Paper #4-5

POLICY OPTIONS FOR DEPLOYMENT OF NATURAL GAS END-USE GHG REDUCTION TECHNOLOGIES

Prepared by the Policy Team
of the
Carbon and Other End-Use Emissions Subgroup

On September 15, 2011, The National Petroleum Council (NPC) in approving its report, *Prudent Development: Realizing the Potential of North America's Abundant Natural Gas and Oil Resources*, also approved the making available of certain materials used in the study process, including detailed, specific subject matter papers prepared or used by the study's Task Groups and/or Subgroups. These Topic and White Papers were working documents that were part of the analyses that led to development of the summary results presented in the report's Executive Summary and Chapters.

These Topic and White Papers represent the views and conclusions of the authors. The National Petroleum Council has not endorsed or approved the statements and conclusions contained in these documents, but approved the publication of these materials as part of the study process.

The NPC believes that these papers will be of interest to the readers of the report and will help them better understand the results. These materials are being made available in the interest of transparency.

The attached paper is one of 57 such working documents used in the study analyses. Also included is a roster of the Team that developed or submitted this paper. Appendix C of the final NPC report provides a complete list of the 57 Topic and White Papers and an abstract for each. The full papers can be viewed and downloaded from the report section of the NPC website (www.npc.org).

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* Individual has since changed organizations but was employed by the specified company while participating in the study.

** Replaced by Robin K. Roy in April 2011. Individual has since changed organizations but was employed by the specified company while participating in the study.

Abbreviations

Item	Abbreviation
British thermal units	Btu
Carbon capture and storage	CCS
carbon dioxide	CO_2
carbon dioxide equivalent	CO_2e
Combined heat and power	CHP
Combustion turbine	CT
greenhouse gas	GHG
metric tonne	tonne
million (mega)	M
Natural gas combined cycle	NGCC
nitrogen oxides	NO_x
short ton	ton
sulfur dioxide	SO_2
thousand (kilo)	K
ton or tonne	t
Watt-hour	Wh

Abstract

Given the abundance of natural gas supplies in the United States, natural gas can play a significant role in the energy consumption patterns of the country. Consistent with Secretary Chu's directive to the National Petroleum Council (NPC), this paper identifies policy options that allows for accelerated deployment of natural gas and associated technologies in various end-use sectors with the goal of reducing greenhouse gas emissions and maintaining energy and economic security. The paper finds that if the United States wants to adopt an energy and environmental strategy that enhances the role of natural gas in the economy, it must work simultaneously and strategically on many policy fronts. In general, increased natural gas supplies, along with new environmental regulations, make natural gas an attractive option as a fuel in the end-use sectors, especially the electric power sector in the near- to midterm, particularly as a replacement fuel if there are significant coal plant retirements. Simple and seemingly attractive environmental policy approaches, such as adopting a price on carbon must play a central role but will not by themselves realize the goals laid out by the Secretary for this study. Under a scenario requiring deeper, long-term emission reductions (e.g., 80% reduction of GHGs by 2050 from a 2005 baseline level), the contribution that natural gas would make to a lower carbon fuel mix may be less certain.

Introduction

In September of 2009, the Secretary of Energy, Steven Chu, requested that the National Petroleum Council (NPC) identify the "policy options that would allow prudent development of North American natural gas and oil resources consistent with government objectives of environmental protection, economic growth and national security." Secretary Chu also sought to identify "the contribution that natural gas can make in a transition to a lower carbon fuel mix." Additionally, the Secretary requested policy guidance on demonstrating "global leadership in technological and environmental innovation" and the research and development (R&D) that "DOE is investing in that may dramatically improve technology choices we could have in 5-15 years."

As part of the larger NPC study that responds to the Secretary's request, a sub-group on Carbon and End-use emissions has focused on the prospects for reducing carbon emissions through the use of natural gas. That sub group included teams that examined likely patterns in emissions (team 1) and clusters of end-use technologies that, if deployed at an accelerated rate, could lead to reductions of emissions of CO_2 (team 2). The present report concerns team 3, which focuses on policies. Another team has focused in more depth on the likely impact of upcoming rules being developed by the Environmental Protection Agency (team 4).

This report identifies policies that could lead to the "accelerated deployment"[1] of natural gas technologies with the goal of reducing greenhouse gas emissions and maintaining energy and economic

[1] The term "accelerated deployment" has been defined by the National Research Council (2009) as the deployment of technologies at a rate that would exceed the reference scenario deployment pace, but at a less dramatic rate than an all-out crash effort, which could require disruptive economic and lifestyle changes that would be challenging to initiate and sustain.

security. The report begins with a brief summary of our methods and then identifies the main findings. A lengthy series of appendices offer more detail.

Overview of Methods

Team 2 identified 15 clusters of natural gas end-use technologies whose accelerated deployment could lead to a material impact on greenhouse gas (GHG) emissions by 2030. That team examined the costs associated with those technologies and the likely volume of GHG reductions.[2] The role of gas beyond 2030 is harder to parse because very deep reductions (perhaps on the order of 80% cuts in emissions by 2050) will require a large role for near-zero emissions energy technologies. Natural gas could play such a role, for example, with widespread use of gas with carbon capture and storage (CCS) technologies—one of the options considered by team 2 and also in this report.

In this report we work with those 15 clusters of technologies to identify the broad policy options that could actually accelerate deployment of those technologies.

Table 1 shows the list of 15 technology clusters. In some cases, the policies that could affect those clusters overlap and thus we grouped some clusters together for the purposes of discussing policy. For example, the policies that affect use of natural gas appliances are similar whether the appliance is deployed in a commercial, residential or industrial setting. Through such grouping we identified 8 case studies that span the technology clusters and tasked policy team experts in each area to review the opportunities associated with each technology, the hurdles facing more widespread deployment of each technology, and to offer expert judgments on policies that would accelerate the deployment of the technology. Those case studies are presented at appendices to this report.

The policy team adopted two perspectives in analyzing the relevant policies. First, we examined a long list of policies that *might* be relevant and focused on those that could be particularly relevant for each case. That long list is presented in Appendix A. This approach helped to ensure some comparability between the case studies and also helped ensure that the case study authors looked broadly at the types of policies that might be relevant.

The second perspective involved evaluation of policies across seven criteria that are often used in policy-making processes. These criteria, which were chosen with the aim of responding to the Secretary's request, allowed for a holistic evaluation of the policies that could have an impact on the accelerated deployment of these technologies:

1. Maturity of technology
2. Cost effectiveness of technology at reducing CO_2 emissions
3. Public acceptance of technology
4. Regulatory and technical barriers
5. Role for government
6. Market barriers
7. Impact on jobs

[2] 15 natural gas technologies were identified with median cost-weighted average reduction volumes estimated at 75 MM MtCO2e with a volume-weighted average cost of $37/MtCO2e

For each of these criteria the policy team evaluated the technology relative to other technologies as high, medium or low. Table 2 summarizes how we defined those criteria.

Overview of Results

The policies that are relevant for any particular technology are usually complex; they depend on particular circumstances. Here we look across all of the team's 8 case studies and adopt a broad perspective. Our central argument is that if the United States wants to adopt an energy and environmental strategy that promotes a substantial increase in the utilization of natural gas, it must work simultaneously and strategically on many policy fronts. Simple and seemingly attractive environmental policy approaches, such as adopting a price on carbon, will not by themselves realize the goals laid out by the Secretary for this study. A clear signal to reduce carbon—such as a cap on emissions, a carbon price or other carbon-focused regulation and standards—must play a central role but will not be enough.

In looking across the 8 case studies first we examined the actual policies that the case studies identified as important. Table 3 is the result of that "bottom up" exercise. It summarizes the policies that could affect the consumption of natural gas generally as well as policies that could be focused on gas-based technologies specifically identified by team 2. It also notes the large array of other policies—such as reform of building standards—that might be necessary to maximize utilization of gas to meet emission reduction goals.

It is also instructive to explore how the seven evaluation criteria interact. To illustrate those interactions we focus on two criteria that are likely to have a big impact on policy design: the cost-effectiveness of a technology (closely linked to maturity and ability to achieve a given level of emissions reduction) and barriers. Figure 1 shows the results from plotting the 8 case studies on these two dimensions for evaluation. Table 4 summarizes the "scores" we assigned on each of the seven evaluation criteria.

At the upper left corner of Figure 1 are technologies (and changes in management) that are already highly cost-effective and face relatively few barriers. Most of the options surrounding the fuller use of natural gas with conventional technologies in the electric power sector fall into this category. We note, however, that placement on this chart is sensitive to the fact that we defined cost-effectiveness with reference to a moderate price on CO_2 emissions of \$20-40 t/CO_2e out to 2030. That price is consistent with the need to put the economy on a trajectory to lower emissions, but by itself such a price is unlikely to yield the very deep cuts in emissions consistent with goals such as an 80% or larger reduction in total emissions.[3] Achieving deep cuts probably will require deploying a much wider array of technologies (including many technologies outside those that utilize natural gas and thus outside the scope of this study) and higher CO2 prices beyond 2030. Higher carbon prices will allow the use of options that sit lower on Figure 1—that is, options that are cost effective only at higher carbon prices.

At the lower right corner are the exact opposite—technologies that are much more expensive and also face large barriers. Many of these technologies have revolutionary potential and, like most revolutionary devices, do not fit easily within the current regulatory system. The most extreme cases—such as fuel cells—face high economic barriers (i.e., low cost effectiveness) many regulatory barriers and

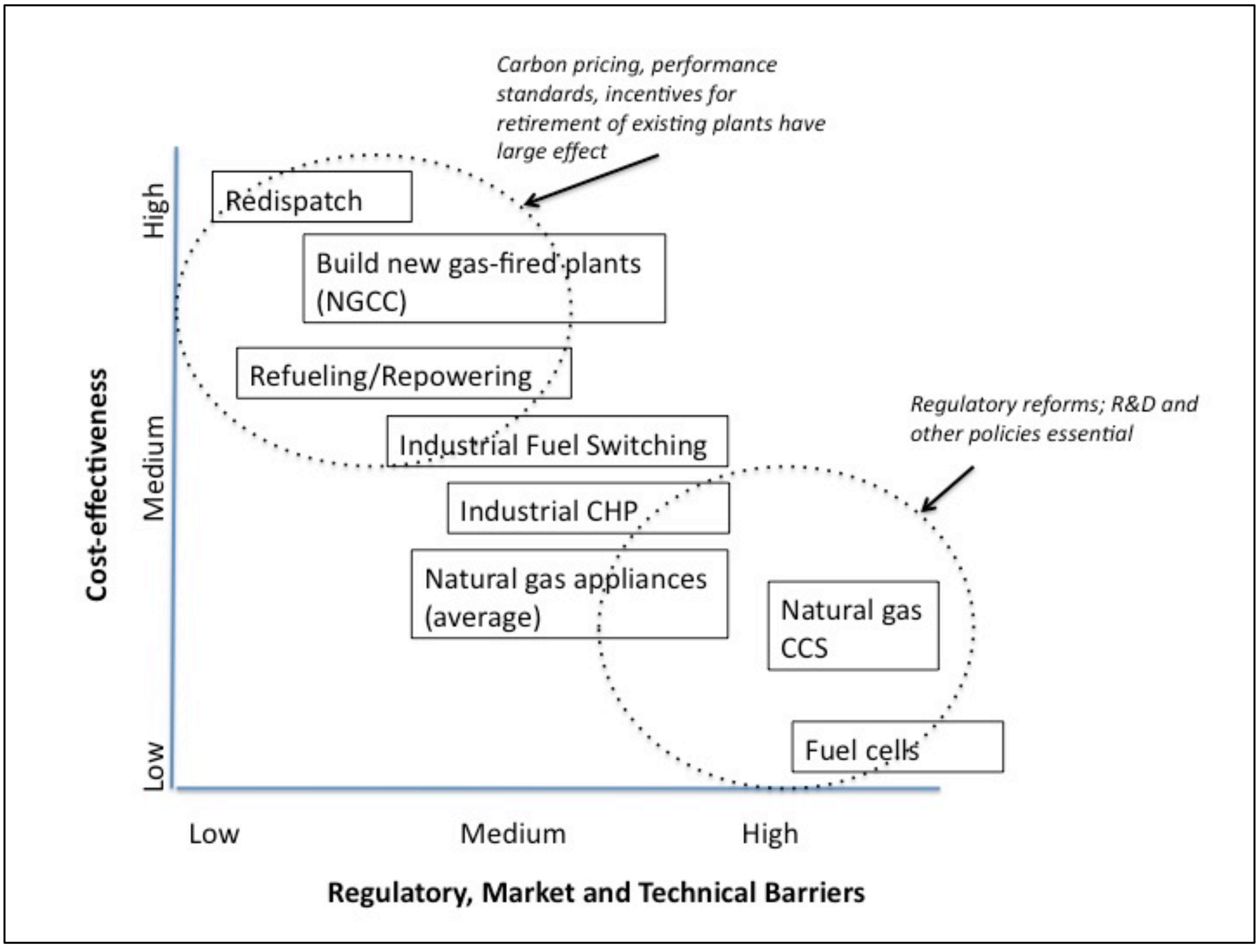
[3] For example, see the EPA's analysis of "Waxman-Markey" (http://www.epa.gov/climatechange/economics/economicanalyses.html#hr2454)

are, at this stage, topics for advanced research and development. Carbon pricing, by itself, is a much less important driver for emerging technologies than direct regulatory actions and support for RD&D that could, in time, lower deployment costs.

In the middle are technologies that have moderate costs along with modest (but not prohibitive) regulatory barriers. That middle range includes many technologies that are already mature (or nearly so) yet will not be deployed at an accelerated rate without a combination of carbon prices and a broad array of regulatory reforms.

Figure 1: Evaluating Gas Use Options According to their Cost-effectiveness and Regulatory barriers for policies designed to achieve low to moderate reductions in GHG emissions.

(Note: High cost-effectiveness means that the technology is at or near competitive with low or zero cost per ton CO2 emission avoided. Low cost-effectiveness means that much larger policy signals—including possibly high costs for CO2 emissions—would be needed for commercial deployment of the technology.)



For the upper left corner options, a policy strategy of carbon pricing can have a large impact if other market conditions favor a shift to gas. Notably, when gas prices are relatively low compared to other energy sources—on its own or with a modest additional incentive in the form of carbon pricing—then gas can compete effectively against coal. Indeed, if gas prices remain low relative to other fuels and conversion technologies, some opportunities in the upper left corner might unfold without much additional policy signal (but perhaps not to a degree to achieve substantial emissions reductions).[4] Carbon prices projections in many legislative actions that have been considered in the 111th Congress are expected to start off within this price range.

Deploying the technologies in the lower right corner is a lot more complicated because it requires a wider array of policies and higher carbon prices. Research, Development a ND Deployment(RD&D) incentives, including subsidies, will likely play a key factor in bringing many of these technologies to commercial deployment. However, accelerated deployment or even widespread adoption of these technologies will require overcoming significant regulatory, economic, and social barriers. For example regulatory and public perception barriers may prevent the widespread penetration of natural gas CCS technology (see Appendix H).

Looking across these 8 case studies our team arrives at the following broad conclusions about the role of policy in accelerating deployment of gas end-use technologies with the aim of reducing GHG emissions:

- The actual policies needed vary widely across the technologies that we have examined. There are no simple silver bullets, not even carbon pricing.
- A price on carbon or similar regulatory actions probably will accelerate shifts from power generation that burns coal to generation technologies that rely on gas, including fuller dispatch of existing gas-fired power plants as well as the construction of new plants. There are mature gas technologies that, today, are already competitive (or nearly so) with coal. A price on carbon or the externalities of fossil fuel use could shift that competition in ways that favor gas (especially if gas prices remain at relatively low levels). A number of studies suggest that the incremental natural gas demand in the power sector could rise between 1 to 4 Tcf per year by 2020 due to carbon and environmental regulations.[5] This would result in 60 to 250 million metric tons of carbon dioxide reductions.[6]
- Even with carbon prices, market and regulatory barriers are many and complicated. Such obstacles include social barriers, such as education or public acceptance of infrastructure, that prevent their adoption. Some technologies, such as appliances, already could save users money without carbon pricing yet are not adopted due to such barriers.
- Absent a very high carbon price, the full potential for reducing GHGs through utilization of natural gas will not be realized without an array of policy reforms that go far beyond simple carbon pricing.

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4 Many other factors are at work as well, such as regulations that affect the ability of incumbent coal plants to compete. For example, the levelized cost of emission controls due to EPA rules associated with the transport of air pollution, ash from combustion, and cooling water regulation ("316(b)") could add between $12-20/MWh to the cost of coal-fired generation.

5 Please see NPC Carbon Subgroup's topic paper on impact of EPA regulations.

6 Not all studies reported potential CO2 reductions. For illustration, it is assumed that the NGCCs picking up the switch operated with an average heat rate of 8,000Btu/kWh, and that emissions were, on average, half that of a representative coal plant.

- For many opportunities, especially those in the power sector, the future role of natural gas depends heavily on the regulation and policy incentives that affect its chief competitors, such as coal-based power supply and renewables. For example, policies that accelerate coal plant retirements could result in significant increases in natural gas demand by the electric power sector to replace the lost coal generation. On the other hand, policies that maintain existing levels of coal-fired generation while encouraging the development of renewables could result in lower gas-fired generation and reduced natural gas demand by the electric power sector.
- Even in the absence of carbon pricing, air quality regulations may result in substantial coal plant retirements, with corresponding increases in gas-fired generation and electric sector gas demand, and decreases in carbon dioxide emissions.[7]
- For some technologies, such as natural gas CCS and fuel cells, the potential for significant emissions reductions will be realized only with sustained and targeted R&D programs as well as incentives for deployment. There is a potential for CCS on natural gas to provide electricity at lower levelized cost than other low- and zero-emission power options. However, realizing that potential will require a concerted R&D program as well as incentives to testing and deployment of candidate technologies. Whether that potential is realized will also depend, of course, on the progress that rival technologies make.
- In some settings, rapid decarbonization along with other environmental rules such as strict urban air pollution standards could impede deployment of natural gas technologies. Some of these conflicts are evident as renewables and gas, to some degree, may compete as a source of carbon emission reductions.

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[7] Please see NPC Carbon Subgroup's topic paper on impact of EPA regulations.

Table 1: 15 Opportunities Identified by Team 2, and names of Team 3 Case Studies[8]

Category	Name of Opportunity (team 2)	Policy Case Study (this report)
Appliances	Residential Appliances	Appliances (Appendix B)
	Commercial Appliances	
	Industrial Appliances	
Generation	Redispatch of Power Plants	Generation Fuel Redispatch (Appendix C)
	Repower Plants	Refueling/Repowering Existing Coal or Oil Fired Generating Capacity (Appendix D)
	Refuel Plants	
	Build New Combustion Turbine plants	Building New Gas-Fired Power Plants (Appendix E)
	Build New combined cycle (NGCC) plants	
	On-Site Generation: combined heat & power (CHP) for commercial and industrial uses	Onsite Generation CHP (Appendix F)
	Distributed fuel cell generation	Fuel Cells for Distributed Electricity (Appendix G)
	Carbon Capture and Storage (CCS)	Carbon Capture and Storage (Appendix H)
Industrial	Fuel Switching	Industrial Fuel Switching (Appendix I)
	Industrial efficiency improvement, including waste heat recovery through combined heat & power	See CHP case study (appendix F)

8 Table 1only lists 13 clusters; commercial and residential appliances can be further broken down to new appliances and conversions

Table 2: Evaluating Policies and Defining "High", "Medium" and "Low"

	Low	Medium	High
Maturity	unknown but possibly large improvement in performance (cost and reliability) from investment in R&D and deployment	typical prospects for improvement in performance from additional deployment	very little likely improvement in performance from additional investment
Cost effectiveness (assuming \$20-40 /tCO_2e policies)	technology is substantially more expensive than rivals that achieve similar levels of overall emission reductions without special policy incentives. Could be competitive for some applications at very high carbon prices—much higher than \$100/tCO_2e	in some settings but not others the technology is cost effective with rivals within the normal variation of prices likely in energy markets in the next few years. Competitiveness would be more widespread at higher carbon prices, such as \$50-100/tCO_2e)	technology is already competitive with rivals
Public acceptance	technology creates large risks or fears--whether real or imagined	technology has some adherents and detractors	technology already widely familiar
Regulatory Barriers	when the technology is cost effective it faces few regulatory barriers to adoption	typical of rival technologies--some barriers exist but they can be surmounted with effort by the backers of the technology	major regulatory barriers to adoption
Role for government	if the technology becomes cost effective on its own then needed role for government is minor	typical need for government support--such as incentives to deploy the first few devices and to convey information about performance	a major role for government policy, such as in addressing market barriers, in building infrastructures to supply the service, etc.
Market barriers	in settings where the technology is cost-effective it enters into service on its own.	modest market barriers, such as lack of complete information on performance, prevent the technology from entering widely into service	information about performance of the technology is largely unavailable; beneficiaries from use of the technology do not control deployment decisions; other market barriers exist as well.
Impact on jobs	very little impact on jobs compared with spending similar amounts of money on other rival projects	comparable impact on jobs as with other technologies	large potential for expanding employment.

Table 3: Policies Identified as Important in the 8 Case Studies

Type of policy	Possible Effects on Gas Consumption	Case Study Illustrations
Regulatory policies that affect gas and other energy sources		
create a price on CO2 emissions (cap & trade or carbon tax)	would encourage shift from higher emission technologies (e.g., coal) to lower emissions for mature technologies	Redispatch away from high carbon plants; repower/refuel high carbon plants; build new gas plants; carbon capture & storage
power plant greenhouse gas emission performance standards	similar effects on fuel mix as a carbon price	Redispatch away from high carbon plants; build new gas plants
alter interconnection standards	could allow some gas-based technologies to compete with incumbent power supplies more effectively	industrial CHP; redispatch
alter clean energy mandates	could allow some natural gas technologies to earn valuable credit as renewable/efficient energy sources.	Redispatch/repower from high carbon plants; build new gas plants, industrial CHP; commercial CHP, CCS
Elimination of long term subsidies or preferential policies for competing energy sources (renewable, nuclear and coal)	Would level the playing field for all sources of energy	Redispatch/repower from high carbon plants; build new gas plants, industrial CHP; commercial CHP,
Incentive policies that could be focused on gas-based technologies		
Financial incentives for gas-fired technologies, such as tax depreciation rules or limited assurances of market shares for early adopters	could lower the cost of gas-fired technologies for some firms	industrial CHP; fuel cells
fast tracking of environmental permitting	could make it easier to site and operate gas-fired technologies	industrial CHP; natural gas appliances; redispatch; repower/refuel; CCS
Targeted research, development, demonstration and deployment	could lead to improved performance of gas-fired technologies, making them more competitive.	industrial CHP; distributed fuel cells; carbon capture & storage; fuel cells; high efficiency residential appliances

Table 3: Policies Identified as Important in the 8 Case Studies (continued)

Type of policy	Possible Effects on Gas Consumption	Case Study Illustrations
Policies that could be focused on competitors to natural gas		
loan guarantees, such as for infrastructure development or state/utility low-interest loans to consumers	could make it easier and less costly to purchase natural gas technologies	natural gas appliances, redispatch, CCS, repower/refuel
Positive incentives to encourage retirement of existing coal plants, such as payments for "stranded costs" in existing plants	would reduce coal-based power supply and require more dispatch and possible new building of gas-fired plants	Redispatch away from high carbon plants; build new gas plants
Stricter regulation of existing and new coal plants	would reduce coal-based power supply and require more dispatch and possible new building of gas-fired plants	Redispatch away from high carbon plants; build new gas plants; repower/refuel coal and oil plants
Other policies		
Ease siting of CO_2 pipelines and clarify assignment of long-term post-closure liability for stored CO_2	would improve prospects for CCS, which could advantage both coal-based and gas-based CCS	carbon capture & storage
Building performance standards	could improve ability to install and operate on-site technologies, such as natural gas appliances	natural gas appliances; fuel cells
educational programs and labeling	could improve awareness of emission-reducing opportunities	natural gas appliances

Table 4: Summary of Scores on Evaluation criteria

	Evaluation Criteria							
Case study	**Description of technological opportunity**	**Maturity of technology**	**Cost effectiveness at reducing CO2 emissions**	**Public Acceptance**	**Regulatory and Technical barriers**	**Role for government**	**Market Barriers**	**impact on jobs**
Natural gas appliances	gas-using appliances in commercial, industrial and residential settings. Available for new build or retrofit	high	high (new build); medium (retrofit)	high (where infrastructure exists); low (where infrastructure such as gas pipelines must be built)	medium (could be high)	Medium	Low	High
Fuel/dispatch switching	make fuller use of existing NGCC plants	high	moderate to high	high	low to medium (could be higher where RPS or other standards disadvantage gas)	low	low	low to medium
Repowering & refueling	convert existing high-emission plants to natural gas	high	moderate to high	medium to high	low	medium	low	low
Build new NGCC	serve new load demands by building new plants fired with gas	high	moderate to high	high	low to medium	medium	low	low to medium

Case study	Description of technological opportunity	Maturity of technology	Cost effectiveness at reducing CO2 emissions	Public Acceptance	Regulatory and Technical barriers	Role for government	Market Barriers	impact on jobs
CHP generation	deploy industrial and commercial heat capture technologies, allowing much more efficient energy supply and lower emissions	high	moderate	low	moderate	moderate	moderate	low
Fuel Cells	allow for decentralized and efficient direct production of electricity	low	low (present) but could be high in future	moderate (public knows very little about them)	high	high (must manage R&D program, create markets, etc.)	low	moderate (probably positive but unknown)
Carbon capture and storage	allows for use of natural gas in power generation at extremely low emissions	moderate (capture); high (transport); moderate (storage)	low to moderate (components such as transport are highly cost effective but whole system is low to moderate)	low to moderate but varies widely	high	moderate (financial and regulatory support needed, requiring efforts comparable with other government actions)	high	moderate
Industrial fuel switching	switching from high carbon fuels to gas in industrial boilers and other applications	high	moderate to high	medium to high	medium to high	moderate	moderate	moderate (probably positive but unknown)

Appendix A:

The Range of Possible Policies Considered in this Study

Federal policies that will affect the baseline choices of energy mix and thus also consumption of gas and GHG emissions

- Implementation of post CAIR rules and HAPs;
- Implementation of ash pond rules for coal plants;
- Implementation of renewable energy mandates;
- Efficiency standards for buildings, end use appliances

Federal policies that could be created in direct response to concerns about GHGs

- Cap and trade
- Carbon tax
- Renewable energy mandates (Bundling requirements to allow renewable and gas to be considered as baseload)
- Technology policies to help develop and deploy alternative low-emission technologies such as coal with CCS; nuclear; gas with CCS; advanced renewables
- Policies explicitly designed to phase out particular technologies-such as "cash for clunkers" applied to old coal plants
- Legislation of CO2 under the Clean Air Act
  - Performance Standards
    - By Equipment
    - By Fleet
    - Trading
  - Technology mandates
- Incentives
  - Tax incentives for installing lower emitting equipment (credit or depreciation schedule)
  - Credits for early retirement
    - Keeping SOx, NOx and CO2 allowances
    - Payment or tax write off for early retirement
  - Support payments for installing lower emitting equipment
- Educational programs (Advertisement/School programs)
- The negotiation of international accords on GHGs, creating obligations for the US as well as on other countries.

State and local policies that will affect GHG emissions

- Renewable energy mandates
- State-based caps and taxes on GHGs
- Carbon performance standards, such as California's 1100 lbs. CO2/MWh performance requirement for power supplies
- 4P regulatory systems (such as Colorado's recent statute, which gives the utility commission the authority to regulate the power sector as if CO2 were a regulated pollutant since that is likely to happen sometime)
- State-based efficiency and technology rules, such as "green buildings" requirements
- Dispatch regulations based on GHG emissions
- State implementation plans for reducing GHG emissions or shutdown of coal fired electric power (an example is the Colorado legislation)
- Cogeneration regulations
- Distributed Generation Incentives (fuel cells)
- Grid access regulations

Private Initiatives

- Lobbying of firms (corporate social responsibility)
- Nuisance suits
- Corporate and individual buying decisions

Appendix B:

Natural Gas Appliances

Residential / Commercial / Industrial Appliances

Description of Technology

Residential Appliances

The unit energy consumption in the residential appliance center has largely reached a saturation point in many areas where natural gas has played a substantial role in the fuel mix over the past decade. For example, even after an 18% reduction in natural gas consumption by residential homeowners over the past six years, saturation rates for residential appliances remains high in most areas. The table below indicates saturation rates for California, a state where gas use is notably high.[9] In other states gas is at an earlier stage of penetration.

Table ES-3: Natural Gas UEC and Appliance Saturation Summaries by Utility

	All		PG&E		SDG&E		SoCal Gas	
Homes with Gas Accounts	UEC	Saturation of Homes with Gas Account	UEC	Saturation of Homes with Gas Account	UEC	Saturation of Homes with Gas Account	UEC	Saturation of Homes with Gas Account
All Households	354		405		298		328	
Space Heating	144	93%	213	95%	100	93%	102	91%
Water Heating	193	87%	188	88%	175	88%	200	86%
Dryer	25	46%	22	31%	25	52%	27	55%
Range/Oven	34	73%	31	58%	32	74%	36	83%
Pool Heating	208	5%	183	3%	179	4%	222	6%
Spa Heating	52	6%	52	4%	53	7%	52	7%
Miscellaneous	24	12%	23	8%	21	16%	25	13%
Gas Use Across Electrically Based Population	348		402		291		Not Applicable	

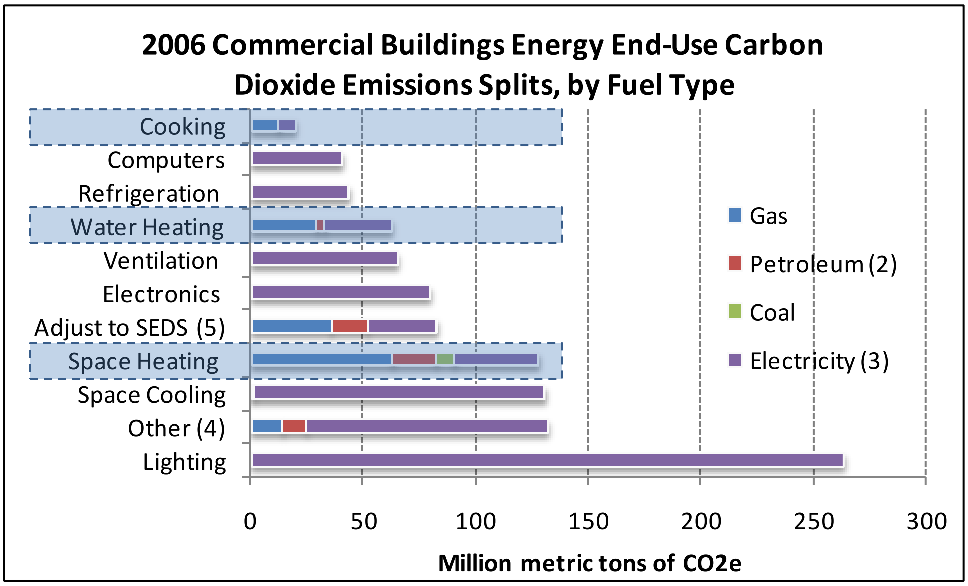
Source: *2010 California Residential Appliance Saturation Survey*

Source: http://www.energy.ca.gov/2010publications/CEC-200-2010-004/CEC-200-2010-004-ES.PDF

[9] KEMA, Inc. 2009 California Residential Appliance Saturation Study, p. 11. October 2010. (http://www.energy.ca.gov/2010publications/CEC-200-2010-004/CEC-200-2010-004-ES.PDF)

Commercial Appliances

The biggest potential lies in space heating, water heating and cooking appliances. Natural gas already has a large share in each of these appliance categories, but electricity still has relatively substantial role.[10]



Source: http://buildingsdatabook.eren.doe.gov/

Industrial Appliances

Unit energy consumption in the industrial sector has also reached a saturation point and is now trending quite closely with manufacturing output, which has been in steady decline for decades.[11] This can be seen in the chemical manufacturing industry where, according to the DOE, natural gas use has dropped 30% from 1998 to 2006 through a combination of efficiency improvements and an overall reduction in output.[12]

Implementation Hurdles

The decision to convert to or adopt new natural gas appliances will depend on regional differences i.e. power prices and availability of natural gas via existing infrastructure.[13] Also residential and commercial entities typically have a shorter payback period than utilities or larger entities, so although natural gas

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[10] Department of Energy. Buildings Energy Data Book. September 2008. (http://buildingsdatabook.eren.doe.gov/docs/xls_pdf/3.4.2.pdf)

[11] Bureau of Economic Analysis, Data Files, 1998-2009 and 1947-1997. (http://www.bea.gov/industry/gdpbyind_data.htm)

[12] Department of Energy, Energy Information Administration. Manufacturing Energy Consumption Survey, 2006, Table 1.2. (http://www.eia.doe.gov/emeu/mecs/mecs2006/pdf/Table1_2.pdf)

[13] Gas Technology Institute. Validation of Direct Natural Gas Use to Reduce CO2 Emissions, June 2009, p. 32-33. (http://www.aga.org/SiteCollectionDocuments/KnowledgeCenter/AboutNaturalGas/Consumer%20Information/0709DIRECT.PDF)

appliances may be more efficient and cost effective versus alternative options, higher upfront costs may discourage adoption of natural gas appliances.[14]

Selection Criteria Evaluation

1. **Maturity**

   High – Technology is readily available.

2. **Cost Effectiveness**

   If existing infrastructure is available;

   New Build – High
   Retrofit – Medium[15]

3. **Public Acceptance of Technology**

   High if infrastructure is in place. Low if infrastructure needs to be built through existing communities.

4. **Regulatory barriers**

   Medium: but could be high where infrastructure is needed

5. **Role for Government**

   Medium: Providing support for infrastructure development, permitting, minimization of impact of capital outlay for consumer, education

6. **Market Barriers**

   Low: Information about the performance of these new technologies is not widely available and thus consumers are unlikely to select them even when they are superior to incumbents

7. **Impact on Jobs**

   High: It could create jobs in installing infrastructure and jobs related to replacement of existing appliances.

Policies that Could Accelerate Deployment of this Technology

1. A balanced and transparent GHG management policy requiring aggressive reductions in GHG emissions.
2. Building codes
3. EPA regulations that require higher emission standards for industrial boilers are expected to provide significant fuel-switching opportunities for natural gas boilers where available.

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[14] McKinsey and Company. Reducing U.S. Greenhouse Gas Emissions, December 2007, p. 36. Note: this applies to all capital "intensive" projects and not just to natural gas appliances.

[15] Gas Technology Institute. Validation of Direct Natural Gas Use to Reduce CO2 Emissions, June 2009, p. 32-33. (http://www.aga.org/SiteCollectionDocuments/KnowledgeCenter/AboutNaturalGas/Consumer%20Information/0709DIRECT.PDF)

4. State/Federal grants infrastructure funding
5. Education
6. Accelerated depreciation for new infrastructure
7. State/Local fast track permitting processes
8. Loan guarantees for infrastructure development
9. State/Utility programs that provide long term low interest loans to consumers. Consider options that include payment as part of the utility bill (example: A consumer program where out of pocket expenses for home heating do not increase from present baseline. Loan is paid by differential between oil/electric heating and gas)

Appendix C:

Generation Fuel Redispatch

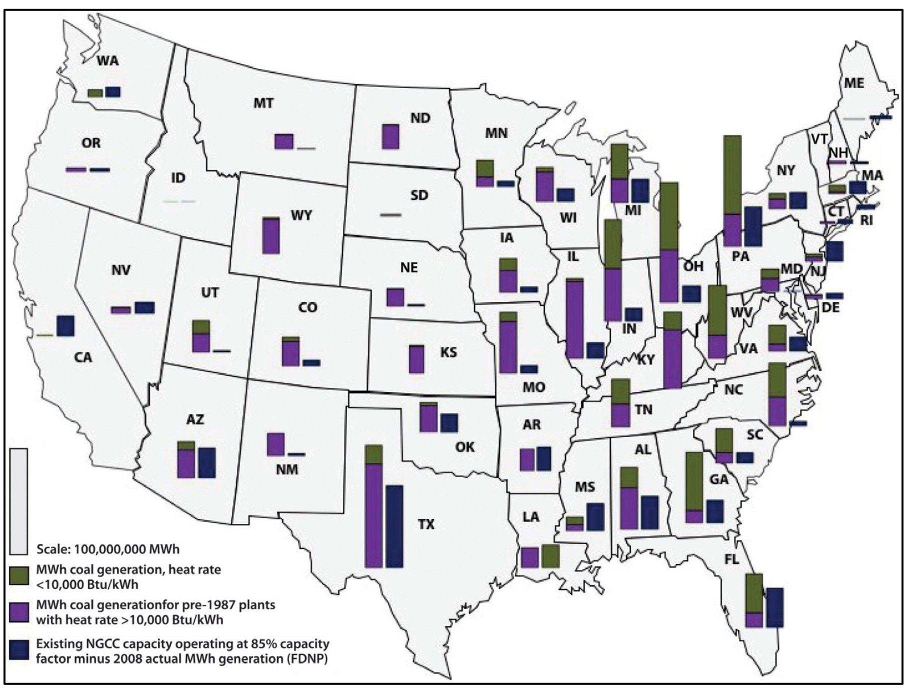
Fuel/Dispatch Switching to Existing Natural Gas-Fired Power Plants

Opportunity: Increased natural gas consumption in the electric power sector
Reduced GHG emissions in the electric power sector

Description of Technology

Fuel/dispatch switching to existing natural gas-fired power plants in the electric power sector has the potential to provide significant reductions in GHG emissions from coal-fired and oil-fired power plants as well as from low efficiency natural gas-fired power plants. Such GHG emission reductions could be achieved by increased use of existing high efficiency natural gas-fired combined cycle ("NGCC") power plants. Some U.S. regions already have significant NGCC capacity (with low capacity factors) as part of their electric generation fleets while other regions have relatively little NGCC capacity. A recent study by MIT found that the current fleet of NGCC units has an average capacity factor of 41% (well below the design capacity factor of up to 85%).[16] The MIT Study also identified the regions with the best opportunities for near-term fuel/dispatch switching (i.e., regions with existing and substantial NGCC capacity where fuel switching could occur). The map below (from the MIT Study) shows substantial fuel switching could occur in the near-term in the U.S. Southeast (Texas, Louisiana, Mississippi, Alabama and Florida) with more limited opportunities for fuel switching in the U.S. Midwest (Illinois, Indiana, and Ohio) where there is less existing NGCC capacity.[17]

Scale and Location of Fully Dispatched NGCC Potential and Coal Generation (MWh, 2008)



Source: "The Future of Natural Gas," MIT Interim Report, p. 47 (Figure 4.4), June 2010.

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16 See "The Future of Natural Gas," June 2010 Interim Report, Massachusetts Institute of Technology, p. 46.
17 *Id.*, p. 47-48.

The potential emissions reductions from fuel/dispatching switching in the electric generation sector are significant. Specifically, studies of redispatch in the power sector (dispatching existing NGCC plants ahead of cheaper, higher emitting coal-based generation) have an average annual potential emission reduction volume of 98 million $MtCO_2e$ (a range from 60 to 182 million $MtCO_2e$) and an average marginal cost of \$38.93/$MtCO_2e$ (a range from \$30 to \$66/$MtCO_2e$).[18] A study by The Brattle Group found that at a \$5/MMBtu gas price and a \$30/ton CO_2 price there would be significant aggregate coal-to-gas dispatch substitution in the ISO regions modeled in the study.[19] Specifically, the study found that gas-fired units would dispatch more often, with the capacity factor of the gas-fired generation fleet (including peaker units) increasing from 21% to 33% and gas demand increasing from about 7.0 Bcf/d to 11.6 Bcf/d (an increase of 65%). CO_2 emissions would be reduced by 182 million $MtCO_2e$ per year.

Fuel switching in the power sector may also arise due to pending air quality regulations that may result in U.S. coal plant retirements and additional use of natural gas in the power sector. In fact, it has been reported that 12,000 MW of coal plant retirements were announced in 2010 (including plans that were announced that will result in the retirement of nearly 10% of the entire western coal fleet).[20] Several recent studies have estimated U.S. coal plant retirements ranging from 40-65 GW over the next 10 years.[21] These studies also recognize the potential for increased U.S. natural gas demand (of approximately 5 to 10 Bcf/d) as a result of these coal plant retirements.[22] In some regions, these retirements will result in the need for additional NGCC capacity. One study finds 13,000 MW of cumulative natural gas additions will be needed from 2010-2020 and 20,500 MW from 2020-2030 to replace retiring coal plants.[23]

Implementation Hurdle

The main challenge is that substantial fuel switching may not occur given existing market conditions, regulations and incentives. For example, in some regions where there is substantial NGCC capacity, the capacity factors of the NGCC plants are quite low. This low utilization is a result of the relatively higher dispatch cost of NGCC units relative to existing coal-fired power plants (since coal prices tend to be lower than natural gas prices). While dispatch costs for an efficient (9,000 Btu/kWh heat rate) coal plant might be in the range of \$25/MWh, the dispatch costs for an efficient NGCC (7,000 Btu/kWh heat rate) plant might be in the range of \$35/MWh (at a natural gas price of \$5.00/MMBtu). The higher dispatch

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18 NPC Carbon Subgroup technology team's working draft, Figure 5.

19 See "Prospects for Natural Gas Under Climate Policy Legislation: Will There Be a Boom in Gas Demand," Steven H. Levine, Frank C. Graves, and Metin Celebi, March 2010, p. 4. The ISO regions modeled covered roughly 60% of U.S. gas and coal generating capacity.

20 "2010, Outlook Dimmed for Coal, Year End State of Coal Report," Sierra Club press release dated December 22, 2010.

21 See, for example, "Growth From Subtraction-Impact of EPA Rules on Power Markets," Credit Suisse, September 23, 2010 (finding 60 GW of coal plant closures to be realistic). See also "Potential Coal Plant Retirements Under Emerging Environmental Regulations," The Brattle Group, Metin Celebi and Frank Graves, December 8, 2010 (finding 40-65 GW of retirements by 2020).

22 Credit Suisse foresees a gas demand increase of 4.9 Bcf/d under its 60 GW coal plant retirement scenario and 10 Bcf/d if retirements reached 100 GW. The Brattle Group study finds a maximum increase in natural gas demand of 5.8 Bcf/d from 40 GW of coal plant retirements by 2020.

23 "Natural Gas and Renewables: A Secure Low Carbon Future Energy Plan for the United States," Deutsche Bank, November 2010, p. 32-33.

costs are partly due to existing regulations in which the units with the highest GHG emissions (coal units) are not penalized.

Other hurdles to substantial fuel switching to natural gas include (1) the perception that natural gas prices are too volatile[24], (2) the lack of sufficient NGCC plant capacity in some regions that heavily depend on coal plant capacity, including the U.S. Midwest (as shown in the map above), (3) the development of renewable generation resources under renewable portfolio standard requirements that tend to displace the marginal fuel from the dispatch stack (which in many regions is natural gas), and (4) transmission constraints that create export-constrained pockets where some natural gas generation units are located.

Despite the challenges, some regions and some utilities are moving forward with emission reductions plans that make greater use of natural gas. Colorado is an example of a state that is implementing such an emissions reduction plan. The Colorado Public Utilities Commission (CoPUC) recently approved a plan to reduce emissions from Xcel Energy's (Colorado Public Service Company's) coal generation fleet. The Colorado plan includes the conversion of some coal plants to natural gas and the construction of new NGCC capacity (since Colorado is a state that has relatively little gas-fired generation). Specifically, the plan includes:

- Retirement of 551 MW of coal plant capacity
- Conversion of 463 MW of coal plant capacity to natural gas
- Additional pollution controls on 951 MW of coal plant capacity (at an estimated capital cost of $384.3 million).
- Construction of a 569 MW NGCC plant by 2015 (at an estimated capital cost of $487.5 million).
- A 10-year fixed-price natural gas contact (with escalation provisions) between Xcel and Anadarko Energy Services[25]

The plan will reduce coal generation from 72% of the fuel mix in 2011 to 48% in 2018 and increase gas-fired generation from 16% to 33% over that period.[26]

<u>Selection Criteria Evaluation</u>

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24 See, for example, the July 22, 2010 letter to the U.S. Senate from the Industrial Energy Consumers of America and 66 other industrial and agriculture organizations regarding legislation providing incentives for increased natural gas demand in the electric power and transportation sectors. The coalition explained, "As manufacturers that rely heavily on the use of natural gas as both an energy source and an essential raw material or 'feedstock' we are concerned that legislative fuel switching incentives could result in short and long-term price volatility and higher prices, causing further industrial 'demand destruction' that forces good U.S. manufacturing jobs to overseas competitors. Higher natural gas prices will also impact electricity prices." See also, "Coal: An Economical Energy Resource," Fact Sheet by the American Coal Council, stating that "When considered in the context of fuel and energy costs, the economic case for using coal is easily supported. Relative to other fuels, coal is among the most abundant and the least expensive of any fuel source (whether considering fossil, renewable, nuclear, or others). By encouraging the use of coal, we avoid volatility in fuel and production costs and keep our electricity prices low."

25 Public Utilities Commission of the State of Colorado, Final Order Addressing Emission Reduction Plan (Decision No. C10-1328 in Docket No. 10M-245E), December 15, 2010.

26 See Xcel Energy's summary of the approved plan at: http://www.xcelenergy.com/Colorado/Company/Environment/Emissions%20Reduction/Pages/ColoradoCleanAir-CleanJobsAct.aspx

1. **Maturity of technology** - High - NGCC power plants already exist in many regions of the U.S.
2. **Cost effectiveness** - Moderate to High - Fuel switching is a relatively low-cost emissions reduction strategy relative to *e.g.*, developing large amounts of renewables generating capacity, but would increase electricity costs to consumers (especially in regions that rely heavily on coal-fired power plants). As discussed above, potential annual emission reduction volumes average 98 million $MtCO_2e$ across the studies that have been reviewed at an average marginal cost of $38.93/$MtCO_2e$.[27] The Colorado plan for Xcel described above (which includes the construction of new NGCC capacity and pollution control equipment) will result in a 2% annual average rate impact over 10 years.[28]
3. **Public Acceptance of Technology** - High in regions with existing capacity, moderate or low elsewhere.
4. **Regulatory barriers**:
    - Lack of a price for GHG emissions and other environmental controls for mercury, SO2, NOx and ash
    - Renewable portfolio standard requirements that displace natural gas from the dispatch stack or Clean Energy Standards that promote nuclear, clean coal, and renewable sources but potentially displace natural gas
    - Regulatory resistance to pre-approval of long-term fixed-price natural gas contracts that could reduce gas price volatility.
5. **Role for Government** - creating a system to price GHG emissions or other regulatory structures and actions to effectuate fuel switching.
6. **Market barriers**:
    - Lack of adequate environmental controls, including a carbon price that is not reflected in the dispatch costs for coal.
    - Perceptions of excessive volatility in natural gas prices
    - Lack of substantial NGCC capacity in regions that rely heavily on inefficient coal plant capacity.
7. **Impact on jobs** - positive impacts due to increased use of gas, but negative impacts due to decreased use of coal and oil as well as due to potential coal generation plant closures. Some studies have found negative employment impacts in aggregate (across all industries) resulting from the adoption of carbon pricing policies in the United States. The Heritage Foundation found net job losses under the Waxman-Markey bill approaching 1.9 million in 2012 and 2.5 million by 2035.[29] A CRA report found that under Waxman-Markey there would be 2.3 to 3.0 million fewer average jobs in the economy.[30]

    Other analyses of specific emission reduction plans have found positive economic impacts. For example, the Colorado Public Utilities Commission's recent approval of Xcel Energy's emission reduction plan (discussed above) cited testimony that the plan would have positive impacts on Colorado's economy and also noted that the plan will create new construction jobs. It also cited a gas producer's view that additional gas generation in Colorado would

[27] NPC Carbon Subgroup technology team's working draft, Figure 5.
[28] See Xcel Energy's summary of the approved plan at: http://www.xcelenergy.com/Colorado/Company/Environment/Emissions%20Reduction/Pages/ColoradoCleanAir-CleanJobsAct.aspx
[29] The Economic Consequences of Waxman-Markey: An Analysis of the American Clean Energy and Security Act of 2009, CDA09-04 (Washington, D.C.: The Heritage Foundation, August 5, 2009).
[30] Impact on the Economy of the American Clean Energy and Security Act of 2009 (H.R.2454), (Washington, D.C.: CRA International, May 2009).

support more gas-industry jobs in the state. Finally, the approval found that the impacts to Colorado's coal industry were ambiguous and would depend on whether new mines would be opened to replace mines that were going to close.[31]

Potential Policies That Would Accelerate Deployment of This Technology

Policies that incorporate the relative superiority of natural gas' environmental and efficiency attributes compared to coal would result in accelerated fuel/dispatch switching to natural gas. These may include a carbon price and incorporation of environmental costs for upcoming rules regarding mercury, SO2, NOx, and ash. Examples are

1. Retirement of inefficient and/or high emitting power plants.
2. Incentives for the development of new natural gas fired power plants (such as investment tax credits for new NGCC plants).
3. Legislative efforts to reduce emissions through greater use of natural gas (such as the emissions reduction plan for Xcel Energy discussed above that was prepared in response to Colorado's "Clean Air-Clean Jobs Act").
4. Cap and trade or carbon tax policies that establish a price for emitting GHGs.
5. Regulation that establishes CO2 emission limits e.g., power plant performance standards
6. Implementation of more stringent criteria pollutant standards or other environmental regulations that for coal that match those for gas
7. Regulations that would prioritize dispatch of lower emitting sources of power (such as NGCC plants) before higher emitting sources
8. Regulatory encouragement of long-term fixed price natural gas contracts.

[31] Public Utilities Commission of the State of Colorado, Final Order Addressing Emission Reduction Plan (Decision No. C10-1328 in Docket No. 10M-245E), December 15, 2010.

Appendix D:

Refueling/Repowering of Existing Coal or Oil Fired Generating Capacity

Refueling/Repowering of Existing Coal or Oil Fired Generating Capacity

Opportunity: Increased natural gas consumption in the power sector
Reduced GHG emissions in the power sector

Description of Technology

Switching existing coal or oil-fired power plants to natural gas power plants has the potential to provide significant reductions in GHGs, as well as other emissions, due to the cleaner environmental attributes of natural gas. And to the extent that there are efficiency gains, such as when switching to a natural gas combined-cycle unit, further emissions reductions would occur on a per MWh basis.

A typical coal power plant involves the combustion of pulverized coal in a boiler, which uses the thermal energy generated to convert water into steam in the boiler tubes. This steam is then expanded through a steam turbine to create the rotational mechanical power needed to spin an electric generator.

There are generally two approaches for converting an existing coal or oil power plant to burn natural gas: refueling and repowering. Refueling is the modification of the existing coal/oil boiler so that it can be fired with natural gas. It involves adding a new gas supply piping system and modifications to the existing combustion system, while retaining the rest of the plant. In some cases, modifications to the boiler heating surfaces become necessary to maintain the full boiler load.[32] In most cases, gas refueling would result in a slight reduction in the overall plant efficiency, because the higher hydrogen content in gas compared to coal or oil reduces boiler efficiency. The required modifications would be expected to cost around $70-80/kW[33]. This cost estimate assumes that gas supply is available at the plant fence. It also assumes that the plant does not have to be retrofitted with an SCR or other emissions control equipment that could be required if a NSR is triggered, which could occur in some cases. While gas refueling has been used in a few power plants, mainly to comply with new environmental regulations, use of more efficient gas-fired units to displace generation from marginally cost-effective coal-fired units has been more common.[34]. Some type of federal/state incentives that support coal-to-gas switching would therefore be required to enable more widespread refueling to occur.

Repowering is accomplished by adding gas combustion turbine(s) to the existing coal or oil plant and utilizing the gas turbine exhaust as a heat source. The turbine can be integrated into the plant in various configurations, resulting in anywhere from a partial to full replacement of the thermal energy from the combustion of coal. In most cases, repowering would result in an increased electrical generation output because of the additional power generated by the gas turbine(s). In the fully optimized replacement case, called “brownfield” repowering, the coal boiler and steam turbine are replaced completely with a modern combined-cycle unit, which is built adjacent to the site to take advantage of the existing coal plant infrastructure. Although new greenfield combined-cycle units are estimated to cost around $1,000/kW,[35] a

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32 “Natural Gas Conversion of Existing Coal-Fired Boilers,” White Paper by Babcock & Wilcox, found at: http://www.babcock.com/library/pdf/MS-14.pdf

33 EIA, “Kyoto – Electricity Supply,” SR/OIAF/98-03, October, 1998, found at: http://www.eia.doe.gov/oiaf/kyoto/electricity.html

34 GAO, “Implications of Switching from Coal to Natural Gas,” GAO 08 601R, May 1, 2008, p. 16.

35 EIA, “Assumptions to the Annual Energy Outlook 2010,” DOE/EIA-0554(2010), April, 9, 2010, Table 8.2.

1999 AEP study showed costs to be about 25% less for brownfield repowered units than for greenfield.[36] This cost reduction benefit will obviously vary from site to site.

Based on data from the EIA, coal-fired power plants currently account for about 50% of the electricity generation in the U.S. These plants will soon be subject to stringent new environmental regulations. About 50% of this fleet is over 40 years old, and nearly 60% of these do not have scrubbers. The new regulations will therefore require significant retrofit investment, replacement or retirement. Replacement by cleaner natural gas boilers or combined-cycle units may be an attractive alternative in some cases.

The potential emissions reductions from refueling/repowering in the power sector are therefore significant. Based on recent EIA data, coal generation in the power sector for 2010 is estimated to be 1,805 billion kWh with CO2 emissions of 1,843 million $MTCO_2$. This represents about 80% of power sector emissions and 33% of total U.S. emissions. If all of this coal capacity were replaced with NGCC plants, CO2 emissions would be reduced by over 900 million MTCO2. Recent studies estimate a more realistic volume of CO2 reductions for refueling to be about 110 million MTCO2 per year by 2030 at an average cost of $37/MTCO2.[37] The repowering approach is typically considered for older units less than 250 MW. This limits the reduction potential to about 80 million MTCO2. The avoided CO2 cost for a greenfield repowering would be about $67/MTCO2[38], so for a brownfield repowering, this cost would be less.

Implementation Hurdle

The main challenge for refueling, and especially for repowering, is the large capital cost requirement in addition to the higher cost of gas versus coal as an operating fuel. Natural gas prices are also perceived to be more volatile than coal, adding risk to the economics of the project. And although coal plants may have some access to natural gas, additional infrastructure requirements will likely be needed, such as long-distance transmission pipelines and storage. Another potential obstacle is that some coal-fired plants are essential to local reliability and reserve margins; therefore, they may not be able to be taken out of service during the retrofit period. Decommissioning and environmental remediation costs can also vary greatly depending on the site.

Selection Criteria Evaluation

1. **Maturity of technology** - High - Gas-fired boilers and natural gas combined-cycle systems are a mature, readily available technology.
2. **Cost effectiveness** - Moderate to High - Refueling/repowering is a relatively low-cost emissions reduction strategy, especially where existing coal generating plants would otherwise be required to invest heavily to meet new and evolving emission control requirements. This assumes that gas is available in proximity to the facility. The need to install gas delivery capacity can significantly increase the cost, depending on the location. The cost-effectiveness depends heavily on the cost of gas relative to coal.

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36 Interlaboratory Working Group. 2000. Scenarios for a Clean Energy Future (Oak Ridge, TN; Oak Ridge National Laboratory and Berkeley, CA; Lawrence Berkeley National Laboratory), ORNL/CON-476 and LBNL-44029, November, Appendix E-7.

37 National Petroleum Council North American Natural Gas and Oil Resources Study, End-Use Emissions & Carbon Regulation Subgroup, Technology Sub-Team, 2011.

38 SFA Pacific, Inc., "Near-Term Technologies for Retrofit CO2 Capture and Storage of Existing Coal-Fired Power Plants in the United States," May 2009, p. 12.

3. **Public Acceptance of Technology** - Medium to High - public acceptance is not a significant barrier for this option except possibly for permitting of infrastructure development.
4. **Regulatory barriers** - Low. Projects will be affected by prices or other environmental penalties for mercury, SO_2, CO_2, NO_x, cooling water and ash, although new emission limits for conventional pollutants are addressing this to some degree. For some projects, permitting of infrastructure development can also be an issue. The regulatory barriers faced by this option appear to be lower than most of the other options considered in this report.
5. **Role for Government** - Medium. The central role for government will be creating a system to price GHG emissions or other regulatory structures, and creating incentives to effectuate fuel switching, such as providing support for infrastructure development, accelerating permitting, and minimizing the impact of capital outlay for the consumer.
6. **Market barriers** - relatively low. However:
   - Lack of environmental penalties, including a carbon price, that are not reflected in the operating costs for coal.
   - Perceptions of excessive volatility in natural gas prices/lack of awareness of hedging opportunities
7. **Impact on jobs** - Low but positive. Positive impacts due to increased use of gas, retrofit of existing facilities, preservation of at risk businesses, but negative impacts due to decreased use of coal and oil.

<u>Potential Policies That Would Accelerate Deployment of This Technology</u>

Policies that incorporate the relative superiority of natural gas' environmental and efficiency attributes would result in accelerated fuel switching from coal/oil to natural gas through refueling and repowering. These may include a carbon price signal and incorporation of environmental costs for upcoming rules regarding air toxics (HAPs MACT and Clean Air Transport Rule), cooling water (Clean Water Act) and ash (RCRA). Other examples are:

1. Implementation of more stringent criteria pollutant standards or other environmental regulations that reflect the environmental cost of producing power from coal
2. State/Federal grants for infrastructure funding. For example: New Jersey lawmakers passed a bill, S2381[39], on 1/10/2011 that would provide incentive payments for the construction of 2,000 MWs of natural gas-fired generation. A Colorado bill signed into law in 2010, HB 1365 required Excel to consider switching to natural gas or installing controls at some of its coal-fired power plants. A Virginia bill would allow for natural gas to qualify as an "alternative fuel" under the state's renewable portfolio goal (http://www.allbusiness.com/energy-utilities/utilities-industry-electric-power-power/15397115-1.html).

3. Accelerated depreciation for new infrastructure – Under the Federal Modified Accelerated Cost-Recovery System (MACRS) + Bonus Depreciation (2008-2012), businesses can recover

[39] S.2381 can be accessed at: http://www.njleg.state.nj.us/2010/Bills/S2500/2381_R4.PDF.

investments in certain property through depreciation deductions. MACRs sets class lives for various types of property, which range from 3 to 50 years over which property can be depreciated. Natural gas pipelines, gathering lines, and distribution lines that meet certain criteria qualify under this program.

4. State/Local fast track permitting processes
5. Loan guarantees for infrastructure development
6. Legislation that includes a production tax credit when emissions are reduced from a power plant efficiency improvement that includes refueling/repowering
7. Cap and trade or carbon tax policies that establish a price for emitting GHGs.
8. Regulation that establishes CO_2 emission limits e.g. performance standards

Appendix E:

Building New Gas-Fired Power Plants

Displacement of Coal and Oil via Building New Natural Gas-Fired Power Plants

Opportunity: Increased natural gas consumption in the electric power sector
Reduced GHG emissions in the electric power sector

Description of Technology

Fuel switching to natural gas in the electric power sector has the potential to provide significant reductions in GHG emissions from coal-fired and oil-fired power plants as well as from low efficiency natural gas-fired power plants. Such GHG emission reductions could be achieved by retiring older coal and oil-fired power plants (and older, low-efficiency natural gas-fired power plants) and replacing the generation from these older plants by building new high efficiency natural gas-fired combined cycle ("NGCC") power plants.

The potential emissions reductions from coal plant retirements and replacement by new NGCC plants are significant. Specifically, studies of coal plant replacement with new build NGCC power plants have an average annual potential emission reduction volume of 89 million $MtCO_2e$ (a range from 51 to 133 million $MtCO_2e$) and an average marginal cost of $46.42/$MtCO_2e$ (a range from $13 to $64/$MtCO_2e$).[40] Moreover, in some regions coal plant retirements will result in the need for additional NGCC capacity. One study finds 13,000 MW of cumulative natural gas additions will be needed from 2010-2020 and 20,500 MW from 2020-2030 to replace retiring coal plants.[41]

Implementation Hurdle

There are several challenges to such a shift from older plants to newer NGCC plants, including

- The older power plants may still be economic and therefore unlikely to retire absent some policy mandate, change in regulation, or incentive provided for their retirement.
- Excess capacity conditions in most U.S. regions[42] result in reduced incentives to invest in new gas-fired generation unless a significant number of coal units retire due to a combination of poor market prices and tightening EPA regulations.
- The relatively low dispatch costs of existing coal-fired power plants versus NGCC plants (since coal prices tend to be lower than natural gas prices) as well as the fact that old coal plants are substantially depreciated also creates some inertia against a shift from coal units to NGCC units since such a shift would be costly for consumers. While dispatch costs for an efficient (9,000 Btu/kWh heat rate) coal plant might be in the range of $25/MWh, the dispatch costs for an efficient NGCC (7,000 Btu/kWh heat rate) plant might be in the range of $35/MWh (at a natural gas price of $5.00/MMBtu). Of course, the lower dispatch costs of coal are partly due to existing regulations in which the units with the highest GHG emissions (coal units) are not penalized.
- The perception that natural gas prices are more volatile than coal prices.[43]

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[40] NPC Carbon Subgroup technology team's working draft, Figure 5.
[41] "Natural Gas and Renewables: A Secure Low Carbon Future Energy Plan for the United States," Deutsche Bank, November 2010, p. 32-33.
[42] These excess capacity conditions can be seen in a recent report by the North American Electric Reliability Corporation (NERC). The NERC report shows current summer reserve margins in excess of 20% for most U.S. regions. See "2010 Long-Term Reliability Assessment," NERC, October 2010 (tables 5a-5f).
[43] See, for example, the July 22, 2010 letter to the U.S. Senate from the Industrial Energy Consumers of America and 66 other industrial and agriculture organizations regarding legislation providing incentives for

- A shift to more NGCC units is likely to require additional natural gas pipeline infrastructure.[44]

Nonetheless, many market observers are expecting a wave (40-65 GW) of coal plant retirements in the next 5-10 years due to stricter air quality regulations being implemented by the EPA.[45] New NGCC plants are well-positioned to replace coal units due to their relatively low construction costs, short construction lead times, and high capacity factors (relative to intermittent resources like wind and solar). Specifically, NGCC units have a levelized all-in cost of roughly $55-70 MWh assuming natural gas prices in the $5-$7/MMBtu range.[46] At these levels, NGCC plants are cheaper than new nuclear, solar and wind (when wind is put on an equivalent reliability basis by adding costs of replacement energy and capacity, as well as new transmission capacity).[47] In fact, gas-fired power plants will remain the most economic choice until CO2 prices reach $80-$100/ton, when coal with carbon capture and sequestration and nuclear plants start to become an attractive choice (but CO2 prices are not expected to reach this level until after 2030).[48]

Selection Criteria Evaluation

1. **Maturity of technology** - High - NGCC power plants have been built in many regions in the U.S.
2. **Cost effectiveness** - Moderate to High - while likely to be more costly than existing coal units, new NGCC units have relatively low costs relative to other types of power plants. As discussed above, potential annual emission reduction volumes average 89 million $MtCO_2e$ across the studies that have been reviewed at an average marginal cost of $46.42/$MtCO_2e$.[49]
3. **Public Acceptance of Technology** - High in many U.S. regions, but moderate or low in regions that rely heavily on coal-fired power plants.

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increased natural gas demand in the electric power and transportation sectors. The coalition explained, "As manufacturers that rely heavily on the use of natural gas as both an energy source and an essential raw material or 'feedstock' we are concerned that legislative fuel switching incentives could result in short and long-term price volatility and higher prices, causing further industrial 'demand destruction' that forces good U.S. manufacturing jobs to overseas competitors. Higher natural gas prices will also impact electricity prices." See also, "Coal: An Economical Energy Resource," Fact Sheet by the American Coal Council, stating that "When considered in the context of fuel and energy costs, the economic case for using coal is easily supported. Relative to other fuels, coal is among the most abundant and the least expensive of any fuel source (whether considering fossil, renewable, nuclear, or others). By encouraging the use of coal, we avoid volatility in fuel and production costs and keep our electricity prices low."

44 See, for example, "Natural Gas and Renewables: A Secure Low Carbon Future Energy Plan for the United States," Deutsche Bank, November 2010, p. 34 (noting that "An incremental cumulative investment of about $129 billion in pipeline capacity additions is likely to be necessary to support the coal to gas switch."). Deutsche Banks's statement appears to be based on ICF International's study for the INGAA Foundation "Natural Gas Pipeline and Storage Infrastructure Projections through 2030," October 20, 2009. The ICF study's base case projected 25 Bcf/d of incremental pipeline capacity additions between 2008-2030 (an increase in interregional pipeline capacity from 130 Bcf/d to 155 Bcf/d) and cumulative pipeline expenditures of $130 billion between 2009-2030 (roughly 40% of which represented Arctic pipeline projects and associated pipelines to bring Arctic gas to the U.S. lower 48).

45 See, for example, "Growth From Subtraction-Impact of EPA Rules on Power Markets," Credit Suisse, September 23, 2010 (finding 60 GW of coal plant closures to be realistic). See also "Potential Coal Plant Retirements Under Emerging Environmental Regulations," The Brattle Group, Metin Celebi and Frank Graves, December 8, 2010 (finding 40-65 GW of retirements by 2020).

46 See "Prospects for Natural Gas Under Climate Policy Legislation: Will There Be a Boom in Gas Demand," Steven H. Levine, Frank C. Graves, and Metin Celebi, March 2010, p. 7.

47 Id., p.6.

48 Id.

49 NPC Carbon Subgroup technology team's working draft, Figure 5.

4. **Regulatory barriers** - low to medium. Lack of a price for GHG emissions and other environmental penalties for mercury, SO2, NOx and ash
5. **Role for Government** - Low to medium - creating a system to price GHG emissions or other regulatory structures and incentives to effectuate retirement of older coal plants with high GHG emissions, which are all roles that government is already largely playing.
6. **Market Barriers** - Low - information is already widely available, although there are perceptions (by utilities and regulators) of risks with high and volatile natural gas prices.
7. **Impact on jobs** - Low to Medium - positive impacts due to increased use of gas and development of new gas-fired power plants, but negative impacts due to decreased use of coal and oil as well as due to potential coal generation plant closures. [50]

<u>Potential Policies That Would Accelerate Deployment of This Technology</u>

Policies that incorporate the relative superiority of natural gas' environmental and efficiency attributes would result in accelerated retirement of coal-fired facilities and construction of new natural gas-fired power plants. These may include a carbon price and incorporation of environmental costs for upcoming rules regarding mercury, SO2, NOx, and ash. Examples are:

1. Retirement incentives for inefficient power plants with high emissions.
2. Incentives for the development of new natural gas fired power plants (such as investment tax credits for new NGCC plants).
3. Legislative efforts to reduce emissions through greater use of natural gas (such as the emissions reduction plan for Xcel Energy discussed above that was prepared in response to Colorado's "Clean Air-Clean Jobs Act").
4. Cap and trade or carbon tax policies that establish a price for emitting GHGs.
5. Regulation that establishes CO2 emission limits e.g., power plant performance standards
6. Implementation of more stringent criteria pollutant standards or other environmental regulations that increase the cost of producing power from coal
7. Regulations that would dispatch lower emitting sources of power (such as NGCC plants) before higher emitting sources
8. Regulatory encouragement of long-term fixed price natural gas contracts.

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[50] Analyses of specific emission reduction plans have found positive economic impacts. For example, the Colorado Public Utilities Commission's recent approval of Xcel Energy's emission reduction plan cited testimony that the plan would have positive impacts on Colorado's economy and also noted that the plan will create new construction jobs. The plan calls for Xcel Energy to retire some coal units, install pollution control equipment at other coal units, convert some coal plants to natural gas, and build new NGCC capacity. It also cited a gas producer's view that additional gas generation in Colorado would support more gas-industry jobs in the state. Finally, the approval found that the impacts to Colorado's coal industry were ambiguous and would depend on whether new mines would be opened to replace mines that were going to close. Public Utilities Commission of the State of Colorado, Final Order Addressing Emission Reduction Plan (Decision No. C10-1328 in Docket No. 10M-245E), December 15, 2010.

Appendix F:

Onsite Combined Heat and Power (CHP) generation

Onsite Power Generation – CHP

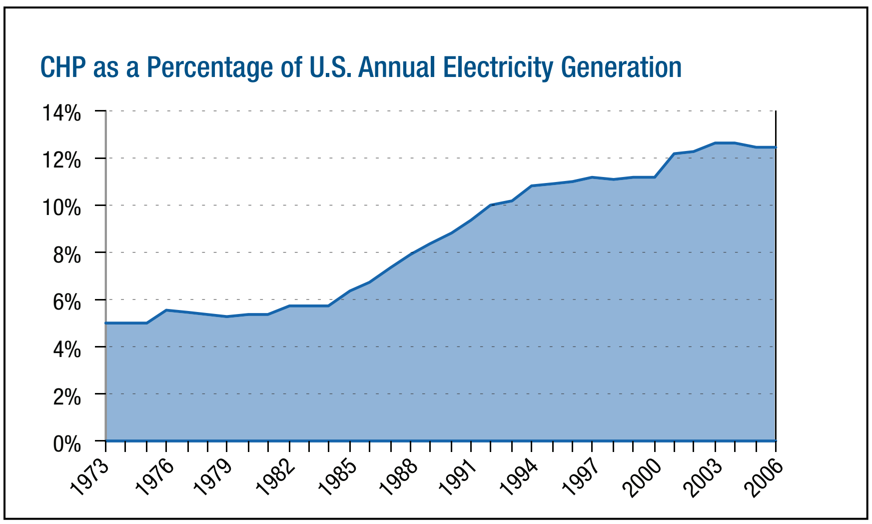
Industrial - CHP

Opportunity: Increased natural gas consumption
Reduced GHG emissions

Description of Technology

CHP, also known as cogeneration, is the concurrent production of electricity and useful thermal energy (heating and/or cooling) from a single source of energy. Combined Heat and Power (CHP) solutions represent a distributed, proven and effective energy option to enhance energy efficiency, ensure environmental quality, promote economic growth, and foster a robust energy infrastructure.

CHP generation capacity currently stands at 85 gigawatts (GW)—almost 9 percent of total US capacity. As of 2006 CHP produced 506 billion Kilowatt Hour (kWh) of electricity—more than 12 percent of total US power generation for that year.



Source: EIA Annual Energy Review, 2009

Natural gas continues to be the preferred fuel for CHP systems, representing 50–80 percent of annual CHP capacity additions since 1990. Natural gas has been the preferred fuel for CHP systems due to the fact that it is readily available at most industrial sites, is clean burning, and has historically been relatively plentiful and affordable.

Implementation Hurdles

While the benefits of added CHP capacity are promising, current market conditions and technical barriers continue to impede full realization of CHP's potential. Challenges include unfamiliarity with CHP, utility business practices, environmental permitting approaches that do not acknowledge and reward the energy efficiency and emissions benefits, and interconnection requirements.

With respect to natural gas, the ability of CHP to create net benefits for the industry is unclear. Under scenarios that look at increasing CHP generation to 20% of US capacity by 2030 (241GW), overall US annual energy consumption is expected to fall by 5.3 Quads, negatively impacting gross natural gas sales over the next two decades.

Selection Criteria Evaluation

1. **Maturity of Technology** – High – CHP technology in all of its forms is well honed, and although efficiency improvements have been made over the past 20 years, CHP efficiency is increasing at a decreasing rate. CHP is also certainly a more mature technology than CCS, and as a CO_2 reduction technology is far more cost effective than retrofitting CCS on existing power plants (http://www1.eere.energy.gov/industry/distributedenergy/pdfs/chp_report_12-08.pdf).
2. **Cost Effectiveness** – Moderate – installation of CHP capacity is a business decision that depends on its economics, i.e., the project needs to have a high "spark spread" to be economically viable. Volatile fuel prices
3. **Public Acceptance** – unknown – CHP technologies are not well known outside large industrial or commercial facilities and thus acceptance of those technologies is unknown. Despite this, large industrial CHP facilities can provide incremental power capacity to the public and can do so largely without public notice given that CHP units are built on site within an existing industrial facility.
4. **Regulatory and technical barriers** – Moderate – Most environmental emission standards are based on vented exhaust pollutant concentrations or are based on heat input (quantity of pollutant per input energy). These metrics of localized emission monitoring do not encourage CHP capacity additions because they do not measure its associated energy efficiency. For example, additional CHP capacity at a plant may actually increase the plant's own total emissions because the CHP unit is providing both power and heat, although *total global* emissions are actually decreased.
5. **Role for Government** – Moderate – Beyond the tax incentives and state RPS policies utilities may not have a favorable view of CHP installations since it could potentially take away revenue from them (and thus impose unfavorable tariffs). Local and state governments can play a role in imposing tariff and utility rate structures that do not discourage CHP.
6. **Market Barriers** – Moderate – volatility in fuel prices could reap unfavorable spark spreads.
7. **Impact on Jobs** – Low – Added CHP capacity should not impact the power sector to such a degree that utility jobs will suffer, in particular because most new CHP capacity is likely to be for own use only, i.e., will not include additional merchant capacity.

Policies that Could Accelerate Deployment of this Technology

1. A balanced and transparent GHG management policy requiring aggressive reductions in GHG emissions.
2. Policies that would regulate fees and tariffs for CHP
3. Adoption of technical interconnection standards
4. Environmental permitting fast tracking based on net emissions under the Clean Air Act
5. Improved tax depreciation
6. Technology research and development.

Appendix G:

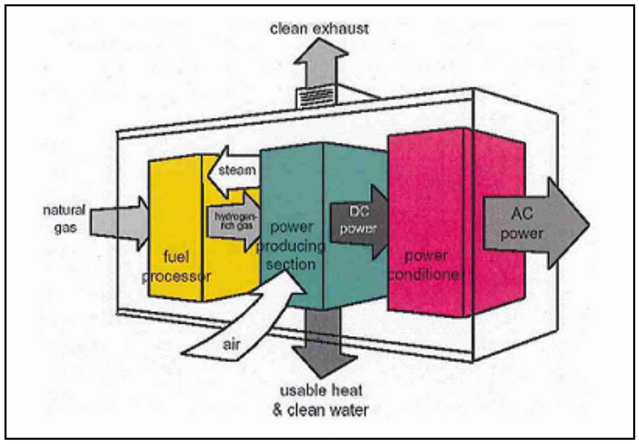
Fuel Cells

Onsite Generation - Fuel Cells

Description of Technology

Fuel cells use an advanced electrochemical process to generate electricity. This process is comparable to that used in conventional batteries, except that the reactant material in fuel cells can be replenished so that the units can be run continuously and reliably for long periods. A wide variety of fuels can power these cells, including hydrogen as well as other fuels such as methanol and natural gas that are reformed to generate a useable fuel source. The cost and prospect for fuel cell technology vary by the fuel source and fuel cell technology, which is still far from mature for large commercial applications.

Because costs per installed kilowatt are still high (more than $300/ton of CO_2 avoided) relative to those of conventional technologies[51], commercially available fuel cells currently suit only very specialized applications. Innovations in new fuel cell technologies could lower these costs significantly, allowing for a low- or zero-emission source of electricity to be located on site (e.g., in buildings). Fuel cell technologies might also play an eventual role in helping to smooth the supply of electricity from renewable energy sources, such as wind and solar, that is more intermittent.



Implementation Hurdle

The challenges faced today are the fuel cell system's higher initial cost and evolving durability and reliability. Cost, durability and reliability are the primary focus of R&D activities.[52]

Selection Criteria Evaluation

1. **Maturity -** Low; Presently in the Research & Development phase[2]
2. **Cost Effectiveness -** Present – Low[1]
   Potential – High – Some studies project electricity costs similar to present delivered electricity prices.[53]
3. **Public Acceptance of Technology** – Unknown since there is no familiarity with the technology; presently in the early mover phase. No consumer objections anticipated if activity is cost effective, but acceptance of some fuel systems (e.g., hydrogen) could prove problematic.
4. **Regulatory Barriers** – unknown but perhaps high. While not much discussed in the Fuel Cell literature, the barriers identified in the Residential/ Commercial/Appliance section of this report (Appendix B) would apply—notably difficulties surrounding the siting of distributed energy sources

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[51] NPC Carbon Subgroup technology team's working draft, Figure 5.

[52] See http://www.netl.doe.gov/technologies/coalpower/fuelcells/seca/refshelf.html for, overview, and funding of DOE sponsored Fuel Cell R&D.

[53] "The Impact of Scale-UP and Production Volume of SOFC Manufacturing Cost," DOE- NETL Report, Jan H.J. S Thijjssen, April 2, 2007, projects and eight-fold decrease in direct manufacturing costs. See Figure 0-4 page 5.

with combustible fuels under current building codes. There may be other barriers related to interconnection with the electrical grid and dispatch.

5. **Role for Government** - High. Assistance is needed in funding development of this technology.[2]
6. **Market Barriers** – unknown but possibly high; Information about the performance of this new technology is not widely available and thus consumers are unlikely to select them even when they are superior to incumbents[54]
7. **Impact on Jobs** – unknown but possibly positive. Could create a new clean energy industry.[55]

Potential Policies That Would Accelerate Deployment of this Technology

Fuel Cells for distributed power generation is a very new technology. Policies that support technology development are best suited to accelerate its deployment. Examples are:

1. R&D support
2. Tax credits, rebates or payments for early purchasers
3. Government/Utility backed performance guarantees
4. Diverse regulatory reforms, such as in building codes and grid interconnect.

[54] "Validation of Direct Natural Gas Use to Reduce CO_2 Emissions," Gas Technology Institute, June 26, 2009, Figure 4 Residential and Commercial Consumption - PR3 Change from Reference Case, indicates that consumer education can result in significant (4% reduction) in baseline emissions.

[55] Renewable Energy Focus.com, 19 January 2010, http://www.renewableenergyfocus.com/view/6562/fuel-cell-industry-could-create-700-000-green-jobs-worldwide-by-2020, States that Fuel Cell Today's proprietary job creation forecasts creation of more than 1 million jobs globally in the fuel cell industry.

Appendix H:

Carbon Capture & Storage

Power Generation – CCS

Opportunity: Increase natural gas demand
Reduce GHG emissions

Description of Technology

Carbon capture and storage (CCS) has the potential to provide significant reductions in CO2 emissions from large stationary sources. CCS has three fundamental components; capture, transportation, and geologic storage. Technologies for each of these components are readily available today, however large-scale application of these technologies as a system to implement CCS has not been demonstrated in power plant applications. Additionally, neither the current nor the anticipated value for CO2 over the near to mid-term (to 2030-40) is likely to support the substantial incremental cost of CCS, although a sound performance based regulatory policy requiring some degree of GHG emission reductions could accelerate such investments.

Substantial research is being conducted with the objective of reducing CCS costs, particularly that of the capture component, which represents 75-85% of the cost of CCS in post combustion applications[56]. Additionally, research efforts are also working on technologies that will improve capabilities in monitoring and verifying storage site integrity.

Implementation Hurdles

The primary hurdles to implementation of CCS are the lack of a national policy for reducing GHG emissions, the high costs associated with constructing and operating CCS facilities, particularly the capture component, and a clear and equitable policy on managing long term responsibility for storage sites

Selection Criteria Evaluation

1. **Maturity of Technology**

   Capture – Moderate to high - Effective capture technologies are available today and used in other applications (natural gas treatment primarily) and are commercially offered by reputable vendors for power plant applications. However, capital and expense costs of current technologies are high. Substantial research effort is being focused on extensions of existing technologies as well as potential breakthrough technologies to reduce current costs[57].

   Transport – High – Compression, pipeline, metering, and metallurgy are well developed and understood and are unlikely to benefit significantly from substantial new research.

   Surface Facilities/Injection Wells – High - Surface facility and injection well design requirements

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[56] Global Carbon Capture and Storage Institute (GCCSI), "Strategic Analysis of the Global Status of Carbon Capture and Storage, 2010, GCCSI, Canberra, Australia, <www.globalccsinstitute.com>

[57] U.S. Department of Energy – National Energy Technology Laboratory, Doe/NETL Carbon Capture and Storage Roadmap, 2010, Washington , DC, <www.netl.doe.gov>

are well understood, supported by over 35 years of oil and gas industry experience, and are unlikely to benefit from substantial new research[58].

Storage – Moderate – Geologic characteristics for sound storage sites are well defined and understood at a conceptual and small-scale demonstration level. A small number "commercial scale" projects are currently operating, however the consensus is that a larger number of integrated projects are necessary[59]. The ability to accurately identify those sites and conduct appropriate monitoring and site integrity verification is the focus of substantial research effort[60].

2. **Cost Effectiveness**

   Capture – Low to moderate – Substantial improvements in energy efficiency of capture processes would significantly benefit the pace of implementing this technology, particularly in post combustion capture applications.

   Transport – Moderate to high – Capital costs are dependent on the capacity of the system. Acquisition of access/right-of-way could be a substantial challenge in some parts of the country

   Surface Facilities/Injection Wells – Moderate to high - Capital costs are dependent on the capacity of the system and the site-specific geologic conditions.

   Storage Site – Moderate – There is a high degree of uncertainty regarding the cost of acquiring storage rights (leasing rates, bonus payments, and "royalty" rates). Management of long-term responsibility has not been addressed and remains a potentially high exposure area.

3. **Public Acceptance** – Low to Moderate – This varies regionally. Site integrity and the perceived potential of site containment failure are the primary public concerns[61]. Similar concerns are possible regarding pipeline siting. The higher cost of power resulting from implementation of CCS may lead to public resistance.

4. **Regulatory Inhibitions** – High – Sound, predictable GHG management policy is necessary to facilitate the substantial investments necessary. Legal and regulatory infrastructure necessary for CCS is emergent[62].

5. **Role for Government** – Moderate – Financial support by government to facilitate technology development is necessary given high costs involved and the lack of a current economic basis to support substantial investment by industry. Policies supporting implementation of CCS should be balanced and focused on the objective of reducing GHG emissions as opposed to supporting favored industrial sectors or technologies.

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[58] American Petroleum Institute, Summary of Carbon Dioxide Enhanced Oil Recovery (CO_2 EOR) Injection Well Technology, 2007, Washington , DC, <www.api.org>

[59] Group of Eight 2008, G8 Summits Hokkaido Official Documents – Environment and Climate, 2008, <ww.g7.utoronto.ca/summit/2008hokkaido.2008-climate.html>

[60] International Energy Agency (IEA), Energy Technology Perspectives 2010 – Scenarios and Strategies to 2050, 2010, OECD, IEA, Paris, France, <www.iea.org>

[61] U.S. Department of Energy – National Energy Technology Laboratory, Best Practices for Public Outreach and Education for Carbon Storage Projects, 2009, Washington, DC, <www.netl.doe.gov>

[62] International Energy Agency, Carbon Capture and Storage – Legal and Regulatory Review, Edition 1, 2010, OECD, IEA, Paris, France, (www.iea.org>

6. **Market Barriers** – None currently known - there is no commercially viable market basis for CCS today.

7. **Impact on Jobs** – Moderate – Primary and secondary employment impacts could rival that of the existing oil and gas industry over the long term if a substantial CCS industry emerges in response to a sound GHG emission reduction policy.

Policies that Could Accelerate Deployment of this Technology

Carbon Capture and Storage is a developing technology that requires several different types of policy actions to accelerate its deployment. These policies include:

1. Research and development support that is fuel neutral. Emphasis and incentives proposed to date have focused heavily on coal based power generation.
2. Balanced and transparent GHG management policies that facilitate substantial reductions in GHG emissions and that lead to a price for carbon that enables economically sound implementation of CCS.
3. Legal and regulatory frameworks for the design and operation of CCS; capture, transport and storage.
4. Policies that provide for a clear transfer of long-term responsibility for closed storage sites, after appropriate site integrity verification, to a government/public entity for long-term management.

Appendix I:

Industrial Fuel Switching

Fuel Switching in Industrial Boilers

Opportunity: Increased natural gas consumption in the industrial sector
Reduced GHG emissions in the industrial sector

Description of Technology

Switching existing coal and oil-fired industrial boilers to natural gas power plants has the potential to provide significant reductions in GHG emissions. Such GHG emission reductions could be achieved by replacing older coal and oil-fired boilers with new, efficient gas boilers or even more efficient gas CHP systems.

Generation of steam is the largest use of combustion in the industrial sector and it is also the largest consumer of coal in the industrial sector. The vast majority of industrial coal boilers is over 30 years old[63] and will soon be subject to stringent new environmental regulations on air toxics (industrial boiler MACT), which will require significant retrofit investment, replacement or shut-down. Replacement by cleaner, possibly more efficient gas boilers may be an attractive alternative in some cases.

The potential emissions reductions from fuel switching in the industrial sector are significant. Based on recent (2006) EIA data, coal consumption for boilers in the industrial sector was 1,066.5 TBtu and emitted 101 $MMTCO_2$. Direct replacement by gas-fired equipment would reduce that roughly in half or by about 41 $MMTCO_2$ at a volume weighted average cost of about $38/tonne[64]. The use of CHP could provide additional reductions.

Oil use in industrial boilers (excluding byproduct still gas in the refining sector) is much smaller only 360 TBtu per year compared to more than 1,000 TBtu per year each for coal, gas and byproduct fuels. Since oil prices have been significantly higher than gas prices for quite a while, most facilities that can easily switch from oil to gas have already done so. Those remaining likely have some impediment such as lack of access to gas supply.

Implementation Hurdle

The main challenge is that switching will typically require potentially large capital costs in addition to the higher cost of gas versus coal as an operating fuel. The design of coal and gas boilers is very different, and it may not be feasible or efficient to simply fire gas in a coal boiler. Some industrial facilities may not have access to natural gas, requiring additional investment to bring gas to the plant. Another hurdle to substantial fuel switching to natural gas is the perception that natural gas prices are too high and/or volatile[65].

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63 Characterization of the U.S. Industrial/Commercial Boiler Population, EEA for ORNL, May 2005.
64 NPC's NARD Carbon & End-use emissions, Technology Team, January 2011
65 See, for example, the July 22, 2010 letter to the U.S. Senate from the Industrial Energy Consumers of America and 66 other industrial and agriculture organizations regarding legislation providing incentives for increased natural gas demand in the electric power and transportation sectors. The coalition explained, "As manufacturers that rely heavily on the use of natural gas as both an energy source and an essential raw material or 'feedstock' we are concerned that legislative fuel switching incentives could result in short and long-term price volatility and higher prices, causing further industrial 'demand destruction' that forces good U.S. manufacturing jobs to overseas competitors. Higher natural gas prices will also impact electricity prices." See also, "Coal: An

Selection Criteria Evaluation

1. **Maturity of technology** - High - Gas boilers and CHP systems are a mature, readily available technology.
2. **Cost effectiveness** - Moderate to High - Fuel switching is a relatively low-cost emissions reduction strategy especially where existing coal-fired boilers would otherwise be required to invest heavily to meet new and evolving emission control requirements. This assumes that gas is available in proximity to the facility. The need to install gas delivery capacity can significantly increase the cost, depending on the location. The cost-effectiveness depends heavily on the cost of gas relative to coal.
3. **Public Acceptance of Technology** - Medium to High - public acceptance is not a significant barrier for this option except possibly for permitting of infrastructure development.
4. **Regulatory and technical barriers** - Lack of clear environmental standards such as for mercury, SO_2, NO_x and ash, though new emission limits for conventional pollutants are addressing this. Permitting of infrastructure development.
5. **Role for Government** - creating a system to price GHG emissions or other regulatory structures and incentives to effectuate fuel switching. Providing support for infrastructure development, permitting, minimization of impact of capital outlay for consumer
6. **Market barriers**:
   - Perceptions of excessive volatility in natural gas prices/lack of awareness of hedging opportunities
7. **Impact on jobs** - Positive impacts due to increased use of gas, retrofit of existing facilities, preservation of at risk businesses, but negative impacts due to decreased use of coal and oil.

Potential Policies That Would Accelerate Deployment of This Technology

Policies that incorporate the relative superiority of natural gas' environmental and efficiency attributes would result in accelerated fuel switching to natural gas. These may include a carbon price and incorporation of environmental costs for upcoming rules regarding air toxics (industrial boiler MACT) and ash. Other examples are:

1. Implementation of more stringent criteria pollutant standards or other environmental regulations that increase the cost of producing steam from coal
2. State/Federal grants for infrastructure funding. For example: New Jersey lawmakers passed a bill, S2381[66], on 1/10/2011 that would provide incentive payments for the construction of 2,000 MWs of natural gas-fired generation. A Colorado bill signed into law in 2010, HB 1365 required Xcel to consider switching to natural gas or installing controls at some of its coal-fired power plants. A Virginia bill would allow for natural gas to qualify as an "alternative fuel" under the state's renewable portfolio goal (http://www.allbusiness.com/energy-utilities/utilities-industry-electric-power-power/15397115-1.html). S.3935 – The Advanced Energy Tax Incentive Act of 2010[67] S.3935 introduced by Senator Jeff Bingaman in 2010 would increase the capacity for which CHP systems can receive a tax credit. Currently CHP systems are only eligible for a tax credit for the first 15 MW of system capacity. If passed, this bill covers the first 25 MW.

Economical Energy Resource," Fact Sheet by the American Coal Council, stating that "When considered in the context of fuel and energy costs, the economic case for using coal is easily supported. Relative to other fuels, coal is among the most abundant and the least expensive of any fuel source (whether considering fossil, renewable, nuclear, or others). By encouraging the use of coal, we avoid volatility in fuel and production costs and keep our electricity prices low."

[66] S.2381 can be accessed at: http://www.njleg.state.nj.us/2010/Bills/S2500/2381_R4.PDF.

[67] http://ase.org/resources/advanced-energy-tax-incentive-act-2010-s-3935

3. Accelerated depreciation for new infrastructure – Under the Federal Modified Accelerated Cost-Recovery System (MACRS) + Bonus Depreciation (2008-2012), businesses can recover investments in certain property through depreciation deductions. MACRs sets class lives for various types of property, which range from 3 to 50 years over which property can be depreciated. Natural gas pipelines, gathering lines, and distribution lines that meet certain criteria qualify under this program. CHP systems also qualify but must meet at least a 60% efficiency requirement, must be 50 MW or less, and other restrictions apply.
4. State/Local fast track permitting processes
5. Loan guarantees for infrastructure development
6. Cap and trade or carbon tax policies that establish a price for emitting GHGs.
7. Regulation that establishes CO_2 emission limits e.g., boiler performance standards