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## A-1.3 METHODOLOGY FOR COMPILING TABLES A-1.1 AND A-1.2

(1) Carbon savings for all sectors are taken from Table 1.4 in the study. When a range is given in the table, we use the lower end of the emissions savings range for the Alternative View case, and the higher end for the Best Estimate case. Where no range is given, we use the same carbon savings number in both Best Estimate and Alternative View cases.

(2) Energy cost savings from the buildings, industry, and transport efficiency options are always the total energy savings times the relevant fuel price from the 2010 BAU scenario.

(3) Annualized technology costs (and dollar savings, where appropriate) for buildings efficiency, industry efficiency, transport efficiency, repowering of coal power plants with natural gas, and electricity dispatch are taken from the study results. Costs for increased power from hydroelectric dams are assumed to be exactly offset by the value of the electricity generated, yielding a NET cost of $0/tonne carbon. Technology costs for all other options are assumed to be $30/tonne C in the Best Estimate case and $50/tonne C in the Alternative View case.

(a) In the Best Estimate case, buildings efficiency technology costs and dollar savings are derived directly from Table C-2.1 in Appendix C-2 (those results are based on a 7% real discount rate).

We increased the real discount rate to 15% in the Alternative View case, which thereby increases the costs of implementing efficiency. Average equipment lifetimes in the buildings sector are assumed to be 18 years.

(b) Industry efficiency technology costs and dollar savings are derived from Table 4.7 of the industrial chapter. This table shows the annual energy savings and investment costs for a single year of investment, which is sufficient information to calculate a Cost of Conserved Energy (CCE). We took the investment costs from Table 4.8 and annualized them using the capital recovery factor based on a 15 year lifetime and a 12.5% real discount rate in the Best Estimate case. We divided the annualized investment costs by the annual energy savings to calculate the CCE (We did this separately for fuels and electricity, and for the efficiency and high-efficiency/low-carbon cases). We then multiplied this CCE by the TOTAL annual energy savings in 2010 from the industrial scenarios to get total annualized costs.

We increased the real discount rate to 20% in the Alternative View case, which causes the costs of implementing efficiency to increase. Average equipment lifetimes in the industrial sector are assumed to be 15 years, as in the Best Estimate case.

(c) Annualized technology costs for light duty vehicles are calculated from Table 5.9 in the transportation chapter which shows the present value of fuel savings at various discount rates (including 10% real), and the incremental costs of achieving those savings. In the efficiency case, the cost is $600 per car and $650 per light truck. In the high-efficiency/low-carbon case, the correct cost is $900 per car and $900 per light truck (relative to the BAU case). The incremental costs of improving efficiency in the high-efficiency/low-carbon case are much lower than for the efficiency case because of technological progress assumed to be engendered by aggressive efforts to achieve carbon reductions.

We annualized the capital costs using a 10% real discount rate and a lifetime of 14 years. We then used the present value of fuel savings at 10% real discount rate to estimate the number of gallons saved per vehicle per year in each scenario, based on the constant $1.20/gallon fuel price and a lifetime of 14 years. We divided the annualized cost per year by the number of gallons saved per year to calculate the CCE in $/gallon for cars and light trucks in each scenario, and weighted those CCEs by the fraction of energy use associated with cars and light trucks over the 1997 to 2010 period (56% and 44%, respectively) to get the average CCE for light duty vehicles in each scenario. Finally, we multiplied the average CCE by the TOTAL expected energy savings for light duty vehicles to get total annualized cost for each scenario.

In the Best Estimate case, the technology costs for other transportation modes (freight trucks, airplanes, trains, marine, and other) are assumed to be exactly equal to the price of fuel that is saved. This assumption is a conservative one, because we know that the technologies chosen by the NEMS model in our efficiency and high-efficiency cases are cost effective at the margin, and the last technology implemented must by definition be less cost-effective than the ones preceding it.

We increased the real discount rate to 20% in the Alternative View case, which causes the costs to increase by 72% (or the ratio of capital recovery factors using 20% and 10% real discount rates plus additional program costs). Average equipment lifetimes in the transport sector are assumed to be 14 years, as in the Best Estimate case.

(d) Best estimate electricity dispatch annualized technology costs are derived from the total costs of the High-Efficiency case and the high-efficiency/low-carbon case. The former case has all the high-efficiency demand-side technologies implemented but no carbon tax, and the latter case has the same efficiency levels but a carbon tax with the associated supply-side dispatch changes. The difference in costs between these two cases (after subtracting out carbon tax revenues) is the cost of the supply side changes (about $33/tonne C). We choose $50/tonne C for the technology costs of dispatch in the Alternative View case.

(e) In the Best Estimate case, the cost of hydroelectric refurbishment and upgrades are assumed to be the same as the benefits associated with the sale of the electricity from these plants, yielding a NET cost of $0/tonne carbon (A review of the literature finds that refurbishment of existing dams is one of the most cost effective renewable options). In the Alternative View case, we choose a net cost of $20/tonne carbon.

(f) Repowering of coal power plants with natural gas costs are derived from Figure 7.7 in the electricity supply chapter. This curve shows carbon saved on the x-axis and incremental cost ($/tonne C) on the y-axis. The graph with the $1.18/MBtu differential between gas and coal was chosen because it is the likely case for 2010. The low environmental credits case was also used. The average incremental cost is about $40/tonne C from this graph for going to 45 MtC savings, so it was chosen this as our "Best Estimate" for the costs of this option. Costs were increased to $50/tonne C in the "Alternative View" case.

(3) Total Annualized costs include program costs of 7% for demand side & 1% for electricity supply-side carbon savings in the Best Estimate case and 15% for demand side & 3% for electricity supply-side carbon savings in the Alternative View case. Demand-side program costs are also applied to fuel cells and industrial low-carbon technologies.

# Interlab Study on Scenarios of U. S. Carbon Reductions

## APPENDIX A-2

## Key Opportunities for Carbon Savings From End-Use Efficiency Improvements

# APPENDIX A-2

# KEY OPPORTUNITIES FOR CARBON SAVINGS FROM END-USE EFFICIENCY IMPROVEMENTS

Each of the three end-use efficiency chapters (Chapters 3-5) assessed the magnitude of carbon savings that could be achieved by the year 2010 from specific submarkets, energy end-uses, and technologies. These key opportunities are summarized in the following table. The table includes those submarkets and end-uses that were estimated to offer the potential for at least 2 MtC of savings by the year 2020. Tables A-2.2 to A-2.4 list some of the key technologies.

Table A-2.1. Key Opportunities for Carbon Savings From End-Use Efficiency Improvements

| Submarkets and Technologies with >2 MtC Estimated Reductions in 2010: | Carbon Reductions Estimated by High Efficiency/Low Carbon Case (in MtC) |
|---|---|
| **Buildings** | |
| Miscellaneous electric uses: residential | 15.9 |
| Miscellaneous electric uses: commercial | 8.5 |
| Commercial lighting | 6.6 |
| Commercial electric space conditioning | 5.4 |
| Residential lighting | 4.4 |
| Commercial gas space conditioning | 3.3 |
| Residential electric space conditioning | 3.1 |
| Electric water heating | 2.9 |
| Gas water heating | 2.7 |
| Refrigerators/freezers | 2.3 |
| **Industry** | |
| **Heavy manufacturing industries:** | 16.1 |
| Petroleum | 4.3 |
| Bulk chemicals | 4.1 |
| Pulp and paper | 2.6 |
| Iron and steel | 2.6 |
| Light manufacturing | 24.0 |
| Non-manufacturing | 10.8 |
| **Transportation** | |
| Light-duty vehicles | 73.3 |
| Freight trucks | 14.1 |
| Air transport | 13.9 |
| Freight rail | 2.5 |

**Table A-2.2. Illustrative Energy-Efficiency Buildings Technologies**

**Residential Building End-Uses**

- Miscellaneous electricity (efficient motors, variable speed drives)
- Lighting (halogen IR lamps, compact fluorescent lamps, motion sensors)
- Electric water heating (standby loss reduction, horizontal axis clothes washer, heat pump water heater – post 2000)
- Electric cooling (more/improved insulation, spectrally-selective glazings, variable speed compressors, white roofs, reduced infiltration)
- Electric space heating (more/improved insulation, reduced infiltration, low-E argon glazings, superwindows, improved compressors)
- Electric clothes dryers (heat pump clothes dryers at very low penetration)
- Refrigeration (improved insulation, improved compressors)
- Gas water heating (standby loss reduction, horizontal axis clothes washer)
- Gas space heating (more/improved insulation, reduced infiltration, low-E argon glazings, superwindows, condensing furnaces)
- Electric cooking (improved insulation)
- Freezers (more/improved insulation, improved compressors)
- Oil space heating (low-E argon glazings, superwindows, improved insulation, reduced infiltration, condensing furnaces)

**Commercial Building End-Uses**

- Miscellaneous electricity (variable speed drives, efficient motors, smart redesign)
- Lighting (electronic ballasts, motion sensors, halogen IR lamps, compact fluorescent lamps)
- Electric cooling (system controls, variable speed compressors, switching systems, white roofs)
- Gas space heating (condensing furnaces, fuel cells, system controls)
- Ventilation (variable speed drives, system controls)
- Refrigeration (improved insulation, better compressors)
- Miscellaneous gas (smart redesign, eliminate pilot lights)
- Electric space heating (switch to heat pump, system controls)
- Gas water heating (standby loss reduction, improved burners, flow
- controls)
- Electric water heating (standby loss reduction, flow controls)
- Oil space heating (condensing furnaces, system controls)

**Table A-2.3. Illustrative High-Efficiency/Low-Carbon Industrial Technologies**

**Fuel Switching**
- Advanced turbine systems for industrial cogeneration applications
- Integrated gasification combined cycle technologies for the forest products industry

**Motors**
- Proper load matching
- Variable speed drives

**Pulp/Paper**
- Impulse drying
- Multiport cylinder drying
- On-machine sensors

**Chemicals**
- Pinch analytic techniques
- Advanced distillation control techniques

**Petroleum Refining**
- Utility system improvements
- Process/equipment modifications

**Glass**
- Oxy-fuel process
- Advanced burner technology
- Glass batch/cullet preheater technology

**Aluminum**
- New aluminum production cell
- Materials recycling
- Improve furnace efficiency
- Titanium diboride cathodes

**Iron/Steel**
- Direct smelting/direct reduction
- Scrap preheating
- Hot connection
- Process controls

**Metal Casting**
- Computer-aided casting design
- Optimized coreless induction melting

**Cement**
- Cement clinker replacement

**Table A-2.4. Key Transportation Technologies Based on the High-Efficiency/Low-Carbon Scenario**

**Light-Duty Vehicles**
- Direct-injection stratified charge (DISC) gasoline engine
- Turbocharged direct-injection clean diesel engine (TDI diesel)
- Hybrid vehicles (gasoline and diesel)
- Gasoline fuel cell vehicle
- Materials substitution, advanced drag reduction, engine friction and pumping loss reductions, and transmission improvements
- Cellulosic ethanol as a blending component with gasoline

**Truck Freight**
- LE-55 diesel engine
- Turbocompound diesel engine
- Improved tires
- Advanced drag reduction
- Electronic controls

**Rail**
- Flywheels
- Alternative fuels
- Fuel cells
- Operational efficiency improvements

**Air**
- Ultra-high bypass turbofans
- Material improvements
- Aerodynamic drag reduction
- Propfans
- Laminar flow control

# Interlab Study on Scenarios of U. S. Carbon Reductions

# APPENDIX A-3

## Summary of R&D'S Potential for Further Carbon Reductions By 2020

# APPENDIX A-3

## SUMMARY OF R&D'S POTENTIAL FOR FURTHER CARBON REDUCTIONS 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, the high-efficiency/low-carbon scenario would also fill an R&D pipeline of next-generation energy technologies that could offer further energy and carbon savings by 2020. Possible future energy-efficiency technologies, and their related R&D challenges, are described in Chapters 3 through 5. An array of R&D activities to enhance renewable energy options are described in Chapter 6. These results are summarized below.

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.

# 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. Energy use in Tables C-2.7a-b and C-2.8a-b is expressed in site energy terms, and all output tables are expressed in primary energy terms[2]. 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-2.7.a-b and C-2.8.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 0.38 quads of site energy (111TWh).*

## 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.

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

[2] See Chapter 6 for details on primary energy conversions in the Business-as-usual, efficiency, and high-efficiency/low-carbon scenarios.

[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.

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 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-2.7.a-b and C-2.8.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 for refrigerators.*

## 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-2.7.a-b and C-2.8.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 0.89. 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 645 kWh/year (2.2 MMBtu site), while stock devices in 1997 are at about 940 kWh/year (3.2 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 645*0.95 = 613 kWh/year (2.1 MMBtu/year), while stock devices in 1997 are at about 940 kWh/year (3.2 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:

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

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*

$$\textit{E use in Froz. Eff. Case 2010} = 0.84 * (0.38 \textit{ quads} * 0.487 + 0.38 \textit{ quads} * (0.416 + 0.25) * \frac{645}{940})$$

$= 0.32$ *quads site*

## Business-As-Usual Case Energy Use

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

Energy use in B.A.U case 2010 = E use in 1997*stock remaining factor +

E use in 1997* (stock replacement factor + stock growth factor) *

$$\frac{\text{expected average new device intensity 1997 to 2010}}{\text{stock device intensity 1997}} \quad (2)$$

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*

$$E \text{ use in B.A.U case } 2010 = 0.84 * (0.38 \text{ quads} * 0.487 + 0.38 \text{ quads} * (0.416 + 0.25) * \frac{613}{940})$$

$= 0.31$ *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 +

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

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

$$E \text{ use in } 1997*(\text{stock growth factor}) * \frac{\text{new device intensity in new homes 1997}}{\text{stock device intensity 1997}} * (1\text{- Svgs factor A - Svgs factor C})) \quad (3)$$

*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.*

$$E \text{ use in Max. Cost Effective Efficiency Case } 2010 = 0.84 *(0.38 \text{ quads} * 0.487 + 0.38 \text{ quads} * 0.028 * \frac{645}{940} * (1 - 0.33) + 0.38 \text{ quads} * 0.388 * \frac{645}{940} * (1 - 0.33 - 0) + 0.38 \text{ quads} * 0.249 * \frac{645}{940} * (1 - 0.33 - 0))$$

$= 0.27$ *quads site energy.*

*The potential savings is therefore 0.32 - 0.27= 0.05 quads relative to the frozen efficiency case and 0.31-0.27= 0.04 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 agressive 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 "business-as-usual" (BAU) case to determine the energy use in the cases where 35% 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 65% implementation case, 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.

## 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:

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

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 $9.90/MMBtu site ($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 BAU 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 for the Business-As-Usual case and the policy scenarios 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 BAU emissions.

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[4] US 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.

## 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.

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

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

where

$E^A_f$ = 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 BAU 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 BAU case. In the latter case, carbon reductions can be achieved at negative net cost to society.

# Interlab Study on Scenarios of U. S. Carbon Reductions

# APPENDIX C-2

## Detailed Results of Residential and Commercial Sectors Forecasts

# APPENDIX C-2

# DETAILED RESULTS OF RESIDENTIAL AND COMMERCIAL SECTOR FORECASTS

## 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 C-2.7a & b and C-2.8a & b. 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. All residential UECs are taken from the LBNL REM and LBNL REEPS residential forecasting models, while all commercial sector 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-2.1: Main results, buildings sector business-as-usual scenario, by fuel**

| Fuel | End-use | *Primary Energy Use (Quads)* 1990 | 1997 | 2010 | *Carbon Emissions (MtC)* 1990 | 1997 | 2010 | *Energy Costs 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-2.2: Main results, residential sector business-as-usual scenario, by end-use**

| | | *Primary Energy Use (Quads)* | | | *Carbon Emissions (MtC)* | | | *Energy Costs Billion 1995 $* |
|---|---|---|---|---|---|---|---|---|
| Fuel | End-use | *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-2.3: Main results, commercial sector business-as-usual scenario, by end-use**

| Fuel | End-use | *Primary Energy Use (Quads)* 1990 | 1997 | 2010 | *Carbon Emissions (MtC)* 1990 | 1997 | 2010 | *Energy Costs 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-2.4: Main results, buildings sector scenarios**

| Fuel | End-use | *Primary Energy Use (Quads)* *1990* | *1997* | *2010* | *Carbon Emissions (MtC)* *1990* | *1997* | *2010* | *Energy costs Billion 1995 $* *2010* | *Efficiency costs Billion 1995 $* *2010* | *Total Costs of Energy Services 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 eff./low C case | 16.7 | 19.1 | 18.0 | 253 | 285 | 287 | 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 eff./low C case | 13.2 | 14.6 | 13.5 | 209 | 225 | 225 | 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 eff./low C case | 29.9 | 33.7 | 31.6 | 462 | 511 | 512 | 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 | 1.06 | 1.00 | 1.10 | 1.11 | 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 | 0.88 | 1.00 | 1.00 | 0.90 | 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.

**Table C-2.5: Main results, residential sector BAU and efficiency scenarios, by end-use**

| | | *Primary Energy Use (Quads)* | | | *Carbon Emissions (MtC)* | | | *Energy Service Costs (B1995 $)* | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | *BAU* | *Efficiency* | *HE/LC* | *BAU* | *Efficiency* | *HE/LC* | *BAU* | *Efficiency* | *HE/LC* |
| Fuel | End-use | *2010* | *2010* | *2010* | *2010* | *2010* | *2010* | *2010* | *2010* | *2010* |
| Electricity | Space heating | 1.4 | 1.4 | 1.3 | 23 | 22 | 22 | 11 | 11 | 11 |
| | Space cooling | 1.4 | 1.4 | 1.3 | 23 | 23 | 22 | 11 | 11 | 11 |
| | Water heating | 1.1 | 1.0 | 0.9 | 18 | 17 | 16 | 9 | 8 | 8 |
| | Refrigeration | 0.9 | 0.9 | 0.8 | 15 | 14 | 14 | 7 | 7 | 7 |
| | Cooking | 0.4 | 0.4 | 0.4 | 7 | 7 | 6 | 3 | 4 | 4 |
| | Clothes Dryers | 0.6 | 0.6 | 0.5 | 10 | 10 | 9 | 5 | 5 | 5 |
| | Freezers | 0.2 | 0.2 | 0.2 | 4 | 4 | 4 | 2 | 2 | 2 |
| | Lighting | 1.0 | 0.8 | 0.7 | 17 | 15 | 12 | 8 | 7 | 6 |
| | Other Uses | 5.87 | 5.33 | 4.7 | 97 | 90 | 81 | 46 | 43 | 41 |
| | Total electric | 13.0 | 12.0 | 10.8 | 213 | 202 | 185 | 102 | 97 | 93 |
| Natural gas | Space heating | 3.9 | 3.8 | 3.8 | 56 | 56 | 55 | 20 | 20 | 20 |
| | Space cooling | 0.0 | 0.0 | 0.0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Water heating | 1.4 | 1.3 | 1.3 | 20 | 19 | 18 | 7 | 7 | 7 |
| | Cooking | 0.1 | 0.1 | 0.2 | 2 | 2 | 2 | 1 | 1 | 1 |
| | Clothes Dryers | 0.1 | 0.1 | 0.1 | 1 | 1 | 1 | 0 | 0 | 0 |
| | Other Uses | 0.1 | 0.1 | 0.1 | 1 | 1 | 1 | 1 | 1 | 1 |
| | Total gas | 5.6 | 5.5 | 5.4 | 81 | 80 | 79 | 29 | 29 | 29 |
| Distillate oil | Space heating | 0.7 | 0.6 | 0.6 | 13 | 13 | 13 | 5 | 5 | 5 |
| | Water heating | 0.1 | 0.1 | 0.1 | 2 | 2 | 2 | 1 | 1 | 1 |
| | Other Uses | 0.0 | 0.0 | 0.0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Total oil | 0.8 | 0.7 | 0.7 | 15 | 15 | 14 | 6 | 6 | 5 |
| LPG | Space heating | 0.3 | 0.3 | 0.3 | 5 | 5 | 5 | 4 | 4 | 4 |
| | Water heating | 0.1 | 0.1 | 0.1 | 2 | 1 | 1 | 1 | 1 | 1 |
| | Cooking | 0.0 | 0.0 | 0.0 | 1 | 0 | 0 | 0 | 0 | 0 |
| | Other Uses | 0.0 | 0.0 | 0.0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Total LPG | 0.5 | 0.4 | 0.4 | 8 | 7 | 7 | 5 | 5 | 5 |
| Renewables | Wood | 0.6 | 0.6 | 0.6 | 0 | 0 | 0 | 6 | 6 | 6 |
| Other fuels | Coal + kerosene | 0.1 | 0.1 | 0.1 | 2 | 2 | 2 | 1 | 1 | 1 |
| Totals | | 20.4 | 19.4 | 18.0 | 319 | 306 | 287 | 149 | 144 | 140 |

(1) BAU = Business-As-Usual; Efficiency = efficiency case; HE/LC = high efficiency/low carbon case.
(2) Energy service costs include cost of purchased fuels and electricity and the annualized costs of incremental efficiency improvements.

**Table C-2.6: Main results, commercial sector BAU and efficiency scenarios, by end-use**

| | | *Primary Energy Use (Quads)* | | | *Carbon Emissions (MtC)* | | | *Energy Service Costs (B1995 $)* | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | *BAU* | *Efficiency* | *HE/LC* | *BAU* | *Efficiency* | *HE/LC* | *BAU* | *Efficiency* | *HE/LC* |
| Fuel | End-use | *2010* | *2010* | *2010* | *2010* | *2010* | *2010* | *2010* | *2010* | *2010* |
| Electricity | Space heating | 0.3 | 0.3 | 0.3 | 6 | 5 | 5 | 3 | 2 | 2 |
| | Space cooling | 1.5 | 1.4 | 1.3 | 25 | 24 | 21 | 11 | 10 | 9 |
| | Water heating | 0.4 | 0.4 | 0.4 | 7 | 7 | 6 | 3 | 3 | 3 |
| | Ventilation | 0.6 | 0.5 | 0.5 | 9 | 9 | 8 | 4 | 4 | 3 |
| | Cooking | 0.1 | 0.1 | 0.1 | 1 | 1 | 1 | 1 | 1 | 1 |
| | Lighting | 3.8 | 3.6 | 3.3 | 63 | 60 | 56 | 28 | 25 | 22 |
| | Refrigeration | 0.5 | 0.4 | 0.4 | 8 | 7 | 7 | 3 | 3 | 3 |
| | PC Off. Equip. | 0.3 | 0.3 | 0.3 | 5 | 5 | 5 | 2 | 2 | 2 |
| | non-PC Off. Equip. | 0.7 | 0.7 | 0.7 | 12 | 12 | 12 | 5 | 5 | 5 |
| | Other Uses | 3.1 | 2.8 | 2.5 | 52 | 48 | 43 | 23 | 21 | 20 |
| | Total electric | 11.4 | 10.7 | 9.7 | 187 | 178 | 165 | 82 | 76 | 71 |
| Natural gas | Space heating | 1.4 | 1.3 | 1.2 | 20 | 18 | 17 | 6 | 6 | 6 |
| | Space cooling | 0.0 | 0.0 | 0.0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Water heating | 0.5 | 0.5 | 0.5 | 8 | 7 | 7 | 2 | 2 | 3 |
| | Cooking | 0.2 | 0.2 | 0.2 | 3 | 3 | 3 | 1 | 1 | 1 |
| | Other Uses | 1.4 | 1.4 | 1.3 | 20 | 20 | 19 | 6 | 6 | 6 |
| | Total gas | 3.5 | 3.4 | 3.2 | 51 | 49 | 46 | 16 | 16 | 16 |
| Distillate oil | Space heating | 0.2 | 0.2 | 0.1 | 3 | 3 | 3 | 1 | 1 | 1 |
| | Water heating | 0.1 | 0.0 | 0.0 | 1 | 1 | 1 | 0 | 0 | 0 |
| | Other Uses | 0.1 | 0.1 | 0.1 | 3 | 3 | 3 | 1 | 1 | 1 |
| | Total oil | 0.4 | 0.3 | 0.3 | 7 | 7 | 6 | 2 | 2 | 2 |
| Renewables | Wood | 0.0 | 0.0 | 0.0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Other fuels | Coal + kerosene | 0.3 | 0.3 | 0.3 | 7 | 7 | 7 | 2 | 2 | 2 |
| Totals | | 15.6 | 14.7 | 13.5 | 252 | 240 | 225 | 102 | 96 | 91 |

(1) BAU = Business-As-Usual; Efficiency = efficiency case; HE/LC = high efficiency/low carbon case.

(2) Energy service costs include cost of purchased fuels and electricity and the annualized costs of incremental efficiency improvements.

**Table C-2.7.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 Stock factor 2010 | Existing New Stock factor 2010 | Retrofit New Stock factor 2010 | New New Stock factor 2010 | Other Energy Service growth factor (1) Ex. shells 2010 | Other Energy Service growth factor (1) New shells 2010 | REFERENCE CASE (NO RETROFITS) Existing Existing UEC MMBtu 1997 | REFERENCE CASE Existing New UEC MMBtu 1997 | REFERENCE CASE New New UEC MMBtu 1997 | REFERENCE CASE Existing New exptd avg UEC kWh 1997-2010 | REFERENCE CASE New New exptd avg UEC MMBtu 1997-2010 | EFFICIENCY CASE Ex no retrofit New rel. to new in 1997 2010 | EFFICIENCY CASE Ex. w/retrofit New shell savings factor 2010 | EFFICIENCY CASE New New shell savings factor 2010 | Existing New CCE $/MMBtu | Retrofit New CCE $/MMBtu | New New CCE $/MMBtu | Achievable Fraction |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 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 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 of all measures up to the cost effective limit, and are expressed in $/MMBtu of site energy

**Table C-2.7.a (continued): Results for the U.S. residential sector reference and efficiency cases**
**35% implementation of efficiency resources**

| | | | | | | | | | | | 100% Implementation case | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| *Fuel* | *End-use* | Base year energy use 1997 Quads | Frozen efficiency energy use 2010 Quads | Baseline B.A.U. energy use 2010 Quads | 35% Implement. Effic. case energy use 2010 Quads | 100% Implement. Effic. case energy use 2010 Quads | Frozen efficiency energy costs 2010 Billion 95$ | Baseline B.A.U. energy costs 2010 Billion 95$ | 35% Implement Effic. case energy costs 2010 Billion 95$ | 100% 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$ | 35% Implement. Effic. case total costs 2010 Billion 95$ | 100% Implement. case total costs 2010 Billion 95$ | Base year carbon emissions 1997 MtC | Frozen efficiency carbon emissions 2010 MtC | Baseline B.A.U. carbon emissions 2010 MtC | 35% Implement. Effic. case carbon emissions 2010 MtC | 100% Implement Effic. case carbon emissions 2010 MtC |
| 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 | 21 |
| Electricity | Space cooling | 0.46 | 0.51 | 0.49 | 0.47 | 0.42 | 11.77 | 11.21 | 10.66 | 9.64 | 0.14 | 0.16 | 0.21 | 10.84 | 10.15 | 23 | 25 | 23 | 23 | 21 |
| 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 | 14 |
| 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 | 13 |
| 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 | 3.53 | 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 | 8 |
| 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 | 10 |
| 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 | 72 |
| | Total electric | 3.73 | 4.52 | 4.46 | 4.05 | 3.27 | 103.53 | 102.04 | 92.55 | 74.92 | 4.94 | 5.95 | 2.78 | 97.33 | 88.58 | 183 | 217 | 213 | 202 | 169 |
| Natural gas | Space heating | 3.68 | 3.99 | 3.88 | 3.84 | 3.77 | 21.04 | 20.45 | 20.25 | 19.87 | 0.04 | 0.28 | 0.23 | 20.44 | 20.43 | 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 | 29.02 | 28.29 | 0.22 | 0.48 | 0.39 | 29.40 | 29.38 | 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 + kerosen | 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 | 11.38 | 10.42 | 151.41 | 148.99 | 138.84 | 120.00 | 5.20 | 6.55 | 3.29 | 144.11 | 135.04 | 285 | 324 | 319 | 306 | 270 |

**Table C-2.7.b: Input assumptions for U.S. residential sector reference and high efficiency cases**
**65% implementation of efficiency resources**

| Fuel | SHELL EQUIPMENT End-use | Base year energy use 1997 Quads | End-use lifetime years | Existing Existing Stock factor 2010 | Existing New Stock factor 2010 | Retrofit New Stock factor 2010 | New New Stock factor 2010 | Other Energy Service growth factor (1) Ex. shells 2010 | Other Energy Service growth factor (1) New shells 2010 | REFERENCE CASE (NO RETROFITS) Existing Existing UEC MMBtu 1997 | Existing New UEC MMBtu 1997 | New New UEC MMBtu 1997 | Existing New exptd avg UEC kWh 1997-2010 | New New exptd avg UEC MMBtu 1997-2010 | EFFICIENCY CASE Ex no retrofit New rel. to new in 1997 2010 | Ex. w/retrofit New shell savings factor 2010 | New New shell savings factor 2010 | Existing New CCE $/MMBtu | Retrofit New CCE $/MMBtu | New New CCE $/MMBtu | Achievable Fraction |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 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 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 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 of all measures up to the cost effective limit, and are expressed in $/MMBtu of site energy.

**Table C-2.7.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 energy use 2010 Quads | Baseline B.A.U. energy use 2010 Quads | 65% Implement. Effic. case energy use 2010 Quads | 100% Implement. Effic. case energy use 2010 Quads | Frozen efficiency energy costs 2010 Billion 95$ | Baseline B.A.U. energy costs 2010 Billion 95$ | 65% Implement. Effic. case energy costs 2010 Billion 95$ | 100% Implement. Effic. case energy costs 2010 Billion 95$ | 100% Implementation case: Existing New efficiency costs 2010 Billion 95$ | 100% Implementation case: Retrofit New efficiency costs 2010 Billion 95$ | 100% Implementation case: New New efficiency costs 2010 Billion 95$ | 65% Implement. Effic. case total costs 2010 Billion 95$ | 100% Implement. case total costs 2010 Billion 95$ | Base year carbon emissions 1997 MtC | Frozen efficiency carbon emissions 2010 MtC | Baseline B.A.U. carbon emissions 2010 MtC | 65% Implement. Effic. case carbon emissions 2010 MtC | 100% Implement. Effic. case carbon emissions 2010 MtC |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 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 | 22 | 21 |
| Electricity | Space cooling | 0.46 | 0.51 | 0.49 | 0.45 | 0.42 | 11.77 | 11.21 | 10.18 | 9.63 | 0.11 | 0.20 | 0.21 | 10.52 | 10.15 | 23 | 25 | 23 | 22 | 21 |
| 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 | 16 | 14 |
| 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 | 14 | 13 |
| 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 Dryers | 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 | 9 | 8 |
| 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 | 4 | 3 |
| Electricity | Lighting | 0.32 | 0.35 | 0.35 | 0.23 | 0.17 | 8.01 | 8.01 | 5.26 | 3.78 | 0.69 | 0.52 | 0.33 | 6.26 | 5.32 | 16 | 17 | 17 | 12 | 10 |
| 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 | 81 | 72 |
| | Total electric | 3.73 | 4.52 | 4.46 | 3.69 | 3.27 | 103.53 | 102.04 | 84.34 | 74.81 | 4.22 | 6.71 | 2.79 | 93.25 | 88.52 | 183 | 217 | 213 | 185 | 169 |
| Natural gas | Space heating | 3.68 | 3.99 | 3.88 | 3.80 | 3.76 | 21.04 | 20.45 | 20.04 | 19.82 | 0.00 | 0.36 | 0.24 | 20.43 | 20.42 | 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 Dryers | 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 | 28.65 | 28.24 | 0.13 | 0.61 | 0.40 | 29.39 | 29.38 | 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 + keroser | 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 | 10.40 | 151.41 | 148.99 | 130.02 | 119.81 | 4.38 | 7.47 | 3.31 | 139.87 | 134.97 | 285 | 324 | 319 | 287 | 270 |

9.85

**Table C-2.8.a: Input assumptions for U.S. commercial 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 Stock factor 2010 | Existing New Stock factor 2010 | Retrofit New Stock factor 2010 | New New Stock factor 2010 | Other Energy Service growth factor (1) Ex. shells 2010 | Other Energy Service growth factor (1) New shells 2010 | REFERENCE CASE (NO RETROFITS) Existing Existing Intensity kBtu/sf 1997 | Existing New Intensity kBtu/sf 1997 | New New Intensity kBtu/sf 1997 | Existing New exptd avg Intensity kBtu/sf 1997-2010 | New New exptd avg Intensity kBtu/sf 1997-2010 | EFFICIENCY CASE Ex no retrofit New rel to new in 1997 2010 | Ex. w/retrofit New shell savings factor 2010 | New New shell savings factor 2010 | Existing New CCE $/MMBtu | Retrofit New CCE $/MMBtu | New New CCE $/MMBtu | Achievable Fraction |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 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 | | | | | | | | | | | | |
| | | | | | | | | 1.00 | 1.00 | | | | | | | | | | | | |
| 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 | | | | | | | | | | | | |
| | | | | | | | | 1.00 | 1.00 | | | | | | | | | | | | |
| 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 | | | | | | | | | | | | |
| | | | | | | | | 1.00 | 1.00 | | | | | | | | | | | | |
| 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 |
| | | | | | | | | 1.00 | 1.00 | | | | | | | | | | | | |
| 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 |
| | | | | | | | | 1.0 | 1.0 | | | | | | | | | | | | |
| Totals | | 7.34 | | | | | | 1.00 | 1.00 | | | | | | | | | | | | |

(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 7.03, 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 AEO97 data.
(4) 1990 commercial sector carbon emissions = 209 million metric tons.
(5) Electricity consumption and prices measured as site energy at 3412 Btus/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 of all measures up to the cost effective limit, and are expressed in $/MMBtu of site energy.

**Table C-2.8.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 energy use 2010 Quads | Baseline B.A.U. energy use 2010 Quads | 35% Implement. Effic. case energy use 2010 Quads | 100% Implement Effic. case energy use 2010 Quads | Frozen efficiency energy costs 2010 Billion 95$ | Baseline B.A.U. energy costs 2010 Billion 95$ | 35% Implement. Effic. case energy costs 2010 Billion 95$ | 100% Implement Effic case energy costs 2010 Billion 95$ | 100% Implementation case: Existing New efficiency costs 2010 Billion 95$ | 100% Implementation case: Retrofit New efficiency costs 2010 Billion 95$ | 100% Implementation case: New New efficiency costs 2010 Billion 95$ | 35% Implement. Effic. case total costs 2010 Billion 95$ | 100% Implement case total costs 2010 Billion 95$ | Base year carbon emissions 1997 MtC | Frozen efficiency carbon emissions 2010 MtC | Baseline B.A.U. carbon emissions 2010 MtC | 35% Implement Effic. case carbon emissions 2010 MtC | 100% Implement Effic. case carbon emissions 2010 MtC |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 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 | 5 |
| | Space cooling | 0.52 | 0.53 | 0.52 | 0.47 | 0.38 | 11.04 | 10.91 | 9.88 | 7.97 | 0.05 | 0.24 | 0.26 | 10.07 | 8.52 | 26 | 25 | 25 | 24 | 20 |
| | 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 | 7 |
| | 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 | 53 |
| | 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 | 6 |
| | 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 | 38 |
| | Total electric | 3.33 | 3.93 | 3.91 | 3.59 | 3.00 | 82.41 | 82.03 | 75.36 | 62.97 | 0.86 | 0.55 | 0.60 | 76.06 | 64.98 | 163 | 188 | 187 | 178 | 153 |
| Natural gas | Space heating | 1.34 | 1.42 | 1.36 | 1.25 | 1.05 | 6.42 | 6.13 | 5.65 | 4.74 | 0.13 | 0.55 | 0.61 | 6.10 | 6.03 | 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 | 3.35 | 3.01 | 16.10 | 15.97 | 15.12 | 13.56 | 0.65 | 0.85 | 0.94 | 15.98 | 16.01 | 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 | 0.00 | 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 | 94.15 | 80.05 | 1.55 | 1.46 | 1.61 | 95.77 | 84.67 | 225 | 254 | 252 | 240 | 210 |

**Table C-2.8.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 Quads | End-use lifetime years | Existing / Existing Stock factor 2010 | Existing / New Stock factor 2010 | Retrofit / New Stock factor 2010 | New / New Stock factor 2010 | Other Energy Service growth factor (1) Ex. shells 2010 | Other Energy Service growth factor (1) New shells 2010 | REFERENCE CASE (NO RETROFITS) Existing / Existing Intensity kBtu/sf 1997 | Existing / New Intensity kBtu/sf 1997 | New / New Intensity kBtu/sf 1997 | Existing / New expid avg Intensity kBtu/sf 1997-2010 | New / New expid avg Intensity kBtu/sf 1997-2010 | EFFICIENCY CASE Ex no retrofit / New rel. to new in 1997 2010 | Ex. w/retrofit / New shell savings factor 2010 | New / New shell savings factor 2010 | Existing / New CCE $/MMBtu | Retrofit / New CCE $/MMBtu | New / New CCE $/MMBtu | Achievable Fraction |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| *Fuel* | *End-use* | | | | | | | | | | | | | | | | | | | | |
| 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 | | | | | | | | | | | | |
| | | | | | | | | 1.00 | 1.00 | | | | | | | | | | | | |
| 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 | | | | | | | | | | | | |
| | | | | | | | | 1.00 | 1.00 | | | | | | | | | | | | |
| 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 | | | | | | | | | | | | |
| | | | | | | | | 1.00 | 1.00 | | | | | | | | | | | | |
| 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 + kerosene | 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 |
| | | | | | | | | 1.0 | 1.0 | | | | | | | | | | | | |
| Totals | | 7.34 | | | | | | 1.00 | 1.00 | | | | | | | | | | | | |

(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 7.03, 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 AEO97 data.
(4) 1990 commercial sector carbon emissions = 209 million metric tons.
(5) Electricity consumption and prices measured as site energy at 3412 Btus/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 of all measures up to the cost effective limit, and are expressed in $/MMBtu of site energy.

**Table C-2.8.b (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 | Baseline B.A.U. energy use 2010 Quads | 65% Implement. Effic. case energy use 2010 Quads | 100% Implement. Effic. case energy use 2010 Quads | Frozen efficiency energy costs 2010 Billion 95$ | Baseline B.A.U energy costs 2010 Billion 95$ | 65% Implement. Effic. case energy costs 2010 Billion 95$ | 100% Implement. Effic. case energy costs 2010 Billion 95$ | 100% Implementation case: Existing New efficiency costs 2010 Billion 95$ | 100% Implementation case: Retrofit New efficiency costs 2010 Billion 95$ | 100% Implementation case: New New efficiency costs 2010 Billion 95$ | 65% Implement. Effic. case total costs 2010 Billion 95$ | 100% Implement. case total costs 2010 Billion 95$ | Base year carbon emissions 1997 MtC | Frozen efficiency carbon emissions 2010 MtC | Baseline B.A.U. carbon emissions 2010 MtC | 65% Implement. Effic. case carbon emissions 2010 MtC | 100% Implement. Effic. case carbon emissions 2010 MtC |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 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 | 5 | 5 |
| | Space cooling | 0.52 | 0.53 | 0.52 | 0.43 | 0.38 | 11.04 | 10.91 | 9.00 | 7.97 | 0.00 | 0.29 | 0.26 | 9.36 | 8.52 | 26 | 25 | 25 | 21 | 20 |
| | 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 |
| | 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 | 8 | 7 |
| | 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 | 1.14 | 1.04 | 27.74 | 27.69 | 23.93 | 21.90 | -0.82 | -1.04 | -0.94 | 22.11 | 19.10 | 62 | 63 | 63 | 56 | 53 |
| | 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 | 7 | 6 |
| | 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 | 0.85 | 0.72 | 22.66 | 22.66 | 17.81 | 15.20 | 1.49 | 1.12 | 1.01 | 20.16 | 18.82 | 32 | 52 | 52 | 43 | 38 |
| | Total electric | 3.33 | 3.93 | 3.91 | 3.32 | 3.00 | 82.41 | 82.03 | 69.64 | 62.97 | 0.74 | 0.67 | 0.60 | 70.95 | 64.98 | 163 | 188 | 187 | 165 | 153 |
| Natural gas | Space heating | 1.34 | 1.42 | 1.36 | 1.16 | 1.05 | 6.42 | 6.13 | 5.23 | 4.74 | 0.00 | 0.68 | 0.61 | 6.07 | 6.03 | 19 | 21 | 20 | 17 | 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 |
| | 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 |
| | 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 | 1.31 | 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 |
| | Total gas | 3.33 | 3.57 | 3.54 | 3.19 | 3.01 | 16.10 | 15.97 | 14.40 | 13.56 | 0.46 | 1.05 | 0.94 | 16.00 | 16.01 | 48 | 52 | 51 | 46 | 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 |
| | 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 | 0.13 | 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 |
| | 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 |
| 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 |
| 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 | 7.17 | 6.66 | 102.40 | 101.74 | 87.64 | 80.05 | 1.22 | 1.79 | 1.61 | 90.65 | 84.67 | 225 | 254 | 252 | 225 | 210 |

**Table C-2.9: Fuel cell calculations for high efficiency/low carbon case** 970716

| | | |
|---|---|---|
| Assume 200kW or smaller fuel cell units (also could use small advanced gas turbines) | | |
| Installed electrical capacity by 2010 | *5.33* | *GW* |
| Capacity factor (elect. load following) | 75% | |
| TWh produced | 35.0 | TWh.e |
| TWh gas used to produce elect. | 77.8 | TWh.f (=TWh.e/electrical efficiency) |
| C emissions from cogen gas use | 3.8 | MtC |
| C emissions displaced by cogen elect | 4.5 | based on marginal C burden of 127 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 | | 27.2 | TWh.thermal |
| Utilized heat | | 20.4 | TWh.thermal |
| To Space heating | 33% | 6.74 | TWh.thermal |
| To Water heating | 67% | 13.7 | TWh.thermal |

| ***Space 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 MtC* |
|---|---|---|---|---|---|---|---|---|---|
| Electricity | 0.10 | 29 | 98% | 28 | 9% | 0.6 | 0.6 | 0.01 | 0.1 |
| Natural gas | 1.16 | 340 | 80% | 272 | 81% | 5.5 | 6.9 | 0.02 | 0.3 |
| Oil | 0.14 | 42 | 80% | 34 | 10% | 0.7 | 0.8 | 0.00 | 0.1 |
| Total | 1.40 | 411 | | 334 | 100% | 6.7 | 8.3 | 0.03 | 0.5 |

| ***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 MtC* |
|---|---|---|---|---|---|---|---|---|---|
| Electricity | 0.13 | 39 | 90% | 35 | 29% | 4.0 | 4.5 | 0.04 | 0.6 |
| Natural gas | 0.47 | 138 | 55% | 76 | 64% | 8.7 | 15.9 | 0.05 | 0.8 |
| Oil | 0.05 | 14 | 55% | 8 | 7% | 0.9 | 1.7 | 0.01 | 0.1 |
| Total | 0.66 | 192 | | 119 | 100% | 13.7 | 22.0 | 0.10 | 1.5 |

*SUMMARY OF COGEN SAVINGS*

| | *MtC* | *primary E* |
|---|---|---|
| Electric generation | 0.6 | 0.00 |
| Use of cogen. heat | 1.9 | 0.14 |
| **Total** | 2.5 | 0.14 |

(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 space and water heating only (Personal communication with Ron Fiskum 4 June 1997, 202/586-9154).
We allocate 1/3 of thermal energy to space heating loads and 2/3 to water heating loads (water heating is much less seasonal).
We distribute cogen thermal energy within space and 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-2.10: Summary of direct and indirect effects of cool roofing**

| | | *Efficiency case* | | | *High efficiency/low carbon case* | | |
|---|---|---|---|---|---|---|---|
| | | *Residential* | *Commercial* | *Total* | *Residential* | *Commercial* | *Total* |
| Electric cooling savings | TWh/year | 3 | 1 | 4 | 6 | 2 | 8 |
| | Quads primary/year | 0.03 | 0.01 | 0.04 | 0.06 | 0.02 | 0.08 |
| Gas heating penalties | Quads/year | 0.01 | 0.00 | 0.01 | 0.02 | 0.00 | 0.02 |
| Net primary energy savings | Quads primary/year | 0.02 | 0.01 | 0.03 | 0.04 | 0.01 | 0.06 |
| Carbon savings from electric cooling | MtC/year | 0.30 | 0.10 | 0.39 | 0.74 | 0.24 | 0.98 |
| Increase in carbon emissions from gas heating | MtC/year | 0.18 | 0.03 | 0.21 | 0.22 | 0.06 | 0.28 |
| Net carbon savings | MtC/year | 0.12 | 0.06 | 0.18 | 0.52 | 0.18 | 0.70 |

(1) Savings include both direct and indirect effects of cool roofing.

(2) Roofs assumed to be replaced at same pace as cooling equipment, with an average lifetime of 13 years for residential buildings and 18 years for commercial buildings.

**Table C-2.11: 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 Scenarios of U. S. Carbon Reductions

# APPENDIX C-3

## Assumptions for Energy Efficiency Calculations Residential and Commercial Sectors

# APPENDIX C-3

## INTERLAB STUDY ON SCENARIOS OF U. S. CARBON REDUCTIONS

## 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 Scenarios of U. S. Carbon Reductions
# 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). |

**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 efficienct 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 | |

**CCE Calculation Assumptions**

| | |
|---|---|
| Capital recovery factor | $0.10 |
| Real discount rate | 0.07 |
| Lifetime | 19 |

# Background Information Sheet
# Interlab Study on Scenarios of U. S. Carbon Reductions
# 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). |

**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 Scenarios of U. S. Carbon Reductions
# 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). |

**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 (Koomey et al., 1997). The summary table for this potentials calculation is shown below.

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 |

Notes: EWHH = households with electric water heating, IES = incremental energy savings, IC = incremental cost, CW = clothes washers, HP WH = heat pump water heaters.

**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 (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 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. |

**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. flourescent lamp ballasts. and TVs.

Source. 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

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

**Determination of 1997 New Unit efficiency from Koomey 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 showerbeads 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 Koomey et al., 1997 (measures (a) thru (d))** | 3899 | 13.3 |

**Determination of Maximum cost-effective efficiency from Koomey 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) | CCE ($1995/kWh) | CCE ($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 |

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 Scenarios of U. S. Carbon Reductions
# 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. |

**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.

| | MMBtu | 1990 dollars | 1997 dollars |
|---|---|---|---|
| Average Stock Water heating UEC from Koomey et al., 1997 | 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% |

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

% 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 Scenarios of U. S. Carbon Reductions
# 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. |

**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: 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.

| | kWh | MMBtu | 1990 dollars | 1995 dollars |
|---|---|---|---|---|
| Average Stock Water heating UEC from Koomey et al., 19 | 880.7 | 3.0 | | |
| Btu conversion is 10800 btu/kWh resource | | | | |

**Determination of 1997 New Unit efficiency from Koomey 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% |

| | kWh | MMBtu |
|---|---|---|
| New Water Heater UEC in 1997 from Koomey et al., 1997 (measures (a) thru (d)) | 830 | 2.8 |

**Determination of Maximum cost-effective efficiency from Koomey 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 | Weighted Saturation in 2010 | Share in 1997 | Share in 2005 | Share in 2010 | Notes |
|---|---|---|---|---|---|
| (a) Electric clothes dryer - Baseline (1997 new UEC) | 94.2% | 100% | 100% | 85% | Assumes that heat pump clothes dryers are produced for 15% of the market |
| (b) Heat pump clothes dryer | 5.8% | 0% | 0% | 15% | beginning in 2005 |

| 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 | 0.0753 | 22.06 |
| Weighted average max econ. potential | 16.5 | 0.1 | 2% | 22.09 | - | |

| | | |
|---|---|---|
| Max Tech Efficient UEC | 813.5 | 2.8 |

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 efficient (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 ($1997) | 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 H-Axis clothes washers are slowly phased in resulting in reduced moisture content of clothes and low drying energy requirements

**LBNL 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) | | | |
| Electric | 76% | 77% | 76% |
| Gas | 24% | 23% | 24% |

# Background Information Sheet
# Interlab Study on Scenarios of U. S. Carbon Reductions
# 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. |

**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: Koomey, 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.

| | MMBtu |
|---|---|
| Average Stock Gas drying UEC from Koomey et al., 1997 | 3.74 |

**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 clothes dryers - Baseline | 0 | $ - | $ - | n/a | 3.71 | 100% |
| (b) Improve clothes dryers to 1994 standard | 0.51 | $ 27.00 | $ 31.27 | 5.5 | 3.2 | 100% |

| | MMBtu |
|---|---|
| New Water Heater UEC in 1997 from Koomey et al., 1997 (measures (a) thru (d)) | 3.2 |

**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 clothes dryers - 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 efficienct (new unit UEC, REM 75 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**

| | 1990 | 1997 | 2010 |
|---|---|---|---|
| Clothes dryer saturation (for both cases) | | | |
| 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) | | | |
| Electric | 76% | 77% | 76% |
| Gas | 24% | 23% | 24% |

## Background Information Sheet
## Interlab Study on Scenarios of U. S. Carbon Reductions
## 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 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 |

# Background Information Sheet
# Interlab Study on Scenarios of U. S. Carbon Reductions
# 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. |

**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 efficienct 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 efficienct 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 (Koomey et al., 1997b)

| Measure | Incremental energy Savings (MMBtu) | 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 | 3.40 | 100% | 19.00 |
| (b) Add Electronic Ignition | 2.2 | $ 48.00 | $ 55.60 | 2.2 | 1.20 | 100% | 19.00 |

| Measure | Incremental energy Savings (MMBtu) | Incremental Cost ($1990) | Incremental Cost ($1995) | CCE ($1990/MMBtu) | New UEC (MMBtu) | Fraction of Current Stock | Measure Lifetime |
|---|---|---|---|---|---|---|---|
| (a) Gas Self Cleaning Oven (1990 Baseline) | 3.40 | $ - | $ - | n/a | 1.90 | 100% | 19.00 |
| (b) Improve door seals & reflective surfaces | 0.27 | $ 9.00 | $ 10.42 | 3.4 | 1.63 | 100% | 19.00 |
| (c) Improve insulation on walls & door | 0.21 | $ 18.00 | $ 20.85 | 8.3 | 1.42 | | 19.00 |
| (d) Forced convection (post 1995 measure) | 0.22 | $ 41.00 | $ 47.49 | 17.9 | 1.20 | | 19.00 |

| Measure | Incremental energy Savings (MMBtu) | Incremental Cost ($1990) | Incremental Cost ($1995) | CCE ($1990/MMBtu) | New UEC (MMBtu) | Fraction of Current Stock | Measure Lifetime |
|---|---|---|---|---|---|---|---|
| (a) Standard Gas Oven (1990 Baseline) | | $ - | $ - | n/a | 3.00 | 100% | 19.00 |
| (b) Add electric glo-bar ignition | 1.57 | $ 47.00 | $ 54.44 | 2.9 | 1.43 | 100% | 19.00 |
| (c) Improve insulation on walls & door | 0.07 | $ 9.00 | $ 10.42 | 12.4 | 1.36 | | 19.00 |
| (d) Improve door seals | 0.02 | $ 4.00 | $ 4.63 | 19.4 | 1.34 | | 19.00 |

| Measure | Incremental energy Savings (MMBtu) | Incremental Cost ($1990) | Incremental Cost ($1995) | CCE ($1990/MMBtu) | New UEC (MMBtu) | Fraction of Current Stock | Measure Lifetime |
|---|---|---|---|---|---|---|---|
| (a) Standard Gas Oven w/ Electronic Ignition (1990 Baseline) | | $ - | $ - | n/a | 1.40 | 100% | 19.00 |
| (b) Improve insulation on walls & door | 0.07 | $ 9.00 | $ 10.42 | 12.4 | 1.33 | 100% | 19.00 |
| (c) Improve door seals | 0.02 | $ 4.00 | $ 4.63 | 19.4 | 1.31 | | 19.00 |

US DOE. 1993. Technical Support Document: Energy Efficiency Standards for Consumer Products: Room A/C, Water heaters, Direct heating equipment, mobil 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 (with power cord) | $ 245.00 | 283.77 | 1.32 | $ 245.00 | 283.77 | 1.32 | | 73.4% | | | | |
| Total (or weighted average) | $ 238.14 | 275.82 | 1.87 | $ 248.00 | | 1.32 | 0.00 | 100.0% | | | | |

| 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 line (w/out power c | $ 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 line (w/ power cord | $ 503.00 | 582.59 | 1.53 | $ 503.00 | 582.59 | 1.53 | | 48.1% | 0.00 | | 1.850 | 1.850 |
| Self-clean oven | $ 829.00 | 960.18 | 1.66 | $ 829.00 | 960.18 | 1.66 | | 23.8% | 0.00 | $ - | 1.850 | 1.850 |
| Total (or weighted average) | $ 573.84 | 664.65 | 1.97 | $ 580.59 | 672.46 | 1.56 | 0.00 | 100.0% | 0.41 | 7.81 | 1.850 | 1.850 |

LCC at 6% in this document

| CCE calculations | |
|---|---|
| Capital recovery factor | $0.10 |
| Real discount rate | 0.07 |
| Lifetime | 19 |

## Background Information Sheet
## Interlab Study on Scenarios of U. S. Carbon Reductions
## Assumptions for Energy Efficiency Calculations: Residential Sector

### *(Miscellaneous Energy)*

<table>
<tr><td>Product/end-use description</td><td>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:<br><br>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<br>oil & other petroleum products</td><td></td><td>pool heaters, gas fireplaces</td></tr>
</table>
</td></tr>
<tr><td>Base Year Energy Use</td><td>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)<br><br><u>Table 2: 1997 Miscellaneous Energy Use</u>
<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 petroleum products</td><td></td><td>0.1</td></tr>
<tr><td>Total Miscellaneous</td><td></td><td>5.4</td></tr>
</table>
</td></tr>
<tr><td>End-use Lifetime</td><td>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.</td></tr>
<tr><td>Average Unit Energy Consumption (UEC)</td><td>Average UECs per household are derived from US DOE (1996).</td></tr>
<tr><td>1997 New UEC</td><td>New UECs are assumed to be the same as for existing homes.</td></tr>
</table>

| | |
|---|---|
| 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)<br><br>**Table 3. Estimated Maximum Cost-Effective Efficiency Potential**<br><br>End-use Category — Potential energy savings (percent)<br>electronics — 25%<br>motors — 53%<br>heating — 33%<br>Total electric misc. — 33%<br>natural gas — 10%<br>oil & other petroleum products — 10%<br><br>Sources: US DOE, 1993; Webber, 1997; Meier, 1993; Rieger, 1994; Stevens, 1996; Meier and Greenberg, 1994; Lamb, 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 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. |

**Miscellaneous Electricity UEC and Cost Calculations**

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

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

Source: Meier, A. Home Energy Magazine, July/August 1993 "What Stays On When You Go Out"

Source: Rieger, 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 Audtor and Retrofitter, Nov/Dec 1987. "Saving the 'Other' Energy in Homes"

Source: Sanchez, M. 1997. ERG Master's thesis on Miscelleneous electricity

Determination of electricity share by end use (shares from Sanchez, 1997 applied to AEO, 1997 energy consumption)

| Shares of electricity use from LBNL Documentation | Implied Misc. electricity based on LBNL shares | Total Misc electricity from AEO, 1997=4.4 Quads |
|---|---|---|
| 35.9% | 1.6 | Electronics |
| 37.4% | 1.6 | Motors |
| 26.7% | 1.2 | Heating |

Estimation of lifetimes and savings potential

| End use | Lifetime | Savings potential | Notes |
|---|---|---|---|
| **Electronics** | | | |
| color television | 11.5 | 25% | DOE, 1993; Webber, 1997 |
| cable boxes | 10 | 20% | judgement |
| Video cassette re | 10 | 40% | Webber, 1997 |
| computers | 8 | 25% | judgement |
| other electronics | 10 | 20% | judgement |
| **Motors** | | | |
| Furnace fans | 15 | 60% | Greenberg, 1997. Assumes taking advantage of VSD and improved fan |
| ceiling fans | 15 | 50% | Greenberg, 1997 Blade redesign |
| pool pumps | 12 | 50% | Greenberg, 1997. Assuming one can redesign pool system (e.g. bigger pipes smaller pumps) esp. for new homes, rights sizing approach. Not even forcing tech. change |
| well pumps | 12 | 20% | Greenberg, 1997. Highly application specific, 20% should be achievable |
| aquariums | 12 | 25% | Greenberg, 1997. Air pumps - analagous; also assuming high efficiency lighting (elec. ballast switch). Lighting and motor savings |
| evaporative cool | 10 | 50% | Greenberg, 1997. Fans are forward curved, like furnaces-lower run time but move a lot of air. Similar savings potential to furnace fans. |
| other motors | 14 | 60% | Stevens, 1996; Greenberg, 1997. Mostly shaded pole (very poor efficiencies) and poor fans |
| **Heating** | | | |
| waterbed heaters | 12 | 40% | Rieger, 1994; Meier, 1993 |
| coffee makers | 8 | 5% | judgement |
| spas/hot tubs | 18 | 20% | Meier & Greenberg, 1994 |
| toasters & toaste | 10 | 5% | judgement |
| crankcase heaters | 10 | 10% | judgement |
| irons | 8 | 10% | judgement |
| electric blankets | 12 | 10% | judgement |
| other heating | 12 | 10% | judgement |

## Background Information Sheet
## Interlab Study on U.S. Scenarios of U. S. Carbon Reductions
## 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. |

light 6/10/97

| Lighting Efficiency Calculations (Measure Name) | Measure No. | Enduse Code | category | CCE (cents/kWh) 1990 $ | CCE (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 | 209352.38 |
| 65W Halogen IR | 1 | L100-2. | non space conditioning | 1.56 | 1.81 | 2.01 | 0.3 | 0.35 | 0 | 104676.19 |
| 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 | 360551.32 |
| 52W ES Incandescent and Motion Sensor | 6 | L60-5. | non space conditioning | 1.6 | 1.85 | 0.16 | 0.07 | 0.08 | 0 | 36055.13 |
| 49W Halogen IR | 1 | L75-5. | non space conditioning | 1.62 | 1.88 | 4.97 | 0.77 | 0.89 | 0 | 104676.19 |
| 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 fits | 2 | L60-5. | non space conditioning | 1.79 | 2.07 | 13.16 | 1.21 | 1.40 | 0 | 194697.71 |
| 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 | 116306.88 |
| 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 fits | 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 Fits | 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 fits | 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 fits | 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 | 72110.26 |
| 30W Electronic Separable CFL where CFL fits | 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 | 72110.26 |
| 15W Electronic Integral Quad where CFL Fits | 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 | 360551.32 |
| 20W Electronic Separable CFL where CFL fits | 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 fits | 2 | L100-3. | non space conditioning | 5.51 | 6.38 | 1 | 1.76 | 2.04 | 0 | 31402.86 |
| 20W Electronic Separable CFL where CFL fits | 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 fits | 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 | 72110.26 |
| 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 fits | 2 | L75-2. | non space conditioning | 11.71 | 13.56 | 1.11 | 1.86 | 2.15 | 0 | 69784.13 |
| 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 fits | 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 fits | 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 fits | 3 | L75-1. | non space conditioning | 25.28 | 29.28 | 0.74 | 1.34 | 1.55 | 0 | 139568.25 |
| | | | | | 1995 c/kWh | | | | | |
| Savings up to 8 cents/kWh | | | | | 2.86 | 82.61 | 24.2 | 28.0 | | |
| | | | | | 1995 $/MMBtu | 83% | | | | |
| 2010 lighting residential frozen efficiency TWh | | | | | 8.34 | 156.6 | | | | |

# Background Information Sheet
# Interlab Study on Scenarios of U. S. Carbon Reductions
# 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 (Koomey 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 Koomey 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 Koomey 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. |

| 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 Clg | Energy Saved heating | 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/-/tight 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/-/loose 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/-/loose homes, South | 1 | ESSE_L | 1714 | 1989 | shell | 2.18 | 2.52 | 0.63 | 1807 | 0 | 0.63 | 93.79 |
| Reduce infiltration in ESF ER/RAC/tight homes, South | 1 | ESSERT | 422 | 1989 | shell | 2.47 | 2.86 | 0.37 | 445 | 0.01 | 0.36 | 254.21 |
| Low-E argon filled windows in ESF ER/RAC/loose homes, North | 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/_/loose homes, North | 2 | ESNE_L | 354 | 1989 | shell | 2.52 | 2.92 | 0.25 | 373 | 0 | 0.25 | 207.89 |
| Reduce infiltration in ESF ER/-/tight homes, South | 1 | ESSE_T | 422 | 1989 | shell | 2.55 | 2.95 | 0.32 | 445 | 0 | 0.32 | 230.02 |
| Low-E argon filled windows in ESF ER/RAC/tight homes, North | 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/_/tight homes, North | 2 | ESNE_T | 466 | 1989 | shell | 2.58 | 2.99 | 1.1 | 491 | 0 | 1.1 | 712.75 |
| Double pane windows in ESF ER/CAC/loose homes, South | 2 | ESSECL | 218 | 1989 | shell | 3.36 | 3.89 | 0.33 | 230 | 0.05 | 0.28 | 606.28 |
| R-25 ceiling in ESF ER/CAC/loose homes, South | 3 | ESSECL | 436 | 1989 | shell | 3.59 | 4.16 | 0.63 | 460 | 0.14 | 0.49 | 606.28 |
| Improve shell in ESF ER/CAC/loose homes, North | 3 | ESNECL | 1281 | 1989 | shell | 4.04 | 4.68 | 0.22 | 1350 | 0.01 | 0.21 | 82.81 |
| Improve floor & ceiling in ESF ER/-/tight homes, North | 3 | ESNE_T | 1959 | 1989 | shell | 4.22 | 4.89 | 2.81 | 2065 | 0 | 2.81 | 712.75 |
| R-23 floor & R-48 ceiling in ESF ER/RAC/tight homes, North | 3 | ESNERT | 2114 | 1989 | shell | 4.26 | 4.93 | 2.25 | 2228 | 0.01 | 2.24 | 533.79 |
| Reduce infiltration by 25% in ESF ER/CAC/tight homes, North | 2 | ESNECT | 245 | 1989 | shell | 4.67 | 5.41 | 0.13 | 258 | 0 | 0.13 | 283.93 |
| Reduce infiltration in ESF ER/CAC/tight homes, South | 2 | ESSECT | 211 | 1989 | shell | 4.83 | 5.59 | 0.55 | 222 | 0.09 | 0.46 | 1486.83 |
| Low-E argon filled windows in ESF ER/RAC/tight homes, South | 3 | ESSERT | 715 | 1989 | shell | 5.15 | 5.96 | 0.3 | 754 | 0.02 | 0.28 | 254.21 |
| R-33 ceiling in ESF ER/RAC/loose homes, South | 3 | ESSERL | 115 | 1989 | shell | 5.31 | 6.15 | 0.02 | 121 | 0 | 0.02 | 103.66 |
| Reduce infiltration to 0.39 ACH in ESF HP/tight homes, South | 2 | ESSHPT | 422 | 1989 | shell | 5.31 | 6.15 | 1.4 | 445 | 0.23 | 1.17 | 2067.37 |
| Low-E argon filled windows in ESF ER/RAC/loose homes, South | 4 | ESSERL | 295 | 1989 | shell | 5.45 | 6.31 | 0.05 | 311 | 0 | 0.04 | 103.66 |
| Low-E argon filled windows in ESF ER/-/tight homes, South | 2 | ESSE_T | 715 | 1989 | shell | 5.47 | 6.34 | 0.26 | 754 | 0 | 0.26 | 230.02 |
| R-33 ceiling in ESF ER/-/loose homes, South | 2 | ESSE_L | 115 | 1989 | shell | 5.58 | 6.46 | 0.02 | 121 | 0 | 0.02 | 93.79 |
| Low-E argon filled windows in ESF ER/-/loose homes, South | 3 | ESSE_L | 295 | 1989 | shell | 5.92 | 6.86 | 0.04 | 311 | 0 | 0.04 | 93.79 |
| Reduce infiltration in ESF ER/CAC/loose homes, South | 4 | ESSECL | 211 | 1989 | shell | 6.03 | 6.98 | 0.18 | 222 | 0.03 | 0.15 | 606.28 |
| Spectrally selective windows, ESF ER/CAC/loose, South | 5 | ESSECL | 288 | 1989 | shell | 6.03 | 6.98 | 0.25 | 304 | 0.26 | -0.02 | 606.28 |
| R-46 ceiling in ESF ER/-/tight homes, North | 4 | ESNE_T | 180 | 1989 | shell | 6.13 | 7.10 | 0.18 | 190 | 0 | 0.18 | 712.75 |
| Superwindows in ESF ER/RAC/loose homes, North (post-1995) | 6 | ESNERL | 347 | 1989 | shell | 6.33 | 7.33 | 0.07 | 366 | 0 | 0.07 | 155.69 |
| Superwindows in ESF ER/_/loose homes, North (post-1995) | 6 | ESNE_L | 347 | 1989 | shell | 6.41 | 7.42 | 0.1 | 366 | 0 | 0.1 | 207.89 |
| Superwindows in ESF ER/RAC/tight homes, North (post-1995) | 6 | ESNERT | 458 | 1989 | shell | 6.44 | 7.46 | 0.32 | 483 | 0.01 | 0.32 | 533.79 |
| Improve shell of ESF/HP/loose homes, South | 2 | ESSHPL | 1694 | 1989 | shell | 6.47 | 7.49 | 0.75 | 1786 | 0.14 | 0.61 | 338.3 |
| Superwindows in ESF ER/-/tight homes, North (post-1995) | 7 | ESNE_T | 458 | 1989 | shell | 6.57 | 7.61 | 0.42 | 483 | 0 | 0.42 | 712.75 |
| Low-E argon filled windows in ESF/HP/loose homes, North | 2 | ESNHPL | 938 | 1989 | shell | 6.6 | 7.64 | 0.03 | 989 | 0 | 0.03 | 23.05 |
| R-37 ceiling in ESF ER/RAC homes, North | 3 | ESNERL | 87 | 1989 | shell | 6.63 | 7.68 | 0.02 | 92 | 0 | 0.02 | 155.69 |
| Low-E argon filled windows in ESF/HP/tight homes, North | 2 | ESNHPT | 548 | 1989 | shell | 6.63 | 7.68 | 0.34 | 578 | 0.02 | 0.32 | 484.11 |
| R-37 ceiling in ESF ER/_/loose homes, North | 3 | ESNE_L | 87 | 1989 | shell | 6.68 | 7.74 | 0.02 | 92 | 0 | 0.02 | 207.89 |
| Low-E argon filled windows in ESF ER/CAC/loose homes, North | 4 | ESNECL | 354 | 1989 | shell | 6.77 | 7.84 | 0.04 | 373 | 0 | 0.04 | 82.81 |
| Low-E argon filled windows in ESF ER/CAC/tight homes, North | 3 | ESNECT | 466 | 1989 | shell | 6.84 | 7.92 | 0.16 | 491 | 0.01 | 0.16 | 283.93 |
| Reduce infiltration (#2) in ESF ER/CAC/tight homes, South | 4 | ESSECT | 211 | 1989 | shell | 7.14 | 8.27 | 0.37 | 222 | 0.06 | 0.31 | 1486.83 |
| R-38 ceiling in ESF ER/RAC/tight homes, South (pre-2000) | 4 | ESSERT | 609 | 1989 | shell | 7.4 | 8.57 | 0.06 | 642 | 0 | 0.06 | 90.91 |
| R-38 ceiling in ESF ER/RAC/tight homes, South (post-2000) | 8 | ESSERT | 609 | 1989 | shell | 7.45 | 8.63 | 0.12 | 642 | 0 | 0.11 | 169.47 |
| Improve floor & ceiling in ESF ER/CAC/loose homes, North | 5 | ESNECL | 895.6 | 1989 | shell | 7.49 | 8.68 | 0.08 | 944 | 0 | 0.08 | 82.81 |
| R-38 ceiling in ESF ER/-/tight homes, South | 3 | ESSE_T | 609 | 1989 | shell | 7.77 | 9.00 | 0.15 | 642 | 0 | 0.15 | 230.02 |
| Spect. selective windows, ESF other/CAC/loose, South | 2 | ESSGCL | 492 | 1989 | shell | 7.93 | 9.18 | 1.98 | 519 | 1.98 | 0 | 3751.63 |
| Spectrally selective windows, ESF/HP/tight, South | 4 | ESSHPT | 590 | 1989 | shell | 8.15 | 9.44 | 1.27 | 622 | 1.28 | 0 | 2067.37 |
| Spect. selective windows, ESF other/CAC/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/CAC/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/CAC/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/CAC/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/HP/loose, South | 3 | ESSHPL | 571 | 1989 | shell | 9.35 | 10.83 | 0.18 | 602 | 0.18 | 0 | 338.3 |
| Improve wall insulation in ESF ER/-/tight homes, North | 5 | ESNE_T | 874 | 1989 | shell | 9.46 | 10.96 | 0.56 | 921 | 0 | 0.56 | 712.75 |
| R-30 ceiling in ESF/HP/loose homes, North | 4 | ESNHPL | 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/CAC/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/CAC/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/-/tight homes, South | 4 | ESSE_T | 161 | 1989 | shell | 11.69 | 13.54 | 0.03 | 170 | 0 | 0.03 | 230.02 |
| R-33 ceiling in ESF/HP/loose homes, South | 4 | ESSHPL | 145 | 1989 | shell | 11.73 | 13.59 | 0.04 | 153 | 0.01 | 0.03 | 338.3 |
| 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 | 155.69 |
| R-45 ceiling in ESF ER/_/loose homes, North | 4 | ESNE_L | 327 | 1989 | shell | 12.39 | 14.35 | 0.05 | 345 | 0 | 0.05 | 207.89 |
| R-36 ceiling in ESF ER/RAC/loose homes, South (pre-2000) | 5 | ESSERL | 72 | 1989 | shell | 12.48 | 14.45 | 0 | 76 | 0 | 0 | 37.07 |
| 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 | 533.79 |
| R-33 ceiling in ESF ER/CAC/loose homes, South | 8 | ESSECL | 115 | 1989 | shell | 12.85 | 14.88 | 0.05 | 121 | 0.01 | 0.03 | 606.28 |
| R-51 ceiling in ESF ER/-/tight homes, North | 6 | ESNE_T | 112 | 1989 | shell | 12.93 | 14.98 | 0.05 | 118 | 0 | 0.05 | 712.75 |
| R-36 ceiling in ESF ER/-/loose homes, South | 4 | ESSE_L | 72 | 1989 | shell | 13.3 | 15.40 | 0 | 76 | 0 | 0 | 93.79 |
| R-44 ceiling in ESF/HP/tight homes, North | 3 | ESNHPT | 395 | 1989 | shell | 14.16 | 16.40 | 0.11 | 416 | 0.01 | 0.11 | 484.11 |
| 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 | 90.91 |
| 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 | 169.47 |
| R-11 wall in ESF ER/-/tight homes, South | 5 | ESSE_T | 775 | 1989 | shell | 14.66 | 16.98 | 0.1 | 817 | 0 | 0.1 | 230.02 |
| 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 | 155.69 |
| R-67 ceiling in ESF ER/_/loose homes, North | 5 | ESNE_L | 632 | 1989 | shell | 15.56 | 18.02 | 0.07 | 666 | 0 | 0.07 | 207.89 |
| Superwindows in ESF/HP/tight homes, North (post-1995) | 4 | ESNHPT | 539 | 1989 | shell | 15.64 | 18.11 | 0.14 | 568 | 0.02 | 0.12 | 484.11 |
| R-46 ceiling in ESF ER/CAC/tight homes, North | 6 | ESNECT | 179 | 1989 | shell | 16 | 18.53 | 0.03 | 189 | 0 | 0.03 | 283.93 |
| Superwindows in ESF/HP/loose homes, North (post-1995) | 5 | ESNHPL | 770 | 1989 | shell | 16.43 | 19.03 | 0.01 | 812 | 0 | 0.01 | 23.05 |
| R-38 ceiling in ESF ER/CAC/tight homes, South | 7 | ESSECT | 609 | 1989 | shell | 17.42 | 20.18 | 0.44 | 642 | 0.1 | 0.34 | 1486.83 |
| R-52 ceiling in ESF/HP/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 Clg | 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 std 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 | EMSHP | 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, North | 1 | ESNHPT | 241 | 1989 | space conditioning | 2.37 | 2.75 | 0.79 | 254 | 0.07 | 0.72 | 645.48 |
| Improve HP beyond 92 std in EMF HP homes, South | 1 | EASHP | 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 9.42 EER in ESF ER/RAC/loose homes, South | 2 | ESSERL | 18 | 1989 | space conditioning | 5.08 | 5.88 | 0.01 | 19 | 0.01 | 0 | 138.22 |
| 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 std 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 | 2 | EASGC | 105 | 1989 | space conditioning | 7.91 | 9.16 | 0.24 | 111 | 0.24 | 0 | 1335.72 |
| Improve CAC beyond 1992 std in EMH non-elec/CAC homes, South | 1 | EMSGC | 309 | 1989 | space conditioning | 8.19 | 9.49 | 0.19 | 326 | 0.19 | 0 | 386.39 |
| 10.0 EER for ESF non-elec/RAC/tight, 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 | 0.29 | 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 std 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 std 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 3 in EMF HP homes, North | 3 | EANHP | 228 | 1989 | space conditioning | 10.81 | 12.52 | 0.06 | 240 | 0.01 | 0.05 | 218.04 |
| Improve HP 2 in EMH HP homes, South | 2 | EMSHP | 109 | 1988 | space conditioning | 10.88 | 12.60 | 0.01 | 120 | 0 | 0.01 | 59.59 |
| Improved 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 |
| 10.0 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 | EASHP | 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 | EMSHP | 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 in 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 | EASHP | 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 |
| 10.06 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 6 cents/kWh | | | | | | | 3.89 | 20.87 | 20.86 | 1.04 | 19.82 | |
| Existing Equipment savings below 6 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 Clg | Energy Saved heating | Applicable Stock (1000s) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| R-19 wall & reduced infiltration in NSF ER/CAC homes, South | 1 | NSSER | 606.1 | 1989 | shell | 1.85 | 2.14 | 0.46 | 639 | 0.01 | 0.45 | 165.79 |
| Reduce infiltration & R-19 wall, NSF ER/- 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/RAC 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/- 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/RAC 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 | 227.3 | 1989 | shell | 2.49 | 2.88 | 0.71 | 240 | 0.12 | 0.6 | 917.45 |
| Argon-filled windows in NSF ER/- 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/RAC homes, South | 2 | NSSER | 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/- 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/RAC 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/- homes, North | 3 | NSNE | 148 | 1989 | shell | 4.25 | 4.92 | 0.05 | 156 | 0 | 0.05 | 185.13 |
| Superwindows in NSF ER/RAC homes, North (post-1995) | 7 | NSNER | 455 | 1989 | shell | 5.1 | 5.91 | 0.1 | 480 | 0 | 0.1 | 136.18 |
| Superwindows in NSF ER/- 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 |
| R-19 wall and R-38 ceiling in NSF HP homes, North | 2 | NSNHP | 360 | 1989 | shell | 5.49 | 6.36 | 0.7 | 379 | 0.03 | 0.67 | 1264.73 |
| Spectrally selective windows, NSF ER/CAC, South | 3 | NSSEC | 738.1 | 1989 | shell | 6.23 | 7.22 | 0.92 | 778 | 0.66 | 0.26 | 917.45 |
| Ceiling to R-30 in NSF ER/RAC homes, South | 4 | NSSER | 56.8 | 1989 | shell | 6.63 | 7.68 | 0.01 | 60 | 0 | 0.01 | 165.79 |
| Argon-filled windows in NSF ER/CAC homes, North | 3 | NSNEC | 494 | 1989 | shell | 6.7 | 7.76 | 0.27 | 521 | 0.01 | 0.26 | 423.29 |
| R-30 ceiling in NSF ER/- homes, South | 3 | NSSE | 57 | 1989 | shell | 6.92 | 8.01 | 0.01 | 60 | 0 | 0.01 | 149.74 |
| Ceiling to R-49, wall to R-27 in NSF ER/CAC homes, North | 4 | NSNER | 1243.5 | 1989 | shell | 7.4 | 8.57 | 0.19 | 1311 | 0 | 0.19 | 136.18 |
| R-27 wall & R-49 ceiling in NSF ER/- homes, North | 4 | NSNE | 1244 | 1989 | shell | 7.44 | 8.62 | 0.26 | 1311 | 0 | 0.26 | 185.13 |
| Wall to R-19 in NSF ER/CAC homes, South | 5 | NSSEC | 378.8 | 1989 | shell | 7.81 | 9.05 | 0.38 | 399 | 0.06 | 0.32 | 917.45 |
| Floor to R-30 in NSF HP homes, North | 3 | NSNHP | 311 | 1989 | shell | 7.83 | 9.07 | 0.43 | 328 | 0.02 | 0.41 | 1264.73 |
| Floor to R-30 in NSF ER/CAC homes, North | 4 | NSNEC | 222.7 | 1989 | shell | 7.88 | 9.13 | 0.1 | 235 | 0.01 | 0.1 | 423.29 |
| R-49 ceiling in NSF HP homes, North | 4 | NSNHP | 100 | 1989 | shell | 8.65 | 10.02 | 0.12 | 105 | 0.01 | 0.12 | 1264.73 |
| Ceiling to R-60 in NSF ER/CAC 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/- homes, North | 5 | NSNE | 148 | 1989 | shell | 9.11 | 10.55 | 0.03 | 156 | 0 | 0.03 | 185.13 |
| Spectrally selective low-E windows, NSF HP, South | 3 | NSSHP | 710 | 1989 | shell | 9.5 | 11.00 | 2.16 | 748 | 2.05 | 0.1 | 3394.86 |
| Spect. selective windows, NSF other/CAC homes, South | 2 | NSSGC | 807 | 1989 | shell | 10.1 | 11.70 | 3.62 | 851 | 3.62 | 0 | 5324.68 |
| Ceiling to R-38 in NSF ER/CAC homes, North | 5 | NSNEC | 148.5 | 1989 | shell | 11.19 | 12.96 | 0.05 | 157 | 0 | 0.04 | 423.29 |
| R-60 ceiling in NSF HP homes, North | 5 | NSNHP | 89 | 1989 | shell | 11.83 | 13.70 | 0.08 | 94 | 0.01 | 0.07 | 1264.73 |
| Ceiling insulation to R-38 in NSF ER/CAC homes, South (pre-2000) | 5 | NSSER | 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 (post-2000) | 8 | NSSER | 322 | 1989 | shell | 12.51 | 14.49 | 0.02 | 339 | 0 | 0.02 | 85.64 |
| Superwindows in NSF ER/CAC homes, North | 6 | NSNEC | 455 | 1989 | shell | 13.18 | 15.27 | 0.12 | 480 | 0.01 | 0.11 | 423.29 |
| Wall to R-19 in NSF HP homes, South | 5 | NSSHP | 328 | 1989 | shell | 13.27 | 15.37 | 0.71 | 346 | 0.11 | 0.61 | 3394.86 |
| Ceiling to R-38 in NSF ER/- homes, South | 4 | NSSE | 322 | 1989 | shell | 13.34 | 15.45 | 0.03 | 339 | 0 | 0.03 | 149.74 |
| Ceiling insulation to R-49 in NSF ER/CAC homes, South (pre-2000) | 6 | NSSER | 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 (post-2000) | 9 | NSSER | 303 | 1989 | shell | 13.79 | 15.97 | 0.02 | 319 | 0 | 0.01 | 85.64 |
| Ceiling to R-49 in NSF ER/- homes, South | 5 | NSSE | 303 | 1989 | shell | 14.71 | 17.04 | 0.03 | 319 | 0 | 0.03 | 149.74 |
| Ceiling to R-30 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 | CCE (¢/kWh) 1990 $ | CCE (¢/kWh) 1995$ | Total Energy Saved (TWh) | Cost in 1990 $ | Energy Saved Clg | 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/RAC 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 | NMSGC | 309 | 1989 | space conditioning | 7.64 | 8.85 | 0.48 | 326 | 0.48 | 0 | 889.49 |
| Incr. 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 14.67 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 | 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 | 4.08 | 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
Total Shell savings below 8 cents/kWh
Total Equipment savings below 8 cents/kWh
Weighted average existing

NEW
Total Shell savings below 8 cents/kWh
Total Equipment savings below 8 cents/kWh
Weighted average new

| EXISTING | CCE ¢/kW | $/MMBTu | Total | Cooling | Heating |
|---|---|---|---|---|---|
| Total Shell savings below 8 cents/kWh | 3.89 | 11.41 | 9.3% | 1.3% | 13.9% |
| Total Equipment savings below 8 cents/kWh | 3.09 | 9.06 | 12.6% | 14.8% | 11.3% |
| Weighted average existing | 3.43 | 10.07 | 21.9% | 16.1% | 25.2% |
| NEW | | | | | |
| Total Shell savings below 8 cents/kWh | 4.50 | 13.18 | 9.9% | 4.1% | 14.6% |
| Total Equipment savings below 8 cents/kWh | 3.99 | 11.69 | 21.8% | 18.2% | 24.7% |
| Weighted average new | 4.15 | 12.15 | 31.8% | 22.3% | 39.3% |

# Background Information Sheet
# Interlab Study on Scenarios of U. S. Carbon Reductions
# 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. |

| 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 infilatration 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 infilatration by 25% & improve insulation to ceiling R-19 | ESSGFL | 759.13 | shell | 5.27 | 6.10 | 12.13 | 1044.21 |
| Reduce infilatration by 25% & improve insulation to ceiling R-19 | ESSGFLC | 759.13 | shell | 5.27 | 6.10 | 27.18 | 2339.74 |
| Reduce infilatration 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 & recrease Infilatration 25% | ESNGFTC | 334.76 | shell | 5.29 | 6.13 | 10.21 | 2002.63 |
| Improve window to double pane-wood frame & reduce infilatration 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 infl additional 25% Add Ceiling R-27, 2-glz, low-E, argon | ESNGFLC | 924.04 | shell | 6.1 | 7.07 | 23.23 | 1904.73 |
| Reduce infl 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 infilatration additional 25% & improve insulation to wall R-11 | ESSGFL | 958.23 | shell | 7.55 | 8.74 | 10.68 | 1044.21 |
| Reduce infilatration additional 25% & improve insulation to wall R-11 | ESSGFLC | 958.23 | shell | 7.55 | 8.74 | 23.92 | 2339.74 |
| Reduce infilatration additional 25% & improve insulation to wall R-11 | ESSGFLR | 958.23 | shell | 7.55 | 8.74 | 11.62 | 1136.59 |
| Reduce infilatration 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 toSuperwindow & 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 infilatration 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 & floorR-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 con | 13.52 | 15.66 | 0 | 0 |
| Improve to condensing gas furnace: New MH/South/CAC | NMSGFC | 432.42 | space con | 13.52 | 15.66 | 0 | 0 |
| Improve to condensing gas furnace: New MH/South/RAC | NMSGFR | 432.42 | space con | 13.52 | 15.66 | 0 | 0 |
| Improve to condensing gas furnace: New SF/South/no clg | NSSGF | 432.42 | space con | 13.88 | 16.08 | 0.48 | 151.61 |
| Improve to condensing gas furnace: New SF/South/CAC | NSSGFC | 432.42 | space con | 13.88 | 16.08 | 11.44 | 3641.25 |
| Improve to condensing gas furnace: New SF/South/RAC | NSSGFR | 432.42 | space con | 13.88 | 16.08 | 0.47 | 149.95 |
| Improve to condensing boiler: New MH/North/no clg | NMNGB | 1250.04 | space con | 22.74 | 26.34 | 0 | 0 |
| Improve to condensing boiler: New MH/North/CAC | NMNGBC | 1250.04 | space con | 22.74 | 26.34 | 0 | 0 |
| Improve to condensing boiler: New MH/North/RAC | NMNGBR | 1250.04 | space con | 22.74 | 26.34 | 0 | 0 |
| Improve to condensing boiler: New MF/North/no clg | NANGB | 1250.04 | space con | 25.59 | 29.64 | 1 | 239.68 |
| Improve to condensing boiler: New MF/North/CAC | NANGBC | 1250.04 | space con | 25.59 | 29.64 | 0 | 0 |
| Improve to condensing boiler: New MF/North/RAC | NANGBR | 1250.04 | space con | 25.59 | 29.64 | 1.09 | 259.66 |
| Improve to condensing boiler: New MH/South/no clg | NMSGB | 1250.04 | space con | 43.83 | 50.77 | 0 | 0 |
| Improve to condensing boiler: New MH/South/CAC | NMSGBC | 1250.04 | space con | 43.83 | 50.77 | 0 | 0 |
| Improve to condensing boiler: New MH/South/RAC | NMSGBR | 1250.04 | space con | 43.83 | 50.77 | 0 | 0 |
| Improve to condensing gas furnace: New MF/South/no clg | NASGF | 432.42 | space con | 54.36 | 62.96 | 0.19 | 237.82 |
| Improve to condensing gas furnace: New MF/South/CAC | NASGFC | 432.42 | space con | 54.36 | 62.96 | 0.56 | 701.62 |
| Improve to condensing gas furnace: New MF/South/RAC | NASGFR | 432.42 | space con | 54.36 | 62.96 | 0.13 | 165.26 |
| Improve to condensing boiler: New MF/South/no clg | NASGB | 1250.04 | space con | 163.07 | 188.87 | 0 | 0 |
| Improve to condensing boiler: New MF/South/CAC | NASGBC | 1250.04 | space con | 163.07 | 188.87 | 0 | 0 |
| Improve to condensing boiler: New MF/South/RAC | NASGBR | 1250.04 | space con | 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 | 5.08 | 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

Total Shell savings below 6$/MMBtu

Total Equipment savings below 6$/MMBtu

NEW

Total Shell savings below 6$/MMBtu

Total Equipment savings below 6$/MMBtu

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

# Background Information Sheet
## Interlab Study on Scenarios of U. S. Carbon Reductions
## 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 (Koomey 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. |

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.

| | % of floor area | New bdgs EUI primary E kBtu/sf/yr | Savings | Savings w/ controls | Savings w/ controls kBtu/sf/yr | Weighted Savings w/ controls kBtu/sf/yr | Cost 1992 $/sf | Cost/sf 1995$/sf | Total Cost w/ controls 1995 $/sf | CCE 1995 $/MMBtu |
|---|---|---|---|---|---|---|---|---|---|---|
| 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 | 48% | |
| Costs | 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 Scenarios of U. S. Carbon Reductions
# 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. |

Lighting

| Lighting Efficiency (Measure Name) | Measure Number | Enduse Code | CCE (cents/kWh) kWh | CCE (cents/kWh) 1995¢/kWh | Energy Saved (TWh) |
|---|---|---|---|---|---|
| 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_LDG | -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_LDG | -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_LDG | -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_LDG | -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_LDG | -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 |
| ELEC4/4F32T8/RS | 1 | EM4/4_HLT | 0.52 | 0.60 | 0.82 |
| ELEC4/4F32T8/RS | 1 | EM4/4_GRC | 0.52 | 0.60 | 0.15 |
| ELEC4/4F32T8/RS | 1 | EM4/4_RST | 0.56 | 0.65 | 0.22 |
| ELEC4/4F32T8/RS | 1 | EM4/4_LDG | 0.56 | 0.65 | 0.59 |
| ELEC4/4F32T8/RS | 1 | EM4/4_COL | 0.58 | 0.67 | 0.36 |
| ELEC4/4F32T8/RS | 1 | EM4/4_RET | 0.58 | 0.67 | 1.89 |
| ELEC4/4F32T8/RS | 1 | EM4/4_LGO | 0.58 | 0.67 | 2.15 |
| ELEC4/4F32T8/RS | 1 | EM4/4_SCH | 0.66 | 0.76 | 0.59 |
| ELEC4/4F32T8/RS | 1 | EM4/4_MSC | 0.66 | 0.76 | 0.85 |
| ELEC4/4F32T8/RS | 1 | EM4/4_SMC | 0.66 | 0.76 | 1.41 |
| ELEC4/4F32T8/RS | 1 | EM4/4_WRI | 0.66 | 0.76 | 0.35 |
| HPS | 2 | MH_GRC | 0.86 | 1.00 | 0 |
| ELEC4/3F32T8/IS/occupancy sensor | 1 | EL4/3_RST | 0.94 | 1.09 | 0.01 |
| ELEC4/3F32T8/IS/occupancy sensor | 1 | EL4/3_LDG | 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 |
| ELEC4/4F32T8/RS/occupancy sensor | 3 | EM4/4_RST | 1.05 | 1.22 | 0 |
| ELEC4/4F32T8/RS/occupancy sensor | 3 | EM4/4_LDG | 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_LDG | 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_LDG | 1.46 | 1.69 | 0.01 |
| HPS, no delamping | 1 | MV_WRH | 1.46 | 1.69 | 0.06 |

Lighting

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|---|---|---|---|---|
| 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 |
| ELEC8/2F96T12/ES/occupancy sensor | 3 EM8/2_GRC | 1.93 | 2.24 | 0 |
| ELEC8/2F96T12/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 |
| ELEC8/2F96T12/ES/occupancy sensor | 3 EM8/2_LDG | 2.18 | 2.52 | 0 |
| ELEC8/2F96T12/ES/occupancy sensor | 3 EM8/2_RST | 2.18 | 2.52 | 0 |
| ELEC8/2F96T12/ES/occupancy sensor | 3 EM8/2_LGO | 2.18 | 2.52 | 0.08 |
| ELEC8/2F96T12/ES/occupancy sensor | 3 EM8/2_RET | 2.18 | 2.52 | 0.03 |
| ELEC8/2F96T12/ES/occupancy sensor | 3 EM8/2_COL | 2.18 | 2.52 | 0.02 |
| ELEC4/3F32T8/IS/occupancy sensor | 2 EL4/3_HLT | 2.32 | 2.69 | 0.02 |
| ELEC4/3F32T8/IS/occupancy sensor | 2 EL4/3_GRC | 2.32 | 2.69 | 0 |
| ELEC4/3F32T8/IS/trg mgmt system | 2 EL4/3_RST | 2.36 | 2.73 | 0.02 |
| ELEC4/3F32T8/IS/trg mgmt system | 2 EL4/3_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/trg mgmt system | 3 EL4/3_HLT | 2.49 | 2.88 | 0.02 |
| ELEC4/3F32T8/IS/trg mgmt system | 3 EL4/3_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/trg mgmt system | 5 EM4/4_RST | 2.54 | 2.94 | 0.01 |
| ELEC4/4F32T8/IS/trg 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_WRI | 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/trg mgmt system | 6 EM4/4_HLT | 4.03 | 4.67 | 0.01 |
| ELEC4/4F32T8/IS/trg mgmt system | 6 EM4/4_GRC | 4.03 | 4.67 | 0.02 |
| ELEC8/2F96T12/ES/trg mgmt system | 4 EM8/2_HLT | 4.35 | 5.04 | 0 |
| ELEC8/2F96T12/ES/trg mgmt system | 4 EM8/2_GRC | 4.35 | 5.04 | 0.07 |
| ELEC4/3F32T8/IS/occupancy sensor | 2 EL4/3_COL | 4.37 | 5.06 | 0.13 |
| ELEC4/3F32T8/IS/occupancy sensor | 2 EL4/3_RET | 4.37 | 5.06 | 0.04 |
| ELEC4/3F32T8/IS/occupancy sensor | 2 EL4/3_LGO | 4.37 | 5.06 | 0.45 |
| 60W HIR flood + trg mgmt system | 4 INCR_LGO | 4.56 | 5.28 | 0.04 |
| 60W HIR flood + trg mgmt system | 4 INCR_RET | 4.56 | 5.28 | 0.12 |
| 60W HIR flood + trg mgmt system | 4 INCR_RST | 4.56 | 5.28 | 0 |
| ELEC8/2F96T12/ES/occupancy sensor | 3 EM8/2_SCH | 4.6 | 5.33 | 0.02 |
| ELEC8/2F96T12/ES/occupancy sensor | 3 EM8/2_MSC | 4.6 | 5.33 | 0.02 |
| ELEC8/2F96T12/ES/occupancy sensor | 3 EM8/2_SMC | 4.6 | 5.33 | 0.07 |
| ELEC8/2F96T12/ES/occupancy sensor | 3 EM8/2_WRI | 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 |
| ELEC8/2F96T12/ES/trg mgmt system | 4 EM8/2_RST | 4.98 | 5.77 | 0 |
| ELEC8/2F96T12/ES/trg mgmt system | 4 EM8/2_LGO | 4.98 | 5.77 | 0.06 |
| ELEC8/2F96T12/ES/trg mgmt system | 4 EM8/2_RET | 4.98 | 5.77 | 0.44 |

Lighting

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|---|---|---|---|---|---|
| ELEC8/2F96T12/ES/nrg mgmt system | 4 | EM8/2_LDG | 4.98 | 5.77 | 0.01 |
| ELEC8/2F96T12/ES/nrg 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 |
| ELEC4/4F32T8/IS/time switch | 3 | EM4/4_SCH | 5.24 | 6.07 | 0.02 |
| ELEC4/4F32T8/IS/time switch | 3 | EM4/4_MSC | 5.24 | 6.07 | 0.01 |
| ELEC4/4F32T8/IS/time switch | 3 | EM4/4_SMC | 5.24 | 6.07 | 0.05 |
| ELEC4/4F32T8/IS/time switch | 3 | EM4/4_WRJ | 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 |
| ELEC8/2F96T12/ES/time switch | 2 | EM8/2_SCH | 5.35 | 6.20 | 0.01 |
| ELEC8/2F96T12/ES/time switch | 2 | EM8/2_MSC | 5.35 | 6.20 | 0 |
| ELEC8/2F96T12/ES/time switch | 2 | EM8/2_SMC | 5.35 | 6.20 | 0.01 |
| ELEC8/2F96T12/ES/time switch | 2 | EM8/2_WRJ | 5.35 | 6.20 | 0.03 |
| ELEC4/4F32T8/IS/time switch | 4 | EM4/4_COL | 5.47 | 6.34 | 0.01 |
| ELEC4/4F32T8/IS/time switch | 4 | EM4/4_RET | 5.47 | 6.34 | 0.11 |
| ELEC4/4F32T8/IS/time switch | 4 | EM4/4_LGO | 5.47 | 6.34 | 0.06 |
| ELEC4/4F32T8/IS/nrg mgmt system | 6 | EM4/4_COL | 5.51 | 6.38 | 0.06 |
| ELEC4/4F32T8/IS/nrg mgmt system | 6 | EM4/4_RET | 5.51 | 6.38 | 0.35 |
| ELEC4/4F32T8/IS/nrg mgmt system | 6 | EM4/4_LGO | 5.51 | 6.38 | 0.33 |
| ELEC8/2F96T12/ES | 1 | EM8/2_HLT | 5.53 | 6.41 | 0.05 |
| ELEC8/2F96T12/ES | 1 | EM8/2_GRC | 5.53 | 6.41 | 0.2 |
| ELEC4/4F32T8/IS/occupancy sensor | 4 | EM4/4_SCH | 5.58 | 6.46 | 0.07 |
| ELEC4/4F32T8/IS/occupancy sensor | 4 | EM4/4_MSC | 5.58 | 6.46 | 0.04 |
| ELEC4/4F32T8/IS/occupancy sensor | 4 | EM4/4_SMC | 5.58 | 6.46 | 0.25 |
| ELEC4/4F32T8/IS/occupancy sensor | 4 | EM4/4_WRJ | 5.58 | 6.46 | 0.07 |
| ELEC8/2F96T12/ES | 1 | EM8/2_LDG | 5.96 | 6.90 | 0.08 |
| ELEC8/2F96T12/ES | 1 | EM8/2_RST | 5.96 | 6.90 | 0.05 |
| ELEC8/2F96T12/ES | 1 | EM8/2_LGO | 5.96 | 6.90 | 0.19 |
| ELEC8/2F96T12/ES | 1 | EM8/2_COL | 5.96 | 6.90 | 0.04 |
| ELEC8/2F96T12/ES | 1 | EM8/2_RET | 5.96 | 6.90 | 1.16 |
| ELEC8/2F96T12/ES/time switch | 2 | EM8/2_RST | 6.35 | 7.35 | 0 |
| ELEC8/2F96T12/ES/time switch | 2 | EM8/2_LGO | 6.35 | 7.35 | 0.01 |
| ELEC8/2F96T12/ES/time switch | 2 | EM8/2_RET | 6.35 | 7.35 | 0.11 |
| ELEC8/2F96T12/ES/time switch | 2 | EM8/2_LDG | 6.35 | 7.35 | 0 |
| ELEC8/2F96T12/ES/time switch | 2 | EM8/2_COL | 6.35 | 7.35 | 0 |
| ELEC8/2F96T12/ES | 1 | EM8/2_SCH | 6.52 | 7.55 | 0.09 |
| ELEC8/2F96T12/ES | 1 | EM8/2_MSC | 6.52 | 7.55 | 0.23 |
| ELEC8/2F96T12/ES | 1 | EM8/2_SMC | 6.52 | 7.55 | 0.19 |
| ELEC8/2F96T12/ES | 1 | EM8/2_WRJ | 6.52 | 7.55 | 0.29 |
| ELEC4/4F32T8/IS | 2 | EM4/4_SCH | 6.74 | 7.81 | 0.15 |
| ELEC4/4F32T8/IS | 2 | EM4/4_MSC | 6.74 | 7.81 | 0.21 |
| ELEC4/4F32T8/IS | 2 | EM4/4_SMC | 6.74 | 7.81 | 0.35 |
| ELEC4/4F32T8/IS | 2 | EM4/4_WRJ | 6.74 | 7.81 | 0.09 |
| ELEC4/3F32T8/IS/time switch | 1 | EL4/3_SCH | 7.01 | 8.12 | 0.02 |
| ELEC4/3F32T8/IS/time switch | 1 | EL4/3_MSC | 7.01 | 8.12 | 0 |
| ELEC4/3F32T8/IS/time switch | 1 | EL4/3_SMO | 7.01 | 8.12 | 0.04 |
| ELEC4/3F32T8/IS/time switch | 1 | EL4/3_WRH | 7.01 | 8.12 | 0.03 |
| ELEC4/4F32T8/IS | 2 | EM4/4_COL | 7.02 | 8.13 | 0.08 |
| ELEC4/4F32T8/IS | 2 | EM4/4_RET | 7.02 | 8.13 | 0.46 |
| ELEC4/4F32T8/IS | 2 | EM4/4_LGO | 7.02 | 8.13 | 0.45 |
| ELEC8/2F96T12/ES/nrg mgmt system | 4 | EM8/2_SCH | 7.1 | 8.22 | 0.02 |
| ELEC8/2F96T12/ES/nrg mgmt system | 4 | EM8/2_MSC | 7.1 | 8.22 | 0.02 |
| ELEC8/2F96T12/ES/nrg mgmt system | 4 | EM8/2_SMC | 7.1 | 8.22 | 0.04 |
| ELEC8/2F96T12/ES/nrg mgmt system | 4 | EM8/2_WRJ | 7.1 | 8.22 | 0.11 |
| ELEC4/4F32T8/IS | 2 | EM4/4_RST | 7.14 | 8.27 | 0.05 |
| ELEC4/4F32T8/IS | 2 | EM4/4_LDG | 7.14 | 8.27 | 0.14 |
| ELEC4/4F32T8/IS/nrg mgmt system | 5 | EM4/4_SCH | 7.17 | 8.30 | 0.07 |
| ELEC4/4F32T8/IS/nrg mgmt system | 5 | EM4/4_MSC | 7.17 | 8.30 | 0.03 |
| ELEC4/4F32T8/IS/nrg mgmt system | 5 | EM4/4_SMC | 7.17 | 8.30 | 0.22 |
| ELEC4/4F32T8/IS/nrg mgmt system | 5 | EM4/4_WRJ | 7.17 | 8.30 | 0.06 |
| ELEC4/4F32T8/IS | 2 | EM4/4_HLT | 7.31 | 8.47 | 0.2 |
| ELEC4/4F32T8/IS | 2 | EM4/4_GRC | 7.31 | 8.47 | 0.04 |
| ELEC4/3F32T8/IS/occup. sensor | 2 | EL4/3_SCH | 7.31 | 8.47 | 0.07 |
| ELEC4/3F32T8/IS/occup. sensor | 2 | EL4/3_MSC | 7.31 | 8.47 | 0.03 |
| ELEC4/3F32T8/IS/occup. sensor | 2 | EL4/3_SMO | 7.31 | 8.47 | 0.21 |
| ELEC4/3F32T8/IS/occup. sensor | 2 | EL4/3_WRH | 7.31 | 8.47 | 0.12 |
| ELEC4/3F32T8/IS/time switch | 1 | EL4/3_COL | 7.35 | 8.51 | 0.02 |
| ELEC4/3F32T8/IS/time switch | 1 | EL4/3_RET | 7.35 | 8.51 | 0.19 |
| ELEC4/3F32T8/IS/time switch | 1 | EL4/3_LGO | 7.35 | 8.51 | 0.07 |
| ELEC4/3F32T8/IS/nrg mgmt system | 3 | EL4/3_COL | 7.39 | 8.56 | 0.1 |
| ELEC4/3F32T8/IS/nrg mgmt system | 3 | EL4/3_RET | 7.39 | 8.56 | 0.57 |
| ELEC4/3F32T8/IS/nrg mgmt system | 3 | EL4/3_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 |

| | | | | | |
|---|---|---|---|---|---|
| CCUT4/2F40T12/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 |
| CCUT4/2F40T12/ES/RE + nrg mgmt system | 3 | EM4/2_RST | 8.6 | 9.96 | 0.01 |
| CCUT4/2F40T12/ES/RE + nrg mgmt system | 3 | EM4/2_LDG | 8.6 | 9.96 | 0.05 |
| ELEC4/3F32T8/IS/nrg mgmt system | 3 | EL4/3_SCH | 9.52 | 11.03 | 0.07 |
| ELEC4/3F32T8/IS/nrg mgmt system | 3 | EL4/3_MSC | 9.52 | 11.03 | 0.03 |
| ELEC4/3F32T8/IS/nrg mgmt system | 3 | EL4/3_SMO | 9.52 | 11.03 | 0.14 |
| ELEC4/3F32T8/IS/nrg mgmt system | 3 | EL4/3_WRH | 9.52 | 11.03 | 0.1 |
| CCUT4/2F40T12/ES/RE + occupancy sensor | 3 | EM4/2_SCH | 11.41 | 13.22 | 0.12 |
| CCUT4/2F40T12/ES/RE + occupancy sensor | 3 | EM4/2_MSC | 11.41 | 13.22 | 0.04 |
| CCUT4/2F40T12/ES/RE + occupancy sensor | 3 | EM4/2_SMC | 11.41 | 13.22 | 0.12 |
| CCUT4/2F40T12/ES/RE + occupancy sensor | 3 | EM4/2_WRJ | 11.41 | 13.22 | 0.04 |
| 60W HIR flood + nrg mgmt system | 4 | INCR_SMO | 11.84 | 13.71 | 0.02 |
| 60W HIR flood + nrg mgmt system | 4 | INCR_WRH | 11.84 | 13.71 | 0.03 |
| 60W HIR flood + nrg mgmt system | 4 | INCR_HLT | 11.84 | 13.71 | 0 |
| CCUT4/2F40T12/ES/RE + time switch | 2 | EM4/2_SCH | 12.96 | 15.01 | 0.04 |
| CCUT4/2F40T12/ES/RE + time switch | 2 | EM4/2_MSC | 12.96 | 15.01 | 0.01 |
| CCUT4/2F40T12/ES/RE + time switch | 2 | EM4/2_SMC | 12.96 | 15.01 | 0.03 |
| CCUT4/2F40T12/ES/RE + time switch | 2 | EM4/2_WRJ | 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 |
| CCUT4/2F40T12/ES/RE + nrg mgmt system | 4 | EM4/2_COL | 13.7 | 15.87 | 0.1 |
| CCUT4/2F40T12/ES/RE + nrg mgmt system | 4 | EM4/2_RET | 13.7 | 15.87 | 0.26 |
| CCUT4/2F40T12/ES/RE + nrg mgmt system | 4 | EM4/2_LGO | 13.7 | 15.87 | 0.2 |
| ELEC4/2FT32T8/IS+nrg mgmt system | 6 | EM4/2_RST | 13.77 | 15.95 | 0 |
| ELEC4/2FT32T8/IS+nrg mgmt system | 6 | EM4/2_LDG | 13.77 | 15.95 | 0.01 |
| CCUT4/2F40T12/ES/RE + time switch | 2 | EM4/2_COL | 14.3 | 16.56 | 0.02 |
| CCUT4/2F40T12/ES/RE + time switch | 2 | EM4/2_RET | 14.3 | 16.56 | 0.09 |
| CCUT4/2F40T12/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+nrg mgmt system | 8 | EM4/2_COL | 14.6 | 16.91 | 0.02 |
| ELEC4/2FT32T8/IS+nrg mgmt system | 8 | EM4/2_RET | 14.6 | 16.91 | 0.05 |
| ELEC4/2FT32T8/IS+nrg 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 + nrg mgmt system | 4 | INCR_MSC | 15.57 | 18.03 | 0 |
| 60W HIR flood + nrg mgmt system | 4 | INCR_SCH | 15.57 | 18.03 | 0 |
| 60W HIR flood + nrg mgmt system | 4 | INCR_COL | 15.57 | 18.03 | 0 |
| CCUT4/2F40T12/ES/RE + occupancy sensor | 3 | EM4/2_HLT | 16.27 | 18.84 | 0.01 |
| CCUT4/2F40T12/ES/RE + occupancy sensor | 3 | EM4/2_GRC | 16.27 | 18.84 | 0 |
| CCUT4/2F40T12/ES/RE + nrg mgmt system | 4 | EM4/2_SCH | 16.31 | 18.89 | 0.12 |
| CCUT4/2F40T12/ES/RE + nrg mgmt system | 4 | EM4/2_MSC | 16.31 | 18.89 | 0.03 |
| CCUT4/2F40T12/ES/RE + nrg mgmt system | 4 | EM4/2_SMC | 16.31 | 18.89 | 0.08 |
| CCUT4/2F40T12/ES/RE + nrg mgmt system | 4 | EM4/2_WRJ | 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_WRJ | 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+nrg mgmt system | 8 | EM4/2_SCH | 17.02 | 19.71 | 0.02 |
| ELEC4/2FT32T8/IS+nrg mgmt system | 8 | EM4/2_MSC | 17.02 | 19.71 | 0.01 |
| ELEC4/2FT32T8/IS+nrg mgmt system | 8 | EM4/2_SMC | 17.02 | 19.71 | 0.02 |
| ELEC4/2FT32T8/IS+nrg mgmt system | 8 | EM4/2_WRJ | 17.02 | 19.71 | 0.01 |
| CCUT4/2F40T12/ES/RE | 1 | EM4/2_HLT | 17.62 | 20.41 | 0.63 |
| CCUT4/2F40T12/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_WRI | 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_LDG | 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 + mg mgmt system | 5 | INC_GRC | 25.81 | 29.89 | 0.01 |
| separable CFL + mg 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_WRI | 26.29 | 30.45 | 0.01 |
| CCUT4/2F40T12/ES/RE + mg mgmt system | 4 | EM4/2_HLT | 26.8 | 31.04 | 0.01 |
| CCUT4/2F40T12/ES/RE + mg mgmt system | 4 | EM4/2_GRC | 26.8 | 31.04 | 0.03 |
| separable CFL + mg mgmt system | 5 | INC_COL | 28.65 | 33.18 | 0.02 |
| separable CFL + mg mgmt system | 5 | INC_RET | 28.65 | 33.18 | 0.13 |
| separable CFL + mg mgmt system | 5 | INC_RST | 28.65 | 33.18 | 0.01 |
| separable CFL + mg mgmt system | 5 | INC_LDG | 28.65 | 33.18 | 0.02 |
| separable CFL + mg 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 + mg mgmt system | 5 | INC_MSC | 42.24 | 48.92 | 0.02 |
| 20W screw-in CFL + mg mgmt system | 5 | INC_SCH | 42.24 | 48.92 | 0.02 |
| 20W screw-in CFL + mg mgmt system | 5 | INC_SMO | 42.24 | 48.92 | 0.03 |
| 20W screw-in CFL + mg 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_LDG | 42.38 | 49.09 | 0.01 |
| separable CFL + time switch | 3 | INC_LGO | 42.38 | 49.09 | 0.01 |
| ELEC8/2F96T12/ES/time switch | 2 | EM8/2_GRC | 45.62 | 52.84 | 0 |
| ELEC8/2F96T12/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 HIR flood + time switch | 2 | INCR_LDG | 74.85 | 86.69 | 0 |
| 60W HIR 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 |
| CCE $/MMBtu | | -18.16 | | | |
| % savings rel. to 1997 | | 25.3% | | | |

# 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% (0.5 quads) 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. |

Refrigeration

**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.

ASSUME 1995 $ (COULDN'T FIND IT IN THE REPORT)

| | 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 | 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 | THIS CONVERSION FACTOR IS ONLY USED TO CONVERT ADL TBUS TO KWH. |
| | 3.185 | |
| 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 Scenarios of U. S. Carbon Reductions
# 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. |

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# Interlab Study on Scenarios of U. S. Carbon Reductions

# APPENDIX C-4

## Energy Savings Potential for Miscellaneous Energy Uses

# APPENDIX C-4

## C-4.1 ENERGY SAVING POTENTIAL FOR MISCELLANEOUS ENERGY USES

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 C-4.1 below shows the summary results of our calculations.

**Table C-4.1 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.

## C-4.2 FUEL SWITCHING IN RESIDENTIAL BUILDINGS

This memo summarizes our calculations of impacts 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 on 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 C-4.1). 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 C-4.1). 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 C-4.2 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 |

## C-4.3 DIRECT AND INDIRECT IMPACTS FROM HIGH ALBEDO ROOFS

We used the Heat Island Group's latest DOE-2 analyses of direct effects of high albedo roofs (Konopacki et al. 1997) and boiled their results down to two parameters in residential and commercial buildings: 1) the percentage change in total electrical cooling use (direct effects only) associated with high albedo roofing, and 2) the number of kBtu that gas heating use goes up per kBtu of site electricity saved in cooling. We divided the sector savings estimated by Konopacki et al. by the 1997 cooling energy consumption for residential and commercial sectors from the AEO97 to derive direct percentage savings factors shown in Table C-4.2.

To account for indirect savings from roofing associated with the decrease in ambient temperatures caused by large-scale implementation of cool roofing, we add an additional 50% to the cooling savings (so the commercial savings percentage becomes 3.4% instead of 2.3%). This savings reflects the results shown in Rosenfeld et al. (1996).

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 C-4.3 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 C-4.3 Summary of High Albedo Roofing Calculations

| End-use Category | Direct Cooling energy use savings (Percent) | Indirect Cooling energy use savings (Percent) | Total Cooling energy use savings (Percent) | kBtu gas use increase per kBtu cooling elect. saved (site) | Incremental unit costs ($1995) |
|---|---|---|---|---|---|
| *Residential* | 5.7% | 2.9% | 8.6% | 0.77 | $0 |
| *Commercial* | 2.3% | 1.1% | 3.4% | 0.66 | $0 |

## C-4.4 REFERENCES

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# APPENDIX D

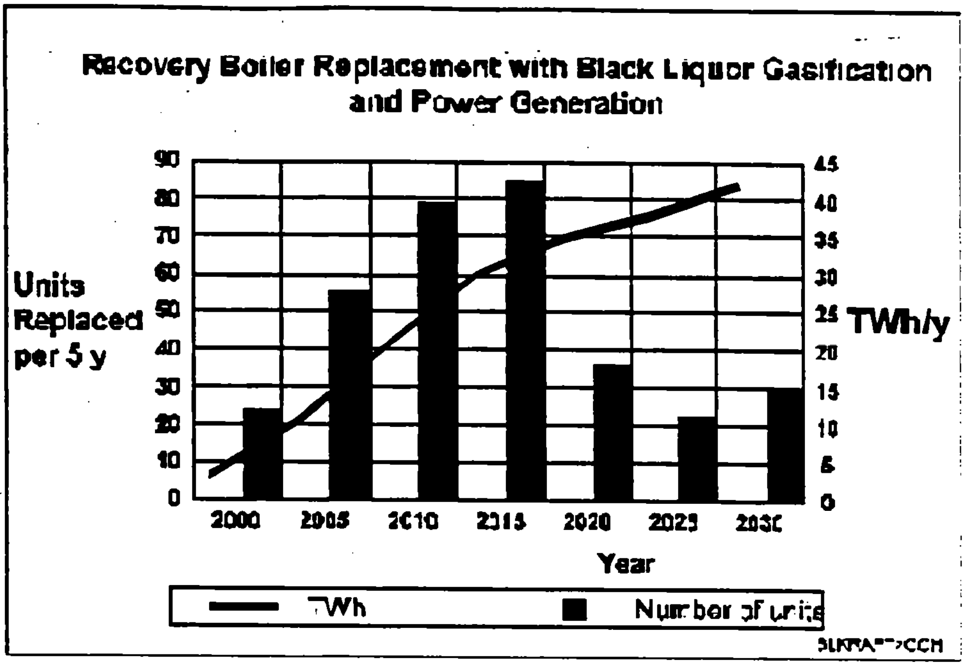


Figure D-4.1 Projected Market Penetration and Power Generation From Black Liquor Integrated Gasification Combined Cycle Use

The annual rate of carbon offset is of course a function of the assumption that all of the current recovery boiler fleet is generating electricity at about 15% efficiency (a pessimistic assumption as it reduces the net benefit) and that the offset for current coal-fired generation is valued at $2.51.10^{-7}$ tonne-C/Wh. On this basis, the 2010 displacement is 5.2 MtC equivalent per year, and the 2020 displacement is 8.7 MtC equivalent per year.

A conservative analysis could preserve the initial penetration rate predicated on 10–50% of the units to be retrofitted to black liquor gasification and assume that 50% is the maximum penetration of this technology (instead of total substitution). Numbers of units replaced in these blocks of time become 14, 29, and 42 respectively for 2000, 2005, and 2010. Such replacements would generate half of the amount of carbon savings, or 2.6 MtC equivalent per year, by 2010. Ultraconservative assumptions could slow the penetration again by 50%, ending at a final penetration rate of 25%, resulting in carbon savings of 1.3 MtC equivalent per year by 2010.

# APPENDIX D-4

## KRAFT PULP RECOVERY BOILER REPLACEMENT RATE

The pulp and paper industry is already at the leading edge of a capital replacement problem in its kraft pulp mills that use chemical recovery boilers (sometimes called Tomlinson Boilers after their developer). The majority of the fleet of boilers will reach 40 years of age over the next two decades. While replacement with modern recovery boilers is possible, the industry has invested in the development of an alternative scheme in which the black liquor is gasified; the fuel gases, after removal of $H_2S$ (to regenerate the pulping chemicals), are fired in a combined cycle; and the chemical smelt IS reprocessed into pulping chemicals. Making the assumption that today's recovery boilers generate steam that is used in a back pressure/extraction turbine, the current electricity generation is at an efficiency of 15% which will increase to 30% in the black liquor IGCC scheme. As the amount of black liquor is constant, this assumes that the future industry will engage in significant energy efficiency investments to allow it to proceed with approximately 25% less thermal energy input resulting from the increased electrical output.

In-service dates of the recovery boilers shown in Figure 4.8, Section 4.4.2.1, has been accumulated into 5-year bins. These are presumed to be a set of age cohorts separated by 5 years as shown in Table D-4.1.

As the first two age cohorts are already beyond 40 years, it is understood that the kraft pulp mills are making life extension investments to keep them running until the new technology arrives. For the purposes of market penetration, it is assumed that the 1950 cohort will be retrofitted with 10% black liquor gasification, that of 1955 will be 25% retrofitted as part of life extension, and that the 1960 cohort will be 50% retrofitted. The 1965 cohort maturing in 2005 will all be replaced by black liquor gasification. The three partially retrofitted cohorts will be finally replaced by 2005, 2010, and 2015 respectively, adding to the fleet that will be replaced in those years.

**Table D-4.1 Age Cohorts of Recovery Boilers**

| Year End | Number |
|---|---|
| 1950 | 16 |
| 1955 | 14 |
| 1960 | 36 |
| 1965 | 39 |
| 1970 | 65 |
| 1975 | 49 |
| 1980 | 36 |
| 1985 | 22 |
| 1990 | 30 |
| Total | 307 |

The number of black liquor gasification units brought onstream in each of the five years from 2000 are shown in Figure D-4.1 (the 1990 and 1995 cohorts are included in the 2000 sum). And the 2005, 2010, and 2015 cohorts incorporate the total conversion of those units. The line is the annual amount of electricity that will offset fossil fuel generation outside of the industry (either through self-use, thus displacing power purchases, or export of the incremental generation).

It was assumed that the 307 boilers in the data set up to 1990 represent 80% of today's black liquor heat output of 1094 TBtu. On this assumption each unit of the 307 units replaced is capable of generating an additional 136 GWh/year (approximately 16 MW incremental output per kraft boiler replacement). The resulting generation in each year is shown in Figure D-4.1.

# Interlab Study on Scenarios of U. S. Carbon Reductions

## APPENDIX D-4

## Kraft Pulp Recovery Boiler Replacement Rate

Based on the above detailed analysis of the chemicals and the food industries (Major 1997), Onsite estimates that half of this boiler capacity could be replaced by ATS.

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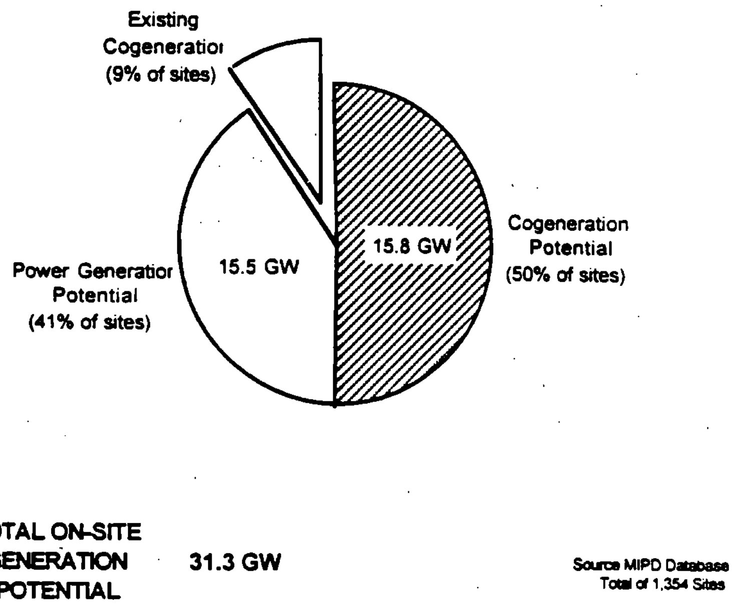
**Figure D-3.3 Total Remaining On-Site Generation Potential in the Chemical Sector**




A similar E/T ratio analysis was performed for the food sector plants represented in the MIPD database. Results indicate a total remaining on-site generation potential of 34.5 GW of which 20 GW is cogeneration potential (see Figure D-3.4). Note that this estimate of 20 GW of technical cogeneration potential exceeds that presented in Figure D-3.2 for the food sector.

**Figure D-3.4 Total Remaining On-Site Generation Potential in the Food Sector**

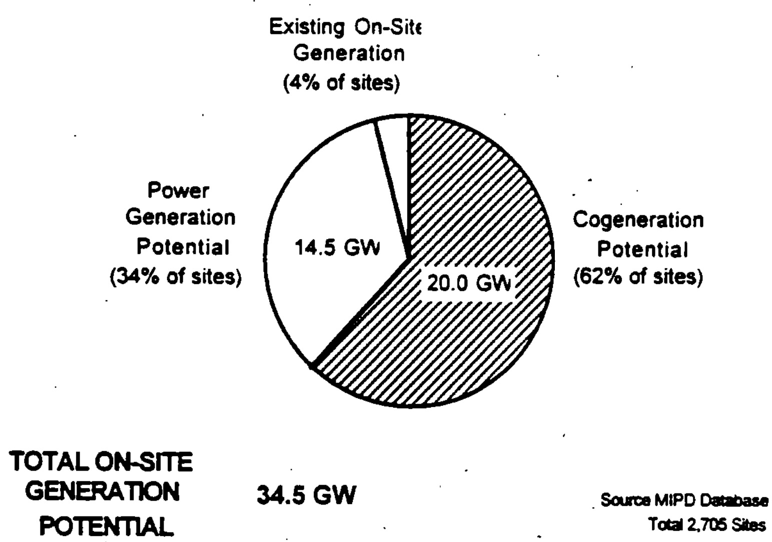
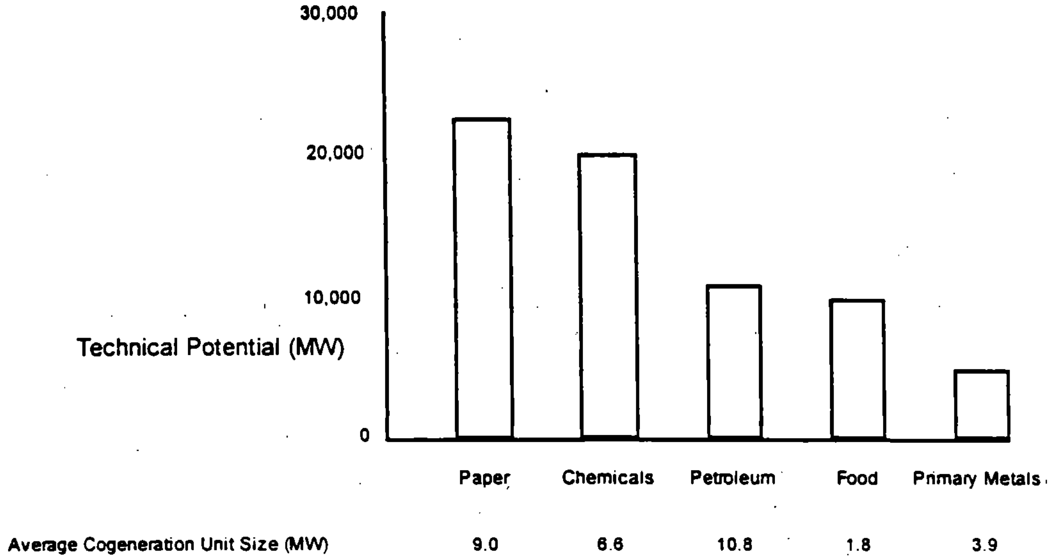


**Figure D-3.2 Cogeneration Technical Potential for Five Major Industrial Sectors**




*New On-Site Generation Potential in the Chemical and Food Sectors Based on E/T Ratio.* Onsite further investigated the total remaining on-site generation potential for two industrial subsectors, chemicals and food, using the MIPD database for each subsector. Instead of referring to boiler capacity for this determination, the ratio of the plant's electric to thermal demand was used. Recognizing the coming competitive market in the electric power industry, this analysis examines the technical potential for both cogeneration and on-site power-only applications. An indicator used to distinguish cogeneration potential from power-only applications is the site's E/T ratio:

$$\text{E/T Ratio} = \frac{\text{Site Electric Demand}}{\text{Site Thermal Demand}}.$$

Calculated E/T ratios were segregated into low, medium and high "bins." Sites with low and medium E/T ratios are assumed suitable for cogeneration while sites with high E/T ratios suggest power-only opportunities.

As shown in Fig. D-3.3, chemical sector results indicate a total remaining on-site generation potential of 31.3 GW of which 15.8 GW is cogeneration potential. The cogeneration potential of 15.8 GW is approximately equivalent to the results obtained by the boiler analysis (as previously shown in Figure D-3.2).

For this analysis, it is assumed that the population of displaced industrial boilers fires natural gas. This should provide conservative results since both oil and coal are frequently used in these applications. Typical seasonally adjusted boiler efficiencies can range from 60-80%. Actual efficiencies depend on heat recovery equipment (economizers, air preheaters), hours at part load operation and maintenance to insure clean boiler surfaces and optimal combustion. Our analysis assumed a boiler efficiency of 70% when determining industrial boiler emission offsets.

$$\text{Industrial Boiler Emission Factor} = \frac{120 \text{ lb/MMBtu (gas)}}{70\% \text{ boiler efficiency}} \times 3.412 \text{ MMBtu/MWh} = 585 \text{ lb/MW}$$

A total emission reduction of 29,700,000 tons of $CO_2$ (8,100,000 tons carbon equivalent) is estimated for the industrial boiler offset.

$$\text{Total Boiler Offset} = \frac{101{,}500{,}000 \text{ MWh} \times 585 \text{ lb/MWh}}{2000 \text{ lb/h}} = 29{,}700{,}000 \text{ tons}.$$

The equivalent emission factor for the industrial boiler offset in terms of electric generation is calculated as follows:

$$\frac{29{,}700{,}000 \text{ tons} \times 2000 \text{ lb/ton}}{160{,}341{,}000 \text{ MWh}} = 370 \text{ lb/MWeh, or } 101 \text{ lb/MWeh (Ce)}$$

As described above, based on the difference between the baseline and ATS, Onsite arrived at an additional carbon savings due to industrial ATS of 30 million (short) tons carbon equivalent, or 27 MtC equivalent. Note that Onsite's boiler offset assumes natural gas boilers, whereas most heavy industrial boilers are coal, oil, or biomass-fired (DAC 1995).

*Onsite Sector-Specific Cogeneration Plus Power-Only Analysis.* Furthermore, ATS will have applicability to industrial markets with little or no steam load which will increase the ATS cogeneration capacity potential. Steam pressure is a function of process requirements. Steam pressure can be as low as 15 psig for low temperature heating, and up to 600–700 psig for combined cycle applications or applications where steam is used to drive a steam turbine.

*Estimation of Fraction of Boilers Suitable for ATS.* Five industries dominate the industrial boiler market: pulp and paper, chemicals, petroleum, food, and primary metals. These five industries represent approximately 47% of the boiler population, 78% of total industrial steam capacity, and 86% of boiler fuel use. A combined technical potential of approximately 70 GW was estimated for these five key industries based on installed boiler capacity as shown below in Figure D-3.2.

***Equivalent Full Load Hours.*** To estimate annual emissions, the number of hours that the sources are emitting must be estimated. Equivalent full load hours for U.S. generating plants were estimated based on the EIA/AEO 1994 as follows (AEO 1994):

$$\text{EFLH} = \frac{3,720,000,000,000,000 \text{ kWh}}{812,000,000 \text{ kW}} = 4580 \text{ hours}.$$

3,720,000 *billion kWh from AEO, 1994, Table F1, p. 165 (2010)*
812 *GW from AEO 1994, Table F1, p. 165 (2010)*

***Fuel Mix.*** The emission reduction estimate assumes that ATS will displace coal, oil and natural gas from utility and non-utility sources. Nuclear and hydropower sources were excluded from the analysis. The basis for the estimate is AEO 1994.

The *overall* fuel mix including all sources was first determined based on the AEO 1994 as follows:

$$\text{Coal} = \frac{\text{Coal}}{\text{Total}} = \frac{(1886 \text{ utility} + 54 \text{ nonutility}) \text{ billion kWh}}{(3260 \text{ utility} + 338 \text{ nonutility}) \text{ billion kWh}} = 54\%,$$

$$\text{Oil} = \frac{\text{Oil}}{\text{Total}} = \frac{(74 \text{ utility} + 0 \text{ nonutility}) \text{ billion kWh}}{(3260 \text{ utility} + 338 \text{ nonutility}) \text{ billion kWh}} = 2\%,$$

$$\text{Natural Gas} = \frac{\text{NG}}{\text{Total}} = \frac{(373 \text{ utility} + 144 \text{ nonutility}) \text{ billion kWh}}{(3260 \text{ utility} + 338 \text{ nonutility}) \text{ billion kWh}} = 14\%.$$

Then, the total generation mix from coal, oil, and gas is equal to:

$$54\% + 2\% + 14\% = 70\%.$$

The above calculated percentages were then adjusted to reflect the generation mix assuming that ATS displaces only coal, oil and natural gas sources.

$$\text{Coal} = \frac{54\%}{70\%} = 77\%,$$

$$\text{Oil} = \frac{2\%}{70\%} = 2.9\%,$$

$$\text{Natural Gas} = \frac{14\%}{70\%} = 20\%.$$

***Industrial Boiler Offset.*** The total industrial boiler emission offset assumes that 25% of the total ATS fuel input can be recovered as useful heat. The following calculations support the information presented in Table D-3.7.

$$\text{Total Heat Recovered from ATS} = \text{Fuel Input} \times 25\%, \text{ or}$$

$$\frac{35,000,000 \text{ kW} \times 9000 \text{ Btu/kWh} \times 4,580 \text{ hours}}{1,000,000 \text{ Btu/MMBtu} \times 3.412 \text{ MMBtu/MW}} \times 25\% = 101,500,000 \text{ MWh}.$$

Table D-3.6 $CO_2$ Emission Comparison Assuming 35 GW Displacement of U.S. Generation Mix and Industrial Sources with ATS (tonnes C)

| | | | | | | Emission Source | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | Combustion | | T&D Losses* | | Boiler Offset | | Combined | |
| Generation Technology | Capacity, MW | Hours | Electric Heat Rate (HHV), Btu/kWh | Generation Mix | Annual Electric Generation, (1000) Mwh | Emission Factor, lb/MWeh | Emissions, 1000 tons | Emission Factor, lb/MWeh | Emissions, 1000 tons | Emission Factor, lb/MWeh | Emissions, 1000 tons | Emission Factor, lb/MWeh | Emissions, 1000 tons |
| Displaced Sources | | | | | | | | | | | | | |
| Coal-Boiler/Turbine | 35 | 4,581 | 10,300 | 77.1% | 123,690 | 598 | 36,990 | 30 | 1,855 | 101** | 6,254 | 729 | 45,098 |
| Oil-Boiler/Turbine | 35 | 4,581 | 10,300 | 2.9% | 4,581 | 506 | 1,159 | 25 | 58 | 101** | 232 | 632 | 1,448 |
| Gas-Boiler/Turbine | 35 | 4,581 | 10,300 | 20.0% | 32,070 | 337 | 5,411 | 17 | 271 | 101** | 1,620 | 455 | 7,301 |
| Total Displaced Sources | | | | 100.0% | 160,341 | 543 | 43,560 | 27 | 2,185 | 101** | 8,105 | 672 | 53,847 |
| Gas-ATS | | | 9,000 | 100.0% | 160,341 | 295 | 23,635 | | | | | 295 | 23,635 |
| Emission Reduction | | | | | | | | | | | | | 30,213 |

*T&D loss assumed equivalent to 5% of combustion emissions.

**Based on a $CO_2$ combustion emission factor of 160 lbs/MWth (Ce) for an industrial boiler.

Onsite then calculated the displaced emissions of industrial boilers and the 2010 electricity grid as shown in Table D-3.6. The industrial ATS used for cogeneration can reduce $CO_2$ emissions by displacing electric generating sources and industrial boilers. Onsite's analysis assumes that the displaced electric generating sources include both utility and non-utility sources firing coal, oil and natural gas. The emission reduction includes a combustion component and a T&D component. Power generated by ATS will not incur a loss to transmit power over long distances since ATS will be located close to load centers. With cogeneration, the ATS will displace industrial boilers by recovering heat in the gas turbine exhaust for steam production.

The target for ATS deployment is estimated at 35 GW by the year 2010. This target assumes that by the year 2010, there will be approximately 90 GW of potential for industrial gas turbines and competing cogeneration technologies and that ATS can capture approximately one-third of this market.

Reduction in $CO_2$ emissions is estimated to be approximately 27 MtC ( converting from short tons in Table D-3.6) equivalent assuming displacement of 35 GW of coal-, oil-, and gas-fired generating sources, and including a T&D loss and industrial boiler offset. The details of this estimated reduction are shown in Table D-3.6 that reflects reduction in tons of carbon equivalent. Some of the assumptions used to develop these tables are explained below.

assumes that the cost of equity for non-utilities is 1.5 percentage points higher than that for utilities, while the cost of debt to non-utilities is 0.75 percentage points higher.

generating capacity, one-half of the installed boiler capacity was used to account for boiler utilization (see Onsite Sector-Specific Cogeneration Plus Power-Only Analysis Section on page 3.13)(load fluctuations and redundancy).

Onsite then calculated the equivalent electric generating capacity for these boilers from the electric/thermal (E/T) ratios. For those boilers that would produce electricity in the industrial ATS range (1-40 MW), Onsite then estimated the fraction that could use ATS for this purpose. Total cogeneration potential in the ATS size range is determined as shown in the following equations. Note that Onsite assumes a simple-cycle industrial ATS with an E/T ratio of 0.6. The E/T ratio for recuperative ATS is approximately 1.0.

$$\frac{E}{T} = 0.6 = \frac{\text{Cogeneration Potential (MW)} \times 3.412 \text{ MMBtu/h/MW}}{700{,}000 \text{ MMBtu/h} \times 0.5 \text{ Capacity Factor}}$$

The boiler capacity utilization factor of major industrial sectors was estimated at between 45–50% based on the MIPD database. It was calculated as actual steam production divided by maximum annual steam production. Capacity utilization efficiencies of cogeneration plants are generally higher and can approach 85-90%.

$$\text{Cogeneration Potential (MW)} = \frac{700{,}000 \text{ MMBtu/h} \times 0.5 \times 0.6}{3.412 \text{ MMBtu/h/MW}} = 60{,}000 \text{ MW}.$$

Onsite's electric capacity potential is thus approximately 60 GW for the ATS and competitive technologies given an eventual product portfolio from 1-25 MW and system configurations that typically comprise multiple turbine units.

**Estimates in the Year 2010.** Assuming industrial growth of 1.5% per year for the next 18 years (using a 1992 baseline), the estimated growth of the ATS market can be adjusted by the following factor:

$$\text{Escalation Factor} = (1 + 0.015)^{(2010-1992)} = 1.3\,.$$

Then, total boiler capacity for the non-cogeneration steam market in 2010 is equal to

$$1.3 \times 1{,}000{,}000 \text{ MMBtu/h} = 1{,}300{,}000 \text{ MMBtu/h}$$

and the ATS cogeneration potential in 2010 is equal to

$$1.3 \times 60 \text{ GW} = 78 \text{ GW}\,.$$

Onsite also estimated that there will be an additional 12 GW of potential technical capacity for industrial ATS cogeneration in 2010 in the commercial and light manufacturing sector. Altogether, the ATS technical potential in 2010 is 90 GW.

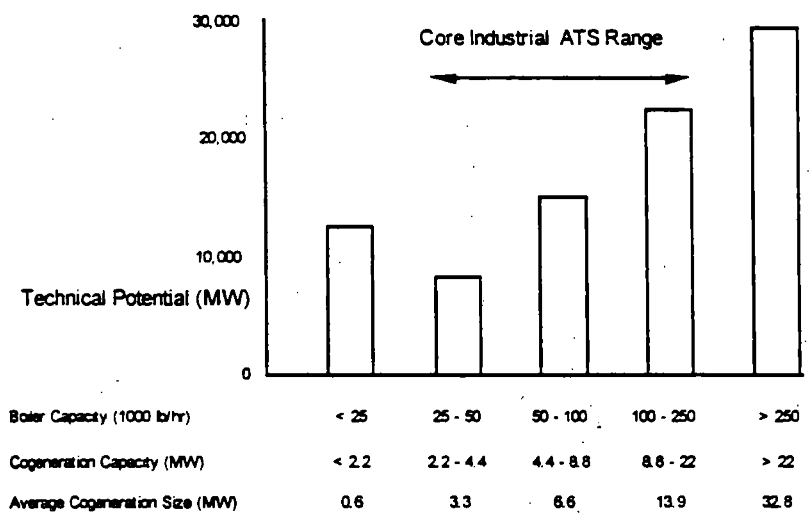
Based on the market projection estimates of Solar Turbines, and assuming that Solar Turbines captures one-third of the ATS market by 2010, Onsite estimates that ATS will be responsible for 35 GW of industrial electric cogeneration capacity (Carroll 1997, Major 1997). Presumably this proprietary Solar Turbines analysis contains some of the same factors considered by the AEO analysis that Energetics used, but this cannot be checked[6].

[6] AEO97 states that non-utility generators have a highly leveraged capital structure compared to that of investor-owned regulated utilities. AEO assumes that the financial structure of non-utilities is 80% debt and 20% equity. It also

will replace industrial boilers. First, electric utility restructuring favors on-site generation because customers will have energy supply choices. In a competitive electric market, customers will always seek low cost solutions. There are adequate natural gas supplies to support increased cogeneration in place of boilers. Second, once environmental regulations on industrial emissions take a life cycle approach and consider power plant emissions, ATS will be environmentally preferable. It has the lowest emissions of both NOx and $CO_2$ per unit of energy (600 lb $CO_2$/MWh) (see figure 4.3.3) of any power technology. In the coming restructured electric utility industry, new capacity additions will be required. Onsite states that efficient, environmentally benign cogeneration will have compelling market value to end users, distribution companies, power marketers and the environmental community. Onsite expects that future penetration, given the huge technical potential not yet served by cogeneration, will exceed the historical industrial market penetration, particularly for smaller power technologies principally sized to meet internal energy requirements. If other sector impacts, such as carbon ordered dispatching, are considered, the replacement of boilers by ATS cogeneration would be greatly accelerated. Thus, Onsite contends that historically based estimates do not apply in this situation.

*New Industrial Cogeneration Potential Based on Installed Boiler Capacity.* New cogeneration potential is approximated by matching boiler capacity with the thermal output of a gas turbine. This steam boiler capacity estimate was drawn from the Major Industrial Plant Database (MIPD) (Petroleum Information Corporation). The MIPD database consists of 20,000 U.S. industrial plants and accounts for approximately 90% of all industrial energy use. Plants currently cogenerating were excluded from the analysis. The resulting industrial cogeneration market potential is illustrated in Figure D-3.1.

Figure D-3.1 Industrial Boiler Market Cogeneration Technical Potential




The total boiler capacity for the non-cogeneration industrial steam market is approximately 1,000,000 MMBtu/h. The core market for the industrial ATS is indicated in Figure D-3.1 for boiler capacities between 25-250 MMBtu/h (equivalent ATS capacity is 2.2-22 MW). To account for multiple engine installations, a portion of the far right column ( greater than 250 MMBtu/h) was included in the ATS market potential. Onsite estimates that a large percentage of the total boiler capacity 700,000 MMBtu/h, or 70%. could be an industrial ATS market These are boilers that fit the size range for the ATS industrial gas turbine. A total ATS technical potential with GW for the ATS and competitive technologies was estimated for an eventual product portfolio from 1-25 MW and system configurations that typically comprise multiple turbine units. When determining equivalent electric

Energetics' analysis estimates that industrial-scale ATS will be used in 39 GW of this market (5% of the total). Energetics notes that recent utility industry trends toward greatly extending plant lifetimes where possible lowers their estimate. They note that carbon reduction policy changes could potentially affect this trend.

Energetics also calculates carbon reductions for two types of biomass markets. First, there is the small new capacity market comprising 1% of all new electrical generating capacity projected by AEO96 in which coal-steam and combustion turbine/diesel segments (utility and non-utility) will be replaced by biomass (an assumption based on a law requiring that 1% of new electrical generating capacity in California be biomass-fueled). This accounts for only 0.1 MtC equivalent or 0.2 GW of electrical capacity. Second, there is the replacement of the existing biomass cogeneration capacity in the forest products industry by ATS coupled to a biomass gasification equipment during the period 2000–2010. This is much larger, comprising 2.4 MtC equivalent carbon reduction or 5 GW of no-carbon capacity.

***Carbon Reduction Calculation.*** Table D-3.5 shows the electric capacity for new (nc) and replacement (repl) capacity in these markets. In order to calculate the carbon reductions due to ATS, Energetics calculated carbon reductions for displacement of coal steam and gas-fired combustion turbines separately. $CO_2$ reductions were calculated by using the different heat rates (coal steam vs. ATS and combustion vs. ATS), the projected generating capacity, and the estimated service load (6500 hours). Carbon equivalent reduction is calculated from $CO_2$ reduction using the ratio of molecular weights of $CO_2$ and carbon, i.e., 44/12 = 0.27.

**Table D-3.5 Energetic's ATS Electric Generation Potential Capacity and Carbon Reduction Calculation**

| Industrial ATS Market | | ATS Industry Capacity Penetration (MW) | CARBON REDUCTION (MMTCE) |
|---|---|---|---|
| NC-NONUTILITY | coal-steam | 879 | 0.8 |
| | combustion | 14,581 | 3.1 |
| NC-COGEN | coal-steam | 700 | 0.6 |
| | combustion | 3,900 | 1.1 |
| NC-DISTRIBUTED | coal-steam | 1,861 | 1.6 |
| | combustion | 11,450 | 2.5 |
| NC-BIOMASS | coal-steam | 52 | 0.0 |
| | combustion | 291 | 0.0 |
| RE-NONUTILITY | coal-steam | 782 | 0.7 |
| | combustion | 2,833 | 0.6 |
| RE-COGEN9,10 | coal-steam | 3,067 | 2.7 |
| | combustion | 10,633 | 3.0 |
| RE-DISTRIBUTED | coal-steam | 6,082 | 1.8 |
| | gas/oil steam | 16,410 | 0.7 |
| | combustion | 3,230 | 0.2 |
| RE-BIOMASS11 | Tomlinson | 1,215 | 2.6 |
| | Hogged-fuel | 1,150 | 2.4 |
| | **TOTAL** | **79,114** | **24.4** |

***Onsite New Cogeneration Analysis.*** This analysis, conducted for ORNL by Onsite Energy, Inc., (Major and Davidson 1997) is a bottom-up analysis that begins with the steam draw capacity that is currently provided by boilers. It does not consider the cogeneration replacement market or the non-cogeneration (power-only)ATS market. Onsite projects that there are several reasons why cogeneration increasingly strategies to pay for the additional capital costs for the on site system. This could dramatically decrease the payback time. In addition, as efficiency is further maximized, more "low carbon" electricity (which would be less expensive in the HE/LC scenario) could be sold to the grid.

*Energetics Analysis.* An analysis conducted for DOE/OIT by Energetics, Inc., used a top-down approach that relies upon the Annual Energy Outlook (AEO) reference case (developed using the NEMS model). Energetics' market analysis was based on the projected electricity generating capability data given in the Reference Case Forecast in AEO96. Energetics used AEO96 instead of AEO97 because the later source did not break out the non-utility market segment from electricity generation by utilities. Energetics first divided the potential industrial ATS market into new capacity, which describes capacity additions between 2000 and 2010, and replacement capacity which describes retired electrical capacity existing in 2000. Within these new and replacement market types, non-utility, cogeneration, distributed, and biomass market components were estimated. These market components are described in the following paragraphs. Although industrial-sized ATS can be as large as 90 MW in multiple units, this analysis was limited to ATS in plants with less than 50 MW generating capacity. Larger-scale ATS could be used in higher capacity applications by industry, but because there is the potential overlap with utilities, they are excluded from this analysis.

Non-utilities (which exclude cogeneration by definition) are usually small power producers and are specifically defined by criteria given in the Public Utility Regulatory Act of 1978; they include industrial plants, commercial establishments, and institutions generating electrical power primarily for on-site use. It is assumed that industrial ATS equipment will capture 73% of all new capacity additions in the coal-steam boiler and combustion turbine/diesel portions of the non-utility market between 2000 and 2010, and 73% of all capacity replacements within this period. Note that 73% of non-utility electrical generation is owned by industrial firms, according to EIA report; thus, 73% was chosen to limit the market captured by the industrial (small-scale) ATS equipment. This can be considered a proxy for some estimate of how much non-utility electricity generating capacity is small scale and thus a suitable market for direct substitution of industrial ATS equipment. Energetics also assumed that one-third of the installed capacity in 2000 will be retired in the period 2000–2010, consistent with a 30-year lifetime for this type of equipment. Total non-utility electricity generating capacity in 2010 is projected as 66.5 GW in AEO96; Energetics' analysis projects that 19 GW of this total (29%) will use industrial ATS technology by 2010. The projected carbon emission reduction associated with industrial ATS use in this market is based upon consideration of the lower heat rate of ATS equipment plus the switch from coal to gas within the coal-steam market component.

Cogenerators include industrial plants requiring steam and electricity in their operations and other establishments such as hospitals and universities requiring both heat and power. The AEO cogeneration estimates are based on the assumption that the historical relationship between industrial steam demand and cogeneration will continue in the future. The data source for this historical data, EIA's *Annual Non-utility Power Producer Report*, consists of data from approximately 400 cogenerators for 1989–1994. The analysis assumes that industrial ATS will compete successfully with other technologies for new capacity in the coal- and natural gas-fired cogeneration market segments in the period 2000–2010, and will also capture available equipment replacements within these market segments. Equipment replacements are estimated based on an assumed useful lifetime of 30 years for this type of equipment. Total cogeneration capacity is projected by AEO96 for year 2010 at 55.3 GW; the total industrial ATS cogenerating capacity (coal- and natural gas-fired) in 2010 estimated in this analysis is 18.3 GW (33% of the total). The projected carbon emission reduction associated with industrial ATS use in this market is based upon consideration of the higher efficiency of ATS equipment plus the switch from coal to gas in the existing coal-fired cogeneration market segment.

The distributed market component for Energetics' ATS analysis is the public utility system itself. Here, Energetics assumed that small-scale ATS equipment will enter the market and displace some marginal capacity that would otherwise have been supplied by large-scale plants owned by public utilities.

Table D-3.4 Results

| Case | MtC | GW | TWh | TcF |
|---|---|---|---|---|
| Efficiency | 4 - 6 | 24 - 27 | 145 - 165 | 1.3 |
| High-Efficiency / Low-Carbon | 16 - 25 | 45- 51 | 270 - 310 | 2.5 |

Table D-3.4 shows the results of the analysis. Note that the gas demand in the two cases corresponds to 12% and 25% of projected total gas demand in the industrial sector in 2010.

*Comparison with Other Analysis.* The estimates by Energetics and Onsite that we describe later in this appendix[4] are more optimistic than our analysis. Even though they are both only slightly higher in carbon reductions than the high end of our HE/LC case, their authors have described them as "optimistic business as usual" case. Furthermore, each of these analyses only considers part of the total ATS market. It appears, however, that industry analysts have reason to be optimistic. Even though the ATS is 2-3 years from being commercialized, some of the ATS manufacturers already have significant orders for ATS (Parks 1997). Since the average order/delivery time is 18 months, this means that the ATS customers are willing to wait at least 18 additional months for a superior technology. This indicates that the ATS may penetrate far more rapidly than traditional energy technologies.

Our results are, however, quite optimistic compared to a recent report (*Energy Innovations* 1997) by a group of energy efficiency-oriented non-profits. While our analysis predicts as much as 310 TWh additional CHP electric capacity in 2010, this new report, (by a coalition that includes the Alliance to Save Energy and the American Council for an Energy Efficient Economy), predicts no additional penetration of ATS-type systems by 2010. The report states that this is not due to technical issues but to policy issues such as "utility restructuring and the lead time associated with permitting." However, after the report's publication, the industrial chapter author (Elliot 1997), stated that he made this assumption (zero penetration by 2010) to simplify the calculation for the industry sector. He also stated that more realistically, under the report's "innovation" scenario, that there could be roughly 100 TWh additional ATS CHP generation by 2010. Beyond 2010, this report assumes that the policy issues that delayed ATS penetration are resolved,[5] and the ATS technology then penetrates rapidly. By 2020, ATS is assumed to account for an additional 400 TWh capacity, and by 2030, more than 640 TWh. Thus, by 2020, the *Energy Innovations* report is even more optimistic than our HE/LC scenario. Our report does not address policy issues, but focuses on technical and economic potential. In light of this, we believe that these two reports are in rough agreement as to the ATS's technical/economic potential (with *Energy Innovations* slightly more optimistic).

*Additional Aspects of PSEM applied to ATS.* If policy is designed correctly, industrial ATS users will have strong incentives to use it as a PSEM technology. For example, one idea (Romm 1997) is to used the savings from the additional energy efficiency gained by using ATS with CHP and other PSEM

[4] Though these two analyses, show similar carbon reductions, as shown later, they each take a very different approach to estimating them. Energetics maximum technical potential does not explicitly include cogenerators that sell power while Onsite's technical potential allows for all cogenerators to sell power. Other estimates of the maximum technical potential for cogeneration from boilers have been much lower than Onsite's, however, according to a 1995 boiler study (DAC 1995), "The [maximum technical] potential for cogeneration calculated above 35 GW of capacity is a function of technology used. Using the heat rates of 10,000 to 25,000 Btu/kWh in the ABMA database, the thermal or steam to electricity ratios S/E (kWh steam/kWh electric) are typically in the order of 6 to 1 to 10 to 1. Gas turbines with waste heat boilers have S/E ratios roughly 50% of this value (i.e., gas turbines can generate more electricity and less process steam) as a result, the technical potential for cogeneration may be considerably higher than calculated above." ATS's heat rate is at least twice as good. If we substitute the ATS heat rate into the above, we arrive at a total maximum technical capacity of at least 70 GW. Thus, under the high-efficiency/low-carbon scenario, Onsite's and our estimate of the new steam market is quite reasonable, and could be considered conservative.

[5] Several reviewers have commented that substantial penetration of ATS into industrial generation would require the cooperation of the utility sector. One scenario that could be imagined in which they cooperate is that the utilities themselves finance and service these industrial ATS's for CHP and power generation.

## Table D-3.3 Calculation of Advanced Turbine Systems 2010 Market Potential and Carbon Savings for Power-Only and Cogeneration Mode

**ATS Analysis**

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| *Results* | GW | TWhr | MMTCe | Tcf | % total industrial gas use in 2010 | | | | | | | | | |
| **Efficiency Case:** | 22-25 | 145-165 | 4-6 | 1.3 | 12% | | | | | | | | | |
| **HE/LC Case:** | 41-47 | 270-310 | 16-25 | 2.5 | 23% | | | | | | | | | |
| *Assumptions to Change* | | | | | | oil or coal to ng carbon factor he/lc case | 1 533156499 | | | | oiltrac--he/lc | 0.692307 | coaltrac-he/lc | 0.307692 |
| | | | | | | | | | | | | 692 | | 308 |
| Forest Products overlap (TWhr) HE/LC case | 5-10 | Forest Products overlap (GW) HE/LC case | 1-2 | Biomass overlap (%) | 38% | oil or coal to ng carbon factor eff case | 1 277241379 | | ngfrac eff | 0 48 | oiltrac--eff | 0 36 | coaltrac-eff | 0 16 |
| CHP market penetration | 0 70 | ATS CHP - steam boiler delta efficiency high | 15% | ATS CHP- steam boiler delta efficiency low | 10% | Steam Boiler Duty-cycle Hours at 52% (Onsite) | 4581 | 1992-2010 CHP scaleup factor (@1 5% per year) | 1 30 | 1994-2010 increase in BAU cogen (TWhr) | 51 00 | 1994-2010 increase in BAU cogen (GW) | 8 | |
| Power-Only Market penetration | 0 20 | Power Duty-cycle Hours at 75% | 6607 | HE/LC Case g/kWhr grid offset | 160 | Efficiency Case g/kWhr grid offset | 89 | 2010 Industrial Electricity Demand TWhr (BAU) | 1289 | 2010 Industrial Electricity Demand TWhr (EC) | 1183 | 2010 Industrial Electricity Demand TWhr (HELC) | 1094 | |

**High Efficiency Low Carbon Case**

| | 1992 Steam Boiler Demand (MMTBtu/hour) | 2010 Steam Boiler Demand (MMTBtu/hr) | Energy-in (quads) | Energy for Electricity (quads) | CHP Max Generation (TWhr) | CHP Max Capacity (GW) | Less AEO97 Growth (TWhr) | Less AEO97 Growth (GW) | less Biomass Fraction (TWhr) | Less Biomass Fraction (GW) | ATS HELC penetration to CHP (TWhr) | ATS HELC penetration to CHP GW | ATS HE/LC CHP TWh to MtC | ATS HE/LC CHP carbon offset | TcF =quads/ 1 03 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| CHP Market high | 1,000,000 | 1,300,000 | 6 0 | 0 9 | 262 | 40 | 211 | 32 | 131 | 20 | 91 | 14 | 15 | 22 | 2.5 |
| CHP Market low | 1,000,000 | 1,300,000 | 6 0 | 0 6 | 175 | 26 | 124 | 19 | 77 | 12 | 54 | 8 | 9 | 13 | 2.5 |
| | | | | | Total Market (TWhr) | Total Market (GW) | | | | | ATS portion of market (TWhr) | ATS portion of market (GW) | T&D offset (TWhr) | ATS HE/LC PO carbon offset | |
| **Power-Only Market** | | | | | 1094 | 166 | | | | | 219 | 33 | 15 | 2 | |
| **Totals--high** | | | | | 1356 | 205 | | | | | 310 | 47 | | 25 | |
| **Totals--low** | | | | | 1268 | 192 | | | | | 272 | 41 | | 16 | |

**Efficiency Case**

| | Total Market (TWHr) Eff Case | Total Market (GW) Eff Case | | ATS Eff Case penetration to CHP (TWhr) | ATS Eff Case penetration to CHP (GW) | ATS eff CHP TWh to MtC | ATS CHP eff carbon offset |
|---|---|---|---|---|---|---|---|
| CHP Market low | 262 | 40 | | 46 | 7 | 4 | 5 |
| CHP Market high | 175 | 26 | | 27 | 4 | 2 | 3 |
| | | | T&D offset of ATS Eff Case penetration to PO | ATS Eff Case penetration to CHP (TWhr) | ATS Eff Case penetration to CHP (GW) | | ATS eff carbon offset |
| Power only Market | 1183 | | 8 | 118 | 18 | | 0 |
| Totals High | 1183 | | | 164 | 25 | | 6 |
| Totals Low | | | | 145 | 22 | | 4 |

1997). This is the *Energy-In* to the steam boilers. We then calculate what the available electricity is assuming that the same amount of steam is needed. (This is a conservative assumption since it is likely that less steam will be required in 2010 due to other efficiency measures—especially under the efficiency HE/LC case[3].) This factor is probably the most uncertain since we are comparing the future operating efficiencies of boilers (now estimated to be near 70% (Onsite 1997) even though most new boilers are rated over 80%)( Roop 1997) with the future "steam-electric" efficiency of the ATS (now estimated to be 80-85%). The difference between these two efficiencies gives us the electricity available in quads that we convert to TWh. We obtain the corresponding GW hours by using the EIA duty cycle found in AEO97's estimates of future industrial cogeneration potential. This is our maximum CHP potential for 2010. It compares favorably to the estimates used as part of the EIA/NEMS modeling (DAC 1995). We then subtract the cogeneration growth already included in the EIA/NEMS BAU. After which we subtract the fraction of these boilers that are biomass boilers. These are mainly the boilers assumed to be replaced in Section 4.4.3.1.

Then, for the high-efficiency/low-carbon (HE/LC) case we use Onsite's estimate of the total available boiler sites appropriate for ATS as the market penetration. For the efficiency case, similar to Section 4.2.2, we assume that the penetration of ATS in these markets will be half that of the HE/LC case. This efficiency case penetration (33%) is similar to Onsite's own estimate (38%) of the penetration in their "optimistic business -as- usual" case. We then use the carbon intensity of the 2010 grid provided by the Chapter 6 authors to convert from TWh to million metric tons of carbon equivalent (MtC). Since coal, not natural gas will be marginal in the HE/LC case, it is not surprising that the offset carbon intensity is higher than in the efficiency case. Finally, we account for the steam boiler fuel switching. Since we have already subtracted biomass boilers, only gas, oil and coal boilers remain for comparison. Again, the HE/LC gas preferentially replaces higher carbon steam boilers. In the efficiency case we assume that the steam boilers are replaced by natural gas ATSs in proportion to their current distribution (see footnote). In the HE/LC case, we assume that the coal and oil boilers are replaced first.. .

The power-only portion of the calculation has far fewer steps. We begin with the total industrial electricity demand for 2010 in the efficiency or HE/LC case. We then simply assume that the ATS will capture a certain portion. There is no strict quantitative basis for this assumption, however our expert reviewers agreed that 20% was a reasonable number for the HE/LC case and 10% for the efficiency case. Given that the ATS is only commericialized in 2001, this implies a penetration much higher than 20% in the 2005-2010 time frame. It is important to remember that this is an artificial power-only market which includes a component of CHP for which some of the steam is used for extra electricity. As mentioned earlier, we only take credit for transmission and distribution (T&D) Twh. We then convert this to MtC using the appropriate carbon intensity for the efficiency or HE/LC case.

Finally, it is important to note that we have focused on those ATS markets where ATS penetration is most likely to result in substantial carbon savings. For example, we did not examine markets such as cogeneration replacements, where ATS is likely to penetrate.

[3] For example, the ATS itself may further maximize system efficiency by replacing electricity used to drive motors that drive equipment with direct power for the equipment. The "new steam" market could also include "district energy" type combined heat and power sites where businesses group together and share electricity and steam from the same turbine. A recent study (IDEA 1997) shows that of the nearly 6,000 current U. S. district heating installations that generate 1.1Q of energy, 8% are industrial.

The values of *a* and *b* are not well known for the entire market. For analytic purposes we further assume that this "CHP market" consists of all those applications, where the *Energy-In* (see Table D-3.3 4th column), for the maximum potential combined heat and power market, equals the *Energy-In* for all industrial steam boilers. This assumption, though more difficult to understand intuitively, also simplifies the calculation. The sites where the *Energy-In* exceeds the energy for the steam boiler are converted as potentially CHP (for the portion of *Energy-In* equal to the energy for steam) and partially power-only (for the portion of *Energy-In* above that used for the steam boiler). We also assume that the ATS in power-only markets will only save carbon due to avoidance of transmission and distribution losses (7%). This conservative assumption also makes the calculation simpler since there is no need for chapter authors to avoid double counting. As shown in tables D-3.3 and D-3.4, this causes the ATS power-only carbon reductions to be much smaller than others' estimates. This assumption amounts to assuming that the power not being used due to CHP has the same average emissions (on a lbs/MWh basis) as the ATS. Table D-3.2 shows the assumptions and factors needed to work across the calculation shown in Table D-3.3.

**Table D-3.2 Assumptions and Factors Used in Calculation of 2010 ATS Electricity Generation and Carbon Offsets for CHP and PO Markets**

| Assumption/Factor | Efficiency | High-Efficiency/ Low-Carbon |
|---|---|---|
| 1-1992-2010 CHP scaleup factor (@1.5% per year) | 1.3 | |
| 2-Steam Boiler Duty-cycle (Hours per year=52% utilization) (Onsite 1997) | 4581 hours | |
| 3-Difference between ATS CHP and Steam Boiler Efficiency (Onsite 1997) | 10 - 15% | |
| 4-Conversion from quads to TWh (= *293) | 1/.003412 | |
| 5-Power Duty-cycle Hours (AEO97) (Hours per year) | 6607 hours | |
| 6-2010 NEMs BAU case additional Electricity generation from Cogeneration (AEO97) | 51 TWh (8 GW) | |
| 7-Biomass Boiler Fraction (Forest Products) (DAC 1995) | 38% | |
| 8-ATS penetration in the CHP market (Onsite 97) | 35% | 70% |
| 9-Grid offset carbon factor (gm/kWh) (Chapter 6) | 89 | 160 |
| 10-Fuel switching factor for conversion of boilers from oil or coal[2] | 1.28 | 1.53 |
| 11-ATS penetration in the Power-only (e.g. ALL industrial demand) | 10% | 20% |
| 12-2010 Industrial Electricity Demand TWhr (scaling from AEO97 BAU of 1289 by results of Chapter 6) | 1183 TWh | 1094 TWh |
| 13-Transmission and Distribution losses | 7% | |

As shown in the tables D-3.3 and D-3.2, we begin with the current stream demand and scale it up at 1.5% per year for both cases. We then convert this to Btus assuming a duty cycle of just over 50% (Onsite

[2] For the efficiency case, we assumed the non-biomass boilers were replaced in the same proportion as their current distribution (DAC 1995.) (Natural Gas-48%, Oil--36% and Coal--16%) For the HE/LC case, we assumed that oil and coal boilers would be replaced first (Oil--69% and Coal--31%).

# APPENDIX D-3

## METHODOLOGY: ESTIMATES OF CARBON REDUCTIONS RESULTING FROM ADVANCED TURBINE SYSTEMS TECHNOLOGY

***Details of Section 4.3.2.1 Analysis.*** We divide the 2010 market for ATS into three segments:

- Power-Only–the steam from the ATS is fed back into electricity generation.
- Cogeneration–traditional "combined heat and power" (CHP) where ATS is optimized for steam production.
- New Steam–new "combined heat and power" (CHP) where electricity generation is the priority and steam is used as needed.

Traditional power-only and cogeneration are already included to some extent in the EIA BAU case for 2010. The power-only ATS would be competing in the IPP market that is projected to grow rapidly. ATS would also be competitive in the cogeneration market (producing more electricity per Btu than its competitors), but cogeneration market growth is constrained[1]. AEO97 predicts that in 2010, there will be 333 TWh of industrial cogeneration capacity in the U.S., a growth of 51 TWh over the best estimates of current industrial cogeneration capacity.

As explained in Section 4.3.2, most of the growth over the BAU for the ATS is in the third "new steam" market. This "new steam" market explains much of the additional penetration of the ATS. However, from an analytic point of view, this new market is difficult to analyze. There is no "existing technology" with which to compare ATS's new steam applications for calculating the carbon reduction. It has aspects of both traditional cogeneration and power market analyses. Therefore, we decomposed this "new steam" market into CHP (cogeneration assuming heat/power balance) and power-only markets.

*New steam = a*CHP + b*PO*

Note that the power-only market here is broader including some high E/T ratio sites where there is little steam demand. The CHP market is also broader than cogeneration because it is not limited to actual sites where the steam and electric needs are matched. Table D-3.1 shows the Onsite sector-specific values for a and b based on the analysis presented at the end of this appendix.

**Table D-3.1 CHP and PO Market Fractions From Figures D-3.3 and D-3.4**

| Sector | a (CHP) | b (PO) |
|---|---|---|
| Chemicals | .51 | .49 |
| Food | .58 | .42 |

[1] This constrained growth is partly due to technical reasons, traditional cogeneration systems require that steam and electricity be matched (or else the efficiency drops off). The new ATS overcomes this problem by running efficiently at a wide range of E/T ratios. Cogeneration has also been constrained by environmental permitting, utility regulation, and utility competition. Together these factors explain why very efficient CHP technology still comprises a relatively small fraction of electricity and steam generation. When policies to promote CHP are instituted, however, this fraction can grow dramatically. (Major 1995). Finland, Denmark and the Netherlands have each achieved a contribution of about 30% of electricity production based on CHP.

# Interlab Study on Scenarios of U. S. Carbon Reductions

# APPENDIX D-3

## Methodology: Estimates of Carbon Reductions from Advanced Turbine Systems Technology

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station electric generating system have been made for 15MW industrial ATS projected to be commercially available by the year 2000 (Major and Davidson 1997).

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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 green house 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 $CO_2$ emission relative to the best available gas-fired-combined cycle central

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 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 $I^2R$ 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.

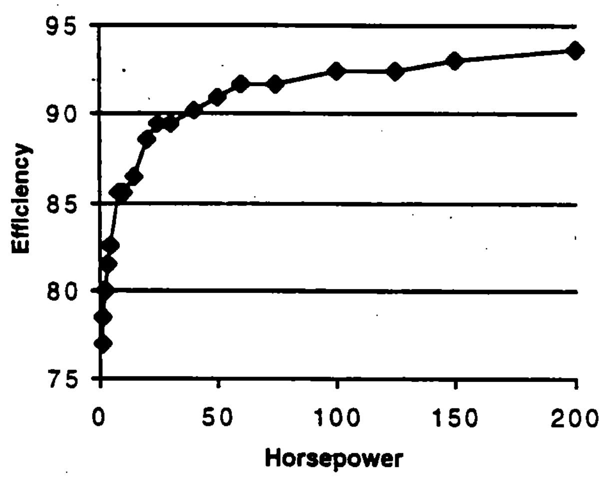
**Table D-2.8.2, Hypothetical Savings from Comprehensive Motor Replacements**

| 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 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 high-efficiency motors have been available for two decades and are included in the current motor population[2]. 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 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.

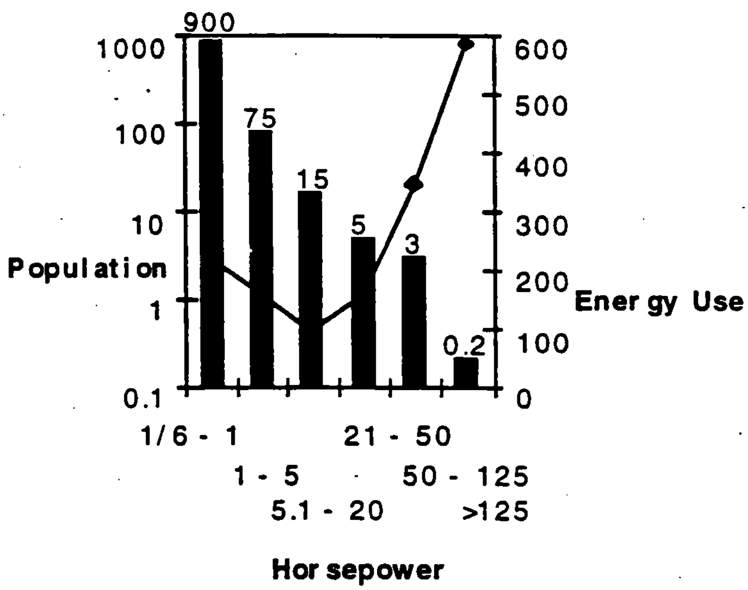
Table D-2.8.2 provides some indication of the relative efficiencies of standard and high-efficiency motors. Since the term "high-efficiency" is vague, the industry has made some effort to specify requirements for motors carrying that designation. Because of manufacturing and materials variations, motor 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 1.2x5% or 6% ( 94% efficiency). A more restrictive class, with maximum losses 10% greater than nominal losses, has also been established.

[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.

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 1977[1], 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 conservation lies in the large motors. Given the size of the embeded 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.

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

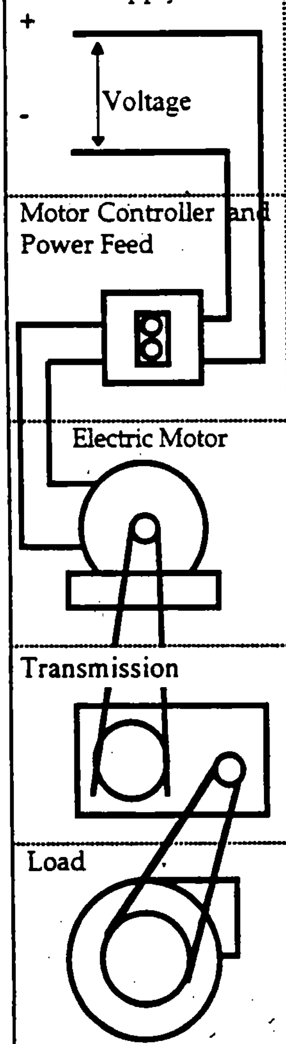
## D-2.8.1 Technology Examples Available Before 2010

### 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.<br>• Deviations from design voltage can reduce motor efficiency and motor torque even if balance is maintained between phases.<br>• 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.<br>• High starting currents (five to seven times normal operating currents) may push the limits of feeders, resulting in low voltage.<br>• 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.<br>• Motor efficiency is often reduced by rewinding.<br>• 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%.<br>• Helical gears are more efficient than worm gears in most applications. Helical gear efficiency drops at part load applications.<br>• 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.<br>• 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. |

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 the to electric grid. This section also discusses cogeneration as an energy efficiency option.

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).

# D-2.8 TECHNOLOGY EXAMPLES FOR CROSSCUTTING TECHNOLOGIES

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

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

### 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.

## D-2.7 TECHNOLOGY EXAMPLES FOR METAL CASTING

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 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

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

## 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 $CO_2$ 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 $CO_2$ 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 x 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).

## 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.

## 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-Herault cells (Energetics 1990).

## 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.

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 $CO_2$ emissions during smelting.

## 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).

## 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). 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/ft$^3$ 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-2.5 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.

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.

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

## 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.

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 bum) 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 (aspheltenes) 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 selectively 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-2.4 TECHNOLOGY EXAMPLES FOR GLASS

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.

electricity and steam at desired pressure levels and to a $H_2$ 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 $SO_2$ 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 NOx, SOx 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 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 promotors, 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/$H_2$ 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 $H_2$. The integration of a coke/residue gasifier with a cogeneration plant and $H_2$ 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 $H_2$ and CO which can then be split into several streams that can be fed to a cogeneration plant to produce single burner boilers, excess air control can lead to similar gains. The technology to automate excess air firing is available.

Recouperative 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 NOx 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 energy 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 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 recouperators to recover energy, e.g., air preheat, is possible, especially for higher temperature processes; cost and an increase in NOx 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 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 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

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, $SO_2$ and NOx 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, $CO_2$ 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 $CO_2$ 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

## D-2.3 TECHNOLOGY EXAMPLES FOR PETROLEUM REFINING

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, $CO_2$), 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 $CO_2$ 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 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, hexamethylendiamine, and dimethyl-terephathalate; the second will convert the unreacted organic material into sythesis 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-2.2 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 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 stream 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.

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

# 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 b 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

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## APPENDIX D-2

## Examples of Energy Saving Technologies for the Future

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-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

# Interlab Study on Scenarios of U. S. Carbon Reductions

# APPENDIX D-1

## Details of the NEMS and LIEF Models

# Interlab Study on Scenarios of U. S. Carbon Reductions

# APPENDIX D-5

## Residual Biomass Makeup and Generation Rates

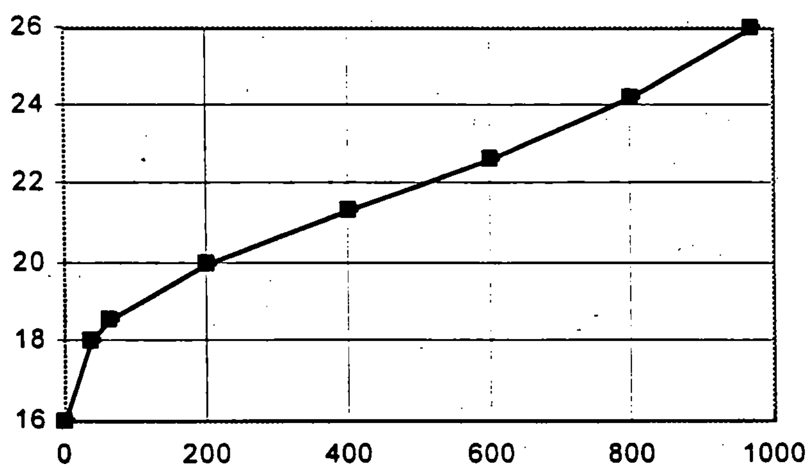
# APPENDIX D-5

# RESIDUAL BIOMASS MAKEUP AND GENERATION RATES

Residue generation is specific to the feedstock composition and manufacturing process. For kraft pulp the feedstock mix for the United States was 73% softwood, 27 % hardwood (USDA, 1990). The assumed average rate is 2.8 dry tonnes residue generated per tonne of kraft pulp produced (the 1990 value). Data from the SE shows that saw timber (with larger diameter bark and slabs as residues) results in softwood and hardwood residue generation rates of 0.062 and 0.22 tonne/tonne of kraft pulp respectively. Pole timber, in contrast has a lesser diameter criterion and results in 0.007 t/t and 0.068 t/t for softwood and hardwood respectively. Additional residues come from stand conversion activities (salvageable dead trees, cull trees, and trees less than 12.5 cm diameter), and have a much higher ratios of 2.25/3.63 t/t, softwood/hardwood to pulp product. Stand conversion activities are region specific (Larson, 1991).

Additional biomass collection from forest management operations in the form of pre-commercial thinnings, harvest residues, and residue acquisition from sawmill and other operations could increase the fuel available by 100% which would allow a typical 750 ton/day pulp mill to produce 35 MW of electricity for export to the grid to offset utility generation (Weyerhaeuser, Stone and Webster, Amoco, and Carolina Power and Light, 1995). For the New Bern, N.C., region this study developed the supply curve shown in Figure D-y. The technology for increased recovery of residues and pre-commercial thinnings in plantation forestry is developed and there is experience in its deployment. The developed calculations remained at the first third of the supply where the feedstock can be obtained at under $21/BDt.

**Figure D-5.1 Example of Biomass Shed Developed for a Specific Weyerhaeuser Mill in New Bern, North Carolina**




In the example of the New Bern mill, although more complex, the effective first generation plant based on a Frame 6B gas turbine and current gasification systems compared well with a stand alone plant at 1750 $/kW total plant investment and an overall efficiency of 30%.

The current cost of IGCC is approximately 50% over the $N^{th}$ plant cost. A proposal is for the industry to form a "buyers' club" that orders 5 or 6 units with government capital cost buy down to create the $N^{th}$ unit rapidly without any one customer being penalized by either cost or operational difficulties as the learning curve is followed. A sum of 300 M$ has been proposed–a 50% buy down on 6 units with a total combined electricity production of 420 MW (with an electricity export of 50%, retaining 50% for self use). This cost is predicated on the $100 million of capital cost for the unit assumed at 750 tons per day.

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# Interlab Study on Scenarios of U. S. Carbon Reductions

# APPENDIX D-6

# Advanced Aluminum Production Cell

# APPENDIX D-6

## ADVANCED ALUMINUM PRODUCTION CELL

All primary aluminum is produced by the Hall-Heroult process, which has evolved and improved continuously since it was first commercialized in the early 1890s. In this process, aluminum oxide (alumina, or $Al_2O_3$) dissolved in a molten cryolite solvent is decomposed into molten aluminum (Al) at a negatively charged pool of aluminum (the cathode) and oxygen at a positively charged carbon (c) anode. The oxygen reacts with the carbon anode to form $CO_2$, as shown below (Haupin 1995):

$$2Al_2O_{3\,(liquid)} + 3C_{(solid)} = 4Al_{(liquid)} + 3CO_{2\,(gas)}$$

The carbon anode is continuously consumed in the process. In pre-bake cells, the anode must be replaced every 2 to 3 weeks (Emad 1996). A direct short in the cell will occur if the anode comes into contact with the molten metal. Maintaining the correct anode-cathode distance to avoid the short is difficult because the surface of the molten aluminum undulates. In practice, therefore, the anode and the cathode are kept at a distance of about 4 centimeters apart. The voltage requirements of the cell and thus the cell's thermal efficiency are proportional to inter-electrode distance. Currently, heat losses resulting from the extra inter-electrode distance account for approximately 40% of the energy consumption of a typical cell (Evans 1995). The anode-cathode distance performance could be significantly improved in an advanced cell incorporating (Kenchington 1997):

- inert anodes to replace consumable carbon anodes, and
- sloped wettable cathode surfaces to replace the molten aluminum cathode, eliminating undulating cathode surfaces and allowing reduction of the inter-electrode distance.

Since the early 1980s, the aluminum industry has done substantial R&D on inert anodes and wettable solid cathodes. The Department of Energy has co-sponsored R&D on an advanced cell incorporating an inert anode, a wettable cathode and other important modifications to the Hall-Heroult process. Recently, the industry has demonstrated the technical feasibility of a wettable solid titanium diboride-graphite ($TiB_2$-G) cathode in a prebaked cell. Preliminary results of short term tests of $TiB_2$-G elements inserted in production cell cathodes indicate significant reductions in energy consumption because the inter-electrode distance and thus the voltage was decreased substantially (Dillich 1997). Improved wettable cathodes depend upon materials development, process development and design. Another key technology in the advanced cell is an inert or "dimensionally stable" anode. With this type of anode, oxygen is evolved rather than $CO_2$ (as is carbon) during the electrolytic decomposition of $Al_2O_3$. Pilot scale tests are currently being conducted using a novel cermet material as the anode and $TiB_2$-G as the cathode. Progress on inert anodes depends upon advances in materials development and processes and cell design. This R&D also features Bayer process improvements and advanced cell design and controls including electrode pack design and materials and controls for management of Heroult cells. (Dillich 1997).

In addition to reducing cell electricity requirements (and reducing the $CO_2$ emissions associated with generation of this electricity), the use of inert anodes will eliminate the process $CO_2$ emissions from smelting (those associated with anode consumption). The use of inert anodes will also eliminate anode effects, conditions of anode overvoltage that lead to emissions of the perfluorocarbons $CF_4$ and $C_2F_6$. Wettable cathodes alone will significantly reduce anode effects and this is reflected in the carbon reductions under the efficiency scenario. Although perfluorocarbon emissions are small by weight, they have a much higher global warming potential (GWP) and thus account for about one third of the carbon emissions from the current cell technology (Margolis 1997). At a typical proportion of 90% $CF_4$ and 10% $C_2F_6$ , these emissions have an equivalent weighted average GWP of 6770, compared to 1 for $CO_2$ (GWP is 6,500 for $CF_4$ and 9,200 for $C_2F_6$) (Gibbs and Jacobs 1996; IPCC 1994).

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# APPENDIX E

# Interlab Study on Scenarios of U. S. Carbon Reductions

## APPENDIX E-1

## Supplemental Tables

# 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 fiction 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% $C_D$ reduction typically will result in a 2 to 2.5% 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 fiction 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% will typically yield a fuel economy improvement of about 1%. *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% weight reduction will yield as much as a 6% 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% (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% 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% on the city part of the Environmental Protection Agency driving cycle, and about 26 to 28% 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% on the city part of the test and 27% on the highway, 24% 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% would reduce fuel consumption by 4%.

- Of the energy that is converted by the engine to actual shaft horsepower:

  ⇒ *braking and idling loss*: 16% (city), 2% (highway), 11% (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%;

  ⇒ *transmission loss*: 10% (city), 7% (highway), 9% (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% (city), 7% (highway), 9 to 10% (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% (city), 84% (highway), 71% (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% of total tractive forces in the city, and 35% on the highway, 31% composite. Both improvement to tires and weight reduction work to reduce this large fiction of tractive forces;

⇒ *aerodynamic drag* accounts for 18% (city) and 50% (highway), 30% composite; and

⇒ *inertia (weight) force* accounts for 54% (city) and 14% (highway), 40% composite. Weight reduction directly attacks this force, or some of the energy used to overcome it can be recovered by regenerative braking.

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[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 NOx catalysts to operate.

# Interlab Study on Scenarios of U. S. Carbon Reductions

## APPENDIX E-3

## Documentation of Technology Benefits Used in the Efficiency and High Efficiency Cases

# APPENDIX E-3

# DOCUMENTATION OF TECHNOLOGY BENEFITS USED IN THE EFFICIENCY AND HIGH-EFFICIENCY CASES

The EIA NEMS model has a very comprehensive list of automotive technology improvements that are likely to be introduced in the future. A few technologies are not considered by NEMS because they represent a more optimistic view of future improvement potential than the "average" view of the auto manufacturers. The technologies are:

- Advanced drag reduction to a $C_d$ of 0.22
- Direct Injection Diesel Engines
- Direct Injection Stratified Charge (DISC) Gasoline Engines
- Hybrid electric power trains with the gasoline or diesel engine
- Fuel cell based powertrains

Most of these technologies with the exception of the fuel cell could be introduced in some niche markets in the 2001-2005 time frame. The fuel cell could conceivably be commercialized before 2010, although "average" expectations are that it will be ready for the market only around 2015. The assumptions regarding each technology are documented below, and were derived primarily from an analysis developed by EEA for the Office of Technology Assessment (OTA) in 1995(EEA, 1995).

## Advanced Drag Reduction

Based on the work for OTA, most of the auto manufacturers interviewed believed that a $C_D$ of 0.25 was a realistic average for a family sedan, although some models such as sports cars could attain lower levels. However, some prototypes displayed at auto shows have demonstrated much lower values of $C_D$ and do not appear to have tradeoffs such as severely restricted headroom due to sloping rooflines, or restricted trunk room with a sharply tapered rear end. One example is the Toyota AXV that attained a $C_D$ of 0.20, but it includes wheel covers and an underbody cover. These covers could affect maintenance and heat rejection, but deleting them would raise the $C_D$ to about 0.22 according to Toyota (1994). The $C_D$ value of 0.22 was also cited by a few manufacturers as potentially achievable with improved dimensional control and better body part fit and finish. Hence, both the efficiency and high-efficiency cases were derived with a $C_D$ of 0.22 as the limit, which provides an additional 2.3% gain in fuel efficiency at constant performance. Costs were based on an EEA derived algorithm for drag reduction that increases marginal costs per $C_D$ increment, and was estimated at $256 per cars relative to the baseline 1990 car with a $C_D$ of 0.36.

## Direct Injection Diesel Engines

Direct Injection (DI) Diesel engines are at a much higher state of technological maturity than the other technologies discussed, and are already available in the U.S. market on one model in 1997. In turbocharged form, a DI diesel can improve fuel economy by 40% (on a per gallon basis) relative to a naturally aspirated gasoline of equivalent technology, based on actual test data from European DI diesels not yet sold in the U.S. market (U.K. DOT, 1995). Although DI diesels are being sold today, they are currently eligible for a waiver from the gasoline engine $NO_x$ emission standard; it is not yet clear whether such a waiver will exist in the future or how low the emission standards for diesel will be.

There are a number of technologies under development to reduce diesel engine emissions and the technologies include (1) use of very high pressure fuel injection to atomize the fuel more finely (2) electronic control of injection rate to tailor fuel delivery to the combustion process (3) exhaust gas recirculation to reduce $NO_x$ emissions (4) use of variable geometry turbocharging to provide sufficient air over a wide range of engine speeds and (5) use of a lean $NO_x$ catalyst. All of these technologies are likely to be used together to reduce $NO_x$ and particulate emissions simultaneously, and the efficiency scenario assumes that the emission reductions available from this set of technologies will allow diesels to meet future standards without an emission penalty. The cost increase relative to a gasoline engine of equal torque is estimated at $1100, which includes a $150 for emission control technology to meet future standards (VW, 1995).

## Direct Injection Stratified Charge (DISC) Engines

The DISC gasoline engine has recently been introduced in Japan, and can be considered a viable option for U.S. introduction in the next few years. The DISC engine is similar to a lean-burn engine conceptually, and the direct-injection of fuel allows better tailoring of a stratified charge that can support combustion even under very lean total air fuel ratios. New DISC engines from Toyota introduced in Japan shows a benefit in fuel economy of about 26% relative to similar conventional engine on the Japanese test cycle (Toyota, 1996a). The Toyota engine incorporates both DISC and variable valve timing (VVT) and Toyota's opinion was that a similar design engine would show a benefit of about 20% on the U.S. cycle. Of course, VVT itself can provide a 8% benefit in fuel economy on conventional gasoline engines, but it's benefits are reduced to about half that level (or 4%) in conjunction with a DISC, based on EEA's engineering analysis of pumping losses. Hence, the DISC technology can potentially provide a 16% benefit in fuel economy without VVT. The incremental price is based on the current incremental price in Japan for Toyota's DISC engine and is estimated at about $300 (Toyota, 1996b).

Like the DI diesel, the DISC engine also has some difficulty in meeting $NO_x$ emission standards. It is more reliant than the diesel on the successful development of a lean $NO_x$ catalyst, which has been developed for use in Japan. The lean-$NO_x$ catalyst is very susceptible to sulfur poisoning, but fuel sulfur levels in Japan are very low, less than a tenth of the levels for U.S. (non-California) fuels. The assumption in this scenario is that fuel sulfur levels in the U.S. are reduced and more sulfur tolerant lean-$NO_x$ catalysts are developed, allowing the DISC engine to meet future $NO_x$ emission standards. Auto manufacturers interviewed by EEA appear to be optimistic that these developments will occur in the near future.

## Hybrid Drivetrains

Hybrid electric/i.c. engine drivetrains were extensively analyzed in the OTA report, and the OTA analysis utilized "expected average" values for the efficiencies of drive motors, electrical generators and electric power storage media. These average efficiencies were utilized in a lumped parameter simulation model (one that utilizes cycle average calculations rather than second-by-second calculations) to derive the fuel efficiency of hybrid vehicles. The OTA analysis indicated that a series hybrid design utilizing the same aerodynamics, body structure and tires as a conventional vehicle would attain a fuel efficiency of 48.5 MPG (EPA composite), while the conventional vehicle using an overhead cam, 4-valve engine with variable valve timing would attain 38.8 MPG. Hence the gasoline engine hybrid offers a 25% benefit in fuel economy over an advanced gasoline engine powered vehicle, or a 33% benefit over a vehicle without VVT (which accounts for an 8% fuel economy benefit).

The same simulation model revealed that the DI diesel engine powered hybrid would obtain only a 10% benefit over a conventional vehicle powered by a DI diesel, i.e. a 54% benefit over a conventional vehicle powered by a conventional gasoline engine (1.4 x 1.1 - 1).

Costs for both hybrid vehicle types were derived from data in the OTA report.

In the high-efficiency case, a re-evaluation of the "expected average" efficiencies utilized for motors, generators and power storage media was performed. Even at the time the OTA report was completed, some reviewers believed that the average efficiencies selected for the OTA report were too conservative.

The re-evaluation suggested that the efficiencies could be increased to reflect more recent technology advancements, as follows:

| | OTA Efficiency Case (%) | High -Efficiency Case (%) |
|---|---|---|
| Generator (Continuous) | 91 | 94 |
| Battery In/Out | 80 | 86 |
| Motor - Urban | 82 | 85 |
| Motor - Highway | 90 | 93 |
| Regenerative Braking | 80 | 83 |

These higher efficiencies were utilized in the simulation model to re-evaluate hybrid vehicle fuel economy. The new efficiency values increased gasoline/hybrid vehicle fuel economy estimates from 48.5 MPG to 54.45 MPG, a 12% increase. A nearly identical % increase in fuel economy was observed for diesel hybrid vehicles, which is not surprising since the changes relate only to the electrical components in the vehicle. Hence, the net effect of this re-evaluation is that the gasoline hybrid vehicle was estimated to be 49% (1.33 x 1.12) more efficient[1] than a conventional vehicle, and the diesel hybrid to be 72% (1.54 x 1.12) more efficient than conventional vehicle. Costs were unchanged for this scenarios from the efficiency scenario.

## Fuel Cells

As with other technologies, the analysis of fuel cell efficiency was derived from data in the OTA report. In that report, the **methanol** fuel cell and reformer were estimated to have a cycle average efficiency of 45%, i.e. the system was a little more efficient than a turbocharged DI diesel engine at 40%. At this efficiency, the simulation model revealed that the equivalent vehicle would have a fuel economy of 66.7 MPG, which is 72% better than the 38.8 MPG attained by an advanced conventional vehicle with similar technology. More recently, the technology has been extended to utilizing gasoline as fuel with some modest loss in efficiency. It was assumed that the loss could be held to about 2%, so that the gasoline fuel cell vehicle would be 70% more efficient than the conventional vehicle, in the efficiency case (Borroni-Bird, 1997).

The efficiency case utilized average efficiency values for motors and power storage media consistent with those used for the hybrid vehicle, and the high-efficiency case derived for the fuel call utilized similar assumptions on efficiency increases for these components as those used for hybrids. The fuel cell vehicle, however, does not have a generator, and utilizes the power storage media a little less than the i.c. engine powered hybrid vehicle, so that the net efficiency gain was estimated at 8.2% relative to the efficiency case, using the simulation model. Hence, the fuel cell vehicle attains 84% better fuel economy than the conventional vehicle (i.e. 1.7 x 1.082) in the high-efficiency case.

No cost data was utilized for the fuel cell vehicle due the extreme uncertainty in costs. However, a strong research effort was estimated to reduce the lead time to commercialization from 15 years to 10 years, so that its introduction into the market could occur in 2007.

## REFERENCES

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[1] This number was incorrectly entered as 42 percent due to a double counting of 4-valve engine benefits of 5 percent).

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# APPENDIX F

# Interlab Study on Scenarios of U. S. Carbon Reductions

# APPENDIX F-1

## Inputs and Outputs of the ORCED Model

# APPENDIX F-1

# INPUTS AND OUTPUTS OF THE ORCED MODEL

The ten tables presented in this appendix show the inputs and outputs for each of the five main runs of the Oak Ridge Competitive Electricity Dispatch (ORCED) used in this study. For each run, the first page shows the input sheet, with those values that are input rather than calculated in bold. The second page shows the outputs, highlighting the key results for each case. The identifying name can be found in the top left of each page. The five cases are:

- AEO 2010 (our approximation of the EIA's AEO '97 results)
- Restructure Case (using pricing on the margin and minimizing avoided costs)
- Efficiency Case (intermediate demand-side efficiency)
- High-Efficiency/Low-Carbon Case (maximum demand-side efficiency)
- Alternative Technology Case (using advanced production technologies defined by DOE's Office of Fossil Energy)

ORCED is a production-costing model that uses load-duration curves rather than chronological loads as inputs. The model is run twice for each year of simulation, once for an onpeak season and a second time for an offpeak season.

For each season, the model has available to it 26 generating units. The first 25 units are characterized in terms of capacity, forced and planned outage rates, fuel type, heat rate, variable O&M costs, fixed O&M costs, and annual capital costs (based on initial construction cost, year of completion, and capitalization structure). The last unit is an energy-limited hydro unit, for which the inputs include, in addition to those noted above, the plant's capacity factor (equivalent to its maximum energy output for the year). This treatment of hydro as energy-limited ensures that hydro displaces the most expensive energy (i.e., at the top of the load-duration curves).

The model dispatches these 26 generating units separately for the two seasons. Although the calculation process is the same for the two seasons, the results differ because of differences in the load-duration curves and because all the planned maintenance is assumed to occur in the offpeak season.

The plants are first dispatched against the load-duration curve on the basis of bid price, the default for which is variable (fuel plus variable O&M) costs. (If the user bids a zero price for a unit, the generator is treated as a must-run unit and is dispatched first by the model.) Because plants are not available 100% of the time, we also model forced outages on a probabilistic basis. Thus, the higher-cost plants will see demands not only from customers, but "equivalent demands" based on the probability that plants lower (i.e., less expensive) in the dispatch order will be undergoing a forced outage. The model creates an equivalent load-duration curve for each plant, which extends the amount of time the plant runs based on the forced-outage rates of the plants lower in the dispatch order.

## INPUTS

The inputs at the top of the Input sheet (lines 1 through 13) are global inputs that determine the two load-duration curves, the number of generators that will be treated probabilistically (vs derated), the cost and carbon emissions per million Btu for each fuel type, and the financial characteristics of the generator owners (book and depreciation lifetimes, capitalization ratios, and return on bonds and common equity).

This portion of the sheet also allows the user to specify either the cost of unserved energy or a price elasticity. In the former case, whenever demand exceeds supply, customers pay and suppliers receive that rate for all the energy sold during that time period. If the elasticity option is used, the price of electricity increases beyond the cost of the most expensive unit then online until demand and supply equilibrate; the lower the elasticity value, the larger the price increase required to reduce demand to the level of available supply.

The user can also specify an uplift charge (analogous to that used in the UK), which is added to every kWh sold, a tax on carbon, or an annual capacity payment in $/kW-year. These various unserved energy, price elasticity, uplift charge, and capacity-payment options allow one to test different structures for a competitive bulk-power market.

The model includes a user input on fuel plus O&M startup costs. This factor is used to ensure that low-capacity-factor units recover all their variable costs, including those associated with startup, shutdown, and no-load operations.

Rows 18 through 44 include the user inputs on the 26 generators that are used by ORCED to meet system load (as specified by the two load-duration curves). For each of the first 25 generators, the user specifies unit capacity, whether the plant is available for use during this particular analysis, forced and planned outage rates, fixed O&M costs, initial plant cost and year of completion (which are used by the fixed-charges rate routine to compute the annual unavoidable fixed cost), heat rate and fuel type (which determine the unit's fuel cost), variable O&M cost, and bid price (input as OP to use the unit's fuel plus variable O&M cost). Line 44 allows the user to input assumptions for an energy-limited hydro unit.

## OUTPUTS

The Output sheet summarizes the results of the particular analysis. Key results are shown in the region A2:N11. These results show the system's overall variable cost per kWh, variable plus avoidable fixed cost per kWh, and total cost per kWh, as well as the average price of electricity, all computed at the generator busbar. The summary information also shows system reliability as measured by reserve margin and the loss of load probability and amounts of unserved energy in the two seasons. The amount of unserved energy, in combination with the assumed onpeak price elasticity, determines the cost of unserved energy (N46). The model calculates the number of plants that are unprofitable relative to avoidable fixed costs (G3) and relative to total fixed costs (G4), with details shown in the region A47:D75. The summary shows the distribution of system capacity, energy production, and cost by type of generation. Finally, the summary shows total carbon emissions for this analysis year (N41). Since ORCED is modeling 2% of the national total, this value (as well as overall sales and peak) should be multiplied by 50 to get national totals for these values.

The middle part of Output shows operating results, revenues, and costs for each of the 26 generators specified in Input. These results show each unit's output, capacity factor, and time on the margin for the year of analysis. These operating results are then used to determine revenues, variable costs, fixed costs, and net revenues.

The lower left portion of this Output sheet (A47:D75) shows the earnings for each generator relative to variable and avoidable fixed costs (but not unavoidable fixed costs, which are primarily related to capital costs). Negative numbers reflect losses per kW, and show the capacity surcharge that would be necessary to keep them operating.

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 operated to meet demand.

# Interlab Study on Scenarios of U. S. Carbon Reductions

## APPENDIX F-2

## Inputs and Outputs of the 2010 Electricity Sector Scenarios

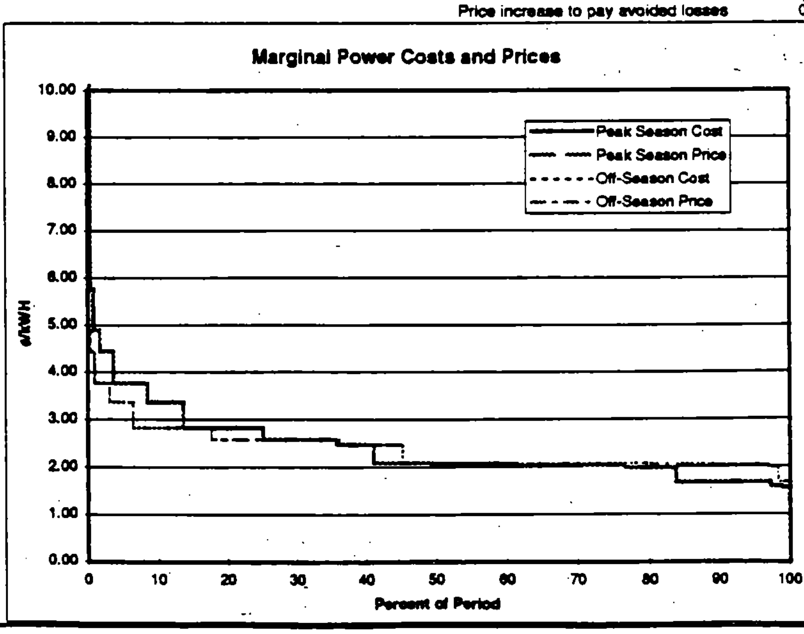
# APPENDIX F-2

## INPUTS AND OUTPUTS OF THE 2010 ELECTRICITY SECTOR SCENARIOS

| | A | B | C | D | E | F | G | H | I | J | K | L | M | N | O | P |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Case ID | 2010 AEO | | | | | CAPITALIZAT | IOU-Existing | IPP-Existing | IPP-New | IPP-Renew | Peak Season LDC | | | | |
| 2 | Peak Demand | | 14686.1517 | Fuel Type | $/MMBTU | kg C/MBTU | | 1 | 2 | 3 | 4 | | Season Peak | Shoulder 2 | Shoulder 1 | Min (100%) |
| 3 | Ratio of Off-peak to peak | | 87.8% | Gas | 2.50 | 14.47 | Term (Years) | 30 | 30 | 20 | 20 | % of Season | 0 | 5 | 95 | 100 |
| 4 | Peak fraction of year | | 25% | Coal | 1.34 | 25.72 | Tax life | 20 | 20 | 12 | 5 | Template ratio | 100% | 90% | 49% | 39% |
| 5 | Load Factor, % | | 62.6% | Oil | 3.00 | 21.40 | Inc. Tax Rate | 36% | 36% | 36% | 36% | Ratio to Peak | 100% | 90% | 49% | 39% |
| 6 | Peak Season Load Factor | | 60.7% | Nuclear | 0.70 | 0 | Prop. Tax rate | 5% | 5% | 5% | 5% | Demand MW | 14,686 | 13,267 | 7,223 | 6,756 |
| 7 | Off-Peak Season Load Factor | | 68.9% | Hydro | 0.00 | 0 | Debt % | 48% | 30% | 30% | 30% | Off-Peak Season LDC | | | | |
| 8 | Carbon Tax, $/metric ton C | | 0.00 | Other | 0.00 | 0 | Interest Rate | 8.0% | 10.0% | 10.0% | 10.0% | % of Season | 0 | 2 | 96 | 100 |
| 9 | Capacity Payment,$/kW | | 0 | Year of Study | 2010 | | Preferr Equity | 14% | 0% | 0% | 0% | Template ratio | 100% | 83% | 55% | 46% |
| 10 | Uplift Charge, ¢/kWh | | 0 | Year of $ | 1995 | | Return Rate | 10.0% | 10.0% | 10.0% | 10.0% | Ratio to Peak | 100% | 83% | 55% | 46% |
| 11 | Unserved Energy, ¢/kWh | | 0 | Start-up Cost, $/MW | | 40 | Common Equ | 38% | 70% | 70% | 70% | Demand MW | 12,892 | 10,736 | 7,108 | 5,994 |
| 12 | Non-general. Price, ¢/kWh | | 3.10 | Min Capacity w/ probab | | 0 | Return Rate | 11.0% | 14.0% | 14.0% | 14.0% | | | | | |
| 13 | Price Elasticity(not used if 0) | | 0.05 | Min Outage Rate w/ probab | | 0.0% | Vary FCR by | TRUE | TRUE | TRUE | TRUE | | | | | |
| 14 | Default Unserved E calc (always allow | | | Max # Plants with prob. | | 10 | Include in Avc | FALSE | FALSE | FALSE | FALSE | Fractional change to start year | | 0.30 | | |
| 15 | | | Capacity | Forced | Planned | | | | Variable | | Fixed | – Plant Construction – | | Capitilization | Unavoidable | Variable |
| 16 | | | Adjust Factor | Outage | Outage | Heat Rate | | Fuel Price | O&M Cost | Bid Price or | O&M Cost | Nominal | Construction | Structure | Fixed Cost | Cost |
| 17 | Name | Capacity | (0 to 1) | Rate | Rate | (BTU/kWh) | Fuel Type | Adjustment | ¢/kwh | OP, ¢/kwh | $/kW-yr | Cost/kW | Year | to Use | const $/kW-yr | ¢/kwh |
| 18 | Nuclear1 | 1,000 | 1 | 8.2% | 12.2% | 10,460 | Nuclear | 1.000 | 0.00 | OP | 90.0 | 800 | 1973 | 1 | 26 | 0.73 |
| 19 | Nuclear2 | 800 | 1 | 8.2% | 12.2% | 10,460 | Nuclear | 1.000 | 0.00 | OP | 90.0 | 2,750 | 1986 | 1 | 180 | 0.73 |
| 20 | Coal1 | 860 | 1 | 7.0% | 14.2% | 9,600 | Coal | 0.833 | 0.21 | OP | 11.7 | 490 | 1983 | 1 | 26 | 1.28 |
| 21 | Coal2 | 850 | 1 | 6.5% | 8.8% | 9,700 | Coal | 1.000 | 0.22 | OP | 11.7 | 370 | 1978 | 1 | 16 | 1.61 |
| 22 | Coal3 | 850 | 1 | 6.5% | 8.8% | 9,800 | Coal | 1.000 | 0.22 | OP | 11.7 | 300 | 1973 | 1 | 10 | 1.63 |
| 23 | Coal4 | 600 | 1 | 6.6% | 10.3% | 9,900 | Coal | 1.000 | 0.23 | OP | 12.4 | 680 | 1981 | 1 | 31 | 1.65 |
| 24 | Coal5 | 600 | 1 | 6.6% | 10.3% | 10,000 | Coal | 1.000 | 0.24 | OP | 12.4 | 380 | 1960 | 1 | 0 | 1.58 |
| 25 | Coal6+7 | 850 | 1 | 8.5% | 12.3% | 10,200 | Coal | 1.000 | 0.32 | OP | 15.2 | 600 | 1980 | 1 | 21 | 1.68 |
| 26 | Coal8 | 450 | 1 | 8.5% | 12.3% | 10,600 | Coal | 1.167 | 0.32 | OP | 15.2 | 300 | 1970 | 1 | 8 | 1.97 |
| 27 | Coal9+10 | 450 | 1 | 6.4% | 10.9% | 11,200 | Coal | 1.167 | 0.35 | OP | 15.3 | 300 | 1970 | 1 | 8 | 2.09 |
| 28 | 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 |
| 29 | Oil1 | 500 | 1 | 11.6% | 5.2% | 10,100 | Oil | 0.840 | 0.50 | OP | 6.0 | 127 | 1973 | 1 | 4 | 3.05 |
| 30 | GasST1 | 600 | 1 | 8.7% | 6.8% | 10,000 | Gas | 0.951 | 0.13 | OP | 9.4 | 170 | 1976 | 1 | 6 | 2.59 |
| 31 | GasST2 | 500 | 1 | 8.7% | 6.8% | 10,100 | Gas | 1.084 | 0.13 | OP | 9.4 | 160 | 1970 | 1 | 4 | 2.96 |
| 32 | GasST3 | 450 | 1 | 8.7% | 6.8% | 10,200 | Gas | 1.111 | 0.13 | OP | 9.4 | 220 | 1967 | 1 | 0 | 3.06 |
| 33 | GasCC1 | 300 | 1 | 6.8% | 13.0% | 9,865 | Gas | 0.951 | 0.10 | OP | 10.0 | 470 | 1992 | 2 | 45 | 2.48 |
| 34 | GasCC2-New | 420 | 1 | 5.5% | 7.5% | 7,760 | Gas | 1.000 | 0.05 | OP | 28.9 | 452 | 1999 | 3 | 40 | 2.08 |
| 35 | GasCC3-new | 420 | 1 | 5.5% | 7.5% | 7,818 | Gas | 1.000 | 0.05 | OP | 28.9 | 477 | 2001 | 3 | 55 | 2.02 |
| 36 | GasCC4-Adv | 420 | 1 | 5.5% | 7.5% | 6,284 | Gas | 1.000 | 0.05 | OP | 26.6 | 638 | 2005 | 3 | 76 | 1.68 |
| 37 | GasCC5-Adv | 600 | 1 | 5.5% | 7.5% | 5,817 | Gas | 1.000 | 0.05 | OP | 26.6 | 615 | 2009 | 3 | 109 | 1.55 |
| 38 | GasCT1+2 | 460 | 1 | 10.0% | 5.4% | 12,800 | Gas | 0.969 | 0.22 | OP | 6.0 | 140 | 1986 | 1 | 9 | 3.42 |
| 39 | GasCT3-new | 650 | 1 | 3.6% | 4.0% | 11,460 | Gas | 1.000 | 0.01 | OP | 11.9 | 364 | 1998 | 3 | 38 | 2.98 |
| 40 | GasCT4-new | 650 | 1 | 3.6% | 4.0% | 10,873 | Gas | 1.000 | 0.01 | OP | 11.9 | 406 | 2002 | 3 | 50 | 2.82 |
| 41 | GasCT5-Adv | 650 | 1 | 3.8% | 3.9% | 7,703 | Gas | 1.000 | 0.05 | OP | 16.9 | 542 | 2008 | 3 | 80 | 2.07 |
| 42 | Renewable | 250 | 1 | 25.0% | 15.0% | 10,280 | Other | 1.000 | 1.27 | OP | 65.5 | 2,361 | 2008 | 4 | 351 | 1.27 |
| 43 | Limited Energ Capacity, MW | | | Peak CF | Non-peak CF | | | | | | | | | | | |
| 44 | Hydro | 1,600 | 1 | 55.0% | 40.0% | | Hydro | | 0.10 | | 10 | 400 | 1957 | 1 | 0 | 0.10 |
| 45 | otal Capacity | 16,260 | | | | | | | | | | | | | | |
| 46 | year | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 |
| 47 | GDP deflator | 1.127 | 1.171 | 1.203 | 1.235 | 1.263 | 1.295 | 1.326 | 1.357 | 1.390 | 1.426 | 1.465 | 1.506 | 1.548 | 1.595 | 1.645 |
| 48 | 1987=100 | 0.946 | | | | | | | | | | | | | | |

| | A | B | C | D | E | F | G | H | I | J | K | L | M | N |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 2010 AEO | | | | | | | | | | | | | |
| 2 | | | Peak | Offpeak | # of Unprofitable plants | | | | | % of Total | | Cap fact | Avoidable | Variable |
| 3 | | Annual | season | season | Against avoid O&M | | 8 | | | Capacity | Generatior | % | ¢/kWh | ¢/kWh |
| 4 | 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 |
| 5 | 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 |
| 6 | 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 |
| 7 | 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 |
| 8 | 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 |
| 9 | 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 |
| 10 | Generation, GWh | 80,790 | 22,419 | 58,371 | Start-up Cost, $/MW | | 40 | | Gas-CT | 14.8% | 5.4% | 20.7% | 2.93 | 2.26 |
| 11 | Unserved Energy, Gl | 5 | 3 | 2 | # plants Probabilistic | | 10 | | Other | 1.5% | 1.6% | 60.0% | 2.51 | 1.27 |
| 12 | Round err not in UE | (2) | 1 | (2) | | | | | | | | | | |
| 13 | Plant | | Output | Capac | Time on | Revenue | Var. +Start | Avoidable | Unavoidable | Total Net | Avoidable | Net Rev | Avoidable | Carbon releas |
| 14 | Name | Capacity | MWyr | Factor | Margin, % | M$ | Cost M$ | xd Cst M$ | Fxd Cst M$ | Rev M$ | M$ | $/kW | cost, ¢/kWh | Million Tons |
| 15 | Nuclear1 | 1,000 | 796.00 | 79.6% | 0.00 | 168 | 51 | 90 | 28 | 0 | 26.91 | 33.80 | 2.02 | 0.00 |
| 16 | Nuclear2 | 800 | 636.80 | 79.6% | 0.00 | 134 | 41 | 72 | 144 | (122) | 21.53 | 33.80 | 2.02 | 0.00 |
| 17 | Coal1 | 950 | 748.60 | 78.8% | 0.00 | 158 | 84 | 11 | 25 | 39 | 63.07 | 84.25 | 1.45 | 1.62 |
| 18 | Coal2 | 850 | 719.96 | 84.7% | 0.00 | 152 | 96 | 10 | 13 | 34 | 46.38 | 64.42 | 1.67 | 1.57 |
| 19 | Coal3 | 850 | 719.96 | 84.7% | 0.00 | 152 | 96 | 10 | 8 | 37 | 45.53 | 63.25 | 1.69 | 1.59 |
| 20 | Coal4 | 600 | 498.60 | 83.1% | 0.00 | 105 | 68 | 7 | 18 | 12 | 29.98 | 60.12 | 1.72 | 1.11 |
| 21 | Coal5 | 600 | 495.96 | 82.7% | 0.40 | 105 | 68 | 7 | 0 | 29 | 28.96 | 58.08 | 1.75 | 1.12 |
| 22 | Coal6+7 | 850 | 648.28 | 76.3% | 3.70 | 138 | 96 | 13 | 18 | 12 | 30.02 | 44.59 | 1.91 | 1.49 |
| 23 | Coal8 | 450 | 330.48 | 73.4% | 2.86 | 71 | 57 | 7 | 3 | 4 | 7.39 | 20.73 | 2.21 | 0.79 |
| 24 | Coal9+10 | 450 | 186.72 | 41.5% | 12.44 | 46 | 34 | 7 | 3 | 1 | 4.29 | 11.53 | 2.54 | 0.47 |
| 25 | Coal-Adv. | 400 | 334.40 | 83.6% | 0.00 | 71 | 45 | 13 | 111 | (98) | 12.31 | 36.82 | 1.99 | 0.72 |
| 26 | Oil1 | 500 | 4.79 | 1.0% | 0.88 | 3 | 2 | 3 | 2 | (4) | (2.07) | (4.97) | 11.59 | 0.01 |
| 27 | GasST1 | 600 | 137.54 | 22.9% | 16.52 | 38 | 31 | 6 | 4 | (3) | 0.80 | 1.59 | 3.06 | 0.17 |
| 28 | GasST2 | 500 | 25.92 | 5.2% | 3.81 | 10 | 8 | 5 | 2 | (5) | (2.68) | (6.42) | 5.43 | 0.03 |
| 29 | GasST3 | 450 | 2.06 | 0.5% | 0.39 | 2 | 1 | 4 | 0 | (3) | (3.49) | (9.29) | 28.31 | 0.00 |
| 30 | GasCC1 | 300 | 96.17 | 32.1% | 8.17 | 25 | 21 | 3 | 14 | (13) | 0.98 | 4.05 | 2.83 | 0.12 |
| 31 | GasCC2-New | 420 | 290.81 | 69.2% | 8.93 | 64 | 52 | 12 | 20 | (20) | (0.06) | (0.17) | 2.53 | 0.29 |
| 32 | GasCC3-new | 420 | 321.04 | 76.4% | 7.46 | 70 | 57 | 12 | 23 | (22) | 0.93 | 2.53 | 2.45 | 0.31 |
| 33 | GasCC4-Adv | 420 | 361.45 | 86.1% | 0.90 | 77 | 53 | 11 | 32 | (20) | 12.28 | 33.61 | 2.03 | 0.29 |
| 34 | GasCC5-Adv | 600 | 521.31 | 86.9% | 0.27 | 110 | 71 | 16 | 65 | (42) | 23.04 | 44.13 | 1.90 | 0.38 |
| 35 | GasCT1+2 | 450 | 0.88 | 0.2% | 0.21 | 1 | 0 | 3 | 4 | (6) | (2.06) | (5.41) | 40.68 | 0.00 |
| 36 | GasCT3-new | 650 | 17.37 | 2.7% | 2.76 | 8 | 6 | 8 | 24 | (29) | (5.83) | (9.71) | 8.86 | 0.03 |
| 37 | GasCT4-new | 650 | 81.59 | 12.6% | 11.27 | 25 | 20 | 8 | 33 | (35) | (2.53) | (4.22) | 3.91 | 0.11 |
| 38 | GasCT5-Adv. | 650 | 395.92 | 60.9% | 18.88 | 91 | 72 | 11 | 58 | (49) | 8.44 | 14.06 | 2.38 | 0.39 |
| 39 | Renewable | 250 | 150.00 | 60.0% | 0.00 | 32 | 17 | 16 | 88 | (89) | (1.35) | (8.97) | 2.51 | 0.00 |
| 40 | Hydro | 1,600 | 700.00 | 43.8% | | 166 | 6 | 16 | 0 | 144 | 143.86 | 89.91 | 0.36 | 0.00 |
| 41 | Totals | 16,260 | 9,223 | 57% | | 2,021 | 1,152 | 382 | 739 | (252) | 487 | | | 12.62 |
| 42 | | | | | | | | | Avoidable | Total | | | | |
| 43 | Unserved Energy | | 0.54 | | | 2 | 2 | w/o UE | 1,534 | 2,273 | | Avg. Carbon kg/MWhr | | 156 |
| 44 | Totals w/ Unserved | | 9,223 | | | 2,022 | 1,154 | w/ UE | 1,536 | 2,274 | | Time wtd marginal cost | | 2.40 |
| 45 | | | | | | | | | | | | Time wtd Unserv E Price | | 18.94 |
| 46 | | | | | | | | | | | | Unserv E. Cost/kWh | | 38.42 |
| 47 | Sort by Net Revenue/kW | | | | | | | | | | | Price increase to pay avoided losses | | 0.02 |

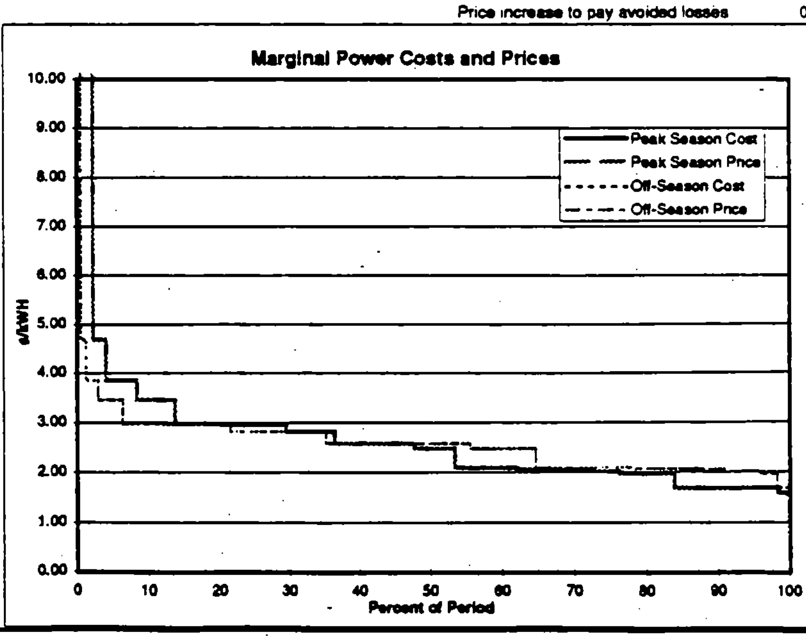
| | A | B | C | D |
|---|---|---|---|---|
| 48 | | Avoidable | | Reserve |
| 49 | Name | Net Rev/kW | Capacity | Margin |
| 50 | Hydro | 89.91 | 1,600 | 11% |
| 51 | Coal1 | 84.25 | 950 | 17% |
| 52 | Coal2 | 64.42 | 850 | 23% |
| 53 | Coal3 | 63.25 | 850 | 29% |
| 54 | Coal4 | 60.12 | 600 | 33% |
| 55 | Coal5 | 58.08 | 600 | 37% |
| 56 | Coal6+7 | 44.59 | 850 | 43% |
| 57 | GasCC5-Adv | 44.13 | 600 | 47% |
| 58 | Coal-Adv. | 36.82 | 400 | 50% |
| 59 | Nuclear1 | 33.80 | 1,000 | 57% |
| 60 | Nuclear2 | 33.80 | 800 | 62% |
| 61 | GasCC4-Adv | 33.61 | 420 | 65% |
| 62 | Coal8 | 20.73 | 450 | 68% |
| 63 | GasCT5-Adv. | 14.06 | 650 | 72% |
| 64 | Coal9+10 | 11.53 | 450 | 75% |
| 65 | GasCC1 | 4.05 | 300 | 77% |
| 66 | GasCC3-new | 2.53 | 420 | 80% |
| 67 | GasST1 | 1.59 | 600 | 84% |
| 68 | GasCC2-New | (0.17) | 420 | 87% |
| 69 | GasCT4-new | (4.22) | 650 | 92% |
| 70 | Oil1 | (4.97) | 500 | 95% |
| 71 | GasCT1+2 | (5.41) | 450 | 98% |
| 72 | GasST2 | (6.42) | 500 | 102% |
| 73 | Renewable | (8.97) | 250 | 103% |
| 74 | GasST3 | (9.29) | 450 | 106% |
| 75 | GasCT3-new | (9.71) | 650 | 111% |



| | A | B | C | D | E | F | G | H | I | J | K | L | M | N | O | P |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Case ID. | Restructure Case | | | | | CAPITALIZAT | IOU-Existing | IPP-Existing | IPP-New | IPP-Renew | Peak Season LDC | | | | |
| 2 | Peak Demand | | 14167.4588 | Fuel Type | $/MMBTU | kg C/MBTU | | 1 | 2 | 3 | 4 | | Season Peak | Shoulder 2 | Shoulder 1 | Min (100%) |
| 3 | 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 |
| 4 | Peak fraction of year | | 25% | Coal | 1.34 | 25.72 | Tax life | 20 | 20 | 12 | 5 | Template ratk | 100% | 94% | 63% | 42% |
| 5 | Load Factor, % | | 65.7% | Oil | 3.00 | 21.49 | Inc. Tax Rate | 36% | 36% | 36% | 36% | Ratio to Peak | 100% | 94% | 63% | 42% |
| 6 | Peak Season Load Factor | | 73.0% | Nuclear | 0.70 | 0 | Prop. Tax rate | 5% | 5% | 5% | 5% | Demand MW | 14,167 | 13,255 | 7,471 | 5,900 |
| 7 | Off-Peak Season Load Factor | | 71.3% | Hydro | 0.00 | 0 | Debt % | 48% | 30% | 30% | 30% | Off-Peak Season LDC | | | | |
| 8 | Carbon Tax, $/metric ton C | | 0.00 | Other | 0.00 | 0 | Interest Rate | 8.0% | 10.0% | 10.0% | 10.0% | % of Season | 0 | 2 | 98 | 100 |
| 9 | Capacity Payment,$/kW | | 0 | Year of Study | 2010 | | Preferr Equity | 14% | 0% | 0% | 0% | Template ratk | 100% | 85% | 58% | 50% |
| 10 | Uplift Charge, ¢/kWh | | 0 | Year of $ | 1995 | | Return Rate | 10.0% | 10.0% | 10.0% | 10.0% | Ratio to Peak | 100% | 85% | 58% | 50% |
| 11 | Unserved Energy, ¢/kWh | | 0 | Start-up Cost, $/MW | | 40 | Common Equ | 38% | 70% | 70% | 70% | Demand MW | 12,572 | 10,736 | 7,264 | 6,265 |
| 12 | Non-generat. Price, ¢/kWh | | 3.18 | Min Capacity w/ probab | | 0 | Return Rate | 11.0% | 14.0% | 14.0% | 14.0% | | | | | |
| 13 | Price Elasticity(not used if 0) | | 0.05 | Min Outage Rate w/ probab | | 0.0% | Vary FCR by y | TRUE | TRUE | FALSE | FALSE | | | | | |
| 14 | Default Unserved E calc (always slow | | | Max # Plants with prob. | | 10 | Include in Avc | FALSE | FALSE | TRUE | TRUE | Fractional change to start year | | 0.30 | | |
| 15 | | | Capacity | Forced | Planned | | | | Variable | | Fixed | – Plant Construction – | | Capitlization | Unavoidable | Variable |
| 16 | | | Adjust Factor | Outage | Outage | Heat Rate | | Fuel Price | O&M Cost | Bid Price or | O&M Cost | Nominal | Construction | Structure | Fixed Cost | Cost |
| 17 | Name | Capacity | (0 to1) | Rate | Rate | (BTU/kWh) | Fuel Type | Adjustment | ¢/kwh | OP, ¢/kwh | $/kW-yr | Cost/kW | Year | to Use | const $/kW-yr | ¢/kwh |
| 18 | Nuclear1 | 1,000 | 1 | 8.2% | 12.2% | 10,460 | Nuclear | 1.000 | 0.00 | OP | 90.0 | 800 | 1973 | 1 | 26 | 0.73 |
| 19 | Nuclear2 | 800 | 1 | 8.2% | 12.2% | 10,460 | Nuclear | 1.000 | 0.00 | OP | 90.0 | 2,750 | 1988 | 1 | 180 | 0.73 |
| 20 | Coal1 | 900 | 1 | 7.0% | 14.2% | 9,600 | Coal | 0.833 | 0.21 | OP | 11.7 | 490 | 1983 | 1 | 26 | 1.28 |
| 21 | Coal2 | 850 | 1 | 6.5% | 8.8% | 9,700 | Coal | 1.000 | 0.22 | OP | 11.7 | 370 | 1978 | 1 | 15 | 1.51 |
| 22 | Coal3 | 850 | 1 | 6.5% | 8.8% | 9,800 | Coal | 1.000 | 0.22 | OP | 11.7 | 300 | 1973 | 1 | 10 | 1.53 |
| 23 | Coal4 | 600 | 1 | 6.6% | 10.3% | 9,900 | Coal | 1.000 | 0.23 | OP | 12.4 | 680 | 1981 | 1 | 31 | 1.55 |
| 24 | Coal5 | 600 | 1 | 6.6% | 10.3% | 10,000 | Coal | 1.000 | 0.24 | OP | 12.4 | 380 | 1960 | 1 | 0 | 1.58 |
| 25 | Coal6+7 | 850 | 1 | 8.5% | 12.3% | 10,200 | Coal | 1.000 | 0.32 | OP | 15.2 | 500 | 1980 | 1 | 21 | 1.68 |
| 26 | Coal8 | 450 | 1 | 8.5% | 12.3% | 10,600 | Coal | 1.167 | 0.32 | OP | 15.2 | 300 | 1970 | 1 | 8 | 1.97 |
| 27 | Coal9+10 | 450 | 1 | 6.4% | 10.9% | 11,200 | Coal | 1.167 | 0.35 | OP | 16.3 | 300 | 1970 | 1 | 8 | 2.09 |
| 28 | 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 |
| 29 | Oil1 | 500 | 1 | 11.6% | 5.2% | 10,100 | Oil | 0.840 | 0.50 | OP | 6.0 | 127 | 1973 | 1 | 4 | 3.05 |
| 30 | GasST1 | 600 | 1 | 9.7% | 6.8% | 10,000 | Gas | 0.951 | 0.13 | OP | 9.4 | 170 | 1976 | 1 | 6 | 2.59 |
| 31 | GasST2 | 500 | 1 | 9.7% | 6.8% | 10,100 | Gas | 1.084 | 0.13 | OP | 9.4 | 150 | 1970 | 1 | 4 | 2.98 |
| 32 | GasST3 | 450 | 1 | 9.7% | 6.8% | 10,200 | Gas | 1.111 | 0.13 | OP | 9.4 | 220 | 1967 | 1 | 0 | 3.06 |
| 33 | GasCC1 | 300 | 1 | 6.8% | 13.0% | 9,665 | Gas | 0.951 | 0.10 | OP | 10.0 | 470 | 1992 | 2 | 45 | 2.48 |
| 34 | GasCC2-New | 200 | 1 | 5.5% | 7.5% | 7,760 | Gas | 1.000 | 0.05 | OP | 28.9 | 452 | 1999 | 3 | 55 | 2.06 |
| 35 | GasCC3-new | 200 | 1 | 5.5% | 7.5% | 7,618 | Gas | 1.000 | 0.05 | OP | 28.9 | 477 | 2001 | 3 | 58 | 2.02 |
| 36 | GasCC4-Adv | 800 | 1 | 5.5% | 7.5% | 6,284 | Gas | 1.000 | 0.05 | OP | 26.6 | 538 | 2005 | 3 | 66 | 1.68 |
| 37 | GasCC5-Adv | 1,000 | 1 | 5.5% | 7.5% | 5,817 | Gas | 1.000 | 0.05 | OP | 26.6 | 615 | 2009 | 3 | 75 | 1.55 |
| 38 | GasCT1+2 | 450 | 1 | 10.0% | 5.4% | 12,800 | Gas | 0.969 | 0.22 | OP | 6.0 | 140 | 1986 | 1 | 9 | 3.42 |
| 39 | GasCT3-new | 350 | 1 | 3.6% | 4.0% | 11,460 | Gas | 1.000 | 0.01 | OP | 11.9 | 364 | 1998 | 3 | 44 | 2.98 |
| 40 | GasCT4-new | 350 | 1 | 3.6% | 4.0% | 10,873 | Gas | 1.000 | 0.01 | OP | 11.9 | 406 | 2002 | 3 | 50 | 2.82 |
| 41 | GasCT5-Adv | 350 | 1 | 3.9% | 3.9% | 7,793 | Gas | 1.000 | 0.05 | OP | 16.9 | 542 | 2008 | 3 | 66 | 2.07 |
| 42 | Renewable | 50 | 1 | 25.0% | 15.0% | 10,280 | Other | 1.000 | 1.27 | OP | 65.5 | 2,361 | 2008 | 4 | 260 | 1.27 |
| 43 | Limited Energ | 1600 | | Peak CF | Non-peak CF | | | | | | | | | | | |
| 44 | Hydro | 1,600 | 1 | 55.0% | 40.0% | | Hydro | | 0.10 | | 10 | 400 | 1957 | 1 | 0 | 0.10 |
| 45 | otal Capacity | 16,700 | | | | | | | | | | | | | | |
| 46 | year | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 |
| 47 | GDP deflator | 1.127 | 1.171 | 1.203 | 1.235 | 1.263 | 1.295 | 1.326 | 1.357 | 1.390 | 1.426 | 1.465 | 1.506 | 1.548 | 1.595 | 1.645 |
| 48 | 1987=100 | 0.646 | | | | | | | | | | | | | | |

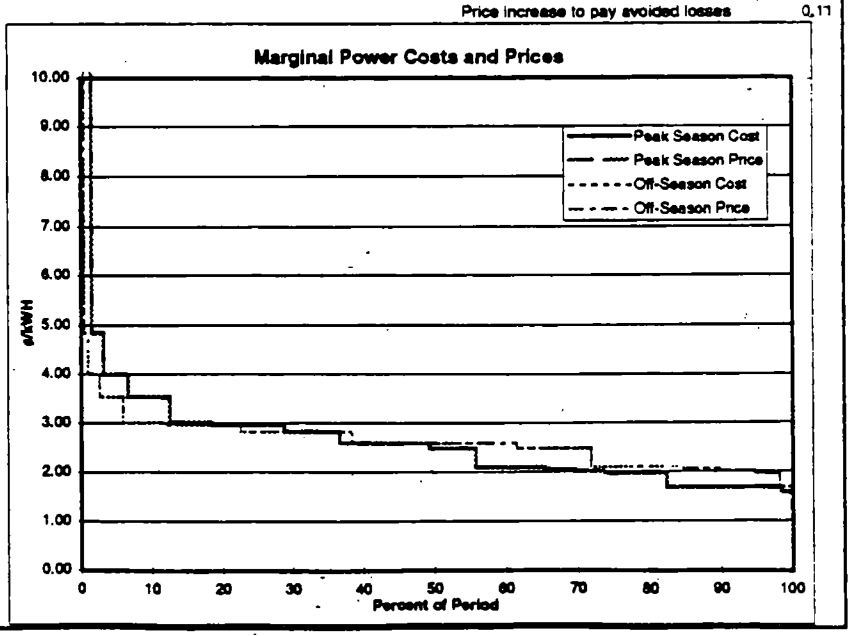
| | A | B | C | D | E | F | G | H | I | J | K | L | M | N |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Restructure Case | | | | | | | | | | | | | |
| 2 | | | Peak | Offpeak | # of Unprofitable plants | | | | | % of Total | | Cap fact | Avoidable | Variable |
| 3 | | Annual | season | season | Against avoid O&M | | 9 | | | Capacity | Generation | % | ¢/kWh | ¢/kWh |
| 4 | Reserve Margin | 6.6% | 6.6% | 5.8% | Against all costs | | 12 | w/ unserv | Hydro | 10.6% | 7.5% | 43.8% | 0.36 | 0.10 |
| 5 | LOLP, % of period | 0.99 | 2.25 | 0.56 | Average Price, ¢/kWh | | 2.87 | 2.89 | Nuclear | 11.9% | 15.4% | 79.6% | 2.02 | 0.73 |
| 6 | LOLP, day/10 Year | 36.01 | 82.28 | 20.59 | Avg. Variable Cost | | 1.45 | 1.47 | Coal | 37.1% | 47.5% | 78.9% | 1.80 | 1.58 |
| 7 | Load factor | 65.7% | 73.0% | 71.3% | Avg. Var+Avoid O&M | | 2.16 | 2.19 | Oil | 3.3% | 0.3% | 5.1% | 4.81 | 3.46 |
| 8 | Peak Demand, MW | 14,167 | 14,167 | 12,572 | Total Cost | | 2.51 | 2.53 | Gas-ST | 10.3% | 3.4% | 20.1% | 3.26 | 2.73 |
| 9 | Energy, GWh | 81,548 | 22,658 | 58,890 | Max loss, $/avail kW | | (415.17) | | Gas-CC | 16.6% | 21.5% | 79.9% | 2.96 | 1.73 |
| 10 | Generation, GWh | 81,509 | 22,635 | 58,874 | Start-up Cost, $/MW | | 40 | | Gas-CT | 9.9% | 4.2% | 26.0% | 4.51 | 2.37 |
| 11 | Unserved Energy, G\ | 37 | 23 | 14 | # plants Probabilistic | | 10 | | Other | 0.3% | 0.3% | 60.0% | 7.47 | 1.27 |
| 12 | Round err not in UE | 2 | 0 | 2 | | | | | | | | | | |
| 13 | Plant | | Output | Capac | Time on | Revenue | Var. +Start | Avoidable | Unavoidable | Total Net | Avoidable | Net Rev | Avoidable | Carbon releas |
| 14 | Name | Capacity | MWyr | Factor | Margin, % | M$ | Cost M$ | xd Cst M$ | Fxd Cst M$ | Rev M$ | M$ | $/kW | cost, ¢/kWh | Million Tons |
| 15 | Nuclear1 | 1,000 | 796.00 | 79.6% | 0.00 | 190 | 51 | 90 | 26 | 22 | 48.69 | 61.17 | 2.02 | 0.00 |
| 16 | Nuclear2 | 800 | 636.80 | 79.6% | 0.00 | 152 | 41 | 72 | 144 | (105) | 38.95 | 61.17 | 2.02 | 0.00 |
| 17 | Coal1 | 900 | 709.20 | 78.8% | 0.00 | 169 | 79 | 11 | 23 | 56 | 79.25 | 111.74 | 1.45 | 1.53 |
| 18 | Coal2 | 850 | 719.95 | 84.7% | 0.00 | 171 | 98 | 10 | 13 | 53 | 65.91 | 91.55 | 1.67 | 1.57 |
| 19 | Coal3 | 850 | 719.95 | 84.7% | 0.00 | 171 | 98 | 10 | 8 | 57 | 65.07 | 90.38 | 1.69 | 1.59 |
| 20 | Coal4 | 600 | 498.60 | 83.1% | 0.00 | 119 | 68 | 7 | 18 | 25 | 43.55 | 87.35 | 1.72 | 1.11 |
| 21 | Coal5 | 600 | 497.11 | 82.9% | 0.31 | 119 | 69 | 7 | 0 | 43 | 42.53 | 85.30 | 1.75 | 1.12 |
| 22 | Coal6+7 | 850 | 648.17 | 76.3% | 3.86 | 157 | 96 | 13 | 18 | 30 | 48.43 | 71.93 | 1.91 | 1.49 |
| 23 | Coal8 | 450 | 329.78 | 73.3% | 3.76 | 81 | 57 | 7 | 3 | 14 | 17.14 | 48.08 | 2.21 | 0.79 |
| 24 | Coal9+10 | 450 | 251.58 | 55.9% | 12.23 | 68 | 46 | 7 | 3 | 11 | 14.24 | 38.25 | 2.43 | 0.63 |
| 25 | Coal-Adv. | 50 | 41.80 | 83.6% | 0.00 | 10 | 6 | 13 | - | (8) | (8.40) | (201.01) | 5.02 | 0.09 |
| 26 | Oil1 | 500 | 25.45 | 5.1% | 3.83 | 15 | 8 | 3 | 2 | 2 | 4.37 | 10.51 | 4.81 | 0.05 |
| 27 | GasST1 | 600 | 223.00 | 37.2% | 18.08 | 66 | 51 | 6 | 4 | 6 | 10.28 | 20.51 | 2.88 | 0.28 |
| 28 | GasST2 | 500 | 77.16 | 15.4% | 9.46 | 29 | 20 | 5 | 2 | 2 | 4.31 | 10.32 | 3.66 | 0.10 |
| 29 | GasST3 | 450 | 11.98 | 2.7% | 2.37 | 10 | 4 | 4 | 0 | 2 | 1.91 | 5.08 | 7.88 | 0.02 |
| 30 | GasCC1 | 300 | 137.91 | 46.0% | 8.22 | 39 | 30 | 3 | 14 | (8) | 6.03 | 25.07 | 2.73 | 0.17 |
| 31 | GasCC2-New | 200 | 146.58 | 73.3% | 4.21 | 37 | 26 | 17 | - | (6) | (6.37) | (36.60) | 3.37 | 0.14 |
| 32 | GasCC3-new | 200 | 153.84 | 76.9% | 4.17 | 38 | 27 | 17 | - | (7) | (6.50) | (37.37) | 3.31 | 0.15 |
| 33 | GasCC4-Adv | 800 | 690.48 | 86.3% | 1.06 | 165 | 101 | 74 | - | (10) | (10.38) | (14.91) | 2.90 | 0.55 |
| 34 | GasCC5-Adv | 1,000 | 869.91 | 87.0% | 0.10 | 207 | 118 | 102 | - | (13) | (13.11) | (15.06) | 2.89 | 0.64 |
| 35 | GasCT1+2 | 450 | 5.44 | 1.2% | 0.96 | 8 | 2 | 3 | 4 | (1) | 2.92 | 7.67 | 10.35 | 0.01 |
| 36 | GasCT3-new | 350 | 36.02 | 10.3% | 5.91 | 16 | 9 | 20 | - | (13) | (12.92) | (39.95) | 9.23 | 0.05 |
| 37 | GasCT4-new | 350 | 95.62 | 27.3% | 11.98 | 31 | 24 | 22 | - | (14) | (13.72) | (42.42) | 5.39 | 0.13 |
| 38 | GasCT5-Adv. | 350 | 252.38 | 72.1% | 8.49 | 65 | 46 | 29 | - | (10) | (9.98) | (30.89) | 3.38 | 0.25 |
| 39 | Renewable | 50 | 30.00 | 60.0% | 0.00 | 7 | 3 | 16 | - | (12) | (12.46) | (415.17) | 7.47 | 0.00 |
| 40 | Hydro | 1,600 | 700.00 | 43.8% | | 198 | 6 | 16 | 0 | 176 | 175.51 | 109.70 | 0.36 | 0.00 |
| 41 | Totals | 15,100 | 9,305 | 62% | | 2,338 | 1,180 | 583 | 284 | 291 | 575 | | | 12.47 |
| 42 | | | | | | | | | Avoidable | Total | | | | |
| 43 | Unserved Energy | | 4.24 | | | 19 | 19 | w/o UE | 1,763 | 2,047 | | | Avg. Carbon kg/MWhr | 153 |
| 44 | Totals w/ Unserved | | 9,309 | | | 2,357 | 1,199 | w/ UE | 1,782 | 2,066 | | | Time wtd marginal cost | 2.63 |
| 45 | | | | | | | | | | | | | Time wtd Unserv E Price | 20.59 |
| 46 | | | | | | | | | | | | | Unserv E. Cost/kWh | 52.45 |
| 47 | Sort by Net Revenue/kW | | | | | | | | | | | | Price increase to pay avoided losses | 0.12 |

| | A | B | C | D |
|---|---|---|---|---|
| 48 | | Avoidable | | Reserve |
| 49 | Name | Net Rev/kW | Capacity | Margin |
| 50 | Coal1 | 111.74 | 900 | 6% |
| 51 | Hydro | 109.70 | 1,600 | 18% |
| 52 | Coal2 | 91.55 | 850 | 24% |
| 53 | Coal3 | 90.38 | 850 | 30% |
| 54 | Coal4 | 87.35 | 600 | 34% |
| 55 | Coal5 | 85.30 | 600 | 38% |
| 56 | Coal6+7 | 71.93 | 850 | 44% |
| 57 | Nuclear2 | 61.17 | 800 | 50% |
| 58 | Nuclear1 | 61.17 | 1,000 | 57% |
| 59 | Coal8 | 48.08 | 450 | 60% |
| 60 | Coal9+10 | 38.25 | 450 | 63% |
| 61 | GasCC1 | 25.07 | 300 | 65% |
| 62 | GasST1 | 20.51 | 600 | 70% |
| 63 | Oil1 | 10.51 | 500 | 73% |
| 64 | GasST2 | 10.32 | 500 | 77% |
| 65 | GasCT1+2 | 7.67 | 450 | 80% |
| 66 | GasST3 | 5.08 | 450 | 83% |
| 67 | GasCC4-Adv | (14.91) | 800 | 89% |
| 68 | GasCC5-Adv | (15.06) | 1,000 | 96% |
| 69 | GasCT5-Adv. | (30.89) | 350 | 98% |
| 70 | GasCC2-New | (36.60) | 200 | 100% |
| 71 | GasCC3-new | (37.37) | 200 | 101% |
| 72 | GasCT3-new | (39.95) | 350 | 103% |
| 73 | GasCT4-new | (42.42) | 350 | 106% |
| 74 | Coal-Adv. | (201.01) | 50 | 106% |
| 75 | Renewable | (415.17) | 50 | 107% |



| | A | B | C | D | E | F | G | H | I | J | K | L | M | N | O | P |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Case ID | Efficiency Case | | | | | CAPITALIZAT | IOU-Existing | IPP-Existing | IPP-New | IPP-Renew | Peak Season LDC | | | | |
| 2 | Peak Demand | | 13163.4503 | Fuel Type | $/MMBTU | kg C/MBTU | | 1 | 2 | 3 | 4 | | Season Peak | Shoulder 2 | Shoulder 1 | Min (100%) |
| 3 | Ratio of Off-peak to peak | | 88.4% | Gas | 2.59 | 14.47 | Term (Years) | 30 | 30 | 20 | 20 | % of Season | 0 | 5 | 95 | 100 |
| 4 | Peak fraction of year | | 25% | Coal | 1.34 | 25.72 | Tax life | 20 | 20 | 12 | 5 | Template ratk | 100% | 93% | 53% | 42% |
| 5 | Load Factor, % | | 65.8% | Oil | 3.00 | 21.49 | Inc. Tax Rate | 36% | 36% | 36% | 36% | Ratio to Peak | 100% | 93% | 53% | 42% |
| 6 | Peak Season Load Factor | | 73.1% | Nuclear | 0.70 | 0 | Prop. Tax rate | 5% | 5% | 5% | 5% | Demand MW | 13,163 | 12,282 | 6,988 | 5,509 |
| 7 | Off-Peak Season Load Factor | | 71.6% | Hydro | 0.00 | 0 | Debt % | 48% | 30% | 30% | 30% | Off-Peak Season LDC | | | | |
| 8 | Carbon Tax, $/metric ton C | | 0.00 | Other | 0.00 | 0 | Interest Rate | 8.0% | 10.0% | 10.0% | 10.0% | % of Season | 0 | 2 | 96 | 100 |
| 9 | Capacity Payment,$/kW | | 0 | Year of Study | 2010 | | Preferr Equity | 14% | 0% | 0% | 0% | Template ratk | 100% | 86% | 58% | 50% |
| 10 | Uplift Charge, ¢/kWh | | 0 | Year of $ | 1995 | | Return Rate | 10.0% | 10.0% | 10.0% | 10.0% | Ratio to Peak | 100% | 86% | 58% | 50% |
| 11 | Unserved Energy, ¢/kWh | | 0 | Start-up Cost, $/MW | | 40 | Common Equ | 38% | 70% | 70% | 70% | Demand MW | 11,637 | 9,950 | 6,789 | 5,841 |
| 12 | Non-general. Price, ¢/kWh | | 3.18 | Min Capacity w/ probab | | 0 | Return Rate | 11.0% | 14.0% | 14.0% | 14.0% | | | | | |
| 13 | Price Elasticity(not used if 0) | | 0.05 | Min Outage Rate w/ probab | | 0.0% | Vary FCR by | TRUE | TRUE | FALSE | FALSE | | | | | |
| 14 | Default Unserved E calc (always slow | | | Max # Plants with prob. | | 10 | Include in Avc | FALSE | FALSE | TRUE | TRUE | Fractional change to start year | | 0.30 | | |
| 15 | | | Capacity | Forced | Planned | | | | Variable | | Fixed | – Plant Construction – | | Captilization | Unavoidable | Variable |
| 16 | | | Adjust Factor | Outage | Outage | Heat Rate | | Fuel Price | O&M Cost | Bid Price or | O&M Cost | Nominal | Construction | Structure | Fixed Cost | Cost |
| 17 | Name | Capacity | (0 to1) | Rate | Rate | (BTU/kWh) | Fuel Type | Adjustment | ¢/kwh | OP, ¢/kwh | $/kW-yr | Cost/kW | Year | to Use | const $/kW-yr | ¢/kwh |
| 18 | Nuclear1 | 1,000 | 1 | 8.2% | 12.2% | 10,460 | Nuclear | 1.000 | 0.00 | OP | 90.0 | 800 | 1973 | 1 | 26 | 0.73 |
| 19 | Nuclear2 | 800 | 1 | 8.2% | 12.2% | 10,460 | Nuclear | 1.000 | 0.00 | OP | 90.0 | 2,750 | 1988 | 1 | 180 | 0.73 |
| 20 | Coal1 | 900 | 1 | 7.0% | 14.2% | 9,600 | Coal | 0.833 | 0.21 | OP | 11.7 | 490 | 1983 | 1 | 26 | 1.28 |
| 21 | Coal2 | 850 | 1 | 6.5% | 8.8% | 9,700 | Coal | 1.000 | 0.22 | OP | 11.7 | 370 | 1978 | 1 | 15 | 1.51 |
| 22 | Coal3 | 850 | 1 | 6.5% | 8.8% | 9,800 | Coal | 1.000 | 0.22 | OP | 11.7 | 300 | 1973 | 1 | 10 | 1.53 |
| 23 | Coal4 | 600 | 1 | 6.6% | 10.3% | 9,900 | Coal | 1.000 | 0.23 | OP | 12.4 | 680 | 1981 | 1 | 31 | 1.55 |
| 24 | Coal5 | 600 | 1 | 6.6% | 10.3% | 10,000 | Coal | 1.000 | 0.24 | OP | 12.4 | 380 | 1960 | 1 | 0 | 1.58 |
| 25 | Coal6+7 | 850 | 1 | 8.5% | 12.3% | 10,200 | Coal | 1.000 | 0.32 | OP | 15.2 | 500 | 1980 | 1 | 21 | 1.68 |
| 26 | Coal8 | 450 | 1 | 8.5% | 12.3% | 10,600 | Coal | 1.167 | 0.32 | OP | 15.2 | 300 | 1970 | 1 | 8 | 1.97 |
| 27 | Coal9+10 | 450 | 1 | 6.4% | 10.9% | 11,200 | Coal | 1.167 | 0.35 | OP | 16.3 | 300 | 1970 | 1 | 8 | 2.09 |
| 28 | 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 |
| 29 | Oil1 | 500 | 1 | 11.6% | 5.2% | 10,100 | Oil | 0.840 | 0.50 | OP | 6.0 | 127 | 1973 | 1 | 4 | 3.05 |
| 30 | GasST1 | 600 | 1 | 9.7% | 6.8% | 10,000 | Gas | 0.951 | 0.13 | OP | 9.4 | 170 | 1976 | 1 | 6 | 2.59 |
| 31 | GasST2 | 500 | 1 | 9.7% | 6.8% | 10,100 | Gas | 1.084 | 0.13 | OP | 9.4 | 150 | 1970 | 1 | 4 | 2.96 |
| 32 | GasST3 | 450 | 1 | 9.7% | 6.8% | 10,200 | Gas | 1.111 | 0.13 | OP | 9.4 | 220 | 1967 | 1 | 0 | 3.08 |
| 33 | GasCC1 | 300 | 1 | 6.8% | 13.0% | 9,665 | Gas | 0.951 | 0.10 | OP | 10.0 | 470 | 1992 | 2 | 45 | 2.48 |
| 34 | GasCC2-New | 200 | 1 | 5.5% | 7.5% | 7,760 | Gas | 1.000 | 0.05 | OP | 28.9 | 452 | 1999 | 3 | 55 | 2.06 |
| 35 | GasCC3-new | 200 | 1 | 5.5% | 7.5% | 7,618 | Gas | 1.000 | 0.05 | OP | 28.9 | 477 | 2001 | 3 | 58 | 2.02 |
| 36 | GasCC4-Adv | 750 | 1 | 5.5% | 7.5% | 6,284 | Gas | 1.000 | 0.05 | OP | 26.6 | 538 | 2005 | 3 | 66 | 1.68 |
| 37 | GasCC5-Adv | 550 | 1 | 5.5% | 7.5% | 5,817 | Gas | 1.000 | 0.05 | OP | 26.6 | 615 | 2009 | 3 | 75 | 1.55 |
| 38 | GasCT1+2 | 450 | 1 | 10.0% | 5.4% | 12,800 | Gas | 0.969 | 0.22 | OP | 6.0 | 140 | 1986 | 1 | 9 | 3.42 |
| 39 | GasCT3-new | 350 | 1 | 3.6% | 4.0% | 11,460 | Gas | 1.000 | 0.01 | OP | 11.9 | 364 | 1998 | 3 | 44 | 2.98 |
| 40 | GasCT4-new | 350 | 1 | 3.6% | 4.0% | 10,873 | Gas | 1.000 | 0.01 | OP | 11.9 | 406 | 2002 | 3 | 50 | 2.82 |
| 41 | GasCT5-Adv | 0 | 1 | 3.8% | 3.9% | 7,793 | Gas | 1.000 | 0.05 | OP | 16.9 | 542 | 2008 | 3 | 68 | 2.07 |
| 42 | Renewable | 50 | 1 | 25.0% | 15.0% | 10,280 | Other | 1.000 | 1.27 | OP | 65.5 | 2,361 | 2008 | 4 | 260 | 1.27 |
| 43 | Limited Energ | 1600 | | Peak CF | Non-peak CF | | | | | | | | | | | |
| 44 | Hydro | 1,600 | 1 | 55.0% | 40.0% | | Hydro | | 0.10 | | 10 | 400 | 1957 | 1 | 0 | 0.10 |
| 45 | otal Capacity | 15,850 | | | | | | | | | | | | | | |
| 46 | year | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 |
| 47 | GDP deflator | 1.127 | 1.171 | 1.203 | 1.235 | 1.263 | 1.295 | 1.326 | 1.357 | 1.390 | 1.426 | 1.465 | 1.506 | 1.548 | 1.595 | 1.645 |
| 48 | 1987=100 | 0.846 | | | | | | | | | | | | | | |

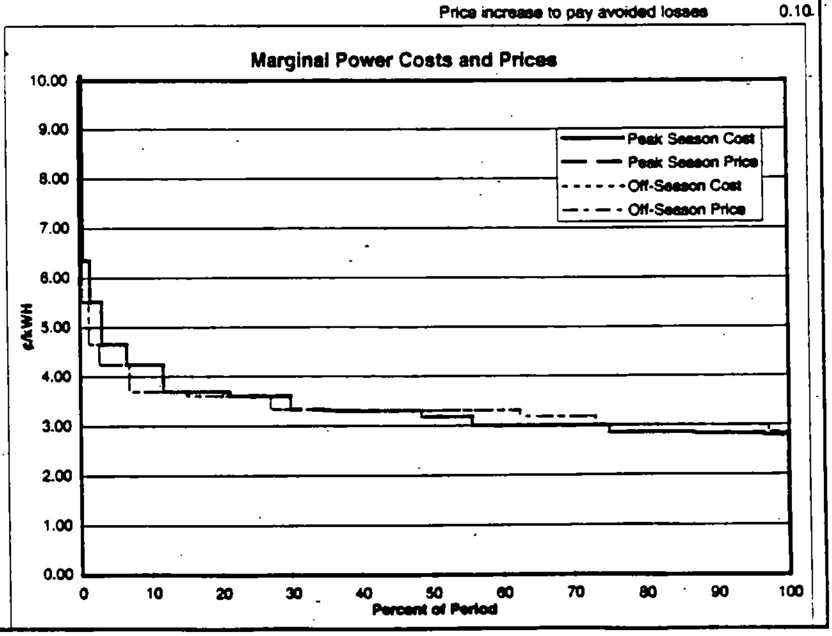
| | A | B | C | D | E | F | G | H | I | J | K | L | M | N |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Efficiency Case | | | | | | | | | | | | | |
| 2 | | | Peak | Offpeak | # of Unprofitable plants | | | | | % of Total | | Cap fact | Avoidable | Variable |
| 3 | | Annual | season | season | Against avoid O&M | | 9 | | | Capacity | Generation | % | ¢/kWh | ¢/kWh |
| 4 | Reserve Margin | 8.3% | 8.3% | 7.7% | Against all costs | | 12 | w/ unserv | Hydro | 11.2% | 8.1% | 43.8% | 0.36 | 0.10 |
| 5 | LOLP, % of period | 0.68 | 1.50 | 0.40 | Average Price, ¢/kWh | | 2.82 | 2.84 | Nuclear | 12.6% | 16.6% | 79.6% | 2.02 | 0.73 |
| 6 | LOLP, day/10 Year | 24.71 | 54.63 | 14.74 | Avg. Variable Cost | | 1.43 | 1.44 | Coal | 39.3% | 51.2% | 79.2% | 1.80 | 1.58 |
| 7 | Load factor | 65.7% | 73.1% | 71.6% | Avg. Vari+Avoid O&M | | 2.09 | 2.11 | Oil | 3.5% | 0.3% | 4.5% | 5.03 | 3.53 |
| 8 | Peak Demand, MW | 13,163 | 13,163 | 11,637 | Total Cost | | 2.47 | 2.48 | Gas-ST | 10.9% | 3.8% | 21.1% | 3.22 | 2.72 |
| 9 | Energy, GWh | 75,835 | 21,068 | 54,767 | Max loss, $/avail kW | | (417.96) | | Gas-CC | 14.0% | 18.1% | 78.5% | 2.98 | 1.78 |
| 10 | Generation, GWh | 75,812 | 21,054 | 54,759 | Start-up Cost, $/MW | | 40 | | Gas-CT | 8.1% | 1.6% | 12.0% | 6.56 | 2.93 |
| 11 | Unserved Energy, Gl | 22 | 14 | 9 | # plants Probabilistic | | 10 | | Other | 0.4% | 0.3% | 60.0% | 7.47 | 1.27 |
| 12 | Round err not in UE | 0 | 0 | (0) | | | | | | | | | | |
| 13 | Plant | | Output | Capac | Time on | Revenue | Var. +Start | Avoidable | Unavoidable | Total Net | Avoidable | Net Rev | Avoidable | Carbon releas |
| 14 | Name | Capacity | MWyr | Factor | Margin, % | M$ | Cost M$ | xd Cst M$ | Fxd Cst M$ | Rev M$ | M$ | $/kW | cost, ¢/kWh | Million Tons |
| 15 | Nuclear1 | 1,000 | 796.00 | 79.6% | 0.00 | 188 | 51 | 90 | 26 | 20 | 46.73 | 58.70 | 2.02 | 0.00 |
| 16 | Nuclear2 | 800 | 636.80 | 79.6% | 0.00 | 150 | 41 | 72 | 144 | (107) | 37.38 | 58.70 | 2.02 | 0.00 |
| 17 | Coal1 | 900 | 709.20 | 78.8% | 0.00 | 167 | 79 | 11 | 23 | 54 | 77.43 | 109.19 | 1.45 | 1.53 |
| 18 | Coal2 | 850 | 719.96 | 84.7% | 0.00 | 170 | 96 | 10 | 13 | 52 | 64.25 | 89.24 | 1.67 | 1.57 |
| 19 | Coal3 | 850 | 719.96 | 84.7% | 0.00 | 170 | 96 | 10 | 8 | 55 | 63.41 | 88.07 | 1.69 | 1.59 |
| 20 | Coal4 | 600 | 498.60 | 83.1% | 0.00 | 118 | 68 | 7 | 18 | 24 | 42.37 | 84.98 | 1.72 | 1.11 |
| 21 | Coal5 | 600 | 497.19 | 82.9% | 0.33 | 117 | 69 | 7 | 0 | 41 | 41.35 | 82.93 | 1.75 | 1.12 |
| 22 | Coal6+7 | 850 | 646.91 | 76.1% | 4.30 | 155 | 95 | 13 | 18 | 29 | 46.76 | 69.46 | 1.91 | 1.49 |
| 23 | Coal8 | 450 | 327.01 | 72.7% | 4.83 | 80 | 56 | 7 | 3 | 13 | 16.30 | 45.73 | 2.21 | 0.78 |
| 24 | Coal9+10 | 450 | 273.17 | 60.7% | 11.99 | 71 | 50 | 7 | 3 | 10 | 13.39 | 35.99 | 2.40 | 0.69 |
| 25 | Coal-Adv. | 50 | 41.80 | 83.6% | 0.00 | 10 | 6 | 13 | - | (9) | (8.50) | (203.46) | 5.02 | 0.09 |
| 26 | Oil1 | 500 | 22.72 | 4.5% | 3.88 | 12 | 7 | 3 | 2 | 0 | 2.14 | 5.14 | 5.03 | 0.04 |
| 27 | GasST1 | 600 | 240.65 | 40.1% | 20.47 | 68 | 55 | 6 | 4 | 4 | 8.02 | 16.00 | 2.85 | 0.31 |
| 28 | GasST2 | 500 | 77.56 | 15.5% | 10.43 | 27 | 20 | 5 | 2 | 0 | 2.20 | 5.26 | 3.65 | 0.10 |
| 29 | GasST3 | 450 | 9.31 | 2.1% | 2.10 | 7 | 3 | 4 | 0 | (0) | (0.13) | (0.34) | 9.19 | 0.01 |
| 30 | GasCC1 | 300 | 150.43 | 50.1% | 9.36 | 41 | 33 | 3 | 14 | (9) | 5.00 | 20.78 | 2.71 | 0.18 |
| 31 | GasCC2-New | 200 | 142.25 | 71.1% | 4.87 | 36 | 26 | 17 | - | (7) | (6.72) | (38.60) | 3.41 | 0.14 |
| 32 | GasCC3-new | 200 | 150.65 | 75.3% | 4.83 | 37 | 27 | 17 | - | (7) | (6.86) | (39.44) | 3.34 | 0.15 |
| 33 | GasCC4-Adv | 750 | 647.40 | 86.3% | 1.03 | 153 | 96 | 69 | - | (11) | (11.20) | (17.16) | 2.90 | 0.52 |
| 34 | GasCC5-Adv | 550 | 478.45 | 87.0% | 0.07 | 113 | 65 | 56 | - | (8) | (8.28) | (17.31) | 2.89 | 0.35 |
| 35 | GasCT1+2 | 450 | 4.22 | 0.9% | 0.82 | 5 | 2 | 3 | 4 | (3) | 1.00 | 2.62 | 12.13 | 0.01 |
| 36 | GasCT3-new | 350 | 33.87 | 9.7% | 6.14 | 14 | 9 | 20 | - | (15) | (14.67) | (45.36) | 9.66 | 0.05 |
| 37 | GasCT4-new | 350 | 100.30 | 28.7% | 13.87 | 31 | 25 | 22 | - | (15) | (15.30) | (47.32) | 5.27 | 0.14 |
| 38 | GasCT5-Adv. | 0 | - | 0.0% | 0.00 | - | - | - | - | - | - | - | 0.00 | 0.00 |
| 39 | Renewable | 50 | 30.00 | 60.0% | 0.00 | 7 | 3 | 16 | - | (13) | (12.54) | (417.96) | 7.47 | 0.00 |
| 40 | Hydro | 1,600 | 700.00 | 43.8% | | 192 | 6 | 16 | 0 | 169 | 169.37 | 105.86 | 0.36 | 0.00 |
| 41 | Totals | 14,250 | 8,654 | 61% | | 2,138 | 1,082 | 503 | 284 | 269 | 553 | | | 11.97 |
| 42 | | | | | | | | | Avoidable | Total | | | | |
| 43 | Unserved Energy | | 2.57 | | | 12 | 12 | w/o UE | 1,586 | 1,869 | | | Avg. Carbon kg/MWhr | 158 |
| 44 | Totals w/ Unserved | | 8,657 | | | 2,150 | 1,094 | w/ UE | 1,597 | 1,881 | | | Time wtd marginal cost | 2.63 |
| 45 | | | | | | | | | | | | | Time wtd Unserv E Price | 19.79 |
| 46 | | | | | | | | | | | | | Unserv E. Cost/kWh | 51.82 |
| 47 | Sort by Net Revenue/kW | | | | | | | | | | | | Price increase to pay avoided losses | 0.11 |
| 48 | | Avoidable | | Reserve | | | | | | | | | | |
| 49 | Name | Net Rev/kW | Capacity | Margin | | | | | | | | | | |
| 50 | Coal1 | 109.19 | 900 | 7% | | | | | | | | | | |
| 51 | Hydro | 105.86 | 1,600 | 19% | | | | | | | | | | |
| 52 | Coal2 | 89.24 | 850 | 25% | | | | | | | | | | |
| 53 | Coal3 | 88.07 | 850 | 32% | | | | | | | | | | |
| 54 | Coal4 | 84.98 | 600 | 36% | | | | | | | | | | |
| 55 | Coal5 | 82.93 | 600 | 41% | | | | | | | | | | |
| 56 | Coal6+7 | 69.46 | 850 | 47% | | | | | | | | | | |
| 57 | Nuclear1 | 58.70 | 1,000 | 55% | | | | | | | | | | |
| 58 | Nuclear2 | 58.70 | 800 | 61% | | | | | | | | | | |
| 59 | Coal8 | 45.73 | 450 | 65% | | | | | | | | | | |
| 60 | Coal9+10 | 35.99 | 450 | 68% | | | | | | | | | | |
| 61 | GasCC1 | 20.78 | 300 | 70% | | | | | | | | | | |
| 62 | GasST1 | 16.00 | 600 | 75% | | | | | | | | | | |
| 63 | GasST2 | 5.26 | 500 | 79% | | | | | | | | | | |
| 64 | Oil1 | 5.14 | 500 | 82% | | | | | | | | | | |
| 65 | GasCT1+2 | 2.62 | 450 | 86% | | | | | | | | | | |
| 66 | GasCT5-Adv. | - | - | 86% | | | | | | | | | | |
| 67 | GasST3 | (0.34) | 450 | 89% | | | | | | | | | | |
| 68 | GasCC4-Adv | (17.16) | 750 | 95% | | | | | | | | | | |
| 69 | GasCC5-Adv | (17.31) | 550 | 99% | | | | | | | | | | |
| 70 | GasCC2-New | (38.60) | 200 | 101% | | | | | | | | | | |
| 71 | GasCC3-new | (39.44) | 200 | 102% | | | | | | | | | | |
| 72 | GasCT3-new | (45.36) | 350 | 105% | | | | | | | | | | |
| 73 | GasCT4-new | (47.32) | 350 | 107% | | | | | | | | | | |
| 74 | Coal-Adv. | (203.46) | 50 | 108% | | | | | | | | | | |
| 75 | Renewable | (417.96) | 50 | 108% | | | | | | | | | | |



| | A | B | C | D | E | F | G | H | I | J | K | L | M | N | O | P |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Case ID | High Efficiency/Low Carbon | | | | | CAPITALIZAT | IOU-Existing | IPP-Existing | IPP-New | IPP-Renew | Peak Season LDC | | | | |
| 2 | Peak Demand | | 12102.8789 | Fuel Type | $/MMBTU | kg C/MBTU | | 1 | 2 | 3 | 4 | | Season Peak | Shoulder 2 | Shoulder 1 | Min (100%) |
| 3 | Ratio of Off-peak to peak | | 88.0% | Gas | 2.59 | 14.47 | Term (Years) | 30 | 30 | 20 | 20 | % of Season | 0 | 5 | 95 | 100 |
| 4 | Peak fraction of year | | 25% | Coal | 1.34 | 25.72 | Tax life | 20 | 20 | 12 | 5 | Template ratio | 100% | 93% | 53% | 42% |
| 5 | Load Factor, % | | 65.7% | Oil | 3.00 | 21.49 | Inc. Tax Rate | 36% | 36% | 36% | 36% | Ratio to Peak | 100% | 93% | 53% | 42% |
| 6 | Peak Season Load Factor | | 72.8% | Nuclear | 0.70 | 0 | Prop. Tax rate | 5% | 5% | 5% | 5% | Demand MW | 12,103 | 11,287 | 6,365 | 5,044 |
| 7 | Off-Peak Season Load Factor | | 72.0% | Hydro | 0.00 | 0 | Debt % | 48% | 30% | 30% | 30% | Off-Peak Season LDC | | | | |
| 8 | Carbon Tax, $/metric ton C | | 50.00 | Other | 0.00 | 0 | Interest Rate | 8.0% | 10.0% | 10.0% | 10.0% | % of Season | 0 | 2 | 98 | 100 |
| 9 | Capacity Payment,$/kW | | 0 | Year of Study | 2010 | | Preferr Equity | 14% | 0% | 0% | 0% | Template ratio | 100% | 86% | 59% | 49% |
| 10 | Uplift Charge, ¢/kWh | | 0 | Year of $ | 1995 | | Return Rate | 10.0% | 10.0% | 10.0% | 10.0% | Ratio to Peak | 100% | 86% | 59% | 49% |
| 11 | Unserved Energy, ¢/kWh | | 0 | Start-up Cost, $/MW | | 40 | Common Equ | 38% | 70% | 70% | 70% | Demand MW | 10,651 | 9,154 | 6,252 | 5,251 |
| 12 | Non-generat. Price, ¢/kWh | | 3.18 | Min Capacity w/ probab | | 0 | Return Rate | 11.0% | 14.0% | 14.0% | 14.0% | | | | | |
| 13 | Price Elasticity(not used if 0) | | 0.05 | Min Outage Rate w/ probab | | 0.0% | Vary FCR by | TRUE | TRUE | FALSE | FALSE | | | | | |
| 14 | Default Unserved E calc (always slow | | | Max # Plants with prob. | | 10 | Include in Avc | FALSE | FALSE | TRUE | TRUE | Fractional change to start year | | 0.30 | | |
| 15 | | | Capacity | Forced | Planned | | | | Variable | | Fixed | – Plant Construction – | | Captilization | Unavoidable | Variable |
| 16 | | | Adjust Factor | Outage | Outage | Heat Rate | | Fuel Price | O&M Cost | Bid Price or | O&M Cost | Nominal | Construction | Structure | Fixed Cost | Cost |
| 17 | Name | Capacity | (0 to1) | Rate | Rate | (BTU/kWh) | Fuel Type | Adjustment | ¢/kwh | OP, ¢/kwh | $/kW-yr | Cost/kW | Year | to Use | const $/kW-yr | ¢/kwh |
| 18 | Nuclear1 | 1,000 | 1 | 8.2% | 12.2% | 10,460 | Nuclear | 1.000 | 0.00 | OP | 90.0 | 800 | 1973 | 1 | 26 | 0.73 |
| 19 | Nuclear2 | 800 | 1 | 8.2% | 12.2% | 10,460 | Nuclear | 1.000 | 0.00 | OP | 90.0 | 2,750 | 1988 | 1 | 180 | 0.73 |
| 20 | Coal1 | 900 | 1 | 7.0% | 14.2% | 9,600 | Coal | 0.833 | 0.21 | OP | 11.7 | 490 | 1983 | 1 | 26 | 2.51 |
| 21 | Coal2 | 850 | 1 | 6.5% | 8.8% | 9,700 | Coal | 1.000 | 0.22 | OP | 11.7 | 370 | 1978 | 1 | 15 | 2.76 |
| 22 | Coal3 | 850 | 1 | 6.5% | 8.8% | 9,800 | Coal | 1.000 | 0.22 | OP | 11.7 | 300 | 1973 | 1 | 10 | 2.79 |
| 23 | Coal4 | 600 | 1 | 6.6% | 10.3% | 9,900 | Coal | 1.000 | 0.23 | OP | 12.4 | 680 | 1981 | 1 | 31 | 2.82 |
| 24 | Coal5 | 600 | 1 | 6.6% | 10.3% | 10,000 | Coal | 1.000 | 0.24 | OP | 12.4 | 380 | 1960 | 1 | 0 | 2.86 |
| 25 | Coal6+7 | 850 | 1 | 8.5% | 12.3% | 10,200 | Coal | 1.000 | 0.32 | OP | 15.2 | 500 | 1980 | 1 | 21 | 2.99 |
| 26 | Coal8 | 200 | 1 | 8.5% | 12.3% | 10,600 | Coal | 1.167 | 0.32 | OP | 15.2 | 300 | 1970 | 1 | 8 | 3.33 |
| 27 | Coal9+10 | 0 | 1 | 6.4% | 10.9% | 11,200 | Coal | 1.167 | 0.35 | OP | 16.3 | 300 | 1970 | 1 | 8 | 3.53 |
| 28 | 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 |
| 29 | Oil1 | 500 | 1 | 11.6% | 5.2% | 10,100 | Oil | 0.840 | 0.50 | OP | 6.0 | 127 | 1973 | 1 | 4 | 4.13 |
| 30 | GasST1 | 600 | 1 | 9.7% | 6.8% | 10,000 | Gas | 0.951 | 0.13 | OP | 9.4 | 170 | 1976 | 1 | 6 | 3.31 |
| 31 | GasST2 | 500 | 1 | 9.7% | 6.8% | 10,100 | Gas | 1.084 | 0.13 | OP | 9.4 | 150 | 1970 | 1 | 4 | 3.69 |
| 32 | GasST3 | 450 | 1 | 9.7% | 6.8% | 10,200 | Gas | 1.111 | 0.13 | OP | 9.4 | 220 | 1967 | 1 | 0 | 3.80 |
| 33 | GasCC1 | 300 | 1 | 6.8% | 13.0% | 9,665 | Gas | 0.951 | 0.10 | OP | 10.0 | 470 | 1992 | 2 | 45 | 3.18 |
| 34 | GasCC2-New | 200 | 1 | 5.5% | 7.5% | 7,760 | Gas | 1.000 | 0.05 | OP | 28.9 | 452 | 1999 | 3 | 55 | 2.62 |
| 35 | GasCC3-new | 200 | 1 | 5.5% | 7.5% | 7,618 | Gas | 1.000 | 0.05 | OP | 28.9 | 477 | 2001 | 3 | 58 | 2.57 |
| 36 | GasCC4-Adv | 400 | 1 | 5.5% | 7.5% | 6,284 | Gas | 1.000 | 0.05 | OP | 26.6 | 538 | 2005 | 3 | 66 | 2.13 |
| 37 | GasCC5-Adv | 950 | 1 | 5.5% | 7.5% | 5,817 | Gas | 1.000 | 0.05 | OP | 26.6 | 615 | 2009 | 3 | 75 | 1.98 |
| 38 | GasCT1+2 | 450 | 1 | 10.0% | 5.4% | 12,800 | Gas | 0.969 | 0.22 | OP | 6.0 | 140 | 1986 | 1 | 9 | 4.35 |
| 39 | GasCT3-new | 350 | 1 | 3.6% | 4.0% | 11,460 | Gas | 1.000 | 0.01 | OP | 11.9 | 364 | 1998 | 3 | 44 | 3.80 |
| 40 | GasCT4-new | 350 | 1 | 3.6% | 4.0% | 10,873 | Gas | 1.000 | 0.01 | OP | 11.9 | 406 | 2002 | 3 | 50 | 3.61 |
| 41 | GasCT5-Adv | 0 | 1 | 3.8% | 3.9% | 7,793 | Gas | 1.000 | 0.05 | OP | 16.9 | 542 | 2008 | 3 | 66 | 2.63 |
| 42 | Renewable | 50 | 1 | 25.0% | 15.0% | 10,280 | Other | 1.000 | 1.27 | OP | 65.5 | 2,361 | 2008 | 4 | 260 | 1.27 |
| 43 | Limited Energy | | | Peak CF | Non-peak CF | | | | | | | | | | | |
| 44 | Hydro | 1,600 | 1 | 55.0% | 40.0% | 1028000.0% | Hydro | | 0.10 | | 10 | 400 | 1957 | 1 | 0 | 0.10 |
| 45 | Total Capacity | 13,600 | | | | | | | | | | | | | | |

| | A | B | C | D | E | F | G | H | I | J | K | L | M | N |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | High Efficiency/Low Carbon | | | | | | | | | | | | | |
| 2 | | | Peak | Offpeak | # of Unprofitable plants | | | | | % of Total | | Cap fact | Avoidable | Variable |
| 3 | | Annual | season | season | Against avoid O&M | | 11 | | | Capacity | Generation | % | ¢/kWh | ¢/kWh |
| 4 | Reserve Margin | 12.4% | 12.4% | 12.6% | Against all costs | | 15 | w/ unserv | Hydro | 11.8% | 8.8% | 43.8% | 0.36 | 0.10 |
| 5 | LOLP, % of period | 0.20 | 0.45 | 0.11 | Average Price, ¢/kWh | | 3.49 | 3.49 | Nuclear | 13.2% | 18.0% | 79.6% | 2.02 | 0.73 |
| 6 | LOLP. day/10 Year | 7.20 | 16.54 | 4.09 | Avg. Variable Cost | | 2.09 | 2.10 | Coal | 36.0% | 46.8% | 76.0% | 3.01 | 2.78 |
| 7 | Load factor | 65.7% | 72.8% | 72.0% | Avg. Vari+Avoid O&M | | 2.81 | 2.82 | Oil | 3.7% | 0.1% | 1.0% | 12.60 | 5.52 |
| 8 | Peak Demand, MW | 12,103 | 12,103 | 10,651 | Total Cost | | 3.21 | 3.22 | Gas-ST | 11.4% | 3.9% | 19.9% | 3.98 | 3.44 |
| 9 | Energy, GWh | 69,686 | 19,301 | 50,384 | Max loss, $/avail kW | | (356.00) | | Gas-CC | 15.1% | 21.1% | 81.7% | 3.41 | 2.25 |
| 10 | Generation, GWh | 69,658 | 19,295 | 50,363 | Start-up Cost, $/MW | | 40 | | Gas-CT | 8.5% | 1.0% | 6.9% | 10.14 | 3.78 |
| 11 | Unserved Energy, G' | 6 | 4 | 2 | # plants Probabilistic | | 9 | | Other | 0.4% | 0.4% | 60.0% | 7.47 | 1.27 |
| 12 | Round err not in UE | 21 | 2 | 19 | | | | | | | | | | |
| 13 | Plant | | Output | Capac | Time on | Revenue | Var. +Start | Avoidable | Unavoidable | Total Net | Avoidable | Net Rev | Avoidable | Carbon releas |
| 14 | Name | Capacity | MWyr | Factor | Margin, % | M$ | Cost M$ | xd Cst M$ | Fxd Cst M$ | Rev M$ | M$ | $/kW | :ost, ¢/kWh | Million Tons |
| 15 | Nuclear1 | 1,000 | 796.00 | 79.6% | 0.00 | 237 | 51 | 90 | 26 | 70 | 96.16 | 120.80 | 2.02 | 0.00 |
| 16 | Nuclear2 | 800 | 636.80 | 79.6% | 0.00 | 190 | 41 | 72 | 144 | (67) | 76.93 | 120.80 | 2.02 | 0.00 |
| 17 | Coal1 | 900 | 709.20 | 78.8% | 0.00 | 211 | 156 | 11 | 23 | 21 | 44.75 | 63.10 | 2.68 | 1.53 |
| 18 | Coal2 | 850 | 719.66 | 84.7% | 0.19 | 214 | 174 | 10 | 13 | 18 | 30.34 | 42.14 | 2.92 | 1.57 |
| 19 | Coal3 | 850 | 715.71 | 84.2% | 0.69 | 213 | 175 | 10 | 8 | 20 | 28.69 | 39.85 | 2.95 | 1.58 |
| 20 | Coal4 | 600 | 484.54 | 80.8% | 3.35 | 145 | 120 | 7 | 18 | (1) | 17.77 | 35.63 | 3.00 | 1.08 |
| 21 | Coal5 | 600 | 465.09 | 77.5% | 4.07 | 140 | 117 | 7 | 0 | 16 | 16.26 | 32.60 | 3.04 | 1.05 |
| 22 | Coal6+7 | 850 | 536.40 | 63.1% | 22.89 | 166 | 141 | 13 | 18 | (6) | 12.02 | 17.85 | 3.27 | 1.23 |
| 23 | Coal8 | 200 | 49.98 | 25.0% | 7.55 | 18 | 15 | 3 | 2 | (2) | (0.11) | (0.68) | 4.03 | 0.12 |
| 24 | Coal9+10 | 0 | - | 0.0% | 0.00 | - | - | - | - | - | - | - | 0.00 | 0.00 |
| 25 | Coal-Adv. | 50 | 41.70 | 83.4% | 0.03 | 12 | 10 | 13 | - | (10) | (10.43) | (249.49) | 6.26 | 0.09 |
| 26 | Oil1 | 500 | 4.84 | 1.0% | 1.07 | 4 | 2 | 3 | 2 | (4) | (1.48) | (3.55) | 12.60 | 0.01 |
| 27 | GasST1 | 600 | 235.55 | 39.3% | 23.75 | 78 | 68 | 6 | 4 | 0 | 3.88 | 7.74 | 3.58 | 0.30 |
| 28 | GasST2 | 500 | 51.27 | 10.3% | 8.49 | 21 | 17 | 5 | 2 | (2) | (0.37) | (0.89) | 4.74 | 0.07 |
| 29 | GasST3 | 450 | 21.26 | 4.7% | 4.47 | 10 | 8 | 4 | 0 | (2) | (1.86) | (4.94) | 6.53 | 0.03 |
| 30 | GasCC1 | 300 | 152.48 | 50.8% | 9.73 | 49 | 42 | 3 | 14 | (10) | 3.27 | 13.59 | 3.40 | 0.19 |
| 31 | GasCC2-New | 200 | 174.00 | 87.0% | 0.00 | 52 | 40 | 17 | - | (5) | (4.90) | (28.16) | 3.72 | 0.17 |
| 32 | GasCC3-new | 200 | 174.00 | 87.0% | 0.00 | 52 | 39 | 17 | - | (5) | (4.80) | (27.59) | 3.72 | 0.17 |
| 33 | GasCC4-Adv | 400 | 348.00 | 87.0% | 0.00 | 104 | 65 | 37 | - | 2 | 1.80 | 5.17 | 3.34 | 0.28 |
| 34 | GasCC5-Adv | 950 | 826.50 | 87.0% | 0.00 | 246 | 143 | 97 | - | 7 | 6.63 | 8.02 | 3.31 | 0.61 |
| 35 | GasCT1+2 | 450 | 1.57 | 0.3% | 0.44 | 2 | 1 | 3 | 4 | (5) | (1.48) | (3.89) | 26.00 | 0.00 |
| 36 | GasCT3-new | 350 | 8.41 | 2.4% | 1.92 | 5 | 3 | 20 | - | (18) | (18.14) | (56.09) | 31.43 | 0.01 |
| 37 | GasCT4-new | 350 | 68.88 | 19.7% | 11.16 | 25 | 22 | 22 | - | (18) | (17.81) | (55.07) | 7.17 | 0.09 |
| 38 | GasCT5-Adv. | 0 | - | 0.0% | 0.00 | - | - | - | - | - | - | - | 0.00 | 0.00 |
| 39 | Renewable | 50 | 30.00 | 60.0% | 0.00 | 9 | 3 | 16 | - | (11) | (10.68) | (356.00) | 7.47 | 0.00 |
| 40 | Hydro | 1,600 | 700.00 | 43.8% | | 226 | 6 | 16 | 0 | 204 | 203.86 | 127.41 | 0.36 | 0.00 |
| 41 | Totals | 13,600 | 7,952 | 58% | | 2,430 | 1,459 | 501 | 278 | 192 | 470 | | | 10.18 |
| 42 | | | | | | | | | Avoidable | Total | | | | |
| 43 | Unserved Energy | | 0.73 | | | 4 | 4 | w/o UE | 1,960 | 2,238 | | Avg. Carbon kg/MWhr | | 146 |
| 44 | Totals w/ Unserved | | 7,953 | | | 2,433 | 1,463 | w/ UE | 1,963 | 2,242 | | Time wtd marginal cost | | 3.38 |
| 45 | | | | | | | | | | | | Time wtd Unserv E Price | | 22.83 |
| 46 | | | | | | | | | | | | Unserv E. Cost/kWh | | 55.90 |
| 47 | Sort by Net Revenue/kW | | | | | | | | | | | Price increase to pay avoided losses | | 0.10 |

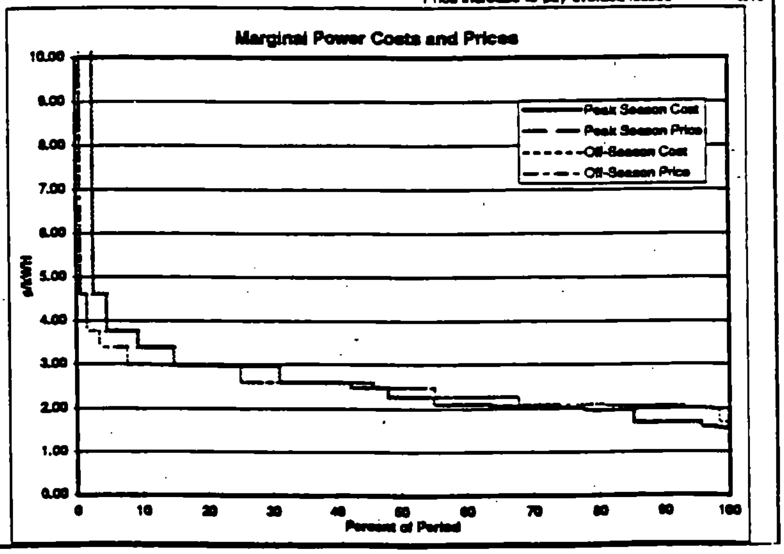
| | Name | Avoidable Net Rev/kW | Capacity | Reserve Margin |
|---|---|---|---|---|
| 50 | Hydro | 127.41 | 1,600 | 13% |
| 51 | Nuclear1 | 120.80 | 1,000 | 21% |
| 52 | Nuclear2 | 120.80 | 800 | 28% |
| 53 | Coal1 | 63.10 | 900 | 36% |
| 54 | Coal2 | 42.14 | 850 | 43% |
| 55 | Coal3 | 39.85 | 850 | 50% |
| 56 | Coal4 | 35.63 | 600 | 55% |
| 57 | Coal5 | 32.60 | 600 | 59% |
| 58 | Coal6+7 | 17.85 | 850 | 67% |
| 59 | GasCC1 | 13.59 | 300 | 69% |
| 60 | GasCC5-Adv | 8.02 | 950 | 77% |
| 61 | GasST1 | 7.74 | 600 | 82% |
| 62 | GasCC4-Adv | 5.17 | 400 | 85% |
| 63 | Coal9+10 | - | - | 85% |
| 64 | GasCT5-Adv. | - | - | 85% |
| 65 | Coal8 | (0.68) | 200 | 87% |
| 66 | GasST2 | (0.89) | 500 | 91% |
| 67 | Oil1 | (3.55) | 500 | 95% |
| 68 | GasCT1+2 | (3.89) | 450 | 99% |
| 69 | GasST3 | (4.94) | 450 | 102% |
| 70 | GasCC3-new | (27.59) | 200 | 104% |
| 71 | GasCC2-New | (28.16) | 200 | 106% |
| 72 | GasCT4-new | (55.07) | 350 | 109% |
| 73 | GasCT3-new | (56.09) | 350 | 112% |
| 74 | Coal-Adv. | (249.49) | 50 | 112% |
| 75 | Renewable | (356.00) | 50 | 112% |



| | A | B | C | D | E | F | G | H | I | J | K | L | M | N | O | P |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Case ID | Alt. Technology | | | | | CAPITALIZAT | IOU-Existing | IPP-Existing | IPP-New | IPP-Renew | Peak Season LDC | | | | |
| 2 | Peak Demand | | 14134.3982 | Fuel Type | $/MMBTU | kg C/MBTU | | 1 | 2 | 3 | 4 | | Season Peak | Shoulder 2 | Shoulder 1 | Min (100%) |
| 3 | 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 |
| 4 | Peak fraction of year | | 25% | Coal | 1.34 | 25.72 | Tax life | 20 | 20 | 12 | 5 | Template ratic | 100% | 94% | 53% | 42% |
| 5 | Load Factor, % | | 65.7% | Oil | 3.00 | 21.49 | Inc. Tax Rate | 36% | 36% | 36% | 36% | Ratio to Peak | 100% | 94% | 53% | 42% |
| 6 | 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 |
| 7 | Off-Peak Season Load Factor | | 71.3% | Hydro | 0.00 | 0 | Debt % | 48% | 30% | 30% | 30% | Off-Peak Season LDC | | | | |
| 8 | Carbon Tax, $/metric ton C | | 0.00 | Other | 0.00 | 0 | Interest Rate | 8.0% | 10.0% | 10.0% | 10.0% | % of Season | 0 | 2 | 98 | 100 |
| 9 | Capacity Payment,$/kW | | 0 | Year of Study | 2010 | | Preferr Equity | 14% | 0% | 0% | 0% | Template ratic | 100% | 85% | 58% | 50% |
| 10 | Uplift Charge, ¢/kWh | | 0 | Year of $ | 1995 | | Return Rate | 10.0% | 10.0% | 10.0% | 10.0% | Ratio to Peak | 100% | 85% | 58% | 50% |
| 11 | Unserved Energy, ¢/kWh | | 0 | Start-up Cost, $/MW | | 40 | Common Equ | 38% | 70% | 70% | 70% | Demand MW | 12,538 | 10,707 | 7,242 | 6,225 |
| 12 | Non-generat. Price, ¢/kWh | | 3.18 | Min Capacity w/ probab | | 0 | Return Rate | 11.0% | 14.0% | 14.0% | 14.0% | | | | | |
| 13 | Price Elasticity(not used if 0) | | 0.05 | Min Outage Rate w/ probab | | 0.0% | Vary FCR by ' | TRUE | TRUE | FALSE | FALSE | | | | | |
| 14 | Default Unserved E calc (always slow | | | Max # Plants with prob. | | 10 | Include in Avc | FALSE | FALSE | TRUE | TRUE | Fractional change to start year | | 0.30 | | |
| 15 | | | Capacity | Forced | Planned | | | | Variable | | Fixed | – Plant Construction – | | Captilization | Unavoidable | Variable |
| 16 | | | Adjust Factor | Outage | Outage | Heat Rate | | Fuel Price | O&M Cost | Bid Price or | O&M Cost | Nominal | Construction | Structure | Fixed Cost | Cost |
| 17 | Name | Capacity | (0 to1) | Rate | Rate | (BTU/kWh) | Fuel Type | Adjustment | ¢/kwh | OP, ¢/kwh | $/kW-yr | Cost/kW | Year | to Use | const $/kW-yr | ¢/kwh |
| 18 | Nuclear1 | 1,000 | 1 | 8.2% | 12.2% | 10,460 | Nuclear | 1.000 | 0.00 | OP | 90.0 | 800 | 1973 | 1 | 26 | 0.73 |
| 19 | Nuclear2 | 800 | 1 | 8.2% | 12.2% | 10,460 | Nuclear | 1.000 | 0.00 | OP | 90.0 | 2,750 | 1988 | 1 | 180 | 0.73 |
| 20 | Coal1 | 900 | 1 | 7.0% | 14.2% | 9,600 | Coal | 0.833 | 0.21 | OP | 11.7 | 490 | 1983 | 1 | 26 | 1.28 |
| 21 | Coal2 | 850 | 1 | 6.5% | 8.8% | 9,700 | Coal | 1.000 | 0.22 | OP | 11.7 | 370 | 1978 | 1 | 15 | 1.51 |
| 22 | Coal3 | 850 | 1 | 6.5% | 8.8% | 9,800 | Coal | 1.000 | 0.22 | OP | 11.7 | 300 | 1973 | 1 | 10 | 1.53 |
| 23 | Coal4 | 600 | 1 | 6.6% | 10.3% | 9,900 | Coal | 1.000 | 0.23 | OP | 12.4 | 680 | 1981 | 1 | 31 | 1.55 |
| 24 | Coal5 | 600 | 1 | 6.6% | 10.3% | 10,000 | Coal | 1.000 | 0.24 | OP | 12.4 | 380 | 1960 | 1 | 0 | 1.58 |
| 25 | Coal6+7 | 850 | 1 | 8.5% | 12.3% | 10,200 | Coal | 1.000 | 0.32 | OP | 15.2 | 500 | 1980 | 1 | 21 | 1.68 |
| 26 | Coal8 | 450 | 1 | 8.5% | 12.3% | 10,600 | Coal | 1.167 | 0.32 | OP | 15.2 | 300 | 1970 | 1 | 8 | 1.97 |
| 27 | Coal9+10 | 450 | 1 | 6.4% | 10.9% | 11,200 | Coal | 1.167 | 0.35 | OP | 16.3 | 300 | 1970 | 1 | 8 | 2.09 |
| 28 | 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 |
| 29 | Oil1 | 500 | 1 | 11.6% | 5.2% | 10,100 | Oil | 0.840 | 0.50 | OP | 6.0 | 127 | 1973 | 1 | 4 | 3.05 |
| 30 | GasST1 | 600 | 1 | 9.7% | 6.8% | 10,000 | Gas | 0.951 | 0.13 | OP | 9.4 | 170 | 1976 | 1 | 6 | 2.59 |
| 31 | GasST2 | 500 | 1 | 9.7% | 6.8% | 10,100 | Gas | 1.084 | 0.13 | OP | 9.4 | 150 | 1970 | 1 | 4 | 2.96 |
| 32 | GasST3 | 450 | 1 | 9.7% | 6.8% | 10,200 | Gas | 1.111 | 0.13 | OP | 9.4 | 220 | 1967 | 1 | 0 | 3.06 |
| 33 | GasCC1 | 300 | 1 | 6.8% | 13.0% | 9,665 | Gas | 0.951 | 0.10 | OP | 10.0 | 470 | 1992 | 2 | 45 | 2.48 |
| 34 | GasCC2-New | 550 | 1 | 5.5% | 7.5% | 7,760 | Gas | 1.000 | 0.05 | OP | 28.9 | 452 | 1999 | 3 | 55 | 2.06 |
| 35 | GasCC3-new | 200 | 1 | 5.5% | 7.5% | 7,618 | Gas | 1.000 | 0.05 | OP | 28.9 | 477 | 2001 | 3 | 58 | 2.02 |
| 36 | GasCC4-Bral | 800 | 1 | 5.5% | 7.5% | 5,688 | Gas | 1.000 | 0.015 | OP | 16.0 | 689 | 2005 | 3 | 84 | 1.49 |
| 37 | GasCC5-Bral | 900 | 1 | 5.5% | 7.5% | 5,538 | Gas | 1.000 | 0.015 | OP | 16.0 | 774 | 2010 | 3 | 95 | 1.45 |
| 38 | GasCT1+2 | 450 | 1 | 10.0% | 5.4% | 12,800 | Gas | 0.969 | 0.22 | OP | 6.0 | 140 | 1986 | 1 | 9 | 3.42 |
| 39 | GasCT3-new | 350 | 1 | 3.6% | 4.0% | 11,460 | Gas | 1.000 | 0.01 | OP | 11.9 | 364 | 1998 | 3 | 44 | 2.98 |
| 40 | GasCT4-Bral | 350 | 1 | 3.6% | 4.0% | 8,699 | Gas | 1.000 | 0.012 | OP | 17.6 | 525 | 2005 | 3 | 64 | 2.26 |
| 41 | GasCT5-Bral | 0 | 1 | 3.8% | 3.9% | 8,533 | Gas | 1.000 | 0.012 | OP | 17.6 | 564 | 2010 | 3 | 69 | 2.22 |
| 42 | Renewable | 50 | 1 | 25.0% | 15.0% | 10,280 | Other | 1.000 | 1.27 | OP | 65.5 | 2,361 | 2008 | 4 | 260 | 1.27 |
| 43 | Limited Energy | | | Peak CF | Non-peak CF | | | | | | | | | | | |
| 44 | Hydro | 1,600 | 1 | 55.0% | 40.0% | | Hydro | | 0.10 | | 10 | 400 | 1957 | 1 | 0 | 0.10 |
| 45 | Total Capacity | 15,000 | | | | | | | | | | | | | | |

| | A | B | C | D | E | F | G | H | I | J | K | L | M | N |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | ALL Technology Case | | | | | | | | | | | | | |
| 2 | | | Peak | Offpeak | # of Unprofitable plants | | | | | % of Total | | Cap fact | Avoidable | Variable |
| 3 | | Annual | season | season | Against avoid O&M | | 8 | | | Capacity | Generation | % | ¢/kWh | ¢/kWh |
| 4 | Reserve Margin | 6.1% | 6.1% | 5.3% | Against all costs | | 10 | w/ unserv | Hydro | 10.7% | 7.6% | 43.8% | 0.36 | 0.10 |
| 5 | LOLP, % of period | 1.14 | 2.56 | 0.66 | Average Price, ¢/kWh | | 2.59 | 2.91 | Nuclear | 12.0% | 16.4% | 79.6% | 2.02 | 0.73 |
| 6 | LOLP, day/10 Year | 41.49 | 93.21 | 24.25 | Avg. Variable Cost | | 1.42 | 1.46 | Coal | 37.3% | 47.7% | 79.0% | 1.79 | 1.58 |
| 7 | Load factor | 66.6% | 73.0% | 71.3% | Avg. Vari+Avoid O&M | | 2.15 | 2.18 | Oil | 3.3% | 0.3% | 5.7% | 4.59 | 3.39 |
| 8 | Peak Demand, MW | 14,134 | 14,134 | 12,538 | Total Cost | | 2.50 | 2.82 | Gas-ST | 10.3% | 3.0% | 17.9% | 3.36 | 2.76 |
| 9 | Energy, GWh | 81,329 | 22,607 | 58,720 | Max loss, $/avail kW | | (414.51) | | Gas-CC | 18.3% | 23.1% | 78.0% | 2.98 | 1.67 |
| 10 | Generation, GWh | 81,282 | 22,580 | 58,702 | Start-up Cost, $/MW | | 40 | | Gas-CT | 7.7% | 2.6% | 20.7% | 4.90 | 2.45 |
| 11 | Unserved Energy, G | 44 | 27 | 18 | # plants Probabilistic | | 10 | | Other | 0.3% | 0.3% | 60.0% | 7.47 | 1.27 |
| 12 | Round err not in UE | (0) | (0) | (0) | | | | | | | | | | |
| 13 | Plant | | Output | Capac | Time on | Revenue | Var. +Start | Avoidable | Unavoidable | Total Net | Avoidable | Net Rev | Avoidable | Carbon release |
| 14 | Name | Capacity | MWyr | Factor | Margin, % | M$ | Cost M$ | Fxd Cst M$ | Fxd Cst M$ | Rev M$ | M$ | $/kW | cost, ¢/kWh | Million Tons |
| 15 | Nuclear1 | 1,000 | 796.00 | 79.6% | 0.00 | 190 | 51 | 90 | 28 | 23 | 49.10 | 61.69 | 2.02 | 0.00 |
| 16 | Nuclear2 | 800 | 636.80 | 79.6% | 0.00 | 182 | 41 | 72 | 144 | (105) | 39.28 | 61.69 | 2.02 | 0.00 |
| 17 | Coal1 | 900 | 709.20 | 78.8% | 0.00 | 170 | 79 | 11 | 23 | 58 | 79.64 | 112.30 | 1.46 | 1.53 |
| 18 | Coal2 | 850 | 719.95 | 84.7% | 0.00 | 172 | 98 | 10 | 13 | 54 | 68.23 | 91.99 | 1.67 | 1.57 |
| 19 | Coal3 | 850 | 719.70 | 84.7% | 0.16 | 172 | 98 | 10 | 8 | 57 | 66.38 | 90.82 | 1.69 | 1.59 |
| 20 | Coal4 | 600 | 496.78 | 82.8% | 0.32 | 119 | 69 | 7 | 18 | 25 | 43.79 | 87.82 | 1.72 | 1.11 |
| 21 | Coal5 | 600 | 494.59 | 82.4% | 0.66 | 118 | 68 | 7 | 0 | 43 | 42.77 | 86.79 | 1.75 | 1.11 |
| 22 | Coal6+7 | 850 | 660.83 | 78.6% | 3.73 | 158 | 98 | 13 | 18 | 31 | 48.83 | 72.54 | 1.91 | 1.50 |
| 23 | Coal8 | 460 | 331.98 | 73.8% | 2.83 | 81 | 57 | 7 | 3 | 14 | 17.31 | 48.57 | 2.21 | 0.79 |
| 24 | Coal9+10 | 460 | 281.37 | 58.1% | 11.74 | 70 | 48 | 7 | 3 | 11 | 14.38 | 38.58 | 2.41 | 0.66 |
| 25 | Coal-Bratch | 50 | 41.80 | 83.6% | 0.00 | 10 | 4 | 10 | - | (4) | (3.78) | (90.46) | 3.78 | 0.08 |
| 26 | Oil1 | 500 | 28.64 | 5.7% | 4.50 | 17 | 9 | 3 | 2 | 4 | 5.92 | 14.24 | 4.59 | 0.06 |
| 27 | GasST1 | 600 | 179.04 | 29.8% | 18.47 | 88 | 41 | 6 | 4 | 8 | 11.39 | 22.74 | 2.96 | 0.23 |
| 28 | GasST2 | 500 | 86.25 | 17.1% | 10.80 | 33 | 22 | 5 | 2 | 4 | 5.87 | 14.05 | 3.59 | 0.11 |
| 29 | GasST3 | 460 | 13.87 | 3.1% | 2.59 | 12 | 5 | 4 | 0 | 3 | 3.27 | 8.70 | 7.25 | 0.02 |
| 30 | GasCC1 | 300 | 117.82 | 39.3% | 8.46 | 36 | 28 | 3 | 14 | (7) | 6.40 | 28.60 | 2.77 | 0.14 |
| 31 | GasCC2-New | 550 | 392.25 | 71.3% | 11.87 | 100 | 71 | 48 | - | (17) | (17.39) | (38.33) | 3.40 | 0.39 |
| 32 | GasCC3-new | 200 | 156.44 | 78.2% | 4.08 | 39 | 28 | 17 | - | (6) | (6.45) | (37.06) | 3.29 | 0.16 |
| 33 | GasCC4-Bratch | 800 | 696.00 | 87.0% | 0.00 | 166 | 91 | 80 | - | (5) | (4.79) | (6.88) | 2.80 | 0.50 |
| 34 | GasCC5-Bratch | 900 | 783.00 | 87.0% | 0.00 | 187 | 99 | 99 | - | (12) | (12.16) | (15.53) | 2.90 | 0.56 |
| 35 | GasCT1+2 | 460 | 6.21 | 1.4% | 1.18 | 9 | 3 | 3 | 4 | 0 | 4.18 | 10.98 | 9.67 | 0.01 |
| 36 | GasCT3-new | 360 | 40.82 | 11.7% | 6.28 | 19 | 11 | 20 | - | (12) | (11.74) | (36.29) | 8.49 | 0.06 |
| 37 | GasCT4-Bratch | 380 | 190.48 | 54.4% | 11.23 | 83 | 38 | 29 | - | (13) | (13.07) | (40.41) | 3.98 | 0.21 |
| 38 | GasCT5-Bratch | 0 | - | 0.0% | 0.00 | - | - | - | - | - | - | - | 0.00 | 0.00 |
| 39 | Renewable | 50 | 30.00 | 60.0% | 0.00 | 7 | 3 | 16 | - | (12) | (12.44) | (414.51) | 7.47 | 0.00 |
| 40 | Hydro | 1,600 | 700.00 | 43.8% | | 201 | 6 | 16 | 0 | 178 | 178.46 | 111.54 | 0.36 | 0.00 |
| 41 | Totals | 16,000 | 9,279 | 62% | | 2,346 | 1,154 | 591 | 284 | 317 | 600 | | | 12.35 |
| 42 | | | | | | | | | Avoidable | Total | | | | |
| 43 | Unserved Energy | | 5.06 | | | 24 | 24 | w/o UE | 1,745 | 2,029 | | Avg. Carbon kg/MWhr | | 182 |
| 44 | Totals w/ Unserved | | 9,284 | | | 2,370 | 1,178 | w/ UE | 1,770 | 2,053 | | Time wtd marginal cost | | 2.61 |
| 45 | | | | | | | | | | | | Time wtd Unserv E Price | | 21.69 |
| 46 | | | | | | | | | | | | Unserv E. Cost/kWh | | 54.37 |
| 47 | Sort by Net Revenue/kW | | | | | | | | | | | Price increase to pay avoided losses | | 0.10 |

| | A | B | C | D |
|---|---|---|---|---|
| 48 | | Avoidable | | Reserve |
| 49 | Name | Net Rev/kW | Capacity | Margin |
| 50 | Coal1 | 112.30 | 900 | 6% |
| 51 | Hydro | 111.54 | 1,600 | 18% |
| 52 | Coal2 | 91.99 | 850 | 24% |
| 53 | Coal3 | 90.82 | 850 | 30% |
| 54 | Coal4 | 87.82 | 600 | 34% |
| 55 | Coal5 | 86.79 | 600 | 38% |
| 56 | Coal6+7 | 72.54 | 850 | 44% |
| 57 | Nuclear1 | 61.69 | 1,000 | 51% |
| 58 | Nuclear2 | 61.69 | 800 | 57% |
| 59 | Coal8 | 48.57 | 460 | 60% |
| 60 | Coal9+10 | 38.58 | 460 | 63% |
| 61 | GasCC1 | 28.60 | 300 | 66% |
| 62 | GasST1 | 22.74 | 600 | 70% |
| 63 | Oil1 | 14.24 | 500 | 73% |
| 64 | GasST2 | 14.05 | 500 | 77% |
| 65 | GasCT1+2 | 10.98 | 460 | 80% |
| 66 | GasST3 | 8.70 | 460 | 83% |
| 67 | GasCT5-Bratch | - | - | 83% |
| 68 | GasCC4-Bratch | (6.88) | 800 | 89% |
| 69 | GasCC5-Bratch | (15.53) | 900 | 95% |
| 70 | GasCT3-new | (36.29) | 360 | 98% |
| 71 | GasCC2-New | (38.33) | 550 | 102% |
| 72 | GasCC3-new | (37.06) | 200 | 103% |
| 73 | GasCT4-Bratch | (40.41) | 380 | 106% |
| 74 | Coal-Bratch | (90.46) | 50 | 106% |
| 75 | Renewable | (414.51) | 50 | 106% |



# APPENDIX G

# Interlab Study on Scenarios of U. S. Carbon Reductions

# APPENDIX G-1

# NGCC Repowering Technology Data

# APPENDIX G-1

# NGCC REPOWERING TECHNOLOGY DATA

## G-1.1 CANDIDATE PLANTS

The approach used in this analysis was to identify the appropriate combined cycle gas turbine technology for the three groups of coal-fired boilers:

- dual fuel—gas and coal can be burned in the existing boiler at the site
- multi-fuel—gas, oil and coal are available for different boilers at the site
- coal only—coal is the only fuel currently available at the site.

The data for each group included the total annual megawatts (MW) output for each plant site, the current fuel requirement, and an estimate of how the total nameplate capacity of each current unit would be redistributed when repowering occurred. A constant value of 1.77 was used for the ratio of the gas turbine to steam turbine capacity, at the repowered plant site. The information on the current units at each plant site was then summed to establish the required gas turbine and steam turbine capacity.

## G-1.2 COST OF CONVERSION

The approach used to generate the cost data was based on the SOAPP CT/CC program; these data provided a first order approximation of the turbine repowering costs by evaluating a limited number of cases based on the use of specific machines. Cases were developed for single GE 6B, 6FA, and 7FA gas turbines and one and three Westinghouse 501F gas turbines (Table G-1.1). It should be pointed out that these costs are general and do not take into account the specific problems that would be encountered at individual sites. As a result, the costs are probably somewhat low relative to actual projects because they do not include removal of the old boiler and any associated asbestos removal requirements. Their main value is that they are consistent with one another.

These values were used for the smaller site repowering cases with the exception of the GE 7FA and Westinghouse 501F numbers. The GE7FA data used was an average of the data obtained from SEPRIL[1] and Gas Turbine World[2], because the SEPRIL data was not available for a reheat systems. The Westinghouse 501F numbers were used to provide background information in the speculative exercise of guessing what the future price of the GE H machine might be. The values that are included in Table G-1.1 are arbitrary estimates of what repowering projects based on these machines would cost.

For the steam turbine repowering cases, the site repowering numbers were adjusted by deleting the costs of the steam turbine and accessories, steam bypass system, steam turbine electrical systems, condenser and accessories, circulating water system, water treatment system and waste water treatment system, as well as half the cost of buildings. The remaining costs were increased by 10% to cover refurbishment.

[1] SEPRIL is a joint-venture consulting arrangement between Sargent & Lundy Consulting Engineers and the Electric Power Research Institute (EPRI) to market and further develop the SOAPP analytic tool.
[2] Gas Turbine World 1996 Handbook

The smaller systems did not include reheat, while the larger Westinghouse systems did. All costs are expressed in 1997 dollars. The units are equipped with dry low $NO_x$ burners and SCR systems so that $NO_x$ emissions are less than 9 ppm.

The ratio of steam turbine repowering costs to site repowering costs were in the range of 0.69 to 0.77. It was decided to use a constant of 0.75, since the cases were not exactly parallel.

The costs that were developed for the GE units were used for the development of the generic repowering project cost data. Similar equipment from other vendors would have about the same ratings, heat rates and prices. The high performance GE "H" models that are scheduled to be available in 1999 were selected as the prime building block for the large repowering projects. Other vendors are expected to offer competitive equipment in the same time frame. These units will be the most efficient units available after 2000 and will likely be priced at the lowest cost per kilowatt of capacity. They will operate with a higher outlet temperature, and therefore produce higher pressure steam (1800 psig) compared with the 1400-1500 psig steam produced with the FA models.[3] This will result in improved steam turbine performance. These combined cycle ratings were then used to select the equipment that would have to be installed to closely match the previous total output from the plant site.

## G-1.3 CAPITAL COST

Table G-1.2 summarizes the new combined cycle equipment that would have to be installed at each plant site to enable it to nominally match its previous nameplate rating. Investment requirements for both site and steam turbine repowering are also provided. This had to be done by ranges since the gas turbines have specific output ratings. In this analysis, the steam turbine that most closely matched the requirements to process the steam generated in the newly installed heat recovery steam generator (HRSG) was selected for continued service.

For the site repowering cases, the new combined cycles will operate at essentially the heat rates indicated. Where the total capacity exceeds the nameplate capacity of the existing units, the heat rates identified should be approximately correct, if the units are run at somewhat less than full capacity to match the previous site nameplate rating, since the heat rate only degrades slightly, about 10%, down to about 75% of capacity.

A 1996 PowerGen paper by Sullivan of Westinghouse and others suggested than the reuse of old equipment would lead to an increase in heat rate of 125-250 Btu/kWh for reheat units and 200-400 Btu/kWh for non reheat units, compared with the heat rates in Table G-1.2.[4] It was assumed that all units less than 500 MW are non-reheat units and all units above 500 MW are reheat units.

[3] Cornan, James C. and Thomas C. Paul, *Power Systems for the 21st Century - H Gas Turbine Combined Cycle.*
[4] Sullivan, Thomas M., et al, *The Sui Generis - Application of Repowering*, PowerGen 1996.

Table G-1.1 Advanced Gas Turbines Data

| Model | MW in combined cycle operation | | Full load heat rate, HHV basis | | $/kW installed turnkey basis | |
|---|---|---|---|---|---|---|
| CT Model | GTW | WITS[5] | GTW | WITS | GTW | WITS |
| GE 6B | 59.8 | 56.5 | 7770 | 8065 | 619 | 712 |
| GE 6FA | 107.1 | 98.8 | 7150 | 7655 | 790 | 585 |
| GE 7 FA | 253.5 | 244.9 | 6840 | 7085 | 465 | 404 |
| - | | | | | 435 | 435 |
| Westinghouse | | | | | | |
| 1-501G | | 322.1 | | 6869 | | 385 |
| 3-501G | | 983.6 | | 6873 | | 315 |
| GE 7H- available in 1999 | 400 GE press release | | 6320 GE press release | | | |
| 1-7H | | | | | | 360 |
| 2-7H | | | | | | 350 |
| 3-7H | | | | | | 340 |
| 4-7H | | | | | | 330 |
| 5-7H | | | | | | 320 |
| 6-7H | | | | | | 310 |
| 7-7H | | | | | | 300 |

Therefore it was decided to add 300 Btu/kWh to the heat rates for the units below 500 MW, and 200 Btu/kWh for the units above 500 MW.

## G-1.4 STEAM TURBINE INTEGRATION

Most of the large modem steam turbines in the U.S. operate with inlet steam conditions of 2400 psig and 1000°F, with a single reheat to 1000°F. In addition, there are a number of very large supercritical units with inlet steam conditions of 3500 psig and 1000°F, with a single reheat to 1000°F. The inlet steam conditions for combined cycle plants are 1400-1500 psig and 1000 °F with a single reheat to 1000°F. Therefore, the repowered plants will be running at much less severe conditions. Since about two-third's of the total power output would be coming from the new gas turbines, only about one third of the prior steam turbine capacity that existed at that

[5] Wolk Integrated Technical Services (WITS).

Table G-1.2 Summary of NGCC Data - Site and Steam Turbine Repowering

| Existing plant nameplate rating, MW | Combined cycle equipment selected | New site heat rate BTU/kW | New plant rating MW | Projected investment for site repowering $, millions | Projected investment for steam turbine repowering $, millions |
|---|---|---|---|---|---|
| 0-60 | 1-6B | 7770 | 60 | 42.7 | 31.9 |
| 60-110 | 1-6FA | 7150 | 110 | 64.4 | 49.3 |
| 110-230 | 2-6FA | 7150 | 220 | 128.8 | 98.6 |
| 230-260 | 7FA | 6840 | 260 | 109 | 81.3 |
| 260-370 | 1-6FA+1-7FA | 6940 | 370 | 174 | 131 |
| 400 | 1-7H | 6320 | 400 | 144 | 108 |
| 400-510 | 1-7H+1-6FA | 6500 | 510 | 208 | 157 |
| 510-650 | 1-7H+1-7FA | 6500 | 650 | 253 | 189 |
| 650-800 | 2-7H | 6320 | 800 | 280 | 210 |
| 800-1050 | 2-7H+1-7FA | 6400 | 1050 | 389 | 291 |
| 1050-1200 | 3-7H | 6320 | 1200 | 408 | 306 |
| 1200-1450 | 3-7H+1-7FA | 6320 | 1450 | 517 | 387 |
| 1450-1600 | 4-7H | 6320 | 1600 | 528 | 397 |
| 1600-1850 | 4-7H+1-7FA | 6320 | 1850 | 637 | 478 |
| 1850-2000 | 5-7H | 6320 | 2000 | 640 | 480 |
| 2000-2250 | 5-7H+1-7FA | 6320 | 2250 | 749 | 561 |
| 2250-2400 | 6-7H | 6320 | 2400 | 744 | 559 |
| 2400-2650 | 6-7H+1-7FA | 6320 | 2650 | 853 | 621 |
| 2650-2800 | 7-7H | 6320 | 2800 | 840 | 630 |

plant site is required. In this analysis, the steam turbine that most closely matched the requirements to process the steam generated in the newly installed HRSG's was selected for continued service. For those plants that have only one steam turbine, it will be run at about 1/3 of capacity.

The major issue when repowering a steam turbine and maintaining its full output is associated with the balance of steam flows. In coal fired boiler plants, a large amount of steam is extracted from the higher pressure sections of the steam turbine for use in feedwater heaters to improve the overall cycle efficiency. This reduces the steam flow to the low pressure section of the turbine. Combined cycle plants do not normally use feedwater heaters so that there is no extraction for feedwater heating. As a result, the low pressure section may be limiting. In this analysis, most of the repowered steam turbines are operating at substantially below their full load capacity, and should not be limited in the low pressure section. The mismatch is usually most severe in the front high pressure section.

The impact of these mismatches in the steam turbine is an approximate loss in steam turbine efficiency of 3-5%. Since the steam turbine provides only one third of the total power, the loss in overall plant efficiency is in the range of 1-2%. This loss can be overcome by redesigning the steam path. The most likely changes would be the new front end buckets and diaphragms. The nominal cost of a revamp of a 300-500 MW unit would be in the range of $6-8 million. Since the equipment at each of the plant sites is different, specific studies must be done on each individual steam turbine that is to be reused to develop a firm estimate of the actual cost of refurbishment to achieve optimum performance.

## G-1.5 O&M COSTS

The 1993 EPRI Technical Assessment Guide (TAG) and recently published papers by SEPRIL[6] were reviewed to determine the fixed and variable O&M costs for repowered natural gas combined cycles and natural gas, oil and coal fired boilers. This data is presented below in the Table G-1.3.

**Table G-1.3 Fixed/Variable O&M Data for Fossil Fuel Plants**

| EPRI 1993 TAG | Fixed O&M $/kW-vr. | Variable O&M Mills/kWh |
|---|---|---|
| 225 MW Combined Cycle | 26.5 | 0.4 |
| 300-500 MW subcritical high sulfur coal boilers with limestone scrubbers | 38.6-47.2 | 1.4-3.0 |
| 300-400 MW supercritical high sulfur coal fired boilers with limestone scrubbers | 43.1-46.6 | 2.8-3.0 |
| SEPRIL Papers | | |
| Gas fired steam plants | 8 | 1.7 |
| Oil fired steam plants | 14 | 3.0 |
| Repowered combined cycles | | |
| 350-800 MW | 12-15 | 1.7-2.0 |
| 100 MW | 25 | 1.7-2.0 |

It is reasonable to assume that the savings from operating a repowered coal plant as a natural gas combined cycle will reduce annual fixed O&M costs by $30/kW and a variable O&M costs by about of 1 mill/kWh or $1/MWH. The fixed O&M costs of the repowered combined cycle would be about the same as an oil fired boiler, but the variable O&M would be about 1 mill/kWh lower. The annual fixed O&M for the repowered combined cycle plant would be about $4-7/kW higher than a gas fired boiler, and the variable O&M would be about the same.

[6] Sapocy, Dale and Stanley Pace, *Using the SOAPP Software for Strategic Analysis to Achieve a Competitive Edge*, American Power Conference 1997

# Interlab Study on
# Scenarios of U. S. Carbon Reductions

## APPENDIX G-2

## Overlap in Utility Carbon Emissions Reduction Estimates: ERI Coal/Gas Repowering Analysis vs ORNL Electricity Market Modeling

# APPENDIX G-2

# OVERLAP IN UTILITY CARBON EMISSIONS REDUCTION ESTIMATES: ERI COAL/GAS REPOWERING ANALYSIS VS ORNL ELECTRICITY MARKET MODELING

## G-2.1 ISSUE

In this report, *U.S. Carbon Reductions by 2010 and Beyond,* two separate analyses repowered (ERI) or retired (ORNL) coal-fired power plants and replaced them with natural gas combined cycle (NGCC) plants. As a result, there was potential duplication in the cost-effectiveness and carbon reduction curves reported. This memo documents the degree of overlap and the corrective action taken.

## G-2.2 BACKGROUND

Energy Resources International, Inc. (ERI) performed a *static* analysis of the cost and feasibility to repower coal-fired power plants with NGCC. The analysis was static in that 1) it repowered plant sites with NGCC holding 1995 *plant* load constant, and 2) it did not re-dispatch plants. The cost of repowering each plant (including conversion, gas hook-up, transmission infrastructure, gas price, environmental externality benefit and O&M performance benefit) was then converted into rank-ordered carbon reduction cost-effectiveness ($/tC). The ORNL electricity market model (described in Section 6) was used initially to examine the impact of end-use (building, transportation, industrial) energy efficiency improvements on reductions in utility sector carbon emissions.

In the executive summary of this report, carbon supply curves are derived which link the results reported in the ORNL (Section 6) and ERI (Section 7.2) analyses. Since both studies examined the replacement of coal-fired capacity with natural gas combined cycle (NGCC) technology—in the ERI study as repowering and in the ORNL study as greenfield—the quantity of carbon removed by replacement of coal-fired capacity with NGCC was double-counted.

## G-2.3 CORRECTIVE ACTION

Retirement of coal-fired capacity in the ORNL model occurred in two steps: 22.5 GW defined by DOE/EIA as uneconomic (>$0.04/kWh); and 45 GW due to reduced load (arising from increased end-use efficiency) and a $50/ton carbon tax. To meet 2010 load requirements (including replacement of the retired coal-fired capacity), the ORNL model added the following new capital stock:

| Technology | GW |
|---|---|
| combined cycle # 4 | 22.5 |
| combined cycle # 5 | 47.5 |
| total | 67.5 |

In addition to this new capital stock, existing coal-fired plants were re-dispatched in the ORNL market model (to meet 2010 load requirements) based on 1) revised operating costs ($50/ton carbon tax), 2) revised load shape (due to end-use energy efficiency improvements), and 3) revised mix of power plants (mix of coal and gas plants).

Since the ORNL model replaced 67.5 GW of coal-fired capacity with new (greenfield)[1] NGCC technology, this is essentially equivalent to *site* repowering[2] coal-fired capacity with NGCC (as done in the ERI study).[3] Consequently, the carbon reductions derived from replacement of 67.5 GW of coal-fired with NGCC is duplicative, as originally represented in the *U.S. Carbon Reductions by 2010 and Beyond* report.

To correct this duplication in utility carbon emissions reduction, 67.5 GW of coal-fired capacity (41.1 MtC) was *deleted* from the ERI coal/gas repowering analysis (Section 7.2):

- 22.5 GW of coal-fired capacity identified by DOE/EIA was removed, totaling 11.2 MtC.
- 45 GW of the most expensive coal-fired capacity to operate (non-fuel O&M) was removed,[4] totaling 29.9 MtC.

The 22.5 GW was removed as follows: the **actual units retired** by EIA (since their 1995 operating costs were >$0.04/kWh) **were *deleted* from the ERI coal-fired power plant inventory.** The characteristics of these *deleted* units are summarized below by carbon cost-effectiveness ($/tC).

**Table G-2.1 Distribution of Candidate Repowered Capacity Deleted From ERI Coal/Gas Study: 22.5 GWs of DOE/EIA Identified Retirements**

| $/tC | # plants | GW | MtC |
|---|---|---|---|
| 0-50 | 23 | 3.5 | 2.7 |
| 51-100 | 15 | 8.3 | 4.4 |
| 101-150 | 15 | 3.6 1.8 | |
| >150 | 56 | 8.8 | 2.5 |
| Total | 109 | 24.1 | 11.2 |

Within the $0-50/tC range, there were 23 plants, 3.5 GW, and 2.7 MtC identified in the ERI coal/gas study as deleted by EIA (and ORNL) as not cost-effective to operate in the future. Due to differences in plant representation (within the ERI and ORNL studies), the same amount of capacity (3.5 GW) in this cost-effectiveness range would only result in approximately 1.5 MtC of reduction in the ORNL model.[5] So, the potential carbon reduction overlap at the <$50/tC level ranges from 1.5 MtC (ORNL) to 2.7 MtC

[1] Greenfield is a term-of-art in the power industry, which refers to a "new" plant; not a repowered or refurbished plant at an existing site.

[2] Site repowering is reuse of the existing power plant site (only); versus steam turbine repowering where the existing steam turbine, ancillary equipment and boiler island are reused to reduce costs (but for which there is an efficiency loss due to non-optimum integration of the combustion and steam turbines).

[3] These cases are essentially equivalent since the NGCC plant characteristics (e.g., capital cost, heat rate) are approximately equal.

[4] The cost of repowering was used as a proxy for the most expensive plants to operate, since the cost of conversion was based on heat rate and fixed/variable operating costs.

[5] The ERI inventory includes actual plants (with their related design and operating characteristics/costs), whereas the ORNL model has 26 "categories" of plants, of which 10 represent alternative coal-fired plants (existing and new).

(ERI).

Identification of the potential overlap for the 45 GW of capacity retired by the ORNL market model due to load reductions (end-use energy efficiency) and imposition of a \$50/tC tax was more difficult due to differences in plant representation in the ERI and ORNL studies. In the ORNL market model, 45 GW of coal-fired capacity was retired based on highest operating cost (non-fuel O&M) of the three coal-fired power plant categories defined in the model. However, these retirements were done incrementally, taking into account load shape/dispatch requirements and mix of fixed and variable O&M. To approximate this retirement procedure in the ERI study, coal-fired power plants were rank-ordered by 1995 non-fuel O&M cost. Then 45 GW of the most expensive plants were identified by moving down the rank-ordered cost curve. The following table summarizes the distribution of *deleted* coal-fired power plants (in the ERI study) by cost-effectiveness range.

**Table G-2.2 Distribution of Candidate Repowered Capacity Deleted From ERI Coal/Gas Study: 45 GWs of Energy Efficiency Retired Coal Plants**

| \$/tC | # plants | GW | MtC |
|---|---|---|---|
| 0-50 | 6 | 6.9 | 7.1 |
| 51-100 | 23 | 18.5 | 14.3 |
| 101-150 | 17 | 13.2 4.9 | |
| >150 | 39 | 9.2 | 3.6 |
| Total | 85 | 45.3 | 29.9 |

Based on this investigation of overlap, within the \$0-50/tC range, there were 6 plants comprising 6.9 GW and 7.1 MtC that were double counted in both the ERI and ORNL studies.

## G-2.4 SUMMARY

In the <\$50/tC range of the cost-effectiveness curve, there was a total of 29 plants, 10.4 GW and 9.8 MtC of overlap between the ORNL and ERI analyses. The carbon overlap in the <\$50/MtC range comprises almost 24% of the total estimated overlap in carbon reduction.

# Interlab Study on Scenarios of U. S. Carbon Reductions

## APPENDIX G-3

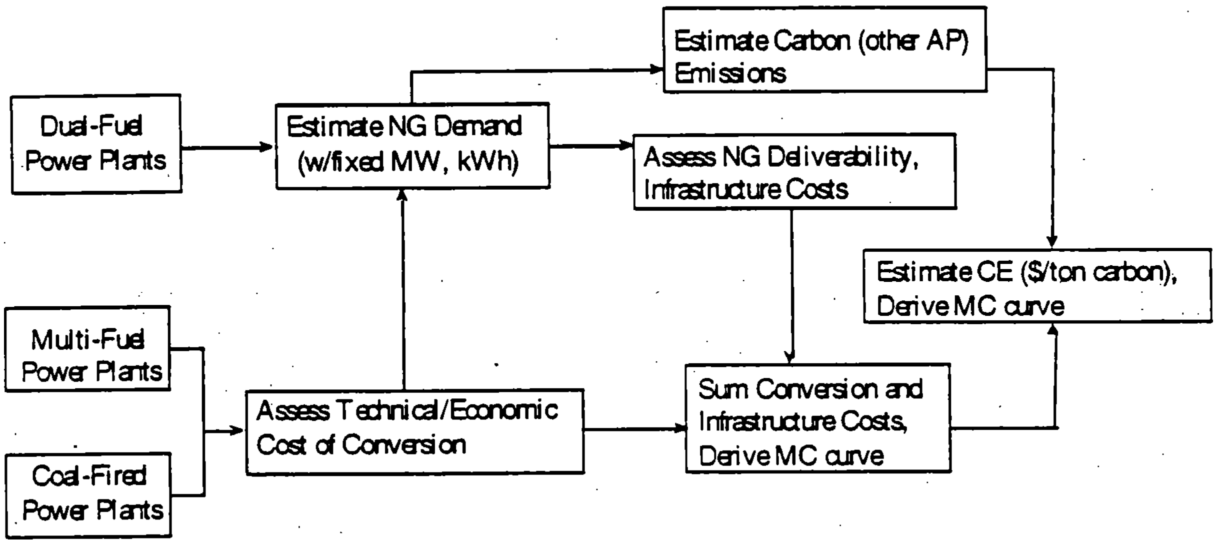
## Methodology

# APPENDIX G-3

# METHODOLOGY

Figure G-3.1 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-1 and G-4.

**Figure G-3.1 Methodological Steps**




## G-3.1 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:[1]

- 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 initially 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 multi-fuel sites

[1] Following this assessment of power plants, it was determined that 67.5 GW (or approximately 20 percent) of the candidate coal-fired capacity needed to be deleted, as discussed in Appendix G-2. The remainder of this discussion, however, pertains to the entire inventory of candidate coal-fired power plants (including the 67.5 GW of capacity deleted).

where gas is consumed it was again 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.

## G-3.2 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 (See Appendix G-1). 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 ($SO_2$) 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. A 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.[2] Thus, hook-up and transmission costs were excluded from the repowering investment cost.

## G-3.3 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 (See Appendix G-1). 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.

## G-3.4 NATURAL GAS DELIVERABILITY AND INFRASTRUCTURE COSTS

To ensure natural gas deliverability to the candidate repowered plants—since gas requirements at these plants 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.

[2] 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) is 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.

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 candidate plants (both those repowered and the set of plants deleted from the inventory, since the GIS was conducted before these plants were deleted and could not be redone—see Appendix G-2). The cost to each plant was then based on its respective pipeline routing and volume of gas 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.

## G-3.5 TOTAL COST OF CONVERSION

The sum of conversion and hook-up/transmission costs 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 Modeling System (NEMS) simulation,[3] the 1995 coal/gas 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 re-licensed.

The total cost of repowering (conversion, hook-up/transmission, gas/coal price differential, O&M credit and $SO_2/NO_x$ credit) for each plant was then divided by the reduction in carbon emissions arising from the repowering.

## G-3.6 VALUE OF ENVIRONMENTAL EXTERNALITIES

There is considerable debate in the literature regarding the value of environmental externalities. In this study, the *market value* for $SO_2$ and $NO_x$ were included, not their estimated damage effects. For $SO_2$ 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 implementing the forthcoming recommendations from the Ozone Transport Assessment Group (OTAG), and subsequent regulatory action by EPA.

[3] DOE/EIA, *An Analysis of Carbon Mitigation Cases*, Service Report SR/OIAF/96-01 (June 3, 1996).

# Interlab Study on
# Scenarios of U. S. Carbon Reductions

## APPENDIX G-4

## Natural Gas Deliverability
## and Infrastructure Assessment

# APPENDIX G-4

## NATURAL GAS DELIVERABILITY AND INFRASTRUCTURE ASSESSMENT

In 1995, the U.S. consumed 19,657,487 MCF of natural gas (EIA "Natural Gas Annual 1995"). The break down of natural gas by end-use sector is shown in Table G-4.1. Electric utilities accounted for 16.3% of total gas consumed in 1995 and approximately 10% overall of total U.S. generation. Interestingly, over 55% of natural gas consumed by electric utilities is utilized in the states of Texas, Louisiana, and California, respectively. Texas alone consumes 33% of the natural gas consumed by electric utilities.

**Table G-4.1 1995 Gas Consumed By End-Use Sector**

| End-Use Sector | Gas Volume (MCF) | Percentage (%) |
|---|---|---|
| Residential | 4,850,318 | 24.7 |
| Industrial | 8,579,585 | 43.6 |
| Electric Utilities | 3,196,507 | 16.3 |
| Commercial | 3,031,077 | 15.4 |
| TOTAL | 19,657,487 | 100.00 |

Table G-4.2 displays the relative size of the proposed electric utility power plants to the total U.S. consumption, and total electric utility consumption. The proposed plants account for a minor percentage of total U.S. 1995 gas consumption (only 0.9%) and account for a small fraction (4.14%) of total natural gas consumption by electric utilities. These 404 plants, in 1995, consumed a very small percentage of natural gas and were easily accommodated by the natural gas transmission infrastructure.

**Table G-4.2 State Comparison of Conversion Impacts On Natural Gas Consumption**

| | Before Conversion | | | | After Conversion | |
|---|---|---|---|---|---|---|
| State | Candidate Gas Use (MCF) | Percent To Total Utility | 1995 Consumption (MCF) | Percent To 1995 Consumption | Candidate Gas Use (MCF) | Percent To 1995 Consumption |
| AL | 5,008 | 63.75 | 321,577 | 1.56 | 436,350 | 135.69 |
| AK | 0 | 0.00 | 430,231 | 0.00 | 0 | 0.00 |
| AZ | 3,014 | 11.64 | 120,126 | 2.51 | 262,415 | 218.45 |
| AR | 0 | 0.00 | 257,068 | 0.00 | 130,965 | 50.95 |
| CA | 0 | 0.00 | 1,925,110 | 0.00 | 0 | 0.00 |
| CO | 1,901 | 95.64 | 283,591 | 0.67 | 228,654 | 80.63 |
| CT | 0 | 0.00 | 132,273 | 0.00 | 15,714 | 11.88 |
| DE | 3,255 | 12.08 | 60,662 | 5.37 | 34,532 | 56.93 |
| DC | 0 | 0.00 | 32,988 | 0.00 | 0 | 0.00 |
| FL | 3,543 | 1.14 | 515,598 | 0.69 | 412,543 | 80.01 |
| GA | 4,637 | 59.34 | 370,385 | 1.25 | 432,241 | 116.70 |

Table G-4.2 State Comparison of Conversion Impacts On Natural Gas Consumption (continued)

| State | Before Conversion | | | Percent To 1995 Consumption | After Conversion | |
|---|---|---|---|---|---|---|
| | Candidate Gas Use (MCF) | Percent To Total Utility | 1995 Consumption (MCF) | | Candidate Gas Use (MCF) | Percent To 1995 Consumption |
| ID | 0 | 0.00 | 63,777 | 0.00 | 0 | 0.00 |
| IL | 7,111 | 17.55 | 1,078,543 | 0.66 | 482,571 | 44.74 |
| IN | 9,015 | 67.26 | 535,311 | 1.68 | 725,753 | 135.58 |
| IA | 1,889 | 60.34 | 262,313 | 0.72 | 198,049 | 75.50 |
| KS | 2,137 | 9.62 | 368,342 | 0.58 | 179,799 | 48.81 |
| KY | 590 | 113.93 | 224,046 | 0.26 | 574,104 | 256.24 |
| LA | 11,891 | 3.87 | 1,717,914 | 0.69 | 108,469 | 6.31 |
| MN | 0 | 0.00 | 5,429 | 0.00 | 0 | 0.00 |
| MD | 14,844 | 89.43 | 194,099 | 7.65 | 179,798 | 92.63 |
| MA | 3,445 | 5.19 | 362,301 | 0.95 | 100,162 | 27.65 |
| MI | 1,282 | 4.43 | 970,851 | 0.13 | 470,880 | 48.50 |
| MN | 4,342 | 93.95 | 353,076 | 1.23 | 204,618 | 57.95 |
| MS | 3,274 | 7.95 | 288,067 | 1.14 | 61,757 | 21.44 |
| MO | 2,723 | 27.09 | 279,078 | 0.98 | 337,261 | 120.85 |
| MT | 115 | 31.17 | 57,827 | 0.20 | 110,378 | 190.88 |
| NE | 884 | 66.10 | 136,384 | 0.65 | 96,655 | 70.87 |
| NV | 2,257 | 5.86 | 111,004 | 2.03 | 112,979 | 101.78 |
| NH | 9 | 0.42 | 19,899 | 0.05 | 24,283 | 122.03 |
| NJ | 20,096 | 51.90 | 590,797 | 3.40 | 43,906 | 7.43 |
| NM | 569 | 2.04 | 215,147 | 0.26 | 183,864 | 85.46 |
| NY | 3,838 | 1.63 | 1,140,488 | 0.34 | 152,159 | 13.34 |
| NC | 263 | 8.71 | 202,726 | 0.13 | 363,021 | 179.07 |
| ND | 1 | 50.00 | 45,378 | 0.00 | 189,374 | 417.33 |
| OH | 1,112 | 20.88 | 896,072 | 0.12 | 805,303 | 89.87 |
| OK | 21,521 | 13.91 | 568,153 | 3.79 | 185,964 | 32.73 |
| OR | 0 | 0.00 | 145,867 | 0.00 | 25,590 | 17.54 |
| PA | 12,885 | 50.38 | 721,433 | 1.79 | 654,898 | 90.78 |
| RI | 0 | 0.00 | 70,137 | 0.00 | 0 | 0.00 |
| SC | 2,840 | 22.30 | 151,915 | 1.87 | 193,049 | 127.08 |
| SD | 0 | 0.00 | 34,292 | 0.00 | 17,498 | 51.03 |
| TN | 2,055 | 96.61 | 256,843 | 0.80 | 372,753 | 145.13 |
| TX | 25,312 | 2.86 | 3,802,489 | 0.67 | 825,981 | 21.72 |
| UT | 0 | 0.00 | 156,824 | 0.00 | 220,013 | 140.29 |
| VT | 0 | 0.00 | 7,275 | 0.00 | 0 | 0.00 |
| VA | 14,036 | 68.59 | 247,198 | 5.68 | 169,085 | 68.40 |
| WA | 0 | 0.00 | 220,427 | 0.00 | 63,736 | 28.91 |
| WV | 346 | 166.54 | 148,364 | 0.23 | 517,437 | 348.76 |
| WI | 2,640 | 26.51 | 380,489 | 0.69 | 298,029 | 78.33 |
| WY | 119 | 113.94 | 97,706 | 0.12 | 285,730 | 292.44 |
| TOTAL | 194,798 | 4.14 | 21,577,890 | 0.90 | 11,488,320 | 53.24 |

If these candidate plants were all converted, the impacts on the natural gas transmission infrastructure would be very substantial. Table G-4.2 shows that 21.6 TCF of natural gas was consumed in 1995. This includes the 19.7 TCF from the end-use sections in Table G-4.1 combined with the natural gas consumed in operations. These 404 converted power plants would cause a 53% increase over 1995 total natural gas consumption levels. Such an increase would require a substantial investment in the natural gas transmission infrastructure to accommodate the extra 11.5 TCF load from these power plants.

**Table G-4.3 Natural Gas Consumed By End-Use Sector After Power Plant Conversions**

| End-Use Sector | Gas Volume (MCF) | Percentage (%) |
|---|---|---|
| Residential | 4,850,318 | 15.6 |
| Industrial | 8,579,585 | 27.5 |
| Electric Utilities | 14,684,827 | 47.1 |
| Commercial | 3,031,077 | 9.7 |
| TOTAL | 33,052,827 | 100.0 |

If Table G-4.1 is recalculated based on the natural gas requirements for the converted power plants while the other sectors remain constant in demand, the electric utility sector would consume close to half of the natural gas in the U.S (see Table G-4.3). This 47% increase from the 1995 16% level and would require a significant investment to be made in the natural gas infrastructure. The next section will attempt to quantify the investment required.

Although there is 21.6 TCF of natural gas consumed in the U.S., this gas travels through a sophisticated network of interstate and intrastate pipelines. There are approximately 1.2 million miles of natural gas pipeline utilized in the system comprised of: transmission (264,900), distribution (935,000) and field (62,200). Almost 65 TCF of natural gas is transported through states to deliver gas to the end-use customers. Table G-4.4 shows the state-by-state receipts and deliveries of natural gas. The net column represents the receipts minus the deliveries. A negative net means that the state delivers more gas then it receives. These are usually the natural gas production states.

Table G-4.4 State Natural Gas Flows

| State | Receipts (MCF) | Deliveries (MCF) | Net (MCF) |
|---|---|---|---|
| AL | 3,253,871 | 3,389,137 | -135,266 |
| AK | 0 | 65,283 | -65,283 |
| AZ | 994,103 | 879,201 | 114,902 |
| AR | 2,614,855 | 2,546,781 | 68,074 |
| CA | 1,690,530 | 0 | 1,690,530 |
| CO | 699,431 | 844,388 | -144,957 |
| CT | 410,639 | 259,486 | 151,153 |
| DE | 54,864 | 3,030 | 51,834 |
| DC | 29,860 | 0 | 29,860 |
| FL | 523,721 | 34 | 523,687 |
| GA | 1,439,907 | 1,075,834 | 364,073 |
| ID | 962,961 | 887,158 | 75,803 |
| IL | 2,446,381 | 1,388,479 | 1,057,902 |
| IN | 2,041,013 | 1,475,557 | 565,456 |
| IA | 1,444,142 | 1,188,548 | 255,594 |
| KS | 1,140,230 | 1,458,930 | -318,700 |
| KY | 3,689,277 | 3,507,584 | 181,693 |
| LA | 2,169,716 | 5,553,146 | -3,383,430 |
| MN | 5,533 | 0 | 5,533 |
| MD | 864,322 | 652,253 | 212,069 |
| MA | 554,296 | 98,974 | 455,322 |
| MI | 1,382,220 | 716,019 | 666,201 |
| MN | 1,762,668 | 1,434,132 | 328,536 |
| MS | 5,623,521 | 5,832,741 | -209,220 |
| MO | 1,544,992 | 1,274,401 | 270,591 |
| MT | 590,603 | 569,852 | 20,751 |
| NE | 1,030,750 | 1,054,114 | -23,364 |
| NV | 355,804 | 247,692 | 108,112 |
| NH | 31,742 | 5,521 | 26,221 |
| NJ | 1,296,464 | 712,420 | 584,044 |
| NM | 343,196 | 1,470,532 | -1,127,336 |
| NY | 2,006,959 | 886,014 | 1,120,945 |
| NC | 913,692 | 696,000 | 217,692 |

Table G-4.4 State Natural Gas Flows (continued)

| State | Receipts (MCF) | Deliveries (MCF) | Net (MCF) |
|---|---|---|---|
| ND | 579,325 | 636,351 | -57,026 |
| OH | 2,817,908 | 1,975,801 | 842,107 |
| OK | 810,112 | 1,872,345 | -1,062,233 |
| OR | 882,385 | 741,523 | 140,862 |
| PA | 2,718,075 | 1,982,831 | 735,244 |
| RI | 251,800 | 151,700 | 100,100 |
| SC | 1,053,357 | 906,316 | 147,041 |
| SD | 638,002 | 604,039 | 33,963 |
| TN | 4,027,113 | 3,758,529 | 268,584 |
| TX | 860,534 | 3,265,069 | -2,404,535 |
| UT | 431,245 | 388,831 | 42,414 |
| VT | 18,429 | 9,335 | 9,094 |
| VA | 1,055,691 | 850,457 | 205,234 |
| WA | 1,140,487 | 882,990 | 257,497 |
| WV | 1,724,557 | 1,777,613 | -53,056 |
| WI | 1,195,087 | 811,591 | 383,496 |
| WY | 384,208 | 1,025,093 | -640,885 |
| TOTAL | 64,500,578 | 61,813,655 | 2,686,923 |

## G-4.1 INTERCONNECTION COSTS (PLANT HOOK-UP)

There are two cost components in estimating the servicing of these electric utility plants. The first component is the cost of hooking up these power plants to their nearest natural gas transmission line, and the second component is upgrading the transmission system to handle the increased natural gas load.

The first component (connecting power plants to their nearest transmission line) was completed through a geographic information system (GIS). The three classes of power plants (dual fuel, multi-fuel and coal only) were grouped into two categories: 1) power plants that did not have a gas hook-up all ready, and 2) power plants that were already hooked-up but need to be expanded. A program was used to compute the distance from each power plant to its closest transmission pipeline. Publicly available data sets were utilized for the power plants and natural gas transmission pipeline files. Table G-4.5 displays the distance distribution for these power plants. 58% of the power plants are less than 5 miles from transmission lines and over 95% of the power plants are within 20 miles of transmission lines. The power plants are well-positioned for hook-up to the natural gas system.

Table G-4.5 Power Plant Hook-Up Distance Distribution

| Distance | Miles | Percentage (%) | Cumulative Percentage (%) |
|---|---|---|---|
| Less than 5 | 235 | 58.17 | 58.17 |
| Between 5 and 10 | 83 | 20.54 | 78.71 |
| Between 10 and 15 | 44 | 10.89 | 89.60 |
| Between 15 and 20 | 25 | 6.19 | 95.79 |
| Between 20 and 25 | 6 | 1.49 | 97.28 |
| Between 25 and 50 | 7 | 1.73 | 99.01 |
| Greater than 50 | 4 | 0.99 | 100.00 |
| TOTAL PLANTS | 404 | 100.00 | |

The converted power plants were assigned pipeline diameter sizes. These represent the pipeline diameters that would be required to meet the power plant load under peak day conditions. The Oil and Gas Journal (OGJ) computes pipeline construction costs. An analysis of five years of data was used to create average costs per mile for each specific pipeline diameter. The analysis was required because of the large range in costs from various projects. For example, in 1996 the costs for an 8" pipe diameter ranged from $84,623 and $12,810,000. The costs vary because of factors such as: terrain, right-of-way costs, population, number of major road crossings, number of major waterway crossings, and number of pipe bends.

There are many uncertainties associated with the costs of expanding the North American natural gas transmission infrastructure to accommodate any particular plant conversion. Costs of building pipelines increases when the terrain being crossed is rocky, mountainous, or requires a water crossing. Building in populous areas increases right of way costs, construction costs, and complicates routing.

There are economies of scale that can be achieved when a large capacity pipeline is built as opposed to building a small capacity line. If the necessary increase in transmission capacity due to a plant conversion coincides with an increase in demand due to other markets, the cost of the share of capacity increase due to the plant conversion is usually smaller than it would be if a pipeline dedicated to the plant were built.

With the distances and average mileage costs computed, the final step is to compute the total costs. The task 3 plants have no pipelines already attached. There costs are computed by multiplying the distance to the nearest transmission pipeline by their respective cost per mile. For the tasks 1 and 2 plants, they already have transmission connections, however, after conversion the annual gas consumption at these plants increase from .19 TCF to 3.4 TCF. This increase requires major upgrades and renders most of the pipelines insufficient. Without being able to analyze each pipeline, some rules of thumb were applied in computing costs. If the gas consumption at a plant was 10 times or less, than the OGJ numbers were discounted 20%.

Table G-4.6 Average Cost Numbers Per Mile

| Diameter (Inches) | Cost ($000s) | Percentage Change (%) |
|---|---|---|
| 6 | 441 | |
| 8 | 541 | 22.68 |
| 10 | 642 | 18.48 |
| 12 | 742 | 15.60 |
| 16 | 942 | 26.99 |
| 20 | 1,142 | 21.25 |
| 24 | 1,342 | 17.53 |
| 30 | 1,642 | 22.37 |

If the gas consumption at a plant was between 10 and 20 times, than the OGJ numbers were discounted 10%. The costs for these task 1 (dual-fuel) and 2 (multi-fuel) plants is computed the same as the task 3 (coal only) plants with the exception of the discount being factored into the cost equation. The interconnection costs to hook-up all 404 of the power plants is $2.78 billion for case 1 and $2.82 billion for case 2.

## G-4.2 TRANSMISSION UPGRADE COSTS

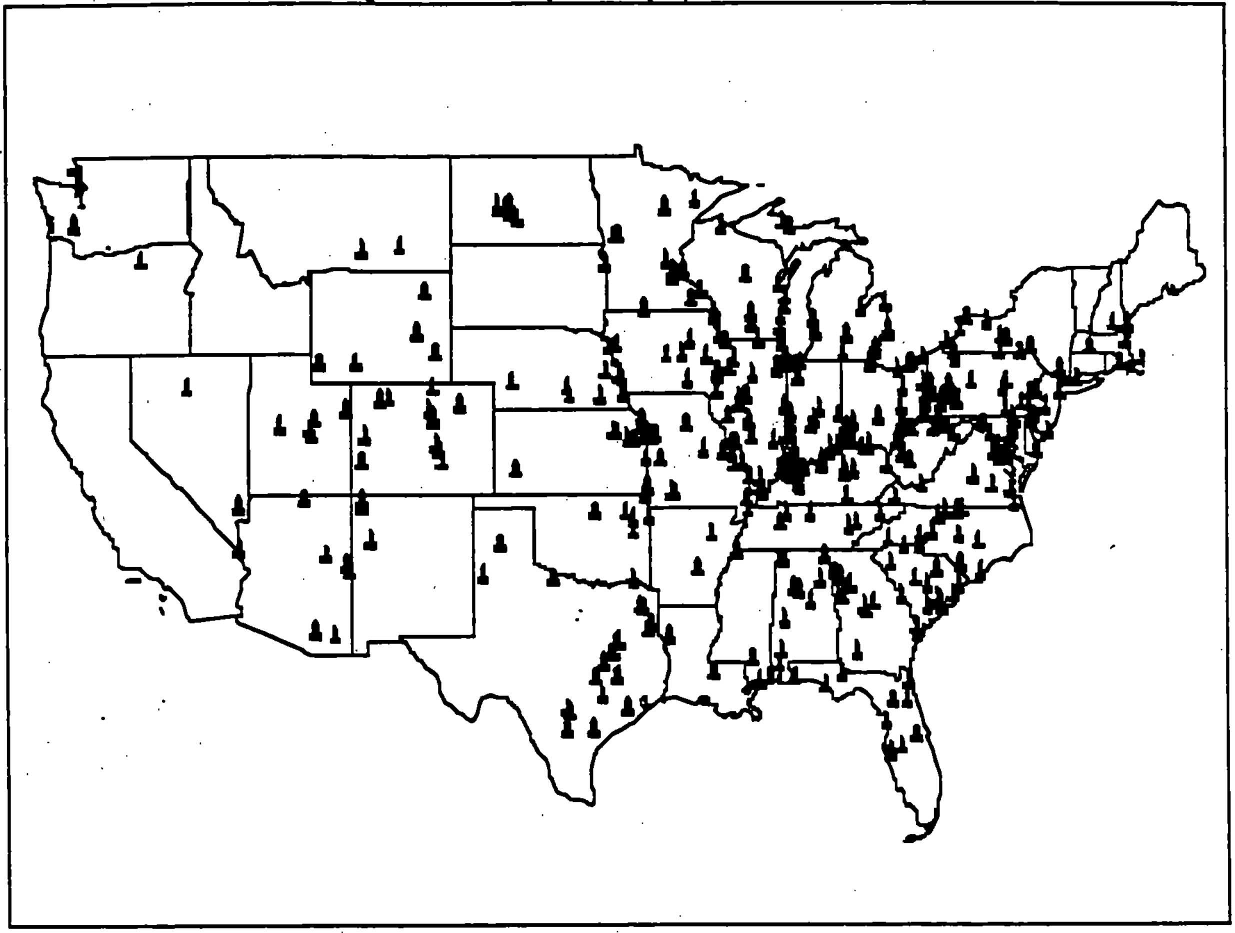
It is a difficult task to estimate the upstream and downstream effects from converting these power plants. The numbers presented represent ball park figures. To compute exact numbers would take sophisticated models combined with proprietary information from the transmission companies. The analysis presented below is a simplified approach in cost estimation. The necessary assumptions and inputs are provided.

Demand for natural gas has been, and is forecasted to continue to increase. Natural gas consumption rose by 3% in 1996 and 4% in 1994, continuing its upward trend which began in 1991. The electric utility sector increased its use of natural gas by 7% in 1995 and decreased 9% in 1996 due to price increases. The future demand for natural gas looks strong. With lower prices and increased supply from Canada, continued growth is projected in all end-use sectors. The current transmission excess capacity can easily be used up by this increased demand. Because of the healthy outlook for natural gas, we are assuming that the current transmission infrastructure does not have the capacity to handle the load from these 404 plants.

Power plants pose problems to natural gas transmission systems. The combined cycle units ramp up very quickly and the electric utility companies are never sure of when their peak times will occur. For this reason most power plants purchase firm contracts. The utility companies need the generation in conjuncture with their customers loads and not the pipeline's convenience. This is yet another reason to assume the current transmission infrastructure can not handle the load from these 404 power plants. This becomes apparent from the 53% increase in gas consumption shown in Table G-4.2.

Figure G-4.1 shows how dispersed the power plants are in tasks 1-3. There are concentrations in the Midwest and northeast regions, however, the 404 power plants are widely dispersed in the U.S.

Figure G-4.1 Graphic Display of Power Plants



Without comprehensive knowledge of future demand growth from all sectors of natural gas consumption, and knowledge of the route that will be followed to build capacity for any given plant, estimates for adding capacity for any particular plant are best considered as a wide range. The methodology used in this analysis focuses on average day power plant consumption in relationship to the main natural gas supply areas. The reason being that one way or another the gas must come from one of these key supply areas.

In lieu of guessing on pipeline routes and locations, the natural gas requirements for each plant were matched with pipeline throughputs. Besides guessing on where to build pipelines, one would have to guess on what cost numbers to use in constructing the pipelines as well. The cost of building the transmission pipelines varies widely. For example, in 1996, the construction costs for an 8 inch pipe vary between $84,623 and $12,810,000. Each power plant was given a fraction of a pipeline's capacity based on its average day consumption requirements.

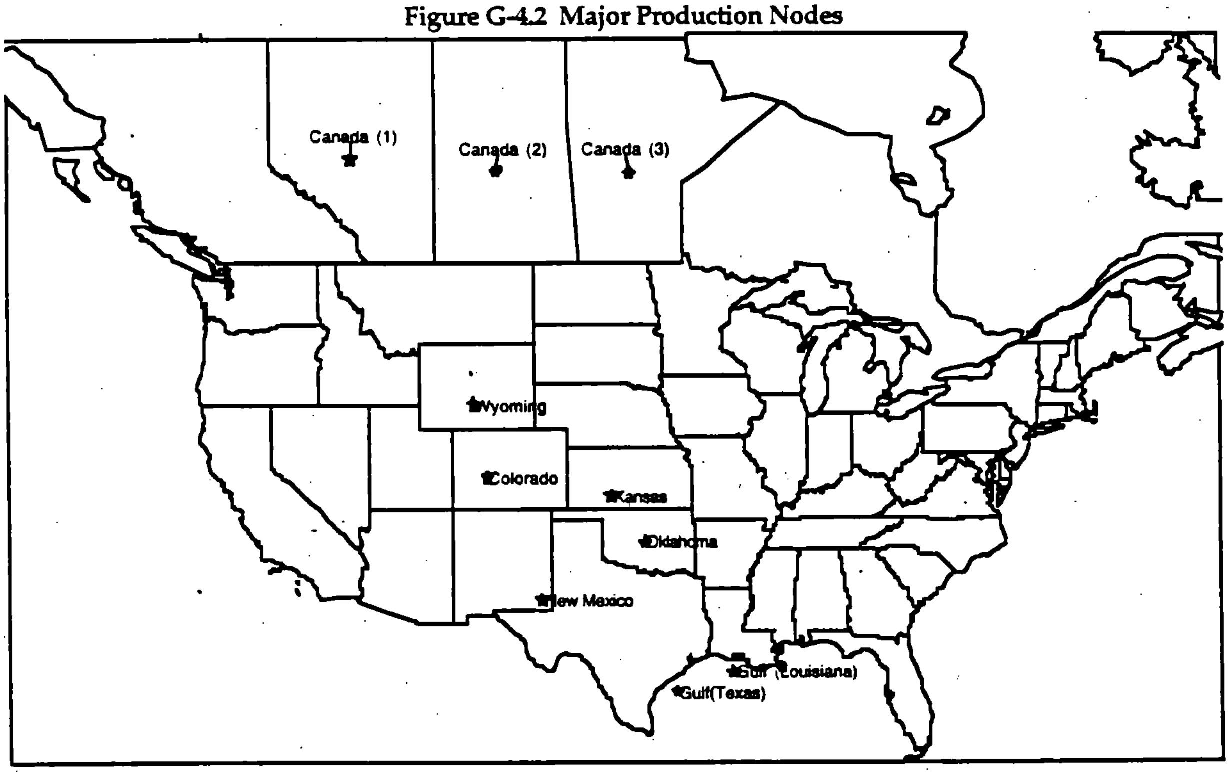
As with the interconnection costs, a GIS was used to help compute distances. In this case, the GIS computed distances from the power plants to supply regions. The seven largest producing states account for over 86% of U.S production. Table G-4.7 contains 1995 production for each of the seven states.

Table G-4.7 1995 Natural Gas Production for the Largest Seven States

| State | Gas Production (MCF) | Percent (%) |
|---|---|---|
| TX | 6,330,048 | 32.45 |
| LA | 5,108,366 | 58.64 |
| OK | 1,811,734 | 67.93 |
| NM | 1,625,837 | 76.26 |
| KS | 721,436 | 79.96 |
| WY | 673,775 | 83.41 |
| CO | 523,084 | 86.10 |

Besides the major 7 producing states, the U.S. receives approximately 2.8 TCF of gas from Canada. 7 nodes were created for the domestic production and three nodes in Canada. Figure G-4.2 contains a map of these nodes.

Figure G-4.2 Major Production Nodes



The GIS computed the distance from each power plant to its closest node. This provided an estimate of how far the natural gas would have to travel. The plants that are being considered for conversion are dispersed across the United States, with a majority of the plants in the northeast and Midwest. These are areas that are current consumers of natural gas, and are the markets for which a majority of the existing transmission lines were built, so the increases in transmission capacity that will be required to accommodate plant conversions can be expected to roughly follow past patterns of construction locations and costs.

To estimate the costs of adding this capacity to the existing system, the analysis used the average cost of adding capacity during the most recent 5 year period for which data is available, 1991 through 1995. This cost was determined by calculating the historical average cost of adding a MCF/Day/Mile (e.g. the capital cost of adding transmission line capacity to carry a million cubic feet of gas one mile in one day) from the construction costs reported in the *Oil and Gas Pipeline Journal* in its annual pipeline economics report. This report summarizes data reported to FERC on pipeline construction costs and includes the length, diameter, and construction costs of pipelines built by in the United States and Canada. This is the infrastructure that will have to be augmented to accommodate the conversion of plants considered by this report.

Table G-4.8 shows the values used in estimating the capacity of pipelines of a given diameter. The actual capacity of a pipeline is determined by a multitude of factors including compression of the gas, its temperature, specific gravity. The data in the table are typical values for throughput that is achieved using standard technology. These values were used to estimate the carrying capacity of new transmission lines added during the 5 year period reviewed. Multiplying the MCF/Day value for a given pipeline diameter by the length of the line gives the number of MCF/Day miles for the pipe. This calculation was performed for all 8" and larger pipelines longer than 1 mile built during the past 5 years. The construction costs for 408 pipelines during the 1991 and 1995 were reviewed. The average cost of adding this capacity was estimated by summing the costs of building these lines to the costs of building compressors added during this period. Dividing these costs by the total number of MCF/Day miles implemented yields the average cost of adding an MCF/Day mile to the existing transmission capacity, $2,250.

**Table G-4.8 Pipeline Throughput Estimates**

| Diameter (Inches) | MCF/Day |
|---|---|
| 6 | 15 |
| 8 | 30 |
| 10 | 50 |
| 12 | 70 |
| 16 | 125 |
| 20 | 225 |
| 24 | 350 |
| 30 | 600 |
| 34 | 770 |
| 36 | 865 |
| 42 | 1175 |
| 48 | 1500 |

Computing the upgrade transmission cost is performed by multiplying the plant distance by its daily

gas flow requirements (annual total/365) and $2,250. The average day was used in lieu of the peak day since the plants peak on different dates and times. Performing this estimation provides an upgraded transmission cost of $64.75 billion for case 1 and $67.38 billion for case 2.
The number of miles of pipeline that would need to be constructed is based on the average diameter pipeline that is built. Taking the average MCF/Day values in Table G-4.8 allows us to compute the needed number of pipeline miles. Table G-4.9 shows how the miles vary significantly depending on the pipeline diameter size. If all the pipeline constructed for the power plants was 6 inch diameter pipe, it would take 1,918,519 miles of pipeline to handle the gas requirements for these plants. The 48 inch diameter pipe would only require 19,185 miles of pipe.

The U.S. natural gas industry is comprised of a variety of pipe diameters. The higher end diameter pipe serves well for long distance transportation routes while the smaller pipe diameters feed into local distribution companies, industrial users, and electric utility plants. A weighted average pipeline diameter was computed across the five year OGJ data set. Assuming that historical construction patterns would be followed, the average size diameter is just under 30 inches which means that 52,323 miles of new pipeline would need to be constructed to handle the increased gas load. This compares with 1,200 miles of pipeline that were built in 1994 and 1,500 miles of pipeline built in 1995 (OGJ).

Table G-4.9 Miles of Pipeline Required

| Diameter | MCF/Dav | Miles |
|---|---|---|
| 6 | 15 | 1,918,519 |
| 8 | 30 | 959,259 |
| 10 | 50 | 575,556 |
| 12 | 70 | 411,111 |
| 16 | 125 | 230,222 |
| 20 | 225 | 127,901 |
| 24 | 350 | 82,222 |
| 30 | 600 | 47,963 |
| 34 | 770 | 37,374 |
| 36 | 865 | 33,269 |
| 42 | 1175 | 24,492 |
| 48 | 1500 | 19,185 |

Between 1991 and 1994, the U.S. added 3.65 TCF of natural gas at a cost of $6.5 billion. If you took the ratio of gas added per dollar and applied it to the 11.5 TCF that the plants would require, the cost would be $20.5 billion. This is significantly lower than the $64.75 billion computed. The increased cost is based primarily on the distance that the natural gas will be required to move. Between 1991 and 1994, most of the natural gas projects were short distances, were well thought out and provided the most economic sense. The location of the repowered plants requires substantial more investment and applying the simple ratio does not work.

## G-4.3 SUMMARY

There would need to be a very sizable investment to interconnect these power plants to the system and accommodate their loads. Table G-4.10 provides the total cost estimates to interconnect the power plants with the transmission lines and includes the costs to upgrade the system to handle the total additional load.

Since this deliverability/infrastructure assessment (which examined the impact of total repowering of coal-fired power plants) was completed before the incremental repowering analysis was requested, per plant costs were used to compute the total cost of repowering, recognizing that the estimate may be on the high-side.[1]

**Table G-4.10 Transmission Costs Summary ($Billion)**

| | Site Repowering | Steam Turbine Repowering |
|---|---|---|
| Interconnection | 2.78 | 2.82 |
| Transmission | 64.75 | 67.38 |
| Total | 67.53 | 70.20 |

[1] The actual hook-up and transmission cost for any individual plant or group of plants is a function of their location, current/projected pipeline utilization rate, and geographic factors. Since the timing for repowering, and thereby the sequence and location of the repowered plants is not known at this time, no assessment can be made of the likely economies of scale possible. It is possible that the transmission cost could be greater than the system average estimated above if it the pipeline load is at its maximum and there are no other plants to share the expense of expanding pipeline capacity.