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CHAPTER 7

IMPROVED ELECTRICITY SUPPLY TECHNOLOGIES

7.1 INTRODUCTION

The electricity industry has many supply-side options at its disposal to reduce or offset its CO₂ emissions by the year 2010. One of these options was discussed in Chapter 6 – reconfiguring the generation mix to reflect a \$50/ton charge for carbon. We labelled this option “carbon-ordered dispatching” because it involves the same technologies that were considered in the EIA reference (“business-as-usual”) scenario and the two efficiency cases. Electricity was redispatched from the existing generation mix, and the construction and retirement of power plants also changed – but no new technologies were introduced.

Chapter 7 considers other electricity supply technology options, including:

- converting coal-based power plants to natural gas;
- cofiring coal with biomass;
- efficiency improvements in generation and transmission and distribution (T&D) systems;
- extending the life of existing nuclear plants;
- increasing generation and capacity at existing hydropower plants; and
- constructing new powerplants using advanced coal technologies.

Each of these options is assessed independently. Thus, interactions between the options are not taken into account, and the possibility of double counting is therefore likely.

Their viability and costs of these supply options in 2010 are based on the assumption that the electricity grid is transformed by the high efficiency/low carbon scenario, as described in Chapter 6. Thus, considerable decarbonization has already occurred. The question addressed is: What additional supply technology options now make sense in a scenario in which carbon has acquired a value of \$50 per metric ton?

We conclude this chapter by discussing the significant contribution that renewable energy technologies can make by the year 2020.

7.2 CONVERTING COAL-BASED POWERPLANTS TO NATURAL GAS

7.2.1 Objective

The objective of this study was to explore the technical and economic feasibility of converting (via repowering) coal-fired power plants (>50 MWe) to natural gas combined cycle (NGCC), as one option to reduce carbon emissions from the U.S. electric power sector. The effects of gas/coal price differential, SO₂/NO_x emission credits (market value), and technical/economic efficiency credits arising from NGCC repowering were incorporated into the analysis.

7.2.2 Approach

Repowering of existing coal-fired powerplants to NGCC offers an opportunity to significantly increase the efficiency of power generation and reduce the emissions of both

criteria air pollutants (Sulfur Dioxide (SO_2), Nitrogen Oxide (NO_x), Total Suspended Particulates (TSP), and Hazardous Air Pollutants (HAPs) (and Carbon (C)).¹

The simplest approach to repowering is *site repowering*, where the existing power plant site is reused with an entirely new NGCC system. Only the switchyard and cooling tower are reused. While this approach provides the highest cycle efficiency, it also requires a greater capital investment.

The more conventional approach is referred to as *steam turbine repowering*. In this case, a new gas turbine and heat recovery steam generator (HRSG) are integrated with the existing steam turbine and auxiliary equipment. Due to age of equipment and the fact that the steam turbine was designed for linkage with a coal-fired boiler, the efficiency of a *repowered* steam turbine plant would be lower than at a site repowered plant. The steam turbine repowering option has a higher operating cost (due to the lower efficiency) but a lower capital cost.

The cost-effectiveness (\$/tC) of both repowering options was examined in this study.² In addition, a sensitivity analysis was performed to examine the impact on cost-effectiveness if additional natural gas pipeline infrastructure (hook-up and transmission) were not needed to ensure gas deliverability. This sensitivity analysis (labeled: no transmission cost case) was only conducted on those plants that are currently connected to the pipeline network (i.e., dual-fuel).

A "static" analysis was performed (i.e., the cost of repowering was computed for each candidate power plant but the analysis did not optimize unit/plant production cost, dispatch, or system load. Moreover, for the steam repowering case, the largest steam turbine (not each individual steam turbine) at the plant was repowered to generate the equivalent of 1995 plant output (kilowatt-hours, kWh), since this is both more economic and consistent with industry practice than repowering each turbine. Lastly, the gas delivery infrastructure costs (hook-up and transmission) were derived assuming 1) no excess capacity in the current delivery system, and 2) that if such a fuel switching strategy were implemented, the natural gas pipeline industry would build capacity (even if done incrementally) to meet the total estimated gas requirements of repowering all candidate plants and allocate appropriate delivery costs to each repowered plant. Appendix G-1 discusses the methodological steps in more detail.

Results

Repowering of coal-fired power plants could reduce between 5 MtC and 269 MtC depending on the gas/coal price, carbon cost and environmental externality value. 

Figure 7.1 portrays the cost-effectiveness of site repowering with NGCC, and the corresponding cumulative carbon removed, for two alternative gas/coal price

¹ Another approach would be to improve the performance of the existing coal-fired power plant through various management and technical improvements. While less costly than NGCC repowering, the emissions reduction potential is not as great due to the carbon (together with sulfur and nitrogen) content of coal versus natural gas.

² The cost-effectiveness calculation included the cost of repowering, hook-up and transmission, a coal/gas price differential, and a credit for SO_2/NO_x emission reduction and technical/fuel efficiency improvement (O&M credit).

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differentials (\$0.72/MCF and \$1.18/MCF).³ When no environmental externalities are considered, approximately 50 MtC can be removed for \$50/tC, 191 MtC for \$100/tC, and 262 MtC for \$150/tC with a gas/coal price differential of \$0.72/MCF. Table 7.1 summarizes the affected gigawatts (GW), SO₂ and NO_x removed, and increase in utility gas consumption (trillion cubic feet, TCF) for each case examined.

Figures 7.2 and 7.3 depict the effect of environmental externality credits (for SO₂/NO_x) on carbon cost-effectiveness. Two alternative market values for used for both SO₂ and NO_x:

	High (\$/ton)	Low (\$/ton)
SO ₂	100	0
NO _x	1400	700

The rationale for these values is explained in Appendix G-1. Both Figures 7.2 and 7.3 (together with Table 7.1) illustrate that the effect of the environmental externality credit dissipates at \$100/tC and is almost nonexistent at \$150/tC. The reason is twofold: the number of candidate plants available for repowering is declining, but more importantly the offsetting effect of the externality credit is substantially reduced at the higher carbon cost levels (since the investment cost of conversion is greater). In many of the low-cost repowering cases, the externality credit is approximately equal to the amortized investment cost of repowering, causing the \$/tC to approach zero.

³ The gas/coal price differential of \$.72/MCF represents the 1995 value as reported by the Energy Information Administration (EIA) in its Annual Energy Outlook (AEO96). It represents a lower bound value, since the differential remains constant over time (and demand), reflecting no price response by the natural gas industry with increasing utility fuel demand. The \$1.18/MCF reflects the 2010 gas/coal price differential within AEO96. This differential reflects a real natural gas price increase of \$0.40/MCF (\$2.04/MCF in 1995 to \$2.44/MCF in 2010) and a 1.9 TCF increase in utility gas demand.

Table 7.1
Summary Statistics: Coal/Gas Repowering Study

Constant 1995 Coal/Gas Price Differential (\$0.72/MCF)

Category	Pretreatment					Sulfur Dioxide					Nitrogen Oxide				
	Removed (MMlbars)	EW (MMlbars)	Removed (MMlbars)	Removed (MMlbars)	Remaining (MMlbars)	Removed (MMlbars)	EW (MMlbars)	Removed (MMlbars)	Removed (MMlbars)	Remaining (MMlbars)	Removed (MMlbars)	EW (MMlbars)	Removed (MMlbars)	Removed (MMlbars)	Remaining (MMlbars)
Externalities	49.6	49	1.1	1	1.7	190.7	207	6.2	3.9	6.9	262.3	311	10.2	5.2	9.7
Externalities	90.2	92.6	2.1	1.9	3.2	233.6	266	8.7	4.8	6.5	266	317	10.4	5.3	9.8
Externalities	143.8	155.4	4.9	3.3	5.1	252.6	293	9.8	5.1	9.3	269	323	10.5	5.4	9.9

Coal/Gas Price Differential In 2010 (\$1.18/MCF)

Category	Pretreatment					Sulfur Dioxide					Nitrogen Oxide				
	Removed (MMlbars)	EW (MMlbars)	Removed (MMlbars)	Removed (MMlbars)	Remaining (MMlbars)	Removed (MMlbars)	EW (MMlbars)	Removed (MMlbars)	Removed (MMlbars)	Remaining (MMlbars)	Removed (MMlbars)	EW (MMlbars)	Removed (MMlbars)	Removed (MMlbars)	Remaining (MMlbars)
Externalities	4.9	4.8	0.06	0.08	0.2	134.5	140	3.3	2.7	4.7	252.8	294.6	9.8	5.1	9.3
Externalities	36.4	34	0.7	0.9	1.3	185.4	202	6.4	3.9	6.7	259.3	305.5	10.1	5.2	9.6
Externalities	105.4	111	3.3	2.4	3.7	235.8	270	8.8	4.8	8.6	265.7	317	10.4	5.3	9.8

Figure 7.1
Carbon Curve for Coal/Gas Site Repowering
No Environmental Credits

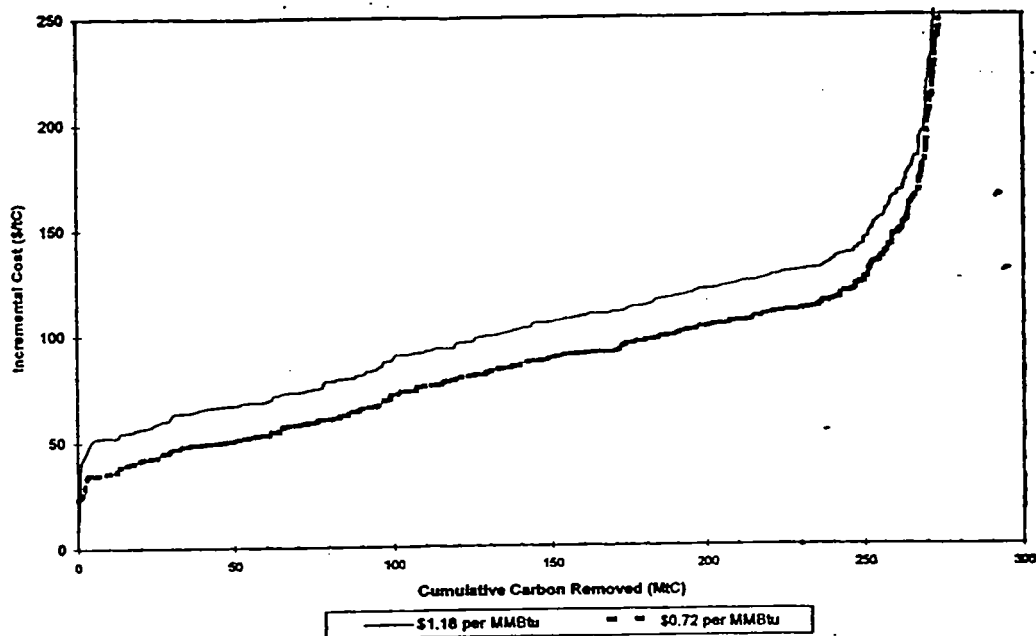


Figure 7.2
Carbon Curve for Coal/Gas Site Repowering
Effect of Environmental Credits on Cost of Carbon Removal
Constant 1995 Coal/Gas Price Differential (\$0.72/MCF)

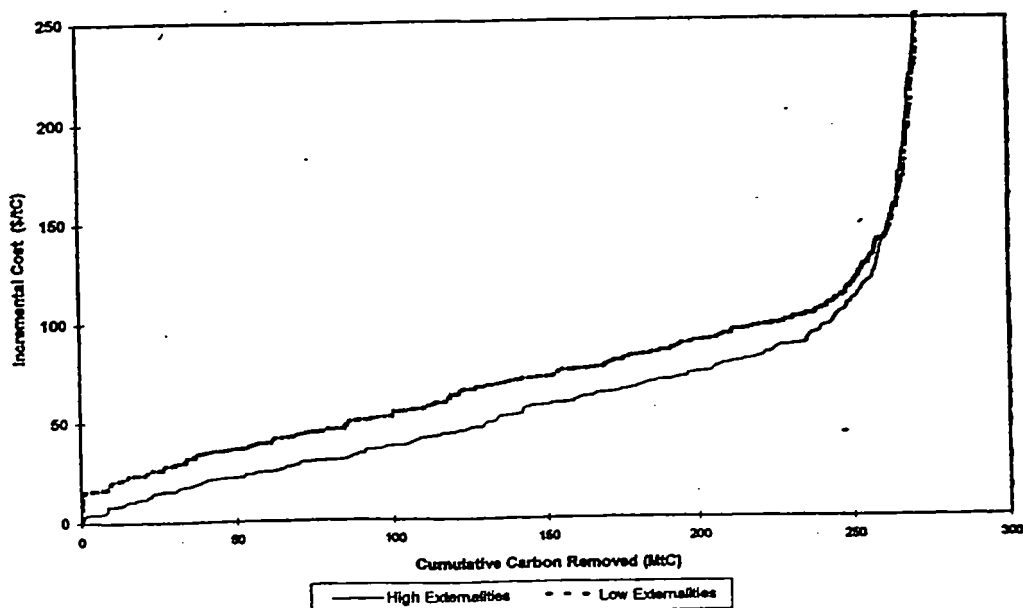
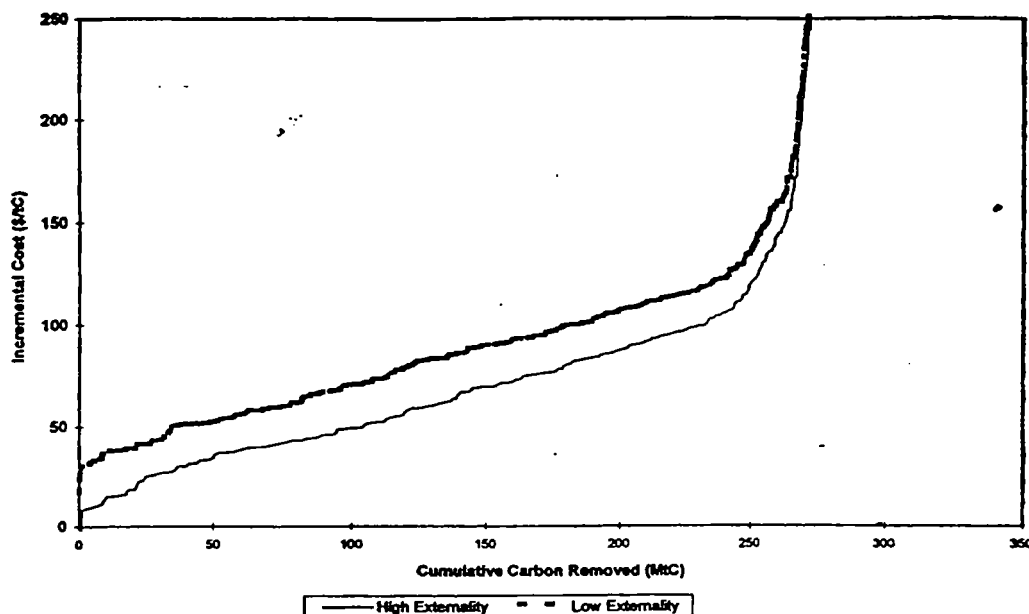


Figure 7.3
Carbon Curve for Coal/Gas Site Repowering
Effect of Environmental Credits on Cost of Carbon Removal
Coal/Gas Price Differential in 2010 (\$1.18/MCF)



Since dual-fuel plants are already receiving natural gas (although a lower volumetric levels than a repowered plant), a sensitivity analysis was conducted wherein no hook-up or transmission costs were incurred to deliver an increased quantity of gas to these repowered plant sites. This "no additional transportation cost case" is depicted in Figures 7.4 and 7.5, which depict alternative gas/coal price differentials and externality credits for site and steam turbine repowering. Since transportation costs comprise approximately 30 percent of the total investment cost, the carbon cost curves shift downward considerably when these costs are removed. In Figure 7.4, approximately 55 GW of coal-fired capacity can be repowered at \$50/tC, removing 49 MtC of carbon, 1.4 Mt of SO₂ and 1.0 Mt of NO_x. The amount of natural gas required by these repowered plants is 1.7 MCF; 50 percent of 1995 utility consumption.

The cost-effectiveness numbers derived in this study are optimistic and should be used with caution because they do not (or do not adequately) consider the following factors that will determine the ultimate cost-effectiveness of the coal-to-gas repowering:

- the effect that the potential increase in gas demand from repowering will have on gas prices
- the actual cost of repowering the candidate coal-fired power plants
- the capacity utilization of the converted plants
- the costs associated with breaking long-term coal contracts
- other economic factors (e.g., differential state/federal tax effects)

The analysis and issues that result are discussed below.

7.2.4 DISCUSSION OF THE MAJOR ELEMENTS AND ISSUES

7.2.4.1 Affected Power Plants

In 1995, there was 335 GW of coal-fired capacity at 408 power plants in the United States. Figure 7.6 indicates that this capacity was comprised of:

319 dual fuel units (units that can burn both coal and natural gas),
122 multi-fuel units (coal-fired units at sites with natural gas or petroleum units), and
711 coal-fired units (units at coal only plant sites).

These categories were used due to an initial presumption regarding the investment cost of conversion and deliverability of natural gas (i.e., those plant sites consuming gas in 1995 would have a natural gas pipeline connection, thereby resulting in a lower hookup cost.

Figure 7.4
Carbon Curve for Coal/Gas Site Repowering
Constant 1995 Coal/Gas Price Differential (\$0.72/MCF)
Low Environmental Credits

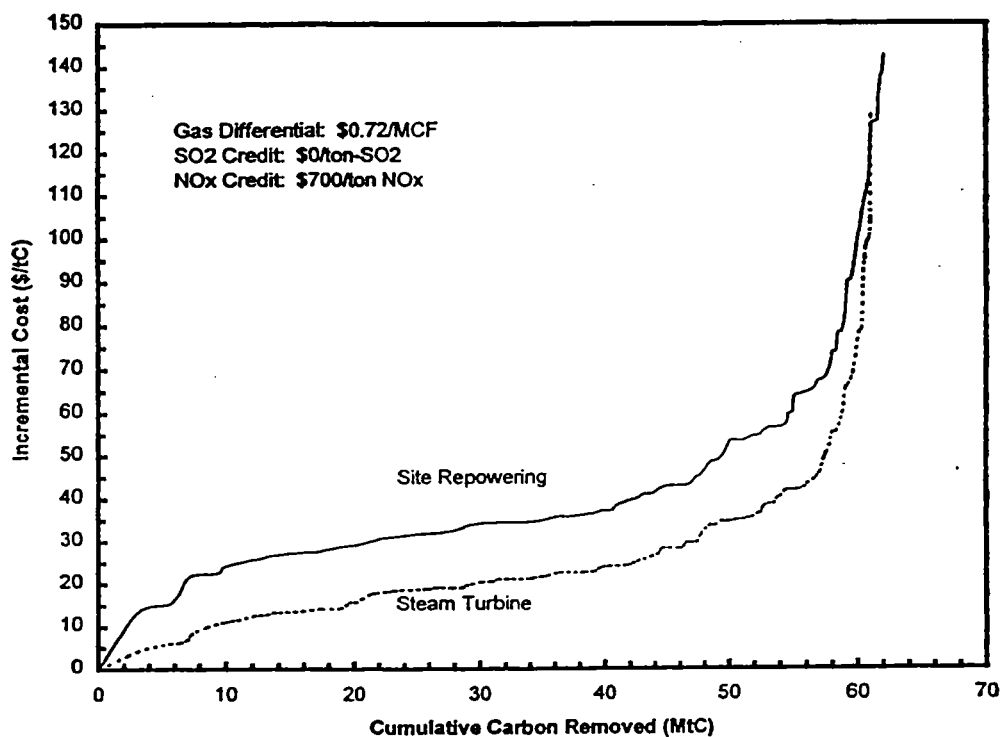


Figure 7.5
Carbon Curve for Partial Repowering
Constant 2010 Coal/Gas Price Differential (\$1.18/MCF)
High Environmental Credits

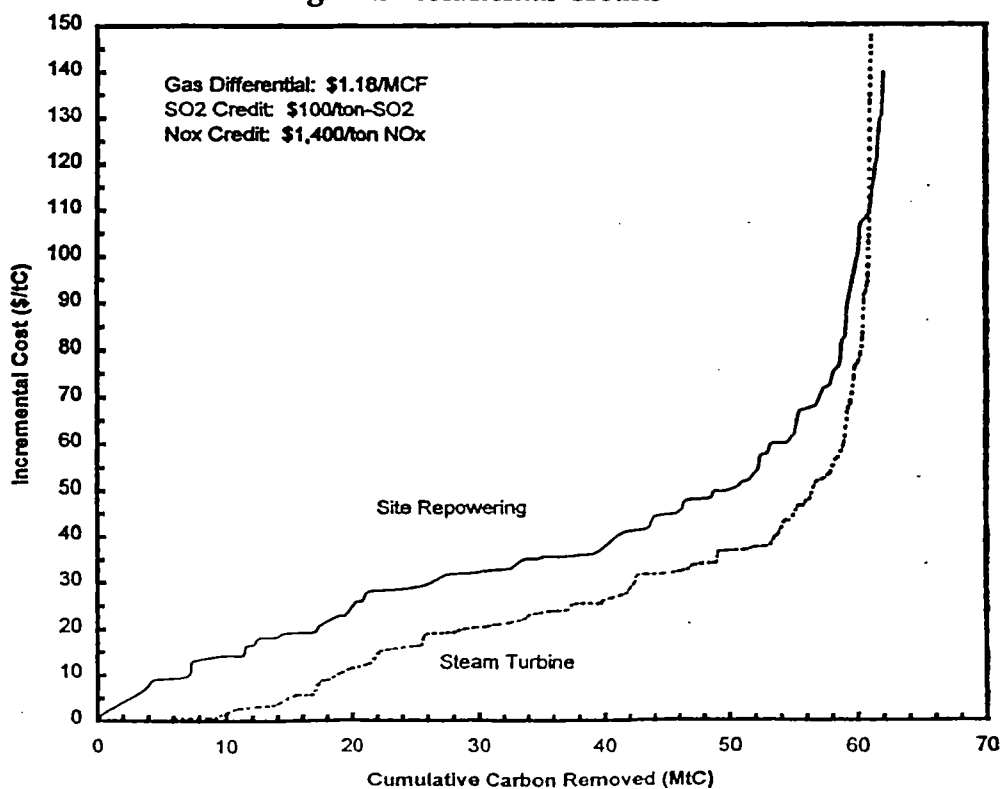
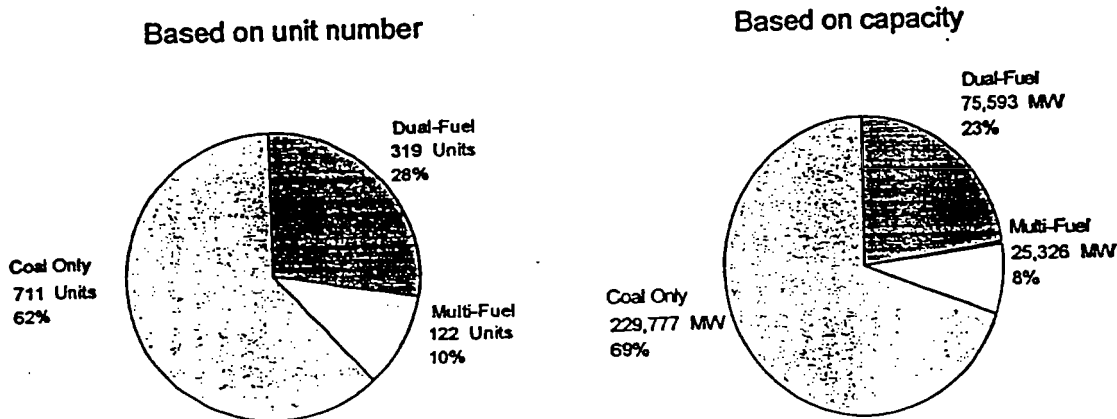


Figure 7.6 Candidate Coal-Fired Power Plants for NGCC Repowering



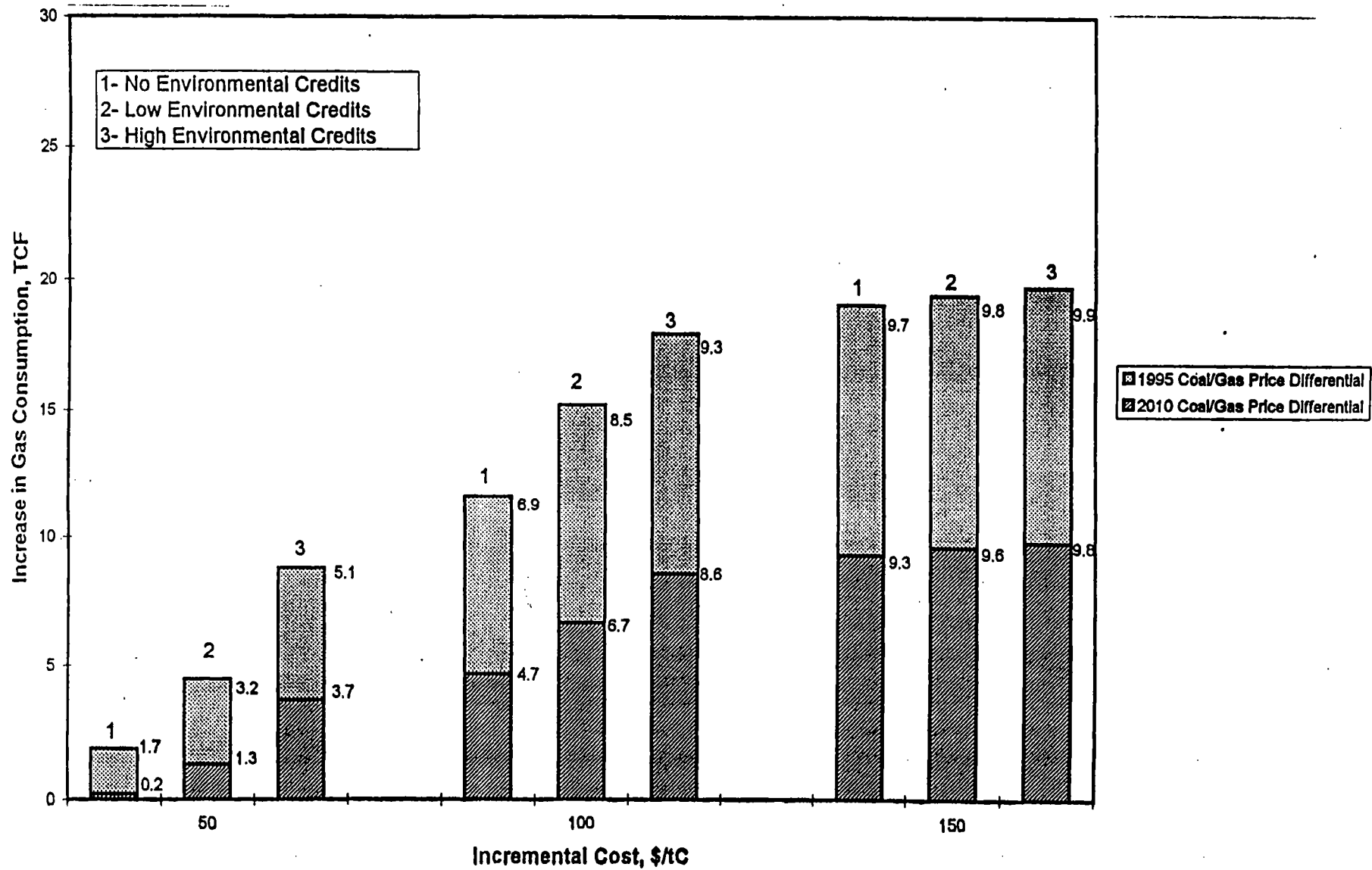
7.2.4.2 Increase in Natural Gas Demand

Utility gas consumption in 1995 was 3.5 trillion cubic feet (TCF). Figure 7.7 shows the increases in natural gas demand from this base that would result from either site or steam turbine repowering for each of three cost effectiveness values (\$50/tC, \$100/tC and \$150/tC. The increase in gas demand ranges from 1.7 MCF to 9.7 MCF MCF in the low gas/coal price differential case without externalities between the \$50/tC and \$100/tC cases. This quantity of gas for repowered plants represents a 50 percent and 275 percent increase in 1995 utility gas consumption, respectively.

If all the candidate coal-fired power plants were repowered with NGCC, natural gas demand in the utility sector would increase by 11.1 TCF/yr (site repowering) or 11.5 TCF/yr (steam turbine repowering) to either 14.52 TCF/yr or 14.95 TCF/yr, respectively. An increase of over 300 percent from current consumption levels. The greatest increase would be for repowered coal-only units (7.8-8.1 TCF/yr over 1995 levels.

The potential gas price increase resulting from NGCC repowered plants was not analyzed in this study. Rather, only the current and projected gas/coal price differentials expected under AEO96 were included in the cost analysis. However, the EIA has prepared a preliminary estimate; they found that an 11 TCF increase in demand would increase natural gas prices by \$3.09/MCF over 20 years (1995-2015), if coal-fired power plants were converted to natural gas when scheduled for life extension/refurbishment and there was considerable demand-side energy efficiency investment.

Figure 7.7
Increase in Gas Consumption Resulting from Coal to Gas Conversion



7.2.4.3 Gas Deliverability

The spatial distribution of the 404 candidate plants are depicted in Figure 7.8. Most of the plants are located in the Mid-Atlantic, South Atlantic, Midwest and Plains regions. While these are also primary gas consuming regions served by major trunklines, many industry experts believe there is limited unused/underutilized capacity in the current 1.2 million mile pipeline system (transmission, 264,900 miles; distribution, 935,000 miles; field, 62,200 miles). Since this capacity is necessary to accommodate peak winter demand and non-utility growth, it is of little value to powerplants considering conversion, since these powerplants require firm pipeline commitments.

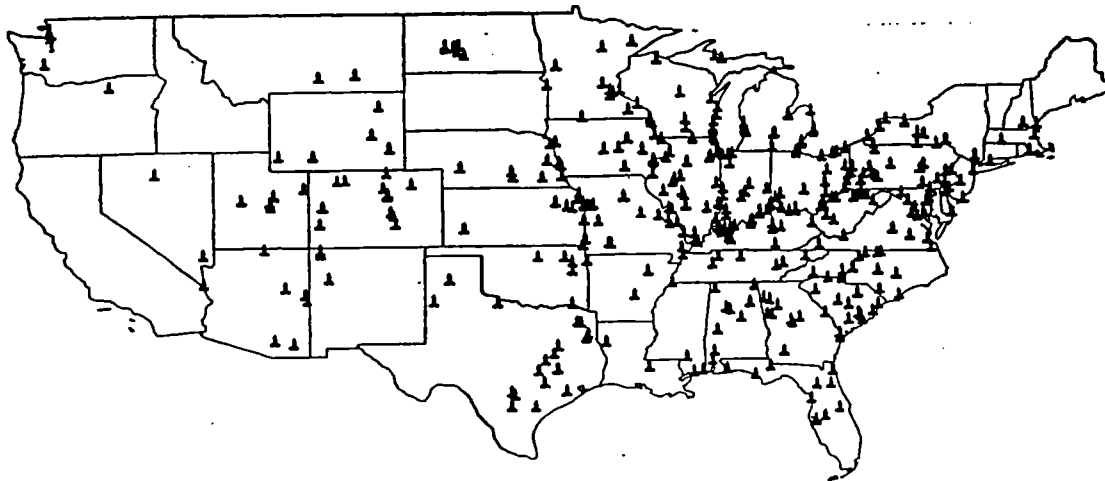
Due to the potentially significant increase in utility gas demand that would result from repowering (either site or steam turbine) coal-fired power plants, this study assumed that new pipeline capacity would be required to ensure deliverability. A detailed assessment was performed (using a geographical information system, GIS) to compute the distance of each candidate powerplant to its nearest trunk line. Cost estimates were derived for the costs of upgrading the lines to meet the increased gas demands. Table 7.2 summarizes the distance of the candidate plants to their closest production zone.

The requirement to add new pipeline capacity could effect the attractiveness of repowering as a carbon mitigation strategy. Although not likely to occur, if all of the candidate plants were converted, 52,323 miles of new pipeline (30-inch average) would be required. For perspective, during 1994 and 1995, between 1,200-1,500 miles of new pipeline were added to the system. According to Federal Energy Regulatory Commission (FERC) filings of pipeline projects, there are a considerable number of new pipelines and pipeline expansions that have been proposed, some of which are still pending approval. While mileage is not included with each filing, in the regions of concern (Central, Midwest, Northeast, and Southeast), more than 8,200 miles of pipe is projected to be added; this level of expansion is greater than the 1994-95 rate of addition. However, it is not known how long it will take to complete these proposed pipelines. So, an accurate assessment of the ability to increase the rate of pipeline expansion/construction could not be estimated as a part of this study.

Table 7.2 Plant Distance from Production Zone

(Miles)	Dual-Fuel		Multi-Fuel		Coal Only		Total	
	# Units	Percent	# Units	Percent	# Units	Percent	# Units	Percent
60-440	48	37	5	12	55	22	103	26
440-620	33	25	8	19	64	26	105	25
620-890	30	23	15	35	59	24	104	25
890-1480	19	15	15	35	67	27	101	24
Total	130	100	43	100	245	100	418	100

Figure 7.8 Location of Candidate Plants



7.2.4.4 Emissions Reduction

Due to the difference in the carbon content of natural gas and coal, and the higher efficiency of NGCC generation, repowering would carbon emissions significantly. If all of the candidate plants were converted, carbon emissions would be reduced by 50/MtC to 269 MtC at cost effectiveness values of between \$50 and \$150/tC in the low price differential (\$0.72/MCF), no externality case.

Because of the differences in the sulfur and nitrogen content of coal and gas and the higher efficiency of the repowered coal units, SO₂ and NO_x would be removed as a result of conversion. Table 7.1 (earlier) summarizes the reduction in SO₂ and NO_x emissions for each case and carbon cost. At the \$50/tC level, approximately 50 percent of the SO₂ and NO_x would be removed; at \$100/tC and higher almost all coal-fired SO₂ and NO_x emissions would be eliminated. If all of the plants were converted, up to 10.5 million tons of SO₂ and 5.7 million tons of NO_x would be removed.

The economic value of the SO₂ and NO_x emissions reductions that would result from conversion of the plants also were assessed in this study. Using the methodology described in the Appendix, SO₂ was valued at between \$0 and \$100/ton; NO_x was valued at between \$700 and \$1400/ton. These values were used as the basis for the environmental externality credits used in this report.

7.2.4.5 Cost-Effectiveness

The cost-effectiveness of the repowering options analyzed range from \$0/tC to \$500/tC, with the majority of the plants located between \$0/tC and \$150/tC. As noted in this report, the cost-effectiveness curves should be used with caution. Gas

deliverability, gas price increases and proper valuation of SO₂ and NO_x credits could significantly affect the results of the study.

In addition, the effectiveness of repowering as a carbon control strategy will depend upon whether and to what extent the converted plants are dispatched. If, because of the costs associated with conversion, the repowered plants are not dispatched or their utilization minimized, the associated carbon reductions will depend on the fuels and technologies used at the plants dispatched ahead of the repowered plants.

7.3 CO-FIRING COAL WITH BIOMASS

Summary: Co-firing biomass with coal has the potential to produce 7.5 GW by 2010 and 26 GW by 2020. Though the current substitution rate is negligible, a rapid expansion is possible based on wood residues (urban wood, pallets, secondary manufacturing products) and dedicated feedstock supply systems (DFSS) such as willow, poplar and switchgrass. A set of three cases were analyzed with differing assumptions on the availability and costs of feedstocks as set out below:

Table 7.3 Summary Table of Parameters and the 2010 Results

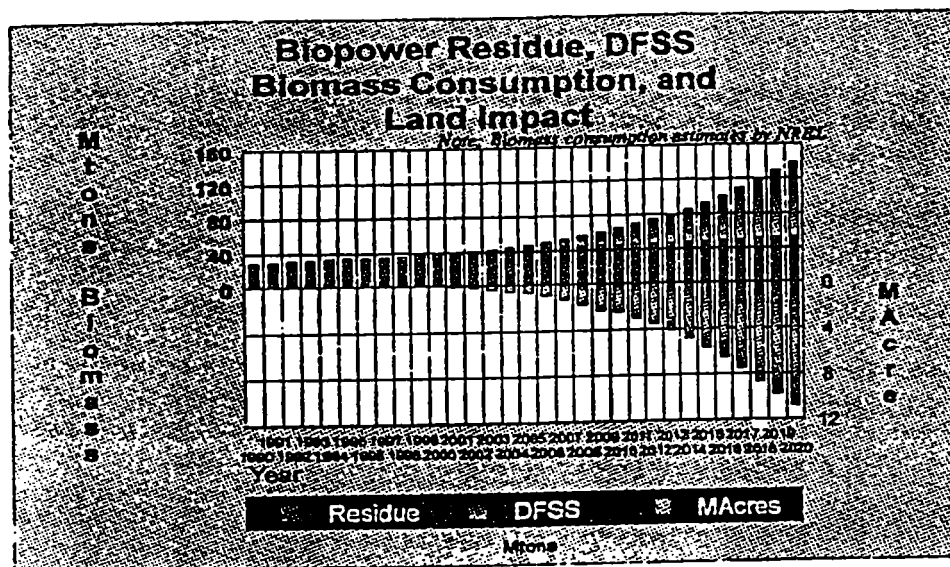
Case	Low Biomass Costs	High Biomass Costs	Carbon 50 \$/t, with high Biomass Cost
Residue cost Beginning	6 \$/ton	15 \$/ton	15 \$/ton
Residue Cost at End	18 \$/ton	25.6 \$/ton	41.56 \$/ton
DFSS Cost at Beginning	44.7 \$/ton	49.8 \$/ton	49.8 \$/ton
DFSS Cost at End of period	18.2 \$/ton	25.2 \$/ton	25.2 \$/ton
Average Cost in 2010 \$/t	18.26 \$/ton	25.8 \$/t	40.96 \$/ton
Average Cost of Energy	0.96 \$/10 ⁶ Btu	1.36 \$/10 ⁶ Btu	1.69 \$/10 ⁶ Btu
Carbon compensation	17.6 \$/ton	33.9 \$/ton	47.7 \$/ton
Carbon replacement in 2010	14.6 Mtonne	14.6 Mtonne	20.1 Mtonne
Fraction of Coal Capacity	2.5%	2.5%	3.5%

The Technology: The current coal fired power generating system represents a direct system for carbon mitigation by substituting biomass-based renewable carbon for fossil carbon. Extensive demonstrations and trials have shown that effective substitutions of biomass energy can be made up to about 15% of the total energy input with little more than burner and feed intake system modifications to existing stations⁴. Since large scale power boilers in the current 310 GW capacity fleet range from 100 MW to 1.3 GW the biomass potential in a single boiler ranges from 15 MW to 150 MW. Preparation of biomass to an appropriate size of minus 1/4 inch and a moisture content of < 25% involves well known and commercial technologies. After "tuning" the boilers combustion output - there is little or no loss in total efficiency, implying that the biomass combustion efficiency to electricity is close to the 33-37% range of the unmodified coal plant, an efficiency that stand-alone biomass generating capacity has yet to demonstrate. Since biomass in general has significantly less sulfur than coal, there is a SO_x benefit, and early results suggest that there is also a NO_x reduction potential with woody biomass.

⁴ CONEG 1996. Utility Coal-Biomass Co-firing Plant Opportunities and Conceptual Assessments. Report available from the Northeast Regional Biomass Program, CONEG Policy Research Center, Inc. Washington, DC. (Work performed by ANTARES Group, Inc. and Parsons Power)

Economics: Investment levels are site-specific and are affected by the available space for yarding and storing the biomass, installation of size reduction and drying facilities, and the nature of the boiler burner modifications. Investments are expected to be in the range of 100 - 700 \$/kW of biomass capacity. A median value of about 180 \$/kW is expected from the early trials. There is an O&M cost increase of 70 k\$/y over coal, as a result of the need for an additional yard worker to handle the biomass. A 100 MW coal plant at 10% biomass substitution would then have an investment of 1.8 million dollars. Assuming the GENCO recovers its investment cost in 3 years, then the annual fuel offset then has to be 670 k\$ to cover capital recovery and the increased O&M. With the average price of coal being about 1.40 \$/10⁶ Btu the annual fuel cost of coal is 1081 k\$ (10 MW at 85% capacity factor and 32.9% thermal efficiency 10,337 Btu/kWh). The allowable cost of biomass then is 411 k\$ or about 9 \$/ton.

Figure 7.9 30 GW Strategic Plan Scenario



Fuel Costs: The near term potential biomass feedstocks are residues in a radius of about 50 miles around the plant. Based on data from existing biomass power plants in the NE and in California - there are extensive sources of biomass residues available for about 0.5 \$/10⁶ Btu (<9\$/tonne). Transportation costs limit the range over which such biomass feedstocks can be acquired, and for the longer term, a dedicated feedstock system much closer to the power plant is envisaged. By definition, the availability of residues (e.g. urban wood residues, rights of way clearance, construction and demolition wood, pallets, and sawdust-shavings from secondary wood processing) is finite and will respond to the prices offered for the residues. In the sensitivity cases tested - it was presumed that a 50 \$/t carbon payment would effectively increase the available residues by 50% over the base case.

Dedicated feedstocks would escape this constraint. However, such resources are much more expensive than residues, and though the current development goal is in the range of 1 - 1.5 \$/10⁶ Btu, with current technology it is in the 2 \$/10⁶ Btu region. It is assumed that with an

estimated 10.4 million acres will be needed to reach a nominal production of 86 Mtonnes by 2020. Since DFSS is in an early stage of development the model assumes that the initial planting will only yield about 6 tonnes/acre by 2002 [Which is today's state of the art], and that by 2010 the yield will be closer to 8 tonnes/acre. Equally today's costs are high with 45 \$/tonne being feasible, however, a combination of learning curve improvements along with scale are presumed to bring the cost down to 18\$/tonne by 2020. The sensitivity case also examined a cost of 25 \$/t by 2020 (approximately \$1.3 \$/GJ). The competing coal prices are assumed to be 1.40 \$/10⁶ Btu (1.33 \$/GJ) throughout.

Carbon Substitution Potential: NREL developed a notional 30 GW scenario for biomass supplies for the current Biomass Power Strategic Plan - this scenario was developed for a mix of steam, co-firing and IGCC biomass generation. However, the resource plan that was developed that included residues and DFSS is independent of the end use and involves the development of almost 12 million acres of land for DFSS by 2020. The resource development is shown in Figure 7.9, above, and is used as the basis for this carbon assessment. This indicates that DFSS would come on rapidly after the year 2001 and that residues are assumed to be capable of only a small increase in quantity - as much is already utilized.

The average cost of residues is expected to increase gradually, while those of DFSS crops are expected to demonstrate a strong learning curve and large economies of scale as shown in Figure 7.10, below. The data on the quantities and the costs from the previous two figures can be combined into Figure 7.11, which is the supply curve for biomass for cofiring in the low cost case. The horizontal line shows the breakeven cost that the biomass has to achieve to be able to satisfy the generators' requirements that the capital investment be offset by fuel cost savings.

Figure 7.10 Cost of residues and DFSS

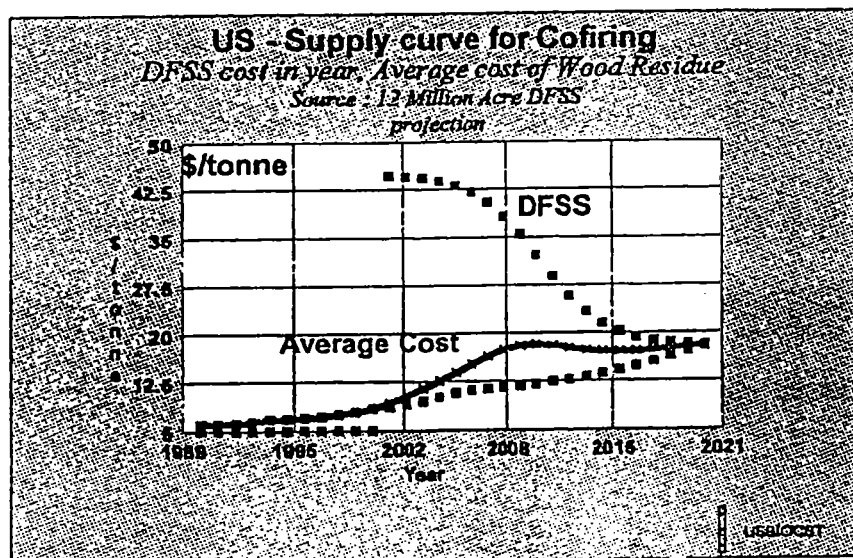
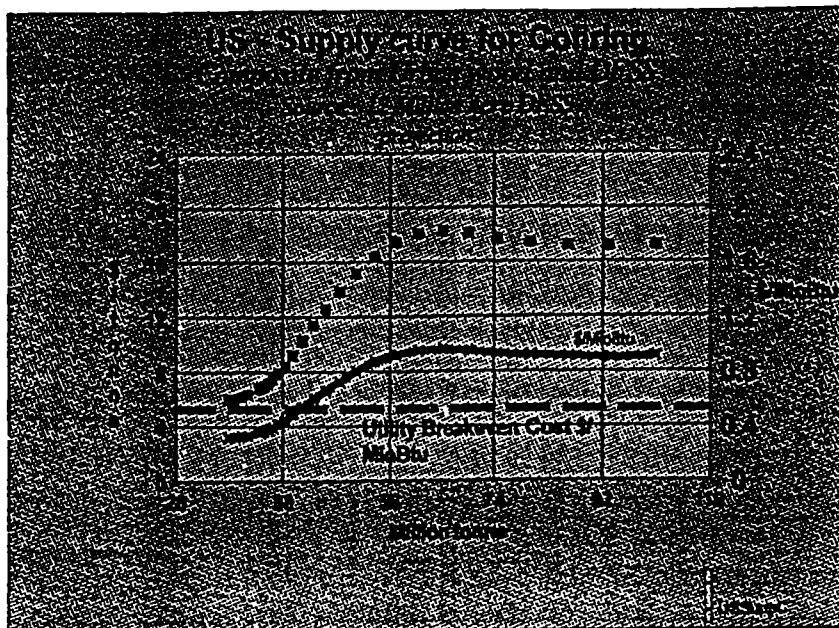


Figure 7.11 Biomass supply curve

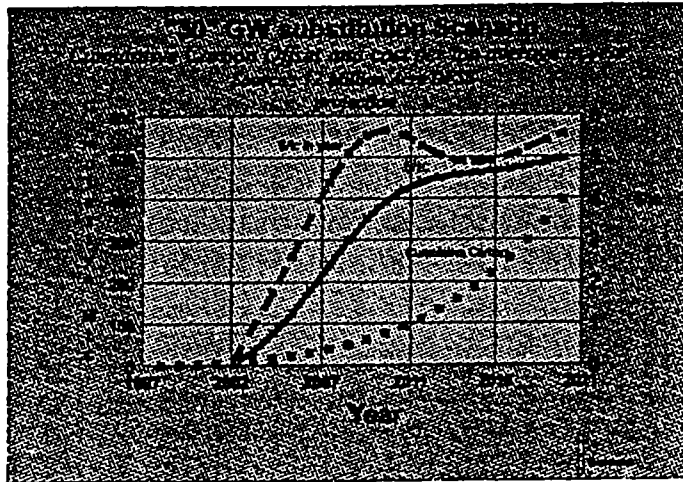


Timing: While a coal fired station could be modified for co-firing in less than one year (including environmental permitting) - the necessary biomass resource assessment, contractual arrangements and logistics for biomass residues could take the better part of 18 months, based on actual project experience. While the availability of residues is assumed to be significant and would ultimately supply 50 Mtonnes or so, it is also recognized that its price and availability are likely to be variable, with the price increasing with demand level, and for that reason the biomass feedstock supply is expected to be a blend of dedicated feedstocks supply systems (DFSS) and residues. The DFSS component is predicated on making a start into land accumulation (purchase, lease, cooperatives etc.), and at the earliest land preparation and planting in 1999 - the crops of choice are probably woody species in much of the NE and SE and would require extensive nursery activity to put in place the needed clonal material for planting out. With willow - the first harvest cycle would be 4 years after planting and a rotation of 3 years thereafter, for poplar the cycle is likely to be in the range of 6 to 8 years.

Supply model sensitivities: Three supply models have been put together. The low (optimistic) and high cost biomass scenarios are based on a 30 GW supply model that uses an incremental amount of 23 Mtonnes residues over today's estimated 29 Mtonnes (Million tonnes), and the biomass produced from about 11 Million Acres of DFSS. In the low and the high cases the assumptions span a range of both residue and DFSS costs, resulting in average 2010 fuel costs of 0.96 \$/MBtu and 1.36 \$/MBtu delivered to the GENCO.

Figure 7.12, below, shows the cumulative carbon displacement with time from the proposed feedstock supply system - the average cost of the carbon substituted is shown by the solid line, while the cost in the year specified is shown by the dotted line.

Figure 7.12 Average costs of carbon compensation and cumulative carbon replacement



Implementation Requirements: A significant effort is required to bring on the 10 - 11 Million Acres proposed for 2020, since today the discussions are for demonstrations in DFSS at the 1000 Acre level. The development of adequate clonal material and management systems for planting, tending, and harvesting will also be required. An idea of the rate of resource deployment and the impacts with time is shown in the Table 7.4 below:

Table 7.4 Net Impacts and Costs - low cost biomass scenario

Year	1998	2000	2005	2010	2015	2020
GW-Biomass	0.2	0.75	3.1	7.6	14.6	26.4
Energy TWh	1.4	5.2	21.5	53	103	185
MTonnes Biomass	0.8	3	12	30	58	104
Percent DFSS	0	0	38	67	78	83
Carbon replacement Mtonnes	0.4	1.4	5.9	14.6	28.4	51
Carbon Compensation \$/tce	0	0	3.94	12.3	14.4	15.5

Environmental Issues: Since most of the coal fired stations have efficient precipitators and some have sulfur capture technologies, the net effect of 10% biomass substitution (on an energy basis) appears to be negligible. The solid wastes (ash) are little changed in either composition or mass (most biomass has considerably less ash than coal.). However, for some stations that sell fly ash to Portland cement manufacture, there may be a need to negotiate the acceptance of mixed biomass and coal ash in such applications with respect to ASTM standards.

The DFSS environmental impact is considered to be dependent on the choice of lands for the plantation. In the case of replacing annual crop land with perennial DFSS there appears to be a

net environmental gain. For pasture land it probably is a wash and for replacement of forest there may be some increased impacts.

The residue utilization has the potential to offset land filling and potential methane emissions from land filling clean biomass materials. Based on experience in California, the issue will be one of rationalizing the cost distribution between the "waste generator," the haulage contractor and the generating station receiving the residue rather than it going to landfill. If such negotiations were successful and the generating station could guarantee the reception of the residues at all times (many urban wood residue generators do not have storage facilities) - both residue costs and their availability could be significantly improved.

7.4 EFFICIENCY IMPROVEMENTS IN GENERATION AND T&D

Increasing operations and maintenance activities to lower heat rates (and thereby improve efficiencies) can cut carbon emissions significantly and at low-cost. Cutting heat rates for all fossil-fuel powerplants, both new and existing, by 5 percent, for instance, would cut emissions by the same 5 percent (Hirst and Baxter, 1997).

Improving the efficiency of transmission and distribution (T&D) systems is another supply-side option available to utilities. As with generation, T&D improvements can include both capital investments (for example, new transformers and conductors) and improved operations. Because T&D losses account for only about seven percent of total generation, the opportunities to reduce CO₂ emissions through such mechanisms are limited. However, they could nonetheless be cost-effective. Improving T&D efficiency by 10 percent would cut emissions by less than 1 percent (Hirst and Baxter, 1997).

7.5 NUCLEAR PLANT LIFE EXTENSION

Hydroelectric power currently supplies about 10% of the nation's electricity and constitutes 84% of the nation's renewable energy production. The adverse environmental affects of some hydropower projects are now relatively well known (e.g., Mattice 1994), but significant progress is also being made in mitigating these problems (Sale et al. 1991). Regulatory processes such as the licensing of non-federal hydropower projects and the Endangered Species Act are having real affects on hydropower projects, leading to a reduction of the environmental impacts from this important energy source. The end result of these regulatory processes has also been a consistent reduction in total energy production from hydropower.

In both the EIA reference case and the restructured case described in Chapter 6, nuclear plants are projected to lose market share in the national mix of electricity generation. The nuclear power capacity of 99.2 Gigawatts that existed in 1995 is forecast to drop to 88.9 gigawatts in EIA reference forecast for 2010. This drop is primarily the result of the retirement of 17 plants whose licenses expire between 1999 and 2010. The combined capacity of these 17 plants is 11.5 gigawatts. The average capacity factor of these plants is expected to remain between 76 and 79 percent throughout the forecast, deviating little from the current capacity factor of 77.

No additional nuclear units are actively under construction in the U.S. Therefore, no new planned units are assumed to come into service during the 2010 forecast. One nuclear unit, Watts Bar 1 owned by the Tennessee Valley Authority, received its license in 1996, but several plants have also recently closed.

The 1997 AEO defines a "high nuclear case" which assumes that every nuclear plant operating in 1996 has an additional 10 years of operation, as long as their operating costs do not exceed 4 cents per kilowatt-hour. This 2010 forecast results in the closure of only three nuclear plants (totalling 1.3 gigawatts of capacity) due to license expirations and the addition of 10.2 gigawatts of new capacity from 14 plant lifetime extensions (EIA, 1996a, Table F5, p. 187; Nuclear Regulatory Commission, 1996). According to the AEO "high nuclear case," 12 million metric tons of carbon would be offset by this additional carbon-free source of electricity. Using the capacity that's on the margin in the restructured case (with carbon emissions averaging 80 grams per kWh), the carbon reduction from this additional nuclear resource drops to 5.6 million metric tons. A range of 2 to 5 million metric tons would appear to be a more realistic forecast for the high efficiency/low carbon scenario.

Figure 7.x illustrates the important role that nuclear power life extension could have after 2020. Only 45 of the nation's 105 nuclear plants have licenses that extend beyond 2020.

EIA (1996b) does not estimate the cost of its high nuclear case, although it acknowledges that the physical degradation of some units would have to be reversed. OTA (1991) also notes the potential carbon savings of extending the useful life of all nuclear plants to 45 years, but assumes that this option involves minimal costs. Understanding the effects of aging in order to better manage the aging nuclear infrastructure is an important R&D topic. Pressure vessel embrittlement and the degradation of cables, pumps, and valves can be slowed by advances in materials science and by developing digital instrumentation and controls technology. Such R&D can help the U.S. maintain the current licensing basis of its nuclear power plants, thereby enabling their operation to extend beyond the standard 40-year licensing period.

7.6 INCREASING GENERATION AND CAPACITY AT EXISTING HYDROPOWER PLANTS

Hydroelectric power currently supplies about 10% (78 GW) of the nation's electricity and constitutes 84% of the nation's generation from renewables (EIA, 1996a, Table A17). Hydroelectric power plants produce no greenhouse gas emissions during operation (U.S. Department of Energy, 1994). In the 1940s, 40% of the country's electricity came from hydropower plants (Williams and Bateman, 1995). The adverse environmental affects of some hydropower projects are now relatively well known (e.g., Mattice, 1994), but significant progress is also being made in mitigating these problems (Sale et al., 1991).

Hydroelectric power uses the energy of falling water to generate electricity. Hydroelectric generation technologies for utility-scale applications are generally considered to be mature, with turbine efficiencies typically in the 75%-85% range (Office of Technology Assessment, 1995). There are three types of hydropower facility:

- Most hydropower plants use dams to raise water levels and regulate water availability, thereby increasing its potential energy. Conventional hydropower (with reservoir storage) can provide baseload, intermediate, or peaking power, depending on the availability of water and project design (Office of Technology Assessment, 1995).
- Some hydropower plants, called run-of-river systems, do not involve large dams or storage reservoirs. Instead, smaller diversion structures are used to channel water through a canal or penstock to a powerhouse, where water is returned to the river. Run-of-river systems reduce some of the costs and environmental impacts associated with large hydro facilities.

- Pumped storage projects use off-peak electricity (usually from a baseload power plant) to pump water to an upper reservoir; this water is later released to flow through a generator during periods of peak demand. Such plants are net consumers of energy. Although pumped storage is not a renewable energy technology, it can produce a net reduction in greenhouse gas emissions when the fuel providing electricity for pumping has a lower carbon content than the fuel being displaced by the pumped storage generation (U.S. Department of Energy, 1994).

The main challenge for hydropower in recent years has been the growing concern over its local environmental impacts. By damming rivers to create storage reservoirs, hydro facilities can adversely affect terrestrial and aquatic ecosystems. Wildlife habitats can become inundated; fish migration routes can be cut off, and fish can die in the generating turbines or because the downstream water quality and habitat is changed; plants that grow along the riverbanks are disrupted by changes in the natural water level, both above and below the dam; and large or rapid variations in the amount of water being discharged can disrupt aquatic habitats and accelerate erosion downstream.

Regulatory processes such as the licensing of non-federal hydropower projects and the Endangered Species Act are having real affects on hydropower projects, leading to a reduction of the environmental impacts from this energy source. The end result of these regulatory processes has been a progressive reduction in total energy production from hydropower. Between 1995 and 2010, 19 GW of hydropower at non-federal projects will be subject to relicensing. Recent trends indicate that relicensing results in an average 8% loss in generation (7,200 Gwh) due to the imposition of new environmental constraints on operation. The most likely replacement for this lost, emission-free generation comes from a combination of fossil fuels.

Under the "high efficiency/low carbon" scenario, and assuming a sustained regulatory reinvention effort between now and the year 2010, incentives will exist that could motivate the growth of hydroelectric power generation in either of two ways. Neither of these opportunities involves the construction of hydropower plants at new sites. However, both will required continued research and development to improve turbine system design and operation to minimize adverse environmental effects.

- **Increasing generation at existing hydropower plants** - This option consists of modernizing and upgrading existing turbines and generators to increase their efficiency and/or electrical output. Given enabling incentives, upgrading hydropower plants can result energy production gains of 5% to 10%. Hydropower upgrades will have significant corralary environmental benefits, because new generating technology offers more effective fish passage, water quality improvements, and opportunities to improve downstream aquatic habitats.
- **Adding generating capacity at existing dams** - A recent resource assessment identified 21 MW of undeveloped hydropower capacity at existing dams (Rinehart et al., 1997). About 36,000 GWh of new hydropower generation could be added by developing these sites between 1995 and 2010 (Office of Conservation and Renewable Energy, 1990).

There are additional gains in hydropower that are more uncertain and best evaluated in the post 2010 period. The national hydropower resource assessment (Rinehart et al., 1997) has identified 2,400 sites and 10 MW of environmentally acceptable hydropower at undeveloped sites (projects that would require the construction of new dams or diversions). These resources may eventually be developed given more adventagous economics, regulatory reinvention, and technology improvements. Further development of efficient low-head generating technologies

would also encourage deployment at the many low-head sites that are otherwise unsuitable for hydropower additions.

Considering just the near-term opportunities (present to 2010), further hydropower development could reduce carbon emissions in 2010 by between 4.1 and 5.4 million tons. Additional reductions can be achieved after 2010 with continuing advancements in generating technologies and environmental mitigation techniques.

7.7 ADVANCED COAL TECHNOLOGIES

To test the possible effects on carbon emissions of other advanced fossil-fired electricity generation technologies, we replaced the advanced technologies used by EIA with estimates from DOE's Office of Fossil Energy (Table 5.6). These estimates changed the construction costs and heat rates for advanced combustion turbines, combined-cycle units, and coal units. ORCED did not select the advanced coal unit with either the EIA or the Fossil Energy estimates of this unit's costs and operating characteristics; in both cases, its initial cost was too high to warrant inclusion in the generation mix. The only significant change to occur was the replacement of the most advanced combustion turbine as specified by EIA with an older combined cycle unit. The net effect of this change on carbon emissions was negligible.

Table 7.5 Base Case vs Advanced Technologies (Costs in 1995\$)

	Original	Alternative	Original	Alternative
<u>Advanced Gas Combined Cycle</u>				
Year of construction	2005	2005	2009	2010
Capital Cost, \$/kW	410	525	410	500
Heat Rate	6284	5688	5817	5538
Fixed O&M, \$/kW-yr	27	16	27	16
Variable O&M, ¢/kWh	0.05	0.015	0.05	0.015
<u>Advanced Gas Combustion Turbine</u>				
Year of construction	2002	2005	2008	2010
Capital Cost, \$/kW	339	400	374	364
Heat Rate	10873	8699	7793	8533
Fixed O&M, \$/kW-yr	11.9	17.6	16.9	17.6
Variable O&M, ¢/kWh	0.010	0.012	0.05	0.012
<u>Advanced Coal</u>				
Year of construction	2006	2005		
Capital Cost, \$/kW	1340	1050		
Heat Rate	9600	7064		
Fixed O&M, \$/kW-yr	34	26		
Variable O&M, ¢/kWh	0.25	0.2		

Source:

This limited analysis suggests that between now and the year 2010, highly efficient (i.e., a heat rate of about 7000 Btu/kWh) but expensive (i.e., an cost of over \$1000/kW) advanced

coal units cannot compete economically with either the generation mix that remains from the 1990s or with gas-fired combined-cycle units.

7.8 POTENTIAL FOR RENEWABLE OPTIONS IN 2020

7.8.1 Overview

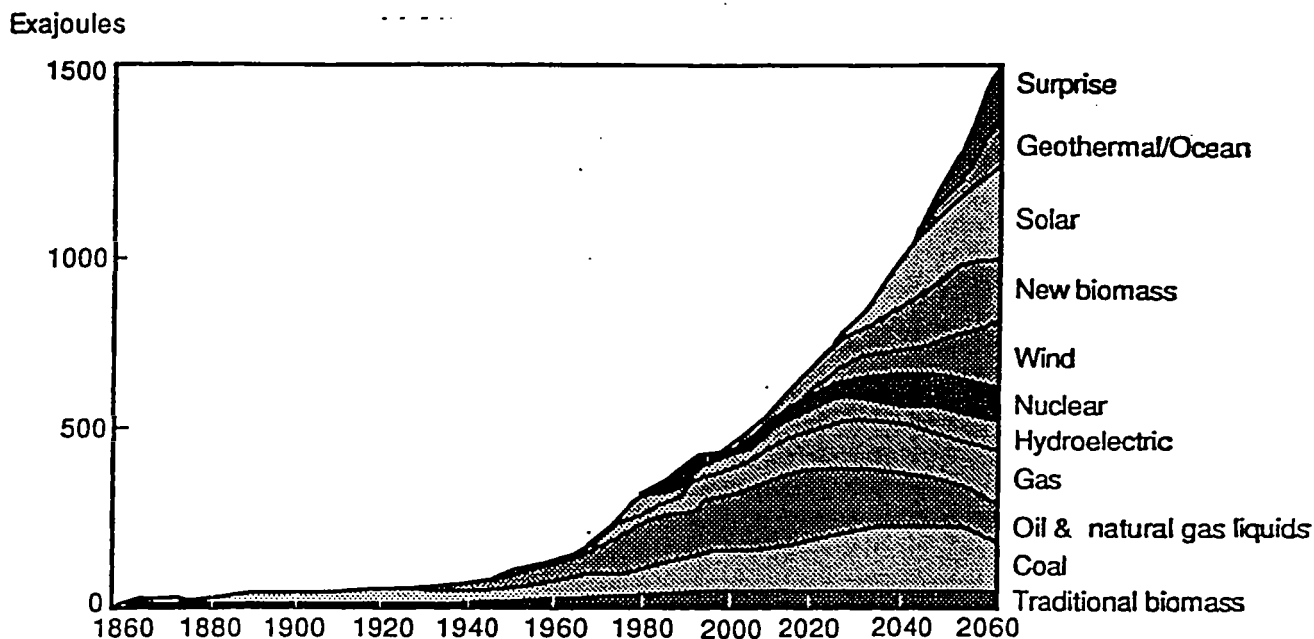
Renewable sources of energy are either continuously resupplied by the sun or they tap inexhaustible resources, such as geothermal energy. In contrast, fossil fuels — oil, coal and natural gas — form so slowly in comparison to our rate of energy use that they are regarded as finite. Today, roughly 12% of the country's electricity generating capacity is based on renewable power systems, primarily hydropower (EIA, 1996a).

The use of modern renewable energy technologies to generate electricity either does not pollute or emits far less pollution than burning fossil fuels. Most renewable energy technologies produce no greenhouse gas emissions at all during operation, and are responsible for only very small emissions during manufacture of the components and construction of the generating plant. Carbon reduction figures quoted in this section are based on emissions during operation only.

With a vigorous and sustained program of research, development and deployment, all of the renewable energy technologies discussed here are capable of serving carbon-reduction goals at competitive electricity prices by 2020. Not only could the contribution from renewables be roughly double that of today, there will be a strong trend toward an even greater reliance on renewables in the years beyond 2020 (Fig. 7.x).⁵ Some renewable energy technologies are already cost-effective today but are not more widely accepted because of a lack of industry experience, others could be cost-effective through economies of scale at higher production levels, and still others need substantial research and development before they will be cost-competitive with fossil-fuel generating technologies. The intermittency of solar and wind resources means that these technologies generally must be used in conjunction with energy storage systems, which themselves require further R&D, although electric utilities have demonstrated that the intermittency issue can be circumvented with appropriate design and operation of transmission and distribution systems. Today, solar energy is most suitable for peak power applications while wind power tends to be used as a fuel saver.

⁵ Many energy analysts, including some from the major oil companies, have accepted that humanity as a whole cannot continue to consume energy at the current rate of growth without eventually turning to renewable energy technologies. In *The Evolution of the World's Energy Systems*, Shell International predicts that fossil fuels will continue to sustain global economic development until 2020-2030, at which time "they reach their maximum potential and no longer contribute to growth, being limited by the rate of production and commercialisation of resources economically competitive with renewable energies." Sustained economic growth beyond this time will be possible only if renewable energy technologies have been developed to the point where they are ready for large-scale implementation in the 2020-2030 time period. The alternative, according to Shell, is to curtail the growth of per capita GDP and find ways to achieve a 2% per year improvement in energy intensity, something that has been seen for only limited periods in the past (Royal Dutch/Shell Group of Companies, 1996).

**Figure 7.13 Sustained Growth Scenario from Shell International
(Reproduced courtesy of Shell International Petroleum Company)**

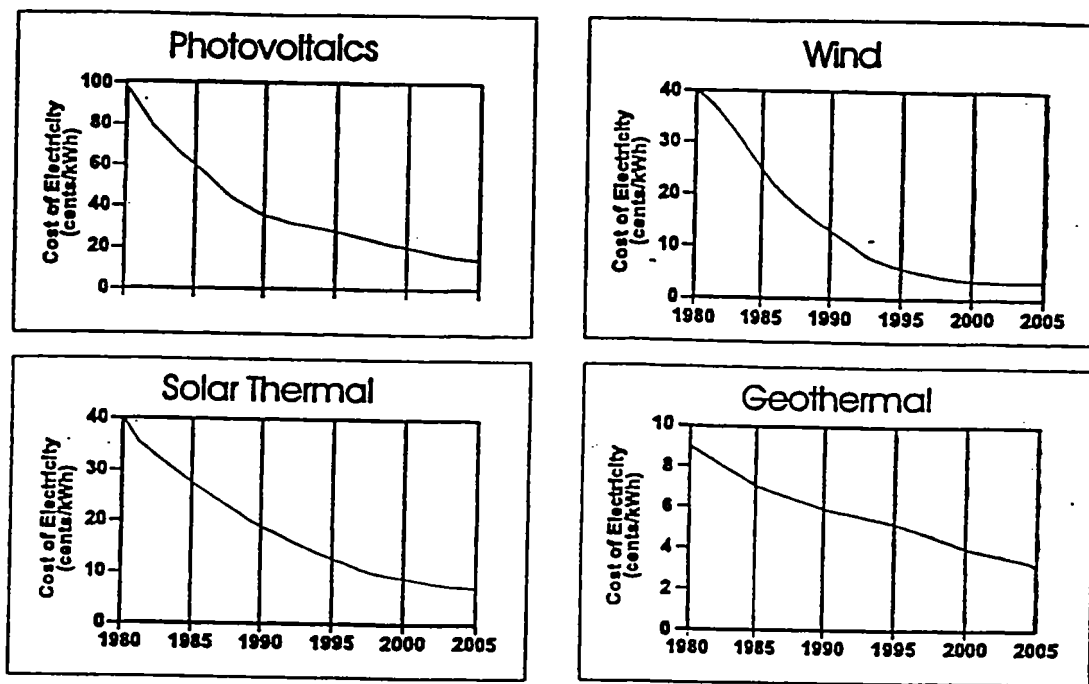


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The demand for electricity is growing most rapidly in the industrializing nations of the developing world, and sales of renewable energy technologies to these countries could be an important component of a U.S. carbon-reduction strategy. Renewables are likely to be adopted more rapidly in the developing world than in the United States. The lack of infrastructure, especially extensive electricity grids, in developing nations means that renewable energy technologies, in particular wind power and photovoltaics, are not competing for marginal markets with a pre-installed base of conventional power technologies, but rather are competing on the ground floor for entry into thousands of separate electricity markets. In addition, many of these countries lack adequate fossil-fuel reserves to meet their projected demand for electricity. If future carbon credits are tradable between nations, international demand for renewable power systems could provide markets for the U.S. renewables industry and increase the supply of carbon credits available for purchase.

Some renewable energy technologies are already cost-effective in certain, specialized applications. However, with the exception of hydroelectric power, their total contribution to the U.S. electricity supply (and carbon-reduction goals) is unlikely to be significant until after 2020. More rapid deployment is likely to be hampered by several factors, including the persistently low price of coal and natural gas. However, the cost of electricity from most of the renewable energy technologies has fallen dramatically over the past 15 years, and is likely to continue to decline relative to the cost of fossil-fuel electricity. Ongoing R&D will make renewables progressively more affordable and competitive in a wider range of applications, especially after 2010.

Figure 7.14 Renewable Technology Cost Trends (Source: NREL)



If renewables are to continue moving down the cost curve into the marketplace, the United States needs an aggressive, integrated R&D strategy that addresses every part of the development cycle, from basic research to improvements in manufacturing technology and commercialization issues. Follow-through is important; if steps are not taken to ensure that a developed technology is introduced to the marketplace, a firm from another country could capitalize on U.S. technological advances.—a risk common to all emerging technologies.

Lowering the cost of electricity from each of the renewable energy technologies to the point where it is competitive will not, however, ensure adequate market penetration to meet carbon-reduction goals in time. The tendency of markets to “lock in” established technologies could significantly slow down the adoption of renewables. Buyers tend to choose familiar products even when they are a little more expensive or in some other way marginally inferior to the competition. This phenomenon slows down the introduction of new technologies, such as renewables, because buyers cannot be relied on to purchase the least costly competitive product (Cowan and Kline, 1996). Demonstration projects go some way toward building industry and market familiarity and confidence but, if we are to realize the carbon-reduction benefits of renewables, more concerted action may be necessary to overcome the lock-in of established (fossil-fuel and hydro) generating technologies.

The potential of each renewable energy technology to reduce atmospheric carbon in 2020 is estimated in the pages that follow. However, with the exception of large-scale hydro, most renewables are not technologically very mature. Terrestrial photovoltaics, for example, has only been in existence for about 25 years, making it difficult to reliably predict the state of the technology, or its likely role in the marketplace, over the same time period into the future.

Because of this uncertainty, the potential for carbon reduction is quoted as a range for most of the renewable technologies.

7.8.2 Hydroelectric Power

The potential for expanding the generation and capacity of hydroelectric power by 2010 is discussed in Section 7.6. This section discusses the potential to establish hydropower at new sites by the year 2020.

FERC has identified 74 GW of untapped hydropower potential in this country, about 60% of it in the western United States and Alaska. Only 2,400 of the nation's 80,000 existing dams are used to generate electricity (Secretary of Energy Advisory Board, 1995).

Few new hydropower projects are currently slated for development. Environmental concerns have led to more stringent licensing requirements, increasing the time required and cost of meeting regulatory requirements. This has not only placed a limit on further hydropower expansion, it has also discouraged renewal applications, jeopardizing the country's existing hydropower capacity. Thus, the potential for new hydroelectric power generation in 2020 is uncertain.⁶

7.8.3 Wind Power

Utility-scale wind power systems use groups of large wind turbines (wind farms) to harness wind energy and convert it into electricity. Wind turbines are mounted on tall towers, usually 100 feet or more above the ground where the wind is faster and less turbulent.

Wind turbines produce no greenhouse gas emissions during operation. About three-fourths of the states in the nation have wind resources that are suitable for utility-scale power generation (Williams and Bateman, 1995), although competing land-use and environmental factors result in the exclusion of some of the land (Energy Information Administration, 1996). Even with these restrictions, however, the U.S. wind resource is large enough to generate one and a half times as much electricity as is currently consumed in the United States (Williams and Bateman, 1995). The intermittency of the wind resource means that the use of wind power on this scale would require careful design and operation of transmission and distribution systems, or the development of improved energy storage systems.

Wind technology has a wide variety of applications, including off-grid remote power for homes and communities, but the greatest contribution to U.S. carbon reduction goals is likely to come from grid-connected utility wind farms. Wind power is already cost-competitive with fossil fuel power in certain situations. It tends to be used as a fuel-saver today, and increasing experience will continue to drive cost and performance improvements. By 2020, improved blade designs could extract even more kinetic energy from the wind, improving the efficiency of the system, and new materials could help turbine blades to better deal with the large and variable mechanical stresses they face, lowering costs while maintaining 30-year blade lifetimes. Computer modeling of components and subsystems will enable the optimization of turbine designs for site-specific operating conditions, and the use of direct-drive generators and variable speed turbines will yield higher conversion efficiencies.

⁶ Throughout section 7.7, calculations for carbon savings are based on 100 kg/MWh, which assumes that the renewable energy technologies are displacing a combination of the latest generation of natural-gas-fired combustion turbines and combined-cycle power plants. The estimate of potential expanded capacity is based on DOE and NREL internal analyses.

Performance improvements such as these will enable utilities to make use of more moderate wind resources, increasing the geographic applicability of wind power, in addition to lowering costs. The cost of wind-generated electricity has already dropped from over 30¢/kWh in 1981 to 4¢/kWh-5¢/kWh today, and is expected to drop another 40% to 50% by 2020 (Office of Technology Assessment, 1995).

Siting issues may have as large an influence on the rate of adoption of wind power as technological considerations. There are sometimes competing demands for the land, although utility-scale wind generation is actually a good complement to agriculture. Good wind sites are often along the tops of ridges, a highly visible location for a large wind farm, and this can be a cause for concern when the site is either close to a population center or in an area of particularly great scenic value. Another environmental consideration affecting site selection is the potential risk to birds, particularly raptors, flying into the rapidly turning rotor blades. The widespread adoption of wind technology is partly dependent on finding ways to reduce this problem.

Wind regimes are extremely site-specific, so even though wind resources have been broadly categorized for the nation as a whole, the siting of individual wind farms requires detailed information in order to select the best site. Wind speeds can vary dramatically over the course of seconds (due to turbulence), hours (diurnal variations), days (weather fronts) and months (seasonal variations). The best locations are those with strong, sustained winds having little turbulence. Finding such locations requires extensive prospecting and monitoring (Office of Technology Assessment, 1995). Better tools for resource characterization and prediction will enhance the value of wind power by enabling utilities to more reliably predict the power output from wind sites.

Strong international interest in wind power could also speed its rate of adoption in the United States. Foreign markets currently account for most new wind installations, so this is where U.S. firms are currently gaining valuable experience with marketing and operations.

In the United States today, wind power accounts for about 2 GW of generating capacity (Energy Information Administration, 1996a). By 2020, new U.S. wind installations could amount to 30-60 GW, displacing 9-18 Mt/yr of carbon emissions.⁷

7.8.4 Biomass Power

Biomass refers to living matter, usually plants, used to produce energy. This includes energy crops grown specifically to be used as fuel, such as fast-growing trees, as well as agricultural and forestry residues. The biomass content of landfills is considered separately (see 7.8.8). Generating power from agricultural and forestry residues can contribute to carbon reduction goals to the extent that the wastes, such as sawmill offcuts, displace fuels with a higher carbon content per Btu, such as coal. But the greatest carbon savings come when biomass power is generated from plant feedstocks grown specifically for this purpose. With dedicated energy crops, biomass power plants generate no *net* carbon emissions during operation.

There are three primary technologies for converting biomass energy to electricity:

- *Direct combustion* involves burning the biomass in a boiler to convert water to steam, then running the steam through a turbine, the same process used in coal-fired plants. Virtually all biomass electric plants today use direct-fired, conventional steam turbines (Office of Technology Assessment, 1995).

⁷ This range of potential expanded capacity is based on DOE and NREL internal analyses.

- *Gasification* involves converting the solid biomass to a gas that is cleaned and then burned in a combustion turbine — potentially much more efficient, and currently in the demonstration stage of development.
- *Cofiring* involves burning a mixture of solid biomass and coal in existing power stations, which requires minimal modifications to the existing station, plus the addition of biomass fuel-handling equipment.

Cofiring with biomass in existing or new coal power stations offers an attractive near-term option for reducing carbon emissions with biomass technologies. It can be a relatively low-cost, low-risk option, particularly for utilities located near existing biomass supplies. Cofiring with low-sulfur biomass also reduces total sulfur dioxide emissions, which helps utilities meet the increasingly stringent environmental constraints on conventional power stations. However, cofiring does not increase generating capacity, so it should not be considered an option for meeting additional demand for electricity, unless new power stations are cofiring stations.

Biomass gasification systems can take advantage of advanced turbine designs and heat-recovery steam generators to achieve almost twice the efficiency of currently installed biomass technologies. This makes it possible to roughly double the amount of electricity or, equivalently, halve the emissions per kilowatt generated. An attractive near-term application of this technology will be industrial-scale systems for repowering pulp and paper mills, which usually cogenerate electricity on site from waste wood. About 70% of the power plants in this industry will need to be replaced in the next 10 to 15 years (NREL estimates, 1997).

New fuel-handling and energy-conversion technologies promise to bring the cost of biomass-fueled electricity down below 4¢/kWh by 2020 (Secretary of Energy Advisory Board, 1995). At this price, biomass power will be competitive with the cost of intermediate-load power from conventional plants. Whole-tree burners, for example, which avoid the cost of chipping the wood before burning it, could reduce the cost of harvesting and delivering the biomass to the power plant by about one-third (Office of Technology Assessment, 1995). The most significant improvements in efficiency and cost are expected to come from the advanced gas turbine technologies, such as combined-cycle turbines and steam-injected gas turbines, that are currently under development. High-pressure gasification technologies yield the highest efficiencies but require more expensive methods for cleaning the hot gases before they enter the turbine (NREL estimates, 1997).

Our ability to meet carbon reduction goals by expanding biomass power generation is contingent on developing dedicated biomass fuel crops on a large-enough scale. Some land areas suitable for biomass development face competition from other uses, such as wildlife habitat or food crop production, but by 2020, U.S. farmers could be growing sufficient biomass feedstocks or hybrid (energy/food) crops to meet demand. Energy crop production is likely to exceed current goals, which include a delivered fuel cost of \$34/ton and yields of 8-10 dry tons per acre per year (Secretary of Energy Advisory Board, 1995), and advances in genetic research could raise the growth rate of energy crops by 50% (NREL estimates, 1997).

Although the potential for biomass production is quite large, transportation costs are a potentially limiting factor, since biomass fuels have a low energy density, i.e., a low Btu content per weight of fuel (Energy Information Administration, 1996a). Because of this, today's biomass plants typically use materials collected within a 50-mile radius. In the future, most biomass power stations are likely to be located near farms dedicated to growing energy crops. Some power stations may run on biomass-derived fuels, such as biocrude oil, which can easily be transported over long distances from biomass fuel refineries. Biocrude has an energy density

three to four times that of the original biomass, and has the potential to fire existing gas turbines with few modifications (Bain and Jones, 1993).

Current grid-connected biomass generating capacity is about 8 GW (Energy Information Administration, 1996a). By 2020, new grid-connected electricity from biomass could total 20-40 GW. This increase, which includes all types of biomass capacity additions, would save 11-22 Mt/yr of carbon emissions, assuming dedicated energy crops are used for three-fourths of the power generation.⁸

7.8.5 Geothermal Electricity

Geothermal generating technologies make use of the heat energy stored within the Earth's crust to produce electricity. There are different types of geothermal resources, each of which requires a different technology to extract the thermal energy for power generation. Today's geothermal power plants are driven by hot water and steam from wells drilled into hydrothermal reservoirs — naturally occurring zones of groundwater trapped in the fissures and pores of underground rock. In most geothermal power plants, which are typically used to provide baseload power, steam from hydrothermal reservoirs is used to generate electricity by spinning a turbine generator directly; in others (binary plants), geothermal hot water is used to vaporize a working fluid that boils at a low temperature — this vapor is then piped to a turbine to generate electricity. Tomorrow's geothermal power plants could make use of hot dry rock resources — areas of exceptionally hot rock (above 150°C) that have little or no water in them. Energy can be extracted from these zones by injecting water from the surface to be heated underground.

Most geothermal power plants release some carbon dioxide during operation but, overall, these emissions are less than 4% of those from coal-fired plants (Office of Technology Assessment, 1995).

Potential geothermal energy reserves are so large that they are considered inexhaustible. With the technologies in use today, however, geothermal power applications in the United States are geographically limited to western regions that have hydrothermal resources of hot water and steam (Energy Information Administration, 1996a). These resources represent only about 4% of the country's total geothermal resources (NREL estimates, 1997). The role of geothermal power in 2020 could be dramatically expanded with advances in technologies for tapping hot dry rock, which accounts for most of the nation's geothermal resource. Zones of hot dry rock are also geographically much more widespread than hydrothermal reservoirs and could provide a virtually limitless supply of energy.

The major challenge and cost-driver for geothermal power systems is resource exploration and characterization — finding geothermal energy resources of sufficient temperature and assessing the amount of energy that can be continuously extracted without depleting them. The cost of geothermal electricity is highly dependent on resource characteristics such as temperature, depth, fluid chemistry and ease of drilling. By 2020, improvements in drilling technology, advanced seismic data gathering and better computer modeling and interpretation of that data could lower the average cost of locating and assessing geothermal resources by 50% (NREL estimates, 1997).

Although total geothermal resources are inexhaustible, the fluid in individual hydrothermal reservoirs can be depleted to the point where the reservoir becomes economically unproductive. For this reason, sustainable use of specific hydrothermal resources always requires the

⁸ This range of potential expanded capacity is based on DOE and NREL internal analyses.

without access to power, this application will have a major impact on PV technology, especially on manufacturing costs.

The biggest U.S. market for PV, and its greatest potential for domestic carbon reduction, ultimately lies in grid-connected electricity generation. One of the biggest near-term markets is likely to be building-integrated photovoltaics. There is a good match between the output of PV systems and the power requirements of commercial buildings, especially offices. By locating a PV system on the building, its demand for grid electricity can be reduced. PV modules are now being developed that can replace standard building materials, such as roofing shingles and exterior cladding, effectively lowering the cost of PV electricity because the modules serve two functions. Incorporating PV into building materials is technically complex, requiring joint development among several normally separate elements of the building industry, but as they enter mass production during the next ten years, such "architectural" PV modules will significantly strengthen the economic appeal of installing PV systems. Other promising applications include utility grid support (when demand at the end of a distribution grid grows beyond design specifications) and extending the life of thermally overloaded substations. The modularity of PV systems and the speed with which they can be deployed are advantages in these applications, since this makes it easy to add incremental power.

Although the cost of PV-generated electricity is still quite high (25¢/kWh to 50¢/kWh), costs have fallen dramatically in the past and are likely to come down by a factor of two to five by 2020,⁹ reducing the cost of electricity from installed PV systems to less than 10¢/kWh (Office of Technology Assessment, 1995). The cost of photovoltaic modules has dropped from roughly \$30 per watt in the mid-1970s to less than \$4 per watt today, and will continue to drop (Secretary of Energy Advisory Board, 1995). The cost of PV electricity is also affected by the cost of the "balance of systems" needed to make use of the modules, including wires, mounting structures, power conditioners, batteries and tracking systems. These components can represent up to half of the cost of a PV system, so improvements in balance-of-systems costs, including more-efficient energy storage devices, could have a dramatic effect on the rate at which PV technology is adopted.

Ongoing research is expected to increase the efficiency of commercial modules by 50% or more and therefore their average energy per unit area. Module lifetimes, currently 10 to 20 years, are projected to be 30 years or more by 2020. System installation and maintenance costs are expected to decline significantly as utilities gain more experience with this technology. Currently, suppliers have to provide custom-designed systems every time they undertake a new installation.

Current efforts to improve manufacturing techniques could also have a significant impact on cost. PV technology is already so advanced that it might be possible to achieve competitive PV electricity through economies of scale in manufacturing alone. In all mature industrial technologies, production costs are ultimately limited by the cost of raw material inputs. PV thin films use highly automated production processes and very little raw material; once their efficiencies have been raised, they may offer the best potential for low-cost generation of PV electricity.

Although PV power systems will definitely see major cost decreases over the next few decades, it is unclear how far and how fast PV will go in penetrating large-scale utility markets in the U.S. Nonetheless, installed PV capacity in this country could realistically be 10-20 GW by 2020, saving 3-5 Mt/yr of carbon emissions (Secretary of Energy Advisory Board, 1995).

⁹ Based on DOE and NREL internal analyses.

reinjection of water into the underground reservoir to maintain pressure. Injection of fluids from the Earth's surface can also help to increase output from reservoirs after they have become depleted. Uncertain reservoir lifetimes substantially increase investor risk, which means that geothermal developers face higher finance rates. Research on reservoir characterization could substantially reduce this risk in the future, speeding the adoption of this technology.

Current geothermal power-generation technologies already enable economic use of many moderate-temperature (<150°C) geothermal resources, which are likely to be the predominant source for near-term geothermal development in the United States (U.S. Department of Energy, 1994). Technological advances are likely to continue raising conversion efficiencies and lowering plant costs. Current R&D in heat exchangers, hot fluid management systems and new thermal conversion cycles suggest that energy cost reductions of at least 20% are likely in the next few years (NREL estimates, 1997). Although the engineering feasibility of extracting energy from hot dry rock has already been demonstrated (Secretary of Energy Advisory Board, 1995), further R&D is necessary to make the technology commercially viable.

Geothermal generating capacity in the United States is currently about 2 GW. By 2020, new U.S. geothermal electric capacity could amount to 10-20 GW, saving 7-15 Mt/yr in carbon emissions.

7.8.6 Photovoltaic Power Systems

Photovoltaic (PV) devices use semiconductor technology to convert light ("photons") into electricity ("voltage") without any moving parts. Individual PV cells, which produce DC electricity, are usually connected together to form modules (panels) that have the desired voltage and output. Photovoltaic systems can provide an independent, stand-alone power supply or can be connected to the electrical grid. In stand-alone applications, batteries can be used to store electrical power for periods when the sun isn't shining, and modules can be connected to inverters to supply AC electricity. Grid-connected systems both feed power into the grid and use the grid as a source of backup power.

There are three types of PV technology in use today:

- *Crystalline silicon wafers* are the most mature technology, with a high sunlight-to-electricity conversion ratio but a high materials cost.
- *Thin films* have the potential of inexpensive manufacture, are easier to handle than silicon wafers, but typically have relatively low conversion efficiencies.
- *Concentrators* use inexpensive lenses to concentrate the sunlight falling on a cell, producing the highest efficiency of all but requiring the use of tracking equipment to follow the sun.

PV power systems produce no atmospheric pollution or fuel wastes during operation. They work well in any climate, can generate electricity in direct or diffuse sunlight, and are suitable for use in every state in the country.

PV is currently a cost-effective power source for a variety of high-value, off-grid applications including telecommunications repeaters, water pumping on farms and ranches, remote residences, highway signs and emergency call boxes. A critical application for PV today, and one that is rapidly expanding, is power for individual homes and villages in developing nations. Since PV serves that market very well, and since there are about two billion people in the world

7.8.7 Solar Thermal Electricity

Solar thermal power systems use the heat energy from solar radiation to generate electricity. Reflective surfaces concentrate the sun's rays to heat a receiver filled with oil or another heat-exchange fluid. The heated fluid is then used in some form of heat engine to generate electricity. Mechanical drives turn the reflective surfaces during the day to keep the solar radiation focused on the receiver, and natural gas is often used to provide backup power for periods when the sun isn't shining.

There are three main types of solar concentrators used in solar thermal electric systems:

- *Parabolic trough systems* concentrate solar rays onto a receiver pipe located along the focal line of a curved, trough-shaped reflector. This technology has a proven track record, with about 350 MW operating successfully in California since the 1980s.
- *Power towers* (central receivers) use a field of sun-tracking mirrors (heliostats) to reflect solar radiation onto a receiver that sits on top of a tall tower. Molten salt is typically used to store heat energy for periods when the sun isn't shining. This technology has been successfully operated in 10-MW pilot plant configurations, and is expected to be economic at plant sizes of 30 MW or more.
- *Parabolic dish systems* use a dish-shaped reflector to concentrate solar radiation onto the receiver of a Stirling heat engine mounted at the focal point of the dish. Dish/engine technology is still under development, but 25-kW systems are expected to be commercially available for grid-connected applications by 1999 (Rueckert, 1997).

Solar thermal electric systems produce no greenhouse gas emissions during operation (U.S. Department of Energy, 1994), although hybrid solar/fossil systems release greenhouse gases in proportion to the degree of fossil fuel used. Trough and dish/engine systems provide utilities with a variety of modular, distributed power options and can be constructed and deployed in a relatively short period of time. Unlike photovoltaic systems, which can generate power in any climate, solar thermal electric systems require high levels of direct solar radiation (direct sunlight) for economic operation. Trough systems and power towers also require large land areas, and face similar siting issues to other large power plants. In the United States, these technologies are, therefore, particularly well-suited to the desert regions of the Southwest.

Although they are in different stages of development, all three types of solar thermal electric technologies are advanced enough to make a significant contribution to carbon reduction goals by 2020. They are likely to become competitive with conventional power technologies when adequate manufacturing levels are reached, with hybrid (solar thermal/fossil-fuel) power systems penetrating utility markets first.

Solar thermal electric technologies need both market deployment and continued R&D to make a significant contribution to global energy demand. There are a number of near-term opportunities for development of commercial solar thermal technologies. Most of these openings are either niches within existing markets or special opportunities related to growing concerns about the impact of energy development on the local and global environment. Further commercial deployment of new solar thermal electric systems is contingent on additional R&D to improve the reliability of the advanced systems currently under development, and to reduce costs through improved components and manufacturing techniques and lower maintenance requirements. With further R&D, a highly attractive option for solar thermal technology lies in hybrid systems that use solar energy for preheat at either stage of a combined-cycle natural gas power plant.

There is currently 364 MW of utility-connected solar thermal generating capacity in the United States. By 2020, new capacity additions could total 8-16 GW, saving the equivalent of 2-5 Mt/yr of carbon emissions.

7.8.8 Landfill Gas Recovery

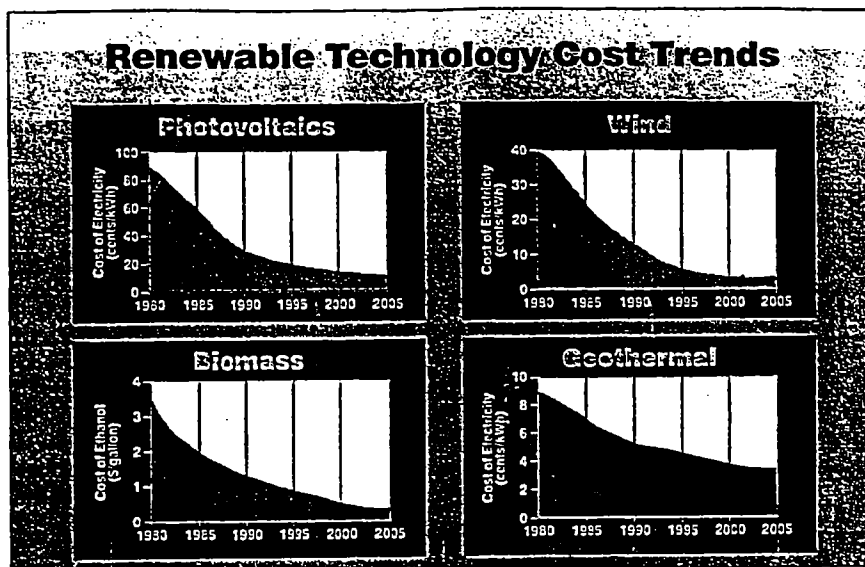
When food scraps and other organic wastes in landfills decompose, they produce methane, a potent greenhouse gas that is also the main ingredient of natural gas. According to the Intergovernmental Panel on Climate Change, each pound of methane is about 21 times more effective at trapping radiation in the atmosphere than a pound of carbon dioxide. Landfills are the largest source of anthropogenic methane emissions in the United States, responsible for almost 40% of these emissions each year (U.S. Environmental Protection Agency, 1997).

New EPA regulations require operators to seal larger, closed landfills with a special cap, collect the gas, and burn it to prevent atmospheric release of methane. But wells sunk into landfills can capture the gas before it escapes the surface. It can then be burned in internal combustion engines to generate electricity, thereby harnessing its energy value. Some landfills clean the gas so that it can be burned in turbines or heat-generating boilers, and a few clean the gas to pipeline quality and sell it. One large landfill cleans the gas and uses it to fuel its garbage trucks.

Today, about 165 landfills recover and utilize methane as a fuel. Various estimates (Governmental Advisory Associates, 1994; U.S. Environmental Protection Agency, 1997) indicate that between 300 and 750 of the country's 3,500 landfills could economically recover methane using currently available technologies. The development of more-efficient, less-expensive technologies for gas recovery, clean-up and utilization could accelerate the adoption of landfill gas-to-energy systems. For example, highly efficient fuel cells have been experimentally operated on landfill gas using new clean-up technology.

By 2020, 0.2-0.5 quads of energy per year could be practicably recovered from the methane in landfills and converted to electricity, saving the equivalent of 22-54 Mt/yr of carbon emissions (U.S. Department of Energy, 1994).

Figure 7.15 Past and Projected Future Costs for Four Renewable Energy Resources



7.8 SUMMARY

Table 7.6 summarizes the potential reductions in carbon emissions that might occur as the result of the technology options discussed in this chapter. Each option is intended to reflect roughly the amount that could be achieved under aggressive policies combined with a carbon incentive of approximately \$50/ton. The total carbon reductions by 2010 are estimated to range from 71 to 79 million metric tons.

Table 7.6 Carbon Reduction Potential of Selected Electricity Supply Technology Options: High Efficiency/Low Carbon Scenario

	High Efficiency/Low Carbon: Moderate	High Efficiency/Low Carbon: High
Converting coal-based power plants to natural gas	50	50
Cofiring coal with biomass	15	20
Extending the life of existing nuclear plants	2	4
Hydropower expansions	4	5
Total	71	79

The analysis of renewable energy potential over the next quarter century indicates that with a vigorous and sustained program of research, development and deployment, renewable energy technologies could be providing a greater and rapidly growing contribution to electricity generation by the year 2020. In combination, hydroelectric, wind, biomass, PV, and solar thermal power options could deliver 78 to 146 GW of electricity in 2020, with a corresponding reduction of 33 to 48 million metric tons of carbon in that same year.

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CHAPTER 8

SUMMARY AND CONCLUSIONS

Two overarching conclusions emerge from the end-use sector analyses. First, a vigorous national commitment to develop and deploy cost-effective energy-efficient technologies can significantly restrain the growth in U.S. energy consumption and carbon emissions such that levels in 2010 are close to those in 1997. In combination with low-carbon technologies and utility sector investments, carbon emissions in the U.S. can be reduced by two-thirds to three-fourths of the levels necessary for stabilization at 1990 levels in 2010.

Second, a next generation of advanced energy efficiency and renewable energy technologies promises to enable the continuation of an aggressive pace of energy and carbon reductions over the next quarter century. Each of the end-use chapters and the analysis of renewable energy options documents a wide array of advanced technologies that could be cost-effective by the year 2020, assuming a vigorous and sustained program of energy R&D beyond 2010.

The analyses behind these conclusions are summarized below.

8.1 THE PROSPECT FOR IMPROVED ENERGY EFFICIENCIES BY 2010

8.1.1 Prospects for Improved Efficiencies and Carbon Emission Reductions by the Year 2010

Table 8.1 and Figure 8.1 compare the nation's primary energy use in quads for the years 1990 and 1997 with the results of the three scenarios for 2010.

Table 8.1 Primary Energy Use in Quads: 1990-2010

	1990	1997	2010		
			Business- as-Usual Case	Efficiency Case	High Efficiency /Low Carbon
Buildings	29.4	33.7	36.0	34.1	32.0
Industry	32.1	32.6	37.4	35.4	33.6
Transportation	22.6	25.5	32.3	29.2	27.8
Total	84.2	91.8	105.7	98.7	93.4

Source: Energy use estimates for 1990 come from Energy Information Administration (1996a, Table 2.1, p. 39). Energy use estimates for 1997 come from forecasts conducted for Energy Information Administration (1996b). Note: numbers may not add to the totals due to rounding.

The major observations from these are as follows.

- In the "business-as-usual" case, energy use increases by 22 quads (26%) between 1990 and 2010; 8 quads of this increase have occurred during the first seven years of this 20-year period. The fastest growing sector during these initial seven years has been buildings (4.3 quads) followed by transportation (2.9 quads) and industry (0.5 quads). In the BAU case, the fastest growing sector during the remaining 13 years is transportation (6.8 quads) followed by industry (4.8 quads) and then buildings (2.3 quads) in the BAU case. The rapid projected growth in the energy consumed for transportation is driven by estimates of increased per capita travel and minimal fuel efficiency gains.
- The "efficiency" scenario cuts the overall growth between 1990 and 2010 from 22 to 15 quads. This is a 17% increase over the level of energy consumption in 1990, down from a 26% increase forecast by the BAU case. Relative to the BAU case, the efficiency scenario for transportation delivers slightly more energy savings (3.1 quads) than do efficiency scenarios for the industrial (2.0) or buildings (1.9) sectors. Compared with 1997 levels, the smallest increase in energy growth for the efficiency case is in buildings (0.4 quads), followed by industry (2.8 quads), and transportation (3.7 quads).
- The "high efficiency/low carbon" scenario further decreases the overall growth between 1990 and 2010, reducing it from 22 to 9 quads. This is an 11% increase over the level of energy consumption in 1990. Relative to the BAU case, the "high efficiency/low carbon" scenario for buildings, industry, and transportation delivers energy savings ranging from 3.8 to 4.5 quads. Compared with 1997 levels, buildings is down about 2 quads and industry and transportation are up 1 and 2 quads respectively.

Figure 8.1 Primary Energy Use in Quads: 1990-2010

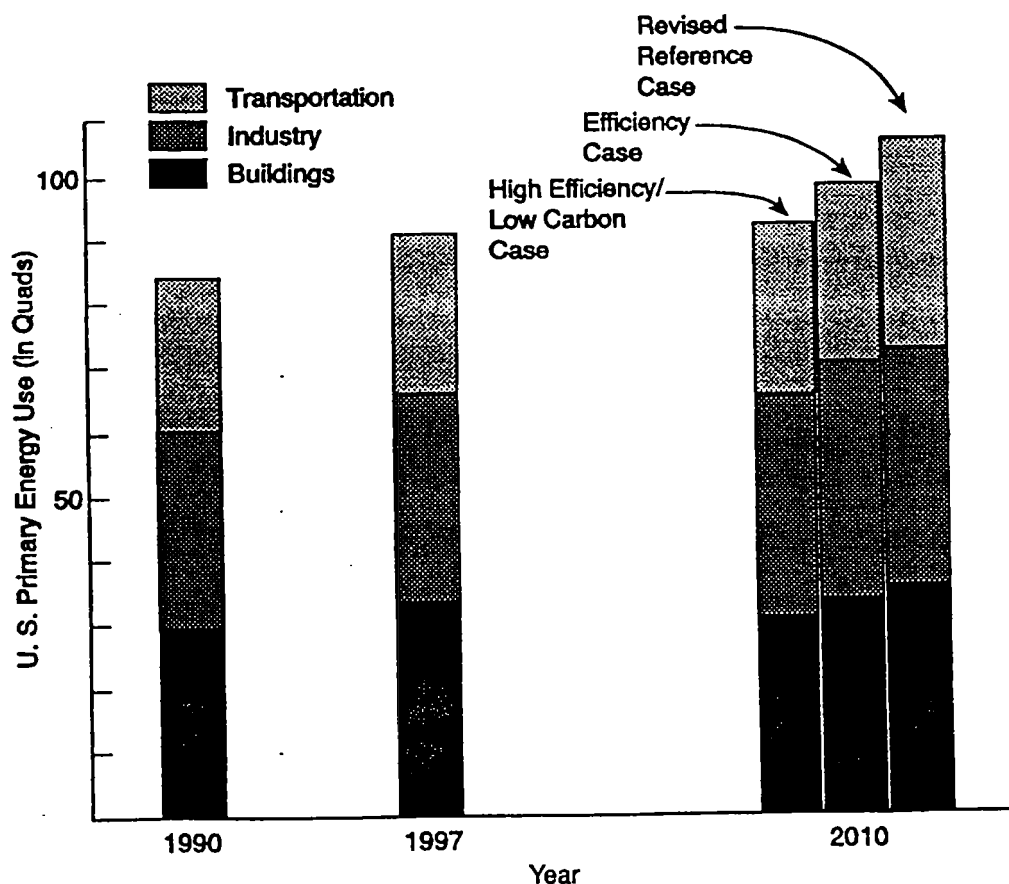


Table 8.2 documents the impact of these projected energy savings in 2010 on carbon emissions in that same year. It also presents the results of a more complete "high efficiency/low carbon" scenario, which characterizes the impacts of including the high level of efficiency improvements along with two additional types of low-carbon technologies.

- It includes end-use carbon reductions that do not result entirely from reduced energy consumption, but rather result from either fuel switching or by displacing carbon from industrial processes. Specifically, the buildings sector includes stationary fuel cells for cogeneration, and the industrial sector includes advanced turbine systems, biomass gasification, inert anodes and wettable cathodes in the aluminum industry, and slag cement. These carbon reductions were not included in the "high efficiency/low carbon" models for buildings and industry; rather, they are based on additional case studies.
- It also includes a number of electricity supply technologies that could reduce carbon emissions in the year 2010 under the conditions characterized by the "high efficiency/low carbon" scenario..

Table 8.2 Carbon Emissions (in million metric tons): 1990-2010

	1990	1997	2010 ^a			
			Business-as-Usual Case	Efficiency Case	High Efficiency Case (w/o Low-Carbon Technologies)	High Efficiency/Low Carbon Case ^b
Buildings	460	511	571	546	532	525 to 530
Industry	452	482	534	512	494	461 to 483
Transportation	432	486	616	543	513	513
Utilities ^c	-	-	-	-	-	-157 to -138
Total (rounded)	1340	1480	1720	1600	1540	1340 to 1390

^aThese carbon forecasts for 2010 represent our best "point estimates." The precision of these estimates is unknown, since none of the forecasts used in this report are based on parameters with known probability distributions.

^bThis scenario includes the carbon emission reductions resulting from a carbon permit price of \$50/tonne: (1) dispatch of power plants in which natural gas is favored relative to coal, (2) repowering and partial repowering of coal-based power plants to convert to natural gas, and (3) introduction of selected low carbon technologies to replace conventional ones, primarily in the industrial sector.

^cThe entries in the last column are negative as they correspond to reductions in carbon emissions resulting from the increased use of natural gas in power plants as a result of the \$50/tonne carbon permit price in this scenario.

The major observations from the above table are:

- In the BAU case, carbon emissions are forecast to increase by approximately 380 million metric tons (MtC) (from 1340 to 1720, or 28%) between 1990 and 2010.
- The energy efficiency gains incorporated in the "efficiency" case cut overall growth between 1990 and 2010 by one third (from 380 to 260 million metric tons). This represents carbon increases of 19% above the emissions in 1990.
- The energy efficiency improvements spurred by the "high efficiency" case reduce overall growth between 1990 and 2010 by an additional 60 MtC (decreasing the increase from 380 to 200 million metric tons or 15% above the emissions in 1990).
- The conversion of electrical generation from coal to natural gas and the preferential dispatch, combined with the use of added low carbon technologies, primarily in the industrial sector, reduce carbon emissions by an additional 150 to 200 MtC. In this case, which we estimate to cost less than \$50/tonne of carbon (for the additional 150 to 200 MtC), results in approximate carbon stabilization in 2010 at the 1990 level (0 to 30 MtC increase).
- Approximately 140 MtC of the increase in carbon emissions between 1990 and 2010 will have occurred by the end of 1997; thus, it is useful to look at the 13-year forecast starting with 1997. The carbon reductions incorporated in the efficiency case cut the overall growth in carbon emissions between 1997 and 2010 from 240 million tons (as forecast in the BAU case) to 120. The "high efficiency/low carbon" scenario reduces carbon emissions in 2010 to about 115 MtC (90 to 140 MtC) below the 1997 level.

Table 8.3 provides a comparison of the growth rate in energy and in carbon emissions for the three cases, from 1990 to 2010. In general, the growth in carbon emissions tracks the increase in energy demand, with carbon growing slightly more rapidly than energy in the efficiency case. This is because the efficiency scenario reduces the need for constructing new low-carbon (combustion turbine and natural gas combined cycle) power plants and therefore results in a generation mix that has a higher percentage of coal-based electricity than would be true with the "business-as-usual" case. In all three scenarios, carbon emissions increase more slowly than the GDP, indicating a net "decarbonization" of the U.S. economy.

Table 8.3 Average Annual Energy and Carbon Growth Rates, 1990 to 2010, for Three Cases

	Revised AEO Reference Case	Efficiency Case	High Efficiency/ Low Carbon Case
Energy Demand	1.14%	0.80%	0.52%
Carbon Emissions	1.24%	0.88%	0 to 0.2%
Energy Consumption Per GDP (E/GDP)	-0.74%	-1.08%	-1.35%
Carbon Emissions Per GDP (C/GDP)	-0.64%	-1.00%	-1.7 to -1.9%

*Note that these changes in carbon emissions are for the entire period, including the seven years that have already occurred. The carbon decrease per unit GDP growth for 1997 to 2010 is 0.7, 1.25, and 2.3 to 2.5 percent per year for the reference, efficiency, and high efficiency cases, respectively.

It is useful to compare the scenarios in this study to those of other studies. The 1991 report by the Office of Technology Assessment (OTA) titled *Changing by Degrees* (U.S. Congress, 1991) analyzed the potential for energy efficiency to reduce carbon emissions by the year 2015, starting with the base year of 1987. Its "moderate" scenario results in a 15% rise in carbon emissions, from 1300 MtC/year of carbon in 1987 to 1500 MtC/year of carbon in 2015 (compared to a "business-as-usual" forecast of 1900 MtC/year). Its "tough" scenario results in a 20% to 35% emissions reduction relative to 1987 levels, or emissions levels of 0.85 to 1.0 MtC/year of carbon in 2015. Our "efficiency" and "high efficiency/low carbon" cases of 1.3 to 1.6 billion metric tons of carbon emissions in 2010 is comparable to OTA's "moderate" case and shows considerably higher emissions than OTA's "tough" case.

Another benchmark is provided by the 1992 National Academy of Sciences (NAS) report on *Policy Implications of Greenhouse Warming* (National Academy of Sciences, 1992). This study identified a set of energy conservation technologies that had either a positive economic return or that had a cost of less than \$2.50 per tonne of carbon. Altogether, NAS concluded that these technologies offer the potential to reduce carbon emissions by 463 million tons, with more than half of these reductions arising from cost-effective investments in building energy efficiency. Our "efficiency" and "high efficiency/low carbon" cases suggest the potential for reducing carbon emissions by between 120 and 380 million metric tons by the year 2010. This is about one-fourth to one-third of the potential estimated by the NAS. One of the reasons for this difference is that the NAS study did not deal with a particular planning horizon. Thus, it did not take into account the replacement rates for equipment and processes, and other factors that prevent the instantaneous, full market penetration of cost-effective energy-efficient technologies.

8.1.2 Sector-Specific Findings

The analysis of the buildings sector offers the following conclusions.

- The "efficiency" scenario results in 1.9 quads (5.3%) less energy use and 25 Mt (4.4%) fewer carbon emissions than the "business-as-usual" scenario in 2010. This represents a savings of \$17 billion in fuel costs in 2010 resulting from an annualized incremental cost of \$6 billion in efficiency improvements.
- The "high efficiency/low carbon" scenario results in 4.0 quads (11.1%) less energy use and 39 Mt (6.8%) fewer carbon emissions than the "business-as-usual" scenario in 2010. These carbon savings increase to 46 Mt (or 8%) when fuel cells are included. This represents a savings of \$31 billion in fuel costs in 2010 resulting from an annualized incremental cost of \$11 billion in efficiency improvements.
- In the residential sector, the greatest energy and carbon savings are achieved in the following end uses: miscellaneous electricity uses, lighting, and water heating. In the commercial sector, the greatest energy and carbon savings are achieved in the following end uses: miscellaneous electricity uses, lighting, and space conditioning.
- For both residential and commercial buildings, the bulk of the energy saved is electricity (including related losses): 1.6 of the 1.9 quads in the "efficiency" scenario and 3.4 of the 4.0 quads in the "high efficiency/low carbon" scenario.

The analysis of the industrial sector leads to the following conclusions.

- The "efficiency" scenario results in 2.0 quads (5.4%) less energy use and 22 Mt (4.1%) fewer carbon emissions than the "business-as-usual" scenario in 2010. This represents a net present value of fuel savings of \$5.2 billion in fuel costs in 2010 resulting from an incremental annual investment of \$2.1 billion in efficiency improvements. Thus, this scenario generates a net benefit of \$3.1 billion in 2010.
- The "high efficiency/low carbon" scenario results in 2.5 quads (6.7%) less energy use and between 57 and 73Mt (or between 5 and 10%) fewer carbon emissions than the "business-as-usual" scenario in 2010. This represents a net present value of fuel savings of \$9.4 billion in 2010 resulting from an incremental investment of \$4.1 billion in efficiency improvements. Thus, this scenario generates a net benefit of \$5.3 billion in 2010. The annual incremental investment required for this scenario is only 3.7% greater than normal manufacturing investment levels.
- The efficiency scenarios indicate that, on a percentage basis, more energy savings can be achieved in light manufacturing than in the energy-intensive industries.
- The energy saved by the "high efficiency/low carbon" scenario is almost equally distributed between fossil fuels and electricity (including related losses). This represents a much greater percentage reduction in electricity use, since in 1997 the industrial sector consumed almost twice as much in fossil fuels as electricity.

The analysis of the transportation sector offers the following conclusions.

- The "efficiency" scenario results in 3.1 quads (10%) less energy use and 73 Mt (12%) fewer carbon emissions than the "business-as-usual" scenario in 2010. For light-duty highway vehicles (passenger cars and light trucks), this represents a savings of \$19 billion in fuel costs to consumers in the year 2010. The total incremental retail price for these fuel economy improvements to light-duty vehicles is \$28 billion.
- The "high efficiency/low carbon" scenario results in 4.5 quads (14%) less energy use and 103 Mt (17%) fewer carbon emissions than the "business-as-usual" scenario in 2010. The incremental costs associated with the breakthrough technologies that are included in this scenario cannot be quantified, but the fuel savings from light-duty highway vehicles are estimated to be \$- billion in 2010.
- Most of the reduction in energy use and carbon emissions comes from light-duty vehicles. New light-truck fuel economy improves the most in the efficiency scenarios by 2010, with passenger car fuel economy improving almost as much.
- Both efficiency scenarios forecast the consumption of significant amounts of ethanol from cellulosic feedstocks (as opposed to corn), as a blending component for motor gasoline. By 2010, 0.46 quads of cellulosic ethanol are forecast in the "efficiency" case and 0.65 quads are forecast in the "high efficiency/low carbon" case.

Several key findings also result from the analysis of the electricity sector's response to end-use efficiencies and carbon charge.

- The revised reference case for the U.S. electric-power-supply system in 2010, which was conducted to assess the impact of a fully competitive industry, resulted in several small differences relative to the AEO '97 reference case: greater electricity use, lower peak demand, and a generation mix that includes more natural gas and less coal. Thus, although consumption is higher, carbon emissions are lower. Comparable reductions in

the retail price of electricity were forecast by AEO '97 and the simulation of a fully competitive industry conducted for this study.

- The "efficiency scenario" reduces the need for constructing new low-carbon (combustion turbine and natural gas combined cycle) power plants. The result is a generation mix that has a higher percentage of coal-based electricity than would be true with the "business-as-usual" case. As a result, the "efficiency" scenario's 7.0% reduction in electricity use in 2010 represents only a 4.0% reduction in carbon emissions.
- The "high efficiency/low carbon" scenario's 14.5% reduction in electricity use in 2010 represents a 18.4% reduction in carbon emissions, because the introduction of a carbon charge lowers the carbon intensity of the generation mix.

Finally, the analysis of improved electricity supply technologies concluded the following.

- The analysis of advanced coal technologies suggests that between now and the year 2010, highly efficient advanced coal units remain too expensive to compete economically with either the generation mix that remains from the 1990s or with natural gas combined cycle units.

8.2 R&D'S POTENTIAL FOR FURTHER BENEFITS BY 2020

By the year 2010, numerous energy efficiency technologies will be introduced into the marketplace that are not available to consumers today. With an aggressive R&D and market transformation push, our "high efficiency/low carbon" scenario suggests that these new technologies, in combination with the greater deployment of existing cost-effective efficiency products and practices, would result in significant energy and carbon savings in 2010. The "high efficiency/low carbon" scenario would also produce an R&D pipeline containing the next generation of energy technologies. It is difficult to estimate the energy and carbon savings that will accrue from the maturation and commercialization of these technologies by the year 2020. However, this report does qualitatively characterize the nature of these technologies, and the results suggest that an aggressive pace of energy and carbon savings over the next quarter century can be sustained.

In the next quarter century, improved energy efficiency technologies will result from a combination of incremental advances and fundamental breakthroughs. Incremental improvements in all sectors can be achieved by the greater reliance on more precise and reliable sensors and controls integrated into smaller packages that cost less, can withstand harsh environments, and are able to characterize and optimize currently impenetrable systems without disturbance. Advanced manufacturing technologies including rapid prototyping and ultraprecision fabrication also offer broad opportunities for continuous incremental improvements in energy efficiency and renewable energy. Breakthroughs in bioprocessing, separations, superconductivity, catalysts, and materials can have wide-ranging impacts on energy efficiency by the year 2020. Examples of specific technology opportunities are described below, by sector.

Six R&D areas are forecast to offer great promise to reduce significantly the energy requirements of our Nation's buildings in 2020.

- *Construction methods* in this time frame will consist primarily of factory-manufactured modules and components assembled onsite, enabling systems engineering to deliver

greater energy efficiency, more affordable construction, and increased use of recycled materials.

- *Adaptive envelopes* will capitalize on changing climatic conditions to reduce energy use and improve occupant comfort and productivity, and *environmental integration* strategies such as reflective roofing materials and turf paving will reduce urban heat island effects.
- *Multi-functional equipment and appliances* offer the opportunity for a quantum leap in efficiency improvements by combining the functions of several appliances into a single, highly effective device that puts to use waste heat and employs high efficiency components to perform dual functions.
- *Advanced lighting systems* in 2020 have the potential to employ highly efficient artificial light sources in combination with tracking sunlight concentrators, light pipes, and daylighting to meet the occupants' precise functional needs for lighting with an order-of-magnitude reduction in energy use.
- *Controls and communications* capabilities will enable greatly reduced energy requirements by matching current and predicted weather conditions, utility rates, and internal environmental measurements to meet fluctuating occupant requirements while expending less energy.
- Finally, *self-powered buildings* will have fuel cells, PV building components, and energy storage devices to provide building owners with new levels of flexibility in meeting their energy needs and generating revenues from electricity sales.

Improvements in energy efficiency and carbon reductions in industry beyond 2010 require further R&D to spawn new and improved technologies. In addition to the broad application of better process modeling, sensors, and controls mentioned above, some process/industry-specific examples include the following.

- In the *pulp and paper industry*, there is tremendous opportunity to better exploit energy sources contained in the biomass that provides the fiber, and to achieve a better balance between heat and power needs. For example, the black liquor gasification combined cycle process and biomass gasification combined cycle technologies could produce significant quantities of low-carbon electricity, and the further development of polyoxometalate bleaching could reduce the electricity consumed by pulp bleaching, in addition to reducing effluent loads.
- In the *chemical industry*, biological processes for producing feedstocks, improved catalysts, and thermochemical processes for producing valuable chemicals from a wide variety of recycled materials are examples of energy-saving opportunities that hold great promise.
- In *petroleum refining*, improved catalyst technology for hydroprocessing, catalytic cracking, and alkylation will be needed to offset the push towards higher energy use that will otherwise result from changing input feedstocks required by stricter environmental objectives.
- Optimizing electric boost, improving furnace design and operation, and recovering and reusing waste heat from oxy-fired furnaces represent three of many promising technology development opportunities for reducing energy intensities in the *glass industry*.
- In the *aluminum industry*, dramatic reductions in energy and emissions could result from new and improved smelting technologies and reduction efficiency, including: inert anodes, carbothermic reduction processes, aluminum chloride processes, and wettable titanium diboride cathode components.
- The *iron and steel industry* could achieve significant energy savings by incorporating both ironmaking and steelmaking into a single system with thin strip casting as a final product, adding a coal-based reductant process that simultaneously produces power, and using sensors and controls to optimize process efficiencies.

- In the *metal casting industry*, energy can be saved by making fundamental changes in the casting process, for example, by using electromagnetic fields to induce eddy currents in liquid metals to assist with stirring and confinement into thin sheets.

Many of the advanced technologies that have the potential to significantly improve the energy efficiency of transportation after 2010 need considerable R&D investment before they can become commercially available in the year 2020.

- To achieve fuel economies in the 60-80 mpg range and remain affordable and safe, *light-duty vehicles* will need breakthroughs in manufacturing processes for composite materials, an order of magnitude reduction in fuel cell costs, ultra-low rolling resistance tires, high efficiency accessories, and highly aerodynamic designs.
- Heavy vehicles in 2020 can achieve improved on-road fuel economy through the development of a high-efficiency, low emission diesel cycle engine with a durable highly efficient, lean NO_x catalyst, reduced aerodynamic drag, low rolling resistance tires, and lightweight material such as magnesium.
- *Methanol-fueled fuel cell busses* will require significant development of the fuel cell itself, power management strategies, and hydrogen fuel production to enable economical solutions by the year 2020.
- *Locomotive engines* may be an ideal test bed and early entry for fuel cell powerplant technologies between 2010 and 2020.

With a vigorous and sustained program of research, development and deployment, renewable energy technologies could be providing a greater and rapidly growing contribution to electricity generation by the year 2020.

- *Hydroelectric power generation* may be increased by modernizing and upgrading turbines at existing sites and by developing efficient low-head generating technologies to enable deployment at the many low-head sites that are otherwise unsuitable for hydropower additions.
- *Wind power systems* can become more cost-competitive as the result of improved blade designs and manufacturing processes, new materials for extended blade lifetimes in their working environment of large and variable mechanical stresses, and computer modeling of components and subsystems to optimize turbine designs for site-specific operating conditions.
- Expanding *biomass power generation* to meet carbon reduction goals is contingent on developing dedicated biomass fuel crops and improving the technologies for converting biomass energy to electricity including advanced turbine designs and heat-recovery steam generators.
- *Photovoltaic power systems* could achieve significant cost savings by improving the efficiency of the PV modules and lowering the cost of balance of systems components (including wires, mounting structures, power conditioners, and tracking systems), especially from the development of more-efficient energy storage devices

The technology opportunities envisioned for the year 2020 will not materialize without strong public-private partnerships to support the array of R&D and market transformation activities needed to ensure that cost-effective products and practices are available and deployed.

8.3 ASSESSMENT OF COSTS AND SOURCES OF CARBON REDUCTIONS

The "business-as-usual" scenario projects an increase of 380 million tonnes/year of carbon between 1990 and 2010. In our efficiency case, in which the nation actively pursues policies and programs to promote market acceptance of energy efficiency while expanding commitments to research and development, energy-efficient technologies reduce this growth in carbon emissions by 120 MtC/year. A very strongly accelerated drive to promote energy efficiency could lead to reductions of 180 MtC/year (high efficiency case). Under a carbon cap and trading system, in which permits for carbon sell for \$50/tonne C, very substantial carbon reductions appear possible. Results for these three cases, showing the sources of the carbon reductions, are contained in Table 8.4. The indicate that, for the high efficiency/low carbon case, there is a potential to roughly return to 1990 levels of carbon emissions in 2010 at a cost of less than \$50/tonne carbon.

**Table 8.4 Potential Reductions in Carbon Emissions to Achieve 1990 Levels in 2010,
(Reductions are in MtC/Year from Business of Usual Case)**

	Efficiency Case	High Efficiency Case (w/o Low Carbon Technology)	High Efficiency/Low Carbon Case:
Buildings			
Energy Efficiency	25	39	39
Fuel Cells	0		2 - 7
Industry			
Energy Efficiency	22	40	40
Advanced Turbine Systems	0		5 - 17
Aluminum Technologies	0		2 - 4
Biomass Gasification	0		2 - 10
Cement	0		2
Transportation			
Energy Efficiency & Ethanol	73	103	103
Utility Supply Options			
Carbon-Ordered Dispatching	0		77
Converting coal-based power plants to natural gas	0		50*
Cofiring coal with biomass	0		5 - 20
Extending the life of existing nuclear plants	0		2 - 5
Hydropower expansions	0		4 - 5
Total (rounded)	120	180	330 - 380

*The potential for converting coal-based power plants to natural gas is much greater than 50 MtC/year, as described in chapter 7. However, the cost-effectiveness of the conversion is highly sensitive to the magnitude of the coal permit charge, the externality value of NOx, and, and the relative price of natural gas and coal. If natural gas prices are, for example, \$10/tonne C higher (lower) than anticipated in the report, then a \$60 (\$40)/tonne C permit price would be needed to achieve 50MtC/year reductions. Because the cost curve of carbon from this source is relatively flat, it may be possible to significant increase the carbon reductions subject to availability of natural gas.

Note: the results in this table are undergoing review at this time. As a result, there may be some changes in numbers. We do not, however, anticipate major changes.

It is important to recognize that there are significant uncertainties in the analysis and many factors that will determine the degree to which and the costs of achieving the carbon reductions shown in Table 8.4. We present below a summary of the expected technology costs in 2010, as well as the cost of implementing a carbon permit system. While these costs are necessarily uncertain, they are our best estimates and, in our view, as likely to be high as to be low. We note, however, that we have confined our analysis to technology costs, and have not assessed policies or programs to achieve market acceptance.

Emissions reductions of 120 to 180 of the 380 MtC needed to achieve stabilization in 2010 result from energy efficiency measures which, based on the data presented in the report, are on balance cost-effective. Ignoring the implementation costs, this means that the cost of reducing carbon emissions are negative overall. Unless there are serious difficulties in implementing the measures, the costs of 120 MtC/year will be close to zero. The next 60 MtC/year – which includes substantially increased implementation of energy efficiency measures for buildings (from 35% of potential cost-effective measures to 65%), increases in ethanol as automotive fuel and the use of more advanced (and costly) energy efficiency technologies for transportation, and both reductions in hurdle rates as well as market lags for industry – will have a very low cost. As indicated in the individual sector discussions, the technology for the high efficiency case is for the most part likely to be cost-effective or near cost-effective in 2010 but there is somewhat more uncertainty about the ability to achieve market acceptance.

The utility sector provides a substantial part of the next increment of carbon reductions: 125 MtC/year are achieved through increased costs associated with the dispatch of higher-cost electricity (using natural gas power plants in place of coal plants up to a cost of \$50/tonne carbon) and through repowering existing coal-fired power plants so that they burn natural gas (again, up to a cost of \$50/tonne carbon). Because the new dispatch and the power plant conversions are up to \$50/tonne, a portion of the carbon reductions will be at less than this cost. The upper limit on these costs is thus \$50/tonne times 125 MtC/year = \$6 billion per year.

In addition, one needs to note that these measures increase demand for natural gas. The demand for natural gas in the AEO '97 business as usual case for 2010 is 30.2 trillion cubic feet (Tcf). Our base case, which simulates a restructured utility industry, increases use of combined cycle power plants compared with AEO '97 by 1.3 Tcf per year in 2010. However, the efficiency case decreases natural gas use by 0.9 Tcf/year compared with AEO '97. This occurs because efficiency measures reduce demand for natural gas, as expected. Interestingly, the altered dispatch, when combined with efficiency measures in the high efficiency case, also reduces demand for natural gas by 0.9 Tcf/year compared with AEO '97. This occurs because of two countervailing factors that happen to balance in this case: (1) increased energy efficiency and further substitution of combined cycle gas plants for combustion turbines reduces natural gas demand while (2) substitution of additional natural gas for coal in the generation mix increases demand.

The roughly 50 MtC/year from repowering increases natural gas demand by 1.7 Tcf/year. This means that the high efficiency/low carbon case uses about 0.8 Tcf/year more natural gas than the AEO '97 (and 0.5 Tcf per year less than a restructured utility industry base case as we have estimated it). This is less than a 3% increase in natural gas demand. EIA model runs indicate that such an increase in natural gas demand would be expected to increase natural gas costs from \$0.15 - 0.20/million cubic feet (Mcf). This price increase has a small economic impact.

Finally, we obtain about 25 to 75 MtC/year from a variety of technologies: advanced turbine systems for cogeneration in industry, co-firing biomass and coal to produce electricity, fuel cells for buildings, low carbon technologies for cement making, biomass gasification, and advanced

aluminum and cement production technologies as well as nuclear plant life extensions and expansion of hydropower. The text estimates that up to 75 MtC/year of carbon reductions could be achieved at less than \$50/tonne carbon. If these estimates are borne out, then the upper limit of these costs is \$4B/year in 2010 (since many of the technologies are estimated to produce savings below \$50/tonne carbon).

In short, the analysis suggests that the overall additional cost of the measures in the high efficiency/low carbon scenario are on the order of \$10B per year in 2010. To the extent that the energy efficiency measures cost less than new supply, the net cost of the stabilization case is reduced. On the other hand, implementation costs of energy efficiency and the other requirements to achieve rapid and widespread market acceptance of technologies will raise the cost of the scenarios, as discussed below

The realizability of the cases depends on many factors. In all cases, carbon reductions require the Nation to embark on an aggressive set of policies and programs, presumably in response to an international agreement on climate change or other events that result in a national determination to reduce growth of carbon emissions. In the case studied, we assume that an international trading regime for carbon has resulted in a domestic permit price of \$50/tonne carbon. Without some scheme that provides an incentive of this nature for switching from coal to natural gas, and for deploying other low carbon technologies, much of the carbon reductions in our case would not be possible.

Government policies and programs that encourage and/or require the adoption of energy efficiency technologies will be needed. Incentives will be needed for industry to increase energy efficiency investment. Additional private and public investments in energy efficiency and low carbon technology is necessary, not only to get some new technology into the market before 2010 but especially to have technology for the period after 2010. The transportation sector is especially dependent on early technological advances to achieve the scenario results in 2010.

There is no assurance that these and other driving forces will cause the scenarios we have described to take place. Our major conclusion is that the technology is available, at a cost that appears to be \$10 B per year or less, to achieve major reductions in carbon emissions by 2010. Efficiency alone can get us 30 to 50 % of the way to 1990 levels (from our expected base case results) at negative or low technology costs. An important new finding is that a detailed analysis of the utility sector shows two significant ways that an additional 30% of the reductions at an estimated cost of \$50/tonne carbon¹: carbon-based dispatch and conversion of existing power plants from coal to natural gas. Finally, we identify additional technologies that could contribute up to 20% of the carbon reductions, also at a cost of up to \$50/tonne. In addition, a next generation of advanced energy efficiency and renewable energy technologies promises to enable the continuation of an aggressive pace of energy and carbon reductions over the next quarter century.

8.4 REFERENCES

Energy Information Administration. 1996. *Emissions of Greenhouse Gases in the United States, 1995*, DOE/EIA-0573(95) (Washington, DC: U.S. Department of Energy), October.

¹ The cost curve for repowering is relatively flat; as such, considerable additional reductions are possible at a cost not too different from \$50/tonne. The results are highly sensitive to the price differential between coal and natural gas; at a lower (higher) price differential, a higher (lower) permit price of carbon is needed.

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**Interlab Study on U.S.
Energy Efficiency and Greenhouse
Gas Emissions**

Appendix C-1

**Detailed Description of
Forecast Methodology**

**Residential and Commercial
Sectors**

APPENDIX C-1: METHODOLOGY FOR ASSESSING END-USE EFFICIENCY POTENTIALS FOR BUILDINGS

Analysis focuses on three years: 1990, 1997, and 2010. We derive baseline usage in 1990 from the 1994 Annual Energy Outlook (AEO)¹. We treat 1997 as the base year, and 2010 as the year in which we are assessing the reservoir of potential savings. We examine a "snapshot" of the buildings sector in 2010, with our end-use totals benchmarked to the AEO 1997 forecast for that year. All energy use is expressed in primary energy terms². For a more detailed discussion of the type of analysis described below, see Krause et al. (1995)³.

We discuss each of the input parameters below, and then carry through a particular example, namely residential refrigerators (all information pertaining to the example is in *italics*). Tables C-2.5.a-b and C-2.6.a-b show the input tables containing each of the relevant parameters for residential and commercial buildings. The end-use categories in these tables are the same as those in NEMS, for consistency with the AEO.

Base year energy use

The calculations begin with the 1997 total energy use for the end-use or subsector. The Annual Energy Outlook 1997 is the basis for this base-year breakdown.

For refrigerators, 1997 base year electricity use is 1.21 quads of primary energy (112 TWh).

Stock accounting

In any forecast of the future impacts of technologies, some method for accounting for changes in the stock of equipment must be adopted. Stock accounting allows calculation of the effect of normal stock turnover on the efficiency of the stock of equipment existing in any year. It also accounts for overall growth in the total number of households or floorstock.

We use a simplified stock accounting framework to treat retirements of buildings and appliances existing in 1997 still existing in 2010. We assume that retirements occur in a linear fashion so that by the time 4/3 of the average lifetime elapses all of the buildings or devices retire. Devices added during the 1997 to 2010 period are assumed not to retire or to be replaced with devices identical to the devices previously added during this period.

For residential building shells, we use a 100 year average lifetime assumption, which results in about 90% of the stock of buildings existing in 1997 still existing in 2010. AEO 97

¹The 1997 AEO starts its forecast in 1994 and does not present 1990.

²The primary energy conversion factor for electricity is 3.25 in 1990 (from AEO 94), 3.18 in 1997, and 3.07 in 2010 (from AEO 96), which includes losses associated with the generation, transmission, and distribution of electricity. This factor is multiplied by site electricity use (any units) to get primary energy in comparable units. As a simplifying assumption, we adopt a factor of 3.17 (10,800 Btu/kWh) as an average over the analysis period (1997-2010), but when calculating primary energy use in 1990, we use the actual factor of 3.25. All electricity consumption numbers are expressed in primary energy terms throughout this analysis. THIS CONVENTION HAS BEEN MODIFIED AS DISCUSSED IN CH. 3, BUT THIS APPENDIX HAS NOT YET BEEN UPDATED TO REFLECT OUR NEW APPROACH.

³ Krause, Florentin, David Olivier, and Jonathan Koomey. 1995. *Negawatt Power: The Cost and Potential of Low-Carbon Resource Options in Western Europe* in *Energy Policy in the Greenhouse*, Vol. . El Cerrito, CA: International Project for Sustainable Energy Paths.

projects about a 15% growth in households from 1997 to 2010, so total stock in 2010 is 115% expressed as a percentage of 1997 stock. Of this total, 25 percentage points represent homes built in the 1997 to 2010 period, and 90 percentage points represent homes existing in 1997 still existing in 2010.

For commercial building shells, we use a 50 year average lifetime assumption, which results in about 81% of the stock of buildings existing in 1997 still existing in 2010. AEO 97 projects about a 12% growth in commercial floor area from 1997 to 2010, so total stock in 2010 is 112% expressed as a percentage of 1997 stock. Of this total, 31 percentage points represent buildings built in the 1997 to 2010 period, and 81 percentage points represent buildings existing in 1997 still existing in 2010.

In the frozen efficiency case, all homes and buildings built in the 1997 to 2010 period are assumed to have equipment with efficiencies equivalent to 1997 new equipment. For homes and buildings existing in 1997 still existing in 2010, retirements of equipment take place using the same retirement function as described above for homes (retirements occur in a linear fashion so that by the time $4/3$ of the average lifetime elapses all of the devices retire).

In Tables C-2.5.a-b and C-2.6.a-b we split the stock of existing homes and buildings with new equipment into two categories: Existing shell and retrofit shell. This distinction is not used in the Frozen Efficiency and Business-As-Usual cases, but is used in the efficiency cases.

Average refrigerator lifetimes are 19 years. By 2010, 9.7% of the homes existing in 1997 still existing in 2010 have been replaced with new homes that have new refrigerators, 48.7% still have 1997 stock refrigerators, and 41.6% have their existing shell but have new refrigerators. No retrofits of equipment are allowed.

Other changes in service demand

Overall growth in service demand is governed by the growth in number of households or floorstock, but within each sector other trends can affect service demand. These trends, such as fuel switching, structural shifts, leveling off of service demand, or rapid growth in a new end-use, can be captured by the use of another factor, which we call here the "other energy service growth" factor. It can be equal to, more, or less than 1.0. Its value will generally be determined by an examination of the trends in the end-use markets under analysis.

We use this factor to calibrate our forecast to the AEO 97 end-use consumption numbers in 2010. We calculate our own forecast of end-use consumption based on our stock accounting framework and the unit energy consumption numbers described below, then take the ratio of the AEO 97 end-use consumption to our forecast. A ratio less than 1.0 means that our internally generated forecast overestimates consumption compared to the AEO 97 forecast, and a ratio greater than 1.0 means our internally generated forecast underestimates consumption.

In Tables C-2.5.a-b and C-2.6.a-b we distinguish between the service demand growth factor for existing shells and new shells, but there is no difference between these two columns. We can change these factors if we feel that growth in service demand will be different in existing and new buildings, but we have not used this capability in this analysis.

Our internally generated refrigeration forecast overestimates consumption compared to the AEO 97 forecast, so the service demand growth factor is 0.84. We believe this result occurs because the AEO reference case forecast contains progress in refrigerator efficiency that our own residential models do not predict. We are working with EIA to fix this issue with their forecast.

Frozen efficiency case: Existing stock vs. new energy intensities

The ratio of new device or process intensities (kWh/device or per household) to base year stock intensities (usually, but not always, less than 1.0) characterizes the efficiency improvement that we can expect from stock turnover alone in a frozen efficiency case.

For new refrigerators in 1997, Unit Energy Consumption (UEC) is about 647 kWh/year (7.0 MMBtu primary), while stock devices in 1997 are at about 944 kWh/year (10.2 MMBtu/year). The ratio of new to stock is therefore 0.69.

Business-as-Usual case: Existing stock vs. new energy intensities

The ratio of expected average new device or process intensities over the 1997-2010 period (kWh/device or per household) to base year stock intensities (usually, but not always, less than 1.0) characterizes the efficiency improvement that we can expect from stock turnover alone in the Business-as-Usual case.

We expect about a 5% improvement in refrigerator efficiency relative to new equipment in 1997, averaged over the 1997 to 2010 period. For new refrigerators, the expected average UEC over the 1997 to 2010 period is therefore $647 \times 0.95 = 615$ kWh/year (6.7 MMBtu/year), while stock devices in 1997 are at 944 kWh/year (10.2 MMBtu/year). The ratio of new to stock is therefore 0.65.

Frozen efficiency case energy use

To determine the frozen efficiency energy use in 2010, we use the following formula:

$$E \text{ use in Froz. Eff. Case 2010} = E \text{ use in 1997} \times \text{stock remaining factor} + E \text{ use in 1997} \times (\text{stock replacement factor} + \text{stock growth factor}) \times \frac{\text{new device intensity 1997}}{\text{stock device intensity 1997}} \quad (1)$$

If the Trends in service demand factor is applicable, it may either be multiplied by the entire frozen efficiency energy use (in the case where all households are affected by the trends embodied in this factor) or by either the stock component or the new component terms. We apply it to both the stock and new components in this analysis.

For refrigerators, this formula yields

$$E \text{ use in Froz. Eff. Case 2010} = 0.84 \times (1.21 \text{ quads} \times 0.487 + 1.21 \text{ quads} \times (0.416 + 0.25) \times \frac{647}{944})$$

$$= 0.95 \text{ quads}$$

Business-as-usual case energy use

To determine the Business-as-usual case energy use in 2010, we use the following formula:

$$E \text{ use in B.A.U case 2010} = E \text{ use in 1997} \times \text{stock remaining factor} +$$

$$E \text{ use in 1997} \times (\text{stock replacement factor} + \text{stock growth factor}) \times$$

The Cost of Energy Services, in billions of 1995 dollars per year in 2010, is calculated as follows:

$$\text{Cost of Energy Services} = (E_f^A \times P_f) + (ES \times CCE) \quad (5)$$

where

E_f^A = Energy use for end-use A using fuel f in any scenario (Quadrillion Btu of primary energy per year in 2010).

P_f = price of fuel f (electricity, natural gas, or oil), in 1995\$/MMBtu primary,

CCE = Cost of Conserved Energy (1995\$/MMBtu primary),

ES = Energy Savings (quads of primary energy per year).

and the other parameters are as described above.

Whenever the CCE is greater than the fuel price, the cost of energy services will increase compared to the B.A.U. case because of the efficiency measure. Whenever the CCE is less than the fuel price, the cost of energy services will be less than that in the B.A.U. case. In the latter case, carbon reductions can be achieved at negative net cost to society.

Discount rate

We used 7% real as the discount rate. The long term average return on investment for the utility industry is about 6% real, and the typical rates for auto loans or business loans are also in this range.

Cost of conserved energy (CCE)

CCE is calculated using the following equation:

$$\text{CCE (\$/kWh)} = \frac{\text{Capital Cost} \times \frac{d}{(1-(1+d)^{-n})}}{\text{Annual Energy Savings}} \quad (4)$$

where d is the discount rate and n is the lifetime of the conservation measure. The numerator in the right hand side of Equation 1 is the annualized cost of the conservation investment. Dividing annualized cost by annual energy savings yields the CCE.

Our life-cycle cost analysis for residential refrigerators results in a CCE of \$3.13/MMBtu primary (\$0.033/kWh) to achieve the maximum cost effective savings level (in 1995 \$).

Fuel and electricity prices

Fuel and electricity price forecasts are taken from the AEO 1997 reference case for 2010.

Conversion to carbon emissions

Emissions factors for fuels do not, of course, change over time or as a function of demand. These factors are taken from the EIA's recent work on this subject.⁴

Electricity carbon emissions per kWh for the Business-As-Usual case are based on the electricity sector analysis, and are multiplied by B.A.U. electricity demand to get total emissions. The emissions savings are calculated using an estimate of the marginal carbon savings per kWh derived by running the electricity sector model using a demand level 10% below that for the Business-As-Usual case in 2010, and calculating the change in emissions per kWh saved. We multiply this marginal carbon emissions factor by the electricity saved in the efficiency scenarios, and subtract these saved emissions from the B.A.U. emissions. In the final version of the report, we will run the electricity sector model using the actual demand levels from the scenarios to more accurately calculate the emissions associated with electricity savings.

Assessment of cost effectiveness

The total cost of energy services delivered in 2010 is a function of energy costs and annualized incremental costs for efficiency improvements in that year.

⁴US DOE. 1994. *Emissions of Greenhouse Gases in the United States, 1987-1992*. Energy Information Administration, U.S. Department of Energy, Washington, DC. DOE/EIA-0573. October.

$$\begin{aligned}
 E \text{ use in Max. Cost Effective Efficiency Case 2010} &= 0.84 * \left(1.21 \text{ quads} * 0.487 + 1.21 \right. \\
 &\text{quads} * 0.028 * \frac{647}{944} * (1 - 0.33) + 1.21 \text{ quads} * 0.388 * \frac{647}{944} * (1 - 0.33 - 0) + 1.21 \text{ quads} * \\
 &\left. 0.249 * \frac{647}{944} * (1 - 0.33 - 0) \right) \\
 &= 0.80 \text{ quads primary energy.}
 \end{aligned}$$

The potential savings is therefore 0.95 - 0.80 = 0.15 quads relative to the frozen efficiency case and 0.93 - 0.80 = 0.13 quads relative to the Business-as-Usual case.

This calculation could just as easily be done relative to the Business-as-usual baseline, but the absolute result will be the same. The choice of which baseline to use in calculating the consumption in the high efficiency case is solely a question of computational convenience and the availability of supply curve data.

Achievable fractions

In the real world, only some fraction of the potential savings can be achieved. We chose implementation factors of 35%, 50%, and 65% after a review of program experience (Brown 1993) and a judgemental assessment of how energy service markets would respond to policies and programs associated with aggressive commitments to reduce carbon emissions. We began with the Brown's conclusion that about half of the techno-economic potential could be captured given coordinated efforts on minimum efficiency standards, utility programs, and information programs. Our choice of 35% and 65% brackets this result. The lower number (efficiency case) matches Brown's most pessimistic sensitivity case, while the higher number (high efficiency case) corresponds to aggressive implementation of non-price policies combined with the assumption of a cap and trade system for carbon and other economic signals that would support these aggressive efforts. Brown did not address price signals in his report, so the most optimistic scenario he considers reaches almost 60% of the maximum economic potential. We believe that the addition of these price signals under an aggressive policy regime would push the achievable efficiency level to 65%.

We apply these achievable fractions to the savings in the maximum cost effective case relative to the B.A.U. case to determine the energy use in the cases where 35%, 50%, and 65% of the maximum cost effective efficiency improvement is assumed to be implemented.

In the 35% implementation case for residential, 35% of homes existing in 1997 still existing in 2010 (i.e., 35% x 90% = 32% of 1997 stock) are assumed to be retrofit. In the 50 and 65% implementation cases, we increase the retrofit percentage to 43%, but do not increase it further because we assume that only homes where the longest lived equipment (i.e., a gas furnace) turn over are eligible for shell retrofits. This assumption ensures that equipment replacement for expensive heating systems occurs at the same time as the retrofits, and that retrofits do not result in premature retirements of expensive systems (which are usually uneconomic).

In the 35% implementation case for commercial buildings, 35% of buildings existing in 1997 still existing in 2010 (i.e., 35% x 81% = 28% of 1997 stock) are assumed to be retrofit. In the 50 and 65% implementation cases, we only increase the retrofit percentage to 43% for the same reason we limited retrofits in the residential building stock.

expected average new device intensity 1997 to 2010
stock device intensity 1997

(2)

If the Trends in service demand factor is applicable, it may either be multiplied by the entire Bus. as Usual efficiency energy use (in the case where all households are affected by the trends embodied in this factor) or by either the stock component or the new component terms separately. We apply it to both the stock and new components in this analysis.

For refrigerators, this formula yields

$$E \text{ use in B.A.U case 2010} = 0.84 * (1.21 \text{ quads} * 0.487 + 1.21 \text{ quads} * (0.416 + 0.25) * \frac{615}{944})$$

$$= 0.93 \text{ quads}$$

Maximum cost effective efficiency case energy use

To calculate the efficiency case, we add three additional factors to the equation above: a) a savings factor for equipment relative to 1997 new equipment, b) a savings factor for retrofits of existing shells (for space conditioning end-uses only) relative to 1997 stock shells, and c) a savings factor for new shells (for space conditioning end-uses only) relative to 1997 new shells. We assume that equipment is not retrofit, only replaced with new equipment. The choice of the savings factors is justified in our detailed discussion of the applicable technologies and their performance for each end-use. Because our conservation supply curve analyses explicitly eliminate the effect of double counting for equipment and shell measures, the savings factors for equipment and shells are additive.

With these modifications, Equation 1 above becomes

E use in Max. Cost Effective Efficiency Case 2010 = Other Energy Service growth factor *

(E use in 1997*stock remaining factor +

E use in 1997*(stock replacement factor [existing shells]) * $\frac{\text{new device intensity in existing homes 1997}}{\text{stock device intensity 1997}}$ * (1- Svgs factor A) +

E use in 1997*(stock replacement factor [retrofit shells]) * $\frac{\text{new device intensity in existing homes 1997}}{\text{stock device intensity 1997}}$ * (1- Svgs factor A - Svgs factor B)

+

E use in 1997*(stock growth factor) * $\frac{\text{new device intensity in new homes 1997}}{\text{stock device intensity 1997}}$ *

(1- Svgs factor A - Svgs factor C))

(3)

Refrigerators are not affected by shell retrofits, so savings factors B and C are zero. For new refrigerators, the minimum life-cycle cost technology yields a savings factor of 33% compared to new equipment in 1997.

**Appendix C-2: Detailed Results Of
Residential And Commercial Sector Forecasts**

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**Interlab Study on U.S.
Energy Efficiency and Greenhouse
Gas Emissions**

Appendix C-2

**Detailed Results of
Residential and Commercial Sector
Forecasts**

**Table C-2.6.b: Input assumptions for U.S. commercial sector reference and high efficiency cases
65% implementation of efficiency resources**

SHELL EQUIPMENT		Base year energy use 1997	End-use	Existing Existing factor 2010	Existing New factor 2010	Retrofit New factor 2010	New New factor 2010	Other Energy Service growth factor (1) Ex. shells 2010	Other Energy Service growth factor (1) New shells 2010	REFERENCE CASE (NO RETROFITS)					EFFICIENCY CASE			Existing New CCE \$/MMBtu	Retrofit New CCE \$/MMBtu	New New CCE \$/MMBtu	Achievable Fraction	
Fuel	End-use	Quads	years	Stock factor 2010	Stock factor 2010	Stock factor 2010	Stock factor 2010			Existing Intensity kBtu/sf 1997	Existing Intensity kBtu/sf 1997	New Intensity kBtu/sf 1997	Existing New expid avg 1997-2010	New New expid avg 1997-2010	Ex no retrofit New rel. to new in 1997 2010	Ex. whetrofit New savings factor 2010	New New savings factor 2010					
Electricity	Space heating	0.12	18	0.46	0.00	0.35	0.31	0.96	0.96	1.54	1.36	1.36	1.44	1.32	48%	0%	0%	4.11	4.11	4.11	0.65	
	Space cooling	0.52	18	0.46	0.00	0.35	0.31	0.96	0.96	5.99	5.38	5.38	5.32	5.21	48%	0%	0%	4.11	4.11	4.11	0.65	
	Water heating	0.17	9	0.00	0.46	0.35	0.31	1.24	1.24	2.32	1.60	1.60	1.38	1.38	20%	0%	0%	9.41	9.41	9.41	0.65	
	Ventilation	0.17	18	0.46	0.00	0.35	0.31	1.06	1.06	2.36	2.05	2.05	2.13	2.13	48%	0%	0%	4.11	4.11	4.11	0.65	
	Cooking	0.03	15	0.35	0.11	0.35	0.31	1.11	1.11	0.43	0.32	0.32	0.31	0.31	0%	0%	0%	N/A	N/A	N/A	0.65	
	Lighting	1.26	12	0.19	0.27	0.35	0.31	0.94	0.94	17.41	17.32	17.32	17.29	17.29	25%	0%	0%	-10.16	-10.16	-10.16	0.65	
	Refrigeration	0.14	15	0.35	0.11	0.35	0.31	0.96	0.96	1.99	2.03	2.03	2.19	2.19	31%	0%	0%	4.62	4.62	4.62	0.65	
	Office equip.-PCs	0.08	5	0.00	0.46	0.35	0.31	1.12	1.12	1.13	1.13	1.13	1.13	1.13	0%	0%	0%	N/A	N/A	N/A	0.65	
	Office equip.-non-PCs	0.19	8	0.00	0.46	0.35	0.31	1.18	1.18	2.69	2.69	2.69	2.69	2.69	0%	0%	0%	N/A	N/A	N/A	0.65	
	Other Uses	0.65	7	0.00	0.46	0.35	0.31	1.49	1.49	9.19	9.19	9.19	9.19	9.19	33%	0%	0%	10.18	10.18	10.18	0.65	
Total electric	3.33						1.09	1.09														
Natural gas	Space heating	1.34	18	0.46	0.00	0.35	0.31	1.02	1.02	17.45	15.38	15.38	14.73	13.55	48%	0%	0%	4.11	4.11	4.11	0.65	
	Space cooling	0.03	18	0.46	0.00	0.35	0.31	0.57	0.57	0.25	0.50	0.50	0.50	0.49	48%	0%	0%	4.11	4.11	4.11	0.65	
	Water heating	0.48	9	0.00	0.46	0.35	0.31	0.98	0.98	6.43	6.10	6.10	6.39	6.39	10%	0%	0%	9.50	9.50	9.50	0.65	
	Cooking	0.19	15	0.35	0.11	0.35	0.31	0.96	0.96	2.63	2.94	2.94	3.14	3.14	0%	0%	0%	N/A	N/A	N/A	0.65	
	Other Uses	1.29	7	0.00	0.46	0.35	0.31	0.97	0.97	18.25	18.25	18.25	18.25	18.25	10%	0%	0%	3.00	3.00	3.00	0.65	
	Total gas	3.33						0.98	0.98													
Distillate oil	Space heating	0.19	18	0.46	0.00	0.35	0.31	1.04	1.04	2.60	1.67	1.67	1.44	1.33	48%	0%	0%	4.11	4.11	4.11	0.65	
	Water heating	0.05	9	0.00	0.46	0.35	0.31	1.58	1.58	0.73	0.45	0.45	0.42	0.42	10%	0%	0%	9.50	9.50	9.50	0.65	
	Other Uses	0.13	7	0.00	0.46	0.35	0.31	0.96	0.96	1.84	1.84	1.84	1.84	1.84	10%	0%	0%	3.00	3.00	3.00	0.65	
	Total oil	0.37						1.06	1.06													
Renewables	Biomass	0.00	18	0.46	0.00	0.35	0.31	1.00	1.00	1	1	1	1.00	0.92	0%	0%	0%	N/A	N/A	N/A	0.65	
								1.00	1.00													
Other fuels	Coal + bioresidue	0.31	18	0.46	0.00	0.35	0.31	1.00	1.00	1	1	1	1.00	0.92	0%	0%	0%	N/A	N/A	N/A	0.65	
Totals		7.34						1.00	1.00													

- (1) Energy service growth factors used to normalize to ABO 97 end-use consumption. Existing shell and new shell growth factors are differentiated in the spreadsheet for potential future use, but this differentiation is not currently used.
- (2) Energy prices in 2010 are 7.03, 4.78, 5.77 \$/MMBtu (1997 \$) for electricity, natural gas, and distillate oil, respectively. Other fuels are assumed to cost the same as distillate oil.
- (3) All intensities are taken from NEMS ABO97 data.
- (4) 1990 commercial sector carbon emissions = 209 million metric tons.
- (5) Electricity consumption and prices measured as site energy at 3412 Btu/kWh.
- (6) Oil efficiency costs and savings are assumed to be the same as for natural gas.
- (7) Costs of conserved energy are weighted averages up to the cost effective limit, and are expressed in \$/MMBtu of primary energy.

Table C-2.6.a (continued): Results for U.S. commercial sector reference and efficiency cases
35% implementation of efficiency resources

Fuel	End-use	Base year energy use 1997 Quads	Frozen efficiency 2010 Quads	Baseline B.A.U. 2010 Quads	35% Implement. Effic. case 2010 Quads	100% Implement. Effic. case 2010 Quads	Frozen efficiency 2010 Billion 95\$	Baseline B.A.U. 2010 Billion 95\$	35% Implement. Effic. case 2010 Billion 95\$	100% Implement. Effic. case 2010 Billion 95\$	100% Implementation case			35% Implement. Effic. case 2010 Billion 95\$	100% Implement. case 2010 Billion 95\$	Base year carbon emissions 1997 MMTC	Frozen efficiency 2010 MMTC	Baseline B.A.U. 2010 MMTC	35% Implement. Effic. case 2010 MMTC	100% Implement. Effic. case 2010 MMTC
											Existing New efficiency costs 2010 Billion 95\$	Retrofit New efficiency costs 2010 Billion 95\$	New New efficiency costs 2010 Billion 95\$							
Electricity	Space heating	0.12	0.12	0.12	0.11	0.09	2.50	2.52	2.28	1.83	0.01	0.06	0.06	2.33	1.97	6	6	6	5	4
	Space cooling	0.52	0.53	0.52	0.47	0.38	11.04	10.91	9.86	7.91	0.05	0.24	0.26	10.06	8.47	26	25	25	23	16
	Water heating	0.17	0.16	0.14	0.14	0.13	3.40	2.94	2.86	2.72	0.05	0.02	0.03	2.90	2.82	8	8	7	7	6
	Ventilation	0.17	0.19	0.19	0.17	0.14	3.91	3.99	3.60	2.87	0.02	0.09	0.10	3.67	3.09	8	9	9	9	6
	Cooking	0.03	0.03	0.03	0.03	0.03	0.65	0.63	0.63	0.63	0.00	0.00	0.00	0.63	0.63	1	1	1	1	1
	Lighting	1.26	1.32	1.32	1.22	1.04	27.74	27.69	25.67	21.90	-1.01	-0.85	-0.94	24.69	19.10	62	63	63	60	46
	Refrigeration	0.14	0.15	0.16	0.15	0.12	3.18	3.36	3.06	2.50	0.04	0.07	0.08	3.12	2.69	7	7	8	7	5
	Office equip.-PCs	0.08	0.10	0.10	0.10	0.10	2.10	2.10	2.10	2.10	0.00	0.00	0.00	2.10	2.10	4	5	5	5	5
	Office equip.-non-PCs	0.19	0.25	0.25	0.25	0.25	5.25	5.25	5.25	5.25	0.00	0.00	0.00	5.25	5.25	9	12	12	12	12
	Other Uses	0.65	1.08	1.08	0.96	0.72	22.66	22.66	20.05	15.20	1.70	0.91	1.01	21.32	18.82	32	52	52	48	30
Total electric	3.33	3.93	3.91	3.59	3.00	82.41	82.03	75.34	62.92	0.86	0.55	0.60	76.05	64.93	163	188	187	178	132	
Natural gas	Space heating	1.34	1.42	1.36	1.25	1.06	6.42	6.13	5.65	4.76	0.13	0.55	0.61	6.11	6.05	19	21	20	18	15
	Space cooling	0.03	0.03	0.03	0.03	0.02	0.14	0.14	0.12	0.09	0.00	0.02	0.02	0.13	0.13	0	0	0	0	0
	Water heating	0.48	0.50	0.52	0.49	0.45	2.24	2.35	2.23	2.02	0.33	0.18	0.19	2.47	2.71	7	7	8	7	6
	Cooking	0.19	0.22	0.23	0.23	0.23	0.99	1.04	1.04	1.04	0.00	0.00	0.00	1.04	1.04	3	3	3	3	3
	Other Uses	1.29	1.40	1.40	1.35	1.26	6.31	6.31	6.09	5.68	0.20	0.11	0.12	6.24	6.10	19	20	20	20	18
	Total gas	3.33	3.57	3.54	3.36	3.01	16.10	15.97	15.13	13.59	0.65	0.85	0.94	15.99	16.03	48	52	51	49	44
Distillate oil	Space heating	0.19	0.17	0.16	0.15	0.13	0.95	0.87	0.82	0.73	0.01	0.05	0.05	0.86	0.84	4	3	3	3	3
	Water heating	0.05	0.05	0.05	0.05	0.05	0.30	0.27	0.27	0.27	0.00	0.00	0.00	0.27	0.28	1	1	1	1	1
	Other Uses	0.13	0.14	0.14	0.14	0.13	0.76	0.76	0.73	0.69	0.02	0.01	0.01	0.75	0.73	3	3	3	3	3
	Total oil	0.37	0.37	0.35	0.34	0.31	2.00	1.90	1.83	1.68	0.03	0.06	0.06	1.88	1.84	7	7	7	7	6
Renewables	Biomass	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0	0	0	0	0	
Other fuels	Coal + kerosene	0.31	0.35	0.34	0.34	0.34	1.88	1.84	1.84	1.84	0.00	0.00	0.00	1.84	1.84	6	7	7	7	7
Totals		7.34	8.21	8.14	7.62	6.66	102.40	101.74	94.14	80.03	1.55	1.46	1.61	95.76	84.64	225	254	252	240	188

1.62

TWh 976 1151 1146 1052 879

Table C-2.6.a: Input assumptions for U.S. commercial sector reference and efficiency cases
35% implementation of efficiency resources

SHELL EQUIPMENT		Base year energy use 1997	End-use lifetime years	Existing Existing	Existing New	Retrofit New	New New	Other Energy Service growth factor (1) Ex. shells	Other Energy Service growth factor (1) New shells	REFERENCE CASE (NO RETROFITS)					EFFICIENCY CASE			Existing New	Retrofit New	New New	Achievable Fraction
Fuel	End-use	Quads	years	Stock factor 2010	Stock factor 2010	Stock factor 2010	Stock factor 2010	2010	2010	Existing Intensity 1997	Existing Intensity 1997	New Intensity 1997	Existing New exp'd avg Intensity 1997-2010	New New exp'd avg Intensity 1997-2010	Ex do retrofit New rel. to new in 1997	Ex. w/retrofit New savings factor 2010	New New savings factor 2010	CCB \$/MMBtu	CCB \$/MMBtu	CCB \$/MMBtu	
Electricity	Space heating	0.12	18	0.46	0.06	0.28	0.31	0.96	0.96	1.54	1.36	1.36	1.44	1.32	48%	0%	0%	4.11	4.11	4.11	0.35
	Space cooling	0.52	18	0.46	0.06	0.28	0.31	0.96	0.96	5.99	5.38	5.38	5.32	5.21	48%	0%	0%	4.11	4.11	4.11	0.35
	Water heating	0.17	9	0.00	0.52	0.28	0.31	1.24	1.24	2.32	1.60	1.60	1.38	1.38	20%	0%	0%	9.41	9.41	9.41	0.35
	Ventilation	0.17	18	0.46	0.06	0.28	0.31	1.06	1.06	2.36	2.05	2.05	2.13	2.13	48%	0%	0%	4.11	4.11	4.11	0.35
	Cooking	0.03	15	0.35	0.17	0.28	0.31	1.11	1.11	0.43	0.32	0.32	0.31	0.31	0%	0%	0%	N/A	N/A	N/A	0.35
	Lighting	1.26	12	0.19	0.34	0.28	0.31	0.94	0.94	17.41	17.32	17.32	17.29	17.29	25%	0%	0%	-10.16	-10.16	-10.16	0.35
	Refrigeration	0.14	15	0.35	0.17	0.28	0.31	0.96	0.96	1.99	2.03	2.03	2.19	2.19	31%	0%	0%	4.62	4.62	4.62	0.35
	Office equip.-PCs	0.08	5	0.00	0.52	0.28	0.31	1.12	1.12	1.13	1.13	1.13	1.13	1.13	0%	0%	0%	N/A	N/A	N/A	0.35
	Office equip.-non-PCs	0.19	8	0.00	0.52	0.28	0.31	1.18	1.18	2.69	2.69	2.69	2.69	2.69	0%	0%	0%	N/A	N/A	N/A	0.35
	Other Uses	0.65	7	0.00	0.52	0.28	0.31	1.49	1.49	9.19	9.19	9.19	9.19	9.19	33%	0%	0%	10.18	10.18	10.18	0.35
Total electric		3.33						1.09	1.09												
Natural gas	Space heating	1.34	18	0.46	0.06	0.28	0.31	1.02	1.02	17.45	15.38	15.38	14.73	13.55	48%	0%	0%	4.11	4.11	4.11	0.35
	Space cooling	0.03	18	0.46	0.06	0.28	0.31	0.57	0.57	0.25	0.50	0.50	0.50	0.49	48%	0%	0%	4.11	4.11	4.11	0.35
	Water heating	0.48	9	0.00	0.52	0.28	0.31	0.98	0.98	6.43	6.10	6.10	6.39	6.39	10%	0%	0%	9.50	9.50	9.50	0.35
	Cooking	0.19	15	0.35	0.17	0.28	0.31	0.96	0.96	2.63	2.94	2.94	3.14	3.14	0%	0%	0%	N/A	N/A	N/A	0.35
	Other Uses	1.29	7	0.00	0.52	0.28	0.31	0.97	0.97	18.25	18.25	18.25	18.25	18.25	10%	0%	0%	3.00	3.00	3.00	0.35
	Total gas		3.33						0.98	0.98											
Distillate oil	Space heating	0.19	18	0.46	0.06	0.28	0.31	1.04	1.04	2.60	1.67	1.67	1.44	1.33	48%	0%	0%	4.11	4.11	4.11	0.35
	Water heating	0.05	9	0.00	0.52	0.28	0.31	1.58	1.58	0.73	0.45	0.45	0.42	0.42	10%	0%	0%	9.50	9.50	9.50	0.35
	Other Uses	0.13	7	0.00	0.52	0.28	0.31	0.96	0.96	1.84	1.84	1.84	1.84	1.84	10%	0%	0%	3.00	3.00	3.00	0.35
	Total oil		0.37						1.06	1.06											
Renewables	Biomass	0.00	18	0.46	0.06	0.28	0.31	1.00	1.00	1	1	1	1.00	0.92	0%	0%	0%	N/A	N/A	N/A	0.35
Other fuels	Coal + kerosene	0.31	18	0.46	0.06	0.28	0.31	1.00	1.00	1	1	1	1.00	0.92	0%	0%	0%	N/A	N/A	N/A	0.35
Totals		7.34						1.00	1.00												

- (1) Energy service growth factors used to normalize to ABO 97 end-use consumption. Existing shell and new shell growth factors are differentiated in the spreadsheet for potential future use, but this differentiation is not currently used.
- (2) Energy prices in 2010 are 7.03, 4.78, 5.77 \$/MMBtu (1997 \$) for electricity, natural gas, and distillate oil, respectively. Other fuels are assumed to cost the same as distillate oil.
- (3) All intensities are taken from NEMS ABO97 data.
- (4) 1990 commercial sector carbon emissions = 209 million metric tons.
- (5) Electricity consumption and prices measured as site energy at 3412 Btu/kWh.
- (6) Oil efficiency costs and savings are assumed to be the same as for natural gas.
- (7) Costs of conserved energy are weighted averages up to the cost effective limit, and are expressed in \$/MMBtu of primary energy.

Table C-2.5.b (continued): Results for the residential sector, reference and high efficiency cases
65 % Implementation of efficiency resources

Fuel	End-use	Base year energy use 1997 Quads	Frozen efficiency case 2010 Quads	Baseline B.A.U. energy use 2010 Quads	65% Implement. Effic. case 2010 Quads	100% Implement. Effic. case 2010 Quads	Frozen efficiency case 2010 Billion 95\$	Baseline B.A.U. energy costs 2010 Billion 95\$	65% Implement. Effic. case 2010 Billion 95\$	100% Implement. Effic. case 2010 Billion 95\$	100% Implementation case			65% Implement. Effic. case 2010 Billion 95\$	100% Implement. Effic. case 2010 Billion 95\$	Base year carbon emissions 1997 MMTC	Frozen efficiency case 2010 MMTC	Baseline B.A.U. carbon emissions 2010 MMTC	65% Implement. Effic. case 2010 MMTC	100% Implement. Effic. case 2010 MMTC
											Existing New efficiency costs 2010 Billion 95\$	Retrofit New efficiency costs 2010 Billion 95\$	New New efficiency costs 2010 Billion 95\$							
Electricity	Space heating	0.45	0.50	0.48	0.44	0.42	11.50	10.98	10.10	9.63	0.02	0.32	0.31	10.52	10.27	22	24	23	21	19
Electricity	Space cooling	0.46	0.51	0.49	0.45	0.43	11.77	11.21	10.26	9.74	0.11	0.19	0.20	10.59	10.25	23	25	23	21	20
Electricity	Water heating	0.35	0.39	0.38	0.31	0.27	8.92	8.69	7.08	6.20	0.50	0.40	0.26	7.83	7.36	17	19	18	14	12
Electricity	Refrigeration	0.38	0.32	0.31	0.28	0.27	7.26	7.09	6.46	6.12	0.02	0.25	0.16	6.73	6.54	19	15	15	13	12
Electricity	Cooking	0.12	0.14	0.14	0.13	0.12	3.23	3.20	2.94	2.80	0.00	1.33	0.00	3.80	4.13	6	7	7	6	6
Electricity	Clothes Dryer	0.18	0.21	0.21	0.18	0.16	4.80	4.80	4.11	3.74	0.00	1.33	0.00	4.97	5.07	9	10	10	8	7
Electricity	Freezers	0.12	0.08	0.08	0.07	0.07	1.83	1.83	1.66	1.57	0.01	0.09	0.06	1.76	1.72	6	4	4	3	3
Electricity	Lighting	0.32	0.35	0.35	0.33	0.17	8.01	8.01	5.26	3.78	0.69	0.52	0.33	6.26	5.32	16	17	17	9	6
Electricity	Other Uses	1.35	2.02	2.02	1.60	1.37	46.22	46.22	36.54	31.34	2.88	2.28	1.46	40.85	37.96	66	97	97	71	57
	Total electric	3.73	4.52	4.46	3.69	3.27	103.53	102.04	84.41	74.92	4.22	6.70	2.78	93.32	88.62	183	217	213	167	142
Natural gas	Space heating	3.68	3.99	3.88	3.81	3.77	21.04	20.45	20.05	19.84	0.00	0.35	0.24	20.44	20.43	53	58	56	55	54
Natural gas	Space cooling	0.00	0.02	0.02	0.02	0.02	0.11	0.11	0.11	0.11	0.00	0.00	0.00	0.11	0.11	0	0	0	0	0
Natural gas	Water heating	1.27	1.40	1.39	1.27	1.21	7.37	7.33	6.72	6.39	0.12	0.21	0.14	7.02	6.86	18	20	20	18	18
Natural gas	Cooking	0.15	0.14	0.14	0.16	0.16	0.75	0.74	0.82	0.87	0.00	0.02	0.01	0.85	0.91	2	2	2	2	2
Natural gas	Clothes Dryer	0.05	0.05	0.05	0.09	0.11	0.26	0.26	0.47	0.58	0.00	0.00	0.00	0.47	0.58	1	1	1	1	2
Natural gas	Other Uses	0.09	0.10	0.10	0.09	0.09	0.53	0.53	0.49	0.48	0.01	0.01	0.01	0.51	0.50	1	1	1	1	1
	Total gas	5.24	5.70	5.58	5.44	5.36	30.05	29.41	28.66	28.26	0.13	0.60	0.39	29.40	29.39	76	83	81	79	78
Distillate oil	Space heating	0.77	0.66	0.65	0.63	0.62	4.92	4.84	4.69	4.60	0.00	0.09	0.06	4.78	4.75	15	13	13	13	12
Distillate oil	Water heating	0.10	0.10	0.10	0.09	0.08	0.74	0.75	0.67	0.62	0.01	0.02	0.01	0.69	0.66	2	2	2	2	2
Distillate oil	Other Uses	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0	0	0	0	0
	Total oil	0.87	0.76	0.75	0.72	0.70	5.67	5.59	5.35	5.22	0.01	0.10	0.07	5.47	5.41	17	15	15	14	14
LPG	Space heating	0.29	0.33	0.32	0.31	0.30	3.87	3.79	3.66	3.59	0.00	0.04	0.04	3.71	3.67	5	6	5	5	5
LPG	Water heating	0.07	0.09	0.09	0.08	0.08	1.08	1.07	0.96	0.90	0.01	0.01	0.01	0.98	0.93	1	2	2	1	1
LPG	Cooking	0.03	0.03	0.03	0.03	0.03	0.36	0.36	0.33	0.32	0.00	0.00	0.00	0.34	0.33	1	1	1	0	0
LPG	Other Uses	0.01	0.01	0.01	0.01	0.01	0.12	0.12	0.11	0.11	0.00	0.00	0.00	0.11	0.11	0	0	0	0	0
	Total LPG	0.40	0.46	0.45	0.43	0.42	5.43	5.33	5.07	4.93	0.01	0.06	0.05	5.14	5.04	7	8	8	7	7
Renewables	Wood	0.58	0.56	0.55	0.55	0.55	5.90	5.80	5.80	5.80	0.00	0.00	0.00	5.80	5.80	0	0	0	0	0
Other fuels	Coal + kerosene	0.12	0.11	0.11	0.11	0.11	0.83	0.82	0.82	0.82	0.00	0.00	0.00	0.82	0.82	2	2	2	2	2
	Totals	10.94	12.12	11.90	10.93	10.41	151.41	148.99	130.11	119.95	4.37	7.46	3.30	139.95	135.08	285	324	319	269	242

9.84

1093 1326 1307 1081 960

Table C-2.5.a: Input assumptions for U.S. residential sector reference and efficiency cases
35 % Implementation of efficiency resources

Fuel	SHELL EQUIPMENT End-use	Base year energy use 1997 Quads	End-use lifetime years	Existing	Existing	Retrofit	New	Other	Other	REFERENCE CASE (NO RETROFITS)					EFFICIENCY CASE			Existing	Retrofit	New	Achievable Fraction
				Existing	Existing	New	New	Energy Service growth factor (1)	Energy Service growth factor (1)	Existing	Existing	New	Existing	New	Ex no retrofit	Ex. w/retrofit	New	Existing	Retrofit	New	
				factor	factor	factor	factor	Ex. shell	New shell	UEC	UEC	UEC	UEC	UEC	rel. to new	New shell	New shell	CCB	CCB	CCB	
				2010	2010	2010	2010	2010	2010	MMBtu	MMBtu	MMBtu	kWh	MMBtu	in 1997	savings	savings	\$/MMBtu	\$/MMBtu	\$/MMBtu	
Electricity	Space heating	0.45	18	0.46	0.13	0.32	0.25	1.04	1.04	32.1	30.5	24.8	28.7	21.7	11%	14%	28%	9.06	10.07	12.15	0.35
	Space cooling	0.46	13	0.25	0.34	0.32	0.25	1.16	1.16	5.5	4.4	4.3	4.2	3.8	15%	1%	7%	9.06	10.07	12.15	0.35
	Water heating	0.35	10	0.02	0.56	0.32	0.25	1.22	1.22	16.8	13.3	13.3	13.0	13.0	28%	0%	0%	9.41	9.41	9.41	0.35
	Refrigeration	0.38	19	0.49	0.10	0.32	0.25	0.89	0.89	3.2	2.2	2.2	2.1	2.1	33%	0%	0%	9.90	9.90	9.90	0.35
	Cooking	0.12	19	0.49	0.10	0.32	0.25	1.02	1.02	2.0	2.0	2.0	2.0	2.0	0%	0%	0%	N/A	N/A	N/A	0.35
	Clothes Dryers	0.18	17	0.43	0.16	0.32	0.25	1.05	1.05	3.0	2.8	2.8	2.8	2.8	0%	0%	0%	N/A	N/A	N/A	0.35
	Freezers	0.12	19	0.49	0.10	0.32	0.25	0.67	0.67	2.0	1.6	1.6	1.6	1.6	28%	0%	0%	13.19	13.19	13.19	0.35
	Lighting	0.32	1	0.00	0.59	0.32	0.25	0.95	0.95	3.2	3.2	3.2	3.2	3.2	53%	0%	0%	8.34	8.34	8.34	0.35
	Other Uses	1.35	10	0.02	0.56	0.32	0.25	1.30	1.30	13.3	13.3	13.3	13.3	13.3	33%	0%	0%	10.18	10.18	10.18	0.35
	Total electric	3.73						1.14	1.14												
Natural gas	Space heating	3.68	20	0.51	0.07	0.32	0.25	1.09	1.09	74.6	65.3	42.4	62.8	38.0	7%	4%	12%	4.99	4.66	4.48	0.35
	Space cooling	0.00	12	0.19	0.40	0.32	0.25	1.00	1.00	1.0	1.0	1.0	1.0	1.0	0%	0%	0%	N/A	N/A	N/A	0.35
	Water heating	1.27	14	0.30	0.29	0.32	0.25	1.04	1.04	33.6	29.7	29.7	29.5	29.5	23%	0%	0%	2.15	2.15	2.15	0.35
	Cooking	0.15	19	0.49	0.10	0.32	0.25	0.82	0.82	3.8	3.8	3.8	3.7	3.7	18%	0%	0%	2.38	2.38	2.38	0.35
	Clothes Dryers	0.05	17	0.43	0.16	0.32	0.25	0.95	0.95	3.7	3.2	3.2	3.2	3.2	0%	0%	0%	N/A	N/A	N/A	0.35
	Other Uses	0.09	10	0.02	0.56	0.32	0.25	0.97	0.97	0.9	0.9	0.9	0.9	0.9	10%	0%	0%	3.00	3.00	3.00	0.35
	Total gas	5.24						1.07	1.07												
Distillate oil	Space heating	0.77	20	0.51	0.07	0.32	0.25	0.85	0.85	70.5	61.7	43.8	61.1	40.0	7%	4%	12%	4.99	4.66	4.48	0.35
	Water heating	0.10	14	0.30	0.29	0.32	0.25	0.95	0.95	33.6	29.7	29.7	29.7	29.7	23%	0%	0%	2.15	2.15	2.15	0.35
	Other Uses	0.00	10	0.02	0.56	0.32	0.25	1.00	1.00	1.0	1.0	1.0	1.0	1.0	10%	0%	0%	3.00	3.00	3.00	0.35
	Total oil	0.87						0.86	0.86												
LPG	Space heating	0.29	20	0.51	0.07	0.32	0.25	1.05	1.05	74.6	65.3	65.3	64.6	59.5	7%	4%	12%	4.99	4.66	4.48	0.35
	Water heating	0.07	14	0.30	0.29	0.32	0.25	1.24	1.24	33.6	29.7	29.7	29.2	29.2	23%	0%	0%	2.15	2.15	2.15	0.35
	Cooking	0.03	19	0.49	0.10	0.32	0.25	0.88	0.88	3.8	3.8	3.8	3.7	3.7	18%	0%	0%	2.38	2.38	2.38	0.35
	Other Uses	0.01	10	0.02	0.56	0.32	0.25	0.87	0.87	0.1	0.1	0.1	0.1	0.1	10%	0%	0%	3.00	3.00	3.00	0.35
	Total LPG	0.40						1.06	1.06												
Renewables	Wood	0.58	20	0.51	0.07	0.32	0.25	0.84	0.84	1.0	1.0	1.0	1.0	0.9	0%	0%	0%	N/A	N/A	N/A	0.35
Other fuels	Coal + kerosene	0.12	20	0.51	0.07	0.32	0.25	0.81	0.81	1.0	1.0	1.0	1.0	0.9	0%	0%	0%	N/A	N/A	N/A	0.35
Totals		10.94						1.05	1.05												

(1) Energy service growth factors used to normalize to AEO 97 end-use consumption. Existing shell and new shell growth factors are differentiated in the spreadsheet for potential future use, but this differentiation is not currently used.

(2) Energy prices in 2010 are 7.67, 5.59, 7.90, and 12.57 \$/MMBtu (1997 \$) for electricity, natural gas, distillate oil, and LPG, respectively.

Other fuels are assumed to cost the same as distillate oil, while renewables are assumed to cost twice as much as natural gas.

(3) All UECs are taken from the LBNL REM and LBNL REEPS residential forecasting models.

(4) 1990 residential sector carbon emissions = 253 million metric tons.

(5) Electricity consumption and prices measured as site energy at 3412 Btu/kWh.

(6) Oil and LPG efficiency costs and savings are assumed to be the same as for natural gas.

(7) Costs of conserved energy are weighted averages up to the cost effective limit, and are expressed in \$/MMBtu of primary energy.

average, weighted by quads per end-use

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Table C-2.4: Main results, commercial sector business-as-usual scenario, by end-use

Fuel	End-use	Primary Energy Use (Quads)			Carbon Emissions (MMTC)			Energy Costs
		1990	1997	2010	1990	1997	2010	Billion 1995 \$ 2010
Electricity	Space heating	0.4	0.4	0.3	6	6	6	3
	Space cooling	1.8	1.7	1.5	29	26	25	11
	Water heating	0.6	0.5	0.4	9	8	7	3
	Ventilation	0.5	0.5	0.6	9	8	9	4
	Cooking	0.1	0.1	0.1	2	1	1	1
	Lighting	3.7	4.0	3.8	59	62	63	28
	Refrigeration	0.4	0.4	0.5	7	7	8	3
	PC Off. Equip.	0.1	0.3	0.3	2	4	5	2
	non-PC Off. Equip.	0.5	0.6	0.7	8	9	12	5
	Other Uses	1.2	2.1	3.1	20	32	52	23
	Total electric	9.4	10.6	11.4	150	163	187	82
Natural gas	Space heating	1.3	1.3	1.4	20	19	20	6
	Space cooling	0.0	0.0	0.0	0	0	0	0
	Water heating	0.5	0.5	0.5	7	7	8	2
	Cooking	0.2	0.2	0.2	2	3	3	1
	Other Uses	0.9	1.3	1.4	13	19	20	6
	Total gas	2.9	3.3	3.5	42	48	51	16
Distillate oil	Space heating	0.2	0.2	0.2	4	4	3	1
	Water heating	0.1	0.1	0.1	1	1	1	0
	Other Uses	0.2	0.1	0.1	4	3	3	1
	Total oil	0.5	0.4	0.4	10	7	7	2
Renewables	Wood	0.0	0.0	0.0	0	0	0	0
Other fuels	Coal + kerosene	0.4	0.3	0.3	7	6	7	2
Totals		13.2	14.6	15.6	209	225	252	102

Table C-2.3: Main results, residential sector business-as-usual scenario, by end-use

Fuel	End-use	Primary Energy Use (Quads)			Carbon Emissions (MMTC)			Energy Costs Billion 1995 \$
		1990	1997	2010	1990	1997	2010	2010
Electricity	Space heating	1.0	1.4	1.4	15	22	23	11
	Space cooling	1.7	1.5	1.4	27	23	23	11
	Water heating	1.1	1.1	1.1	18	17	18	9
	Refrigeration	1.7	1.2	0.9	27	19	15	7
	Cooking	0.5	0.4	0.4	8	6	7	3
	Clothes Dryers	0.6	0.6	0.6	9	9	10	5
	Freezers	0.5	0.4	0.2	8	6	4	2
	Lighting	1.0	1.0	1.0	15	16	17	8
	Other Uses	2.2	4.3	5.9	36	66	97	46
	Total electric	10.2	11.9	13.0	162	183	213	102
Natural gas	Space heating	3.1	3.7	3.9	45	53	56	20
	Space cooling	0.0	0.0	0.0	0	0	0	0
	Water heating	1.1	1.3	1.4	16	18	20	7
	Cooking	0.2	0.2	0.1	3	2	2	1
	Clothes Dryers	0.1	0.1	0.1	1	1	1	0
	Other Uses	0.1	0.1	0.1	1	1	1	1
	Total gas	4.5	5.2	5.6	66	76	81	29
Distillate oil	Space heating	0.8	0.8	0.7	15	15	13	5
	Water heating	0.1	0.1	0.1	2	2	2	1
	Other Uses	0.0	0.0	0.0	0	0	0	0
	Total oil	0.8	0.9	0.8	17	17	15	6
LPG	Space heating	0.2	0.3	0.3	4	5	5	4
	Water heating	0.1	0.1	0.1	1	1	2	1
	Cooking	0.1	0.0	0.0	1	1	1	0
	Other Uses	0.0	0.0	0.0	0	0	0	0
	Total LPG	0.4	0.4	0.5	6	7	8	5
Renewables	Wood	0.6	0.6	0.6	0	0	0	6
Other fuels	Coal + kerosene	0.1	0.1	0.1	3	2	2	1
Totals		16.7	19.1	20.4	253	285	319	149

Table C-2.2: Main results, buildings sector business-as-usual scenario, by fuel								
Fuel	End-use	Primary Energy Use (Quads)			Carbon Emissions (MMTC)			Energy Costs
		1990	1997	2010	1990	1997	2010	Billion 1995 \$ 2010
Residential	Electricity	10.2	11.9	13.0	162	183	213	102
	Natural gas	4.5	5.2	5.6	66	76	81	29
	Distillate oil	0.8	0.9	0.8	17	17	15	6
	Other fuels	1.1	1.1	1.1	9	9	10	12
	Total	16.7	19.1	20.4	253	285	319	149
Commercial	Electricity	9.4	10.6	11.4	150	163	187	82
	Natural gas	2.9	3.3	3.5	42	48	51	16
	Distillate oil	0.5	0.4	0.4	10	7	7	2
	Other fuels	0.4	0.3	0.3	7	6	7	2
	Total	13.2	14.6	15.6	209	225	252	102
Total	Electricity	19.7	22.5	24.3	312	346	401	184
	Natural gas	7.4	8.6	9.1	107	124	132	45
	Distillate oil	1.3	1.2	1.1	26	25	22	7
	Other fuels	1.5	1.4	1.4	16	15	17	14
	Total	29.9	33.7	36.0	462	511	571	251

(1) Other fuels includes LPG, renewables, coal, and kerosene.

Table C-2.1: Main results, buildings sector scenarios

Fuel	End-use	Primary Energy Use (Quads)			Carbon Emissions (MMTC)			Energy costs	Efficiency costs	Total Costs of Energy Services
		1990	1997	2010	1990	1997	2010	Billion 1995 \$ 2010	Billion 1995 \$ 2010	Billion 1995 \$ 2010
Residential	B.A.U.	16.7	19.1	20.4	253	285	319	149	0	149
	Efficiency case	16.7	19.1	19.4	253	285	306	139	5	144
	High efficiency case	16.7	19.1	18.2	253	285	269	130	10	140
Commercial	B.A.U.	13.2	14.6	15.6	209	225	252	102	0	102
	Efficiency case	13.2	14.6	14.7	209	225	240	94	2	96
	High efficiency case	13.2	14.6	13.7	209	225	211	88	3	91
Total	B.A.U.	29.9	33.7	36.0	462	511	571	251	0	251
	Efficiency case	29.9	33.7	34.1	462	511	546	233	7	240
	High efficiency case	29.9	33.7	32.0	462	511	480	218	13	231
Index	1990 = 1.0	1.00	1.13	1.20	1.00	1.10	1.24	N/A	N/A	N/A
	1991 = 1.0	1.00	1.13	1.14	1.00	1.10	1.18	N/A	N/A	N/A
	1992 = 1.0	1.00	1.13	1.07	1.00	1.10	1.04	N/A	N/A	N/A
Index	B.A.U. = 1.0	1.00	1.00	1.00	1.00	1.00	1.00	1.00	N/A	1.00
	B.A.U. = 1.0	1.00	1.00	0.95	1.00	1.00	0.96	0.93	N/A	0.96
	B.A.U. = 1.0	1.00	1.00	0.89	1.00	1.00	0.84	0.87	N/A	0.92

(1) Other fuels includes LPG, renewables, coal, and kerosene.

(2) Efficiency case assumes 35% implementation of efficiency resources, and high efficiency case assumes 65% implementation.

(3) Efficiency costs are annualized in 2010.

TERMINOLOGY AND CONVENTIONS FOR BUILDINGS SECTOR SPREADSHEET

Stock factors	These factors are fractions of the 1997 stock attributable to different parts of the building stock. They are calculated using a simple stock accounting model and the average equipment lifetimes shown in Tables R.1 and C.1. The lifetime of building shells is 100 years for residential and 50 years for commercial. The sum of the stock factors for 2010 is 1.15 for residential and 1.12 for commercial, which means that over the 1997-2010 period, total households and total floor area grow 15% and 12%, respectively. We separately account for retrofit and new shells, though in the reference case there are no retrofits. About 10% of the residential buildings existing in 1997 are retired by 2010, while about 19% of the commercial buildings existing in 1997 are retired by 2010.
Energy service growth factors	These factors are used to normalize our forecasted total consumption by end-use to the AEO97 results. They correct for differences in the stock accounting and other aspects of our methodology. If these numbers are less than 1.0, they imply that our methodology overforecasts demand compared to AEO97, while if they are larger than 1.0, our methodology underforecasts demand compared to AEO97.
UECs and EUIs	The ratios of the UECs or EUIs for the different categories of houses are used along with our simple stock accounting to capture the effect of stock turnover on energy use. With the exception of residential refrigerators and freezers (which come from LBNL REM), the UECs and EUIs come directly from the AEO97 model outputs.
Efficiency factors	These are defined relative to current practice in 1997. The first column in this section (with the heading "EFFICIENCY CASE") is the savings associated with new equipment, expressed as the percentage by which this new equipment exceeds the efficiency of 1997 new equipment. The second column (ex. with retrofit, new equipment) is the shell savings factor that is to be added to the equipment efficiency factor to get total savings for these buildings. The third column (new shell, new equipment) is the shell savings factor for new buildings that is to be added to the equipment efficiency factor to get total savings for new buildings.
CCE (\$/MMBtu site)	The cost of conserved energy (CCE) is calculated using a 7% real discount rate. It represents the average CCE for a package of measures that all cost less than the price cutoff of 8 cents/kWh or \$6/MMBtu. It is the weighted average cost of adding all technically cost-effective efficiency options up to that price cutoff.
Efficiency costs (Billion 1997\$/year)	The costs of improving efficiency are assessed on an annualized basis. They are calculated by multiplying the annual energy savings by the CCE.
Total cost of energy services (Billion 1997\$/year)	Total cost of energy services is the sum of energy costs and efficiency costs.

Table C-2.5.a (continued): Results for the U.S. residential sector reference and efficiency cases
35% Implementation of efficiency resources

(1) (2)

(2) (1)

Fuel	End-use	Base year energy use 1997 Quads	35% 100%				35% 100%				100% Implementation case			35%	100%	Base year carbon emissions 1997 MMTC	Frozen efficiency carbon emissions 2010 MMTC	Baseline B.A.U. carbon emissions 2010 MMTC	35% Implement. Effic. case carbon emissions 2010 MMTC	100% Implement. Effic. case carbon emissions 2010 MMTC
			Frozen efficiency energy use 2010 Quads	Baseline B.A.U. energy use 2010 Quads	Implement. Effic. case energy use 2010 Quads	Implement. Effic. case energy use 2010 Quads	Frozen efficiency energy costs 2010 Billion 95\$	Baseline B.A.U. energy costs 2010 Billion 95\$	Implement. Effic. case energy costs 2010 Billion 95\$	Implement. Effic. case energy costs 2010 Billion 95\$	Existing New efficiency costs 2010 Billion 95\$	Retrofit New efficiency costs 2010 Billion 95\$	New New efficiency costs 2010 Billion 95\$	Implement. Effic. case total costs 2010 Billion 95\$	Implement. Effic. case total costs 2010 Billion 95\$					
Electricity	Space heating	0.45	0.50	0.48	0.46	0.43	11.50	10.98	10.54	9.73	0.04	0.25	0.31	10.75	10.33	22	24	23	22	20
Electricity	Space cooling	0.46	0.51	0.49	0.47	0.43	11.77	11.21	10.70	9.75	0.14	0.16	0.20	10.88	10.25	23	25	23	23	20
Electricity	Water heating	0.35	0.39	0.38	0.34	0.27	8.92	8.69	7.82	6.20	0.58	0.33	0.26	8.23	7.36	17	19	18	17	12
Electricity	Refrigeration	0.38	0.32	0.31	0.30	0.27	7.26	7.09	6.75	6.12	0.06	0.20	0.16	6.90	6.54	19	15	15	14	12
Electricity	Cooking	0.12	0.14	0.14	0.13	0.12	3.23	3.20	3.06	2.80	0.00	1.33	0.00	3.33	4.13	6	7	7	7	6
Electricity	Clothes Dryers	0.18	0.21	0.21	0.19	0.16	4.80	4.80	4.43	3.74	0.00	1.33	0.00	4.90	5.07	9	10	10	10	7
Electricity	Freezers	0.12	0.08	0.08	0.08	0.07	1.83	1.83	1.74	1.57	0.02	0.07	0.06	1.79	1.72	6	4	4	4	3
Electricity	Lighting	0.32	0.35	0.35	0.29	0.17	8.01	8.01	6.53	3.78	0.78	0.42	0.33	7.07	5.32	16	17	17	15	6
Electricity	Other Uses	1.35	2.02	2.02	1.79	1.37	46.22	46.22	41.01	31.34	3.30	1.86	1.46	43.33	37.96	66	97	97	90	57
	Total electric	3.73	4.52	4.46	4.05	3.28	103.53	102.04	92.59	75.03	4.93	5.94	2.77	97.37	88.68	183	217	213	202	142
Natural gas	Space heating	3.68	3.99	3.88	3.84	3.78	21.04	20.45	20.25	19.90	0.04	0.27	0.23	20.45	20.44	53	58	56	56	55
Natural gas	Space cooling	0.00	0.02	0.02	0.02	0.02	0.11	0.11	0.11	0.11	0.00	0.00	0.00	0.11	0.11	0	0	0	0	0
Natural gas	Water heating	1.27	1.40	1.39	1.33	1.21	7.37	7.33	7.00	6.39	0.16	0.17	0.14	7.16	6.86	18	20	20	19	18
Natural gas	Cooking	0.15	0.14	0.14	0.15	0.16	0.75	0.74	0.78	0.87	0.01	0.02	0.01	0.80	0.91	2	2	2	2	2
Natural gas	Clothes Dryers	0.05	0.05	0.05	0.07	0.11	0.26	0.26	0.37	0.58	0.00	0.00	0.00	0.37	0.58	1	1	1	1	2
Natural gas	Other Uses	0.09	0.10	0.10	0.10	0.09	0.53	0.53	0.51	0.48	0.01	0.01	0.01	0.52	0.50	1	1	1	1	1
	Total gas	5.24	5.70	5.58	5.51	5.37	30.05	29.41	29.03	28.32	0.22	0.47	0.38	29.40	29.40	76	83	81	80	78
Distillate oil	Space heating	0.77	0.66	0.65	0.64	0.62	4.92	4.84	4.76	4.61	0.01	0.07	0.06	4.81	4.76	15	13	13	13	12
Distillate oil	Water heating	0.10	0.10	0.10	0.09	0.08	0.74	0.75	0.70	0.62	0.01	0.01	0.01	0.71	0.66	2	2	2	2	2
Distillate oil	Other Uses	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0	0	0	0	0
	Total oil	0.87	0.76	0.75	0.73	0.70	5.67	5.59	5.46	5.24	0.02	0.08	0.07	5.53	5.41	17	15	15	15	14
LPG	Space heating	0.29	0.33	0.32	0.31	0.30	3.87	3.79	3.73	3.60	0.00	0.03	0.04	3.75	3.68	5	6	5	5	5
LPG	Water heating	0.07	0.09	0.09	0.09	0.08	1.08	1.07	1.01	0.90	0.01	0.01	0.01	1.02	0.93	1	2	2	1	1
LPG	Cooking	0.03	0.03	0.03	0.03	0.03	0.36	0.36	0.34	0.32	0.00	0.00	0.00	0.35	0.33	1	1	1	0	0
LPG	Other Uses	0.01	0.01	0.01	0.01	0.01	0.12	0.12	0.11	0.11	0.00	0.00	0.00	0.12	0.11	0	0	0	0	0
	Total LPG	0.40	0.46	0.45	0.44	0.42	5.43	5.33	5.19	4.94	0.02	0.05	0.05	5.23	5.05	7	8	8	7	7
Renewables	Wood	0.58	0.56	0.55	0.55	0.55	5.90	5.80	5.80	5.80	0.00	0.00	0.00	5.80	5.80	0	0	0	0	0
Other fuels	Coal + kerosene	0.12	0.11	0.11	0.11	0.11	0.83	0.82	0.82	0.82	0.00	0.00	0.00	0.82	0.82	2	2	2	2	2
Totals		10.94	12.12	11.90	11.39	10.43	151.41	148.99	138.89	120.14	5.19	6.54	3.28	144.15	135.15	285	324	319	306	243

1093 1326 1307 1186 961

Table C-2.5.b: Input assumptions for U.S. residential sector reference and high efficiency cases
65% implementation of efficiency resources

SHELL EQUIPMENT		Base year energy use 1997 Quads	End-use lifetime years	Existing	Existing	Retrofit	New	Other Energy Service growth factor (1) Ex. shells 2010	Other Energy Service growth factor (1) New shells 2010	REFERENCE CASE (NO RETROFITS)					EFFICIENCY CASE			Existing	Retrofit	New	Achievable Fraction
Fuel	End-use			Existing	New	New	New	Existing	Existing	New	Existing	New	Existing	New	Existing	New	Existing	Retrofit	New		
				Stock factor 2010	Stock factor 2010	Stock factor 2010	Stock factor 2010			UEC MMBtu 1997	UEC MMBtu 1997	UEC MMBtu 1997	UEC New expid avg 1997-2010 kWh	UEC MMBtu 1997-2010	Ex no retrofit New 2010	Ex. w/retrofit New shell savings factor 2010	New shell savings factor 2010	CCB \$/MMBtu	OCE \$/MMBtu	OCB \$/MMBtu	
Electricity	Space heating	0.45	18	0.46	0.06	0.39	0.25	1.04	1.04	32.1	30.5	24.8	28.7	21.7	11%	14%	28%	9.06	10.07	12.15	0.65
	Space cooling	0.46	13	0.25	0.26	0.39	0.25	1.16	1.16	5.5	4.4	4.3	4.2	3.8	15%	1%	7%	9.06	10.07	12.15	0.65
	Water heating	0.35	10	0.02	0.49	0.39	0.25	1.22	1.22	16.8	13.3	13.3	13.0	13.0	28%	0%	0%	9.41	9.41	9.41	0.65
	Refrigeration	0.38	19	0.49	0.03	0.39	0.25	0.89	0.89	3.2	2.2	2.2	2.1	2.1	33%	0%	0%	9.90	9.90	9.90	0.65
	Cooking	0.12	19	0.49	0.03	0.39	0.25	1.02	1.02	2.0	2.0	2.0	2.0	2.0	0%	0%	0%	N/A	N/A	N/A	0.65
	Clothes Dryers	0.18	17	0.43	0.09	0.39	0.25	1.05	1.05	3.0	2.8	2.8	2.8	2.8	0%	0%	0%	N/A	N/A	N/A	0.65
	Freezers	0.12	19	0.49	0.03	0.39	0.25	0.67	0.67	2.0	1.6	1.6	1.6	1.6	28%	0%	0%	13.19	13.19	13.19	0.65
	Lighting	0.32	1	0.00	0.51	0.39	0.25	0.95	0.95	3.2	3.2	3.2	3.2	3.2	53%	0%	0%	8.34	8.34	8.34	0.65
	Other Uses	1.35	10	0.02	0.49	0.39	0.25	1.30	1.30	13.3	13.3	13.3	13.3	13.3	33%	0%	0%	10.18	10.18	10.18	0.65
	Total electric	3.73							1.14	1.14											
Natural gas	Space heating	3.68	20	0.51	0.00	0.39	0.25	1.09	1.09	74.6	65.3	42.4	62.8	38.0	7%	4%	12%	4.99	4.66	4.48	0.65
	Space cooling	0.00	12	0.19	0.33	0.39	0.25	1.00	1.00	1.0	1.0	1.0	1.0	1.0	0%	0%	0%	N/A	N/A	N/A	0.65
	Water heating	1.27	14	0.30	0.22	0.39	0.25	1.04	1.04	33.6	29.7	29.7	29.5	29.5	23%	0%	0%	2.15	2.15	2.15	0.65
	Cooking	0.15	19	0.49	0.03	0.39	0.25	0.82	0.82	3.8	3.8	3.8	3.7	3.7	18%	0%	0%	2.38	2.38	2.38	0.65
	Clothes Dryers	0.05	17	0.43	0.09	0.39	0.25	0.95	0.95	3.7	3.2	3.2	3.2	3.2	0%	0%	0%	N/A	N/A	N/A	0.65
	Other Uses	0.09	10	0.02	0.49	0.39	0.25	0.97	0.97	0.9	0.9	0.9	0.9	0.9	10%	0%	0%	3.00	3.00	3.00	0.65
	Total gas	5.24						1.07	1.07												
Distillate oil	Space heating	0.77	20	0.51	0.00	0.39	0.25	0.85	0.85	70.5	61.7	43.8	61.1	40.0	7%	4%	12%	4.99	4.66	4.48	0.65
	Water heating	0.10	14	0.30	0.22	0.39	0.25	0.95	0.95	33.6	29.7	29.7	29.7	29.7	23%	0%	0%	2.15	2.15	2.15	0.65
	Other Uses	0.00	10	0.02	0.49	0.39	0.25	1.00	1.00	1.0	1.0	1.0	1.0	1.0	10%	0%	0%	3.00	3.00	3.00	0.65
	Total oil	0.87						0.86	0.86												
LPG	Space heating	0.29	20	0.51	0.00	0.39	0.25	1.05	1.05	74.6	65.3	65.3	64.6	59.5	7%	4%	12%	4.99	4.66	4.48	0.65
	Water heating	0.07	14	0.30	0.22	0.39	0.25	1.24	1.24	33.6	29.7	29.7	29.2	29.2	23%	0%	0%	2.15	2.15	2.15	0.65
	Cooking	0.03	19	0.49	0.03	0.39	0.25	0.88	0.88	3.8	3.8	3.8	3.7	3.7	18%	0%	0%	2.38	2.38	2.38	0.65
	Other Uses	0.01	10	0.02	0.49	0.39	0.25	0.87	0.87	0.1	0.1	0.1	0.1	0.1	10%	0%	0%	3.00	3.00	3.00	0.65
	Total LPG	0.40						1.06	1.06												
Renewables	Wood	0.58	20	0.51	0.00	0.39	0.25	0.84	0.84	1.0	1.0	1.0	1.0	0.9	0%	0%	0%	N/A	N/A	N/A	0.65
Other fuels	Coal + kerosene	0.12	20	0.51	0.00	0.39	0.25	0.81	0.81	1.0	1.0	1.0	1.0	0.9	0%	0%	0%	N/A	N/A	N/A	0.65
Totals		10.94						1.05	1.05												

- (1) Energy service growth factors used to normalize to AEO 97 end-use consumption. Existing shell and new shell growth factors are differentiated in the spreadsheet for potential future use, but this differentiation is not currently used.
- (2) Energy prices in 2010 are 7.67, 5.59, 7.90, and 12.57 \$/MMBtu (1997 \$) for electricity, natural gas, distillate oil, and LPG, respectively. Other fuels are assumed to cost the same as distillate oil, while renewables are assumed to cost twice as much as natural gas.
- (3) All UBCs are taken from the LBNL RBM and LBNL REEPS residential forecasting models.
- (4) 1990 residential sector carbon emissions = 253 million metric tons.
- (5) Electricity consumption and prices measured as site energy at 3412 Btus/kWh.
- (6) Oil and LPG efficiency costs and savings are assumed to be the same as for natural gas.
- (7) Costs of conserved energy are weighted averages up to the cost effective limit, and are expressed in \$/MMBtu of primary energy.

Fuel cells

Table C-2.7: Fuel cell calculations for high efficiency/low carbon case

970605

Assume 200kW or smaller phosphoric acid fuel cell units (also could use small advanced gas turbines)

Installed electrical capacity by 2010 5 GW THIS NUMBER NEEDS TO BE VALIDATED AND CHECKED.

Capacity factor (elect. load following) 95%

TWh produced 41.6 TWh.e

TWh gas used to produce elect. 92.5 TWh.f (=TWh.e/electrical efficiency)

C emissions from cogen gas use 4.6 MMTC

C emissions displaced by cogen elect 8.6 based on marginal C burden of 207 gC/kWh.e

Not all of the usable heat can be utilized in the buildings % of usable heat that is utilized 75%

Electricity production rate 1.29 kWh.elect/kWh.usable thermal output (=45%/35%)

Usable heat 32.4 TWh.thermal

Utilized heat 24.3 TWh.thermal

Water heating 2010	Site Energy use in high eff/low C case Quads site	Energy use TWh.e or TWh.f	Efficiency	Service demand (loads) TWh.th	Loads %	Cogen heat distributed TWh.th	Site Energy displaced TWh.e or TWh.f	Primary Energy displaced quads	Carbon saved MMTC
Electricity	0.13	39	90%	35	29%	7.2	8.0	0.08	1.6
Natural gas	0.47	138	55%	76	64%	15.5	28.2	0.28	1.4
Oil	0.05	14	55%	8	7%	1.6	2.9	0.03	0.2
Total	0.66	192		119	100%	24.3	39.1	0.39	3.2

SUMMARY OF COGEN SAVINGS

	MMTC	primary E
Electric generation	4.0	0.0
Use of cogen. heat	3.2	0.4
Total	7.3	0.4

(1) TWh.e = TWh of site electricity; TWh.f = TWh of direct fuel use; TWh.th = TWh of thermal load.

(2) For details on electricity production rate terminology and other standard cogeneration terms, see

Krause, Florentin, Jonathan Koomey, Hans Becht, David Olivier, Giuseppe Onufrio, and Pierre Radanne. 1994.

Energy Policy in the Greenhouse. Volume II, Part 3C. Fossil Generation: The Cost and Potential of Low-Carbon Resource Options in Western Europe.

El Cerrito, CA: International Project for Sustainable Energy Paths.

(3) Electrical efficiency of fuel cell = 45% for electricity-only operation. Usable heat from fuel cell is 35% of total fuel input, leaving 20% of heat being unrecoverable. Of the usable heat, only 75% can be utilized in the buildings.

(4) Temperatures of hot water (~160 deg. F) not high enough for absorption chilling, so we allocate heat to water heating only (Personal communication with Ron Fiskum 4 June 1997, 202/586-9154).

Water heating loads alone are large enough to cover cogen heat (they are not as seasonal as space heating, so we prefer them for this analysis). We distribute cogen thermal energy across water heating fuels using same ratio of loads as found in high efficiency/low carbon case.

(5) Primary energy savings on the electric side are zero because primary energy benefits of cogen all allocated to heating side. Carbon savings accrue on the electric side because marginal carbon burden is much higher than that of gas fired generation.

Table C-2.6b (continued): Results for U.S. commercial sector reference and high efficiency cases
65% implementation of efficiency resources

Fuel	End-use	Base year energy use 1997 Quads	Frozen efficiency energy use 2010 Quads	65%		100%		Frozen efficiency energy costs 2010 Billion 95\$	Baseline B.A.U. energy costs 2010 Billion 95\$	65%		100%		100% Implementation case			65%	100%	Base year carbon emissions 1997 MMTC	Frozen efficiency carbon emissions 2010 MMTC	Baseline B.A.U. carbon emissions 2010 MMTC	65%		100%	
				Implement. B.A.U. energy use 2010 Quads	Implement. Effic. case energy use 2010 Quads	Implement. Effic. case energy costs 2010 Billion 95\$	Implement. Effic. case energy costs 2010 Billion 95\$			Existing New efficiency costs 2010 Billion 95\$	Retrofit New efficiency costs 2010 Billion 95\$	New New efficiency costs 2010 Billion 95\$	Implement. Effic. case total costs 2010 Billion 95\$	Implement. Effic. case total costs 2010 Billion 95\$	Implement. Effic. case carbon emissions 2010 MMTC	Implement. Effic. case carbon emissions 2010 MMTC									
Electricity	Space heating	0.12	0.12	0.12	0.10	0.09	2.50	2.52	2.07	1.83	0.00	0.07	0.06	2.16	1.97	6	6	6	4	4	4	4	4	4	4
	Space cooling	0.52	0.53	0.52	0.43	0.38	11.04	10.91	8.96	7.91	0.00	0.29	0.26	9.32	8.47	26	25	25	19	16	16	16	16	16	16
	Water heating	0.17	0.16	0.14	0.13	0.13	3.40	2.94	2.80	2.72	0.04	0.03	0.03	2.86	2.82	8	8	7	6	6	6	6	6	6	6
	Ventilation	0.17	0.19	0.19	0.16	0.14	3.91	3.99	3.26	2.87	0.00	0.11	0.10	3.40	3.09	8	9	9	7	6	6	6	6	6	6
	Cooking	0.03	0.03	0.03	0.03	0.03	0.65	0.63	0.63	0.63	0.00	0.00	0.00	0.63	0.63	1	1	1	1	1	1	1	1	1	1
	Lighting	1.26	1.32	1.32	1.14	1.04	27.74	27.69	23.93	21.90	-0.82	-1.04	-0.94	22.11	19.10	62	63	63	52	46	46	46	46	46	46
	Refrigeration	0.14	0.15	0.16	0.13	0.12	3.18	3.36	2.80	2.50	0.03	0.09	0.08	2.92	2.69	7	7	8	6	5	5	5	5	5	5
	Office equip.-PCs	0.08	0.10	0.10	0.10	0.10	2.10	2.10	2.10	2.10	0.00	0.00	0.00	2.10	2.10	4	5	5	5	5	5	5	5	5	5
	Office equip.-non-PCs	0.19	0.25	0.25	0.25	0.25	5.25	5.25	5.25	5.25	0.00	0.00	0.00	5.25	5.25	9	12	12	12	12	12	12	12	12	12
	Other Uses	0.65	1.08	1.08	0.85	0.72	22.66	22.66	17.81	15.20	1.49	1.12	1.01	20.16	18.82	32	52	52	38	30	30	30	30	30	30
Total electric	3.33	3.93	3.91	3.32	3.00	82.41	82.03	69.61	62.92	0.74	0.67	0.60	70.91	64.93	163	188	187	151	132	132	132	132	132	132	
Natural gas	Space heating	1.34	1.42	1.36	1.16	1.06	6.42	6.13	5.34	4.76	0.00	0.68	0.61	6.08	6.05	19	21	20	17	15	15	15	15	15	15
	Space cooling	0.03	0.03	0.03	0.02	0.02	0.14	0.14	0.11	0.09	0.00	0.02	0.02	0.13	0.13	0	0	0	0	0	0	0	0	0	0
	Water heating	0.48	0.50	0.52	0.47	0.45	2.24	2.35	2.13	2.02	0.29	0.22	0.19	2.58	2.71	7	7	8	7	6	6	6	6	6	6
	Cooking	0.19	0.22	0.23	0.23	0.23	0.99	1.04	1.04	1.04	0.00	0.00	0.00	1.04	1.04	3	3	3	3	3	3	3	3	3	3
	Other Uses	1.29	1.40	1.40	1.31	1.26	6.31	6.31	5.90	5.68	0.17	0.13	0.12	6.18	6.10	19	20	20	19	18	18	18	18	18	18
	Total gas	3.33	3.57	3.54	3.20	3.01	16.10	15.97	14.42	13.59	0.46	1.05	0.94	16.01	16.03	48	52	51	46	44	44	44	44	44	44
Distillate oil	Space heating	0.19	0.17	0.16	0.14	0.13	0.95	0.87	0.78	0.73	0.00	0.06	0.05	0.85	0.84	4	3	3	3	3	3	3	3	3	3
	Water heating	0.05	0.05	0.05	0.05	0.05	0.30	0.27	0.27	0.27	0.00	0.00	0.00	0.27	0.28	1	1	1	1	1	1	1	1	1	1
	Other Uses	0.13	0.14	0.14	0.13	0.13	0.76	0.76	0.71	0.69	0.02	0.01	0.01	0.74	0.73	3	3	3	3	3	3	3	3	3	3
	Total oil	0.37	0.37	0.35	0.32	0.31	2.00	1.90	1.76	1.68	0.02	0.07	0.06	1.86	1.84	7	7	7	6	6	6	6	6	6	6
Renewables	Biomass	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0	0	0	0	0	0	0	0	0	0
Other fuels	Coal + keromene	0.31	0.35	0.34	0.34	0.34	1.88	1.84	1.84	1.84	0.00	0.00	0.00	1.84	1.84	6	7	7	7	7	7	7	7	7	7
Totals		7.34	8.21	8.14	7.18	6.66	102.40	101.74	87.63	80.03	1.22	1.79	1.61	90.63	84.64	225	254	252	211	188	188	188	188	188	188

976 1151 1146 972 879

Table C-2.8: Energy use untouched by our scenarios, corrected for stock turnover

Fuel	End-use	Primary Energy use B.A.U case Quads 2010	Primary Energy use untouched by efficiency Quads 2010	Primary energy untouched by efficiency corrected for stock turnover Quads 2010	Primary Energy use untouched by efficiency B.A.U. = 1.0 2010	Primary Energy use untouched corrected B.A.U. = 1.0 2010
Residential	Electricity	13.0	2.2	1.9	0.17	0.14
	Natural gas	5.6	2.5	2.2	0.45	0.40
	Distillate oil	0.8	0.4	0.3	0.49	0.43
	Other fuels	1.1	0.5	0.5	0.45	0.42
	Total	20.4	5.6	4.9	0.27	0.24
Commercial	Electricity	11.4	1.9	1.8	0.17	0.15
	Natural gas	3.5	0.7	0.6	0.20	0.18
	Distillate oil	0.4	0.1	0.1	0.26	0.17
	Other fuels	0.3	0.1	0.1	0.42	0.42
	Total	15.6	2.8	2.6	0.18	0.17
Total	Electricity	24.3	4.0	3.6	0.17	0.15
	Natural gas	9.1	3.2	2.9	0.35	0.31
	Distillate oil	1.1	0.5	0.4	0.41	0.34
	Other fuels	1.4	0.6	0.6	0.44	0.42
	Total	36.0	8.4	7.5	0.23	0.21

(1) Other fuels includes LPG, renewables, coal, and kerosene.

(2) Untouched energy is that energy use associated with equipment that is not replaced during the 1997-2010 analysis period and hence is not given the opportunity to upgrade its efficiency to the cost effective level. We do not consider early retirements because they are usually uneconomic.

(3) We correct the Untouched energy by the ratio of new energy intensities to stock energy intensities in 1997 to determine the amount of energy that will still be untouched after normal stock turnover.

**Interlab Study on U.S.
Energy Efficiency and Greenhouse
Gas Emissions**

Appendix C-3

**Assumptions for Energy
Efficiency Calculations**

**Residential and Commercial
Sectors**

Interlab Study on U.S. Energy Efficiency and Greenhouse Gas Emissions

Definition of Terms

Base Year	The base year of the forecast is 1997. Energy use for the base year is based on the output from the US DOE's Annual Energy Outlook 1997.
Forecast Period	The forecast period for the study is 1997-2010. This generally allows for the penetration of commercial or near-commercial high efficiency technologies but is too short a period for any significant penetration of long-term R&D technologies.
Unit Energy Consumption (UEC) and Energy Use Intensity (EUI)	Unit Energy Consumption (UEC) is the amount of energy required to operate an appliance or end-use for a specified period. In our study UEC is either specified in kilowatt-hours/year (Kwh), particularly for electric appliances or end-uses, or in million British thermal units per year (MMBtu) for non-electric appliances and end-uses. The UEC is often derived from data published by the US Department of Energy on energy consumption of particular appliances or equipment measured under DOE test procedures. In our study the UEC will often be a weighted average over various appliance product classes (for equipment) or of building types (for space conditioning and lighting). Energy Use Intensity (EUI) is a more aggregate measure of energy use used by the US Energy Information Administration in their modeling for the AEO 97 forecast. For the commercial sector it is defined as energy consumption per unit floor area for the sector as a whole.
Maximum cost-effective potential	The maximum cost-effective potential is the highest estimated achievable efficiency savings assuming that 100% of cost-effective efficiency resources (or measures) are applied to the building, and that only technological constraints hamper the implementation of these resources. For example the maximum cost-effective potential for residential lighting would estimate the current amount, type, and use rate of current incandescent lamps and calculate the efficiency savings if all incandescent lamps that can physically be replaced were replaced with more efficient bulbs (e.g. compact fluorescent, halogen IR A lamps). This calculation does not take into account some of the often difficult to calculate transaction costs that hamper the achievement of maximum cost effective levels of penetration, such as lack of information or imperfect functioning of particular end-use markets.
Achievable cost-effective potential (efficiency and high-efficiency cases)	The achievable cost-effective potential implicitly estimates what fraction of the maximum cost-effective potential is achievable for a specific appliance or end-use. For this study we scale the maximum cost-effective potential assuming 35%, 50%, and 65% implementation of demand-side resources.
Energy Conversion Factors	All electricity end-use energy is converted to site energy assuming a conversion rate of 3412 Btus/kWh. When primary energy is shown in the report, it is calculated using the appropriate conversion factors from the electricity utility chapter.
Inflation corrections and Discount rate	We adjust costs from other sources to 1995\$ using chain-type price indices from the Statistical Abstract of the US Department of Commerce (US DOC, 1996) for 1995 and before. The discount rate for the analysis is 7% real.
Incremental capital cost	The incremental capital cost is the additional first cost to the consumer for purchasing a high-efficiency appliance or package of efficiency measures for a particular end-use.
Life cycle cost	Life cycle cost is the first cost to a consumer of purchasing a particular appliance or set of efficiency measures plus the cost for operations and maintenance of the appliance (or efficiency package) over the useful lifetime of the product.
Cost of conserved energy	The CCE is a ratio of the incremental capital expenditure (amortized over the lifetime of the appliance) to the annual energy savings expected from the purchase of the unit. The CCE is used to evaluate the cost-effectiveness of a high-efficiency appliance or efficiency package. If the CCE is below the average cost of electricity or natural gas, the measure is considered to be cost-effective.

**Background Information Sheet: Interlab Study on U.S.
Energy Efficiency and Greenhouse Gas Emissions
Assumptions for Energy Efficiency Calculations: Residential Sector**

Refrigerators

Product/end-use description	The refrigerator is a major household electric appliance designed for the refrigerated storage of food products. A refrigerator consists of a refrigerated cabinet at 0°C or above. Many refrigerators are also equipped with freezer compartments which are designed for the freezing and storing food at temperatures below -13.3°C. Several varieties of product classes for refrigerators exist which can affect energy consumption, including volume, existence of automatic or manual defrost, and those with the refrigerator/freezer separated by vertical compartments (top mount) versus side-by-side separations (US DOE, 1995).
Base Year Energy Use	Refrigeration energy use accounts for an estimated 6% (1.2 quads) of residential primary energy consumption in 1997 (US EIA, 1996).
End-use Lifetime	The end-use lifetime for refrigerators was estimated at 19 years. This is based on estimates developed by the Federal government in baseline calculations for energy efficiency standards (US DOE, 1995).
Average Unit Energy Consumption in 1997 (UEC)	Base year UEC for refrigerator stock was estimated at 944 kWh/year (3.2 MMBtu). This is based on output from the LBL-REM model used in (US DOE, 1995).
1997 New Product UEC	1997 UEC was estimated at 647 kWh/year (2.2 MMBtu). Current UEC was based on a shipment weighted average of the UEC of current models, based on calculations from the LBL-REM model used in US DOE (1995).
Maximum Cost-effective Efficiency Potential	The maximum cost-effective efficiency potential as measured in UEC was estimated at 437 kWh/year (1.5 MMBtu), or a savings of 33% from the UEC of current 1997 models. This UEC was based on the 1992 shipment weighted average UEC for the lowest life-cycle cost models from US DOE (1995).
Achievable cost-effective efficiency potential - efficiency case	In our efficiency case, we assume that the achievable adoption level over the analysis period is 35% of maximum cost-effective potential levels.
Achievable cost-effective efficiency potential - high efficiency case	In our high-efficiency case, we assume that the achievable adoption level over the analysis period is 65% of maximum cost-effective potential levels.
Incremental Capital Cost	The average incremental cost for adopting the maximum cost-effective efficiency model was estimated to be \$73 (\$1995). This cost is the difference between the shipment weighted estimated retail price of the high-efficiency model and the average retail price for models sold in 1997. Both prices are based on output from the LBL-REM model. Prices were adjusted to 1995 levels based on the personal consumption price index (US DOC, 1996).
Cost of Conserved Energy (CCE)	The CCE is a ratio of the incremental capital expenditure (amortized over the lifetime of the appliance) to the annual energy savings expected from the purchase of the unit. The CCE for the high efficiency model was estimated at \$0.03/kWh (\$9.9/MMBtu) (\$1995).

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U.S. Department of Commerce, 1996. *Statistical Abstract of the US*. Economics and Statistics Administration, Bureau of the Census, Washington, DC.

U.S. Department of Energy, 1995. *Technical Support Document: Energy Efficiency Standards for Consumer Products: Refrigerators, Refrigerator-Freezers, & Freezers*. U.S. DOE, Washington, DC.

U.S. Energy Information Administration, Office of Integrated Analysis and Forecasting, 1996. *Annual Energy Outlook 1997*. Report Number DOE/EIA-0383(97). U.S. Department of Energy, Washington, DC.

Refrigerator UEC and CCE calculations

Source: U.S. Department of Energy, 1995. Technical Support Document: Energy Efficiency Standards for Consumer Products: Refrigerators, Refrigerator-Freezers, & Freezers.

Product Class	New Model Baseline Retail (\$1992)	New Baseline UEC (kWh/year)	Lowest LCC Retail (\$1992)	Lowest LCC UEC (kWh/year)	Shipments (1992) Millions	Percent of Shipments
Top Mount Auto Defrost - No thru the door features	\$ 554.67	700.86	\$ 651.50	436.66	5.05	65.0%
Top Mount Auto Defrost - thru the door features	\$ 1,047.28	795.37	\$ 1,174.66	548.81	0.09	1.2%
Side-by-side Auto Defrost - No thru the door features	\$ 1,055.08	761.19	\$ 1,165.75	552.98	0.65	8.3%
Side-by-side Auto Defrost - thru the door features	\$ 1,161.51	799.9	\$ 1,278.57	508.33	0.85	10.9%
Bottom Mount Auto Defrost	\$ 908.95	714.81	\$ 1,021.93	472.43	0.09	1.1%
Compact Manual Defrost	\$ 156.20	315	\$ 158.64	295.29	1.06	13.6%
Total (or weighted average)	\$ 617.76	665.47	\$ 705.66	436.60	7.78	

Product Class	Baseline Retail (\$1995)	Baseline UEC (MMBtu/year)	Lowest LCC Retail (\$1995)	Lowest LCC UEC (MMBtu/year)	Shipments (1992) Millions	Percent of Shipments
Top Mount Auto Defrost - No thru the door features	\$ 596.82	2.39	\$ 701.01	1.49	5.05	65.0%
Top Mount Auto Defrost - thru the door features	\$ 1,126.87	2.71	\$ 1,263.93	1.87	0.09	1.2%
Side-by-side Auto Defrost - No thru the door features	\$ 1,135.27	2.60	\$ 1,254.35	1.89	0.65	8.3%
Side-by-side Auto Defrost - thru the door features	\$ 1,249.78	2.73	\$ 1,375.74	1.73	0.85	10.9%
Bottom Mount Auto Defrost	\$ 978.03	2.44	\$ 1,099.60	1.61	0.09	1.1%
Compact Manual Defrost	\$ 168.07	1.07	\$ 170.70	1.01	1.06	13.6%
Total (or weighted average)	\$ 664.71	2.27	\$ 759.29	1.49	7.78	100.0%

	kWh	MMBtu	Percent Savings	Retail price (\$1992)	Retail price (\$1995)	CCE (\$1995/kWh)	CCE (\$1995/MMBtu)	Notes
Average Stock in 1997 (LBNL-REM runs for DOE, 1995)	944	3.2	n/a	n/a	n/a	n/a	n/a	Btu conversion is 3412 btu/kWh resource
1997 New Refrigerator (LBNL-REM runs for DOE, 1995)	647	2.2	n/a	\$ 637.40	\$ 685.84	n/a	n/a	
Maximum cost-effective energy efficient refrigerator (DOE, 1995)	437	1.5	n/a	\$ 705.66	\$ 759.29	n/a	n/a	Lowest weighted LCC model from DOE, 1995
Energy, Cost, and UEC comparison	kWh	MMBtu	Percent Savings	Increase in Capital Costs (\$1992)	Increase in Capital Costs (\$1997)			
Max. cost effective compared to 1997 new	210	0.7	32.5%	\$ 68.26	\$ 73.44	\$ 0.034	\$ 9.90	

CCH Calculation Assumptions

Capital recovery factor	\$0.10
Real discount rate	0.07
Lifetime	19

**Background Information Sheet: Interlab Study on U.S.
Energy Efficiency and Greenhouse Gas Emissions
Assumptions for Energy Efficiency Calculations: Residential Sector**

Freezers

Product/end-use description	The freezer is a household electric appliance designed for the freezing and storing food at temperatures below -13.3°C. Several varieties of product classes for freezers exist which can affect energy consumption, including volume, existence of automatic or manual defrost, and an upright versus chest configuration. (US DOE, 1995)
Base Year Energy Use	Energy use by freezers account for an estimated 2% (0.4 quads) of residential primary energy consumption in 1997. (US EIA, 1996)
End-use Lifetime	The end-use lifetime for freezers was estimated at 19 years. This is based on estimates developed by the Federal government in baseline calculations for energy efficiency standards. (US DOE, 1995)
Average Unit Energy Consumption in 1997 (UEC)	Base year average UEC was estimated at 599 kWh/year (2.0 MMBtu). This is based on output from the LBL-REM model used in (US DOE, 1995) adjusting for the inclusion of compact freezers.
1997 New Product UEC	1997 new unit UEC was estimated at 455 kWh/year (1.6 MMBtu). Current UEC was based on a shipment weighted average of the UEC of current models, based on calculations from the LBL-REM model used in (US DOE, 1995) Compact freezers were also weighted in this calculation.
Maximum Cost-effective Efficiency Potential	The maximum cost-effective efficiency potential as measured in UEC was estimated at 328 kWh/year (1.1 MMBtu), or a savings of 28% from the current 1997 models. This UEC was based on calculating the 1992 shipment weighted average UEC for the lowest life cycle cost models from (US DOE, 1995).
Achievable cost-effective efficiency potential - Efficiency Case	In our efficiency case, we assume that the achievable adoption level over the analysis period is 35% of maximum cost-effective potential levels.
Achievable cost-effective efficiency potential - High Efficiency Case	In our high-efficiency case, we assume that the achievable adoption level over the analysis period is 65% of maximum cost-effective potential levels.
Incremental Capital Cost	The average incremental cost for adopting the maximum cost-effective efficiency model was estimated to be \$59 (\$1995). This cost is the difference between the shipment weighted estimated retail price of the high-efficiency model and the average retail price for models sold in 1997. Both prices are based on output from the LBL-REM model. Prices were adjusted to 1995 levels based on the personal consumption price index (US DOC, 1996).
Cost of Conserved Energy	The CCE is a ratio of the incremental capital expenditure (amortized over the lifetime of the appliance) to the annual energy savings expected from the purchase of the unit. The CCE for the high efficiency model was estimated at \$0.05/kWh (\$13.2/MMBtu).

References:

U.S. Department of Commerce, 1996. *Statistical Abstract of the US*. Economics and Statistics Administration, Bureau of the Census, Washington, DC.

U.S. Department of Energy, 1995. *Technical Support Document: Energy Efficiency Standards for Consumer Products: Refrigerators, Refrigerator-Freezers, & Freezers*. U.S. DOE, Washington, DC.

U.S. Energy Information Administration, Office of Integrated Analysis and Forecasting, 1996. *Annual Energy Outlook 1997*. Report Number DOE/EIA-0383(97). U.S. Department of Energy, Washington, DC.

Freezer UEC and CCE Calculations

Source: U.S. Department of Energy, 1995. Technical Support Document: Energy Efficiency Standards for Consumer Products: Refrigerators, Refrigerator-Freezers, & Freezers.

Product Class	Baseline Retail (\$1992)	Baseline UEC (kWh/year)	Lowest LCC Retail (\$1992)	Lowest LCC UEC (kWh/year)	Shipments (1992) Millions	Percent of Shipments
Upright Auto Defrost	\$ 451.11	759.24	\$ 544.43	531.8	0.16	10.5%
Upright Manual Defrost	\$ 379.63	482.94	\$ 405.29	328	0.47	31.7%
Chest Manual Defrost	\$ 356.37	471.72	\$ 395.69	324.43	0.60	40.4%
Compact Freezer - Chest (Manual Defrost)	\$ 220.15	253.43	\$ 248.35	186.47	0.20	13.7%
Compact Freezer - Upright (Manual Defrost)	\$ 249.23	410.71	\$ 269.66	306.22	0.06	3.7%
Total (or weighted average)	\$ 350.98	473.19	\$ 389.40	327.69	1.49	100.0%

Product Class	Baseline Retail (\$1995)	Baseline UEC (MMBtu/year)	Lowest LCC Retail (\$1995)	Lowest LCC UEC (MMBtu/year)	Shipments (1992) Millions	Percent of Shipments
Upright Auto Defrost	\$ 485.39	2.59	\$ 585.81	1.81	0.16	10.5%
Upright Manual Defrost	\$ 408.48	1.65	\$ 436.09	1.12	0.47	31.7%
Chest Manual Defrost	\$ 383.45	1.61	\$ 425.76	1.11	0.60	40.4%
Compact Freezer - Chest (Manual Defrost)	\$ 236.88	0.86	\$ 267.22	0.64	0.20	13.7%
Compact Freezer - Upright (Manual Defrost)	\$ 268.17	1.40	\$ 290.15	1.04	0.06	3.7%
Total (or weighted average)	\$ 377.66	1.61	\$ 419.00	1.12	1.49	100.0%

CCE Calculation

	kWh	MMBtu	Percent Savings	Retail price (\$1992)	Retail price (\$1995)	CCE (\$1995/kWh)	CCE (\$1995/MMBtu)	Notes
Average Stock in 1997 (LBNL-REM runs for DOE, 1995)	599.42	2.0	n/a	n/a	n/a	n/a	n/a	Assumes 15% share of compact freezers. Btu conversion is 3412 btu/kWh resource
1997 New Refrigerator (LBNL-REM runs for DOE, 1995)	455.41	1.6	n/a	\$ 334.18	\$ 359.58	n/a	n/a	Weighted for addition of compact freezers
Maximum cost-effective energy efficient (DOE, 1995)	327.69	1.1	n/a	\$ 389.40	\$ 419.00	n/a	n/a	Lowest LCC from DOE, 1995
Energy, Cost, and UEC comparison	kWh	MMBtu	Percent Savings	Increase in Capital Costs (\$1992)	Increase in Capital Costs (\$1997)			
Max. cost effective compared to 1997 new	127.71	0.4	28%	\$ 55.22	\$ 59.42	\$ 0.045	\$ 13.19	

CCE Calculation Assumptions

Capital recovery factor	\$0.10
Real discount rate	0.07
Lifetime	19

Freezer stock assumptions

Compact Freezer Share in 1997 stock	17%
Non-Compact Freezer Share in 1997 stock	83%

**Background Information Sheet: Interlab Study on U.S.
Energy Efficiency and Greenhouse Gas Emissions
Assumptions for Energy Efficiency Calculations: Residential Sector**

Electric Water Heating

Product/end-Use description	Water heaters are products that utilize oil, gas, LPG, or electricity to heat potable water for use outside the heater upon demand. Hot water is used to provide a variety of services in a household. Most hot water heaters are storage heaters consisting of a cylindrical insulated storage tank with electric heating elements or a gas burner. Several appliances or products use hot water, primarily showerheads and faucets, clothes washers, and dishwashers. Reductions in water heating energy use can be achieved both through improvements in the water heating device as well as improvements in the efficiency of hot-water using appliances, thereby reducing the source demand for the hot water. (DOE, 1993)
Base Year Energy Use	Electric water heating accounts for an estimated 6% (1.1 quads) of residential primary energy consumption in 1997. (Source: US EIA, 1996)
End-use Lifetime	The end-use lifetime for electric water heaters was estimated at 10 years. This is based on estimates developed by the Federal government in baseline calculations for energy efficiency standards. (US DOE, 1993)
Existing Average Unit Energy Consumption (UEC)	Base year average UEC for electric water heaters in 1997 was estimated at 4924 kWh (16.8 MMBtu). This estimate is derived from Koomey et al. (1997).
1997 New UEC	1997 new unit UEC for electric water heaters is 3899 kWh (13.3 MMBtu). The new unit UEC accounts for the implementation of the Federal 1990 water heater standards and the Federal 1994 standards on showers and faucets, dishwashers and clotheswashers (Koomey et al., 1994).

**Background Information Sheet: Interlab Study on U.S.
Energy Efficiency and Greenhouse Gas Emissions
Assumptions for Energy Efficiency Calculations: Residential Sector**

Electric Water Heating (Continued)

Maximum Cost-effective Efficiency Potential	The maximum cost-effective efficiency potential as measured in UEC was estimated at 2822 kWh/year (9.6 MMBtu), or a savings of 28% from the current 1997 models. This UEC was calculated as a stock weighted of four "efficiency" packages modeled for residences: (1) a high-efficiency electric water heater (equipped with features to reduce standby losses) combined with a horizontal axis clothes washer (EWH w/ CW), (2) a high-efficiency electric water heater without a clothes washer (EWH w/o CW), (3) a heat pump water heater combined with a horizontal axis clothes washer (HPWH w/ CW), and (4) a heat pump water heater without a clothes washer (HPWH w/o CW). In addition, we assume a clothes washer saturation of 81% in 2010, and that of all electrically water-heated households in 2010 (less than half of all households), 25% of these can be converted to a heat pump water heater (Kooimey et al., 1997). The summary table for this potentials calculation is shown below. <table><tr><th colspan="6">Summary Table 1: Maximum Cost Effective Efficiency Potential - Water Heaters</th></tr><tr><th></th><th>EWHH (%)</th><th>IES (Kwh)</th><th>IES (MMBtu)</th><th>Savings (%)</th><th>IC (\$1995)</th></tr><tr><td>EWH w/ CW</td><td>61%</td><td>647</td><td>2.2</td><td>17%</td><td>231</td></tr><tr><td>EWH w/o CW</td><td>14%</td><td>286</td><td>1.0</td><td>7%</td><td>49</td></tr><tr><td>HPWH w/CW</td><td>20%</td><td>2607</td><td>8.9</td><td>67%</td><td>688</td></tr><tr><td>HP WH w/o CW</td><td>5%</td><td>2423</td><td>8.3</td><td>62%</td><td>507</td></tr><tr><td>Total/Wtd</td><td></td><td></td><td></td><td></td><td></td></tr><tr><td>Average</td><td>100%</td><td>1077</td><td>3.7</td><td>28%</td><td>311</td></tr></table> Notes: EWHH = households with electric water heating, IES = incremental energy savings, IC = incremental cost, CW = clothes washers, HP WH = heat pump water heaters.	Summary Table 1: Maximum Cost Effective Efficiency Potential - Water Heaters							EWHH (%)	IES (Kwh)	IES (MMBtu)	Savings (%)	IC (\$1995)	EWH w/ CW	61%	647	2.2	17%	231	EWH w/o CW	14%	286	1.0	7%	49	HPWH w/CW	20%	2607	8.9	67%	688	HP WH w/o CW	5%	2423	8.3	62%	507	Total/Wtd						Average	100%	1077	3.7	28%	311
Summary Table 1: Maximum Cost Effective Efficiency Potential - Water Heaters																																																	
	EWHH (%)	IES (Kwh)	IES (MMBtu)	Savings (%)	IC (\$1995)																																												
EWH w/ CW	61%	647	2.2	17%	231																																												
EWH w/o CW	14%	286	1.0	7%	49																																												
HPWH w/CW	20%	2607	8.9	67%	688																																												
HP WH w/o CW	5%	2423	8.3	62%	507																																												
Total/Wtd																																																	
Average	100%	1077	3.7	28%	311																																												
Achievable cost-effective efficiency potential - Efficiency Case	In our efficiency case, we assume that the achievable adoption level over the analysis period is 35% of maximum cost-effective potential levels.																																																
Achievable cost-effective efficiency potential - High Efficiency Case	In our high-efficiency case, we assume that the achievable adoption level over the analysis period is 65% of maximum cost-effective potential levels.																																																
Incremental Capital Cost	The average incremental cost for adopting the high-efficiency packages was estimated to be \$311 (\$1995). The incremental costs, (listed in summary table 1 above for each package) represent the difference in cost between the purchase of a high efficiency package (e.g. high efficiency electric water heaters, heat pump water heaters, and horizontal axis clothes washers) compared to new 1997 equipment (Kooimey et al., 1997). Prices were adjusted to 1995 levels based on the personal consumption price index (US DOC, 1996).																																																
Cost of Conserved Energy	The CCE for the average high efficiency package was the product of the weighted estimated CCEs for the four maximum cost effective efficiency potential packages as described above, and was estimated at \$0.032/kWh (\$9.41/MMBtu). The CCE is a ratio of the incremental capital expenditure (amortized over the lifetime of the appliance) to the annual energy savings expected from the purchase of the unit. The CCE for water heating includes the present value of the water savings from the use of horizontal axis clothes washers.																																																

**Background Information Sheet: Interlab Study on U.S.
Energy Efficiency and Greenhouse Gas Emissions
Assumptions for Energy Efficiency Calculations: Residential Sector**

Electric Water Heating (Continued)

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U.S. Department of Energy, 1993. *Technical Support Document: Energy Efficiency Standards for Consumer Products: Room Air Conditioners, Water Heaters, Direct Heating Equipment, Mobil Home Furnaces, Kitchen Ranges and Ovens, Pool Heaters, Fluorescent Lamp Ballasts, and Television Sets*. US DOE, Washington, DC.

U.S. Energy Information Administration, Office of Integrated Analysis and Forecasting, 1996. *Annual Energy Outlook 1997*. Report Number DOE/EIA-0383(97). U.S. Department of Energy, Washington, DC.

Electric Water Heating, UEC and cost calculations

Source: U.S. Department of Energy, 1990. Technical Support Document: Energy Conservation Standards for Consumer Products:

Room A/C, Water Heaters, Direct Heating Equip, mobil home furn, kitchen ranges, pool heaters, flores lamp ballasts, and TVs.

Source: Koomsey, Jonathan G., Diana A. Vorsatz, Richard E. Brown, and Celina S. Atkinson, 1997. Updated Potential for Electricity

Efficiency Improvements in the U.S. Residential Sector. Lawrence Berkeley Laboratory. DRAFT LBNL-38894. in process

	kWh	MMBtu	1990 dollars	1995 dollars
Average Stock Water heating UEC from Koomsey et al., 1	4924	16.8		

Determination of 1997 New Unit efficiency from Koomsey et al., 1997

Measure	Incremental energy Savings (KWh)	Incremental energy Savings (MMBtu)	Incremental Cost (\$1990)	Incremental Cost (\$1995)	CCE (\$1990/kWh)	New UEC (KWh)	Fraction of Current Electric WH Stock
(a) Electric Water Heater - Baseline	0	0	\$ -	\$ -	n/a	4786	100%
(b) Improve clothes washers to 1994 standard	199	0.7	\$ 2.00	\$ 2.32	-0.009	4587	100%
(c) Improve aerators and showerheads to 1994 standard	586	2.0	\$ 53.00	\$ 61.39	-0.004	4001	100%
(d) Improve dishwashers to 1994 standard	102	0.3	\$ 21.00	\$ 24.32	0.016	3899	100%

	kWh	MMBtu
New Water Heater UEC in 1997 from Koomsey et al., 1997 (measures (a) thru (d))	3899	13.3

Determination of Maximum cost-effective efficiency from Koomsey et al., 1997

High Efficiency Electric WITH CLOTHES WASHERS

Measure	Incremental energy Savings (KWh)	Incremental energy Savings (MMBtu)	Incremental Cost (\$1990)	Incremental Cost (\$1995)	CCE (\$1990/kWh)	New UEC (KWh)
(a) Electric Water Heater - Baseline (1997 new UEC)	0	0	\$ -	\$ -	n/a	3899
(b) Reduce water heater standby losses	286	1.0	\$ 42.98	\$ 49.78	\$ 0.018	3613
(c) Horizontal axis clothes washer w/ EWH	361	1.2	\$ 156.49	\$ 181.25	\$ 0.032	3252
Total	647	2.21	\$ 199.47	\$ 231.03	\$ 0.026	3252

High Efficiency Electric WITHOUT CLOTHES WASHERS

Measure	Incremental energy Savings (KWh)	Incremental energy Savings (MMBtu)	Incremental Cost (\$1990)	Incremental Cost (\$1995)	CCE (\$1990/kWh)	New UEC (KWh)
(a) Electric Water Heater - Baseline (1997 new UEC)	0	0	\$ -	\$ -	n/a	3899
(b) Reduce water heater standby losses	286	1.0	\$ 42.98	\$ 49.78	\$ 0.018	3613
Total	286	0.98	\$ 42.98	\$ 49.78	\$ 0.018	3613

Heat Pump Water Heaters WITH CLOTHES WASHERS

Measure	Incremental energy Savings (KWh)	Incremental energy Savings (MMBtu)	Incremental Cost (\$1990)	Incremental Cost (\$1995)	CCE (\$1990/kWh)	New UEC (KWh)
(a) Electric Water Heater - Baseline (1997 new UEC)	0	0	\$ -	\$ -	n/a	3899
(b) Reduce water heater standby losses	286	1.0	\$ 42.98	\$ 49.78	\$ 0.018	3613
(c) Heat pump water heater - post 2000	2137	7.3	\$ 395.00	\$ 457.50	\$ 0.039	1476
(d) Horizontal axis clothes washer w/ HPWH - post 2000	184	0.6	\$ 156.49	\$ 181.25	\$ 0.062	1292
Total (weighted by share of stock in measure (d))	2607	8.9	\$ 594.47	\$ 688.53	\$ 0.038	1292

Heat Pump Water Heaters WITHOUT CLOTHES WASHERS

Measure	Incremental energy Savings (KWh)	Incremental energy Savings (MMBtu)	Incremental Cost (\$1990)	Incremental Cost (\$1995)	CCE (\$1990/kWh)	New UEC (KWh)
(a) Electric Water Heater - Baseline (1997 new UEC)	0	0	\$ -	\$ -	n/a	3899
(b) Reduce water heater standby losses	286	1.0	\$ 42.98	\$ 49.78	\$ -0.018	3613
(c) Heat pump water heater - post 2000	2137	7.3	\$ 395.00	\$ 457.50	\$ 0.039	1476
Total (weighted by share of stock in measure (d))	2423	8.3	\$ 437.98	\$ 507.28	\$ 0.037	1476

Shares	Baseline (1997)	Saturation Max econ. case	Saturation High efficiency case	Share of electricity only, no constraints	Share of electricity only, Max econ. case
Non electric water heating	55.5%	55.5%	55.5%		
Baseline electric water heating	44.5%	0.0%	0.0%	0%	0.0%
High Efficiency Electric WITH CLOTHES WASHERS		15.7%	27.0%	35.3%	60.7%
High Efficiency Electric WITHOUT CLOTHES WASHERS		3.7%	6.4%	8.3%	14.3%
Heat Pump Water Heaters WITH CLOTHES WASHERS		20.3%	9.0%	45.6%	20.2%
Heat Pump Water Heaters WITHOUT CLOTHES WASHERS		4.8%	2.1%	10.8%	4.8%
Total	100%	100%	100%	100.0%	100.0%

Clothes washer saturation (for both cases) 80.9%

High efficiency electric fraction 43.6% 75.0%

Heat pump fraction 56.4% 25.0%

Fraction affected by policies in high efficiency case 100.0%

Max econ. potential case

Summary Table	Incremental energy Savings (KWh)	Incremental energy Savings (MMBtu)	% Savings relative to New 1997 UEC	Incremental Cost (\$1995)	OCE (\$1995/kWh)	OCE (\$1995/MMBtu)	Internally calculated CCE (\$1995/kWh)	Notes
High Efficiency Electric WITH CLOTHES WASHERS	647	2.2	17%	231	0.030	8.76	0.051	also include detergent and water savings which makes our internally calculated CCEs too high in the case where the
High Efficiency Electric WITHOUT CLOTHES WASHERS	286	1.0	7%	50	0.0208	6.11	0.0248	Btu conversion is 3412 Btu/kWh resource
Heat Pump Water Heaters WITH CLOTHES WASHERS	2607	8.9	67%	689	0.044	13.01	0.054	
Heat Pump Water Heaters WITHOUT CLOTHES WASHERS	2423	8.3	62%	507	0.042	12.40	0.047	
Weighted average NO CONSTRAINTS	1703	5.8	44%	454	0.037	10.87	0.050	
Weighted average MAX ECON POTENTIAL	1077	3.7	28%	311	0.032	9.41	0.040	

Max Tech Efficiency UEC	2822	9.6
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Internal note: WE MUST USE THE SUPPLY CURVES CCE IN THE INTEGRATING SPREADSHEET.

CCE Calculation Assumptions

Capital recovery factor \$0.14

Real discount rate 0.07

Lifetime 10

**Background Information Sheet: Interlab Study on U.S.
Energy Efficiency and Greenhouse Gas Emissions
Assumptions for Energy Efficiency Calculations: Residential Sector**

Gas/Oil/LPG Water Heating

Product/end-Use description	Water heaters utilize oil, gas, LPG, or electricity to heat potable water for use outside the heater upon demand. Hot water is used to provide a variety of services in a household. Most hot water heaters are storage heaters consisting of a cylindrical insulated storage tank with electric heating elements or a gas burner. Several appliances or products use hot water, primarily showerheads and faucets, clothes washers, and dishwashers. Reductions in water heating energy use can be achieved both through improvements in the water heating device as well as improvements in the efficiency of hot-water using appliances, thereby reducing the source demand for the hot water. For our analysis we have chosen to develop forecasts based on gas water heaters only since oil and LPG water heaters have roughly the same per-unit energy use (US DOE, 1993).
Base Year Energy Use	Gas, oil, and LPG water heaters account for an estimated 7.5% (1.4 quads) of residential primary energy consumption. (Source: US EIA, 1996)
End-use Lifetime	The end-use lifetime for gas water heaters was estimated at 13.9 years. This is based on estimates developed by the Federal government in baseline calculations for energy efficiency standards. (US DOE, 1990)
Existing Average Unit Energy Consumption (UEC)	Average UEC for gas water heaters in 1997 is 33.55 MMBtu. This estimate is derived from Koomey et al., 1997.
1997 New UEC	1997 new UEC for gas/oil/LPG water heaters is 29.7 MMBtu. This estimate is derived from Koomey et al., 1997. The new UEC accounts for the implementation of the federal 1990 water heater standards and the federal 1994 standards on showers and faucets, dishwashers and clotheswashers.
Maximum Cost-effective Efficiency Potential	The maximum cost-effective efficiency potential as measured in UEC was estimated at 23 MMBtu, or a savings of 23% from the current 1997 models. It was determined that the inclusion of a horizontal axis clothes washer as an efficiency measure was not cost effective with gas water heaters, therefore, the maximum efficiency gas water heater package includes measures that reduce standby losses and an electric ignition and flue damper only.
Achievable cost-effective efficiency potential - Efficiency Case	In our efficiency case, we assume that the achievable adoption level over the analysis period is 35% of maximum cost-effective potential levels.
Achievable cost-effective efficiency potential - High Efficiency Case	In our high-efficiency case, we assume that the achievable adoption level over the analysis period is 65% of maximum cost-effective potential levels.
Incremental Capital Cost	The incremental cost for adopting the high-efficiency model was estimated to be \$126 (\$1995). This cost is the incremental cost between the purchase of high efficiency equipment compared to new 1997 equipment (Koomey et al., 1997). Prices were adjusted to 1995 levels based on the personal consumption price index (US DOC, 1996).
Cost of Conserved Energy	The CCE for the high efficiency model was estimated at \$2.15/MMBtu (\$1995). The CCE is a ratio of the incremental capital expenditure (amortized over the lifetime of the appliance) to the annual energy savings expected from the purchase of the unit.

**Background Information Sheet: Interlab Study on U.S.
Energy Efficiency and Greenhouse Gas Emissions
Assumptions for Energy Efficiency Calculations: Residential Sector**

Gas/Oil Water Heating (continued)

References:

Koomey, Jonathan G., Marla C. Sanchez, Diana Vorsatz, Richard E. Brown, and Celina S. Atkinson. 1997. *The Potential for Natural Gas Efficiency Improvements in the U.S. Residential Sector*. Lawrence Berkeley Laboratory. DRAFT LBNL-38893. in process.

U.S. Department of Commerce. 1996. *Statistical Abstract of the US*. Economics and Statistics Administration, Bureau of the Census, Washington, DC.

U.S. Department of Energy, 1993. *Technical Support Document: Energy Efficiency Standards for Consumer Products: Room Air Conditioners, Water Heaters, Direct Heating Equipment, Mobil Home Furnaces, Kitchen Ranges and Ovens, Pool Heaters, Fluorescent Lamp Ballasts, and Television Sets*. (DOE/EE-0009) U.S. DOE, Washington, DC.

U.S. Energy Information Administration, Office of Integrated Analysis and Forecasting, 1996. *Annual Energy Outlook 1997*. Report Number DOE/EIA-0383(97). U.S. Department of Energy, Washington, DC.

Gas/Oil Water Heating, UEC and cost calculations

Source: U.S. Department of Energy, 1993. Technical Support Document: Energy Conservation Standards for Consumer Products:

Room A/C. Water Heaters, Direct Heating Equip, mobil home furn, kitchen ranges, pool heaters, floures lamp ballasts, and TVs.

Source: Koomey, Jonathan G., Marla C. Sanchez, Diana Vorsatz, Richard E. Brown, and Celina S. Atkinson. 1997.

The Potential for Natural Gas Efficiency Improvements in the U.S. Residential Sector. Lawrence Berkeley Laboratory. DRAFT LBNL-38893. in process.

Average Stock Water heating UEC from Koomey et al., 1997

MMBtu 1990 dollars 1997 dollars

33.55

Determination of 1997 New Unit efficiency from Koomey et al., 1997

Measure	Incremental energy Savings (MMBtu)	Incremental Cost (\$1990)	Incremental Cost (\$1995)	CCE (\$1990/MMBtu)	New UEC (MMBtu)	Fraction of Current Gas WH Stock
(a) Gas Water Heater - Baseline	0	\$ -	\$ -	n/a	36.9	100%
(b) Improve clothes washers to 1994 standard	1.09	\$ 2.00	\$ 2.32	-1.7	35.8	100%
(c) Improve aerators and showerheads to 1994 standard	2.5	\$ 53.00	\$ 61.39	-0.9	33.3	100%
(d) Improve dishwashers to 1994 standard	3.6	\$ 21.00	\$ 24.32	3.6	29.7	100%

New Water Heater UEC in 1997 from Koomey et al., 1997 (measures (a) thru (d))

MMBtu

29.7

Determination of Maximum cost-effective efficiency from Koomey et al., 1997

High Efficiency Gas WITH CLOTHES WASHERS

Measure	Incremental energy Savings (MMBtu)	Incremental Cost (\$1990)	Incremental Cost (\$1995)	CCE (\$1990/MMBtu)	New UEC (MMBtu)
(a) Gas Water Heater - Baseline (1997 new UEC)	0	\$ -	\$ -	n/a	29.7
(b) Reduce water heater standby losses	2.052	\$ 24.00	\$ 27.80	\$ 1.300	27.648
(c) Install electric ignition and flue damper	4.69	\$ 85.00	\$ 98.45	\$ 2.100	22.958
(d) Horizontal axis clothes washer w/ EWH	1.06	\$ 131.00	\$ 151.73	\$ 7.900	21.898
Total	7.802	\$ 240.00	\$ 277.98	\$ 2.678	21.898

Wtd avg no horizontal axis \$ 1.857

High Efficiency Gas WITHOUT CLOTHES WASHERS

Measure	Incremental energy Savings (MMBtu)	Incremental Cost (\$1990)	Incremental Cost (\$1995)	CCE (\$1990/MMBtu)	New UEC (MMBtu)
(a) Gas Water Heater - Baseline (1997 new UEC)	0	\$ -	\$ -	n/a	29.7
(b) Reduce water heater standby losses	2.052	\$ 24.00	\$ 27.80	\$ 1.300	27.648
(c) Install electric ignition and flue damper	4.69	\$ 85.00	\$ 98.45	\$ 2.100	22.958
Total	6.74	\$ 109.00	\$ 126.25	\$ 1.857	22.958

Shares	Baseline (1997)	Saturation Max tech econ. case	Share of gas only. - Max tech case
Electric water heating	44.5%	44.5%	
Baseline GAS water heating	55.5%	0.0%	0%
High Efficiency GAS W/or W/O CLOTHES WASHERS		55.5%	100.0%
Total	100%	100%	100.0%

Horizontal axis measure not cost effective, therefore we do not distinguish between homes have clothes washers and those that don't.

Clothes washer saturation (for both cases) 80.9%

High efficiency GAS fraction 100.0%

Non high efficiency GAS 0.0%

Fraction affected by policies in high efficiency case 100.0%

Max econ. potential case

Summary Table	Incremental energy Savings (MMBtu)	% Savings relative to New 1997 UEC	Incremental Cost (\$1995)	CCE (\$1995/MMBtu)	Internally calculated CCE (\$1995/MMBtu)	Notes
High Efficiency Gas WITH CLOTHES WASHERS	6.742	23%	126	2.150	2.150	
High Efficiency Gas WITHOUT CLOTHES WASHERS	6.74	23%	126	2.150	2.150	

Max Tech Efficiency UEC	23.0
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% savings relative to 1997 new unit

23%

Internal note: WE MUST USE THE SUPPLY CURVES CCE IN THE INTEGRATING SPREADSHEET.

CCE Calculation Assumptions

Capital recovery factor	\$0.11
Real discount rate	0.07
Lifetime	13.9

**Background Information Sheet: Interlab Study on
U.S. Energy Efficiency and Greenhouse Gas Emissions
Assumptions for Energy Efficiency Calculations: Residential Sector**

Clothes Dryers (Electric)

Product/end-use description	The clothes dryer is a cabinet-like appliance designed to dry fabrics in a tumble-type drum with forced-air circulation. The heat source may be either electricity or natural gas. Electricity is used by the drum and fan motors. Improved clothes washer efficiency, particularly measures that reduce the moisture content of washed clothes, reduce clothes drying energy use since less run time is needed for drying (US DOE, 1990)
Base Year Energy Use	Electric clothes dryers account for an estimated 3% (0.6 quads) of residential primary energy consumption in 1997. (Source: USEIA, 1996)
End-use Lifetime	The end-use lifetime for clothes dryers was estimated to be 17 years. This is based on data provided by the Association of Home Appliance Manufacturers. (US DOE, 1990)
Existing Average Unit Energy Consumption (UEC)	Base year UEC was estimated at 881 kWh/year (3.0 MMBtu) for electric. This average is based on (Koomey et al., 1997)
1997 New UEC	1997 new UEC was estimated at 830 kWh/year (2.8 MMBtu) for electric clothes. This new unit UEC accounts for the implementation of the federal 1994 standards on clothes dryers.
Maximum Cost-effective Efficiency Potential	For electric clothes dryers the maximum cost-effective efficiency potential as measured in UEC was estimated at 813.5 kWh/year (2.8 MMBtu), or a savings of 2% from the current 1997 models. This maximum cost-effective estimate was a sales weighted estimate that assumes that from 2005 to 2010 heat pump clothes dryers capture 15% of the new clothes dryers market. Part of the low savings potential is a result of reduced moisture content of washed clothes based on improvements in clothes washers over the forecast period (Koomey et al., 1997).
Achievable cost-effective efficiency potential - Efficiency Case	In our efficiency case, we assume that the achievable adoption level over the analysis period is 35% of maximum cost-effective potential levels.
Achievable cost-effective efficiency potential - High Efficiency Case	In our high-efficiency case, we assume that the achievable adoption level over the analysis period is 65% of maximum cost-effective potential levels.
Incremental Capital Cost	The incremental cost for adopting the high-efficiency model was estimated to be \$72 (\$1995). This cost is the incremental cost between the purchase of a heat pump clothes dryer compared to new 1997 equipment (Koomey et al., 1997a). Prices were adjusted to 1995 levels based on the personal consumption price index (US DOC, 1996).
Cost of Conserved Energy	The CCE for the high efficiency model was estimated at \$0.04/kWh (\$11.1/MMBtu). The CCE is a ratio of the incremental capital expenditure (amortized over the lifetime of the appliance) to the annual energy savings expected from the purchase of the unit.

References:

Koomey, Jonathan G., Diana A. Vorsatz, Richard E. Brown, and Celina S. Atkinson. 1997. *Updated Potential for Electricity Efficiency Improvements in the U.S. Residential Sector*. Lawrence Berkeley Laboratory. DRAFT LBNL-38894. in process.

U.S. Department of Commerce, 1996. *Statistical Abstract of the US*. Economics and Statistics Administration, Bureau of the Census, Washington, DC.

U.S. Department of Energy, 1990. *Technical Support Document: Energy Conservation Standards for Consumer Products: Dishwashers, Clothes Washers, and Clothes Dryers*. (DOE/CE-0299P). U.S. DOE, Washington, DC.

U.S. Energy Information Administration, Office of Integrated Analysis and Forecasting, 1996. *Annual Energy Outlook 1997*. Report Number DOE/EIA-0383(97). U.S. Department of Energy, Washington, DC.

Clothes drying (electric) UEC and cost calculations

Source: U.S. Department of Energy, 1990. Technical Support Document: Energy Conservation Standards for Consumer Products: Dishwashers, Clothes Washers, and Clothes Dryers.

Source: Koomsey, Jonathan G., Diana A. Vornatz, Richard E. Brown, and Celina S. Atkinson. 1997. Updated Potential for Electricity

Efficiency Improvements in the U.S. Residential Sector. Lawrence Berkeley Laboratory. DRAFT LBNL-34894. in process

Average Stock Water heating UEC from Koomsey et al., 1997
Btu conversion is 10800 btu/kWh resource

Determination of 1997 New Unit efficiency from Koomsey et al., 1997

Measure	Incremental energy Savings (KWh)	Incremental energy Savings (MMBtu)	Incremental Cost (\$1990)	Incremental Cost (\$1995)	CCE (\$1990/kWh)	New UEC (KWh)	Fraction of Current Electric WH Stock
(a) Electric Water Heater - Baseline	0	0	\$ -	\$ -	n/a	903	100%
(b) Improve clothes dryers to 1994 NAECA standard	73	0.2	\$ 31.96	\$ 37.02	0.045	830	100%

New Water Heater UEC in 1997 from Koomsey et al., 1997 (measures (a) thru (d))

Determination of Maximum cost-effective efficiency from Koomsey et al., 1997

High Efficiency Electric clothes dryers

Measure	Incremental energy Savings (KWh)	Incremental energy Savings (MMBtu)	Incremental Cost (\$1990)	Incremental Cost (\$1995)	CCE (\$1990/kWh)	CCE (\$1995/kWh)	New UEC (KWh)	Internally calculated CCE (\$1995/kWh)
(a) Electric clothes dryer - Baseline (1997 new UEC)	0	0	\$ -	\$ -	n/a	n/a	830	n/a
(b) Heat pump clothes dryer	286	1.0	\$ 330.60	\$ 382.92	\$ 0.065	\$ 0.08	544	0.14
Total	286	0.98	\$ 330.60	\$ 382.92	\$ 0.065	\$ 0.075	544	

Maximum cost-effective efficiency case: 2010
(a) Electric clothes dryer - Baseline (1997 new UEC)
(b) Heat pump clothes dryer

Summary Table	Incremental Energy Savings (KWh)	Incremental Energy Savings (MMBtu)	% Savings relative to New 1997 UEC	Incremental Cost (\$1995)	CCE (\$1995/kWh)	CCE (\$1995/MMBtu)
1997 new	830	2.8	n/a	n/a	n/a	n/a
2010 high efficiency electric	0	0.0	0%	0	0.000	0.00
2010 heat pump clothes dryers	286	1.0	34%	382.92	0.0752	22.06
Weighted average max econ. potential	16.5	0.1	2%	22.09		

Max Tech Efficiency UEC	813.5	2.8
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Cost of Conserved Energy (CCE) calculation

Capital recovery factor \$0.10
Real discount rate 0.07
Lifetime 17

Background information from LBNL REM output and AHAM Fact book, 1996

From LBNL-REM	kWh	MMBtu	Percent Savings	Retail price (\$1990)	Retail price (\$1995)	CCE (\$1995/kWh)	CCE (\$1995/MMBtu)	Notes
Average Stock in 1997 (LBNL-REM)	902.0	3.1	n/a	n/a	n/a	n/a	n/a	Assumes 15% share of compact freezers. Btu conversion is 3412 btu/kWh resource
1997 New (LBNL-REM, AHAM fact book)	792.0	2.7	n/a	289.0	\$ 334.78	n/a	n/a	addition of compact freezers
Maximum cost-effective energy efficiency (new unit UEC, REM 7% case in 2010)	597.0	2.0	n/a	356.1	\$ 412.45	n/a	n/a	Lowest LCC from DOE, 1995
Energy, Cost, and UEC comparisons	kWh	MMBtu (primary)	Percent Savings	Increase in Capital Costs (\$1992)	Increase in Capital Costs (\$1997)			
Max. cost effective compared to 1997 new	195.00	0.7	25%	\$ 67.06	\$ 72.15	\$ 0.04	\$ 11.11	

REM run assumes that Hor. Axis clothes washers are slowly phased in resulting in reduced moisture content of clothes and low drying energy requirements

LBNL REM output

Clothes dryer saturations (for both cases)	1990	1997	2010
Electric	53%	56%	59%
Gas	16%	17%	18%
Noise	31%	27%	23%
Total	100%	100%	100%
New Clothes dryer installation in existing & new stock (millions)	1990	1997	2010
Electric	3.469	3.771	4.468
Gas	1.102	1.157	1.385
Total	4.571	4.928	5.853
New Clothes dryer installation in existing & new stock (percent share)			
Electric	76%	77%	76%
Gas	24%	23%	24%

**Background Information Sheet: Interlab Study on
U.S. Energy Efficiency and Greenhouse Gas Emissions
Assumptions for Energy Efficiency Calculations: Residential Sector**

Clothes Dryers (Gas)

Product/end-use description	The clothes dryer is a cabinet-like appliance designed to dry fabrics in a tumble-type drum with forced-air circulation. The heat source may be either electricity or natural gas. Electricity is used by the drum and fan motors. Improved clothes washer efficiency, particularly measures that reduce the moisture content of washed clothes, reduce clothes drying energy use since less run time is needed for drying (US DOE, 1990)
Base Year Energy Use	Gas clothes dryers account for an estimated 0.3% (0.1 quads) of residential primary energy consumption in 1997. (Source: USEIA, 1996)
End-use Lifetime	The end-use lifetime for clothes dryers was estimated to be 17 years. This is based on data provided by the Association of Home Appliance Manufacturers. (US DOE, 1990)
Existing Average Unit Energy Consumption (UEC)	Base year UEC was estimated 3.7 MMBtu for gas clothes dryers. This average is based on (Koomey et al., 1997)
1997 New UEC	1997 new UEC was estimated at 3.2 MMBtu for gas clothes dryers. This new unit UEC accounts for the implementation of the federal 1994 standards on clothes dryers.
Maximum Cost-effective Efficiency Potential	For gas clothes dryers we find no cost-effective approach to reduce clothes dryer energy use from the 1997 baseline.
Achievable cost-effective efficiency potential - Efficiency Case	Not applicable.
Achievable cost-effective efficiency potential - High Efficiency Case	Not applicable.
Incremental Capital Cost	Not applicable.
Cost of Conserved Energy	Not applicable.

References:

Koomey, Jonathan G., Marla C. Sanchez, Diana Vorsatz, Richard E. Brown, and Celina S. Atkinson. 1997. *The Potential for Natural Gas Efficiency Improvements in the U.S. Residential Sector*. Lawrence Berkeley Laboratory. DRAFT LBNL-38893. in process.

U.S. Department of Commerce, 1996. *Statistical Abstract of the US*. Economics and Statistics Administration, Bureau of the Census, Washington, DC.

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U.S. Energy Information Administration, Office of Integrated Analysis and Forecasting, 1996. *Annual Energy Outlook 1997*. Report Number DOE/EIA-0383(97). U.S. Department of Energy, Washington, DC.

Clothes drying (gas) UEC and cost calculations

Source: U.S. Department of Energy, 1990. Technical Support Document: Energy Conservation Standards for Consumer Products: Dishwashers, Clothes Washers, and Clothes Dryers.

Source: Kooimey, Jonathan G., Maria C. Sanchez, Diana Vorsatz, Richard E. Brown, and Celina S. Atkinson. 1997.

The Potential for Natural Gas Efficiency Improvements in the U.S. Residential Sector. Lawrence Berkeley Laboratory. DRAFT LBNL-38893. in process.

Average Stock Gas drying UEC from Kooimey et al., 1997

MMBtu
3.74

Determination of 1997 New Unit efficiency from Kooimey et al., 1997

Measure	Incremental energy Savings (MMBtu)	Incremental Cost (\$1990)	Incremental Cost (\$1995)	CCE (\$1990/MMBtu)	New UEC (MMBtu)	Fraction of Current Gas WH Stock
(a) Gas clothes drivers - Baseline	0	\$ -	\$ -	n/a	3.7	100%
(b) Improve clothes drivers to 1994 standard	0.51	\$ 27.00	\$ 31.27	5.5	3.2	100%

MMBtu

New Water Heater UEC in 1997 from Kooimey et al., 1997
(measures (a) thru (d))

3.2

Determination of Maximum cost-effective efficiency from Kooimey et al., 1997

High Efficiency Gas WITH CLOTHES WASHERS

Measure	Incremental energy Savings (MMBtu)	Incremental Cost (\$1990)	Incremental Cost (\$1995)	CCE (\$1990/MMBtu)	New UEC (MMBtu)
(a) Gas clothes drivers - Baseline (1997 new UEC)	0	\$ -	\$ -	n/a	3.2
(b) Recycle exhaust heat	0.2	\$ 56.00	\$ 64.86	\$ 28.600	2.99
Total	0.2	\$ 56.00	\$ 64.86	\$ 28.600	2.99

There is assumed no cost effective approach to significantly reduce gas clothes dryer energy use beyond the 1997 baseline

Check on calculations with REM output

	MMBtu	Percent Savings	Retail price (\$1990)	Retail price (\$1995)	CCE (\$1995/MMBtu)	Notes
Average Stock in 1997 (LBNL-REM runs for DOE, 1995)	3.45	n/a				
1997 New (LBNL-REM, AHAM fact book)	2.91	n/a	\$ 287.27	\$ 332.73	n/a	
Maximum cost-effective energy efficient (new unit UEC, REM 7% case in 2010)	2.11	n/a	\$ 356.10	\$ 412.45	n/a	
Energy, Cost, and UEC comparison	MMBtu (primary)	Percent Savings	Capital Costs (\$1990)	Increase in Capital Costs (\$1997)		
Max. cost effective compared to 1997 new	0.8	27%	\$ 68.83	\$ 79.72	\$ 10.21	

CCE calculations

Capital recovery factor \$0.10
Real discount rate 0.07
Lifetime 17

REM output

Clothes dryer saturation (for both cases)

	1990	1997	2010
Electric	53%	56%	59%
Gas	16%	17%	18%
None	31%	27%	23%
Total	100%	100%	100%

New Clothes dryer installation in existing & new stock (millions)

	1990	1997	2010
Electric	3.469	3.771	4.468
Gas	1.102	1.157	1.385
Total	4.571	4.928	5.853

New Clothes dryer installation in existing & new stock (percent share)

	76%	77%	76%
Electric			
Gas	24%	23%	24%

**Background Information Sheet: Interlab Study on
U.S. Energy Efficiency and Greenhouse Gas Emissions
Assumptions for Energy Efficiency Calculations: Residential Sector**

Cooking (Electric)

Product/end-use description	Cooking involves the use of electric, gas, LPG appliances to prepare warm or hot food. The types of appliances include ranges and ovens, and microwaves. (US DOE, 1993)
Base Year Energy Use	Electric Cooking accounts for an estimated 2% (0.4 quads) of primary residential energy consumption in 1997. (Source: US EIA, 1996)
End-use Lifetime	The end-use lifetime for most cooking products is relatively long. For electric ranges (ovens and cooktops) the end-use lifetime was estimated at 19 years. For microwaves the lifetime was estimated at 10 years. In our estimates we use a shipment weighted lifetime estimate of 14 years. This is based on data provided by the Association of Home Appliance Manufacturers. (LBNL, 1996)
Existing Average Unit Energy Consumption (UEC)	Unit energy consumptions were analyzed in three categories: ovens, cooktops, and microwaves. Base year UECs for these three products were estimated to be the same as 1997 new UECs given available information.
1997 New UEC	1997 new UEC was estimated at 290.9 KWh (1.0 MMBtu) for ovens, 234.4 KWh (0.8 MMBtu) for cooktops, and 143.2 KWh (0.5 MMBtu) for microwaves. This new unit UEC was based on estimates from (LBNL, 1996)
Maximum Cost-effective Efficiency Potential	For electric cooking equipment we find that there is no cost-effective approach to reduce energy use from the 1997 baseline. (LBNL, 1996).
Achievable cost-effective efficiency potential - Efficiency Case	Not applicable
Achievable cost-effective efficiency potential - High Efficiency Case	Not applicable
Incremental Capital Cost	Not applicable
Cost of Conserved Energy	Not applicable

References:

AHAM. *AHAM Fact Book*, 1996, Chicago, IL.

LBNL, 1996. *Draft Report on Potential Impact of Alternative Efficiency Levels for Residential Cooking Products*.

U.S. Department of Commerce, 1996. *Statistical Abstract of the US*. Economics and Statistics Administration, Bureau of the Census, Washington, DC.

U.S. Energy Information Administration, Office of Integrated Analysis and Forecasting, 1996. *Annual Energy Outlook 1997*. Report Number DOE/EIA-0383(97). U.S. Department of Energy, Washington, DC.

**Background Information Sheet: Interlab Study on
U.S. Energy Efficiency and Greenhouse Gas Emissions
Assumptions for Energy Efficiency Calculations: Residential Sector**

Cooking (Gas)

Product/end-use description	Cooking involves the use of electric or gas appliances to prepare warm or hot food. The types of appliances include ranges and ovens, and microwaves. (US DOE, 1993)
Base Year Energy Use	Non-electric cooking accounts for an estimated 1% (0.2 quads) of residential primary energy consumption in 1997. (Source: USEIA, 1996)
End-use Lifetime	The end-use lifetime for most cooking products is relatively long. For gas cooktops and gas ranges the lifetime was estimated at 19 years. This is based on data provided by the Association of Home Appliance Manufacturers. (LBNL, 1996)
Existing Average Unit Energy Consumption (UEC)	1997 existing UEC was estimated at 2.0 MMBtu for gas ovens and 2.1 MMBtu for gas cooktops. This is based on data provided by the Association of Home Appliance Manufacturers. (US DOE, 1993)
1997 New UEC	1997 new UEC was estimated at 2.0 MMBtu for gas ovens and 1.6 MMBtu for gas cooktops. This is based on data provided by the Association of Home Appliance Manufacturers. (US DOE, 1993)
Maximum Cost-effective Efficiency Potential	The maximum cost-effective efficiency potential as measured in UEC was estimated at 1.4 MMBtu, or a savings of 22% from the current 1997 levels. This UEC was calculated as a shipments weighted of share of maximum cost-effective potentials for efficiency improvements to cooktops and ovens (LBNL, 1996).
Achievable cost-effective efficiency potential - Efficiency Case	In our efficiency case, we assume that the achievable adoption level over the analysis period is 35% of maximum cost-effective potential levels.
Achievable cost-effective efficiency potential - High Efficiency Case	In our high-efficiency case, we assume that the achievable adoption level over the analysis period is 65% of maximum cost-effective potential levels.
Incremental Capital Cost	The incremental cost for adopting the high-efficiency model was estimated to be \$7.3 (\$1995). This cost is the incremental cost between the high-efficiency options compared to new 1997 equipment (LBNL, 1996). Prices were adjusted to 1995 levels based on the personal consumption price index (US DOC, 1996).
Cost of Conserved Energy	The CCE for the high efficiency model was estimated at \$2.4/MMBtu (\$1995). The CCE is a ratio of the incremental capital expenditure (amortized over the lifetime of the appliance) to the annual energy savings expected from the purchase of the unit.

References:

AHAM. AHAM Fact Book, 1996, Chicago, IL.

Koomey, Jonathan G., Marla C. Sanchez, Diana Vorsatz, Richard E. Brown, and Celina S. Atkinson. 1997b. *The Potential for Natural Gas Efficiency Improvements in the U.S. Residential Sector*. Lawrence Berkeley Laboratory. DRAFT LBNL-38893. in process.

U.S. Department of Commerce, 1996. *Statistical Abstract of the US*. Economics and Statistics Administration, Bureau of the Census, Washington, DC.

LBNL, 1996. *Draft Report on Potential Impact of Alternative Efficiency Levels for Residential Cooking Products*.

U.S. Energy Information Administration, Office of Integrated Analysis and Forecasting, 1996. *Annual Energy Outlook 1997*. Report Number DOE/EIA-0383(97). U.S. Department of Energy, Washington, DC.

Gas Cooking UEC and Cost Calculations						
Source: Koomey, Jonathan G., Marla C. Sanchez, Diana Vorsatz, Richard E. Brown, and Celina S. Atkinson. 1997.						
The Potential for Natural Gas Efficiency Improvements in the U.S. Residential Sector. Lawrence Berkeley Laboratory. DRAFT LBNL-38893. in process.						
Source: LBNL. 1996. Draft Report on Potential Impact of Alternative Efficiency Levels for Residential Cooking Products.						
Source: AHAM Fact book, 1996						
Oven Gas						
	MMBtu	Percent Savings	Retail price (\$1990)	Retail price (\$1995)	CCE (\$1995/MMBtu)	Notes
Average Stock in 1997 (LBNL-REM runs for DOE, 1993)	2.01	n/a	n/a	n/a	n/a	
1997 New (LBNL-REM runs for DOE, 1993)	1.97	n/a	\$ 573.84	\$ 617.46	n/a	
Maximum cost-effective energy efficient oven (DOE, 1995)	1.56	n/a	\$ 580.59	\$ 624.71	n/a	LCC model from LBNL, 1996
Difference between Max tech and 1997 new	0.41	20.8%	\$ 6.74	\$ 7.26	1.72	
Cooktop Gas						
	MMBtu	Percent Savings	Retail price (\$1990)	Retail price (\$1995)	CCE (\$1995/MMBtu)	Notes
Average Stock in 1997 (LBNL-REM runs for DOE, 1993)	2.1	n/a	n/a	n/a	n/a	
1997 New (LBNL-REM runs for DOE, 1993)	1.6	n/a	\$ 238.14	\$ 256.24	n/a	
Maximum cost-effective energy efficient cooktop (DOE, 1993)	1.3	na	\$ 245.00	\$ 263.62	n/a	LCC model from LBNL, 1996
Difference between Max tech and 1997 new	0.23	14.8%	\$ 6.86	\$ 7.38	3.11	
Shares						
	Baseline (1997)	Saturation Baseline	Saturation Max tech econ case	Share of gas only - Max econ. case		
Non gas cooking	82.0%	82.0%	82.0%			
Baseline gas cooking	18.0%	18.0%	18.0%			
Gas Oven			9.4%	52.4%		
Gas Cooktop			8.6%	47.6%		
Total	100%	100%	18%	100.0%		
2010 scenario						
Oven saturation	43.0%					
Cooktop	39.0%					
Max econ. potential case						
Summary Table (efficiency combination weighted by saturation in households)	Incremental energy Savings (MMBtu)	% Savings relative to New 1997 UEC	Incremental Cost (\$1995)	CCE (\$1995/MMBtu)	Notes	
Gas Oven	0.4	20.8%	7	2		
Gas Cooktop	0.2	14.8%	7	3		
Weighted average MAX ECON POTENTIAL	0.3	18.0%	7.3	2.4		
Weighted 1997 New UEC						
Gas Oven	1.0					
Gas Cooktop	0.7					
Weighted average 1997 new	1.8					
Max Tech Efficiency UEC	1.4					

Gas Efficiency Measures (Kramer et al. 1997b)												
Measure	Incremental energy Savings (MMBtu/yr)	Incremental Cost (\$1990)	Incremental Cost (\$1995)	CCE (\$1990/MMBtu)	New UEC (MMBtu)	Fraction of Current Stock	Measure Lifetime					
(a) Gas Cooktop (1990) Baseline	3.4	\$ -	\$ -	n/a	2.40	100%	19.00					
(b) Add Electronic Ignition	2.2	\$ 48.00	\$ 55.60	2.2	1.20	100%	19.00					
Measures												
(a) Gas Self-Cleaning Oven (1990) Baseline	3.40	\$ -	\$ -	n/a	1.90	100%	19.00					
(b) Insulate door, hinge & reflective surfaces	0.27	\$ 9.00	\$ 10.42	3.4	1.63	100%	19.00					
(c) Insulate interior of walls & door	0.21	\$ 18.00	\$ 20.85	8.3	1.62		19.00					
(d) Furnace conversion (not 1990 measure)	0.22	\$ 41.00	\$ 47.49	17.9	1.20		19.00					
Measures												
(a) Standard Gas Oven (1990) Baseline		\$ -	\$ -	n/a	3.00	100%	19.00					
(b) Add electric kitchen range	1.57	\$ 47.00	\$ 54.44	2.9	1.43	100%	19.00					
(c) Insulate interior of walls & door	0.07	\$ 9.00	\$ 10.42	12.4	1.36		19.00					
(d) Insulate door seals	0.02	\$ 4.00	\$ 4.63	19.4	1.34		19.00					
Measures												
(a) Standard Gas Oven w/ Electronic Ignition (1990) Baseline		\$ -	\$ -	n/a	1.40	100%	19.00					
(b) Insulate interior of walls & door	0.07	\$ 9.00	\$ 10.42	12.4	1.33	100%	19.00					
(c) Insulate door seals	0.02	\$ 4.00	\$ 4.63	19.4	1.31		19.00					
U.S. DOE, 1993 Technical Support Document: Energy Efficiency Standards for Consumer Products: Room A/C, Water heaters, Direct heating equipment, mobile home furnaces, kitchen ranges and ovens, pool heaters, fluorescent lamp ballasts & TVs												
Gas Cooktops - Product Classes	New Model Baseline Retail (\$1990)	New Model Baseline Retail (\$1995)	New Baseline UEC (MMBtu/year)	Lowest LCC Retail (\$1990)	Lowest LCC Retail (\$1995)	Lowest LCC UEC (MMBtu/year)	Shipments (1992) Millions	Percent of Shipments	Incremental energy use (MMBtu)	Incremental Cost (\$1995)	CCE (\$1995/MMBtu)	CCE (\$1995/MMBtu)
Conventional burners w/out power cord	\$ 219.21	253.90	3.37	\$ 245.00	283.77	1.32	n/a	26.6%	2.05	\$ 29.87	1.410	1.410
Conventional burners w/out power cord	\$ 245.00	283.77	1.32	\$ 245.00	283.77	1.32		73.4%				
Conventional burners w/out power cord	\$ 245.00	283.77	1.32	\$ 245.00	283.77	1.32	0.00	100.0%				
Total (or weighted average)	\$ 238.14	275.82	1.87	\$ 245.00		1.32						
Gas Ovens - Product Classes	New Model Baseline Retail (\$1990)	New Model Baseline Retail (\$1995)	New Baseline UEC (MMBtu/year)	Lowest LCC Retail (\$1990)	Lowest LCC Retail (\$1995)	Lowest LCC UEC (MMBtu/year)	Shipments (1992) Millions	Percent of Shipments	Incremental energy use (MMBtu)	Incremental Cost (\$1995)	CCE (\$1995/MMBtu)	CCE (\$1995/MMBtu)
Standard oven w/ or w/out catalytic liner (w/out power cord)	\$ 479.00	554.79	2.98	\$ 503.00	582.59	1.53		28.1%	1.45	\$ 27.80	1.850	1.850
Standard oven w/ or w/out catalytic liner (w/out power cord)	\$ 503.00	582.59	1.53	\$ 503.00	582.59	1.53		48.1%	0.00		1.850	1.850
Standard oven w/ or w/out catalytic liner (w/out power cord)	\$ 829.00	960.18	1.66	\$ 829.00	960.18	1.66		23.8%	0.00		1.850	1.850
Self-clean oven	\$ 573.84	664.65	1.97	\$ 580.59	672.46	1.56	0.00	100.0%	0.41	7.81	1.850	1.850
Total (or weighted average)												
LCC at 6% in this document												
CCE calculations												
Capital recovery factor	\$0.10											
Real discount rate	0.07											
Life expectancy	19											

**Background Information Sheet: Interlab Study on U.S.
Energy Efficiency and Greenhouse Gas Emissions
Assumptions for Energy Efficiency Calculations: Residential Sector**

(Miscellaneous Energy)

Product/end-use description	Miscellaneous residential energy use involves end-uses in the home that are not currently allocated to other end-uses, namely refrigeration, space conditioning, lighting, cooking, and water heating. While miscellaneous energy (particularly electricity) can encompass a variety of activities in one's home, for the purposes of this study we have divided miscellaneous energy into the following categories shown in table 2 below: Table 1: Miscellaneous Energy Use <table><tr><th>Fuel</th><th>Category</th><th>Main end-uses in category</th></tr><tr><td>electricity</td><td>electronics</td><td>color televisions, Video cassette recorders, cable boxes, computers</td></tr><tr><td>electricity</td><td>motors</td><td>Furnace fans, ceiling/ventilation fans, pumps (e.g. pool, well), evaporative cooler</td></tr><tr><td>electricity</td><td>heating</td><td>waterbed heaters, coffee makers, crankcase heaters, irons, electric blankets, spas/hot tubs, toasters</td></tr><tr><td>natural gas</td><td></td><td></td></tr><tr><td>oil & other</td><td></td><td>pool heaters, gas fireplaces</td></tr><tr><td>petroleum products</td><td></td><td></td></tr></table>	Fuel	Category	Main end-uses in category	electricity	electronics	color televisions, Video cassette recorders, cable boxes, computers	electricity	motors	Furnace fans, ceiling/ventilation fans, pumps (e.g. pool, well), evaporative cooler	electricity	heating	waterbed heaters, coffee makers, crankcase heaters, irons, electric blankets, spas/hot tubs, toasters	natural gas			oil & other		pool heaters, gas fireplaces	petroleum products								
Fuel	Category	Main end-uses in category																										
electricity	electronics	color televisions, Video cassette recorders, cable boxes, computers																										
electricity	motors	Furnace fans, ceiling/ventilation fans, pumps (e.g. pool, well), evaporative cooler																										
electricity	heating	waterbed heaters, coffee makers, crankcase heaters, irons, electric blankets, spas/hot tubs, toasters																										
natural gas																												
oil & other		pool heaters, gas fireplaces																										
petroleum products																												
Base Year Energy Use	Miscellaneous electricity use was estimated at 23% of residential primary energy use (4.4 quads) in 1997 (AEO, 1996). Natural gas and oil end-uses account for another quad of primary energy in 1997. Estimates by main end-use category are shown in the table below based on (AEO, 1996; LBNL, 1997) Table 2: 1997 Miscellaneous Energy Use <table><tr><th>End-use Category</th><th>Share</th><th>Quads Primary</th></tr><tr><td>electronics</td><td>35.9%</td><td>1.6</td></tr><tr><td>motors</td><td>37.4%</td><td>1.6</td></tr><tr><td>heating</td><td>26.7%</td><td>1.2</td></tr><tr><td>Total electricity</td><td></td><td>4.4</td></tr><tr><td>natural gas</td><td></td><td>0.9</td></tr><tr><td>oil & other</td><td></td><td></td></tr><tr><td>petroleum products</td><td></td><td>0.1</td></tr><tr><td>Total Miscellaneous</td><td></td><td>5.4</td></tr></table>	End-use Category	Share	Quads Primary	electronics	35.9%	1.6	motors	37.4%	1.6	heating	26.7%	1.2	Total electricity		4.4	natural gas		0.9	oil & other			petroleum products		0.1	Total Miscellaneous		5.4
End-use Category	Share	Quads Primary																										
electronics	35.9%	1.6																										
motors	37.4%	1.6																										
heating	26.7%	1.2																										
Total electricity		4.4																										
natural gas		0.9																										
oil & other																												
petroleum products		0.1																										
Total Miscellaneous		5.4																										
End-use Lifetime	End-use lifetime was estimated at 12 years. This lifetime was determined as the energy-use weighted average of the lifetimes of various miscellaneous end-uses.																											
Average Unit Energy Consumption (UEC)	Average UECs per household are derived from US DOE (1996).																											

**Background Information Sheet: Interlab Study on U.S.
Energy Efficiency and Greenhouse Gas Emissions
Assumptions for Energy Efficiency Calculations: Residential Sector**

(Miscellaneous Energy) Continued

1997 New UEC	New UECs are assumed to be the same as for existing homes.														
Maximum Cost-effective Efficiency Potential	The maximum cost-effective efficiency potential was determined as a weighted average of cost-effective energy savings potentials for various end-use categories. Potentials for each category were estimated from existing studies as well as judgment by LBNL (see table 3) Table 3. Estimated Maximum Cost-Effective Efficiency Potential <table> <tr> <th>End-use Category</th><th>Potential energy savings (percent)</th></tr> <tr> <td>electronics</td><td>25%</td></tr> <tr> <td>motors</td><td>53%</td></tr> <tr> <td>heating</td><td>33%</td></tr> <tr> <td><u>Total electric misc.</u></td><td><u>33%</u></td></tr> <tr> <td>natural gas</td><td>10%</td></tr> <tr> <td><u>oil & other petroleum products</u></td><td><u>10%</u></td></tr> </table> Sources: US DOE, 1993; Webber, 1997; Meier, 1993; Rieger, 1994; Stevens, 1996; Meier and Greenberg, 1994; Lamb, 1996	End-use Category	Potential energy savings (percent)	electronics	25%	motors	53%	heating	33%	<u>Total electric misc.</u>	<u>33%</u>	natural gas	10%	<u>oil & other petroleum products</u>	<u>10%</u>
End-use Category	Potential energy savings (percent)														
electronics	25%														
motors	53%														
heating	33%														
<u>Total electric misc.</u>	<u>33%</u>														
natural gas	10%														
<u>oil & other petroleum products</u>	<u>10%</u>														
Achievable cost-effective efficiency potential - Efficiency Case	In our efficiency case, we assume that the achievable adoption level over the analysis period is 35% of maximum cost-effective potential levels.														
Achievable cost-effective efficiency potential - High Efficiency Case	In our high-efficiency case, we assume that the achievable adoption level over the analysis period is 65% of maximum cost-effective potential levels.														
Incremental Capital Cost	The incremental capital cost varied depending on the particular efficiency measures being examined. Due to the limited availability of data, no attempt was made to average the total incremental cost for miscellaneous energy. Instead, we directly estimated the CCE based on cost estimates for the few parts of miscellaneous electricity that have been explicitly categorized (see below).														
Cost of Conserved Energy	We have estimated an average cost of conserved energy of \$0.03/KWh (\$1990) or \$0.035/KWh (\$1995) for miscellaneous electricity, and \$6/MMBtu (\$1995) for gas/oil measures. We analyzed the cost of conserved energy for technical efficiency measures on televisions, video cassette recorders, and waterbed heaters, and found all three of the CCEs in these cases to be below \$0.03/KWh (\$1995). The CCE is a ratio of the incremental capital expenditure (amortized over the lifetime of the appliance) to the annual energy savings expected from the purchase of the unit.														

References:

US DOE, 1993. *Technical Support Document: Energy Efficiency Standards for Consumer Products: Room Air Conditioners, Water Heaters, Direct Heating Equipment, Mobile Home Furnaces, Kitchen Ranges and Ovens, Pool Heaters, Fluorescent Lamp Ballasts & Television Sets*

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Lamb, Michael. *Home Energy Magazine*, July/August 1996. "Off is a Three-letter word."

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**Background Information Sheet: Interlab Study on U.S.
Energy Efficiency and Greenhouse Gas Emissions
Assumptions for Energy Efficiency Calculations: Residential Sector**

(Miscellaneous Energy) Continued

Rieger, T. *Home Energy Magazine*, September/October 1994 "Waterbed Heating: Uncovering the Savings in the Bedroom"

Stevens, D. *Home Energy Magazine*, March/April 1996 "Mechanical Ventilation for the Home"

U.S. Department of Commerce, 1996. *Statistical Abstract of the US*. Economics and Statistics Administration, Bureau of the Census, Washington, DC.

U.S. Energy Information Administration, Office of Integrated Analysis and Forecasting, 1996. *Annual Energy Outlook 1997*. Report Number DOE/EIA-0383(97). Department of Energy, Washington, DC.

Miscellaneous Energy (Electric)

Fuel	End-use	Energy Use in 1995 TWh	Share of electronics	Share of total misc. electricity	Lifetime (years)	Potential Energy Savings by category (Italics = judgement)	Notes
Electronics							
electricity	color television	36.31	49.2%	17.7%	11.5	25%	1997
electricity	cable boxes	10.34	14.0%	5.0%	10	20%	judgement
electricity	Video cassette recorders	7.57	10.3%	3.7%	10	40%	Webber, 1997
electricity	computers	2.81	3.8%	1.4%	8	25%	judgement
electricity	other electronics (excl. microwaves)	16.72	22.7%	8.1%	10	20%	judgement
subtotal	electronics	73.75	100.0%	35.9%	10.7	25%	
Motors							
electricity	Furnace fans	28.76	37.4%	14.0%	15	60%	Assumes taking advantage of VSD
electricity	ceiling fans	6.55	8.5%	3.2%	15	50%	Blade redesign
electricity	pool pumps	6.53	8.5%	3.2%	12	50%	Assuming one can redesign pool system (e.g. bigger pipes smaller pumps) esp.
electricity	well pumps	4.81	6.3%	2.3%	12	20%	Highly application specific, 20% should
electricity	aquariums	4.24	5.5%	2.1%	12	25%	pumps - analogous; also assuming high efficiency lighting
electricity	evaporative cooler	3.28	4.3%	1.6%	10	50%	Fans are forward curved, like furnaces- lower run time but
electricity	other motors	22.73	29.6%	11.1%	14	60%	Greenberg, 1997. Mostly shaded pole (very poor)
subtotal	motors	76.9	100.0%	37.4%	13.9	53%	
Heating							
electricity	waterbed heaters	9.65	17.6%	4.7%	12	40%	1993
electricity	coffee makers	9.4	17.2%	4.6%	8	5%	judgement
electricity	spas/hot tubs	6.6	12.0%	3.2%	18	20%	1994
electricity	toasters & toaster ovens	5.3	9.7%	2.6%	10	5%	judgement
electricity	crankcase heaters	4.95	9.0%	2.4%	10	10%	judgement
electricity	irons	4.6	8.4%	2.2%	8	10%	judgement
electricity	electric blankets	3.49	6.4%	1.7%	12	10%	judgement
electricity	other heating	10.8	19.7%	5.3%	12	10%	judgement
subtotal	heating	54.79	100.0%	26.7%	11.3	15%	
Total Misc. Electricity--all categories		205.44		100.0%	12.0	33%	

Implied Share of Miscellaneous From AEO, 1997

		Shares from LBNL Documentation	Implied Misc. Energy based on LBNL shares
Total Misc from AEO, 1997	4.4		
Electronics		35.8%	1.5
Motors		37.4%	1.6
Heating		26.7%	1.2

1995 cents/kWh 1995\$/MMBtu resource
Choose CCE 0.435 16.18
based on analyses below
3 cents/kWh in 1990 \$

Energy Efficiency Options

Color Televisions

Source: US DOE, 1993. Technical Support Document: Energy Efficiency Standards for Consumer Products: Room Air Conditioners, Water Heaters, Direct Heating Equipment, Mobile Home Furnaces, Kitchen Ranges and Ovens, Pool Heaters, Fluorescent Lamp Ballasts & Television Sets

Baseline Retail (\$1990)	Baseline Retail (\$1995)	Baseline UEC (KWh)	Lowest LCC Retail (\$1990)	Lowest LCC Retail (\$1995)	Lowest LCC UEC (KWh)	Energy Savings	Incremental Cost (\$1990)	% Energy Savings	CCE (\$1990)
358.55		204.66	378.92		138.52	66.34	19.37	32.4%	\$0.04

CCE Calculation Assumptions (Electronics)

Capital recovery factor
Real discount rate
Lifetime

CCE Calculation Assumptions (Waterbeds)

0.13 Capital recovery factor
0.07 Real discount rate
15 Lifetime

Source: Webber, C. 1997. LBNL Technical Analysis of Reduction of Standby Electricity Use in Televisions and Video Cassette Recorders

Measure	Incremental energy Savings (KWh)	Incremental energy Savings (MMBtu)	Incremental Cost (\$1990)	Incremental Cost (\$1995)	CCE (\$1990/kWh)	New UEC (KWh)	Fraction of Current Electric WH Stock	% Energy Savings
TV Baseline	0	0	\$ -	\$ -	n/a	141	100%	n/a
Set standby to EPA energy star	22	0.1	\$ 6.00	\$ 6.79	\$0.03	119	100%	16.8%

Determination VCR Standby Reduction Efficiency

Measure	Incremental energy Savings (KWh)	Incremental energy Savings (MMBtu)	Incremental Cost (\$1990)	Incremental Cost (\$1995)	CCE (\$1990/kWh)	New UEC (KWh)	Fraction of Current Electric WH Stock	% Energy Savings
VCR Baseline	0	0	\$ -	\$ -	n/a	37	100%	n/a
Set standby to EPA energy star	32	0.1	\$ 6.00	\$ 6.79	\$0.02	25	100%	56.1%

Source: Meier, A. Home Energy Magazine, July/August 1993 "What Stays On When You Go Out"
Source: Pieger, T. Home Energy Magazine, September/October 1994 "Waterbed Heating: Uncovering the Savings in the Bedroom"
Source: Stevens, D. Home Energy Magazine, March/April 1996 "Mechanical Ventilation for the Home"
Source: Meier, A. & Greenberg, S. Home Energy Magazine, July/August 1994 "A Journey through the Gray Literature"
Source: Lamb, Michael. Home Energy Magazine, July/August 1996 "Off is a Three-letter word"
Source: Energy Auditor and Retrofitter, Nov/Dec 1987, "Saving the 'Other' Energy in Homes"

Waterbeds	Incremental energy Savings (KWh)	Incremental energy Savings (MMBtu)	Incremental Cost (\$1990)	Incremental Cost (\$1995)	CCE (\$1990/kWh)	New UEC (KWh)	Fraction of Current Electric WH Stock	% Energy Savings	% of stock applicable
Waterbed Baseline	0	0	\$ -	\$ -	n/a	1200	100%		
Foam bed/carbon installation	\$47.5		\$ 80.00	\$104.24	\$0.02	652		45.8%	70 percent & vt. lifetime?
Lower thermostat/cover w/ blankets		0.0			\$0.04/KI	1200	100%		
Aquariums	Incremental energy Savings (KWh)	Incremental energy Savings (MMBtu)	Incremental Cost (\$1990)	Incremental Cost (\$1995)	CCE (\$1990/kWh)	New UEC (KWh)	Fraction of Current Electric WH Stock	% Energy Savings	
Aquarium baseline	0	0.0	\$ -	\$ -	n/a	900	100%		
?		0.0			\$0.04/KI	900	100%		
Computers	Incremental energy Savings (KWh)	Incremental energy Savings (MMBtu)	Incremental Cost (\$1990)	Incremental Cost (\$1995)	CCE (\$1990/kWh)	New UEC (KWh)	Fraction of Current Electric WH Stock	% Energy Savings	
Computer baseline	0	0	\$ -	\$ -	n/a	36	100%		
?		0.0			\$0.04/KI	36	100%		
Pool Pumps	Incremental energy Savings (KWh)	Incremental energy Savings (MMBtu)	Incremental Cost (\$1990)	Incremental Cost (\$1995)	CCE (\$1990/kWh)	New UEC (KWh)	Fraction of Current Electric WH Stock	% Energy Savings	
Pool pump baseline	0	0	\$ -	\$ -	n/a	1200	100%		
?		0.0			\$0.04/KI	1200	100%		
Boes	Incremental energy Savings (KWh)	Incremental energy Savings (MMBtu)	Incremental Cost (\$1990)	Incremental Cost (\$1995)	CCE (\$1990/kWh)	New UEC (KWh)	Fraction of Current Electric WH Stock	% Energy Savings	
Soa baseline	0	0	\$ -	\$ -	n/a	1200	100%	21.3%	
Improved covers	255.5	0.9			\$0.00	\$44.5	100%		

Ventilation Fans

Analysis shows that the majority of the market contains fans with efficiencies of 0.03-0.07 while Panasonic manufactures fans with average efficiencies of 0.8-0.14. This suggests a conservative max tech cost effective efficiency improvement of 40%.

**Background Information Sheet: Interlab Study on U.S.
Energy Efficiency and Greenhouse Gas Emissions
Assumptions for Energy Efficiency Calculations: Residential Sector**

Lighting

Product/end-use description	Lighting involves the use of electricity to pass electrons through a filament to produce light and heat (incandescent light) or to pass electrons through an inert gas which then emits light. Significant savings are possible in residential lighting systems with the replacement of traditional incandescent lights. About 90% of lighting energy in residential buildings is from incandescent sources.
Base Year Energy Use	Lighting accounts for an estimated 5% (1.0 quads) of residential primary energy consumption in 1997. (Source: US EIA, 1996)
End-use Lifetime	The end-use lifetime for lighting was estimated at 1 year. There are many different lifetimes for lighting products, but incandescent bulbs typically last for about 750 hours. At the average usage level of 2.1 hours/day, these bulbs last about a year.
Existing Average Unit Energy Consumption (UEC)	The AEO 97 forecast assumes a per household lighting UEC of 927 kWh/year
1997 New UEC	New UEC is the same as the existing UEC.
Maximum Cost-effective Efficiency Potential	The maximum cost-effective efficiency potential was estimated as the savings potential from 2010 assuming the implementation of technically cost effective lighting measures, including widespread use of halogen IR and compact fluorescent technologies. The efficiency measures are ranked based on cost of conserved energy for five separate usage categories (0-1 hours/day, 1-2 hours/day, etc). The savings costing less than \$0.08/kWh are 53% of the 1997 baseline, based on Koomey et al. (1997).
Achievable cost-effective efficiency potential - Efficiency Case	In our efficiency case, we assume that the achievable adoption level over the analysis period is 35% of maximum cost-effective potential levels.
Achievable cost-effective efficiency potential - High Efficiency Case	In our high-efficiency case, we assume that the achievable adoption level over the analysis period is 65% of maximum cost-effective potential levels.
Incremental Capital Cost	The CCEs are directly calculated in Koomey et al. based on the incremental costs of halogen IR and compact fluorescent technologies. Prices were adjusted to 1995 levels based on the personal consumption price index (US DOC, 1996).
Cost of Conserved Energy	The weighted average CCE for high efficiency lighting measures costing less than \$0.08/kWh is \$0.03/kWh (\$8.3/MMBtu). The CCE is a ratio of the incremental capital expenditure (amortized over the lifetime of the appliance) to the annual energy savings expected from the purchase of the unit.

References:

Koomey, Jonathan G., Diana A. Vorsatz, Richard E. Brown, and Celina S. Atkinson. 1997. *Updated Potential for Electricity Efficiency Improvements in the U.S. Residential Sector*. Lawrence Berkeley Laboratory. DRAFT LBNL-38894. in process.

U.S. Department of Commerce, 1996. *Statistical Abstract of the US*. Economics and Statistics Administration, Bureau of the Census, Washington, DC.

U.S. Energy Information Administration, Office of Integrated Analysis and Forecasting, 1996. *Annual Energy Outlook 1997*. Report Number DOE/EIA-0383(97). Department of Energy, Washington, DC.

Lighting Efficiency Calculations (Measure Name)	Measure No.	Bund Code	category	OCE (cents/kWh) 1990 \$	OCE (cents/kWh) 1995 \$	Energy Saved TWh	Cost in 1990 \$	Cost in 1995 \$	O & M cost	Applicable Stock (1000s)
100W GS Incandescent and Motion Sensor	4	L100-5.	non space conditioning	0.45	0.52	1.34	0.58	0.67	0	10467.62
75W GS Incandescent and Motion Sensor	4	L75-5.	non space conditioning	0.6	0.69	1.12	0.58	0.67	0	11630.69
60W GS Incandescent and Motion Sensor	5	L60-5.	non space conditioning	1.02	1.18	2.77	0.78	0.90	0	36055.13
65W Halogen IR	1	L100-5.	non space conditioning	1.2	1.39	6.02	0.77	0.89	0	94208.57
65W Halogen IR	1	L100-4.	non space conditioning	1.27	1.47	2.34	0.57	0.66	0	52338.09
65W Halogen IR	1	L100-3.	non space conditioning	1.35	1.56	1.67	0.43	0.50	0	52338.09
90W ES Incandescent	1	L100-1.	non space conditioning	1.53	1.77	0.38	0.03	0.03	0	208352.38
65W Halogen IR	1	L100-2.	non space conditioning	1.56	1.81	2.01	0.3	0.35	0	10467.619
52W ES Incandescent	1	L60-4.	non space conditioning	1.56	1.81	1.84	0.16	0.19	0	180275.66
52W ES Incandescent	1	L60-5.	non space conditioning	1.57	1.82	4.74	0.23	0.27	0	324496.19
52W ES Incandescent	1	L60-2.	non space conditioning	1.6	1.85	1.58	0.07	0.08	0	340551.32
52W ES Incandescent and Motion Sensor	4	L60-5.	non space conditioning	1.6	1.85	0.16	0.07	0.08	0	34055.13
49W Halogen IR	1	L75-5.	non space conditioning	1.62	1.88	4.97	0.77	0.89	0	10467.619
52W ES Incandescent	1	L60-3.	non space conditioning	1.64	1.90	1.32	0.12	0.14	0	180275.66
49W Halogen IR	1	L75-4.	non space conditioning	1.71	1.98	1.93	0.57	0.66	0	58153.44
15W Electronic Separable CFL where CFL fit	2	L60-5.	non space conditioning	1.79	2.07	13.16	1.21	1.40	0	184667.71
49W Halogen IR	1	L75-3.	non space conditioning	1.81	2.10	1.38	0.43	0.50	0	58153.44
90W ES Incandescent and Motion Sensor	5	L100-5.	non space conditioning	1.82	2.11	0.06	0.1	0.12	0	10467.62
52W ES Incandescent	1	L60-1.	non space conditioning	2.05	2.37	1.05	0.03	0.03	0	721102.64
67W ES Incandescent	1	L75-1.	non space conditioning	2.05	2.37	0.34	0.03	0.03	0	232613.75
49W Halogen IR	1	L75-2.	non space conditioning	2.11	2.44	1.66	0.3	0.35	0	116306.69
67W ES Incandescent and Motion Sensor	5	L75-5.	non space conditioning	2.28	2.64	0.05	0.1	0.12	0	11630.69
15W Electronic Separable CFL where CFL fit	2	L60-4.	non space conditioning	2.45	2.84	5.12	1.16	1.34	0	108165.4
65W Halogen IR	2	L100-1.	non space conditioning	2.85	3.30	0.96	0.13	0.15	0	209352.38
15W Electronic Integral Quad CFL where CFL Fit	2	L60-3.	non space conditioning	3.4	3.94	3.65	1.15	1.33	0	108165.4
30W Elec. Separable CFL where CFL fit	2	L100-5.	non space conditioning	3.6	4.17	3.61	2.3	2.66	0	56525.14
41W Halogen IR where CFL doesn't fit	3	L60-5.	non space conditioning	4.18	4.84	2.61	0.84	0.97	0	129798.47
20W Electronic Separable CFL where CFL fit	2	L75-5.	non space conditioning	4.25	4.92	3.33	2.25	2.61	0	62805.71
49W Halogen IR	2	L75-1.	non space conditioning	4.26	4.93	0.77	0.14	0.16	0	232613.75
41W Halogen IR where CFL doesn't fit	3	L60-4.	non space conditioning	4.41	5.11	1.01	0.62	0.72	0	721102.26
30W Electronic Separable CFL where CFL fit	2	L100-4.	non space conditioning	4.54	5.26	1.4	2.03	2.35	0	31402.86
41W Halogen IR where CFL doesn't fit	3	L60-3.	non space conditioning	4.68	5.42	0.72	0.47	0.54	0	721102.26
15W Electronic Integral Quad where CFL Fit	3	L60-2.	non space conditioning	5.27	6.10	3.08	0.75	0.87	0	216330.79
41W Halogen IR	2	L60-2.	non space conditioning	5.31	6.15	2.17	0.32	0.37	0	340551.32
20W Electronic Separable CFL where CFL fit	2	L75-4.	non space conditioning	5.42	6.28	1.29	2.01	2.33	0	34892.06
30W Electronic Separable CFL where CFL fit	2	L100-3.	non space conditioning	5.51	6.38	1	1.76	2.04	0	31402.86
20W Electronic Separable CFL where CFL fit	2	L75-3.	non space conditioning	7.18	8.32	0.92	1.9	2.20	0	34892.06
15W Elec. Separable CFL and Fixture where CFL doesn't fit	4	L60-5.	non space conditioning	7.86	9.10	6.16	3.73	4.32	0	129798.47
30W Electronic Integral Quad CFL where CFL fit	2	L100-2.	non space conditioning	8.29	9.60	1.2	1.59	1.84	0	62805.71
30W Elec. Separable CFL and Fixture where CFL doesn't fit	3	L100-5.	non space conditioning	8.85	10.25	2.41	5.66	6.56	0	37683.43
41W Halogen IR Incandescent	2	L60-1.	non space conditioning	8.96	10.38	1.45	0.18	0.21	0	721102.64
15W Elec. Separable CFL and Fixture where CFL doesn't fit	4	L60-4.	non space conditioning	9.95	11.52	2.4	3.31	3.83	0	721102.26
20W Elec. Separable CFL and Fixture where CFL doesn't fit	3	L75-5.	non space conditioning	10.61	12.29	2.22	5.62	6.51	0	41870.48
30W Elec. Separable CFL and Fixture where CFL doesn't fit	3	L100-4.	non space conditioning	11.24	13.02	0.94	5.03	5.83	0	20935.24
20W Electronic Integral Quad CFL where CFL fit	2	L75-2.	non space conditioning	11.71	13.56	1.11	1.86	2.15	0	68784.13
20W Elec. Separable CFL and Fixture where CFL doesn't fit	3	L75-4.	non space conditioning	12.62	14.62	0.86	4.68	5.42	0	23261.38
15W Electronic Integral Quad CFL where CFL fit	3	L60-1.	non space conditioning	15.37	17.80	2.06	0.73	0.85	0	432661.58
30W Electronic Integral Quad CFL where CFL fit	3	L100-1.	non space conditioning	19.54	22.63	0.8	1.25	1.45	0	125611.43
20W Electronic Integral Quad CFL where CFL fit	3	L75-1.	non space conditioning	25.28	29.28	0.74	1.34	1.55	0	139568.25
Savings up to 8 cents/kWh				1995 d/kWh						
				2.85		82.61	24.2	28.0		
2010 lighting residential frozen efficiency TWh				1995 \$/MMBtu		83%				
				8.34		156.6				

**Background Information Sheet: Interlab Study on U.S.
Energy Efficiency and Greenhouse Gas Emissions
Assumptions for Energy Efficiency Calculations: Residential Sector**

Heating, Ventilation, and Air Conditioning (Space Conditioning, Electric)

Product/end-use description	Heating, ventilation, and air-conditioning systems (also known as space conditioning) in residential buildings are a significant energy use. Systems fueled by electricity involved the use of either central or dispersed space heating and cooling. The energy use of space conditioning is most significantly affected by the climate (or number of days in which heating or cooling is required), the efficiency of the shell of the home, and the efficiency of the heating and cooling equipment.
Base Year Energy Use	Electric space conditioning accounts for an estimated 15% (2.9 quads) of residential primary energy consumption in 1997. (Source: US EIA, 1996)
End-use Lifetime	The end-use lifetime for electric space conditioning is different for the building shell and the space conditioning equipment. Lifetime for the shell was estimated at 100 years. The weighted average lifetime for electric space heating equipment was estimated at 18 years and the lifetime for electric space cooling equipment was estimated at 13 years (Kooimey et al., 1997a).
Existing Average Unit and New Unit Energy Consumption (UEC)	In our forecast we divide energy consumption between existing and new shells and equipment. UECs are calculated for more than 30 different prototypes in North and South climates, as given in Kooimey et al. (1997a).
Maximum Cost-effective Efficiency Potential	The maximum cost-effective efficiency potential was estimated as the savings potential assuming the implementation of space conditioning measures costing less than \$0.08/kWh. The savings for equipment efficiency in existing buildings was estimated at 11% for heating and 15% for cooling (relative to the 1997 baseline efficiencies), while savings new buildings was estimated at 25% for heating and 18% for cooling. Savings for existing shells are 14% for heating and 1% for cooling, while savings for new shells are 15% for heating and 4% for cooling. These savings can be directly added to the equipment savings because the supply curves methodology avoids double counting of energy savings.
Achievable cost-effective efficiency potential - Efficiency Case	In our efficiency case, we assume that the achievable adoption level over the analysis period is 35% of maximum cost-effective potential levels.
Achievable cost-effective efficiency potential - High Efficiency Case	In our high-efficiency case, we assume that the achievable adoption level over the analysis period is 65% of maximum cost-effective potential levels.
Incremental Capital Cost	The CCEs are directly calculated in Kooimey et al. based on the incremental costs for space conditioning equipment and thermal shell measures. Prices were adjusted to 1995 levels based on the personal consumption price index (US DOC, 1996).
Cost of Conserved Energy	The CCE is a ratio of the incremental capital expenditure (amortized over the lifetime of the appliance) to the annual energy savings expected from the purchase of the unit. The weighted average CCE for equipment efficiency measures costing less than \$0.08/kWh is \$0.031/kWh (\$9.1/MMBtu) for existing buildings and \$0.04/kWh (\$11.7/MMBtu) for new buildings. The weighted average CCE for shell efficiency measures costing less than \$0.08/kWh is \$0.039/kWh (\$11.4/MMBtu) for existing buildings and \$0.045/kWh (\$13.2/MMBtu) for new buildings. The CCEs do not differ for heating and cooling.

References:

Kooimey, Jonathan G., Diana A. Vorsatz, Richard E. Brown, and Celina S. Atkinson. 1997a. *Updated Potential for Electricity Efficiency Improvements in the U.S. Residential Sector*. Lawrence Berkeley Laboratory. DRAFT LBNL-38894. in process.

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Electric Heating, Ventilation, and Air Conditioning (Measure name)	Measure No.	Enduse Code	Incremental Cost	Year	Category	CCE (¢/kWh) 1990 \$	CCE (¢/kWh) 1995 \$	Total Energy Saved (TWh)	Cost in 1990 \$	Energy Saved Cts	Energy Saved \$/kWh	Applicable Stock (1000s)
Improve shell in ESF ER/RAC/loose homes, North	1	ESNERL	279	1989	shell	0.24	0.28	1.56	294	0.01	1.55	155.69
Reduce infiltration by 25% in ESF ER/RAC/tight homes, North	1	ESNERT	245	1989	shell	1.67	1.93	0.67	258	0	0.67	533.79
Decrease ACH by 25% in ESF ER/Aight homes, North	1	ESNE_T	248	1989	shell	1.69	1.96	0.89	261	0	0.89	712.75
Improve shell in ESF ER/Aight homes, North	1	ESNE_L	2656	1989	shell	1.89	2.19	2.49	2800	0	2.49	207.89
Improve shell in ESF ER/RAC/loose homes, South	1	ESSERL	1714	1989	shell	2.12	2.46	0.71	1807	0.02	0.69	103.66
Improve shell in ESF ER/RAC/loose homes, South	1	ESSE_L	1714	1989	shell	2.18	2.52	0.63	1807	0	0.63	93.79
Improve shell in ESF ER/Aight homes, South	1	ESSERT	422	1989	shell	2.47	2.86	0.37	445	0.01	0.36	254.21
Reduce infiltration in ESF ER/RAC/tight homes, South	2	ESNERL	354	1989	shell	2.51	2.91	0.19	373	0	0.19	155.69
Low-E argon filled windows in ESF ER/RAC/loose homes, North	2	ESNE_L	354	1989	shell	2.52	2.92	0.25	373	0	0.25	207.89
Low-E argon filled windows in ESF ER/Aight homes, North	2	ESNE_T	422	1989	shell	2.55	2.95	0.32	445	0	0.32	230.02
Reduce infiltration in ESF ER/Aight homes, South	2	ESNERT	466	1989	shell	2.56	2.97	0.83	491	0.01	0.82	533.79
Low-E argon filled windows in ESF ER/RAC/tight homes, North	2	ESNE_L	466	1989	shell	2.58	2.99	1.1	491	0	1.1	712.75
Low-E argon filled windows in ESF ER/Aight homes, North	2	ESNE_T	466	1989	shell	3.36	3.89	0.33	230	0.05	0.28	606.28
Double pane windows in ESF ER/RAC/loose homes, South	2	ESSECL	218	1989	shell	3.59	4.16	0.63	460	0.14	0.49	606.28
R-25 ceiling in ESF ER/RAC/loose homes, South	3	ESSECL	436	1989	shell	4.04	4.68	0.22	1350	0.01	0.21	82.81
Improve shell in ESF ER/RAC/loose homes, North	3	ESNECL	1281	1989	shell	4.22	4.89	2.81	2063	0	2.81	712.75
Improve floor & ceiling in ESF ER/Aight homes, North	3	ESNE_T	1959	1989	shell	4.26	4.93	2.25	2228	0.01	2.24	533.79
R-25 floor & R-48 ceiling in ESF ER/RAC/tight homes, North	3	ESNERT	2114	1989	shell	4.67	5.41	0.13	258	0	0.13	283.93
Reduce infiltration by 25% in ESF ER/RAC/tight homes, North	2	ESNECT	245	1989	shell	4.83	5.59	0.55	222	0.09	0.46	1486.83
Reduce infiltration in ESF ER/RAC/tight homes, South	2	ESSECT	211	1989	shell	5.15	5.96	0.3	754	0.02	0.28	254.21
Low-E argon filled windows in ESF ER/RAC/tight homes, South	3	ESSECT	715	1989	shell	5.31	6.15	0.02	121	0	0.02	103.66
R-33 ceiling in ESF ER/RAC/loose homes, South	3	ESSECL	115	1989	shell	5.31	6.15	1.4	445	0.23	1.17	2067.37
Reduce infiltration to 0.39 ACH in ESF ER/Aight homes, South	2	ESSHPT	422	1989	shell	5.45	6.31	0.05	311	0	0.04	103.66
Low-E argon filled windows in ESF ER/RAC/loose homes, South	4	ESSECL	295	1989	shell	5.47	6.34	0.26	754	0	0.26	230.02
Low-E argon filled windows in ESF ER/Aight homes, South	2	ESSE_T	715	1989	shell	5.58	6.46	0.02	121	0	0.02	93.79
R-33 ceiling in ESF ER/Aight homes, South	2	ESSE_L	115	1989	shell	5.92	6.86	0.04	311	0	0.04	93.79
Low-E argon filled windows in ESF ER/Aight homes, South	3	ESSE_L	295	1989	shell	6.03	6.98	0.18	222	0.03	0.15	606.28
Reduce infiltration in ESF ER/RAC/loose homes, South	4	ESSECL	211	1989	shell	6.03	6.98	0.25	304	0.26	-0.02	606.28
Spectrally selective windows in ESF ER/RAC/loose homes, South	5	ESSECL	288	1989	shell	6.13	7.10	0.18	190	0	0.18	712.75
R-48 ceiling in ESF ER/Aight homes, North	4	ESNE_T	180	1989	shell	6.33	7.33	0.07	366	0	0.07	155.69
Supervindows in ESF ER/RAC/loose homes, North (post-1995)	6	ESNERL	347	1989	shell	6.41	7.42	0.1	366	0	0.1	207.89
Supervindows in ESF ER/Aight homes, North (post-1995)	6	ESNE_L	347	1989	shell	6.44	7.46	0.32	483	0.01	0.32	533.79
Supervindows in ESF ER/RAC/tight homes, North (post-1995)	6	ESNERT	458	1989	shell	6.47	7.49	0.75	1786	0.14	0.61	338.3
Improve shell of ESF/RAC/loose homes, South	2	ESSHPT	1694	1989	shell	6.57	7.61	0.42	483	0	0.42	712.75
Supervindows in ESF ER/Aight homes, North (post-1995)	7	ESNE_T	458	1989	shell	6.6	7.64	0.03	989	0	0.03	23.05
Low-E argon filled windows in ESF/RAC/loose homes, North	2	ESNHPT	938	1989	shell	6.63	7.68	0.02	92	0	0.02	155.69
R-37 ceiling in ESF ER/RAC/loose homes, North	3	ESNERL	87	1989	shell	6.63	7.68	0.34	578	0.02	0.32	484.11
Low-E argon filled windows in ESF/RAC/tight homes, North	2	ESNHPT	548	1989	shell	6.68	7.74	0.02	92	0	0.02	207.89
R-37 ceiling in ESF ER/Aight homes, North	3	ESNE_L	87	1989	shell	6.77	7.84	0.04	373	0	0.04	82.81
Low-E argon filled windows in ESF ER/RAC/loose homes, North	4	ESNECL	354	1989	shell	6.84	7.92	0.16	491	0.01	0.16	283.93
Low-E argon filled windows in ESF ER/RAC/tight homes, North	3	ESNECT	466	1989	shell	7.14	8.27	0.37	222	0.06	0.31	1486.83
Reduce infiltration (42) in ESF ER/RAC/tight homes, South	4	ESSECT	211	1989	shell	7.4	8.57	0.06	642	0	0.06	90.91
R-38 ceiling in ESF ER/RAC/tight homes, South (pre-2000)	4	ESSECT	609	1989	shell	7.45	8.63	0.12	642	0	0.12	169.47
R-38 ceiling in ESF ER/RAC/tight homes, South (post-2000)	8	ESSERT	609	1989	shell	7.49	8.68	0.08	944	0	0.08	82.81
Improve floor & ceiling in ESF ER/RAC/loose homes, North	3	ESNE_T	893.6	1989	shell	7.77	9.00	0.15	642	0	0.15	230.02
R-38 ceiling in ESF ER/Aight homes, South	2	ESSGCL	492	1989	shell	7.93	9.18	1.98	519	1.98	0	375.163
Spectrally selective windows: ESF other/RAC/loose, South	4	ESSHPT	590	1989	shell	8.15	9.44	1.27	622	1.28	0	2067.37
Spectrally selective windows: ESF other/RAC/tight, South	2	ESSGCT	609	1989	shell	8.26	9.57	1.87	642	1.87	0	2990.16
Improve floor insulation in ESF ER/RAC/loose homes, North	6	ESNECL	235	1989	shell	8.33	9.65	0.02	248	0	0.02	82.81
Improve shell in ESF ER/RAC/loose homes, South	6	ESSECL	849	1989	shell	8.49	9.83	0.51	895	0.08	0.44	606.28
Spectrally selective windows: ESF ER/RAC/tight, South	5	ESSECT	705	1989	shell	8.51	9.86	1.05	743	0.94	0.11	1486.83
R-11 wall in ESF ER/RAC/tight homes, North	4	ESNERT	864	1989	shell	9.3	10.77	0.42	911	0	0.42	533.79
Spectrally selective windows: ESF/RAC/loose, South	3	ESSHPT	571	1989	shell	9.35	10.83	0.18	602	0.18	0	338.3
Improve wall insulation in ESF ER/Aight homes, North	4	ESNE_T	874	1989	shell	9.46	10.96	0.56	921	0	0.56	712.75
R-30 ceiling in ESF/RAC/loose homes, North	4	ESNHPT	1065	1989	shell	10.67	12.36	0.02	1123	0	0.02	23.05
R-46 ceiling in ESF ER/RAC/tight homes, South (pre-2000)	5	ESSERT	161	1989	shell	10.94	12.67	0.01	170	0	0.01	90.91
R-46 ceiling in ESF ER/RAC/tight homes, South (post-2000)	9	ESSERT	161	1989	shell	11.03	12.78	0.02	170	0	0.02	169.47
Improve floor insulation in ESF ER/RAC/tight homes, North	4	ESNECT	1264	1989	shell	11.07	12.82	0.28	1332	0.01	0.27	283.93
R-40 ceiling in ESF ER/RAC/tight homes, North	5	ESNECT	672	1989	shell	11.24	13.02	0.14	708	0.01	0.14	283.93
R-46 ceiling in ESF ER/Aight homes, South	4	ESSE_T	161	1989	shell	11.69	13.54	0.04	153	0.01	0.03	338.3
R-33 ceiling in ESF/RAC/loose homes, South	4	ESSHPT	145	1989	shell	11.73	13.59	0.04	345	0	0.03	155.69
R-45 ceiling in ESF ER/RAC/loose homes, North	4	ESNERL	327	1989	shell	12.3	14.25	0.04	345	0	0.03	207.89
R-45 ceiling in ESF ER/Aight homes, North	4	ESNE_L	327	1989	shell	12.39	14.35	0.05	345	0	0.05	37.07
R-36 ceiling in ESF ER/RAC/loose homes, South (pre-2000)	5	ESSERT	72	1989	shell	12.48	14.45	0	76	0	0	533.79
R-51 ceiling in ESF ER/RAC/tight homes, North	5	ESNERT	111	1989	shell	12.57	14.56	0.04	117	0	0.04	606.28
R-33 ceiling in ESF ER/RAC/loose homes, South	6	ESSECL	115	1989	shell	12.83	14.88	0.05	121	0.01	0.03	712.75
R-51 ceiling in ESF ER/Aight homes, North	6	ESNE_T	112	1989	shell	12.93	14.98	0.05	118	0	0.05	93.79
R-36 ceiling in ESF ER/Aight homes, North	4	ESSE_L	72	1989	shell	13.3	15.40	0	76	0	0	484.11
R-44 ceiling in ESF/RAC/tight homes, North	3	ESNHPT	395	1989	shell	14.16	16.40	0.11	416	0.01	0.11	90.91
R-11 wall in ESF ER/RAC/tight homes, South (pre-2000)	6	ESSERT	775	1989	shell	14.31	16.57	0.04	817	0	0.04	169.47
R-11 wall in ESF ER/RAC/tight homes, South (post-2000)	10	ESSERT	775	1989	shell	14.37	16.64	0.08	817	0	0.08	230.02
R-11 wall in ESF ER/Aight homes, South	5	ESSE_T	775	1989	shell	14.66	16.98	0.1	817	0	0.1	155.69
R-67 ceiling in ESF ER/RAC/loose homes, North	5	ESNERL	632	1989	shell	15.41	17.85	0.05	666	0	0.05	207.89
R-67 ceiling in ESF ER/Aight homes, North	5	ESNE_L	632	1989	shell	15.56	18.02	0.07	666	0	0.07	484.11
Supervindows in ESF/RAC/tight homes, North (post-1995)	4	ESNHPT	539	1989	shell	15.64	18.11	0.14	568	0.02	0.12	283.93
R-48 ceiling in ESF ER/RAC/tight homes, North	6	ESNECT	179	1989	shell	16	18.53	0.03	189	0	0.03	23.05
Supervindows in ESF/RAC/loose homes, North (post-1995)	5	ESSHPT	770	1989	shell	16.43	19.03	0.01	812	0	0.01	1486.83
R-38 ceiling in ESF ER/RAC/tight homes, South	7	ESSECT	609	1989	shell	17.42	20.18	0.44	642	0.1	0.34	484.11
R-52 ceiling in ESF/RAC/tight homes, North	5	ESNHPT	104.5	1989	shell	18.49	21.42	0.02	110	0	0.02	484.11

Electric Heating, Ventilation, and Air Conditioning (Measure name)	Measure No.	Enduse Code	Incremental Cost	\$/Year	Category	CCE (¢/kWh) 1990 \$	CCE (¢/kWh) 1995 \$	Total Energy Saved (TWh)	Cost in 1990 \$	Energy Saved Ctr	Energy Saved heating	Applicable Stock (1000s)
Switch elec furn to HP in ESF ER/CAC/loose homes, North	1	ESNECL	822	1989	space conditioning	0.68	0.79	0.96	866	0.01	0.95	66.25
Switch elec furn to HP in ESF ER/CAC/tight homes, North	1	ESNECT	912	1989	space conditioning	0.99	1.15	2.51	961	0.04	2.47	227.15
Improve heat pump efficiency in ESF/HP/loose homes, North	1	ESNHPL	241	1989	space conditioning	1.11	1.29	0.08	254	0.01	0.07	30.74
Improve HP in ESF ER/CAC/loose homes, North	2	ESNECL	90	1989	space conditioning	1.2	1.39	0.06	95	0	0.06	66.25
Improve HP beyond 92 in EMF HP homes, North	1	EANHP	104	1989	space conditioning	1.22	1.41	0.22	110	0.02	0.21	218.04
Switch elec furn to HP in ESF ER/CAC/loose homes, South	1	ESSECL	822	1989	space conditioning	1.41	1.63	3.42	866	0.37	3.05	485.02
Improve HP beyond 1992 standard in EMH HP homes, North	1	EMNHP	151	1988	space conditioning	1.66	1.92	0.01	167	0	0.01	10.3
Switch elec furn to HP in ESF ER/CAC/tight homes, South	1	ESSECT	822	1989	space conditioning	1.71	1.98	6.91	866	0.91	6	1189.47
Improve heat pump in ESF/HP/tight homes, South	1	ESSHPT	183	1989	space conditioning	1.87	2.17	3.26	193	1.57	1.69	2756.5
Improve heat pump in ESF/HP/loose homes, South	1	ESSHPL	292	1989	space conditioning	1.97	2.28	0.8	308	0.31	0.49	451.06
Improve HP beyond 1992 standard in EMH HP homes, South	1	EMSHPT	183	1988	space conditioning	2.36	2.73	0.06	202	0.03	0.03	59.59
Improve heat pump efficiency in ESF/HP/tight homes, South	1	ESNHPT	241	1989	space conditioning	2.37	2.75	0.79	254	0.07	0.72	645.48
Improve HP beyond 92 in EMF HP homes, South	1	EASHPT	104	1989	space conditioning	2.71	3.14	0.41	110	0.19	0.22	886
Improve RAC efficiency in ESF non-elec/RAC/loose homes, South	1	ESSGRL	18	1989	space conditioning	3.16	3.66	0.16	19	0.16	0	2429.92
Improve RAC in EMH ER/RAC homes, South	1	EMSER	9.6	1989	space conditioning	3.17	3.67	0.01	10	0.01	0	136.53
Improve RAC in EMH non-elec/RAC homes, South	1	EMSGR	9.6	1989	space conditioning	3.32	3.85	0.02	10	0.02	0	568.52
Improve RAC efficiency in ESF non-elec/RAC/tight homes, South	1	ESSGRT	18	1989	space conditioning	3.86	4.47	0.1	19	0.1	0	1936.72
Improve RAC in ESF ER/RAC/tight homes, South (pre-2000)	2	ESSERT	18	1989	space conditioning	4.08	4.73	0.02	19	0.02	0	338.95
Improve HP (2) in EMF HP homes, North	2	EANHP	62	1989	space conditioning	4.17	4.83	0.04	65	0	0.04	218.04
Improve CAC in ESF non-elec/CAC/loose homes, South	1	ESSGCL	309	1989	space conditioning	4.75	5.50	4.32	326	4.32	0	5002.17
Variable speed RAC in ESF non-elec/RAC/loose, South (post-2000)	3	ESSGRL	122	1989	space conditioning	4.89	5.66	0.47	129	0.47	0	1619.95
Improve RAC to 9.4 EER in ESF ER/RAC/loose homes, South	2	ESSERL	18	1989	space conditioning	5.08	5.88	0.01	19	0.01	0	138.21
Improve RAC (2) in EMH ER/RAC homes, South (post-2000)	2	EMSER	55.5	1989	space conditioning	5.7	6.60	0.01	58	0.01	0	91.02
Variable speed RAC in ESF non-elec/RAC/tight, South (post-2000)	3	ESSGRT	109	1989	space conditioning	5.71	6.61	0.29	115	0.29	0	1291.15
Improve CAC in ESF non-elec/CAC/tight homes, South	1	ESSGCT	309	1989	space conditioning	5.73	6.64	2.85	326	2.85	0	3986.88
Switch to improved HP in ESF ER/CAC/tight homes, South	3	ESSECT	90	1989	space conditioning	5.96	6.90	0.22	95	0.07	0.15	1189.47
Improve RAC (2) in EMH non-elec/RAC homes, South (post-2000)	2	EMSGR	55.5	1989	space conditioning	5.97	6.91	0.05	58	0.05	0	379.01
Improve HP (2) in EMH HP homes, North	2	EMNHP	90	1988	space conditioning	6.16	7.13	0	99	0	0	10.3
Variable speed RAC in ESF ER/RAC/tight homes, South (post-2000)	7	ESSERT	109	1989	space conditioning	6.47	7.49	0.04	115	0.04	0	225.96
Improve RAC in EMH ER/RAC homes, North	1	EMNER	9.6	1989	space conditioning	6.89	7.98	0	10	0	0	61.46
Variable speed RAC in ESF ER/RAC/loose, South (post-2000)	6	ESSERL	109	1989	space conditioning	7.13	8.26	0.02	115	0.02	0	92.14
Improve RAC in EMH non-elec/RAC homes, North	1	EMNGR	9.6	1989	space conditioning	7.45	8.63	0	10	0	0	276.82
Improve RAC in EMF ER/RAC homes, South	1	EASER	9.6	1989	space conditioning	7.77	9.00	0.01	10	0.01	0	402.89
Improve RAC in EMF non-elec/RAC homes, South	1	EASGR	9.6	1989	space conditioning	7.77	9.00	0.02	10	0.02	0	1017.13
Improve CAC beyond 1992 in EMH ER/CAC homes, South	1	EMSEC	309	1989	space conditioning	7.82	9.06	0.07	326	0.07	0	142.25
Variable speed CAC compressor in EMF ER/CAC homes, South	2	EASEC	105	1989	space conditioning	7.91	9.16	0.31	111	0.31	0	1751.87
Variable speed CAC compressor in EMF non-elec/CAC homes, South	1	EASGC	105	1989	space conditioning	7.91	9.16	0.24	111	0.24	0	1335.72
Improve CAC beyond 1992 in EMH non-elec/CAC homes, South	4	ESSGRT	309	1989	space conditioning	8.19	9.49	0.19	326	0.19	0	386.39
10.08 EER for ESF non-elec/RAC/loose, South (post-2000)	4	ESSGRT	13.5	1989	space conditioning	8.22	9.52	0.02	14	0.02	0	1291.15
Improve heat pump (#2) in ESF/HP/tight homes, South	3	ESSHPT	109	1989	space conditioning	8.26	9.57	0.44	115	0.15	0.39	2756.5
Switch to improved HP, ESF ER/CAC/loose, South	7	ESSECL	90	1989	space conditioning	8.96	10.38	0.06	95	0.02	0.04	485.02
Improve heat pump efficiency (#2) in ESF/HP/loose homes, North	3	ESNHPL	330	1989	space conditioning	9.38	10.86	0.01	348	0	0.01	30.74
Improve CAC beyond 1992 in EMF ER/CAC homes, South	1	EASEC	169	1989	space conditioning	9.6	11.12	0.22	178	0.22	0	947.28
Improve CAC beyond 1992 in EMF non-elec/CAC homes, South	1	EASGC	169	1989	space conditioning	9.6	11.12	0.17	178	0.17	0	722.25
Improve HP (2) in EMH HP homes, North	2	EANHP	228	1989	space conditioning	10.81	12.52	0.06	240	0.01	0.05	218.04
Improve HP (2) in EMF HP homes, South	2	EMSHPT	109	1988	space conditioning	10.88	12.60	0.01	120	0	0.01	59.59
Improve HP (#2) in ESF ER/CAC/tight homes, South	6	ESSECT	330	1989	space conditioning	11.7	13.55	0.4	348	0.28	0.12	1189.47
10.08 EER RAC in ESF ER/RAC/loose, South (post-2000)	7	ESSERL	13.5	1989	space conditioning	12.02	13.92	0	14	0	0	92.14
Improve HP (2) in EMF HP homes, South	2	EASHPT	62	1989	space conditioning	12.11	14.03	0.05	65	0.02	0.04	886
Improve RAC (2) in EMH ER/RAC homes, North (post-2000)	2	EMNER	55.5	1989	space conditioning	12.42	14.39	0	58	0	0	40.98
Improve HP (3) in EMH HP homes, North	3	EMNHP	330	1988	space conditioning	12.76	14.78	0	365	0	0	10.3
CAC (#2) in ESF non-elec/CAC/loose homes, South	3	ESSGCL	292	1989	space conditioning	13.53	15.67	1.43	308	1.43	0	5002.17
Switch to improved HP (#2), ESF ER/CAC/loose, South	9	ESSECL	330	1989	space conditioning	13.76	15.94	0.14	348	0.11	0.03	485.02
Improve RAC efficiency in ESF non-elec/RAC/loose homes, North	1	ESNGRL	18	1989	space conditioning	13.89	16.09	0.06	19	0.06	0	3878.95
Improve RAC (2) in EMF ER/RAC homes, South (post-2000)	2	EASER	55.5	1989	space conditioning	14	16.22	0.01	58	0.01	0	268.59
Improve RAC (2) in EMF non-elec/RAC homes, South (post-2000)	2	EASGR	55.5	1989	space conditioning	14	16.22	0.04	58	0.04	0	678.09
Improve HP (3) in EMH HP homes, South	3	EMSHPT	399	1988	space conditioning	14.01	16.23	0.02	441	0.02	0.01	59.59
Switch to improved HP in ESF ER/CAC/loose homes, North	7	ESNECL	330	1989	space conditioning	14.48	16.77	0.02	348	0.01	0.01	66.25
Improve heat pump (#3) in ESF/HP/tight homes, South	5	ESSHPT	399	1989	space conditioning	14.53	16.83	0.91	421	0.65	0.26	2756.5
Heat pump (#3) in ESF/HP/loose homes, South	5	ESSHPL	399	1989	space conditioning	14.57	16.88	0.15	421	0.11	0.04	451.06
Improve RAC efficiency in ESF non-elec/RAC/tight homes, North	1	ESNGRT	18	1989	space conditioning	14.88	17.23	0.06	19	0.06	0	4078.34
10.20 EER for ESF non-elec/RAC/loose, South (pre-2000)	2	ESSGRL	142	1989	space conditioning	15.36	17.79	0.09	150	0.09	0	868.94
Improve CAC in ESF non-elec/CAC/loose homes, North	1	ESNGCL	264	1989	space conditioning	16.14	18.69	1.05	278	1.05	0	4843.87
Improve HP (3) in EMF HP homes, South	3	EASHPT	228	1989	space conditioning	16.75	19.40	0.15	240	0.1	0.05	886
Improve CAC in ESF non-elec/CAC/tight homes, North	1	ESNGCT	264	1989	space conditioning	16.84	19.50	1.06	278	1.06	0	5092.85
10.20 EER for ESF non-elec/RAC/loose, South (post-2000)	4	ESSGRL	19.5	1989	space conditioning	17.36	20.11	0.02	21	0.02	0	1619.95
CAC (#2) in ESF non-elec/CAC/tight homes, South	3	ESSGCT	292	1989	space conditioning	17.86	20.69	0.87	308	0.87	0	3986.88
10.08 EER for ESF non-elec/RAC/tight, South (pre-2000)	2	ESSGRT	122	1989	space conditioning	18.58	21.52	0.05	129	0.05	0	692.57

Existing Shell savings below 8 cents/kWh

3.89 20.87 20.86 1.04 19.82

Existing Equipment savings below 8 cents/kWh

3.09 28.1 28.11 11.95 16.16

Electric Heating, Ventilation, and Air Conditioning (Measure name)

Measure No.	Enduse Code	Incremental Cost	\$/year	Category	CCE (¢/kWh) 1990 \$	CCE (¢/kWh) 1995 \$	Total Energy Saved (TWh)	Cost in 1990 \$	Energy Saved Cte	Energy Saved heating	Applicable Stock (1000s)
R-19 wall & reduced infiltration in NSF ER/CAC homes, South	1 NSSE	606.1	1989	shell	1.85	2.14	0.46	639	0.01	0.45	165.79
Reduce infiltration & R-19 wall, NSF ER/CAC homes, South	1 NSSE	606	1989	shell	1.91	2.21	0.4	639	0	0.4	149.74
R-19 wall, R-30 floor in NSF ER/CAC homes, North	1 NSNER	408.3	1989	shell	2.39	2.77	0.2	430	0	0.2	136.18
R-19 wall, R-30 floor insulation in NSF ER/CAC homes, North	1 NSNE	408	1989	shell	2.41	2.79	0.27	430	0	0.27	185.13
Argon-filled windows in NSF ER/CAC homes, North	2 NSNER	494	1989	shell	2.49	2.88	0.23	521	0	0.23	136.18
Infiltration to 0.4 ACH in NSF ER/CAC homes, South	2 NSSEC	227.5	1989	shell	2.49	2.88	0.71	240	0.12	0.6	917.45
Argon-filled windows in NSF ER/CAC homes, North	2 NSNE	494	1989	shell	2.5	2.90	0.31	521	0	0.31	185.13
Argon-filled low-E windows in NSF ER/CAC homes, South	2 NSSE	748.2	1989	shell	3.68	4.26	0.29	789	0.02	0.27	165.79
Argon-filled low-E windows in NSF ER/CAC homes, South	2 NSSE	748	1989	shell	3.9	4.52	0.24	788	0	0.24	149.74
Improve shell in NSF HP homes, South	2 NSSHP	529	1989	shell	3.99	4.62	3.83	558	0.8	3.02	3394.86
Ceiling to R-38 in NSF ER/CAC homes, North	3 NSNER	148.5	1989	shell	4.23	4.90	0.04	157	0	0.04	136.18
Ceiling to R-38 in NSF ER/CAC homes, North	3 NSNE	148	1989	shell	4.25	4.92	0.05	156	0	0.05	185.13
Supersidewalls in NSF ER/CAC homes, North (post-1995)	7 NSNER	455	1989	shell	5.1	5.91	0.1	480	0	0.1	136.18
Supersidewalls in NSF ER/CAC homes, North (post-1995)	6 NSNE	455	1989	shell	5.16	5.98	0.14	480	0	0.14	185.13
Wall to R-19 in NSF ER/CAC homes, North	2 NSNEC	185.6	1989	shell	5.24	6.07	0.13	196	0	0.12	423.29
Wall to R-19 in NSF ER/CAC homes, North	2 NSNHP	360	1989	shell	5.49	6.36	0.7	379	0.03	0.67	1264.73
R-19 wall and R-38 ceiling in NSF HP homes, North	3 NSSEC	738.1	1989	shell	6.23	7.22	0.92	778	0.66	0.26	917.45
Spectrally selective windows in NSF ER/CAC homes, South	4 NSSE	56.8	1989	shell	6.63	7.68	0.01	60	0	0.01	165.79
Ceiling to R-30 in NSF ER/CAC homes, South	3 NSSEC	494	1989	shell	6.7	7.76	0.27	521	0.01	0.26	423.29
Argon-filled windows in NSF ER/CAC homes, North	3 NSSE	57	1989	shell	6.92	8.01	0.01	60	0	0.01	149.74
R-30 ceiling in NSF ER/CAC homes, South	4 NSNER	1243.5	1989	shell	7.4	8.57	0.19	1311	0	0.19	136.18
Ceiling to R-49, wall to R-27 in NSF ER/CAC homes, North	4 NSNE	1244	1989	shell	7.44	8.62	0.26	1311	0	0.26	185.13
R-27 wall & R-49 ceiling in NSF ER/CAC homes, North	5 NSSEC	378.8	1989	shell	7.81	9.05	0.38	399	0.06	0.32	917.45
Wall to R-19 in NSF ER/CAC homes, South	3 NSNHP	311	1989	shell	7.83	9.07	0.43	328	0.02	0.41	1264.73
Floor to R-30 in NSF HP homes, North	4 NSNEC	222.7	1989	shell	7.88	9.13	0.1	235	0.01	0.1	423.29
Floor to R-30 in NSF ER/CAC homes, North	4 NSNHP	100	1989	shell	8.65	10.02	0.12	105	0.01	0.12	1264.73
R-49 ceiling in NSF HP homes, North	5 NSNER	148.5	1989	shell	9.06	10.49	0.02	157	0	0.02	136.18
Ceiling to R-60 in NSF ER/CAC homes, North	5 NSNE	148	1989	shell	9.11	10.55	0.03	156	0	0.03	185.13
Ceiling to R-60 in NSF ER/CAC homes, North	3 NSSHP	710	1989	shell	9.5	11.00	2.16	748	2.05	0.1	3394.86
Spectrally selective low-E windows, NSF HP, South	2 NSSGC	807	1989	shell	10.1	11.70	3.62	651	3.62	0	5324.68
Spectrally selective windows in NSF ER/CAC homes, South	5 NSNEC	148.5	1989	shell	11.19	12.96	0.05	157	0	0.04	423.29
Ceiling to R-38 in NSF ER/CAC homes, North	5 NSNHP	89	1989	shell	11.83	13.70	0.08	94	0.01	0.07	1264.73
R-60 ceiling in NSF HP homes, North	5 NSSE	322	1989	shell	12.47	14.44	0.02	339	0	0.02	80.14
Ceiling insulation to R-38 in NSF ER/CAC homes, South (pre-2000)	8 NSSE	322	1989	shell	12.51	14.49	0.02	339	0	0.02	85.64
Ceiling insulation to R-38 in NSF ER/CAC homes, South (post-2000)	6 NSNEC	455	1989	shell	13.18	15.27	0.12	480	0.01	0.11	423.29
Supersidewalls in NSF ER/CAC homes, North	5 NSNHP	328	1989	shell	13.27	15.37	0.71	346	0.11	0.61	3394.86
Wall to R-19 in NSF HP homes, South	4 NSSE	322	1989	shell	13.34	15.45	0.03	339	0	0.03	149.74
Ceiling to R-38 in NSF ER/CAC homes, South	6 NSSE	303	1989	shell	13.74	15.91	0.02	319	0	0.01	80.14
Ceiling insulation to R-49 in NSF ER/CAC homes, South (pre-2000)	9 NSSE	303	1989	shell	13.79	15.97	0.02	319	0	0.01	85.64
Ceiling insulation to R-49 in NSF ER/CAC homes, South (post-2000)	5 NSSE	303	1989	shell	14.71	17.04	0.03	319	0	0.03	149.74
Ceiling to R-49 in NSF ER/CAC homes, South	7 NSSEC	56.8	1989	shell	15.98	18.51	0.03	60	0.01	0.02	917.45

Electric Heating, Ventilation, and Air Conditioning (Measure name)	Measure No.	Enduse Code	Incremental Cost	Year	Category	OCE (¢/kWh) 1990 \$	OCE (¢/kWh) 1995 \$	Total Energy Saved (TWh)	Cost in 1990 \$	Energy Saved Ctr	Energy Saved heating	Applicable Stock (1000s)
Switch elec furnace to HP in NSF ER/CAC homes. North	1 NSNEC		412	1989	space conditioning	0.64	0.74	3.3	434	0.1	3.2	423.29
Switch elec furnace to HP in NSF ER/CAC homes. South	1 NSSEC		422	1989	space conditioning	0.79	0.92	5.92	445	0.71	5.21	917.45
Improve HP beyond 1992 standard in NSF HP homes. North	1 NSNHP		241	1989	space conditioning	1.87	2.17	1.97	254	0.17	1.8	1264.73
Improve HP beyond 1992 standard in NSF HP homes. South	1 NSSHP		183	1989	space conditioning	1.97	2.28	3.81	193	1.93	1.88	3394.86
Improve HP beyond 1992 std in NMF HP homes. North	1 NANHP		104	1989	space conditioning	2.01	2.33	0.24	110	0.03	0.21	392.31
Improve HP beyond 1992 standard in NMH HP homes. South	1 NMSHP		183	1988	space conditioning	2.52	2.92	0.16	202	0.09	0.07	179.56
Improve RAC in NMH ER/RAC homes. South	1 NMSER		9.6	1989	space conditioning	3.09	3.58	0	10	0	0	14.64
Improve RAC in NMH non-elec/RAC homes. South	1 NMSGR		9.6	1989	space conditioning	3.09	3.58	0.03	10	0.03	0	661.76
Increase RAC condenser rows in NSF non-elec/RAC. South	1 NSSGR		18	1989	space conditioning	3.79	4.39	0.03	19	0.03	0	487.22
Increase RAC condenser rows in NSF ER/RAC homes. South	3 NSSER		18	1989	space conditioning	4.51	5.22	0.01	19	0.01	0	165.79
Variable speed RAC in NSF non-elec/RAC. South (post-2000)	2 NSSGR		108.8	1989	space conditioning	4.81	5.57	0.07	115	0.07	0	251.69
Improve HP beyond 1992 std in NMF HP homes. South	1 NASHP		104	1989	space conditioning	5.14	5.95	0.33	110	0.24	0.09	1350.52
Improve RAC (2) in NMH ER/RAC homes. South (post-2000)	2 NMSER		55.5	1989	space conditioning	5.57	6.45	0	58	0	0	7.72
Improve RAC (2) in NMH non-elec/RAC homes. South (post-2000)	2 NMSGR		55.5	1989	space conditioning	5.57	6.45	0.05	58	0.05	0	348.93
Improve CAC in NSF non-elec/CAC homes. South	1 NSSGC		308.88	1989	space conditioning	5.66	6.56	3.86	326	3.86	0	5324.68
Variable speed RAC in NSF ER/CAC homes. South (post-2000)	7 NSSER		108.8	1989	space conditioning	6.73	7.79	0.02	115	0.02	0	85.64
Improve HP in NSF ER/CAC homes. South	4 NSSEC		90	1989	space conditioning	6.97	8.07	0.14	95	0.04	0.11	917.45
Improve RAC in NMH ER/RAC homes. North	1 NMNER		9.6	1989	space conditioning	7.04	8.15	0	10	0	0	5.53
Improve RAC in NMH non-elec/RAC homes. North	1 NMNGR		9.6	1989	space conditioning	7.04	8.15	0.01	10	0.01	0	316.21
Improve HP (2) in NMF HP homes. North	2 NANHP		62	1989	space conditioning	7.05	8.17	0.04	65	0	0.04	392.31
Improve CAC beyond 1992 std in NMH ER/CAC homes. South	1 NMSEC		309	1989	space conditioning	7.64	8.85	0.22	326	0.22	0	414.36
Improve CAC beyond 1992 std in NMH non-elec/CAC homes. South	1 NMSSC		309	1989	space conditioning	7.64	8.85	0.48	326	0.44	0	889.49
fact RAC evaporator area: NSF non-elec/RAC. South (post-2000)	3 NSSGR		13.5	1989	space conditioning	8.58	9.94	0	14	0	0	251.69
Improve RAC in NMF ER/RAC homes. South	1 NASER		9.6	1989	space conditioning	9.72	11.26	0	10	0	0	132.75
Improve RAC in NMF non-elec/RAC homes. South	1 NASGR		9.6	1989	space conditioning	9.72	11.26	0	10	0	0	230.58
Variable speed CAC compressor in NMF ER/CAC. South	2 NASEC		105	1989	space conditioning	9.9	11.47	0.07	111	0.07	0	493.45
Variable speed CAC compressor in NMF non-elec/CAC homes. South	2 NASGC		105	1989	space conditioning	9.9	11.47	0.06	111	0.06	0	444.11
Improve HP in NSF HP homes. South	4 NSSHP		109	1989	space conditioning	11.58	13.41	0.38	115	0.12	0.26	3394.86
Improve HP (2) in NMH HP homes. South	2 NMSHP		109	1988	space conditioning	11.94	13.83	0.02	120	0.01	0.01	179.56
Improve CAC beyond 1992 std in NMF ER/CAC homes. South	1 NASEC		169	1989	space conditioning	12.01	13.91	0.06	178	0.06	0	328.3
Improve CAC beyond 1992 std in NMF non-elec/CAC homes. South	1 NASGC		169	1989	space conditioning	12.01	13.91	0.06	178	0.06	0	295.48
Increase RAC condenser rows in NSF non-elec/RAC homes. North	1 NSNGR		15	1989	space conditioning	12.05	13.96	0.02	16	0.02	0	1113.5
Improve HP in NSF ER/CAC homes. South	6 NSSEC		330	1989	space conditioning	12.67	14.67	0.29	348	0.21	0.08	917.45
Improve HP to 9.93 HSPF/15.14 SEER in NSF HP homes. North	6 NSNHP		330	1989	space conditioning	14.1	16.33	0.36	348	0.13	0.23	1264.73
Improve HP (3) in NMH HP homes. South	3 NMSHP		399	1988	space conditioning	15.43	17.87	0.06	441	0.02	0.04	179.56
Improve CAC to 13.3 SEER in NSF non-elec/CAC homes. North	1 NSNGC		264	1989	space conditioning	16.84	19.50	1.07	278	1.07	0	5163.82
Improve HP (3) in NMF HP homes. North	3 NANHP		228	1989	space conditioning	17.04	19.74	0.06	240	0.01	0.05	392.31
Improve room AC efficiency in NSF ER/CAC homes. North	6 NSNER		18	1989	space conditioning	17.36	20.11	0	19	0	0	136.18
Improve RAC (2) in NMF ER/RAC homes. South (post-2000)	2 NASER		55.5	1989	space conditioning	17.54	20.32	0	58	0	0	79.72
Improve RAC (2) in NMF non-elec/RAC homes. South (post-2000)	2 NASGR		55.5	1989	space conditioning	17.54	20.32	0.01	58	0.01	0	138.46
Improve HP (#2) in NSF HP homes. South	6 NSSHP		399	1989	space conditioning	17.68	20.48	0.92	421	0.72	0.21	3394.86
CAC to 14.87 SEER. NSF non-elec/CAC homes. South	3 NSSGC		292.5	1989	space conditioning	18.04	20.89	1.15	308	1.15	0	5324.68
Improve HP (2) in NMF HP homes. South	2 NASHP		62	1989	space conditioning	28.41	32.91	0.04	65	0.02	0.02	1350.52

								Cooling as Heating savings				
New Shell savings below 8 cents/kWh								4.50	9.02	9.01	1.64	7.37
New Equipment savings below 8 cents/kWh								3.99	19.78	19.78	7.32	12.46
Total Shell savings below 8 cents/kWh								4.06	29.89	29.87	2.68	27.19
Total Equipment savings below 8 cents/kWh								3.46	47.88	47.89	19.27	28.62
								3.70	77.77			
Frozen efficiency use in 2010												
Existing										223.52	80.63	142.89
New										90.61	40.2	50.41
Total										323.13	129.83	193.3
% savings												
Total Shell savings below 8 cents/kWh										9.3%	2.1%	14.1%
Total Equipment savings below 8 cents/kWh										14.8%	14.8%	14.8%
										24.1%	16.9%	28.9%

EXISTING		EXISTING				Cooling		Heating	
		CCE @ W \$/MBtu per Total							
Total Shell savings below 8 cents/tWh		3.89	11.41	9.3%	1.3%				
Total Equipment savings below 8 cents/tWh		3.89	9.06	12.6%	14.8%				
Weighted average existing		3.43	10.87	21.9%	16.1%				
NEW		NEW							
Total Shell savings below 8 cents/tWh		4.50	13.18	9.9%	4.1%				
Total Equipment savings below 8 cents/tWh		3.99	11.49	21.8%	18.2%				
Weighted average new		4.15	12.15	31.8%	22.3%				

**Background Information Sheet: Interlab Study on U.S.
Energy Efficiency and Greenhouse Gas Emissions
Assumptions for Energy Efficiency Calculations: Residential Sector**

Heating (Space Conditioning, Gas)

Product/end-use description	Heating, ventilation, and air-conditioning systems (also known as space conditioning) in residential buildings are a significant energy use. Systems fueled by electricity involved the use of either central or dispersed space heating and cooling. The energy use of space conditioning is most significantly affected by the climate (or number of days in which heating or cooling is required), the efficiency of the shell of the home, and the efficiency of the heating and cooling equipment.
Base Year Energy Use	Gas space conditioning accounts for an estimated 19% (3.7 quads) of residential primary energy consumption in 1997. (Source: US EIA, 1996)
End-use Lifetime	The end-use lifetime for electric space conditioning is different for the building shell and the space conditioning equipment. Lifetime for the shell was estimated at 100 years. The weighted average lifetime for gas space heating equipment was estimated at 20 years (Koomey et al., 1997b).
Existing Average Unit and New Unit Energy Consumption (UEC)	In our forecast we divide energy consumption between existing and new shells and equipment. UECs are calculated for more than 30 different prototypes in North and South climates, as given in Koomey et al. (1997b).
Maximum Cost-effective Efficiency Potential	The maximum cost-effective efficiency potential was estimated as the savings potential assuming the implementation of space conditioning measures costing less than \$6/MMBtu. The savings for equipment efficiency in new and existing buildings was estimated at 7% (relative to the 1997 baseline efficiencies). Savings for existing shells are 4%, while savings for new shells are 11%. These savings can be directly added to the equipment savings because the supply curves methodology avoids double counting of energy savings.
Achievable cost-effective efficiency potential - Efficiency Case	In our efficiency case, we assume that the achievable adoption level over the analysis period is 35% of maximum cost-effective potential levels.
Achievable cost-effective efficiency potential - High Efficiency Case	In our high-efficiency case, we assume that the achievable adoption level over the analysis period is 65% of maximum cost-effective potential levels.
Incremental Capital Cost	The CCEs are directly calculated in Koomey et al. (1997b) based on the incremental costs for space conditioning equipment and thermal shell measures. Prices were adjusted to 1995 levels based on the personal consumption price index (US DOC, 1996).
Cost of Conserved Energy	The CCE is a ratio of the incremental capital expenditure (amortized over the lifetime of the appliance) to the annual energy savings expected from the purchase of the unit. The weighted average CCE for equipment efficiency measures costing less than \$6/MMBtu is \$5.0/MMBtu for existing buildings and \$5.4/MMBtu for new buildings. The weighted average CCE for shell efficiency measures costing less than \$6/MMBtu is \$4.1/MMBtu for existing buildings and \$3.9/MMBtu for new buildings.

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Gas Heating Efficiency (Measure Code)	Enduse Code	Incremental Cost	Category	CCE (\$/MMBtu)	CCE (\$/MMBtu) 1995 \$	Energy Saved (TBtu)	Applicable Stock
Improve Ceiling Insulation to R-19	ESNGFL	321.9 shell		2.81	3.25	18.65	2017.47
Improve ceiling insulation to R-19	ESNGFLC	321.9 shell		2.81	3.25	17.6	1904.73
Improve ceiling insulation to R-19	ESNGFLR	321.9 shell		2.81	3.25	14.1	1525.3
Improve insulation to ceiling R-19 & reduce infiltration by 25%	ESNGBL	580 shell		3.15	3.65	6.56	442.19
Improve insulation to ceiling R-19 & reduce infiltration by 25%	ESNGBLC	580 shell		3.15	3.65	6.19	417.48
Improve insulation to ceiling R-19 & reduce infiltration by 25%	ESNGBLR	580 shell		3.15	3.65	4.96	334.31
Improve insulation to ceiling R-19 and reduce infiltration by 25%	ESSGBL	759.13 shell		4.07	4.71	0.38	25.5
Improve insulation to ceiling R-19 & reduce infiltration 25%	ESSGBLC	759.13 shell		4.07	4.71	0.86	57.13
Improve insulation to ceiling R-19 and reduce infiltration 25%	ESSGBLR	759.13 shell		4.07	4.71	0.42	27.75
Reduce infiltration by 25% & add double pane-wood frame window	ESNGBT	334.76 shell		4.65	5.39	2.7	464.92
Reduce infiltration by 25%, add double pane-wood frame window	ESNGBTC	334.76 shell		4.65	5.39	2.54	438.93
Reduce infiltration by 25% & add double pane-wood frame window	ESNGBTR	334.76 shell		4.65	5.39	2.04	351.5
Improve insulation to wall R-11 & reduce infiltration additional 25%	ESNGBL	1492.81 shell		4.68	5.42	11.37	442.19
Improve insulation to wall R-11 & reduce infiltration additional 25%	ESNGBLC	1492.81 shell		4.68	5.42	10.74	417.48
Improve insulation to wall R-11 & reduce infiltration additional 25%	ESNGBLR	1492.81 shell		4.68	5.42	8.6	334.31
Reduce infiltration by 25%	ESSGFT	222.51 shell		5.01	5.80	2.98	832.27
Reduce infiltration by 25%	ESSGFTC	222.51 shell		5.01	5.80	6.68	1864.85
Reduce infiltration by 25%	ESSGFTR	222.51 shell		5.01	5.80	3.24	905.89
Reduce infiltration by 25% & improve wall insulation to R-11	ESNGFL	1492.81 shell		5.02	5.81	48.33	2017.47
Reduce infiltration by 25% & improve wall insulation to R-11	ESNGFLC	1492.81 shell		5.02	5.81	45.63	1904.73
Reduce infiltration by 25% & improve wall insulation to R-11	ESNGFLR	1492.81 shell		5.02	5.81	36.54	1525.3
Reduce Infiltration by 25%	ESSGBT	222.51 shell		5.13	5.94	0.07	20.32
Reduce Infiltration by 25%	ESSGBTC	222.51 shell		5.13	5.94	0.16	45.54
Reduce Infiltration by 25%	ESSGBTR	222.51 shell		5.13	5.94	0.08	22.12
Reduce infiltration by 25% & improve insulation to ceiling R-19	ESSGFL	759.13 shell		5.27	6.10	12.13	1044.21
Reduce infiltration by 25% & improve insulation to ceiling R-19	ESSGFLC	759.13 shell		5.27	6.10	27.18	2339.74
Reduce infiltration by 25% & improve insulation to ceiling R-19	ESSGFLR	759.13 shell		5.27	6.10	13.2	1136.59
Improve window to Double Pane-Wood Frame, reduce infiltration 25%	ESNGFT	334.76 shell		5.29	6.13	10.81	2121.17
Improve window to double pane-wood frame & decrease Infiltration 25%	ESNGFTC	334.76 shell		5.29	6.13	10.21	2002.63
Improve window to double pane-wood frame & reduce infiltration 25%	ESNGFTR	334.76 shell		5.29	6.13	8.17	1603.7
Improve insulation to wall R-11	ESSGBL	735.73 shell		5.52	6.39	0.27	25.5
Improve insulation to wall R-11	ESSGBLC	735.73 shell		5.53	6.41	0.61	57.13
Improve insulation to wall R-11	ESSGBLR	735.73 shell		5.53	6.41	0.3	27.75
Improve insulation to ceiling R-27, add 2-glz,low-E, argon windows	ESNGBL	665.94 shell		5.6	6.49	4.24	442.19
Improve insulation to ceiling R-27 & replace with 2-glz,low-E, argon	ESNGBLC	665.94 shell		5.6	6.49	4	417.48
Improve insulation to ceiling R-27 & add 2-glz,low-E, argon windows	ESNGBLR	665.94 shell		5.6	6.49	3.2	334.31
Reduce ACH additional 25%,Add Ceiling R-27, 2-glz, low-E, argon	ESNGFL	924.04 shell		6.1	7.07	24.61	2017.47
Reduce infil additional 25%,Add Ceiling R-27, 2-glz, low-E, argon	ESNGFLC	924.04 shell		6.1	7.07	23.23	1904.73
Reduce infil additional 25%, add Ceiling R-27, 2-glz, low-E, argon	ESNGFLR	924.04 shell		6.1	7.07	18.6	1525.3
Improve window to 2-glz, low-e, argon (from double-wood)	ESNGFT	507.82 shell		6.58	7.62	13.19	2121.17
Improve window to 2-glz, low-e, argon (from double-wood)	ESNGFTC	507.82 shell		6.58	7.62	12.45	2002.63
Improve window to 2-glz, low-e, argon (from double-wood)	ESNGFTR	507.82 shell		6.58	7.62	9.97	1603.7
Reduce infiltration by an additional 25%	ESSGBT	222.51 shell		7.1	8.22	0.05	20.32
Reduce infiltration additional 25%	ESSGBTC	222.51 shell		7.1	8.22	0.11	45.54
Reduce infiltration by an additional 25%	ESSGBTR	222.51 shell		7.1	8.22	0.06	22.12
Reduce infiltration additional 25% & improve insulation to wall R-11	ESSGFL	958.23 shell		7.55	8.74	10.68	1044.21
Reduce infiltration additional 25% & improve insulation to wall R-11	ESSGFLC	958.23 shell		7.55	8.74	23.92	2339.74
Reduce infiltration additional 25% & improve insulation to wall R-11	ESSGFLR	958.23 shell		7.55	8.74	11.62	1136.59
Reduce infiltration by additional 25%	ESSGFT	222.51 shell		8.09	9.37	1.84	832.27
Reduce infiltration by an additional 25%	ESSGFTC	222.51 shell		8.09	9.37	4.13	1864.85
Reduce infiltration by additional 25%	ESSGFTR	222.51 shell		8.09	9.37	2.01	905.89
Improve insulation to ceiling R-27 & Reduce infiltration additional 25%	ESSGBL	364.39 shell		8.41	9.74	0.09	25.5
Improve insulation to ceiling R-27 & Reduce infiltration additional 25%	ESSGBLC	364.39 shell		8.41	9.74	0.2	57.13
Improve insulation to ceiling R-27	ESSGBLR	364.39 shell		8.41	9.74	0.1	27.75
Improve windows to 2-glz, low-E, argon (from double-wood)	ESNGBT	507.82 shell		10.26	11.88	1.85	464.92
Improve window to 2-glz, low-E, argon (from double-wood)	ESNGBTC	507.82 shell		10.26	11.88	1.75	438.93
Improve window to 2-glz, low-E, argon (from double-wood)	ESNGBTR	507.82 shell		10.26	11.88	1.4	351.5
Improve insulation to ceiling R-19	ESNGBT	386.65 shell		10.47	12.13	1.38	464.92
Improve insulation to ceiling R-19	ESNGBTC	386.65 shell		10.47	12.13	1.31	438.93
Improve insulation to ceiling R-19	ESNGBTR	386.65 shell		10.47	12.13	1.05	351.5
Improve windows to Superwindow & increase to floor R-11	ESNGBL	1316.14 shell		11.53	13.35	4.07	442.19
Improve window to superwindow (from 2-glz,low-E,argon), add floor R-11	ESNGBLC	1316.14 shell		11.53	13.35	3.84	417.48
Improve window to Superwindow (from 2-glz,low-E,argon), add floor R-11	ESNGBLR	1316.14 shell		11.53	13.35	3.07	334.31
Improve window to double pane-wood frame	ESSGFL	171.63 shell		12.66	14.66	1.14	1044.21
Improve window to double pane-wood frame	ESSGFLC	171.63 shell		12.66	14.66	2.56	2339.74
Improve window to double pane-wood frame	ESSGFLR	171.63 shell		12.66	14.66	1.24	1136.59
Improve insulation to floor R-11, floor R-19, ceiling R-30	ESNGFL	1263.27 shell		12.82	14.85	16.02	2017.47
Improve insulation to floor R-11, floor R-19 & ceiling R-30	ESNGFLC	1263.27 shell		12.82	14.85	15.12	1904.73
Improve insulation to floor R-11, floor R-19 & ceiling R-30	ESNGFLR	1263.27 shell		12.82	14.85	12.11	1525.3
Improve insulation to floor R-11 & wall R-11	ESNGBT	2463.97 shell		12.99	15.05	7.11	464.92
Improve insulation to floor R-11 & wall R-11	ESNGBTC	2463.97 shell		12.99	15.05	6.71	438.93
Improve insulation to floor R-11 & wall R-11	ESNGBTR	2463.97 shell		12.99	15.05	5.37	351.5
Improve insulation to floor R-19 & ceiling R-30	ESNGBL	339.76 shell		13.41	15.53	0.9	442.19
Improve insulation to floor R-19 & ceiling R-30	ESNGBLC	339.76 shell		13.41	15.53	0.85	417.48
Improve insulation to floor R-19 & ceiling R-30	ESNGBLR	339.76 shell		13.41	15.53	0.68	334.31
Improve windows to 2-glz, Low-E, argon	ESSGBL	526.88 shell		14.22	16.47	0.08	25.5
Improve windows to 2-glz, Low-E, argon	ESSGBLC	526.88 shell		14.22	16.47	0.17	57.13
Improve windows to 2-glz, Low-E, argon	ESSGBLR	526.88 shell		14.22	16.47	0.08	27.75
Improve insulation to ceiling R-19, wall R-11 & floor R-11	ESNGFT	2850.62 shell		14.31	16.57	34.05	2121.17
Improve insulation to ceiling R-19, wall R-11 & floor R-11	ESNGFTC	2850.62 shell		14.31	16.57	32.15	2002.63
Improve insulation to ceiling R-19, wall R-11 & floor R-11	ESNGFTR	2850.62 shell		14.31	16.57	25.75	1603.7
Improve windows to double pane-wood frame	ESSGBT	212.55 shell		14.48	16.77	0.02	20.32

Improve windows to double-wood frame	ESSGBTC	212.55	shell	14.48	16.77	0.05	45.54
Improve windows to double-wood frame	ESSGBTR	212.55	shell	14.48	16.77	0.03	22.12
Improve insulation to ceiling R-27 & floor R-19, add superwindow	ESNGBT	945.39	shell	14.72	17.05	2.41	464.92
Improve insulation to ceiling R-27 & floor R-19, add superwindow	ESNGBTC	945.39	shell	14.72	17.05	2.27	438.93
Improve insulation to Ceiling R-27 & floor R-19, add Superwindows	ESNGBTR	945.39	shell	14.72	17.05	1.82	351.5
Improve to ceiling R-27 & improve to 2-glz, low-E, argon (from double)	ESSGFL	497.14	shell	14.78	17.12	2.83	1044.21
Improve ceiling insulation to R-27, 2-glz & low-E, argon (from double)	ESSGFLC	497.14	shell	14.78	17.12	6.34	2339.74
Improve to ceiling R-27 & improve to 2-glz low-E, argon (from double)	ESSGFLR	497.14	shell	14.78	17.12	3.08	1136.59
Improve window to double pane-wood frame	ESSGFT	212.55	shell	15.68	18.16	0.91	832.27
Improve window to double pane-wood frame	ESSGFTC	212.55	shell	15.68	18.16	2.04	1864.85
Improve window to double pane-wood frame	ESSGFTR	212.55	shell	15.68	18.16	0.99	905.89
Improve window to superwindow (from 2glz, low-E, argon)	ESNGFL	392.63	shell	16.31	18.89	3.91	2017.47
Improve window to superwindow (from 2glz, low-E, argon)	ESNGFLC	392.63	shell	16.31	18.89	3.7	1904.73
Improve window to superwindow (from 2glz, low-E, argon)	ESNGFLR	392.63	shell	16.31	18.89	2.96	1525.3
Improve insulation to ceiling R-27 & floor R-19	ESNGFT	446.64	shell	16.72	19.37	4.57	2121.17
Improve insulation to ceiling R-27 & floor R-19	ESNGFTC	446.64	shell	16.72	19.37	4.31	2002.63
Improve insulation to ceiling R-27 & floor R-19	ESNGFTR	446.64	shell	16.72	19.37	3.45	1603.7
Improve windows to 2-glz, low-e, argon (from double-wood)	ESSGBT	439.95	shell	16.74	19.39	0.04	20.32
Improve windows to 2-glz, low-e, argon (from double-wood)	ESSGBTC	439.95	shell	16.74	19.39	0.1	45.54
Improve windows to 2-glz, low-e, argon (from double-wood)	ESSGBTR	439.95	shell	16.74	19.39	0.05	22.12
Improve window to superwindow (from 2-glz, low-e, argon)	ESNGFT	498.75	shell	16.77	19.42	5.08	2121.17
Improve window to superwindow (from 2-glz, low-e, argon)	ESNGFTC	498.75	shell	16.77	19.42	4.8	2002.63
Improve window to Superwindow (from 2-glz, low-e, argon)	ESNGFTR	498.75	shell	16.77	19.42	3.84	1603.7
Improve window to 2-glz, low-E, argon (from double) & add wall R-11	ESSGFT	1260.08	shell	19.98	23.14	4.23	832.27
Improve window to 2-glz, low-E, argon (from Double) & add wall R-11	ESSGFTC	1260.08	shell	19.98	23.14	9.48	1864.85
Switch to 2-glz, low-E, argon (from Double), Add Wall R-11	ESSGFTR	1260.08	shell	19.98	23.14	4.61	905.89
Improve window to Superwindow (from 2-glz, low-E, argon)	ESSGFL	348.92	shell	99.83	115.63	0.29	1044.21
Improve window to superwindow (from 2-glz, low-E, argon)	ESSGFLC	348.92	shell	99.83	115.63	0.66	2339.74
Improve window to superwindow (from 2-glz, low-E, argon)	ESSGFLR	348.92	shell	99.83	115.63	0.32	1136.59
Improve to Condensing Gas Furnace; Ex. SF/North/no clg/Loose shell	ESNGFL	432.42	space con.	3.74	4.33	26.89	2305.68
Improve to condensing gas furnace; Ex. SF/North/CAC/Loose shell	ESNGFLC	432.42	space con.	3.74	4.33	25.39	2176.83
Improve to condensing gas furnace; Ex. SF/North/RAC/Loose shell	ESNGFLR	432.42	space con.	3.74	4.33	20.33	1743.2
Improve to condensing gas furnace; Ex. SF/North/no clg/Tight shell	ESNGFT	432.42	space con.	4.67	5.41	22.64	2424.19
Improve to condensing gas furnace; Ex. SF/North/CAC/Tight shell	ESNGFTC	432.42	space con.	4.67	5.41	21.38	2288.72
Improve to condensing gas furnace; Ex. SF/North/RAC/Tight shell	ESNGFTR	432.42	space con.	4.67	5.41	17.12	1832.8
Improve to condensing gas furnace; Ex. SF/South/no clg/Loose shell	ESSGFL	432.42	space con.	4.7	5.44	11.08	1193.39
Improve to condensing gas furnace; Ex. SF/South/CAC/Loose shell	ESSGFLC	432.42	space con.	4.7	5.44	24.82	2673.99
Improve to condensing gas furnace; Ex. SF/South/RAC/Loose shell	ESSGFLR	432.42	space con.	4.7	5.44	12.06	1298.96
Improve to condensing gas furnace; Ex. MF/North/no clg	EANGF	432	space con.	4.98	5.77	9.15	1046.59
Improve to condensing gas furnace; Ex. MF/North/CAC	EANGFC	432	space con.	4.98	5.77	2.73	311.94
Improve to condensing gas furnace; Ex. MF/North/RAC	EANGFR	432	space con.	4.98	5.77	9.91	1133.81
Improve to condensing gas furnace	ESSGFT	432.42	space con.	6.48	7.51	6.4	951.16
Improve to condensing gas furnace; Ex. SF/South/CAC/Tight shell	ESSGFTC	432.42	space con.	6.48	7.51	14.34	2131.25
Improve to condensing gas furnace; Ex. SF/South/RAC/Tight shell	ESSGFTR	432.42	space con.	6.48	7.51	6.97	1035.31
Improve to condensing gas furnace; Ex. MH/North/no clg	EMNGF	432	space con.	6.81	7.89	2.59	404.01
Improve to condensing gas furnace; Ex. MH/North/CAC	EMNGFC	432	space con.	6.81	7.89	1.56	243.93
Improve to condensing gas furnace; Ex. MH/North/RAC	EMNGFR	432	space con.	6.81	7.89	1.52	237.28
Improve to condensing gas furnace; Ex. MH/South/no clg	EMSGF	432	space con.	13.5	15.64	1.39	432.13
Improve to condensing gas furnace; Ex. MH/South/CAC	EMSGFC	432	space con.	13.5	15.64	1.07	331.19
Improve to condensing gas furnace; Ex. MH/South/RAC	EMSGFR	432	space con.	13.5	15.64	1.57	487.3
Improve to condensing gas furnace; Ex. MF/South/no clg	EASGF	432	space con.	15.17	17.57	1.73	601.31
Improve to condensing gas furnace; Ex. MF/South/CAC	EASGFC	432	space con.	15.17	17.57	1.89	658.49
Improve to condensing gas furnace; Ex. MF/South/RAC	EASGFR	432	space con.	15.17	17.57	1.2	417.86
Improve to a condensing gas boiler; Ex. MF/North/no clg	EANGB	1245	space con.	15.58	18.05	7.1	1035.99
Improve to a condensing gas boiler; Ex. MF/North/CAC	EANGBC	1245	space con.	15.58	18.05	2.12	308.78
Improve to a condensing gas boiler; Ex. MF/North/RAC	EANGBR	1245	space con.	15.58	18.05	7.7	1122.32
Improve to a condensing gas boiler; Ex. MH/North/no clg	EMNGB	1245	space con.	22.02	25.50	0	0
Improve to a condensing gas boiler; Ex. MH/North/CAC	EMNGBC	1245	space con.	22.02	25.50	0	0
Improve to a condensing gas boiler; Ex. MH/North/RAC	EMNGBR	1245	space con.	22.02	25.50	0	0
Improve to condensing boiler; Ex. SF/South/no clg/Loose shell	ESSGBL	1126.1	space con.	26.88	31.13	0.07	20.4
Improve to condensing boiler; Ex. SF/South/CAC/Loose shell	ESSGBLC	1126.1	space con.	26.88	31.13	0.16	45.71
Improve to condensing boiler; Ex. SF/South/RAC/Loose shell	ESSGBLR	1126.1	space con.	26.88	31.13	0.08	22.2
Improve to condensing boiler; Ex. SF/North/no clg/Tight shell	ESNGBT	1126.1	space con.	28.49	33.00	1.26	371.93
Improve to condensing boiler; Ex. SF/North/CAC/Tight shell	ESNGBTC	1126.1	space con.	28.49	33.00	1.19	351.15
Improve to condensing boiler; Ex. SF/North/RAC/Tight shell	ESNGBTR	1126.1	space con.	28.49	33.00	0.95	281.2
Improve to condensing boiler; Ex. SF/South/no clg/Tight shell	ESSGBT	1126.1	space con.	29.62	34.31	0.05	16.26
Improve to condensing boiler; Ex. SF/South/CAC/Tight shell	ESSGBTC	1126.1	space con.	29.62	34.31	0.12	36.43
Improve to condensing boiler; Ex. SF/South/RAC/Tight shell	ESSGBTR	1126.1	space con.	29.62	34.31	0.06	17.7
Improve to condensing boiler; Ex. SF/North/no clg/Loose shell	ESNGBL	1126.1	space con.	31.94	36.99	1.07	353.75
Improve to condensing boiler; Ex. SF/North/CAC/Loose shell	ESNGBLC	1126.1	space con.	31.94	36.99	1.01	333.98
Improve gas boiler to condensing boiler	ESNGBLR	1126.1	space con.	31.94	36.99	0.81	267.45
Improve to a condensing gas boiler; Ex. MH/South/no clg	EMSGB	1245	space con.	43.64	50.55	0	0
Improve to a condensing gas boiler; Ex. MH/South/CAC	EMSGBC	1245	space con.	43.64	50.55	0	0
Improve to a condensing gas boiler; Ex. MH/South/RAC	EMSGBR	1245	space con.	43.64	50.55	0	0
Improve to a condensing gas boiler; Ex. MF/South/no clg	EASGB	1245	space con.	47.43	54.94	0.16	69.29
Improve to a condensing gas boiler; Ex. MF/South/CAC	EASGBC	1245	space con.	47.43	54.94	0.17	75.88
Improve to a condensing gas boiler; Ex. MF/South/RAC	EASGBR	1245	space con.	47.43	54.94	0.11	48.15

Existing Shell savings below 6\$/MMBtu

4.10 107.71

Existing Equipment savings below 6\$/MMBtu

4.99 181.71

Increase insulation to ceiling value 30 & reduce infiltration 25%	NSNGF	300.65 shell	3.03	3.51	4.64	579.56
Improve insulation to ceiling R-30 & reduce infiltration 25%	NSNGFC	300.65 shell	3.03	3.51	39.54	4941.46
Improve insulation to ceiling R-30 & reduce infiltration 25%	NSNGFR	300.65 shell	3.03	3.51	3.42	427
Improve insulation to ceiling R-30 & reduce Infiltration by 25%	NSNGB	300.65 shell	3.11	3.60	1.05	135.19
Improve insulation to ceiling R-30 & reduce infiltration by 25%	NSNGBC	300.65 shell	3.11	3.60	0.5	63.68
Improve insulation to ceiling R-30 & reduce infiltration by 25%	NSNGBR	300.65 shell	3.11	3.60	0.81	104.48
Reduce infiltration by 36%	NSSGF	274.57 shell	3.76	4.35	0.89	151.61
Reduce infiltration by 25%	NSSGFC	274.57 shell	3.76	4.35	21.43	3641.25
Reduce infiltration by 25%	NSSGFR	274.57 shell	3.76	4.35	0.88	149.95
Reduce infiltration by 25%	NSSGB	274.57 shell	3.86	4.47	1.02	177.51
Reduce infiltration by 25%	NSSGBC	274.57 shell	3.86	4.47	8.39	1463.19
Reduce infiltration by 25%	NSSGBR	274.57 shell	3.86	4.47	1.18	204.88
Improve insulation to wall R-19	NSNGB	284.31 shell	5.03	5.83	0.62	135.19
Improve insulation to wall R-19	NSNGBC	284.31 shell	5.03	5.83	0.29	63.68
Improve insulation to wall R-19	NSNGBR	284.31 shell	5.03	5.83	0.48	104.48
Improve insulation to foundation R5.2ft	NSSGF	376.39 shell	5.7	6.60	0.81	151.61
Improve insulation to foundation R5.2ft	NSSGFC	376.39 shell	5.7	6.60	19.39	3641.25
Improve insulation to foundation R5.2ft	NSSGFR	376.39 shell	5.7	6.60	0.8	149.95
Improve insulation to wall R-19	NSNGF	284.31 shell	5.72	6.63	2.32	579.56
Improve insulation to wall R-19	NSNGFC	284.31 shell	5.72	6.63	19.79	4941.46
Improve insulation to wall R-19	NSNGFR	284.31 shell	5.72	6.63	1.71	427
Improve foundation insulation to R- 5.2 ft	NSSGB	376.39 shell	5.84	6.76	0.92	177.51
Improve foundation to R- 5.2 ft	NSSGBC	376.39 shell	5.84	6.76	7.6	1463.19
Improve foundation insulation to R-5.2 ft	NSSGBR	376.39 shell	5.84	6.76	1.06	204.88
Improve insulation to ceiling R-38 & floor R-30	NSNGB	432.93 shell	6.43	7.45	0.73	135.19
Improve insulation to ceiling R-38 & floor R-30	NSNGBC	432.93 shell	6.43	7.45	0.35	63.68
Improve insulation to ceiling R-38 & floor R-30	NSNGBR	432.93 shell	6.43	7.45	0.57	104.48
Improve insulation to floor R-30 & ceiling R-38	NSNGF	432.93 shell	7.31	8.47	2.77	579.56
Improve insulation to floor R-30 & ceiling R-38	NSNGFC	432.93 shell	7.31	8.47	23.59	4941.46
Improve insulation to floor R-30 & ceiling R-38	NSNGFR	432.93 shell	7.31	8.47	2.04	427
Improve insulation to ceiling R-49	NSNGF	108.23 shell	9.23	10.69	0.55	579.56
Improve insulation to ceiling R-49	NSNGFC	108.23 shell	9.23	10.69	4.67	4941.46
Improve insulation to ceiling R-49	NSNGFR	108.23 shell	9.23	10.69	0.4	427
Improve insulation to ceiling R-49 & add double pane-wood frame window	NSNGB	565.49 shell	9.86	11.42	0.62	135.19
Improve insulation to ceiling R-49, add double pane-wood windows	NSNGBC	565.49 shell	9.86	11.42	0.29	63.68
Improve insulation to ceiling R-49, add double pane-wood frame windows	NSNGBR	565.49 shell	9.86	11.42	0.48	104.48
Improve window to 2-glz, low-E, argon (from double-wood)	NSNGB	618.11 shell	10.55	12.22	0.64	135.19
Improve windows to 2-glz, low-E, argon (from double-wood)	NSNGBC	618.11 shell	10.55	12.22	0.3	63.68
Improve windows to 2-glz, low-E, argon (from double-wood)	NSNGBR	618.11 shell	10.55	12.22	0.49	104.48
Improve window to superwindow (from 2-glz, Low-E, argon)	NSNGB	607.08 shell	13.27	15.37	0.5	135.19
Improve windows to superwindow (from 2-glz, Low-E, argon)	NSNGBC	607.08 shell	13.27	15.37	0.23	63.68
Improve windows to superwindow (from 2-glz, Low-E, argon)	NSNGBR	607.08 shell	13.27	15.37	0.39	104.48
Improve insulation to ceiling R-30 & wall R-19	NSSGB	503.38 shell	14.67	16.99	0.49	177.51
Improve insulation to ceiling R-30 & wall R-19	NSSGBC	503.38 shell	14.67	16.99	4.05	1463.19
Improve insulation to ceiling R-30 & wall R-19	NSSGBR	503.38 shell	14.67	16.99	0.57	204.88
Improve insulation to ceiling R-30 & wall R-19	NSSGF	549.14 shell	15.6	18.07	0.43	151.61
Improve insulation to ceiling R-30 & wall R-19	NSSGFC	549.14 shell	15.6	18.07	10.33	3641.25
Improve insulation to ceiling R-30 & wall R-19	NSSGFR	549.14 shell	15.6	18.07	0.43	149.95
Improve window to 2-glz, low E, argon	NSSGF	903.9 shell	15.86	18.37	0.7	151.61
Improve windows to 2-glz, low E, argon	NSSGFC	903.9 shell	15.86	18.37	16.72	3641.25
Improve windows to 2-glz, low E, argon	NSSGFR	903.9 shell	15.86	18.37	0.69	149.95
Improve windows to 2-glz, low-E, argon	NSSGB	903.9 shell	16.27	18.84	0.79	177.51
Improve windows to 2-glz, low-E, argon	NSSGBC	903.9 shell	16.27	18.84	6.55	1463.19
Improve windows to 2-glz, low-E, argon window	NSSGBR	903.9 shell	16.27	18.84	0.92	204.88
Improve to condensing gas furnace; New SF/North/no clg	NSNGF	432.42 space con	4.65	5.39	5.44	579.56
Improve to condensing gas furnace; New SF/North/CAC	NSNGFC	432.42 space con	4.65	5.39	46.4	4941.46
Improve to condensing gas furnace; New SF/North/RAC	NSNGFR	432.42 space con	4.65	5.39	4.01	427
Improve to condensing gas furnace; New MH/North/no clg	NMNGF	432.42 space con	7.01	8.12	1.35	217.1
Improve to condensing gas furnace; New MH/North/CAC	NMNGFC	432.42 space con	7.01	8.12	2.67	428.81
Improve to condensing gas furnace; New MH/North/RAC	NMNGFR	432.42 space con	7.01	8.12	0.79	127.5
Improve to condensing gas furnace; New MF/North/no clg	NANGF	432.42 space con	8.53	9.88	0.19	37.52
Improve to condensing gas furnace; New MF/North/CAC	NANGFC	432.42 space con	8.53	9.88	6.39	1250.53
Improve to condensing gas furnace; New MF/North/RAC	NANGFR	432.42 space con	8.53	9.88	0.21	40.64

Improve to condensing gas furnace; New MH/South/no clg	NMSGF	432.42	space cost	13.52	15.66	0	0
Improve to condensing gas furnace; New MH/South/CAC	NMSGFC	432.42	space cost	13.52	15.66	0	0
Improve to condensing gas furnace; New MH/South/RAC	NMSGFR	432.42	space cost	13.52	15.66	0	0
Improve to condensing gas furnace; New SF/South/no clg	NSSGF	432.42	space cost	13.88	16.08	0.48	151.61
Improve to condensing gas furnace; New SF/South/CAC	NSSGFC	432.42	space cost	13.88	16.08	11.44	3641.25
Improve to condensing gas furnace; New SF/South/RAC	NSSGFR	432.42	space cost	13.88	16.08	0.47	149.95
Improve to condensing boiler; New MH/North/no clg	NMNGB	1250.04	space cost	22.74	26.34	0	0
Improve to condensing boiler; New MH/North/CAC	NMNGBC	1250.04	space cost	22.74	26.34	0	0
Improve to condensing boiler; New MH/North/RAC	NMNGBR	1250.04	space cost	22.74	26.34	0	0
Improve to condensing boiler; New MF/North/no clg	NANGB	1250.04	space cost	25.59	29.64	1	239.68
Improve to condensing boiler; New MF/North/CAC	NANGBC	1250.04	space cost	25.59	29.64	0	0
Improve to condensing boiler; New MF/North/RAC	NANGBR	1250.04	space cost	25.59	29.64	1.09	259.66
Improve to condensing boiler; New MH/South/no clg	NMSGB	1250.04	space cost	43.83	50.77	0	0
Improve to condensing boiler; New MH/South/CAC	NMSGBC	1250.04	space cost	43.83	50.77	0	0
Improve to condensing boiler; New MH/South/RAC	NMSGBR	1250.04	space cost	43.83	50.77	0	0
Improve to condensing gas furnace; New MF/South/no clg	NASGF	432.42	space cost	54.36	62.96	0.19	237.82
Improve to condensing gas furnace; New MF/South/CAC	NASGFC	432.42	space cost	54.36	62.96	0.56	701.62
Improve to condensing gas furnace; New MF/South/RAC	NASGFR	432.42	space cost	54.36	62.96	0.13	165.26
Improve to condensing boiler; New MF/South/no clg	NASGB	1250.04	space cost	163.07	188.87	0	0
Improve to condensing boiler; New MF/South/CAC	NASGBC	1250.04	space cost	163.07	188.87	0	0
Improve to condensing boiler; New MF/South/RAC	NASGBR	1250.04	space cost	163.07	188.87	0	0

New Shell savings below 6\$/MMBtu 3.87 83.75

New Equipment savings below 6\$/MMBtu 5.39 55.85

	1997 \$/MMBtu	
Total Shell savings below 6\$/MMBtu	4.80	191.46
Total Equipment savings below 6\$/MMBtu	5.06	237.56
	4.60	429.02

Frozen efficiency use in 2010

Existing	2631.06
New	754.52
Total	3,386.00

% savings	% Savings
Total Shell savings below 6\$/MMBtu	5.7%
Total Equipment savings below 6\$/MMBtu	7.0%
	12.7%

EXISTING	EXISTING	CCE \$/MMBtu	% savings
Total Shell savings below 6\$/MMBtu	Total Shell savings below 6\$/MMBtu	4.10	4.1%
Total Equipment savings below 6\$/MMBtu	Total Equipment savings below 6\$/MMBtu	4.99	6.9%
	NEW	4.66	11.0%
Total Shell savings below 6\$/MMBtu	Total Shell savings below 6\$/MMBtu	3.87	11.1%
Total Equipment savings below 6\$/MMBtu	Total Equipment savings below 6\$/MMBtu	5.39	7.4%
		4.48	18.5%

**Background Information Sheet: Interlab Study on U.S.
Energy Efficiency and Greenhouse Gas Emissions
Assumptions for Energy Efficiency Calculations: Commercial Sector**

Heating, Ventilation, and Air Conditioning (Space Conditioning, all fuels)

Product/end-use description	Heating, ventilation, and air-conditioning systems (also known as space conditioning) in commercial buildings are a significant energy use. Space conditioning energy use is affected by internal thermal gains from occupants and equipment, the characteristics of the ventilation system, the climate, the efficiency of the heating and cooling equipment, and the efficiency of the building shell.
Base Year Energy Use	Space conditioning accounts for an estimated 28% (4.1 quads) of commercial primary energy consumption in 1997, with 2.6 quads of electricity and the rest from oil and gas (Source: US EIA, 1996)
End-use Lifetime	The end-use lifetime for space conditioning is different for the building shell and the space conditioning equipment. Lifetime for the shell was estimated at 50 years. The weighted average lifetime for all space conditioning equipment is estimated at 18 years (Kooimey et al., 1997a).
Existing Average Energy Use Index (EUI in kBtu/sf)	In our forecast we divide energy consumption between existing and new shells and equipment. EUIs are taken from US EIA (1996).
1997 New Energy Use Index (EUI in kBtu/sf)	In our forecast we divide energy consumption between existing and new shells and equipment. EUIs are taken from US EIA (1996).
Maximum Cost-effective Efficiency Potential	We used data from Sezgen et al. (1995) and plotted the total EUI (primary energy terms) for all common combinations of commercial building systems against the capital costs of the systems. The system types are: Ducted, Unitary, Fan Coil, Heating Only, and Miscellaneous systems. We then grouped the systems of common type together, and calculated the weighted average EUI for the typical new system for each type. We then read the efficiency factors off the graph by looking at the percentage reduction from the typical system for switching to the best system of that type, and then weighted by the floor area attributable to each system type. The cost of achieving a 50% reduction in EUI for the ducted systems is \$0.54/sf (1995\$). The cost of achieving a 40% reduction in EUI for the unitary systems is \$0.54/sf (1995\$). Fan coils, heating only, and Miscellaneous systems are assumed to be able to achieve 20% savings for a cost of \$0.22/sf. Controls are assumed to save an additional 10% on all systems for an additional cost of \$0.22/sf. The weighted average energy savings factor based on these assumptions is 48%, which applies to all heating, ventilation, and air conditioning energy use.
Achievable cost-effective efficiency potential - Efficiency Case	In our efficiency case, we assume that the achievable adoption level over the analysis period is 35% of maximum cost-effective potential levels.
Achievable cost-effective efficiency potential - High Efficiency Case	In our high-efficiency case, we assume that the achievable adoption level over the analysis period is 65% of maximum cost-effective potential levels.
Incremental Capital Cost	The CCEs are directly calculated based on the EUIs from the work documented in Sezgen et al (1995). Prices were adjusted to 1995 levels based on the personal consumption price index (US DOC, 1996).
Cost of Conserved Energy	The CCE is a ratio of the incremental capital expenditure (amortized over the lifetime of the appliance) to the annual energy savings expected from the purchase of the unit. The weighted average CCE for HVAC end-uses is \$1.3/MMBtu. This cost applies to all heating, ventilation, and air conditioning energy use.

References:

Sezgen, A. Osman, Ellen M. Franconi, Jonathan G. Kooimey, Steve E. Greenberg, and Asim Afzal. 1995. *Technology data characterizing space conditioning in commercial buildings: Application to end-use forecasting with COMMEND 4.0*. Lawrence Berkeley Laboratory. LBL-37065. December.

U.S. Energy Information Administration, Office of Integrated Analysis and Forecasting, 1996. *Annual Energy Outlook 1997*. Report Number DOE/EIA-0383(97). Department of Energy: Washington, DC.

Commercial HVAC

treat all commercial HVAC together. Osman has created EUIs using primary energy (10800 Btu/kWh) and adding up all fuel use.

The reference for this is

Sezgen, A. Osman, Ellen M. Franconi, Jonathan G. Koomey, Steve E. Greenberg, and Asim Afzal. 1995. Technology data characterizing space conditioning in commercial buildings: Application to end-use forecasting with COMMEND 4.0. Lawrence Berkeley Laboratory. LBL-37065. December.

We pulled out the data on the different system types from this report, estimated EUIs by system type (converting electricity to primary energy), and plotted the data by system type. We then used the graph of capital cost versus EUI for each system type to estimate the percentage savings that can be purchased for a given cost/sf. Controls are assumed to save 10% for an additional \$0.20/sf capital cost.

	New bldgs				Weighted					
		EUI	Savings	Savings w/	Savings w/	Savings w/	Cost	Cost/sf	Total	CCE
	% of floor area	primary E		controls	controls	controls	1992 \$/sf	1995\$/sf	Cost w/	1995 \$/MMBtu
		kBtu/sf/yr			kBtu/sf/yr	kBtu/sf/yr			controls	
									1995 \$/sf	
Ducted systems	26%	148.3	50%	55%	81.57	21.21	0.5	0.54	0.75	0.87
Unitary systems	26%	52.9	40%	46%	24.32	6.32	0.5	0.54	0.75	2.92
Fan coil systems (1)	6%	40.6	20%	28%	11.36	0.64	0.2	0.22	0.43	3.58
Heating only	15%	47.5	20%	28%	13.29	1.98	0.2	0.22	0.43	3.06
Miscellaneous systems	10%	40.6	20%	28%	11.36	1.12	0.2	0.22	0.43	3.58
Unconditioned space	18%	0.0	0%	0%	0.00	0.00	0	0	0	-
	100%	79.7				37.95				1.30

(1) 2% of fan coil floor area uses district heat, and 4% uses standard packaged equipment (total = 6%)

(2) Assume miscellaneous systems have same EUI as fan coil systems.

(3) Controls assumed to save 10% for a cost of \$0.20/sf.

Savings
Costs

48 %
4.11 1995 \$/MMBtu site

discount rate 7%
Lifetime 20 years
CRF \$0.09

controls savings 10%
controls costs 0.22 1995 \$/sf

**Background Information Sheet: Interlab Study on U.S.
Energy Efficiency and Greenhouse Gas Emissions
Assumptions for Energy Efficiency Calculations: Commercial Sector**

Lighting

Product/end-use description	Lighting involves the use of electricity to pass electrons through a filament to produce light and heat (incandescent light) or to pass electrons through an inert gas which then emits light. Significant savings are possible in commercial lighting systems with the replacement of traditional incandescent lights. Additional savings can be achieved in fluorescent lighting as well. About 70% of lighting energy in commercial buildings is from fluorescent sources, 12% from HID sources, and 18% from incandescents.
Base Year Energy Use	Lighting accounts for an estimated 27% (4 quads) of commercial primary energy consumption in 1997. (Source: US EIA, 1996)
End-use Lifetime	The end-use lifetime for lighting was estimated at 12 years. There are many different lifetimes for lighting products, fluorescent fixtures and ballasts turn over on average about once every 12 years.
Existing Average Energy Use Index (EUI in kBtu/sf)	EUIs for existing buildings are about 17 kBtu/sf. EUIs are taken from US EIA (1996).
1997 New Energy Use Index (EUI in kBtu/sf)	New EUI is roughly the same as the existing UEC.
Maximum Cost-effective Efficiency Potential	The maximum cost-effective efficiency potential was estimated as the savings potential from 2010 assuming the implementation of technically cost effective lighting measures, including widespread use of halogen IR and compact fluorescent technologies. The efficiency measures are ranked based on cost of conserved energy for different building types, each with its own usage. The savings costing less than \$0.08/kWh are 25% of the 1997 baseline, based on Vorsatz and Koomey (1997).
Achievable cost-effective efficiency potential - Efficiency Case	In our efficiency case, we assume that the achievable adoption level over the analysis period is 35% of maximum cost-effective potential levels.
Achievable cost-effective efficiency potential - High Efficiency Case	In our high-efficiency case, we assume that the achievable adoption level over the analysis period is 65% of maximum cost-effective potential levels.
Incremental Capital Cost	The CCEs are directly calculated in Koomey et al. based on the incremental costs of halogen IR, fluorescent, and compact fluorescent technologies. Prices were adjusted to 1995 levels based on the personal consumption price index (US DOC, 1996).
Cost of Conserved Energy	The weighted average CCE for high efficiency lighting measures costing less than \$0.08/kWh is \$-0.037/kWh (-\$10.2/MMBtu). The CCE is a ratio of the incremental capital expenditure (amortized over the lifetime of the appliance) to the annual energy savings expected from the purchase of the unit. The negative CCE is caused by the labor savings associated with switching to longer lived halogen IR lamps and compact fluorescents.

References:

Vorsatz, Diana, and Jonathan G. Koomey. 1997. *The Potential for Efficiency Improvements in the U.S. Commercial Lighting Sector*. Lawrence Berkeley Laboratory. DRAFT LBNL-38895. in process.

U.S. Energy Information Administration, Office of Integrated Analysis and Forecasting, 1996. *Annual Energy Outlook 1997*. Report Number DOE/EIA-0383(97). Department of Energy, Washington, DC.

Lighting

Lighting Efficiency (Measure Name)	Measure Number	Enduse Code	OCE		Energy Saved (TWh)
			(cents/kWh)	(cents/kWh)	
			kWh	1995¢/kWh	
Halogen IR 55W	1	INC_GRC	-17.21	-19.93	0.15
Halogen IR 55W	1	INC_HLT	-17.21	-19.93	0.49
Halogen IR 55W	1	INC_COL	-17.18	-19.90	0.39
Halogen IR 55W	1	INC_RET	-17.18	-19.90	2.73
Halogen IR 55W	1	INC_RST	-17.18	-19.90	0.57
Halogen IR 55W	1	INC_LDQ	-17.18	-19.90	2.28
Halogen IR 55W	1	INC_LGO	-17.18	-19.90	1.28
Halogen IR 55W	1	INC_MSC	-17.12	-19.83	2.21
Halogen IR 55W	1	INC_SCH	-17.12	-19.83	0.6
Halogen IR 55W	1	INC_SMO	-17.12	-19.83	0.93
Halogen IR 55W	1	INC_WRH	-17.12	-19.83	0.64
60W HIR flood + occup. sensor	3	INCR_LDQ	-3.85	-4.46	0
60W HIR flood + occup. sensor	3	INCR_GRC	-3.85	-4.46	0
20W separable; elec. ballast	2	INC_GRC	-1.96	-2.27	0.27
20W separable; elec. ballast	2	INC_HLT	-1.96	-2.27	0.86
20W screw-in CFL	2	INC_MSC	-1.88	-2.18	3.87
20W screw-in CFL	2	INC_SCH	-1.88	-2.18	1.05
20W screw-in CFL	2	INC_SMO	-1.88	-2.18	1.64
20W screw-in CFL	2	INC_WRH	-1.88	-2.18	1.12
20W separable; elec. ballast	2	INC_COL	-1.78	-2.06	0.69
20W separable; elec. ballast	2	INC_RET	-1.78	-2.06	4.78
20W separable; elec. ballast	2	INC_RST	-1.78	-2.06	0.99
20W separable; elec. ballast	2	INC_LDQ	-1.78	-2.06	4
20W separable; elec. ballast	2	INC_LGO	-1.78	-2.06	2.24
MH + time switch	1	MH_GRC	-1.17	-1.36	0.01
60W HIR flood + nrg mgmt system	4	INCR_LDQ	-1.03	-1.19	0.01
60W HIR flood + nrg mgmt system	4	INCR_GRC	-1.03	-1.19	0.01
MH + time switch	1	MH_RET	-0.78	-0.90	0.07
MH + time switch	1	MH_RST	-0.78	-0.90	0
MH + time switch	1	MH_LGO	-0.78	-0.90	0.02
MH + time switch	1	MH_HLT	-0.78	-0.90	0.01
MH + time switch	1	MH_SCH	-0.52	-0.60	0.01
MH + time switch	1	MH_MSC	-0.52	-0.60	0.01
MH + time switch	1	MH_SMO	-0.52	-0.60	0.02
MH + time switch	1	MH_COL	-0.52	-0.60	0.01
MH + time switch	1	MH_LDQ	-0.52	-0.60	0.01
MH + time switch	1	MH_WRH	-0.52	-0.60	0.05
60W HIR flood + occup. sensor	3	INCR_LGO	0.02	0.02	0.06
60W HIR flood + occup. sensor	3	INCR_RET	0.02	0.02	0.01
60W HIR flood + occup. sensor	3	INCR_RST	0.02	0.02	0
ELEC4/4F32T/RS	1	EM4/4_HLT	0.52	0.60	0.82
ELEC4/4F32T/RS	1	EM4/4_GRC	0.52	0.60	0.15
ELEC4/4F32T/RS	1	EM4/4_RST	0.56	0.65	0.22
ELEC4/4F32T/RS	1	EM4/4_LDQ	0.56	0.65	0.59
ELEC4/4F32T/RS	1	EM4/4_COL	0.58	0.67	0.36
ELEC4/4F32T/RS	1	EM4/4_RET	0.58	0.67	1.89
ELEC4/4F32T/RS	1	EM4/4_LGO	0.58	0.67	2.15
ELEC4/4F32T/RS	1	EM4/4_SCH	0.66	0.76	0.59
ELEC4/4F32T/RS	1	EM4/4_MSC	0.66	0.76	0.85
ELEC4/4F32T/RS	1	EM4/4_SMO	0.66	0.76	1.41
ELEC4/4F32T/RS	1	EM4/4_WRH	0.66	0.76	0.35
HPS	2	MH_GRC	0.86	1.00	0
ELEC4/3F32T/RS/occupancy sensor	1	EL4/3_RST	0.94	1.09	0.01
ELEC4/3F32T/RS/occupancy sensor	1	EL4/3_LDQ	0.94	1.09	0.02
HPS	2	MH_RET	0.98	1.14	0.01
HPS	2	MH_RST	0.98	1.14	0
HPS	2	MH_LGO	0.98	1.14	0
HPS	2	MH_HLT	0.98	1.14	0
ELEC4/4F32T/RS/occupancy sensor	3	EM4/4_RST	1.05	1.22	0
ELEC4/4F32T/RS/occupancy sensor	3	EM4/4_LDQ	1.05	1.22	0.01
HPS	2	MH_SCH	1.19	1.38	0
HPS	2	MH_MSC	1.19	1.38	0
HPS	2	MH_SMO	1.19	1.38	0
HPS	2	MH_COL	1.19	1.38	0
HPS	2	MH_LDQ	1.19	1.38	0
HPS	2	MH_WRH	1.19	1.38	0.01
HPS, no delamping	1	MV_HLT	1.37	1.59	0
HPS, no delamping	1	MV_GRC	1.37	1.59	0.01
HPS, no delamping	1	MV_COL	1.46	1.69	0.06
HPS, no delamping	1	MV_LGO	1.46	1.69	0.06
HPS, no delamping	1	MV_RET	1.46	1.69	0.09
HPS, no delamping	1	MV_LDQ	1.46	1.69	0.01
HPS, no delamping	1	MV_WRH	1.46	1.69	0.06

Lighting

MH, no delamping	2 MV_HLT	1.74	2.02	0.01
MH, no delamping	2 MV_GRC	1.74	2.02	0.04
HPS, no delamping	1 MV_SCH	1.76	2.04	0.03
HPS, no delamping	1 MV_MSC	1.76	2.04	0.06
HPS, no delamping	1 MV_SMO	1.76	2.04	0.01
HPS, no delamping	1 MV_RST	1.76	2.04	0
MH, no delamping	2 MV_COL	1.82	2.11	0.29
MH, no delamping	2 MV_LGO	1.82	2.11	0.31
MH, no delamping	2 MV_RET	1.82	2.11	0.45
MH, no delamping	2 MV_LDG	1.82	2.11	0.06
MH, no delamping	2 MV_WRH	1.82	2.11	0.29
ELEC8/2P96T12/ES/occupancy sensor	3 EM8/2_GRC	1.93	2.24	0
ELEC8/2P96T12/ES/occupancy sensor	3 EM8/2_HLT	1.93	2.24	0
MH, no delamping	2 MV_SCH	2.1	2.43	0.17
MH, no delamping	2 MV_MSC	2.1	2.43	0.29
MH, no delamping	2 MV_SMO	2.1	2.43	0.03
MH, no delamping	2 MV_RST	2.1	2.43	0.01
ELEC8/2P96T12/ES/occupancy sensor	3 EM8/2_LDG	2.18	2.52	0
ELEC8/2P96T12/ES/occupancy sensor	3 EM8/2_RST	2.18	2.52	0
ELEC8/2P96T12/ES/occupancy sensor	3 EM8/2_LGO	2.18	2.52	0.08
ELEC8/2P96T12/ES/occupancy sensor	3 EM8/2_RET	2.18	2.52	0.03
ELEC8/2P96T12/ES/occupancy sensor	3 EM8/2_COL	2.18	2.52	0.02
ELEC4/3F32T8/IS/occupancy sensor	2 ELA/3_HLT	2.32	2.69	0.02
ELEC4/3F32T8/IS/occupancy sensor	2 ELA/3_GRC	2.32	2.69	0
ELEC4/3F32T8/IS/hrg mgmt system	2 ELA/3_RST	2.36	2.73	0.02
ELEC4/3F32T8/IS/hrg mgmt system	2 ELA/3_LDG	2.36	2.73	0.06
CCUT4/2F40T12/ES/RE	1 EM4/2_RST	2.43	2.81	0.14
CCUT4/2F40T12/ES/RE	1 EM4/2_LDG	2.43	2.81	0.79
ELEC4/3F32T8/IS/hrg mgmt system	3 ELA/3_HLT	2.49	2.88	0.02
ELEC4/3F32T8/IS/hrg mgmt system	3 ELA/3_GRC	2.49	2.88	0.09
CCUT4/2F40T12/ES/RE	1 EM4/2_COL	2.51	2.91	0.43
CCUT4/2F40T12/ES/RE	1 EM4/2_RET	2.51	2.91	0.96
CCUT4/2F40T12/ES/RE	1 EM4/2_LGO	2.51	2.91	0.86
ELEC4/4F32T8/IS/hrg mgmt system	5 EM4/4_RST	2.54	2.94	0.01
ELEC4/4F32T8/IS/hrg mgmt system	5 EM4/4_LDG	2.54	2.94	0.02
60 W Halogen IR flood reflector	1 INCR_LDG	2.61	3.02	0.44
60 W Halogen IR flood reflector	1 INCR_GRC	2.61	3.02	0.11
60 W Halogen IR flood reflector	1 INCR_LGO	2.65	3.07	0.75
60 W Halogen IR flood reflector	1 INCR_RET	2.65	3.07	1.66
60 W Halogen IR flood reflector	1 INCR_RST	2.65	3.07	0.17
60 W Halogen IR flood reflector	1 INCR_SMO	2.69	3.12	0.49
60 W Halogen IR flood reflector	1 INCR_WRH	2.69	3.12	0.37
60 W Halogen IR flood reflector	1 INCR_HLT	2.69	3.12	0.18
CCUT4/2F40T12/ES/RE	1 EM4/2_SCH	2.74	3.17	0.68
CCUT4/2F40T12/ES/RE	1 EM4/2_MSC	2.74	3.17	0.58
CCUT4/2F40T12/ES/RE	1 EM4/2_SMC	2.74	3.17	0.46
CCUT4/2F40T12/ES/RE	1 EM4/2_WRH	2.74	3.17	0.15
60 W Halogen IR flood reflector	1 INCR_MSC	2.8	3.24	0.2
60 W Halogen IR flood reflector	1 INCR_SCH	2.8	3.24	0.1
60 W Halogen IR flood reflector	1 INCR_COL	2.8	3.24	0.07
CCUT4/2F40T12/ES/RE + occupancy sensor	2 EM4/2_RST	3.01	3.49	0
CCUT4/2F40T12/ES/RE + occupancy sensor	2 EM4/2_LDG	3.01	3.49	0.02
ELEC4/4F32T8/RS/occupancy sensor	3 EM4/4_HLT	3.08	3.57	0.01
ELEC4/4F32T8/RS/occupancy sensor	3 EM4/4_GRC	3.08	3.57	0
ELEC4/4F32T8/RS/occupancy sensor	3 EM4/4_COL	3.44	3.98	0.08
ELEC4/4F32T8/RS/occupancy sensor	3 EM4/4_RET	3.44	3.98	0.03
ELEC4/4F32T8/RS/occupancy sensor	3 EM4/4_LGO	3.44	3.98	0.46
ELEC4/4F32T8/IS/hrg mgmt system	6 EM4/4_HLT	4.03	4.67	0.01
ELEC4/4F32T8/IS/hrg mgmt system	6 EM4/4_GRC	4.03	4.67	0.02
ELEC8/2P96T12/ES/hrg mgmt system	4 EM8/2_HLT	4.35	5.04	0
ELEC8/2P96T12/ES/hrg mgmt system	4 EM8/2_GRC	4.35	5.04	0.07
ELEC4/3F32T8/IS/occupancy sensor	2 ELA/3_COL	4.37	5.06	0.13
ELEC4/3F32T8/IS/occupancy sensor	2 ELA/3_RET	4.37	5.06	0.04
ELEC4/3F32T8/IS/occupancy sensor	2 ELA/3_LGO	4.37	5.06	0.45
60W HIR flood + hrg mgmt system	4 INCR_LGO	4.56	5.28	0.04
60W HIR flood + hrg mgmt system	4 INCR_RET	4.56	5.28	0.12
60W HIR flood + hrg mgmt system	4 INCR_RST	4.56	5.28	0
ELEC8/2P96T12/ES/occupancy sensor	3 EM8/2_SCH	4.6	5.33	0.02
ELEC8/2P96T12/ES/occupancy sensor	3 EM8/2_MSC	4.6	5.33	0.02
ELEC8/2P96T12/ES/occupancy sensor	3 EM8/2_SMC	4.6	5.33	0.07
ELEC8/2P96T12/ES/occupancy sensor	3 EM8/2_WRH	4.6	5.33	0.12
60W HIR flood + occup. sensor	3 INCR_SMO	4.84	5.61	0.04
60W HIR flood + occup. sensor	3 INCR_WRH	4.84	5.61	0.03
60W HIR flood + occup. sensor	3 INCR_HLT	4.84	5.61	0
ELEC8/2P96T12/ES/hrg mgmt system	4 EM8/2_RST	4.98	5.77	0
ELEC8/2P96T12/ES/hrg mgmt system	4 EM8/2_LGO	4.98	5.77	0.06
ELEC8/2P96T12/ES/hrg mgmt system	4 EM8/2_RET	4.98	5.77	0.44

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ELEC8/2P96T12/ES/arg mgmt system	4 EM8/2_LDg	4.98	5.77	0.01
ELEC8/2P96T12/ES/arg mgmt system	4 EM8/2_COL	4.98	5.77	0.01
60W HIR flood + time switch	2 INCR_LGO	5.22	6.05	0.01
60W HIR flood + time switch	2 INCR_RET	5.22	6.05	0.04
60W HIR flood + time switch	2 INCR_RST	5.22	6.05	0
ELEC4/4F32T/MSAime switch	3 EM4/4_SCH	5.24	6.07	0.02
ELEC4/4F32T/MSAime switch	3 EM4/4_MSC	5.24	6.07	0.01
ELEC4/4F32T/MSAime switch	3 EM4/4_SMC	5.24	6.07	0.05
ELEC4/4F32T/MSAime switch	3 EM4/4_WRH	5.24	6.07	0.02
60W HIR flood + time switch	2 INCR_SMO	5.27	6.10	0.01
60W HIR flood + time switch	2 INCR_WRH	5.27	6.10	0.01
60W HIR flood + time switch	2 INCR_HLT	5.27	6.10	0
ELEC8/2P96T12/ESAime switch	2 EM8/2_SCH	5.35	6.20	0.01
ELEC8/2P96T12/ESAime switch	2 EM8/2_MSC	5.35	6.20	0
ELEC8/2P96T12/ESAime switch	2 EM8/2_SMC	5.35	6.20	0.01
ELEC8/2P96T12/ESAime switch	2 EM8/2_WRH	5.35	6.20	0.03
ELEC4/4F32T/MSAime switch	4 EM4/4_COL	5.47	6.34	0.01
ELEC4/4F32T/MSAime switch	4 EM4/4_RET	5.47	6.34	0.11
ELEC4/4F32T/MSAime switch	4 EM4/4_LGO	5.47	6.34	0.06
ELEC4/4F32T/MS/arg mgmt system	6 EM4/4_COL	5.51	6.38	0.06
ELEC4/4F32T/MS/arg mgmt system	6 EM4/4_RET	5.51	6.38	0.35
ELEC4/4F32T/MS/arg mgmt system	6 EM4/4_LGO	5.51	6.38	0.33
ELEC8/2P96T12/ES	1 EM8/2_HLT	5.53	6.41	0.05
ELEC8/2P96T12/ES	1 EM8/2_GRC	5.53	6.41	0.2
ELEC4/4F32T/MS/occupancy sensor	4 EM4/4_SCH	5.58	6.46	0.07
ELEC4/4F32T/MS/occupancy sensor	4 EM4/4_MSC	5.58	6.46	0.04
ELEC4/4F32T/MS/occupancy sensor	4 EM4/4_SMC	5.58	6.46	0.25
ELEC4/4F32T/MS/occupancy sensor	4 EM4/4_WRH	5.58	6.46	0.07
ELEC8/2P96T12/ES	1 EM8/2_LDg	5.96	6.90	0.08
ELEC8/2P96T12/ES	1 EM8/2_RST	5.96	6.90	0.05
ELEC8/2P96T12/ES	1 EM8/2_LGO	5.96	6.90	0.19
ELEC8/2P96T12/ES	1 EM8/2_COL	5.96	6.90	0.04
ELEC8/2P96T12/ES	1 EM8/2_RET	5.96	6.90	1.16
ELEC8/2P96T12/ESAime switch	2 EM8/2_RST	6.35	7.35	0
ELEC8/2P96T12/ESAime switch	2 EM8/2_LGO	6.35	7.35	0.01
ELEC8/2P96T12/ESAime switch	2 EM8/2_RET	6.35	7.35	0.11
ELEC8/2P96T12/ESAime switch	2 EM8/2_LDg	6.35	7.35	0
ELEC8/2P96T12/ESAime switch	2 EM8/2_COL	6.35	7.35	0
ELEC8/2P96T12/ES	1 EM8/2_SCH	6.52	7.55	0.09
ELEC8/2P96T12/ES	1 EM8/2_MSC	6.52	7.55	0.23
ELEC8/2P96T12/ES	1 EM8/2_SMC	6.52	7.55	0.19
ELEC8/2P96T12/ES	1 EM8/2_WRH	6.52	7.55	0.29
ELEC4/4F32T/MS	2 EM4/4_SCH	6.74	7.81	0.15
ELEC4/4F32T/MS	2 EM4/4_MSC	6.74	7.81	0.21
ELEC4/4F32T/MS	2 EM4/4_SMC	6.74	7.81	0.35
ELEC4/4F32T/MS	2 EM4/4_WRH	6.74	7.81	0.09
ELEC4/3F32T/MSAime switch	1 ELA/3_SCH	7.01	8.12	0.02
ELEC4/3F32T/MSAime switch	1 ELA/3_MSC	7.01	8.12	0
ELEC4/3F32T/MSAime switch	1 ELA/3_SMO	7.01	8.12	0.04
ELEC4/3F32T/MSAime switch	1 ELA/3_WRH	7.01	8.12	0.03
ELEC4/4F32T/MS	2 EM4/4_COL	7.02	8.13	0.08
ELEC4/4F32T/MS	2 EM4/4_RET	7.02	8.13	0.46
ELEC4/4F32T/MS	2 EM4/4_LGO	7.02	8.13	0.45
ELEC8/2P96T12/ES/arg mgmt system	4 EM8/2_SCH	7.1	8.22	0.02
ELEC8/2P96T12/ES/arg mgmt system	4 EM8/2_MSC	7.1	8.22	0.02
ELEC8/2P96T12/ES/arg mgmt system	4 EM8/2_SMC	7.1	8.22	0.04
ELEC8/2P96T12/ES/arg mgmt system	4 EM8/2_WRH	7.1	8.22	0.11
ELEC4/4F32T/MS	2 EM4/4_RST	7.14	8.27	0.05
ELEC4/4F32T/MS	2 EM4/4_LDg	7.14	8.27	0.14
ELEC4/4F32T/MS/arg mgmt system	5 EM4/4_SCH	7.17	8.30	0.07
ELEC4/4F32T/MS/arg mgmt system	5 EM4/4_MSC	7.17	8.30	0.03
ELEC4/4F32T/MS/arg mgmt system	5 EM4/4_SMC	7.17	8.30	0.22
ELEC4/4F32T/MS/arg mgmt system	5 EM4/4_WRH	7.17	8.30	0.06
ELEC4/4F32T/MS	2 EM4/4_HLT	7.31	8.47	0.2
ELEC4/4F32T/MS	2 EM4/4_GRC	7.31	8.47	0.04
ELEC4/3F32T/MS/occup. sensor	2 ELA/3_SCH	7.31	8.47	0.07
ELEC4/3F32T/MS/occup. sensor	2 ELA/3_MSC	7.31	8.47	0.03
ELEC4/3F32T/MS/occup. sensor	2 ELA/3_SMO	7.31	8.47	0.21
ELEC4/3F32T/MS/occup. sensor	2 ELA/3_WRH	7.31	8.47	0.12
ELEC4/3F32T/MSAime switch	1 ELA/3_COL	7.35	8.51	0.02
ELEC4/3F32T/MSAime switch	1 ELA/3_RET	7.35	8.51	0.19
ELEC4/3F32T/MSAime switch	1 ELA/3_LGO	7.35	8.51	0.07
ELEC4/3F32T/MS/arg mgmt system	3 ELA/3_COL	7.39	8.56	0.1
ELEC4/3F32T/MS/arg mgmt system	3 ELA/3_RET	7.39	8.56	0.57
ELEC4/3F32T/MS/arg mgmt system	3 ELA/3_LGO	7.39	8.56	0.35
CCUT4/2F40T12/ES/RE + occupancy sensor	3 EM4/2_COL	7.44	8.62	0.13
CCUT4/2F40T12/ES/RE + occupancy sensor	3 EM4/2_RET	7.44	8.62	0.02

Lighting

OCUT4/2F40T12/ES/RE + occupancy sensor	3	EM4/2_LGO	7.44	8.62	0.26
ELEC4/4F32T8/IS/occupancy sensor	5	EM4/4_COL	7.59	8.79	0.01
ELEC4/4F32T8/IS/occupancy sensor	5	EM4/4_RET	7.59	8.79	0
ELEC4/4F32T8/IS/occupancy sensor	5	EM4/4_LGO	7.59	8.79	0.05
ELEC4/4F32T8/IS/occupancy sensor	5	EM4/4_HLT	7.64	8.85	0
ELEC4/4F32T8/IS/occupancy sensor	5	EM4/4_GRC	7.64	8.85	0
ELEC4/4F32T8/IS/occupancy sensor	4	EM4/4_RST	7.85	9.09	0
ELEC4/4F32T8/IS/occupancy sensor	4	EM4/4_LDg	7.85	9.09	0
OCUT4/2F40T12/ES/RE + arg mgmt system	3	EM4/2_RST	8.6	9.96	0.01
OCUT4/2F40T12/ES/RE + arg mgmt system	3	EM4/2_LDg	8.6	9.96	0.05
ELEC4/3F32T8/IS/arg mgmt system	3	EL4/3_SCH	9.52	11.03	0.07
ELEC4/3F32T8/IS/arg mgmt system	3	EL4/3_MSC	9.52	11.03	0.03
ELEC4/3F32T8/IS/arg mgmt system	3	EL4/3_SMO	9.52	11.03	0.14
ELEC4/3F32T8/IS/arg mgmt system	3	EL4/3_WRH	9.52	11.03	0.1
OCUT4/2F40T12/ES/RE + occupancy sensor	3	EM4/2_SCH	11.41	13.22	0.12
OCUT4/2F40T12/ES/RE + occupancy sensor	3	EM4/2_MSC	11.41	13.22	0.04
OCUT4/2F40T12/ES/RE + occupancy sensor	3	EM4/2_SMC	11.41	13.22	0.12
OCUT4/2F40T12/ES/RE + occupancy sensor	3	EM4/2_WRI	11.41	13.22	0.04
60W HIR flood + arg mgmt system	4	INCR_SMO	11.84	13.71	0.02
60W HIR flood + arg mgmt system	4	INCR_WRH	11.84	13.71	0.03
60W HIR flood + arg mgmt system	4	INCR_HLT	11.84	13.71	0
OCUT4/2F40T12/ES/RE + time switch	2	EM4/2_SCH	12.96	15.01	0.04
OCUT4/2F40T12/ES/RE + time switch	2	EM4/2_MSC	12.96	15.01	0.01
OCUT4/2F40T12/ES/RE + time switch	2	EM4/2_SMC	12.96	15.01	0.03
OCUT4/2F40T12/ES/RE + time switch	2	EM4/2_WRI	12.96	15.01	0.01
60W HIR flood + occup. sensor	3	INCR_MSC	12.99	15.05	0
60W HIR flood + occup. sensor	3	INCR_SCH	12.99	15.05	0
60W HIR flood + occup. sensor	3	INCR_COL	12.99	15.05	0
OCUT4/2F40T12/ES/RE + arg mgmt system	4	EM4/2_COL	13.7	15.87	0.1
OCUT4/2F40T12/ES/RE + arg mgmt system	4	EM4/2_RET	13.7	15.87	0.26
OCUT4/2F40T12/ES/RE + arg mgmt system	4	EM4/2_LGO	13.7	15.87	0.2
ELEC4/2FT32T8/IS+arg mgmt system	6	EM4/2_RST	13.77	15.95	0
ELEC4/2FT32T8/IS+arg mgmt system	6	EM4/2_LDg	13.77	15.95	0.01
OCUT4/2F40T12/ES/RE + time switch	2	EM4/2_COL	14.3	16.56	0.02
OCUT4/2F40T12/ES/RE + time switch	2	EM4/2_RET	14.3	16.56	0.09
OCUT4/2F40T12/ES/RE + time switch	2	EM4/2_LGO	14.3	16.56	0.04
ELEC4/2FT32T8/IS+time switch	6	EM4/2_COL	14.36	16.63	0.01
ELEC4/2FT32T8/IS+time switch	6	EM4/2_RET	14.36	16.63	0.02
ELEC4/2FT32T8/IS+time switch	6	EM4/2_LGO	14.36	16.63	0.01
ELEC4/2FT32T8/IS+arg mgmt system	8	EM4/2_COL	14.6	16.91	0.02
ELEC4/2FT32T8/IS+arg mgmt system	8	EM4/2_RET	14.6	16.91	0.05
ELEC4/2FT32T8/IS+arg mgmt system	8	EM4/2_LGO	14.6	16.91	0.04
60W HIR flood + time switch	2	INCR_MSC	14.85	17.20	0
60W HIR flood + time switch	2	INCR_SCH	14.85	17.20	0
60W HIR flood + time switch	2	INCR_COL	14.85	17.20	0
60W HIR flood + arg mgmt system	4	INCR_MSC	15.57	18.03	0
60W HIR flood + arg mgmt system	4	INCR_SCH	15.57	18.03	0
60W HIR flood + arg mgmt system	4	INCR_COL	15.57	18.03	0
OCUT4/2F40T12/ES/RE + occupancy sensor	3	EM4/2_HLT	16.27	18.84	0.01
OCUT4/2F40T12/ES/RE + occupancy sensor	3	EM4/2_GRC	16.27	18.84	0
OCUT4/2F40T12/ES/RE + arg mgmt system	4	EM4/2_SCH	16.31	18.89	0.12
OCUT4/2F40T12/ES/RE + arg mgmt system	4	EM4/2_MSC	16.31	18.89	0.03
OCUT4/2F40T12/ES/RE + arg mgmt system	4	EM4/2_SMC	16.31	18.89	0.08
OCUT4/2F40T12/ES/RE + arg mgmt system	4	EM4/2_WRI	16.31	18.89	0.04
separable CFL + occupancy sensor	4	INC_COL	16.75	19.40	0.02
separable CFL + occupancy sensor	4	INC_RET	16.75	19.40	0.01
separable CFL + occupancy sensor	4	INC_RST	16.75	19.40	0
separable CFL + occupancy sensor	4	INC_LDg	16.75	19.40	0.01
separable CFL + occupancy sensor	4	INC_LGO	16.75	19.40	0.07
ELEC4/2FT32T8/IS+time switch	6	EM4/2_SCH	16.79	19.45	0.01
ELEC4/2FT32T8/IS+time switch	6	EM4/2_MSC	16.79	19.45	0
ELEC4/2FT32T8/IS+time switch	6	EM4/2_SMC	16.79	19.45	0.01
ELEC4/2FT32T8/IS+time switch	6	EM4/2_WRI	16.79	19.45	0
separable CFL + occupancy sensor	4	INC_GRC	16.9	19.57	0
separable CFL + occupancy sensor	4	INC_HLT	16.9	19.57	0
ELEC4/2FT32T8/IS+arg mgmt system	8	EM4/2_SCH	17.02	19.71	0.02
ELEC4/2FT32T8/IS+arg mgmt system	8	EM4/2_MSC	17.02	19.71	0.01
ELEC4/2FT32T8/IS+arg mgmt system	8	EM4/2_SMC	17.02	19.71	0.02
ELEC4/2FT32T8/IS+arg mgmt system	8	EM4/2_WRI	17.02	19.71	0.01
OCUT4/2F40T12/ES/RE	1	EM4/2_HLT	17.62	20.41	0.63
OCUT4/2F40T12/ES/RE	1	EM4/2_GRC	17.62	20.41	0.11
ELEC4/2F32T8/IS	4	EM4/2_RST	22.81	26.42	0.04
ELEC4/2F32T8/IS	4	EM4/2_LDg	22.81	26.42	0.21
ELEC4/2F32T8/IS	5	EM4/2_COL	23.06	26.71	0.07
ELEC4/2F32T8/IS	5	EM4/2_RET	23.06	26.71	0.18
ELEC4/2F32T8/IS	5	EM4/2_LGO	23.06	26.71	0.15
ELEC4/2F32T8/IS	5	EM4/2_SCH	23.76	27.52	0.14

Lighting

ELEC4/2F32T8/IS	5 EM4/2_MSC	23.76	27.52	0.15
ELEC4/2F32T8/IS	5 EM4/2_SMC	23.76	27.52	0.09
ELEC4/2F32T8/IS	5 EM4/2_WRH	23.76	27.52	0.02
ELEC4/2FT32T8/IS+occup. sensor	5 EM4/2_RST	24.97	28.92	0
ELEC4/2FT32T8/IS+occup. sensor	5 EM4/2_LD	24.97	28.92	0
ELEC4/2FT32T8/IS+occup. sensor	7 EM4/2_COL	24.98	28.93	0.01
ELEC4/2FT32T8/IS+occup. sensor	7 EM4/2_RET	24.98	28.93	0
ELEC4/2FT32T8/IS+occup. sensor	7 EM4/2_LGO	24.98	28.93	0.02
separable CFL + arg mgmt system	5 INC_GRC	25.81	29.89	0.01
separable CFL + arg mgmt system	5 INC_HLT	25.81	29.89	0
ELEC4/2FT32T8/IS+occup. sensor	7 EM4/2_SCH	26.29	30.45	0.01
ELEC4/2FT32T8/IS+occup. sensor	7 EM4/2_MSC	26.29	30.45	0
ELEC4/2FT32T8/IS+occup. sensor	7 EM4/2_SMC	26.29	30.45	0.01
ELEC4/2FT32T8/IS+occup. sensor	7 EM4/2_WRH	26.29	30.45	0.01
OCUT4/2F40T12/ES/RE + arg mgmt system	4 EM4/2_HLT	26.8	31.04	0.01
OCUT4/2F40T12/ES/RE + arg mgmt system	4 EM4/2_GRC	26.8	31.04	0.03
separable CFL + arg mgmt system	5 INC_COL	28.65	33.18	0.02
separable CFL + arg mgmt system	5 INC_RET	28.65	33.18	0.13
separable CFL + arg mgmt system	5 INC_RST	28.65	33.18	0.01
separable CFL + arg mgmt system	5 INC_LD	28.65	33.18	0.02
separable CFL + arg mgmt system	5 INC_LGO	28.65	33.18	0.05
20W screw-in CFL + time switch	3 INC_MSC	31.7	36.72	0
20W screw-in CFL + time switch	3 INC_SCH	31.7	36.72	0.01
20W screw-in CFL + time switch	3 INC_SMO	31.7	36.72	0.01
20W screw-in CFL + time switch	3 INC_WRH	31.7	36.72	0.01
20W screw-in CFL + occup sensor	4 INC_MSC	34.06	39.45	0.03
20W screw-in CFL + occup sensor	4 INC_SCH	34.06	39.45	0.02
20W screw-in CFL + occup sensor	4 INC_SMO	34.06	39.45	0.04
20W screw-in CFL + occup sensor	4 INC_WRH	34.06	39.45	0.03
20W screw-in CFL + arg mgmt system	5 INC_MSC	42.24	48.92	0.02
20W screw-in CFL + arg mgmt system	5 INC_SCH	42.24	48.92	0.02
20W screw-in CFL + arg mgmt system	5 INC_SMO	42.24	48.92	0.03
20W screw-in CFL + arg mgmt system	5 INC_WRH	42.24	48.92	0.03
separable CFL + time switch	3 INC_COL	42.38	49.09	0
separable CFL + time switch	3 INC_RET	42.38	49.09	0.03
separable CFL + time switch	3 INC_RST	42.38	49.09	0
separable CFL + time switch	3 INC_LD	42.38	49.09	0.01
separable CFL + time switch	3 INC_LGO	42.38	49.09	0.01
ELEC8/2P96T12/ES/Time switch	2 EM8/2_GRC	45.62	52.84	0
ELEC8/2P96T12/ES/Time switch	2 EM8/2_HLT	45.62	52.84	0
ELEC4/4F32T8/IS/Time switch	4 EM4/4_HLT	49.85	57.74	0
ELEC4/4F32T8/IS/Time switch	4 EM4/4_GRC	49.85	57.74	0
ELEC4/3F32T8/IS/Time switch	1 EL4/3_HLT	64.41	74.60	0
ELEC4/3F32T8/IS/Time switch	1 EL4/3_GRC	64.41	74.60	0
60W HID flood + time switch	2 INCR_LD	74.85	86.69	0
60W HID flood + time switch	2 INCR_GRC	74.85	86.69	0
ELEC4/2F32T8/IS	2 EM4/2_HLT	84.1	97.41	0.18
ELEC4/2F32T8/IS	2 EM4/2_GRC	84.1	97.41	0.02
separable CFL + time switch	3 INC_GRC	228.06	264.15	0
separable CFL + time switch	3 INC_HLT	228.06	264.15	0

Savings costing less than 8 cents/kWh

-3.47 61.59

Business as usual electricity use

243.21

OCE \$/MMBtu

-18.16

% savings rel. to 1997

28.3%

**Background Information Sheet: Interlab Study on U.S.
Energy Efficiency and Greenhouse Gas Emissions
Assumptions for Energy Efficiency Calculations: Commercial Sector**

Refrigeration

Product/end-use description	Commercial refrigeration involves cooling large volumes to a variety of different temperatures.
Base Year Energy Use	Refrigeration accounts for an estimated 3% (0.5quads) of commercial primary energy consumption in 1997. (Source: US EIA, 1996)
End-use Lifetime	The end-use lifetime for refrigeration was estimated at 15 years.
Existing Average Energy Use Index (EUI in kBtu/sf)	EUIs for existing buildings are 2.0 kBtu/sf. EUIs are taken from US EIA (1996).
1997 New Energy Use Index (EUI in kBtu/sf)	EUIs for new buildings are 2.0 kBtu/sf. EUIs are taken from US EIA (1996).
Maximum Cost-effective Efficiency Potential	The maximum cost-effective efficiency potential was estimated as the savings potential from 2010 assuming the implementation of all measures with a simple payback time of 5 years or less. The cost effective savings are 31% of the 1997 baseline, based on Westphalen et al. (1996).
Achievable cost-effective efficiency potential - Efficiency Case	In our efficiency case, we assume that the achievable adoption level over the analysis period is 35% of maximum cost-effective potential levels.
Achievable cost-effective efficiency potential - High Efficiency Case	In our high-efficiency case, we assume that the achievable adoption level over the analysis period is 65% of maximum cost-effective potential levels.
Incremental Capital Cost	The incremental costs for efficient refrigeration equipment vary widely. All were taken from Westphalen et al. (1996). Prices were adjusted to 1995 levels based on the personal consumption price index (US DOC, 1996).
Cost of Conserved Energy	The weighted average CCE for high efficiency lighting measures with less than a five year payback is \$0.016/kWh (\$4.66/MMBtu). The CCE is a ratio of the incremental capital expenditure (amortized over the lifetime of the appliance) to the annual energy savings expected from the purchase of the unit.

References:

- Sezgen, A. Osman, and Jonathan G. Koomey. 1995. *Technology data characterizing refrigeration in commercial buildings: Application to end-use forecasting with COMMEND 4.0*. Lawrence Berkeley Laboratory. LBL-37397. December.
- Westphalen, Detlef, Robert A. Zogg, Anthony F. Varone, and Matthew A. Foran. 1996. *Energy Savings Potential for Commercial Refrigeration Equipment*. Prepared by Arthur D. Little, Inc. for the Building Equipment Division, Office of Building Technologies, US Department of Energy. ADL Reference No. 46230. June.
- U.S. Department of Commerce, 1996. *Statistical Abstract of the US*. Economics and Statistics Administration, Bureau of the Census, Washington, DC.
- U.S. Energy Information Administration, Office of Integrated Analysis and Forecasting, 1996. *Annual Energy Outlook 1997*. Report Number DOE/EIA-0383(97). Department of Energy, Washington, DC.

Commercial Refrigeration Efficiency Calculations

Westphalen, Detlef, Robert A. Zogg, Anthony F. Varone, and Matthew A. Foran. 1996. Energy Savings Potential for Commercial Refrigeration Equipment. Prepared by Arthur D. Little, Inc. for the Building Equipment Division, Office of Building Technologies, US Department of Energy. ADL Reference No. 46230. June.

	Equipment inventory (1000s)	Total 1996 Primary E TBTu	Total 1996 Electricity TWh	Usage per unit kWh/unit	% savings < 5 year SPT	cost premium per unit	ASSUME 1995 \$ (COULDN'T FIND IT IN THE REPORT)				
							Savings 1996 Electricity TWh	Savings per unit	CCE 1995\$/kWh	CCE 1995\$/kWh	CCE \$/MMBTu site
Ice makers	1200	102	9.4	7822	18%	146	1.7	1408	0.010	0.010	2.87
Supermarkets	30	326	30.0	999969	20%	36650	6.1	201744	0.017	0.017	5.03
Centralized systems (exc. supermarkets): Walk-ins	880	180	16.6	18823	30%	1000	5.0	5647	0.017	0.017	4.90
Centralized systems (exc. supermarkets): Small grocery	20	26	2.4	119628	30%	1000	0.7	35888	0.003	0.003	0.77
Vending machines	4100	134	12.3	3008	42%	290	5.2	1263	0.022	0.022	6.35
Self contained: Reach-in refrigerators	1300	54	5.0	3822	45%	313	2.2	1720	0.017	0.017	5.03
Self contained: Reach-In freezers	800	65	6.0	7477	44%	382	2.6	3290	0.011	0.011	3.21
Self contained: Beverage merchandisers	800	52	4.8	5981	55%	376	2.6	3290	0.011	0.011	3.16
Self contained: Other	1150	54	5.0	4321	45%	313	2.2	1944	0.015	0.015	4.45
Total		993.0	91.4		31%		28.3		0.016	0.016	4.62

ADL primary E conversion factor

10,867 Btu/kWh
3.185

THIS CONVERSION FACTOR IS ONLY USED TO CONVERT ADL TBUS TO KWH.

Discount rate

7%

Lifetime

20.00 years

CRF

\$0.09

- (1) These systems consist of supermarket-style display cases with single remotely located condensing units (compressor configuration is not parallel as in supermarkets).
 (2) Other consists of roll-ins, under-counter, over-counter, non-beverage merchandisers.
 (3) % svgs and cost premium per unit for centralized systems taken from "combination of technologies" option for walk in refrigerators and freezers (small grocery cent. system svgs and costs assumed to be the same as for Walk-ins)
 (4) Other savings and costs assumed to be the same as reach-in refrigerators.

Supermarkets
 % machine room E 5%
 % display case E 95%

**Background Information Sheet: Interlab Study on U.S.
Energy Efficiency and Greenhouse Gas Emissions
Assumptions for Energy Efficiency Calculations: Commercial Sector**

Miscellaneous electricity, natural gas, and oil

Product/end-use description	Miscellaneous energy use in the commercial sector covers a wide variety of end-uses including office equipment, telecommunications equipment, pumps, cooking, and other uses (US EIA, 1996).
Base Year Energy Use	Miscellaneous energy accounts for an estimated 24% (3.5 quads) of commercial primary energy consumption in 1997. (Source: US EIA, 1996)
End-use Lifetime	The end-use lifetime for miscellaneous varies depending on the particular end-use.
Existing Average Energy Use Index (EUI in kBtu/sf)	EUIs for existing buildings are 10.5 kBtu/sf. EUIs are taken from US EIA (1996).
1997 New Energy Use Index (EUI in kBtu/sf)	No EUI's for miscellaneous energy for new buildings are available.
Maximum Cost-effective Efficiency Potential	Little information was available to construct a detailed cost-effective potential analysis for this end-use. We therefore assumed that miscellaneous electricity, natural gas, and oil end uses are assumed to have the same efficiency potentials and costs as in the residential sector.
Achievable cost-effective efficiency potential - Efficiency Case	In our efficiency case, we assume that the achievable adoption level over the analysis period is 35% of maximum cost-effective potential levels.
Achievable cost-effective efficiency potential - High Efficiency Case	In our high-efficiency case, we assume that the achievable adoption level over the analysis period is 65% of maximum cost-effective potential levels.
Incremental Capital Cost	Inadequate information was available to construct incremental costs for efficiency improvements in the commercial misc. energy.
Cost of Conserved Energy	We have estimated an average cost of conserved energy of \$0.03/KWh (\$1990) or \$0.035/KWh (\$1995) for miscellaneous electricity, and \$6.00/MMBtu (\$1997) for gas/oil measures. These are CCE values which are consistent with those derived from the analysis of miscellaneous energy uses in the residential sector. The CCE is a ratio of the incremental capital expenditure (amortized over the lifetime of the appliance) to the annual energy savings expected from the purchase of the unit.

References:

U.S. Department of Commerce, 1996. *Statistical Abstract of the US*. Economics and Statistics Administration, Bureau of the Census, Washington, DC.

U.S. Energy Information Administration, Office of Integrated Analysis and Forecasting, 1996. *Annual Energy Outlook 1997*. Report Number DOE/EIA-0383(97). Department of Energy, Washington, DC.

Interlab Study on U.S. Energy Efficiency and Greenhouse Gas Emissions

Appendix C-4

**Memoranda re:
Calculations for Energy Saving Potential for
Miscellaneous Energy Use,
Impact from Electricity to Gas Fuel
Switching, and Savings from High Albedo
Roofs**

**Residential and Commercial
Sectors**

MEMORANDUM

March 27, 1997

TO: Mark Levine
FROM: Jon Koomey and Nathan Martin
RE: Energy Efficiency Savings Potential for Miscellaneous Energy Use in Buildings

This memo summarizes our calculations of the potential for energy savings for miscellaneous energy end-use in buildings. (Miscellaneous end-uses include electricity required to operate electronics, motors in pumps and ventilation systems, and gas or oil required for assorted miscellaneous heating end-uses.) Based on our current calculations we have estimated that the maximum cost effective potential for miscellaneous energy savings in both residential and commercial buildings in 2010 is 33% for miscellaneous electricity and 10% for miscellaneous gas and oil end-uses. For our scenario calculations we used an average cost of conserved energy of \$3/MMBtu for miscellaneous energy.

Description of calculation

We first developed an estimate of miscellaneous energy savings in the residential sector and then applied similar savings estimates to miscellaneous energy savings potential in the commercial sector. Our savings calculations for the residential sector involved 1) characterizing residential energy use, 2) collecting and analyzing existing literature on energy savings in specific miscellaneous energy end-uses, and 3) extrapolating these potentials to all end-uses based on best judgment.

The characterization of miscellaneous energy use in the residential sector was based on Sanchez (1997) where we estimated 1997 miscellaneous electricity use by main category (electronics, motors, heating) and applied these shares to 1997 energy use given in (US DOE, 1996). We then determined energy savings for the main miscellaneous electricity end-uses based on judgment and existing literature as shown in the detailed spreadsheet accompanying this memo. (Documented information on potential energy savings was available for televisions, video cassette recorders, and waterbed heaters, where we found all three of the CCEs in these cases to be below \$0.03/KWh (\$1995)). Savings estimates for non-electricity miscellaneous end-uses were based on judgment. Table 1 below shows the summary results of our calculations.

Table 1: 1997 Miscellaneous Energy Use and Estimated Energy Efficiency Potentials

End-use Category	Primary Energy Use (Quads)	Share of Primary Energy Use (Percent)	Estimated Energy Efficiency Potential (Percent)
electronics	1.6	29%	25%
motors	1.6	29%	53%
heating	1.2	22%	33%
Total electricity	4.4	80%	33%
natural gas	0.9	17%	10%
oil & other petroleum products	0.1	2%	10%
Total Miscellaneous	5.4	100%	29%

While we feel that these estimates are both credible and conservative, the paucity of existing research literature on miscellaneous energy savings suggests that significantly more effort would be required to develop more detailed and robust estimates of energy savings for specific end uses, and that this is a subject clearly worthy of continued investigation.

MEMORANDUM

March 27, 1997

TO: Mark Levine
FROM: Jon Koomey
RE: Calculation of Impact from Electricity to Gas Fuel Switching in Residential Buildings

I am writing this memo to report to you our findings concerning our calculations of impact from switching from electricity-based to gas-based water heating, cooking, and drying in residential homes that currently have gas space conditioning and electric appliances for these end-uses. Based on our current calculations we have estimated that in the business as usual scenario fuel switching energy savings is 0.11 quads. The additional capital cost for these measures was estimated to be \$27 billion in 2010 or \$2.7 billion on an annualized basis.

Description of calculation

The calculation of energy savings and cost potential involved several steps: 1) characterization of the U.S. residential building stock to estimate what percentage of homes that currently have gas space conditioning would replace their electric water-heating, cooking, and drying appliances within or before 2010, 2) estimation of the unit incremental cost and energy savings for switching from electric water heating, cooking, and drying to gas systems for these end-uses, 3) calculation of the electricity savings, increased gas use, and increased cost to the appropriate segments of the residential building stock in our spreadsheet calculation model, 4) calculation of total increase in capital expenditures nationally for undertaking this fuel switching measure.

Background analysis undertaken for estimated that by 2010 between 5 and 36% of residential buildings would be candidates for replacing their electric water heating, cooking, and drying appliances with gas appliances in 2010. These percentages reflect those buildings that have gas space-conditioning systems and are expected to need to purchase a replacement appliance during the forecast period and were derived from background analysis for (Koomey et al, 1997) combined with end-use stock accounting calculations undertaken for this study. For each end-use, the displacement of electricity by the gas end-use results in unit energy savings between 29% and 59% (table 1). The incremental costs for the fuel switching includes any increase in the cost of the gas appliance in addition to the additional labor and materials charges for installing the gas system and are further detailed in the attached spreadsheet.

To estimate the electricity savings we calculated the business as usual electricity demand for electric water-heating, cooking, and drying appliances but excluded the fraction of housing stock that would be switching to gas appliances. After accounting for the increase in gas we were then able to calculate the net energy savings from this option for each end use (table 1). The additional national cost for the fuel switching was the product of the incremental capital cost per unit of electricity savings for each end use and the total electricity savings. Similar calculations of energy savings and cost were undertaken for the 100% implementation of maximum cost-effective efficiency technology scenario, thereby enabling the use of a business as usual and efficiency scenario that includes fuel switching.

Table 1: Summary of Fuel Switching Calculations

End-use Category	Fraction of 2010 housing stock (Percent)	Unit energy savings from Fuel Switch (MMBtu)	Unit Energy Savings from Fuel Switch (Percent)	Incremental unit cost (\$1995)	U.S. Energy Savings in 2010 BAU Case (Quads)	U.S. incremental cost BAU Case (\$Billion 1995)
Water heating	5%	12.4	29%	\$1,266	0.02	\$1.7
Cooking	22%	1.9	33%	\$1,391	0.01	\$13.0
Clothes Drying	36%	4.7	59%	\$690	0.08	\$12.3

MEMORANDUM

April 1, 1997

TO: Mark Levine
FROM: Jon Koomey and Sarah Bretz
RE: Calculation of Savings from high albedo roofs in buildings

This memo summarizes our calculations of impacts from high albedo roofs.

Description of calculation

We relied on calculations conducted by Steve Konopacki and conversations that Sarah Bretz had with Hashem Akbari and Konopacki (Bretz 1997). We summarized the Heat Island Group's latest DOE-2 analyses and boiled them down to two parameters in residential and commercial buildings: 1) the percentage change in total electrical cooling use associated with high albedo roofing, averaged across northern and southern regions, and 2) the number of kBtu that gas heating use goes up per kBtu of site electricity saved in cooling. We initially calculated the percentage savings figures separately for north and south regions, but we found that the percentage savings were not very different across the regions. Therefore, we chose the round numbers of 7% savings for residential, and 5% savings for commercial, which were close to the results for both regions. We did calculate a weighted average for the increase in gas use per kBtu of savings across the regions, using the distribution of cooling energy use from Koomey et al (1997) for residential and from US DOE (1994) for commercial.

To estimate the electricity savings from high albedo roofs in 2010, we calculated the business-as-usual electricity demand associated with cooling appliances that are expected to be replaced during the analysis period, and applied the percentages shown in Table 1 to that demand. For simplicity, we assumed that roofs are replaced at the same rate as cooling equipment in each sector (this assumption implies average roof lifetimes of 13 years for residential and 18 years for commercial). The electricity savings were then multiplied by the kBtu of gas demand increase associated with each kBtu of electricity demand reduced, and this gas use was then added to the gas heating category. The capital cost is assumed to be zero, because the incremental costs for these materials is negligible.

Table 1: Summary of high albedo roofing calculations

End-use Category	Cooling energy use savings (Percent)	kBtu gas use increase per kBtu cooling elect. saved (site)	Incremental unit costs (\$1995)
<i>Residential</i>	7%	1.1	\$0
North	7%	3.7	\$0
South	7%	0.5	\$0
<i>Commercial</i>	5%	0.8	\$0
North	5%	1.5	\$0
South	5%	0.3	\$0

References

Koomey, Jonathan G., Diana Vorsatz, Richard E. Brown, Celina S. Atkinson, and Marla C. Sanchez. 1997. *Updated Potential for Electricity Efficiency Improvements in the U.S. Residential Sector*. Lawrence Berkeley Laboratory. DRAFT LBNL-38894. in process.

US DOE, U.S. Department of Energy. 1994. *Energy End-Use Intensities in Commercial Buildings*. Energy Information Administration. DOE/EIA-0555(94)/2. September.

APPENDIX D

APPENDIX D-1: Details of the NEMS and LIEF Models

This appendix describes the procedure used to create the LIEF and NEMS model scenarios presented in the industrial chapter. The LIEF model runs on a PC platform and is available, with the input files for each scenario, upon request. The NEMS industrial model run use a standalone version of the workstation model used by EIA. The version used for this study is the same as that used for the AEO97, compiled for a SUN workstation instead of a IBM RISC workstation. The full output (and input) files from the NEMS runs are also available on request.

Three basic steps were used to perform the scenario analysis with LIEF; calibration to AEO and modification of the input files to represent the efficiency and high efficiency/low carbon case. In addition the NEMS industrial model was run in a standalone mode and compared to the LIEF model scenarios.

Calibration of the LIEF model to the AEO97 industrial forecast.

The LIEF model was run using all of the macroeconomic growth rates and energy prices from the 1997 AEO. Growth rates for the value of shipments were taken from supplemental *Table 23. Industrial Sector Macroeconomic Indicators*. Industrial delivered energy prices were taken from table A3. Since LIEF requires an aggregate weighted fossil fuel price, the AEO fuel consumption in Industry (Table A2) for each fossil fuel was use to construct the weighted average fossil fuel price. Based on these inputs the LIEF model was run. A technology penetration rate of 3% was found to provide the same overall decline in energy intensity in LIEF as for the AEO forecast.

Efficiency case

In the efficiency case the capital recovery rate in the LIEF model, which is set at a default of 33%, was changed to 15% for each industry sector. Since the LIEF model runs in five year time steps the change was made effective in the time step 2000-2005. The growth rates of energy intensity between this run and the calibrated LIEF BAU were calculated for the period 1995-2010 for each industry and for each energy type, fossil and electric.

High Efficiency / Low Carbon case

In the High Efficiency / Low Carbon case the penetration rate in the LIEF model, which was set at 3% for purposes of calibration to AEO was changed to 6% for each industry sector. Since the LIEF model runs in five year time steps the change was made effective in the time step 1995-2000. This timing differs slightly from the efficiency case. Since the falling prices imply that the idealized energy intensity does not differ greatly from the average energy intensity, increasing penetration rates in the earlier time step has very little effect. Most of the effect comes in the period 2000-2005, when the CRF is lower. The growth rates of energy intensity between this run and the calibrated LIEF BAU were calculated for the period 1995-2010 for each industry and for each energy type, fossil and electric.

Presentation of results

The average annual growth rates based on the three 5-year time steps, 1995-2010, were assumed to apply for the 13-year period 1998-2010. The cumulative effect of the lower energy intensity, for each industry and energy form, was computed by compounding the computed

annual growth rates. The cumulative energy savings in 2010, in percentage terms, was used to calculate energy and carbon savings from the AEO industrial baseline energy consumption (table A6) and carbon emissions (table A19).

NEMS model runs

Several standalone NEMS industrial model were performed to compare to the LIEF model scenarios. The two that were presented reflect a doubling of the NEMS industrial model retirement rate and a doubling of the slope of the TPC, representing an acceleration of the technology improvement in the process industries. Both of these changes were achieved by means of the NEMS model input file (available on request). Since these runs only effect the NEMS process industry sectors it was necessary to compare those sector specific results to the corresponding LIEF sectors. The reduction in total energy use in the sectors for which both models had similar levels of (dis)aggregation was computed and compared on a percentage basis.

APPENDIX D-2 EXAMPLES OF ENERGY SAVING TECHNOLOGIES FOR THE FUTURE

D-2.1 TECHNOLOGY EXAMPLES FOR PULP AND PAPER

The Forest Products Industry, as the association is now known, consists of wood products manufacturing and paper manufacturing, and in 1994 consumed more than 3 Quads of energy (14.6% of all manufacturing energy consumption). Paper manufacturing was also one of the most energy intensive industries in the United States in 1994, using more than 18,500 Btu per dollar value of shipments. The manufacturing of paper requires that a fiber source, normally wood, be chipped, digested, bleached, and then formed as a slurry to make paper or board. Once formed as paper, the product must be dried. Large amounts of steam and power are used to debark and chip the wood, digest the wood, bleach the pulp and dry the paper products. Much of this energy source (over 51%) comes from the reprocessing of lignins from the wood, bark and unusable portions of the tree. In lumber and wood products, the fraction of biomass energy sources is even higher – nearly 70%.

D-2.1.1 Technology Examples Available before 2010

In paper manufacturing especially, any technology that will economize on the use of steam, reduce the need for heat, better utilize the biomass fuel sources available, or help to balance both steam and power needs will improve the performance of the industry. The technologies that hold promise to reduce energy and carbon emissions in the near term continue to economize on the use of heat. Longer term options alter the balance between steam and power. The most promising near term options are:

Impulse Drying

In the papermaking process, a dilute slurry of <1% pulp fibers and 99% water are laid down on a moving wire. Removing the 99% water is a very energy intensive process which includes draining, pressing, and finally evaporative drying. Impulse drying reduces the huge energy requirements of evaporative drying by removing more water in the pressing section and reducing the amount of water which must be evaporated from about 1.5 lb. per lb. of paper to about 0.5 lb. per lb. of paper.

The technology uses pressure and heat to superheat water in the sheet and increase the normal hydraulic forces for expelling water from the sheet. The energy saved in the evaporating section more than offsets the extra heat required to superheat the sheet. The total energy savings for full implementation of this technology could be approx. 0.25 quad/yr. The net energy savings have been estimated to be about 12 trillion Btu annually from a market penetration of only 60 drying units by 2020.

Multiport Cylinder Drying

The evaporative drying in a paper mill is accomplished by winding the continuous sheet of paper serpentine over a series of rollers. The rollers are pressurized with steam inside which condenses on the inside of the roller. The accumulating condensate must then be removed from the drum or it builds up and interferes with the heat transfer from the steam to the roller to the paper. Current technology implements a "shoe" in the bottom of the hollow roller to pick up the condensate from the roller and convey it out of the drum. As the shoes wear they become

less effective at removing condensate and a thicker film of condensate is left in the drum. The multiport cylinder drying concept utilizes a different method to remove the condensate from the drier. This has been shown to reduce the condensate film thickness inside the drier to 25-30% of conventional technology which improves heat transfer and increases drying.

On-Machine Sensors for Paper Properties

While many people think of paper in terms of three grades, brown, white, and tissue, papermaking involves literally hundreds of grades. Each grade is designed and manufactured to optimize its performance in the customers application. To achieve its various performance characteristics the paper grades differ in thickness, strength, moisture content, stiffness, porosity, smoothness, and many other parameters. The individual parameter are controlled through multiple process controls which are intended to be constant but, in fact, are not. Current technology for some properties relies on spot samples individually tested in a paper testing laboratory to determine whether the operation was on grade at the time the sample was tested. Significant off-grade material can be produced between samples.

The development of new sensors to provide real-time feedback on whether the process and product are within specification can save the energy of reprocessing off-grade material and allow the use of greater amounts of recycled fiber. Recycled fiber is weaker than virgin fiber. In paper grades where strength is important the amount of recycled fiber which can be used is limited by the need to keep a safety margin between the process target and customer specifications. The safety margin allows for normal process variability while producing an acceptable product. With an on-line sensor for strength properties the process variability can be reduced and greater proportions of recycled fiber utilized. In particular, the stiffness properties of the paper sheet can be measured using an ultrasonic sensor in real time this information can be used to reduce refiner energy in the process. A 10% reduction in refiner energy at a single mill saves 70+ billion Btu/yr. Reducing the normal off-grade production rate by 50% (from a typical 5% to 2.5%) can save an additional 118 billion Btu/yr.

D-2.1.2 Technology Examples beyond 2010 Requiring Further R&D

The Vision process for the Forest Products Industry of the Future was developed by the industry in collaboration with the Department of Energy's Office of Industrial Technologies, and is called "Agenda 2020 - A Technology Vision and Research Agenda for America's Forest, Wood, and Paper Industry". Two of the major concerns of this document are Environmental Performance and Energy Performance. Some of the ways these objectives might be met are with the following technologies.

Black Liquor Gasification

The pulp and paper industry is a highly energy intensive industry but also one which generates a high fraction of its own energy. Traditionally, about 40% of the energy used in a mill is generated from burning the lignin solids. Lignin is that portion of the wood which holds the fibers together and makes them stiff. The pulping process separates the lignin from the pulp fiber. The lignin is a dilute solution which is evaporated and burned in a boiler designed to recover the pulping chemicals and heat from the combustion to make steam. The steam is used to supply the mill's needs plus some is used to generate electricity for the mill. The energy efficiency of the electricity generation is about 25%.

In the black liquor gasification combined cycle (BLGCC) process a little less steam is generated to supply the mill but significantly more electricity is produced, 2-3 times more. Trends in process changes to make mills more environmentally friendly change the balance of energy forms that a mill uses. Mills are using less steam energy and more electrical energy; the BLGCC process fits right into the future process needs.

The technology is coming on the scene at an opportune time because most of the existing recovery boilers in the industry are reaching the end of their useful safe operating life. If the new technology is implemented as these old boilers are retired, between approx. 2005 and 2020, it would represent approximately 8 gigawatts of installed power generation.

Biomass Gasification

The pulp and paper industry is already utilizing nearly all of the available wood residues. The residues from lumber manufacture and residues from pulping (e.g., bark, shives, etc.) are used in hog-fuel boilers to generate extra steam and electricity for the mill. This offsets fuel fired (e.g., natural gas or oil) boilers and purchased electricity. If these boilers were also converted to gasification type technology, biomass gasification combined cycle (BGCC), then they would complete the industry steam needs and generate an extra 2 gigawatts of electricity.

A larger impact from this technology may be realized if additional forest residues which are not now utilized were brought to a BGCC facility; then as much as 30 gigawatts of electricity could be generated. A life cycle value of this would have to include significant transportation costs to collect these residues; this is not yet established.

Polyoxometalate Bleaching

Traditionally, the last remnants of lignin from the pulp have been removed with a chlorine bleaching process. However, the environmental impacts of chlorine has led to significant effort to find alternative methods to produce a desirable soft white fiber. Among these have been ozone bleaching and peroxide bleaching. Unfortunately, nothing has come to market which is as effective and selective as chlorine or chlorine dioxide. Polyoxometalates may be just such a new process. They are highly selective and can be regenerated within the process. In addition to desirable performance characteristics, the polyoxometalate system is consistent with the goals of increasing recycling of process water and reducing the effluent load from pulp mills. Compared to chlorine based systems the new process promises to reduce electrical energy consumption of pulp bleaching by 50%.

Sulfur-Free Pulping

The general public perception of the pulp and paper industry derives from the "rotten egg" or "stinky cabbage" odors which come from sulfur by-products formed during pulping. The actual emissions of these sulfur containing compounds may be quite small and environmentally benign. Nevertheless, these odors are unpleasant and bothersome to a mill's neighbors. Although tremendous strides have been made to reduce these emissions, the particular compounds are so odiferous that alternatives are being sought which can achieve the same performance.

Anthraquinone is one compound known to produce a high quality pulp and improve the yield of pulp from wood, thus conserving the use of wood. However, anthraquinone is currently too expensive to be used to replace sulfur. The basic building blocks of anthraquinone are within the wood itself. If a suitable manufacturing process can be developed, anthraquinone can be

manufactured reasonably and in sufficient supply to impact the entire industry. Alternative sulfur substitutes are also being sought.

D-2.2 TECHNOLOGY EXAMPLES FOR CHEMICALS

The chemical industry is almost too complex to characterize as a single industry. Some products – chlorine and other industrial gases – are made electrolytically or using electricity to compress and liquify gases. Other processes, such as petrochemical processing, require high temperatures and pressures to effect the chemical combination or separation that is required. Within chemical manufacturing there are over 30 industries and more than 10,000 products. Reaction and separation are at the heart of most chemical engineering processes, and they typically require heat, high pressure, or both. Because of these requirements, the industry in 1994 used 5.3 Quads of energy (second only to Petroleum Refining) and required nearly 16,000 Btu per dollar of product shipped.

D-2.2.1 Technology Examples Available before 2010

As with paper, the most promising technologies for the near term are those that economize on the use of heat or cooling or bring the two in better balance. Examples are:

Pinch Analytical Techniques

The “pinch” technique was originally a method for optimizing heat recovery in thermal processes and was first applied in the 1970s. It has more recently been applied as a general optimization tool.

Energy savings occur because of the heat recovery process (waste heat from one process is used to provide needed heat to another). In the classic case of heat exchanger networks, the pinch point helps to define the best match between available and needed heat, allowing the heat exchange system to be optimally sized for greatest cost effectiveness. A larger system would save more energy but would have an excessively long payback period; a smaller system might pay back sooner but would save less than the optimal amount of energy.

Pinch optimization was originally applied to any new or existing system where there was available waste heat at a higher temperature than required. Today's applications are much broader, extending to water, emissions, and site integration, with benefits including capital and energy cost reductions, emissions reduction and improvements in yield and operability. A slight drawback to broad application of this analytical method is its complexity for use by energy managers who prefer to use “rules of thumb”; however, the energy savings sometimes prove a stronger motivation.

In early applications, energy savings averaging 30%, with capital cost savings in new plant designs and one year paybacks in retrofits are common. Refinements to the technique have resulted in typical savings of 50% in new plants and retrofit paybacks of six months. By the mid-1980s the use of pinch analysis was widespread in the chemical industry, and its use has broadened further since then. (WEC, 1995)

Advanced Distillation Control Techniques

Distillation in refining and chemical industries consumes 3% of total U.S. energy use, which amounts to approximately 2.4 Quads of energy annually. In addition, distillation columns

usually determine the quality of final products and many times determine the maximum production rates.

Distillation columns are often over-refluxed to ensure that the product purity specifications are met. That is, more energy than necessary is used to meet the product specifications. As a result, industry commonly uses 30% to 50% more energy than is necessary to produce its products. It has been estimated that an overall average 15% reduction of distillation energy consumption can be attained if better column controls are applied.

Industry does not have a consistent basis on which to compare the various options for distillation control. Since distillation controls are not fully understood, they may be applied where not needed or not applied where needed. Current research is involved in performing detailed simulations of a range of distillation columns with varying degrees of control difficulty to assess the control performance of various control options. It is expected that the refinement of distillation control techniques resulting from this research will yield energy savings of 288 trillion Btu by the year 2010. (DOE, 1997)

D-2.2.2 Technology Examples beyond 2010 Requiring Further R&D

Biological/Chemical Caprolactam Process

Nylon-6 is currently produced from caprolactam. The chemical synthesis of caprolactam from cumene is a complex, multi-step process that is energy intensive and generates considerable waste. Nylon-6 could also be produced from caprolactone. However, the current market price for caprolactone makes this route uneconomical.

A laboratory-demonstrated biological process has been developed that would provide a one-step, cost-effective production process for caprolactam manufacture that requires 50% less energy than the current process, costs half as much (considering both capital and energy costs), and produces almost no waste byproducts. Research on this process has established the technical feasibility of the biomanufacturing process for converting inexpensive cyclohexane into caprolactone. Under this project, the feasibility of the laboratory-demonstrated biomanufacturing process was established, and the process is now available to be optimized for possible scale-up to pilot plant scale. It is estimated that by the year 202, this technology can provide annual energy savings of 12 trillion Btu. (DOE, 1997)

Flexible Chemical Processing of Polymeric Materials

Waste textiles and recycled waste materials from automobiles, appliances, and furniture contain polymers (such as nylon-6, nylon-66, PET, and polyurethanes) that can be converted into valuable chemical feedstocks. However, processes that can only convert a single type of recycled material can face high costs for material collection and for transportation of the resulting feedstocks. Because these costs are the major contributors to process costs, processes are needed that can convert a variety of recycled materials.

Research in this area is working toward developing a thermochemical process that can convert a wide variety of recycled materials into valuable chemicals. A two-stage process is envisioned: the first will use selective catalytic pyrolysis to recover chemicals such as caprolactam, hexamethylenediamine, and dimethyl-terephthalate; the second will convert the unreacted organic material into synthesis gas, which can be converted to a variety of chemicals of use to the chemical industry.

Because the process can address a wide variety of recycled materials, large regional recycling plants can be developed, lowering material collection and transportation costs and thereby increasing the viability of recycling many materials. It is estimated that by the year 2020, the use of this technology will save 265 trillion Btu annually. (DOE, 1997)

D-2.3 TECHNOLOGY EXAMPLES FOR PETROLEUM REFINING

[Prepared by M. Petrick, Argonne National Laboratory]

The amount of process energy used in refining petroleum crude oil to supply the US marketplace depends upon many factors and not surprisingly therefore has varied over time. Key factors impacting energy use and its utilization efficiency are (1) the quality of crude slate processed; (2) the cost and availability of fuel and energy; (3) product slate produced to meet market demand; (4) refinery configuration (complexity and size); (5) capital availability; and (6) environmental dictates (product specifications). Over the past three decades these factors have forced the refining industry to change dramatically; these changes in turn have impacted energy utilization. Over the time period of 1969 to 1974 energy used/bbl processed declined at a rate of 0.8%/yr (Haynes, 1976). In 1975, energy use was about 3.2 Quads. The oil supply disruptions and high price of oil in the 70s motivated the industry to continue efforts to minimize energy usage. By 1983, energy utilization had dropped to 2.6 Quads (DOE, 1990). Since 1985 the refineries have become more complex and plant size has increased. Gasoline is tending to become a commodity whose specifications are being set by environmental regulations. The quality of the crude slate processed has declined. The deteriorating crude quality and the market pressures to produce more "white products" per barrel processed motivated refiners to add more advanced processing capability, thus increasing refining complexity and energy utilization per unit of output. By 1990 energy usage had again risen to a level of about 3.0 Quads. Since 1990, energy usage has remained relatively constant; projected 1997 utilization is 2.941 Quads (EIA, 1996)

Potential For Future Reductions In Energy Utilization

The potential for reducing energy utilization in the future will continue to be impacted in large measure by the various factors cited above. The 1997 EIA outlook, taking into account market and crude supply factors, projects that the energy usage in the industry can be expected to increase by 0.3%/yr. To reverse this trend (and thus to achieve reductions in the critical greenhouse gas, CO₂), the energy efficiency of key (highest energy consuming) refining processes and energy supply systems must be improved. Such efficiency improvements can be achieved via various steps, e.g.s., (1) introduction of more efficient equipment; (2) reducing process activation energies (through improved catalysts); (3) improving equipment integration to recover more heat; (4) adopting improved process control, etc. Before such steps are taken, however, they must be shown to be economically viable and be demonstrated to have acceptable risk (in accordance with the industry's standards). A number of studies have identified the key processes that must be addressed and processes and technology innovations/modifications that have the potential to substantially reduce energy consumption (Haynes, 1976; DOE, 1990)

The most energy intensive processes in a refinery considering both specific energy use for the process stream and percentage of total energy use in the refining process were identified as; distillation; catalytic hydrocracking, reforming and hydrotreating; alkylation; and hydrogen production. While the aforementioned studies cite numerous technology options that could

improve the processes energy efficiency utilization, the issues of the economic viability and risk involved in retrofitting these modifications/components into the spectrum of plant configurations that exist in the industry today were not addressed. It is clear that the cost/benefit ratios for incorporating the candidate technologies/processes are highly site specific and are very sensitive to future market and governmental dictates.

An important parallel issue is that while refiners can make improvements/modifications to improve energy utilization, they may also be forced to modify refinery processes/configurations to be able to refine crudes of lower quality and comply with environmental dictates. While such changes may not be driven by energy issues, they will very likely impact energy usage as well as emissions. They could result in a decrease in energy efficiency or an increase in CO₂ emissions, a major greenhouse gas. A clear example of this is given by Ladeur and Bijwaard (1993), wherein a major \$2.2 billion revamp of a 400,000 bbl/day refinery that is being made to meet current and future product volume and quality demands is described. The refinery crude supply is expected to shift to a higher proportion of Middle East crude, increasing the sulfur intake (to the refinery) by about 45%. The changes in refinery output as a result of the extensive modifications are (1) the white product make will increase by 10% and (2) fuel oil production will decrease by 40%. With regard to environmental emissions, SO₂ and NO_x emissions are expected to be reduced by 35 and 45%, respectively, due primarily to reduced residual oil firing; also, particulate matter emissions will be halved. However, CO₂ emissions from the refining site are expected to rise substantially – by about 22% – because of the use of greater amounts of hydrogen in the refining process. The global emission level of CO₂ resulting from the refining and the combustion of the products produced is, however, expected to remain essentially constant, because of the higher hydrogen content of the refinery's products.

The above example serves to underscore the complexity/uncertainties in generating projections relative to levels of energy efficiency improvements and the magnitude of emission reductions that can be achieved. Nevertheless, it seems clear that there are a number of steps and/or technology options that, if implemented, could reduce energy usage and help reduce emissions. Specific opportunities are cited in the following sections. The implementation of refining process/configurations modifications to reduce energy areas will require that the industry provide strong environmental stewardship and that an appropriate investment climate exist.

Examples Of Technologies And Changes In Operations That Would Likely Improve Energy Efficiency Utilization

The current ambiance in the refining industry is such that energy utilization improvement programs have a lower priority relative to requisite environmental and general process optimization activities. Nevertheless, based on the argument that "it is just good business and good citizenship" to be energy efficient, the following sections contain examples of process/technology/operating improvements that could potentially generate substantial improvements in energy utilization efficiency. They are broken down into three categories, namely: (1) near-term, straightforward improvement opportunities; (2) process/equipment modifications; and (3) long-range opportunities requiring further R&D.

D-2.3.1 Technology Examples Available before 2010

Near-Term Improvement Opportunities

There are a number of equipment, maintenance, and operational improvements that can be considered relatively straight forward and that can be made to improve overall system energy utilization efficiency. Such improvements generally can be expected to have longer pay-backs than current industry standards. They are likely to be difficult to justify under current economic conditions of low fuel costs, limited availability of capital (from cash flow) and management preoccupation with meeting environmental regulatory mandates, etc. Nevertheless, under an "appropriate investment climate" their implementation could produce substantial energy savings.

Monitoring Overall Energy Performance

Every refinery could promote energy efficiency stewardship by rigorously pursuing a program to monitor equipment/process/overall refinery energy performance to identify (as early as possible) when a system or piece of equipment begins to become inefficient so that corrective actions can be initiated. Measured usage of energy for key equipment/systems can be compared with allocated energy values based on efficient, established (allocated) performance criteria and/or targets. Estimates of energy savings that can be realized through such action range from 1-4% (Robertson, 1997; ANL, 1997)

Utility System Improvements

The principal utility systems in a refinery are the cooling, steam, power, and fuel-gas systems. They are integrated with virtually every process subsystem. Relatively speaking, these systems in general have not and do not receive the same level of attention as the critical refining process subsystems since they basically support these systems, and their impact on the overall refinery operating profit margin is relatively small. The potential for energy savings, however, is substantial (Robertson, 1997).

The lowest water temperature available from the cooling water system can impact the energy utilization/separation characteristics (operation) of the distillation towers substantially. Operating the distillation towers at the lowest possible temperature reduces the amount of energy required to perform a separation. Reducing tower overhead temperatures by reducing pressure (through more cooling) also reduces tower bottom temperatures. This in turn opens up the temperature difference between the reboiled fluid and the energy source for the distillation tower.

Cooling Water. Perhaps the most overlooked opportunity for saving energy lies within the cooling water system. Reduction in light ends from towers (e.g., deethanizer, depropanizer and debutanizers) reduce the reboiler duty for a constant separation. Similarly, lower temperature operation of absorbers reduces the amount of light hydrocarbons lost to fuel gas. Cooling the feed to the suction of a compressor may knock out additional liquid and is more efficient, so lowering the suction and intercooler temperatures will improve efficiency even if no additional liquid is formed.

The cooling water temperature is especially critical in the summer. Refineries generally maximize gasoline make in the summer. This leads to additional light hydrocarbons made from coking, cracking, and reforming processes. Ethane and ethylene can "lift" additional

hydrocarbons from the light ends systems associated with these processes. Proper cooling of the absorber-deethanizers can reduce the light hydrocarbon losses that often wind up in the flare, thus improving product recovery. The larger flares observed at refineries in the summer demonstrates this phenomenon.

Lower cooling water temperatures can be achieved by revamping cooling towers using modern fill material to get a closer approach to the wet bulb temperature. Additional/enhanced cooling capability can be achieved by judicious use of the new generation of more efficient waste heat-driven absorption chiller systems to either further cool waste streams or to cool process streams directly. Such systems also provide an opportunity to utilize low-grade heat that is in excess in many parts of the refinery. A Climate Wise Program demonstration of the use of a waste-heat ammonia absorption refrigeration system (WHAARP) is currently under way at the Total Refinery in Denver (ANL, 1997). The chiller is being used to cool the net gas/treat gas stream in the reformer unit, the FCC main column overhead wet gas stream, and the unsat gas plant sponge absorber light cycle oil streams. The enhanced cooling not only provides direct energy savings but also indirect savings from enhanced product recovery and debottlenecking and improved operating characteristics of the FCC wet gas compressors.

Steam Systems. Steam is used for a number of purposes throughout the refinery and accounts for about 20% of energy use. It is used as stripping agent, in vacuum jets, as a heating medium, and in powering turbines and pumps. Steam is used at several different pressures and temperatures. Several opportunities exist to increase steam (energy) utilization efficiency. For example, as an alternative to using letdown valves, back-pressure turbines can be used to reduce pressures to the desired intermediate levels and in so doing produce electrical power supporting purchased power. The steam used in condensing turbines that drives pumps, blowers, etc. can be replaced by the new generation of more efficient electrical motors thus generating a net reduction in energy usage. Similar benefits can be derived by replacing the steam ejector system on the vacuum still with a mechanical system driven by efficient motors. The opportunity also exists to use low-grade steam to preheat boiler feedwater in many refineries. More vigorous maintenance of steam traps, valves, and rapid repair of other steam leaks can also generate significant steam savings.

Increased attention to stripping steam usage can also provide dividends. Stripping steam is often sent through a restriction orifice at a constant rate initially set to be proportional to some maximum feed rate. Controlled reduction of stripping steam can have several benefits besides the obvious direct energy consumption. For atmospheric pipestills, reducing the stripping steam to the minimum required to achieve the flash point or IBP specifications can help unload the vapor rate at the top of the fractionator. This in turn can make the fractionation more efficient in the top of the tower and reduce the reflux or pumparound requirements to meet separation specifications. Furthermore, less steam means less sour water from the tower overhead and consequently less energy requirement in the sour water stripper.

The opportunities for reduction of steam usage cited can be best accomplished in conjunction with introduction and integration of a state-of-the-art cogeneration plant into the refinery and optimizing both steam and electricity use as discussed in a subsequent section.

Fuel Gas System. The refinery fuel gas system supplies about 1/2-2/3 of the energy consumed in the refining process. The fuel gas is derived from the various conversion processes in the refinery. The heat content of the gases' combustion products can, under certain conditions, actually exceed the total energy requirements of the refinery; then the refinery is faced with the situation of having excess energy. Traditionally, the excess fuel gas problem has been dealt with

by tolerating inefficient combustion, generating excess steam, and flaring (burning) the gas into the atmosphere. The excess gas (energy) problem, if it exists in a refinery, is generally exacerbated in the summer when the light ends separation systems are overtaxed, thus generating additional losses of propane and other higher heating value products into the fuel gas system. A number of opportunities can be pursued to "recover" a greater fraction of the fuel gas (excess energy). Examples of potential solutions include (1) generating additional electrical energy via an on-site cogeneration plant to reduce electrical purchases from utilities; (2) sale of the gas to a utility (if one exists near by); (3) isolating and utilizing high hydrogen containing streams as feed to the hydrogen plant, thus supplanting the usual methane (purchased gas) feed; and (4) utilizing waste heat driven absorption refrigeration systems to recover the heavier hydrocarbon products from the fuel streams, as described previously.

Equipment Maintenance

Aggressive maintenance programs to keep equipment operating in optimal condition can reduce energy consumption substantially. A major opportunity exists with regard to controlling heat exchanger fouling.

Heat Exchanger Fouling Minimization. Heat exchangers, including furnaces, are the workhorses in refineries. A typical modern day refinery is equipped with hundreds of heat exchangers in variable sizes. The overall energy efficiency of refineries is heavily dependent on the feed/effluent heat exchangers that recover thermal energy from high temperature processes. Foulant buildup impedes heat transfer, and the lost energy must be compensated by burning additional gas or liquid fuels in furnaces. Thus, fouling of equipment significantly reduces the efficiency of process operations and increases capital and operating costs. The resulting economic and energy costs for the US refineries are well known: 0.2 Quads of energy (about 6.5% of the total energy consumed in refining) and more than \$2 billion are lost each year due to fouling (Leach and Holuska, 1981). The total worldwide energy and cost penalties are in the range of 8 to 10 times that of the US refineries. The fouling problem (energy inefficiency) will become more critical as more heavy oil and residuum is processed in the future.

It is estimated that the energy penalty due to fouling can be reduced by a factor of two with an accelerated deployment of mitigation technologies. The key to achieving significant fouling mitigation in the near term (3-7 years) is extending laboratory experimental data to field operating conditions and incorporating various mitigation technologies in retrofitting the existing heat exchange equipment and/or pursuing more rigorous maintenance procedures, e.g., increased frequency of heat exchanger cleaning, operating heat exchanger equipment below threshold fouling conditions, and use of optimally designed physical devices such as enhanced tubes and tube inserts in conjunction with chemical additives. In the long-term, research on developing mitigation measures which can be employed before the process lines go into operation can generate even larger dividends. The long-term solution of the refinery fouling problem will require the development of prediction models and comprehensive data bases. An added benefit from an aggressive effort to control fouling is that this will facilitate additional heat integration of process equipment, thereby further increasing the energy efficiency.

A major factor impacting the pursuit of an aggressive program to minimize fouling is the economic justification. The energy savings must be balanced against other costs, e.g., down time for cleaning (which is generally very expensive), installation of fouling prevention devices, etc. It is clear that these costs could easily exceed energy saving values.

Mid-Term Improvement Opportunities

Major opportunities to reduce energy usage in the mid-term also exist through retrofitting and/or replacement of existing equipment nearing the end of its useful life and during major refinery revamps that are periodically undertaken to meet market/environmental dictates. Examples of process/equipment modification opportunities are as follows.

Fired (Process) Heaters

As indicated previously, over 60% of the energy used in refineries is obtained from burning gaseous fuels in refinery heaters. Several approaches that seek to alter furnace designs and control and greater heat recovery can be used to improve process heater efficiency. One of these, "heat release profiling", seeks to match heat release with load and the flame shape with process tube configuration. Radiant burners, which can be constructed to conform to the shape of the load and thus can concentrate heat where it is needed can also be used. (Radiant burners are generally more expensive than conventional burners, however.) Another approach is to improve heat transfer through improved luminosity. Efficiency gains in the 5 to 10% range are possible. A variety of luminosity enhancing techniques have been tried with varying degrees of success. Also, the use of oscillating (pulsed) combustion, in which the fuel flow is oscillated while the air flow remains constant, a technique now being evaluated, is realizing efficiency gains of 5 to 10% in process heater applications. Also possible are re-radiation plates which have been reported to produce similar gains. The use of recuperators to recover energy, e.g., air preheat, is possible, especially for higher temperature processes; cost and an increase in NO_x emissions constrain the use of this approach.

Boilers

As indicated previously about 20% of all energy used by petroleum refiners is used for generation of steam. One route for improving boiler efficiency is through improved sensors and controls. For example, balancing the burners in a multi-burner boiler and reducing excess air can cut fuel use by 10 to 25%. In single burner boilers, excess air control can lead to similar gains. The technology to automate excess air firing is available.

Recuperative systems such as air preheaters and feedwater preheaters can capture waste heat. For many industrial-scale boilers, air preheaters are however not cost effective and they also can impact NO_x emissions. Installation of additional boiler tubes at the back end of the boiler can also improve heat recovery but with the current price of energy and current investment climates it will likely be difficult to justify this additional capital cost.

Distillation

Approximately one-fourth of the energy used in refining is in the distillation process (DOE 1990). Accordingly, a number of studies have been undertaken to identify opportunities to reduce energy usage in the distillation system. As an example, an exergy analysis was conducted to identify where, within the overall distillation system, the highest potential exists to reduce energy consumption (Rivero, 1989). Not surprisingly, the equipment/subsystems with the highest improvement potential identified were the fired heater, condensate reflux system, the crude preheating train, and the effluent cooling train. The opportunities identified underscore the importance of enhancing combustion efficiency and improving waste heat recovery. The result is consistent with the most frequently recommended modifications to the distillation processes, summarized in (Levine et al, 1995; Mix et al, 1978) namely, (1) improving

the fired heater combustion efficiency through modification of the burners, applying advanced control technology, and use of a recuperative air preheater; (2) incorporating staged crude preheat; and (3) replacement of stream ejector vacuum pumps with efficient electrically-driven mechanical vacuum pumps (as discussed earlier). Other recommended actions to improve distillation energy efficiency include (1) Selective introduction of vapor recompression into the overhead reflux condenser subsystem, e.g., in the depropanizer column (Flores, 1984) ; (2) improving heat recovery and integration between the crude and vacuum distillation units (estimates of reduction of distillation energy usage range from 10-20%) (Levine et al, 1995); and (3) substitution of reboilers heated by the main column bottom for the stripping steam in the stripping columns (Rivero et al, 1989)

A more limited opportunity exists to improve the efficiency of the distillation tower (process) itself, for example, by optimizing the number of trays, using more efficient packings, etc. The greatest potential for improving distillation efficiency would require major revamps of towers to essentially alter the distillation process by increasing the number of heat-integrated (internal) and condensing steps, thus reducing the loads on the fired heater and main condenser. Although the improvements in distillation efficiency that can be achieved in this manner is limited, it should be noted that small increases in efficiency can have major impact on the consumption of energy because of the amount of high-quality energy used. Major opportunities thus exist to reduce the energy consumption in the refinery distillation processes; a 10% reduction in energy usage would reduce overall refinery energy consumption by about 2%.

Fluid Catalytic Cracker (FCC)

As indicated previously, substantive reductions in total industry energy usage can be achieved through modification of key processes to increase efficiency and/or increase product yields per barrel processed to meet market demand. This approach not only reduces energy usage and emissions but also improves competitiveness. The FCC presents an especially attractive opportunity because it is now and is likely to continue to be a key process for meeting future demand for "white products". As an example, the FCC currently produces approximately 40% of the gasoline pool. The product slate yields from the FCC can be adjusted through modification of operating parameters in the riser reactor, e.g., residence time, and/or equipment such as feed nozzles, injection locations, etc., and by utilizing improved catalysts as discussed in a following section. Recent studies suggest that it may be possible to increase desired product yields from 2-6% per barrel of crude processed with appropriate modifications of equipment and operating conditions and in so doing producing an essentially similar reduction in energy usage and emissions. The expected shift to lower quality (lower API gravity and higher sulfur) crudes expected to occur in the future will impact the savings achievable because of their impact on FCC as well as overall refining operations. Expected increases in coke generation provides opportunities to generate more heat and/or H_2 as discussed in a following section. Higher coke lay down on the FCC catalyst will turn the FCC into an exporter of energy that will require installation of additional heat recovery equipment such as catalyst coolers, CO boilers, etc., that can be used for generation of additional steam, air preheat, etc. or for production of electric power. Judicious integration of the excess heat into the refinery utility system would thus reduce consumption of other fuels such as gas and electricity purchased from utilities. The FCC thus stands in sharp contrast to the catalytic hydrocracker which is a major consumer of energy.

Process Heat Integration

Process heat recovery and integration is one of the most effective means for reducing energy usage in the refinery. The objective is to identify, capture and utilize the waste heat that is generated when process streams are cooled and/or that result from the combustion of the variety of fuels used in the refinery (e.g., from fired heaters). At times the industry has in fact pursued process heat recovery and integration vigorously when economically justified (e.g., under high-cost energy conditions such as occurred in the 1970s). An example of such a success is given in (Robertson, 1990), wherein it was reported that EXXON had improved energy refinery energy efficiency by about 25% between 1969-1981; a significant fraction of the improvement was due to enhanced heat integration. There are undoubtedly substantial additional opportunities to achieve enhanced integration assuming a lower ROI can be justified and the issue of capital availability can be resolved. The application of pinch technology analysis to streams within a process and hence between processes can be used to develop a composite heat availability/recovery balance sheet that can be used to identify which equipment can be most advantageously modified, added, or relocated to debottleneck the heat recovery system and thus to achieve the highest energy recovery and the "biggest bang for the buck." (Robertson, 1997, 1990) One of the most promising opportunities where heat integration can substantially reduce energy use is between the crude and vacuum distillation towers. Several studies (Sunden, ?; Clayton, ?) have indicated potential energy saving in excess of 10% with payback less than 2 years.

Requisite heat exchanger modifications can be achieved by adding heat transfer area or installation of devices that will improve heat transfer such as turbulence promoters, auto fouling devices, extended surface tubing, plate heat exchangers, etc. The introduction of these and other evolving new heat exchanger improvement technologies will require that the risk issue be adequately addressed in order not to degrade refinery reliability.

Coke/Residue Gasification for Cogeneration/H₂ Production

The gasification technology that exists today provides refiners with a unique opportunity, albeit a costly one, to simultaneously improve energy utilization, reduce emissions, and add value to the bottom of the barrel by converting the coke and waste residues to a synthesis gas that can be used for producing electricity, process steam and H₂. The integration of a coke/residue gasifier with a cogeneration plant and H₂ production system would provide refiners with an enhanced capability to process the lower quality petroleum feeds (expected in the future), to meet changing market product demand and environmentally mandated specifications. The technology would also allow the refiner to become an exporter of energy and provide an inherent capability to dispose of various problem liquid/solid carbonaceous residues. The gasifier converts the various residues into a clean syngas composed of H₂ and CO which can then be split into several streams that can be fed to a cogeneration plant to produce electricity and steam at desired pressure levels and to a H₂ plant. If desired, the syngas can also be fed into the fuel gas system and used as the fuel for fired heaters. The conventional cleanup process used in the gasification system recovers the sulfur from the fuel gas in the elemental state and thus reduces SO₂ emissions dramatically. The cleanup system can also be sized to clean up segments of the primary fuel gas stream as well. Any excess electrical power generated in the cogeneration plant can be fed into the utility grid stream. Incorporation of a cogeneration plant also provides the capability to optimize the steam utility system. The syngas generated from the low-value residual waste thus supplants natural gas normally needed to augment the

refinery's fuel gas supply and that used for the production of H_2 . The technology is already being introduced into various refineries. (Ladeur and Bijwaard, 1993; Quintana et al, ?)

D-2.3.2 Technology Examples beyond 2010 Requiring Further R&D

Long-Range Opportunities Requiring Further R&D

For the longer term there are a number of research directions in regard to novel refinery process development/improvement that have the potential to produce breakthroughs in regard to refinery efficiency and hence reductions of emissions of NO_x , SO_x and CO_2 . As indicated, the quality of the crude supply is expected to continue to deteriorate in the future in regard to sulfur metals and API gravity level (increased resid content). To process such crudes more energy in general will likely be needed since process complexity will increase. To counteract the pressure on increasing refinery complexity and energy utilization, new approaches to refining need to be developed. A number of R&D directions have been identified that hold considerable promise. Examples of several promising directions that can have major impacts on enhancing refinery efficiency and reducing gaseous emissions are briefly described below.

Development of Improved Catalysts

The purpose of a catalyst is not to lower the energy needs of a reaction (which are governed by thermodynamics) but to lower the energy of activation for a process and thereby increase the kinetics and/or product selectivity. If it accomplishes either or both of these tasks, the energy demands on a given process should decrease either due to lower heat demand (lower energy of activation) or from greater throughput. Three major process areas which impact the energy utilization efficiency in a refinery and thus that could benefit from improvements in catalyst technology are: (1) hydroprocessing; (2) catalytic cracking; and (3) alkylation.

In hydroprocessing, much energy is utilized in heating up heavy oils and resids to temperatures where the catalyst activity is high enough. Additional energy is expended in the compression of hydrogen to pressures up to 2000 psi. Improved catalysts (capable of functioning at lower temperatures and pressures) could reduce the energy used by decreasing the reaction temperature of this process. Currently the hydrotreating reactions take place at temperatures of 660-750°F. Work on various catalysts and catalysts combined with various solvents has shown that significant hydrotreating activity can be attained at 570°F. In addition, the hydrogen selectivity of some of these catalysts is equal or superior to that of commercial catalysts. Improved hydrogen selectivity would reduce hydrogen consumption per barrel of oil converted and hence less hydrogen will need to be generated and compressed.

Energy usage could be improved for catalytic cracking in terms of product selectivity. Cracking catalysts are extremely efficient at converting "good" gas oils to gasoline and distillate. However, when significant fractions of resid and the metals that come along with these resids are used as FCC feeds the selectivity (in terms of gasoline yield) drops dramatically. This gasoline loss comes at the expense of increased coke and dry gas make. This requires catalyst coolers in order to keep the temperature of the catalyst bed down (which comes from increased coke burn) and higher compressor capacity to handle the increased dry gas yield. If catalysts were designed to more properly handle higher amounts of heavy oils without the detrimental effects outlined above then more resid could be handled in the highly efficient FCC with and subsequent decreased utilization of the less efficient hydrotreaters.

The largest energy demand in the alkylation units are in the refrigeration units used to keep the HF temperature down. Here the need is for a catalyst which will operate at temperature above ambient. Many solid alkylation catalysts which are in pre-commercial testing and evaluation function at temperatures around 300°F. This is a relatively low temperature for the refiner and many of the streams requiring alkylation are at or near this temperature when they exit their respective processing units. Such heat is normally considered waste heat and thus could easily be utilized for the alkylation process. Therefore, even though the reaction temperature would go up, the energy demand would go down.

Refining Process Modifications

In order to more effectively process the lower quality (higher metal, nitrogen and sulfur) crudes while maintaining or enhancing product yields and energy utilization efficiency modifications of current refining practice will likely be necessary. As indicated in the previous section, metals, sulfur, and nitrogen, adversely affect catalyst performance (product yields) and energy utilization in key processes, such as fluid catalytic cracking and hydrocracking and hydrotreating processes. An incentive exists therefore to remove or reduce the levels of metals, sulfur, and nitrogen as early as possible in refining process. An incentive also exists to reduce the amounts of energy used in the crude and vacuum distillation, towers, the major consumers of energy in the refinery process. An example of a potentially attractive process modification that has been suggested is to input the crude directly into a thermal cracking unit bypassing the atmospheric and vacuum towers. (Bartholis et al, 1986) The objective is to initially crack the heaviest (asphaltenes) molecules in the 1000+ fraction of crude into lower boiling point products while simultaneously removing the major portion of the metals, sulfur, and nitrogen from the crude in the coke that would also be generated from this fraction. An equally important parallel objective is not to alter the molecular structure of the material boiling at <1000°F. The products emerging from the Thermal Cracking Unit are then processed through the catalytic cracking, hydrocracking and hydrotreating units to generate the product yields desired. Hydrogen requirements are expected to be less in these processing steps as is the catalyst volume needed. Also enhanced product yield and selectivity can be anticipated. These improvements are expected to be derived from the removal of 30-50 % sulfur, 50-80% nitrogen and greater than 90% of metals with the coke that is sent to the regenerator and burned to provide the heat for the cracking process. Major energy savings and reduced gaseous emissions would evolve from such a process. The technology can also be used as a field upgrader (Dawson et al, 1995), thus facilitating utilization of heavy US crudes, e.g., California Midwest Sunset crudes.

D-2.3.3 References

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D-2.4 TECHNOLOGY EXAMPLES FOR GLASS

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The glass industry is comprised of several major product segments each with their own processes for producing final products. The segments include container, flat glass, wool and textile fiber, specialty, lighting, and hand glass. The major common energy intensive stage of the glass industry is the glass furnace. There are nearly 500 furnaces in over 200 plants in the glass industry (ignoring the smaller hand glass segment). While there are other stages of product finishing which also require significant amounts of energy, the examples below focus on the glass furnace as the primary area of concern for energy efficiency. Other process and product specific areas of energy efficiency are also possible.

D-2.4.1 Technology Examples Available before 2010

Considerable energy savings may be achieved by the year of 2010 by partially adopting current commercially available technologies, such as the oxy-fuel process, advanced burner and batch/cullet preheating technology.

Oxy-Fuel Process

Since 1991, the fiber, container and specialty glass industries have accepted the oxy-fuel process as an alternative to regenerative and recuperative air-fuel furnaces. According to one source, more than 50 major (20 ton/day) furnaces have been converted to oxy-fuel combustion technology (Geiger 1996). The advantages of oxy-fuel over air-fuel combustion system are reduced NO_x and SO_x emissions, lowered particulate carryover, improvements in glass quality, and higher throughput and energy efficiency.

Anticipated or recently enacted air emission regulations will be a significant driving force for oxy-fuel conversion in the near future, especially for NO_x and particulates. In particular, oxy-fuel provides a viable option for resolving the NO_x "new source" issues of increasing production in Ozone non-attainment areas, requiring Best Available Control Technology or Best Available Retrofit Control Technology. Particulate stack emissions are reduced by inherently lower gas velocities over the melt and reduced flue gas volumes.

Oxy-fuel glass melting has a number of significant operational improvements over conventional furnaces. Varying the individual burner inputs longitudinally and flame length laterally, to establish desirable thermal profiles of the melter, will use energy only where needed, and avoid excessive temperature in other areas. Configurations for placing oxy-fuel burners in a melter can allow more precise thermal input and more closely control the melting process. Where previously glass quality has been affected by marginal melting conditions, oxy-fuel conversions have been reported to also improve quality.

In the oxy-fuel process, oxygen or oxygen-enriched air is used in combustion in the melting furnace. Energy input with oxy-fuel firing is reduced because the energy required for heating the 79% of inert nitrogen in the air-fuel process is avoided. This results in further efficiency improvement by reducing the volume of combustion products, which remove BTU's from the system. The atmosphere of oxy-fuel furnaces is different from conventional furnaces. Water and CO_2 concentrations in the oxy-fuel furnace are much higher than in the conventional furnace. This results in higher heat transfer efficiency from the combustion gas to the melting batch because the radiative emissivities of water and CO_2 are much higher than nitrogen. It is reported that fuel savings from oxy-fuel conversions are typically 10-15% for well designed soda-lime regenerative furnaces, and at least 30-40% for direct fired or regenerative boro-silicate or lead glasses (Ross 1996).

The reasons for converting to oxy-fuel are different for each segment of the glass industry. The cost of purchasing oxygen for furnace conversion must be justified by specific benefits and other desired attributes. Meeting the NO_x requirement is the most significant reason for converting to oxy-fuel. Other important reasons, in descending order, are capital cost reduction, energy savings and production increase. In the container segment, NO_x reduction is the dominant reason for conversion to oxy-fuel. The oxy-fuel process has become the preferred process in the fiberglass industry, with capital reduction being the leading reason. The flat glass segment is the only segment that hasn't adopted the oxy-fuel process.

Currently, approximately 15% of the large commercial furnaces in the U.S. have been converted to the oxy-fuel process (Ross 1996). By the year 2010, an additional 35% of the large commercial furnaces may be converted to the oxy-fuel process.

Advanced Burner Technology

Adoption of newly developed burners in the oxy-fuel process further improves the energy efficiency of the process. Replacement of conventional burners with the new burners is less complicated and requires less cost and downtime. It is anticipated that the new burners will be 100% used in the oxy-fuel process by 2010. Descriptions of three different types of burners follow.

Air Products and Chemicals Inc. (Allentown, PA) has developed clean-fire High Radiation (HR) oxy-fuel burners (*Chemical Engineering* 1995), and has demonstrated this technology in a glass manufacture's furnace. These burners produce flames that have higher radiation and better bath coverage than conventional oxy-fuel burners. Increased flame radiation is accomplished through a proprietary soot generation process. The system's design provides twice the radiation and creates potential cost savings by reducing fuel and oxygen requirements, each by up to 10%. The key to the burner's performance is a proprietary oxygen-proportioning system, which uses a diverter valve that can introduce oxygen in stages. This enables glass producers to cut NO_x emissions by an additional 30-40%, relative to traditional oxy-fuel burners.

A full-scale, field demonstration was undertaken at Owens-Brockway (Los Angeles) with Praxair's oxy-fuel burner system technology in a container-glass furnace (Geiger 1996). The technology uses a J-L burner configuration developed by Praxair. A major portion of the oxygen for combustion in this system is diverted to an oxygen lance, typically located between the burner and the glass surface. The oxygen introduced through the lance is diluted to low concentration by mixing it with furnace atmosphere before reacting with fuel. This results in staged combustion of the fuel and a flame with much lower peak temperatures than the flame of conventional oxy-fuel burners, so that reduced NO_x emissions and improved glass quality can be achieved.

BOC Gases (Maumee, OH) presented results on application of the Flat Jet oxy-fuel burner to three different furnaces and glass types (Geiger 1996). The Flat Jet oxy-fuel burner is designed to produce a low momentum, highly laminar flame that has a well-defined envelop over a wide operating range. Use of this burner in a conversion of a lighting products furnace to oxy-gas firing has resulted in 35% increase in daily pull rate, 30% decrease in fuel use, and improvement of product quality.

Glass Batch/Cullet Preheater Technology

With Gas Research Institute support, a dual batch/cullet preheater technology has recently been developed. The batch/cullet preheater uses the oxy-gas furnace's waste heat to preheat cullet and batch before feeding it to the furnace. The cullet is fed from the top and encounters waste heat—the hot combustion gases rising from below. Preheating cullet and batch reduces the amount of energy and oxygen required in the overall melting process. Because there is no consolidation of batch (briquetting) required as a first step in the so-called "raining bed" preheater, heat transfer is more efficient, leading to smaller units that are less expensive. Corning, Inc. has been granted a license to the technology (GRID 1996).

D-2.4.2 Technology Examples beyond 2010 Requiring Further R&D

In January, 1996, the glass industry issued "A Clear Vision For A Bright Future" to meet the challenges by the year 2020. The document presented the goals of the industry and the research

priorities that will ensure its continuing competitiveness. To build a strong foundation for the future of American glass, the industry has identified the following areas for technology improvements:

- Production efficiency, including improved manufacturing processes and new techniques that maximize glass strength and quality;
- Energy efficiency and conservation;
- Recycling;
- Environmental protection, including control of nitrogen oxides, sulfur oxides and particulate; solid waste reductions; and waste water reuse;
- Innovative uses of glass.

The industry has set a goal to reduce process energy consumption from the present level by 50%. This indicates that energy savings of 63 trillion Btu per year will be achieved according to the current level of 170 trillion Btu per year. In the following, R&D needs relevant to the improvement of energy efficiency will be discussed according to the vision document.

Optimizing Electric Boost to Reduce Total Energy Consumption

High energy efficiency, through conversion of electric energy into useful heat, and low volatilization are the primary advantages of electric melting. Current operating practice has shown that effective use of electricity near the back end of the furnace, where the batch is added, can reduce fossil fuel needs. Research needs for optimizing electric boost include, but are not limited to, investigating new electrode and electric arc melting processes, modeling of the current technology to fine-tune operation conditions, such as energy inputs and locations of the electrodes, and improving the electrode control system (Glass Industry Working Group date?).

Improving Furnace Design and Operation to Maximize Combustion Efficiency

In recent years, furnace energy efficiency has significantly increased through adoption of new refractory, oxy-fuel process, new burners and other technologies. However, the basic design of conventional fuel-fired furnaces has remained unchanged for many years. There is a need to improve the furnace design to integrate the newly developed technologies and optimize furnace performance.

Computer modeling can provide a cost-effective tool for testing new design ideas, such as furnace configuration, burner arrangement, firing strategy, etc. The model should include the dynamics of combustion, heat transfer between the gas phase and the melting phase, mixing and reaction in the batch and glass melt. In order to develop a reliable model, thorough understanding of chemical and physical processes in the melting phase is essential. Physical properties and kinetic data need to be acquired and validated. Finally, the model should be evaluated against data measured in a typical glass furnace.

There is a need to develop commercially viable rapid glass melters that speed up the melting process, reducing the size of the batch and the time required to produce glass. These melters should have higher energy efficiency and flexibility, and lower pollution emissions, so that they can be built in close proximity to consumers to reduce transportation costs.

Heat losses from the furnace wall and openings consists of more than one third of the energy required in the melting process. New port designs and better insulation materials are needed to increase the furnace heat efficiency.

Recovering and Reusing Waste Heat from Oxy-Fired Furnaces

Recovery and reuse of waste heat from the oxy-fuel process will further increase energy efficiency of the process. Preheating the batch and cullet, described above, is one method to recover heat from the flue gas. Other options, such as regenerative oxygen heat recovery (Browning and Nabors 1996) and a "synthetic air" concept (Argent 1997), have been proposed, and need to be tested and evaluated.

Producing Oxygen More Efficiently for Oxy-Fuel Firing

A Thermal Swing Adsorption (TSA) oxygen production process has been demonstrated in the laboratory with enrichments of up to 89% (Mathur date?). The process is based on synthetic chemicals that can reversibly bind oxygen at low temperatures and release it at elevated temperatures. The operation is in a temperature range of 70 to 220°F, so low grade waste heat can be used to drive the process, and the external energy required for produce oxygen can be reduced.

Discussion of Energy Savings in the Glass Industry

The estimation of energy savings by using the oxy-fuel process does not include energy consumption in the production of oxygen. It is estimated that about 2 MMBtu is required to produce one ton of pure oxygen. If an energy input for melting one ton of glass of 6 MMBtu and a heat content of 1000 Btu/ft³ for natural gas are assumed, approximately 0.5 ton of oxygen is required to melt one ton of glass. Therefore, about 1 MMBtu per ton of glass is consumed in the production of oxygen. Considering this factor, the total energy savings by using the oxy-fuel process is not as significant as calculated above, unless waste heat in the process can be recovered for the use in the production of oxygen, such as the TSA process.

In a regenerative glass furnace, a rough heat balance indicates that about 37% of the energy input goes to the melted glass, 23% to the stack and 40% through the wall. Most of current research is focused on reducing heat loss through the stack. However, potential for energy savings would be even greater by recovering heat from the melted glass and from reducing heat loss through the wall. From increasing energy efficiency point of view, research in these two area should be enhanced.

In the forming process, cullet is generated and circulated back to the melter. Technologies to reduce cullet generation in the forming process can increase production efficiency and reduce the cullet amount, so that the energy consumption per ton of glass will be decreased.

D-2.4.3 References

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D-2.5 TECHNOLOGY EXAMPLES FOR ALUMINUM

Aluminum smelting is highly capital intensive, with capacity cost estimates ranging from \$3,000 per metric ton for expansion of existing facilities to \$5,000 per metric ton for new facilities (BOM 1993). Low energy costs in countries such as Brazil, Canada, and Australia have made the international aluminum industry extremely competitive, and near term construction of smelting capacity is not expected in the United States. Investment in state-of-the-art technology has also been limited by capital constraints.

D-2.5.1 Technology Examples Available before 2010

A variety of technologies exist, however, that have the potential to incrementally reduce energy intensity in the aluminum industry in the timeframe to 2010.

Improving Hall-Heroult Cell Efficiency

The primary starting material for the production of aluminum is bauxite, containing high concentrations (45 - 60%) of aluminum hydroxide. Bauxite is mined and, through the Bayer process, converted into alumina (aluminum oxide) which is ground to a powder and then reduced to aluminum by the Hall-Heroult process.

In the Hall-Heroult process the alumina is dissolved in steel boxes, or cells, in a mixture of molten cryolite. Direct electrical current is passed through the mixture, reducing the alumina to aluminum and oxygen. The oxygen combines with carbon at the system anode forming carbon dioxide. The aluminum, which is heavier than cryolite, sinks to the bottom of the cell and then can be tapped off.

Modern aluminum smelting cells consist of a steel shell lined with refractory insulation. These are then lined with either a rammed mix of pitch and anthracite coal or coke baked in place by

the passage of electric current, or prebaked cathode blocks cemented together. The carbon lining acts as a cathode in the system. Cell relining, which normally occurs every 2 to 4 years, is an appreciable part of production expense, including not only the cost of labor, collectors, lining, and insulation materials, but also loss of electrolyte materials absorbed by the spent lining.

Anodes, either prebaked or Soderberg, are suspended from a superstructure above the cell and connected to a movable bus so that their vertical position can be adjusted. The cell is brought into operation by first lowering the anode until it contacts the carbon cathode lining of the cell. Current is then passed through the cell to increase the temperature. Cryolite is added and the anode raised until the cell fills to the appropriate height. During operation of the cell a crust forms on the surface of the molten bath. Alumina is added on top of the crust, where it preheats and water is removed. The crust is then broken and the alumina stirred into the bath.

The current U.S. composite baseline energy intensity for aluminum smelting is estimated at 15.2 kWh/kg of aluminum, with the potential near-term reduction using retrofit technology estimated at 13 kWh/kg (Energetics 1997). Performance in the range of 13 to 15 kWh/kg has been achieved in domestic smelters through a variety of techniques including enhanced potline controls, better anode rod connections, improved cathode block materials, and increases in anode size resulting in lower current density (Newsted et al. 1992, Jeltsch and Franklin 1992).

Additional research to design dimensionally stable cells and to optimize materials use for internal control of cells, and to use signal analysis to analyze cell voltages in potlines are seen as areas which can improve smelting performance in the next 10 years (Energetics 1997). The primary barriers to adoption of high efficiency technologies may be economic, however.

Materials Recycling

Remelting aluminum scrap requires only a small fraction of the energy required to smelt aluminum from alumina. Recovery of old scrap (discarded aluminum products) has increased from less than 200 metric tons per year in 1970 to more than 1,600 metric tons in 1992 (Aluminum Association 1993). In 1993, aluminum recovered from old scrap was equivalent to about 25% of apparent consumption in the U.S. (DOI 1994).

While some of the barriers to higher recycling rates are institutional (e.g., perceived value of recycling beverage containers), technological barriers also exist. These include problems with scrap sorting, separation, cleaning, and pre-treatment, which inhibit the increased use of different types of scrap and also contribute to problems with metal quality. Byproduct recycling (e.g., salt cake and spent potlining) is also inhibited by a lack of knowledge of byproduct characteristics (Energetics 1997).

Research needs identified by the DOE include the development of alternative pre-treatment technologies for scrap, the development of lower-cost aluminum purification technologies, and statistical analysis to characterize the composition of waste streams from smelters. A critical review of the U.S. recycling industry infrastructure could also identify ways to enhance aluminum recycling rates (Energetics 1997). Given the magnitude of energy savings associated with recycled aluminum versus virgin aluminum, enhanced recycling may offer the greatest energy savings and greenhouse gas emissions reduction opportunities in the short term.

Improve Furnace Efficiency

Improving energy efficiency of melting and holding furnaces offers significant potential for energy savings in the secondary aluminum industry. Several commercially available technologies exist for reducing energy use in furnaces including heat recuperators and regenerators, and the use of oxygen assisted combustion. Heat recuperators operate by passing the combustion products through heat exchanger tubes allowing the preheating of inlet combustion air and recovery of heat that would otherwise be exhausted to the atmosphere. Heat regenerators accomplish heat recovery through a paired burner/exhaust system in which the burners alternate in the firing mode in cycles lasting about 20 seconds. As the combustion products are exhausted through the non-firing burner, a heat storage material absorbs energy. In the firing cycle this stored energy is released to the cool intake air, with the result that again less heat is rejected to the atmosphere.

Oxygen assisted combustion uses oxygen in a dual-firing burner to increase furnace melt rates, reduce energy use, and reduce emissions. Oxygen assisted combustion has been used for more than 30 years in the aluminum industry (Heffron et al. 1993), but often results in problems such as large dross formation, excessive refractory consumption, and less than expected energy savings. Low flame luminosity with oxygen assisted burners can also reduce radiative heat transfer. Advanced burner designs incorporate more precise gas, air, and oxygen control to produce a high temperature, high luminosity flame. Energy savings from oxygen assisted combustion can be substantial.

D-2.5.2 Technology Examples beyond 2010 Requiring Further R&D

Many advanced technologies have been researched that could provide dramatic reductions in energy use in the aluminum manufacturing process. Because of the inherently high energy requirements of the Hall-Herault process, the most dramatic energy savings and emissions reductions are likely to result from new or improved smelting technologies. These include the development and commercialization of inert anodes, carbothermic reduction processes, aluminum chloride processes, and wettable titanium diboride cathode components.

Inert Anodes

Inert anodes offer a variety of advantages over traditional carbon anodes, including increased cell productivity, reduction in cell shorting due to undulations in the molten metal, and higher metal purity. The most promising materials presently being evaluated are ceramic/metal composites consisting primarily of nickel oxide and nickel ferrite with a copper/nickel metal phase (Windisch and Strachan 1991). Energy savings from inert electrodes are estimated at 11% over current production methods (Energetics 1990). In addition, inert anodes have the potential to substantially reduce CO₂ emissions during smelting.

Carbothermic Reduction Process

Direct reduction processes for aluminum production have long been the subject of research by the aluminum industry. Several carbothermic production methods have been patented, for instance, and one was even brought into production by the Pechiney Company in France, but none are currently operating. One problem with carbothermic reduction of alumina in electric furnaces is low yields as the result of formation of solid aluminum carbide and aluminum suboxide, and aluminum vapors that react with carbon monoxide as they leave the furnace. Vaporization and carbide formation can be reduced by adding a metal to the furnace, thus

forming an alloy. Aluminum can then be extracted through a separate purification process. Direct reduction has the potential to reduce energy consumption as much as 25% below that of conventional Hall-Heroult cells (Energetics 1990).

Aluminum Chloride Process

In aluminum chloride processes, alumina, carbon, and chlorine are reacted to produce aluminum chloride and carbon dioxide. The aluminum chloride is then electrolyzed in bipolar electrode cells to produce aluminum and chlorine. Though the process has the potential to reduce energy consumption as much as 25% below existing Hall-Heroult cells (Energetics 1990), the need for a reactor to convert chlorine to aluminum chloride offsets the cost advantages.

Titanium Diboride Cathodes

Wettable titanium diboride cathodes have the potential to significantly reduce energy use in aluminum production. Because of its good electrical conductivity, titanium diboride cathodes can significantly reduce voltage drop at the cathodic aluminum interface. Potential energy savings are estimated as high as 30% over conventional cells (DOE 1990). Though most of the major aluminum producers have conducted research on titanium diboride cathodes, the high cost of production and early failure of the components have kept them from commercialization.

D-2.6 TECHNOLOGY EXAMPLES FOR IRON AND STEEL

(Prepared by Ken Natesan, Energy Technology Division and Leslie Nieves, Decision and Information Sciences Division, Argonne National Laboratory.)

Iron and steel industry comprises of the ore based integrated steel plants and the scrap based "mini mill". Steel production via integrated plants has been decreasing, while that of the Electric Arc Furnace (EAF) based mini mills has been increasing. At present, the production capacity of the mini mills is comparable to some of the smaller integrated plants. Mini-mills are more energy efficient, since they use 100% scrap, but the range of products that can be produced in mini-mill is somewhat limited by scrap quality issues.

As technologies introduced for mini-mills are adopted in the integrated mills and mini-mill begin to backward integrate into the manufacturing of iron (rather than relying exclusively on scrap) these distinctions begin to blur. Most of the issues the iron and steel industry face are generic in nature, such as process development, process efficiency, raw material availability and flexibility, process control, environmental compliance, sensors and monitors, and intelligent processing. The following sections identify some currently available technologies, if implemented, can have a significant impact on the industry.

Technology and R&D discussions in this section are grouped by their relationship to the topics of ironmaking, steelmaking, and thermomechanical processing. However, many of the issues faced by the iron and steel industry are generic in nature, such as process development, process efficiency, raw material availability and flexibility, process control, and environmental compliance.

D-2.6.1 Technology Examples Available before 2010

Ironmaking

The current practice for primary production of iron is by blast furnace processes which involve reaction of iron ore with a reductant (traditionally coke) and a flux (limestone) at elevated temperatures in a shaft furnace. The process normally takes about 6-8 h to produce liquid metal from a given charge. The industry currently is in a state of flux regarding ironmaking process alternatives to the blast furnace. Direct reduction and direct smelting are the two approaches that are being examined in a variety of processes under development in the U.S. and abroad. The drivers for the alternate processes are the elimination/minimization of coke and coke oven batteries (which are environmentally unacceptable without significant investments for compliance) and increased reaction rates thereby improving the iron production rate.

Gas-based direct reduction processes

These processes include MIDREX, HYL, SPIREX, Iron Carbide, and CIRCORED, which all involve direct reduction of iron ore pellets/fines with natural gas/hydrogen as a reductant to produce a solid or, sometimes, liquid iron-rich product.

Coal-based direct reduction processes

These include the Rotary Kiln, Grate Car, Fastmet, Comet, Circofer processes, involving intimate mixing of iron ore fines and coal at elevated temperatures to accomplish the reduction process. The processes differ in details with regard to feedstock, type of reactor, operational features, and level of development.

Typical examples of direct reduction processes are:

- Qualitytech Steel Corporation, Corpus Christi, Texas, has begun construction of an iron carbide facility, expected to be operational by July 1998. The facility will annually convert 1.2 million tons of high-grade iron ore fines, by deoxidizing the ore and adding a carbon bond, to create iron carbide for use by electric furnace steel makers. Only one other facility worldwide manufactures iron carbide on a large scale.
- Kobe Steel and Midrex Direct Reduction Corp. have developed a production approach for molten iron that reduces the process from hours to minutes (Metals Industry 1996). Midrex (a subsidiary of Kobe Steel located in Charlotte, NC) hopes within five years to commercialize the process. With this approach, pellets made of iron ore fines and pulverized coal are heated to 1300-1500°C using natural gas as a reductant. A reduction time of 6-10 minutes is claimed, compared to the 6-8 h with a traditional blast furnace. Because the product is in molten form, there are savings in downstream steelmaking operations and the material can be cooled to iron shot or ingots without reoxidation.
- A rotary hearth process called COMET is being developed by the Belgian steel research organization and a demonstration plant is under construction at Sidmar's plant near Gent (Steel Times 1997). The process produces high-grade sponge iron from ore fines and coal, without pelletizing the charge materials.

Direct smelting processes

Direct smelting takes iron ore and coal and directly converts them to hot metal without the use of coke. Several processes (COREX, HISMELT, AUSMELT, ROMELT, Cyclone Converter furnace, etc.) are under development in the U.S. and abroad (Nilles 1996). All of these processes have goals of high productivity, simplicity of engineering, ability to use a wide range of coals, ability to scale-up to a level equivalent to a blast furnace, and environmental compliance with minimum cost. All produce hot metal with compositions comparable to that from a blast furnace.

Typical examples of direct smelting processes are:

- The COREX process is commercially available and the C-2000 module at Posco's Pohang Works in Korea has successfully demonstrated hot metal production at a rate of 2000 t/day with acceptable steel composition (Steel times 1997). Several COREX C-2000 modules are under construction in Korea, India, and South Africa.
- Cyclone converter furnace technology is being examined in a 20 t/h pilot plant in Holland. Independent evaluation of a cyclone converter furnace is also being made by Centro Sviluppo Materiali (CSM) in Italy with a pilot unit of 3-5 t/h (Steel Times 1997).

Top Gas Power Recovery Turbines, Compression/Expansion

Due to its energy content, blast furnace top gas is used as fuel in various facility stoves, furnaces, and boilers after cleaning. In large, newer blast furnaces which operate at higher pressures, installation of an energy-recovery turbine in the gas cleaning system can contribute to the facility's electricity needs. A gas expansion turbine using the excess pressure can recover both pressure energy and some sensible heat energy from the gas. Energy savings are estimated at 0.6 GJ/tonne crude steel (De Beer, et al. 1994).

Coal or Natural Gas Injection

Pulverized or granulated coal, residual oil, or natural gas can be injected directly into the blast furnace to partially substitute for coke inputs, thus reducing CO₂ production and toxic emissions of coke production. The injection of oil or natural gas has operational benefits, and has been practiced for many years. Interest in very high levels of injection is more recent, encouraged by the diminishing availability of domestic coke. Coke remains essential to blast furnace operation, since coke layers are essential for supporting alternating layers of ore and maintaining bed permeability.

Operation based on all coke requires about 1000 lb of coke per ton of hot metal (THM). Coal injection rates range from about 200 to 400 lb per THM, with each ton of coal displacing approximately one ton of coke. There is a tendency for this coke replacement ratio (mass of coke displaced per unit mass of coal injected) to drop at higher levels of injection. Typical values are 0.8 to 1.0. The reduction in net energy consumption and CO₂ emissions are realized as a result of the fact that about 1.39 tons of coal are required to produce a ton of coke. Thus, even at a coke replacement ratio of 0.8 tons of coke displaced per ton of coal injected, the injection of that ton of coal avoids the use of $0.8 \times 1.39 = 1.11$ tons of coal for coke production for a net reduction in coal use of 0.11 ton. This substitution increases the oxygen requirement of

the iron reduction process. The net savings, given the increased oxygen production needed, is estimated at 3.76 GJ/tonne of coal injected (De Beer et al. 1994).

Injection of hydrocarbons into the lower section of the furnace also has the advantage of improving furnace stability and hot metal quality. Pulverized coal injection allows substitution of lower grade, lower cost coal for metallurgical coal, which is used for coke making.

All active U.S. furnaces inject one or a combination of supplemental fuels. Natural gas is injected at rates up to 250 lb. per ton of iron (125 lb./ton average) at 25 furnaces (Hogan and Koelble 1996a). Current coal injection designs, of which there are three basic types, theoretically can inject at a rate of up to 400 lb/ton of hot metal (Carmichael 1992). In the US as of 1993, 15 furnaces incorporated coal injection systems. These include some of the largest furnaces totaling over one third of 1993 North American hot metal production (Gardner et al. 1996). Injection rates currently range up to 375 lb./ton of iron. Four more furnaces are scheduled to start coal injection in 1997.

Steelmaking

Steelmaking operations are generally conducted in two stages, melting of the iron/scrap in a basic oxygen furnace (BOF) or in an electric arc furnace (EAF) and subsequent refining operations. Some of the major concerns are the variability in feedstock composition (especially, scrap quality and trace elements in scrap which may impart deleterious properties to the final product), availability of sufficient scrap material, and costs involved in front-end separation and/or preparation of the scrap material as a feedstock for EAFs. Directly reduced iron, hot briquette iron, and iron carbide constitute less than 5% of the feedstock in EAF operations but are expected to increase substantially in the next 15 years.

Scrap Preheating

Energy consumption in electric arc furnace operations can be reduced by preheating scrap to approximately 400°C with EAF offgases. Heated metal charges comprising 20-30% of inputs can result in power consumption rates of <300 kWh/tonne liquid steel (Scheidig 1995). The potential energy savings is roughly 90 kWh/ton of liquid steel. This is based on a 76 ton furnace, with an annual capacity of 900,000 tons. For a DC Fuchs shaft furnace compared to a conventional DC furnace, energy savings of 13.5% are estimated and reduced electrode consumption of 29%. Baghouse dust reduction is estimated at 30% (Haissig 1994).

In addition to energy savings, scrap preheating with furnace offgases has other advantages. In the dual shaft furnace design, iron particles in the offgas tend to adhere to the scrap, resulting in iron recovery in the melt and leaving the offgas zinc-enriched (Burgmann and Pelts 1995). If zinc levels are enriched to above 25%, the dust may be an acceptable input to zinc refining, rather than requiring disposal as a RCRA-listed hazardous waste (Center for Metals Production 1987). Preheating also reduces furnace tap-to-tap time (normally about an hour) by 12 to 15 minutes (Scheidig 1995), resulting in increased raw steel production capacity, measured in terms of sustainable annual production.

A British study of scrap preheating involving modification of an existing furnace found an energy saving of about 25 kWh/liquid tonne. The plant-specific investment required had an actual payback period of over four years (Dept. of Energy 1987).

Use of DC, Rather Than AC EAFs

DC EAFs are similar to more widely used AC EAFs except that they are powered by DC current and have one large electrode in the furnace roof, rather than three, and a smaller one in the furnace floor. DC arc furnaces require slightly less energy for heating than AC designs due to better heat transfer and less radiant heat loss (Center for Metals Production 1987). In operation, the top electrode is covered by foamy slag to increase the power input and reduce electrode consumption. The technology is used in Europe and Japan; in the US, use is mainly by one company, Nucor. Existing AC units can be modified for DC operation, but new installations that incorporate scrap preheating systems and other energy saving features provide substantial advantages over modification.

DC arc furnaces have several advantages over AC furnaces: 1) more even distribution of temperatures due to the central location of the electrode, 2) lower rate of refractory furnace lining wear due to less arcing to the side walls, 3) increased bath stirring, 4) less electrical network disturbance (Center for Metals Production 1987), and 5) a lower rate of electrode consumption. Reduced electrode consumption is important from an electrode cost perspective, as well as reduced downtime.

Thermomechanical Processing

Regardless of whether steel is made by BOF, EAF, or any of the specialty processes discussed earlier, the ingot or the continuous cast steel product generally has to be thermomechanically treated to achieve the desired microstructures and mechanical properties for usage. The plate, sheet, bar, and pipe products undergo different rolling, annealing, forging, and pickling treatments dictated by the steel composition and properties desired.

Process Controls

At present, thermomechanical treatments are predominantly based on empirically developed technical information and the practice is largely dictated by tradition and accomplished by a trial and error approach. The time and temperature sequence for an annealing line is set, based on trial and error, to achieve a given hardness. The systems have almost no intelligent processing (with feedback) to obtain microstructural control in the sheets. As a result, the steels are normally over annealed (with regard to time at temperature). This is especially inefficient in processes where the continuous annealing lines operate at 50-200 m/min. Significant advances in thin strip casting have been made in Japan and the process, if implemented, can result in reduction in intermediate rolling steps and lower energy consumption, a decrease in industrial scrap generation, and lower unit cost of the product.

Hot Connection

Depending on plant layout, moving forms from the continuous casting operation to the rolling operation with minimal cooling may provide energy savings. Reheat furnaces are generally employed to bring the cast forms back to rolling temperature. Adjusting plant layout to move the cast semi to the rolling operation at a temperature of 600° to 800°C can result in an energy savings of 0.4 to 0.6 GJ/tonne semi based on the IISI reference plant defined in 1982 (Etienne and Irving 1985). A Dutch study based on a transport or connection temperature of 700°C estimated an 18% reduction in energy for reheating, for a savings of 0.3 GJ/tonne of crude steel (De Beer et al. 1994).

D-2.6.2 Technology Examples beyond 2010 Requiring Further R&D

Ironmaking

Activity will be largely dictated by the viability of different ironmaking processes that are under development. R&D effort should focus on developing a process scheme that incorporates both ironmaking and steelmaking into one system with thin strip casting as a final product. The effort should incorporate a coal-based reductant process which can be coupled with steelmaking operations and simultaneously produce power in a combined cycle that includes both gas and steam turbines

Steelmaking

Steelmaking processes currently utilize computer technology primarily to implement prespecified procedures in a timely manner. There is very little feedback in these systems to either enhance process efficiency or improve the product quality. Key process parameters should be identified so that interactive logic and high-speed computer systems can be used to control/modify/maintain these process parameters to obtain a quality product. Such an intelligent-processing approach is essential for the production of so called "cleaner steel" with low residual elements.

Thermomechanical Processing

The development of sensors for all aspects of process control and for enabling process changes with a feedback system is essential for improving process efficiency and optimizing different stages of the melting, casting, thermomechanical processing, and final heat treatment. Applications of novel ideas and approaches need to be explored and transfer of technologies available from defense and chemical processing industries may be a fruitful approach.

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D-2.7 TECHNOLOGY EXAMPLES FOR METAL CASTING

(Prepared by Jim Chang, Energy Systems Division, Argonne National Laboratory.)

Metal casting is not a single industry segment according to the SIC system, but covers a diverse group of products and metals. Products range from cast pipes, motor vehicle components, and tools. Iron, steel, aluminum, copper and zinc are all metals used by the industry. The industry is labor intensive, with many small plants; four out of five have fewer than 100 workers. Over half of the energy use is in melting metal. Technologies which improve the melting stage or reduce waste/recasting have important energy implications.

D-2.7.1 Technology Examples Available before 2010

The technologies described below can lower energy use and are not currently in widespread use in the metal casting industry.

Computer-Aided Casting Design

Rapid advances in computer modeling of the casting process and in computer-aided drafting of castings have led to an increased use of computers in working foundries, and hence, an increased need for integration in casting design systems. Increased integration in the casting design functions is needed to realize the full potential of the computer for improving both casting designs and production lead time.

Two kinds of information are produced by the casting analysis and simulation function: (a) results predicting the outcome of casting the current design; and (b) the processing parameters for the casting process, if the casting design appears sound. The predictive results allow the foundry engineer to evaluate the filling of the mold cavity, the potential for defects such as

porosity in the casting to occur, the sequence of solidification, and the time for complete solidification.

Benefits have already been realized based on the proportion of parts being cast with the software (Hickie 1996, Cooley 1996). An average of 25% improvement was found in the casting yield among the PC and workstation users. Overall, the mean improvement was at least 25%, regardless of either performance criteria or computer platform (Lensen 1996, Lensen et al. 1996).

Optimized Coreless Induction Melting

Most foundries can dramatically reduce a major portion of their energy costs without spending a single capital equipment dollar, simply through proper optimization of their induction melting equipment. It has been estimated that foundries are only operating their induction furnaces at 50-80% of their optimal efficiency (Horwath et al. 1996), wasting valuable energy dollars daily. For instance, a foundry melting 1000 tons/month could easily reduce its monthly melting costs by \$5/ton simply by altering its melting practice.

Four major variables were considered the most important in determining power required for melting: (1) charge makeup, (2) furnace cover, (3) power application, and (4) furnace condition. These variables were found to be significant in determining the power consumption during coreless induction melting. In some cases, optimal material use resulted in higher energy use (22% more) and use of a furnace cover reduced energy consumption by 12%. Furnace condition (i.e., hot, medium, or cold) interacts with the charge to significantly affect energy consumption. Maintaining the furnace in hot condition resulted in 15.4% less energy consumption for melting the charge (Horwath et al. 1996). A better recognition of the impact of these variables will trigger operational changes to better control the melt power consumption.

D-2.7.2 Technology Examples beyond 2010 Requiring Further R&D

The R&D issues/opportunities described below are critical to the development of the metal casting industry and must be addressed to achieve further energy savings after 2010.

Electromagnetic Casting

An electromagnetic field in a casting is brought about by an inductor that produces a time-varying magnetic field. The field induces eddy currents in the liquid metal that, together with the field, give rise to an EM force (Lorentz force) that stir and contain the liquid metal in the casting. Two examples are discussed below:

EM Stirring: In continuous casting, the solidification process can be improved by EM stirring. EM stirring can produce better metallurgical results, improve internal quality of the casting, and even reduce meniscus instability and surface defects (Beitelman and Mulcahy 1994, Chang et al. 1995). Therefore, a study of EM stirring is needed to design and fabricate EM stirrers, optimize the existing casting processes and improve the quality of products.

The benefit from EM stirring will be reduced wastage per cast. Thus, less metal will need to be melted and poured per cast part. As a minimum, we expect that the present average yield of 55% for the industry will increase to 65%, a saving of 130,000 tons per year, with an associated energy savings of 25 trillion BTUs per year (American Foundrymen's Society 1995).

EM Confinement: In the presently dominant sheet-forming process, thick steel slabs are cast and then hot-rolled. The hot-rolling stage is very capital- and energy-intensive and adds greatly to the cost of the final product. Twin-roll casting with EM confinement has the potential to cast thin sheets by eliminating the hot-rolling stage and it gives the sheet product an enormous economic advantage over products made by competing methods (Saucedo and Blazek 1994, Blazek et al. 1994). Because there is no contact with liquid metal, EM confinement bypasses fundamental problems of solid dams and provides benefits that include energy conservation, cost savings, and enhancement of the competitiveness of US industry in the world market (Argonne National Laboratory 1995, Chang et al. 1996).

Clean Metal Casting

It is necessary to develop a technology for clean metal processing that is capable of consistently providing a metal cleanliness level fit for metal casting. The technology to economically produce sound castings and lower energy use will be important for the survival of many steel/iron/aluminum foundries (American Foundrymen's Society 1995, Cast Metal Coalition 1997). The technology is expected to improve casting product quality by (1) removing or minimizing oxide defects and allowing the production of higher integrity castings, (2) reducing the incidence of macroinclusions in castings, and (3) reducing reoxidation of the metal during pouring. The required technology is summarized below (DOE 1996a, b):

- Use of inert and reactive gases for reducing hydrogen and inclusions (oxides, carbides), and minimizing hydrogen absorption.
- Use of alloying elements and cover media to reduce melt oxidation.
- Reduced pressure techniques.
- Development of specific apparatus and procedures for measuring air entrainment during pouring.
- Phase separation technology including knowledge of sedimentation, filtration, and fluxing techniques.

Metal Penetration in Iron and Steel Castings

Penetration defects cost American iron and steel foundries about \$65 million per year. Penetration in castings is caused by mechanical pressure of metal forcing itself into the sand mold and most penetration defects are caused by pool casting design and poor molds. In the past years, it has been found that the probability of penetration occurring in cast iron increases with 1) higher pouring temperatures, 2) higher silicon and carbon levels, 3) higher casting heights, and 4) faster pouring speeds (Lane et al. 1996).

Further research is underway on steel castings and, while common principles apply to the two metal groups, there are some important differences, especially regarding the conditions under which chemical penetration can occur. However, prevention of penetration in both iron and steel is a combination of mold practice and casting design. If both are done correctly, nearly all cast penetration problems can be eliminated. Research in this area should be planned to establish methodology to determine interfacial gas composition, develop computer models of liquid metal oxidation, and determine effects of iron/steel composition at the mold/metal interface (DOE 1995).

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D-2.8 TECHNOLOGY EXAMPLES FOR CROSSCUTTING TECHNOLOGIES

(Prepared by John Molburg, Information and Decision Sciences Division, Argonne National Laboratory.)

There are a variety of crosscutting technologies, i.e., those that are not process or product specific, in operation in industry. Some include the lighting and HVAC examples that are in common with commercial applications and are not discussed here (see chapter 2). Others include sensors and computer control systems which have a common underlying technology, but have a variety of configurations and benefits depending on the industry. Motor systems, on the other hand, encompass a wide range of industrial applications are discussed here as an example of non-process specific efficiency applications. The second major type of efficiency application is cogeneration, sometimes also referred to as combined heat and power (CHP). Cogeneration is the joint production of useful steam and electricity, either for on-site use or sales back to the electric grid. This section also discusses cogeneration as an energy efficiency option.

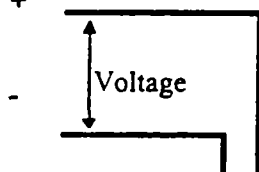
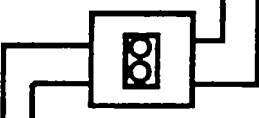
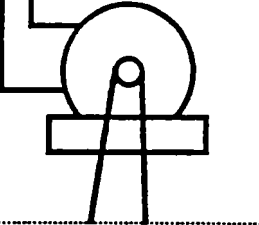
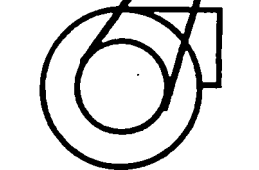
D-2.8.1 Technology Examples Available before 2010

Electric Motor Applications

Energy use by Electric Motor Systems Systems employing electric motors convert only a portion of the energy consumed into useful mechanical work. This fraction of useful work is the system efficiency. To understand the energy conservation opportunities presented by these applications, it is essential to trace the energy conversion processes throughout the system, which includes power supply and controls, electric motor, power transmission, and the load (the driven equipment).

Table D-2.8.1 shows a schematic of an electric motor application and lists some of the factors associated with each component that affect system efficiency.

Table D-2.8.1 Efficiency Losses in Electric Motor Applications

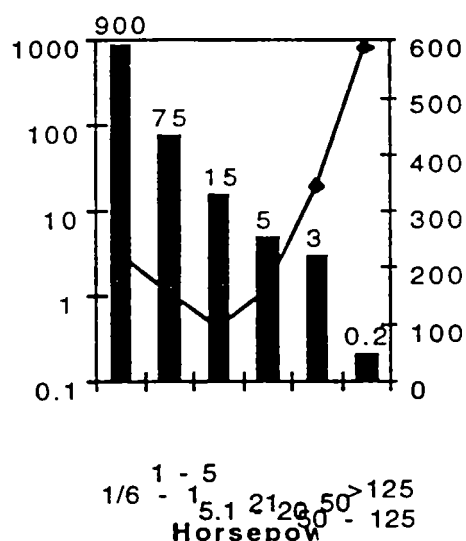
Component	Energy Efficiency Issues
Power Supply 	• Voltage unbalance (uneven voltage between phases) can increase motor losses and damage motors. • Deviations from design voltage can reduce motor efficiency and motor torque even if balance is maintained between phases. • Harmonics (deviations from simple sinusoidal voltage form) can reduce motor efficiency and adversely affect mechanical operation. Adjustable speed drives can introduce harmonics.
Motor Controller and Power Feed 	• Power losses in motor feed cables can lead to low voltage at the motor. Low voltage can reduce efficiency. • High starting currents (five to seven times normal operating currents) may push the limits of feeders, resulting in low voltage. • A high power factor can increase losses in distribution lines and transformers and can lead to undervoltage and the associated problems of low motor torque and efficiency.
Electric Motor 	• Motor energy losses include electrical resistance losses, magnetic field losses, mechanical (frictional) losses, and stray losses due largely to minor design compromises and manufacturing irregularities. These are addressed by high efficiency motors. • Motor efficiency is often reduced by rewinding. • Energy efficient motors are typically 1% to 5% more efficient than standard motors for large motors. For fractional HP motors the difference may be 40%.
Transmission 	• Drive train efficiency, including belts, gears, etc., can be as high as 95%, but may be below 50%. • Helical gears are more efficient than worm gears in most applications. Helical gear efficiency drops at part load applications. • About 1/3 of drives use belts and pulleys. These are typically 90% to 99% efficient if properly selected and installed.
Load 	• Oversized motors are very frequently selected. Motor efficiency declines rapidly at loads below 40% of rated load. About 20% of motors over 5 HP are in this category. • Fans and pumps account for most motor power consumption. Optimal selection of fans and pumps and associated control systems can reduce motor drive requirements substantially. Use of variable speed controls rather than throttling is a particularly important strategy.

An overview of the distribution of motors and energy consumption by motor size is essential for targeting an efficiency program. Based on an assumed 3% growth rate in motor population since 1977¹, ACEEE (Nadel, Shepard et al. 1992) estimates the current population of motors over 1/6 HP at about 1 million units. Motors of less than 1 HP constitute 90% of the population and consume about 15% of the energy. Conversely, motors exceeding 1 HP, though only 10% of the motor population, consume 85% of the electrical energy consumed for motor drive. Figure D-2.8.1 provides a summary of the population and energy use estimates by motor size classification. In fact, motors larger than 50 HP consume about 60% of motor drive power consumption. This has led ACEEE to conclude that most of the potential for energy

¹ One of the few comprehensive surveys of U.S. motor populations was completed by A.D. Little in 1977.

conservation lies in the large motors. Given the size of the embedded motor population, this seems fortunate for planning an energy conservation strategy. However, as noted below, the replacement of standard motors with high efficiency motors results in a far higher percentage efficiency improvement for fractional HP motors than for large motors. Therefore, at least for the motor replacement strategy, the fractional HP motors are still an important target for conservation programs.

Figure D-2.8.1 Comparison of Motor Population and Energy Use by Horsepower (Nadel, Shepard et al. 1992 Fig. 6-1)



Energy Efficient Motors

As noted above, energy efficient motors (EEMs) present only one of several important options to reduce energy consumption by motor systems. In fact, the direct substitution of EEMs for equivalent size standard motors for the existing population characterized in Figure D-2.8.1 would result in about a 7% reduction in power consumption. This estimate is based on the assumption that the current motor population efficiency is at a level representative of new standard motors in the respective size classes. While the actual efficiency of older motors is probably below the efficiency of current standard units, high efficiency motors have been available for two decades and are included in the current motor population². The resulting errors tend to cancel. For this hypothetical comprehensive replacement program, the total savings is 109 Twh/yr out of the total motor power consumption of 1570 Twh/yr for the current motor population.

High efficiency or energy efficient motors are more efficient than standard motors because they reduce one or more of the four types of losses associated with motor operation: electrical losses (rotor and stator losses), magnetic losses (core losses), mechanical losses (friction and windage), and stray losses. Electrical losses are due to the familiar conversion of electrical power to heat due to current flow through conductors of non-zero resistance. These are known

² Several sources cited by ACEEE (Nadel, Shepard et al. 1992) suggest that about 3% of current motors are EEMs on a horsepower-weighted basis.

as I^2R losses because they are proportional to the resistance, R , and to the square of the current, I . These electrical losses are controlled by reducing conductor resistance through increased conductor wire size.

Magnetic or core losses result from the build-up and break-down of magnetic fields in the laminated iron cores in response to currents. Hysteresis and eddy current losses result. While these are small compared to the electrical losses, considerable effort has been invested in new magnetic materials to reduce similar core losses in transformers. These new materials, along with larger cores and thinner laminations can reduce magnetic losses. Magnetic losses are roughly equivalent to rotor and to stator electrical losses at very low load, but are far less than electrical losses at full load.

Frictional losses result from bearing friction and from windage, the consumption of motor power for intentional and inadvertent air movement due to motor rotation. These are nearly independent of load, depending primarily on rotational speed. Changes in motor frame and fan design can reduce windage losses.

An important advantage of energy efficient motors is that they maintain (or increase) their efficiency advantage at part load. This is particularly important in view of the prevalence of motor oversizing, as discussed below.

Table D-2.8.2 provides some indication of the relative efficiencies of standard and high efficiency motors. Since the term "high efficiency" is vague, the industry has made some effort to specify requirements for motors carrying that designation. Because of manufacturing and materials variations, motor efficiency can vary considerably and must be described by a statistical distribution applicable to a given motor. Motor efficiency is nearly normally distributed about a mean or nominal efficiency value. The standards specify that the minimum efficiency at full load and rated voltage must be close to the nominal efficiency for that motor. Standards in place in 1991 required that the losses associated with the minimum efficiency be within 20% of the losses associated with the nominal efficiency. Thus, for a given design to claim 95% efficiency (5% loss), any particular motor of that design must not have losses greater than $1.2 \times 5\%$ or 6% (94% efficiency). A more restrictive class, with maximum losses 10% greater than nominal losses, has also been established.

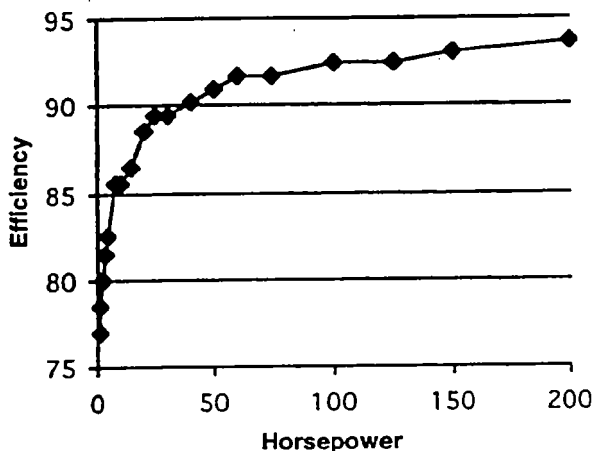
Table D-2.8.2, Hypothetical Savings from Comprehensive Motor Replacements

Horsepower	Standard Efficiency	High Efficiency	Energy Savings (TWh/yr)
1/6 - 1	0.55	0.75	60
1.1 - 5	0.76	0.84	15
5.1 - 20	0.87	0.91	4
21 - 50	0.89	0.93	7
50 - 125	0.92	0.95	11
> 125	0.94	0.96	12

Source: Efficiency values from manufacturer's data as reported in (Nadel, Shepard et al. 1992 Table 2-3).

In addition to the statistical allowance for variation, a minimum criteria for high efficiency motors has also been adopted by the National Electrical Manufacturer's Association (NEMA). The minimum requirement is shown in Figure D-2.8.2 for one common motor type.

Figure D-2.8.2, Minimum Efficiency Criteria for High Efficiency Motors



Source: NEMA MG 1-1987, TEFC, 4-pole, 1800 RPM as cited in Resource Dynamics Corp. (1992).

Efficiency Opportunities in Power Supply, Controller, and Feed

Alternating current or AC motors consume about 90% of the power provided for motor drive. In addition, the market for AC motors is growing at the expense of DC motors. DC motors offered the advantage of economical speed control and high starting torque. As recently as 1987, about 50% of motors over 1 HP sold were DC motors, though this corresponds to only 2.5% of the market because of the large number of fractional HP motors sold (Resource Dynamics Corporation 1992). ACEEE notes that the development of economical speed control for AC motors has reduced the DC motor market to less than 5% (Nadel, Shepard et al. 1992)p.32. While this appears to be inconsistent with the 1987 sales, the ACEEE data may include small DC motors for portable power applications. In any case, AC motors are dominant both in power consumption and in population. Therefore, we have addressed power supply concerns as they pertain to AC motors.

AC motors are of two basic types: single phase and polyphase (generally three phase). While fractional HP motors essentially all single phase, sales of integral HP motors are fairly equally split between single and polyphase units. A three phase motor simply has three sets of windings, each connected to a separate AC line. The three windings are offset to improve uniformity of the magnetic forces exerted on the rotor. Two power characteristics are important for optimum motor performance. The voltage must be uniform in all three phases and the voltage wave form must be smoothly sinusoidal.

Unfortunately, the voltage can vary substantially between the three phases of a polyphase motor. This can result from a plant electrical layout that imposes more load on one phase than on the others, which leads to a greater voltage drop in one phase before it reaches the motor. A modest phase voltage unbalance can severely impact motor performance. ACEEE notes that a 2% unbalance in phase voltage can result in a 25% increase in losses (Nadel, Shepard et al. 1992, p. 66). This would reduce the efficiency of a 90% efficient motor to 87.5%. Unbalanced

phase voltage also results in reduced motor torque, requiring derating to protect the motor from over heating. Since unbalanced phase voltage generally reflects deficiencies in plant electrical layout, the cure lies in modifications to plant wiring, including conductor sizing, redistribution of plant loads, and proper overcurrent protection.

AC motors are ideally suited to operation with smooth sinusoidal input voltage. However, certain loads cause distortions in the voltage waveform that can affect motor operation. These distortions can result in reduced or pulsating torque, motor vibration, increased losses, overheating, and damage to electronic controls. Among the loads that can cause these distortions or harmonics are adjustable speed drives (ASD). If adjustable speed drives are used on a substantial fraction of total plant load and particularly on large motors, great care should be taken to properly install the ASD. Energy efficient motors are less susceptible to operating problems associated with harmonics, providing additional incentive for EEM installation.

AC and DC motors are also adversely affected by low voltage. That is, even if the voltage is balance across phases, it may be below the motor design specification because of electrical power losses in the plant distribution wiring or motor feed wires. While voltage deviations of 10% are generally acceptable, larger deviations can result in reduced efficiency and reduced service life. The solution is to provide adequate wire size for the distribution and feed cables that service motors. Electrical code standards for wire gauge are based on safety concerns, primarily limiting I²R heating losses to prevent risk of fire. However, larger wire sizes may be recommended by overall economics, since increased wire size reduces electrical losses. If these reduced losses also improve motor efficiency and operation, the economics of increased wire size are further improved. However, increasing wire size in existing plants may be difficult or uneconomic because of constraints imposed by existing conduits.

Power Transmission Efficiency Issues

Mechanical transmission systems are generally required to transfer the motor torque to the driven load. In most cases the motor speed must be matched to the desired load speed by the intervention of a drive train of gears, pulleys, or both. About one third of motor applications employ belt drive systems, which are highly efficient if properly selected and installed. V-belts are about 90% efficient, with losses resulting from friction on pulleys, slippage, and belt flexing. Some improvement in efficiency is possible through the use of notched v-belts, which are more flexible than standard v-belts. Further improvement is possible with thin synchronous belts that have cogs or teeth that engage mating teeth in the pulley. Belt drive efficiency up to 99% is possible with such systems.

Gear-based transmission systems are of two basic types, worm gears and helical gears. Worm gears provide inexpensive means of large speed reductions for power applications below about 15 HP. However, worm gears result in high friction losses, particularly for large reduction ratios. Worm gear efficiency is typically 70% to 80%. Helical gear systems are more efficient and are more economical for higher power applications. Helical gear efficiency is 90% to 96%. For high reductions, efficiencies of both gear types are greatly reduced. A worm gear operating at a reduction of 60:1 will have an efficiency of 50% to 65%. In contrast, a helical gear train at that reduction ratio remains over 90% efficient.

The efficiency of helical reducers drops slightly at part-load down to about 20% of rated load. Below that the efficiency drops precipitously, emphasizing the importance of matching equipment to load, as discussed for motors below.

One of the most important loads, pumps, are most often directly coupled to the motor via flexible or rigid couplings between the motor and pump shafts. These generally result in little efficiency loss, though failure to properly align the shafts can result in reduced efficiency and accelerated bearing wear, which leads to higher frictional losses.

Motor and Load Issues

When the load presented to an electric motor is below the rated load of the motor, the motor will draw less current and perform less work. For instance, the motor operating an air compressor will draw more current as the pressure builds in the storage tank. Since both power output and power input are reduced in part load operation, these changes do not reflect a precipitous decline in efficiency (the ratio of output to input). However, some change in efficiency does normally accompany part load operation. Peak efficiency is normally achieved at about 75% of full load. As the load increases to full rated load, a slight decline in efficiency (1% to 2%) occurs. At loads exceeding rated load some additional decline is experienced. The more troubling effect is the rapid decline in efficiency at part load, particularly below 40% of rated load. A 10% decline in efficiency (from 85% to 75%) is representative of operation at 25% of rated load. It has been estimated that one third of motors are operated below 50% of rated load (Nadel, Shepard et al. 1992, p. 162).

Proper sizing of motors is not an easy task. As in the example of the compressor, loads may vary over a broad range during normal operation. In addition, transient loads must be taken into account, and the aging of equipment changes load. For instance, the buildup or scale in piping systems increases pumping load. Finally, it may be prudent to design a system for growth. In addition there is a tendency to oversize motors by the application of formal or informal safety factors. A very common practice is to oversize motors in ventilation systems. Motors in owner or consultant designed ventilation systems frequently operate below 35% of rated load (Nadel, Shepard et al. 1992, p. 163).

Fans and pumps are the most common motor loads, constituting over 40% of industrial motor loads (Resource Dynamics Corporation 1992). As noted above, it is common to oversize motors for these applications. However, it is also common to design fan and pump applications that consume more energy than is actually required to accomplish the fluid movement task at hand. Power consumption by a fan or pump is proportional to the product of flow rate and pressure drop. The pressure drop is the pressure loss caused by friction as the fluid flows through its conduit. However, the pressure drop is proportional to the square of the flow rate. Therefore, the power consumed is proportional to the cube of the flow rate. For instance, a flow rate reduction from 1 unit to 0.8 units (20% reduction) results in a power requirement of about one half, $(0.8)^3$, of that at full load. Thus, substantial savings may be possible if flow rates can be reduced in a given process, say in building ventilation. The recent switch to smoke free offices has reduced the need for fresh air, suggesting a change in ventilation standards may be appropriate in some older buildings.

Related issues arise in consideration of fan and pump design. The efficiency of fans and pumps are the ratio of the theoretical power required to maintain a given flow rate against a given pressure drop to the actual power required by a particular fan or pump. The efficiency of this equipment is highest within a narrow operating range of pressure and flow. Outside of this range, the efficiency can drop substantially. Therefore, it is important to match a fan or pump to a particular set of operating requirements. It is common practice to adjust pump performance by reducing the impeller diameter. this too is accompanied by reduced efficiency.

As an alternative, pump speed can be varied to adjust flow rate. This can allow operation at higher efficiency while matching load. The use of speed control on fans can be equally important, permitting operation near optimum efficiency over a range of flow conditions. Current practice relies on throttling (restricting flow by valves or dampers) to achieve flow control. This is obviously accompanied by substantial friction losses and, less obviously, by operation of fans and pumps at sub-optimal efficiency.

The development of economical adjustable speed drives for AC motor systems may provide the largest potential efficiency opportunity. On average, adjustable speed drives result in 15% to 40% reduction in energy consumption, and only about 10% of appropriate opportunities for adjustable speed drives have been exploited (Resource Dynamics Corporation 1992).

Cogeneration

An important strategy for reducing greenhouse gas emissions is to implement improvements in the efficiency of energy conversion processes. Fossil fuel is used at many industrial sites to raise steam for process heating and other process requirements. Depending on the relative electricity demand (steam to electricity ratio, kWh/Btu) and the price of electricity, such industrial sites may be candidates for the cost effective application of cogeneration. However, NO_x emission regulations may be a major impediment to the expanded adoption of industrial cogeneration.

In a cogeneration system, the thermal energy generated by the combustion of fossil fuels is first used to generate electricity before it is used to provide process steam. The advantage of such an approach is that little additional fuel is required for the electricity generation over that required for simple steam production. Thus, the efficiency for use of the thermal energy available from the fuel is higher than with separate electricity generation and steam production, and the net greenhouse gas emissions can be reduced by the application of cogeneration. There are two common alternatives for the power generation side of cogeneration: a Rankine cycle (steam turbine) with turbine exhaust steam directed to meet process requirements and a Brayton cycle (gas turbine) with steam raised in a heat recovery steam generator (HRSG) using the hot turbine exhaust gas.

The economics of a cogeneration system depend on the steam requirements of the plant and can vary tremendously, depending on the industry. Local steam load, need for backup power charges, and on site electrical equipment may be required. Based on a typical boiler configuration, the gas turbine with HRSG appears to be the most cost effective application. In 1994, manufacturing cogeneration accounted for 158 billion kWh. A relative penetration cogeneration index shows that paper and chemicals have much higher than average cogeneration. The penetration index developed shows substantial variation in penetration by industry and by state. (Boyd, Molburg and Thimmapuram, 1996)

A new generation of advanced turbine systems (ATS) is likely to be commercially available before 2010. Estimates of a 22% lower CO₂ emission relative to the best available gas-fired-combined cycle central station electric generating system have been made for 15MW industrial ATS projected to be commercially available by the year 2000 (Major and Davidson 1997).

D-2.8.2 References

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APPENDIX E

APPENDIX E-1 SUPPLEMENTAL TABLES

Table E-1.1 Standard Technology Matrix for Cars

Vehicle Technology	Fractional Fuel Efficiency Change	Incremental Cost (\$1990)	Incremental Cost (\$/unit wgt)	Incremental Weight (lbs)	Incremental Weight (lbs/unit wgt)	First Year Introduced	Fractional Horsepower Change
FRONT WHEEL DRIVE	0.06	160	0	0	-0.08	1980	0
UNIT BODY	0.04	80	0	0	-0.05	1980	0
MATERIAL SUBSTITUTION II	0.033	0	0.6	0	-0.05	1987	0
MATERIAL SUBSTITUTION III	0.066	0	0.8	0	-0.1	1997	0
MATERIAL SUBSTITUTION IV	0.099	0	1	0	-0.15	2007	0
MATERIAL SUBSTITUTION V	0.132	0	1.5	0	-0.2	2017	0
DRAG REDUCTION II	0.023	32	0	0	0	1985	0
DRAG REDUCTION III	0.046	64	0	0	0.05	1991	0
DRAG REDUCTION IV	0.069	112	0	0	0.01	2004	0
DRAG REDUCTION V	0.092	176	0	0	0.02	2014	0
ICLU	0.03	40	0	0	0	1980	0
4-SPEED AUTOMATIC	0.045	225	0	30	0	1980	0.05
5-SPEED AUTOMATIC	0.065	325	0	40	0	1995	0.07
CVT	0.1	250	0	20	0	1995	0.07
6-SPEED MANUAL	0.02	100	0	30	0	1991	0.05
ELECTRONIC TRANSMISSION I	0.005	20	0	5	0	1988	0
ELECTRONIC TRANSMISSION II	0.015	40	0	5	0	1998	0
ROLLER CAM	0.02	16	0	0	0	1987	0
OHC 4	0.03	100	0	0	0	1980	0.2
OHC 6	0.03	140	0	0	0	1980	0.2
OHC 8	0.03	170	0	0	0	1980	0.2
4C/4V	0.08	240	0	30	0	1988	0.45
6C/4V	0.08	320	0	45	0	1991	0.45
8C/4V	0.08	400	0	60	0	1991	0.45
CYLINDER REDUCTION	0.003	-100	0	-150	0	1988	-0.1
4C/3V	0.1	300	0	45	0	1998	0.55
TURBO	0.05	500	0	80	0	1980	0.45
ENGINE FRICTION REDUCTION I	0.02	20	0	0	0	1987	0
ENGINE FRICTION REDUCTION II	0.035	50	0	0	0	1996	0
ENGINE FRICTION REDUCTION III	0.05	90	0	0	0	2006	0
ENGINE FRICTION REDUCTION IV	0.065	140	0	0	0	2016	0
VVT I	0.08	140	0	40	0	1998	0.1
VVT II	0.1	180	0	40	0	2008	0.15
LEAN BURN	0.1	150	0	0	0	2012	0
TWO STROKE	0.15	150	0	-150	0	2004	0
TBI	0.02	40	0	0	0	1982	0.05
MPI	0.035	80	0	0	0	1987	0.1
AIR PUMP	0.01	0	0	-10	0	1982	0
DFS	0.015	15	0	0	0	1987	0.1
OIL 5W-30	0.005	2	0	0	0	1987	0
OIL SYNTHETIC	0.015	5	0	0	0	1997	0
TIRES I	0.01	16	0	0	0	1992	0
TIRES II	0.02	32	0	0	0	2002	0
TIRES III	0.03	48	0	0	0	2012	0
TIRES IV	0.04	64	0	0	0	2018	0
ACC I	0.005	15	0	0	0	1992	0
ACC II	0.01	30	0	0	0	1997	0
EPS	0.015	40	0	0	0	2002	0
4WD IMPROVEMENTS	0.03	100	0	0	-0.05	2002	0
AIR BAGS	-0.01	300	0	35	0	1987	0
EMISSIONS TIER I	-0.01	150	0	10	0	1994	0
EMISSIONS TIER II	-0.01	300	0	20	0	2003	0
ABS	-0.005	300	0	10	0	1987	0
SIDE IMPACT	-0.005	100	0	20	0	1996	0
ROOF CRUSH	-0.003	100	0	5	0	2001	0
INCREASED SIZE/WT	-0.033	0	0	0	0.05	1991	0

Table E-1.2 Standard Technology Matrix for Trucks

Vehicle Technology	Fractional Fuel Efficiency Change	Incremental Cost (\$1990)	Incremental Cost (\$/unit wgt)	Incremental Weight (lbs)	Incremental Weight (lbs/unit wgt)	First Year Introduced	Fractional Horsepower Change
FRONT WHEEL DRIVE	0.02	160	0	0	-0.08	1985	0
UNIT BODY	0.06	80	0	0	-0.05	1995	0
MATERIAL SUBSTITUTION II	0.033	0	0.6	0	-0.05	1996	0
MATERIAL SUBSTITUTION III	0.066	0	0.8	0	-0.1	2006	0
MATERIAL SUBSTITUTION IV	0.099	0	1	0	-0.15	2016	0
MATERIAL SUBSTITUTION V	0.132	0	1.5	0	-0.2	2026	0
DRAG REDUCTION II	0.023	32	0	0	0	1990	0
DRAG REDUCTION III	0.046	64	0	0	0.05	1997	0
DRAG REDUCTION IV	0.069	112	0	0	0.01	2007	0
DRAG REDUCTION V	0.092	176	0	0	0.02	2017	0
TCLU	0.03	40	0	0	0	1980	0
4-SPEED AUTOMATIC	0.045	225	0	30	0	1980	0.05
5-SPEED AUTOMATIC	0.065	325	0	40	0	1997	0.07
CVT	0.1	250	0	20	0	2005	0.07
6-SPEED MANUAL	0.02	100	0	30	0	1997	0.05
ELECTRONIC TRANSMISSION I	0.005	20	0	5	0	1991	0
ELECTRONIC TRANSMISSION II	0.015	40	0	5	0	2006	0
ROLLER CAM	0.02	16	0	0	0	1986	0
OHC 4	0.03	100	0	0	0	1980	0.15
OHC 6	0.03	140	0	0	0	1985	0.15
OHC 8	0.03	170	0	0	0	1995	0.015
4C/4V	0.06	240	0	30	0	1990	0.3
6C/4V	0.06	320	0	45	0	1990	0.3
8C/4V	0.06	400	0	60	0	2002	0.3
CYLINDER REDUCTION	0.03	-100	0	-150	0	1990	-0.1
4C/5V	0.08	300	0	45	0	1997	0.55
TURBO	0.05	500	0	80	0	1980	0.45
ENGINE FRICTION REDUCTION I	0.02	20	0	0	0	1991	0
ENGINE FRICTION REDUCTION II	0.035	50	0	0	0	2002	0
ENGINE FRICTION REDUCTION III	0.05	90	0	0	0	2012	0
ENGINE FRICTION REDUCTION IV	0.065	140	0	0	0	2022	0
VVT I	0.08	140	0	40	0	2006	0.1
VVT II	0.1	180	0	40	0	2016	0.15
LEAN BURN	0.1	150	0	0	0	2018	0
TWO STROKE	0.15	150	0	-150	0	2008	0
TBI	0.02	40	0	0	0	1985	0.05
MPI	0.035	80	0	0	0	1985	0.1
AIR PUMP	0.01	0	0	-10	0	1985	0
DPS	0.015	15	0	0	0	1985	0.1
OIL 5W-30	0.005	2	0	0	0	1987	0
OIL SYNTHETIC	0.015	5	0	0	0	1997	0
TIRES I	0.01	16	0	0	0	1992	0
TIRES II	0.02	32	0	0	0	2002	0
TIRES III	0.03	48	0	0	0	2012	0
TIRES IV	0.04	64	0	0	0	2018	0
ACC I	0.005	15	0	0	0	1997	0
ACC II	0.01	30	0	0	0	2007	0
EPS	0.015	40	0	0	0	2002	0
4WD IMPROVEMENTS	0.03	100	0	0	-0.05	2002	0
AIR BAGS	-0.01	300	0	35	0	1992	0
EMISSIONS TIER I	-0.01	150	0	10	0	1996	0
EMISSIONS TIER II	-0.01	300	0	20	0	2004	0
ABS	-0.005	300	0	10	0	1990	0
SIDE IMPACT	-0.005	100	0	20	0	1996	0
ROOF CRUSH	-0.005	100	0	5	0	2001	0
INCREASED SIZE/WT	0.033	0	0	0	0.05	1991	0

APPENDIX E-2

ENERGY USE AND REDUCTION IN LIGHT-DUTY VEHICLES

Understanding how an automobile uses energy is an important first step in evaluating the wide array of technologies available to improve fuel economy. Briefly, vehicles use energy primarily to produce power at the wheels to overcome three tractive forces that would otherwise prevent the vehicle from moving:

- aerodynamic drag, the force of air friction on the body surfaces of the vehicle;
- rolling resistance, the resistive forces between the tires and the road; and
- inertia and gravity forces, the first the resistance of any mass to acceleration, the second the downward restraining force of gravity on the vehicle's mass when it is climbing a grade.

In addition, the vehicle must produce energy to power accessories such as heating fan, air conditioner, lights, radio, and power steering. And, unless the engine is turned off, during idle and braking the engine energy is largely wasted because it is not being used to provide motive force.

To obtain motive power, the automobile must transform the chemical energy in its fuel into power at the wheels. First, the engine translates the fuel's chemical energy into shaft power. Some of this power is then bled off to power accessories and the remainder is transformed by the transmission and other drivetrain components into power that can drive the wheels.

The transformation from chemical energy to motive force is a relatively inefficient process. Energy is lost because moving parts in the engine create friction; because air and fuel must be pumped through the engine, causing aerodynamic and fluid drag losses; because much of the heat generated by combustion cannot be used for work and is wasted; and because slippage in the transmission causes losses. As discussed later, a conventional vehicle drivetrain generally will be able to transform about 14 (city) to 23 (highway) percent of the fuel energy into usable power at the wheels.

To reduce fuel consumption, vehicle designers can work to reduce all of the forces acting on the vehicle (the tractive forces) and the accessory power, as well as the losses in turning fuel into motive power. Each of these are treated in turn, below.

1. *Reducing Tractive Forces: Aerodynamic Drag*

Aerodynamic drag is the resistive force of the air as the vehicle tries to push its way through it. The power required to overcome the aerodynamic drag force increases with the cube of vehicle speed,¹ and the energy/mile required varies with the square of speed. Thus, aerodynamic drag principally affects highway fuel economy. Aside from speed, aerodynamic drag depends primarily on the vehicle's frontal area, its shape, and the smoothness of its body surfaces. To minimize drag, vehicle designers thus seek to minimize frontal area by shaving off unused space, redesigning seating arrangements, and finding ways to make the vehicle's side structure thinner; smooth vehicle surfaces by flush-mounting windows, achieving better fit of body panels, even changing the texture of vehicle paint or adding panels to the vehicle's underside; reduce or eliminate obstructions to air flow by removing radio antennae or putting cowlings on outside mirrors; redirect airflow with front air dams and other devices; and change the vehicle's basic shape both to smooth airflow (e.g., by increasing the slope of the windshield) and eliminate problems associated with issues such as boundary layer separation and flow regimes, subjects for aerodynamic specialists. There are also more arcane measures that can be taken, but these are unlikely for the time period of this study.

The effect of the vehicle's shape and smoothness on drag is characterized by the vehicle drag coefficient C_D , a nondimensional measure of how the vehicle compares aerodynamically to a flat surface of the same frontal area directly facing the airflow. In today's automobiles, a 10 percent C_D reduction typically will result in a 2 to 2.5 percent improvement in fuel economy, if vehicle performance is held constant.² The same ratio holds for a reduction in frontal area, although the potential for such reductions is limited by interior space requirements. *Note that the ratio of reduced C_D to increased fuel economy will depend on the relative values of the three tractive forces and accessory loss. As vehicles evolve and the balance of forces change, reducing C_D may yield a higher or lower fuel economy benefit. Also, the ratio is dependent on the driving cycle; in this case, the cycle referred to is the Federal Test Procedure. At a lower speed cycle, for example, reducing C_D would have less effect because aerodynamic forces are less important.*

2. Reducing Tractive Forces: Rolling Resistance

Rolling resistance is the resistive force between the tires and the road, and depends on the design and materials of the tire (and road) and on the weight borne by the tire; depending on how it's measured, rolling resistance may also include friction losses in wheel bearings and seals. The primary source of tire rolling resistance is internal friction in the rubber compounds as the tire deflects on contact with the road.

Rolling resistance may be reduced by:

- (1) redesigning tires and tire materials to minimize the energy lost as the tire flexes,
- (2) lowering vehicle weight (see below), and
- (3) redesigning wheel bearings and seals.

A major concern in tire redesign is to avoid compromising tire durability and handling capabilities.

The rolling resistance coefficient (RRC), like the aerodynamic drag coefficient, is a measure of the resistance to a vehicle's movement—in this case, of the tires. A reduction in rolling resistance of 6 percent will typically yield a fuel economy improvement of about 1 percent. *As with the C_D , this is an approximate value that will change as vehicle design changes.*

3. Reducing Tractive Forces: Inertial Force (Weight Reduction)

Inertial force is the resistance of vehicle mass to acceleration or grade-climbing, and is largest in city driving, with its frequent speed changes, and hill-climbing. Inertial force is reduced by making the vehicle lighter, e.g., by reducing waste, using lighter, stronger materials, and possibly by redesigning the vehicle interior or structure. An added benefit of reducing vehicle weight is the resulting reduction in rolling resistance, which varies linearly with weight. Starting from current vehicles, a 10 percent weight reduction will yield as much as a 6 percent increase in fuel economy, at constant performance.³

4. Reducing Accessory Power

Accessory losses may be reduced by improving the design of air conditioners, water and oil pumps, power steering, and other power equipment, or by reducing the work these accessories must do (for example, heating and cooling loads can be reduced by providing insulation and coating window surfaces with coatings that reflect unwanted solar radiation).

5. *Turning Fuel Energy into Motive Power—Improving Engine Efficiency*

The process of turning fuel's chemical energy into shaft power is inefficient. To begin with, spark ignition (SI) engines, the dominant passenger car and light truck powerplant in the United States, have a theoretical maximum efficiency of about 45 percent (for a compression ratio of 10:1, and the stoichiometric air-fuel ratio needed to allow current emission control systems to operate properly.⁴ And for several reasons, SI engines cannot achieve this theoretical efficiency level.

First, even the 45 percent maximum efficiency assumes an ideal cycle where combustion is instantaneous and occurs precisely at the point where it can do the most work; the finite time of the combustion process allows some fuel to be burned at less than the highest possible pressure and some heat to be lost through the cylinder walls before it can do work. Second, mechanical friction associated with the motion of the piston, crankshaft, and valves consumes a significant fraction of total power. Friction is a stronger function of engine speed than of torque; therefore, efficiency is degraded considerably at light load and high rpm conditions. Third, aerodynamic frictional and pressure losses associated with air flow through the air cleaner, intake manifold and valves, exhaust manifold, silencer, and catalyst are significant, especially at high air flow rates through the engine. Fourth, SI engines reduce their power output by throttling the air flow, which causes additional aerodynamic losses called "pumping losses" that are very high at light loads.

Because of these losses, production spark ignition engines are significantly less efficient than their theoretical maximum even when they are operating at their most efficient operating point. Further, in real world driving they often operate under conditions that push their efficiencies even lower. For example, their maximum efficiency point generally occurs at relatively high loads, whereas most driving is under light load conditions, when pumping losses are highest (e.g., during city driving and steady state cruise on the highway). The high power that these engines are capable of is used only during strong accelerations, at very high speeds or when climbing steep grades. And during stop-and-go driving conditions typical of city driving, a substantial amount of time is spent at idle, where efficiency is zero. Typical modern spark ignition engines have an efficiency of about 18 to 20 percent on the city part of the Environmental Protection Agency driving cycle, and about 26 to 28 percent on the highway part of the cycle.

The complex nature of engine efficiency losses implies that engine designers have a wide variety of pathways to explore in the search for higher efficiency. These range from measures that would improve thermodynamic efficiency (measures that will improve spark timing, allow increased compression ratios, and promote faster combustion – for example, advanced electronic controls and better cylinder design) to measures that attack mechanical friction (lighter valve-trains, advanced coatings on pistons, improved lubricants) and aerodynamic losses (increased number of valves per cylinder, deactivating cylinders at light loads, variable timing for valve opening).

6. *Turning Fuel Energy into Motive Power—Improving Automatic Transmissions*

Automatic transmissions match the speed and power required at the wheels to the speed and power output of the engine, choosing gear ratios that keep the engine operating in speed ranges that allow the engine to maintain high efficiency. Energy is lost within the transmission itself, through hydraulic losses in the torque converter, and in the engine because the transmission may not have the capability to keep the engine at its maximum efficient point – either because it has a finite number of gears, or because it lacks the sensing technology or sensitive controls that would allow the perfect choice of shift points. Also, the vehicle designer may deliberately move shift points from the true (efficiency) optimum to gain an improvement in other attributes, for example, less frequent downshifts or smoother engine operation.

Transmission improvements can come from reducing torque converter losses with better design and materials, increasing the number of gears (or ultimately moving to continuously variable transmissions), and improving the electronics that control transmission shift points and sense when shifts should occur.

7. Another Potential Source of Energy Savings—Sacrificing Vehicle Capabilities

Fuel consumption may also be reduced by sacrificing consumer amenities—reducing the size of the passenger compartment (and, consequently, the size and weight of the vehicle), using a less powerful engine that cannot provide the same acceleration (and that may cause greater noise and vibration), designing transmission shifts that achieve higher efficiency at the cost of more harshness, reducing the number of accessories such as air conditioning or power locks and windows, and so forth. Most modern attempts to reduce fuel consumption do not contemplate sacrificing these amenities, but some types of vehicle redesigns may achieve higher efficiency only at the cost of such a sacrifice.

- *Maintenance* of consumer amenities is not the goal of vehicle designers, however—their goal generally is *improvement*. All technologies with the potential to enhance fuel economy can be used for other consumer amenities such as acceleration performance, and tradeoffs between fuel economy and other, competing amenities are a constant feature of vehicle design — with fuel economy often the loser in today's marketplace. Examples include:
- Structural redesign using supercomputers can be used to increase structural stiffness at constant weight rather than to reduce weight at constant stiffness. Anecdotal evidence suggests that increasing structural stiffness is virtually a universal goal for car designers, and all new models have increased stiffness;
- Technologies that increase engine power density and efficiency can be used to increase power at constant displacement, with a lesser or zero fuel economy improvement, rather than downsize the engine to achieve the same power with improved fuel economy. Generally, replacement of 2-valve engines with 4-valve engines has involved higher power, no change in displacement, and little fuel economy increase.

As noted earlier, the balance of energy losses will vary from vehicle to vehicle according to each vehicle's design, and will shift as technology advances. Nevertheless, an examination of the energy losses in a typical 1995 mid-size car will provide an indicator of target areas for saving fuel. The vehicle in question gets 27.7 mpg on the EPA test cycle (22.7 mpg city; 38.0 mpg, highway):

- *Engine efficiency*: the fraction of fuel energy that emerges as shaft horsepower—is about 22 percent on the city part of the test and 27 percent on the highway, 24 percent composite. In other words, three quarters of fuel energy is lost in the engine, a tempting target for improvement. Raising engine efficiency from 24 to 25 percent would reduce fuel consumption by 4 percent.
- Of the energy that is converted by the engine to actual shaft horsepower:
 - ⇒ *braking and idling loss*: 16 percent (city), 2 percent (highway), 11 percent (composite) is lost because it cannot be used when the vehicle is braking or idling. Systems that turn the engine off during braking and idle (engine off or electric drivetrains), or store the energy produced (hybrid systems can do this), can recover much of this 11 percent;

- ⇒ *transmission loss*: 10 percent (city), 7 percent (highway), 9 percent (composite) is lost by transmission inefficiencies. This is the target for improved transmissions or, for electric vehicles, avoiding the need for a transmission;
- ⇒ *accessory loss*: 11 percent (city), 7 percent (highway), 9 to 10 percent (composite) is used to power the accessories. Aside from conventional strategies to improve accessory efficiency or to reduce heating and cooling loads, electric vehicles have a different mix of accessories--some differences help (no oil pump), and some hurt (may need a heat pump to generate cabin heat);
- ⇒ *energy for motive power*: 63 percent (city), 84 percent (highway), 71 percent (composite) is actually used to overcome the tractive forces on the vehicle.
- The *three tractive forces* play different roles at different speeds:
 - ⇒ *rolling resistance* accounts for 28 percent of total tractive forces in the city, and 35 percent on the highway, 31 percent composite. Both improvement to tires and weight reduction work to reduce this large fraction of tractive forces;
 - ⇒ *aerodynamic drag* accounts for 18 percent (city) and 50 percent (highway), 30 percent composite; and
 - ⇒ *inertia (weight) force* accounts for 54 percent (city) and 14 percent (highway), 40 percent composite. Weight reduction directly attacks this force, or some of the energy used to overcome it can be recovered by regenerative braking.

¹ More precisely, the relative speed of the vehicle and the air. If the vehicle is heading into the wind, the relative speed is the sum of vehicle speed and windspeed; with a tailwind, the relative speed is the difference of the two speeds.

² One way to hold performance constant is to change the ratio of the highest transmission gear; at high speeds, a reduced C_D means that the engine need not deliver as much power to the wheels to maintain speed or accelerate, and the gears can be adjusted accordingly.

³ Including a less powerful engine, since a lighter vehicle is easier to accelerate and take up steep grades.

⁴ Stoichiometric defines a balance of air to fuel that allows just enough oxygen to complete burn the fuel and no more. Avoiding an excess of fuel is important to minimizing engine-out emissions of hydrocarbons; avoiding an excess of air provides the oxygen-free exhaust that allows current NO_x catalysts to operate.

APPENDIX F

The chart shows the generating price of power at the busbar for the peak and offpeak seasons. These prices are higher during the fraction of each season when higher-cost plants are required to operate to meet demand.

Blank

Case ID	2010 AEO	CAPITALIZAT IOU-Existing IPP-Existing IPP-New IPP-Renew Peak Season LDC													
Peak Demand	14685.1517	Fuel Type	\$/MMBTU	kg C/MBTU	1	2	3	4	Season Peak	Shoulder 2	Shoulder 1	Min (100%)			
Ratio of Off-peak to peak	87.8%	Gas	2.59	14.47	Term (Years)	30	30	20	20	% of Season	0	5	95	100	
Peak fraction of year	25%	Coal	1.34	25.72	Tax life	20	20	12	5	Template ratio	100%	90%	49%	39%	
Load Factor, %	62.8%	Oil	3.00	21.49	Inc. Tax Rate	36%	36%	36%	36%	Ratio to Peak	100%	90%	49%	39%	
Peak Season Load Factor	69.7%	Nuclear	0.70	0	Prop. Tax rate	5%	5%	5%	5%	Demand MW	14,685	13,257	7,223	5,755	
Off-Peak Season Load Factor	68.9%	Hydro	0.00	0	Debt %	48%	30%	30%	30%	Off-Peak Season LDC					
Carbon Tax, \$/metric ton C	0.00	Other	0.00	0	Interest Rate	6.0%	10.0%	10.0%	10.0%	% of Season	0	2	98	100	
Capacity Payment, \$/kW	0	Year of Study	2010		Preferred Equity	14%	0%	0%	0%	Template ratio	100%	83%	55%	46%	
Uplift Charge, \$/kWh	0	Year of \$	1995		Return Rate	10.0%	10.0%	10.0%	10.0%	Ratio to Peak	100%	83%	55%	46%	
Unreserved Energy, \$/kWh	0	Start-up Cost, \$/MW	40		Common Equi	38%	70%	70%	70%	Demand MW	12,892	10,735	7,108	5,994	
Non-generat. Price, \$/kWh	3.18	Min Capacity w/ probab	0		Return Rate	11.0%	14.0%	14.0%	14.0%						
Price Elasticity(not used if 0)	0.05	Min Outage Rate w/ probab	0.0%		Vary FCR by 1	TRUE	TRUE	TRUE	TRUE	Fractional change to start year	0.30				
Default Unreserved E calc (always show)		Max # Plants with prob.	10		Include in Avo	FALSE	FALSE	FALSE	FALSE						
Name	Capacity	Capacity Adjust Factor (0 to 1)	Forced Outage Rate	Planned Outage Rate	Heat Rate (BTU/kWh)	Fuel Type	Fuel Price Adjustment	Variable O&M Cost \$/kwh	Bid Price or OP, \$/kwh	Fixed O&M Cost \$/kW-yr	- Plant Construction - Nominal Construction Cost/kW	Capitilization Structure to Use	Unavoidable Fixed Cost \$/kW-yr	Variable Cost \$/kwh	
Nuclear1	1,000	1	8.2%	12.2%	10,460	Nuclear	1.000	0.00	OP	90.0	800	1973	1	26	0.73
Nuclear2	800	1	8.2%	12.2%	10,460	Nuclear	1.000	0.00	OP	90.0	2,750	1988	1	180	0.73
Coal1	950	1	7.0%	14.2%	9,600	Coal	0.833	0.21	OP	11.7	490	1983	1	28	1.28
Coal2	850	1	8.5%	8.8%	9,700	Coal	1.000	0.22	OP	11.7	370	1978	1	15	1.51
Coal3	850	1	8.5%	8.8%	9,800	Coal	1.000	0.22	OP	11.7	300	1973	1	10	1.53
Coal4	600	1	8.6%	10.3%	9,900	Coal	1.000	0.23	OP	12.4	680	1981	1	31	1.55
Coal5	600	1	8.6%	10.3%	10,000	Coal	1.000	0.24	OP	12.4	380	1960	1	0	1.58
Coal6+7	850	1	8.5%	12.3%	10,200	Coal	1.000	0.32	OP	15.2	500	1980	1	21	1.68
Coal8	450	1	8.5%	12.3%	10,600	Coal	1.167	0.32	OP	15.2	300	1970	1	8	1.97
Coal9+10	450	1	8.4%	10.9%	11,200	Coal	1.167	0.35	OP	16.3	300	1970	1	8	2.09
Coal-Adv.	400	1	4.1%	12.3%	9,600	Coal	1.000	0.25	OP	33.6	1,816	2006	3	277	1.53
Oil1	500	1	11.6%	5.2%	10,100	Oil	0.840	0.50	OP	6.0	127	1973	1	4	3.05
GasST1	600	1	9.7%	6.8%	10,000	Gas	0.951	0.13	OP	9.4	170	1978	1	6	2.59
GasST2	500	1	9.7%	6.8%	10,100	Gas	1.084	0.13	OP	9.4	150	1970	1	4	2.96
GasST3	450	1	9.7%	6.8%	10,200	Gas	1.111	0.13	OP	9.4	220	1967	1	0	3.06
GasCC1	300	1	8.8%	13.0%	9,665	Gas	0.951	0.10	OP	10.0	470	1992	2	45	2.48
GasCC2-New	420	1	5.5%	7.5%	7,760	Gas	1.000	0.05	OP	28.9	452	1999	3	49	2.06
GasCC3-new	420	1	5.5%	7.5%	7,616	Gas	1.000	0.05	OP	28.9	477	2001	3	55	2.02
GasCC4-Adv	420	1	5.5%	7.5%	6,284	Gas	1.000	0.05	OP	26.6	538	2005	3	78	1.68
GasCC5-Adv	600	1	5.5%	7.5%	5,817	Gas	1.000	0.05	OP	26.6	615	2009	3	109	1.55
GasCT1+2	450	1	10.0%	5.4%	12,800	Gas	0.969	0.22	OP	6.0	140	1986	1	9	3.42
GasCT3-new	650	1	3.6%	4.0%	11,460	Gas	1.000	0.01	OP	11.9	364	1998	3	36	2.98
GasCT4-new	650	1	3.6%	4.0%	10,873	Gas	1.000	0.01	OP	11.9	406	2002	3	50	2.82
GasCT5-Adv.	650	1	3.8%	3.9%	7,793	Gas	1.000	0.05	OP	16.9	542	2008	3	89	2.07
Renewable	250	1	25.0%	15.0%	10,280	Other	1.000	1.27	OP	65.5	2,361	2008	4	351	1.27
Limited Energy Capacity, MW		Peak CF	Non-peak CF												
Hydro	1,800	1	55.0%	40.0%		Hydro		0.10		10	400	1957	1	0	0.10
Total Capacity	16,260														

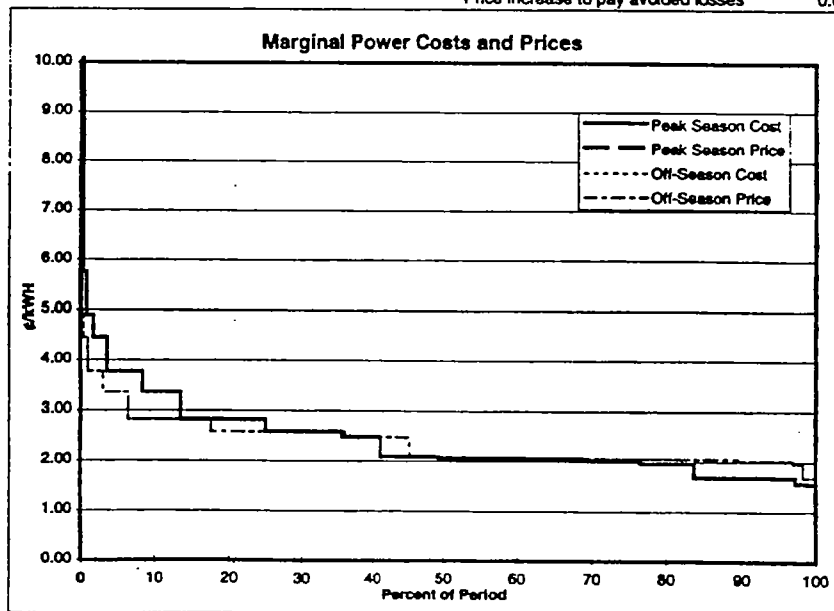
2010 AEO

	Annual	Peak season	Offpeak season	# of Unprofitable plants	Against avoid O&M	8				% of Total Capacity	% of Total Generation	Cap fact %	Avoidable e/kWh	Variable e/kWh	
Reserve Margin	10.7%	10.7%	11.2%	Against all costs	16 w/ unserv					Hydro	9.8%	7.6%	43.8%	0.36	0.10
LOLP, % of period	0.13	0.34	0.07	Average Price, ¢/kWh	2.50	2.50				Nuclear	11.1%	15.5%	79.6%	2.02	0.73
LOLP, day/10 Year	4.90	12.40	2.41	Avg. Variable Cost	1.43	1.43				Coal	36.9%	50.8%	78.0%	1.78	1.57
Load factor	62.8%	69.7%	68.9%	Avg. Vari+Avoid O&M	1.90	1.90				Oil	3.1%	0.1%	1.0%	11.59	4.44
Peak Demand, MW	14,685	14,685	12,892	Total Cost	2.61	2.61				Gas-ST	9.5%	1.8%	10.7%	3.74	2.74
Energy, GWh	80,793	22,423	58,370	Max loss, \$/avail kW	(9.71)					Gas-CC	13.3%	17.2%	73.6%	2.21	1.82
Generation, GWh	80,790	22,419	58,371	Start-up Cost, \$/MW	40					Gas-CT	14.8%	5.4%	20.7%	2.93	2.26
Unserv'd Energy, G	5	3	2	# plants Probabilistic	10					Other	1.5%	1.6%	60.0%	2.51	1.27
Round err not in UE	(2)	1	(2)												
Plant Name	Capacity	Output MWYr	Capac Factor	Time on Margin, %	Revenue M\$	Var. Cost M\$	+Start Avoidable Cst M\$	Unavoidable Fxd Cst M\$	Total Net Rev M\$	Avoidable Net Rev M\$	Avg. Carbon kg/MWhr	Avoidable cost, ¢/kWh	Carbon release Million Tons		
Nuclear1	1,000	796.00	79.6%	0.00	168	51	90	26	0	26.91	33.80	2.02	0.00		
Nuclear2	800	636.80	79.6%	0.00	134	41	72	144	(122)	21.53	33.80	2.02	0.00		
Coal1	950	748.60	78.8%	0.00	158	84	11	25	39	63.07	84.25	1.45	1.62		
Coal2	850	719.95	84.7%	0.00	152	96	10	13	34	46.38	64.42	1.67	1.57		
Coal3	850	719.95	84.7%	0.00	152	96	10	8	37	45.53	63.25	1.69	1.59		
Coal4	600	498.60	83.1%	0.00	105	68	7	18	12	29.98	60.12	1.72	1.11		
Coal5	600	495.96	82.7%	0.40	105	68	7	0	29	28.98	58.08	1.75	1.12		
Coal6+7	850	648.28	76.3%	3.70	138	96	13	18	12	30.02	44.59	1.91	1.48		
Coal8	450	330.48	73.4%	2.86	71	57	7	3	4	7.39	20.73	2.21	0.79		
Coal9+10	450	186.72	41.5%	12.44	46	34	7	3	1	4.29	11.53	2.54	0.47		
Coal-Adv.	400	334.40	83.6%	0.00	71	45	13	111	(98)	12.31	36.82	1.99	0.72		
Oil1	500	4.79	1.0%	0.88	3	2	3	2	(4)	(2.07)	(4.97)	11.59	0.01		
GasST1	600	137.54	22.9%	16.52	38	31	6	4	(3)	0.80	1.59	3.06	0.17		
GasST2	500	25.92	5.2%	3.81	10	8	5	2	(5)	(2.68)	(6.42)	5.43	0.03		
GasST3	450	2.06	0.5%	0.39	2	1	4	0	(3)	(3.49)	(9.29)	28.31	0.00		
GasCC1	300	96.17	32.1%	8.17	25	21	3	14	(13)	0.98	4.05	2.83	0.12		
GasCC2-New	420	290.81	69.2%	8.93	64	52	12	20	(20)	(0.06)	(0.17)	2.53	0.29		
GasCC3-new	420	321.04	76.4%	7.46	70	57	12	23	(22)	0.93	2.53	2.45	0.31		
GasCC4-Adv	420	361.45	86.1%	0.90	77	53	11	32	(20)	12.28	33.61	2.03	0.29		
GasCC5-Adv	600	521.31	86.9%	0.27	110	71	16	65	(42)	23.04	44.13	1.90	0.38		
GasCT1+2	450	0.88	0.2%	0.21	1	0	3	4	(6)	(2.06)	(5.41)	40.68	0.00		
GasCT3-new	650	17.37	2.7%	2.76	8	6	8	24	(29)	(5.83)	(9.71)	8.86	0.03		
GasCT4-new	650	81.59	12.6%	11.27	25	20	8	33	(35)	(2.53)	(4.22)	3.91	0.11		
GasCT5-Adv.	650	395.92	60.9%	18.88	91	72	11	58	(49)	8.44	14.06	2.38	0.39		
Renewable	250	150.00	60.0%	0.00	32	17	16	88	(89)	(1.35)	(8.97)	2.51	0.00		
Hydro	1,600	700.00	43.8%		166	6	16	0	144	143.86	89.91	0.36	0.00		
Totals	16,260	9,223	57%		2,021	1,152	382	739	(252)	487			12.62		

Unserv'd Energy	0.54	2	2	w/o UE	1,534	2,273	Avg. Carbon kg/MWhr	156
Totals w/ Unserved	9,223	2,022	1,154	w/ UE	1,536	2,274	Time wtd marginal cost	2.40
							Time wtd Unserved E Price	18.94
							Unserv E. Cost/kWh	38.42
							Price increase to pay avoided losses	0.02

Sort by Net Revenue/kW

Name	Avoidable Net Rev/kW	Capacity	Reserve Margin
Hydro	89.91	1,600	11%
Coal1	84.25	950	17%
Coal2	64.42	850	23%
Coal3	63.25	850	29%
Coal4	60.12	600	33%
Coal5	58.08	600	37%
Coal6+7	44.59	850	43%
GasCC5-Adv	44.13	600	47%
Coal-Adv.	36.82	400	50%
Nuclear1	33.80	1,000	57%
Nuclear2	33.80	800	62%
GasCC4-Adv	33.61	420	65%
Coal8	20.73	450	68%
GasCT5-Adv.	14.06	650	72%
Coal9+10	11.53	450	75%
GasCC1	4.05	300	77%
GasCC3-new	2.53	420	80%
GasST1	1.59	600	84%
GasCC2-New	(0.17)	420	87%
GasCT4-new	(4.22)	650	92%
Oil1	(4.97)	500	95%
GasCT1+2	(5.41)	450	98%
GasST2	(6.42)	500	102%
Renewable	(8.97)	250	103%
GasST3	(9.29)	450	106%
GasCT3-new	(9.71)	650	111%



Case ID	Restructure case				CAPITALIZAT		IOU-Existing	IPP-Existing	IPP-New	IPP-Renew	Peak Season LDC				
Peak Demand	14188.3366	Fuel Type	\$/MMBTU	kg C/MBTU	1	2	3	4	Season Peak		Shoulder 2	Shoulder 1	Min (100%)		
Ratio of Off-peak to peak	88.7%	Gas	2.59	14.47	Term (Years)	30	30	20	20	% of Season	0	5	95	100	
Peak fraction of year	25%	Coal	1.34	25.72	Tax life	20	20	12	5	Template ratio	100%	94%	53%	42%	
Load Factor, %	65.8%	Oil	3.00	21.49	Inc. Tax Rate	36%	36%	36%	36%	Ratio to Peak	100%	94%	53%	42%	
Peak Season Load Factor	73.1%	Nuclear	0.70	0	Prop. Tax rate	5%	5%	5%	5%	Demand MW	14,188	13,276	7,491	6,918	
Off-Peak Season Load Factor	71.4%	Hydro	0.00	0	Debt %	48%	30%	30%	30%	Off-Peak Season LDC					
Carbon Tax, \$/metric ton C	0.00	Other	0.00	0	Interest Rate	8.0%	10.0%	10.0%	10.0%	% of Season	0	2	96	100	
Capacity Payment, \$/kW	0	Year of Study	2010	0	Preferred Equity	14%	0%	0%	0%	Template ratio	100%	85%	58%	50%	
Up/lt Charge, \$/kWh	0	Year of \$	1995	0	Return Rate	10.0%	10.0%	10.0%	10.0%	Ratio to Peak	100%	85%	58%	50%	
Unserved Energy, \$/kWh	0	Start-up Cost, \$/MW	40	0	Common Equi	38%	70%	70%	70%	Demand MW	12,589	10,755	7,285	6,285	
Non-generat. Price, \$/kWh	3.18	Min Capacity w/ probab	0	0	Return Rate	11.0%	14.0%	14.0%	14.0%						
Price Elasticity(not used if 0)	0.05	Min Outage Rate w/ probab	0.0%	0.0%	Vary FCR by 1	TRUE	TRUE	FALSE	FALSE						
Default Unserved E calc (always show)		Max # Plants with prob.	10	10	Include in Avo	FALSE	FALSE	TRUE	TRUE	Fractional change to start year	0.30				
Name	Capacity	Capacity Adjust Factor (0 to 1)	Forced Outage Rate	Planned Outage Rate	Heat Rate (BTU/kWh)	Fuel Type	Fuel Price Adjustment	Variable O&M Cost \$/kWh	Bid Price or OP, \$/kWh	Fixed O&M Cost \$/kW-yr	- Plant Construction - Nominal Construction Cost/kW	Capitilization Structure to Use	Unavoidable Fixed Cost \$/kW-yr	Variable Cost \$/kWh	
Nuclear1	1,000	1	8.2%	12.2%	10,460	Nuclear	1.000	0.00	OP	90.0	800	1973	1	26	0.73
Nuclear2	800	1	8.2%	12.2%	10,460	Nuclear	1.000	0.00	OP	90.0	2,750	1988	1	180	0.73
Coal1	900	1	7.0%	14.2%	9,600	Coal	0.833	0.21	OP	11.7	490	1983	1	26	1.28
Coal2	850	1	6.5%	8.8%	9,700	Coal	1.000	0.22	OP	11.7	370	1978	1	15	1.51
Coal3	850	1	6.5%	8.8%	9,800	Coal	1.000	0.22	OP	11.7	300	1973	1	10	1.53
Coal4	600	1	6.6%	10.3%	9,900	Coal	1.000	0.23	OP	12.4	680	1981	1	31	1.55
Coal5	600	1	6.6%	10.3%	10,000	Coal	1.000	0.24	OP	12.4	380	1960	1	0	1.58
Coal6+7	850	1	8.5%	12.3%	10,200	Coal	1.000	0.32	OP	15.2	500	1980	1	21	1.68
Coal8	450	1	8.5%	12.3%	10,600	Coal	1.167	0.32	OP	15.2	300	1970	1	8	1.97
Coal9+10	450	1	6.4%	10.9%	11,200	Coal	1.167	0.35	OP	16.3	300	1970	1	8	2.09
Coal-Adv.	50	1	4.1%	12.3%	9,600	Coal	1.000	0.25	OP	33.6	1,818	2006	3	222	1.53
Oil1	500	1	11.6%	5.2%	10,100	Oil	0.840	0.50	OP	6.0	127	1973	1	4	3.05
GasST1	600	1	9.7%	8.8%	10,000	Gas	0.951	0.13	OP	9.4	170	1976	1	6	2.59
GasST2	500	1	9.7%	8.8%	10,100	Gas	1.084	0.13	OP	9.4	150	1970	1	4	2.96
GasST3	450	1	9.7%	8.8%	10,200	Gas	1.111	0.13	OP	9.4	220	1967	1	0	3.06
GasCC1	300	1	6.8%	13.0%	9,665	Gas	0.951	0.10	OP	10.0	470	1992	2	45	2.48
GasCC2-New	200	1	5.5%	7.5%	7,760	Gas	1.000	0.05	OP	28.9	452	1999	3	55	2.06
GasCC3-new	200	1	5.5%	7.5%	7,618	Gas	1.000	0.05	OP	28.9	477	2001	3	58	2.02
GasCC4-Adv	800	1	5.5%	7.5%	6,284	Gas	1.000	0.05	OP	26.6	538	2005	3	66	1.68
GasCC5-Adv	950	1	5.5%	7.5%	5,817	Gas	1.000	0.05	OP	26.6	615	2009	3	75	1.55
GasCT1+2	450	1	10.0%	5.4%	12,800	Gas	0.969	0.22	OP	6.0	140	1986	1	9	3.42
GasCT3-new	350	1	3.6%	4.0%	11,460	Gas	1.000	0.01	OP	11.9	364	1998	3	44	2.98
GasCT4-new	350	1	3.6%	4.0%	10,873	Gas	1.000	0.01	OP	11.9	406	2002	3	50	2.82
GasCT5-Adv.	450	1	3.8%	3.9%	7,793	Gas	1.000	0.05	OP	18.9	542	2008	3	66	2.07
Renewable	50	1	25.0%	15.0%	10,280	Other	1.000	1.27	OP	65.5	2,361	2008	4	260	1.27
Limited Energy			Peak CF	Non-peak CF											
Hydro	1,600	1	55.0%	40.0%	1028000.0%	Hydro		0.10		10	400	1957	1	0	0.10
Total Capacity	15,150														

Restructure case

	Annual	Peak season	Offpeak season	# of Unprofitable plants	Against avoid O&M	9
Reserve Margin	6.8%	6.8%	6.1%	Against all costs		12 w/ unserv
LOLP, % of period	0.92	2.12	0.52	Average Price, c/kWh	2.84	2.86
LOLP, day/10 Year	33.67	77.55	19.04	Avg. Variable Cost	1.45	1.47
Load factor	65.7%	73.1%	71.4%	Avg. Vari+Avoid O&M	2.17	2.19
Peak Demand, MW	14,188	14,188	12,589	Total Cost	2.51	2.53
Energy, GWh	81,727	22,703	59,024	Max loss, \$/avail kW	(417.34)	
Generation, GWh	81,692	22,682	59,010	Start-up Cost, \$/MW	40	
Unserv Energy, G	34	21	13	# plants Probabilistic	10	
Round err not in UE	1	0	0			

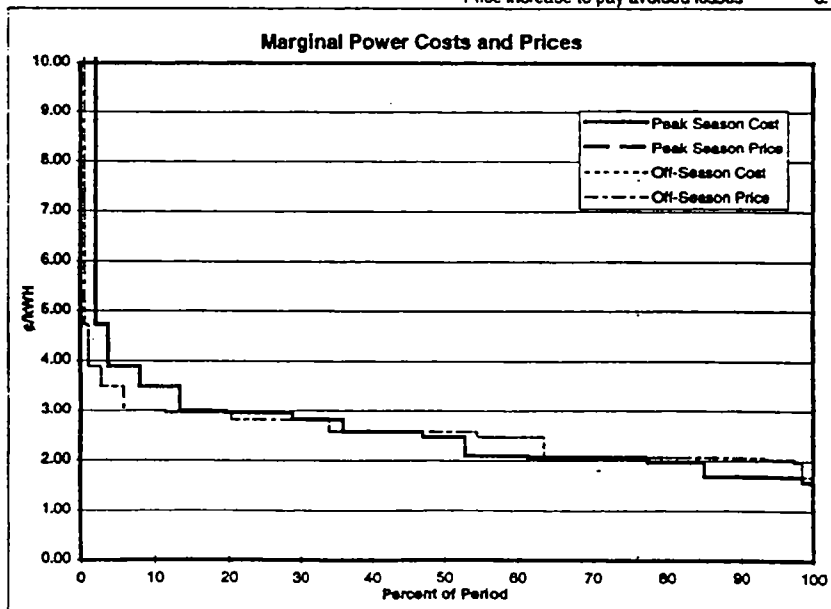
	% of Total Capacity	% of Total Generation	Cap fact %	Avoidable c/kWh	Variable c/kWh
Hydro	10.6%	7.5%	43.8%	0.36	0.10
Nuclear	11.9%	15.4%	79.6%	2.02	0.73
Coal	37.0%	47.4%	78.9%	1.80	1.58
Oil	3.3%	0.3%	4.8%	4.91	3.49
Gas-ST	10.2%	3.3%	19.6%	3.27	2.73
Gas-CC	16.2%	21.0%	80.0%	2.95	1.74
Gas-CT	10.6%	4.9%	28.6%	4.34	2.32
Other	0.3%	0.3%	60.0%	7.47	1.27

Plant Name	Capacity	Output MWYr	Capac Factor	Time on Margin, %	Revenue MS	Var. Cost MS	+Start Avoidable Cst MS	Unavoidable Fxd Cst MS	Total Net Rev MS	Avoidable Net Rev MS	Net Rev \$/kW	Avoidable cost, c/kWh	Carbon release Million Tons
Nuclear1	1,000	796.00	79.6%	0.00	188	51	90	26	21	47.00	59.04	2.02	0.00
Nuclear2	800	636.80	79.6%	0.00	150	41	72	144	(106)	37.60	59.04	2.02	0.00
Coal1	900	709.20	78.8%	0.00	168	79	11	23	54	77.73	109.60	1.45	1.53
Coal2	850	719.95	84.7%	0.00	170	96	10	13	52	64.39	89.44	1.67	1.57
Coal3	850	719.95	84.7%	0.00	170	96	10	8	55	63.55	88.27	1.69	1.59
Coal4	600	498.60	83.1%	0.00	118	68	7	18	24	42.50	85.23	1.72	1.11
Coal5	600	497.33	82.9%	0.31	118	69	7	0	41	41.48	83.18	1.75	1.12
Coal6+7	850	650.83	76.6%	3.76	156	96	13	18	29	46.99	69.80	1.91	1.50
Coal8	450	331.95	73.8%	2.76	80	57	7	3	13	16.33	45.83	2.21	0.79
Coal9+10	450	248.27	55.2%	12.40	66	46	7	3	10	13.36	35.90	2.43	0.63
Coal-Adv.	50	41.80	83.6%	0.00	10	6	13	-	(8)	(8.49)	(203.14)	5.02	0.09
Oil1	500	24.14	4.8%	3.60	14	7	3	2	2	3.65	8.78	4.91	0.05
GasST1	600	218.00	36.3%	18.17	64	49	6	4	5	9.32	18.60	2.88	0.28
GasST2	500	74.36	14.9%	9.00	28	19	5	2	2	3.65	8.75	3.68	0.10
GasST3	450	11.21	2.5%	2.29	9	4	4	0	1	1.27	3.39	8.20	0.01
GasCC1	300	135.63	45.2%	8.25	38	29	3	14	(8)	5.54	23.02	2.73	0.17
GasCC2-New	200	149.36	74.7%	4.20	37	27	17	-	(7)	(6.78)	(38.94)	3.34	0.15
GasCC3-new	200	156.58	78.3%	4.00	38	28	17	-	(7)	(6.90)	(39.66)	3.29	0.15
GasCC4-Adv	800	691.10	86.4%	0.77	183	101	74	-	(12)	(11.85)	(17.02)	2.90	0.55
GasCC5-Adv	950	826.46	87.0%	0.06	195	113	97	-	(14)	(14.19)	(17.17)	2.89	0.61
GasCT1+2	450	5.10	1.1%	0.87	7	2	3	4	(2)	2.32	6.10	10.77	0.01
GasCT3-new	350	34.22	9.8%	5.78	15	9	20	-	(14)	(13.54)	(41.87)	9.59	0.05
GasCT4-new	350	92.17	26.3%	12.00	30	23	22	-	(14)	(14.26)	(44.10)	5.49	0.13
GasCT5-Adv.	450	326.60	72.6%	10.89	83	59	37	-	(14)	(13.80)	(33.22)	3.37	0.32
Renewable	50	30.00	60.0%	0.00	7	3	18	-	(13)	(12.52)	(417.34)	7.47	0.00
Hydro	1,600	700.00	43.8%		195	6	18	0	173	172.60	107.88	0.36	0.00
Totals	15,150	9,326	62%		2,317	1,184	586	284	263	547			12.50

Unserv Energy	3.87	17	17	w/o UE	1,770	2,054	Avg. Carbon kg/MWhr	153
Totals w/ Unserved	9,329	2,335	1,202	w/ UE	1,788	2,071	Time wtd marginal cost	2.61
							Time wtd Unserv E Price	19.86
							Unserv E. Cost/kWh	50.65
							Price increase to pay avoided losses	0.13

Sort by Net Revenue/kW

Name	Avoidable Net Rev/kW	Capacity	Reserve Margin
Coal1	109.60	900	6%
Hydro	107.88	1,600	18%
Coal2	89.44	850	24%
Coal3	88.27	850	30%
Coal4	85.23	600	34%
Coal5	83.18	600	38%
Coal6+7	69.80	850	44%
Nuclear2	59.04	800	50%
Nuclear1	59.04	1,000	57%
Coal8	45.83	450	60%
Coal9+10	35.90	450	63%
GasCC1	23.02	300	65%
GasST1	18.60	600	69%
Oil1	8.78	500	73%
GasST2	8.75	500	76%
GasCT1+2	6.10	450	80%
GasST3	3.39	450	83%
GasCC4-Adv	(17.02)	800	88%
GasCC5-Adv	(17.17)	950	85%
GasCT5-Adv.	(33.22)	450	98%
GasCC2-New	(38.94)	200	100%
GasCC3-new	(39.66)	200	101%
GasCT3-new	(41.87)	350	104%
GasCT4-new	(44.10)	350	106%
Coal-Adv.	(203.14)	50	106%
Renewable	(417.34)	50	107%



Case ID	Efficiency Case	Fuel Type	\$/MMBTU	kg C/MBTU	CAPITALIZATION-Existing	IPP-Existing	IPP-New	IPP-Renew	Peak Season LDC	Season Peak	Shoulder 2	Shoulder 1	Min (100%)		
Peak Demand	13019.9318	Gas	2.59	14.47	Term (Years)	30	30	20	20 % of Season	0	5	95	100		
Ratio of Off-peak to peak	88.4%	Coal	1.34	25.72	Tax life	20	20	12	5 Template ratio	100%	93%	53%	42%		
Peak fraction of year	25%	Oil	3.00	21.49	Inc. Tax Rate	36%	36%	36%	36% Ratio to Peak	100%	93%	53%	42%		
Load Factor, %	65.5%	Nuclear	0.70	0	Prop. Tax rate	5%	5%	5%	5% Demand MW	13,020	12,133	6,870	5,409		
Peak Season Load Factor	72.9%	Hydro	0.00	0	Debt %	48%	30%	30%	30% Off-Peak Season LDC						
Off-Peak Season Load Factor	71.4%	Other	0.00	0	Interest Rate	8.0%	10.0%	10.0%	10.0% % of Season	0	2	96	100		
Carbon Tax, \$/metric ton C	0.00	Year of Study	2010	0	Preferred Equity	14%	0%	0%	0% Template ratio	100%	85%	58%	50%		
Capacity Payment, \$/kW	0	Year of \$	1995	0	Return Rate	10.0%	10.0%	10.0%	10.0% Ratio to Peak	100%	85%	58%	50%		
Uplift Charge, \$/kWh	0	Start-up Cost, \$/MW	40	0	Common Equity	38%	70%	70%	70% Demand MW	11,507	9,823	6,669	5,731		
Unserved Energy, \$/kWh	3.18	Min Capacity w/ probab	0	0	Return Rate	11.0%	14.0%	14.0%							
Non-generat. Price, \$/kWh	0.05	Min Outage Rate w/ probab	0.05	0.05	Vary FCR by %	TRUE	TRUE	FALSE							
Price Elasticity(not used if 0)	0.05	Max # Plants with prob.	10	10	Include in Avo	FALSE	FALSE	TRUE	Fractional change to start year	0.30					
Default Unserved E calc (always show)															
Name	Capacity	Capacity Adjust Factor (0 to 1)	Forced Outage Rate	Planned Outage Rate	Heat Rate (BTU/kWh)	Fuel Type	Fuel Price Adjustment	Variable O&M Cost \$/kWh	Bid Price or OP, \$/kWh	Fixed O&M Cost \$/kW-yr	- Plant Construction - Nominal Construction Cost/kW	Year	Capitilization Structure to Use	Unavoidable Fixed Cost \$/kW-yr	Variable Cost \$/kWh
Nuclear1	1,000	1	8.2%	12.2%	10,460	Nuclear	1.000	0.00	OP	90.0	800	1973	1	26	0.73
Nuclear2	800	1	8.2%	12.2%	10,460	Nuclear	1.000	0.00	OP	90.0	2,750	1988	1	180	0.73
Coal1	900	1	7.0%	14.2%	9,600	Coal	0.833	0.21	OP	11.7	490	1983	1	28	1.28
Coal2	850	1	6.5%	8.8%	9,700	Coal	1.000	0.22	OP	11.7	370	1978	1	15	1.51
Coal3	850	1	6.5%	8.8%	9,800	Coal	1.000	0.22	OP	11.7	300	1973	1	10	1.53
Coal4	600	1	6.6%	10.3%	9,900	Coal	1.000	0.23	OP	12.4	680	1981	1	31	1.55
Coal5	600	1	6.6%	10.3%	10,000	Coal	1.000	0.24	OP	12.4	380	1960	1	0	1.58
Coal6+7	850	1	8.5%	12.3%	10,200	Coal	1.000	0.32	OP	15.2	500	1980	1	21	1.68
Coal8	450	1	8.5%	12.3%	10,600	Coal	1.167	0.32	OP	15.2	300	1970	1	8	1.97
Coal9+10	450	1	6.4%	10.9%	11,200	Coal	1.167	0.35	OP	16.3	300	1970	1	8	2.09
Coal-Adv.	50	1	4.1%	12.3%	9,600	Coal	1.000	0.25	OP	33.6	1,816	2006	3	222	1.53
Oil1	500	1	11.6%	5.2%	10,100	Oil	0.840	0.50	OP	6.0	127	1973	1	4	3.05
GasST1	600	1	9.7%	6.8%	10,000	Gas	0.951	0.13	OP	9.4	170	1976	1	6	2.59
GasST2	500	1	9.7%	6.8%	10,100	Gas	1.084	0.13	OP	9.4	150	1970	1	4	2.98
GasST3	450	1	9.7%	6.8%	10,200	Gas	1.111	0.13	OP	9.4	220	1967	1	0	3.06
GasCC1	300	1	6.6%	13.0%	9,665	Gas	0.951	0.10	OP	10.0	470	1992	2	45	2.48
GasCC2-New	200	1	5.5%	7.5%	7,760	Gas	1.000	0.05	OP	28.9	452	1999	3	55	2.06
GasCC3-new	200	1	5.5%	7.5%	7,618	Gas	1.000	0.05	OP	28.9	477	2001	3	58	2.02
GasCC4-Adv	800	1	5.5%	7.5%	6,284	Gas	1.000	0.05	OP	26.6	538	2005	3	66	1.68
GasCC5-Adv	300	1	5.5%	7.5%	5,817	Gas	1.000	0.05	OP	26.6	615	2009	3	75	1.55
GasCT1+2	450	1	10.0%	6.4%	12,800	Gas	0.969	0.22	OP	6.0	140	1986	1	9	3.42
GasCT3-new	350	1	3.6%	4.0%	11,460	Gas	1.000	0.01	OP	11.9	364	1998	3	44	2.98
GasCT4-new	350	1	3.6%	4.0%	10,873	Gas	1.000	0.01	OP	11.9	406	2002	3	50	2.82
GasCT5-Adv.	0	1	3.6%	3.9%	7,793	Gas	1.000	0.05	OP	16.9	542	2008	3	66	2.07
Renewable	50	1	25.0%	15.0%	10,280	Other	1.000	1.27	OP	65.5	2,361	2008	4	260	1.27
Limited Energy			Peak CF	Non-peak CF											
Hydro	1,600	1	55.0%	40.0%	1028000.0%	Hydro		0.10		10	400	1957	1	0	0.10
Total Capacity	14,050														

Efficiency Case

	Annual	Peak season	Offpeak season	# of Unprofitable plants	Against avoid O&M	8
Reserve Margin	7.9%	7.9%	7.3%		Against all costs	11 w/ unserv
LOLP, % of period	0.73	1.64	0.43		Average Price, ¢/kWh	2.85 2.87
LOLP, day/10 Year	26.77	59.82	15.72		Avg. Variable Cost	1.43 1.45
Load factor	65.5%	72.9%	71.4%		Avg. Vari+Avoid O&M	2.08 2.09
Peak Demand, MW	13,020	13,020	11,507		Total Cost	2.46 2.47
Energy, GWh	74,733	20,777	53,956		Max loss, \$/avail kW	(415.33)
Generation, GWh	74,709	20,761	53,948		Start-up Cost, \$/MW	40
Unserv Energy, G	24	15	9		# plants Probabilistic	10
Round err not in UE	(1)	0	(1)			

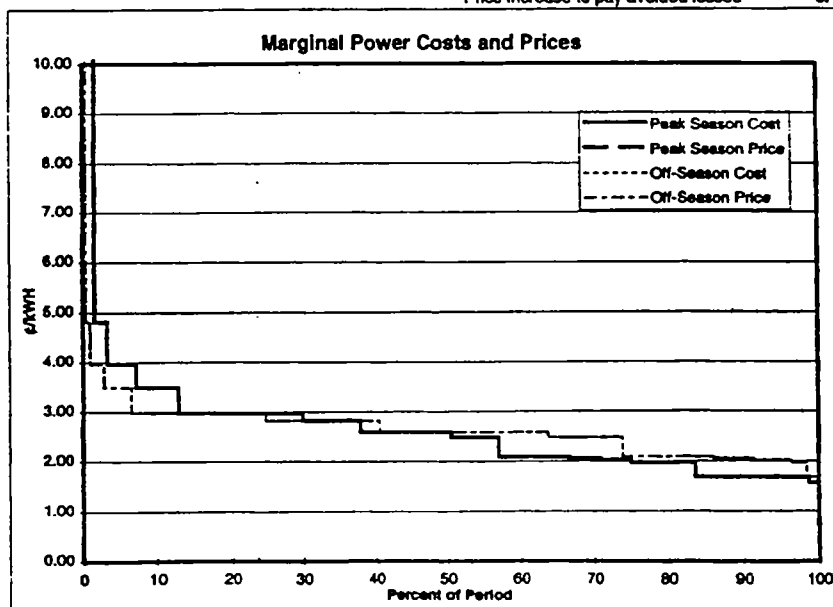
	% of Total Capacity	% of Total Generator	Cap fact %	Avoidable ¢/kWh	Variable ¢/kWh
Hydro	11.4%	8.2%	43.8%	0.36	0.10
Nuclear	12.8%	16.6%	79.6%	2.02	0.73
Coal	39.9%	52.1%	79.4%	1.80	1.58
Oil	3.6%	0.3%	4.8%	4.92	3.49
Gas-ST	11.0%	4.0%	22.1%	3.20	2.72
Gas-CC	12.8%	16.5%	78.1%	2.97	1.82
Gas-CT	8.2%	1.7%	12.8%	6.33	2.92
Other	0.4%	0.4%	60.0%	7.47	1.27

Plant Name	Capacity	Output MWYr	Capac Factor	Time on Margin, %	Revenue Var. M\$	Start Cost M\$	Avoidable Cost M\$	Unavoidable Cost M\$	Total Net Rev M\$	Avoidable Net Rev M\$	Net Rev \$/KW	Avoidable cost, \$/KWh	Carbon release Million Tons
Nuclear1	1,000	796.00	79.6%	0.00	190	51	90	26	22	48.80	61.31	2.02	0.00
Nuclear2	800	636.80	79.6%	0.00	152	41	72	144	(105)	39.04	61.31	2.02	0.00
Coal1	900	709.20	78.8%	0.00	169	79	11	23	56	79.29	111.80	1.45	1.53
Coal2	850	719.95	84.7%	0.00	172	96	10	13	53	66.12	91.84	1.67	1.57
Coal3	850	719.95	84.7%	0.00	172	96	10	8	57	65.28	90.67	1.69	1.59
Coal4	600	498.60	83.1%	0.00	119	68	7	18	25	43.67	87.58	1.72	1.11
Coal5	600	497.67	82.9%	0.32	119	69	7	0	43	42.65	85.53	1.75	1.12
Coal6+7	850	649.88	76.5%	4.25	157	96	13	18	30	48.51	72.05	1.91	1.49
Coal8	450	329.66	73.3%	3.58	81	57	7	3	14	17.18	48.20	2.21	0.79
Coal9+10	450	279.28	62.1%	11.64	73	51	7	3	11	14.24	38.28	2.39	0.70
Coal-Adv.	50	41.80	83.6%	0.00	10	6	13	-	(8)	(8.40)	(200.85)	5.02	0.09
Oil1	500	24.03	4.8%	4.24	13	7	3	2	0	2.54	6.11	4.92	0.05
GasST1	600	250.40	41.7%	20.53	71	57	6	4	5	8.74	17.45	2.84	0.32
GasST2	500	81.68	16.3%	11.55	28	21	5	2	1	2.54	6.09	3.62	0.10
GasST3	450	10.09	2.2%	2.26	8	3	4	0	0	0.22	0.58	8.74	0.01
GasCC1	300	155.17	51.7%	9.26	42	34	3	14	(8)	5.40	22.44	2.70	0.19
GasCC2-New	200	145.06	72.5%	4.99	37	26	17	-	(6)	(6.31)	(36.27)	3.38	0.14
GasCC3-new	200	153.58	76.8%	4.84	38	27	17	-	(6)	(6.45)	(37.05)	3.32	0.15
GasCC4-Adv	800	691.42	86.4%	0.71	165	101	74	-	(10)	(10.14)	(14.57)	2.90	0.55
GasCC5-Adv	300	261.00	87.0%	0.00	62	36	30	-	(4)	(3.84)	(14.72)	2.89	0.19
GasCT1+2	450	4.41	1.0%	0.84	6	2	3	4	(3)	1.31	3.45	11.80	0.01
GasCT3-new	350	36.25	10.4%	6.35	15	9	20	-	(14)	(14.26)	(44.11)	9.19	0.05
GasCT4-new	350	106.55	30.4%	13.91	33	26	22	-	(15)	(14.97)	(46.28)	5.13	0.15
GasCT5-Adv.	0	-	0.0%	0.00	-	-	-	-	-	-	-	0.00	0.00
Renewable	50	30.00	60.0%	0.00	7	3	16	-	(12)	(12.46)	(415.33)	7.47	0.00
Hydro	1,600	700.00	43.8%		194	6	16	0	172	171.63	107.27	0.36	0.00
Totals	14,050	8,528	61%		2,132	1,069	483	284	296	580			11.92

Unserv Energy	2.79	13	13	w/o UE	1,552	1,836	Avg. Carbon kg/MWhr	159
Totals w/ Unserv	8,531	2,145	1,082	w/ UE	1,565	1,849	Time wtd marginal cost	2.65
							Time wtd Unserv E Price	19.99
							Unserv E. Cost/kWh	53.89
							Price increase to pay avoided losses	0.10

Sort by Net Revenue/kW

Name	Avoidable Net Rev/kW	Capacity	Reserve Margin
Coal1	111.80	900	7%
Hydro	107.27	1,600	19%
Coal2	91.84	850	26%
Coal3	90.67	850	32%
Coal4	87.58	600	37%
Coal5	85.53	600	41%
Coal6+7	72.05	850	48%
Nuclear2	61.31	800	54%
Nuclear1	61.31	1,000	62%
Coal8	48.20	450	65%
Coal9+10	38.28	450	69%
GasCC1	22.44	300	71%
GasST1	17.45	600	76%
Oil1	6.11	500	79%
GasST2	6.09	500	83%
GasCT1+2	3.45	450	87%
GasST3	0.58	450	90%
GasCT5-Adv.	-	-	90%
GasCC4-Adv	(14.57)	800	96%
GasCC5-Adv	(14.72)	300	99%
GasCC2-New	(36.27)	200	100%
GasCC3-new	(37.05)	200	102%
GasCT3-new	(44.11)	350	104%
GasCT4-new	(46.28)	350	107%
Coal-Adv.	(200.85)	50	108%
Renewable	(415.33)	50	108%



Case ID	HI Effici/Low Carbon					CAPITALIZAT	IOU-Existing	IPP-Existing	IPP-New	IPP-Renew	Peak Season LDC								
Peak Demand	11911.4734	Fuel Type	\$/MMBTU	kg C/MBTU			1	2	3	4	Season Peak	Shoulder 2	Shoulder 1	Min (100%)					
Ratio of Off-peak to peak	88.1%	Gas	2.59	14.47	Term (Years)		30	30	20	20	% of Season	0	6	95	100				
Peak fraction of year	25%	Coal	1.34	25.72	Tax life		20	20	12	5	Template ratio	100%	93%	52%	41%				
Load Factor, %	65.5%	Oil	3.00	21.49	Inc. Tax Rate		36%	36%	36%	36%	Ratio to Peak	100%	93%	52%	41%				
Peak Season Load Factor	72.6%	Nuclear	0.70	0	Prop. Tax rate		5%	5%	5%	5%	Demand MW	11,911	11,108	6,223	4,927				
Off-Peak Season Load Factor	71.7%	Hydro	0.00	0	Debt %		48%	30%	30%	30%	Off-Peak Season LDC								
Carbon Tax, \$/metric ton C	50.00	Other	0.00	0	Interest Rate		8.0%	10.0%	10.0%	10.0%	% of Season	0	2	96	100				
Capacity Payment, \$/kW	0	Year of Study	2010	0	Preferred Equity		14%	0%	0%	0%	Template ratio	100%	86%	58%	51%				
Uplift Charge, \$/kWh	0	Year of \$	1995	0	Return Rate		10.0%	10.0%	10.0%	10.0%	Ratio to Peak	100%	86%	58%	51%				
Unreserved Energy, \$/kWh	0	Start-up Cost, \$/MW	40	0	Common Equi		38%	70%	70%	70%	Demand MW	10,488	9,000	6,105	5,305				
Non-general. Price, \$/kWh	3.18	Min Capacity w/ probab	0	0	Return Rate		11.0%	14.0%	14.0%	14.0%									
Price Elasticity(not used if 0)	0.05	Min Outage Rate w/ probab	0.0%	0.0%	Vary FCR by	TRUE	TRUE	FALSE	FALSE										
Default Unreserved E calc (always show)	Max # Plants with prob.	10	Include in Avo	FALSE	FALSE	TRUE	TRUE				Fractional change to start year	0.30							
Name	Capacity	Capacity Adjust Factor (0 to 1)	Forced Outage Rate	Planned Outage Rate	Heat Rate (BTU/kWh)	Fuel Type	Fuel Price Adjustment	Variable O&M Cost \$/kWh	Bid Price or OP, \$/kWh	Fixed O&M Cost \$/kW-yr	- Plant Construction - Nominal Construction Cost/kW	Capitilization Structure to Use	Unavoidable Fixed Cost \$/kW-yr	Variable Cost \$/kWh					
Nuclear1	1,000	1	8.2%	12.2%	10,460	Nuclear	1.000	0.00	OP	90.0	800	1973	1	26	0.73				
Nuclear2	800	1	8.2%	12.2%	10,460	Nuclear	1.000	0.00	OP	90.0	2,750	1988	1	180	0.73				
Coal1	900	1	7.0%	14.2%	9,600	Coal	0.833	0.21	OP	11.7	490	1983	1	26	2.51				
Coal2	850	1	6.5%	8.8%	9,700	Coal	1.000	0.22	OP	11.7	370	1978	1	15	2.76				
Coal3	850	1	6.5%	8.8%	9,800	Coal	1.000	0.22	OP	11.7	300	1973	1	10	2.79				
Coal4	600	1	6.6%	10.3%	9,900	Coal	1.000	0.23	OP	12.4	680	1981	1	31	2.82				
Coal5	600	1	6.6%	10.3%	10,000	Coal	1.000	0.24	OP	12.4	380	1960	1	0	2.86				
Coal6+7	850	1	8.5%	12.3%	10,200	Coal	1.000	0.32	OP	15.2	500	1980	1	21	2.99				
Coal8	0	1	8.5%	12.3%	10,600	Coal	1.167	0.32	OP	15.2	300	1970	1	8	3.33				
Coal9+10	0	1	8.4%	10.9%	11,200	Coal	1.167	0.35	OP	16.3	300	1970	1	8	3.53				
Coal-Adv.	50	1	4.1%	12.3%	9,600	Coal	1.000	0.25	OP	33.6	1,816	2006	3	222	2.76				
Oil1	500	1	11.6%	5.2%	10,100	Oil	0.840	0.50	OP	6.0	127	1973	1	4	4.13				
GasST1	600	1	9.7%	6.8%	10,000	Gas	0.951	0.13	OP	9.4	170	1976	1	6	3.31				
GasST2	500	1	9.7%	6.8%	10,100	Gas	1.084	0.13	OP	9.4	150	1970	1	4	3.69				
GasST3	450	1	9.7%	6.8%	10,200	Gas	1.111	0.13	OP	9.4	220	1967	1	0	3.80				
GasCC1	300	1	6.8%	13.0%	9,665	Gas	0.951	0.10	OP	10.0	470	1992	2	45	3.18				
GasCC2-New	200	1	5.5%	7.5%	7,760	Gas	1.000	0.05	OP	28.9	452	1999	3	55	2.62				
GasCC3-new	200	1	5.5%	7.5%	7,618	Gas	1.000	0.05	OP	28.9	477	2001	3	58	2.57				
GasCC4-Adv	450	1	5.5%	7.5%	6,284	Gas	1.000	0.05	OP	26.6	538	2005	3	66	2.13				
GasCC5-Adv	950	1	5.5%	7.5%	5,817	Gas	1.000	0.05	OP	26.6	615	2009	3	75	1.98				
GasCT1+2	450	1	10.0%	5.4%	12,800	Gas	0.969	0.22	OP	6.0	140	1986	1	9	4.35				
GasCT3-new	350	1	3.6%	4.0%	11,460	Gas	1.000	0.01	OP	11.9	364	1996	3	44	3.80				
GasCT4-new	350	1	3.6%	4.0%	10,873	Gas	1.000	0.01	OP	11.9	406	2002	3	50	3.61				
GasCT5-Adv.	0	1	3.8%	3.9%	7,793	Gas	1.000	0.05	OP	16.9	542	2008	3	66	2.63				
Renewable	50	1	25.0%	15.0%	10,280	Other	1.000	1.27	OP	65.5	2,361	2008	4	260	1.27				
Limited Energy			Peak CF	Non-peak CF															
Hydro	1,600	1	55.0%	40.0%	1028000.0%	Hydro		0.10		10	400	1957	1	0	0.10				
Total Capacity	13,450																		

HI Effc./Low Carbon

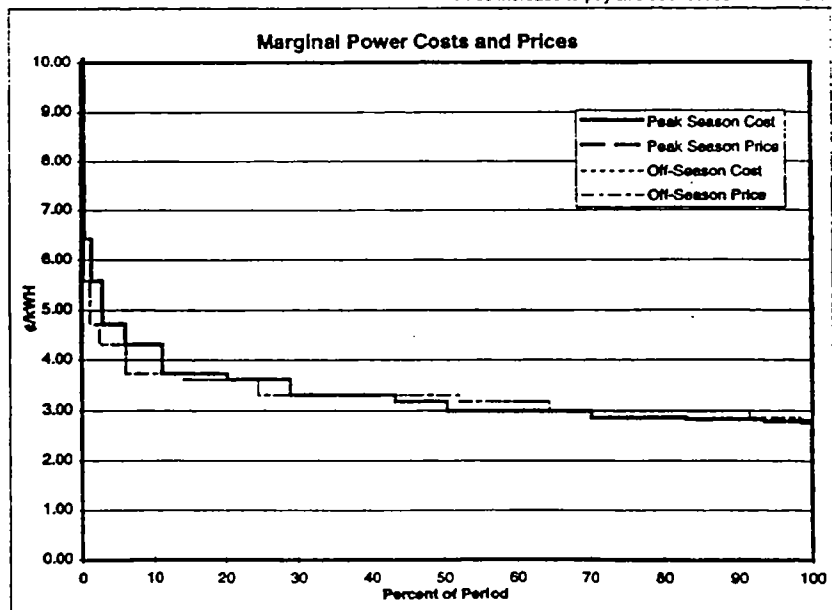
		Peak season	Offpeak season	# of Unprofitable plants Against avoid O&M	10		% of Total Capacity	Generation	Cap fact %	Avoidable e/kWh	Variable e/kWh	
Reserve Margin	12.9%	12.9%	13.2%	Against all costs	15 w/ unserv	Hydro	11.9%	9.0%	43.8%	0.36	0.10	
LOLP, % of period	0.17	0.40	0.10	Average Price, e/kWh	3.45	3.45	Nuclear	13.4%	18.4%	79.6%	2.02	0.73
LOLP, day/10 Year	6.34	14.58	3.59	Avg. Variable Cost	2.07	2.07	Coal	34.9%	46.2%	76.8%	3.00	2.77
Load factor	65.5%	72.6%	71.7%	Avg. Vari+Avoid O&M	2.80	2.81	Oil	3.7%	0.1%	0.9%	13.45	5.58
Peak Demand, MW	11,911	11,911	10,468	Total Cost	3.21	3.21	Gas-ST	11.5%	3.3%	16.5%	4.12	3.47
Energy, GWh	68,373	18,949	49,424	Max loss, \$/avail kW	(359.93)		Gas-CC	15.6%	21.8%	80.9%	3.41	2.23
Generation, GWh	68,350	18,945	49,405	Start-up Cost, \$/MW	40		Gas-CT	8.6%	0.9%	6.4%	10.59	3.78
Unserv Energy, G	6	4	2	# plants Probabilistic	9		Other	0.4%	0.4%	60.0%	7.47	1.27

Plant Name	Capacity	Output MWYr	Capac Factor	Time on Margin, %	Revenue M\$	Var. Cost M\$	+Start M\$	Avoidable M\$	Unavoidable M\$	Total Net Rev M\$	Avoidable Net Rev M\$	Avg. Carbon kg/MWhr	Carbon release Million Tons
Nuclear1	1,000	796.00	79.6%	0.00	234	51	90	26	67	93.00	116.84	2.02	0.00
Nuclear2	800	636.80	79.6%	0.00	187	41	72	144	(70)	74.40	116.84	2.02	0.00
Coal1	900	709.20	78.8%	0.00	209	156	11	23	19	41.94	59.14	2.68	1.53
Coal2	850	719.20	84.6%	0.32	211	174	10	13	15	27.47	38.15	2.92	1.57
Coal3	850	713.96	84.0%	1.30	210	174	10	8	17	25.82	35.87	2.95	1.58
Coal4	600	479.35	79.9%	3.75	142	119	7	18	(3)	15.80	31.68	3.00	1.07
Coal5	600	454.18	75.7%	8.52	136	114	7	0	14	14.31	28.70	3.05	1.02
Coal6+7	850	490.19	57.7%	25.20	151	129	13	18	(8)	9.83	14.60	3.29	1.13
Coal8	0	-	0.0%	0.00	-	-	-	-	-	-	-	0.00	0.00
Coal9+10	0	-	0.0%	0.00	-	-	-	-	-	-	-	0.00	0.00
Coal-Adv.	50	41.64	83.3%	0.04	12	10	13	-	(11)	(10.59)	(253.46)	6.28	0.09
Oil1	500	4.35	0.9%	0.96	4	2	3	2	(4)	(1.59)	(3.83)	13.45	0.01
GasST1	600	188.70	31.5%	24.18	64	55	6	4	(0)	3.40	6.79	3.65	0.24
GasST2	500	47.81	9.6%	8.38	20	16	5	2	(3)	(0.71)	(1.69)	4.86	0.06
GasST3	450	19.32	4.3%	4.00	9	7	4	0	(2)	(2.05)	(5.44)	6.81	0.02
GasCC1	300	132.15	44.1%	11.09	43	37	3	14	(11)	2.79	11.60	3.44	0.16
GasCC2-New	200	174.00	87.0%	0.00	51	40	17	-	(6)	(5.59)	(32.15)	3.72	0.17
GasCC3-new	200	174.00	87.0%	0.00	51	39	17	-	(5)	(5.50)	(31.58)	3.72	0.17
GasCC4-Adv	450	391.50	87.0%	0.00	115	73	42	-	0	0.46	1.18	3.34	0.31
GasCC5-Adv	950	826.50	87.0%	0.00	243	143	97	-	3	3.33	4.03	3.31	0.81
GasCT1+2	450	1.37	0.3%	0.40	2	1	3	4	(5)	(1.58)	(4.14)	28.97	0.00
GasCT3-new	350	7.62	2.2%	1.78	5	3	20	-	(18)	(18.27)	(56.49)	34.28	0.01
GasCT4-new	350	64.64	18.5%	9.93	24	20	22	-	(18)	(17.89)	(55.32)	7.41	0.09
GasCT5-Adv.	0	-	0.0%	0.00	-	-	-	-	-	-	-	0.00	0.00
Renewable	50	30.00	60.0%	0.00	9	3	16	-	(11)	(10.80)	(359.93)	7.47	0.00
Hydro	1,600	700.00	43.8%	0.00	224	6	16	0	201	201.45	125.90	0.36	0.00
Totals	13,450	7,802	58%		2,355	1,413	502	277	163	439			9.85

Unserv Energy	0.65	3	3	w/o UE	1,915	2,192	Avg. Carbon kg/MWhr	144
Totals w/ Unserv	7,803	2,358	1,416	w/ UE	1,919	2,195	Time wtd marginal cost	3.34
							Time wtd Unserv E Price	23.44
							Unserv E. Cost/kWh	57.52
							Price increase to pay avoided losses	0.11

Sort by Net Revenue/kW

Name	Avoidable Net Rev/kW	Capacity	Reserve Margin
Hydro	125.90	1,600	13%
Nuclear2	116.84	800	20%
Nuclear1	116.84	1,000	29%
Coal1	59.14	900	36%
Coal2	38.15	850	43%
Coal3	35.87	850	50%
Coal4	31.68	600	55%
Coal5	28.70	600	60%
Coal6+7	14.60	850	68%
GasCC1	11.80	300	70%
GasST1	6.79	600	75%
GasCC5-Adv	4.03	950	83%
GasCC4-Adv	1.18	450	87%
Coal8	-	-	87%
Coal9+10	-	-	87%
GasCT5-Adv.	-	-	87%
GasST2	(1.69)	500	91%
Oil1	(3.83)	500	95%
GasCT1+2	(4.14)	450	99%
GasST3	(5.44)	450	103%
GasCC3-new	(31.58)	200	105%
GasCC2-New	(32.15)	200	106%
GasCT4-new	(55.32)	350	108%
GasCT3-new	(56.49)	350	112%
Coal-Adv.	(253.46)	50	112%
Renewable	(359.93)	50	113%



Case ID	Alt. Technology	Fuel Type	\$/MMBTU	kg C/MBTU	CAPITALIZAT	IOU-Exsting	IPP-Exsting	IPP-New	IPP-Renew	Peak Season LDC	Season Peak	Shoulder 2	Shoulder 1	Min (100%)		
Peak Demand	14134.3982	Gas	2.59	14.47	Term (Years)	30	30	20	20	% of Season	0	5	95	100		
Ratio of Off-peak to peak	88.7%	Coal	1.34	25.72	Tax life	20	20	12	5	Template ratio	100%	94%	53%	42%		
Peak fraction of year	25%	Oil	3.00	21.49	Inc. Tax Rate	36%	36%	36%	36%	Ratio to Peak	100%	94%	53%	42%		
Load Factor, %	65.7%	Nuclear	0.70	0	Prop. Tax rate	5%	5%	5%	5%	Demand MW	14,134	13,228	7,452	5,887		
Peak Season Load Factor	73.0%	Hydro	0.00	0	Debt %	48%	30%	30%	30%	Off-Peak Season LDC						
Off-Peak Season Load Factor	71.3%	Other	0.00	0	Interest Rate	8.0%	10.0%	10.0%	10.0%	% of Season	0	2	96	100		
Carbon Tax, \$/metric ton C	0.00	Year of Study	2010	0	Prefer Equity	14%	0%	0%	0%	Template ratio	100%	85%	58%	50%		
Capacity Payment, \$/kW	0	Year of \$	1995	0	Return Rate	10.0%	10.0%	10.0%	10.0%	Ratio to Peak	100%	85%	58%	50%		
Uplift Charge, \$/kWh	0	Start-up Cost, \$/MW	40	0	Common Equi	38%	70%	70%	70%	Demand MW	12,538	10,707	7,242	6,225		
Unserved Energy, \$/kWh	0	Min Capacity w/ probab	0	0	Return Rate	11.0%	14.0%	14.0%	14.0%							
Non-generat. Price, \$/kWh	3.18	Min Outage Rate w/ probab	0.05	0.0%	Vary FCR by 1	TRUE	TRUE	FALSE	FALSE							
Price Elasticity(not used if 0)	0.05	Max # Plants with prob.	10	Include in Avo	FALSE	FALSE	TRUE	TRUE	Fractional change to start year	0.30						
Default Unserved E calc (always show)																
Name	Capacity	Adjust Factor	Capacity (0 to 1)	Forced Outage Rate	Planned Outage Rate	Heat Rate (BTU/kWh)	Fuel Type	Fuel Price Adjustment	Variable O&M Cost \$/kWh	Bid Price or OP, \$/kWh	Fixed O&M Cost \$/kW-yr	Plant Construction - Nominal Cost/kW	Construction Year	Capitilization Structure to Use	Unavoidable Fixed Cost \$/kW-yr	Variable Cost \$/kWh
Nuclear1	1,000	1		8.2%	12.2%	10,460	Nuclear	1.000	0.00	OP	90.0	800	1973	1	26	0.73
Nuclear2	800	1		8.2%	12.2%	10,460	Nuclear	1.000	0.00	OP	90.0	2,750	1988	1	180	0.73
Coal1	900	1		7.0%	14.2%	9,600	Coal	0.833	0.21	OP	11.7	490	1983	1	26	1.28
Coal2	850	1		8.5%	8.8%	9,700	Coal	1.000	0.22	OP	11.7	370	1978	1	15	1.51
Coal3	850	1		8.5%	8.8%	9,800	Coal	1.000	0.22	OP	11.7	300	1973	1	10	1.53
Coal4	600	1		8.6%	10.3%	9,900	Coal	1.000	0.23	OP	12.4	680	1981	1	31	1.55
Coal5	600	1		8.6%	10.3%	10,000	Coal	1.000	0.24	OP	12.4	380	1960	1	0	1.58
Coal6+7	850	1		8.5%	12.3%	10,200	Coal	1.000	0.32	OP	15.2	500	1980	1	21	1.68
Coal8	450	1		8.5%	12.3%	10,600	Coal	1.167	0.32	OP	15.2	300	1970	1	8	1.97
Coal9+10	450	1		6.4%	10.9%	11,200	Coal	1.167	0.35	OP	16.3	300	1970	1	8	2.09
Coal-Braltch	50	1		4.1%	12.3%	6,805	Coal	1.000	0.20	OP	26.0	1,377	2005	3	168	1.11
Oil1	500	1		11.6%	5.2%	10,100	Oil	0.840	0.50	OP	6.0	127	1973	1	4	3.05
GasST1	600	1		9.7%	8.8%	10,000	Gas	0.951	0.13	OP	9.4	170	1976	1	6	2.59
GasST2	500	1		9.7%	8.8%	10,100	Gas	1.084	0.13	OP	9.4	150	1970	1	4	2.98
GasST3	450	1		9.7%	8.8%	10,200	Gas	1.111	0.13	OP	9.4	220	1967	1	0	3.06
GasCC1	300	1		8.8%	13.0%	9,665	Gas	0.951	0.10	OP	10.0	470	1992	2	45	2.48
GasCC2-New	550	1		5.5%	7.5%	7,760	Gas	1.000	0.05	OP	28.9	452	1999	3	55	2.06
GasCC3-new	200	1		5.5%	7.5%	7,618	Gas	1.000	0.05	OP	28.9	477	2001	3	58	2.02
GasCC4-Bral	800	1		5.5%	7.5%	5,688	Gas	1.000	0.015	OP	16.0	689	2005	3	84	1.49
GasCC5-Bral	900	1		5.5%	7.5%	5,538	Gas	1.000	0.015	OP	16.0	774	2010	3	95	1.45
GasCT1+2	450	1		10.0%	5.4%	12,800	Gas	0.969	0.22	OP	6.0	140	1988	1	9	3.42
GasCT3-new	350	1		3.8%	4.0%	11,460	Gas	1.000	0.01	OP	11.9	364	1998	3	44	2.98
GasCT4-Bral	350	1		3.8%	4.0%	8,699	Gas	1.000	0.012	OP	17.6	523	2005	3	64	2.26
GasCT5-Bral	0	1		3.8%	3.9%	8,533	Gas	1.000	0.012	OP	17.6	564	2010	3	69	2.22
Renewable	50	1		25.0%	15.0%	10,280	Other	1.000	1.27	OP	65.5	2,361	2008	4	260	1.27
Limited Energy				Peak CF	Non-peak CF											
Hydro	1,600	1		55.0%	40.0%		Hydro		0.10		10	400	1957	1	0	0.10
Total Capacity	15,000															

Alt Technology

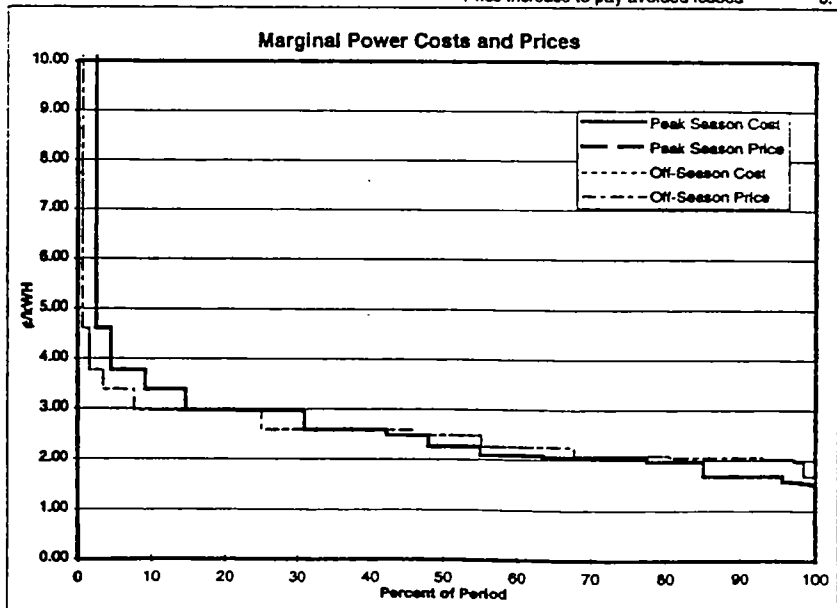
	Annual	Peak season	Offpeak season	# of Unprofitable plants	Against avoid O&M	8	% of Total		Cap fact	Avoidable	Variable
				Against all costs		10 w/ unserv	Capacity	Generation	%	e/kWh	e/kWh
Reserve Margin	6.1%	6.1%	5.3%				Hydro	10.7%	7.5%	43.8%	0.36
LOLP, % of period	1.14	2.55	0.66	Average Price, ¢/kWh	2.89	2.91	Nuclear	12.0%	15.4%	79.6%	2.02
LOLP, day/10 Year	41.49	93.21	24.25	Avg. Variable Cost	1.42	1.45	Coal	37.3%	47.7%	79.0%	1.79
Load factor	65.6%	73.0%	71.3%	Avg. Var+Avoid O&M	2.15	2.18	Oil	3.3%	0.3%	5.7%	4.59
Peak Demand, MW	14,134	14,134	12,538	Total Cost	2.50	2.52	Gas-ST	10.3%	3.0%	17.9%	3.36
Energy, GWh	81,326	22,607	58,720	Max loss, \$/avail kW	(414.51)	40	Gas-CC	18.3%	23.1%	78.0%	2.98
Generation, GWh	81,282	22,580	58,702	Start-up Cost, \$/MW	40	10	Gas-CT	7.7%	2.6%	20.7%	4.90
Unserv Energy, G	44	27	18	# plants Probabilistic	10		Other	0.3%	0.3%	60.0%	7.47
Round err not in UE	(0)	(0)	(0)								

Plant Name	Capacity	Output MWYr	Capac Factor	Time on Margin, %	Revenue Var. M\$	Start Cost M\$	Avoidable x d Cst M\$	Unavoidable Fxd Cst M\$	Total Net Rev M\$	Avoidable Net Rev M\$	Net Rev \$/kW	Avoidable Net Rev cost, c/kWh	Carbon release Million Tons
Nuclear1	1,000	796.00	79.6%	0.00	190	51	90	26	23	49.10	61.69	2.02	0.00
Nuclear2	800	636.80	79.6%	0.00	152	41	72	144	(105)	39.28	61.69	2.02	0.00
Coal1	900	709.20	78.8%	0.00	170	79	11	23	56	79.64	112.30	1.45	1.53
Coal2	850	719.95	84.7%	0.00	172	96	10	13	54	66.23	91.99	1.67	1.57
Coal3	850	719.70	84.7%	0.16	172	96	10	8	57	65.38	90.82	1.69	1.59
Coal4	600	496.76	82.8%	0.32	119	68	7	18	25	43.79	87.82	1.72	1.11
Coal5	600	494.59	82.4%	0.68	118	68	7	0	43	42.77	85.79	1.75	1.11
Coal6+7	850	650.83	76.6%	3.73	158	96	13	18	31	48.83	72.54	1.91	1.50
Coal8	450	331.98	73.8%	2.83	81	57	7	3	14	17.31	48.57	2.21	0.79
Coal9+10	450	261.37	58.1%	11.74	70	48	7	3	11	14.36	38.58	2.41	0.66
Coal-Braith	50	41.80	83.6%	0.00	10	4	10	-	(4)	(3.78)	(90.46)	3.78	0.06
Oil1	500	28.64	5.7%	4.50	17	9	3	2	4	5.92	14.24	4.59	0.05
GasST1	600	179.04	29.8%	18.47	58	41	6	4	8	11.39	22.74	2.95	0.23
GasST2	500	85.25	17.1%	10.80	33	22	5	2	4	5.87	14.05	3.59	0.11
GasST3	450	13.87	3.1%	2.59	12	5	4	0	3	3.27	8.70	7.25	0.02
GasCC1	300	117.82	39.3%	8.45	35	26	3	14	(7)	6.40	26.60	2.77	0.14
GasCC2-New	550	392.25	71.3%	11.87	100	71	46	-	(17)	(17.39)	(36.33)	3.40	0.39
GasCC3-new	200	156.44	78.2%	4.06	39	28	17	-	(6)	(6.45)	(37.06)	3.29	0.15
GasCC4-Braith	800	696.00	87.0%	0.00	166	91	80	-	(5)	(4.79)	(6.88)	2.80	0.50
GasCC5-Braith	900	783.00	87.0%	0.00	187	99	99	-	(12)	(12.16)	(15.53)	2.80	0.55
GasCT1+2	450	6.21	1.4%	1.18	9	3	3	4	0	4.18	10.98	9.57	0.01
GasCT3-new	350	40.82	11.7%	6.28	19	11	20	-	(12)	(11.74)	(36.29)	8.49	0.06
GasCT4-Braith	350	190.48	54.4%	11.23	53	38	29	-	(13)	(13.07)	(40.41)	3.98	0.21
GasCT5-Braith	0	-	0.0%	0.00	-	-	-	-	-	-	-	0.00	0.00
Renewable	50	30.00	60.0%	0.00	7	3	16	-	(12)	(12.44)	(414.51)	7.47	0.00
Hydro	1,600	700.00	43.8%		201	6	16	0	178	178.46	111.54	0.36	0.00
Totals	15,000	9,279	62%		2,346	1,154	591	284	317	600			12.35

Unserv Energy	5.06	24	24	w/o UE	1,745	2,029	Avg. Carbon kg/MWhr	152
Totals w/ Unserv	9,284	2,370	1,178	w/ UE	1,770	2,053	Time wtd marginal cost	2.61
							Time wtd Unserv E Price	21.69
							Unserv E. Cost/kWh	54.37
							Price increase to pay avoided losses	0.10

Sort by Net Revenue/kW

Name	Avoidable Net Rev/kW	Capacity	Reserve Margin
Coal1	112.30	900	6%
Hydro	111.54	1,600	18%
Coal2	91.99	850	24%
Coal3	90.82	850	30%
Coal4	87.82	600	34%
Coal5	85.79	600	38%
Coal6+7	72.54	850	44%
Nuclear1	61.69	1,000	51%
Nuclear2	61.69	800	57%
Coal8	48.57	450	60%
Coal9+10	38.58	450	63%
GasCC1	26.60	300	65%
GasST1	22.74	600	70%
Oil1	14.24	500	73%
GasST2	14.05	500	77%
GasCT1+2	10.98	450	80%
GasST3	8.70	450	83%
GasCT5-Braith	-	-	83%
GasCC4-Braith	(6.88)	800	89%
GasCC5-Braith	(15.53)	900	95%
GasCT3-new	(36.29)	350	98%
GasCC2-New	(36.33)	550	102%
GasCC3-new	(37.06)	200	103%
GasCT4-Braith	(40.41)	350	105%
Oil-Braith	(90.46)	50	106%
Renewable	(414.51)	50	106%



APPENDIX F-2

INPUTS AND OUTPUTS OF THE 2010 ELECTRICITY SECTOR SCENARIOS

1500-1-67007 A OR PM

2010 AEO

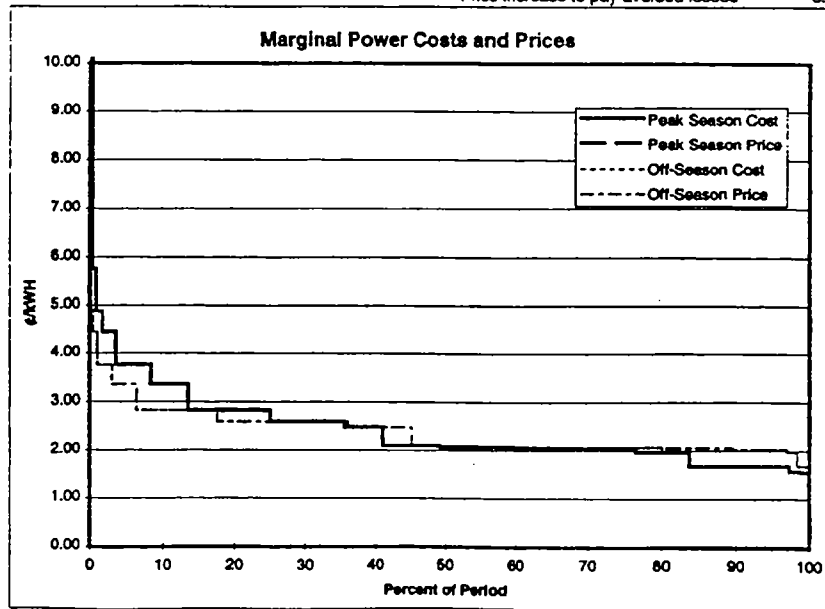
	Annual	Peak season	Offpeak season	# of Unprofitable plants Against avoid O&M	8		% of Total Capacity	% of Total Generator	Cap fact %	Avoidable ¢/kWh	Variable ¢/kWh	
Reserve Margin	10.7%	10.7%	11.2%	Against all costs	16	w/ unserv	Hydro	9.8%	7.6%	43.8%	0.36	0.10
LOLP, % of period	0.13	0.34	0.07	Average Price, ¢/kWh	2.50	2.50	Nuclear	11.1%	15.5%	79.6%	2.02	0.73
LOLP, day/10 Year	4.90	12.40	2.41	Avg. Variable Cost	1.43	1.43	Coal	36.9%	50.8%	78.0%	1.78	1.57
Load factor	62.8%	69.7%	68.9%	Avg. Vari+Avoid O&M	1.90	1.90	Oil	3.1%	0.1%	1.0%	11.59	4.44
Peak Demand, MW	14,685	14,685	12,892	Total Cost	2.81	2.81	Gas-ST	9.5%	1.8%	10.7%	3.74	2.74
Energy, GWh	80,793	22,423	58,370	Max loss, \$/avail KW	(9.71)		Gas-CC	13.3%	17.2%	73.6%	2.21	1.82
Generation, GWh	80,790	22,419	58,371	Start-up Cost, \$/MW	40		Gas-CT	14.8%	5.4%	20.7%	2.93	2.26
Unserv Energy, G	5	3	2	# plants Probabilistic	10		Other	1.5%	1.6%	60.0%	2.51	1.27

Plant Name	Capacity	Output MWYr	Capac Factor	Time on Margin, %	Revenue M\$	Var. Cost M\$	+Start Avoidable M\$	Unavoidable Fxd Cst M\$	Total Net Rev M\$	Avoidable Net Rev M\$	Avg. Carbon kg/MWhr	Carbon release Million Tons	
Nuclear1	1,000	796.00	79.6%	0.00	166	51	90	26	0	26.91	33.80	2.02	0.00
Nuclear2	800	636.80	79.6%	0.00	134	41	72	144	(122)	21.53	33.80	2.02	0.00
Coal1	950	748.60	78.8%	0.00	158	84	11	25	39	63.07	84.25	1.45	1.62
Coal2	850	719.95	84.7%	0.00	152	96	10	13	34	46.38	64.42	1.67	1.57
Coal3	850	719.95	84.7%	0.00	152	96	10	8	37	45.53	63.25	1.69	1.59
Coal4	600	498.60	83.1%	0.00	105	68	7	18	12	29.98	60.12	1.72	1.11
Coal5	600	495.96	82.7%	0.40	105	68	7	0	29	28.96	58.08	1.75	1.12
Coal6+7	850	648.28	76.3%	3.70	138	96	13	18	12	30.02	44.59	1.91	1.49
Coal8	450	330.48	73.4%	2.86	71	57	7	3	4	7.39	20.73	2.21	0.79
Coal9+10	450	186.72	41.5%	12.44	46	34	7	3	1	4.29	11.53	2.54	0.47
Coal-Adv.	400	334.40	83.6%	0.00	71	45	13	111	(98)	12.31	36.82	1.99	0.72
Oil1	500	4.79	1.0%	0.88	3	2	3	2	(4)	(2.07)	(4.97)	11.59	0.01
GasST1	600	137.54	22.9%	16.52	38	31	6	4	(3)	0.80	1.59	3.06	0.17
GasST2	500	25.92	5.2%	3.81	10	8	5	2	(5)	(2.68)	(6.42)	5.43	0.03
GasST3	450	2.06	0.5%	0.39	2	1	4	0	(3)	(3.49)	(9.29)	28.31	0.00
GasCC1	300	96.17	32.1%	8.17	25	21	3	14	(13)	0.98	4.05	2.83	0.12
GasCC2-New	420	290.81	69.2%	8.93	64	52	12	20	(20)	(0.06)	(0.17)	2.53	0.29
GasCC3-new	420	321.04	76.4%	7.46	70	57	12	23	(22)	0.93	2.53	2.45	0.31
GasCC4-Adv	420	361.45	86.1%	0.90	77	53	11	32	(20)	12.28	33.61	2.03	0.29
GasCC5-Adv	600	521.31	86.9%	0.27	110	71	16	65	(42)	23.04	44.13	1.90	0.38
GasCT1+2	450	0.88	0.2%	0.21	1	0	3	4	(6)	(2.06)	(5.41)	40.68	0.00
GasCT3-new	650	17.37	2.7%	2.78	8	6	8	24	(29)	(5.83)	(9.71)	8.86	0.03
GasCT4-new	650	81.59	12.6%	11.27	25	20	8	33	(35)	(2.53)	(4.22)	3.91	0.11
GasCT5-Adv.	650	395.92	60.9%	18.88	91	72	11	58	(49)	8.44	14.06	2.38	0.39
Renewable	250	150.00	60.0%	0.00	32	17	16	88	(89)	(1.35)	(8.97)	2.51	0.00
Hydro	1,600	700.00	43.8%		166	6	16	0	144	143.86	89.91	0.36	0.00
Totals	16,260	9,223	57%		2,021	1,152	382	739	(252)	487			12.62

Unserv Energy	0.54				2	2	w/o UE	1,534	2,273		Avg. Carbon kg/MWhr	158
Totals w/ Unserv	9,223				2,022	1,154	w/ UE	1,536	2,274		Time wtd marginal cost	2.40
											Time wtd Unserv E Price	18.94
											Unserv E. Cost/kWh	38.42
											Price increase to pay avoided losses	0.02

Sort by Net Revenue/kW

Name	Avoidable Net Rev/kW	Capacity	Reserve Margin
Hydro	89.91	1,600	11%
Coal1	84.25	950	17%
Coal2	64.42	850	23%
Coal3	63.25	850	29%
Coal4	60.12	600	33%
Coal5	58.08	600	37%
Coal6+7	44.59	850	43%
GasCC5-Adv	44.13	600	47%
Coal-Adv.	36.82	400	50%
Nuclear1	33.80	1,000	57%
Nuclear2	33.80	800	62%
GasCC4-Adv	33.61	420	65%
Coal8	20.73	450	68%
GasCT5-Adv.	14.06	650	72%
Coal9+10	11.53	450	75%
GasCC1	4.05	300	77%
GasCC3-new	2.53	420	80%
GasST1	1.59	600	84%
GasCC2-New	(0.17)	420	87%
GasCT4-new	(4.22)	650	92%
Oil1	(4.97)	500	95%
GasCT1+2	(5.41)	450	98%
GasST2	(6.42)	500	102%
Renewable	(8.97)	250	103%
GasST3	(9.29)	450	106%
GasCT3-new	(9.71)	650	111%



Case ID	Restructure case				CAPITALIZAT				IOU-Exsting	IPP-Exsting	IPP-New	IPP-Renew	Peak Season LDC				
Peak Demand	14188.3366	Fuel Type	\$/MMBTU	kg C/MBTU					1	2	3	4		Season Peak	Shoulder 2	Shoulder 1	Min (100%)
Ratio of Off-peak to peak	88.7%	Gas	2.59	14.47	Term (Years)	30	30	20	20	20	20	20	% of Season	0	5	95	100
Peak fraction of year	25%	Coal	1.34	25.72	Tax life	20	20	20	12	12	12	6	Template ratio	100%	94%	53%	42%
Load Factor, %	65.8%	Oil	3.00	21.49	Inc. Tax Rate	36%	36%	36%	36%	36%	36%	36%	Ratio to Peak	100%	94%	53%	42%
Peak Season Load Factor	73.1%	Nuclear	0.70	0	Prop. Tax rate	5%	5%	5%	5%	5%	5%	5%	Demand MW	14,188	13,276	7,491	5,918
Off-Peak Season Load Factor	71.4%	Hydro	0.00	0	Debt %	48%	30%	30%	30%	30%	30%	30%	Off-Peak Season LDC				
Carbon Tax, \$/metric ton C	0.00	Other	0.00	0	Interest Rate	8.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	% of Season	0	2	96	100
Capacity Payment, \$/kW	0	Year of Study	2010		Prefer Equity	14%	0%	0%	0%	0%	0%	0%	Template ratio	100%	85%	58%	50%
Uplift Charge, \$/kWh	0	Year of \$	1995		Return Rate	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	Ratio to Peak	100%	85%	58%	50%
Unserved Energy, \$/kWh	0	Start-up Cost, \$/MW		40	Common Equi	38%	70%	70%	70%	70%	70%	70%	Demand MW	12,589	10,755	7,285	6,285
Non-general. Price, \$/kWh	3.18	Min Capacity w/ probab		0	Return Rate	11.0%	14.0%	14.0%	14.0%	14.0%	14.0%	14.0%					
Price Elasticity(not used if 0)	0.05	Min Outage Rate w/ probab		0.0%	Vary FCR by	TRUE	TRUE	FALSE	FALSE	FALSE	FALSE	FALSE					
Default Unserved E calc (always show)		Max # Plants with prob.		10	Include in Avo	FALSE	FALSE	TRUE	TRUE	TRUE	TRUE	TRUE	Fractional change to start year	0.30			
Name	Capacity	Capacity Adjust Factor (0 to 1)	Forced Outage Rate	Planned Outage Rate	Heat Rate (BTU/kWh)	Fuel Type	Fuel Price Adjustment	O&M Cost \$/kWh	Bid Price or OP, \$/kWh	O&M Cost \$/kW-yr	Nominal Construction Cost/kW-yr	Construction Year	Capitilization Structure to Use	Unavoidable Fixed Cost const \$/kW-yr	Variable Cost \$/kWh		
Nuclear1	1,000	1	8.2%	12.2%	10,460	Nuclear	1,000	0.00	OP	90.0	800	1973	1	28	0.73		
Nuclear2	800	1	8.2%	12.2%	10,460	Nuclear	1,000	0.00	OP	90.0	2,750	1988	1	180	0.73		
Coal1	900	1	7.0%	14.2%	9,600	Coal	0.833	0.21	OP	11.7	490	1983	1	26	1.28		
Coal2	850	1	6.5%	8.8%	9,700	Coal	1,000	0.22	OP	11.7	370	1978	1	15	1.51		
Coal3	850	1	6.5%	8.8%	9,800	Coal	1,000	0.22	OP	11.7	300	1973	1	10	1.53		
Coal4	800	1	6.8%	10.3%	9,900	Coal	1,000	0.23	OP	12.4	680	1981	1	31	1.55		
Coal5	800	1	6.8%	10.3%	10,000	Coal	1,000	0.24	OP	12.4	380	1980	1	0	1.58		
Coal6+7	850	1	8.5%	12.3%	10,200	Coal	1,000	0.32	OP	15.2	500	1980	1	21	1.68		
Coal8	450	1	8.5%	12.3%	10,600	Coal	1,167	0.32	OP	15.2	300	1970	1	8	1.97		
Coal9+10	450	1	6.4%	10.9%	11,200	Coal	1,167	0.35	OP	16.3	300	1970	1	8	2.09		
Coal-Adv.	50	1	4.1%	12.3%	9,600	Coal	1,000	0.25	OP	33.8	1,816	2006	3	222	1.53		
Oil1	500	1	11.6%	5.2%	10,100	Oil	0.840	0.50	OP	6.0	127	1973	1	4	3.05		
GasST1	600	1	9.7%	6.8%	10,000	Gas	0.951	0.13	OP	9.4	170	1976	1	6	2.59		
GasST2	500	1	9.7%	6.8%	10,100	Gas	1.084	0.13	OP	9.4	150	1970	1	4	2.96		
GasST3	450	1	9.7%	6.8%	10,200	Gas	1.111	0.13	OP	9.4	220	1967	1	0	3.06		
GasCC1	300	1	6.8%	13.0%	9,665	Gas	0.951	0.10	OP	10.0	470	1992	2	45	2.48		
GasCC2-New	200	1	5.5%	7.5%	7,760	Gas	1,000	0.05	OP	28.9	452	1999	3	55	2.06		
GasCC3-new	200	1	5.5%	7.5%	7,618	Gas	1,000	0.05	OP	28.9	477	2001	3	58	2.02		
GasCC4-Adv	800	1	5.5%	7.5%	6,284	Gas	1,000	0.05	OP	26.6	538	2005	3	66	1.68		
GasCC5-Adv	950	1	5.5%	7.5%	5,817	Gas	1,000	0.05	OP	26.6	615	2009	3	75	1.55		
GasCT1+2	450	1	10.0%	5.4%	12,800	Gas	0.969	0.22	OP	6.0	140	1986	1	9	3.42		
GasCT3-new	350	1	3.8%	4.0%	11,460	Gas	1,000	0.01	OP	11.9	364	1998	3	44	2.98		
GasCT4-new	350	1	3.8%	4.0%	10,873	Gas	1,000	0.01	OP	11.9	406	2002	3	50	2.82		
GasCT5-Adv.	450	1	3.8%	3.9%	7,793	Gas	1,000	0.05	OP	16.9	542	2008	3	66	2.07		
Renewable	50	1	25.0%	15.0%	10,280	Other	1,000	1.27	OP	65.5	2,361	2008	4	260	1.27		
Limited Energy			Peak CF	Non-peak CF													
Hydro	1,600	1	55.0%	40.0%	1028000.0%	Hydro		0.10		10	400	1957	1	0	0.10		
Total Capacity	15,150																

Restructure case

	Annual	Peak season	Offpeak season	# of Unprofitable plants
Reserve Margin	6.8%	6.8%	6.1%	Against avoid O&M
LOLP, % of period	0.92	2.12	0.52	Against all costs
LOLP, day/10 Year	33.67	77.55	18.04	Average Price, \$/kWh
Load factor	65.7%	73.1%	71.4%	Avg. Variable Cost
Peak Demand, MW	14,188	14,188	12,589	Avg. Vari+Avoid O&M
Energy, GWh	81,727	22,703	59,024	Total Cost
Generation, GWh	81,692	22,682	59,010	Max loss, \$/avail kW
Unserv Energy, G	34	21	13	Start-up Cost, \$/MW
Round err not in UE	1	0	0	# plants Probabilistic
Plant Name	Capacity	Output MWyr	Capac Factor	Time on Margin, %

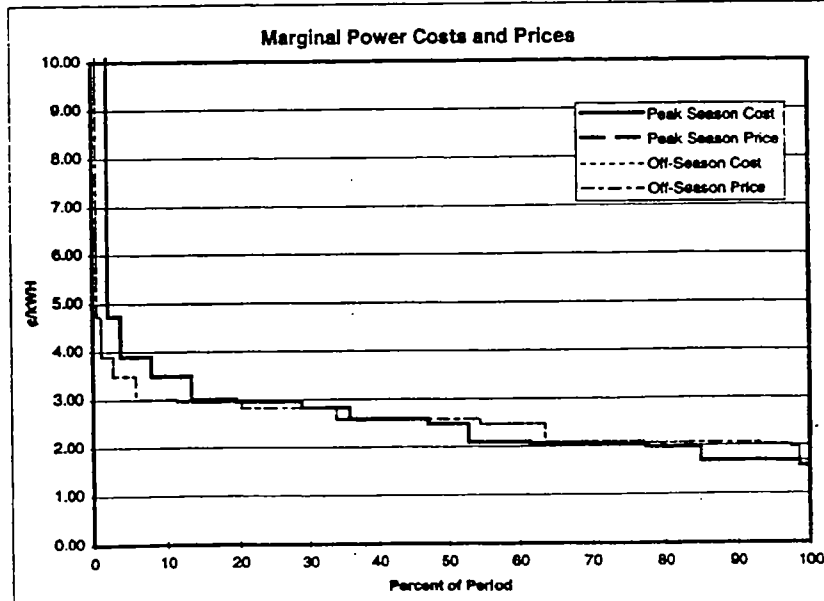
	% of Total Capacity	% of Total Generation	Cap fact %	Avoidable \$/kWh	Variable \$/kWh
Hydro	10.6%	7.5%	43.8%	0.36	0.10
Nuclear	11.9%	15.4%	79.6%	2.02	0.73
Coal	37.0%	47.4%	78.9%	1.80	1.58
Oil	3.3%	0.3%	4.8%	4.91	3.49
Gas-ST	10.2%	3.3%	19.6%	3.27	2.73
Gas-CC	16.2%	21.0%	80.0%	2.95	1.74
Gas-CT	10.6%	4.9%	28.6%	4.34	2.32
Other	0.3%	0.3%	60.0%	7.47	1.27

Plant Name	Capacity	Output MWYr	Capac Factor	Time on Margin, %	Revenue M\$	Var. Cost M\$	+Start M\$	Avoidable xrd Cst M\$	Unavoidable Fxd Cst M\$	Total Net Rev M\$	Avoidable Net Rev \$/kW	Net Rev \$/kW	Avoidable Cost, \$/kWh	Carbon release, Million Tons
Nuclear1	1,000	796.00	79.6%	0.00	188	51		90	26	21	47.00	59.04	2.02	0.00
Nuclear2	800	636.80	79.6%	0.00	150	41		72	144	(106)	37.60	59.04	2.02	0.00
Coal1	900	709.20	78.8%	0.00	168	79		11	23	54	77.73	109.60	1.45	1.53
Coal2	850	719.95	84.7%	0.00	170	96		10	13	52	64.39	89.44	1.67	1.57
Coal3	850	719.95	84.7%	0.00	170	96		10	8	55	63.55	88.27	1.69	1.59
Coal4	600	498.60	83.1%	0.00	118	68		7	18	24	42.50	85.23	1.72	1.11
Coal5	600	497.33	82.9%	0.31	118	69		7	0	41	41.48	83.18	1.75	1.12
Coal6+7	850	650.83	76.6%	3.76	156	96		13	18	29	46.99	69.80	1.91	1.50
Coal8	450	331.95	73.8%	2.76	80	57		7	3	13	16.33	45.83	2.21	0.79
Coal9+10	450	248.27	55.2%	12.40	66	46		7	3	10	13.36	35.90	2.43	0.63
Coal-Adv.	50	41.80	83.6%	0.00	10	6		13	-	(8)	(8.49)	(203.14)	5.02	0.09
Oil1	500	24.14	4.8%	3.60	14	7		3	2	2	3.65	8.78	4.91	0.05
GasST1	600	218.00	36.3%	18.17	64	49		6	4	5	9.32	18.60	2.88	0.28
GasST2	500	74.36	14.9%	9.00	28	19		5	2	2	3.65	8.75	3.68	0.10
GasST3	450	11.21	2.5%	2.29	9	4		4	0	1	1.27	3.39	8.20	0.01
GasCC1	300	135.63	45.2%	8.25	38	29		3	14	(8)	5.54	23.02	2.73	0.17
GasCC2-New	200	149.36	74.7%	4.20	37	27		17	-	(7)	(6.78)	(38.94)	3.34	0.15
GasCC3-new	200	156.58	78.3%	4.00	38	28		17	-	(7)	(6.90)	(39.66)	3.29	0.15
GasCC4-Adv	800	691.10	86.4%	0.77	163	101		74	-	(12)	(11.85)	(17.02)	2.90	0.55
GasCC5-Adv	950	826.46	87.0%	0.06	195	113		97	-	(14)	(14.19)	(17.17)	2.89	0.61
GasCT1+2	450	5.10	1.1%	0.87	7	2		3	4	(2)	2.32	6.10	10.77	0.01
GasCT3-new	350	34.22	9.8%	5.78	15	9		20	-	(14)	(13.54)	(41.87)	9.59	0.05
GasCT4-new	350	92.17	26.3%	12.00	30	23		22	-	(14)	(14.26)	(44.10)	5.49	0.13
GasCT5-Adv.	450	326.60	72.6%	10.89	83	59		37	-	(14)	(13.80)	(33.22)	3.37	0.32
Renewable	50	30.00	60.0%	0.00	7	3		16	-	(13)	(12.52)	(417.34)	7.47	0.00
Hydro	1,600	700.00	43.8%		195	6		18	0	173	172.60	107.88	0.36	0.00
Totals	15,150	9,326	62%		2,317	1,184		586	284	263	547			12.50

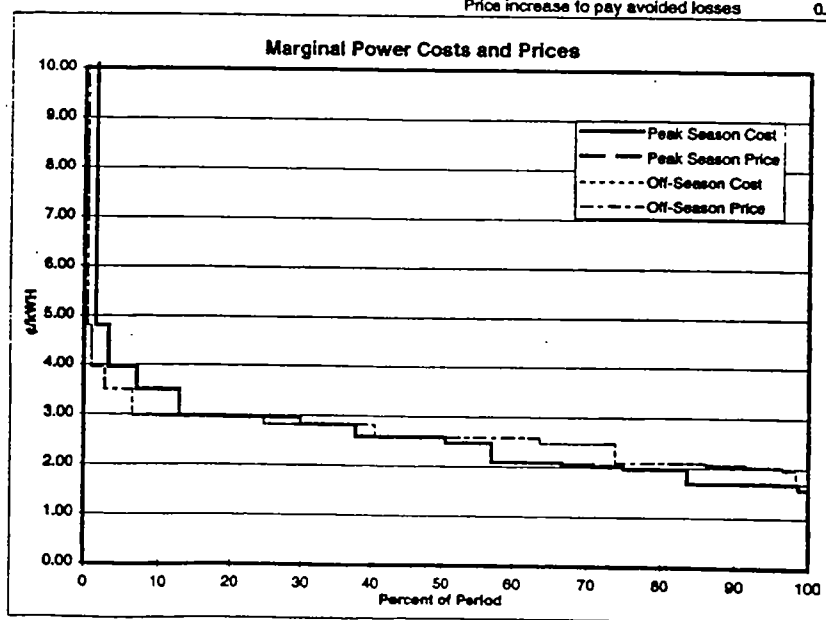
Unserv Energy	3.87	17	17	w/o UE	1,770	2,054	Avg. Carbon kg/MWhr	153
Totals w/ Unserved	9,329	2,335	1,202	w/ UE	1,788	2,071	Time wld marginal cost	2.61
							Time wld Unserved E Price	19.86
							Unserv E. Cost/kWh	50.65
							Price increase to pay avoided losses	0.13

Sort by Net Revenue/kW

Name	Avoidable Net Rev/kW	Capacity	Reserve Margin
Coal1	109.60	900	6%
Hydro	107.88	1,600	18%
Coal2	89.44	850	24%
Coal3	88.27	850	30%
Coal4	85.23	800	34%
Coal5	83.18	600	38%
Coal6+7	69.80	850	44%
Nuclear2	59.04	800	50%
Nuclear1	59.04	1,000	57%
Coal8	45.83	450	60%
Coal9+10	35.90	450	63%
GasCC1	23.02	300	65%
GasST1	18.60	600	69%
Oil1	8.78	500	73%
GasST2	8.75	500	78%
GasCT1+2	6.10	450	80%
GasST3	3.39	450	83%
GasCC4-Adv	(17.02)	800	88%
GasCC5-Adv	(17.17)	950	95%
GasCT5-Adv.	(33.22)	450	96%
GasCC2-New	(38.94)	200	100%
GasCC3-new	(39.66)	200	101%
GasCT3-new	(41.87)	350	104%
GasCT4-new	(44.10)	350	106%
Coal-Adv.	(203.14)	50	106%
Renewable	(417.34)	50	107%



Case ID	Efficiency Case	Fuel Type	\$/MMBTU	kg C/MBTU	CAPITALIZAT	IOU-Existing	IPP-Existing	IPP-New	IPP-Renew	Peak Season LDC	Season Peak	Shoulder 2	Shoulder 1	Min (100%)	
Peak Demand	13019.9318	Gas	2.59	14.47	Term (Years)	30	30	20	20	% of Season	0	5	95	100	
Ratio of Off-peak to peak	88.4%	Coal	1.34	25.72	Tax life	20	20	12	5	Template ratio	100%	93%	53%	42%	
Peak fraction of year	25%	Oil	3.00	21.49	Inc. Tax Rate	36%	36%	36%	36%	Ratio to Peak	100%	93%	53%	42%	
Load Factor, %	65.5%	Nuclear	0.70	0	Prop. Tax rate	5%	5%	5%	5%	Demand MW	13,020	12,133	6,870	5,409	
Peak Season Load Factor	72.9%	Hydro	0.00	0	Debt %	48%	30%	30%	30%	Off-Peak Season LDC					
Off-Peak Season Load Factor	71.4%	Other	0.00	0	Interest Rate	8.0%	10.0%	10.0%	10.0%	% of Season	0	2	96	100	
Carbon Tax, \$/metric ton C	0.00	Year of Study	2010	0	Preferred Equity	14%	0%	0%	0%	Template ratio	100%	85%	58%	50%	
Capacity Payment, \$/kW	0	Year of \$	1995	40	Return Rate	10.0%	10.0%	10.0%	10.0%	Ratio to Peak	100%	85%	58%	50%	
Uplift Charge, \$/kWh	0	Start-up Cost, \$/MW	40	Common Equi	38%	70%	70%	70%	Demand MW	11,507	9,823	6,669	5,731		
Unreserved Energy, \$/kWh	0	Min Capacity w/ probab	0	Return Rate	11.0%	14.0%	14.0%	14.0%							
Non-general. Price, \$/kWh	3.18	Min Outage Rate w/ probab	0.0%	Vary FCR by	TRUE	TRUE	FALSE	FALSE	Fractional change to start year	0.30					
Price Elasticity(not used if 0)	0.05	Max # Plants with prob.	10	Include In Av	FALSE	FALSE	TRUE	TRUE	- Plant Construction -	Capitilization	Unavoidable	Variable			
Default Unreserved E calc (always allow		Capacity	Forced	Planned	Heat Rate	Fuel Type	Fuel Price	O&M Cost	Bid Price or	Fixed	Nominal	Construction	Structure	Fixed Cost	Variable
		Adjust Factor	Outage	Outage	(BTU/kWh)		Adjustment	\$/kWh	OP, \$/kWh	O&M Cost	Cost/kW	Year	to Use	const \$/kW-yr	Cost
		(0 to 1)	Rate	Rate											\$/kWh
Nuclear1	1,000	1	8.2%	12.2%	10,460	Nuclear	1,000	0.00	OP	90.0	800	1973	1	26	0.73
Nuclear2	800	1	8.2%	12.2%	10,460	Nuclear	1,000	0.00	OP	90.0	2,750	1988	1	180	0.73
Coal1	900	1	7.0%	14.2%	9,600	Coal	0.833	0.21	OP	11.7	490	1983	1	26	1.28
Coal2	850	1	6.5%	8.8%	9,700	Coal	1,000	0.22	OP	11.7	370	1978	1	15	1.51
Coal3	850	1	6.5%	8.8%	9,800	Coal	1,000	0.22	OP	11.7	300	1973	1	10	1.53
Coal4	800	1	6.6%	10.3%	9,900	Coal	1,000	0.23	OP	12.4	680	1981	1	31	1.55
Coal5	800	1	6.6%	10.3%	10,000	Coal	1,000	0.24	OP	12.4	380	1960	1	0	1.58
Coal6+7	850	1	8.5%	12.3%	10,200	Coal	1,000	0.32	OP	15.2	500	1980	1	21	1.68
Coal8	450	1	8.5%	12.3%	10,600	Coal	1,167	0.32	OP	15.2	300	1970	1	8	1.97
Coal9+10	450	1	6.4%	10.9%	11,200	Coal	1,167	0.35	OP	16.3	300	1970	1	8	2.09
Coal-Adv.	50	1	4.1%	12.3%	9,600	Coal	1,000	0.25	OP	33.6	1,816	2006	3	222	1.53
Oil1	500	1	11.6%	5.2%	10,100	Oil	0.840	0.50	OP	6.0	127	1973	1	4	3.05
GasST1	600	1	9.7%	6.8%	10,000	Gas	0.951	0.13	OP	9.4	170	1978	1	6	2.59
GasST2	500	1	9.7%	6.8%	10,100	Gas	1.084	0.13	OP	9.4	150	1970	1	4	2.96
GasST3	450	1	9.7%	6.8%	10,200	Gas	1,111	0.13	OP	9.4	220	1967	1	0	3.06
GasCC1	300	1	6.8%	13.0%	9,665	Gas	0.951	0.10	OP	10.0	470	1992	2	45	2.48
GasCC2-New	200	1	5.5%	7.5%	7,760	Gas	1,000	0.05	OP	28.9	452	1999	3	55	2.06
GasCC3-new	200	1	5.5%	7.5%	7,618	Gas	1,000	0.05	OP	28.9	477	2001	3	58	2.02
GasCC4-Adv	800	1	5.5%	7.5%	6,284	Gas	1,000	0.05	OP	26.6	538	2005	3	66	1.68
GasCC5-Adv	300	1	5.5%	7.5%	5,817	Gas	1,000	0.05	OP	26.6	615	2009	3	75	1.55
GasCT1+2	450	1	10.0%	5.4%	12,800	Gas	0.969	0.22	OP	6.0	140	1986	1	9	3.42
GasCT3-new	350	1	3.6%	4.0%	11,460	Gas	1,000	0.01	OP	11.9	364	1998	3	44	2.96
GasCT4-new	350	1	3.6%	4.0%	10,873	Gas	1,000	0.01	OP	11.9	406	2002	3	50	2.82
GasCT5-Adv.	0	1	3.6%	3.9%	7,793	Gas	1,000	0.05	OP	16.9	542	2008	3	66	2.07
Renewable	50	1	25.0%	15.0%	10,280	Other	1,000	1.27	OP	65.5	2,361	2008	4	260	1.27
Limited Energy			Peak CF	Non-peak CF											
Hydro	1,800	1	55.0%	40.0%	1028000.0%	Hydro		0.10		10	400	1957	1	0	0.10
Total Capacity	14,050														



Case ID	HI Effic./Low Carbon	Fuel Type	\$/MMBTU	kg C/MBTU	CAPITALIZATIOU-Existing	IPP-Existing	IPP-New	IPP-Renew	Peak Season LDC	Season Peak	Shoulder 2	Shoulder 1	Min (100%)		
Peak Demand	11911.4734				1	2	3	4	% of Season	0	5	95	100		
Ratio of Off-peak to peak	88.1%	Gas	2.59	14.47	Term (Years)	30	30	20	5 Template ratio	100%	93%	82%	41%		
Peak fraction of year	25%	Coal	1.34	25.72	Tax life	20	20	12	36% Ratio to Peak	100%	93%	52%	41%		
Load Factor, %	65.5%	Oil	3.00	21.49	Inc. Tax Rate	36%	36%	36%	5% Demand MW	11,911	11,106	6,223	4,927		
Peak Season Load Factor	72.6%	Nuclear	0.70	0	Prop. Tax rate	5%	5%	5%	30% Off-Peak Season LDC						
Off-Peak Season Load Factor	71.7%	Hydro	0.00	0	Debt %	48%	30%	30%	10.0% % of Season	0	2	96	100		
Carbon Tax, \$/metric ton C	50.00	Other	0.00	0	Interest Rate	8.0%	10.0%	10.0%	0% Template ratio	100%	86%	58%	51%		
Capacity Payment, \$/kW	0	Year of Study	2010	0	Preferred Equity	14%	0%	0%	10.0% Ratio to Peak	100%	86%	58%	51%		
Uplift Charge, \$/kWh	0	Year of \$	1995	0	Return Rate	10.0%	10.0%	10.0%	70% Demand MW	10,488	9,000	6,105	5,305		
Unreserved Energy, \$/kWh	0	Start-up Cost, \$/MW		40	Common Equi	38%	70%	70%							
Non-general. Price, \$/kWh	3.18	Min Capacity w/ probab		0	Return Rate	11.0%	14.0%	14.0%							
Price Elasticity(not used if 0)	0.05	Min Outage Rate w/ probab		0.0%	Vary FCR by 1	TRUE	TRUE	FALSE	Fractional change to start year	0.30					
Default Unreserved E calc (always show)		Max # Plants with prob.		10	Include in Avo	FALSE	FALSE	TRUE							
Name	Capacity	Capacity Adjust Factor (0 to 1)	Forced Outage Rate	Planned Outage Rate	Heat Rate (BTU/kWh)	Fuel Type	Fuel Price Adjustment	O&M Cost \$/kWh	Bid Price or OP, \$/kwh	O&M Cost \$/kW-yr	Fixed - Plant Construction - Nominal Construction Cost/kW Year	Capitilization Structure to Use	Unavoidable Fixed Cost \$/kW-yr	Variable Cost \$/kWh	
Nuclear1	1,000	1	8.2%	12.2%	10,460	Nuclear	1.000	0.00	OP	90.0	800	1973	1	28	0.73
Nuclear2	800	1	8.2%	12.2%	10,460	Nuclear	1.000	0.00	OP	90.0	2,750	1988	1	180	0.73
Coal1	900	1	7.0%	14.2%	9,600	Coal	0.833	0.21	OP	11.7	490	1983	1	26	2.51
Coal2	850	1	8.5%	8.8%	9,700	Coal	1.000	0.22	OP	11.7	370	1978	1	15	2.76
Coal3	850	1	8.5%	8.8%	9,800	Coal	1.000	0.22	OP	11.7	300	1973	1	10	2.79
Coal4	600	1	8.6%	10.3%	9,900	Coal	1.000	0.23	OP	12.4	680	1981	1	31	2.82
Coal5	600	1	8.6%	10.3%	10,000	Coal	1.000	0.24	OP	12.4	380	1960	1	0	2.86
Coal6+7	850	1	8.5%	12.3%	10,200	Coal	1.000	0.32	OP	15.2	500	1980	1	21	2.99
Coal8	0	1	8.5%	12.3%	10,600	Coal	1.167	0.32	OP	15.2	300	1970	1	8	3.33
Coal9+10	0	1	8.4%	10.9%	11,200	Coal	1.167	0.35	OP	16.3	300	1970	1	8	3.53
Coal-Adv.	50	1	4.1%	12.3%	9,600	Coal	1.000	0.25	OP	33.6	1,816	2006	3	222	2.76
Oil1	500	1	11.6%	5.2%	10,100	Oil	0.840	0.50	OP	6.0	127	1973	1	4	4.13
GasST1	600	1	9.7%	6.8%	10,000	Gas	0.951	0.13	OP	9.4	170	1976	1	6	3.31
GasST2	600	1	9.7%	6.8%	10,100	Gas	1.084	0.13	OP	9.4	150	1970	1	4	3.69
GasST3	450	1	9.7%	6.8%	10,200	Gas	1.111	0.13	OP	9.4	220	1967	1	0	3.80
GasCC1	300	1	6.6%	13.0%	9,665	Gas	0.951	0.10	OP	10.0	470	1992	2	45	3.18
GasCC2-New	200	1	5.5%	7.5%	7,760	Gas	1.000	0.05	OP	28.9	452	1999	3	55	2.62
GasCC3-new	200	1	5.5%	7.5%	7,618	Gas	1.000	0.05	OP	28.9	477	2001	3	58	2.57
GasCC4-Adv	450	1	5.5%	7.5%	6,284	Gas	1.000	0.05	OP	26.6	638	2005	3	66	2.13
GasCC5-Adv	950	1	5.5%	7.5%	5,817	Gas	1.000	0.05	OP	26.6	615	2009	3	75	1.98
GasCT1+2	450	1	10.0%	5.4%	12,800	Gas	0.969	0.22	OP	6.0	140	1986	1	9	4.35
GasCT3-new	350	1	3.6%	4.0%	11,480	Gas	1.000	0.01	OP	11.9	384	1998	3	44	3.80
GasCT4-new	350	1	3.6%	4.0%	10,873	Gas	1.000	0.01	OP	11.9	406	2002	3	50	3.61
GasCT5-Adv.	0	1	3.6%	3.9%	7,793	Gas	1.000	0.05	OP	16.9	542	2008	3	66	2.63
Renewable	50	1	25.0%	15.0%	10,280	Other	1.000	1.27	OP	65.5	2,361	2008	4	260	1.27
Limited Energy			Peak CF	Non-peak CF											
Hydro	1,600	1	55.0%	40.0%	1028000.0%	Hydro		0.10		10	400	1957	1	0	0.10
Total Capacity	13,450														

Hi Eff/Low Carbon

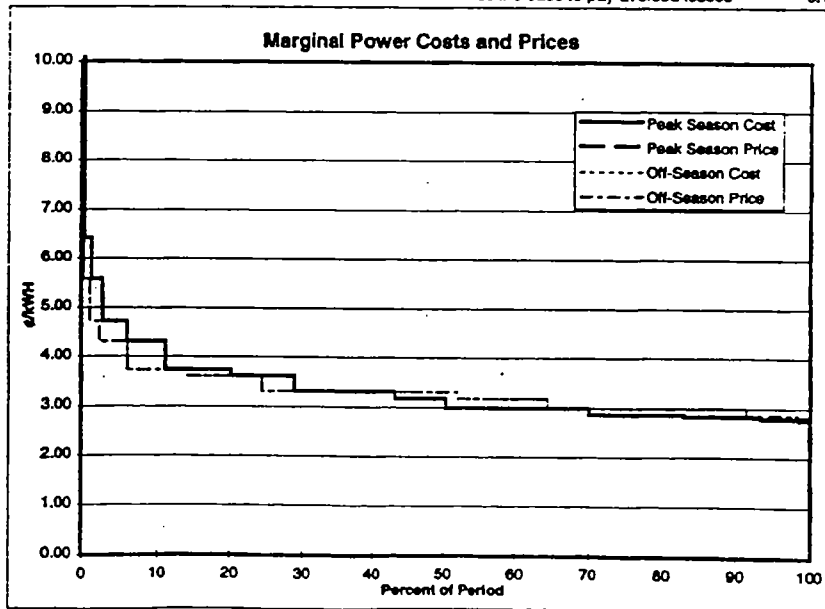
	Annual	Peak season	Offpeak season	# of Unprofitable plants	Against avoid O&M	10		% of Total Capacity	% of Total Generation	Cap fact %	Avoidable e/kWh	Variable e/kWh	
Reserve Margin	12.9%	12.9%	13.2%		Against all costs	15	w/ unserv	Hydro	11.9%	9.0%	43.8%	0.36	0.10
LOLP, % of period	0.17	0.40	0.10		Average Price, c/kWh	3.45	3.45	Nuclear	13.4%	18.4%	78.6%	2.02	0.73
LOLP, day/10 Year	6.34	14.58	3.59		Avg. Variable Cost	2.07	2.07	Coal	34.9%	46.2%	76.8%	3.00	2.77
Load factor	65.5%	72.6%	71.7%		Avg. Var+Avoid O&M	2.80	2.81	Oil	3.7%	0.1%	0.9%	13.45	5.58
Peak Demand, MW	11,911	11,911	10,488		Total Cost	3.21	3.21	Gas-ST	11.5%	3.3%	16.5%	4.12	3.47
Energy, GWh	68,373	18,949	49,424		Max loss, \$/avail kW	(359.93)		Gas-CC	15.6%	21.8%	80.9%	3.41	2.23
Generation, GWh	68,350	18,945	49,405		Start-up Cost, \$/MW	40		Gas-CT	8.6%	0.9%	6.4%	10.59	3.78
Unserv Energy, G	6	4	2		# plants Probabilistic	9		Other	0.4%	0.4%	60.0%	7.47	1.27

Plant Name	Capacity	Output MWYr	Capac Factor	Time on Margin, %	Revenue M\$	Var. Cost M\$	+Start M\$	Avoidable Cst M\$	Unavoidable Fxd Cst M\$	Total Net Rev M\$	Avoidable Net Rev M\$	Net Rev \$/kW	Avoidable cost, e/kWh	Carbon release Milion Tons
Nuclear1	1,000	796.00	79.6%	0.00	234	51	90	26	67	93.00	116.84	2.02	0.00	
Nuclear2	800	636.80	79.6%	0.00	187	41	72	144	(70)	74.40	116.84	2.02	0.00	
Coal1	900	709.20	78.6%	0.00	209	156	11	23	19	41.94	59.14	2.68	1.53	
Coal2	850	719.20	84.6%	0.32	211	174	10	13	15	27.47	38.15	2.92	1.57	
Coal3	850	713.96	84.0%	1.30	210	174	10	8	17	25.82	35.87	2.95	1.58	
Coal4	600	479.35	79.9%	3.75	142	119	7	18	(3)	15.80	31.68	3.00	1.07	
Coal5	600	454.18	75.7%	8.52	136	114	7	0	14	14.31	28.70	3.05	1.02	
Coal6+7	850	490.19	57.7%	25.20	151	129	13	18	(8)	9.83	14.60	3.29	1.13	
Coal8	0	-	0.0%	0.00	-	-	-	-	-	-	-	0.00	0.00	0.00
Coal9+10	0	-	0.0%	0.00	-	-	-	-	-	-	-	0.00	0.00	0.00
Coal-Adv.	50	41.64	83.3%	0.04	12	10	13	-	(11)	(10.59)	(253.46)	6.26	0.09	0.09
Oil1	500	4.35	0.9%	0.96	4	2	3	2	(4)	(1.59)	(3.83)	13.45	0.01	0.01
GasST1	600	188.70	31.5%	24.18	64	55	6	4	(0)	3.40	6.79	3.65	0.24	0.24
GasST2	500	47.81	9.6%	8.38	20	16	5	2	(3)	(0.71)	(1.69)	4.86	0.06	0.06
GasST3	450	19.32	4.3%	4.00	9	7	4	0	(2)	(2.05)	(5.44)	6.81	0.02	0.02
GasCC1	300	132.15	44.1%	11.09	43	37	3	14	(11)	2.79	11.60	3.44	0.18	0.18
GasCC2-New	200	174.00	87.0%	0.00	51	40	17	-	(6)	(5.59)	(32.15)	3.72	0.17	0.17
GasCC3-new	200	174.00	87.0%	0.00	51	39	17	-	(5)	(5.50)	(31.58)	3.72	0.17	0.17
GasCC4-Adv	450	391.50	87.0%	0.00	115	73	42	-	0	0.46	1.18	3.34	0.31	0.31
GasCC5-Adv	950	826.50	87.0%	0.00	243	143	97	-	3	3.33	4.03	3.31	0.61	0.61
GasCT1+2	450	1.37	0.3%	0.40	2	1	3	4	(5)	(1.58)	(4.14)	28.97	0.00	0.00
GasCT3-new	350	7.62	2.2%	1.78	5	3	20	-	(18)	(18.27)	(56.49)	34.28	0.01	0.01
GasCT4-new	350	64.64	18.5%	9.93	24	20	22	-	(18)	(17.89)	(55.32)	7.41	0.09	0.09
GasCT5-Adv.	0	-	0.0%	0.00	-	-	-	-	-	-	-	0.00	0.00	0.00
Renewable	50	30.00	60.0%	0.00	9	3	16	-	(11)	(10.80)	(359.93)	7.47	0.00	0.00
Hydro	1,600	700.00	43.8%	0.00	224	6	16	0	201	201.45	125.90	0.36	0.00	0.00
Totals	13,450	7,802	58%		2,355	1,413	502	277	163	439				9.85

Unserv Energy	0.65	3	3	w/o UE	1,915	2,192	Avg. Carbon kg/MWhr	144
Totals w/ Unserv	7,803	2,358	1,416	w/ UE	1,919	2,195	Time wtd marginal cost	3.34
							Time wtd Unserv E Price	23.44
							Unserv E. Cost/kWh	57.52
							Price increase to pay avoided losses	0.11

Sort by Net Revenue/kW

Name	Avoidable Net Rev/kW	Capacity	Reserve Margin
Hydro	125.90	1,600	13%
Nuclear2	116.84	800	20%
Nuclear1	116.84	1,000	29%
Coal1	59.14	900	36%
Coal2	38.15	850	43%
Coal3	35.87	850	50%
Coal4	31.68	600	55%
Coal5	28.70	600	60%
Coal6+7	14.60	850	68%
GasCC1	11.60	300	70%
GasST1	6.79	600	75%
GasCC5-Adv	4.03	950	83%
GasCC4-Adv	1.18	450	87%
Coal8	-	-	87%
Coal9+10	-	-	87%
GasCT5-Adv.	-	-	87%
GasST2	(1.69)	500	91%
Oil1	(3.83)	500	95%
GasCT1+2	(4.14)	450	99%
GasST3	(5.44)	450	103%
GasCC3-new	(31.58)	200	105%
GasCC2-New	(32.15)	200	106%
GasCT4-new	(55.32)	350	109%
GasCT3-new	(56.49)	350	112%
Coal-Adv.	(253.46)	50	112%
Renewable	(359.93)	50	113%



Case ID	Alt. Technology			CAPITALIZAT		IOU-Existing	IPP-Existing	IPP-New	IPP-Renew	Peak Season LDC						
Peak Demand	14134.3982	Fuel Type	\$/MMBTU	kg C/MBTU	1	2	3	4	Season Peak					Shoulder 2	Shoulder 1	Min (100%)
Ratio of Off-peak to peak	88.7%	Gas	2.59	14.47	Term (Years)	30	30	20	20	% of Season	0	5	95	100		
Peak fraction of year	25%	Coal	1.34	25.72	Tax life	20	20	12	5	Template ratio	100%	94%	83%	42%		
Load Factor, %	65.7%	Oil	3.00	21.49	Inc. Tax Rate	36%	36%	36%	36%	Ratio to Peak	100%	94%	53%	42%		
Peak Season Load Factor	73.0%	Nuclear	0.70	0	Prop. Tax rate	5%	5%	5%	5%	Demand MW	14,134	13,226	7,452	5,887		
Off-Peak Season Load Factor	71.3%	Hydro	0.00	0	Debt %	48%	30%	30%	30%	Off-Peak Season LDC						
Carbon Tax, \$/metric ton C	0.00	Other	0.00	0	Interest Rate	8.0%	10.0%	10.0%	10.0%	% of Season	0	2	96	100		
Capacity Payment, \$/kW	0	Year of Study	2010		Preferred Equity	14%	0%	0%	0%	Template ratio	100%	85%	58%	50%		
Uplift Charge, \$/kWh	0	Year of \$	1995		Return Rate	10.0%	10.0%	10.0%	10.0%	Ratio to Peak	100%	85%	58%	50%		
Unreserved Energy, \$/kWh	0	Start-up Cost, \$/MW	40		Common Equi	38%	70%	70%	70%	Demand MW	12,538	10,707	7,242	6,225		
Non-generat. Price, \$/kWh	3.18	Min Capacity w/ probab	0		Return Rate	11.0%	14.0%	14.0%	14.0%							
Price Elasticity(not used if 0)	0.05	Min Outage Rate w/ probab	0.0%		Vary FCR by	TRUE	TRUE	FALSE	FALSE							
Default Unreserved E calc (always allow		Max # Plants with prob.	10		Include in Avo	FALSE	FALSE	TRUE	TRUE	Fractional change to start year	0.30					
Name	Capacity	Capacity Adjust Factor (0 to 1)	Forced Outage Rate	Planned Outage Rate	Heat Rate (BTU/kWh)	Fuel Type	Fuel Price Adjustment	Variable O&M Cost \$/kwh	Bid Price or OP, \$/kwh	Fixed O&M Cost \$/kW-yr	- Plant Construction - Nominal Construction Cost/kW Year	Capitilization Structure to Use const \$/kW-yr	Unavoidable Fixed Cost \$/kW-yr	Variable Cost \$/kwh		
Nuclear1	1,000	1	8.2%	12.2%	10,460	Nuclear	1.000	0.00	OP	90.0	800	1973	1	26	0.73	
Nuclear2	800	1	8.2%	12.2%	10,460	Nuclear	1.000	0.00	OP	90.0	2,750	1988	1	180	0.73	
Coal1	900	1	7.0%	14.2%	9,800	Coal	0.833	0.21	OP	11.7	490	1983	1	26	1.28	
Coal2	880	1	8.5%	8.8%	9,700	Coal	1.000	0.22	OP	11.7	370	1978	1	15	1.51	
Coal3	880	1	8.5%	8.8%	9,800	Coal	1.000	0.22	OP	11.7	300	1973	1	10	1.53	
Coal4	800	1	8.6%	10.3%	9,900	Coal	1.000	0.23	OP	12.4	680	1981	1	31	1.55	
Coal5	800	1	8.6%	10.3%	10,000	Coal	1.000	0.24	OP	12.4	380	1960	1	0	1.58	
Coal6+7	850	1	8.5%	12.3%	10,200	Coal	1.000	0.32	OP	15.2	500	1980	1	21	1.68	
Coal8	450	1	8.5%	12.3%	10,600	Coal	1.167	0.32	OP	15.2	300	1970	1	8	1.97	
Coal9+10	450	1	8.4%	10.9%	11,200	Coal	1.167	0.35	OP	16.3	300	1970	1	8	2.09	
Coal-Braitch	50	1	4.1%	12.3%	8,805	Coal	1.000	0.20	OP	26.0	1,377	2005	3	168	1.11	
Oil1	500	1	11.6%	5.2%	10,100	Oil	0.840	0.50	OP	8.0	127	1973	1	4	3.05	
GasST1	600	1	9.7%	6.8%	10,000	Gas	0.951	0.13	OP	9.4	170	1976	1	6	2.59	
GasST2	500	1	9.7%	6.8%	10,100	Gas	1.084	0.13	OP	9.4	150	1970	1	4	2.96	
GasST3	450	1	9.7%	6.8%	10,200	Gas	1.111	0.13	OP	9.4	220	1967	1	0	3.06	
GasCC1	300	1	8.8%	13.0%	9,665	Gas	0.951	0.10	OP	10.0	470	1992	2	45	2.48	
GasCC2-New	550	1	5.5%	7.5%	7,760	Gas	1.000	0.05	OP	28.9	452	1999	3	55	2.06	
GasCC3-new	200	1	5.5%	7.5%	7,618	Gas	1.000	0.05	OP	28.9	477	2001	3	58	2.02	
GasCC4-Bral	800	1	5.5%	7.5%	5,888	Gas	1.000	0.015	OP	16.0	689	2005	3	84	1.49	
GasCC5-Bral	900	1	5.5%	7.5%	5,538	Gas	1.000	0.015	OP	16.0	774	2010	3	95	1.45	
GasCT1+2	450	1	10.0%	5.4%	12,800	Gas	0.969	0.22	OP	6.0	140	1986	1	9	3.42	
GasCT3-new	350	1	3.6%	4.0%	11,460	Gas	1.000	0.01	OP	11.9	364	1998	3	44	2.98	
GasCT4-Bral	350	1	3.6%	4.0%	8,699	Gas	1.000	0.012	OP	17.6	525	2005	3	64	2.26	
GasCT5-Bral	0	1	3.8%	3.9%	8,533	Gas	1.000	0.012	OP	17.6	564	2010	3	69	2.22	
Renewable	50	1	25.0%	15.0%	10,280	Other	1.000	1.27	OP	65.5	2,361	2008	4	260	1.27	
Limited Energy			Peak CF	Non-peak CF												
Hydro	1,600	1	55.0%	40.0%		Hydro		0.10		10	400	1957	1	0	0.10	
Total Capacity	15,000															

Alt. Technology

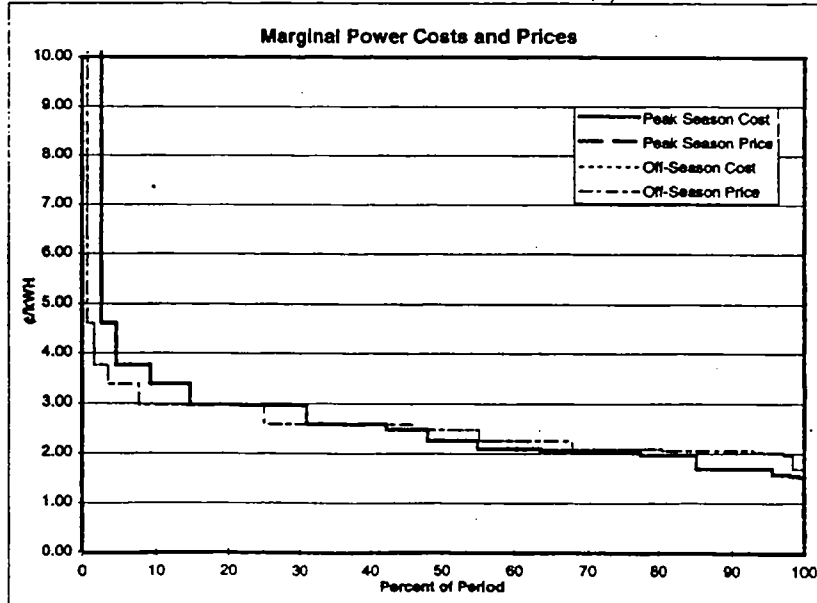
	Annual	Peak season	Offpeak season	# of Unprofitable plants	Against avoid O&M	8		% of Total Capacity	% of Total Generation	Cap fact %	Avoidable e/kWh	Variable e/kWh
Reserve Margin	6.1%	6.1%	5.3%	Against all costs		10 w/ unserv	Hydro	10.7%	7.5%	43.8%	0.36	0.10
LOLP, % of period	1.14	2.55	0.66	Average Price, c/kWh	2.89	2.91	Nuclear	12.0%	15.4%	79.6%	2.02	0.73
LOLP, day/10 Year	41.49	93.21	24.25	Avg. Variable Cost	1.42	1.45	Coal	37.3%	47.7%	79.0%	1.79	1.58
Load factor	65.6%	73.0%	71.3%	Avg. Var+Avoid O&M	2.15	2.18	Oil	3.3%	0.3%	5.7%	4.59	3.39
Peak Demand, MW	14,134	14,134	12,538	Total Cost	2.50	2.52	Gas-ST	10.3%	3.0%	17.9%	3.36	2.76
Energy, GWh	81,326	22,607	58,720	Max loss, \$/avail kW	(414.51)		Gas-CC	18.3%	23.1%	78.0%	2.98	1.67
Generation, GWh	81,282	22,580	58,702	Start-up Cost, \$/MW	40		Gas-CT	7.7%	2.6%	20.7%	4.90	2.45
Unserv Energy, G	44	27	18	# plants Probabilistic	10		Other	0.3%	0.3%	60.0%	7.47	1.27

Plant Name	Capacity	Output MWYr	Capac Factor	Time on Margin, %	Revenue M\$	Var. Cost M\$	+Start M\$	Avoidable Cst M\$	Unavoidable Fxd Cst M\$	Total Net Rev M\$	Avoidable Net Rev M\$	Net Rev \$/kW	Avoidable cost, e/kWh	Carbon release Million Tons
Nuclear1	1,000	796.00	79.6%	0.00	190	51	90	26	23	49.10	61.69	2.02	0.00	
Nuclear2	800	636.80	79.6%	0.00	152	41	72	144	(105)	39.28	61.69	2.02	0.00	
Coal1	900	709.20	78.8%	0.00	170	79	11	23	56	79.64	112.30	1.45	1.53	
Coal2	850	719.95	84.7%	0.00	172	96	10	13	54	66.23	91.99	1.67	1.57	
Coal3	850	719.70	84.7%	0.16	172	96	10	8	57	65.38	90.82	1.69	1.59	
Coal4	600	496.76	82.8%	0.32	119	68	7	18	25	43.79	87.82	1.72	1.11	
Coal5	600	494.59	82.4%	0.66	118	68	7	0	43	42.77	85.79	1.75	1.11	
Coal6+7	850	650.83	76.6%	3.73	158	96	13	18	31	48.83	72.54	1.91	1.50	
Coal8	450	331.98	73.8%	2.83	81	57	7	3	14	17.31	48.57	2.21	0.79	
Coal9+10	450	261.37	58.1%	11.74	70	48	7	3	11	14.36	38.58	2.41	0.68	
Coal-Braitch	50	41.80	83.6%	0.00	10	4	10	-	(4)	(3.78)	(90.46)	3.78	0.06	
Oil1	500	28.64	5.7%	4.50	17	9	3	2	4	5.92	14.24	4.59	0.05	
GasST1	600	179.04	29.8%	18.47	58	41	6	4	8	11.39	22.74	2.95	0.23	
GasST2	500	85.25	17.1%	10.80	33	22	5	2	4	5.87	14.05	3.59	0.11	
GasST3	450	13.87	3.1%	2.59	12	5	4	0	3	3.27	8.70	7.25	0.02	
GasCC1	300	117.82	39.3%	8.45	35	26	3	14	(7)	6.40	26.60	2.77	0.14	
GasCC2-New	550	392.25	71.3%	11.87	100	71	46	-	(17)	(17.39)	(36.33)	3.40	0.39	
GasCC3-new	200	156.44	78.2%	4.06	39	28	17	-	(6)	(6.45)	(37.06)	3.29	0.15	
GasCC4-Braitch	800	696.00	87.0%	0.00	166	91	80	-	(5)	(4.79)	(6.88)	2.80	0.50	
GasCC5-Braitch	900	783.00	87.0%	0.00	187	99	99	-	(12)	(12.16)	(15.53)	2.90	0.55	
GasCT1+2	450	6.21	1.4%	1.18	9	3	3	4	0	4.18	10.98	9.57	0.01	
GasCT3-new	350	40.82	11.7%	6.28	19	11	20	-	(12)	(11.74)	(38.29)	8.49	0.06	
GasCT4-Braitch	350	190.48	54.4%	11.23	53	38	29	-	(13)	(13.07)	(40.41)	3.98	0.21	
GasCT5-Braitch	0	-	0.0%	0.00	-	-	-	-	-	-	-	0.00	0.00	
Renewable	50	30.00	60.0%	0.00	7	3	16	-	(12)	(12.44)	(414.51)	7.47	0.00	
Hydro	1,600	700.00	43.8%		201	6	16	0	178	178.46	111.54	0.36	0.00	
Totals	15,000	9,279	62%		2,346	1,154	591	284	317	600			12.35	

Unserv Energy	5.06	24	24	w/o UE	1,745	2,029	Avg. Carbon kg/MWhr	152
Totals w/ Unserved	9,284	2,370	1,178	w/ UE	1,770	2,053	Time wtd marginal cost	2.61
							Time wtd Unserved E Price	21.69
							Unserv E. Cost/kWh	54.37
							Price increase to pay avoided losses	0.10

Sort by Net Revenue/kW

Name	Avoidable net Rev/kW	Capacity	Reserve Margin
Coal1	112.30	900	6%
Hydro	111.54	1,600	18%
Coal2	91.99	850	24%
Coal3	90.82	850	30%
Coal4	87.82	600	34%
Coal5	85.79	600	38%
Coal6+7	72.54	850	44%
Nuclear1	61.69	1,000	51%
Nuclear2	61.69	800	57%
Coal8	48.57	450	60%
Coal9+10	38.58	450	63%
GasCC1	26.60	300	65%
GasST1	22.74	600	70%
Oil1	14.24	500	73%
GasST2	14.05	500	77%
GasCT1+2	10.98	450	80%
GasST3	8.70	450	83%
GasCT5-Braitch	-	-	83%
GasCC4-Braitch	(6.88)	800	89%
GasCC5-Braitch	(15.53)	900	95%
GasCT3-new	(36.29)	350	98%
GasCC2-New	(36.33)	550	102%
GasCC3-new	(37.06)	200	103%
GasCT4-Braitch	(40.41)	350	105%
Coal-Braitch	(90.46)	50	106%
Renewable	(414.51)	50	106%

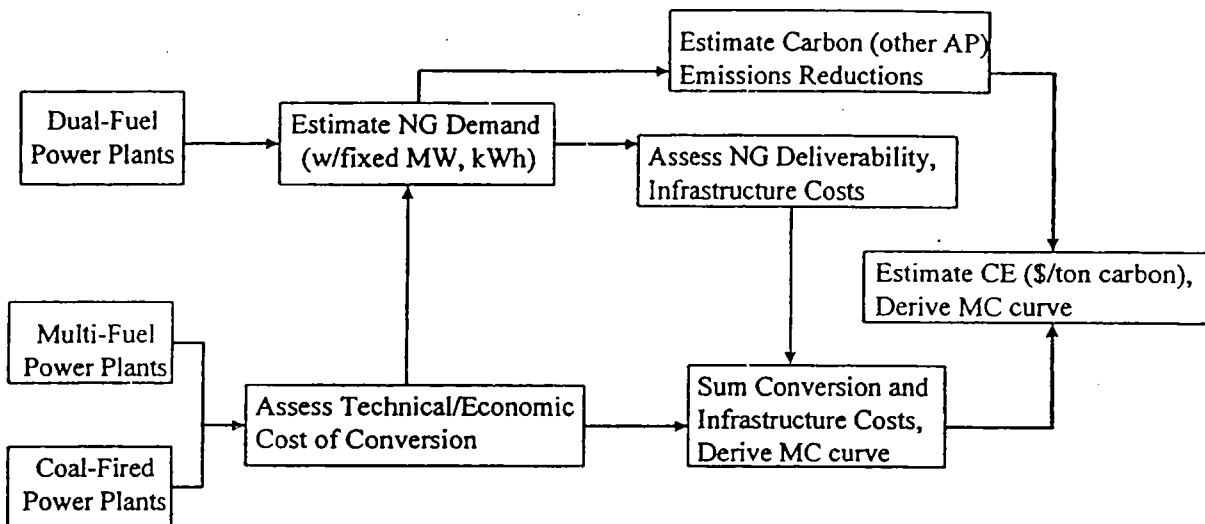


APPENDIX G

Appendix G-1 Methodology

Figure G-1.1 defines the methodological steps performed in conducting the coal/gas repowering analysis. Each step is described in more detail in this Appendix. Some elements of the methodology are described in even greater detail in Appendices G-2 and G-3.

Figure G-1.1 Methodological Steps



Powerplant Population Analyzed

The candidate powerplants for repowering with natural gas combined cycle were the population of coal-fired plants greater than 50 megawatts (MW). Three categories of coal-fired powerplants were assessed:

- dual-fuel powerplants (319 units, 130 plants, 86 GW);
- multi-fuel powerplants (122 units, 29 plants, 15 GW);
- coal-fired powerplants (711 units, 245 plants, 230 GW).

Dual-fuel plants are those designed to burn *either* coal or natural gas. They were assessed separately since it was presumed that they have adequate natural gas hook-up and transmission supply infrastructure to operate at current design capacity, and may be able to expand generation capacity without additional infrastructure costs. Multi-fuel plants burn coal, natural gas and/or petroleum at the same site, but generally in single fuel boilers; only a small proportion of multi-fuel plant sites have dual-fuel boilers. In those sites where gas is consumed it was presumed (as with dual-fuel) that they have adequate natural gas hook-up and transmission supply infrastructure to operate at current design capacity; however, here it was presumed that additional transmission infrastructure would be required to expand natural gas usage at the plant. Coal-fired plants have boilers that can only burn coal, and do not have natural gas supply infrastructure, except in those instances where it is used as start-up fuel.

Technical/Economic Cost of Conversion

For each plant type (dual-fuel, multi-fuel and coal) the investment cost of converting them to natural gas combined cycle (NGCC) was derived by correlating the nameplate capacity of each plant site with the closest NGCC system commercially available. The capital cost of repowering the plant (both steam turbine repowering and site repowering) was estimated together with the cost associated with hook-up and transmission infrastructure to deliver natural gas to the plant site. These investment costs were then adjusted for 1) the fixed/variable operations and maintenance (O&M) savings (credit) that would result from using natural gas (relative to coal), 2) the credit for reducing sulfur dioxide (SO₂) and nitrogen oxide (NO_x) emissions with the fuel switch, and 3) the coal/gas price differential and increase in real natural gas prices due to increased gas demand from the power sector after repowering.

Current industry estimates for NGCC with a state-of-the-art General Electric (GE) H-frame turbine were used. Credit of \$30/kW and \$1/MWh was included to represent annual savings (coal-to-gas) in fixed O&M and variable O&M costs, respectively. A "partial" repowering case was examined, wherein it was presumed that up to approximately 2 trillion cubic feet (TCF) of new utility gas demand, no additional gas transmission infrastructure would be required.¹ Thus, hook-up and transmission costs were excluded from the repowering investment cost.

Natural Gas Demand

Based on the existing nameplate rating of the plant, an appropriate NGCC system was selected with the objective of achieving the equivalent of 1995 plant-level generation. A corresponding heat rate (ranging from 7770 Btu/kW for 60 MW, to 6320 Btu/kW for >400 MW) was assigned and gas demand for the repowered unit/plant derived. The increase in gas demand was derived by subtracting 1995 gas consumption from the estimated value after repowering. In addition to estimating the quantity of gas demand, the analysis also included the physical and economic efficiency improvements that would result from NGCC-repowering.

Natural Gas Deliverability and Infrastructure Costs

To ensure natural gas deliverability to the repowered plants (since the gas requirements are annual, baseload) it was presumed that new transmission capacity was necessary (except in the partial repowering sensitivity analysis). While some unused/underutilized capacity does exist in the system, it is either regionally or seasonally constrained.

To determine the required transmission capabilities and infrastructure cost of delivering gas to the repowered NGCC plants a geographic information system (GIS) was used. The GIS permitted examination of each pipeline link between the repowered plant and the closest gas supply region to 1) identify the least-cost route, and 2) tabulate the cost of expanding existing transmission capacity to meet the cumulative gas requirement of all repowered candidate plants.

Since the ranking of cost-effective NGCC-repowered power plant was not known in advance of the GIS analysis, the cost of expanding the transmission infrastructure was based on the requirement to deliver 11 TCF of gas, or the equivalent of repowering all the candidate plants. The cost to each plant was then based on its respective pipeline routing and volume of gas

¹ While "partial repowering" actually refers to repowering a portion of the steam turbine (ST) to meet a load requirement more cost-effectively, in this static analysis 1) it was determined that (based on the data) such an option was not cost-effective, and 2) it was not possible to ensure that the balance of plant, after partial ST-repowering, would be capable of meeting 1995 generation (kWh) at the plant.

required. Based on the methodology employed, the hook-up/transmission costs allocated to each plant are a conservative estimate of the ultimate infrastructure delivery cost.

Total Cost of Conversion

The sum of conversion and hook-up/transmission cost represents total investment cost. This value was then adjusted for the O&M credit discussed above. In addition, several alternative coal/gas price differentials were included to reflect 1) the fuel price difference between coal and gas, and 2) an approximation of the gas price increase from higher utility demand for natural gas.

Based on a special Energy Information Administration (EIA), National Energy Modelling System (NEMS) simulation,² the 1995 gas/coal price differential was \$0.72/MMBtu (1994 dollars); in 2010 this differential increases to \$1.18/MMBtu, which reflects both an increase in natural gas prices and a decrease in coal prices. The increase in natural gas prices is partially attributable to increased utility demand from NGCC (merchant) plants constructed to meet new load growth and displace nuclear power plants not relicensed.

The total cost of repowering (conversion, hook-up/transmission, gas/coal price differential, O&M credit and SO₂/NO_x credit) for each plant was then divided by the reduction in carbon emissions arising from the repowering.

Value of Environmental Externalities

There is considerable debate in the literature regarding the value of environmental externalities. In this study, the market value for SO₂ and NO_x were included, not their estimated damage effects. For SO₂ values of zero (0) and \$100/ton were used, where zero represents a market saturated with allowances; at the high end, \$100/ton represents the current spot market price.

For NO_x, the low end represents estimates of a saturated NO_x market; \$2,000/ton represents a nationwide average for NO_x, with values approaching \$10,000/ton in nonattainment areas. The ultimate value will be a function of the forthcoming recommendations from the Ozone Transport Assessment Group (OTAG), and subsequent regulatory action by EPA.

² DOE/EIA, *An Analysis of Carbon Mitigation Cases*, Service Report SR/OIAF/96-01 (June 3, 1996).