, re-imagined auto industry that can compete and win. Millions of jobs depend on it. Scores of communities depend on it. And I believe the nation that invented the automobile cannot walk away from it.

None of this will come without cost, nor will it be easy. But this is America. We don't do what's easy. We do what is necessary to move this country forward.

For that same reason, we must also address the crushing cost of health care.

This is a cost that now causes a bankruptcy in America every thirty seconds. By the end of the year, it could cause 1.5 million Americans to lose their homes. In the last eight years, premiums have grown four times faster than wages. And in each of these years, one million more Americans have lost their health insurance. It is one of the major reasons why small businesses close their doors and corporations ship jobs overseas. And it's one of the largest and fastest-growing parts of our budget.

Given these facts, we can no longer afford to put health care reform on hold.

Already, we have done more to advance the cause of health care reform in the last thirty days than we have in the last decade. When it was days old, this Congress passed a law to provide and protect health insurance for eleven million American children whose parents work full-time. Our recovery plan will invest in electronic health records and new technology that will reduce errors, bring down costs, ensure privacy, and save lives. It will launch a new effort to conquer a disease that has touched the life of nearly every American by seeking a cure for cancer in our time. And it makes the largest investment ever in preventive care, because that is one of the best ways to keep our people healthy and our costs under control.

This budget builds on these reforms. It includes an historic commitment to comprehensive health care reform – a down-payment on the principle that we must have quality, affordable health care for every American. It's a commitment that's paid for in part by efficiencies in our system that are long overdue. And it's a step we must take if we hope to bring down our deficit in the years to come.

Now, there will be many different opinions and ideas about how to achieve reform, and that is why I'm bringing together businesses and workers, doctors and health care providers, Democrats and Republicans to begin work on this issue next week.

I suffer no illusions that this will be an easy process. It will be hard. But I also know that nearly a century after Teddy Roosevelt first called for reform, the cost of our health care has weighed down our economy and the conscience of our nation long enough. So let there be no doubt: health care reform cannot wait, it must not wait, and it will not wait another year.

The third challenge we must address is the urgent need to expand the promise of education in America.

In a global economy where the most valuable skill you can sell is your knowledge, a good education is no longer just a pathway to opportunity – it is a pre-requisite.

Right now, three-quarters of the fastest-growing occupations require more than a high school diploma. And yet, just over half of our citizens have that level of education. We have one of the highest high school dropout rates of any industrialized nation. And half of the students who begin college never finish.

This is a prescription for economic decline, because we know the countries that out-teach us today will out-compete us tomorrow. That is why it will be the goal of this administration to ensure that every child has access to a complete and competitive education – from the day they are born to the day they begin a career.

Already, we have made an historic investment in education through the economic recovery plan. We have dramatically expanded early childhood education and will continue to improve its quality, because we know that the most formative learning comes in those first years of life. We have made college affordable for nearly seven million more students. And we have provided the resources necessary to prevent painful cuts and teacher layoffs that would set back our children's progress.

But we know that our schools don't just need more resources. They need more reform. That is why this budget creates new incentives for teacher performance; pathways for advancement, and rewards for success. We'll invest in innovative programs that are already helping schools meet high standards and close achievement gaps. And we will expand our commitment to charter schools.

It is our responsibility as lawmakers and educators to make this system work. But it is the responsibility of every citizen to participate in it. And so tonight, I ask every American to commit to at least one year or more of higher education or career training. This can be community college or a four-year school; vocational training or an apprenticeship. But whatever the training may be, every American will need to get more than a high school diploma. And dropping out of high school is no longer an option. It's not just quitting on yourself, it's quitting on your country – and this country needs and values the talents of every American. That is why we will provide the support necessary for you to complete college and meet a new goal: by 2020, America will once again have the highest proportion of college graduates in the world.

I know that the price of tuition is higher than ever, which is why if you are willing to volunteer in your neighborhood or give back to your community or serve your country, we will make sure that you can afford a higher education. And to encourage a renewed spirit of national service for this and future generations, I ask this Congress to send me the bipartisan legislation that bears the name of Senator Orrin Hatch as well as an American who has never stopped asking what he can do for his country – Senator Edward Kennedy.

These education policies will open the doors of opportunity for our children. But it is up to us to ensure they walk through them. In the end, there is no program or policy that can substitute for a mother or father who will attend those parent/teacher conferences, or help with homework after dinner, or turn off the TV, put away the video games, and read to their child. I speak to you not just as a President, but as a father when I say that responsibility for our children's education must begin at home.

There is, of course, another responsibility we have to our children. And that is the responsibility to ensure that we do not pass on to them a debt they cannot pay. With the deficit we inherited, the cost of the crisis we face, and the long-term challenges we must meet, it has never been more important to ensure that as our economy recovers, we do what it takes to bring this deficit down.

I'm proud that we passed the recovery plan free of earmarks, and I want to pass a budget next year that ensures that each dollar we spend reflects only our most important national priorities.

Yesterday, I held a fiscal summit where I pledged to cut the deficit in half by the end of my first term in office. My administration has also begun to go line by line through the federal budget in order to eliminate wasteful and ineffective programs. As you can imagine, this is a process that will take some time. But we're starting with the biggest lines. We have already identified two trillion dollars in savings over the next decade.

In this budget, we will end education programs that don't work and end direct payments to large agribusinesses that don't need them. We'll eliminate the no-bid contracts that have wasted billions in Iraq, and reform our defense budget so that we're not paying for Cold War-era weapons systems we don't use. We will root out the waste, fraud, and abuse in our Medicare program that doesn't make our seniors any healthier, and we will restore a sense of fairness and balance to our tax code by finally ending the tax breaks for corporations that ship our jobs overseas.

In order to save our children from a future of debt, we will also end the tax breaks for the wealthiest 2% of Americans. But let me perfectly clear, because I know you'll hear the same old claims that rolling back these tax breaks means a massive tax increase on the American people: if your family earns less than $250,000 a year, you will not see your taxes increased a single dime. I repeat: not one single dime. In fact, the recovery plan provides a tax cut – that's right, a tax cut – for 95% of working families. And these checks are on the way.

To preserve our long-term fiscal health, we must also address the growing costs in Medicare and Social Security. Comprehensive health care reform is the best way to strengthen Medicare for years to come. And we must also begin a conversation on how to do the same for Social Security, while creating tax-free universal savings accounts for all Americans.

Finally, because we're also suffering from a deficit of trust, I am committed to restoring a sense of honesty and accountability to our budget. That is why this budget looks ahead ten years and accounts for spending that was left out under the old rules – and for the first time, that includes the full cost of fighting in Iraq and Afghanistan. For seven years, we have been a nation at war. No longer will we hide its price.

We are now carefully reviewing our policies in both wars, and I will soon announce a way forward in Iraq that leaves Iraq to its people and responsibly ends this war.

And with our friends and allies, we will forge a new and comprehensive strategy for Afghanistan and Pakistan to defeat al Qaeda and combat extremism. Because I will not allow terrorists to plot against the American people from safe havens half a world away.

As we meet here tonight, our men and women in uniform stand watch abroad and more are readying to deploy. To each and every one of them, and to the families who bear the quiet burden of their absence, Americans are united in sending one message: we honor your service, we are inspired by your sacrifice, and you have our unyielding support. To relieve the strain on our forces, my budget increases the number of our soldiers and Marines. And to keep our sacred trust with those who serve, we will raise their pay, and give our veterans the expanded health care and benefits that they have earned.

To overcome extremism, we must also be vigilant in upholding the values our troops defend – because there is no force in the world more powerful than the example of America. That is why I have ordered the closing of the detention center at Guantanamo Bay, and will seek swift and certain justice for captured terrorists – because living our values doesn't make us weaker, it makes us safer and it makes us stronger. And that is why I can stand here tonight and say without exception or equivocation that the United States of America does not torture.

In words and deeds, we are showing the world that a new era of engagement has begun. For we know that America cannot meet the threats of this century alone, but the world cannot meet them without America. We cannot shun the negotiating table, nor ignore the foes or forces that could do us harm. We are instead called to move forward with the sense of confidence and candor that serious times demand.

To seek progress toward a secure and lasting peace between Israel and her neighbors, we have appointed an envoy to sustain our effort. To meet the challenges of the 21st century – from terrorism to nuclear proliferation; from pandemic disease to cyber threats to crushing poverty – we will strengthen old alliances, forge new ones, and use all elements of our national power.

And to respond to an economic crisis that is global in scope, we are working with the nations of the G-20 to restore confidence in our financial system, avoid the possibility of escalating protectionism, and spur demand for American goods in markets across the globe. For the world depends on us to have a strong economy, just as our economy depends on the strength of the world's.

As we stand at this crossroads of history, the eyes of all people in all nations are once again upon us – watching to see what we do with this moment; waiting for us to lead.

Those of us gathered here tonight have been called to govern in extraordinary times. It is a tremendous burden, but also a great privilege – one that has been entrusted to few generations of Americans. For in our hands lies the ability to shape our world for good or for ill.

I know that it is easy to lose sight of this truth – to become cynical and doubtful; consumed with the petty and the trivial.

But in my life, I have also learned that hope is found in unlikely places; that inspiration often comes not from those with the most power or celebrity, but from the dreams and aspirations of Americans who are anything but ordinary.

I think about Leonard Abess, the bank president from Miami who reportedly cashed out of his company, took a $60 million bonus, and gave it out to all 399 people who worked for him, plus another 72 who used to work for him. He didn't tell anyone, but when the local newspaper found out, he simply said, "I knew some of these people since I was 7 years old. I didn't feel right getting the money myself."

I think about Greensburg, Kansas, a town that was completely destroyed by a tornado, but is being rebuilt by its residents as a global example of how clean energy can power an entire community – how it can bring jobs and businesses to a place where piles of bricks and rubble once lay. "The tragedy was terrible," said one of the men who helped them rebuild. "But the folks here know that it also provided an incredible opportunity."

And I think about Ty'Sheoma Bethea, the young girl from that school I visited in Dillon, South Carolina – a place where the ceilings leak, the paint peels off the walls, and they have to stop teaching six times a day because the train barrels by their classroom. She has been told that her school is hopeless, but the other day after class she went to the public library and typed up a letter to the people sitting in this room. She even asked her principal for the money to buy a stamp. The letter asks us for help, and says, "We are just students trying to become lawyers, doctors, congressmen like yourself and one day president, so we can make a change to not just the state of South Carolina but also the world. We are not quitters."

We are not quitters.

These words and these stories tell us something about the spirit of the people who sent us here. They tell us that even in the most trying times, amid the most difficult circumstances, there is a generosity, a resilience, a decency, and a determination that perseveres; a willingness to take responsibility for our future and for posterity.

Their resolve must be our inspiration. Their concerns must be our cause. And we must show them and all our people that we are equal to the task before us.

I know that we haven't agreed on every issue thus far, and there are surely times in the future when we will part ways. But I also know that every American who is sitting here tonight loves this country and wants it to succeed. That must be the starting point for every debate we have in the coming months, and where we return after those debates are done. That is the foundation on which the American people expect us to build common ground.

And if we do – if we come together and lift this nation from the depths of this crisis; if we put our people back to work and restart the engine of our prosperity; if we confront without fear the challenges of our time and summon that enduring spirit of an America that does not quit, then someday years from now our children can tell their children that this was the time when we performed, in the words that are carved into this very chamber, "something worthy to be remembered." Thank you, God Bless you, and may God Bless the United States of America.

Technical Support Document: -
Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis -
Under Executive Order 12866 -

Interagency Working Group on Social Cost of Carbon, United States Government

With participation by

Council of Economic Advisers
Council on Environmental Quality
Department of Agriculture
Department of Commerce
Department of Energy
Department of Transportation
Domestic Policy Council
Environmental Protection Agency
National Economic Council
Office of Management and Budget
Office of Science and Technology Policy
Department of the Treasury

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Revised November 2013
See Appendix B for Details on Revision

Executive Summary

Under Executive Order 12866, agencies are required, to the extent permitted by law, "to assess both the costs and the benefits of the intended regulation and, recognizing that some costs and benefits are difficult to quantify, propose or adopt a regulation only upon a reasoned determination that the benefits of the intended regulation justify its costs." The purpose of the "social cost of carbon" (SCC) estimates presented here is to allow agencies to incorporate the social benefits of reducing carbon dioxide (CO_2) emissions into cost-benefit analyses of regulatory actions that impact cumulative global emissions. The SCC is an estimate of the monetized damages associated with an incremental increase in carbon emissions in a given year. It is intended to include (but is not limited to) changes in net agricultural productivity, human health, property damages from increased flood risk, and the value of ecosystem services due to climate change.

The interagency process that developed the original U.S. government's SCC estimates is described in the 2010 interagency technical support document (TSD) (Interagency Working Group on Social Cost of Carbon 2010). Through that process the interagency group selected four SCC values for use in regulatory analyses. Three values are based on the average SCC from three integrated assessment models (IAMs), at discount rates of 2.5, 3, and 5 percent. The fourth value, which represents the 95th percentile SCC estimate across all three models at a 3 percent discount rate, is included to represent higher-than-expected impacts from temperature change further out in the tails of the SCC distribution.

While acknowledging the continued limitations of the approach taken by the interagency group in 2010, this document provides an update of the SCC estimates based on new versions of each IAM (DICE, PAGE, and FUND). It does not revisit other interagency modeling decisions (e.g., with regard to the discount rate, reference case socioeconomic and emission scenarios, or equilibrium climate sensitivity). Improvements in the way damages are modeled are confined to those that have been incorporated into the latest versions of the models by the developers themselves in the peer-reviewed literature.

The SCC estimates using the updated versions of the models are higher than those reported in the 2010 TSD. By way of comparison, the four 2020 SCC estimates reported in the 2010 TSD were $7, $26, $42 and $81 (2007$). The corresponding four updated SCC estimates for 2020 are $12, $43, $64, and $128 (2007$). The model updates that are relevant to the SCC estimates include: an explicit representation of sea level rise damages in the DICE and PAGE models; updated adaptation assumptions, revisions to ensure damages are constrained by GDP, updated regional scaling of damages, and a revised treatment of potentially abrupt shifts in climate damages in the PAGE model; an updated carbon cycle in the DICE model; and updated damage functions for sea level rise impacts, the agricultural sector, and reduced space heating requirements, as well as changes to the transient response of temperature to the buildup of GHG concentrations and the inclusion of indirect effects of methane emissions in the FUND model. The SCC estimates vary by year, and the following table summarizes the revised SCC estimates from 2010 through 2050.

Revised Social Cost of CO_2, 2010 – 2050 (in 2007 dollars per metric ton of CO_2)

Discount Rate Year	5.0% Avg	3.0% Avg	2.5% Avg	3.0% 95th
2010	11	32	51	89
2015	11	37	57	109
2020	12	43	64	128
2025	14	47	69	143
2030	16	52	75	159
2035	19	56	80	175
2040	21	61	86	191
2045	24	66	92	206
2050	26	71	97	220

I. Purpose

The purpose of this document is to update the schedule of social cost of carbon (SCC) estimates from the 2010 interagency technical support document (TSD) (Interagency Working Group on Social Cost of Carbon 2010).[1] E.O. 13563 commits the Administration to regulatory decision making "based on the best available science."[2] Additionally, the interagency group recommended in 2010 that the SCC estimates be revisited on a regular basis or as model updates that reflect the growing body of scientific and economic knowledge become available.[3] New versions of the three integrated assessment models used by the U.S. government to estimate the SCC (DICE, FUND, and PAGE), are now available and have been published in the peer reviewed literature. While acknowledging the continued limitations of the approach taken by the interagency group in 2010 (documented in the original 2010 TSD), this document provides an update of the SCC estimates based on the latest peer-reviewed version of the models, replacing model versions that were developed up to ten years ago in a rapidly evolving field. It does not revisit other assumptions with regard to the discount rate, reference case socioeconomic and emission scenarios, or equilibrium climate sensitivity. Improvements in the way damages are modeled are confined to those that have been incorporated into the latest versions of the models by the developers themselves in the peer-reviewed literature. The agencies participating in the interagency working group continue to investigate potential improvements to the way in which economic damages associated with changes in CO_2 emissions are quantified.

Section II summarizes the major updates relevant to SCC estimation that are contained in the new versions of the integrated assessment models released since the 2010 interagency report. Section III presents the updated schedule of SCC estimates for 2010 – 2050 based on these versions of the models. Section IV provides a discussion of other model limitations and research gaps.

II. Summary of Model Updates

This section briefly summarizes changes to the most recent versions of the three integrated assessment models (IAMs) used by the interagency group in 2010. We focus on describing those model updates that are relevant to estimating the social cost of carbon, as summarized in Table 1. For example, both the DICE and PAGE models now include an explicit representation of sea level rise damages. Other revisions to PAGE include: updated adaptation assumptions, revisions to ensure damages are constrained by GDP, updated regional scaling of damages, and a revised treatment of potentially abrupt shifts in climate damages. The DICE model's simple carbon cycle has been updated to be more consistent with a more complex climate model. The FUND model includes updated damage functions for sea level rise impacts, the agricultural sector, and reduced space heating requirements, as well as changes to the transient response of temperature to the buildup of GHG concentrations and the inclusion of indirect effects of

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[1] In this document, we present all values of the SCC as the cost per metric ton of CO_2 emissions. Alternatively, one could report the SCC as the cost per metric ton of carbon emissions. The multiplier for translating between mass of CO_2 and the mass of carbon is 3.67 (the molecular weight of CO_2 divided by the molecular weight of carbon = 44/12 = 3.67).

[2] http://www.whitehouse.gov/sites/default/files/omb/inforeg/eo12866/eo13563_01182011.pdf

[3] See p. 1, 3, 4, 29, and 33 (Interagency Working Group on Social Cost of Carbon 2010).

methane emissions. Changes made to parts of the models that are superseded by the interagency working group's modeling assumptions – regarding equilibrium climate sensitivity, discounting, and socioeconomic variables – are not discussed here but can be found in the references provided in each section below.

Table 1: Summary of Key Model Revisions Relevant to the Interagency SCC

IAM	Version used in 2010 Interagency Analysis	New Version	Key changes relevant to interagency SCC
DICE	2007	2010	Updated calibration of the carbon cycle model and explicit representation of sea level rise (SLR) and associated damages.
FUND	3.5 (2009)	3.8 (2012)	Updated damage functions for space heating, SLR, agricultural impacts, changes to transient response of temperature to buildup of GHG concentrations, and inclusion of indirect climate effects of methane.
PAGE	2002	2009	Explicit representation of SLR damages, revisions to damage function to ensure damages do not exceed 100% of GDP, change in regional scaling of damages, revised treatment of potential abrupt damages, and updated adaptation assumptions.

A. DICE

DICE 2010 includes a number of changes over the previous 2007 version used in the 2010 interagency report. The model changes that are relevant for the SCC estimates developed by the interagency working group include: 1) updated parameter values for the carbon cycle model, 2) an explicit representation of sea level dynamics, and 3) a re-calibrated damage function that includes an explicit representation of economic damages from sea level rise. Changes were also made to other parts of the DICE model—including the equilibrium climate sensitivity parameter, the rate of change of total factor productivity, and the elasticity of the marginal utility of consumption—but these components of DICE are superseded by the interagency working group's assumptions and so will not be discussed here. More details on DICE2007 can be found in Nordhaus (2008) and on DICE2010 in Nordhaus (2010). The DICE2010 model and documentation is also available for download from the homepage of William Nordhaus.

Carbon Cycle Parameters

DICE uses a three-box model of carbon stocks and flows to represent the accumulation and transfer of carbon among the atmosphere, the shallow ocean and terrestrial biosphere, and the deep ocean. These parameters are "calibrated to match the carbon cycle in the Model for the Assessment of Greenhouse

Gas Induced Climate Change (MAGICC)" (Nordhaus 2008 p 44).[4] Carbon cycle transfer coefficient values in DICE2010 are based on re-calibration of the model to match the newer 2009 version of MAGICC (Nordhaus 2010 p 2). For example, in DICE2010, in each decade, 12 percent of the carbon in the atmosphere is transferred to the shallow ocean, 4.7 percent of the carbon in the shallow ocean is transferred to the atmosphere, 94.8 percent remains in the shallow ocean, and 0.5 percent is transferred to the deep ocean. For comparison, in DICE 2007, 18.9 percent of the carbon in the atmosphere is transferred to the shallow ocean each decade, 9.7 percent of the carbon in the shallow ocean is transferred to the atmosphere, 85.3 percent remains in the shallow ocean, and 5 percent is transferred to the deep ocean.

The implication of these changes for DICE2010 is in general a weakening of the ocean as a carbon sink and therefore a higher concentration of carbon in the atmosphere than in DICE2007, for a given path of emissions. All else equal, these changes will generally increase the level of warming and therefore the SCC estimates in DICE2010 relative to those from DICE2007.

Sea Level Dynamics

A new feature of DICE2010 is an explicit representation of the dynamics of the global average sea level anomaly to be used in the updated damage function (discussed below). This section contains a brief description of the sea level rise (SLR) module; a more detailed description can be found on the model developer's website.[5] The average global sea level anomaly is modeled as the sum of four terms that represent contributions from: 1) thermal expansion of the oceans, 2) melting of glaciers and small ice caps, 3) melting of the Greenland ice sheet, and 4) melting of the Antarctic ice sheet.

The parameters of the four components of the SLR module are calibrated to match consensus results from the IPCC's Fourth Assessment Report (AR4).[6] The rise in sea level from thermal expansion in each time period (decade) is 2 percent of the difference between the sea level in the previous period and the long run equilibrium sea level, which is 0.5 meters per degree Celsius (°C) above the average global temperature in 1900. The rise in sea level from the melting of glaciers and small ice caps occurs at a rate of 0.008 meters per decade per °C above the average global temperature in 1900.

The contribution to sea level rise from melting of the Greenland ice sheet is more complex. The equilibrium contribution to SLR is 0 meters for temperature anomalies less than 1 °C and increases linearly from 0 meters to a maximum of 7.3 meters for temperature anomalies between 1 °C and 3.5 °C. The contribution to SLR in each period is proportional to the difference between the previous period's sea level anomaly and the equilibrium sea level anomaly, where the constant of proportionality increases with the temperature anomaly in the current period.

[4] MAGICC is a simple climate model initially developed by the U.S. National Center for Atmospheric Research that has been used heavily by the Intergovernmental Panel on Climate Change (IPCC) to emulate projections from more sophisticated state of the art earth system simulation models (Randall et al. 2007).
[5] Documentation on the new sea level rise module of DICE is available on William Nordhaus' website at: http://nordhaus.econ.yale.edu/documents/SLR_021910.pdf.
[6] For a review of post-IPCC AR4 research on sea level rise, see Nicholls et al. (2011) and NAS (2011).

The contribution to SLR from the melting of the Antarctic ice sheet is -0.001 meters per decade when the temperature anomaly is below 3 °C and increases linearly between 3 °C and 6 °C to a maximum rate of 0.025 meters per decade at a temperature anomaly of 6 °C.

Re-calibrated Damage Function

Economic damages from climate change in the DICE model are represented by a fractional loss of gross economic output in each period. A portion of the remaining economic output in each period (net of climate change damages) is consumed and the remainder is invested in the physical capital stock to support future economic production, so each period's climate damages will reduce consumption in that period and in all future periods due to the lost investment. The fraction of output in each period that is lost due to climate change impacts is represented as one minus a fraction, which is one divided by a quadratic function of the temperature anomaly, producing a sigmoid ("S"-shaped) function.[7] The loss function in DICE2010 has been expanded by adding a quadratic function of SLR to the quadratic function of temperature. In DICE2010 the temperature anomaly coefficients have been recalibrated to avoid double-counting damages from sea level rise that were implicitly included in these parameters in DICE2007.

The aggregate damages in DICE2010 are illustrated by Nordhaus (2010 p 3), who notes that "…damages in the uncontrolled (baseline) [i.e., reference] case … in 2095 are $12 trillion, or 2.8 percent of global output, for a global temperature increase of 3.4 ^{o}C above 1900 levels." This compares to a loss of 3.2 percent of global output at 3.4 ^{o}C in DICE2007. However, in DICE2010, annual damages are lower in most of the early periods of the modeling horizon but higher in later periods than would be calculated using the DICE2007 damage function. Specifically, the percent difference between damages in the base run of DICE2010 and those that would be calculated using the DICE2007 damage function starts at +7 percent in 2005, decreases to a low of -14 percent in 2065, then continuously increases to +20 percent by 2300 (the end of the interagency analysis time horizon), and to +160 percent by the end of the model time horizon in 2595. The large increases in the far future years of the time horizon are due to the permanence associated with damages from sea level rise, along with the assumption that the sea level is projected to continue to rise long after the global average temperature begins to decrease. The changes to the loss function generally decrease the interagency working group SCC estimates slightly given that relative increases in damages in later periods are discounted more heavily, all else equal.

B. FUND

FUND version 3.8 includes a number of changes over the previous version 3.5 (Narita et al. 2010) used in the 2010 interagency report. Documentation supporting FUND and the model's source code for all versions of the model is available from the model authors.[8] Notable changes, due to their impact on the

[7] The model and documentation, including formulas, are available on the author's webpage at http://www.econ.yale.edu/~nordhaus/homepage/RICEmodels.htm.

[8] http://www.fund-model.org/. This report uses version 3.8 of the FUND model, which represents a modest update to the most recent version of the model to appear in the literature (version 3.7) (Anthoff and Tol, 2013a). For the purpose of computing the SCC, the relevant changes (between 3.7 to 3.8) are associated with improving

SCC estimates, are adjustments to the space heating, agriculture, and sea level rise damage functions in addition to changes to the temperature response function and the inclusion of indirect effects from methane emissions.[9] We discuss each of these in turn.

Space Heating

In FUND, the damages associated with the change in energy needs for space heating are based on the estimated impact due to one degree of warming. These baseline damages are scaled based on the forecasted temperature anomaly's deviation from the one degree benchmark and adjusted for changes in vulnerability due to economic and energy efficiency growth. In FUND 3.5, the function that scales the base year damages adjusted for vulnerability allows for the possibility that in some simulations the benefits associated with reduced heating needs may be an unbounded convex function of the temperature anomaly. In FUND 3.8, the form of the scaling has been modified to ensure that the function is everywhere concave and that there will exist an upper bound on the benefits a region may receive from reduced space heating needs. The new formulation approaches a value of two in the limit of large temperature anomalies, or in other words, assuming no decrease in vulnerability, the reduced expenditures on space heating at any level of warming will not exceed two times the reductions experienced at one degree of warming. Since the reduced need for space heating represents a benefit of climate change in the model, or a negative damage, this change will increase the estimated SCC. This update accounts for a significant portion of the difference in the expected SCC estimates reported by the two versions of the model when run probabilistically.

Sea Level Rise and Land Loss

The FUND model explicitly includes damages associated with the inundation of dry land due to sea level rise. The amount of land lost within a region is dependent upon the proportion of the coastline being protected by adequate sea walls and the amount of sea level rise. In FUND 3.5 the function defining the potential land lost in a given year due to sea level rise is linear in the rate of sea level rise for that year. This assumption implicitly assumes that all regions are well represented by a homogeneous coastline in length and a constant uniform slope moving inland. In FUND 3.8 the function defining the potential land lost has been changed to be a convex function of sea level rise, thereby assuming that the slope of the shore line increases moving inland. The effect of this change is to typically reduce the vulnerability of some regions to sea level rise based land loss, thereby lowering the expected SCC estimate. [10]

Agriculture

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consistency with IPCC AR4 by adjusting the atmospheric lifetimes of CH4 and N2O and incorporating the indirect forcing effects of CH4, along with making minor stability improvements in the sea wall construction algorithm.

[9] The other damage sectors (water resources, space cooling, land loss, migration, ecosystems, human health, and extreme weather) were not significantly updated.

[10] For stability purposes this report also uses an update to the model which assumes that regional coastal protection measures will be built to protect the most valuable land first, such that the marginal benefits of coastal protection is decreasing in the level of protection following Fankhauser (1995).

In FUND, the damages associated with the agricultural sector are measured as proportional to the sector's value. The fraction is bounded from above by one and is made up of three additive components that represent the effects from carbon fertilization, the rate of temperature change, and the level of the temperature anomaly. In both FUND 3.5 and FUND 3.8, the fraction of the sector's value lost due to the level of the temperature anomaly is modeled as a quadratic function with an intercept of zero. In FUND 3.5, the coefficients of this loss function are modeled as the ratio of two random normal variables. This specification had the potential for unintended extreme behavior as draws from the parameter in the denominator approached zero or went negative. In FUND 3.8, the coefficients are drawn directly from truncated normal distributions so that they remain in the range $[0,\infty)$ and $(-\infty,0]$, respectively, ensuring the correct sign and eliminating the potential for divide by zero errors. The means for the new distributions are set equal to the ratio of the means from the normal distributions used in the previous version. In general the impact of this change has been to decrease the range of the distribution while spreading out the distributions' mass over the remaining range relative to the previous version. The net effect of this change on the SCC estimates is difficult to predict.

Transient Temperature Response

The temperature response model translates changes in global levels of radiative forcing into the current expected temperature anomaly. In FUND, a given year's increase in the temperature anomaly is based on a mean reverting function where the mean equals the equilibrium temperature anomaly that would eventually be reached if that year's level of radiative forcing were sustained. The rate of mean reversion defines the rate at which the transient temperature approaches the equilibrium. In FUND 3.5, the rate of temperature response is defined as a decreasing linear function of equilibrium climate sensitivity to capture the fact that the progressive heat uptake of the deep ocean causes the rate to slow at higher values of the equilibrium climate sensitivity. In FUND 3.8, the rate of temperature response has been updated to a quadratic function of the equilibrium climate sensitivity. This change reduces the sensitivity of the rate of temperature response to the level of the equilibrium climate sensitivity, a relationship first noted by Hansen et al. (1985) based on the heat uptake of the deep ocean. Therefore in FUND 3.8, the temperature response will typically be faster than in the previous version. The overall effect of this change is likely to increase estimates of the SCC as higher temperatures are reached during the timeframe analyzed and as the same damages experienced in the previous version of the model are now experienced earlier and therefore discounted less.

Methane

The IPCC AR4 notes a series of indirect effects of methane emissions, and has developed methods for proxying such effects when computing the global warming potential of methane (Forster et al. 2007). FUND 3.8 now includes the same methods for incorporating the indirect effects of methane emissions. Specifically, the average atmospheric lifetime of methane has been set to 12 years to account for the feedback of methane emissions on its own lifetime. The radiative forcing associated with atmospheric methane has also been increased by 40% to account for its net impact on ozone production and stratospheric water vapor. All else equal, the effect of this increased radiative forcing will be to increase the estimated SCC values, due to greater projected temperature anomaly.

C. PAGE

PAGE09 (Hope 2013) includes a number of changes from PAGE2002, the version used in the 2010 SCC interagency report. The changes that most directly affect the SCC estimates include: explicitly modeling the impacts from sea level rise, revisions to the damage function to ensure damages are constrained by GDP, a change in the regional scaling of damages, a revised treatment for the probability of a discontinuity within the damage function, and revised assumptions on adaptation. The model also includes revisions to the carbon cycle feedback and the calculation of regional temperatures.[11] More details on PAGE09 can be found in Hope (2011a, 2011b, 2011c). A description of PAGE2002 can be found in Hope (2006).

Sea Level Rise

While PAGE2002 aggregates all damages into two categories – economic and non-economic impacts -, PAGE09 adds a third explicit category: damages from sea level rise. In the previous version of the model, damages from sea level rise were subsumed by the other damage categories. In PAGE09 sea level damages increase less than linearly with sea level under the assumption that land, people, and GDP are more concentrated in low-lying shoreline areas. Damages from the economic and non-economic sector were adjusted to account for the introduction of this new category.

Revised Damage Function to Account for Saturation

In PAGE09, small initial economic and non-economic benefits (negative damages) are modeled for small temperature increases, but all regions eventually experience economic damages from climate change, where damages are the sum of additively separable polynomial functions of temperature and sea level rise. Damages transition from this polynomial function to a logistic path once they exceed a certain proportion of remaining Gross Domestic Product (GDP) to ensure that damages do not exceed 100 percent of GDP. This differs from PAGE2002, which allowed Eastern Europe to potentially experience large benefits from temperature increases, and which also did not bound the possible damages that could be experienced.

Regional Scaling Factors

As in the previous version of PAGE, the PAGE09 model calculates the damages for the European Union (EU) and then, assumes that damages for other regions are proportional based on a given scaling factor. The scaling factor in PAGE09 is based on the length of a region's coastline relative to the EU (Hope 2011b). Because of the long coastline in the EU, other regions are, on average, less vulnerable than the EU for the same sea level and temperature increase, but all regions have a positive scaling factor. PAGE2002 based its scaling factors on four studies reported in the IPCC's third assessment report, and allowed for benefits from temperature increase in Eastern Europe, smaller impacts in developed countries, and higher damages in developing countries.

[11] Because several changes in the PAGE model are structural (e.g., the addition of sea level rise and treatment of discontinuity), it is not possible to assess the direct impact of each change on the SCC in isolation as done for the other two models above.

Probability of a Discontinuity

In PAGE2002, the damages associated with a "discontinuity" (nonlinear extreme event) were modeled as an expected value. Specifically, a stochastic probability of a discontinuity was multiplied by the damages associated with a discontinuity to obtain an expected value, and this was added to the economic and non-economic impacts. That is, additional damages from an extreme event, such as extreme melting of the Greenland ice sheet, were multiplied by the probability of the event occurring and added to the damage estimate. In PAGE09, the probability of discontinuity is treated as a discrete event for each year in the model. The damages for each model run are estimated either with or without a discontinuity occurring, rather than as an expected value. A large-scale discontinuity becomes possible when the temperature rises beyond some threshold value between 2 and 4°C. The probability that a discontinuity will occur beyond this threshold then increases by between 10 and 30 percent for every 1°C rise in temperature beyond the threshold. If a discontinuity occurs, the EU loses an additional 5 to 25 percent of its GDP (drawn from a triangular distribution with a mean of 15 percent) in addition to other damages, and other regions lose an amount determined by the regional scaling factor. The threshold value for a possible discontinuity is lower than in PAGE2002, while the rate at which the probability of a discontinuity increases with the temperature anomaly and the damages that result from a discontinuity are both higher than in PAGE2002. The model assumes that only one discontinuity can occur and that the impact is phased in over a period of time, but once it occurs, its effect is permanent.

Adaptation

As in PAGE2002, adaptation is available to help mitigate any climate change impacts that occur. In PAGE this adaptation is the same regardless of the temperature change or sea level rise and is therefore akin to what is more commonly considered a reduction in vulnerability. It is modeled by reducing the damages by some percentage. PAGE09 assumes a smaller decrease in vulnerability than the previous version of the model and assumes that it will take longer for this change in vulnerability to be realized. In the aggregated economic sector, at the time of full implementation, this adaptation will mitigate all damages up to a temperature increase of 1°C, and for temperature anomalies between 1°C and 2°C, it will reduce damages by 15-30 percent (depending on the region). However, it takes 20 years to fully implement this adaptation. In PAGE2002, adaptation was assumed to reduce economic sector damages up to 2°C by 50-90 percent after 20 years. Beyond 2°C, no adaptation is assumed to be available to mitigate the impacts of climate change. For the non-economic sector, in PAGE09 adaptation is available to reduce 15 percent of the damages due to a temperature increase between 0°C and 2°C and is assumed to take 40 years to fully implement, instead of 25 percent of the damages over 20 years assumed in PAGE2002. Similarly, adaptation is assumed to alleviate 25-50 percent of the damages from the first 0.20 to 0.25 meters of sea level rise but is assumed to be ineffective thereafter. Hope (2011c) estimates that the less optimistic assumptions regarding the ability to offset impacts of temperature and sea level rise via adaptation increase the SCC by approximately 30 percent.

Other Noteworthy Changes

Two other changes in the model are worth noting. There is a change in the way the model accounts for decreased CO_2 absorption on land and in the ocean as temperature rises. PAGE09 introduces a linear feedback from global mean temperature to the percentage gain in the excess concentration of CO_2, capped at a maximum level. In PAGE2002, an additional amount was added to the CO_2 emissions each period to account for a decrease in ocean absorption and a loss of soil carbon. Also updated is the method by which the average global and annual temperature anomaly is downscaled to determine annual average regional temperature anomalies to be used in the regional damage functions. In PAGE2002, the scaling was determined solely based on regional difference in emissions of sulfate aerosols. In PAGE09, this regional temperature anomaly is further adjusted using an additive factor that is based on the average absolute latitude of a region relative to the area weighted average absolute latitude of the Earth's landmass, to capture relatively greater changes in temperature forecast to be experienced at higher latitudes.

III. Revised SCC Estimates

The updated versions of the three integrated assessment models were run using the same methodology detailed in the 2010 TSD (Interagency Working Group on Social Cost of Carbon 2010). The approach along with the inputs for the socioeconomic emissions scenarios, equilibrium climate sensitivity distribution, and discount rate remains the same. This includes the five reference scenarios based on the EMF-22 modeling exercise, the Roe and Baker equilibrium climate sensitivity distribution calibrated to the IPCC AR4, and three constant discount rates of 2.5, 3, and 5 percent.

As was previously the case, the use of three models, three discount rates, and five scenarios produces 45 separate distributions for the global SCC. The approach laid out in the 2010 TSD applied equal weight to each model and socioeconomic scenario in order to reduce the dimensionality down to three separate distributions representative of the three discount rates. The interagency group selected four values from these distributions for use in regulatory analysis. Three values are based on the average SCC across models and socio-economic-emissions scenarios at the 2.5, 3, and 5 percent discount rates, respectively. The fourth value was chosen to represent the higher-than-expected economic impacts from climate change further out in the tails of the SCC distribution. For this purpose, the 95th percentile of the SCC estimates at a 3 percent discount rate was chosen. (A detailed set of percentiles by model and scenario combination and additional summary statistics for the 2020 values is available in the Appendix.) As noted in the 2010 TSD, "the 3 percent discount rate is the central value, and so the central value that emerges is the average SCC across models at the 3 percent discount rate" (Interagency Working Group on Social Cost of Carbon 2010, p. 25). However, for purposes of capturing the uncertainties involved in regulatory impact analysis, the interagency group emphasizes the importance and value of including all four SCC values.

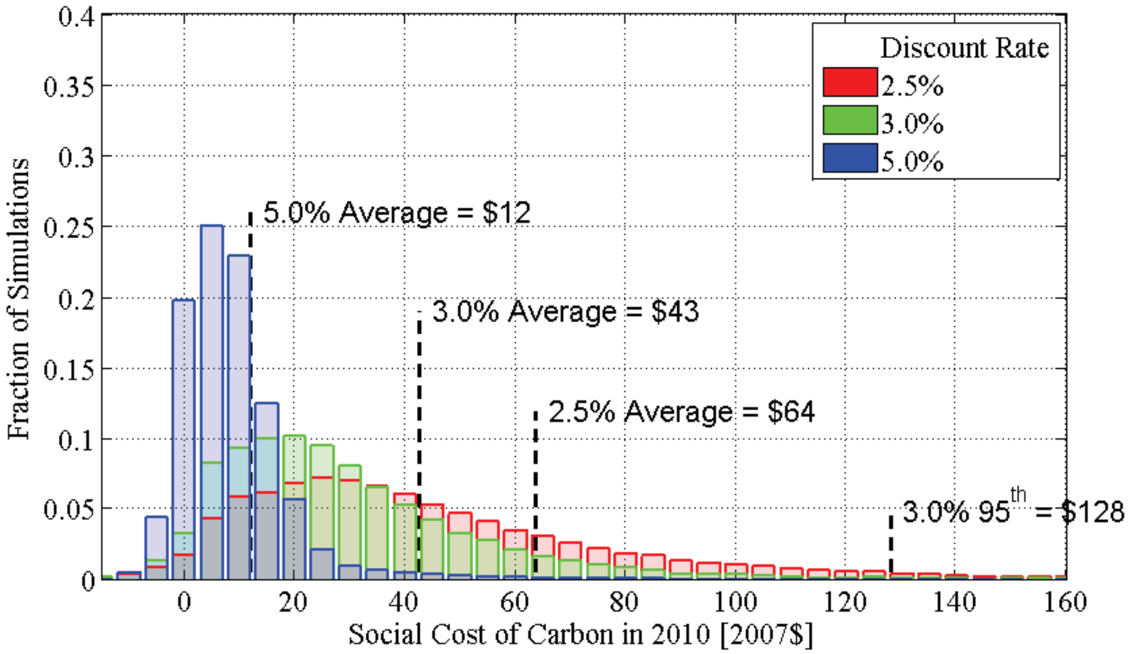
Table 2 shows the four selected SCC estimates in five year increments from 2010 to 2050. Values for 2010, 2020, 2030, 2040, and 2050 are calculated by first combining all outputs (10,000 estimates per model run) from all scenarios and models for a given discount rate. Values for the years in between are calculated using linear interpolation. The full set of revised annual SCC estimates between 2010 and 2050 is reported in the Appendix.

Table 2: Revised Social Cost of CO_2, 2010 – 2050 (in 2007 dollars per metric ton of CO_2)

Discount Rate Year	5.0% Avg	3.0% Avg	2.5% Avg	3.0% 95th
2010	11	32	51	89
2015	11	37	57	109
2020	12	43	64	128
2025	14	47	69	143
2030	16	52	75	159
2035	19	56	80	175
2040	21	61	86	191
2045	24	66	92	206
2050	26	71	97	220

The SCC estimates using the updated versions of the models are higher than those reported in the 2010 TSD due to the changes to the models outlined in the previous section. By way of comparison, the 2020 SCC estimates reported in the original TSD were \$7, \$26, \$42 and \$81 (2007\$) (Interagency Working Group on Social Cost of Carbon 2010). Figure 1 illustrates where the four SCC values for 2020 fall within the full distribution for each discount rate based on the combined set of runs for each model and scenario (150,000 estimates in total for each discount rate). In general, the distributions are skewed to the right and have long tails. The Figure also shows that the lower the discount rate, the longer the right tail of the distribution.

Figure 1: Distribution of SCC Estimates for 2020 (in 2007\$ per metric ton CO_2)



As was the case in the 2010 TSD, the SCC increases over time because future emissions are expected to produce larger incremental damages as physical and economic systems become more stressed in response to greater climatic change. The approach taken by the interagency group is to compute the cost of a marginal ton emitted in the future by running the models for a set of perturbation years out to 2050. Table 3 illustrates how the growth rate for these four SCC estimates varies over time.

Table 3: Average Annual Growth Rates of SCC Estimates between 2010 and 2050

Average Annual Growth Rate (%)	5.0% Avg	3.0% Avg	2.5% Avg	3.0% 95th
2010-2020	1.2%	3.3%	2.4%	4.4%
2020-2030	3.4%	2.1%	1.7%	2.4%
2030-2040	3.0%	1.9%	1.5%	2.1%
2040-2050	2.6%	1.6%	1.3%	1.5%

The future monetized value of emission reductions in each year (the SCC in year *t* multiplied by the change in emissions in year *t*) must be discounted to the present to determine its total net present value for use in regulatory analysis. As previously discussed in the 2010 TSD, damages from future emissions should be discounted at the same rate as that used to calculate the SCC estimates themselves to ensure internal consistency – i.e., future damages from climate change, whether they result from emissions today or emissions in a later year, should be discounted using the same rate.

Under current OMB guidance contained in Circular A-4, analysis of economically significant proposed and final regulations from the domestic perspective is required, while analysis from the international perspective is optional. However, the climate change problem is highly unusual in at least two respects. First, it involves a global externality: emissions of most greenhouse gases contribute to damages around the world even when they are emitted in the United States. Consequently, to address the global nature of the problem, the SCC must incorporate the full (global) damages caused by GHG emissions. Second, climate change presents a problem that the United States alone cannot solve. Even if the United States were to reduce its greenhouse gas emissions to zero, that step would be far from enough to avoid substantial climate change. Other countries would also need to take action to reduce emissions if significant changes in the global climate are to be avoided. Emphasizing the need for a global solution to a global problem, the United States has been actively involved in seeking international agreements to reduce emissions and in encouraging other nations, including emerging major economies, to take significant steps to reduce emissions. When these considerations are taken as a whole, the interagency group concluded that a global measure of the benefits from reducing U.S. emissions is preferable. For additional discussion, see the 2010 TSD.

IV. Other Model Limitations and Research Gaps

The 2010 interagency SCC TSD discusses a number of important limitations for which additional research is needed. In particular, the document highlights the need to improve the quantification of both non-catastrophic and catastrophic damages, the treatment of adaptation and technological change, and the way in which inter-regional and inter-sectoral linkages are modeled. While the new version of the models discussed above offer some improvements in these areas, further work remains warranted. The 2010 TSD also discusses the need to more carefully assess the implications of risk aversion for SCC estimation as well as the inability to perfectly substitute between climate and non-climate goods at higher temperature increases, both of which have implications for the discount rate used. EPA, DOE, and other agencies continue to engage in research on modeling and valuation of climate impacts that can potentially improve SCC estimation in the future.

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Appendix A

Table A1: Annual SCC Values: 2010-2050 (2007$/metric ton CO_2)

Discount Rate Year	5.0% Avg	3.0% Avg	2.5% Avg	3.0% 95th
2010	11	32	51	89
2011	11	33	52	93
2012	11	34	54	97
2013	11	35	55	101
2014	11	36	56	105
2015	11	37	57	109
2016	12	38	59	112
2017	12	39	60	116
2018	12	40	61	120
2019	12	42	62	124
2020	12	43	64	128
2021	12	43	65	131
2022	13	44	66	134
2023	13	45	67	137
2024	14	46	68	140
2025	14	47	69	143
2026	15	48	70	146
2027	15	49	71	149
2028	15	50	72	152
2029	16	51	73	155
2030	16	52	75	159
2031	17	52	76	162
2032	17	53	77	165
2033	18	54	78	168
2034	18	55	79	172
2035	19	56	80	175
2036	19	57	81	178
2037	20	58	83	181
2038	20	59	84	185
2039	21	60	85	188
2040	21	61	86	191
2041	22	62	87	194
2042	22	63	88	197
2043	23	64	89	200
2044	23	65	90	203
2045	24	66	92	206
2046	24	67	93	209
2047	25	68	94	211
2048	25	69	95	214
2049	26	70	96	217
2050	26	71	97	220

Table A2: 2020 Global SCC Estimates at 2.5 Percent Discount Rate (2007$/metric ton CO_2)

Percentile	1st	5th	10th	25th	50th	Avg	75th	90th	95th	99th
Scenario[12]	PAGE									
IMAGE	6	11	15	27	58	129	139	327	515	991
MERGE	4	6	9	16	34	78	82	196	317	649
MESSAGE	4	8	11	20	42	108	107	278	483	918
MiniCAM Base	5	9	12	22	47	107	113	266	431	872
5th Scenario	2	4	6	11	25	85	68	200	387	955
Scenario	DICE									
IMAGE	25	31	37	47	64	72	92	123	139	161
MERGE	14	18	20	26	36	40	50	65	74	85
MESSAGE	20	24	28	37	51	58	71	95	109	221
MiniCAM Base	20	25	29	38	53	61	76	102	117	135
5th Scenario	17	22	25	33	45	52	65	91	106	126
Scenario	FUND									
IMAGE	-14	-2	4	15	31	39	55	86	107	157
MERGE	-6	1	6	14	27	35	46	70	87	141
MESSAGE	-16	-5	1	11	24	31	43	67	83	126
MiniCAM Base	-7	2	7	16	32	39	55	83	103	158
5th Scenario	-29	-13	-6	4	16	21	32	53	69	103

Table A3: 2020 Global SCC Estimates at 3 Percent Discount Rate (2007$/metric ton CO_2)

Percentile	1st	5th	10th	25th	50th	Avg	75th	90th	95th	99th
Scenario	PAGE									
IMAGE	4	7	10	18	38	91	95	238	385	727
MERGE	2	4	6	11	23	56	58	142	232	481
MESSAGE	3	5	7	13	29	75	74	197	330	641
MiniCAM Base	3	5	8	14	30	73	75	184	300	623
5th Scenario	1	3	4	7	17	58	48	136	264	660
Scenario	DICE									
IMAGE	16	21	24	32	43	48	60	79	90	102
MERGE	10	13	15	19	25	28	35	44	50	58
MESSAGE	14	18	20	26	35	40	49	64	73	83
MiniCAM Base	13	17	20	26	35	39	49	65	73	85
5th Scenario	12	15	17	22	30	34	43	58	67	79
Scenario	FUND									
IMAGE	-13	-4	0	8	18	23	33	51	65	99
MERGE	-7	-1	2	8	17	21	29	45	57	95
MESSAGE	-14	-6	-2	5	14	18	26	41	52	82
MiniCAM Base	-7	-1	3	9	19	23	33	50	63	101
5th Scenario	-22	-11	-6	1	8	11	18	31	40	62

[12] See 2010 TSD for a description of these scenarios.

Table A4: 2020 Global SCC Estimates at 5 Percent Discount Rate (2007$/metric ton CO_2)

Percentile	1st	5th	10th	25th	50th	Avg	75th	90th	95th	99th
Scenario	PAGE									
IMAGE	1	2	2	5	10	28	27	71	123	244
MERGE	1	1	2	3	7	17	17	45	75	153
MESSAGE	1	1	2	4	9	24	22	60	106	216
MiniCAM Base	1	1	2	3	8	21	21	54	94	190
5th Scenario	0	1	1	2	5	18	14	41	78	208

Scenario	DICE									
IMAGE	6	8	9	11	14	15	18	22	25	27
MERGE	4	5	6	7	9	10	12	15	16	18
MESSAGE	6	7	8	10	12	13	16	20	22	25
MiniCAM Base	5	6	7	8	11	12	14	18	20	22
5th Scenario	5	6	6	8	10	11	14	17	19	21

Scenario	FUND									
IMAGE	-9	-5	-4	-1	2	3	6	10	14	24
MERGE	-6	-4	-2	0	3	4	6	11	15	26
MESSAGE	-10	-6	-4	-1	1	2	5	9	12	21
MiniCAM Base	-7	-4	-2	0	3	4	6	11	14	25
5th Scenario	-11	-7	-5	-3	0	0	3	5	7	13

Table A5: Additional Summary Statistics of 2020 Global SCC Estimates

Discount rate:	5.0%				3.0%				2.5%			
Statistic:	Mean	Variance	Skewness	Kurtosis	Mean	Variance	Skewness	Kurtosis	Mean	Variance	Skewness	Kurtosis
DICE	12	26	2	15	38	409	3	24	57	1097	3	30
PAGE	22	1616	5	32	71	14953	4	22	101	29312	4	23
FUND	3	41	5	179	19	1452	-42	8727	33	6154	-73	14931

Appendix B

The November 2013 revision of this technical support document is based on two corrections to the runs based on the FUND model. First, the potential dry land loss in the algorithm that estimates regional coastal protections was misspecified in the model's computer code. This correction is covered in an erratum to Anthoff and Tol (2013a) published in the same journal (Climatic Change) in October 2013 (Anthoff and Tol (2013b)). Second, the equilibrium climate sensitivity distribution was inadvertently specified as a truncated Gamma distribution (the default in FUND) as opposed to the truncated Roe and Baker distribution as was intended. The truncated Gamma distribution used in the FUND runs had approximately the same mean and upper truncation point, but lower variance and faster decay of the upper tail, as compared to the intended specification based on the Roe and Baker distribution. The difference between the original estimates reported in the May 2013 version of this technical support document and this revision are generally one dollar or less.