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General Approach for Energy Efficiency and Conservation

Similar, bottoms-up approaches were used for all end-use sectors for the energy efficiency and conservation analyses for both electricity and natural gas. Estimates of the major natural gas and electricity end uses for each of the states were developed. Based on a review of available literature, estimates were developed of the implementable savings that could be achieved in five years through the implementation of aggressive programs similar to those that have been deployed in recent years in response to recent regional energy shortages. These estimates were then applied to the end-use estimates in each state to develop sectoral estimates of energy savings for each state.

General Assumptions

To facilitate the performance of this analysis, we made several assumptions. The following parameters are assumed to be embodied in the base-case analysis, and were not being considered in the scenarios (except as noted):

- Demand destruction—the permanent elimination of energy demand due to facilities closing or shifting operations to other regions.
- Price-based fuel switching outside of renewables;
- Utility plant shutdowns or ramp-ups.
- Changes to natural gas infrastructure (except in the NYS/RPS scenario where we will explicitly assume no new gas transmission lines are constructed during the study period).
- A change in industrial feedstock utilization or sourcing—natural gas is used by some industries as a feed stock in addition to its use as a fuel.

To make the analysis doable, we made the following simplifying assumptions:

- Potential for industrial end-use energy efficiency and conservation does not vary by region.
- The load curve for industrial power and natural gas consumption does not vary seasonally.
- No significant new renewable resources are likely to become available in the first year above the base case.
- Wind, biomass, and solar are the principal renewable resources contributing to displaced utility generation above the base case.
- Additional displacement of consumer end-use gas by renewables is considered small, and is assumed to be zero for purposes of this analysis.

State-by-State Adjustments

The potential to achieve energy-efficiency savings varies among the states. Some states like New York and California have well established energy-efficiency programs supported by many market allies, and could expand efficiency programs off of existing policy platforms. Some other states, such as South Dakota and Mississippi, have no record of running energy efficiency programs, so are less likely to be able to rapidly deploy new programs. In order to estimate the energy saving potential for individual state, a state a weighting factor was developed. This state-weighting factor is intended to measure the current status of a state's energy-efficiency and renewable energy delivery infrastructure. The quality of the infrastructure is based on a matrix of policy handles and mechanisms, intended as a quantifiable measure of the various qualitative policy mechanisms (Table 1). Based on these factors, a "grade" was assigned to each state. Grades of "a", "b", "c", and "d" were assigned to each state. An "a" represented 100%, a "b" was equal to 85%, a "c" was equal to 70%, and a "d" was equal to 55%. This means that an "a" state would be able to achieve 100% of the regional savings potential. California, for example, located in the west census region was given a grade of "a" for its energy-efficiency and renewables infrastructure. The west regional maximum achievable five-year electricity and natural gas savings are 5.41% and 5.19%, respectively. California is expected to be able to achieve 100% of these savings under an aggressive policy scenario.

Table 1. State Energy Efficiency and Renewable Energy Programs and Policies

State	Public Benefit Fund[2]	IAC	RPS	Residential Buildings Codes	Commercial Buildings Codes	Utility Restructuring[3]	Regional Initiatives	Environmental Trust/ Environmental Trading Group	Tax Credits for Energy Efficiency	Tax Credits for Renewables	Score
Alabama	0	y		c	c	N					d
Arizona	0	y		c	c	A			Y	Y	b
Arkansas	0			c	b	D					d
California	2	y	y	a	a	S		Y			a
Colorado	1	y		c	c	N					b
Connecticut	2	y	y	b	b	A	y				a
Delaware	1	y		c	b	A	y				b
Florida	1	y		a	a	N					c
Georgia	0	y		a	a	N					d
Idaho	1			a	a	N			Y	Y	b
Illinois	0	y		c	c	A	y				b
Indiana	0	y		c	c	N	y				c
Iowa	1	y		c	b	N	y				b
Kansas	0			c	b	N					d
Kentucky	0			a	a	N					d
Louisiana	0	y		c	b	N					d
Maine	2		y	c	a	A	y				a
Maryland	0	y		a	b	A	y		Y	Y	b
Massachusetts	2		y	b	a	A	y	Y	Y	Y	a
Michigan	0	y		c	c	A	y				b
Minnesota	1			b	b	N	y				b
Missouri	0			c	c	N	y				d
Mississippi	0			c	c	N					d
Montana	1			c	b	D	y				c
Nebraska	0			c	c	N					d
Nevada	0		y	c	c	D					c

[2] Spending greater than 1% of revenues = 2, greater than 0.1% = 1, and less than 0.1% = 0
[3] N=no, A=active, D=delayed, S=suspended (CA only)

State	Public Benefit Fund[2]	IAC	RPS	Residential Buildings Codes	Commercial Buildings Codes	Utility Restructuring[3]	Regional Initiatives	Environmental Trust/ Environmental Trading Group	Tax Credits for Energy Efficiency	Tax Credits for Renewables	Score
New Hampshire	1	y		a	b	A	y				b
New Jersey	2	y	y	b	a	A	y		Y	Y	a
New Mexico	0			a	a	D					d
New York	2	y		a	a	A	y		Y	Y	a
North Carolina	0	y		a	a	N					d
North Dakota	1			a	c	N					d
Ohio	0	y		a	a	A	y				c
Oklahoma	0	y		b	b	D					d
Oregon	1	y		a	a	A	y	Y	Y	Y	a
Pennsylvania	1	y	Y	a	a	A					a
Rhode Island	2	y		a	a	A	y				a
South Carolina	1			a	b	N					d
South Dakota	0			c	c	N					d
Tennessee	1			c	c	N					c
Texas	1	y	y	a	a	A					a
Utah	1	y		a	a	N					b
Vermont	2	y		b	c	N	y				a
Virginia	0	y		b	b	A					c
Washington	1	y		a	a	N	y				b
West Virginia	0	y		c	c	N					d
Wisconsin	2	y	y	a	b	N	y				a
Wyoming	1			c	c	N	y				c

Residential/Commercial Methodology and Characterization

General Approach

The estimation of the implementable savings from the residential and commercial sectors used a "bottoms-up" approach. The analysis began with data on energy use in each of the 48 states by end-use (e.g. lighting, cooling, heating, etc). A variety of published studies were then used to estimate average annual electric and gas savings over five years from efficiency programs, including adjustments for reasonable savings by end-use. We then estimated the savings achievable in one year, relative to savings achievable over five years. Finally, we looked at current policy initiatives to promote efficiency in each of the 48 states, and adjusted savings downward in states without strong efficiency policies, reasoning that a sudden change in policy was unlikely, thus, lower savings were likely in these states. Each step is discussed in the following sections.

Base Case by End-Use

Base case energy use for each state was estimated for each of the 48 states using data from the *1997 Residential Energy Consumption Survey* (RECS) (EIA 1999) and the *1999 Commercial Building Energy Consumption Survey* (CBECS) (EIA 2001a).

RECS provides energy use consumption and saturation figures for the four largest states (California, Texas, New York, and Florida) and for each Census region. We used data for space heating, space cooling, water heating and appliances/other. For the 44 states not individually profiled, we assumed that the regional figures would apply. For Census regions with the four large states, we subtracted out data on the large state in order to calculate average energy use for the remaining states. In the case of the Mountain region, given the large differences in latitude involved, we differentiated between north Mountain and south Mountain using data from a study on the region by the Southwest Energy Efficiency Project (SWEEP 2002).

CBECS also provides data on each region, but not for individual states. End-uses covered were space heating, space cooling, water heating, lighting, refrigeration, ventilation, cooking, office equipment, and other. We used regional data to characterize each of the individual states.

Overall Energy Savings Achievable Over Five Years

A variety of studies have been conducted in recent years to estimate the economic and achievable efficiency potentials for reducing gas and electricity use in different states. Economic potential is an estimate of the savings that can be achieved if all measures which are cost-effective to end-users are implemented. Achievable potential is a subset of economic potential and includes allowances for reasonable measure penetration rates given likely policy and program interventions.

To estimate achievable potential over one and five years, we considered two types of data. First, substantial savings can be achieved in the short-term through behavioral changes in response to high prices and appeals for conservation. For example, in 2001, in response to the California electricity crisis, California end-users reduced their energy use about 6%, of which about two-thirds was a behavioral response (Global Energy Partners 2003). Thus Californians used behavioral actions to reduce energy use by about 4%. The California situation was particularly dire; therefore, we estimated that a new campaign in response to the natural gas crisis could only achieve two-thirds of these savings—an average of 2.7%.

Second, energy use can be reduced through hardware improvements. To estimate these savings, we compiled information from ten different studies, including six studies on potential gas savings and eight studies on potential electricity savings (four studies included both fuels). Energy savings estimates were divided by the period of analysis (e.g. five years, 20 years, etc.) in order to estimate annual incremental savings. We examined overall savings estimates by sector (residential and commercial), as well as by end-use. In estimating the overall savings achievable, we only looked at achievable potential studies, and in order to be conservative, emphasized the lower end of the savings estimates. Based on these studies, we estimated an overall achievable savings potential, from hardware improvements (Table 2).

Table 2. Achievable Savings Potential in the Residential and Commercial Sectors from Hardware Improvements

Sector	Fuel	Savings Achievable (%/year)
Residential	Natural gas	0.5
	Electricity	0.7
Commercial	Natural gas	0.4
	Electricity	0.8

As a check on these figures, we compared the annual achievable savings figures to actual savings achieved by leading utility programs. For example, one of the leading gas efficiency programs in the country is run by XCEL Minnesota. They have achieved approximately 0.5% savings per year in recent years, right in line with our estimate (XCEL Energy 2003). Likewise, among electric utilities, a 1995 analysis by ACEEE found that the leading utilities were achieving energy savings of 0.5 to 1.0% per year, in line with the estimates above (Nadel and Geller 1995). And in 2001, as noted above, California achieved 6% electricity savings, of which one-third (i.e. 2%/year) was in hardware improvements.

We then added the behavioral savings (2.7%) to the hardware savings over five years (annual savings times five) to arrive at overall savings over five years for each fuel and sector.

End-Use Adjustments

Achievable savings varies somewhat by end-use. However, data on achievable savings by end-use is rarely compiled. As a proxy, we looked at estimates on economic savings potential by end-use in comparison to overall sector economic savings potential. Based on these data, we developed multipliers for each end-use, in which a multiplier greater than one means higher than average savings potential and visa versa. Multipliers used are displayed in Table 3.

Table 3. End-Use Adjustments for the Residential and Commercial Sectors

Sector	Fuel	End-Use	Multiplier
Residential	Gas	Space heating	1.0
		Water heating	1.1
		Other	0.6
Residential	Electric	Space heating	0.8
		Space cooling	1.2
		Water heating	1.0
		Appliances & other	0.9
Commercial	Gas	Space heating	0.9
		Water heating	1.4
		Cooking	0.6
		Other	0.6
Commercial	Electricity	Space heating	0.2
		Space cooling	1
		Ventilation	0.9
		Water heating	0.6
		Lighting	1.2
		Cooking	0.5
		Refrigeration	0.8
		Office equipment	1.1
		Other	0.5

Savings in Year 1

In the first year, the vast bulk of the behavioral savings can be achieved, plus one year of hardware savings. Across the different fuels and sectors, we estimate that approximately half of the five-year savings can be achieved in the first year, assuming a high prices and an active efficiency promotion campaign, with the remaining savings evenly distributed across the remain years of the study period.

Estimates of Implementable Residential and Commercial Energy Savings

Based on the above data, for each state, the base case end-use share for each state was multiplied by the appropriate end-use factor and overall achievable savings estimate to come up with maximum five-year savings. These savings were then multiplied by the numeric percentage for each state's current programs and policies, in order to reduce savings in those states with low or moderate current programs and policies. The result is total percent savings, by state, over five years. As noted above, the first year savings are half of the five-year savings figures. State-by-state savings estimates are provided in Table 4 and Table 5. A more detailed breakdown of the savings measures are presented in Appendix B.

Table 4. Estimated Residential and Commercial Natural Gas Energy Efficiency and Conservation Savings

State	State Score	Commercial: Savings Possible In 5 Yrs	Commercial: Adjusted 5 Yr Savings	Commercial: Year-One Savings	Residential: Savings Possible In 5 Yrs	Residential: Adjusted 5 Yr Savings	Residential: Year-One Savings
Alabama	d	4.7%	2.6%	1.3%	5.2%	2.9%	1.4%
Arizona	b	4.7%	4.0%	2.0%	5.3%	4.5%	2.2%
Arkansas	d	4.7%	2.6%	1.3%	5.2%	2.9%	1.4%
California	a	4.8%	4.8%	2.4%	5.1%	5.1%	2.6%
Colorado	b	4.7%	4.0%	2.0%	5.2%	4.4%	2.2%
Connecticut	a	4.7%	4.7%	2.3%	5.2%	5.2%	2.6%
Delaware	b	4.5%	3.8%	1.9%	5.2%	4.4%	2.2%
Florida	c	4.5%	3.1%	1.6%	4.8%	3.4%	1.7%
Georgia	d	4.5%	2.5%	1.2%	5.2%	2.9%	1.4%
Idaho	b	4.7%	4.0%	2.0%	5.2%	4.4%	2.2%
Illinois	b	4.6%	3.9%	1.9%	5.2%	4.4%	2.2%
Indiana	c	4.6%	3.2%	1.6%	5.2%	3.6%	1.8%
Iowa	b	4.6%	3.9%	2.0%	5.2%	4.4%	2.2%
Kansas	d	4.6%	2.6%	1.3%	5.2%	2.9%	1.4%
Kentucky	d	4.7%	2.6%	1.3%	5.2%	2.9%	1.4%
Louisiana	d	4.7%	2.6%	1.3%	5.2%	2.9%	1.4%
Maine	a	4.7%	4.7%	2.3%	5.2%	5.2%	2.6%
Maryland	b	4.5%	3.8%	1.9%	5.1%	4.4%	2.2%
Massachusetts	a	4.7%	4.7%	2.3%	5.2%	5.2%	2.6%
Michigan	b	4.6%	3.9%	1.9%	5.2%	4.4%	2.2%
Minnesota	b	4.6%	3.9%	2.0%	5.2%	4.4%	2.2%
Missouri	d	4.6%	2.6%	1.3%	5.2%	2.9%	1.4%
Mississippi	d	4.7%	2.6%	1.3%	5.2%	2.9%	1.4%
Montana	c	4.7%	3.3%	1.6%	5.2%	3.7%	1.8%
Nebraska	d	4.6%	2.6%	1.3%	5.2%	2.9%	1.4%
Nevada	c	4.7%	3.3%	1.6%	5.3%	3.7%	1.8%
New Hampshire	b	4.7%	4.0%	2.0%	5.2%	4.4%	2.2%
New Jersey	a	4.5%	4.5%	2.2%	5.1%	5.1%	2.6%
New Mexico	d	4.7%	2.6%	1.3%	5.3%	2.9%	1.5%
New York	a	4.5%	4.5%	2.2%	5.1%	5.1%	2.6%
North Carolina	d	4.5%	2.5%	1.2%	5.2%	2.9%	1.4%
North Dakota	d	4.6%	2.6%	1.3%	5.2%	2.9%	1.4%
Ohio	c	4.6%	3.2%	1.6%	5.2%	3.6%	1.8%
Oklahoma	d	4.7%	2.6%	1.3%	5.2%	2.9%	1.4%
Oregon	a	4.8%	4.8%	2.4%	5.1%	5.1%	2.5%
Pennsylvania	a	4.5%	4.5%	2.2%	5.1%	5.1%	2.6%
Rhode Island	a	4.7%	4.7%	2.3%	5.2%	5.2%	2.6%
South Carolina	d	4.5%	2.5%	1.2%	5.2%	2.9%	1.4%
South Dakota	d	4.6%	2.6%	1.3%	5.2%	2.9%	1.4%
Tennessee	c	4.7%	3.3%	1.7%	5.2%	3.6%	1.8%
Texas	a	4.7%	4.7%	2.4%	5.1%	5.1%	2.6%
Utah	b	4.7%	4.0%	2.0%	5.2%	4.4%	2.2%
Vermont	a	4.7%	4.7%	2.3%	5.2%	5.2%	2.6%

State	State Score	Commercial: Savings Possible In 5 Yrs	Commercial: Adjusted 5 Yr Savings	Commercial: Year-One Savings	Residential: Savings Possible In 5 Yrs	Residential: Adjusted 5 Yr Savings	Residential: Year-One Savings
Virginia	c	4.5%	3.1%	1.6%	5.2%	3.6%	1.8%
Washington	b	4.8%	4.1%	2.1%	5.1%	4.3%	2.2%
West Virginia	d	4.5%	2.5%	1.2%	5.2%	2.9%	1.4%
Wisconsin	a	4.6%	4.6%	2.3%	5.2%	5.2%	2.6%
Wyoming	c	4.7%	3.3%	1.6%	5.2%	3.7%	1.8%

Table 5. Estimated Residential and Commercial Electric Energy Efficiency and Conservation Savings

State	State Score	Commercial: Savings Possible In 5 Yrs	Commercial: Adjusted 5 Yr Savings	Commercial: Year-One Savings	Residential: Savings Possible In 5 Yrs	Residential: Adjusted 5 Yr Savings	Residential: Year-One Savings
Alabama	d	6.5%	3.6%	1.8%	5.7%	3.2%	1.6%
Arizona	b	6.8%	4.7%	2.4%	5.9%	4.1%	2.1%
Arkansas	d	6.7%	3.7%	1.9%	5.8%	3.2%	1.6%
California	a	6.7%	6.7%	3.4%	5.7%	5.7%	2.8%
Colorado	b	6.8%	4.7%	2.4%	5.6%	3.9%	2.0%
Connecticut	a	6.8%	6.8%	3.4%	5.6%	5.6%	2.8%
Delaware	b	6.7%	4.7%	2.3%	5.6%	3.9%	2.0%
Florida	c	6.7%	4.7%	2.3%	6.1%	4.3%	2.1%
Georgia	d	6.7%	4.7%	2.3%	5.8%	4.1%	2.0%
Idaho	b	6.8%	5.8%	2.9%	5.6%	4.8%	2.4%
Illinois	b	6.7%	5.7%	2.8%	5.7%	4.8%	2.4%
Indiana	c	6.7%	5.7%	2.8%	5.7%	4.8%	2.4%
Iowa	b	6.8%	5.8%	2.9%	5.7%	4.8%	2.4%
Kansas	d	6.8%	3.8%	1.9%	5.7%	3.1%	1.6%
Kentucky	d	6.5%	3.6%	1.8%	5.7%	3.2%	1.6%
Louisiana	d	6.7%	3.7%	1.9%	5.8%	3.2%	1.6%
Maine	a	6.8%	6.8%	3.4%	5.6%	5.6%	2.8%
Maryland	b	6.7%	5.7%	2.8%	5.8%	4.9%	2.5%
Massachusetts	a	6.8%	6.8%	3.4%	5.6%	5.6%	2.8%
Michigan	b	6.7%	4.7%	2.3%	5.7%	4.0%	2.0%
Minnesota	b	6.8%	5.8%	2.9%	5.7%	4.8%	2.4%
Missouri	d	6.8%	3.8%	1.9%	5.7%	3.1%	1.6%
Mississippi	d	6.5%	3.6%	1.8%	5.7%	3.2%	1.6%
Montana	c	6.8%	4.7%	2.4%	5.6%	3.9%	2.0%
Nebraska	d	6.8%	3.8%	1.9%	5.7%	3.1%	1.6%
Nevada	c	6.8%	4.7%	2.4%	5.9%	4.1%	2.1%
New Hampshire	b	6.8%	5.8%	2.9%	5.6%	4.8%	2.4%
New Jersey	a	6.6%	6.6%	3.3%	5.6%	5.6%	2.8%
New Mexico	d	6.8%	3.7%	1.9%	5.9%	3.3%	1.6%
New York	a	6.6%	6.6%	3.3%	5.6%	5.6%	2.8%
North Carolina	d	6.7%	3.7%	1.8%	5.8%	3.2%	1.6%

State	State Score	Commercial: Savings Possible In 5 Yrs	Commercial: Adjusted 5 Yr Savings	Commercial: Year-One Savings	Residential: Savings Possible In 5 Yrs	Residential: Adjusted 5 Yr Savings	Residential: Year-One Savings
North Dakota	d	6.8%	3.8%	1.9%	5.7%	3.1%	1.6%
Ohio	c	6.7%	4.7%	2.3%	5.7%	4.0%	2.0%
Oklahoma	d	6.7%	3.7%	1.9%	5.8%	3.2%	1.6%
Oregon	a	6.7%	6.7%	3.4%	5.5%	5.5%	2.8%
Pennsylvania	a	6.6%	4.6%	2.3%	5.6%	3.9%	2.0%
Rhode Island	a	6.8%	6.8%	3.4%	5.6%	5.6%	2.8%
South Carolina	d	6.7%	3.7%	1.8%	5.8%	3.2%	1.6%
South Dakota	d	6.8%	3.8%	1.9%	5.7%	3.1%	1.6%
Tennessee	c	6.5%	4.6%	2.3%	5.7%	4.0%	2.0%
Texas	a	6.7%	6.7%	3.4%	5.9%	5.9%	3.0%
Utah	b	6.8%	5.8%	2.9%	5.6%	4.8%	2.4%
Vermont	a	6.8%	6.8%	3.4%	5.6%	5.6%	2.8%
Virginia	c	6.7%	4.7%	2.3%	5.8%	4.1%	2.0%
Washington	b	6.7%	5.7%	2.9%	5.5%	4.7%	2.3%
West Virginia	d	6.7%	3.7%	1.8%	5.8%	3.2%	1.6%
Wisconsin	a	6.7%	6.7%	3.3%	5.7%	5.7%	2.8%
Wyoming	c	6.8%	4.7%	2.4%	5.6%	3.9%	2.0%

Industrial Methodology and Characterization

General Approach

A "bottom-up" approach was used for determining the electricity and natural gas savings potential for the industrial sector. The estimated savings were calculated based on electric and natural gas end-use savings estimates. Because there is no specific state-level end-use data for the industrial sector, the state estimates were based on the four Census regions for which specific sub-sector and end-use data is available through the Energy Information Administration. Once maximum achievable savings estimates were determined, a weighting factor based on each state's existing programmatic infrastructure was applied.

Energy Savings by End-Use

Disaggregated state-level energy use is not available. In order to develop estimates for each of the 48 states, regional data from the Manufacturing Energy Consumption Survey (MECS) 1998 was used (EIA 2001b). Regional savings estimates were determined using the methodology described below.

MECS provides energy consumption and end-use data on a sub-sector level for four major Census regions—Northeast, Midwest, South, and West. Because the industrial sector is highly heterogeneous, it is necessary to obtain data on a 3-digit North American Industrial Classification System (NAICS) code level in order to determine accurate estimates of potential savings in a region. It was assumed that the breakdown of energy use in each state was identical to its Census region breakdown. The six industrial sub-sectors that were included in estimating the Census region electricity and natural gas savings are summarized in Table 6.

Table 6. North American Industrial Classification System (NAICS) Key

NAICS Code	Industrial Sub-Sector
311	Food
322	Paper
324	Petroleum and Coal Products
325	Chemicals
327	Nonmetallic Mineral Products
331	Primary Metals
	All Others

These sub-sectors align with the sub-sectors represented in the EEA natural gas forecasting model. Specific end-use data for each of these sub-sectors within each of the four census regions was obtained. For determining electricity conservation potential, the following end-uses were considered: motors, process heating, HVAC, and lighting. For determining the natural gas conservation potential, the following end-uses were considered: boilers, process heating, and space heating.

The conservation potential by end-use was based on figures reported in "California Industrial Energy Efficiency Market Characterization Study" (XENERGY 2001). This study was done for the Pacific Gas and Electric Company (PG&E), and the end-use savings figures line up closely with recent studies done by ACEEE and Optimal Energy Inc. (NYSERDA 2003). The XENERGY study details achievable savings by end-use for both electric and natural gas-fired processes. Because the scope of our study focused on a relatively short 1-year and 5-year timeframe, we estimated that 50% of the total achievable savings cited in the study would be achievable by year 5. The Energy study concentrated on a 10-yr timeframe, making the 50% assumption for the 5-year outlook reasonable. These estimates align closely with data obtained from the Industrial Assessment Centers (IAC) database (IAC 2003). Table 7 includes maximum achievable 5-year savings estimates by end-use.

Table 7. Industrial Sector End-Use Breakdown

	End-Uses	5-Year Savings Potential
Electricity End-Uses	Motors	7%
	Process Heating	5%
	HVAC	12%
	Lighting	10%
Natural Gas End-Uses	Boilers	6%
	Process Heating	5%
	Space Heating	5%

These end-use savings estimates were then applied to the unique end-use breakdowns for the seven major industrial sub-sectors that were considered in the analysis. Since each Census region has a distinct mix of industrial activity, the total regional savings potential will vary from the national average. Table 8 includes the end-use breakdowns for the various industrial sub-groups in the analysis.

Table 8. Industrial Sub-Sector End-Use

NAICS Code	Industrial Sub-Sector	Electricity End-Uses (Percent of Sub-Sector Electricity Consumption)				Natural Gas End-Uses (Percent of Sub-Sector Natural Gas Consumption)		
		Motors	Process Heating	HVAC	Lighting	Boilers	Process Heating	Space Heating
311	Food	78%	3%	6%	9%	60%	32%	6%
322	Paper	89%	2%	3%	4%	70%	21%	3%
324	Petroleum and Coal Products	92%	0%	0%	8%	26%	66%	2%
325	Chemicals	70%	3%	6%	4%	50%	44%	2%
327	Nonmetallic Mineral Products	61%	16%	5%	4%	4%	88%	5%
331	Primary Metals	26%	22%	3%	3%	15%	77%	7%
	All Others	64%	12%	9%	7%	38%	51%	7%

Overall Energy Savings Achievable Over Five Years

A variety of studies have been conducted in recent years to estimate the economic and achievable efficiency potentials for reducing gas and electricity use in different states. Economic potential is an estimate of the savings that can be achieved if all measures, which are cost-effective to end-users, are implemented. Achievable potential is a subset of economic potential and includes allowances for reasonable measure penetration rates given likely policy and program interventions. Following the previous methodology, the following maximum achievable five-year savings potentials for the various census regions of the industrial sector are displayed in Table 9.

Table 9. Achievable Potential for the Industrial Sector in 2008

Census Region	Electricity Savings Potential	Natural Gas Savings Potential
Northeast	5.96%	4.53%
Midwest	6.04%	4.94%
South	6.16%	5.19%
West	5.41%	5.19%

Savings in Year 1

In the first year under an aggressive policy scenario, a large portion (40%) of the five-year savings can be achieved. This result depends on an assumption of relatively high prices and an active efficiency promotion campaign.

Estimates of Implementable State Industrial Energy Savings

Based on the above data, the following one- and five-year cumulative state-by-state results were obtained (see Table 10):

Table 10. State Industrial Savings in 2004 and 2008

State	Infra-structure Score	Electricity Savings		Natural Gas Savings	
		1 year	5 years	1 year	5 years
Alabama	d	1.35%	3.39%	1.14%	2.85%
Arizona	c	1.51%	3.79%	1.45%	3.63%
Arkansas	d	1.35%	3.39%	1.14%	2.85%
California	a	2.16%	5.41%	2.08%	5.19%
Colorado	c	1.51%	3.79%	1.45%	3.63%
Connecticut	a	2.38%	5.96%	1.81%	4.53%
Delaware	c	1.72%	4.31%	1.45%	3.63%
Florida	c	1.72%	4.31%	1.45%	3.63%
Georgia	c	1.72%	4.31%	1.45%	3.63%
Idaho	b	1.84%	4.60%	1.76%	4.41%
Illinois	b	2.05%	5.14%	1.68%	4.20%
Indiana	b	2.05%	5.14%	1.68%	4.20%
Iowa	b	2.05%	5.14%	1.68%	4.20%
Kansas	d	1.35%	3.39%	1.14%	2.85%
Kentucky	d	1.35%	3.39%	1.14%	2.85%
Louisiana	d	1.35%	3.39%	1.14%	2.85%
Maine	a	2.38%	5.96%	1.81%	4.53%
Maryland	b	2.09%	5.23%	1.76%	4.41%
Massachusetts	a	2.38%	5.96%	1.81%	4.53%
Michigan	c	1.69%	4.23%	1.38%	3.46%
Minnesota	b	2.05%	5.14%	1.68%	4.20%
Missouri	d	1.33%	3.32%	1.09%	2.72%
Mississippi	d	1.35%	3.39%	1.14%	2.85%
Montana	c	1.51%	3.79%	1.45%	3.63%
Nebraska	d	1.33%	3.32%	1.09%	2.72%
Nevada	c	1.51%	3.79%	1.45%	3.63%
New Hampshire	b	2.03%	5.06%	1.54%	3.85%
New Jersey	a	2.38%	5.96%	1.81%	4.53%
New Mexico	d	1.19%	2.98%	1.14%	2.85%
New York	a	2.38%	5.96%	1.81%	4.53%
North Carolina	d	1.35%	3.39%	1.14%	2.85%
North Dakota	d	1.33%	3.32%	1.09%	2.72%
Ohio	c	1.69%	4.23%	1.38%	3.46%
Oklahoma	d	1.35%	3.39%	1.14%	2.85%
Oregon	a	2.16%	5.41%	2.08%	5.19%
Pennsylvania	c	1.67%	4.17%	1.27%	3.17%
Rhode Island	a	2.38%	5.96%	1.81%	4.53%
South Carolina	d	1.35%	3.39%	1.14%	2.85%
South Dakota	d	1.33%	3.32%	1.09%	2.72%
Tennessee	c	1.72%	4.31%	1.45%	3.63%
Texas	a	2.46%	6.16%	2.08%	5.19%
Utah	b	1.84%	4.60%	1.76%	4.41%
Vermont	a	2.38%	5.96%	1.81%	4.53%
Virginia	c	1.72%	4.31%	1.45%	3.63%
Washington	b	1.84%	4.60%	1.76%	4.41%
West Virginia	d	1.35%	3.39%	1.14%	2.85%
Wisconsin	a	2.42%	6.04%	1.98%	4.94%
Wyoming	c	1.51%	3.79%	1.45%	3.63%

Renewable Methodology and Characterization

General Approach

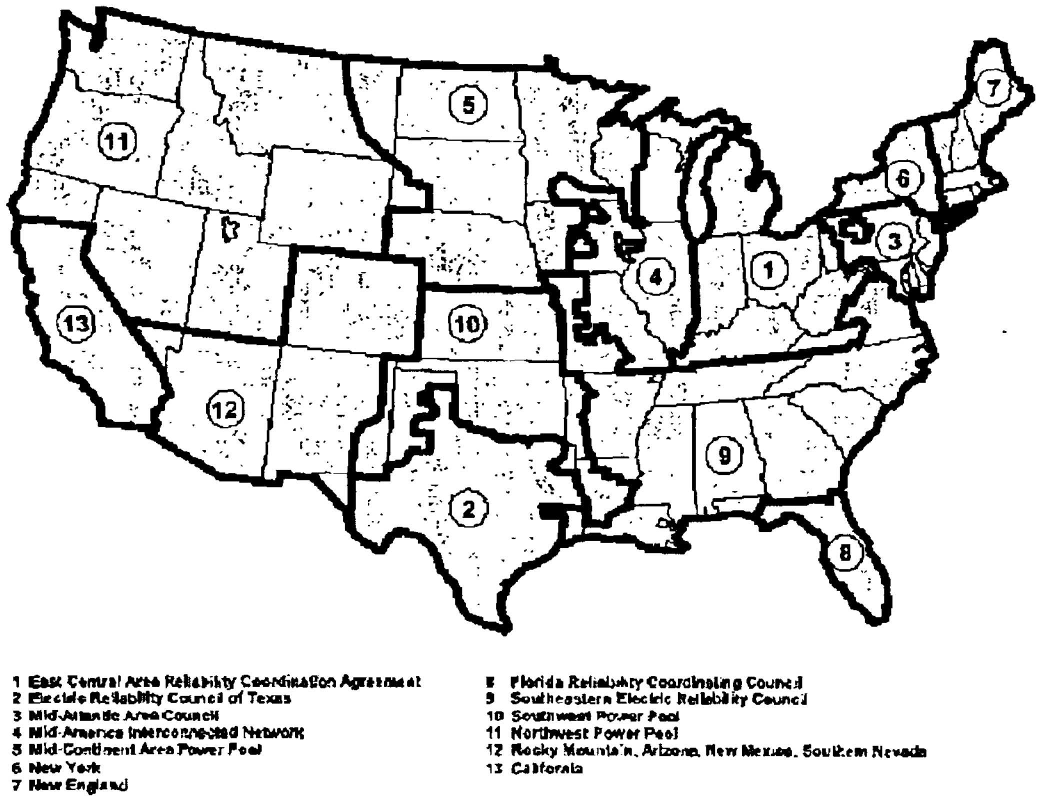
While estimates of the implementable potential for energy efficiency and conservation are somewhat available in the literature at a state level, data of nearer-term, implementable potential of renewable generation is less available. In addition, there is less need to make state-level estimates of renewables because generation markets are inherently multi-state. We elected to use the electric supply regions, used by EIA, which for the most part correspond to the National Electric Reliability Councils (NERC) sub-regions (Figure 8). The EEA model uses similar regions with the exception of Nevada which is placed in the same region as California, rather than with the upper West as does EIA and NERC.

We reviewed the available literature on renewables and interviewed experts. Based on the collected information, we developed estimates of the net additions of non-conventional hydro renewables for each of the thirteen EIA Electricity Supply Regions. These estimates were mapped to the EEA regions, and used as the model input. No independent assessment was attempted because of time and budget constraints. Nor was any attempt to estimate specific shares of renewable technologies, though it is likely that the renewables will be dominated by wind, along with biomass and solar in some regions.

Sources for Estimates

We reviewed the available literature on renewables and interviewed a number of leading experts. Many studies have looked at resource and economic potential at the state level and regional level, and most project the level that could be achieved over a fairly long policy horizon. Most of the studies use different assumptions, and study periods, so that it is difficult to place the findings on a common basis. One difficulty was that studies do not use a common definition of renewables. Most national data includes municipal solid waste (MSW) and conventional hydro power in the renewables definitions. Many renewable portfolio standards (RPS) exclude these two resources.

Figure 8. National Energy Modeling System Electricity Supply Regions (EIA 2002)



At the national level, EIA recently conducted two studies (EIA 2002, 2003) of the impacts of various RPSs using the National Energy Modeling System (NEMS). Both studies were prompted by requests from Congress to review legislation under consideration and look at 10 and 20% national RPS targets in 10 years. The base case developed for the more recent study was chosen as the base case for this study. However, data obtained for New York State indicated that the base case understated the anticipated renewables share (NYSERDA 2002b), so the base was modified from the EIA case.

A review of EIA's most recent regional projections from a national RPS indicated that they were not particularly aggressive. This result stems in large part from the fact that the modeled RPS only began in 2007, so little impact was realized. As a result, we decided we would turn to other sources for estimating near-term, implementable results.

The Environmental Law & Policy Center (ELCP 2001) had commissioned a study, *Repowering the Midwest* that presents energy futures in the Midwest, including a 2010 projection for renewables in the region. The prorated projection was for a renewables share of 1.4% in 2008. This was slightly higher than the EIA projection of 1.3%.

Another study, *Powering the South,* was prepared by the Renewable Energy Policy Project (REPP 2001) for the South projecting a 4% market share in 2010. The prorated 2008 estimate is 3.2%, which contrasts with the EIA projection of 1.6%.

A similar study of the West is underway for Western Resource Advocates (WRA) (Nielsen 2003). Preliminary results for the three electricity supply regions are presented in Table 11. In addition, a UCS study for California projected a renewables share of 20% in 2010 that prorates to 17.1% in 2008 (UCS 2001). For Washington State, a recent study (Shimshak 2003) projected a 14% market share for 2020, which prorates to 4.1% in 2008. We chose to use the preliminary WRA estimates.

Table 11. Projected Non-Hydro Renewables Share of Generation in the West (Nielsen 2003)

Region	2008 Renewables Generation (Mill. MWh)	2008 Renewables Share
ID, MT, OR, UT, WA, WY	11.4	5.2%
AZ, CO, NM, NV	8.5	7.3%
CA	42.2	17.4%

For New York State, three sources were used. NYSERDA has just released a study of energy efficiency and renewable energy potential (NYSERDA 2003). This study projects an economically achievable renewables share of 5.5% in 2008. A recent internal NYSERDA (Pakenas 2003) assessment projects renewables share of 5.9% in 2008 while environmental groups have been setting an RPS target of 27 million MWh (Greene 2003) that would prorate to an 8.7% market share in 2008. We chose to use the environmental groups' target.

Texas represents perhaps the most successful renewables market, with current installation of renewables (largely wind) outstripping the targets in the state's current RPS (about 2% of electric sales. While no systematic analysis has been done recently, renewables experts in the state believe Texas could achieve more than twice its existing 2008 target (Marston 2003).

Estimates of Implementable Renewable Energy Resources

Based on this review of existing studies, we developed a set of estimates for additional non-hydro generation that could be plausibly installed in each region by 2008 for each of the thirteen EIA Electricity Supply Regions. These estimates were mapped to the EEA regions. In most cases this represented an approximate doubling of installed generation relative to the EIA renewables base case discussed above. These results and the adjusted EIA base case are presented in Table 12.

We assume that the new renewable generation will displace existing and new conventional generation in the region. The electric module of the EEA model handles the dispatch of the additional renewables. We assume that since natural gas is the fuel on the margin in most of these regions, renewable generation is likely to disproportionately displace natural gas generation.

Table 12. Base Case and Policy Case Renewables Generation (Mill. MWh) by EIA Electricity Supply Regions

		EIA Renewables Base Case (2003)					2008 Policy Case		
EIA Region	States in Region	2008 Total Electricity Generation	2008 Base Renew. Generation	Conventional Hydro Generation	Non-Hydro Renew. Generation	Renew. Share	Total Non-Hydro Renewables Generation	Net New Renewables Generation	Renew. Share
1	MI, IN, OH, WV	680.79	7.86	3.18	4.69	0.7%	9.37	4.69	1.4%
2	TX	318.58	9.65	0.73	8.92	2.8%	15.32	6.40	4.8%
3	DE, DC, MD, NJ, PA	291.47	12.26	4.52	7.74	2.7%	15.48	7.74	5.3%
4	WI, IL	310.40	6.00	2.45	3.55	1.1%	20.23	16.67	6.5%
5	IA, MN, MO, NE, ND, SD	198.48	19.80	15.04	4.76	2.4%	24.33	19.58	12.3%
6	NY	172.40	23.46	26.40	10.20	5.9%	15.00	4.80	8.7%
7	CT, MA, ME, NH, RI, VT	131.16	12.99	5.10	7.88	6.0%	15.76	7.88	12.0%
8	FL	182.76	4.49	0.05	4.45	2.4%	11.72	7.27	6.4%
9	AL, GA, KY, NC, SC, TN, VA	910.18	39.15	33.28	5.87	0.6%	23.26	17.38	2.6%
10	AR, KS, LA, MS, OK	203.69	5.82	5.10	0.72	0.4%	1.45	0.72	0.7%
11	OR, WA, ID, MT, NV, UT, WY	311.19	165.36	154.31	11.06	3.6%	21.16	10.10	6.8%
12	AZ, CO, NM	209.80	20.81	15.12	5.69	2.7%	10.91	5.22	5.2%
13	CA	256.76	63.63	41.20	22.43	8.7%	44.01	21.57	17.1%

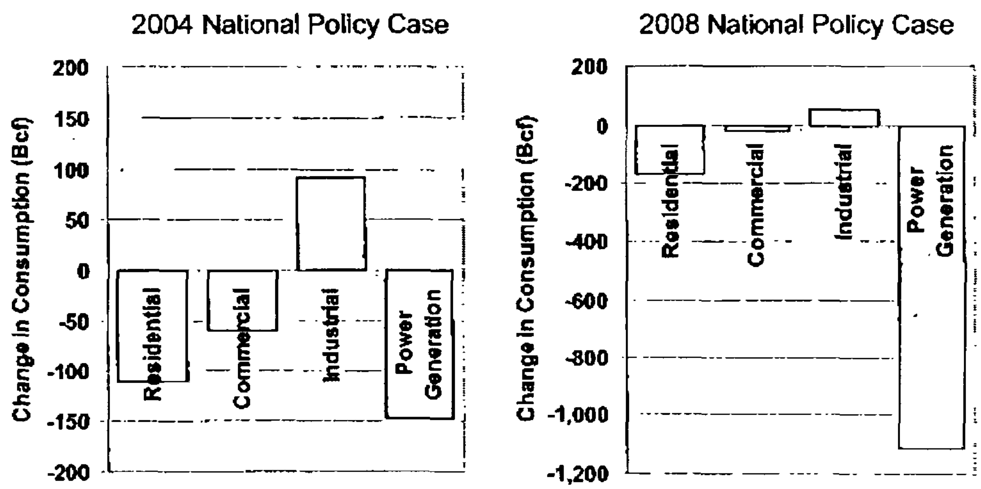
Changes in Natural Gas Consumption, Price, and Expenditures

Efficiency and Renewables Reduce Gas Consumption

Four different scenarios were examined in detail as part of this analysis. First, a "national" scenario was examined in which all 48 states in the continental United States implemented energy efficiency and renewable energy. In the other three scenarios, we looked at the effects of implementing efficiency or renewable energy in just one region or state. Table 13 displays the change in natural gas consumption on a national level for each of the scenarios. Our initial discussion will focus on the national scenario, followed by discussion of the other scenarios as part of a discussion of selected regional effects.

Our analysis of the national scenario shows that energy efficiency could reduce natural gas consumption by 1.1% in the next 12 months, significantly reducing wholesale and retail prices. By 2008, the combined energy efficiency and renewable energy measures would reduce total gas consumption by 5.5% (see Table 13). The power generation sector would represent the largest national natural gas savings in both 2004 and 2008 (see Figure 9). The 2004 results reflect the impact of electric efficiency savings by all consumers while the 2008 results reflect the combined effects of efficiency and expanded use of renewables that would both displace gas-fired electricity generation. Detailed sectorial and state specific information about natural gas consumption is presented in Appendix C.

Figure 9. Natural Gas Savings from Energy Efficiency and Renewable Energy



Residential consumers could make important contributions to natural gas efficiency (especially in the near-term) through many low- and no-cost measures such as furnace tune-ups and shifts to more efficient. These savings are projected to grow over the five years studied.

In addition, electricity savings, particularly from residential air conditioners are important in reducing demand for natural gas-produced electricity. Commercial air conditioning and lighting improvements are also important to electric savings.
Commercial gas savings are more modest than from the other sectors.

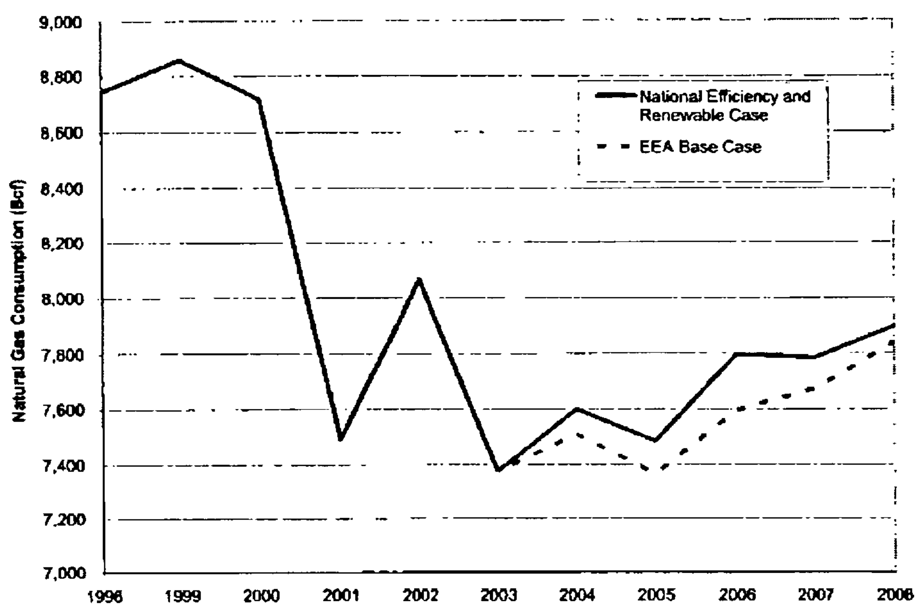
Table 13. Changes in Natural Gas Consumption under Different Policy Scenarios

	Change from EEA Base Case in 2004		Change From EEA Base Case in 2008	
	Bcf	Percent	Bcf	Percent
Total Demand				
EEA July 2003 Base Case				
ACEEE: National	-238	-1.1%	-1,349	-5.5%
ACEEE: Pacific West	-31	-0.1%	-290	-1.2%
ACEEE: Northeast/PJM	-31	-0.1%	-230	-0.9%
ACEEE: NY Renewables	0	0.0%	-9	0.0%
Residential				
EEA July 2003 Base Case				
ACEEE: National	-112	-2.1%	-167	-3.1%
ACEEE: Pacific West	-14	-0.3%	-12	-0.2%
ACEEE: Northeast/PJM	-30	-0.6%	-48	-0.9%
ACEEE: NY Renewables	0	0.0%	1	0.0%
Commercial				
EEA July 2003 Base Case				
ACEEE: National	-59	-1.8%	-22	-0.6%
ACEEE: Pacific West	-5	-0.2%	16	0.5%
ACEEE: Northeast/PJM	-19	-0.6%	-18	-0.5%
ACEEE: NY Renewables	0	0.0%	1	0.0%
Industrial				
EEA July 2003 Base Case				
ACEEE: National	91	1.2%	57	0.7%
ACEEE: Pacific West	41	0.5%	60	0.8%
ACEEE: Northeast/PJM	53	0.7%	72	0.9%
ACEEE: NY Renewables	0	0.0%	9	0.1%
Power Generation				
EEA July 2003 Base Case				
ACEEE: National	-147	-3.3%	-1,115	-18.5%
ACEEE: Pacific West	-51	-1.1%	-332	-5.5%
ACEEE: Northeast/PJM	-26	-0.6%	-199	-3.3%
ACEEE: NY Renewables	0	0.0%	-19	-0.3%

Note: The sum of end-use sector consumption will not equal the national total because pipeline fuel, and lease and plant fuel are not reported in the table.

Industrial gas consumption would decline less under all the efficiency and renewable energy scenarios than in the base case—in large part as a result of a decrease in "demand destruction" in the base case (see Figure 10). "Demand destruction" refers to plant closures and layoffs at natural gas-dependent industries such as chemicals and primary metals that would have occurred as a result of higher natural gas prices. Because gas prices would be lower as a result of energy efficiency and renewable energy investments, gas would be more affordable for feedstock uses and certain more such businesses would remain in operation relative to the base case. Hence industrial demand for natural gas would increase slightly under the scenarios run in this study. The industrial increases in gas use would be greatest in the first three years of the analysis when the projected natural gas consumption declines from the base case are most pronounced.

Figure 10. Efficiency and Renewable Energy Frees Gas for Industrial Use



The reductions in natural gas consumption the power sector are slightly lower that the combined reductions in the residential and commercial sector in 2004 when only electric efficiency measures are implemented. By 2008, with four years of increased renewables and five years of electric efficiency measures in place, the power generation sector dominates the gas savings. These results reflect the importance of the growing relationship between natural gas markets and the electric power sector.

Reductions in Natural Gas Consumption Reduce Natural Gas Prices

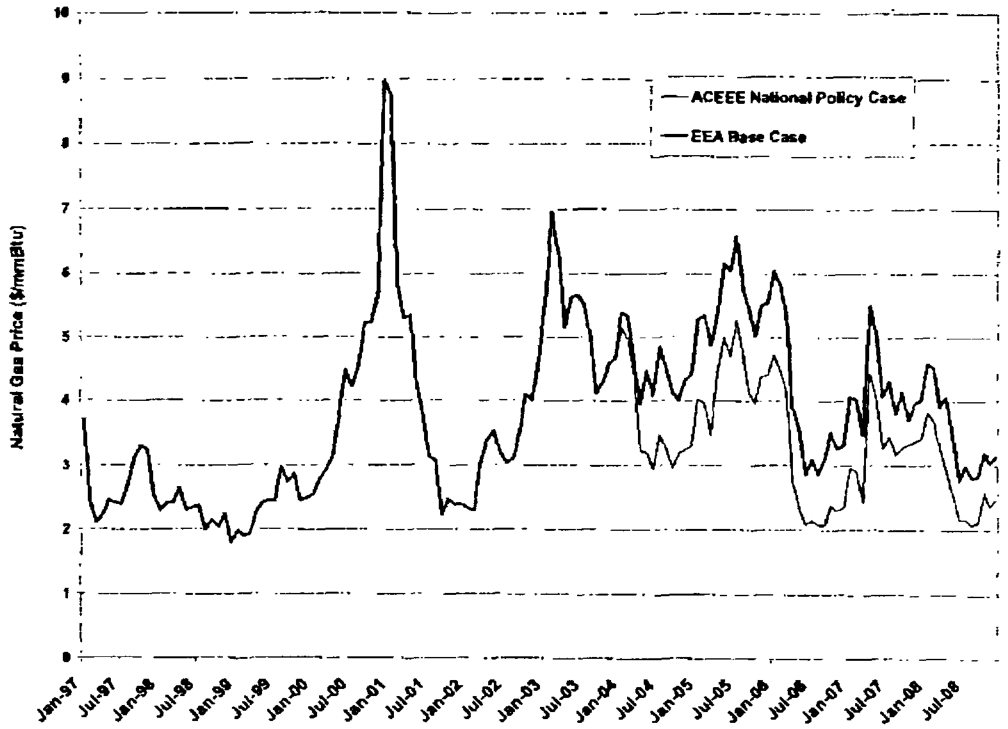
As we have seen in recent years, modest increases in natural gas consumption have produced dramatic increases in natural gas prices. This volatility results from a very tight supply situation. As we would expect from this experience, the modeling shows that modest reductions in natural gas consumption from energy efficiency and renewable energy generation would result in large reduction in the price of natural gas. The national reference Henry Hub wholesale price (see map in Appendix A) would be reduced by almost $0.90/MMBtu or 20% in 2004, and by 22% in 2008 (see Figure 11 and Table 14).

Regional Gas Savings Would Have National Price Impacts

Energy efficiency and renewable energy efforts that would be restricted to a region would reduce wholesale and retail prices in the region in which they would be implemented. The Northeast/PJM scenario would have about the same impact on the New York City Hub as it would on New England hub prices of natural gas (see map in Appendix A and Table 14). Under this scenario, the average New York State residential gas customer could save about $60 annually on her gas bill. Likewise, the Pacific West scenario would have marked price impact on the Southern California Hub wholesale price. At the retail level, the average

California residential natural gas customer would save about $37/year, and the combined state residential, commercial, and industrial savings would average over $900 million annually for the five years studied.

Figure 11. Energy Efficiency and Renewable Energy Reduce Wholesale Gas Prices



In addition, the modeling indicates that these regional efforts would cause natural gas price reductions nationally—for example, the Northeast/PJM scenario would produce a 6.1% reduction in Southern California Hub pricing in 2004 and the Pacific West Scenario would produce a 5.2% reduction in the New York City hub wholesale price of gas (see map in Appendix A and Table 14). It is important to remember, as will be discussed in greater detail in the next section, that changes in natural gas prices account for only a fraction of the consumer bill savings that result from expanded deployment of energy efficiency and renewable energy resources. The bill savings that result from reductions in both gas and electricity consumption are important contributors to consumers' overall benefits. Thus, while consumers everywhere will benefit from nationally reduced natural gas prices, only consumers in those regions in which greater energy efficiency and renewables are implemented will realize this large fraction of the savings potential.

Table 14. Change in Wholesale Natural Gas Prices at Key Transmission Hubs*

Gas Prices (in 2002$/MMBtu)	Change from EEA Base Case in 2004		Change from EEA Base Case in 2008	
	Dollars	Percent	Dollars	Percent
Henry Hub				
EEA July 2003 Base Case				
ACEEE: National	-0.89	-19.8%	-0.76	-22.1%
ACEEE: Pacific West	-0.27	-5.9%	-0.15	-4.3%
ACEEE: Northeast/PJM	-0.28	-6.2%	-0.21	-6.0%
ACEEE: NY Renewables	0.00	0.0%	-0.02	-0.5%
New York City				
EEA July 2003 Base Case				
ACEEE: National	-0.95	-19.0%	-0.94	-23.6%
ACEEE: Pacific West	-0.26	-5.2%	-0.13	-3.2%
ACEEE: Northeast/PJM	-0.35	-7.1%	-0.43	-10.9%
ACEEE: NY Renewables	0.00	0.0%	-0.07	-1.8%
New England				
EEA July 2003 Base Case				
ACEEE: National	-0.95	-19.2%	-0.90	-23.6%
ACEEE: Pacific West	-0.26	-5.3%	-0.14	-3.6%
ACEEE: Northeast/PJM	-0.35	-7.0%	-0.36	-9.3%
ACEEE: NY Renewables	0.00	0.0%	-0.03	-0.7%
Southern California				
EEA July 2003 Base Case				
ACEEE: National	-0.91	-20.1%	-0.95	-29.1%
ACEEE: Pacific West	-0.34	-7.4%	-0.66	-20.3%
ACEEE: Northeast/PJM	-0.28	-6.1%	-0.15	-4.7%
ACEEE: NY Renewables	0.00	0.0%	-0.01	-0.4%

* See Appendix A for a map of North American natural gas transmission system

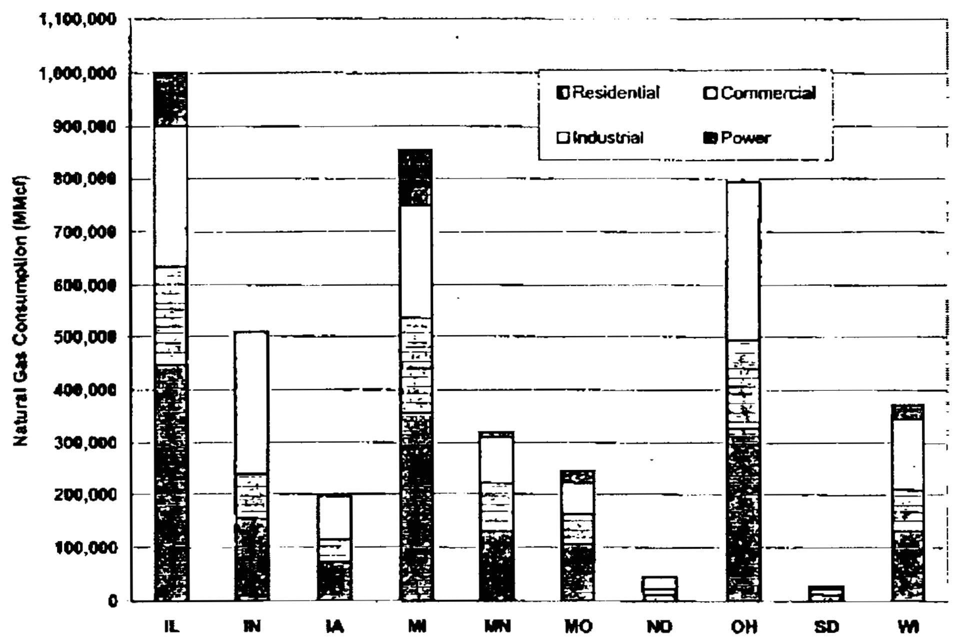
Regional Results

The potential impacts vary by state, with those most dependent on gas for peak electric power generation benefiting the most. In addition to the bill savings from reduced natural gas prices and consumption that retail customers would realize from energy efficiency measures, the customer would also experience additional savings from reductions in electricity prices and consumption. The model used for our analysis does not project electricity prices, so we cannot quantify these savings. However, if we assume that consumer electricity prices would remain constant at 2002 levels (they are actually forecast to rise), the dollar savings nationally would be similar to those from natural gas savings. We would, however, anticipate significant variation in the ratio of electric-to-gas savings among the states due to variation in the end-use energy mix. Several examples follow.

Midwest

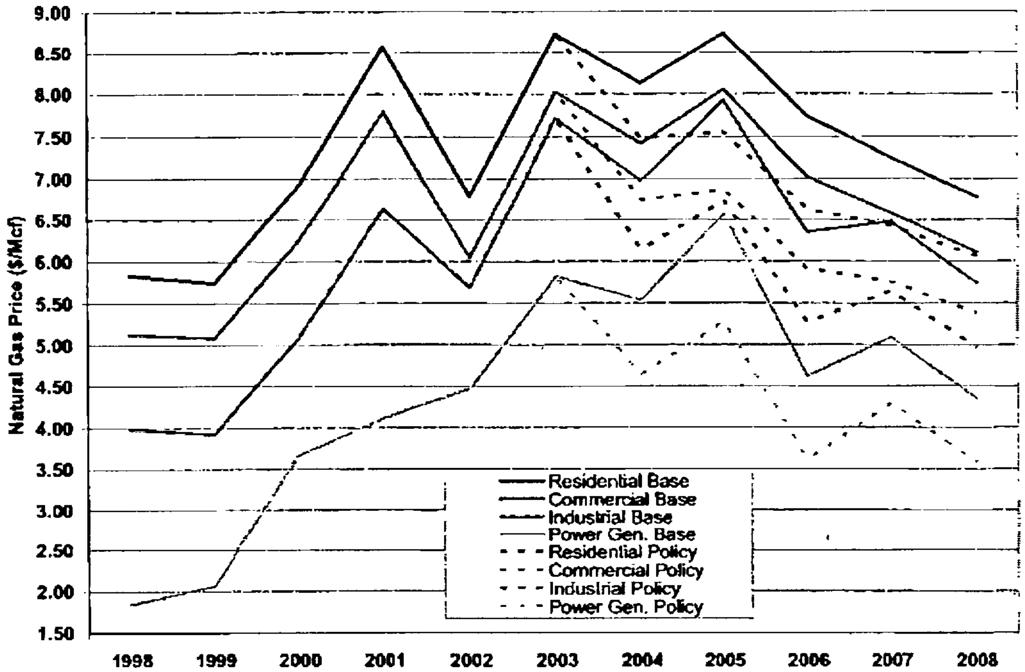
Natural gas represents an increasingly important energy source for the Midwest. Average residential gas customer natural gas bills are 3.6 times as much as the national average, with residential customers' bills in Illinois being 4.5 times the national average. Natural gas consumption in the residential, commercial and industrial sectors of the Midwest is projected to continue to grown at a rate slightly greater than the national average over the next five years. Electric power generation from gas in the region is relatively modest, with only Michigan having significant share of total generation from natural gas generation at 12% (EIA/EA 2003). However, projections suggest that natural gas generation in Indiana, North Dakota and Ohio will grow rapidly in coming years.

Figure 12. 2002 Natural Gas Consumption in the Midwest (Source: EEA 2003).



Wholesale natural gas prices in the Midwest average slightly less than the national average, except for the industrial sector where prices are slightly above national averages. There is significant variation in the industrial, commercial, residential, and power generation prices in the various states. Natural gas prices in the region are projected to remain high in the base case (Figure 13). With expanded energy efficiency and renewable energy at the national level, natural gas prices are projected to be reduced dramatically, with industrial and power sectors seeing the greatest price reductions.

Figure 13. Historical and Projected Retail Natural Gas Prices



EE and RE policies reduce natural gas consumption in the residential and commercial sectors in all the states in the region (see Figure 14). Industrial consumption of gas expands robustly in Illinois, Indiana, Michigan and Ohio reflecting an enhanced recovery of these depressed energy intensive industries due to reduced natural gas prices. Natural gas consumption by electric power generators in Indiana, Michigan and Ohio expands due to the reduced price of natural gas to the power sector. Part of this increase is likely due to expanded operation of industrial CHP facilities in these states reflecting the corresponding increase in industrial activity.

Total expenditures for natural gas decline in almost all sectors in all states in the region, except for the power and manufacturing sectors in Indiana and Ohio where increased industrial activity outweighs the price and efficiency savings (Figure 15).

Figure 14. Cumulative Change in Consumption by Sector in the Midwest

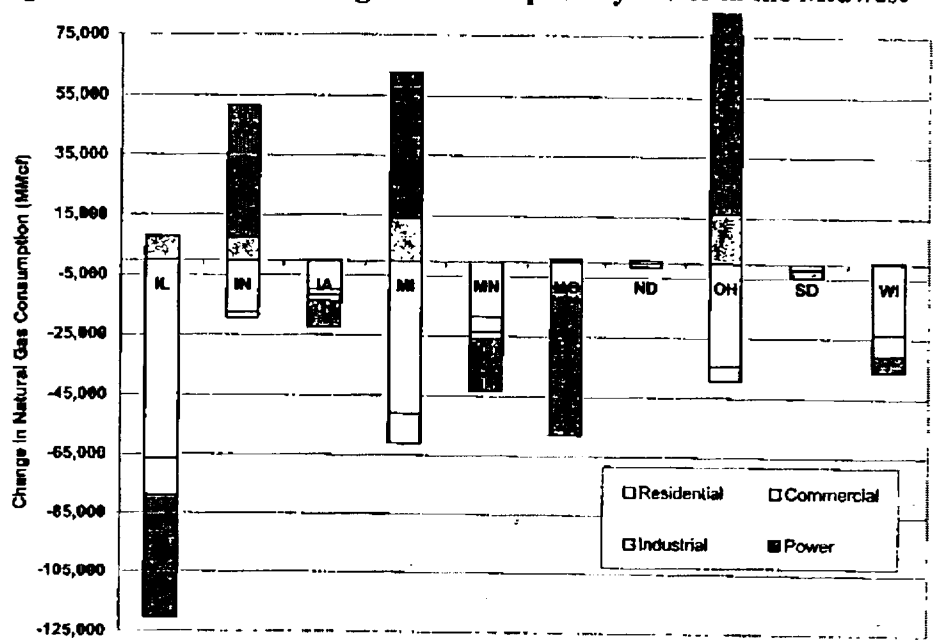
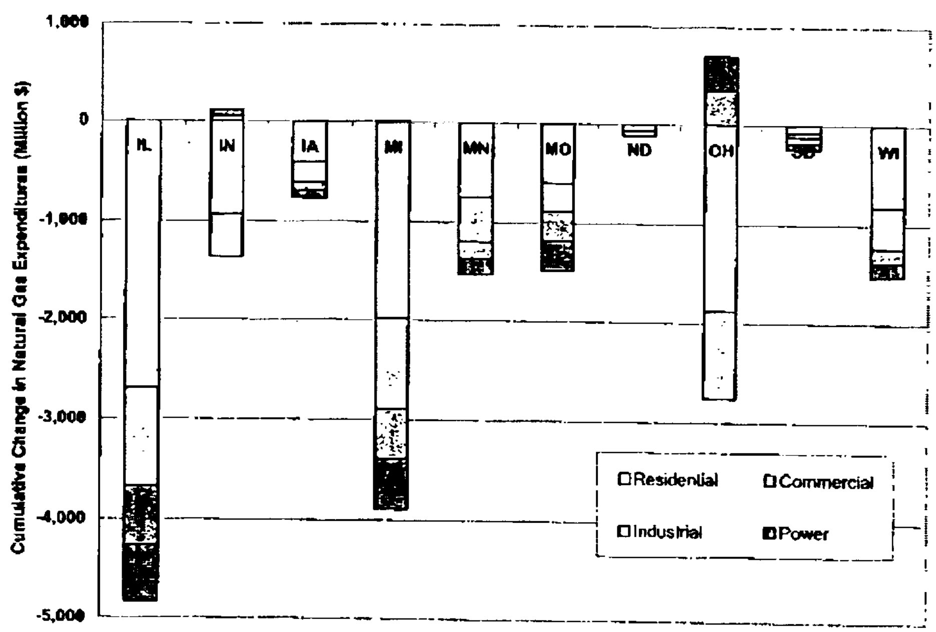


Figure 15. Cumulative Change in Natural Gas Expenditure by Sector for the Midwest



New England and Mid-Atlantic

How natural gas is consumed varies significantly among the New England and Mid-Atlantic states. In 2002, power generation accounted for more than 20% of total gas consumption in seven of the 12 states, the majority of total consumption in Maine and Rhode Island (Figure 16). Gas demand for power generation has increased rapidly in the region, jumping by more than 30% from 1998 to 2002. While growth is projected to decrease for the next few years, likely due to increased gas prices, rapid growth in gas fired generation is projected to resume in 2006 increasing to 169% of the 1998 level by 2008. Residential gas usage provides the base in most states in the region, varying between 20 and 50% of state consumption. Industrial gas demand is modest in New Hampshire, Pennsylvania and Vermont which all exceed 25% of total state demand. Delaware leads the region, with industrial demand accounting for about 50% of the state's total gas demand.

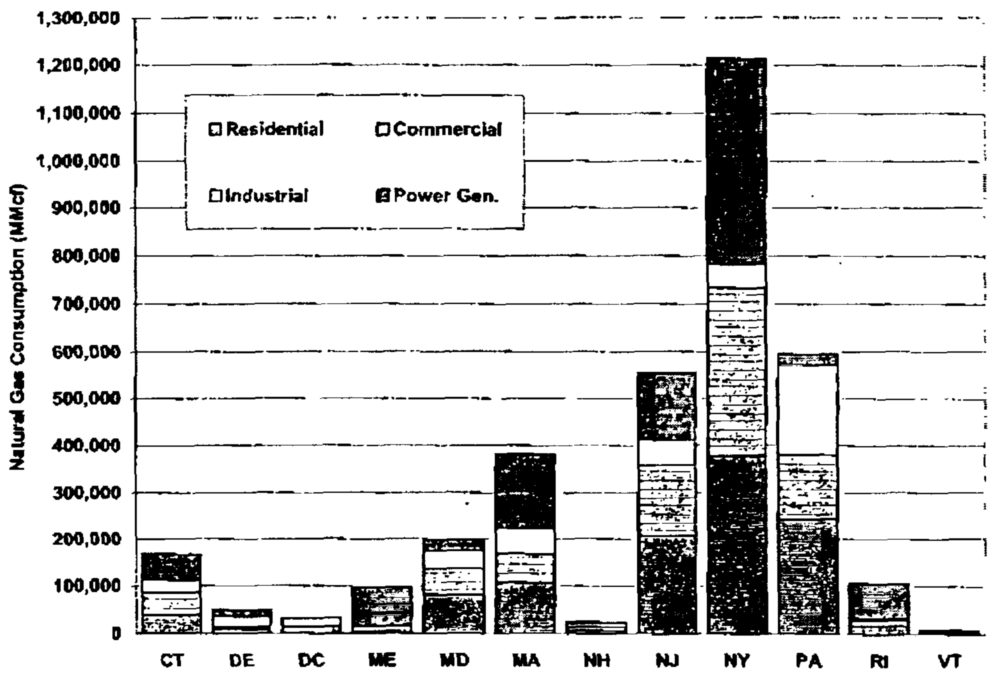
Natural gas prices vary significantly across the region (see Table 15). The average residential, commercial and industrial retail gas prices were above the national average in 2002, though the average power generation price was slightly below the national average. Residential prices for gas vary almost a factor of two, with Delaware and New Jersey having residential prices less than the national average. New Jersey at $5.93 per Mcf had some of the lowest cost residential gas in the country in 2002. D.C., while Massachusetts and New Hampshire all had natural gas prices approaching $11 per Mcf. Industrial and commercial prices showed similar variability. Commercial prices were more than a $1 per Mcf higher than the national average while industrial prices were almost $2 higher. Vermont was the only state in the region in which the average industrial natural gas cost is less than the national average while Maryland and Massachusetts have the highest industrial prices in the region. The range in natural gas prices was even more dramatic, with Maine and New Hampshire averaging less than $2 per Mcf and Pennsylvania leading the region at $8.74.

Table 15. Average Annual Retail Natural Gas Price by Sector (EEA 2003).

	$ per thousand cubic feet (Mcf)			
	Residential	**Commercial**	**Industrial**	**Power Gen.**
CT	10.63	6.34	6.06	5.42
DE	7.32	8.68	5.93	3.91
DC	10.84	10.58	NA+	NA+
ME	10.49	9.18	7.15	1.95
MD	9.90	8.75	8.38	7.12
MA	11.00	9.85	8.51	2.90
NH	10.96	9.59	7.10	1.90
NJ	5.93	6.22	5.76	3.26
NY	9.98	8.22	6.67	4.05
PA	9.78	9.08	6.31	8.74
RI	10.37	9.12	5.74	4.72
VT	8.31	6.41	4.32	4.25
NE/PJM Region	9.29	8.12	6.70	3.90
US Average	7.86	6.95	4.79	4.22

Notes: + D.C. has no significant reported Industrial or Power Generation natural gas sales so no price available.

Figure 16. Natural Gas in the Northeast and Mid-Atlantic State in 2002 by Sector (EEA 2003)



In the New England and Mid-Atlantic region we can compare the results for both the National and the New England and Mid-Atlantic scenario. As can be see in Figure 16, the application of energy efficiency and renewable energy measures in the region achieve 32% of the price reduction seen with lower-48 state application of the measures. Similarly, we see about a third of the price reduction at the retail level (Figure 19).

In contrast to the Midwest were we see significant increases in industrial gas consumption as a result of avoided demand destruction, we only see modest increases in industrial consumption in Maryland and Pennsylvania, both noted for their gas dependent industries (see Figure 18). In eight of the states, the power generation sector experiences the greatest cumulative gas savings as a result of the combined effects of electric energy efficiency and conservation and expanded renewables. In the remaining jurisdictions, (D.C., Massachusetts, Rhode Island and Vermont), it is the residential gas conservation that contributes the greatest share to the total state gas reductions. The commercial sector also factors prominently in the gas reduction in these states.

The residential sector accounts for more than half of the cumulative natural gas expenditure reductions in seven of the states I the region (see Figure 20), while power generation accounts for more than half in Delaware, Maine and New Hampshire. The share of savings in the commercial sector is modest in all the states, while the industrial sector experiences significant natural gas expenditure reductions in Delaware, Maine, Massachusetts, Pennsylvania, and Vermont.

Figure 17. Impact of Regional and National Application of Renewable Energy Efficiency and Renewable Energy Measures on Regional Wholesale Prices

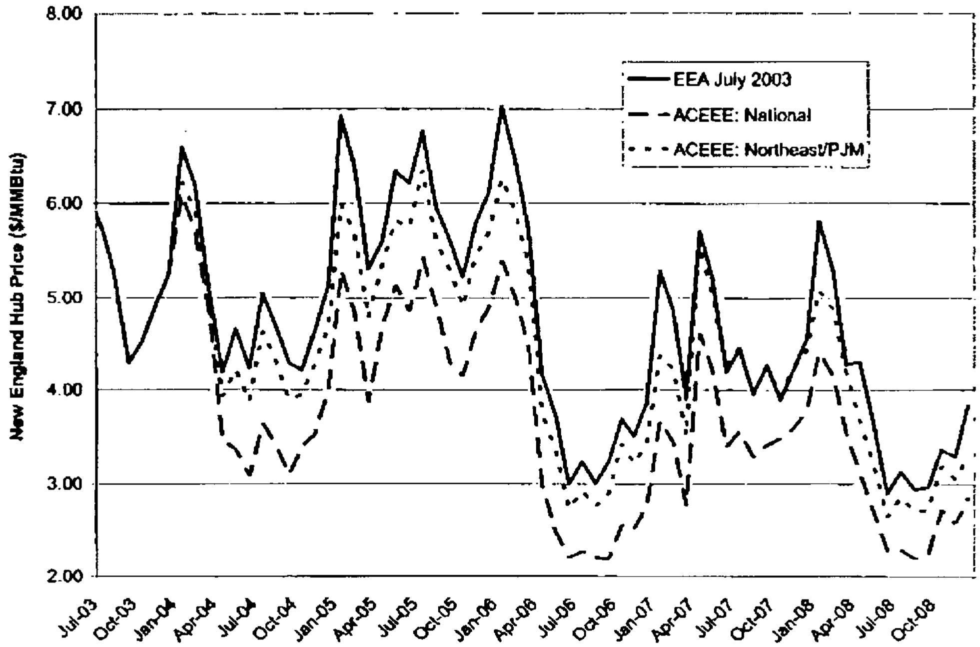


Figure 18. Change in Natural Gas Consumption in the Northeast and Mid-Atlantic

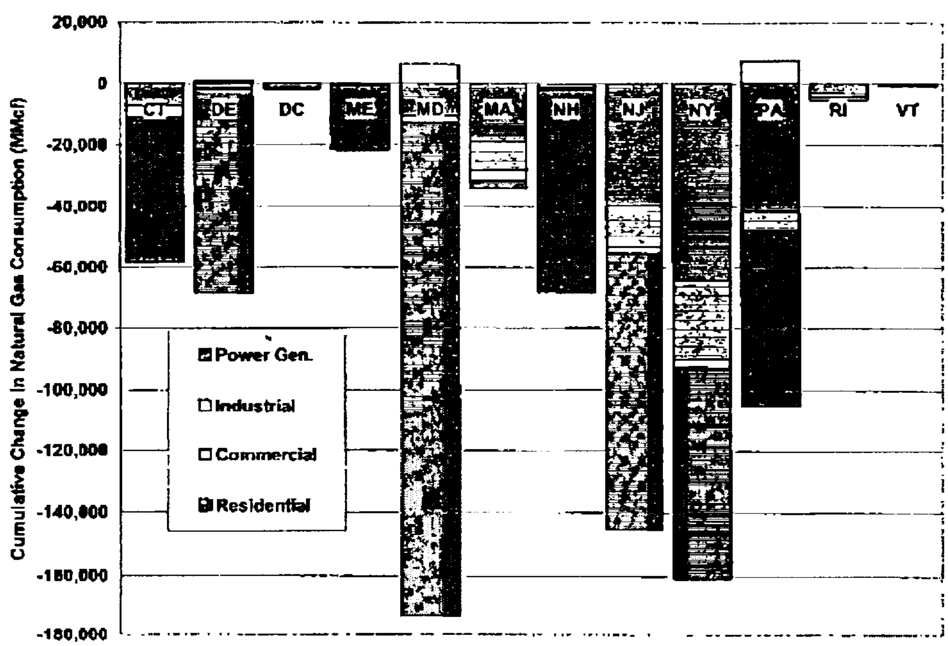


Figure 19. Historical and Projected Average Annual Retail Natural Gas Prices in the New England / Mid-Atlantic Region for both Base and Scenario Cases

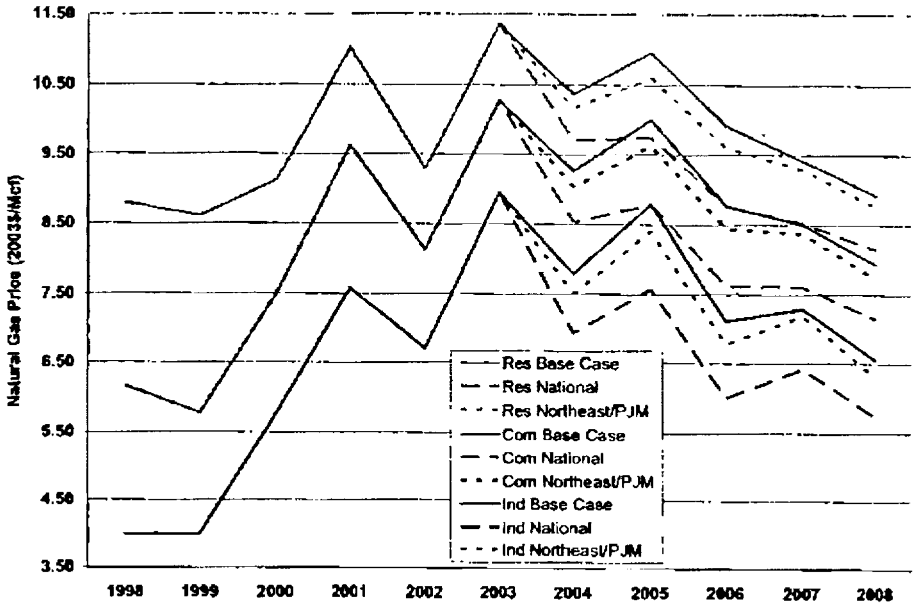
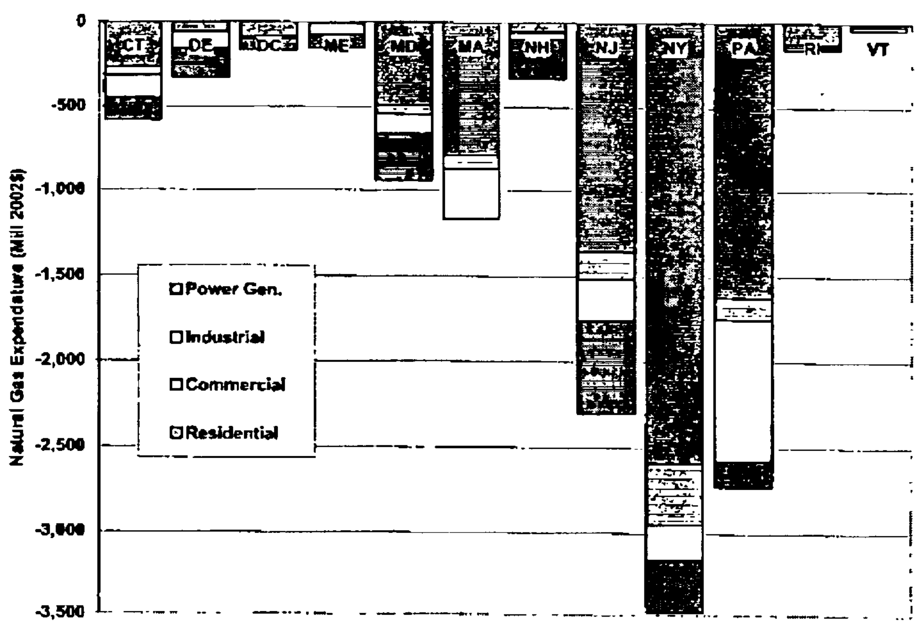


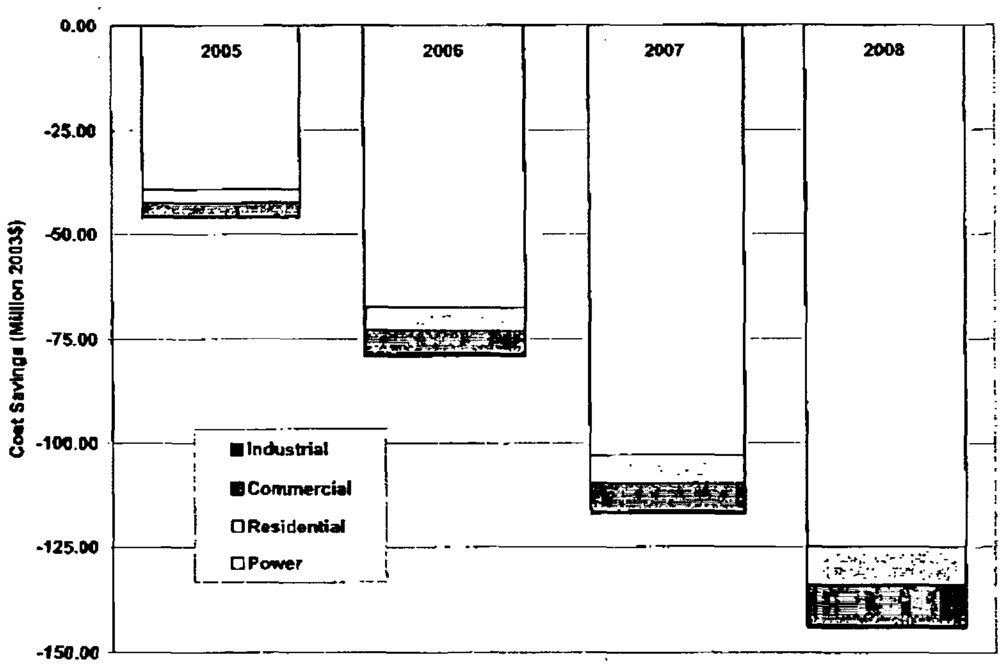
Figure 20. Cumulative Change in Natural Gas Expenditures by Sector in New England and the Mid-Atlantic Region



Expanded Renewables in New York State Would Reduce Gas Prices

In the most geographically narrow scenario, we expand only renewable energy generation in New York State from 5.9% of total generation to 8.7% in 2008. This increase in renewables share would displace 19 Bcf in electric generation fuel and reduce the New York City wholesale price by almost 2%. The combined savings in natural gas expenditures resulting from expanded use of renewables in New York State would increase from about $46 million in the first year of expanded renewables, 2005, to about $144 million in 2008 (see Figure 21). In the power sector, natural gas expenditures would be reduced by almost $125 million in 2008 from a combination of a 5% reduction in consumption of gas for power production and a 1.4% reduction in pricing to electricity generators. Overall expenditures by retail residential, commercial, and industrial customers would be reduced 0.25% for a savings of $19 million in 2008. As the share of renewable power generation expands, this saving would continue to increase as well.

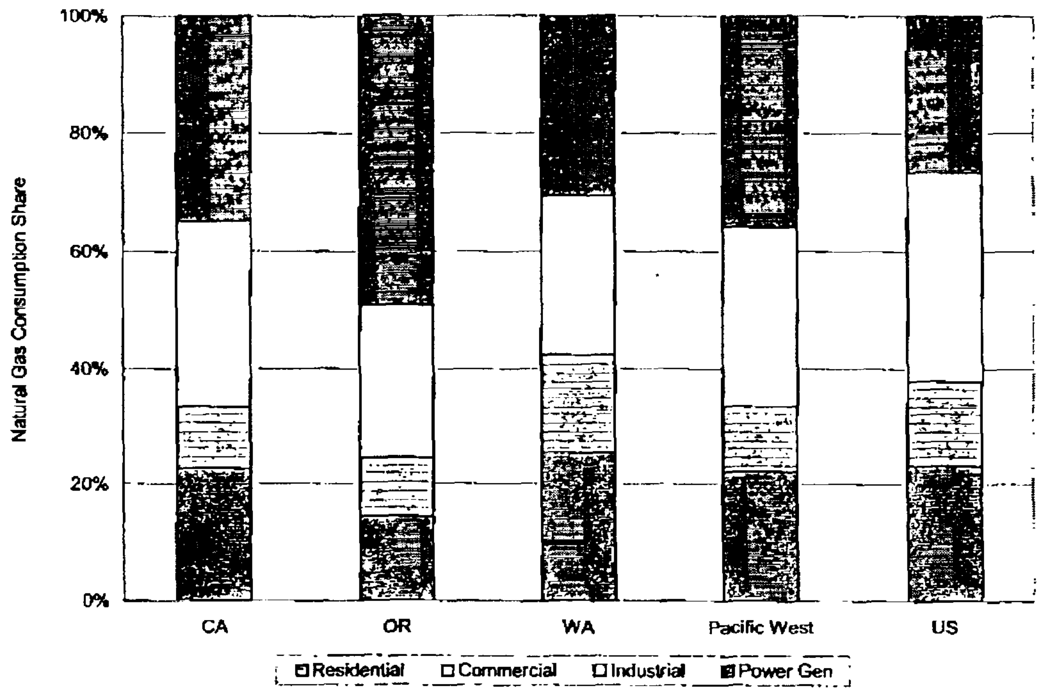
Figure 21. Impact of Expanded Renewables in New York



Pacific West

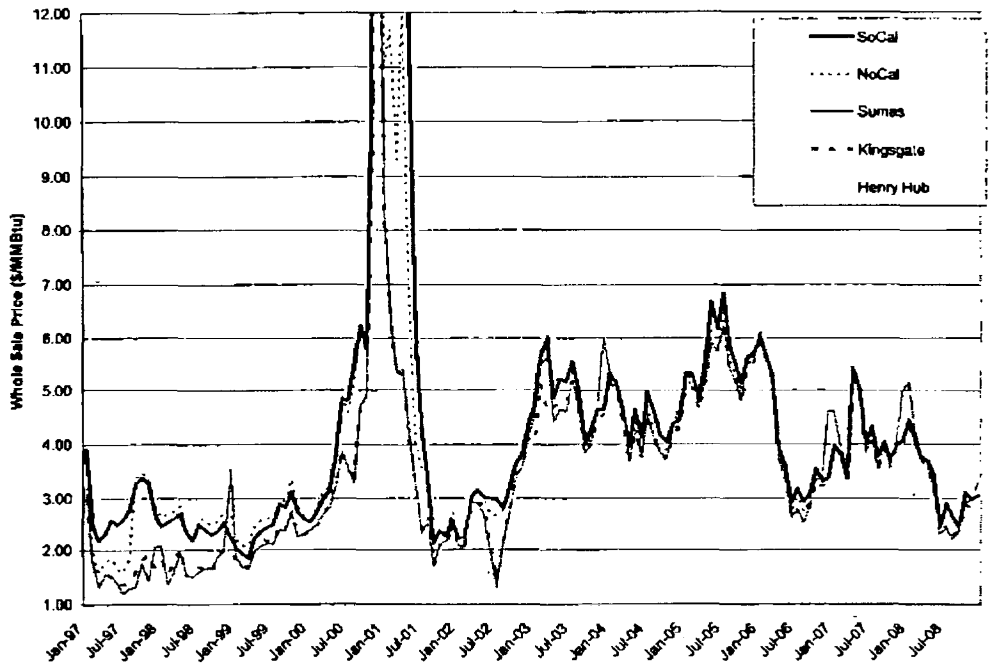
Natural gas consumption in the pacific west region (California, Oregon and Washington) in 2002 was dominated by California which accounts for 79% of the gas consumed in the region and almost 10% of the national consumption (Figure 22). Distribution of use in the region is fairly similar to the national average, with residential use representing slightly more than 20% and industrial about 25%, almost identical to the national average. Commercial usage is somewhat less than the national average while gas use for power generation was somewhat greater. Within the region, power generation (as a percentage of natural gas use) was most dominant in Oregon where it accounted for about half of the total. Commercial gas consumption (as a percentage of state total consumption) was greatest in Washington State, while the power generation was the lowest.

Figure 22. Share of Natural Gas by End-Use Sector for the Pacific West Region compared to the National Average



Historically the wholesale price of natural gas in the Northwest has been somewhat lower, particularly at the points of price excursions compared with the Henry Hub and prices in Southern California. The moderation in the northwest occurs because the northwest is tied to the Canadian producing regions by two import hubs (Kings Gate and Sumas – see map in appendix for locations). The wholesale prices are also somewhat moderated in Northern California compared with Southern California, where prices track Henry Hub except during excursions. The EEA projection is for prices in the west to moderate to the $3-4 per MMBtu range after a few more years on volatility (Figure 23).

Figure 23. Wholesale Natural Gas Prices in Pacific West



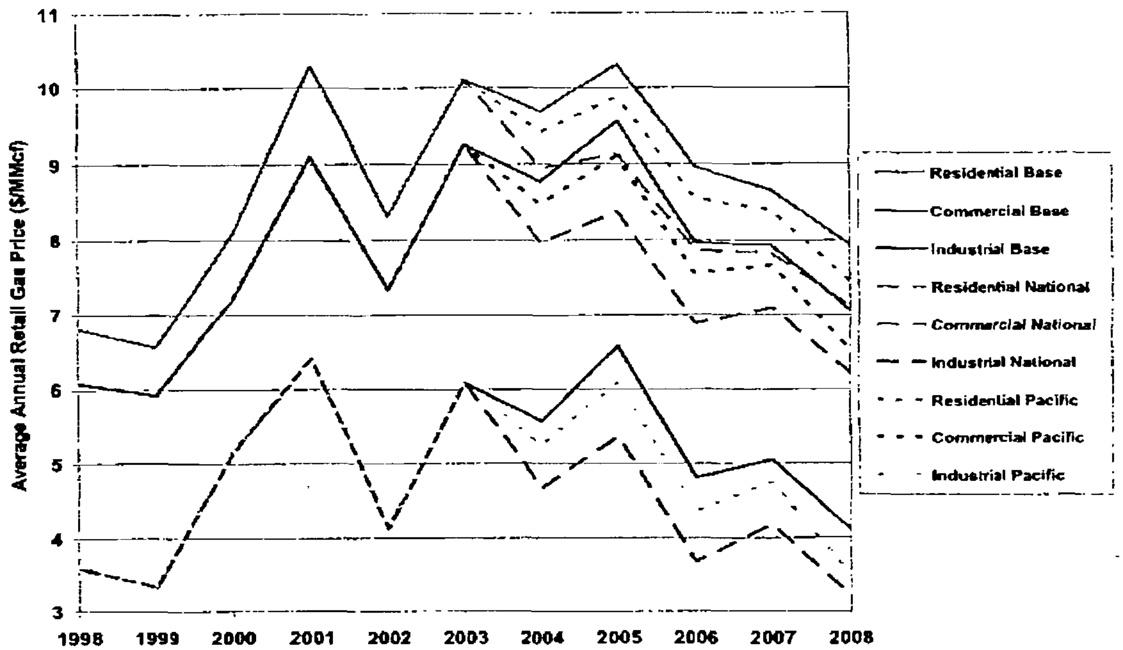
The lower wholesale prices in Washington and Oregon translate into lower residential, commercial and industrial retail price of natural gas compared to California (Table 16). Northwest prices have been at or below the national average, while California prices are slightly above the national average. Prices for natural gas used in power generation are below the national average for Oregon, but above the national average for California and Washington. These price trends are projected to continue in the base case.

As with the New England and Mid-Atlantic region, in the Pacific West we can compare the results for both the National and the region only scenarios. Significant retail price reductions are achieved in all sectors. As can be seen in Figure 24, the application of energy efficiency and renewable energy measures in the region achieve 36% of the price reduction seen with lower-48 state application of the measures for the first four years, but achieved over 60% of the retail price reductions in 2008. Thus regional application of the measures would achieve for the region a significant share of the benefits that would result from national level application of efficiency and renewable energy investments.

Table 16. Historical and Projected Average Annual Retail Natural Gas Prices ($/MMcf) in the Pacific West Compared to the National Average (EEA 2003)

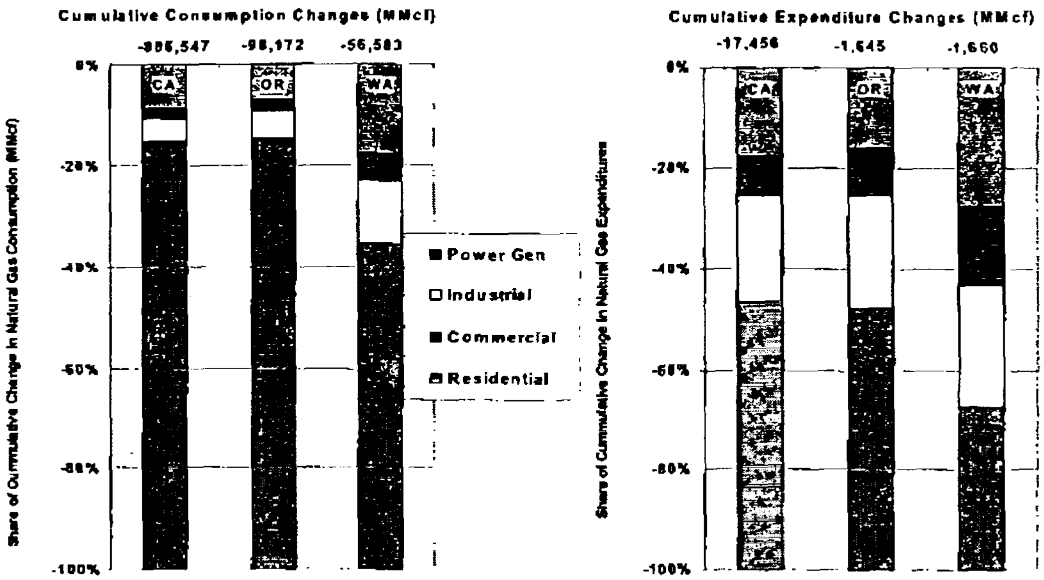
	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
RESIDENTIAL											
CA	6.92	6.62	8.21	10.43	8.34	10.13	9.70	10.32	8.91	8.61	7.88
OR	6.81	7.13	8.12	9.70	8.23	10.07	9.65	10.38	9.30	8.97	8.22
WA	5.84	5.88	7.16	9.79	8.22	9.97	9.54	10.24	9.14	8.81	8.04
Pacific West	6.81	6.57	8.08	10.30	8.32	10.11	9.68	10.31	8.97	8.66	7.93
US Average	6.83	6.68	7.80	9.68	7.86	9.86	9.16	9.77	8.71	8.24	7.76
COMMERCIAL											
CA	6.37	6.17	7.54	9.33	7.48	9.42	8.93	9.70	7.99	8.00	7.10
OR	5.25	5.66	6.48	7.99	6.54	8.44	8.02	8.83	7.62	7.45	6.66
WA	4.76	4.89	6.02	8.62	7.11	8.93	8.49	9.28	8.06	7.88	7.06
Pacific West	6.08	5.93	7.22	9.09	7.33	9.25	8.77	9.56	7.97	7.93	7.05
US Average	5.56	5.38	6.71	8.56	6.95	9.00	8.25	8.98	7.76	7.49	6.94
INDUSTRIAL											
CA	3.75	3.33	5.29	6.60	4.07	6.00	5.49	6.50	4.69	4.92	4.00
OR	3.75	4.01	4.93	6.09	4.95	7.04	6.50	7.54	5.92	6.19	5.22
WA	2.64	2.82	4.01	5.02	3.88	5.94	5.43	6.46	4.83	5.10	4.09
Pacific West	3.60	3.34	5.15	6.41	4.13	6.08	5.57	6.58	4.81	5.05	4.11
US Average	3.24	3.26	4.69	5.76	4.79	6.77	6.00	7.02	5.35	5.58	4.83
POWER GEN											
CA	2.79	2.76	5.88	9.38	6.18	8.19	7.68	8.73	6.79	7.12	6.16
OR	1.56	1.96	2.94	3.82	3.21	5.19	4.90	5.86	4.53	4.55	3.73
WA	3.44	3.39	5.19	6.01	4.90	7.02	6.68	7.56	6.28	6.27	5.42
Pacific West	2.74	2.74	5.63	8.73	5.66	7.68	7.25	8.31	6.49	6.77	5.84
US Average	2.45	2.66	4.56	5.31	4.22	6.29	5.59	6.69	4.82	5.21	4.42

Figure 24. Historical and Projected Average Annual Retail Natural Gas Prices in the Pacific West Region for both Base and Scenario Cases



In the national scenario results in a 3.1% reduction in gas consumption in 2004, increasing to more than a 10% reduction in 2008. The cumulative consumption reduction is dominated by reductions in the power generation sector (Figure 25) resulting from electric efficiency and conservation, and expanded renewable power generation. Power generation accounts for more than 80% of the consumption reductions in California and Oregon, and more than two thirds of the reduction in Washington State. On the natural gas expenditures side, power generation still remains the dominant source of reduction though less so than with consumption. Power generation accounts for slightly more than half of the cumulative savings in California and Oregon, and about a third of the savings in Washington State. Industry accounts for about a fifth of the savings in all states, while residential savings over a quarter in Washington State, but less than a fifth in the other states.

Figure 25. Cumulative Change in Consumption and Expenditures in the Pacific West Region from National Application of Energy Efficiency and Renewable Energy



Energy Efficiency and Renewable Energy Reduce Consumer Energy Expenditures

Implementation of expanded energy efficiency and renewable energy result in a significant change in energy expenditures by end-use consumers (i.e., residential, commercial and industrial). These changes in expenditures come from five effects:

- Changes in natural gas prices resulting from the market effects discussed previously
- Changes in natural gas consumption resulting from natural gas energy efficiency measures
- Changes in electricity gas prices resulting from the reduced price of natural gas and increased use of renewables
- Changes in electricity consumption resulting from electric energy efficiency measures
- Changes in consumption of both gas and electricity due to changes in economic activity (This effect is most noticeable in the industrial sector of state with significant gas-intensive industries)

Unfortunately the analysis in this study does not allow the relative effects of each of these elements to be discretely determined because of the limited set of scenarios that were modeled and because of interaction between the various elements.

In addition, expenditures for natural gas by the power generation sector are also reduced as a result of reduced natural gas prices and because natural gas generation is displaced by electric efficiency and renewable generation. Because electric power markets are regional in most of the lower-48 states, this analysis cannot attribute these savings to the end-user consumers in individual states.

Changes in Natural Gas Expenditures – National Scenario

The analysis does produce a detailed estimation of aggregate changes in natural gas expenditures by sector and by state. The total net changes in end-use consumer expenditures for gas are presented in Table 17.

Table 17. Total Net Reductions (2004–2008) in End-Use Consumer Gas Expenditures (Million Dollars)

	Residential	Commercial	Industrial	Total		Residential	Commercial	Industrial	Total
AL	253	113	839	1,206	NE	210	111	148	470
AZ	226	159	65	450	NV	186	126	19	333
AR	259	169	395	825	NH	49	52	39	140
CA	3,098	1,336	3,714	8,149	NJ	1,354	916	239	2,510
CO	594	250	254	1,098	NM	224	157	39	421
CT	269	280	133	683	NY	2,585	2,080	208	4,874
DE	54	27	101	183	NC	364	204	294	862
DC	84	94	-	178	ND	60	50	94	206
FL	81	233	283	598	OH	1,877	870	1,264	4,012
GA	715	245	521	1,482	OK	343	185	478	1,006
ID	110	62	116	289	OR	263	153	370	787
IL	2,684	993	1,138	4,816	PA	1,621	740	828	3,190
IN	928	439	1,177	2,545	RI	125	82	15	223
IA	404	207	375	986	SC	160	98	301	560
KS	361	168	380	910	SD	67	45	14	128
KY	363	179	411	954	TN	385	250	520	1,157
LA	265	118	3,066	3,451	TX	1,141	949	8,109	10,201
ME	7	17	63	88	UT	297	168	127	593
MD	492	300	117	910	VT	18	16	18	53
MA	782	468	294	1,545	VA	495	373	251	1,120
MI	1,982	905	908	3,796	WA	456	262	397	1,116
MN	742	458	411	1,612	WV	148	122	169	440
MS	179	111	429	721	WI	808	425	621	1,855
MO	591	279	258	1,128	WY	76	66	101	244
MT	110	62	36	209	US	28,964	16,196	30,151	75,311

Table 18 displays what this national scenario would mean specifically for individual residential gas customers. The data in this table represents the average annual natural gas bill reduction per residence with gas service. While these are annual savings numbers, the great majority of these savings would be obtained during the peak winter heating season when residential consumer gas consumption and bills are the highest.

Table 18. Average Annual Natural Gas Expenditure Change per Residential Natural Gas Customer ($/customer)

	Number of Natural Gas Residential Consumers	2004	2008	5-Year Avg.		Number of Natural Gas Residential Consumers	2004	2008	5-Year Avg.
AL	807,245	-47	-54	-63	**NE**	476,275	-70	-78	-88
AZ	884,789	-40	-47	-51	**NV**	550,850	-53	-69	-68
AR	552,716	-70	-85	-94	**NH**	84,760	-85	-111	-116
CA	9,600,493	-52	-61	-65	**NJ**	2,436,771	-79	-100	-111
CO	1,365,594	-77	-76	-87	**NM**	485,969	-70	-88	-92
CT	458,105	-85	-112	-118	**NY**	4,243,130	-90	-112	-122
DE	122,829	-65	-78	-88	**NC**	891,227	-58	-72	-82
DC	138,412	-90	-107	-122	**ND**	106,758	-89	-99	-114
FL	590,221	-22	-24	-28	**OH**	3,195,407	-87	-101	-118
GA	1,737,850	-62	-68	-82	**OK**	868,314	-62	-67	-79
ID	251,004	-70	-84	-88	**OR**	542,799	-73	-87	-97
IL	3,670,693	-111	-128	-146	**PA**	2,542,724	-94	-116	-127
IN	1,613,373	-85	-101	-115	**RI**	216,781	-85	-110	-116
IA	818,313	-76	-85	-99	**SC**	501,161	-45	-56	-64
KS	836,486	-68	-73	-86	**SD**	144,310	-72	-81	-94
KY	749,106	-70	-84	-97	**TN**	993,363	-56	-68	-78
LA	952,753	-42	-49	-56	**TX**	3,738,260	-47	-53	-61
ME	17,302	-59	-76	-80	**UT**	657,728	-80	-81	-91
MD	959,772	-77	-92	-103	**VT**	29,463	-89	-114	-122
MA	1,283,008	-89	-116	-122	**VA**	941,582	-78	-97	-105
MI	3,011,205	-98	-111	-132	**WA**	841,617	-82	-95	-108
MN	1,249,748	-90	-100	-119	**WV**	363,126	-60	-69	-82
MS	437,899	-62	-77	-82	**WI**	1,484,536	-82	-95	-109
MO	1,326,160	-69	-77	-89	**WY**	129,897	-105	-110	-118
MT	226,171	-76	-85	-98	**US**	60,252,745	-73	-86	-96

Changes in Electricity Expenditures

The EEA model used in this study does not directly provide estimates of changes in end-use consumer expenditures for electricity. Thus, ACEEE undertook an indirect approach to obtain an approximation of the end-user electric savings.

The electric power sector experiences a significant reduction in expenditures for natural gas because of decreases in natural gas prices and reduced consumption of gas. These consumption reductions occur because overall demand for electricity is reduced as a result of increased energy efficiency and conservation by end-use consumers, and because a portion of the remaining natural gas generation is displaced by new renewable generation. Changes in natural gas expenditures by the power sector in each of the lower-48 states are presented in Table 19.

It is important to keep in mind that with the exception of Texas (for all practical purposes has an autonomous grid), all other states are part of broad regional markets so that the changes in gas consumption in the power sector in a state may actually result from reductions in electricity demand and increased renewables in other states. As a result, these "savings" from the power sector in a state may not solely benefit the electricity consumers in that state. A portion of these expenditure reductions are likely to be passed along to end-use electricity consumers in the form of lower rates. Another portion is likely to be used to offset the costs associated with procurement of new renewable power generation. The analysis and modeling do not allow for an apportioning of these expenditure changes to price reductions at either the state or national level. In addition, some states that have undergone restructuring have frozen retail rates (for at least some customer classes) so these savings would not be passed along to consumers. The reductions in power generation gas expenditures should be viewed as the upper limit on savings to end-use consumers from electricity price reductions. However, these expenditure reductions do, represent an important benefit at the regional and national level in the evaluation of the cost/benefit relationship of energy efficiency and renewable energy on natural gas markets.

Table 19. Reductions in Natural Gas Expenditures in the Power Sector (Million 2002$)

State	2004	2008	Cum.	State	2004	2008	Cum.
AL	133	385	1,377	NC	48	126	482
AR	27	38	213	ND	0	0	1
AZ	162	127	747	NE	3	21	79
CA	1,090	2,312	9,306	NH	2	3	16
CO	55	24	172	NJ	183	234	1,027
CT	67	129	528	NM	38	37	192
DC	0	0	0	NV	231	730	2,491
DE	40	170	493	NY	431	545	2,499
FL	648	1,026	4,655	OH	-70	-53	-350
GA	130	263	1,106	OK	84	90	508
IA	2	23	75	OR	144	179	857
ID	21	38	155	PA	67	326	828
IL	89	129	581	RI	85	149	643
IN	-11	-3	-55	SC	38	82	351
KS	18	18	104	SD	-1	15	62
KY	35	94	352	TN	37	103	371
LA	124	147	802	TX	1,550	1,805	8,413
MA	176	280	1,283	UT	27	29	127
MD	37	82	304	VA	25	54	213
ME	71	69	403	VT	1	1	7
MI	99	86	501	WA	100	110	543
MN	8	45	169	WI	28	31	151
MO	23	94	310	WV	-10	-10	-62
MS	48	102	510	WY	5	6	27
MT	28	75	269	US-Total	-1,896	727	24,361

End-use consumers <u>do</u> directly benefit from expenditure reductions that result from reduced consumption energy efficiency and conservation. Assuming no direct electricity price impacts beyond the base case, this analysis projects consumers would reduce their electricity bills cumulatively by $4.24 billion for the 2004-2008 modeling period. This reduction represents a 2.5% change in 2004, rising to 4.9% by 2008. Cumulative changes in end-use consumer electric expenditures by state and sector are presented in Table 20. Annual values can be found in Appendix C.

Table 20. Cumulative Electricity Expenditure Reductions (2004-2008) in Million 2002$[1]

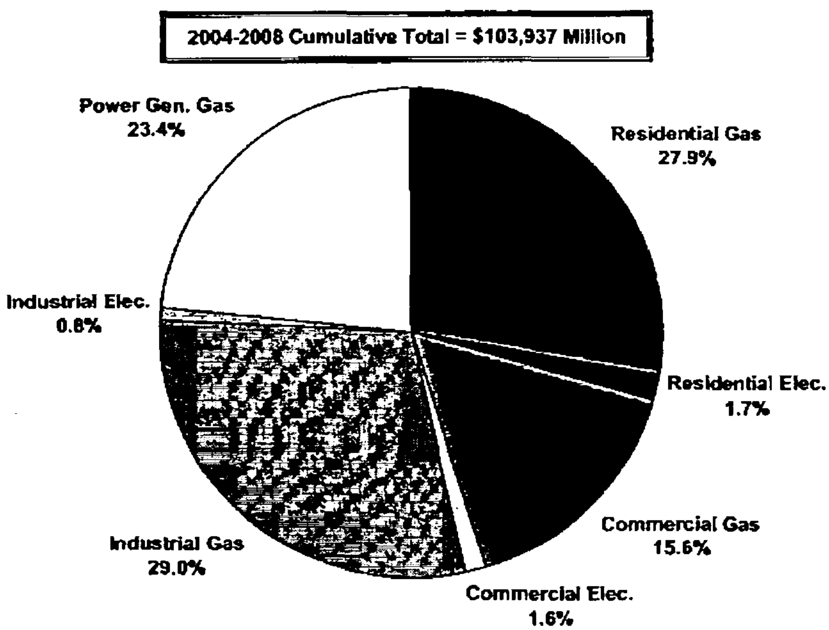
STATE	Residential	Commercial	Industrial	Total End-Users	STATE	Residential	Commercial	Industrial	Total End-Users
AL	23.0	15.8	14.4	53.2	NC	44.8	31.6	17.7	94.1
AR	14.0	7.5	8.8	30.3	ND	2.6	2.5	1.3	6.4
AZ	33.7	27.4	8.0	69.0	NE	6.6	5.3	3.2	15.1
CA	207.4	299.8	86.8	594.1	NH	8.4	8.5	4.0	20.9
CO	15.9	17.1	6.5	39.5	NJ	54.8	74.0	21.4	150.2
CT	27.3	27.9	8.9	64.1	NM	5.3	6.8	3.0	15.1
DC	1.9	9.7	0.2	11.8	NV	13.5	9.5	9.8	32.9
DE	4.7	4.2	2.5	11.4	NY	129.8	182.3	28.5	340.7
FL	139.4	87.0	15.2	241.6	OH	58.8	55.7	40.9	155.3
GA	52.4	41.6	22.1	116.1	OK	17.2	11.4	6.8	35.4
IA	14.4	11.8	12.3	38.5	OR	22.7	19.4	10.5	52.6
ID	7.4	6.9	4.4	18.7	PA	65.6	57.9	40.1	163.6
IL	65.6	64.7	33.7	164.1	RI	6.9	9.0	2.7	18.6
IN	36.8	27.4	31.2	95.4	SC	22.8	14.7	14.5	52.1
KS	10.9	10.6	5.7	27.2	SD	3.1	2.6	0.9	6.5
KY	15.8	9.6	14.0	39.4	TN	35.1	26.8	19.6	81.4
LA	36.8	17.7	19.0	73.6	TX	229.9	163.6	110.3	503.7
MA	37.7	67.9	19.2	124.8	UT	8.0	9.4	4.2	21.7
MD	37.2	32.9	7.8	78.0	VA	44.1	28.3	12.3	84.7
ME	10.6	11.6	4.7	27.0	VT	5.3	5.3	2.7	13.2
MI	39.6	43.9	25.6	109.1	WA	31.7	26.4	14.9	73.0
MN	26.8	24.7	16.6	68.1	WI	34.2	28.2	23.5	85.9
MO	24.8	20.6	8.1	53.5	WV	7.3	4.8	4.9	17.1
MS	14.7	10.1	8.0	32.8	WY	2.1	2.7	3.5	8.3
MT	3.9	3.8	2.9	10.6	US-Total	1,763.6	1,688.9	788.2	4,240.7

[1]Note: These changes in electricity expenditures are calculated from the projected base-case electricity price by state and sector, and reductions in electricity consumption provided as an input to the model. No attempt was made to account for changes in electricity prices resulting from the effects of the energy efficiency or renewable energy policies.

Cumulative Changes in Energy Expenditure

The proposed energy efficiency and renewable energy expansion proposed in this study produce cumulative energy expenditure reductions for natural gas and electricity of almost $104 billion for the five year study period. The $30,170 million in industrial gas expenditure reductions account for largest share of the savings (29% of the total), followed closely by residential sector (27.8% or $28,966 million) (see Figure 26). These expenditure reductions however come from different market effects. In the industrial sector, most of the expenditure reductions occur from the average 16.4% reduction in the natural gas price while actual industrial consumption increases modestly as was discussed above. More of the residential savings results from the 3.1% reduction in consumption in 2008 resulting from energy efficiency and conservation, rather than the 10% average reduction in residential natural gas prices. Electric power generation reduces natural gas by $24,361 million (23.4% of cumulative reductions) with these reductions resulting from a reduction in consumption that rises to over 15% by 2008 and an average 18.8% reduction in price. The $ 1,689 million reduction in commercial natural gas (15.6% of the total) results from a modest reduction in consumption and an average 11.6% reduction in natural gas pricing for the sector. The electric expenditure reductions from reduced consumption in all of the end-use sectors account for 4.1% of the total national expenditure reductions.

Figure 26. Total Net Energy Expenditure Reductions (2004-2008) from Expanded Energy Efficiency and Renewable Energy

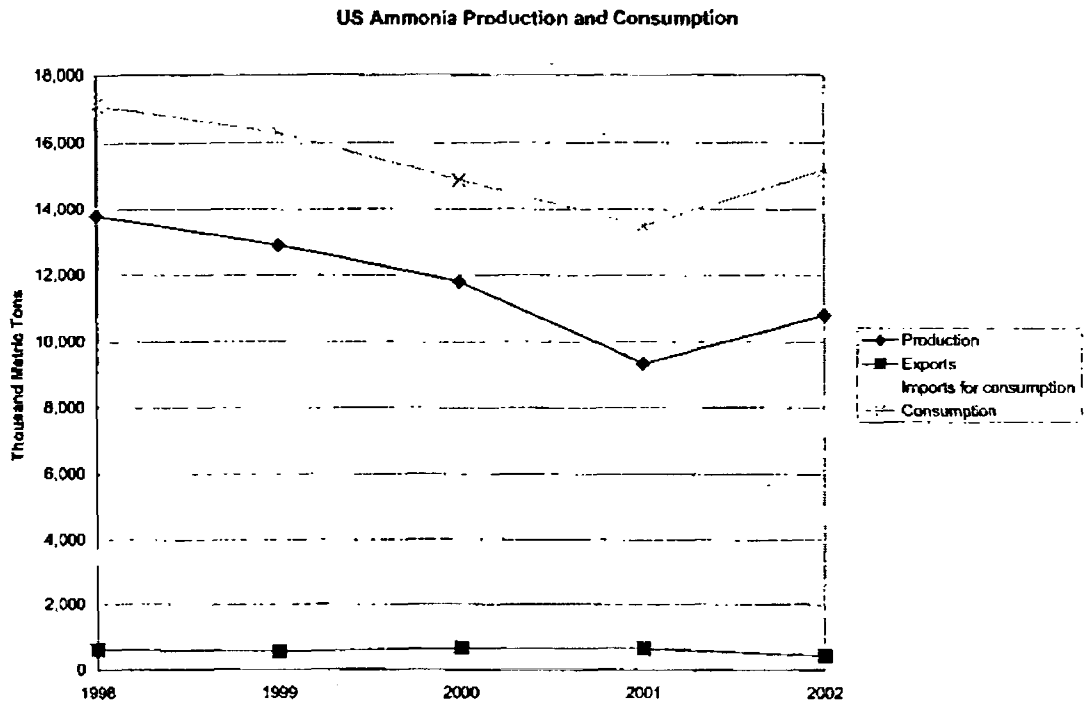


Renewable Energy and Energy Efficiency Can Lower the Cost of Natural Gas, Fertilizer, and Crops

Introduction

Volatile and high prices for natural gas are having serious repercussions in the U.S. fertilizer industry, and by extension, are raising production costs for farmers. Since natural gas accounts for the bulk of raw material costs for fertilizer, price spikes for natural gas result in price spikes for fertilizer. In 2001, when gas prices rose to $10 per million BTU, fertilizer prices more than doubled. The result is plant closures by American producers, increased fertilizer imports from abroad and higher production costs for farmers.

Figure 27. Ammonia Production and Consumption



Aggressive policies to promote renewable energy and energy efficiency can reduce the price of natural gas by lowering demand, especially gas used for electric power production. Modeling by ACEEE and EEA finds that efficiency improvements in furnaces, appliances, and industry, along with rapid increases in cost-effective renewable energy (such as wind power), can reduce wholesale gas prices by 20 percent, resulting in a significant reduction of fertilizer costs. This will modestly reduce corn production costs, increasing profits in a very low-margin business.

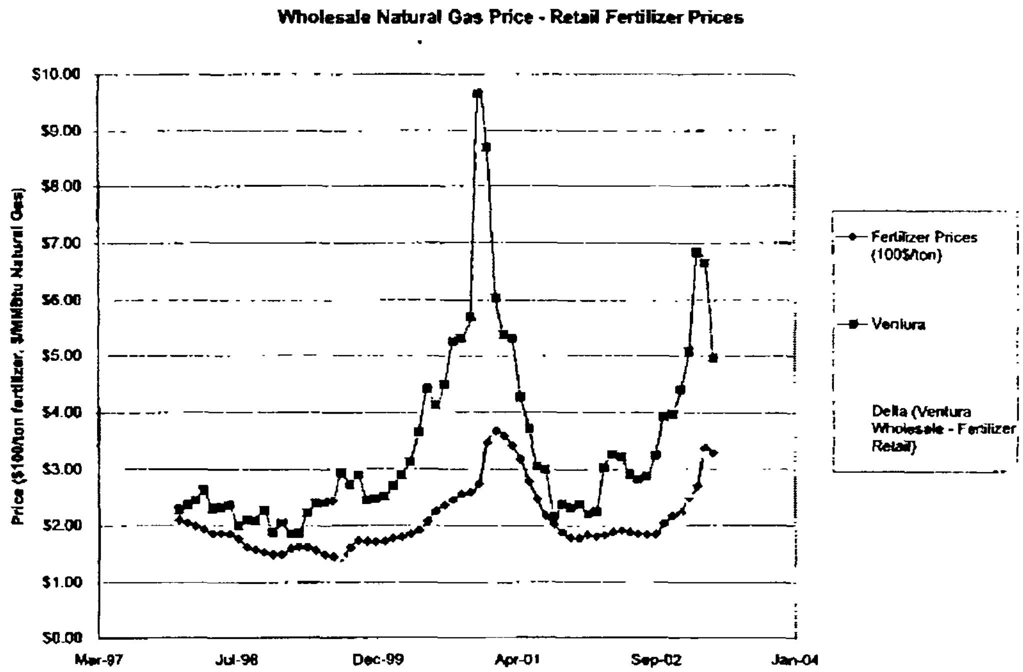
Nitrogenous Fertilizer Trends

Nitrogenous fertilizers utilize a large quantity of natural gas in their production. The cost of natural gas typically represents 70-90% percent of the raw material cost of producing anhydrous ammonia, one of the more commonly utilized nitrogenous fertilizers. Fertilizer production has been historically a low profit margin business, and higher gas prices have resulted in the shutdown of over 8 ammonia producing facilities in the US since 2001. Domestic production of nitrogenous fertilizers (Figure 27) was 25% lower in 2001 than 2000 (USGS 2003). Anhydrous ammonia production facilities are located close to central natural gas production and transmission hubs. The majority of ammonia is produced in the gulf coast region of the US.

The following table shows the amount of anhydrous ammonia produced and consumed in the US. Both domestic consumption and production decreased significantly between 1998 and 2001. A slow, but steady increase in fertilizer imports is continuing, while exports are slowly decreasing.

In January 2001, when Henry Hub spot price for natural gas rose to well over $10/mmbtu, the spot price for anhydrous ammonia increased by 144%, from $119 to $290 per ton (GAO 2003). The wholesale spot market price of ammonia closely follows that of natural gas. The following chart shows the wholesale price of natural gas at the Ventura hub (located in Iowa) and the retail price of ammonia paid by Iowa farmers. The retail price of ammonia tends to follow a similar curve as the price of natural gas, but with a 2-3 month delay (Figure 28).

Figure 28. Gas Price and Ammonia Price



The decline in ammonia production due to plant closures, coupled with the increased retail price in domestically produced ammonia, resulted in a significant increase in the retail price paid by farmers for ammonia-based fertilizer. Farmers, who are the primary consumers of anhydrous ammonia fertilizer, were somewhat sheltered from the spot market price spikes for ammonia. The volatility of retail ammonia price was somewhat dampened because of the 43% increase in imports (primarily from Canada and Trinidad and Tobago). Farmers also have some control over their need for nitrogenous fertilizer. There are several farming techniques that can be employed during periods of fertilizer price spikes that can lessen the need for fertilizer.

Impact on Farmers and Corn Production

Nitrogen is a necessary nutrient in soil for the production of corn and other crops. When the retail price of fertilizer increases, the cost of corn also increases to compensate for the increased costs of production. There are several fixed and variable costs incurred by farmers during the production of corn. Fixed costs included items such as land, machinery, and labor. The variable costs of corn production include the cost of seed, fertilizers, and pesticides. Pesticide costs have also increased along with the price of natural gas, though much less dramatically.

In the typical production of silage corn, fixed costs are between $230 and $290 per acre of harvested corn (or $12 to $15 per ton). Variable costs are between $190 and $230 per acre (or $10 to $12 per ton). Nitrogen costs range from $28 to $38 per acre, depending on the productivity level of the soil. Nitrogen represents between 6.6 and 7.3% ($1.65 to $1.80 per ton) of the cost of silage corn production. A doubling in the retail price of nitrogenous fertilizer, as occurred in the spring of 2001, can increase the price of corn production by about 7% (Iowa State University 2003).

Even seemingly small increases in production costs such as these can have a tremendous impact on farmers, since profit margins in corn production are miniscule. When the price of ammonia is anticipated to be higher than normal, farmers have employed crop rotation techniques as well as utilizing alternate nitrogen sources such as manure to maintain high crop yields.

The Impact of Efficiency and Renewable Energy on Gas, Fertilizer, and Corn Production Costs

Modeling by ACEEE and EEA ("Impacts of Energy Efficiency and Renewable Energy on Natural Gas Markets," http://aceee.org/energy/efnatgas-study.htm) found that a package of policies and programs aimed at increasing energy efficiency and renewable energy production could reduce natural gas demand by 4.1 percent over the next five years, reducing prices by 22 percent, and saving American consumers $75 billion. This reduction in natural gas prices would provide a significant boost to domestic natural gas production, protecting American jobs, and reducing fertilizer costs to farmers.

These policies would see other direct and indirect benefits for farmers as well. Wind power developers, for example, pay farmers and ranchers between $2000 and $5000 per turbine per year to site turbines on their land. This typically takes a quarter acre out of production for each turbine, but allows continued use of the rest of the land for crops and grazing. (See National Wind Coordinating Committee, "Assessing the Economic Development Impacts of Wind Power," March 2003, http://nationalwind.org/pubs/economic/econ_final_report.pdf). Likewise, programs that encourage the use of more efficient motors, pumps, and refrigeration systems can help farmers reduce electricity costs

Analysis of Investment and Program Costs

Analysis of the consumer and programmatic costs of delivering the energy efficiency and renewable energy improvements described earlier shows a very favorable cost-to-benefit ratio. Implementation of efficiency and renewables across the United States would cost consumers just over $23 billion over five years (see Figure 29 and Table 21). Significant programmatic support would be necessary however to achieve the savings. An additional $7.2 billion would be required from programmatic administration offices such as state energy offices, public benefit funds, and the federal government. A nation-wide effort would require a total societal investment of just over $30 billion. As presented in the previous section, these levels of investment would save consumers over $100 billion over the next five years. For every dollar invested, $3.44 would be gained in reduced consumption and energy bills. From the public expenditure perspective, the total program costs of just over $7 billion would produce $14.71 of benefit for each program dollar.

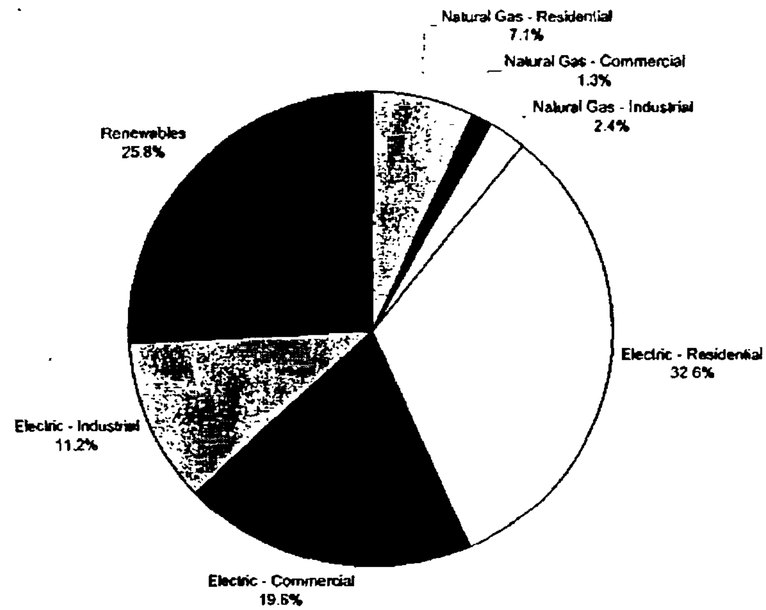
Summary of Costs for Efficiency and Renewable Energy

Table 21 and Figure 29 show how investment and program costs must be allocated in order to achieve the savings described earlier. Nearly two-thirds (64%) of the total investment will have to be made in the areas of electric efficiency, with half of those electric efficiency investments being made in the residential sector. The end-use natural gas savings will require only 11% of the total investment. Overall, the residential efficiency investments account for about 40% of the total required investment. Just over a quarter of the total investment is required to meet the renewable market share for all of the regions specified in the national scenario.

Table 21. Costs of Implementing Energy Efficiency and Renewable Energy

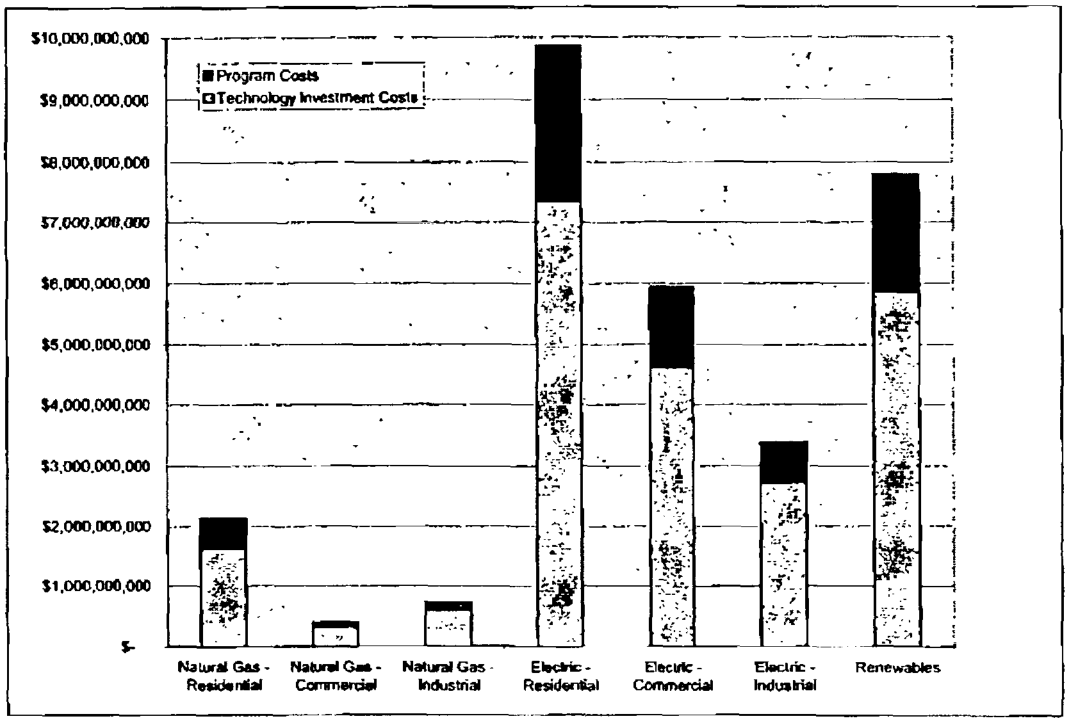
Sector	Technical Investment Costs	Program Costs	Total Cost
Natural Gas - Residential	$1,623,514,825	$514,062,322	$2,137,577,147
Natural Gas - Commercial	$314,589,436	$81,180,475	$395,769,910
Natural Gas - Industrial	$602,709,583	$124,440,731	$727,150,313
Total Natural Gas	**$2,540,813,843**	**$719,683,528**	**$3,260,497,371**
Electric - Residential	$7,341,513,564	$2,521,965,439	$9,863,479,003
Electric - Commercial	$4,617,018,241	$1,322,652,656	$5,939,670,897
Electric - Industrial	$2,726,631,713	$651,168,588	$3,377,800,301
Total Electric	**$14,685,163,518**	**$4,495,786,683**	**$19,180,950,201**
Renewables - $0.045/kWh Installed	**$5,851,457,683**	**$1,950,485,894**	**$7,801,943,577**
Total Cost of Efficiency and Renewables	**$23,077,435,044**	**$7,165,956,105**	**$30,243,391,149**

Figure 29. Distribution of Technical Investment and Program Costs to National Implement Energy Efficiency and Renewable Energy Scenario



Overall, the program costs represent about 24% of the total cost required to implement the national scenario. The program share of the total costs varies by the sector. Figure 30 displays both the magnitude of total investment in each sector as well as the ratio of consumer-borne technical investment costs and the programmatic costs. For energy efficiency, the programmatic costs as a percentage are highest in the residential sector (25% of total costs), followed by the commercial (22%) and industrial (19%) sectors. The high program cost for residential results from the need to work with many small consumers to obtain significant energy reductions, in contrast to the commercial and industrial sectors where contacts can be more efficiently made with the largest energy users. For renewables, the program costs average about 25%, in large part because of the incentives specified under the policy section.

Figure 30. Investment and Program Costs of Energy Efficiency and Renewable Energy



It is important to note that while the economics of efficiency and renewables are attractive for consumers; these savings will require an up-front investment on the part of both consumers and program administrators. Without the programmatic support to educate the consumer and create an attractive market for efficiency and renewable products, very little of this potential will be achieved. Furthermore, the cost of administering the efficiency and renewable programs will be higher in states with little or no experience in delivering such services to their consumers. To account for the differences in administrative experience among the various states, it was assumed that an "a" state would incur no additional charges beyond its standard sector-based administrative adder. A "b" state would incur 5% in additional costs, a "c" state would incur 10%, and a "d" state would incur 15%.

Sector Cost Methodologies

Because the estimates for achievable savings potential were different for each sector, the approaches to estimating the costs were different. As with the savings potential natural gas and electric efficiency costs estimates were made on a state basis, while renewable energy costs were made at the regional level. The next sections discuss how the costs estimates were made.

Residential and Commercial Sector Methodologies

Estimated costs for energy efficiency were based on the average cost per saved Therm of end-use gas and average cost per saved kWh from leading utility and state energy efficiency programs. This analysis separately looked at the residential and commercial programs, and separately looked at programs to save natural gas and electricity. Most of this program cost data combined the residential and commercial sectors, so we first calculated average cost per unit gas and electricity savings across programs, and then adjusted these costs to reflect the cost of commercial versus residential programs.

In the case of electricity savings, available data covered programs operated in California, Vermont, and Massachusetts, as well as projected program costs from a study of six mountain states. Overall, we found that on average, programs cost $0.03 per kWh saved. For gas savings, available data covered programs in Vermont, Minnesota, and projected program costs in Washington and New York. Overall, we found that programs cost an average of $0.15 per Therm saved. To adjust these averages to reflect differences between the residential and commercial sectors, we looked at several studies that examined either program costs or program benefit-cost by sector. This analysis included studies of electric programs from Massachusetts, Connecticut and the mountain states, and studies on gas programs from Vermont and New York. Based on these studies, we calculated average ratios of residential sector program costs to total program costs, and commercial sector program costs to total program costs. In general, residential sector programs are more expensive per kWh or Therm saved than commercial programs. For example, for electric programs, as noted above, the average residential program had costs per kWh saved 36% higher than the average program (e.g., $0.041/kWh saved for residential versus $0.03/kWh saved for the average program) while the average commercial program had costs per kWh saved 21% lower than the average program (e.g. $0.024/kWh saved for commercial versus $0.03/kWh saved for the average program). Calculations by sector for both electric and gas programs are shown in Table 22.

Table 22. Residential and Commercial Costs of Saved Energy

Resource	Technology Costs (Customer-Borne)	Administrative Adder	Total Cost of Energy Savings
Residential Energy Efficiency			
Electricity	$0.041/kWh	25%	$0.051/kWh
Natural Gas	$2.400/MCF	25%	$3.000/MCF
Commercial Energy Efficiency			
Electricity	$0.024/kWh	20%	$0.029/kWh
Natural Gas	$0.800/MCF	20%	$0.960/MCF

Industrial Sector Methodology

There remains a great wealth of cost-effective measures for both electric and natural gas efficiency in the industrial sector. Several good sources of "real-world" data regarding energy efficiency improvements exist for this sector. One of the best sources of this data is the Industrial Assessment Center (IAC) database[4]. The IAC Program, direct, one-to-one contact with industrial end-users and plant site managers significantly increases the adoption of commercially available and emerging energy-efficient technologies. In addition to

[4] Since the program's inception in the 1970s, data has been collected on recommendations, implementation, and costs. The database is available at http://iac.rutgers.edu/database/.

traditional energy streams, IAC targets waste streams and productivity improvements. The program is focused on preparing energy and waste audits of small-to medium-sized manufacturing facilities. IAC is implemented through 26 universities.

In order to determine the customer cost of efficiency improvements in the industrial sector, data from implemented recommendations was obtained from the IAC database. Data was obtained for efficiency measures that were implemented between 1995 and the present. There were 3319 electricity efficiency measures and 1637 natural gas efficiency measures in the database. Table 23 shows the total installation costs and first year energy savings of these measures.

Table 23. Installation Costs and First-Year Savings of IAC Projects

Electricity Efficiency Measures		Natural Gas Efficiency Measures	
Total First-Year Electricity Savings (kWh)	246,783,051	Total First-Year Natural Gas Savings (MCF)	3,375,022
Total Implementation Cost	$19,230,983	Total Implementation Cost	$8,592,863
Total First-Year $/kWh Saved	$0.078	Total First-Year $/MCF Saved	$2.546
Cost of Saved Energy ($/kWh)	$0.016	Cost of Saved Energy ($/MCF)	$0.509

Note: Cost of saved energy figures estimates a typical 5-year capital improvement cycle for industrial facilities.

These figures align with program data provided from the US DOE and other industrial efficiency programs (see Table 24). A comprehensive study of the industrial electric efficiency potential in New York found that a portfolio of 35 different measures would cost an average of $0.018/kWh saved (NYSERDA 2003). The Steam Saver Programs of the U.S. Department of Energy provides data for 203 boiler and steam projects (DOE 2001). These measures included more extensive and capital intensive project improvements such as boiler unit replacements and heat recovery and economizer projects. These improvements typically have a long equipment life.

Table 24. DOE Steam Saver Program Data

Natural Gas Efficiency Measures	
Total First-Year Natural Gas Savings (MCF)	1,659,295
Total Implementation Cost	$15,493,967
Total First-Year $/MCF Saved	$9.33
Cost of Saved Energy ($/MCF) (5-year capital cycle)	$1.866
Cost of Saved Energy ($/MCF) (15-year capital cycle)	$0.622

Savings Estimates Used for Industrial Analysis

The data indicates that the technology and programmatic costs of energy efficiency in the industrial sector vary. The tables in the previous section represent some of the best data available for this sector. In summary, the values used to estimate the technological and programmatic costs of delivering efficiency are listed in Table 25.

Table 25. Industrial Cost of Saved Energy

Resource	Technology Costs (Customer-Borne)	Administrative Adder	Total Cost of Energy Savings
Electricity	$0.016/kWh	15%	$0.0184/kWh
Natural Gas	$0.6/MCF	15%	$0.69/MCF

Renewables Sector Methodology

Because of the limited nature of the renewables analysis, for purposes of cost estimation it was assumed that the vast majority of the new capacity would be wind power. Over the course of our study horizon, certain types of wind power in the United States are the most cost effective of the renewable energy options. The economics of wind power were described by the American Wind Energy Association (AWEA) in a 2002 white paper (AWEA 2002), and depend on many variables, including:

1. Proximity of electricity use to source. The price of onsite wind power is lower because transmission and distribution costs do not need to be included in the price.
2. Size and conditions of wind farms. Large spaces with good wind conditions are the best candidates for higher margin wind power.
3. Size and appropriate configuration of the wind turbine. It is economically important that the wind turbine be the most appropriate and have the best configuration for the wind farm location chosen. Inefficiencies in the wind turbine decrease the economics of the project.
4. The cost of financing. Wind power, like many renewable energy technologies is capital intensive, so the effect of competitive interest rates and expeditious loan processing is large.
5. Tax and environmental regulations. Financially encouraging tax policies as well as tighter environmental regulations create a better environment for wind power.

There a number of programs that encourage the use of wind power in various sectors. Most of the financial incentives for wind power are state-based tax credits or deductions, including the federal production tax credit that applies to wind energy. In Minnesota, for example, there is a statute that offers an incentive for wind (and other renewable technology) electricity generators (under 2 MW) that are owned by the same person who owns the land they are on of 1.5 cents per kWh (Minn 2002). Several other states (a full list can be found at dsire.org) have similar incentives. Other wind incentive programs, such as NYSERDA's Wind Incentive Program (NYSERDA 2003), support partial funding of wind projects using public benefit fund monies or, in regulated states, the utility money earmarked for efficiency and conservation.

Due to the variables in the economics of wind energy and the financial incentive programs available, there is a large range of averages prices for wind power. The AWEA white paper indicates that the range is two to four cents per kWh, when including the federal tax incentive (AWEA 2002). In Texas specifically, AWEA claims wind prices of three to six cents per kWh (with federal incentive) (AWEA 2002). Researchers for the New York State Renewable Portfolio Standard (RPS) team found contract prices for installed wind power as low as 2.6 cents per kWh (NYDPS 2003). There is however still a discrepancy between utility and individually owned prices for wind power, due to economies of scale and general access to the grid. LBNL's report, *Alternative Windpower Ownership Structures: Financing Terms and Project Costs*, approached the issue of how ownership affects the price of wind power. If a facility that is financed by a wind developer could sell power at about 5 ¢/kWh, the same facility could sell power for about $0.035/kWh if it were owned by an IOU (Wiser and Kahn 1996).

For this analysis, an average price of $0.045/kWh for the installation of new renewable energy resources was used. A programmatic adder of $0.015/kWh was assumed.

Table 26. Renewables Cost of Generation

Resource	Technology Costs (Customer-Borne)	Administrative Adder	Total Cost of Energy Savings
Renewable Energy	$0.045/kWh	33%	$0.06/kWh

Discussion of Benefits and Costs

As noted earlier, the ratio of benefits to costs is very attractive. With all of the technology and administrative costs included, the overall benefit to cost ratio is 3.44 (see Table 27). The total benefit to consumer investment ratio is 4.5, while the total benefit to program expenditure ratio is 14.5.

Table 27. Benefit to Cost Ratio of Energy-Efficiency and Renewable Energy

Sector	Total Cost of Efficiency and Renewables	Total Change in Consumer Expenditures	Total Benefit to Total Cost Ratio	Total Benefit to Consumer Cost Ratio
Natural Gas - Residential	$2,137,577,147	$-28,965,921,332	13.55	-17.84
Natural Gas - Commercial	$395,769,910	$-16,199,503,576	40.93	-51.49
Natural Gas – Industrial	$727,150,313	$-30,170,074,072	41.49	-50.06
Electric - Residential	$9,863,479,003	$-1,763,644,596	0.18	-0.24
Electric - Commercial	$5,939,670,897	$-1,688,852,069	0.28	-0.37
Electric – Industrial	$3,377,800,301	$-788,171,289	0.23	-0.29
Power Generation	NA	$-24,360,986,280	-	-
Renewables	$7,801,943,577	NA	-	-
Total	**$30,243,391,149**	**$-103,937,153,213**	**3.44**	**4.50**

It is important to note that while most of the costs are incurred from measures that affect electric power (i.e., electric efficiency and renewable energy), most of the benefits to end-use consumers accrue in the form of reductions in natural gas expenditures. The analysis does not allow for the determination of the relative impacts of electric efficiency and renewable energy on the total benefits.

Policy Mechanisms for Obtaining Results

Policymakers at the state and federal level could take a number of concrete actions to realize the benefits that would result from expanded energy efficiency and renewable energy resources. No single policy strategy would achieve the results outlined in our recent study (Elliott et al. 2003). Rather, a portfolio of strategies would be most likely to achieve quick and sustained savings from energy efficiency and renewable energy resources.

Energy Efficiency Performance Targets

One of the leading sources of energy efficiency savings are incentive and technical assistance programs operated by utilities and states. These programs reduced peak electric demand by 11% and electricity sales by 6% during the 2001 California electricity crisis. Other leading states are achieving regular savings on the order of 1% each year. Establishing binding savings targets for states built around the achievements of the most effective programs could expand these benefits to additional customers. Financing for these programs could come from state system benefit funds or through electric and gas rates. The benefits of these programs are typically on the order of two-times program costs, making them very cost-effective to consumers and businesses. Such targets could be established at the state level, as Texas has done (Kushler and Witte 2001), or at the federal level. Possible models are contained in electricity legislation drafted in 2002 by House Energy and Air Quality Subcommittee Chairman Joe Barton or the oil savings amendment adopted on the Senate floor in the spring of 2003 (Barton 2002).

Alternatively, states or the federal government could adopt system benefit funds, providing a stable source of funding for energy efficiency and renewable energy initiatives. State system benefit programs are proving themselves to be an attractive strategy for funding in many states where a small fee is collected on each unit of energy sold in the state (York and Kushler 2002). These funds are then used to support energy efficiency and renewable energy programs. These programs could also be funded by including them in electric and gas rates.

Regardless of whether programs are induced through the setting of targets or through providing a source of funding, these programs can be tailored to meet the unique needs of their states. Increasing the funding for existing programs represents a sound strategy for expanding the impact of energy efficiency and renewable energy resources. States that do not currently have significant programs should be encouraged to establish them through state or federal action.

Expanded Federal Funding for EERE Implementation Programs at DOE and EPA

If Americans are called upon to take action, government and public institutions must be prepared to provide people and businesses with direction and resources that target their energy and interests. The federal government should expand funding for existing energy efficiency and renewable energy programs at the U.S. Department of Energy (DOE) and Environmental Protection Agency (EPA). These agencies should be encouraged to partner with state and local governments, existing programs run by the public sector and utilities, and the private sector to leverage the agencies' funding for maximum impact.

The experience from the California response to the blackouts of 2001 should lead us to expand support for existing programs (Kushler and Vine 2003). These initiatives represented the installed infrastructure of energy efficiency and renewable energy resources. Federal initiatives such as ENERGY STAR® and Industrial Best Practices are already having impacts in the marketplace. Similarly, many state and regional initiatives are well positioned to channel funding into the market.

Appliance Efficiency Standards

Appliance standards have been one of the greatest energy policy successes over the past decade, transforming the energy use of many consumer and commercial products. While developing new standards from scratch takes a number of years, we have important standards waiting in the wings for a number of products that could result in important energy savings in the mid term, even as soon as 2005. At the federal level, the energy bill currently under consideration in Congress includes standards on six products that would go into effect in either 2005 or 2006. In addition, three federal rulemakings are underway that should move forward as quickly as possible, and additional rulemakings are behind legislatively mandated schedules and should begin soon. Standards for a number of products are also ready to be implemented at the state level. Model state legislation includes 10 products (some the same as in federal legislation), but California is considering as many as 25 products for state standards. Significant independent opportunities exist for both state and federal action. In addition, standards on additional products represent a critical long-term strategy that could deliver significant energy savings (Prindle et al. 2003).

Insuring More Efficient Buildings through Codes

As with appliance standards, buildings codes represent an energy efficiency success story. These specifications, administered at the local level, define how new residential commercial builds are constructed, and in some cases what upgrades need to be made when major renovations take place. Energy efficiency experts have developed model building codes that represent the current state of the art in design and construction practice. Buildings built to these codes have reduced heating and cooling requirements, and commercial office buildings require much less electricity for lighting (Prindle et al. 2003). Some localities have already adopted these codes, but others need to be encouraged to move quickly to implement these codes.

Support of Clean and Efficient Distributed Generation

One of the challenges faced by many renewable energy resources, as well as other clean distributed generation systems, is the interconnection and tariff practices of some utilities across the country. The federal government should work with state regulators to establish consistent interconnection standards and procedures, and remove tariffs and "exit fees" that act as disincentives to the development of new distributed resources (Brown and Elliott 2003).

State and federal governments should establish or increase customer incentives for renewable generation (such as solar and small wind generators) and clean distributed generation (such as combined heat and power systems). These incentives could take the form of tax credits or production incentives (Elliott 2001).

Renewable Portfolio Standards

A renewable portfolio standard (RPS) is a market-based policy that increases the diversity of our electricity supply by establishing a minimum commitment to generate electricity from renewable resources. The experiences of the 13 states that have implemented renewable portfolio standards have proven them an effective means of reducing market barriers and encouraging the installation of renewable energy technologies. Several states have successful programs that could be expanded (i.e., Texas, California, Connecticut, Iowa, and Wisconsin) and proposals are under consideration to establish renewable portfolio standards in several other states (ELPC 2001, UCS 2001, Marston 2003), such as New York (Greene 2003). The other states without renewable portfolio standards should be encouraged to implement them as has been proposed by several regional initiatives (ELPC 2001, REPP 2001, Nielsen 2003 and Shimshak 2003).

Because renewable energy can help meet critical national fuel diversity, energy security, economic, and environmental goals, a renewable portfolio standard should be a cornerstone of America's national energy policy. In July, the Senate passed a renewable portfolio standard requiring major electricity companies to obtain 10% of their electricity from renewable energy sources by 2020 (Senate 2003). A national renewable portfolio standard should also establish a minimum commitment that allows states to adopt higher standards.

In addition, tax credits, grants, and financing can play an important role as has been demonstrated for wind energy (Elliott 2001). It is important that the existing production tax credit for renewable energy sources (now slated to expire at the end of 2003) be extended through at least 2006. Grants and loans for renewable energy were part of the *Farm Bill of 2002* passed by the 107th Congress, and it is important that funding for future years be continued. Other tax credits and grants at both the state and federal levels for other renewable technologies should also be implemented, as has been proposed in the Senate Energy Bill. Several states (Oregon, Massachusetts, New York, and California) have designated that system benefit charges should be used to support renewable energy projects.

Public Awareness Campaign by State and National Leaders

Finally, our state and national leaders are in a unique position to raise public awareness of energy efficiency and renewables, and mobilize action to aid in the implementation of the strategies mentioned above. Witness the public response to Federal Reserve Chairman Alan Greenspan's Congressional testimonies. Our public leaders should use their position to issue a call to action by the people and businesses of America to take steps to improve their energy efficiency and encourage investment in renewable energy resources. The window of opportunity to effect significant savings is however limited as was learned in the Northwest in 2002. Once a market has adapted to higher electricity prices it is difficult to motivate public action. The lesson learned is that policy makers must also quickly mobilize the resources needed to support the public's actions as they were in California (Kushler and Vine 2003) if maximum results are to be achieved.

Conclusions, Discussions, and Recommendations

Energy efficiency and renewable energy resources can have a relatively quick moderating effect on natural gas markets, resulting in significant savings to the economy at an attractive cost.

As a result of these findings, it is clear that natural gas and electric efficiency and renewable energy resources should be important components in our response to our current natural gas price problems. A consensus appears to exist that in the near term, efficiency and renewable energy resources can be brought to the market faster than new wells can be drilled or new pipelines and liquefied natural gas (LNG) terminals could be built.

The findings of this study do not indicate that energy efficiency renewable energy are the only policy solution required to address the future natural gas needs of the United States. Additional sources of natural gas will be required whether from domestic sources such as the proposed pipeline to bring Alaskan gas to the lower-48 state, as has been explored in a recent report by the National Commission on Energy Policy (NCEP 2003), or through importation of gas in the form of LNG. However, due to energy efficiency and renewable energy resources' low cost and environmental impacts, these resources also can be an important part of the long-term solution reducing the rate of increase in demand. In addition, expanded energy efficiency and renewable energy resources provide national decision- makers with some breathing room to develop rational energy policies that can result in the lowest cost to consumers and to the environment. Research is underway by a number of groups ranging from the National Petroleum Council to the National Commission on Energy Policy, which has several analyses underway, to the Federal Reserve and Congress. Time is needed to complete and analyze the results of this research to develop a comprehensive natural gas policy. The questions are complex because of the interrelationships between natural gas, industrial production and electric power generation; thus, simple long-term solutions are not likely.

If we don't address the natural gas price problem, we will further damage our economy: industry will move overseas where prices are lower, and businesses and individual consumers will divert money from other purchases to pay higher natural gas and electricity bills. Efficiency and renewable energy may not completely solve our natural gas problems, but they represent an important part of the portfolio of policies needed to insure a healthy economy. Public and private leaders need to step up to the podium and issue a call to action to implement the policies and programs needed to realize the benefits that will result from increased use of energy efficiency and renewable energy. A window of opportunity may be closing in the near future, so leaders must act now if the full, cost-effective benefits of energy efficiency and renewable energy are to be realized. We have provided some concrete policy recommendations. These policies are relatively low-cost and the measures recommended are cost-effective from the customer's perspective. However, local, state, and federal governments all must be prepared to commit resources if this opportunity is to be realized.

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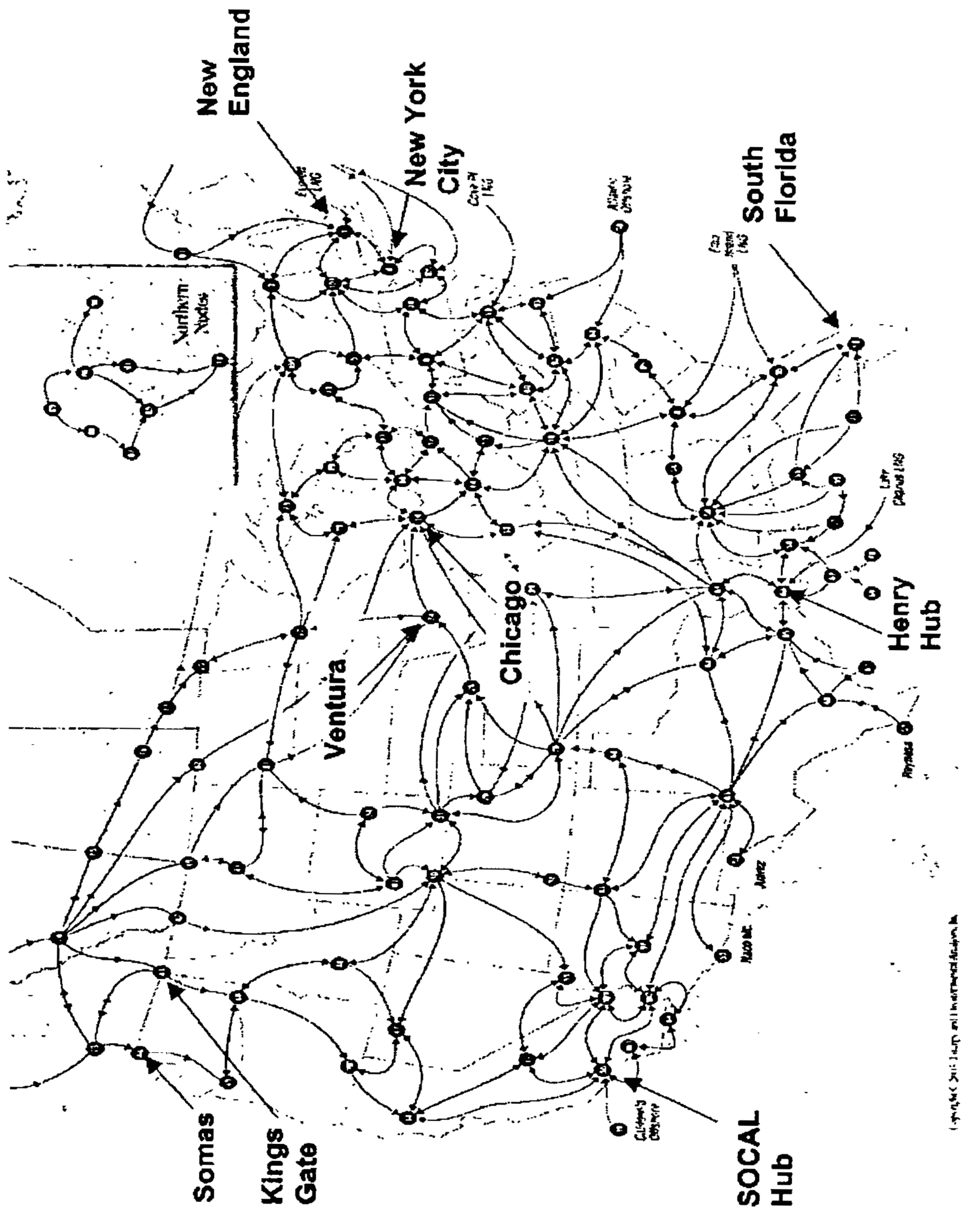
Appendix A-The North American Natural Gas Transmission Network



Appendix B-Residential and Commercial Savings by State by Measure

Residential Natural Gas Savings by end use by state

	Avg NG use/hh	Summed, Weighted NG/per	Weighted for total fuel use in hhs with SH, WH, OT Avg NG Use as sum of parts			% By Enduse			% Enduse Sum of Parts				Adjusted Savings	
State	Mbtu	hh	SH (MBTU/hh)	WH (MBTU/hh)	OT (MBTU/hh)	SH	WH	OT	SH	WH	OT	Score	5 yr (%)	1 yr (%)
Alabama	30	30	21	7	2	69	24	7	69	24	7	d	2.9%	1.4%
Arizona	56	37	20	15	2	35	27	4	53	41	6	b	4.5%	2.2%
Arkansas	50	49	30	15	4	59	31	8	61	31	8	d	2.9%	1.4%
California	41	41	17	19	6	41	46	15	40	45	15	a	5.1%	2.6%
Colorado	56	110	92	15	2	164	27	4	84	14	2	b	4.4%	2.2%
Connecticut	31	33	24	7	2	75	22	7	72	21	6	a	5.2%	2.6%
Delaware	181	26	18	6	2	10	4	1	69	24	6	b	4.4%	2.2%
Florida	27	4	1	2	1	3	9	5	17	52	31	c	3.4%	1.7%
Georgia	181	26	18	6	2	10	4	1	69	24	6	d	2.9%	1.4%
Idaho	56	110	92	15	2	164	27	4	84	14	2	b	4.4%	2.2%
Illinois	99	97	73	19	5	73	19	5	75	20	6	b	4.4%	2.2%
Indiana	99	97	73	19	5	73	19	5	75	20	6	c	3.6%	1.8%
Iowa	73	73	56	15	3	77	20	4	76	20	4	b	4.4%	2.2%
Kansas	73	73	56	15	3	77	20	4	76	20	4	d	2.9%	1.4%
Kentucky	30	30	21	7	2	69	24	7	69	24	7	d	2.9%	1.4%
Louisiana	50	49	30	15	4	59	31	8	61	31	8	d	2.9%	1.4%
Maine	31	33	24	7	2	75	22	7	72	21	6	a	5.2%	2.6%
Maryland	68	62	46	11	5	67	17	7	74	18	8	b	4.4%	2.2%
Massachusetts	31	33	24	7	2	75	22	7	72	21	6	a	5.2%	2.6%
Michigan	99	97	73	19	5	73	19	5	75	20	6	b	4.4%	2.2%
Minnesota	73	73	56	15	3	77	20	4	76	20	4	b	4.4%	2.2%
Missouri	73	73	56	15	3	77	20	4	76	20	4	d	2.9%	1.4%
Mississippi	30	30	21	7	2	69	24	7	69	24	7	d	2.9%	1.4%
Montana	56	110	92	15	2	164	27	4	84	14	2	c	3.7%	1.8%
Nebraska	73	73	56	15	3	77	20	4	76	20	4	d	2.9%	1.4%
Nevada	56	37	20	15	2	35	27	4	53	41	6	c	3.7%	1.8%
New Hampshire	31	33	24	7	2	75	22	7	72	21	6	b	4.4%	2.2%
New Jersey	68	62	46	11	5	67	17	7	74	18	8	a	5.1%	2.6%
New Mexico	56	37	20	15	2	35	27	4	53	41	6	d	2.9%	1.5%
New York	57	53	36	12	5	63	22	8	68	23	9	a	5.1%	2.6%
North Carolina	181	26	18	6	2	10	4	1	69	24	6	d	2.9%	1.4%
North Dakota	73	73	56	15	3	77	20	4	76	20	4	d	2.9%	1.4%
Ohio	99	97	73	19	5	73	19	5	75	20	6	c	3.6%	1.8%
Oklahoma	50	49	30	15	4	59	31	8	61	31	8	d	2.9%	1.4%
Oregon	159	81	48	23	10	30	14	6	59	28	12	a	5.1%	2.5%
Pennsylvania	68	62	46	11	5	67	17	7	74	18	8	a	5.1%	2.6%
Rhode Island	31	33	24	7	2	75	22	7	72	21	6	a	5.2%	2.6%
South Carolina	181	26	18	6	2	10	4	1	69	24	6	d	2.9%	1.4%
South Dakota	73	73	56	15	3	77	20	4	76	20	4	d	2.9%	1.4%
Tennessee	30	30	21	7	2	69	24	7	69	24	7	c	3.6%	1.8%
Texas	46	46	24	16	5	53	36	11	53	35	11	a	5.1%	2.6%
Utah	56	110	92	15	2	164	27	4	84	14	2	b	4.4%	2.2%
Vermont	31	33	24	7	2	75	22	7	72	21	6	a	5.2%	2.6%
Virginia	181	26	18	6	2	10	4	1	69	24	6	c	3.6%	1.8%
Washington	159	81	48	23	10	30	14	6	59	28	12	b	4.3%	2.2%
West Virginia	181	26	18	6	2	10	4	1	69	24	6	d	2.9%	1.4%
Wisconsin	99	97	73	19	5	73	19	5	75	20	6	a	5.2%	2.6%
Wyoming	56	110	92	15	2	164	27	4	84	14	2	c	3.7%	1.8%

5 yr savings potential	5.20%
End-use multipliers	
Space heating	1.00
Water heating	1.10
Other	0.60

Legend:
SH=Space Heating
WH= Water Heating
OT=Other
EP=Economic Potential
hh=Household

Commercial Natural Gas Savings by State by Measure

	Percent By Enduse				State Score	Adjusted Savings (%)	
State	SH	WH	CK	OT		5 yr	1 yr
Alabama	58	30	5	7	d	2.6%	1.3%
Arizona	62	26	7	5	b	4.0%	2.0%
Arkansas	44	34	16	6	d	2.6%	1.3%
California	31	42	17	11	a	4.8%	2.4%
Colorado	62	26	7	5	b	4.0%	2.0%
Connecticut	56	29	7	8	a	4.7%	2.3%
Delaware	41	29	21	9	b	3.8%	1.9%
Florida	41	29	21	9	c	3.1%	1.6%
Georgia	41	29	21	9	d	2.5%	1.2%
Idaho	62	26	7	5	b	4.0%	2.0%
Illinois	67	22	8	4	b	3.9%	1.9%
Indiana	67	22	8	4	c	3.2%	1.6%
Iowa	77	19	3	0	b	3.9%	2.0%
Kansas	77	19	3	0	d	2.6%	1.3%
Kentucky	58	30	5	7	d	2.6%	1.3%
Louisiana	44	34	16	6	d	2.6%	1.3%
Maine	56	29	7	8	a	4.7%	2.3%
Maryland	41	29	21	9	b	3.8%	1.9%
Massachusetts	56	29	7	8	a	4.7%	2.3%
Michigan	67	22	8	4	b	3.9%	1.9%
Minnesota	77	19	3	0	b	3.9%	2.0%
Missouri	77	19	3	0	d	2.6%	1.3%
Mississippi	58	30	5	7	d	2.6%	1.3%
Montana	62	26	7	5	c	3.3%	1.6%
Nebraska	77	19	3	0	d	2.6%	1.3%
Nevada	62	26	7	5	c	3.3%	1.6%
New Hampshire	56	29	7	8	b	4.0%	2.0%
New Jersey	55	23	11	12	a	4.5%	2.2%
New Mexico	62	26	7	5	d	2.6%	1.3%
New York	55	23	11	12	a	4.5%	2.2%
North Carolina	41	29	21	9	d	2.5%	1.2%
North Dakota	77	19	3	0	d	2.6%	1.3%
Ohio	67	22	8	4	c	3.2%	1.6%
Oklahoma	44	34	16	6	d	2.6%	1.3%
Oregon	31	42	17	11	a	4.8%	2.4%
Pennsylvania	55	23	11	12	a	4.5%	2.2%
Rhode Island	56	29	7	8	a	4.7%	2.3%
South Carolina	41	29	21	9	d	2.5%	1.2%
South Dakota	77	19	3	0	d	2.8%	1.3%
Tennessee	58	30	5	7	c	3.3%	1.7%
Texas	44	34	16	6	a	4.7%	2.4%
Utah	62	26	7	5	b	4.0%	2.0%
Vermont	56	29	7	8	a	4.7%	2.3%
Virginia	41	29	21	9	c	3.1%	1.6%
Washington	31	42	17	11	b	4.1%	2.1%
West Virginia	41	29	21	9	d	2.5%	1.2%
Wisconsin	67	22	8	4	a	4.6%	2.3%
Wyoming	62	26	7	5	c	3.3%	1.6%

5 yr savings potential	4.70%
End-use multipliers	
Space heating	0.9
Water heating	1.4
Cooking	0.6
Other	0.6

[illegible]

Commercial Electricity Savings by State by Measure

	Percent By Enduse									Score	Adjusted 5 Yr Savings	1 Yr Savings
State	SH	CL	VE	WH	LI	CK	RE	OE	OT		%	%
Alabama	6	16	5	2	44	1	8	11	8	d	3.6%	1.8%
Arizona	4	13	7	2	46	1	7	14	7	c	4.7%	2.4%
Arkansas	2	19	7	1	43	1	8	11	8	d	3.7%	1.9%
California	5	10	6	1	48	1	7	15	8	a	6.7%	3.4%
Colorado	4	13	7	2	46	1	7	14	7	c	4.7%	2.4%
Connecticut	2	10	5	3	51	1	6	13	8	a	6.8%	3.4%
Delaware	4	16	6	2	43	1	6	13	8	c	4.7%	2.3%
Florida	4	16	6	2	43	1	6	13	8	c	4.7%	2.3%
Georgia	4	16	6	2	43	1	6	13	8	c	4.7%	2.3%
Idaho	4	13	7	2	46	1	7	14	7	b	5.8%	2.9%
Illinois	4	11	6	2	47	1	7	13	9	b	5.7%	2.8%
Indiana	4	11	6	2	47	1	7	13	9	b	5.7%	2.8%
Iowa	4	10	7	1	50	0	5	14	8	b	5.8%	2.9%
Kansas	4	10	7	1	50	0	5	14	8	d	3.8%	1.9%
Kentucky	6	16	5	2	44	1	8	11	8	d	3.6%	1.8%
Louisiana	2	19	7	1	43	1	8	11	8	d	3.7%	1.9%
Maine	2	10	5	3	51	1	6	13	8	a	6.8%	3.4%
Maryland	4	16	6	2	43	1	6	13	8	b	5.7%	2.8%
Massachusetts	2	10	5	3	51	1	6	13	8	a	6.8%	3.4%
Michigan	4	11	6	2	47	1	7	13	9	c	4.7%	2.3%
Minnesota	4	10	7	1	50	0	5	14	8	b	5.8%	2.9%
Missouri	4	10	7	1	50	0	5	14	8	d	3.8%	1.9%
Mississippi	6	16	5	2	44	1	8	11	8	d	3.6%	1.8%
Montana	4	13	7	2	46	1	7	14	7	c	4.7%	2.4%
Nebraska	4	10	7	1	50	0	5	14	8	d	3.8%	1.9%
Nevada	4	13	7	2	46	1	7	14	7	c	4.7%	2.4%
New Hampshire	2	10	5	3	51	1	6	13	8	b	5.8%	2.9%
New Jersey	5	10	6	2	48	0	9	12	9	a	6.6%	3.3%
New Mexico	4	13	7	2	46	1	7	14	7	d	3.7%	1.9%
New York	5	10	6	2	48	0	9	12	9	a	6.6%	3.3%
North Carolina	4	16	6	2	43	1	6	13	8	d	3.7%	1.8%
North Dakota	4	10	7	1	50	0	5	14	8	d	3.8%	1.9%
Ohio	4	11	6	2	47	1	7	13	9	c	4.7%	2.3%
Oklahoma	2	19	7	1	43	1	8	11	8	d	3.7%	1.9%
Oregon	5	10	6	1	48	1	7	15	8	a	6.7%	3.4%
Pennsylvania	5	10	6	2	48	0	9	12	9	c	4.6%	2.3%
Rhode Island	2	10	5	3	51	1	6	13	8	a	6.8%	3.4%
South Carolina	4	16	6	2	43	1	6	13	8	d	3.7%	1.8%
South Dakota	4	10	7	1	50	0	5	14	8	d	3.8%	1.9%
Tennessee	6	16	5	2	44	1	8	11	8	c	4.6%	2.3%
Texas	2	19	7	1	43	1	8	11	8	a	6.7%	3.4%
Utah	4	13	7	2	46	1	7	14	7	b	5.8%	2.9%
Vermont	2	10	5	3	51	1	6	13	8	a	6.8%	3.4%
Virginia	4	16	6	2	43	1	8	13	8	c	4.7%	2.3%
Washington	5	10	6	1	48	1	7	15	8	b	5.7%	2.9%
West Virginia	4	16	6	2	43	1	6	13	8	d	3.7%	1.8%
Wisconsin	4	11	6	2	47	1	7	13	9	a	6.7%	3.3%
Wyoming	4	13	7	2	46	1	7	14	7	c	4.7%	2.4%

5 yr savings potent	6.70%
End-use multipliers	
Space heating	0.2
Cooling	1
Ventilation	0.9
Water heating	0.6
Lighting	1.2
Cooking	0.5
Refrigeration	0.8
Office equipment	1.1
Other	0.5

Legend:
CL=Cooling
VE=Ventilation
LI=Lighting
CK=Cooking
RE=Refrigeration
OE=Office Equipment
SH=Space Heating
WH= Water Heating
OT=Other
EP=Economic Potential

Residential Electricity Use Savings by State by Measure

	MBTU/hh					% Enduse				Score	Adjusted Savings	
State	Elec Use	SH	WH	OT	AC	SH	WH	OT	AC		5 yr	1 yr
Alabama	49	11	3	28	7	22	6	58	14	d	3.2%	1.6%
Arizona	35	3	3	23	6	9	9	65	18	c	4.1%	2.1%
Arkansas	50	10	2	28	9	21	5	56	18	d	3.2%	1.6%
California	20	2	0	17	1	9	2	82	7	a	5.7%	2.8%
Colorado	31	4	3	23	1	12	10	75	3	c	3.9%	2.0%
Connecticut	26	4	3	18	1	16	11	71	3	a	5.6%	2.8%
Delaware	39	5	3	29	2	14	8	74	4	c	3.9%	2.0%
Florida	45	2	4	27	12	5	8	59	27	c	4.3%	2.1%
Georgia	51	9	12	24	5	18	24	48	10	c	4.1%	2.0%
Idaho	31	4	3	23	1	12	10	75	3	b	4.8%	2.4%
Illinois	32	5	2	23	2	14	7	71	7	b	4.8%	2.4%
Indiana	34	5	2	25	2	14	7	73	6	b	4.8%	2.4%
Iowa	38	7	3	25	4	18	9	64	9	b	4.8%	2.4%
Kansas	38	7	3	25	4	18	9	64	9	d	3.1%	1.6%
Kentucky	49	11	3	28	7	22	6	58	14	d	3.2%	1.6%
Louisiana	50	10	2	28	9	21	5	56	18	d	3.2%	1.6%
Maine	26	4	3	18	1	16	11	71	3	a	5.6%	2.8%
Maryland	51	9	12	24	5	18	24	48	10	b	4.9%	2.5%
Massachusetts	26	4	3	18	1	16	11	71	3	a	5.6%	2.8%
Michigan	32	5	2	23	2	14	7	71	7	c	4.0%	2.0%
Minnesota	38	7	3	25	4	18	9	64	9	b	4.8%	2.4%
Missouri	38	7	3	25	4	18	9	64	9	d	3.1%	1.6%
Mississippi	49	11	3	28	7	22	6	58	14	d	3.2%	1.6%
Montana	31	4	3	23	1	12	10	75	3	c	3.9%	2.0%
Nebraska	38	7	3	25	4	18	9	64	9	d	3.1%	1.6%
Nevada	35	3	3	23	6	9	9	65	18	c	4.1%	2.1%
New Hampshire	26	4	3	18	1	16	11	71	3	b	4.8%	2.4%
New Jersey	39	5	3	29	2	14	8	74	4	a	5.6%	2.8%
New Mexico	35	3	3	23	6	9	9	65	18	d	3.3%	1.6%
New York	21	3	0	17	1	13	1	81	5	a	5.6%	2.8%
North Carolina	51	9	12	24	5	18	24	48	10	d	3.2%	1.6%
North Dakota	38	7	3	25	4	18	9	64	9	d	3.1%	1.6%
Ohio	32	5	2	23	2	14	7	71	7	c	4.0%	2.0%
Oklahoma	50	10	2	28	9	21	5	56	18	d	3.2%	1.6%
Oregon	42	11	5	26	1	25	11	61	2	a	5.5%	2.8%
Pennsylvania	39	5	3	29	2	14	8	74	4	c	3.9%	2.0%
Rhode Island	26	4	3	18	1	16	11	71	3	a	5.6%	2.8%
South Carolina	51	9	12	24	5	18	24	48	10	d	3.2%	1.6%
South Dakota	38	7	3	25	4	18	9	64	9	d	3.1%	1.6%
Tennessee	49	11	3	28	7	22	6	58	14	c	4.0%	2.0%
Texas	48	7	1	29	10	15	2	62	22	a	5.9%	3.0%
Utah	31	4	3	23	1	12	10	75	3	b	4.8%	2.4%
Vermont	26	4	3	18	1	16	11	71	3	a	5.6%	2.8%
Virginia	51	9	12	24	5	18	24	48	10	c	4.1%	2.0%
Washington	42	11	5	26	1	25	11	61	2	b	4.7%	2.3%
West Virginia	51	9	12	24	5	18	24	48	10	d	3.2%	1.6%
Wisconsin	32	5	2	23	2	14	7	71	7	a	5.7%	2.8%
Wyoming	31	4	3	23	1	12	10	75	3	c	3.9%	2.0%

5 yr savings potent	6.20%
End-use multipliers	
Space heating	0.8
Cooling	1.2
Water heating	1
Other	0.9

Legend:
SH=Space Heating
WH= Water Heating
AC= Air Conditioning
OT=Other
EP=Economic Potential
hh=Household

CHANGE IN RESIDENTIAL GAS DEMAND

MMcf	2004	2005	2006	2007	2008
AL	-606	-614	-637	-615	-693
AZ	-870	-959	-1,051	-1,136	-1,297
AR	-1,177	-1,336	-1,495	-1,661	-1,911
CA	-12,595	-14,066	-15,343	-16,603	-18,781
CO	-2,451	-2,707	-3,168	-3,460	-4,110
CT	-1,127	-1,266	-1,405	-1,539	-1,756
DE	-221	-247	-272	-298	-339
DC	-189	-206	-223	-239	-272
FL	-213	-224	-231	-237	-266
GA	-1,709	-1,740	-1,775	-1,762	-1,991
ID	-384	-428	-477	-525	-614
IL	-10,954	-12,029	-13,082	-14,162	-16,165
IN	-3,004	-3,201	-3,386	-3,573	-4,056
IA	-1,635	-1,769	-1,907	-2,045	-2,327
KS	-1,014	-1,019	-1,019	-1,015	-1,139
KY	-1,135	-1,190	-1,246	-1,288	-1,463
LA	-803	-848	-893	-938	-1,072
ME	-26	-29	-32	-36	-41
MD	-1,731	-1,886	-2,036	-2,181	-2,490
MA	-2,995	-3,364	-3,733	-4,089	-4,664
MI	-8,340	-9,170	-9,995	-10,821	-12,362
MN	-3,002	-3,320	-3,637	-3,965	-4,559
MS	-1,065	-1,210	-1,354	-1,503	-1,723
MO	-1,564	-1,567	-1,559	-1,547	-1,719
MT	-357	-374	-396	-414	-474
NE	-602	-604	-604	-602	-673
NV	-624	-675	-720	-766	-878
NH	-184	-207	-230	-252	-287
NJ	-6,165	-6,987	-7,809	-8,653	-9,969
NM	-1,251	-1,454	-1,667	-1,868	-2,183
NY	-10,112	-11,432	-12,733	-13,907	-15,821
NC	-839	-864	-883	-890	-1,008
ND	-200	-209	-222	-232	-266
OH	-6,041	-6,400	-6,734	-7,067	-7,983
OK	-955	-959	-959	-956	-1,072
OR	-1,071	-1,199	-1,341	-1,465	-1,707
PA	-6,646	-7,424	-8,188	-8,961	-10,210
RI	-489	-550	-610	-668	-762
SC	-404	-415	-422	-424	-478
SD	-259	-280	-302	-324	-368
TN	-1,091	-1,144	-1,197	-1,237	-1,407
TX	-5,392	-6,014	-6,617	-7,247	-8,332
UT	-2,060	-2,414	-2,796	-3,212	-3,731
VT	-67	-75	-84	-92	-105
VA	-2,003	-2,269	-2,537	-2,807	-3,229
WA	-1,591	-1,778	-1,989	-2,174	-2,515
WV	-423	-425	-424	-422	-472
WI	-3,669	-4,136	-4,604	-5,090	-5,855
WY	-680	-781	-891	-1,017	-1,181
US	-111,986	-123,464	-134,915	-145,986	-166,782

CHANGE IN COMMERCIAL GAS DEMAND

MMcf	2004	2005	2006	2007	2008
AL	-259	-136	-40	142	193
AZ	-511	-384	-272	-110	-67
AR	-719	-661	-598	-519	-564
CA	-5,120	-4,533	-3,740	-2,709	-2,654
CO	-1,070	-828	-851	-600	-783
CT	-996	-900	-793	-618	-630
DE	-113	-98	-81	-61	-61
DC	-246	-185	-120	-33	-13
FL	-560	-383	-188	54	115
GA	-551	-263	4	383	517
ID	-207	-163	-122	-65	-62
IL	-4,177	-3,328	-2,428	-1,376	-1,215
IN	-1,138	-785	-409	24	169
IA	-769	-571	-375	-146	-89
KS	-513	-252	7	308	419
KY	-507	-327	-147	83	159
LA	-400	-244	-89	97	155
ME	-64	-58	-51	-40	-40
MD	-968	-727	-471	-130	-51
MA	-2,354	-2,127	-1,874	-1,461	-1,488
MI	-3,351	-2,685	-1,983	-1,134	-1,007
MN	-1,617	-1,301	-969	-577	-539
MS	-576	-533	-485	-424	-454
MO	-694	-365	-24	367	534
MT	-174	-102	-39	41	64
NE	-335	-157	11	211	280
NV	-330	-217	-92	58	119
NH	-175	-158	-139	-108	-110
NJ	-3,633	-3,210	-2,721	-2,054	-2,088
NM	-882	-874	-896	-832	-1,014
NY	-6,873	-6,183	-5,395	-3,807	-3,701
NC	-440	-212	21	328	459
ND	-143	-84	-32	34	53
OH	-2,526	-1,747	-914	47	371
OK	-443	-217	6	266	362
OR	-697	-580	-480	-309	-315
PA	-1,767	-1,533	-1,275	-949	-950
RI	-304	-274	-242	-188	-192
SC	-189	-89	8	139	189
SD	-162	-120	-79	-31	-19
TN	-707	-456	-206	116	222
TX	-4,027	-3,467	-2,869	-2,121	-2,248
UT	-1,203	-1,270	-1,377	-1,524	-1,829
VT	-71	-64	-56	-44	-45
VA	-1,460	-1,342	-1,210	-1,008	-1,089
WA	-872	-725	-597	-385	-366
WV	-282	-134	22	206	288
WI	-1,877	-1,659	-1,414	-1,118	-1,164
WY	-579	-564	-571	-603	-725
US	-57,635	-47,276	-36,632	-22,180	-20,906

CHANGE IN INDUSTRIAL GAS DEMAND

MMcf	2004	2005	2006	2007	2008
AL	1,117	-228	338	1,659	-629
AZ	50	91	559	505	189
AR	4,178	6,373	6,973	4,043	3,821
CA	-6,369	-17,369	-607	-2,538	-13,232
CO	-141	485	-790	1,012	-1,807
CT	32	-173	-72	-328	-490
DE	85	72	268	153	211
DC	0	0	0	0	0
FL	2,607	3,054	6,095	5,354	4,173
GA	3,668	4,296	7,412	7,533	5,233
ID	-148	64	635	368	29
IL	-282	-1,317	4,618	3,731	1,135
IN	-276	-1,291	4,527	3,657	1,054
IA	-627	-1,157	460	123	-671
KS	2,063	3,011	3,995	2,434	2,011
KY	656	-338	762	885	-275
LA	28,196	42,630	46,569	27,000	25,079
ME	2	-12	-5	-22	-33
MD	795	918	1,879	1,624	1,139
MA	100	-546	-228	-1,037	-1,546
MI	472	-264	5,762	5,284	3,051
MN	-671	-1,203	314	-37	-825
MS	1,202	-248	1,981	1,774	593
MO	-132	-362	729	624	244
MT	-6	154	322	230	146
NE	-79	-249	610	538	252
NV	-55	190	886	553	548
NH	5	-27	-11	-50	-75
NJ	-312	-858	710	-1,004	-358
NM	1,789	2,583	3,003	1,257	146
NY	-427	-1,176	759	-1,433	-409
NC	2,662	3,178	5,753	5,508	4,463
ND	-33	4	434	348	187
OH	536	-303	6,653	6,000	3,457
OK	3,528	5,150	6,832	4,162	3,440
OR	-527	1,273	-702	-2,167	-3,227
PA	772	497	2,847	1,266	2,305
RI	27	-148	-62	-280	-418
SC	2,418	2,886	5,166	5,002	4,025
SD	-39	-72	29	8	-42
TN	913	-471	1,061	1,233	-384
TX	41,717	64,970	67,436	23,936	13,864
UT	-55	188	802	586	314
VT	2	-11	-5	-21	-32
VA	1,592	1,840	3,739	3,254	2,332
WA	-733	1,797	-893	-3,001	-4,199
WV	1,077	1,285	2,442	2,228	1,863
WI	-491	-1,111	1,539	979	-394
WY	-174	288	1,531	1,007	457
US	91,689	121,031	205,051	115,302	57,993

CHANGE IN POWER GENERATION GAS DEMAND

MMcf	2004	2005	2006	2007	2008
AL	-7,292	-17,506	-922	-53,928	-47,251
AZ	4,919	6,250	22,140	5,152	9,948
AR	4,637	-2,365	5,346	1,844	2,409
CA	-41,332	-107,921	-134,976	-210,744	-255,315
CO	4,699	6,455	14,260	3,807	8,198
CT	-3,400	-5,531	-8,615	-12,781	-15,981
DE	-1,819	-4,473	-9,895	-18,711	-31,726
DC	0	0	0	0	0
FL	-3,472	-25,496	-34,201	-74,709	-91,475
GA	-10,901	-25,624	-1,660	-64,510	-55,548
ID	-1,498	-1,563	-2,073	-4,351	-4,187
IL	-1,901	-2,286	-7,000	-14,703	-15,298
IN	6,944	6,216	10,342	11,694	8,693
IA	-389	-843	-1,587	-2,664	-3,363
KS	1,441	-503	1,727	457	689
KY	-3,811	-8,635	-506	-20,974	-17,989
LA	9,625	-4,601	8,355	482	403
ME	0	0	0	0	0
MD	-1,464	-2,533	-1,304	-7,855	-7,872
MA	-11,774	-19,156	-29,838	-44,264	-55,350
MI	8,226	6,564	10,887	13,408	9,270
MN	-1,151	-2,234	-3,305	-4,589	-5,909
MS	22,909	-6,199	18,788	11,535	9,801
MO	-3,305	-6,079	-9,442	-13,371	-17,347
MT	-1,493	-2,571	-3,979	-5,607	-7,580
NE	-549	-1,023	-1,537	-2,186	-2,820
NV	-10,592	-24,133	-47,842	-63,367	-79,972
NH	-206	-335	-521	-773	-967
NJ	-3,738	-1,231	-12,733	-17,644	-30,892
NM	-374	853	1,150	-1,574	-13
NY	-1,870	-892	-5,176	-38,014	-44,280
NC	-4,057	-10,232	-714	-26,055	-22,125
ND	-6	-10	-16	-22	-30
OH	12,307	10,491	14,584	16,616	12,754
OK	7,911	-2,763	9,485	2,508	3,784
OR	-11,472	-8,191	-14,703	-25,022	-24,270
PA	-2,931	-3,817	-9,957	-18,959	-32,360
RI	-4,182	-6,804	-10,598	-15,722	-19,659
SC	-3,225	-8,916	-182	-22,116	-18,809
SD	-117	-254	-478	-803	-1,014
TN	-3,317	-7,517	-441	-18,258	-15,660
TX	-80,248	-15,527	-124,404	-193,097	-232,148
UT	-3,548	-1,801	-4,740	-5,341	-6,266
VT	-14	-24	-37	-54	-68
VA	-909	-3,043	511	-8,578	-7,619
WA	-6,032	-2,641	-7,369	-10,160	-10,361
WV	2,245	2,468	3,916	4,281	3,392
WI	-339	-348	-864	-1,892	-1,908
WY	-355	-409	-549	-837	-1,048
US	-147,216	-306,732	-370,670	-952,447	-1,115,164

CHANGE IN RESIDENTIAL GAS PRICE
Real$/Mcf

	2004	2005	2006	2007	2008
AL	-0.68	-1.21	-1.13	-0.87	-0.75
AZ	-0.72	-1.20	-1.12	-0.84	-0.78
AR	-0.67	-1.21	-1.12	-0.85	-0.73
CA	-0.75	-1.19	-1.11	-0.84	-0.86
CO	-0.70	-1.09	-0.91	-0.49	-0.58
CT	-0.62	-1.16	-1.11	-0.88	-0.77
DE	-0.66	-1.22	-1.15	-0.88	-0.77
DC	-0.67	-1.21	-1.14	-0.88	-0.77
FL	-0.71	-1.19	-1.11	-0.88	-0.77
GA	-0.65	-1.19	-1.11	-0.81	-0.68
ID	-0.69	-1.15	-0.98	-0.64	-0.73
IL	-0.65	-1.18	-1.10	-0.82	-0.72
IN	-0.66	-1.21	-1.14	-0.87	-0.76
IA	-0.65	-1.16	-1.07	-0.78	-0.70
KS	-0.68	-1.19	-1.09	-0.81	-0.73
KY	-0.64	-1.21	-1.14	-0.85	-0.73
LA	-0.69	-1.22	-1.13	-0.86	-0.75
ME	-0.69	-1.24	-1.19	-0.95	-0.85
MD	-0.67	-1.21	-1.14	-0.87	-0.76
MA	-0.69	-1.24	-1.19	-0.95	-0.85
MI	-0.67	-1.20	-1.12	-0.84	-0.73
MN	-0.64	-1.16	-1.08	-0.79	-0.66
MS	-0.66	-1.19	-1.11	-0.84	-0.73
MO	-0.66	-1.19	-1.10	-0.82	-0.75
MT	-0.69	-1.16	-1.07	-0.79	-0.73
NE	-0.66	-1.14	-1.04	-0.74	-0.75
NV	-0.70	-1.14	-1.01	-0.71	-0.84
NH	-0.69	-1.24	-1.18	-0.95	-0.84
NJ	-0.65	-1.21	-1.15	-0.88	-0.77
NM	-0.71	-1.21	-1.12	-0.85	-0.82
NY	-0.67	-1.21	-1.15	-0.89	-0.78
NC	-0.64	-1.21	-1.15	-0.89	-0.76
ND	-0.69	-1.16	-1.08	-0.80	-0.72
OH	-0.65	-1.20	-1.13	-0.86	-0.75
OK	-0.68	-1.19	-1.09	-0.81	-0.73
OR	-0.67	-1.15	-1.07	-0.81	-0.68
PA	-0.65	-1.21	-1.14	-0.87	-0.76
RI	-0.69	-1.23	-1.18	-0.94	-0.84
SC	-0.63	-1.21	-1.15	-0.89	-0.76
SD	-0.65	-1.17	-1.08	-0.78	-0.70
TN	-0.65	-1.21	-1.14	-0.87	-0.75
TX	-0.68	-1.18	-1.10	-0.81	-0.70
UT	-0.67	-1.07	-0.87	-0.45	-0.55
VT	-0.70	-1.25	-1.20	-0.96	-0.86
VA	-0.66	-1.20	-1.13	-0.86	-0.75
WA	-0.67	-1.16	-1.08	-0.83	-0.69
WV	-0.66	-1.22	-1.15	-0.88	-0.76
WI	-0.65	-1.18	-1.10	-0.82	-0.70
WY	-0.68	-1.07	-0.86	-0.45	-0.54
US	-0.67	-1.19	-1.11	-0.83	-0.74

CHANGE IN COMMERCIAL GAS PRICE
Real$/Mcf

	2004	2005	2006	2007	2008
AL	-0.74	-1.21	-1.12	-0.86	-0.76
AZ	-0.81	-1.20	-1.11	-0.83	-0.80
AR	-0.71	-1.21	-1.11	-0.84	-0.74
CA	-0.85	-1.19	-1.09	-0.84	-0.88
CO	-0.72	-1.09	-0.90	-0.50	-0.58
CT	-0.71	-1.20	-1.13	-0.90	-0.81
DE	-0.69	-1.22	-1.15	-0.88	-0.77
DC	-0.73	-1.21	-1.13	-0.87	-0.77
FL	-0.81	-1.19	-1.10	-0.86	-0.78
GA	-0.71	-1.19	-1.10	-0.81	-0.71
ID	-0.72	-1.14	-0.97	-0.64	-0.73
IL	-0.68	-1.19	-1.11	-0.83	-0.73
IN	-0.67	-1.21	-1.14	-0.86	-0.76
IA	-0.67	-1.17	-1.08	-0.78	-0.70
KS	-0.76	-1.19	-1.07	-0.80	-0.74
KY	-0.68	-1.21	-1.13	-0.85	-0.74
LA	-0.74	-1.21	-1.11	-0.85	-0.75
ME	-0.75	-1.24	-1.17	-0.93	-0.85
MD	-0.73	-1.21	-1.13	-0.86	-0.77
MA	-0.75	-1.24	-1.17	-0.93	-0.84
MI	-0.68	-1.20	-1.12	-0.84	-0.73
MN	-0.67	-1.17	-1.09	-0.80	-0.68
MS	-0.73	-1.20	-1.10	-0.84	-0.74
MO	-0.69	-1.19	-1.09	-0.81	-0.75
MT	-0.70	-1.16	-1.07	-0.79	-0.73
NE	-0.80	-1.10	-0.96	-0.73	-0.72
NV	-0.78	-1.12	-0.98	-0.71	-0.84
NH	-0.75	-1.24	-1.17	-0.94	-0.85
NJ	-0.71	-1.22	-1.14	-0.88	-0.79
NM	-0.81	-1.21	-1.11	-0.85	-0.84
NY	-0.77	-1.22	-1.14	-0.88	-0.81
NC	-0.73	-1.21	-1.13	-0.87	-0.77
ND	-0.70	-1.16	-1.08	-0.80	-0.72
OH	-0.66	-1.20	-1.13	-0.86	-0.75
OK	-0.76	-1.19	-1.07	-0.80	-0.74
OR	-0.72	-1.15	-1.08	-0.82	-0.71
PA	-0.68	-1.21	-1.14	-0.87	-0.77
RI	-0.74	-1.24	-1.17	-0.93	-0.84
SC	-0.76	-1.21	-1.11	-0.86	-0.77
SD	-0.67	-1.17	-1.08	-0.78	-0.71
TN	-0.69	-1.22	-1.13	-0.86	-0.76
TX	-0.79	-1.19	-1.09	-0.81	-0.73
UT	-0.69	-1.07	-0.88	-0.46	-0.56
VT	-0.76	-1.25	-1.18	-0.94	-0.85
VA	-0.72	-1.20	-1.12	-0.85	-0.76
WA	-0.72	-1.16	-1.09	-0.84	-0.72
WV	-0.71	-1.22	-1.14	-0.87	-0.77
WI	-0.66	-1.18	-1.10	-0.82	-0.71
WY	-0.69	-1.07	-0.87	-0.46	-0.55
US	-0.72	-1.18	-1.09	-0.83	-0.75

CHANGE IN INDUSTRIAL GAS PRICE
Real$/Mcf

	2004	2005	2006	2007	2008
AL	-0.87	-1.20	-1.08	-0.83	-0.76
AZ	-0.90	-1.20	-1.09	-0.83	-0.80
AR	-0.85	-1.20	-1.06	-0.82	-0.76
CA	-0.91	-1.23	-1.13	-0.87	-0.92
CO	-0.86	-1.05	-0.81	-0.51	-0.55
CT	-0.91	-1.24	-1.12	-0.90	-0.86
DE	-0.86	-1.22	-1.10	-0.86	-0.80
DC	0.00	0.00	0.00	0.00	0.00
FL	-0.88	-1.20	-1.16	-0.86	-0.80
GA	-0.90	-1.20	-1.10	-0.84	-0.79
ID	-0.86	-1.11	-0.95	-0.71	-0.75
IL	-0.83	-1.18	-1.06	-0.81	-0.75
IN	-0.85	-1.21	-1.10	-0.85	-0.78
IA	-0.85	-1.16	-1.04	-0.78	-0.74
KS	-0.88	-1.18	-1.05	-0.80	-0.75
KY	-0.86	-1.21	-1.09	-0.83	-0.77
LA	-0.85	-1.20	-1.06	-0.82	-0.76
ME	-0.91	-1.25	-1.13	-0.91	-0.86
MD	-0.90	-1.21	-1.12	-0.85	-0.80
MA	-0.91	-1.25	-1.13	-0.91	-0.86
MI	-0.83	-1.19	-1.08	-0.82	-0.76
MN	-0.86	-1.18	-1.07	-0.82	-0.75
MS	-0.86	-1.20	-1.08	-0.83	-0.76
MO	-0.86	-1.17	-1.04	-0.79	-0.76
MT	-0.86	-1.16	-1.05	-0.81	-0.75
NE	-0.86	-1.14	-1.01	-0.77	-0.74
NV	-0.86	-1.11	-0.96	-0.74	-0.89
NH	-0.92	-1.25	-1.13	-0.91	-0.87
NJ	-0.87	-1.23	-1.11	-0.88	-0.82
NM	-0.90	-1.21	-1.09	-0.84	-0.86
NY	-0.86	-1.22	-1.11	-0.88	-0.84
NC	-0.90	-1.21	-1.11	-0.85	-0.80
ND	-0.86	-1.17	-1.06	-0.82	-0.75
OH	-0.82	-1.20	-1.09	-0.84	-0.77
OK	-0.88	-1.18	-1.05	-0.80	-0.75
OR	-0.87	-1.18	-1.08	-0.83	-0.78
PA	-0.85	-1.21	-1.10	-0.86	-0.79
RI	-0.90	-1.23	-1.12	-0.89	-0.85
SC	-0.90	-1.21	-1.11	-0.85	-0.80
SD	-0.86	-1.18	-1.06	-0.81	-0.76
TN	-0.87	-1.21	-1.09	-0.84	-0.77
TX	-0.89	-1.19	-1.06	-0.82	-0.75
UT	-0.86	-1.05	-0.83	-0.51	-0.59
VT	-0.94	-1.28	-1.15	-0.94	-0.90
VA	-0.89	-1.20	-1.11	-0.85	-0.80
WA	-0.87	-1.17	-1.07	-0.84	-0.78
WV	-0.89	-1.21	-1.11	-0.85	-0.79
WI	-0.85	-1.20	-1.10	-0.84	-0.77
WY	-0.85	-1.04	-0.81	-0.50	-0.56
US	-0.87	-1.19	-1.07	-0.81	-0.77

CHANGE IN POWER GENERATION GAS PRICE
Real$/Mcf

	2004	2005	2006	2007	2008
AL	-0.87	-1.25	-1.23	-0.84	-0.85
AZ	-0.99	-1.24	-1.03	-0.83	-0.77
AR	-1.00	-1.21	-1.03	-0.83	-0.76
CA	-0.95	-1.22	-1.11	-0.86	-0.89
CO	-0.99	-1.01	-0.77	-0.55	-0.55
CT	-0.86	-1.21	-1.04	-0.85	-0.81
DE	-1.03	-1.30	-1.32	-0.91	-1.01
DC	0.00	0.00	0.00	0.00	0.00
FL	-0.92	-1.20	-1.12	-0.85	-0.82
GA	-0.88	-1.26	-1.24	-0.85	-0.85
ID	-0.80	-1.08	-1.08	-0.70	-0.87
IL	-1.10	-1.19	-1.05	-0.81	-0.89
IN	-1.02	-1.34	-0.96	-0.84	-0.70
IA	1.43	-7.80	-6.16	-5.87	-5.21
KS	-1.03	-1.18	-1.02	-0.83	-0.76
KY	-0.85	-1.22	-1.27	-0.81	-0.87
LA	-0.98	-1.19	-1.03	-0.84	-0.76
ME	-0.89	-1.26	-1.08	-0.94	-0.86
MD	-0.98	-1.23	-1.17	-0.86	-0.85
MA	-0.89	-1.25	-1.08	-0.93	-0.85
MI	-0.99	-1.29	-0.93	-0.82	-0.69
MN	0.30	-6.96	-5.77	-5.16	-4.59
MS	-1.05	-1.21	-1.04	-0.85	-0.75
MO	0.36	-6.24	-5.02	-4.50	-4.06
MT	-0.86	-1.13	-1.07	-0.71	-0.75
NE	0.06	-5.82	-4.78	-4.30	-3.90
NV	-0.95	-1.13	-0.94	-0.82	-0.96
NH	-0.89	-1.26	-1.09	-0.95	-0.86
NJ	-1.10	-1.28	-1.05	-0.90	-0.89
NM	-0.99	-1.21	-1.08	-0.85	-0.91
NY	-1.03	-1.28	-1.03	-0.89	-0.83
NC	-0.89	-1.29	-1.26	-0.87	-0.87
ND	-0.85	-1.11	-1.05	-0.68	-0.72
OH	-0.96	-1.28	-0.94	-0.83	-0.69
OK	-1.03	-1.18	-1.00	-0.82	-0.76
OR	-0.72	-0.95	-1.05	-0.56	-0.71
PA	-1.02	-1.28	-1.27	-0.91	-0.98
RI	-0.88	-1.25	-1.08	-0.93	-0.85
SC	-0.91	-1.28	-1.26	-0.87	-0.87
SD	0.67	-7.14	-5.68	-5.40	-4.86
TN	-0.88	-1.29	-1.24	-0.86	-0.85
TX	-0.97	-1.20	-1.01	-0.82	-0.77
UT	-0.76	-0.98	-0.75	-0.41	-0.53
VT	-0.91	-1.28	-1.10	-0.97	-0.89
VA	-1.00	-1.23	-1.25	-0.85	-0.91
WA	-0.73	-1.02	-1.06	-0.60	-0.72
WV	-0.94	-1.28	-0.95	-0.84	-0.70
WI	-1.12	-1.18	-1.05	-0.82	-0.88
WY	-0.77	-0.92	-0.70	-0.37	-0.50
US	-0.95	-1.22	-1.11	-0.86	-0.87

CHANGE IN RESIDENTIAL GAS CONSUMER COSTS
Millions of $

	2004	2005	2006	2007	2008
AL	-38	-64	-60	-48	-43
AZ	-35	-55	-52	-43	-42
AR	-39	-64	-60	-50	-47
CA	-500	-745	-696	-571	-587
CO	-106	-159	-138	-87	-104
CT	-39	-64	-62	-54	-51
DE	-8	-13	-13	-10	-10
DC	-12	-21	-20	-16	-15
FL	-13	-20	-19	-15	-14
GA	-107	-185	-174	-132	-117
ID	-18	-28	-25	-18	-21
IL	-406	-672	-633	-504	-469
IN	-137	-232	-221	-176	-162
IA	-62	-103	-96	-74	-70
KS	-57	-93	-85	-65	-61
KY	-52	-92	-87	-69	-63
LA	-40	-67	-62	-50	-46
ME	-1	-2	-2	-1	-1
MD	-74	-120	-115	-95	-89
MA	-115	-184	-179	-155	-149
MI	-296	-506	-475	-372	-333
MN	-112	-188	-178	-140	-125
MS	-27	-43	-41	-35	-34
MO	-91	-152	-140	-107	-102
MT	-17	-28	-26	-20	-19
NE	-33	-54	-49	-36	-37
NV	-29	-46	-42	-32	-38
NH	-7	-12	-11	-10	-9
NJ	-192	-333	-321	-264	-245
NM	-34	-54	-51	-42	-43
NY	-382	-621	-600	-506	-477
NC	-52	-91	-87	-71	-64
ND	-10	-15	-14	-11	-11
OH	-278	-474	-447	-355	-323
OK	-54	-88	-81	-62	-58
OR	-40	-64	-61	-51	-47
PA	-239	-395	-378	-314	-295
RI	-18	-30	-29	-25	-24
SC	-22	-40	-38	-31	-28
SD	-10	-17	-16	-12	-12
TN	-56	-97	-92	-74	-67
TX	-177	-283	-267	-215	-199
UT	-53	-78	-67	-46	-53
VT	-3	-4	-4	-4	-3
VA	-73	-119	-115	-97	-92
WA	-69	-112	-107	-89	-80
WV	-22	-38	-36	-28	-25
WI	-121	-201	-191	-153	-142
WY	-14	-19	-17	-12	-14
US	-4,391	-7,188	-6,779	-5,446	-5,159

CHANGE IN COMMERCIAL GAS CONSUMER COSTS
Millions of $

	2004	2005	2006	2007	2008
AL	-20	-30	-27	-20	-17
AZ	-29	-41	-36	-27	-26
AR	-28	-44	-40	-31	-28
CA	-241	-328	-294	-230	-243
CO	-50	-70	-58	-33	-39
CT	-43	-69	-65	-53	-50
DE	-4	-7	-7	-5	-5
DC	-16	-24	-22	-17	-15
FL	-43	-60	-53	-41	-37
GA	-43	-67	-59	-42	-36
ID	-11	-17	-14	-10	-11
IL	-165	-260	-235	-175	-158
IN	-69	-115	-106	-79	-70
IA	-34	-55	-49	-36	-33
KS	-32	-45	-39	-27	-25
KY	-29	-48	-43	-32	-28
LA	-21	-31	-28	-20	-18
ME	-3	-4	-4	-3	-3
MD	-50	-77	-70	-54	-50
MA	-76	-113	-106	-88	-85
MI	-141	-236	-218	-165	-146
MN	-74	-121	-110	-82	-71
MS	-19	-28	-26	-20	-19
MO	-48	-75	-66	-47	-43
MT	-11	-16	-15	-11	-10
NE	-23	-30	-24	-17	-17
NV	-23	-32	-28	-20	-24
NH	-8	-13	-12	-10	-9
NJ	-142	-230	-215	-171	-159
NM	-27	-38	-35	-28	-29
NY	-344	-517	-478	-382	-359
NC	-34	-53	-48	-36	-32
ND	-9	-13	-12	-9	-8
OH	-135	-229	-210	-158	-139
OK	-34	-50	-43	-30	-28
OR	-26	-39	-36	-28	-25
PA	-115	-190	-177	-137	-123
RI	-13	-20	-19	-16	-15
SC	-17	-26	-23	-17	-15
SD	-8	-12	-11	-8	-7
TN	-41	-66	-60	-45	-39
TX	-168	-243	-218	-167	-154
UT	-31	-45	-38	-25	-30
VT	-3	-4	-4	-3	-3
VA	-60	-93	-87	-69	-64
WA	-44	-66	-62	-48	-42
WV	-19	-32	-29	-22	-20
WI	-67	-110	-102	-77	-70
WY	-12	-17	-15	-10	-12
US	-2,704	-4,152	-3,775	-2,876	-2,690

CHANGE IN INDUSTRIAL GAS CONSUMER COSTS
Millions of $

	2004	2005	2006	2007	2008
AL	-148	-215	-192	-142	-143
AZ	-13	-17	-13	-10	-12
AR	-73	-89	-88	-74	-73
CA	-650	-942	-792	-626	-705
CO	-58	-67	-56	-30	-43
CT	-22	-32	-29	-25	-25
DE	-18	-26	-23	-18	-17
DC	0	0	0	0	0
FL	-56	-75	-63	-41	-49
GA	-102	-132	-118	-79	-91
ID	-25	-30	-23	-18	-21
IL	-211	-305	-246	-186	-191
IN	-217	-317	-252	-193	-198
IA	-71	-99	-80	-62	-64
KS	-73	-91	-84	-66	-66
KY	-71	-107	-92	-70	-71
LA	-560	-701	-691	-563	-552
ME	-11	-16	-14	-12	-11
MD	-24	-32	-24	-17	-20
MA	-46	-69	-63	-58	-59
MI	-166	-240	-201	-150	-151
MN	-76	-107	-90	-71	-69
MS	-75	-114	-95	-72	-74
MO	-50	-69	-55	-42	-43
MT	-8	-9	-8	-6	-6
NE	-29	-40	-31	-24	-25
NV	-6	-6	-2	-2	-4
NH	-7	-9	-9	-7	-7
NJ	-40	-60	-49	-47	-42
NM	-6	-1	-5	-10	-19
NY	-34	-52	-40	-45	-38
NC	-60	-78	-65	-42	-49
ND	-18	-25	-21	-16	-16
OH	-228	-341	-277	-209	-210
OK	-95	-115	-100	-83	-86
OR	-66	-74	-82	-74	-74
PA	-146	-213	-184	-149	-135
RI	-1	-3	-3	-4	-4
SC	-60	-77	-68	-46	-51
SD	-3	-4	-3	-2	-3
TN	-89	-136	-116	-88	-91
TX	-1,522	-1,857	-1,803	-1,485	-1,443
UT	-30	-35	-26	-15	-20
VT	-3	-4	-4	-3	-3
VA	-48	-64	-55	-39	-44
WA	-71	-78	-89	-81	-79
WV	-33	-43	-39	-27	-29
WI	-113	-164	-134	-105	-106
WY	-28	-30	-17	-10	-16
US	-5,562	-7,407	-6,611	-5,227	-5,344

CHANGE IN POWER GENERATION GAS CONSUMER COSTS
Millions of $

	2004	2005	2006	2007	2008
AL	-133	-246	-190	-422	-385
AZ	-162	-191	-126	-143	-127
AR	-27	-73	-39	-36	-38
CA	-1,090	-1,898	-1,820	-2,186	-2,312
CO	-55	-40	-23	-31	-24
CT	-67	-105	-103	-124	-129
DE	-40	-67	-96	-119	-170
DC	0	0	0	0	0
FL	-648	-963	-1,018	-1,001	-1,026
GA	-130	-229	-195	-288	-263
ID	-21	-27	-31	-37	-38
IL	-89	-100	-122	-140	-129
IN	11	9	3	28	3
IA	-2	-13	-15	-21	-23
KS	-18	-29	-21	-18	-18
KY	-35	-69	-47	-106	-94
LA	-124	-224	-162	-145	-147
ME	-71	-101	-87	-75	-69
MD	-37	-54	-46	-85	-82
MA	-176	-281	-251	-296	-280
MI	-99	-131	-112	-73	-86
MN	-8	-36	-38	-42	-45
MS	-48	-174	-111	-74	-102
MO	-23	-51	-63	-80	-94
MT	-28	-48	-57	-62	-75
NE	-3	-18	-18	-19	-21
NV	-231	-395	-502	-632	-730
NH	-2	-4	-3	-4	-3
NJ	-183	-199	-204	-207	-234
NM	-38	-39	-38	-40	-37
NY	-431	-497	-473	-554	-545
NC	-48	-94	-72	-141	-126
ND	0	0	0	0	0
OH	70	67	59	100	53
OK	-84	-152	-95	-87	-90
OR	-144	-160	-196	-179	-179
PA	-67	-82	-144	-210	-326
RI	-85	-133	-126	-149	-149
SC	-38	-74	-67	-90	-82
SD	1	-17	-15	-16	-15
TN	-37	-72	-43	-117	-103
TX	-1,550	-1,507	-1,706	-1,846	-1,805
UT	-27	-17	-26	-28	-29
VT	-1	-2	-1	-1	-1
VA	-25	-42	-34	-58	-54
WA	-100	-100	-126	-108	-110
WV	10	12	11	20	10
WI	-28	-30	-31	-32	-31
WY	-5	-6	-5	-5	-6
US	-6,170	-8,702	-8,621	-9,973	-10,366

Appendix C-Changes in Natural Gas Consumption, Price and Expenditures for National EE/RE Scenario

The result for the base-case and the four policy scenarios are available in Microsoft Excel format on the ACEEE web site at: http://aceee.org/energy/efnatgas-study.htm.

Exhibit 5

Addendum A: Synapse Energy Economics Comments

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Establish Policies and Rules to Ensure Reliable, Long-Term Supplies of Natural Gas to California	; ; ; ;	Rulemaking 04-01-025

Comments of Synapse Energy Economics on the California Natural Gas Utilities' Phase 1 Proposals

Prepared for:
Ratepayers for Affordable Clean Energy

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March 23, 2004

Introduction

The Ratepayers for Affordable Clean Energy ("RACE") requested that Synapse Energy Economics, Inc. ("Synapse") review the California Public Utilities Commission's ("Commission") Order Instituting this proceeding and the proposals expected to be submitted by Pacific Gas and Electric Company ("PG&E"), Southern California Gas Company ("SoCalGas"), San Diego Gas and Electric Company ("SDG&E"), and Southwest Gas Corporation. (hereinafter "California's natural gas utilities") RACE also requested that Synapse evaluate whether the Commission should pre-approve full cost recovery of contracts between the natural gas utilities and liquid natural gas ("LNG") suppliers and the costs of interconnecting their systems with LNG facilities.

This report presents Synapse's comments on the Phase I Proposals submitted by the natural gas utilities and identifies a number of actions the Commission should initiate to assure that in coming years there will be adequate supplies of natural gas in California at reasonable rates and with the lowest possible environmental impact.

Synapse Energy Economics

Synapse Energy Economics, Inc. provides research, testimony, reports and regulatory support to consumer advocates, environmental organizations, regulatory commissions, state energy offices, and others. The company was founded in May 1996 to specialize in consulting on electric industry issues.

We assess the many public policy implications of electricity industry planning, regulation and restructuring, with an emphasis on consumer and environmental protection. Our work covers various inter-related issues pertaining to restructuring, such as market power, stranded costs, performance-based ratemaking, reliability, mergers and acquisitions, divestiture plans, energy efficiency, renewable resources, consumer aggregation, power plant economics, environmental disclosure, and regulation of distribution companies. Our research frequently incorporates economic analyses and computer modeling of electricity generation facilities.

Synapse works for a wide range of clients throughout the US, including Attorneys General, Offices of Consumer Advocates, Public Utility Commission staff, a variety of environmental groups, foundations, the Environmental Protection Agency, the Department of Energy, the Department of Justice, the Federal Trade Commission, the National Association of Regulatory Utility Commissioners, and others.

Additional information regarding Synapse Energy Economics, its qualifications, staff, clients, projects and reports are available on-line at www.synapse-energy.com.

Conclusion and Recommendations

The Commission should not adopt the fundamental changes in traditional gas ratemaking policy presented in the Phase 1 Proposals submitted by the natural gas utilities that would allow for pre-approval of cost recovery for capacity acquisitions involving supplies from proposed LNG facilities and for the costs of building interconnections with such facilities. In general, there should be no guarantees of full rate recovery of gas utility capacity acquisitions or related interconnection investments in the absence of:

- a showing that the utility explored and considered all reasonable supply and demand side alternatives, including energy efficiency and the use of renewable energy sources;
- a showing that the utility used a methodology that recognizes both the economic and environmental benefits and costs of such alternatives; and
- a showing that the proposed new resources are absolutely essential for reliable service and are clearly and materially superior on a societal least cost basis.

These required evaluations should take into account the economic benefits that reduced consumption provides by reducing the market power of gas and electricity suppliers, tempering volatility of gas and electric market prices, and reducing clearing prices in gas and electric markets, especially at times of highest prices.

Therefore, in place of approving regulatory changes proposed by the natural gas utilities, the Commission should expeditiously initiate a gas integrated resource planning process that would include participation by a broad range of stakeholders. In addition, the Commission should work with the California Energy Commission ("CEC") (1) to ensure that comprehensive California-specific analyses of cost-effective gas energy efficiency measures are completed expeditiously and (2) to dramatically increase funding of gas energy efficiency programs and related efforts regarding improving building and appliance standards. The appropriate regulatory policies for addressing the issues raised by the Commission in the Order Instituting Rulemaking ("OIR") in this proceeding cannot be determined without considering the potential for such cost-effective gas energy efficiency measures and without resolving the related questions on energy efficiency being addressed in Rulemaking 01-08-028.

The Commission also should work with the CEC to ensure that California's aging power plants are either repowered or replaced by more efficient generating facilities.

Finally, the Commission should ensure that there are strong affiliate transaction rules in place to govern negotiations and interactions between the California natural gas utilities and any affiliates supplying LNG.

Summary of Comments

The above conclusion and recommendations are based on the following comments:

Comment No. 1 - California's natural gas utilities have requested substantial and significant changes in traditional ratemaking and regulatory oversight of capacity acquisition and investment decisions.

Comment No. 2 - The natural gas utilities have provided no evidence that the fundamental changes in regulatory policies and oversight that they have proposed are needed or will provide benefits for ratepayers.

Comment No. 3 - The gas utilities' proposals would allow for only minor stakeholder input or review of their gas capacity acquisition decisions.

Comment No. 4 - The Commission should not be rushed into approving by this summer the fundamental changes in natural gas regulation that have been proposed by the natural gas utilities.

Comment No. 5 - Portfolio Management is the appropriate approach for securing adequate supplies of natural gas at reasonable rates.

Comment No. 6 - Commission oversight is critical to achieving the goals of portfolio management.

Comment No. 7 - Conservation and renewable energy should be the cornerstone of California's plan for meeting future natural gas needs.

Comment No. 8 - The future demand for natural gas can be significantly reduced through the Implementation of more extensive electric energy efficiency programs and the Acceleration of the state's Renewable Portfolio Standard from 2017 to 2010.

Comment No. 9 – Future natural gas demand also can be reduced significantly by the repowering or retirement of California's aging power plants.

Comment No. 10 - There is a significant potential for reducing both core and non-core natural gas demand.

Comment No. 11 - PG&E's proposal that ratepayers continue to pay for existing facilities that are used less due to the addition of new supply sources or system capacity is contrary to established regulatory policy.

Methodology

Synapse has reviewed in detail the Commission's OIR and the proposals submitted by the natural gas utilities. Synapse also has reviewed the projections of future electricity and natural gas supplies and demands prepared by the natural gas utilities and the CEC. In addition, Synapse has reviewed the assessments, by the CEC and others, of the potential for electricity and gas demand reductions through increased funding of efficiency programs and acceleration of the state's Renewable Portfolio Standard.

This Report also relies on the results of earlier Synapse work including, most particularly, analyses of the benefits of repowering older, inefficient power plants[1]; reviews of electricity supplies and demands in the Desert Southwest and WECC[2]; modeling studies of the interconnected WECC system as part of the development of a plan for the implementation of energy efficiency and renewable resources in seven Interior West

1 For example, see the testimony of David Schlissel in Cases 99-F-1627 and 00-F-1356 before the New York State Board on Electric Generation Siting and the Environment.

2 For example, see the testimony of David Schlissel in Arizona Public Service Commission Dockets Nos. E-01345A-01-0822 and E-01345A-03-0437.

states[3]; and a study on the need for, the benefits of, and the development of portfolio management strategies for procuring electricity resources.[4]

Comment No. 1: California's natural gas utilities have requested substantial and significant changes in traditional ratemaking and regulatory oversight of capacity acquisition and investment decisions.

In their Phase I proposals the California Natural Gas Utilities have requested substantial changes in the Commission's established ratemaking practices and policies related to cost recovery and the oversight of the natural gas capacity acquisition and investment decisions.

PG&E

PG&E has proposed that all pipeline, storage and LNG contracts falling within a Commission-approved Capacity Commitment Range would be pre-approved for cost recovery.[5] PG&E proposes to hold firm annual interstate and intrastate transportation capacity between 1000 MDth/day and 1200 MDth/day.[6] During the summer months, PG&E would hold between 750 and 850 MDth/day of intrastate capacity. PG&E also would hold between 40 and 46 MMDth of storage capacity, which is higher than its current storage inventory holding of 33.5 MMDth.

PG&E emphasizes that all commitments within this pre-approved Capacity Range would be deemed reasonable and fully recoverable in rates for any of the following:

- Any existing interstate, intrastate, and storage capacity;
- Individual interstate, intrastate, storage capacity, and LNG supply contracts with terms of three years or less;
- Individual interstate, intrastate, storage capacity, and LNG supply contracts with terms of more than three years and quantities less than or equal to 100 MDth/day or 3 MMDth of storage; and
- Interstate, intrastate, storage capacity, and LNG supply maintained by the exercise of ROFR options (in response to other shippers' bids) or evergreen terms.[7]

For capacity commitments that fall outside of these terms, and for all capacity in excess of PG&E's current holdings that would be acquired initially to meet the standards

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3 *A Balanced Energy Plan for the Interior West*, forthcoming, prepared by Synapse, Western Resources Advocates and Tellus Institute for the Hewlett Foundation.

4 *Portfolio Management: How to Procure Electricity Resources to Provide Reliable, Low-Cost, and Efficient Electricity Services to All Retail Customers*," prepared for the Regulatory Assistance Project and the Energy Foundation, October 2003.

5 *Phase I Proposals and Data Response of Respondent Pacific Gas and Electric Company*, dated February 24, 2004, at page 10.

6 Ibid., at page 8.

7 Ibid., at page 12.

established by the Commission, PG&E proposes to file an Expedited Capacity Advice Letter after consultation with the ORA, TURN, and the Energy Division.[8] PG&E's proposed Expedited Capacity Advice Letter procedure would allow ten days for protests and comments and three days for replies, and would seek Commission approval within 21 days of the filed date. However, PG&E does not specify the precise nature of this "consultation with the ORA, TURN and the Energy Division" and whether it would require approval from some or all of these organizations before it sought Commission approval.

PG&E also proposes that utilities be deemed in compliance with the pre-approved Capacity Range if the range is not exceeded for a cumulative period of six months in any 36-month period.[9] Consequently, under PG&E's proposal, it could exceed the pre-approved Capacity Range for 29 months of any 36-month period and still be deemed to be in compliance with the pre-approved Range.

In addition, PG&E proposes a policy change in that currently, PG&E requires interstate pipelines and third-party storage providers to build their own facilities to PG&E's system and pay PG&E for its costs to build the interconnect and related system changes. This policy would be changed so that PG&E would build the facilities necessary to transport the gas from the LNG facility (or another utility's or pipeline's facilities interconnected to the LNG facility) to PG&E's existing gas transmission and distribution network.[10]

PG&E further proposes that if it needs to build new intrastate facilities to connect to a new supply source, such as an LNG terminal, the certificate approval process must guarantee recovery of all of its reasonable costs. This change would modify or eliminate the requirement in Public Utilities Code Section 1005.5 that, for projects expected to exceed $50 million in cost, the Commission must specify a maximum reasonable and prudent cost for the facility, subject to revision for reasonable additional costs.[11]

Finally, PG&E proposes that ratepayers continue to pay the costs of any existing PG&E transmission or storage facilities that are being used less due to the addition of new supply or capacity.[12]

SoCalGas/SDG&E

SoCalGas and SDG&E have submitted capacity acquisition pre-approval proposals that were in many ways similar to PG&E's proposals.

SoCalGas proposes hold firm interstate capacity within a Commission-approved Transportation Capacity Commitment Range that averages between 80 percent and 110 percent of the forecasted core procurement portfolio's average temperature year daily demand during non-winter months and averages an amount between 90 percent and 120

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8 Ibid, at page 12.

9 Ibid, at page 11.

10 Ibid, at page 15.

11 Ibid, at page 16.

12 Ibid, at page ES-2.

percent of this demand during the winter months.[13] After consultation with the ORA, TURN, and the Energy Division, and with ORA's approval, interstate capacity commitments within this Commitment Range would be deemed reasonable and fully recoverable in rates in the event that any one of the following criteria is satisfied:

- Interstate capacity contracts with terms of more than three years and quantities les than or equal to 100 MMcf/d; or
- Interstate capacity contracts acquired by the exercise of ROFR options in response to posted bids by other shippers.

Multiple contracts with substantially similar material terms (i.e., price, contract term, and receipt and delivery points) on one pipeline would be aggregated to determine compliance with the limits of the Authorized Capacity Commitment process.[14]

Like PG&E, SoCalGas proposes an expedited Capacity Advice Letter approval process for commitments outside the limits of the Authorized Capacity Commitment process.[15]

SDG&E's proposal is almost exactly the same as that of SoCalGas. The only difference is that SDG&E proposes that interstate capacity commitments be deemed reasonable and fully recoverable in rates if any one of the following criteria is satisfied:

- Interstate contracts with terms of three years or less;
- Interstate contracts with terms of more than three years and quantities less than or equal to 20 MMcf/d; or
- Interstate capacity contracts acquired by the exercise of ROFR options in response to posted bids by other shippers.[16]

As in SoCalGas' proposal, multiple contracts with substantially similar material terms (i.e., price, contract term, and receipt and delivery points) on one pipeline would be aggregated to determine compliance with the limits of the Authorized Capacity Commitment process.

In addition, SoCalGas and SDG&E also proposed that the Commission adopt a policy that to the extent that the benefits to all utility customers of access to new gas supplies are greater than the cost to utility customers, the costs of expanding utility backbone facilities necessary to accommodate new gas supplies should be rolled-in to the utilities' system wide transportation rate. Below a certain cost threshold, it would be presumed that benefits exceed costs.[17] SoCalGas and SDG&E then proposed to roll-in new or expanded

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13 *Proposals of San Diego Gas & Electric Company and Southern California Gas Company*, dated February 24, 2004, at page 30.

14 Ibid, at page 31.

15 Ibid, at page 31.

16 Ibid, at page 43.

17 Ibid, at page 70.

supply access infrastructure costs up to $100,000 per MMcf/d of added supply capacity, with a maximum cost for all projects of $200 million.[18]

SoCalGas and SDG&E also made a number of specific proposals concerning related to Otay Mesa access and integration of their transmission systems.[19]

Comment No. 2: The natural gas utilities have provided no evidence that the fundamental changes in regulatory policies and oversight that they have proposed are needed or will provide benefits for ratepayers.

Apart from some general, unsupported statements about the need to move quickly to secure access to new gas and a few comments about the short amounts of time that capacity release transactions are posted on a pipeline's Electronic Bulletin Board, the gas utilities' Phase I Proposals are devoid of any concrete evidence about why the significant changes they seek in Commission oversight of procurement decisions are needed or would be expected to produce benefits for ratepayers. There is no showing in any of the Proposals that the utilities' past gas capacity acquisition efforts were hampered in any way by the existing regulatory scheme. There also is no showing that future capacity acquisitions would be more difficult or expensive due to the absence of pre-approval for cost recovery or by a requirement to provide subsequent proof to the Commission that such acquisitions were prudent under the circumstances.

SoCalGas and SDG&E did present the results of an analysis by the Cambridge Energy Resource Associates ("CERA") that they claim shows the potential magnitude of commodity price reductions that are expected to result from access to LNG supplies.[20] At Synapse's request, RACE requested a copy of the CERA analysis, and the related workpapers, in order to evaluate the study's methodology, assumptions and conclusions. Unfortunately, SoCalGas and SDG&E refused to provide copies of either the requested analysis or the related workpapers without a non-disclosure agreement.[21] Because such an agreement could not be negotiated in the short time frame allowed for the preparation of these comments, Synapse has not had any opportunity to assess the reasonableness of the claims made by the companies concerning the CERA report.[22]

It is easy to see why the gas utilities favor their proposals: apart from some unspecified "consultation" by TURN, there would not be any meaningful opportunity for stakeholders other than the ORA and Commission staff to question the reasonableness of their capacity acquisition decisions. At the same time, the gas utilities would not face

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18 Ibid, at page 70.

19 Ibid, at pages 82 and following.

20 *Proposals of San Diego Gas & Electric Company and Southern California Gas Company*, dated February 24, 2004; at page 9.

21 Responses of SoCalGas and SDG&E to Questions Nos. 4 and 11 of RACE's First Data Request.

22 SoCalGas and SDG&E also objected to another seven of the other fifteen questions contained in RACE's First Data Request to the companies. PG&E has to date failed to provide answers to any of the questions submitted by RACE to that company.

Commission review of the prudence of capacity acquisition related costs or the prospect of having some of those costs disallowed.

Some limited flexibility may be necessary to allow the gas utilities to react quickly to opportunities in the short term gas markets. However, the number and scope of such opportunities will be limited by the utilities' medium and long-term contracts.

Moreover, there will be many instances in which the utilities would not have to move quickly to secure the new supplies or pipeline capacity, such as in the decisions to renew existing contracts or to exercise RFOR or evergreen options. There is no need for the utilities' proposed pre-approval in such instances.

The Commission should not adopt the pre-approved process presented in the utilities' Phase 1 Proposals unless the utilities can offer specific evidence that without the requested pre-approval of capacity acquisitions they would be unable to secure adequate gas supplies from existing and new sources. Even then, the Commission should limit the pre-approval process to only those classes of capacity acquisitions or instances where there is a demonstrated need for the gas utilities to take actions quickly and ratepayers can be expected to benefit from the change.

The gas utilities need not fear subsequent Commission review of the prudence of their capacity acquisition decisions if they are able to fully document the bases of those decisions and can show that they were reasonable under the circumstances that existed at the time they were entered into and that the company fully considered all reasonable demand and supply options.

Comment No. 3: The gas utilities' proposals would allow for only minor stakeholder input or review of their gas capacity acquisition decisions.

The SoCalGas and PG&E Phase 1 Proposals commit the companies to "consult" with TURN as part of their authorized capacity commitment processes.[23] However, the exact nature of this consultation is unspecified. Moreover, there is no commitment by the utilities to follow or even fully consider any of the concerns raised by or the recommendations made by TURN. No other representatives of stakeholders, other than the Commission's Energy Division and ORA, would be consulted before the Companies entered into the categories of commitments specified in each company's proposal. The SDG&E Phase 1 Proposal does not even include a commitment to consult with TURN or any other stakeholder other than the ORA and the Energy Division.

The utilities' also propose an Expedited Capacity Advice Letter process in which the acquisition of capacity outside of their pre-approved ranges would be reviewed by the Commission. Although the specifics differ between the utility proposals, these Expedited Capacity Advice Letters would be used in situations where the utilities were seeking to

23 *Phase 1 Proposals and Data Response of Respondent Pacific Gas and Electric Company*, dated February 24, 2004, at page 11 and *Proposals of San Diego Gas & Electric Company and Southern California Gas Company*, dated February 24, 2004, at page 26.

obtain new capacity for terms of longer than three years or beyond pre-approved quantities.

As proposed, the Expedited Capacity Advice Letter process would allow interested parties ten days to submit protests and comments and three days for replies, and would seek Commission approval within 21 days of the filed date. Consequently, there would be no opportunity before filing their protests and comments for interested stakeholders to do any discovery to elicit information from the utility about the other supply and demand alternatives that were available and considered. Nor would there be any hearings or opportunity to cross-examine the utility's claims. In this system, in order to provide meaningful comments on proposed capacity acquisitions, interested stakeholders would need significant budgets sufficient to maintain full-time monitoring of the gas supply and demand situations and alternatives.

Comment No. 4: The Commission should not be rushed into approving by this summer the fundamental changes in natural gas regulation that have been proposed by the natural gas utilities.

The Commission's Order instituting this ratemaking expressed concern that the Phase 1 issues had to be resolved by this summer. Not surprisingly, the Phase 1 Proposals submitted by the natural gas utilities echoed the sentiment that the Commission needed to approve the requested changes in traditional ratemaking and oversight by this summer. However, the proposals submitted by the utilities were devoid of any concrete evidence showing that the Commission needed to decide these issues that quickly. Indeed, the utilities' Phase 1 proposals contained evidence which shows that the Commission need not rush to judgment in this proceeding.

First, the only SDG&E pipeline contract that has an upcoming termination notice date before the end of May 2005 is the relatively small Canadian Path contract with Trans-Canada Nova Gas Limited which has a notice date of October 31, 2004. This contract provides for 17,375 Mcf/day of capacity.[24]

Second, SoCalGas has two substantial contracts with Transwestern which have RFOR dates of November 1, 2004.[25] However, SoCalGas already has stated its intention to terminate or to negotiate reduced amounts of capacity on its contracts with Transwestern or El Paso. Consequently, it is inconceivable that SoCalGas has not already been evaluating possible alternative sources and developing plans to replace part or all of the two contracts which have November 1, 2004 RFOR dates.

Similarly, PG&E has three contracts with GTNC, TransCanada BC and TransCanada NOVA which expire in late 2005 and have notice dates of October 31 and December 31, 2004. However, PG&E has expressed satisfaction with its existing natural gas supply sources and pipeline contracts:

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24 Table Q4 of SDG&E's Responses to CPUC Data Requests (R.04-01-025).

25 Table Q4 of SoCalGas's Responses to CPUC Data Requests (R.04-01-025).

> One of the issues the Commission has asked the parties to address is supply diversity. PG&E is currently exceptionally well-situated to purchase natural gas from a variety of competing sources in Canada and the U.S. Southwest. PG&E's pipeline capacity contracts are structured to afford PG&E the opportunity to purchase gas from these competing sources. PG&E's comments herein are intended to preserve and expand upon this existing level of supply diversity.[26]

As with SoCalGas, it is inconceivable that PG&E has not already been evaluating possible alternative sources and deciding whether to terminate or replace some of the pipeline capacity provided by these three contracts.

Consequently, the Commission certainly does not need to make any decision in the Phase I proceeding before late October 2004, if not later. Moreover, the Commission can use the intervening seven months to examine the reasonableness of the plans that these three companies have for renewing, replacing or terminating their pipeline contracts within the context of a proceeding allowing for hearings and public participation.

Comment No. 5: Portfolio Management is the appropriate approach for securing adequate supplies of natural gas at reasonable rates.

The gas utilities say in their Phase I Proposals that it is important for them to obtain natural gas from a variety of supply sources and under a blend of short, medium and long-term contracts. We agree. Developing an optimal resource mix is essential for ensuring that there will be adequate supplies of natural gas to meet the demands of core and non-core customers and electric generators at reasonable rates and with minimal environmental impact.

Such an optimal mix should include demand side options and obtaining gas from diversified supply sources, under contracts of varying lengths and with some reliance on spot markets. Indeed, as California's Energy Action Plan recognizes, the implementation of cost-effective *energy efficiency measures must be the first step in developing the* optimal mix of resources. An optimal resource mix also can include financial and physical hedges.

However, the gas utilities have provided no evidence that they have carried out an integrated resource process to determine the appropriate mix of supply sources and contract terms. Until they provide such evidence, the Commission should withhold pre-adoption of any process that provides for any pre-approval of any resource acquisitions. Pre-approval of resources with some assurance of cost recovery should be used with great caution, and only if certain critical conditions are met. It is essential that pre-approval only be applied to resource portfolios that were developed with proper portfolio management techniques, with meaningful and substantial input from key stakeholders, and with proper oversight from regulators.

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[26] *Phase I Proposals and Data Response of Respondent Pacific Gas and Electric Company*, dated February 24, 2004, at page 5.

Moreover, there should be no guarantees of full rate recovery of gas utility capacity acquisitions or related investments in the absence of a showing that the utility explored and considered all reasonable supply and demand side alternatives, including energy efficiency and the use of renewable energy sources, a showing that the utility used a methodology that recognizes both the economic and environmental benefits and costs of such alternatives, and a showing that the proposed new resources are absolutely essential for reliable service and clearly and materially superior on a societal least cost basis. Such evaluation and comparison should take into account the economic benefit reduced consumption provides by reducing the market power of gas and electricity suppliers, tempering volatility of gas and electric market prices, and reducing clearing prices in gas and electric markets, especially at times of highest prices.

Comment No. 6: Commission oversight is critical to achieving the goals of portfolio management

The Commission must maintain an active oversight role if it is to be assured that the natural gas utilities are pursuing an optimal mix of both supply and demand resources. The Commission cannot merely adopt a pre-approval process that, in essence, delegates both the oversight role and the determination of the appropriate resource mix to be pursued to the gas utilities themselves, with some involvement by the ORA, the Energy Division, and, in some instances, TURN.

Instead, the Commission must be actively involved in the development and implementation of the resource mix to be pursued by the utility:

- To ensure that there gas utilities have adequate funding for energy efficiency activities and that those activities are prudently designed and implemented.
- To assure that there is broad stakeholder input in the process. One of the more challenging aspects of portfolio management is in the balancing of the many different criteria for selecting the optimal resource portfolio. This balancing often involves trade-offs that affect different stakeholders differently. In order to ensure proper balancing of different interests, it is essential to allow the various stakeholders to provide input into the portfolio management process.

In addition, there must be periodic regulatory review of the portfolio management process. Successful portfolio management requires regulatory guidance and oversight on an on-going basis. This requires that regulators periodically review and assess the decisions and the actions of the portfolio managers. The utilities should have no reason to fear such periodic ex post reviews if they have adequately documented their capacity acquisition and investment decisions and the utilities' actions can be shown to have provided benefits to ratepayers and society that exceed their costs. Even in pre-approval regimes, the implementation of the process must still be monitored by the Commission, if only to identify needed changes in policy.

Consequently, the Commission should implement a periodic gas integrated resource process with the goal of assisting the utilities in developing optimal mixes of supply and demand resources, instead of adopting the pre-approval processes proposed by the gas utilities. The utilities would have some flexibility in implementing the resulting resources plans and there could, in certain circumstances, be limited pre-approval of a range of short-term capacity acquisitions. This could encourage the gas utilities to take advantage of acquiring capacity resources in those situations in which quick action is required.

This periodic gas integrated resource process could be coordinated with the Gas Reports filed by the utilities every few years and the periodic gas infrastructure reviews.

Comment No. 7: Conservation and renewable energy should be the cornerstone of California's plan for meeting future natural gas needs.

The State's Energy Action Plan was adopted last May by the CPUC, the California Energy Commission and the California Power Authority with the overall goal of ensuring that adequate, reliable, and reasonably priced electricity and natural gas supplies are achieved and provided through policies, strategies and actions that are cost-effective and environmentally sound for California's consumers and taxpayers.[27]

The Energy Action Plan envisions a loading order of resources in which the first priority is given to optimizing strategies for energy conservation and efficiency. However, the OIR and Phase 1 proposals focus exclusively on actions to increase supplies rather than incorporating those actions into an integrated plan that first reduces the state's demand for natural gas. This emphasis on supply side solutions is significant because it could cause the Commission to lose sight of the ways in which the demand for natural gas, and, hence, the supplies that are needed in future years, can be dramatically reduced.

Assessments by the California Energy Commission and other responsible organizations have identified a number of policies, strategies and actions that the Commission should require be implemented before it grants the fundamental changes in traditional regulatory oversight of natural gas capacity acquisition and investments decisions that the natural gas utilities are requesting in their Phase 1 Proposals. These policies, strategies and actions are discussed in the various assessments cited in Comment Number 8 and Comment Number 10 in this Report.

Comment No. 8: The demand for natural gas can be significantly reduced through the implementation of more extensive electric energy efficiency programs and the acceleration of the state's Renewable Portfolio Standard from 2017 to 2010.

Electric generation currently represents about 37 percent of the natural gas consumed in California each year. The Staff of the California Energy Commission has estimated that the gas demand for electricity will grow from 0.80 Tcf in 2003 to 0.93 Tcf in 2013, an annual growth of 1.5 percent per year.[28] However, analyses by the Energy Commission Staff show that this growth can be reduced or even reversed if achievable electric energy efficiency goals are adopted and met and the achievement of the 20 percent goal for the

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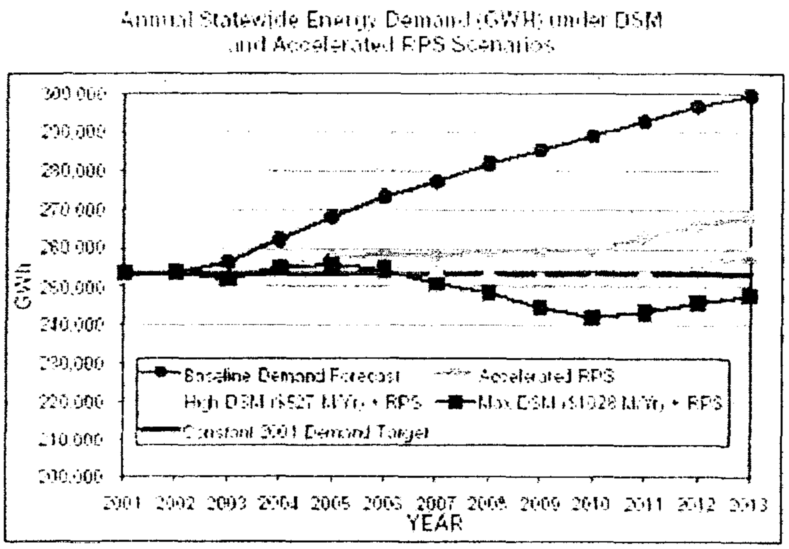
27 *Energy Action Plan Legislative Report*, dated January 5, 2004.

28 *Natural Gas Market Assessment*, California Energy Commission Staff Paper, August, 2003, at page 14.

state's renewable energy portfolio standard is accelerated to 2010 from the current goal of 2017.

Figure 1[29]



For example, the Energy Commission staff has recommended that the CPUC and the CEC set energy efficiency savings goals for the efficiency programs funded by the public goods charges and supplemental procurement programs. These goals are 7,000 GWh per year of savings from all energy efficiency programs by 2006, 13,000 GWh by 2008, and 30,000 GWh by 2013.[30]

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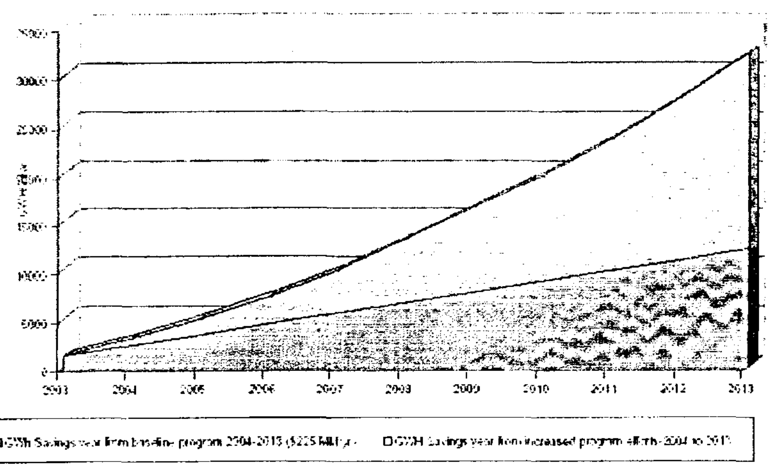
29 *Public Interest Energy Strategies Report*, California Energy Commission Report, December 2003, at page 11.

30 *Proposed Energy Savings Goals for Energy Efficiency Programs in California*, California Energy Commission Staff Report, dated October 27, 2003, at page 1.

Figure 2[31]

Long Term Electricity Savings Goal for Energy Efficiency Programs



Meeting these goals would provide an additional 20,000 GWh of savings by 2013 (over the Energy Commission's base case forecasts) and would be equivalent to roughly 50 percent of the projected increase in electricity usage in the state over the next decade.[32]

A 2002 study on "California's Secret Energy Surplus, the Potential for Energy Efficiency," similarly concluded that over the next decade there is a significant remaining achievable and cost-effective potential for energy-efficiency savings in California, beyond the Business-as-Usual savings that are likely to occur under continuation of current public goods funding levels.[33] However, this study found that even higher levels of potential savings from energy efficiency than the CEC staff has recommended. In fact, Xenergy concluded that 40,146 GWh of electricity could be saved each year by 2011 through the implementation technically achievable and economic measures.[34] This would be more than 10,000 GWh above the goals proposed by the Energy Commission Staff.

Additional energy also will be saved over the next decade as a result of the recently adopted 2005 building standards. These standards provide a 10 percent improvement over the 2001 standard and include efficiency requirements for outdoor lighting, a first in the nation according to the January 2004 Energy Action Plan Legislative Report. These standards apply to all new construction and some commercial and residential remodels.

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31 Figure 7 in *Proposed Energy Savings Goals for Energy Efficiency Programs in California*, California Energy Commission Staff Report, dated October 27, 2003, at page 27.

32 The Energy Commission staff also found that additional savings could be achieved through improved building and appliance standards. Ibid, at footnote no. 1 on page 1.

33 *California's Secret Energy Surplus, the Potential for Energy Efficiency*, Xenergy, Inc., September 2002, at page 4-1.

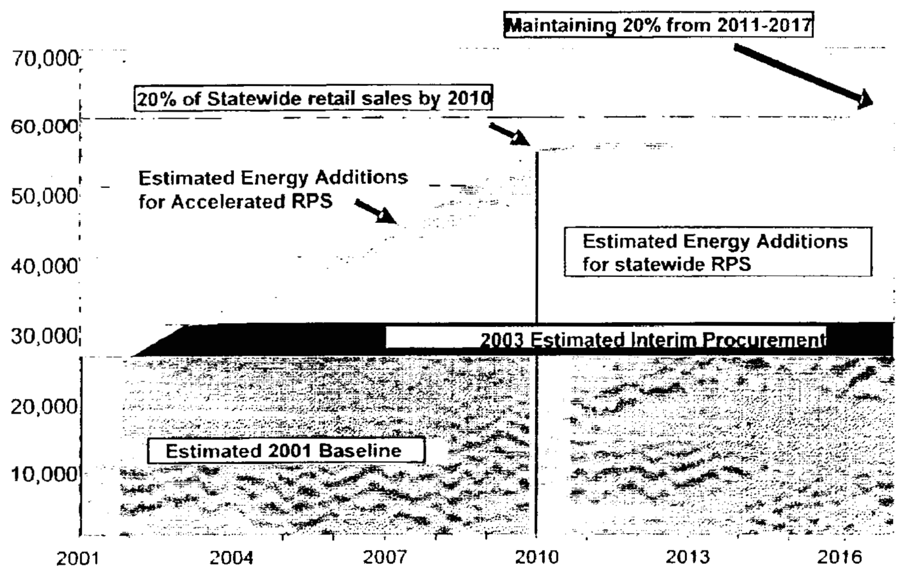
34 Ibid, at page 3-3.

They are expected to produce annual electricity savings of 1,800 MW and 4,750 GWh by 2016.[35]

Improved appliance standards also are expected to provide significant savings but these savings have not been quantified.

The Energy Commission Staff also has concluded that the remaining incremental system GWh needs in 2013, over the base demand in 2003, could be met through aggressive pursuit of the states Renewable Portfolio Standard for renewable generation plants.[36] For example, a Renewable Resources Development Report prepared by the CEC Staff found that accelerating the state's RPS to 20% by 2010 could produce 55,170 GWh of electricity from renewable energy sources by 2010.[37]

Figure 3[38]
Accelerating the Renewable Portfolio Standard to 2010



The Renewable Resources Development Report found that there are plenty of renewable energy resources in California to meet the current Renewable Portfolio Standard and the

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35 *Energy Action Plan Legislative Report*, dated January 5, 2004, at page 1.

36 *Proposed Energy Savings Goals for Energy Efficiency Programs in California*, California Energy Commission Staff Report, dated October 27, 2003,at page 32.

37 *Renewable Resources Development Report*, , a Presentation by Ann Peterson, Project Manager, at the California Energy Commission Business Meeting, November 19, 2003.

38 *Renewable Resources Development Report*, a Presentation by Ann Peterson, Project Manager, at the California Energy Commission Business Meeting, November 19, 2003.

accelerated Renewable Portfolio Standard.[39] It also found that there are significant untapped renewable resources both in California and the other WECC states.

The November 2003 CEC Renewable Resources Development Report also emphasized that accelerating California's RPS was part of the integrated strategy identified in the state's Energy Action Plan to maintain fuel diversity in electric generation by:

- Reducing demand for electricity, especially during peak hours
- Accelerating development of renewable energy
- Replacing/repowering inefficient gas-fired generation.

Achieving the energy efficiency goals recommended by the Energy Commission staff and accelerating the RPS to 2010 could reduce electric energy usage in California in 2013 by an additional 25,000 GWh over base case Energy Commission Staff forecasts. This would reflect an additional 20,000 GWh of savings from increased energy efficiency program expenditures,[40] 3,000 to 4,000 GWh of additional savings from the 2005 building standards, and 1,000 to 2,000 GWh from the acceleration of the state's Renewable Portfolio Standard to 2010. Achieving these goals also would reduce the amount of natural gas used to generate electricity by approximately 155 Bcf per year.[41]

Some of this reduced gas usage would occur at power plants outside California, but it is not possible to determine how much without running a simulation of the integrated WECC system. But if even only half of the savings were to be from the displacement of generation at plants in California, the achievement of these savings would offset a significant portion of the 130 Bcf that the Energy Commission Staff has assumed the annual natural gas demand for electric generation will grow between 2003 and 2013. In addition, reduced natural gas use at power plants in other WECC states, due to energy efficiency programs in California and in-state generation by renewable sources, also would free up additional natural gas supplies that could be available for other uses in California.

Comment No. 9: Future natural gas demand also can be reduced significantly by the repowering or retirement of California's aging power plants.

There are approximately 16,600 MW of generating capacity at older natural-gas fired steam generating plants in California.[42] These units are generally more than 30 to 40

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39 Ibid.

40 *Proposed Energy Savings Goals for Energy Efficiency Programs in California*, California Energy Commission Staff Report, dated October 27, 2003,at page 35.

41 This estimate makes the conservative assumption that only 90 percent of the electricity that would be displaced by the increased energy efficiency and renewable energy output would have been generated at natural gas-fired plants. Synapse modeling and estimates from the California Energy Commission suggest that this figure might be between 95 and 100 percent.

42 *Aging Natural Gas Power Plants in California*, California Energy Commission Staff Paper, July 2003.

years old, having been built in the 1950s, 1960s or early 1970s. All of these units have heat rates of 9,000 BTU/KWh or higher. Most have heat rates above 10,000 BTU/KWh.

These older, inefficient plants generated 60,961,190 MWh of electricity in 2001 and consumed approximately 593,420 Mcf of natural gas. As shown in Table 1 below, repowering just the older non-peaking plants in California with newer, combined cycle technology, with heat rates of approximately 7,000 BTU/KWh would save approximately 174 Bcf of natural gas each year. Retiring these aging power plants and replacing their generation with production by newer facilities at more remote sites would save slightly less natural gas due to transmission line losses.

Table 1
Potential Gas Savings from Repowering Aging Power Plants

	2001							After Repowering			
Plant Name	MW	2001 Capacity Factor (percent)	2001 Generation (MWh)	Approx. Heat Rate (BTU/KWh)	BTUs gas/year	Gas Heat Content (BTU/cf)	Unit 2001 Gas Use MMcf/year	Repowered Heat Rate (BTU/KWh)	Repowered BTUs gas/year	Repowered Unit Gas Use MMcf/year	Change from 2001 Gas Use (MMcf/year)
Moss Landing											
Units 6,7	1485	65	8,455,590	9000	7.61003E+13	1019	74,681	7000	5.9189E+13	58,086	-16,596
Alamitos											
Units 1,2	348	13	396,302	13000	5.15193E+12	1019	5,056	7000	2.7741E+12	2,722	-2,333
Units 3,4	642	46	2,587,003	11000	2.8457E+13	1019	27,926	7000	1.8109E+13	17,771	-10,155
Units 5,6	963	58	4,892,810	10000	4.89281E+13	1019	48,016	7000	3.425E+13	33,611	-14,405
Haynes											
Units 1,2	444	33	1,283,515	10000	1.28352E+13	1019	12,596	7000	8.9846E+12	8,817	-3,779
Units 3,4	444	17	661,205	10000	6.61205E+12	1019	6,489	7000	4.6284E+12	4,542	-1,947
Units 5,6	682	25	1,493,580	10000	1.49358E+13	1019	14,657	7000	1.0455E+13	10,260	-4,397
Ormand Beach											
Units 1,2	1492	42	5,489,366	10000	5.48937E+13	1019	53,870	7000	3.8426E+13	37,709	-16,161
Pittsburg power											
Units 5,6	632	60	3,321,792	10000	3.32179E+13	1019	32,599	7000	2.3253E+13	22,819	-9,780
Units 7	700	56	3,433,920	10000	3.43392E+13	1019	33,699	7000	2.4037E+13	23,589	-10,110
Redondo Beach											
Units 5,6	350	17	521,220	13000	6.77586E+12	1019	6,650	7000	3.6485E+12	3,581	-3,069
Units 7,8	967	44	3,727,205	10000	3.7272E+13	1019	36,577	7000	2.609E+13	25,604	-10,973
Morro Bay											
Units 1,2	342	30	898,776	11000	9.88654E+12	1019	9,702	7000	6.2914E+12	6,174	-3,528
Units 3,4	679	55	3,271,422	10000	3.27142E+13	1019	32,104	7000	2.29E+13	22,473	-9,631
Encina											
Units 1,2,3	320	40	1,121,280	11000	1.23341E+13	1019	12,104	7000	7.849E+12	7,703	-4,401
Units 4,5	635	44	2,447,544	11000	2.6923E+13	1019	26,421	7000	1.7133E+13	16,813	-9,608
Huntington Beach											
Units 1,2	430	37	1,393,716	9000	1.25434E+13	1019	12,310	7000	9.756E+12	9,574	-2,735
Scattergood											
Units 1,2	358	28	878,102	10000	8.78102E+12	1019	8,617	7000	6.1467E+12	6,032	-2,585
Units 3	445	25	974,550	10000	9.7455E+12	1019	9,564	7000	6.8219E+12	6,695	-2,869
Etiwanda											
Units 3,4	640	26	1,457,664	9000	1.3119E+13	1019	12,874	7000	1.0204E+13	10,013	-2,861
El Segundo											
Units 3,4	708	37	2,294,770	10000	2.29477E+13	1019	22,520	7000	1.6063E+13	15,764	-6,756
Contra Costa											
Unit 6	336	63	1,854,317	10000	1.85432E+13	1019	18,197	7000	1.298E+13	12,738	-5,459
Unit 7	336	52	1,530,547	10000	1.53055E+13	1019	15,020	7000	1.0714E+13	10,514	-4,506
South Bay											
Units 1,2	297	43	1,118,740	10000	1.11874E+13	1019	10,979	7000	7.8312E+12	7,685	-3,294
Unit 3	176	33	508,781	10000	5.08781E+12	1019	4,993	7000	3.5615E+12	3,495	-1,498
Unit 4	170	12	178,704	12000	2.14445E+12	1019	2,104	7000	1.2509E+12	1,228	-877
Coolwater											
Unit 1	65	43	244,842	10000	2.44842E+12	1019	2,403	7000	1.7139E+12	1,682	-721
Unit 2	82	57	409,442	10000	4.09442E+12	1019	4,018	7000	2.8661E+12	2,813	-1,205
Units 3,4	482	53	2,237,830	9000	2.01405E+13	1019	19,765	7000	1.5665E+13	15,373	-4,392
Mandalay											
Units 1,2	433	45	1,706,886	9000	1.5362E+13	1019	15,076	7000	1.1948E+13	11,725	-3,350
Valley											
Units 1,2	190	0	0	12000	0	1019	0	7000	0	0	0
Units 3,4	323	6	169,769	11000	1.86746E+12	1019	1,833	7000	1.1884E+12	1,166	-666
Total	16,596		60,961,190				593,420			418,772	-174,648

These aging power plants probably can be expected to generate less electricity in the future than they did in 2001 as a result of expanded energy efficiency programs and increased output from renewable energy sources and new more-efficient gas-fired units. In addition, some generation from more efficient gas-fired units located outside California also can probably be expected to displace some of the electricity that would otherwise be generated by these aging plants. However, some of the aging units in California are located within transmission constrained areas and, depending on transmission system improvements, can be expected to continue to generate significant amounts of electricity. Consequently, repowering/replacement of aging facilities remains a strategy that has the potential to save significant amounts of natural gas.

There also are other significant benefits from the repowering of aging power plants such as reduced fuel and operating costs and lower NO_x emissions. Water usage also would be dramatically reduced if the repowering is accompanying by conversion from a once-through to a closed-cycle cooling system.

Comment No. 10: There is a significant potential for reducing both core and non-core natural gas demand.

The California Energy Commission's Demand Analysis Office forecasts that the core natural gas demand will increase from 0.66 Tcf to 0.73 Tcf between 2003 and 2013, yielding an annual growth rate of 0.9 percent.[43] Non-core natural gas demand is expected to increase from 0.74 Tcf to 0.77 Tcf during the same period, which is an annual growth rate of only 0.4 percent.[44]

Viewed in terms of end-use consumption by different classes of customers, these forecasts reflect that the residential and commercial sectors' demand for natural gas is expected to grow at approximately one per cent per year.[45] The industrial demand growth is expected to be essentially flat, growing at 0.1 percent per year.

These forecasts assume that the 2003 levels of funding for utility energy efficiency programs will continue through 2011.[46] However, there appears to be widespread agreement among groups as diverse as Sempra Energy, the National Petroleum Council, the American Council for an Energy-Efficient Economy ("ACEEE"), and the Center for Energy Efficiency and Renewable Technologies that increased spending on efficiency programs can lead to significant reductions in natural gas demands.

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43 *Natural Gas Market Assessment*, California Energy Commission Staff Paper, August, 2003, at page 14.

44 Ibid.

45 *Natural Gas Market Assessment*, California Energy Commission Staff Paper, August, 2003, at page ii.

46 *Natural Gas Market Assessment*, California Energy Commission Staff Paper, August, 2003, at page 14.

For example, the National Petroleum Council has concluded that "greater energy efficiency and conservation are vital near-term and long-term mechanisms for moderating price levels and reducing volatility."[47]

A recent study by ACEEE has estimated that energy efficiency and conservation programs could reduce the residential and commercial use of natural gas in California by 4.8 percent by 2008.[48] Industrial use of natural gas could be reduced by 5.2 percent by 2008.[49] Achieving these reductions would save approximately 70 Bcf per year in total core and non-core demand in 2008 and 73 Bcf in 2013.

Unfortunately, there do not appear to be any comprehensive California-specific studies of the potential for reducing natural gas demand through efficiency programs. Nevertheless, California's gas utilities have themselves emphasized the potential savings from energy efficiency programs. For example, SoCalGas and SDG&E, have recently reported that:

- The current SoCalGas energy efficiency programs have been very effective, consistently exceeded goals and averaging over 1 Bcf per year in reductions.
- SoCalGas's core gas sales per capita decreased from about 193 therms in 1994 to approximately 175 therms in 2001.
- Customer response indicates that the demand for natural gas programs continues to exceed the current funding levels, which have remained constant for the past five years.
- Energy efficiency options are more cost effective because of higher gas commodity costs.[50]

PG&E has similarly reported that the potential for saving natural gas "remains high."[51] In fact, according to PG&E, almost 250 million therms (i.e., approximately 25 Bcf) of natural gas could potentially be saved by increased energy efficiency programs in the residential sector.[52] One hundred and ninety three million therms of natural gas (approximately 19 Bcf) could potentially be saved by increased energy efficiency programs in the commercial sector.[53] Approximately 200 million therms of natural gas

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47 *Balancing Natural Gas Policy – Fueling the Demands of a Growing Economy, Volume I, Summary of Comments and Recommendations*, A Report of the National Petroleum Council, September 25, 2003, at page 21.

48 *Natural Gas Price Effects of Energy Efficiency and Renewable Energy Practices and Policies*, ACEEE, December 2003, at page 17.

49 Ibid, at page 22.

50 *Demand* Reduction, a presentation by Geoffrey Ayres, Director Commercial/Industrial Markets, SoCalGas, SDG&E, as part of Panel II. A. - Demand Reduction at the December 9 and 10, 2003 Natural Gas Workshop.

51 *Demand Reduction Efforts*, a presentation by Dave Hickman, PG&E Manager, Customer Energy Management, as part of Panel II. A. - Demand Reduction at the December 9 and 10, 2003 Natural Gas Workshop.

52 Ibid.

53 Ibid.

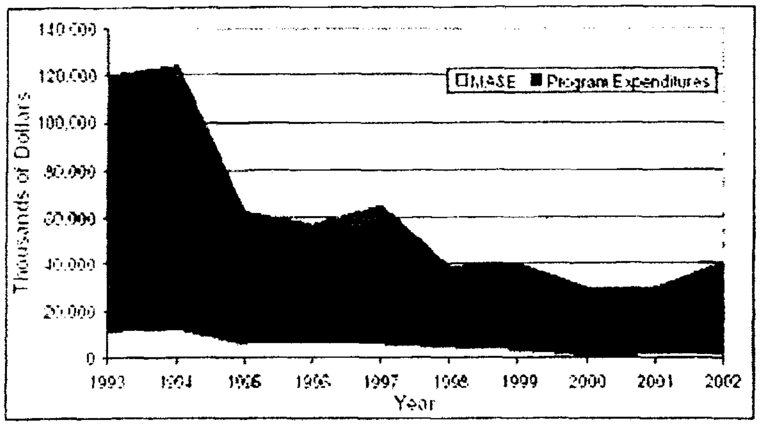
(i.e., 20 Bcf) could be saved in the residential and commercial sectors by just a doubling of the low energy efficiency funding levels of the mid-1990s.

The recently adopted 2005 building standards are expected to save 88 million therms (approximately 8 to 9 Bcf) of natural gas per year by 2016.[54]

Unfortunately, as shown in the following chart from the California Energy Commission, spending on gas efficiency programs has been dramatically reduced since the early 1990s.

Figure 4[55]

Natural Gas Efficiency Program and Evaluation Expenditure Trends



Annual spending on natural gas efficiency programs and evaluation has declined over the past decade.
Source: California Energy Commission and Xenergy

It appears clear that increased spending on energy efficiency programs has the potential to offset much, if not all, of the projected growth in core and non-core natural gas consumption. The Commission should adopt policies to spur the development and effective implementation of these programs.

By way of contrast, SDG&E and SoCalGas have assumed only relatively minor reductions in natural gas consumption in the forecasts that they have provided in response to Question 1 in OIR R.04-01-025. SDG&E assumed that for the period 2004-2006, the impact of energy efficiency programs would be a reduction in residential gas consumption of roughly 1.8 million therms. For the period 2007-2016, there was an assumed additional reduction of roughly 2.3 million therms.[56] These appear to be reductions of less than one percent of SDG&E's projected average year core gas demand in 2006 and 2016. These reductions are even smaller percentages of the utility's projected 2006 and 2016 core demands in the colder than average year scenarios.

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[54] *Energy Action Plan Legislative Report*, dated January 5, 2004, at page 1.

[55] *Public Interest Energy Strategies Report*, California Energy Commission, December 2003, at page 37.

[56] SDG&E response to Question 1 in RACE's First Data Request.

In its response to Question 1 in OIR R.04-01-025, SoCalGas assumed reductions in core residential, commercial and industrial natural gas consumption of 2.244 Bcf in 2006 and 2.153 Bcf in 2016.[57] These also appear to be reductions of less than one percent of SoCalGas's projected average year core gas demand in 2006 and 2016. As with SDG&E, these reductions are even smaller percentages of SoCalGas's projected 2006 and 2016 core demands in the colder than average year scenarios.

Comment No. 11: PG&E's proposal that ratepayers continue to pay for existing facilities that are used less due to the addition of new supply sources or system capacity is contrary to established regulatory policy.

PG&E has proposed that it "not be penalized" if the addition of new supply or capacity results in some existing PG&E transmission or storage capacity being used less.[58] However, used and useful disallowances are a long standing traditional rate making principle. If the new supply or capacity results in lower cost service, but idles some existing capacity on a permanent basis, there should be some risk to the utility. It is established utility law that rates should provide an opportunity (not a guarantee) for a utility to earn a reasonable return on its investments, but only those investments used and useful for the provision of utility service. Where a resource is obsolete and not used and useful, the resource is, in general, removed from rate base (along with any corresponding reduction in the reserve for depreciation) and from current expenses.

If changing market circumstances that could not have been foreseen lead to the resource becoming not used and useful, despite prudent and economical management, a sharing of the costs that are not used and useful may be considered. One common way to do this, when sharing is deemed appropriate, is to allow recovery of the remaining investments over a reasonable period, say ten years, but without any return on the unamortized balance. At normal rates of return, this amounts to approximately a 50-50 sharing of the remaining investment in present value terms.

57 SoCalGas response to Question 1 in RACE's First Data Request.

58 *Phase I Proposals and Data Response of Respondent Pacific Gas and Electric Company*, dated February 24, 2004, at page 17.

Exhibit 6

Thomas O. Spicer, III, PhD, PE
Consulting Chemical Engineer
3335 Kendall Drive
Fayetteville, AR 72704

18 December 2004

Ms. Alicia I. Finigan
Environmental Defense Center
906 Garden Street
Santa Barbara, California 93110

RE: Review of Draft Environmental Impact Statement/Environmental Impact Report (EIS/EIR) for Cabrillo Port Liquefied Natural Gas (LNG) Deepwater Port (DWP)

Dear Ms. Finigan:

Per our agreement, I have reviewed the above captioned report particularly Section 4.2 Public Safety: Hazards and Risk Analysis and its discussion of thermal radiation and vapor dispersion hazards. This section summarizes assessment of the worst-case consequences associated with the proposed project and identifies objectives of the assessment process as (quoting from the report page 4.2-1):

- identify and evaluate potential hazards;
- define scenarios to bracket the range of potential accidents (resulting either from operations or terrorist attacks);
- use state of the art computer models to define the consequences for each scenario (including the worst-case scenario);
- compare the results to existing safety thresholds and other criteria; and
- make the results available to decision makers and the public, while also ensuring that release of relevant information does not in turn create a security threat.

This process has been conducted on the basis of an Independent Risk Assessment involving a team of experts commissioned to prepare a site-specific evaluation of the project. The Draft EIS/EIR summarizes the results of the Independent Risk Assessment but concludes that it contains sensitive security information which cannot be made available to the general public.

The Draft EIS/EIR bases its evaluation of the thermal and vapor dispersion hazards on several assumptions summarized in the report (page 4.2-19) including:

- High natural gas methane content.
- Wind profile is based on atmospheric stability class D.
- Wind speed at 33 feet (10 m) height above sea level is 13.4 mph (6 m/s)
- LNG is released instantaneously.

- Once spilled onto water, the LNG pool does not begin to evaporate "until the pool formed by a release has dispersed to a considerable distance. This assumption, coupled with the wind profile and speeds, is used to produce a conservative estimate (larger distance downwind potentially impacted by the release, which would be expected during a marine inversion) for horizontal dispersion of the LNG and the resulting natural gas cloud." (page 4.2-6)
- Each FSRU Moss storage tank contains 24 million gallons (91,000 m^3) of LNG.

Other assumptions would have been made as part of the assessment process, but such assumptions are apparently available only in the Independent Risk Assessment (such as the ambient humidity). In addition to these assumptions, the Draft EIS/EIR indicates the use of the Fire Dynamics Simulator (FDS) for the consequence estimates. Finally, the Draft EIS/EIR assigns a thermal radiation level (12.5 kW/m^2) and a natural gas vapor concentration level (equal to the lower flammable limit, LFL, for methane of 5%). In assessing the thermal radiation hazard, the Draft EIS/EIR seems to assume that an ignition source will become available only after the natural gas cloud has reached its maximum extent to the 5% level. From this analysis, the Draft EIS/EIR reports distances for three cases:

- Worst-Case Credible Release #1 (WC #1). Release of 50,000 m^3 LNG (one-half of one full tank) though a wall surface opening of 12.5%. The hazard distance was reported to be 2.0 km.
- Worst-Case Credible Release #2 (WC #2). Release of 100,000 m^3 LNG (one full tank) though a wall surface opening of 20 m^2. The hazard distance was reported to be 1.8 km.
- Terrorist Attack A (TA-A). Release of 300,000 m^3 LNG (three full tanks) instantaneously. The hazard distance was reported to be 2.6 km.

For all of these scenarios, the report indicates that the distances exceed the 500 m safety zone but are less than the Applicant's proposed 2 NM (3.7 km) designated Area to be Avoided.

There are several aspects of the analysis in the Draft EIS/EIR that may work to significantly underestimate these hazard distances.

The analysis in the Draft EIS/EIR is based on a computer model which has not been *verified or validated for this application.* Although the Fire Dynamics Simulator (FDS) is a sophisticated computer model which has been studied with regard to simulation of fires, its stated intended purposes include:

- Low speed transport of heat and combustion products from fire
- radiative and convective heat transfer between the gas and solid surfaces

- Pyrolysis
- Flame spread and fire growth
- Sprinkler and heat detector activation
- Sprinkler sprays and suppression by water

from page 6 of "Fire Dynamics Simulator (Version 4) Technical Reference Guide," NIST Special Publication 1018, Kevin McGrattan, editor. Specifically, FDS has not been verified for the purpose of predicting the dispersion of LNG vapor. It is well established that denser-than-air gases such as LNG vapor behave according to different physical rules than are used in FDS. Furthermore, FDS has not been validated against the extensive available data pertaining to the dispersion of denser-than-air contaminants such as LNG vapor.

The assumptions used to model the consequences in the Draft EIS/EIR are not conservative as presumed in the report. Although the Draft EIS/EIR reassures the reader that the assumptions made in the hazard assessment are conservative, there is no documentation of this assertion. Furthermore, whether some of the assumptions are conservative or not may be based on the choice of the FDS to model the LNG vapor dispersion. Based on my experience, the following assumptions are questionable:

- Wind speed and atmospheric stability of 6 m/s and D stability give longer downwind distances that 2 m/s and F stability. This assertion would not be valid for models specified in federal regulations for determination of the vapor dispersion hazards of LNG.
- LNG does not evaporate as it spreads. In addition to this assumption being vague, it is physically impossible, computationally unnecessary, and very questionable as to whether it is even conservative in the sense used in the report.

In addition to these assumptions about the model inputs, the Draft EIS/EIR makes assumptions about the criteria used to determine the hazard distance which are inconsistent with other standards and regulations. The Executive Summary lists 49 CFR 193 as part of the "Key Elements and Thresholds" used in preparation of the report (page ES-15) and states that 49 CFR 193 "mandates compliance with American National Standards Institute/National Fire Protection Association (ANSI/NFPA) 59A, Standard for the Production, Storage, and Handling of Liquefied Natural Gas (LNG)." For on-shore facilities, 49 CFR 193 and NFPA 59A require the determination of exclusion zones for thermal hazard distances be based on thermal radiation levels of 5 kW/m^2. In a report prepared for the Federal Energy Regulatory Commission (FERC), ABS Consulting reports that the thermal radiation level of 5 kW/m^2 would be expected to produce second degree burns after 30 s exposure and third-degree burns (1% fatality) after 50 s exposure. For on-shore facilities, 49 CFR 193 and NFPA 59A also require the determination of exclusion zones for vapor hazard distances be based in LNG vapor concentrations of 2.5%

(LFL/2). Since the Draft EIS/EIR uses higher thermal radiation and concentration levels to determine the hazards, its consequence assessments are not conservative.

More appropriate models are available to predict the thermal and vapor cloud hazards than were used in the Draft EIS/EIR. There are models available which take into account the appropriate physical principles that govern the dispersion of denser-than-air gases such as LNG vapor and are referenced in 49 CFR 193 and NFPA 59A. Such modeling questions have been recently revisited by FERC. Under contract number FERC 04C40196, ABS Consulting summarized methods for determining thermal radiation and vapor dispersion hazards for LNG spills on water. The pertinent reports from this work are "Consequence Assessment Methods for Incidents Involving Releases from Liquefied Natural Gas Carriers" (dated 13 May 2004) and "Notice of Availability of Detailed Computations for the Consequence Assessment Methods for Incidents Involving Releases from Liquefied Natural Gas Carriers" (dated 29 June 2004) as part of FERC Docket No. AD-04-6-0000. Notwithstanding my concerns about the validity of the meteorological conditions of 6 m/s and D stability as representing the worst case conditions, I prepared estimates of the two worst case scenarios using the methods prescribed by the FERC report as summarized in the Table below (using the 6 m/s wind speed and D stability).

Worst-Case Credible Releases
Hazard Distances from FSRU

	Case 1	Case 2
Thermal radiation hazard distance	2.3 km	2.6 km
Vapor dispersion hazard distance	9.4 km	11.9 km

These hazard distances exceed the 500 m safety zone radius around the FSRU as well as the Applicant's proposed Area to be Avoided of 2 NM (3.7 km). I did not make calculations for scenario TA-A because I do not believe that the instantaneous release of the contents of all three tanks while fully loaded is a credible event (also the position stated in the Draft EIS/EIR. However, I do believe that the instantaneous release of the contents of two tanks while fully loaded should be considered. Such a scenario could occur because of a fire from either of the worst case scenarios discussed in the Draft EIS/EIR. If such a fire were to occur and not be controlled, the fire could compromise the insulation systems on the remaining two tanks thereby threatening their integrity. Such a potential hazard does not seem to be addressed in the Draft EIS/EIR.

In summary, the Draft EIS/EIR was prepared to address the objectives quoted at the beginning of this letter. I believe the report fails to meet the stated objectives in several very important ways with regard to thermal radiation and vapor dispersion hazards.

Sincerely,

T. Spicer

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Professor, Department of Chemical Engineering, University of Arkansas, 1996 to present
Consulting Chemical Engineer, clients including American Petroleum Institute, Dow, Exxon, Mitsubishi Heavy Industries, TNO, U.S. Environmental Protection Agency, U.S. Department of Justice, U.S. National Oceanic and Atmospheric Administration, and others, 1985 to present
Interim Department Head, Department of Chemical Engineering, University of Arkansas, July 2001 to October 2003
Associate Professor, Department of Chemical Engineering, University of Arkansas, 1988-96
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American Institute of Chemical Engineers
American Society of Engineering Education
Omega Chi Epsilon
National Fire Protection Association
Registered Professional Engineer - Arkansas
Sigma Xi
Tau Beta Pi

SERVICE

American Institute of Chemical Engineers (AIChE) Student Chapter Faculty Co-Sponsor, 2001 to present
ASEE Midwest Section Bylaws Committee, 1991 to 1992

ASEE Midwest Section Meeting Paper Committee, 1992
Chemical Engineering Computing Facility and Use Committee, 1988 to 1990
Chemical Engineering Graduate Studies Committee, 1992 to present
College of Engineering Academic Ethics Board, 1993-1995 and 1997 to 2002
College of Engineering Faculty Computer Committee, 2000 to present
Habitat for Humanity, Site Selection and Building Committees; Board of Directors
Safety and Chemical Engineering Education (SACHE) of Center for Chemical Process Safety (CCPS) of the American Institute of Chemical Engineers (AIChE), 2001 to present

PROFESSIONAL ACTIVITIES

Refereed Journal Articles

1. Spicer, T.O., and J.A. Havens, "Modeling the Phase I Thorney Island Experiments," *Journal of Hazardous Materials*, June 1985.
2. Havens, J.A., P.J. Schreurs, and T.O. Spicer, "Analysis and Simulation of Thorney Island Trial 34," *Journal of Hazardous Materials*, November 1987.
3. Spicer, T.O., and J.A. Havens, "Field Test Validation of the DEGADIS Model," *Journal of Hazardous Materials*, November 1987.
4. Hanna, S., P. Chatwin, E. Chikhliwala, R. Londergan, T. Spicer, and J. Weil, "Results from the Model Evaluation Panel," *Plant/Operations Progress*, Vol. 11, No.1, January 1992.
5. Havens, J., H. Walker, and T.O. Spicer, "Wind-Tunnel Data Sets for Complex Dispersion Model Evaluation," *Journal of Loss Prevention in the Process Industries*, Vol.7, No.2, 1994.
6. Baik, J.H., H. Walker, T.O. Spicer, and J. Havens, "Measurement of Low Velocities in CO_2/Air Mixtures Using Hot-Wire/Film Anemometry," *Process Safety and Environmental Protection: Transactions of the Institution of Chemical Engineers Part B*, Vol. 74, May 1996.
7. Spicer, T.O., J.H. Baik, and J. Havens, "Molecular Diffusion Effects on Entrainment in Wind Tunnel Studies of Dense Gas Dispersion," *Process Safety and Environmental Protection: Transactions of the Institution of Chemical Engineers Part B*, Vol. 74, August 1996.
8. Spicer, T.O., and J. Havens, "Application of Dispersion Models to Flammable Cloud Analyses," *Journal of Hazardous Materials*, Vol. 49, 1996.
9. Havens, J., H. Walker, and T.O. Spicer, "Wind tunnel study of air entrainment into two-dimensional dense gas plumes at the Chemical Hazards Research Center", *Atmospheric Environment*, Vol. 35, 2001.

Other Journal Publications

1. Havens, J., and T.O. Spicer, "Software Review - TECJET: An Atmospheric Dispersion Model," *Risk Analysis*, Vol. 10, No. 3, 1990.
2. Havens, J., and T. Spicer, "Book Reviews: Estimating the Flammable Mass of a Vapor Cloud," *Process Safety and Environmental Protection: Transactions of the Institution of Chemical Engineers Part B*, Vol. 79, January 2001.
3. Spicer, T., "Letter to the Editor," Chemical Engineering Education, Vol. 35(2), Spring 2001.
4. Havens, J., T. Spicer, and K. Perry, "New Models Predict Consequences of LNG Releases," Gas Technology Institute and U.S. Department of Energy Gas TIPS, Fall 2002.

Symposium Proceedings

1. Havens, J.A., and T.O. Spicer, "Further Analysis of Catastrophic LNG Spill Vapor Dispersion," *Heavy Gas and Risk Assessment--II*, S. Hartwig (ed.), 1983.
2. Havens, J.A., and T.O. Spicer, "Gravity Spreading and Air Entrainment by Heavy Gases Instantaneously Released in a Calm Atmosphere," I.U.T.A.M. Symposium on Atmospheric Dispersion of Heavy Gases and Small Particles, Den Haag, The Netherlands, 1983.
3. Spicer, T.O., and J.A. Havens, "Development of a Heavier-than-Air Gas Dispersion Model for the U.S. Coast Guard Hazard Assessment Computer System," *Heavy Gas and Risk Assessment--III*, S. Hartwig (ed.), 1985.
4. Spicer, T.O., and J.A. Havens, "Application of a Heavy Gas Dispersion Model to the Prediction of Dispersion of Nitrogen Tetroxide," JANNAF Safety and Environmental Protection Subcommittee Meeting, Monterey, CA, 1985.
5. Spicer, T.O., J.A. Havens, P.A. Tebeau, and L.E. Key, "DEGADIS--A Heavier-than-Air Gas Atmospheric Dispersion Model Developed for the U.S. Coast Guard," Air Pollution Control Association Annual Meeting, Minneapolis, MN, 1986.
6. Spicer, T.O., and J.A. Havens, "Gravity Flow and Entrainment by Dense Gases Released Instantaneously into Calm Air," Third International Symposium on Stratified Flows, Pasadena, CA, 1987.
7. Spicer, T.O., J.A. Havens, and L.E. Key, "Evaluation of the DEGADIS Dispersion Model Using Data from Field Releases of Pressurized Ammonia," Air Pollution Control Association Annual Meeting, New York, NY, 1987.
8. Havens, J.A., T.O. Spicer, and P.J. Schreurs, "Evaluation of 3- Dimensional Numerical Atmospheric Dispersion Models," International Conference on Vapor Cloud Modeling, Boston, MA, 1987.
9. Havens, J.A., T.O. Spicer, and D.E. Layland, "A Dispersion Model for Elevated Heavy Gas Jet Releases," International Conference on Vapor Cloud Modeling, Boston, MA, 1987.
10. Spicer, T.O., J.A. Havens, and L.E. Key, "Extension of DEGADIS for Modeling Aerosol Releases," International Conference on Vapor Cloud Modeling, Boston, MA,

1987.

11. Spicer, T.O., J.A. Havens, and L.E. Key, "Uncertainties in the Application of Atmospheric Dispersion Models in the Presence of Jet Releases, Aerosol Releases, or Heterogeneous Surface Roughness," JANNAF Safety and Environmental Protection Subcommittee Meeting, Monterey, CA, 1988.
12. Spicer, T.O., and J. Havens, "Modeling HF and NH_3 Spill Test Data Using DEGADIS," 1988 Summer National Meeting of the American Institute of Chemical Engineers, Denver, CO, 1988.
13. Spicer, T.O., J. Havens, and D. Guinnup, "A Dispersion Model for Gas Pipeline Accidental Releases," 1989 Spring National Meeting, American Institute of Chemical Engineers, April 1989.
14. Havens, J.A., T.O. Spicer, and D. Guinnup, "Extension of the DEGADIS Atmospheric Dispersion Model for Elevated Jet Releases," 6th International Symposium - Loss Prevention and Safety Promotion in the Process Industries, Oslo, Norway, June 1989.
15. Spicer, T.O., and J. Havens, "Modelling Aerosol Dispersion for Accident Consequence Analyses," 1990 American Institute of Chemical Engineers Spring National Meeting, Orlando, FL, 1990.
16. Havens, J., T.O. Spicer, S. Khajehnajafi, and T. Williams, "Developments in Liquefied Natural Gas Dispersion Modeling," International Conference and Workshop on Modeling and Mitigating the Consequences of Accidental Releases of Hazardous Materials, AIChE, New Orleans, LA, May 1991.
17. Touma, J.S., D. Guinnup, and T.O. Spicer, "Development of a Guidance Document for the Application of Refined Dispersion Models for Air Toxics Releases," 85th Annual Meeting of the Air and Waste Management Association , Kansas City, MO, June 1992.
18. Miller, Billy D., and T.O. Spicer, "Spreading And Vaporization of LNG Spills on Land,American Gas Association Distribution Transmission Conference and Exhibit, Orlando, FL, May 1993.
19. Ohba, R., H. Mishima, and T.O. Spicer, "The Calculation of LNG Vapor Dispersion," Japan Society for Aeronautical and Space Sciences (West Branch), Nagasaki, Japan, November 1993.
20. Spicer, T.O., and J. Havens, "Application of Dispersion Models to Flammable Cloud Analyses," 6th Annual Petro-Safe, Houston, February 1995.
21. Havens, J., T.O. Spicer, H. Walker, and T. Williams, "Validation of Mathematical Models for Dense Gas Dispersion in the Presence of Obstacles using Wind-Tunnel Data Sets," 8th International Symposium on Loss Prevention and Safety Promotion in the Process Industries, Antwerp, Belgium, June 1995.
22. Havens, J., T.O. Spicer, H. Walker, and T. Williams, "Regulatory Application of Wind Tunnel Models and Complex Mathematical Models for Simulating Atmospheric Dispersion of LNG Vapor," International Conference and Workshop on Modeling and Mitigating the Consequences of Accidental Releases of Hazardous Materials, New Orleans, September 1995.
23. Havens, J., T.O. Spicer, H. Walker, and S. Wiersma, "The Effects of Structures on Large

LNG Spills," 1998 Process Plant Safety Symposium, October, 1998.

24. Havens, J.A., and T.O. Spicer, "Improvements in Rational Dispersion Modeling for Consequence Assessment," EUROMECH Colloquium 391, Prague, The Czech Republic, September 1999.
25. Spicer, T.O., and J.A. Havens, "Description and Analysis of Atmospheric Dispersion Tests Conducted by EPA at the DOE Hazmat Spills Center," International Conference and Workshop on Modeling and Mitigating the Consequences of Accidental Releases of Hazardous Materials, San Francisco, September 1999.
26. Havens, J.A., and T.O. Spicer, "Improvements in Rational Dispersion Modeling for Consequence Assessment," Mary Kay O'Connor Process Safety Center Symposium, College Station, Texas, October 1999.
27. Havens, J.A., and T.O. Spicer, "Effects of Roughness and Obstacles on Denser-than-Air Gas Cloud Dispersion," International Workshop on Physical Modelling of Flow and Dispersion Phenomenon, Hamburg, Germany, September 2001.
28. Spicer, T., and J. A. Havens, "Modeling Aerosol Rainout," Mary Kay O'Connor Process Safety Center – 2001 Process Plant Safety Symposium, College Station, Texas, October 2001.
29. Havens, J., and T. Spicer, "LNG Shipping Safety and Plant Siting Fundamentals --Post 911 (11 September 2001)," IGT Shipping Symposium, London, England, March 2002.
30. Spicer, T., and J. A. Havens, "Modeling Aerosol Rainout -- Effect of Droplet Mass Transfer," Mary Kay O'Connor Process Safety Center – 2002 Process Plant Safety Symposium, College Station, Texas, October 2002.
31. Havens, J., T. Spicer, and W. Sheppard, "Wind tunnel experiments for LNG terminal siting," in "Proceedings of PHYSMOD2003: International Workshop on Physical Modelling of Flow Dispersion Phenomena," G. Manfrida and D. Contini, eds., Firenze University Press, September 2003.
32. Spicer, T., J. Havens, and D. Johnson, "Modeling the Initial Velocity of Aerosol Jets," Mary Kay O'Connor Process Safety Center – 2003 Process Plant Safety Symposium, College Station, Texas, October 2003.
33. Havens, J., and T. Spicer, "Regulatory Requirements for Safety Exclusion Zones for United States LNG Import Terminals," IGT Shipping Symposium, London, England, April 2004.
34. Spicer, T., and J. Havens, "Modeling the Initial Velocity of Aerosol Jets: Initiating a New Experimental Program for Model Verification," Mary Kay O'Connor Process Safety Center – 2004 Process Plant Safety Symposium, College Station, Texas, October 2004.

Research Reports

1. Havens, J.A., and T.O. Spicer, "Analysis of Nitrogen Tetroxide Releases into the Atmosphere--Consideration of Dense Gas Effects," U.S. Coast Guard, Washington, DC, 1983.

2. Havens, J.A., and T.O. Spicer, "Development of an Atmospheric Dispersion Model for Heavier-than-Air Gas Mixtures," U.S. Coast Guard Report No. CG-D-23-85, Washington, DC, 1985.
3. Spicer, T.O., "Mathematical Modeling and Experimental Investigation of Heavier-than-Air Gas Dispersion in the Atmosphere," Doctoral Dissertation, University of Arkansas, Fayetteville, AR, 1985.
4. Spicer, T.O., and J.A. Havens, "Development of Vapor Dispersion Models for Nonneutrally Buoyant Gas Mixtures--Analysis of USAF/N_2O_4 Test Data," USAF Engineering and Services Laboratory, May 1986.
5. Spicer, T.O., "Using Different Time Averaging Periods in DEGADIS," Exxon Education Foundation, July 1987.
6. Havens, J.A., T.O. Spicer, and P.J. Schreurs, "Evaluation of 3-D Hydrodynamic Computer Models for Prediction of LNG Vapor Dispersion in the Atmosphere," Gas Research Institute Report 5083-252-0788, August 1987.
7. Spicer, T.O., and J.A. Havens, "Development of Vapor Dispersion Models for Nonneutrally Buoyant Gas Mixtures--Analysis of USCG/NH_3 Test Data," USAF Engineering and Services Laboratory, October 1988.
8. Havens, J.A., and T.O. Spicer, "A Dispersion Model for Elevated Dense Gas Jet Chemical Releases," Environmental Protection Agency, 1988.
9. Havens, J.A., and T.O. Spicer, "Review of Phosgene Release Mitigation Methodology and Development of a Mathematical Model for Reactive Spray - Curtain Design," Chemical Manufacturer's Assoc., 1988.
10. Spicer, T.O., and J.A. Havens, "Users Guide for the DEGADIS 2.1 Dense Gas Dispersion Model," Environmental Protection Agency, Report EPA-450/4-89-019, 1989.
11. Spicer, T.O., "Implementation of DEGADIS V2.1 on a Personal Computer," American Petroleum Institute, 1990.
12. Havens, J., and T.O. Spicer, "LNG Vapor Dispersion Prediction with the DEGADIS Dense Gas Dispersion Model," Gas Research Institute Report 89/0242, 1990.
13. Havens, J.A., and T. Spicer, "Feasibility Assessment of a Conjunctive Modeling Approach for LNG Vapor Dispersion Prediction," Gas Research Institute Report, 1991.
14. Havens, J.A., and T.O. Spicer, "Evaluation of Wind Tunnel Simulation and Complex Mathematical Simulation of LNG Vapor Dispersion," Gas Research Institute Topical Report, 1992.
15. Havens, J.A., and T.O. Spicer, "Prediction of LNG Vapor Dispersion with the FEM3A Model for Comparison with Mercure Model Predictions," Gas Research Institute Topical Report, 1992.
16. Havens, J., and T.O. Spicer, "A Comparison/Evaluation of DEGADIS and NOAA-DEGADIS," Report to Environmental Protection Agency, 1992.
17. Spicer, T.O., "Application of DEGADIS to Example Chemical Release Scenarios," Report to Environmental Protection Agency, 1992.
18. Spicer, T.O., "Screening Methods for Consequence Analyses: Release Rate and

Dispersion Estimates for Denser-than-Air Gases and Aerosols," Report to Environmental Protection Agency, 1993.

19. Havens, J., T.O. Spicer, and H. Walker, "Regulatory Application of Wind Tunnel Models and Complex Mathematical Models for Simulating Atmospheric Dispersion of LNG Vapor," Gas Research Institute Topical Report, 1994.
20. Havens , J., and T.O. Spicer, "LNG Vapor Dispersion Case Analyses for the ENAGAS Company," Gas Research Institute Topical Report, 1994.
21. Havens, J.A., and T.O. Spicer, "Mathematical Modeling of Water Spray Curtain Mitigation of Accidental Hydrogen Fluoride Releases," Allied Signal Report, 1995.
22. Havens, J., H. Walker, and T. Spicer, "Characterization of the LGFSTF Wind Tunnel in Preparation for the DOE/EPA Hazardous Chemical Evaporation Rate Experiments," U.S. DOE/EPA Chemical Hazards of Atmospheric Releases Research (CHARR) Program Report, March 1995.
23. Havens, J., T.O. Spicer, and H. Walker, "Evaluation of Mitigation Methods for Accidental LNG Releases: Volume 1/5--Wind Tunnel Experiments and Mathematical Model Simulations to Study Dispersion of a Vapor Cloud Formed following LNG Spillage into a Diked Area Surrounding a Storage Tank," Topical Report for Gas Research Institute, November 1996.
24. Havens, J., T.O. Spicer, and H. Walker, "Evaluation of Mitigation Methods for Accidental LNG Releases: Volume 2/5--Wind Tunnel Experiments and Mathematical Model Simulations to Study Heat Transfer from a Flat Surface to a Cold Nitrogen Cloud in a Simulated Atmospheric Boundary Layer," Topical Report for Gas Research Institute, November 1996.
25. Havens, J., T.O. Spicer, and H. Walker, "Evaluation of Mitigation Methods for Accidental LNG Releases: Volume 3/5--Wind Tunnel Experiments for Mitsubishi Heavy Industries, Ltd.," Topical Report for Gas Research Institute, November 1996.
26. Havens, J., T.O. Spicer, and H. Walker, "Evaluation of Mitigation Methods for Accidental LNG Releases: Volume 4/5--Wind Tunnel Experiments for Osaka Gas Company," Topical Report for Gas Research Institute, November 1996.
27. Spicer, T.O., J. Havens, and H. Walker, "Evaluation of Mitigation Methods for Accidental LNG Releases: Volume 5/5--Using FEM3A for LNG Accident Consequence Analysis," Topical Report for Gas Research Institute, February 1997.
28. Spicer, T., "Atmospheric Dispersion Predictions in Support of the DOE HSC Project Hazards Assessment for the Chlorine Institute Rail Car Transfer Project," U.S. Department of Energy HAZMAT Spill Center, July 2000.
29. Spicer, T., "Atmospheric Dispersion Predictions in Support of the DOE HSC Project Hazards Assessment for Atomized Releases of Methyl Salicylate and Ammonia," U.S. Department of Energy HAZMAT Spill Center, February 2001.
30. Spicer, T., "Model for Estimating Fire Hazard during a Terrorist Attack from a LNG Tanker," National Oceanic and Atmospheric Administration, Hazardous Materials Response Division, October 2001.
31. Spicer, T., "Atmospheric Dispersion Predictions in Support of the DOE HSC Project

Hazards Assessment for Explosive Releases of Phosgene," U.S. Department of Energy HAZMAT Spill Center, May 2002.

Invited Lectures and Presentations

1. Mathematical Modeling and Experimental Investigation of Heavier-than-Air Gas Dispersion in the Atmosphere, Oklahoma State University, Stillwater, OK, April 1985.
2. Dispersion Modeling Workshop, Dow Chemical Company, Freeport, TX, March 1987.
3. Fundamentals of Denser-than-Air Gas Dispersion, EPA Modeling Workshop for Toxic Air Contaminants, Kansas City, Mo, June 1988; San Francisco, CA, October 1988.
4. Model Evaluation Workshop, International Conference and Workshop on Modeling and Mitigating the Consequences of Accidental Releases of Hazardous Materials, New Orleans, May 1991.
5. Application of the DEGADIS Dispersion Model to Accidental Releases of Hazardous Chemicals, Los Angeles City Fire Department, Los Angeles, CA, August 1993.
6. Boiling and Spreading of LNG Pools, Supplemental Gas Committee American Gas Association Roundtable, New Orleans, March 1994.
7. Application of the DEGADIS Dispersion Model to Accidental Releases of Anhydrous Ammonia, Joint Gas Research Institute and Fertilizer Institute Workshop, New Orleans, September 1994.
8. Validation of FEM3A for Dense Gas Dispersion in the Presence of Obstacles Using Wind-Tunnel Data Sets, Japanese National Committee of LNG Safety Study Meeting, Nagasaki, Japan, June 1995.
9. Validation of FEM3A for Dense Gas Dispersion in the Presence of Obstacles Using Wind-Tunnel Data Sets, Mitsubishi Heavy Industries, Ltd., Heat Transfer Laboratory Staff Seminar, Nagasaki, Japan, June 1995.
10. The FEM3A Vapor Dispersion Model, Gas Technology Institute Workshop, University of Arkansas, Fayetteville, AR, February 2003.
11. GTI Workshop on LNG Safety Models: FEM3A, Gas Technology Institute Workshop, Houston, TX, September 2004.
12. Bhopal: A 20 Year Perspective, National Association of Science Writers, 2nd Annual NASW Fall Workshop, Fayetteville, AR, November 2004.

Invited Panelist

1. Fumigant Bystander Exposure Model Review: Probabilistic Exposure and Risk Model for Fumigants (PERFUM) Using Iodomethane as a Case Study, FIFRA Scientific Advisory Panel Meeting, August 2004.
2. Fumigant Bystander Exposure Model Review: The Fumigant Exposure Modeling System (FEMS) Using Metam Sodium as a Case Study, FIFRA Scientific Advisory Panel Meeting, August 2004.
3. Fumigant Bystander Exposure Model Review: Soil Fumigant Exposure Assessment

SYStem (SOFEA©)) Using Telone as a Case Study, FIFRA Scientific Advisory Panel Meeting, September 2004.

Presentations

1. Application of a Heavy Gas Dispersion Model to the Prediction of Dispersion of Nitrogen Tetroxide, JANNAF Safety and Environmental Protection Subcommittee Meeting, Monterey, CA, November 1985.
2. DEGADIS--A Heavier-than-Air Gas Atmospheric Dispersion Model Developed for the U.S. Coast Guard, Air Pollution Control Association Annual Meeting, Minneapolis, MN, June 1986.
3. Field Test Validation of the DEGADIS Model, Second Symposium on Heavy Gas Dispersion Trials at Thorney Island, Sheffield, England, September 1986.
4. Gravity Flow and Entrainment by Dense Gases Released Instantaneously into Calm Air, Third International Symposium on Stratified Flows, California Institute of Technology, Pasadena, CA, February 1987.
5. Evaluation of the DEGADIS Dispersion Model Using Data from Field Releases of Pressurized Ammonia, Air Pollution Control Association Annual Meeting, New York, NY, June 1987.
6. Extension of DEGADIS for Modeling Aerosol Releases, International Conference on Vapor Cloud Modeling, Boston, MA, November 1987.
7. Uncertainties in the Application of Atmospheric Dispersion Models in the Presence of Jet Releases, Aerosol Releases, or Heterogeneous Surface Roughness, JANNAF Safety and Environmental Protection Subcommittee Meeting, Monterey, CA, 1988.
8. Modeling HF and NH_3 Spill Test Data Using DEGADIS, 1988 Summer National Meeting of the American Institute of Chemical Engineers, Denver, CO, 1988.
9. A Dispersion Model for Gas Pipeline Accidental Releases, 1989 Spring National Meeting, American Institute of Chemical Engineers, Houston, TX, April 1989.
10. Modeling Aerosol Dispersion for Accident Consequences Analyses, 1990 Spring National Meeting of the American Institute of Chemical Engineers, Orlando, FL, 1990.
11. DEGADIS Dense Gas Dispersion Model, Gas Research Institute Project Advisors Meeting, Fayetteville, AR, 1990.
12. Development of a Guidance Document for the Application of Refined Dispersion Models for Air Toxics Releases, 85th Annual Meeting of the Air and Waste Management Association, Kansas City, MO, June 1992.
13. Spreading and Vaporization of LNG Spills on Land, American Gas Association Distribution Transmission Conference and Exhibit, Orlando, FL, May 1993.
14. Application of Dispersion Models to Flammable Cloud Analyses, 6th Annual Petro-Safe, Houston, TX, February 1995.
15. Description and Analysis of Atmospheric Dispersion Tests Conducted by EPA at the DOE Hazmat Spills Center, International Conference and Workshop on Modeling and Mitigating the Consequences of Accidental Releases of Hazardous Materials, San

Francisco, September 1999.

16. Fundamentals of Atmospheric Dispersion, Safety and Chemical Engineering Education Committee Meeting, Detroit, MI, May 2001.
17. Modeling Aerosol Rainout, Mary Kay O'Connor Process Safety Center – 2001 Process Plant Safety Symposium, College Station, Texas, October 2001.
18. Modeling the Initial Velocity of Aerosol Jets, Mary Kay O'Connor Process Safety Center – 2003 Process Plant Safety Symposium, College Station, Texas, October 2003.
19. Modeling the Initial Velocity of Aerosol Jets: Initiating a New Experimental Program for Model Verification, Mary Kay O'Connor Process Safety Center – 2004 Process Plant Safety Symposium, College Station, Texas, October 2004.

Poster Presentations

1. Spicer, T.O. and J.A. Havens, "Gravity Flow and Entrainment by Dense Gases Released Instantaneously into Calm Air," Third International Symposium on Stratified Flows, Pasadena, CA, 1987.
2. Havens, J., T. O. Spicer, H. Walker, and T. Williams, "LNG Vapor Dispersion Experiments for Complex Mathematical Model Evaluation," LNG-11; 8th International Conference and Exhibition on LNG, 3-6 July 1995, Birmingham, U.K.

Interviews

1. "Mathematical Modeling at the Chemical Hazards Research Center," live television interview on "Breakfast Time," fX network, Fayetteville, AR, March 1995.
2. "Research Info May Help Lower Deaths," Russell Ray, The Morning News, 29 April, 1995.

Exhibit 7

December 13, 2004

Lieutenant Ken Kusano
U.S. Coast Guard
2100 Second Street, S.W.
Washington, D.C. 20593-0001

Cy Oggins
California State Lands Commission
100 Howe Ave., Suite 100-South
Sacramento, California 95825-8202

RE: Cabrillo Port Liquefied Natural Gas Deepwater Port – Comments on Draft EIS/R

Dear Lieutenant Kusano and Mr. Oggins,

This letter is sent on behalf of the California Coastal Protection Network. I was asked to perform an independent, objective review of the safety analysis contained in the Draft EIS/EIR for the Cabrillo Port LNG Deepwater Port. The following comments reflect my own independent expert analysis of the safety sections, particularly focusing on the consequence modeling methodologies utilized in the Draft EIS/EIR. Attached to this letter, please find a copy of my curricula vitae.

I have reviewed section 4.2 Public Safety: Hazard and Risk Analysis of the October 2004 Draft EIS/EIR for the Cabrillo Port LNG Deepwater Port project, as listed on the web site http://www.cabrilloport.ene.com/draft_eiseir.htm. In particular, I reviewed pages 4.2-13 to 4.2-29, which cover spills of LNG onto water from the FSRU and its attendant LNG marine tankers. My review considers only the consequence analysis for these spills and is not concerned with any risk analysis.

To its credit, the safety analysis includes a "worst case" scenario (5), in which the entire contents of the FSRU (300,000 cubic meters) is suddenly discharged, in addition to a several single tank releases of 100,000 cubic meters. On the other hand, the detailed analysis of these spill scenarios is questionable, for several reasons.

(1) Some scenarios are defined as "release with subsequent ignition". This appears to be a spill that evaporates to form a vapor cloud that is subsequently ignited after a time and travel distance at which the cloud is still ignitable, and through which a flame could propagate. The possibility that the spill could ignite at the location and time of the spill discharge, forming a pool fire, is not considered. Such pool fires could emit harmful thermal radiation to greater distances than the "release with subsequent ignition" spills.

(2) Although the details of the modeling are missing (an "Independent Risk Assessment report", referred to on page 4.2-16, is not contained in the draft document), it appears to me that the methods used do not meet the standards for consequence analysis that are now used for land side terminals and contained in recent EIS's published by the Federal Energy Regulatory Commission. This includes both the pool fire and vapor dispersion modeling required for assessing the safety hazards of spills from onshore LNG facilities.

Based upon my reading of the Draft EIS/EIR, the consequence analysis is incomplete and technically flawed, and almost certainly underestimates the offshore safety hazard of spills from the proposed FSRU project.

Sincerely yours,

Dr. James Fay

May 1998

JAMES ALAN FAY

Biographical Summary

James A. Fay is Professor Emeritus of Mechanical Engineering and Senior Lecturer at the Massachusetts Institute of Technology. His current field of interest is environmental engineering, and his recent research activities have concentrated on air and water pollution problems, including the dispersion of air pollutants in the atmosphere, acid rain, the safety hazards of liquefied gases, renewable energy (including small scale tidal power) and the spread of oil and other hazardous liquids on the ocean. In previous years he carried out research on combustion and detonation, hypersonic heat transfer, magnetohydrodynamics and plasmadynamics.

Professor Fay served as Chairman of the Massachusetts Port Authority (1972-1977) and as Chairman of the Air Pollution Control Commission of the City of Boston (1969-1972). He has served on twelve boards, committees and panels of the National Research Council, including two terms on the Environmental Studies Board. He is currently a director emeritus of the Union of Concerned Scientists and a former director of the Conservation Law Foundation.

A fellow of the American Academy of Arts and Sciences, the American Physical Society, the American Institute of Aeronautics and Astronautics, and the American Association for the Advancement of Science, Professor Fay is also a member of the National Academy of Engineering and three technical societies. In 1980 he was an Overseas Fellow of Churchill College, Cambridge University, and in 1990 a Fulbright Lecturer in India.

Professor Fay received his B.S. degree from Webb Institute of Naval Architecture in 1944, the M.S. degree from the Massachusetts Institute of Technology in 1947 and the Ph.D. degree from Cornell University in 1951. He was an Assistant Professor in the Department of Engineering Mechanics at Cornell University from 1951 to 1955. Since 1955 he has been a member of the faculty in the Department of Mechanical Engineering at M.I.T.

JAMES ALAN FAY

Biographical Data

Born November 1, 1923 at Southold, NY.

Married Agatha M. Kelly, Jan. 12, 1946

Children David A. (b. 1947), Mark B. (b. 1949), Colin M. (b. 1950), Jamie M. (b. 1953), Peter R. (b. 1955), Michele M. (b. 1959).

Education

B.S. in Naval Architecture and Marine Engineering, Webb Institute of Naval Architecture (1944).
M.S. in Marine Engineering, Massachusetts Institute of Technology (1947).
Ph.D. in Engineering Mechanics, Cornell University (1951)

Professional Experience

Asst. Planning and Estimating Supt., Long Beach Naval Shipyard, Long Beach, CA (1945-46).
Research Engineer, Lima-Hamilton Corp., Hamilton, OH (1947-49).
Assistant Professor, Department of Engineering Mechanics, Cornell University (1951-55).
Associate Professor (1955-60), Professor (1960-89), Professor Emeritus and Senior Lecturer (1989-), Department of Mechanical Engineering, Massachusetts Institute of Technology.

Professional Societies

Fellow, American Academy of Arts and Sciences.
Fellow, American Physical Society.
Fellow, American Institute of Aeronautics and Astronautics.
Fellow, American Association for the Advancement of Science
Member, National Academy of Engineering
Member, American Society of Mechanical Engineers
Member, Sigma XI
Member, Air and Waste Management Association

Professional Activities

Executive Committee, Division of Fluid Dynamics, American Physical Society (1964-67).

Subcommittee on Fluid Mechanics, NASA Research and Technology Advisory Committee on Basic Research (1965-68).

Chairman, Plasmadynamics Committee, American Institute of Aeronautics and Astronautics (1967-68).

Chairman, Air Pollution Control Commission, City of Boston (1969-72).

Environmental Study Group, Environmental Studies Board, National Academy of Sciences (1969-70).

Chairman, Jamaica Bay Environmental Study Group, National academy of Sciences (1970-71).

Fluid Dynamics Committee and Atmospheric Environment Committee, American Institute of Aeronautics and Astronautics (1971-74).

Committee on Motor Vehicle Emissions, National Academy of Sciences (1971-74).

Chairman, Massachusetts Port Authority (1972-77).

Executive Committee, Metropolitan Area Planning Council (1972-77).

Environmental Studies Board, National Research Council (1973-78).

Maritime Transportation Research Board, National Research Council (1973-74).

Director, Boston Shipping Association (1973-75).

Director, Boston Harbor Associates (1974-78).

New England Energy Policy Council (1975-78).

Committee on Environmental Decision Making, National Research Council (1975-77).

National Energy Policy Committee, Sierra Club (1976-78).

Advisory Committee, Dept. of Aerospace and Mechanical Engineering, Princeton University (1977-81).

Director, SCA Services, Inc. (1977-84)

Committee on Radioactive Waste Management, National Research Council (1978-81).

Director, Union of Concerned Scientists (1978-).

Committee on Urban Waterfront Lands, National Research Council (1978-79).

Committee on Environmental Research and Development, National Research Council (1978-79).

Associate Director, Massachusetts Audubon Society (1978-81).

Panel on Social and Economic Aspects of Radioactive Waste Management, National Research Council (1980-84).

Environmental Studies Board, National Research Council (1980-83).

Panel on Risk Analysis of Marine Transport of Hazardous Material, National Research Council (1981-82).

Exploratory Committee on the Future of Nuclear Power, National Research Council (1984-85).

Director, Conservation Law Foundation (1984-94)

Committee or Risk Assessment and Communication, National Research Council (1987-89).

Honors and Awards

New York State Regents Scholarship (1941-44)

American Bureau of Shipping Prize, Webb Institute of Naval Architecture (1944).
Stevenson Taylor Memorial Prize, Webb Institute of Naval Architecture (1944).
Society of Naval Architects and Marine Engineers Scholarship (1946).
Dupont Fellowship, Cornell University (1949-50).
Fellow, American Academy of Arts and Sciences (1963).
Fellow, American Physical Society (1964).
Fellow, American Institute of Aeronautics and Astronautics (1968).
Fellow, American Association for the Advancement of Science (1978).
Overseas Fellow, Churchill College, Cambridge University (1980).
Fulbright Lecturer, India (1990).
Member, National Academy of Engineering (1998)

Consulting Experience

American Locomotive Co. (1950-55).
Midwest Research Institute (1952-54).
Avco-Everett Research Laboratory (1955-69).
Executive Dept., State of Maine (1971-72).
Dept. of Sea and Shore Fisheries, State of Maine (1972).
Town of East Hartford, CT (1972-74).
Union of Concerned Scientists (1973-78).
Dept. of Marine Resources, Sate of Maine (1975-76).
Amscan Associates (1975-78).
Mt. Auburn Research Associates (1975-76).
Natural Resources Council of Maine (1977-92).
Massachusetts Energy Facilities Siting Council (1977-83).
Aberdour and Dalgety Bay Joint Action Group (1978-81)
Canvey I. Oil Refineries Resistance Group (1979-83).
Woodbridge Township, NJ (1981-85).
City of Port Moody, British Columbia (1981-82).
Conservation Law Foundation (1981-83).
Town of Weston, MA (1986-89).
Harvard Institute for International Development (1987-88).

96. James A. Fay, "Thermal fluctuations of electric field and solute density in biological cells," Physical Review E, **56,** 3460-3467, 1997.

Exhibit 8

December 15, 2004

To: United States Coast Guard (USCG), the United States Maritime Administration (MARAD), and the California State Lands Commission (CSLC)

Regarding: Draft Environmental Impact Statement/Environmental Impact Report (EIS/EIR) for the Cabrillo Liquefied Natural Gas (LNG) Deepwater Port (the Project) proposed by BHPB Billiton LNG International, Inc.

I have worked as a marine policy consultant and contractor on a number of CEQA and NEPA documents that focus on marine use, marine conservation, and coastal habitat and open space preservation and enhancement. I also teach graduate and undergraduate courses in ocean and coastal policy at UC Santa Barbara. I am currently the Acting Director of UC Santa Barbara's Ocean and Coastal Policy Center.

This letter focuses on the relevant sections of the BHP Billiton Cabrillo LNG Deepwater Port DEIS/DEIR (hereafter, BHPB DEIS/DEIR) with respect to general impacts and risks of the proposed project on coastal marine ecosystems of the study area, and the potential risks associated with the introduction of non-native marine invasive species from the operation of the proposed project. The major points of this comment letter are:

- The current plan of the Port of Los Angeles/Long Beach is to increase capacity by 100% by the year 2020. This information is not included in the BHPB DEIS/DEIR. Vessel traffic in the project area will be greater than the BHPB DEIS/DEIR identifies and evaluates. The result is that the characterization of this risk and cumulative impacts of the proposed project is inadequate. Additional mitigation measures are needed to address Class I impacts to marine ecosystems from a potential vessel collisions or accidents.
- The BHPB DEIS/DEIR fails to identify and assess the current and future marine resource use and associated multiple-use conflict of the project area. The BHPB will exacerbate existing and future multiple-use conflict of the area. The BHPB DEIS/DEIR should offer mitigation to address these multiple-use and cumulative impacts.
- The BHPB DEIS/DEIR fails to describe the general character of marine ecosystem disturbance in the study area, and therefore inadequately addresses the potential Class I impacts and risks of the proposed project on marine ecosystem health and integrity.
- The management approach adopted in the BHPB DEIS/DEIR focuses on ballast water exchange beyond the EEZ. Scientists show that this management approach cannot prevent the introduction of marine invasive species to coastal marine ecosystems. Scientists show that marine invasive species pose a significant threat

[redacted]

to marine biodiversity. Designated marine protected areas or MPAs that are designated in State waters around the northern Channel Islands are threatened by marine invasive species. Additional mitigation measures are needed to address the threat of marine invasive species.

- It is unclear whether the Independent Risk Analysis comprehensively evaluates the true nature of future risks to the coastal marine ecosystems of the area from a vessel accident. Management and mitigation options should be described in the BHPB DEIS/DEIR that accommodate uncertainty rather than ignore it, delaying policy until a risk probability distribution is defined with certainty. Additional mitigation measures should be included in the BHPB DEIS/DEIR that address ecosystem-based impacts, such as the potential threats posed by marine invasive species and increased future vessel traffic.

Threats of Increased Vessel Traffic

The characterization of risks and cumulative impacts to coastal marine ecosystems of the study area described in the BHP Billiton Cabrillo Port LNG Deepwater DEIS/DEIR (hereafter, BHPB DEIS/DEIR) is inadequate. In the description of cumulative impacts, Page 4.20-14 notes, "The Project would increase maritime traffic in the area." As Page 4.2-27 of BHPB DEIS/DEIR notes, the potential frequency of vessel collisions involving a LNG carrier or other large container ships (in addition to commercial and recreational fishing vessels) was <u>not</u> estimated.

Due to the close proximity of the proposed project to nationally and internationally designated marine protected areas (e.g., the northern Channel Islands), the release of bunker or diesel fuel used in vessel transportation during a vessel accident, such as a collision, poses Class I impacts to coastal marine ecosystems of the study area.

For the greater northern Channel Islands marine region, the characterization of the risk in the BHPB DEIS/DEIR, given future vessel traffic in and around the project area, is inadequate. The floating storage and regasification unit (FSRU) mooring would be situated near the southbound Coastwise Traffic Lane. The BHPB DEIS/DEIR lacks a substantive analysis on potential cumulative effects on marine ecosystems and marine resource users from potential maritime accidents. Should an incident occur (e.g., LNG tanker collision) there will likely be Class I impacts to coastal marine ecosystems of the northern Southern California Bight, including the Channel Islands National Marine Sanctuary (CINMS) and Channel Islands National Park (CINP).

Without a more thorough and credible use of the best available scientific information in risk and environmental impact assessments, the BHPB DEIS/DEIR falls short of the required identification and evaluation of potential direct, indirect, and cumulative impacts on the natural environment that may result from, for example, increased vessel traffic (i.e., vessel collision or maritime accidents) within the project area.

In accordance with CEQA and NEPA, the cumulative impacts analysis should include an analysis of impacts of "reasonably foreseeable future projects". Page 4.3-1 characterizes the number of annual commercial vessel traffic in the area transiting the Coastwise TSS to and from the Port of Los Angeles/Long Beach (approximately 10,000 transits in total). Page 4.3-10 of the BHPB DEIS/DEIR estimates the number of LNG carriers as 104 to 156 annually.

In Section 4.20, the BHPB DEIS fails to consider and evaluate the cumulative impacts of the expansion of the Port of Los Angeles/Long Beach and resulting increased vessel traffic on the operation of the proposed project during its estimated 40-year life. Table 4.20-1 of the BHPB DEIS/DEIR does not include detail on the Port of Los Angeles/Long Beach expansion.

Vessel traffic in the project area will likely be greater than the BHPB DEIS/DEIR identifies and evaluates in terms of risk and cumulative impacts. As a consequence, the BHPB DEIS/DEIR undervalues the level of risk associated with a vessel collision and the impacts that such a collision may have on the coastal marine environment. Moreover, it is unclear whether the Independent Risk Assessment includes the expansion of the Port of Los Angeles/Long Beach in the analysis.

The current plan for the Port of Los Angeles/Long Beach is to increase capacity by 100% by the year 2020 [while the proposed project completion date is 2008]. Port expansion will dramatically increase the number of transits during the proposed project operation. It is crucial that this factor be considered, evaluated and assessed in terms of potential risk to public health and the marine ecosystems of the northern Southern California Bight.

The Port of Los Angeles/Long Beach is the busiest port of entry on the West Coast, and serves all of the Pacific Rim countries. Since 1990, containerized trade at the Port of Los Angeles/Long Beach has increased by 150% making it the third largest port in the world (behind Hong Kong and Singapore). The Port of Los Angeles/Long Beach is now constructing the largest harbor expansion project ever done in the United States. Today, the 26 miles of wooden wharves in Port of Los Angeles/Long Beach are being replaced with modern cement docks for containerized cargo, petroleum and chemical transshipment, open cargo loading facilities and, in addition, new recreational areas are being created. This information is readily available and should be included in the analysis.

The future capacity at the Port of Los Angeles/Long Beach will lead to larger vessels and container ships that carry more fuel and cargo. Fuel and cargo released during a maritime accident in the study area could significantly impact coastal marine ecosystems. Increased use of the Santa Barbara TSS is likely. Vessel traffic will increase and will occur in close proximity to OCS oil and gas platforms and structures, such as Platform Grace. Vessel traffic will also increase in a marine region that is used by the U.S. Department of Defense military operations, e.g., the SOCAL Range Complex. In the foreseeable future, larger container ships and vessels will carry more heavy bulk fuel (and diesel fuel) during the operation of the proposed project to and from the Port of Los Angeles/Long Beach via the Santa Barbara TSS.

One real threat to coastal marine ecosystems is that large container ships, fast moving LNG carriers, and other large vessels can lose power, as in the current example of the double-hulled Selendang Ayu, a soybean freighter that is spilling heavy bulk and diesel fuel off of Analaska Island, Alaska. The risk of losing power within the Coastwise Traffic Lane, near Anacapa Island or Santa Barbara Island, near an OCS platform, should be assessed in the BHPB DEIS/DEIR. The impact of vessel collision or accident and the associated "oil spill" or other marine pollution on the marine ecosystems of the area will be significant (i.e., Class I impact).

There are several recent examples of significant ecological impact from vessel accidents:

- The Ecuadorean-registered tanker Jessica ran aground on January 16, 2001 in a bay on San Cristobal Island near the environmentally-sensitive Galapagos Islands, and began leaking oil on January 19, 2001. Over 600,000 liters of fuel seeped out the tanker. Ecuador's government said the damage from the oil spill was "extremely grave." Slicks affected a marine area over 303-square kilometers, and reached Espanola Island, home to large colonies of sea lions, and the island of Santa Fe, famed for the Santa Fe land iguana, a species found nowhere else. Local biologists say the long-term danger is that the fuel will sink to the ocean floor and destroy algae vital to the food chain, threatening marine iguanas, sharks and other species. Slicks have already reached some nearby beaches and harmed sea lions and birds, including blue-footed boobies, pelicans and albatrosses.

- In early December 2004, the 738-foot Malaysian-flagged vessel, the Selendang Ayu, lost power and began drifting in the Bering Sea, according to Coast Guard reports (Attachment I). Efforts to tow it and to anchor it failed because lines broke in the stormy weather. The ship was carrying 480,000 gallons of bunker fuel and 21,000 gallons of diesel fuel when it broke apart off an island's rocky coast. It is estimated that 140,000 gallons poured out because the breach in the ship opened one of the fuel tanks, officials said.

Given the proposed LNG carrier East-West traffic scheme, and the North-South vessel traffic for large container ships using the Port of Los Angeles/Long Beach, the threats posed by a vessel accident to the marine life of the region are under-estimated in the BHPB DEIS/DEIR. Santa Barbara and Anacapa Islands are particular concerns given the importance of these islands for bird reproduction. An "oil spill" and other vessel-related accidents in the project area will likely be difficult to contain. The "ecological core" of the Southern California Bight is the northern Channel Islands, which was designated as a national marine sanctuary in 1980. The Channel Islands National Marine Sanctuary (CINMS) encompasses 1252 square nautical miles of nearshore and offshore waters surrounding the islands of Santa Cruz, Santa Barbara, Anacapa, San Miguel and Santa Rosa. The CINMS includes forests of giant kelp, which are important nurseries for populations of fish and invertebrates. At least 27 species of whales and dolphins have been sighted in the CINMS and about 18 species are seen regularly and are considered "residents". The *largest* concentration of blue whales in the world can be found within the area. The CINMS lies on the migratory pathway of the California gray whale and other large baleen and toothed whales. San Miguel Island supports the most numerous and diverse avifauna in the CINMS, with nine species having established colonies.

The project area for the proposed LNG terminal is part of a marine "ecotone" or transition area that combines warmer and colder-water oceanographic provinces. Within the Southern California Bight, the Santa Barbara Channel includes patterns of warm, saline water from the Southern California Countercurrent and the colder water from the California Current. The "mixing" of oceanographic currents produces one of the world's hot spots for coastal marine life; the marine area of the northern Channel Islands should be considered "the Galapagos of the eastern Pacific" due to the region's biodiversity. The prevailing countercurrent is an important factor that may contribute to the risk of a catastrophe of a vessel-related accident. For example, a LNG carrier or containership that loses power could be carried by the countercurrent into one of the northern Channel Islands.

The potential impacts of an "oil spill" or other vessel-related accident and catastrophe on the marine environment should be thoroughly re-evaluated and assessed. A vessel accident could have major long-term impacts on biological communities and ecosystem relationships, and would likely diminish the ecological importance of designated Marine Protected Areas (Allison et al. 2003). Allison et al. (2003) describe the risks associated with catastrophic events in the Santa Barbara Channel in relation to the CINMS's priority management goal of biodiversity protection and the recent designation of MPAs in State waters.

The study area is located along the Pacific Flyway, a major migratory route for birds, and the habitats of the area are a stopover during both north (April-May) and south (September-December) migrations. The habitats of the Southern California Bight (SCB) provide breeding, nesting, and feeding sites for many species and large numbers of seabirds, including many federally and state listed endangered and threatened species. Over 60 species of marine birds may be using sanctuary waters to varying degrees as nesting and feeding habitat, for wintering, and /or as migratory or staging areas. Of the 16 resident species of marine birds in the SCB, eleven breed in the CINMS. Santa Barbara Island has several nationally and internationally significant seabird nesting areas, including the largest nesting Xantus' murrelet colony and the only nesting site in the United States of black storm-petrels. The brown pelican, a listed endangered species, maintains its <u>only</u> permanent rookery in California on Anacapa Island, which is the closest island to the proposed LNG terminal.

Threats to Coastal Marine Ecosystem Health and Integrity

It appears as if the consultants to the proposed project are unfamiliar with the coastal and marine ecology of the study area. The BHPB DEIS/DEIR fails to include the Xantus's murrelet as a nesting bird on Anacapa Island. The consultants to the developer incorrectly cite a NOAA 2002 document on Marine Protected Areas (Page 4.1-19). The correct reference is CDFG 2002. Section 4.7 Biological Resources in the BHPB DEIS/DEIR fails to refer to important peer reviewed scientific literature on the general status of the marine ecosystems, and other technical reports, such as S. Polefka (2004). *Anthropogenic Noise and the Channel Islands National Marine Sanctuary: How Noise Affects Sanctuary Resources, and What We Can Do About I.* A report by the Environmental Defense Center (Santa Barbara, CA). Because of the species richness and unique habitats of this marine system, this marine area is designated by the United Nations (UN) as one of the world's biosphere reserves. This information is also not included in the environmental impact assessment. Anecdotal information that has not been peer reviewed is often cited and referred to in the section on marine mammals. Indeed, a significant amount of peer reviewed scientific literature on the study area is available, yet it is not reviewed in Section 4.7. These types of omissions or failures on the part of the consultants to the BHPB DEIS/DEIR undermine the credibility of the assessment. This is one of the most studied marine ecosystems in the world; the information is readily available and should be included in the analysis.

<u>A major failure of the BHPB DEIS/DEIR is that project consultants do not describe the general character of the decline in coastal marine ecosystem health</u> of the area in Section 4.7.1. This is surprising given recent focus on the plight of marine ecosystems at the federal level (U.S. Ocean Commission Report) and at the state level (e.g., the Governor's "Protecting Our Ocean: California's Action Strategy"). Section 4.7 provides an inventory of species identified in the study area. The uniqueness and fragile nature of the coastal marine ecosystem linkages and relationships are not described in the BHPB DEIS/DEIR. Important relationships and linkages that exist in the study area between coastal and marine species and habitats are described in McGinnis (2000).

The CDFG (2002), *Marine Protected Areas in NOAA's Channel Islands National Marine Sanctuary*, Volume I, Chapter 4, provides a much more thorough and credible identification and analysis of the environmental setting and the affected environment. Section 4.2.5.2 of the CDFG Final EIR provides an excellent summary of the existing status of marine ecosystem health. As described in CDFG (2002), scientific evidence indicates that the maintenance of marine ecosystem structure and patterns of native species diversity have dramatically changed in the Southern California Bight. Recent data from extracted cores from the Santa Barbara Channel includes high quality information that can be tracked in increments of close to 50 years. The cores show rapid and extreme shifts in water temperatures during the last 60,000 years. These shifts are known as "regime shifts" that influence the distribution and abundance of marine animals and plants of the Bight. This information is also described in the CINMS "Study Area Report" by McGinnis (2000), the National Park Service, *Gaviota National Seashore*

Feasibility Study (2003), and other government documents and technical reports. This material and information is not reviewed in the BHPB DEIS/DEIR.

In addition, the impacts to coastal ecosystems from the proposed project and operation should be considered within a framework that includes an understanding of the loss of coastal ecosystems of the south coast. California ranks second in the U.S. in the number of listed threatened and endangered species. A majority of these species depend on coastal wetlands during part of their life cycle. Notable examples of wetland types that largely have been eliminated in southern California include: estuarine wetlands (i.e., salt marshes) as an entire subsystem at 75-90%; "the riparian community" at 90-95% including loss of 40% of the riparian wetlands in San Diego County during the last decade alone; and vernal pools at 90%. This material and information is not reviewed in the BHPB DEIS/DEIR.

A general summary of the decline in coastal ecosystem health of the study area is depicted in Table 1 below (McGinnis 2000; CDFG 2002):

Table 1
Ecosystem Disturbance of the Southern California Bight (SCB)

- The Euphotic Zone (upper sunlight zone of the sea, less than 120 m thick): There has been a long-term deficit in the supply of food necessary to meet the metabolic demands of the sediment community. Despite this decline in food supply, the food demand of the deep-benthic sea community remained constant.
- Macrozooplankton: Since the late 1970s, macrozooplankton volume in the California Current has declined over 70%, in concert with increasing sea surface temperatures. Reduced macrozooplankton has a major impact at higher trophic levels by changing the nature of the food supply.
- Fishes and Invertebrates: There has been a decrease in harvest for most categories of groundfish, rockfish, California sea urchin landings, landings of swordfish and selected shark species, California halibut, among others. Many of these declines began in late 1970s.
- Oceanic Birds: Ecological theory predicts that in a stable ecosystem those species occupying high trophic levels maintain native species diversity and community structure. Upper trophic level animals such as pelagic birds are indicators of the health of the marine environment. Evidence suggests that the abundance of oceanic birds in the region and the SCB have declined steadily since 1988. Ocean warming and climatic events change pelagic bird abundance within the California current system.
- Southern California Kelp: Starting in the late 1970s, kelp forests have suffered great damage, and show a two-thirds reduction in standing biomass since 1957 in southern California kelp forests.
- Global Climate Change: There is also some indication that the frequency of these climatic events may be increasing, and will have significant impacts on coastal and marine systems.

This is important ecosystem-based information that is not included in the evaluation of cumulative impacts to the coastal marine ecosystems of the study area. Scientists have also shown the human use of the marine environment (e.g., overfishing and marine pollution) are the primary causes of general ecosystem decline. For example, Dr. Jeremy Jackson et al. (2001) describe the history of the collapse of kelp and other coastal marine ecosystems off southern California. "Overfishing and ecological extinction," according to Jackson et al. (2001), "predate and precondition modern ecological investigations and the collapse of marine ecosystems in recent times, raising the possibility that many more marine ecosystems may be vulnerable to collapse in the near future".

Given the cumulative and current levels of resource over-use in the area, the proposed development should be characterized as a Class I impact to the coastal marine ecosystem and associated biodiversity – a marine ecosystem that is currently showing signs of significant disturbance. Scientists have shown a decline in primary and secondary levels of ecological productivity in the marine area (McGowan et al. 1998). General marine impacts from the proposed development are described in Table 1.4-1. These impacts should be carefully evaluated within the context of a degraded marine ecosystem and in terms of cumulative impacts of the multiple-use of marine resources of the study area.

Given the project area's close proximity to major urban centers and the availability of important marine resources, the nature of multiple-use conflict (OCS oil and gas activity, commercial and recreational fishing, non-consumptive use, Department of Defense operations, among others) has not been carefully identified and evaluated in the BHPB DEIS/DEIR, despite the fact that this information is readily available. I would recommend that the developer review recent material on the affected environment of the study area by CINMS at http://channelislands.noaa.gov/manplan/documents.html. The BHPB DEIS/DEIR should include a more detailed characterization of the nature of marine resource use and multiple-use conflict. In addition, the proposed project will exacerbate existing and future multiple-use conflict of the area and should offer mitigation to address associated impacts.

Additional mitigation and specific details on emergency procedures for all phases of the proposed project (construction to operation) should be included in the BHPB DEIS/DEIR that address these issues described above.

The Threat of Marine Invasive Species

I now turn to a final comment concerning the threats posed by marine invasive species associated with the operation of the LNG terminal. The BHPB DEIS/DEIR describes the proposed Cabrillo Port operations and the existing regulatory setting for ballast water exchange. Ships arriving from outside the Exclusive Economic Zone (EEZ) in the East-West spatial dimension are now asked to conduct ballast water exchange in water greater than 200 nautical miles (370.4 km) from land and greater than 2,000 meters in depth according to International Maritime Organization guidelines.

However, <u>the management approach adopted in the BHPB DEIS/DEIR will not prevent or control the introduction of marine invasive species to the study area</u>. Marine invasive species pose a threat to nationally and internationally significant MPAs that are located around the northern Channel Islands (Attachment II). Appropriate mitigation measures should be included in the project to focus on prevention and control of marine invasive species. Preventative rather than reactive policy measures are necessary to control the spread of marine invasive species due to the extremely difficult nature of locating and eradicating these invasives and the uncertainty of their impacts on ecosystems (Ruiz and Carlton 2003 among others).

Commercial shipping is the primary vector for introductions of marine invasive species. The problem of marine invasive species have been identified by scientists and policymakers as a major threat to marine biodiversity and have resulted in hundreds of millions of U.S. dollars in direct costs and losses of ecosystem services during the last century. Invasive species are the second leading cause of biodiversity loss worldwide. Marine invasive species pose potential impacts on human health, marine ecosystem health, and may impact the economic production of resources from marine systems.

The General Accounting Office (2002) and the U.S. Commission on Ocean Policy (2004) note that the primary reason for the problems caused by marine invasive species is incomplete unilateral action for a transboundary pollution problem. An example of unilateral action is California policy that requires mandatory reporting of ballast water exchange or other methods to treat ballast water outside of the EEZ for vessels arriving to the state. [Not all ships, however, discharge ballast water outside of the EEZ. Approximately 50% of the vessels discharging ballast upon arrival to California ports during the first six months of 2000 were from Japan, China and Korea. However, 50% of shipping traffic to California takes place *within* 200 miles of the coastal mainland, primarily from vessel traffic between Mexico and Canada. These vessels are <u>not subject</u> to any guidelines for ballast water or <u>biofouling</u>.] <u>There are also known limitations to ballast water exchange as new introductions have not been abated</u>.

The study area for the proposed BHPB is a particular concern regarding the potential introduction of marine invasive species. Scholars have found that the rapid increase in the rate of invasive species introductions corresponds with the significant increase in shipping traffic along coastal California. Current national and international policies are ineffective in preventing new marine invasions and also in dealing with identified introductions once they have occurred. The U. S. Commission on Ocean Policy (2004) reaffirmed this position by stating, "Invasive species policies are not keeping pace with the problem primarily because of inadequate funding, a lack of coordination among federal agencies, redundant programs, and outdated technologies".

It is widely recognized that the first and foremost line of defense for combating the potentially damaging effects of marine invasive species is to prevent introductions. This position was recently supported by the U. S. Commission on Ocean Policy (2004): "Recognizing the economic and biological harm caused by invasive species, and acknowledging the difficulty of eradicating a species once it is established, aggressive steps should be taken to prevent such introductions". Preventing introductions requires vector management. As pointed out by Ruiz and Carlton (2003), preventing marine invasive species introductions is a recognized priority in policy development and preventive measures are being taken in various ways throughout the United States and the world. Actions focusing on preventing introduction through vector management have the advantage of focusing on the mechanism of introduction and being applicable to multiple species.

With regard to marine invasions, the BHPB DEIS/DEIR focuses on ballast water as a vector for introducing marine invasive species. Open ocean exchange is designed to reduce the abundances of coastal organisms, which have the greatest probability of being able to survive in the non-native waters of distant ports, by replacing them with open ocean species. There is considerable evidence, however, that compliance with open ocean exchange of ballast water is not high. To reduce the likelihood of introductions, more attention needs to be given to other vectors, including ship fouling (e.g., hulls, anchor chains, and ship surfaces).

<u>Biofouling of invasive species on boat hulls has not been properly accounted for in the BHPB DEIS/DEIR.</u>

Given the nature of the proposed project, it is important that Australia and the U.S. (and California) encourage a comprehensive and coordinated proactive strategy to prevent the spread of marine invasive species. The International Maritime Organization (IMO) has developed a number of recommendations. These recommendations focus on the incentives to individual countries and regional trading blocs to stimulate actual adoption of the international standards. Joint protection (such as programs that support general surveillance and eradication of marine invasives) should be considered in this project, and should be developed as important mitigation measures.

Alternative options to ballast water exchange include techniques that mechanically, physically, chemically or biologically kill or remove the unwanted invasive species. Alternatives include: 1) heat in-transit practices, 2) ultra violet treatment, 3) filtration, 4) ozonation, and 5) deoxygenation. These alternatives to ballast water exchange may overcome the spatial limitations and incomplete effectiveness of exchange in cases involving coastal traffic.

Australia has moved beyond ballast water to address pre-border and post-border control systems for a variety of vectors. Their national plan includes monitoring activities to distinguish between new incursions or the spread of existing marine invasive species, emergency response including interagency coordination, and cost-sharing arrangements. A similar management approach is warranted for the proposed project.

In addition, a common theme in recommendations concerning effective control of marine invasive species is the development of effective field monitoring programs. Field programs are needed for early detection, to track the rate of spread of invaders, and to determine their ecological impacts. Effective monitoring programs also can provide data for evaluating the efficacy of vector interdiction or other control programs. An effective, bi-national field monitoring program (Australia and the U.S.) should be developed in conjunction with the proposed project to address introductions of invasives. Such a program should be highly coordinated, implemented across a network of sites, and include robust, standardized measures of species composition, distributions, and abundances over time.

Thank you for the opportunity to comment on the BHPB DEIS/DEIR.

Sincerely,

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Dramatic rescue of ship attempted in brutal seas, December 11, 2004
By ERIC NALDER, SEATTLE POST-INTELLIGENCER INVESTIGATIVE REPORTER

"Thick fuel oil is spreading toward a marine sanctuary".

The attempt to rescue the Selendang Ayu has implications in Washington state. For years, a local environmentalist, Fred Felleman, has been fighting first to post a tractor tug at the entrance to the Strait of Juan de Fuca at Neah Bay and now to keep it there. The tug would keep ships like the Selendang Ayu from going aground and spilling oil on a nearby marine sanctuary.

Currently, there is a powerful Foss tug at Neah Bay with all the right equipment to tackle a ship the size of the 738-foot Selendang Ayu, according to officials at Foss. But a smaller tug, with less power, is usually posted there.

"This really underscores the need to have the appropriate sized tug, and with the appropriate equipment on board, at Neah Bay," said Felleman.

Felleman said a kit with towing equipment would be "better than a poke in the eye" but not good enough. He wants tugs posted year-round at critical locations to protect marine sanctuaries."

When he arrived at the hellish scene where seas as tall as a three-story building were battering the bulk carrier Selendang Ayu, tug captain Rob Campbell knew he had only a slim chance to help keep the disabled freighter from going aground on a rocky beach.

It was 4 a.m., and the winds pushing the ship were screaming at more than 60 miles per hour.

Another tug, the Sidney Foss, had a steel line attached to the stricken ship's bow, but it could pull only so hard without tipping itself over. Ten hours of pulling -- with 3,000 horsepower -- had slowed the ship's steady drift to shore from only about 4 knots to 2 knots.

Campbell, 51, could see the Selendang Ayu was in the most dangerous position possible. It was stuck in the trough of the heavy seas, sideways to the pounding 35-foot waves -- a death sentence.

His tug, the James Dunlap, had only one way to help. It had to get another line attached to the ship's bow so the vessel could be pulled around to face the waves.

Then, and only then, might the freighter be pulled away from the rocks.

But Campbell didn't have the right equipment. He had no line gun to fire a messenger rope onto the stricken ship. A messenger line allows a thicker cable to be drawn aboard the ship, so the tug can be lashed to the vessel for pulling.

For years, Campbell said, he's been urging the Coast Guard to purchase a kit containing a line gun, plus some strong but lightweight towing rope and a special hook that can capture a ship's anchor. The kit, which he estimates would cost $50,000, could be stored in Dutch Harbor so that any tug that was sent to rescue a vessel could use it.

The James Dunlap is a 100-foot, 4,300-horsepower tractor tug with a propeller fitted in a nozzle that can be turned in any direction. That gives it the ability to pull powerfully in any direction.

But it's a harbor tug, equipped to guide container ships into their docks, not a rescue tug equipped to salvage ships.

"Nobody wants to pay for all this, but if you really want to make sure these things don't happen ... pay me now or pay me later," Campbell said. "For years, I've been suggesting every time we have one of these meetings that we have some emergency tow gear set up in place in Dutch Harbor. We are a work-boat, not a salvage boat. Every time we do these kinds of things, we have to make do with what we can put together."

Capt. Jack Davin, chief of the Coast Guard's marine safety office in Alaska, said he'd prefer if all tugs would carry line guns and two cables, as the Sidney Foss did. But Coast Guard regulations don't require it, he said.

He said he hadn't heard about Campbell's suggestion but wouldn't reject it outright. He's skeptical, however.

"Normally the United States government doesn't buy equipment for use by private companies to make more money and do their job," he said.

Only three hours after the James Dunlap arrived on the scene, the steel cable the Sidney Foss was pulling on broke. That was around 7 a.m. Wednesday. Hours later, the ship ran aground and then broke in half. During an effort to rescue the crew, a Coast Guard helicopter crashed. The Coast Guard crew and one sailor from the freighter were rescued, but six of the Selendang Ayu's crew are missing. Thick fuel oil is spreading toward a marine sanctuary.

The attempt to rescue the Selendang Ayu has implications in Washington state. For years, a local environmentalist, Fred Felleman, has been fighting first to post a tractor tug at the entrance to the Strait of Juan de Fuca at Neah Bay and now to keep it there. The tug would keep ships like the Selendang Ayu from going aground and spilling oil on a nearby marine sanctuary.

Currently, there is a powerful Foss tug at Neah Bay with all the right equipment to tackle a ship the size of the 738-foot Selendang Ayu, according to officials at Foss. But a smaller tug, with less power, is usually posted there.

"This really underscores the need to have the appropriate sized tug, and with the appropriate equipment on board, at Neah Bay," said Felleman.

Felleman said a kit with towing equipment would be "better than a poke in the eye" but not good enough. He wants tugs posted year-round at critical locations to protect marine sanctuaries.

Though the efforts of the Sidney Foss and the James Dunlap failed, they were not without heroics.

The Coast Guard learned that the Selendang Ayu was drifting without power at around 3:30 a.m. Tuesday. A Coast Guard cutter, the Alex Haley, was diverted from patrol in the North Pacific at 5 a.m., said Coast Guard Chief Petty Officer Darrell Wilson. It had a line gun, but Wilson wasn't sure whether the cutter helped in any effort to tow the vessel.

Sending tugs to save the ship took a bit longer. The Sidney Foss left Dutch Harbor around 10 a.m. and the James Dunlap headed out at around 7:30 p.m. Campbell said the fact the Selendang Ayu was a foreign ship created delays in sending out tugs. He said officials had to determine who was responsible for paying for the salvage. If it had been a U.S.-flagged ship, Campbell said, the dispatch might have been quicker.

The Sidney Foss is an oceangoing tug, about 125 feet long, and its normal job is to tow cargo barges to Adak. It is the only vessel that does so. Called into emergency service, the Foss tug dropped off its barge and headed for the Selendang Ayu, arriving at 8:30 p.m.

Luckily, the Sidney Foss has a line gun, which it carries for emergencies like this, said Doug Pearson, manager of marine transportation for Foss Maritime in Seattle.

But conditions were horrible. The Sidney Foss crew had to work from the tug's second deck because the tug's main deck was buried in roiling seas. Twenty- to 25-foot waves pitched the vessel as it approached the Selendang Ayu.

A lucky shot from the line gun -- which is big, like an elephant gun -- carried a messenger line to the stricken ship on the first try, Pearson said. A thicker line was dragged aboard the freighter, and then a steel cable. That was the end of their luck.

Though the cable was attached to the bow, the Sidney Foss could not pull the ship around to face the increasingly punishing seas.

Tug Capt. Bob Farrell and his crew of five were hoping for "enough time to get out of the darkness, at least get daylight," said Pearson. "We pulled on the ship as hard as we could safely for the crew and the tug, without putting them in jeopardy," said Steve Scalzo, president of Foss Maritime.

The James Dunlap was bucking heavy seas just to get to the scene. "We were getting hammered, we got abused, beat up, on the way out there," said chief mate Steve Devitt. The tug had left Dutch Harbor with only the captain and two crewmembers. Normally, they would have five.

Arriving at 4 a.m., Campbell couldn't get his tug closer than 600 feet from the ship, and even that close was dangerous. It was dark, with howling winds, and the seas were so huge they were threatening the James Dunlap at both the high and low end. In the trough of a wave, the James Dunlap was threatened with slamming its hull into the bottom. At the top of the wave, it might be tossed onto the deck of the Selendang Ayu.

"If you get up on top of one of those swells, it could throw you onto the ship," said Scott Manley, port captain for James Dunlap Towing Co., the La Conner, Wash., firm that owns the tug.

Other dangers included being sucked under the ship or forced around it toward the beach.

Without a line gun, he said he had no chance to lash up to the ship. Even if he had a line gun, in those conditions, he would have had only a limited number of tugs to try to turn the ship into the seas before his line, too, would have broken.

"At 7:30 the mate told me they (the Sidney Foss) parted their tow wire," recalled Campbell. "The rest was history."

The salvage vessel Reedemer was also on the scene, but its role was unclear. The Sidney Foss crew recovered its cable and prepared for another try at lashing to the ship, but to no avail. The James Dunlap -- named after the father of tug company owner Jim Dunlap -- was only able to stand its ground in the heavy seas and could render no assistance.

At one point, Campbell hoped to rescue crewmembers from the deck of the Selendang Ayu, but that, too, was impossible. He said he was "aghast" when he heard the ship's captain say over the radio that he had only three survivor suits for 26 crewmembers.

Davin, of the Coast Guard, confirmed there were only three survival suits aboard. He said he and other Coast Guard officials were surprised, but they found that three suits are all that is required under international treaty. He said it is too early to tell whether the lack of survival suits contributed to crewmembers' deaths, but it is possible.