

means that the heat being rejected is very low grade heat, requiring lots of air movement or large radiator surface areas, neither very appealing to vehicle designers (Borroni-Bird, 1997)) and prevention of freezing in cold weather.

On-board fuel storage represents a significant barrier because hydrogen's energy density is very low,⁷ and the easiest fuel to reform into hydrogen onboard the vehicle, methanol, has no significant supply infrastructure. Chrysler in partnership with DOE recently announced significant progress towards onboard production of hydrogen from gasoline, which would solve the supply infrastructure problem and allow much easier fuel storage than hydrogen. Not surprisingly, however, the selection of gasoline as the preferred "hydrogen carrier" for fuel cells is by no means an easy call. For example, gasoline's availability and easier fuel storage must be traded off against the cost and space occupied by the reformer (Jost, 1997).⁸ Toyota has claimed a substantial improvement in hydrogen storage technology using an advanced metal hydride adsorbent that matches the energy density of liquefied hydrogen storage with only 10 atmospheres of pressure required (Yamaguchi, 1997). Presumably, however, this type of storage would be extremely heavy. Other options being pursued by various researchers include direct methanol fuel cells, which preclude the need for a reformer, and the use of ethanol in place of methanol or gasoline as a hydrogen source. The latter option is especially attractive if the ethanol can be produced from cellulosic materials, because the effect on reducing greenhouse gas emissions is particularly large for this technology.

We expect the rate of progress and probability of commercialization of fuel cell powertrains to be sensitive to the level of R&D funding and market pressures to improve overall vehicle fuel economy. Progress has in fact been rapid, as shown by the improvements in power density discussed above. Ford, GM, and Chrysler are all pursuing fuel cell vehicle R&D, as are Japanese and European companies, with Toyota's and Mercedes Benz's programs being the most visible. A Canadian company, Ballard, appears to be in a leading position in PEM fuel cell R&D, and has supplied systems to most of the vehicle R&D programs. Given current funding levels and the market's lack of pressure on fuel economy levels as well as the large amount of development work that remains to be done, however, introduction of fuel cells into mass market vehicles appears likely to be beyond the 2010 time frame, and the base scenario adheres to this projection. This, in fact, was the conclusion of the NRC's advisory panel overseeing the PNGV program (NRC, 1997, Table H-1). On the other hand, increased funding and market pressure and/or particularly fortuitous progress in the ongoing R&D program might move the date of introduction forward. Further, the newness of the technology and the dependence of the basic fuel cell stack costs on manufacturing design leaves open the potential that the eventual cost of the fuel cell system might be somewhat lower than competing ICE drivetrains; this depends on substantial cost reduction over a range of technologies, because the costs of hydrogen storage or reforming, the electric motor, and even the battery that is likely to be necessary for startup power, all play a significant role in total system costs.

The efficiency case assumes that fuel cells will not be introduced in mass market vehicles before 2010; we note that the major auto makers are not projecting a pre-2010 commercial introduction of fuel cell vehicles even assuming a high level of success in their development programs. The PNGV program envisions that the earliest fuel cells will use a reformer to produce hydrogen from gasoline. We assume that fuel cells in conjunction with a gasoline reformer will be about 70% more efficient than current gasoline engines, but only slightly more efficient than a diesel hybrid drivetrain. The high-efficiency/low-carbon case assumes introduction of commercial gasoline fuel cell vehicles by 2007. Although ethanol from cellulosic material would make an excellent fuel for the fuel cell hybrid and would result in further reductions in greenhouse emissions, we assume the first fuel cell vehicles will use widely-available gasoline.

5.2.13 Fuel Cells in Heavy Trucks and Locomotives

In many ways, fuel cell propulsion may be attractive for large transportation vehicles, such as locomotives or ships, before it is ready for use in light-duty vehicles. Use of fuel cells in heavy trucks will require a breakthrough in hydrogen production, distribution, or on-board storage, or else a breakthrough in reforming technology before it will be competitive with the diesel engine. The drive-cycle thermal efficiency of current heavy-duty diesel truck drivetrains is in the range of 35% to 40%. The drive-cycle thermal efficiency of current methanol steam-reforming fuel cell drivetrains (including electric motor/controller and battery) is also 35% to 40%. Thus, there is likely to be little incentive for heavy trucks to switch to fuel cells until hydrogen fuel cells, with drivetrain efficiencies in the range of 45% to 50%, become available.

Fuel cells may succeed in the locomotive market first because, (1) fuel costs are more important to rail carriers than to truckers, (2) locomotives already use electric traction drive and, (3) fuel cells of the size necessary for locomotive powerplant output (4000 HP) are already commercially viable in stationary powerplant applications. Therefore, we consider the use of fuel cells in locomotives in the high-efficiency/low-carbon scenario. Fuel cells may also have applicability to marine vessels, again because of their size. We do not introduce marine fuel cell applications in the high-efficiency/low-carbon technology scenario, simply because we are not aware of suitable applicability studies. We believe that analysis of the potential for fuel cell technology in heavier transportation vehicles would likely reveal additional promising applications. Thus, the locomotive fuel cell analysis is intended more to be indicative of potential large-scale fuel cell applications in transportation than a reflection of our judgment of the true potential market.

Locomotives can be broadly classified into two types: local service and line haul. Local service locomotives are primarily older line-haul locomotives that are low powered (2000-3000 HP), and are typically utilized in light load applications. Local service locomotives consume about 120,000 gallons/year of fuel per locomotive. Line-haul locomotives are more powerful (4000 HP) and consume 375,000 gallons/yr of fuel per locomotive. Both types spend considerable amounts of time at idle, over 70% of the time for local service locomotives and over 50% of the time for line-haul. Idle fuel consumption accounts for 38% of fuel consumed in local service locomotives, and only 6.3% of fuel consumed for line-haul locomotives (CARB, 1991; CARB, 1992).

Locomotives have very long useful lives and the engines are rebuilt several times. The diesel engine alone costs about \$400,000, but a complete rebuild costs only about \$100,000 to \$150,000. Engines are typically rebuilt every eight years, and the entire locomotive is rebuilt every 24 years and/or moved to local service at that point. Hence, a useful life calculation of 24 years may be reasonable in terms of a replacement cycle.

A fuel cell based locomotive could utilize methanol, ethanol, or liquefied natural gas (LNG) and could be of the PEM type being considered for cars or the Phosphoric Acid type used for power generation. It is believed that for high power applications, the Phosphoric Acid Fuel Cell is in a relatively greater state of maturity. Several large units are currently operating as prototypes for power generation. Estimates of future fuel cell costs are highly uncertain, but megawatt size Phosphoric Acid units could be manufactured at low volumes for approximately \$1000/kW in the near future, and perhaps at \$400-500 per kilowatt in ten years. At this cost, a typical locomotive unit of 3000 kW would cost \$1.2 to \$1.5 million in 2007 reflecting a cost premium of \$800,000 to \$1.1 million over a diesel engine powered locomotive. It is also possible that "rebuilt" would not be required every eight years so that net cost differences may be smaller over the lifetime of the locomotive. Also, developers of PEM cells for highway vehicles are aiming at sharply lower costs, in the range of \$50 per kilowatt (for the fuel cell only) or lower, although the size, duty cycle, and manufacturing volume of locomotive and automotive power plants are clearly very different.

presumably a portion of any cost reductions achieved in automotive fuel cells would be applicable to fuel cells designed for locomotives.

The average efficiency of the fuel cell over the duty cycle would be 1.6 to 1.7 times as high as the diesel engine (whose cycle average efficiency excluding idle is about 35%). Fuel savings of 40% are possible, which is approximately 150,000 gallons/year for a line-haul locomotive. Hence fuel savings alone could pay for the capital cost increases over about eight years, making the technology reasonably cost-effective in the context of a 24-year useful life. Of course, major uncertainties exist in the actual cost of the fuel cell for a 3000 kW unit, the life of the fuel cell, and the maintenance requirements relative to a diesel engine.

If successful, fuel cell locomotives could have a 5 to 6% market share by 2010, and 16 to 18% by 2015, for the total fleet. In the high-efficiency/low-carbon scenario, we assume a 5% share in 2010 and 20% by 2015. We further assume use of cellulosic ethanol, although methanol and LNG would also be likely candidates.

5.2.14 Costs and Timing of Technology

As part of the OTA study, the cost of all the above-described automotive technologies was derived on the basis of near-term estimates, though at high production volume. One possible area for improvement in costs is the effect of research and additional learning to provide an "experience" based cost reduction. Lipman and Sperling (1997) have analyzed cost reductions based on cumulative total production, and concluded that many new technologies experience a 20 to 35% cost reduction for every order of magnitude increase in cumulative production (i.e., the cost decline function is linear with respect to the logarithm of cumulative units produced). If these new technologies are manufactured at typical automotive volumes from their introduction, then an order of magnitude increase in cumulative production will occur over a span of five to seven years with sales growth over the period. The next order of magnitude increase in cumulative production will take much longer unless the technology essentially increases market share to 100% over the next decade. We have utilized the data from the Lipman and Sperling paper to conclude that a 30% cost reduction over the 1997-2005 period is possible relative to the costs derived for OTA.

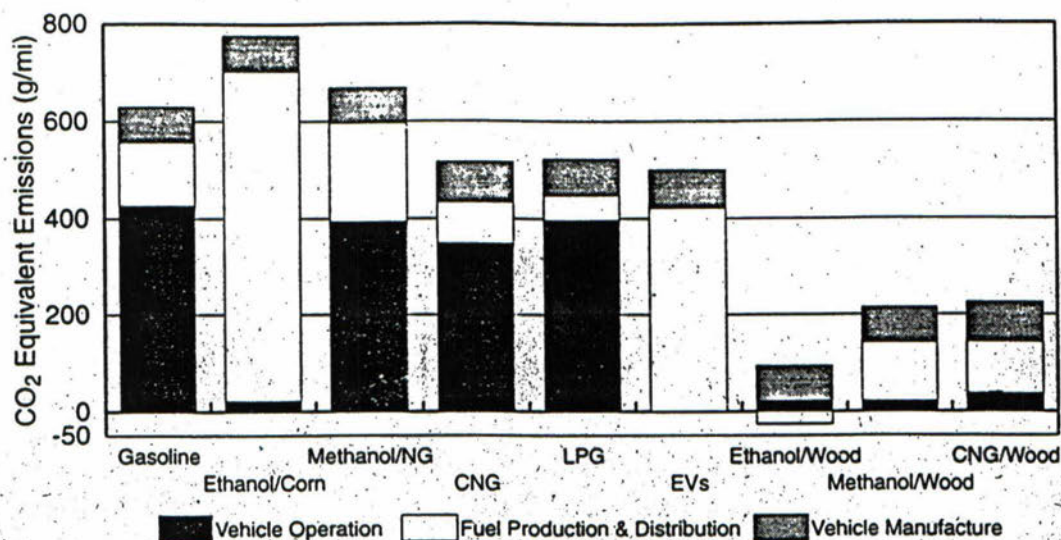
A second factor is the timing of technology introduction. The contrast here is between new technology introduction in a business-as-usual scenario relative to one where both business and government invest in research and development at rates consistent with an accelerated PNGV, coupled with changes in market preferences for fuel economy. The resulting reduction in lead time is assumed to be 30% relative to the earliest introduction dates forecast by OTA, starting from 1997. In other words, a technology forecast by OTA to be commercialized in 2010 (13 years from 1997) would be expected to arrive in 2006 ($1996 + [13 \times 0.7]$) under the regime of increased R&D spending and market changes. This factor has been incorporated for all post-2005 technologies defined in NEMS or added to the NEMS technology list for the efficiency and high-efficiency/low-carbon cases.

5.2.15 Alternative Transportation Fuels

Alternative Fuels derived from fossil energy sources have limited potential to reduce greenhouse gas emissions. The full fuel cycle greenhouse gas emissions of fossil fuels have been compared in detail by Delucchi (1991, Tables 9a-e), Wang (1996) and others. Several fossil fuel alternatives have somewhat lower CO₂ emissions than conventional or reformulated gasoline (RFG), most notably liquefied petroleum gases and natural gas, whether compressed (CNG) or liquefied (LNG). On the basis of emissions of CO₂ equivalent greenhouse gases per vehicle mile, CNG and LPG offer moderate reductions both for light (Figure 5.1) and heavy-duty (Figure 5.2) vehicles. Methanol

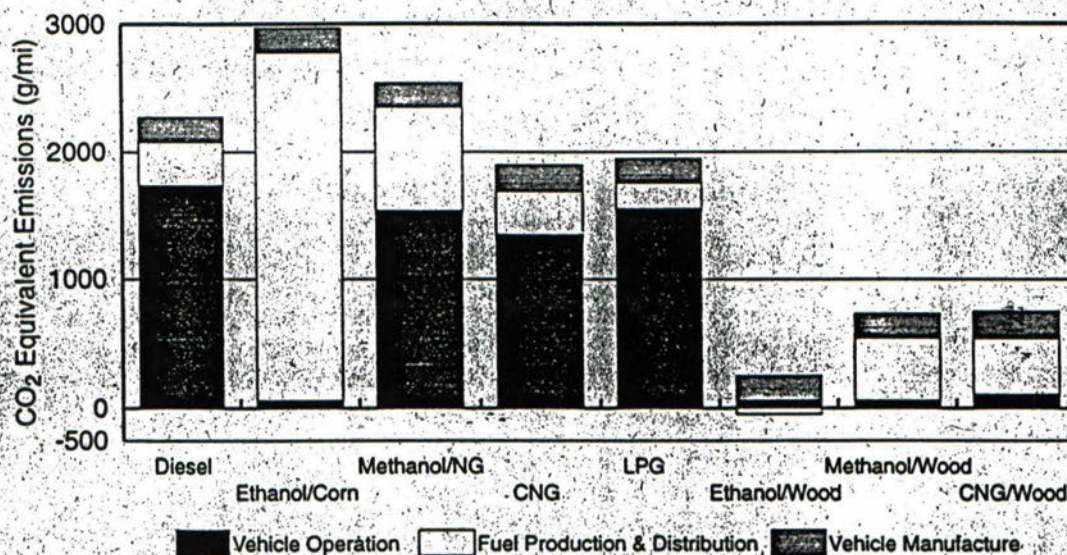
from natural gas, while it is a relatively attractive alternative fuel for spark-ignited internal combustion engines, seems to offer no CO₂ reduction potential.

Figure 5.1 Fuel Cycle Greenhouse Gas Emissions for Light-Duty Vehicles



Source: Leiby et al., 1996, Table D-4

Figure 5.2 Fuel Cycle Greenhouse Gas Emissions for Heavy-Duty Vehicles

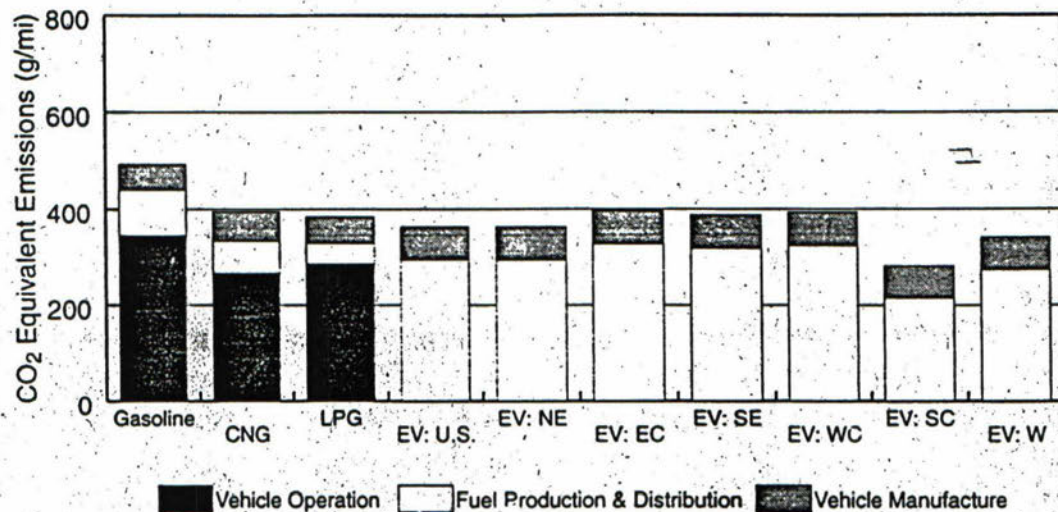


Source: Leiby et al., 1996, Table D-4

Battery-powered electric vehicles (EVs) can also lower greenhouse gas emissions, depending on the energy source used to produce the electricity stored in the vehicle's batteries. Electricity obtained from nuclear or solar power would very nearly eliminate greenhouse gas emissions. Use of nuclear power is unlikely, however, since nuclear power plants tend to operate at capacity at present and are not likely to supply a marginal increase in demand due to electric vehicle use. Electricity from

current natural gas-fired plants would achieve roughly a one-third reduction, and electricity from advanced combined cycle natural gas generations could do even better. Estimating CO₂ emissions reductions from electric vehicles is highly dependent on assumptions about when vehicles will be recharged and how utilities will choose to operate different kinds of generating units. One such set of estimates, developed based on technologies and generation mixes projected for 2015, is shown in Figure 5.3. There are no CO₂ emissions from vehicle operation and emissions from vehicle manufacture are the same for all regions. Largely due to greater use of natural gas in advanced generating units, the south central and west regions are expected to produce the lowest greenhouse gas emissions for EVs operated there.

Figure 5.3 Projected Fuel Cycle Greenhouse Gas Emissions of Battery-Powered Electric Vehicles by Region in 2015



Source: Singh (1997)

The analyses in Chapters 6 and 7 indicate that there is considerable opportunity to reduce carbon emissions in the electric utility sector. A substantial shift towards lower-carbon electric generating facilities will increase the carbon-reducing benefits of electric vehicles. For example, large shifts away from coal and towards natural gas, especially with combined cycle technology, will tend to push the relatively high EV emissions in regions whose dominant fuel is now coal (Figure 5.3) down towards the lower emissions prevalent in areas with primarily gas-fired electricity (e.g. California).

The AEO97 reference case already projects large increases in the numbers of electric and natural gas vehicles on the road. Primarily as a result of zero emission vehicle (ZEV) regulations in California, AEO97 foresees annual sales of 75,000 battery electric cars and 150,000 battery electric light trucks in 2010. To this is added more than a quarter million hybrid electric vehicles. By 2010, the AEO97 reference case projects nearly 2 million battery-electric and over 2 million hybrid electric light-duty vehicles in operation. Given the recent relaxation of ZEV mandates in California, this projection now seems optimistic. The AEO97 reference case also projects compressed natural gas vehicle sales at 325,000 units in 2010 with a total on-road stock of 2.6 million light-duty vehicles. This is more than thirty times the 82,000 CNG vehicles estimated to be on the road today (EIA, 1996c, Table 1). We retain these alternative fuel vehicles in all three scenarios, but do not expand them.

Among the alternative transportation fuels under consideration, biomass fuels derived from wood appear to have the greatest potential to reduce greenhouse gas emissions. Whereas ethanol derived from corn may actually produce higher levels of CO₂ equivalent emissions than conventional gasoline (depending on the fuel used to power the distillation plant, and other factors), ethanol derived from cellulosic sources (wood, switchgrass, wood wastes, agricultural residues, municipal solid waste), can reduce carbon emissions by about 90% for both light-duty and heavy-duty vehicles (Figures 5.1 and 5.2). Cellulosic ethanol has the potential to be more effective than compressed synthetic natural gas derived from wood, partly because of the energy that must be used to compress methane for storage on board the vehicle, and partly because cellulosic ethanol production yields by-products that can be used to generate more electricity than is required to produce the ethanol (Delucchi, 1991, Table 9b; Wang, 1996).

Both battery electric vehicles and compressed natural gas vehicles, but especially battery-powered vehicles, are likely to cost more than conventional gasoline vehicles, will require more frequent refueling, and will have reduced range (Greene, 1994). It does not appear likely that most consumers will consider these drawbacks to be outweighed by the likely lower fuel costs for these vehicles. Thus, we expect these potential low CO₂ fuel technologies will not easily achieve the business-as-usual forecast market shares (of course, technological breakthroughs in batteries or gaseous fuel storage could make these vehicle technologies much more attractive). It is for these reasons that we focus below on the use of cellulosic ethanol as a transport fuel.

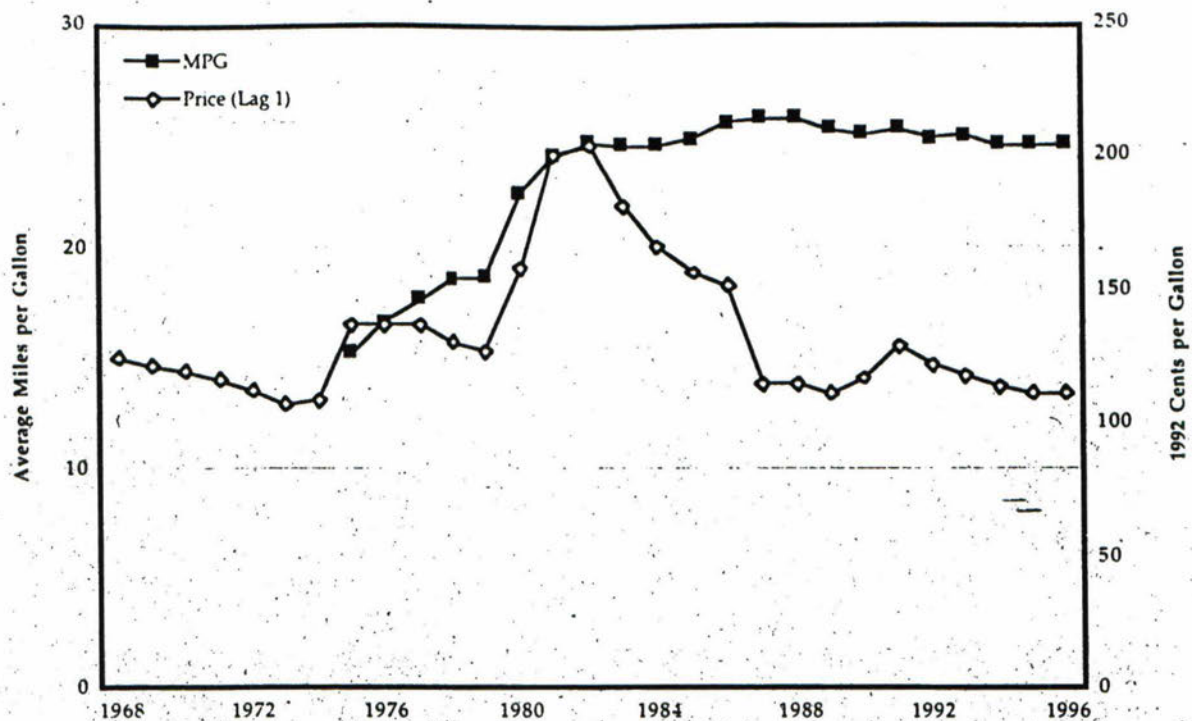
5.3 SCENARIOS FOR 2010

5.3.1 The Business-as-Usual Scenario for Transportation

The AEO97 reference case serves as the business-as-usual case, except for its forecast of increasing light-duty vehicle MPG through 2015. The EIA AEO97 reference case projects an increase in passenger car MPG from 27.5 in 1997 to 31.5 in 2010 and 32.6 in 2015. Light truck MPG is projected to increase from 20.5 to 22.9 MPG in 2010 and 24.2 MPG in 2015. We view this as inconsistent with the historical record, which appears to us to indicate that, without increasing fuel prices or a policy intervention such as fuel economy standards, MPG is not likely to increase. Thus, we incorporate zero MPG improvement after 1997 for light-duty vehicles into our business-as-usual case, reflecting the view that the current level of CAFE standards are and probably will remain a binding constraint on light-duty vehicle fuel economy throughout the business-as-usual forecast.

From 1982 to 1997, light-duty vehicle fuel economy remained essentially constant, as shown in Figure 5.4. Of course, motor fuel prices declined sharply at the beginning of the 1983-1997 period, but are at about the same levels today as they were in 1986, and as they were in the early 1970s prior to the first oil price shock. Given that the AEO97 oil price forecast projects no significant increase in oil or gasoline prices through 2015, it is reasonable to ask why fuel economy should increase. The EIA's view is that advances in motor vehicle technology will permit not only fuel economy but other vehicle attributes such as performance and weight to be increased at lower costs, resulting in greater consumer satisfaction. There is a very small increase in the price of gasoline through 2010, and this together with a slowing of income growth may allow the rate of technological advance to catch up with and pass the effect of consumer demand for larger, more powerful vehicles. Because a significant slate of cost-effective current and future fuel economy technologies are represented in the reference case input data, the model takes advantage of them even though fuel prices do not increase. NEMS would make greater use of the technologies if prices increased significantly, but the model is driven partly by technology availability and partly by changes in economic parameters. To some extent, the fuel economy benefits of these technologies are offset by a predicted increase in demand for performance. Nonetheless, a 5 MPG gain remains.

Figure 5.4 New Light-Duty Vehicle Fuel Economy and Gasoline Prices, 1967-1996

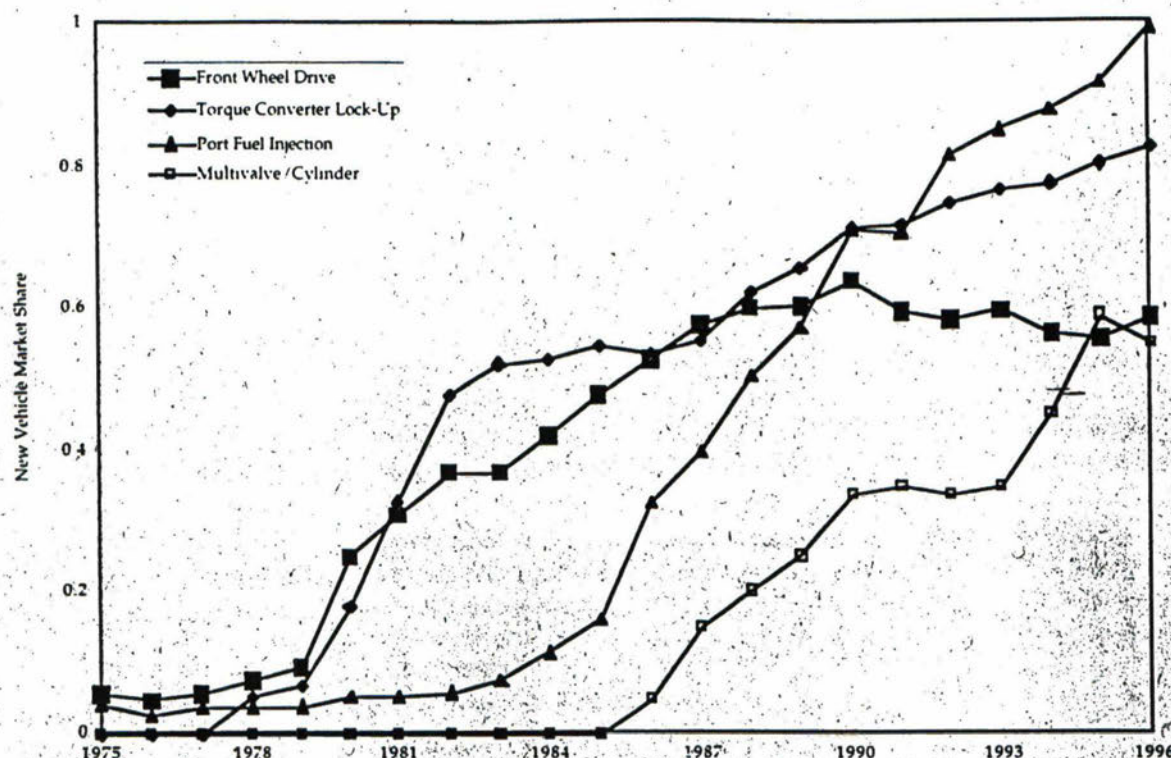


It is difficult to separate out analytically the impacts of CAFE standards and the effect of the marketplace in pushing fleet fuel economy one way or the other. However, we believe that the most likely explanation for the stagnation of fuel economy levels over the past decade is that the CAFE standards have tended to act as a floor on fuel economy, that without the standards the market level of fuel economy would have been lower than it was. We note that important fuel economy technologies, such as fuel injection, front-wheel drive, lock-up torque conversion, 4-valves per cylinder, overhead cam design, improved aerodynamics, and others, all increased their market penetration over the 1983-1997 period (Figure 5.5). Fuel economy technologies were adopted, yet average fuel economy did not increase. There are two major reasons. First, much of the potential to improve fuel economy was used instead to increase average light-duty vehicle horsepower by 55% and weight by 13% from 1983 to 1996 (Heavenrich and Hellman, 1996, Table 1). The second reason is that the impact of a technology on fuel economy depends on how that technology is implemented. To some extent, the fuel economy benefit of a technology is inherent in it. But to a degree, the benefit also depends on the details of vehicle design, specifically whether the technology is implemented with the purpose of increasing MPG or with some other purpose in mind.

If CAFE was in fact a binding constraint during the past decade and remains so today, fleet MPG will not begin to increase significantly until a market equilibrium is reached wherein actual fleet fuel economy becomes equal to the fuel economy level that would be achieved in the absence of CAFE standards. In our view, estimating "free market" fuel economy levels is basically a judgment call. We have assumed that market equilibrium will *not* be reached in the base case, so that fleet fuel economy will remain unchanged. In other words, we assume that, although fuel economy technology will continue to be adopted, it will be used to provide other benefits than fuel economy, particularly increased size and performance. Note that the AEO97 reference case also projects increased

performance and size over the forecast period; the difference here is a matter of degree, not one of radically different visions of the most likely future.

Figure 5.5 Use of Fuel Economy Technology In New Light-Duty Vehicles



5.3.2 The Efficiency Scenario For Transportation

The efficiency case was created by making reasonable, incremental assumptions about how a concerted effort to accelerate the development and promote the adoption of low greenhouse gas technologies could reduce emissions by the U.S. transportation sector. In this section, the specific changes made to the business-as-usual case are described in detail.

5.3.2.1 Changes to the Modal Models

The efficiency scenario assumes that the time required for market introduction of advanced technologies can be reduced by 25% through increased emphasis on technology R&D, and that several new technologies will be developed that would otherwise not be available in significant numbers before 2010. For light-duty vehicles, these technologies include the following:

- A direct-injection stratified charge (DISC) gasoline engine,
- A turbocharged direct-injection clean diesel engine (TDI Diesel) that meets current and future emissions standards,
- Advanced drag reduction, materials substitution, and engine friction reduction (Drag VI),

- A gasoline/electric hybrid vehicle (Gasoline Hybrid), and
- A diesel/electric hybrid drive vehicle (Diesel Hybrid).

In fact, the diesel hybrid and the 2-stroke engine were not included in the efficiency scenario for the following reasons. In preparing the technology list for NEMS, it is the analysts' responsibility to insure that technologies are truly distinct and different. If the same technology were listed twice by mistake, the analyst would in effect be instructing the model that two entirely different technologies were available to improve fuel economy. By excluding the diesel hybrid we are, in effect, asserting that the gasoline and diesel hybrids are too similar to be considered different technologies. Reality is obviously somewhere in between. We chose the gasoline over the diesel hybrid because its emissions of conventional pollutants can very likely be reduced to extremely low levels, making it attractive for air quality reasons. The 2-stroke engine, on the other hand, was left off the efficiency scenario list to reduce the number of engine technologies manufacturers would have to accommodate. Again, it is mainly the analyst's responsibility to see that the extent of change demanded of manufacturers is reasonable. In the high-efficiency/low-carbon scenario, both the 2-stroke and the diesel hybrid are included (the 2-stroke is assumed to be applicable only in compact or smaller-sized vehicles). The result is that new powerplant technologies all but entirely replace today's conventional gasoline engine by 2015. This seems a very ambitious undertaking and one that would require greater expense and a higher degree of technical success than is consistent with the efficiency scenario.

The efficiency scenario assumes a cost reduction of about one-third over estimates developed by OTA (1995) for the advanced technologies shown in Table 5.2. Among conventional technologies, the cost of CVTs was reduced from \$250 to \$150 and the cost of VVT was cut in half for passenger cars and left unchanged for light trucks. The cost reductions are intended to reflect the success of an enhanced R&D effort.

In the truck freight sector, several new technologies were brought into the forecast by reducing the fuel price threshold at which they would become attractive to buyers. These include:

- The LE-55 diesel engine with a 21% efficiency improvement for heavy trucks,
- Reduced empty weight,
- The turbo compound diesel engine, and
- Advanced drag reduction.

For commercial aircraft, an efficiency improvement of 40% was projected for 2015 for new aircraft, comprised of 25% engine efficiency gains and 15% aerodynamics and materials substitution. Also, load factors were assumed to increase to 70% in accord with industry projections as a result of advanced informational and operational technologies. Finally, railroad freight efficiency per ton-mile was assumed to improve at 2% per year, actually somewhat lower than the 2.8%/yr. rate experienced over the past 20 years.

5.3.2.2 New Technologies

Table 5.2 shows the fuel economy benefits, price impacts, years of introduction, effects on vehicle weight, and effects on vehicle performance of the five new technologies that were added to the AEO97 reference case set. Detailed assumptions underlying the cost of fuel economy improvement estimates shown in Table 5.2 are provided as an appendix to this chapter. In order to meet current

and future emissions standards, the DISC and TDI Diesel engines, as well as the two-stroke engine included in the business-as-usual case, will require the development of practical, lean-combustion nitrogen oxide catalysts. Catalyst technology for treatment of exhaust emissions has been advanced significantly over the past few years and, with further research, the prospects for its early commercialization appear to be very good (e.g., Buchholz, 1997; Strehlau et al., 1997). Achieving equivalent results for diesel exhaust NO_x appears to be more difficult, and commercialization of diesel catalysts is likely to occur several years after introduction of gasoline-engine catalysts (U.S. Congress, OTA, 1995). In addition, the DI Diesel will require advances in fuel and emissions control technology in order to meet likely future particulate standards.

Fuel economy benefits, incremental costs and other changes are calculated with reference to a 1995 technology gasoline vehicle. In the NEMS model, light-duty vehicles are classified into passenger cars vs. light trucks, domestic vs. imported, and four size classes. In each class, the 1995 base vehicle has the average characteristics of cars in its class. For example, half of the passenger cars in 1995 had 4-valve per cylinder engines, but less than 10% of the light trucks did (Heavenrich and Hellman, 1996). One hundred percent of passenger cars and 99% of light trucks had port fuel injection, and so on. Future fuel economy improvements are calculated based on the additional penetration of fuel economy technologies beyond the business-as-usual case. Thus, the ability of further use of port fuel injection to improve fuel economy is negligible, while considerable potential remains for 4-valve technology.

Table 5.2 New Light-Duty Vehicle Technologies Added to the Efficiency and High-Efficiency/Low-Carbon Scenarios*

Technology	MPG Benefit (%) [*] (EFF, HE/LC)	OTA Price Increase	Scenario Price	Introduction Date [*] (EFF, HE/LC)
DISC	18, 23	\$450	\$300	2000, 2000
Turbo DI Diesel	40, 40	\$1100	\$750	2004, 2004
Hybrid/Gasoline	33, 42	\$3000	\$2000	2005, 2005
e				
Hybrid/Diesel	54, 72	\$3500	\$2300	2005, 2005
Drag VI	12, 12	\$256	\$256	2012, 2012
Gasoline Fuel Cell	7, 84	-	\$800	- , 2007

* For an explanation of the assumptions underlying these estimates please see the appendix to this chapter.

5.3.2.3 Valuing Energy Savings

The NEMS model values the fuel economy savings of advanced technology by computing the expected discounted value of annual fuel savings over a payback period. The reference case discount rate is 8% per year and the payback period is four years. This was changed to a 7% real discount rate over five years in order to equate the total discounted lifetime miles to a vehicle with an expected life of 14 years, using an annual real discount rate of 20%.

5.3.2.4 Trends in Vehicle Performance

The NEMS model predicts consumer demand for increased performance and then adjusts new car MPG downward to reflect the effect of higher horsepower on fuel economy. The model's predictions are consistent with recent trends in light-duty vehicle performance since the early 1980s. Over this period, new vehicle fuel economy was constrained by the federal Automotive Fuel Economy Standards (CAFE) to levels higher than the market would otherwise have demanded. Gasoline prices fell precipitously, starting in 1983 and reaching pre-1974 levels by 1987 (Figure 5.4). As a result, new technology adopted since the mid-1980s, that could have increased fuel economy, was instead used to hold fuel economy constant while increasing vehicle horsepower and weight. The ratio of horsepower to weight for passenger cars increased by 50% from 1982 to 1996). The NEMS horsepower equations essentially continue this trend of ever-increasing performance.

Continued use of new technology to increase performance without increasing fuel economy is consistent with the continued low motor fuel prices projected in the AEO97 reference case. The reference case foresees gasoline prices rising from \$1.15 in 1995 to \$1.23 in 2010 and falling to \$1.18 per gallon in 2015 (1995\$). Such variations are within the noise of year-to-year fluctuations. For example, the actual average price of gasoline in 1995 was \$1.20 and the average price for 1996 will likely exceed \$1.30 per gallon (EIA, 1997, Table 9.4). With no increase in price and binding fuel economy standards, it is likely that performance and weight will continue to increase and fuel economy will not.

In the efficiency case, the trend toward ever greater horsepower is questionable. In the presence of higher fuel economy standards, voluntary commitments by manufacturers to meet GHG targets, "greener" consumers, externality-based fuel taxes, or some other change in policies or preferences focusing consumers' and manufacturers' attention on efficiency, it is likely that performance trends would change. Nonetheless, we retain the NEMS performance projection in the efficiency case, but relax it in the high-efficiency/low-carbon case by permitting only half of the projected increase in horsepower. This results in new vehicle fuel economy levels 1-2 MPG higher in the high-efficiency/low-carbon case than would otherwise be the case.

5.3.2.5 NEMS New Light-Duty Vehicle Fuel Economy Estimates

Transforming the technology of transportation energy use takes time. First, manufacturers must implement a new technology. New designs must be engineered, tested, and certified to meet government standards. Generally, capital equipment will also have to be replaced or retooled. The orderly replacement of long-lived production facilities (engine production lines may last 15 years, or more) is important to holding down the cost of technological change. Second, consumers must become accustomed to the new technology, and the supporting infrastructure of maintenance and repair must be developed. Finally, new technologies must compete with existing technologies and with other new technologies. In general, a single technology will not dominate all possible applications (vehicle types and consumer preferences). For all these reasons, new technologies rarely achieve 100% (or even 10%) market penetration of the new vehicle fleet in the first year of introduction. The NEMS model simulates the gradual evolution of technology market shares toward their eventual equilibrium levels by means of technology adoption curves calibrated to historical rates of adoption.

As a result, the NEMS forecast of average fuel economy for new vehicles will lag behind the full technological potential. This is illustrated in Table 5.3, which lists all of the best technology predicted to be available in 2010 and 2015 in the efficiency scenario, except that the diesel rather than the gasoline hybrid is included. The effects of regulations that are likely to reduce fuel economy are also included. Further increases in performance (horsepower/weight) predicted by the NEMS model are not considered (i.e., horsepower-to-weight ratios are assumed to remain constant

at 1997 levels); this applies only to Table 5.3 – all scenarios incorporate substantial increases in hp/wt ratios. The combined effect of all technologies could improve the fuel economy of the average passenger car by 100% to 55 MPG in 2010, and by another 20% to over 60 MPG in 2015. Yet, even in the high-efficiency/low-carbon scenario, these levels are not achieved by the new car fleet in the NEMS forecasts.

Table 5.3 Maximum Technological Fuel Economy Potential Versus NEMS New Car Average Estimates

Technology	2010 Fuel Economy Improvement (%)	2015 Fuel Economy Improvement (%)
Material Substitution IV	9.9	13.2
Drag Reduction V	9.2	12.0
Engine Friction III	5.0	6.5
Tires III	5.0	7.0
ACC II	1.0	1.0
Electric Transmission II	1.5	1.5
Electric Power Steering	1.5	1.5
Air Bags	-1.0	-1.0
Emissions Tier II	-1.0	-1.0
ABS	-0.5	-0.5
Side-Impact	-0.5	-0.5
Roof Crush	-0.3	-0.3
Diesel Hybrid	54.0	60.0
Total % Improvement	100.0	123.0

	1997 MPG 27.5	2010 MPG	2015 MPG
Maximum Use of All Fuel Economy Technology			
Miles per Gallon		55.0	61.3
Percent Improvement		100	123
New Car Salesweighted Average Fuel Economy: Low CO ₂ Scenario			
Miles per Gallon		37.5	41.4
Percent Improvement		36	51
New Car Salesweighted Average Fuel Economy: Breakthrough Scenario			
Miles per Gallon		43.1	50.2
Percent Improvement		57	83

Clearly, faster rates of fuel economy improvement than predicted in either scenario are achievable, but at added cost. The constraint that fuel economy improvements be approximately cost-effective requires that the changeover of technologies and manufacturing capital occur at approximately normal rates. This causes realized new car MPG levels to lag considerably behind the full technological potential. On the one hand, this implies that considerable additional energy-efficiency improvement can be made beyond 2015. On the other, it implies that markets must be encouraged, through public policy measures, to make continuous improvements if cost-effective reductions in CO₂ emissions are to be realized.

5.3.2.6 Changes to the Heavy Truck Model

In contrast to the business-as-usual case, the efficiency scenario for heavy trucks:

- Advances introduction dates for two fuel economy technologies,
- Introduces one additional technology,
- Expands the applicability of several truck technologies,
- Reduces the "trigger price" at which the technologies are assumed to become cost-effective, and
- Accelerates the rate at which new technologies are assumed to penetrate the new truck market.

The AEO97 reference case assumes that the Turbocompound Diesel Engine and the Advanced LE-55 Heat Engine will not be available through 2015. The efficiency scenario assumes these technologies will be introduced in 2003. Advanced drag reduction, which is also excluded from the reference case for heavy trucks is assumed to have become available in 1997.

The additional technology introduced is reduction in vehicle empty weight through material substitution. Reducing vehicle empty weight by 10% should be possible, with a consequent 3% increase in fuel economy (Roberts and Greene, 1983; Greene, 1996a, Table 5.5). Reduced empty weight is assumed to be applicable to all types of heavy trucks.

The AEO97 reference case assumes that advanced drag reduction, the turbocompound diesel, and the LE-55 heat engine will be applicable only to the heaviest diesel trucks. The efficiency case extends the applicability of these technologies to medium-heavy diesel trucks, as well. However, the fuel economy benefits of advanced drag reduction are cut from 18% to 10% for medium trucks to reflect the fact that they are generally operated at lower speeds.

A key factor governing the use of fuel economy technology in the NEMS Heavy Truck Model is the "trigger price." Until market fuel prices reach the "trigger price" level specified for a technology, the technology will not be introduced. Diesel fuel prices never exceed \$8.70 (1995\$) per million Btu (\$1.21/gal.) in the AEO97 reference case. Trigger prices for all but existing technologies, however, are \$9/MMBtu, or greater in the reference case. The efficiency case assumes that all of the new technology can be made cost-effective at \$8/MMBtu.⁹

Other parameters controlling the rate and extent of market penetration for technologies were also changed. One of these is the number of years until 99% of the maximum potential market penetration is achieved. For improved tires and lubricants, electronic engine controls, and electronic transmission controls, a value of 20 years is assumed in the AEO97 reference case. But for advanced drag reduction, turbocompound diesel, and the LE-55 engine, 99 years is the assumed value. For the efficiency case, all were set at 20 years. The AEO97 reference case assumed that the LE-55 engine would have a maximum market potential of 50% for heavy-duty diesels. The efficiency scenario assumes a 100% maximum for heavy diesels, but only 50% for heavy gasoline, LPG, and CNG trucks. Likewise, the maximum market potential for other advanced technologies was increased to 100% for the heavy diesel market, but left at the reference case values for other fuel types. For medium diesel trucks the maximum penetration for new technologies was raised to 90%, but left at the reference case levels for other fuel types. These changes do not imply that any of these technologies will actually reach maximum market penetration over the forecast time period. Table 5.4

summarizes the primary fuel economy technologies for heavy trucks in the efficiency scenario for 2010.

Table 5.4 Key Heavy Truck Fuel Economy Technologies for the Efficiency Scenario in 2010

Technology	Year of Introduction	Trigger Price (1995\$/MMBtu)	Maximum Market Potential (other / diesel)	Fuel Economy Improvement % (medium/heavy)
Improved Tires & Lubes	1994	\$7.75	80% / 100%	10% / 6%
Electronic Engine Controls	1994	\$7.75	70% / 100%	2%
Elec. Transmission Controls	1994	\$7.75	75% / 100%	5% / 2%
Advanced Drag Reduction	2000	\$7.75	25% / 100%	7% / 18%
Turbocompound Diesel	2000	\$7.75	25% / 100%	15% / 17%
LE-55 Heat Engine	2003	\$7.75	50% / 100%	19% / 21%
Reduced Empty Weight	1997	\$7.75	90% / 100%	3%

5.3.2.7 Changes to the Rail Model

The AEO97 reference case scenario assumes an annual rate of reduction in rail freight energy use per ton-mile of 1%. Since 1972, the average annual rate of reduction in energy use per ton-mile has been 2.8% per year. The vast majority of this improvement has been due to operational efficiency improvements reflected in increased load factors per car (Greene and Fan, 1995, p. 15). Higher load factors are partly due to the restructuring of the rail industry following deregulation in 1980, and partly due to the use of advanced technology for managing operations. Technologies such as lighter weight and higher capacity cars, lower resistance axle bearings, rail-wheel lubrication and improved efficiency locomotives also played an important role (Cataldi, 1995). These technologies are, as yet, still only partially implemented. Based on Cataldi (1995), advanced technologies that can play a role in substantially reducing rail energy use in the future include the following:

- **Flywheels:** Trains presently give up large amounts of kinetic energy on downgrades that could be transferred to flywheels and later used to power the train. The volume and mass necessary to store huge quantities of power can be readily accommodated on trains.
- **Oxygen-enrichment to increase engine thermal efficiency:** Membranes that exclude part of the free nitrogen in the air, thereby enriching the oxygen concentration, can be incorporated into locomotives' air filtration systems. This technology should benefit new, higher power density engine designs, while helping to hold down their nitrogen oxide emissions.
- **Alternative fuels:** Railroads and locomotive manufacturers have been studying and testing the use of natural gas fired locomotives. Once again, the ability of trains to accommodate the volume and mass of storage systems for liquefied natural gas gives them a distinct advantage over smaller vehicles in the application of this technology. Although natural gas locomotives are not expected to provide energy-efficiency gains over diesels, natural gas will produce fewer CO₂ and NO_x emissions and reduce U.S. dependence on oil.
- **Fuel cells:** Beyond 2010, fuel cells for locomotives hold promise. Locomotives already use electric drive systems. And carrying fuel, even compressed hydrogen in large volumes, is less of a problem for trains than for highway vehicles.

Because existing energy-efficiency technologies have yet to achieve full utilization, because other promising options exist, and because further operational efficiency gains are likely with the advance of information technology and some additional railroad consolidation, rail energy-efficiency improvements could continue at a substantial rate. A concerted effort to develop and implement cost-effective technologies is represented here by a 2% annual improvement in ton-mile efficiency in the efficiency case compared with the 1% rate assumed in the AEO97 reference case.

5.3.2.8 Changes to the Air Model

No new technologies were introduced in the NEMS Air Travel Model, but several important changes were made to promote and accelerate the introduction of fuel efficient technology in accordance with goals set by the Committee on Aeronautical Technologies, Aeronautics and Space Engineering Board of the NRC. Broadly, these goals call for a reduction in fuel burn per seat of about 40% by the 2010 to 2015 time period, to be achieved through a combination of improved propulsion system performance (25%) and aerodynamic and weight improvements (15%) (NRC, 1992, p. 49).

Once again, in the AEO97 reference case, new technologies do not enter the commercial aircraft market because trigger prices are set well in excess of \$1.00 per gallon and jet fuel prices never exceed \$0.80/gal. over the forecast period. Trigger prices for ultra-high bypass turbo-fans, already in use on the new Boeing 777s, were lowered to \$0.58/gal., just slightly above current jet fuel prices. Advanced aerodynamics, weight reduction through advanced materials use, and improved engine thermodynamics, were all given the same, lower trigger price. The prices of turboprop engines and laminar flow control were left at levels high enough to prohibit their introduction on new aircraft through 2015.

Ultra-high bypass turbofans were introduced in 1995. The other three technologies were assumed to be introduced in 2000. Consistent with estimates presented in NRC (1992), Greene (1992, Table 4), and Greene (1996b), the efficiency improvement potentials for all four new technologies were set at 15%.

Finally, the AEO97 reference case predicts no changes in aircraft load factors. Aircraft industry analyses foresee commercial load factors increasing to 70% by 2015 (Boeing, 1995, p. 25; McDonnell Douglas, 1996, p. 18). The industry view is adopted in the efficiency scenario, on the grounds that it will very likely be advances in information technology that permit the increase in load factors. On the other hand, although the industry predicts an increase in aircraft size (seats/aircraft) of about 15% by 2015 while the AEO97 reference case does not, no such increase is included in the efficiency scenario on the grounds that more seats per aircraft will be less a reflection of technological change than of airframe choice.

5.3.2.9 Introduction of Cellulosic Ethanol

Alternative fuels derived from fossil fuels have limited potential to reduce greenhouse gas emissions. The full fuel cycle greenhouse gas emissions of fossil fuels have been compared in detail by Delucchi (1991, Table 9a), Wang (1996), U.S. DOE (Leiby et al., 1996, Tables D-4 and D-5), and others; see Wang (1996) for a review. Several fuel alternatives have lower CO₂ emissions than conventional or reformulated gasoline (RFG), most notably liquefied petroleum gases (LPG), methane and battery-powered electric vehicles in certain regions, whether compressed (CNG) or liquefied (LNG). Estimates of greenhouse gas emissions are strongly dependent on context and assumptions. Absolute levels and sometimes the relative rankings of fuels vary across studies. Several general patterns seem to hold up, however. Fossil-fuel-based alternatives to gasoline or diesel fuel, including battery-electric vehicles where substantial amounts of coal are used for

electricity generation, offer about a 20% net reduction in greenhouse gas emissions per mile (Figure 5.3).

In the context of this analysis, a 20% reduction in greenhouse gas emissions will not create a strong incentive to adopt an alternative fuel. For light-duty vehicles, if society's willingness to pay for greenhouse gas emissions reductions were on the order of \$25-\$50 per tonne of carbon, this could justify up to a \$0.06 to \$0.12 per gallon subsidy¹⁰ for a fuel that produced no greenhouse gas emissions. A 20% reduction would therefore be worth \$0.01 to \$0.02 per gallon, hardly enough to get motorists' attention. Also, the principal near-term alternative fuels entail some increase in vehicle cost or loss of amenity (Leiby et al., 1996). Thus, unless much higher incentives are introduced, it is unlikely that enough substitution of alternative fossil fuels for conventional gasoline will occur to produce significant greenhouse gas reductions in transportation (Leiby et al., 1996).

Alternative fuels produced from renewable biomass feedstocks can yield significant reductions in greenhouse gas emissions. The most recent estimates indicate that ethanol derived from cellulosic feedstocks (as opposed to grain) produces less than 1% as much greenhouse gas emissions on a fuel cycle basis as conventional gasoline or diesel fuels (Singh, 1997).¹¹ Table 5.5 shows the greenhouse gas emission coefficients used to estimate the effects of cellulosic ethanol use and increased demand for diesel fuel on transportation sector greenhouse gas emissions. Ethanol from cellulose generates negligible amounts of greenhouse gases in comparison to fossil fuels or ethanol from grain. Whether ethanol is derived from grain or woody biomass, the carbon in the fuel itself does not count because equivalent carbon will be recaptured from the atmosphere by the next rotation of crops. The differences lie in feed stock cultivation, fertilizer manufacture, and fuel production. Corn requires more cultivation and more fertilizer than woody crops, and fertilizer production, in particular, generates significant greenhouse gas emissions. Whereas distillation of alcohol after the fermentation of grain is energy intensive, by-products from the wood-to-alcohol process will produce excess power, on net, resulting in a greenhouse gas credit for replacing fossil fuels with biomass in the generation of electricity. Indeed, given current practice, ethanol from corn may produce more greenhouse gas emissions than gasoline, on a per Btu basis. Thus, ethanol from cellulosic feedstocks will not only reduce greenhouse gas emissions by replacing gasoline, but might achieve even greater benefits by replacing ethanol from corn. However, the net greenhouse gas balance of ethanol production from corn is strongly dependent on future corn yields, the market for distillation byproducts, and the efficiency of and fuel used in distillation (currently, coal is often the preferred fuel because of corn-based ethanol's disadvantage in greenhouse gas emissions, but future widespread use of corn stillage as fuel would swing ethanol's greenhouse gas emissions strongly towards a positive balance).

A new process for producing ethanol from cellulosic biomass that appears to have the potential to dramatically reduce costs is under development by the U.S. DOE's National Renewable Energy Laboratory (Chem Systems, Inc., 1993). After initial preparation of the biomass, pretreatment with sulfuric acid and then steam is used to expose the cellulose and convert xylan to xylose. Two percent of the resulting mixture is separated for conversion to cellulase, an enzyme that hydrolyzes cellulose. The cellulase is then combined with the rest of the mixture fermented in a key step known as simultaneous saccharification and fermentation (SSF) because the hydrolyzation of cellulose and the fermentation of xylose occur simultaneously. The inclusion of xylose fermentation in this step increases the output of ethanol by about 25% over previous processes. Effluent from the SSF process goes to an ethanol purification and solids separation phase, which produces ethanol and solids. After removal of water, the solids are burned as fuel to cogenerate steam and electricity required for the plant, with surplus electricity that can be sold as a byproduct.

Table 5.5 Greenhouse Gas Emissions Factors for Transportation Fuels

Fuel	g/Btu	Btu/gallon	g/gallon
Conventional Gasoline			
Summer	0.10554	114,500	12,084
Winter	0.10304	112,700	11,613
Average	0.10421	113,537	11,832
Diesel	0.09617	128,700	12,377
Ethanol from corn	0.13390	76,100	10,190
Ethanol from cellulose	0.00076	76,100	58

Source: Singh (1997)

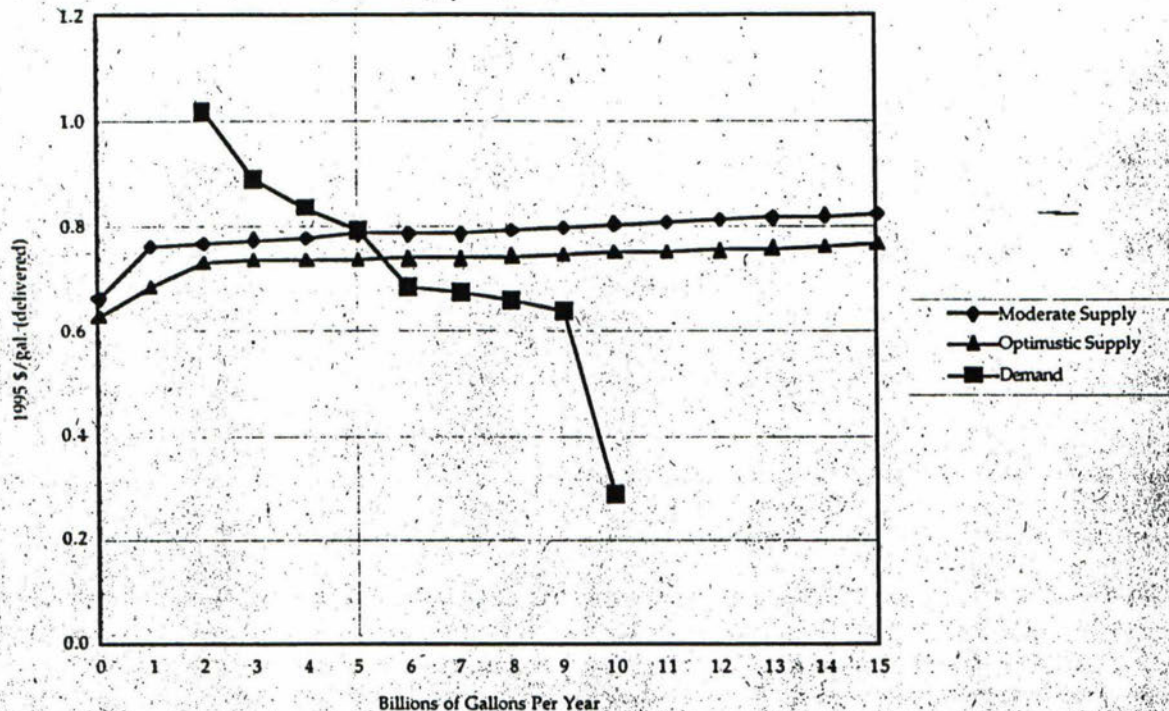
Initial estimates of the cost of ethanol produced by the NREL process ranged from \$0.78 to \$1.27 (1990\$) per gallon, plant gate price (Chem Systems, 1993, Tables II-9 to II-13). However, recent cost projections (Bowman et al., 1997) based on a comprehensive assessment of feed stock supply in the United States (Walsh et al., 1997) and anticipated improvements in the ethanol conversion process predict that much lower production costs can be achieved by 2010 or 2015. Ethanol can be produced from a variety of cellulosic feed stocks: short rotation woody crops, switch grass, softwood and hardwood wastes, agricultural residues, and even municipal solid wastes. Selecting the lowest cost feedstock at each level of output, aggregate ethanol supply curves were constructed for 2000, 2005, 2010, and 2015 under "moderate" and "optimistic" assumptions. The optimistic curves assume that the yield improvements of the moderate case are accelerated by five years, with the net result that the real cost of feed stocks does not rise over time. The moderate scenario curves are used in the efficiency scenario. The optimistic case, being similar in intent to our high-efficiency/low-carbon scenario, is used in that scenario.

In the moderate scenario, ethanol production costs drop dramatically after 2005, the year in which advanced ethanol conversion technology is assumed to be introduced. In 2000, the first billion gallons cost \$1.10 (1995\$) per gallon at the plant gate, which rises to almost \$1.25 per gallon at a 10 billion gallon output level. These prices exclude motor fuel taxes and transportation costs. By comparison, the average refinery price of all grades of gasoline in 1995 was \$0.63 per gallon (EIA, 1996a, Tables 5.20 and 5.21). Because ethanol has only about two-thirds of the energy content of gasoline, the comparable price of ethanol per gasoline energy equivalent gallon would be \$1.63 for the first billion gallons and \$1.85 at the 10 billion gallon level of output. By 2010, the cost of ethanol drops to about \$0.75 per gallon (\$1.11 per gasoline equivalent gallon) at the 1 billion gallon output level, \$0.79/gallon (\$1.17 equivalent) at 10 billion gallons of production. Even in the optimistic case, the first billion gallons cost \$0.67/gallon (\$0.99 equivalent), increasing to \$0.73/gallon (\$1.08 equivalent) at the 10 billion gallon output level. Despite dramatic reductions in the cost of producing ethanol from biomass, because of the lower energy content of ethanol, ethanol still cannot compete with gasoline as a pure fuel.

We conclude that the market for cellulosic ethanol in 2010 will be largely as a blending component for gasoline. Demand curves for ethanol for blending with gasoline have been estimated by Hadder (1997) for the year 2010. These show the value to refiners of being able to produce a gasoline refined to be blended with alcohol downstream. Ethanol increases the gasoline's octane rating and adds oxygenates that are required in certain areas under the Clean Air Act. The demand for ethanol as a blending component turns out to be sensitive to the market share of RFG. The more RFG that is required, the lower the demand for ethanol. We assume that RFG's market share remains at its

current level of about 30%. Estimated ethanol demand increases as its price declines, from 2 billion gallons per year at an ethanol price of just over \$1 per gallon to 5 billion gallons at \$0.80/gallon and 9 billion at \$0.65/gallon. From this point, increases in demand associated with further price decreases drop off sharply as the limits of economical blending are reached. The moderate 2010 supply curve for cellulosic ethanol intersects the demand curve at about 5 billion gallons per year (Figure 5.6).

Figure 5.6 Biomass Ethanol Supply and Demand for Ethanol in Gasoline Blending



These calculations include no tax subsidy for cellulosic ethanol from biomass. If the projected supply curves are correct, cellulosic ethanol would require no subsidy to be economically attractive as a blending component for gasoline. The current tax subsidy for ethanol – now produced from grain – is due to expire, and the future of the industry is uncertain. Assuming discontinuation of the subsidy, cellulosic ethanol would displace corn-based ethanol from the gasohol, yielding significant greenhouse gas emissions reductions.

5.3.2.10 Adjustment of NEMS Gasoline Forecast

The 5.5 billion gallons of cellulosic ethanol demanded in the efficiency case reduce greenhouse gas emissions by 13 million tonnes of carbon equivalent in 2010 compared to the business-as-usual case. Cellulosic ethanol is assumed to replace first corn-based ethanol, and then conventional gasoline. The Federal Highway Administration (FHWA) estimates that 1,214 billion gallons of ethanol were used in gasohol in 1995 (U.S. DOT/FHWA, 1996, Table MF-33E). If gasohol made from corn-based ethanol were to maintain a constant share of the gasoline market, then corn-based ethanol use would grow to 1,263 million gallons in 2010, then shrink to 1,119 million gallons in 2015. Table 5.6 shows the projected demand for cellulosic ethanol, the corn-based ethanol assumed to be replaced and the impact on fuel cycle greenhouse gas emissions. Because the upstream effects cannot be

assumed to be accounted for in the other sectoral models, they are included here. Note that the reduction is shown in tonnes of carbon, while the emissions before and after are in tonnes of CO₂.

Table 5.6 Impact of Cellulosic Ethanol on Greenhouse Gas Emissions from Light-Duty Vehicles in 2010

	Efficiency	Optimistic
Cellulosic Ethanol (million gallons)	5,514	7,480
Corn Ethanol Displaced (million gallons)	1,263	1,119
Gasoline Equivalent Energy Displaced (million gallons)	3,696	5,014
GHG Emissions Before (million tonnes CO ₂ per year)	46.6	62.2
GHG Emissions After (million tonnes CO ₂ per year)	0.3	0.4
GHG Emissions Reduction (million tonnes C per year)	12.6	16.8

5.3.2.11 Adjustments for Increased Light-Duty Vehicle Diesel Use

Because the TDI Diesel engine and the Diesel-hybrid technologies were introduced in the NEMS Transportation Sector Model as fuel economy technologies, the fuel-type accounting algorithms of NEMS were bypassed. We introduced the advanced diesel in this way because we believe that its characteristics will be more similar to gasoline engines than the diesels available in the past. The TDI will fully meet all gasoline vehicle standards and will be quite similar in terms of performance, noise, and odor.¹² Thus, an adjustment must be made *ex post*, to transfer an appropriate amount of energy from the gasoline to the distillate category. The adjustment affects the energy use projections in three (relatively minor) ways. First, the TDI Diesel's impact is specified in terms of a change in miles per gallon. Since diesel fuel contains more Btu per gallon than gasoline and since the NEMS model assumes that gasoline is being consumed, the energy use transferred from gasoline to diesel must be increased by the ratio of diesel to gasoline Btus per gallon. Second, distillate fuel produces slightly less carbon emissions per Btu than gasoline. Therefore the estimated carbon emissions must be adjusted both for the slight increase in energy use and the slightly lower emissions per Btu for that greater energy use (the net result is a very small increase in carbon emissions). Third, and finally, the reduction in gasoline use reduces the potential pool for ethanol blending in gasoline. As a result, the demand for ethanol must be adjusted downward to reflect the lower level of gasoline use. The net result of all of these changes on energy use and carbon emissions is less than 1%.

5.3.3 The High-Efficiency/Low-Carbon Scenario for Transportation

The high-efficiency/low-carbon scenario postulates the introduction before 2010 of several new technologies and combines them with other changes to reflect greater success in developing and implementing low greenhouse gas technologies and greater public concern over greenhouse gas emissions. Note that successfully achieving these outcomes requires some technological breakthroughs, implying that the outcomes are significantly less certain than those in the efficiency case.

5.3.3.1 Light-Duty Vehicles

Changes for light-duty vehicles include introducing a fuel-cell hybrid in the year 2007 and reintroducing the diesel hybrid and the 2-stroke engine for smaller vehicles. In the projections shown here, we assume that the fuel cell hybrid vehicle uses gasoline which is reformed to provide hydrogen for the fuel cell's operation (e.g., Jost, 1997). The vehicle could just as easily have been

designed to operate on alcohol fuels. The gasoline fuel cell hybrid achieves an 84% efficiency gain over a conventional gasoline vehicle, assuming major progress not only in fuel cell and gasoline processor technology, but also in electric motors and other electric drivetrain components. Because a major breakthrough would be required to make this vehicle marketable, we do not attempt to estimate its cost. Instead, we assume that it will be cost-effective on a life-cycle cost basis – that is, that its incremental cost will be equal to its lifetime fuel savings. This implies a price increment of \$800.

Some of the technologies necessary to produce an 84% efficiency gain for the fuel cell hybrid would also make the internal combustion engine hybrids, both gasoline and diesel, somewhat more efficient (e.g., ultra high-efficiency electric motors, improved energy storage devices with high specific power and high in/out efficiency). Fuel economy gains for the gasoline and diesel hybrids are boosted to 42% and 72%, respectively. A more optimistic assumption is made for the DISC engine, as well. Its fuel economy benefit is increased to 23% from 18%.

If Intelligent Transportation Systems technologies are highly successful, they should be able to improve traffic flow, resulting in higher on-road fuel economy. To reflect this, the on-road fuel economy factor, which otherwise deteriorates by 3% from 1997 to 2015, is held constant. The high-efficiency/low-carbon case further assumes that the current emphasis on horsepower (HP) will abate substantially, although increased HP will still be valued. This case is consistent with a change in attitudes favoring "greener" automobiles or policies to encourage higher MPG. To reflect greater public concern over greenhouse gas emissions, the demand for increased horsepower is reduced by decreasing its sensitivity to income, from an elasticity of 0.9 to 0.5.

As noted earlier, there are other potential technology breakthroughs capable of significantly reducing greenhouse emissions (e.g. breakthroughs in batteries for electric vehicles, or in gas storage for natural gas vehicles (see box)). These were left out of the high-efficiency/low-carbon scenario not because they are necessarily less plausible than fuel cells, but because the inclusion of large numbers of technology breakthroughs in a single scenario would be implausible.

Another Potential Breakthrough Technology

Aside from the new technologies postulated in the high-efficiency/low-carbon scenario, other potential technologies could yield substantial reductions in greenhouse gas emissions with technology breakthroughs or, in some cases, with a substantial market push. In the light-duty vehicle market, for example, battery electric vehicles have potential to reduce greenhouse gases if they can greatly increase their market share and improve their energy efficiency. For example, several recent studies have concluded that, under plausible assumptions about EV efficiency and the mix of fuels and technology used to generate recharge electricity, use of EVs will yield net reductions of greenhouse gases. Delucchi (1997) estimates a national average reduction of 26% in 2015, with power generation heavily weighted to coal; whereas Wang (1997) estimates a 19% reduction in 2005. Areas with predominately natural gas-generated electricity could have much larger savings. Note, however, that these results are dominated by assumptions about EV and baseline gasoline vehicle efficiency, type of fuel and technology used for power generation, inclusion or exclusion of non-CO₂ greenhouse gases, and the types of trips replaced by EV use; it is, relatively easy to construct plausible scenarios with much higher or lower reductions in greenhouse gases, or even increases (with coal-fired electric power and extremely efficient competing gasoline vehicles).

Crucial technological roadblocks for EV market penetration are:

- Battery improvements – especially higher specific energy and power, lower cost, improved longevity, higher in/out efficiency,
- Power electronics – especially lower cost, and
- Electric motors – especially higher efficiency over a range of driving cycles and higher specific power.

There are claims that transportation use of alternative fuels other than electricity (particularly compressed natural gas) will yield strong greenhouse benefits. In natural gas's case, recent analyses have shown contrasting greenhouse effects. For example, Delucchi (1997) estimates a 20% reduction in greenhouse gases compared to gasoline use in 2015, whereas Wang (1997) estimates a 5% increase in 2005. The primary difference in the two analyses is that Wang computes a 10% energy-efficiency penalty associated with switching to CNG, based on recent test data; Delucchi estimates an 11% improvement in energy efficiency based on potential efficiency gains from higher compression CNG engines. Delucchi's optimism may well be the more appropriate approach for the longer term, but at best CNG offers only a modest greenhouse emissions improvement.

Although we selected fuel cell vehicles fueled by gasoline (with onboard fuel processors) as the "breakthrough" technology in the high-efficiency/low-carbon scenario, some analysts believe that the direct use of hydrogen as a fuel is sufficiently more attractive to outweigh the disadvantages of hydrogen's low energy density (complicating onboard storage) and lack of a supply infrastructure (Ogden, 1977). The advantages of direct hydrogen include avoidance of the added weight and cost of the fuel processor and larger fuel cell required (fuel cell performance is reduced because the processor does not produce pure hydrogen), and reduced vehicle efficiency because of the energy losses in the processor and added vehicle weight (assuming the higher fuel storage weight for hydrogen is less than the weight savings from removing the processor and reducing fuel cell size). Although lack of infrastructure still represents a barrier, there have been advances in small scale-steam reforming of natural gas that could greatly ease the introduction of a viable hydrogen supply infrastructure (Ogden, 1977).

5.3.3.2 Changes to the Medium and Heavy Truck Model

Medium heavy trucks are typically operated locally in pick-up and delivery mode. For such vehicles, hybrid technology, with regenerative braking and energy storage capabilities, should offer significant advantages. It is assumed that a diesel hybrid becomes available to heavy trucks starting in the year 2005. This technology is assumed to offer the same 72% fuel economy benefit as the light-duty vehicle version.

Greater success in materials, aerodynamics, tires, and engines, should make these technologies more economically attractive to truckers. Since the NEMS Heavy Truck Model does not explicitly include an economic trade-off between fuel savings and technology penetration, this effect was simulated by shortening the time to 99% penetration for each technology by 30%. For most technologies, this implies a 15 year period from time of introduction to nearly full market penetration.

5.3.3.3 Changes to Other Modes

Several changes were made to the commercial air model inputs. Starting in 2005, propfans were assumed to be available for smaller commercial aircraft. Propfans offer a 20-30% efficiency improvement over high bypass turbofan engines, and 10-15% over even ultra-high bypass engines. Development of propfans has been hindered by concerns about initial cost, maintenance, and vibration. Propfans are made available to only one-third of new aircraft in the high-efficiency/low-carbon scenario. Additionally, partial success in hybrid laminar flow (HLF) technology to reduce drag is assumed by 2010. Although HLF has the potential to reduce fuel use by 15% or more, only a 9% efficiency gain is assumed due to the continuing difficulties in developing a practical system. In the efficiency case, ultra-high bypass engines are assumed to give a 10% efficiency gain, thermodynamic improvements provide a 15% gain, and advanced aerodynamics yield an 18% improvement. In this case, those are increased to 17%, 18% and 27%, respectively, certainly optimistic but not implausible estimates (for example, see Greene, 1992, Table 4).

The annual efficiency improvement rate for railroads is increased to 2.5%, still slightly lower than the 2.8% rate achieved over the past two decades. Waterborne freight's efficiency improvement rate is bumped up to 1% per year from 0.05% to reflect a 10% total efficiency gain achievable through improved hull designs and coatings. In fact, these modes have substantial potential to use alternative power plants and fuels, as reflected in the 2020 technology discussion below.

5.3.4 Comparison of Forecasts

The efficiency and high-efficiency/low-carbon scenarios indicate that advanced energy technologies could reduce emissions of greenhouse gases from transportation by 12-17% by 2010 and by 18-25% by 2015 (Table 5.7). Although these are large changes, they may appear modest compared to the changes in new vehicles, the "leading edge" of changes in the entire transportation fleet. Changing the technology of transportation requires turning over a vast stock of vehicles, and this requires decades. As a result, the impact of advanced technologies introduced between now and 2010 will only just begin to be felt in 2010 and will still not have achieved its full effect by 2015. This phenomenon can be most easily seen by comparing the fuel economy of new cars and light trucks to that of the entire fleet of light-duty vehicles. In the efficiency case in 2015, for example, new cars average 41.4 MPG and light trucks 31.9 MPG (EPA-rated fuel economy), but the fleet as a whole lags behind at 28.2 MPG (24.0 MPG onroad). Given enough time to turn over the stock of vehicles, the eventual light-duty fleet MPG will climb about one-third higher to nearly 38 MPG (32 MPG onroad). The time lag required for new technology to penetrate the light-duty vehicle fleet is a common feature of all modes. Thus, the energy savings and greenhouse gas reductions shown in Tables 5.7 and 5.8 for 2010 and 2015 reflect less than half of the ultimate savings that the technology introduced over this period will eventually achieve.

Passenger car and light truck fuel economy improvements are, in general, attributable to the combined effect of many fuel economy technologies rather than a single, dominant technology. A number of improvements to conventional engines combine to increase average new vehicle MPG in 2010 by almost 20% for passenger cars and by about 10% for light trucks. These include engine friction reduction, greater use of multi-valve engines, and variable valve timing and lift control. Substitution of lighter weight materials, aerodynamic drag reductions, various transmission improvements, and the combined effects of advanced lubricants, tires, and accessories, each contribute 2-5% gains. Of all the technologies added to the efficiency and high-efficiency scenarios, the lean-burn gasoline engines (DISC and 2-stroke) deliver the greatest fuel economy benefits, about 15% for passenger cars and 12% for light trucks. These numbers represent sales weighted average effects, taking into consideration the fact that even in 2010 new vehicles are not equipped with these technologies. Diesel and hybrid technologies each boost average new car and light truck fuel economy by about 5% in 2010, their smaller impact being due to their smaller market shares.

The sales weighted average impacts of nine classes of fuel economy technologies in the high-efficiency/low-carbon case are illustrated in Figures 5.7 and 5.8. The measured percent fuel economy gain applies to the impact of the technology on the average fuel economy of all new passenger cars or light trucks and, thus, takes into account the estimated market penetration for each category of technologies. In 2010, passenger cars get a considerably greater benefit from engine efficiency improvements than light trucks, but the gap narrows considerably by 2015. Although the DISC and 2-stroke technologies are the most significant new technologies in 2010, the gasoline fuel cell comes on strong by 2015. The impact of the fuel cell in 2010 is obviously limited by the assumption that it would be first introduced in 2007. The impacts shown in Figures 5.7 and 5.8 depend entirely on the cost, fuel economy benefit, and introduction date assumptions shown in Table 5.2, and the way the NEMS model translates those assumptions into market success. Thus, the graphs do not represent a prediction of what specific technologies will achieve, but rather an illustration of what could happen given the outstanding successes in fuel economy technology R&D, as reflected in our high-efficiency/low-carbon scenario assumptions.

The 23% gain for light-duty vehicles in 2015 is just slightly higher than the 21% and 22% improvements by freight trucks and rail in the efficiency scenario. Aircraft efficiency gains seem to lag behind at a mere 9% in 2015, but this is due to the fact that air passenger efficiencies increase the most (17%) in the business-as-usual case. In 2010, rail and air have made the greatest efficiency gains over 1997. This is consistent with the record of the past quarter century, during which time these two modes have led all others in energy-efficiency improvement.

Table 5.7 Transportation Sector Energy Use and Energy Efficiency Projections to 2010 and 2015
(continued on next page)

	1997	2010		Change	% Change
	BAU	BAU	Efficiency		
Energy Use (quads)	25.5	32.3	29.3	-3.1	-9%
Carbon Emissions (MtC/Yr.)	487	616	543	-73	-12%
Fuel Use by Fuel Type (quads)					
Motor Gasoline	15.1	18.0	15.2	-2.8	-15%
Cellulosic Ethanol (in motor gasoline)	0.0	0.0	0.5	0.5	***
Distillate	4.6	5.8	5.7	-0.1	-2%
Jet Fuel	3.6	4.7	4.2	-0.5	-11%
Residual	1.2	1.6	1.6	0.0	0%
Other	1.1	2.2	2.1	-0.1	-4%
Energy Use by Mode (quads)					
Light-Duty Vehicles	14.6	18.2	16.3	-1.9	-11%
Freight Trucks	5.6	6.8	6.3	-0.5	-8%
Air	3.6	4.7	4.2	-0.5	-11%
Rail	0.5	0.5	0.4	-0.1	-16%
Marine	1.7	2.3	2.3	0	0%
Pipeline	0.8	0.9	0.9	0	0%
Other	0.2	0.3	0.3	0	0%
Energy-efficiency Indicators					
New Car MPG ⁺	27.5	27.8	37.5	9.7	35%
New Light Truck MPG	20.5	20.6	27.1	6.5	32%
Light-Duty Fleet MPG	19.6	19.4	21.5	2.1	11%
Aircraft Efficiency (Seat-Miles/Gal.)	51.8	58.2	61.6	3.4	6%
Freight Truck Fleet MPG	5.6	6.0	6.8	0.8	13%
Rail Efficiency (ton-miles/1,000 Btu)	2.7	3.0	3.6	0.6	20%
Transportation Activity Levels (billions)					
Light-duty Vehicle Miles of Travel	2262	2762	2774	12	0%
Freight Truck VMT	173	237	238	1	0%
Commercial Air Seat-Miles	1116	1729	1608	-121	-7%
Rail Ton-Miles	1208	1459	1464	5	0%
Marine Ton-Miles	892	1047	1050	3	0%

Note: Because some light truck energy use is included in the freight truck sector, the totals by mode will not add to the totals by fuel type.

* After all scenarios had been completed, a minor error was discovered in the NEMS passenger car-fuel economy technology input data. This error allowed four wheel drive improvements to be applied to certain categories of cars to which they are, in fact, not applicable. The overall effect on new car fuel economy is less than 0.3 MPG in 2010 and less than 0.5 MPG in 2015.

Table 5.7 Transportation Sector Energy Use and Energy Efficiency Projections to 2010 and 2015
(Continued)

	1997	2015		Change	% Change
	BAU	BAU	Efficiency		
Energy Use (quads)	25.5	34.0	28.7	-5.2	-15%
Carbon Emissions (MtC/Yr.)	487	646	532	-114	-18%
Fuel Use by Fuel Type (quads)					
Motor Gasoline	15.1	18.7	13.5	-5.3	-28%
Cellulosic Ethanol (in motor gasoline)	0.0	0.0	0.4	0.4	***
Distillate	4.6	6.0	6.5	0.5	8%
Jet Fuel	3.6	5.0	4.2	-0.7	-15%
Residual	1.2	1.8	1.8	0.0	0%
Other	1.1	2.5	2.4	-0.2	-6%
Energy Use by Mode (quads)					
Light-Duty Vehicles	14.6	19.1	15.5	-3.6	-19%
Freight Trucks	5.6	7.1	6.3	-0.8	-12%
Air	3.6	5.0	4.3	-0.7	-15%
Rail	0.5	0.5	0.4	-0.1	-20%
Marine	1.7	2.5	2.5	0.0	0%
Pipeline	0.8	0.9	0.9	0.0	0%
Other	0.2	0.3	0.3	0.0	0%
Energy-efficiency Indicators					
New Car MPG	27.5	27.9	41.4	13.5	48%
New Light Truck MPG	20.5	20.6	31.9	11.3	55%
Light-Duty Fleet MPG	19.6	19.5	24.0	4.5	23%
Aircraft Efficiency (Seat-Miles/Gal.)	51.8	60.6	66.1	5.5	9%
Freight Truck Fleet MPG	5.6	6.1	7.4	1.3	21%
Rail Efficiency (ton-miles/1,000 Btu)	2.7	3.2	3.9	0.7	22%
Transportation Activity Levels (billions)					
Light-duty Vehicle Miles of Travel	2262	2914	2937	23	1%
Freight Truck VMT	173	250	251	1	0%
Commercial Air Seat-Miles	1116	1923	1759	-164	-9%
Rail Ton-Miles	1208	1535	1540	5	0%
Marine Ton-Miles	892	1099	1102	3	0%

Table 5.8 Transportation Sector Energy Use and Energy Efficiency Projections to 2010 and 2015
(continued on next page)

	1997	2010		Change	% Change
	BAU	BAU	Efficiency		
Energy Use (quads)	25.5	32.3	27.9	-4.5	-14%
Carbon Emissions (MtC/Yr.)	487	616	512	-104	-17%
Fuel Use by Fuel Type (quads)					
Motor Gasoline	15.1	18.0	13.9	-4.2	-23%
Cellulosic Ethanol (in motor gasoline)	0.0	0.0	0.7	0.7	***
Distillate	4.6	5.8	5.7	-0.1	-2%
Jet Fuel	3.6	4.7	4.0	-0.7	-14%
Residual	1.2	1.6	1.6	0.0	0%
Other	1.1	2.2	2.1	-0.2	-8%
Energy Use by Mode (quads)					
Light-Duty Vehicles	14.6	18.2	15.2	-3.0	-16%
Freight Trucks	5.6	6.8	6.2	-0.6	-9%
Air	3.6	4.7	4.1	-0.7	-14%
Rail	0.5	0.5	0.4	-0.1	-25%
Marine	1.7	2.3	2.3	-0.0	-1%
Pipeline	0.8	0.9	0.9	0.0	0%
Other	0.2	0.3	0.3	0.0	0%
Energy-efficiency Indicators					
New Car MPG ⁺	27.5	27.8	43.1	15.3	55%
New Light Truck MPG	20.5	20.6	30.8	10.2	50%
Light-Duty Fleet MPG	19.6	19.4	23.2	3.8	20%
Aircraft Efficiency (Seat-Miles/Gal.)	51.8	58.2	64.6	6.4	11%
Freight Truck Fleet MPG	5.6	6.0	7.0	1.0	17%
Rail Efficiency (ton-miles/1,000 Btu)	2.7	3.0	4.0	1.0	34%
Transportation Activity Levels (billions)					
Light-duty Vehicle Miles of Travel	2262	2762	2806	44	2%
Freight Truck VMT	173	237	238	1	0%
Commercial Air Seat-Miles	1116	1729	1619	-110	-6%
Rail Ton-Miles	1208	1459	1467	8	1%
Marine Ton-Miles	892	1047	1051	4	0%

Note: Because some light truck energy use is included in the freight sector, the totals by mode will not add to the totals by fuel type.

* After all scenarios had been completed, a minor error was discovered in the NEMS passenger car fuel economy technology input data. This error allowed four wheel drive improvements to be applied to certain categories of cars to which they are, in fact, not applicable. The overall effect on new car fuel economy is less than 0.3 MPG in 2010 and less than 0.5 MPG in 2015.

Table 5.8 Transportation Sector Energy Use and Energy Efficiency Projections to 2010 and 2015
(Continued)

	1997	2015		Change	% Change
	BAU	BAU	Efficiency		
Energy Use (quads)	25.5	34.0	26.7	-7.3	-21%
Carbon Emissions (MtC/Yr.)	487	646	484	-162	-25%
Fuel Use by Fuel Type (quads)					
Motor Gasoline	15.1	18.7	11.2	-7.5	-40%
Cellulosic Ethanol (in motor gasoline)	0.0	0.0	0.7	0.7	***
Distillate	4.6	6.0	6.7	0.7	-12%
Jet Fuel	3.6	5.0	4.0	-1.0	-19%
Residual	1.2	1.8	1.8	-0.0	-1%
Other	1.1	2.5	2.2	-0.3	-12%
Energy Use by Mode (quads)					
Light-Duty Vehicles	14.6	19.1	13.8	-5.2	-27%
Freight Trucks	5.6	7.1	6.2	-0.9	-13%
Air	3.6	5.0	4.1	-0.9	-19%
Rail	0.5	0.5	0.4	-0.2	-38%
Marine	1.7	2.5	2.4	-0.0	-1%
Pipeline	0.8	0.9	0.9	0.0	0%
Other	0.2	0.3	0.3	0.0	0%
Energy-efficiency Indicators					
New Car MPG	27.5	27.9	50.2	22.3	80%
New Light Truck MPG	20.5	20.6	37.8	17.2	83%
Light-Duty Fleet MPG	19.6	19.5	27.1	7.6	39%
Aircraft Efficiency (Seat-Miles/Gal.)	51.8	60.6	70.7	10.1	17%
Freight Truck Fleet MPG	5.6	6.1	7.5	1.4	23%
Rail Efficiency (ton-miles/1,000 Btu)	2.7	3.2	4.8	1.6	51%
Transportation Activity Levels (billions)					
Light-duty Vehicle Miles of Travel	2262	2914	2974	60	2%
Freight Truck VMT	173	250	252	2	1%
Commercial Air Seat-Miles	1116	1923	1923	-152	-8%
Rail Ton-Miles	1208	1535	1542	7	0%
Marine Ton-Miles	892	1099	1103	4	0%

Figure 5.7 Sources of Fuel Economy Improvements in High-Efficiency Scenario, 2010

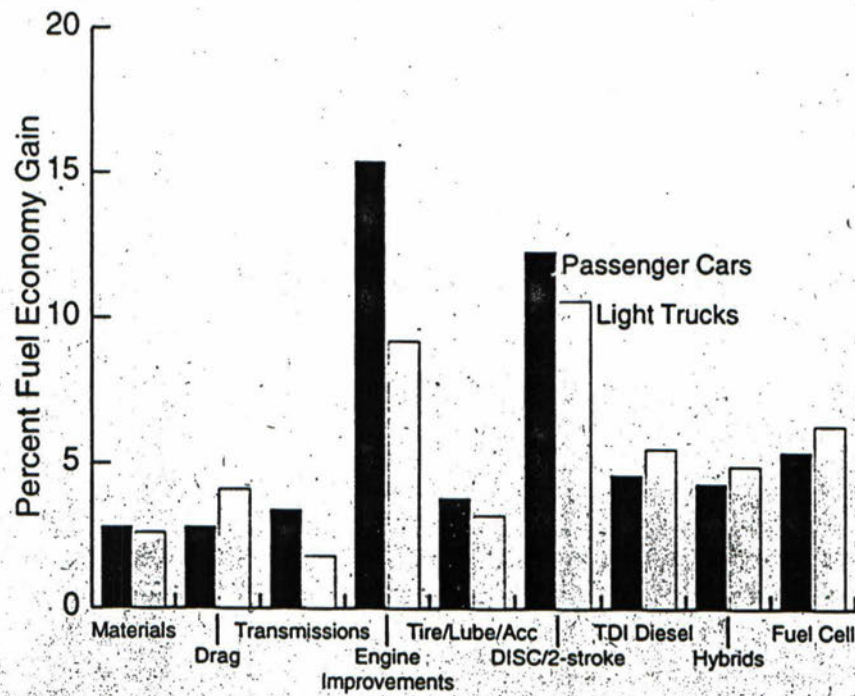
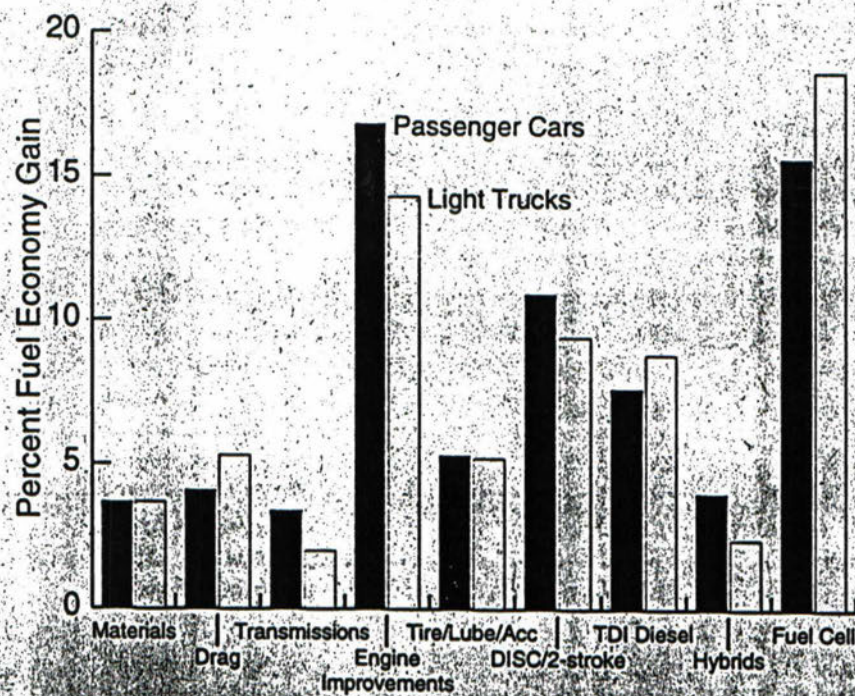


Figure 5.8 Sources of Fuel Economy Improvements in High-Efficiency Scenario, 2015



Transportation activity increases at moderate rates in the business-as-usual case and, indeed, in all the other scenarios as well. Transportation activity in the NEMS model is relatively insensitive to energy prices. In the business-as-usual scenario, light-duty vehicle travel increases by 22% from 1997 to 2010, an average annual rate of just 1.5%. In the high-efficiency/low-carbon scenario, the increase is 24%, reflecting a very small increase due to the lower fuel cost per mile of vehicle travel (1.7%/year). Growth from 2010 to 2015 is slower still, 1.1% per annum. Air travel is the fastest growing mode, with seat-miles growing at 3.4% annually through 2010 and slowing to 2.1% annually from 2010 to 2015. Efficiency improvements in the efficiency and high-efficiency/low-carbon scenarios include increased load factors (passenger-miles per seat-mile) so that seat-miles are actually 7% lower in the efficiency case than in the business-as-usual case in 2010 (Tables 5.7 and 5.8). Freight truck vehicle miles increase at a faster rate than light-duty vehicle miles, 2.5% per year through 2010, slowing to 1.1% from 2010 to 2015. These levels are almost unchanged by further increases in truck freight energy-efficiency. NEMS measures rail and marine activity in ton-miles, and these are up 21% and 17%, respectively, by 2010. Once again, the growth rate from 2010 to 2015 is at the much slower rate of about 1% per year.

The combined effects of moderately increasing transportation activity and significant efficiency gains are still not enough to reduce energy use or carbon emissions below present levels by 2010. Overall, transportation energy use in the business-as-usual case grows from 25.5 quads in 1997 to 32.3 in 2010 and 34.0 in 2015. The efficiency scenario lowers energy use by 9% in 2010 and carbon emissions by an additional 3%, due to the success of cellulosic ethanol as a gasoline blending component. Still, energy use is up 15% over the 1997 level, and carbon emissions are 12% higher. In 2015, however, energy use and carbon emissions are reduced compared to 2010 but still higher than in 1997. Although the 1997 version of the NEMS model does not forecast beyond 2015, it is reasonable to assume that energy use and emissions will continue to fall for a decade or so beyond 2015 as technological improvements penetrate the stock of transportation vehicles.

Motor gasoline use, on the other hand, is only 0.15 quads higher in 2010 than in 1997, and is a full 1.6 quads lower than the current level in 2015. The use of 0.4 quads of cellulosic ethanol and an equivalent shift to diesel are partially responsible for the reduction in gasoline consumption. Because cellulosic ethanol produces almost no net greenhouse gas emissions, it is far more effective than any fossil-based alternative fuel at reducing transportation's carbon emissions. Demand for distillate and jet fuel combined is up 1.7 quads in 2010 and is 2.6 quads higher than the 1997 levels in 2015. The slower growth of gasoline demand suggests a change in refinery operations would be required, but no analysis of the impacts of this change has been made.

The high-efficiency/low-carbon scenario achieves the milestone of reducing CO₂ emissions below 1997 levels, but by 2015 rather than 2010 (Table 5.7). In 2010, CO₂ emissions are 17% (a full 100 MtC per year) below the business-as-usual case, but still 4% above 1997 levels. With new cars at 43 MPG (EPA test value), new light trucks at 31 MPG, and the fleet average at only 27 MPG (23 MPG onroad), efficiency is improving rapidly and still has a long way to go. New passenger car MPG hits a fleet average of 50 in 2015 in this scenario, buoyed by market shares of 25-30% for hybrid vehicles, and 15-20% for turbo-charged direct-injection diesel vehicles. Two-stroke engines are also popular in this scenario, capturing about one-third of the small-car market. By 2015, all remaining new light-duty vehicles are equipped with DISC engines, the gasoline engine of today having been all but entirely squeezed out by newer technologies.

Yet even the high-efficiency/low-carbon case, with its breakthrough technology assumptions, illustrates how much time it takes to fundamentally change the technology of transportation energy use. Though fleet average light-duty vehicle MPG is up from 19.6 to 27.1 (onroad) by 2015, there is another 10.3 MPG to go before the fleet achieves equilibrium with the efficiency of new vehicles. Similarly, in the rail mode, use of fuel cells has penetrated only 5% of the stock of locomotives by

2010 and 15% by 2015. In most cases, the majority of CO₂ emission reductions have yet to be realized, even by 2015. The point is not that little can be done to reduce transportation's CO₂ emissions. The point is that if CO₂ emissions must be reduced, the sooner one gets started, the better.

5.3.5 Cost-Effectiveness of Light-Duty Vehicle Fuel Economy Improvement

The cost-effectiveness of technological changes that improve fuel economy is a very complex issue, depending not merely on the value of fuel savings and the increase in retail price, but on how each technology affects the performance, reliability, appearance and feel of a vehicle. Even such a seemingly simple matter as computing the value of fuel savings is not straightforward, since it depends on car buyers' expectations about future fuel prices, vehicle lifetime (or, alternatively, market valuation of remaining fuel savings when the vehicle is traded in or resold), consumer discounting of future savings, expectations about future depreciation of the vehicle's value, and expected utilization rates.

Technological advances are likely to create new opportunities to provide other benefits of importance to car buyers and to society. For example, multi-point fuel injection is generally held to be not cost-effective solely on the basis of fuel savings – yet every new car sold and nearly every new light truck is equipped with it. The reason for including fuel injection is that it improves drivability and also is a critical technology for meeting emissions standards. Technologies included in the efficiency scenarios also have the potential to create social benefits. By reducing oil consumption, they will decrease the volume of U.S. oil imports. By making it easier and cheaper to improve efficiency and substitute alternative energy sources for oil, these technologies will improve U.S. energy security. Technologies such as hybrid vehicles and fuel cells will help vehicles meet increasingly stringent emissions standards. Most importantly, technological advances will be essential to creating a sustainable world transport system.

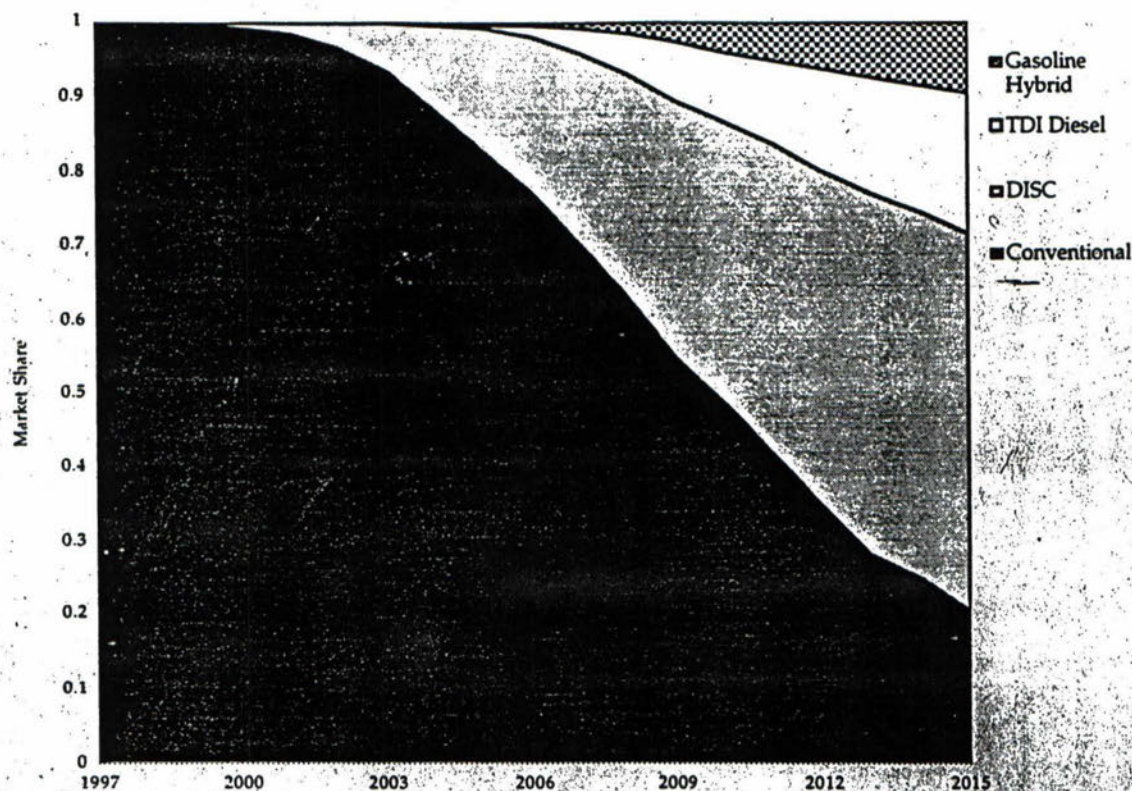
The cost of supplying technologies is also not a simple matter, since it depends on the rate at which capital equipment must be replaced. If the rate of adoption exceeds the normal rate of turnover of manufacturing equipment, the costs of technological change increase. Also, new technologies must often be certified to meet safety and environmental standards, which takes time and involves some degree of risk. Consumers expect a high degree of reliability of vehicles, and this might be threatened by too rapid introduction of novel technologies.

For all these reasons, the NEMS model does not base technology adoption on a simple cost-effectiveness calculation, but rather attempts to simulate the complex process described above. The market penetration of fuel economy technologies is a function of cost-effectiveness, but is not solely determined by it. Market penetration follows an s-shaped curve that predicts 50% market penetration for precisely cost-effective technologies, with increasing or decreasing market share as cost-effectiveness increases or decreases, respectively. This simulates the fact that consumers are not identical in their valuation of technology (e.g., high mileage drivers such as sales representatives might tend to value fuel economy more than would average drivers), and that technologies have other characteristics that consumers may, or may not, value. Also, introduction is not immediate when cost-effectiveness is reached, but is rather phased in over time, simulating a normal process of retirement and replacement of manufacturing capital.

The phasing in of new technologies can be seen in Figures 5.9 to 5.11, which show the predicted market penetrations of engine technologies. Engine technology penetrations in the efficiency case are shown for passenger cars and light trucks in Figures 5.9 and 5.10. Although the DISC, TDI Diesel, and Gasoline Hybrid technologies eventually come to dominate the market, it takes about a decade for this to occur, allowing time for orderly introduction of the technologies. For comparison, the historical market penetration rates of fuel injection technologies are shown in Figure 5.11.

Although it took less time for multi-point fuel injection to replace carburetted fuel systems, this technological change was urged on by emissions regulations. Nonetheless, as a point of comparison, it suggests that the rates predicted by the NEMS model are comparable to similar historical transitions.

Figure 5.9 Market Penetration of Advanced Engines for Domestic Passenger Cars - Efficiency Scenario



For all the reasons noted above, simple cost-effectiveness calculations based solely on incremental first cost and the value of future fuel savings can be misleading. Indeed, the NEMS model outputs do not include direct measures of the costs of technological changes or their value to vehicle purchasers. However, for light-duty vehicles, approximate technology cost estimates can be derived from the market shares of each technology and from the initial cost estimates. By comparing the weighted average cost of fuel economy technology in the efficiency and high-efficiency cases in 2010 with the weighted average cost in 1997 for the BAU case, we can obtain an estimate of the increase in retail price per vehicle due to the adoption of fuel economy technology. The incremental costs must be adjusted, however, to reflect the fact that a significant fraction of the potential MPG increase is used in the NEMS model to produce higher horsepower or increased vehicle weight, or to offset small MPG losses due to safety and emissions improvements. The cost adjustment is made by multiplying the full cost increase by the ratio of the actual MPG gain to the potential MPG. For example, for automobiles in the efficiency case, this ratio is 0.7. Using the same assumptions employed in the model to calculate cost-effectiveness, we can also estimate the value to the average consumer of the change in fuel economy. These estimates are summarized in Table 5.9.

Figure 5.10 Market Penetration of Advanced Engines for Domestic Light Trucks - Efficiency Scenario

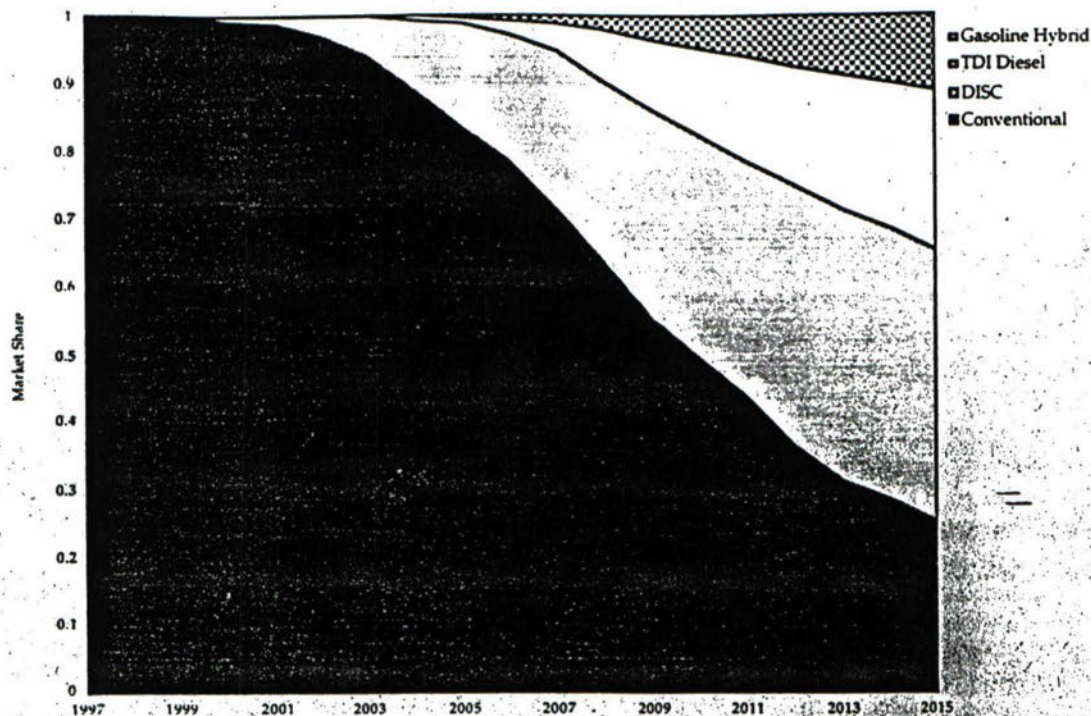
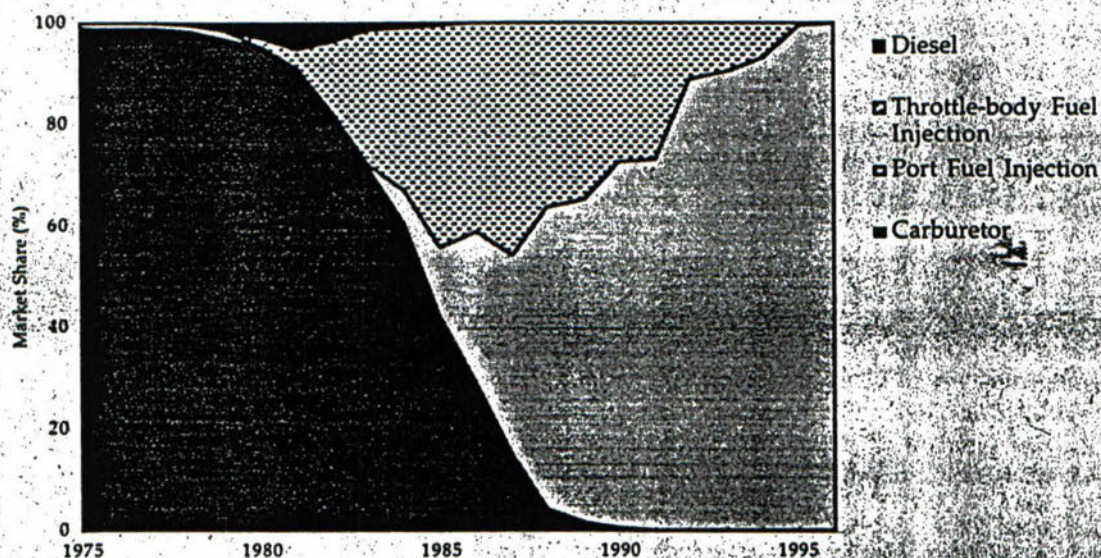


Figure 5.11 Penetration of Fuel Injection Technology



Based on a simple comparison of incremental vehicle costs to the value of fuel savings to the consumer, fuel economy improvements in the efficiency scenarios appear to be cost-effective as a whole. Savings exceed costs for both discounting formulas shown. Choosing the correct discount rate

is somewhat controversial. In the buildings chapter, for example, a 7% real rate is used to value fuel savings. We believe the 20% rate should be used for valuing light-duty vehicle fuel economy savings for the following reasons. First, when consumers invest in a fuel economy technology, they are investing in a depreciating asset. Motor vehicles depreciate in real value by about 10% per year. Thus, a passenger car that cost \$20,000 when new, would bring a little more than \$12,000 five years later. We believe that it is reasonable to assume that incremental investments in fuel economy technology will depreciate at the same rate. Second, empirical evidence shows that vehicle use decreases with vehicle age at approximately 4% per year (Davis and McFarlin, 1996, Table 3.11). By reducing the quantity of fuel consumed, this effectively reduces the value of future fuel savings at the rate of about 4% per year. Finally, consumers will have a simple discount rate, reflecting their time preference for money. If we assume that the simple discount rate is 6% per year, we obtain a total discount rate of $10\% + 6\% + 4\% = 20\%$. We recommend using that rate to value future fuel savings from the consumers' perspective. That rate is also consistent with the valuation of future fuel savings in the NEMS model. We show a lower 10% rate here for purposes of comparison with other sectors.

Table 5.9. Simple, Total Cost-Effectiveness Estimates for Light-Duty Vehicle Fuel-Economy Technology

Scenario	MPG	Full Incremental Cost	Adjusted Incremental Cost	Value of Fuel Savings to Consumer	
				6% Discount Rate + 4% Usage Rate	6% Discount + 4% Usage + 10% Depreciation
Passenger Cars					
Business as Usual	27.5	\$0	\$0	—	—
Efficiency	37.5	\$850	\$600	\$1,600	\$1,000
High-efficiency	43.1	\$900	\$900	\$2,150	\$1,350
Light Trucks					
Business as Usual	20.5	\$0	\$0	—	—
Efficiency	27.1	\$800	\$650	\$1,950	\$1,200
High-efficiency	30.8	\$950	\$900	\$2,700	\$1,700

Gasoline prices assumed to remain constant at \$1.20 per gallon. Vehicle usage rate of 15,500 miles per year, declining with vehicle age at 4% per year, and lifetime of 14 years. For calculating value to consumers, MPG estimates are reduced by 15% to reflect actual operating conditions.

Given our preferred method of valuing fuel savings, it would appear that the model is allowing a substantial amount of technological change that is not, on the basis of fuel savings, cost-effective to the average consumer. However, the NEMS model's fuel economy technology simulation also takes into account the fact that (1) the technology will presumably offer other benefits (e.g., lower emissions, better performance, etc.), and (2) not all consumers are identical (some will have lower discount rates and place a higher value on fuel economy, some will drive many more annual miles than average).

These rough estimates should be treated with considerable caution. First, they represent a comparison of total costs of fuel economy changes with total benefits, taxes included rather than the more correct comparison of marginal costs and benefits. Markets will, in theory, stop improving fuel economy when the marginal costs equal the marginal benefits. In general, this will be at a lower level of fuel economy than the point at which total costs equal total benefits. Second, the NEMS model represents technology adoption as a more complex process than a simple computation of

monetary costs and benefits, and attempts to simulate actual market behavior. Thus, the calculations reported above do not correspond to the NEMS technology adoption methodology.

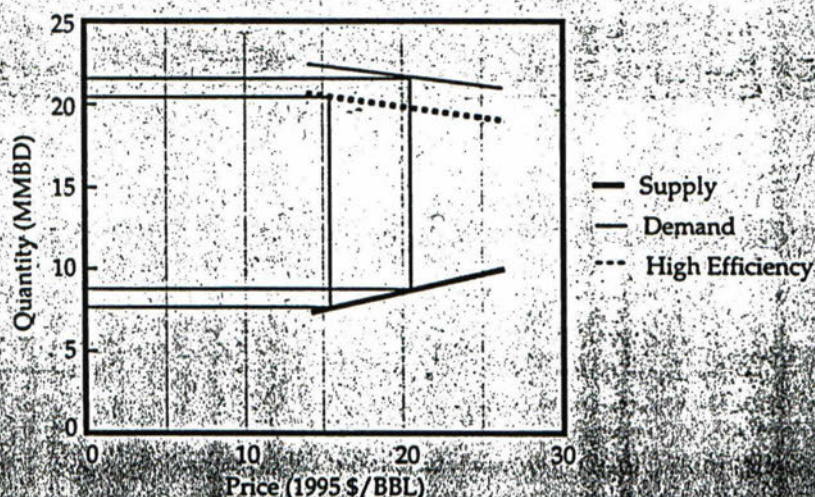
5.3.6 Oil Imports and Oil Market Benefits

The reductions in energy use achieved in the efficiency and high-efficiency/low carbon scenarios represent significant reductions in U.S. petroleum demand which should result in reduced U.S. oil import dependence and lower oil prices to consumers. Because of transportation's continuing dependence on petroleum in the business-as-usual scenario, 95% of transportation energy is still derived from petroleum in 2010. In the BAU scenario, transportation uses 30.6 quads (14.5 million metric barrels per day (MMBD)) of petroleum products. Technological advances contained in the efficiency scenario reduce petroleum consumption by 3.4 quads (1.6 MMBD) in 2010, and those in the high-efficiency/low-carbon scenario produce total oil savings of 4.9 quads (2.3 MMBD).

Lower U.S. oil consumption due to more energy-efficient technology and substitution of cellulosic ethanol should reduce U.S. oil imports, or reduce world oil prices, or both. The exact world oil market response is indeterminate because it depends on the actions of the OPEC cartel. In a competitive world oil market, the response to reduced U.S. demand could be predicted based on knowledge of the U.S. and rest-of-world supply and demand curves for oil. But because the cartel's supply does not necessarily follow the rules of competitive market behavior there is, in effect, no OPEC oil supply curve. Faced with reduced demand, competitive producers would lower prices, encouraging demand and driving out the higher cost producers until a new equilibrium were reached. But a cartel can choose to cut production, raise production, or do nothing, making the ultimate outcome uncertain. Cutting production would raise world oil prices but the cost to OPEC would be loss of market share, a key determinant of market power.

No matter what the OPEC cartel chose to do, however, either U.S. imports would fall, or oil prices would fall, or both, as a result of the technological advances reflected in the efficiency and high-efficiency/low-carbon scenarios. This is illustrated in Figure 5.12, which shows U.S. long-run supply and demand curves for petroleum derived from the 1997 Annual Energy Outlook's Low, High, and Reference Oil Price Cases for 2010 (EIA, 1996b, Table C11). The curves clearly show that at the reference case oil price of \$20.41 per barrel, domestic supply and demand curves do not intersect, with the result that the 12.9 MMBD shortfall must be imported.

Figure 5.12 U. S. Oil Supply and Demand in 2010



The advanced technologies of the high-efficiency/low-carbon scenario shift the demand curve towards lower demand, and may also change its slope (perhaps making demand more responsive to price). If we assume that the world price of oil does not change (to achieve this result, OPEC would have to cut production by an amount roughly equivalent to the reduction in U.S. consumption), then U.S. imports would be lower by about 2 MMBD. If OPEC maintains previous production levels or increases its output, world oil prices would fall. As prices fall, U.S. domestic supply will decline and demand will increase, pushing imports back up. However, to achieve the original level of imports (12.9 MMBD), prices would have to fall by about \$5 per barrel (given the supply and demand curves shown in Figure 5.12). The \$5/bbl. price cut would reduce the total cost of oil to the economy by about \$35 billion, and reduce the cost of oil imports by about \$20 billion, in comparison to the AEO97 reference case. The possible outcomes are: 1) U.S. imports are reduced by 2.3 MMBD or more, 2) world oil prices fall by about \$5/bbl or more, or 3) a combination of reduced imports of up to 2.3 MMBD and a price decrease of up to \$5/bbl. occurs.

5.4 R&D POTENTIAL FOR ADVANCED TECHNOLOGIES IN 2020

5.4.1 Light-Duty Vehicles

Many of the advanced technologies that have the potential to impact U.S. automotive fuel use after 2010 or 2020 need considerable research and development work before they can attain commercialization. The federal government has supported work on many of these technologies for more than 20 years, beginning with the Energy Policy and Conservation Act of 1975. The current U.S. R&D effort on the more exotic of the new technologies has been characterized as "the most comprehensive, best organized, and best funded in the world" (U.S. Congress, OTA, 1995). Nevertheless, over the years, federal funding for vehicle technology R&D has been erratic, and there are continuing budget battles over funding for DOE's Electric and Hybrid Vehicle Program and the PNGV as a whole. As noted above, the National Research Council Committee that is reviewing the PNGV program has stated in no uncertain terms that they believe the program is seriously under-funded relative to its ambitious goals.

The OTA identified several R&D areas that will require considerable new resources including: safety; analysis and development of infrastructure for manufacturing, refueling, servicing, recycling, and so forth; and development of new standards for new materials and fuels (U.S. Congress, OTA, 1995). Also, OTA concluded that the current federal program may not take appropriate advantage of the innovative capabilities of small business, especially with budget pressure on the National Institute of Science and Technology's Advanced Technology Program and other R&D efforts that focus on smaller companies.

Although there are many hurdles to overcome, a strong R&D effort coupled with a market or regulatory incentive to improve fuel economy should be capable of producing, by 2020 or earlier, mid-sized vehicles with fuel economies in the 60-80 MPG range and performance similar to current vehicles – that is, "PNGV territory." Note that continuing fleet increases in power and performance will tend to reduce future fuel economy potential, since generally there is a direct tradeoff between performance and fuel economy. An optimistic vision of a potential high-efficiency/low-carbon vehicle in 2020, assuming the necessary breakthroughs in a number of areas (e.g., manufacturing processes for composite materials, two orders of magnitude reduction in fuel cell costs) would combine the following characteristics:

- Highly aerodynamic design with C_d of 0.22 or below;
- Lightweight body with composite body structure (safer alternative: optimized aluminum);

- Ultra-low rolling resistance tires, CR of 0.005 (about half that of today's tires);
- Hybrid drivetrain with lightweight, highly efficient storage device (ultracapacitor or flywheel) and electric motor/controller;
- Fuel cell powerplant with advanced hydrogen storage or efficient fuel reformer (safer alternatives: DISC engine or DI diesel with lean NO_x catalysts); and
- Use of high-efficiency/low-carbon accessories and low-energy-use design (e.g., advanced window coatings and insulation).

The current PNGV program is addressing many of the remaining R&D roadblocks though some need considerably more attention and the solution to others might be accelerated with greater resources. For example, development of manufacturing processes for composites has been hit hard by budget cutbacks; as noted, without major breakthroughs, composites will likely be too expensive to play a major role in vehicle light-weighting. In addition, there is some concern that Japanese and European firms are devoting more resources to DISC and DI diesel engines than are U.S. companies, and these engines may play a critical role in future high-efficiency/low-carbon vehicles, especially if fuel cell development is delayed or is unsuccessful at reducing costs sufficiently for commercialization.

Fuel cells are widely believed to be the most attractive powerplant option for future vehicles, and recent progress in increasing their power density and lowering costs through reducing their platinum requirements has been extremely promising. Nevertheless, as discussed previously, many hurdles remain, and their costs must decline remarkably for them to compete successfully with internal combustion engines. In fact, they would revolutionize the power generation industry long before they reached the \$30/kW level of ICEs.¹³

Although some may view a fuel cell hybrid vehicle as an "ideal" vehicle, there are sufficient uncertainties in the potential of the technologies needed for such a vehicle, and sufficient heterogeneity in regional requirements and markets, to imply that an ideal R&D program in light-duty vehicle technologies should be a broad program incorporating a range of alternative technology pathways to high vehicle efficiency and low emissions. A breakthrough in high-specific-energy battery technology coupled with significant progress in electric motors and power electronics, for example, could put large numbers of efficient electric vehicles into many urban markets; in some of those markets (e.g., California) both the overall emissions effects and the greenhouse gas emissions effects could be extremely positive. Similarly, breakthroughs in on-board storage technology for natural gas might allow substantial penetration of natural gas vehicles into many markets, although the positive greenhouse gas emissions impact of such vehicles would likely be substantially less than for EVs or fuel cell hybrids.

5.4.2 Freight Trucks and Locomotives

The diesel cycle engine will dominate the freight truck sector at least until 2020 because of its high thermal efficiency, potential fuel flexibility, and durability. DOE's Office of Heavy Vehicle Technologies (OHVT) within the Office of Transportation Technologies is attempting to develop the enabling technologies needed to achieve fuel flexibility, ultra-low emissions, and high fuel efficiency in all classes of trucks, buses, and other heavy vehicles such as off-highway vehicles. The typical new Class 8 tractor trailer in 2020 is expected to achieve an on-road fuel economy of over 10 MPG, compared to about 7 MPG today, assuming a high-efficiency/low-carbon, low emission diesel cycle engine (thermal efficiency of at least 55% at rated speed and load at the flywheel) and other technologies such as reduced aerodynamic drag, low rolling resistance tires, and lightweight materials (such as magnesium) become an economic reality.¹⁴ While many of these technologies

have already been demonstrated to a limited extent, a key enabler is a durable highly efficient NO_x catalyst capable of operating at high-efficiency/low-carbon in an oxidizing atmosphere.¹⁵ Fuel reformulation is envisioned, as well as nonpetroleum fuels, during this period (2000-2020).

However, as the efficiency of the diesel cycle becomes fully exploited (thermal efficiencies of over 63% will be highly unlikely), the hydrogen fuel cell, unconstrained by the Carnot cycle, may be the next powerplant of choice for freight trucks, locomotives, and passenger cars. Significant R&D efforts at DOE have enabled the demonstration of methanol-fueled fuel cell buses and other vehicles. However, significant development of the fuel cell itself, power management strategies, and hydrogen fuel production, distribution and storage are required, and economical solutions are hard to envision before 2020. Particularly problematic are the low cost, efficient production, delivery, and storage of hydrogen fuel (carbon-containing fuels significantly degrade fuel cell thermal efficiency – in many cases to efficiencies below that of current-production diesel engines). The fuel cell powerplant, combined with low aerodynamic drag, low rolling resistance tires, and lightweight materials may raise Class 8 tractor trailer fuel efficiency to 15 MPG or more. Locomotive engines may be an ideal test bed and an early entry for fuel cell powerplant technologies, because sizes needed (4000 hp-equivalent) are on the scale of smaller stationary electrical power generation plants which are already commercial. In addition, locomotives are already driven by computer-driven electric motors for traction control.

5.5 SUMMARY

Cost-effective or near cost-effective technologies and alternative energy sources have the potential to significantly restrain the growth of the U.S. transportation sector's greenhouse gas emissions through 2010. There remains a substantial reservoir of proven technology for improving motor vehicle fuel economy, and technologies that are very nearly market-ready (such as the DISC engine with lean-NO_x catalytic converter) will almost certainly further expand the potential to increase MPG by 2010. New technologies and operational efficiency gains hold out similar potential for air passenger travel and for truck and rail freight. Ethanol derived from cellulosic feed stocks instead of grain could also make a significant contribution by 2010 as a blending component for conventional gasoline if cost reductions foreseen by energy researchers are achieved. Overall, the combined impact of such technologies could be to reduce greenhouse gas emissions by 10% in 2010 and by almost 20% in 2015, relative to the business-as-usual case. If important breakthroughs can be achieved in fuel cells and other key technology, transportation's greenhouse gas emissions in 2015 could be held below current levels.

In the business-as-usual case, transportation energy use grows from 25.5 quads in 1997 to 32.3 in 2010 and 34.0 in 2015. Carbon dioxide emissions, in million tonnes of carbon, increase from 487 in 1997 to 616 in 2010, and to 646 in 2015. As mentioned earlier, the business-as-usual case anticipates rates of growth in transportation activity that are slow by historical standards. The actual outcome could easily be 10% higher. The efficiency case holds transportation energy use to 29.3 quads in 2010 and 28.7 in 2015. Accordingly, carbon emissions grow to only 543 MtC in 2010 and 532 in 2015. The fact that emissions are lower in 2015 than in 2010 reflects the fact that changing the technology of transportation energy use requires the orderly turnover of durable capital stock. The high-efficiency/low-carbon scenario holds 2010 carbon emissions from transport to 512 MtC, and reduces 2015 emissions to 484 MtC, just slightly below the 1997 level.

Changes in the mix of transportation fuels in the three 2010 scenarios are summarized in Table 5.10. Although petroleum fuels are still the predominant source of energy for transportation, use of alternative fuels expands in all three scenarios. Natural gas consumption for transport grows from 0.75 TCF in 1997 (about 98% of which is used in natural gas pipelines) to roughly 1.2 TCF in 2010. In

2010 pipelines still account for 70-75% of natural gas use, but CNG vehicles consume about 0.25 TCF, and natural gas used to produce methanol for motor fuel accounts for nearly all of the rest. Biofuels in the form of cellulosic ethanol come on strong in the efficiency and high-efficiency/low-carbon scenarios, providing from one-fourth to one-third of an MMBD oil equivalent. In accord with the AEO97 reference case projections, all scenarios foresee substantial increase in electricity use, essentially all going to electric vehicles. The lower levels of electricity use in the efficiency and high-efficiency/low-carbon scenarios, like those of natural gas use, are due to the general improvements in vehicle technology in those scenarios.

Table 5.10 Transportation Energy Use by Fuel Type

Fuel	1997	2010		
		BAU	Efficiency	High-Efficiency
Petroleum Fuels (MMBD)	11.77	14.59	12.91	12.18
Natural Gas (TCF)	0.75	1.22	1.19	1.16
Biofuels (MMBD OE)	0.001	0.04	0.25	0.34
Electricity (MMBD OE)	0.04	0.23	0.22	0.20

Note: Petroleum fuels converted to million barrels per day oil equivalent using a heat content of 5.738 MMBtu/barrel. Natural gas includes natural gas used to produce methanol for use as a neat fuel, but does not include natural gas used to produce methanol for use in Methyl Tertiary Butyl Ether. It is assumed that, to produce one quad of methanol, 1.44 quads of natural gas are required. For electricity generation, 3.38 quads of primary energy are assumed to be required for each quad of electrical energy consumed.

Carbon emissions by mode are summarized in Table 5.11. Light-duty vehicles account for the vast majority of carbon emissions reductions versus the business-as-usual case, with significant contributions also being made by trucks and commercial aircraft. Rail freight shows the greatest relative reduction, while emissions from shipping, military and "other" are essentially constant across the three scenarios.

Table 5.11 Carbon Emissions in 2010 (MtC)

	1997	2010		
		BAU	Efficiency	High-Efficiency
Light-Duty Vehicles	278.7	346.3	297.3	273.0
Freight Trucks	73.3	95.0	83.4	80.9
Freight Rail	8.9	9.6	8.1	7.1
Shipping	30.8	42.7	42.3	41.6
Air Transport	60.0	83.5	72.9	69.6
Military, Transit, Other	35.3	39.0	39.3	39.3
TOTAL	486.9	615.9	543.3	511.5

Note: Breakdown into modal carbon emissions based on emissions factors taken from EIA (1996d) and DOE (1996)

Most of the reduction in energy use and carbon emissions comes from light-duty highway vehicles. There are four reasons for this. First, light-duty vehicle technology has been far more intensively studied, so that a great deal more is known about the technological potential for this mode. Second, the level of expenditure on technology R&D is greatest for this mode, with the possible exception of aerospace R&D, including defense aerospace. Third, the commercial modes are believed to be more

sensitive to fuel costs and more aggressive in the adoption of energy-efficient technology. Therefore, the rates of energy-efficiency improvement in the business-as-usual case are higher for these modes. Finally, light-duty vehicles simply use more energy than any other mode: 60% in the business-as-usual case. The other modes cannot be ignored, however, and should probably be given much greater attention with respect to R&D investment.

Although technological improvements have the potential to cost-effectively restrain greenhouse gas emissions from transportation, it is not likely that the changes will come about without a major public policy initiative. There are two reasons for this. First, the problems posed by greenhouse gas emissions are what economists term a classical public good externality. This means that the market economy will not provide the right price signals either for the development or the adoption of low-carbon technologies. Second, the AEO97 projections foresee a world where fossil fuels are abundant, available and inexpensive. In particular, none of the oil market upheavals of the past quarter century are present in the forecast. As a result, there are no other economic incentives to encourage either energy-efficiency or alternative fuels. In such an environment, it is not reasonable to expect either that appropriate technology will be developed or that success in the marketplace will result.

As a result, the efficiency case is based on the assumption that policies are implemented to promote the development of cost-effective low-carbon technologies and to spur the adoption of these technologies. In our view, this would include at a minimum a greatly increased public sector investment in R&D addressing energy-efficient and low greenhouse gas technologies, perhaps two to ten times the current level of effort. There are other public interests in developing such technologies (e.g., energy security and environmental sustainability) that, we believe, could easily justify such a level of investment. But policies to insure the adoption of low-carbon technologies in the market would also be necessary. It is not the purpose of this study to recommend what those policies should be; nonetheless, we are obliged to point out that meaningful policies will be necessary.

Indeed, technology has enormous potential to reduce transportation's greenhouse gas emissions. Cost-effective technological change will take time however, and its full effects will not be felt for two decades or more. Because the problems that may result from increased carbon emissions affect the global environment, significant reductions will demand meaningful public policy initiatives. These must include a greater effort to develop low-carbon technologies and a commitment to implement policies that will insure their adoption in the market.

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ENDNOTES

¹ This rate applies to the period 1973 (18.605 trillion Btus) to 1985 (20.067 trillion Btus). Source is Table 2.2, Monthly Energy Review, April 1997, DOE/ELA-0035(97/04), U.S. Department of Energy, Energy Information Administration, Washington, DC.

² This is a summary report. The full report, which presents this material, was not published due to OTA's closure, but it is now available as part of a three-CD set that contains all of OTA's reports since its inception. U.S. Congress, Office of Technology Assessment, *OTA Legacy: 1972 through 1995*, U.S. Government Printing Office, Washington, DC, Stock no. 052-003-01457-2, \$23 U.S.

³ The Toyota AXV5, with a C_d of 0.20, appears to avoid sacrifices in interior and cargo space. Removing its wheel skirts, which might inhibit maintenance and restrict the vehicle's turning circle, would likely raise its C_d to about 0.22. Because the vehicle's underbody cover adds weight, the net positive effect on fuel economy will be reduced somewhat (U.S. Congress, OTA, 1995).

⁴ In particular, requirements for 0-60 mph acceleration and sustained gradeability.

⁵ Also referred to as compression ignition direct injection (CIDI) engines and turbocharged direct injection (TDI) diesel engines.

⁶ An accurate cost comparison would have to account for the transmission needed by the engine versus the electric motor needed to convert the fuel cell's output electricity into shaft power. Also, the fuel cell drivetrain may need a powerful battery to drive the vehicle until the cell can warm up.

⁷ At about 3700 psi storage pressure, storage volume for hydrogen is about 5 times that needed for gasoline (Oei, 1997).

⁸ An additional cost may be the loss in system efficiency associated with onboard reforming as well as the original refining of the gasoline. However, onboard hydrogen storage has energy costs in the form of hydrogen production (probably at a large scale, and more efficient than the onboard reformer) and pressurization if stored in high pressure tanks.

⁹ Despite what is implied in the NEMS Transportation Model documentation, we were informed by Mr. David Chien, principal in charge of the Transportation Model, that the model's calculations were in 1987\$. Thus, \$8 in 1995 dollars equates to approximately \$6 in 1987 dollars.

¹⁰ For carbon only; or \$.08-\$.16 per gallon if the tax applies to all greenhouse gases, on a carbon equivalent basis.

¹¹ Communication from Margaret Singh of Argonne National Laboratory, April 3, 1997. Her calculations were made using the August, 1993 version of M. A. Delucchi's greenhouse gas emissions model and exclude any vehicle efficiency gains which might occur with the use of an ethanol vehicle.

¹² An alternative approach would have been to introduce these technologies using the Transportation Model's alternative fuel vehicle capabilities. This approach was not taken on the

grounds that diesel is more conventional than an alternative fuel. Consumers are familiar with it, it is widely available and, especially for the advanced, clean, TDI technology considered here, its performance would be essentially identical to that of a gasoline vehicle.

¹³ Actually, for an accurate comparison, an ICE plus a transmission and inexpensive fuel tank should be compared with a fuel cell, hydrogen storage or liquid fuel storage/reformer system, battery for warmup power and power buffer, and electric traction motor, making the task of commercializing fuel cells all the more onerous.

¹⁴ The Class 8 truck is very efficient already. Considering an energy per ton-mile measure of performance, an equivalent passenger car needs to travel about 140 miles on a gallon of gas to be as efficient as a 7 MPG Class 8 truck.

¹⁵ This technology is required for direct-injection gasoline engines as well.

Chapter 6

THE ELECTRICITY SECTOR'S RESPONSE TO END-USE EFFICIENCY CHANGES

6.1 INTRODUCTION

Electricity consumption accounts for about 36% of both total primary energy consumption and carbon emissions in the United States (EIA 1996a). As a consequence, converting efficiency-induced electricity savings in the residential, commercial, and industrial sectors into carbon reductions is a critical part of this study.

This task is complicated by several factors. First, the U.S. electricity industry is in the midst of a major restructuring, from a highly regulated, vertically integrated industry to a largely competitive, deintegrated industry. Because this transformation is far from complete, it is difficult to predict the structure and operation characteristics of electricity markets for the year 2010. Second, electricity production in the year 2010 will depend on the generating units that are retired, repowered, and constructed between now and then, as well as on how those units are operated in 2010. The decisions made by the profit-maximizing owners of individual generating units are likely to be different than the cost-minimizing decisions made in the past by utility owners of large generation and transmission systems. As a result of these changing dynamics of capacity expansion and system operation, one cannot assume that the average and marginal carbon intensities of electricity use (tonnes of carbon/GWh) will be the same in 2010 as they are today. Indeed, they are likely to be quite different. Third, electricity prices in the year 2010 are likely to vary from hour to hour based on current spot-market prices; consumer response to such time-varying prices is likely to be substantial but is largely unknown.

The next section describes some of the key changes in the structure of the U.S. bulk-power system that are likely to occur over the next decade. Section 6.3 describes the Oak Ridge Competitive Electricity Dispatch (ORCED) model that is used here to project the characteristics of the electricity sector in the year 2010. Section 6.4 compares ORCED's projections for the electricity sector with those developed by EIA in its *Annual Energy Outlook 1997* (AEO97). We then develop a competitive-electricity market case for 2010, which is used as the base case against which the efficiency and high-efficiency/low-carbon cases are compared.

6.2 BACKGROUND

In response to the 1992 Energy Policy Act, the Federal Energy Regulatory Commission (FERC) issued a major order (Order 888) in April 1996, which it slightly revised in March 1997. This order requires utilities to unbundle their generation and transmission services. A utility cannot offer preferential transmission pricing for electricity generated by its own power plants. A key purpose of this order is to eliminate problems associated with vertical market power in bulk-power markets and thereby assure open access to the nation's transmission facilities.

Other factors are also forcing the U.S. electricity industry to change. These factors include low natural gas prices (both today and over the next 10 to 15 years), substantial improvements in the efficiency of gas-fired combustion turbines, and broad public sentiment to deregulate economic sectors wherever possible.

We see a future in which the generation sector will be driven primarily by competitive forces rather than by regulatory mandates. Decisions on whether, when, and where to build, repower, or retire generating units will be made by investors, not by regulators.¹ Historically, vertically integrated utilities have planned, built, and operated power plants to minimize the life-cycle costs of the entire electric-power system over a long time (e.g., 20- to 30-year horizon). In tomorrow's competitive environment, this decision rule will be replaced by one that emphasizes the profitability of individual generating units over a much shorter time horizon, using a higher discount rate to reflect the increased riskiness of power-plant ownership.

Our view of the future calls for most of today's utility-operated control centers to be replaced by *independent* system operators (ISOs) that cover larger areas. As a consequence, the number of control areas will decline from about 140 to perhaps only 20 to 50. Because these ISOs perform a monopoly function, they will be regulated by FERC.

Similarly, transmission will remain a monopoly function, also regulated by FERC. Increasingly, transmission will be separated from generation. Today, FERC requires utilities to "functionally" unbundle generation from transmission. In the future, utilities will increasingly divest themselves of their generation assets and will become "pure" transmission or transmission-plus-distribution utilities. In this environment, transmission will become a common carrier.

6.3 MODEL DESCRIPTION

ORCED is an expanded version of part of a previously developed model called ORFIN (Oak Ridge Financial Model) (Hadley 1996). Whereas ORFIN is a comprehensive electric-utility planning model, ORCED deals only with generation. We developed ORCED to aid in the analysis of the operation of competitive (as opposed to the traditional regulated) bulk-power markets. The model allows the following issues to be examined:

- Horizontal market power: concentration of generation assets among a few owners;
- Generator profitability: which units will be retired because their expected revenues will not cover the sum of their fuel costs, variable operations and maintenance (O&M) costs, and (avoidable) fixed O&M costs, as well as repowering and new construction decisions;
- Carbon emissions and other environmental effects of changes in the U.S. bulk-power sector; and
- Optimal mix of new and existing generators, including new generating technologies.

The model is structured to allow simulation of different bulk-power market structures. In particular, the user can specify various generation pricing schemes:

- An energy-only spot price as proposed by the three California investor-owned electric utilities. When unconstrained demand exceeds available supply, what would otherwise be unserved energy is "curtailed" because spot prices rise sufficiently to suppress demand to match the level of available generating capacity. The user simulates this situation by specifying a value for the price elasticity of demand during these time periods. ORCED uses the amount of demand to be curtailed and the price elasticity to calculate the value of unserved energy in ϵ/kWh .²
- An energy-only spot price plus the loss-of-load probability (capacity) component used in the United Kingdom. Here, the user specifies a value for unserved energy (e.g., 200 ϵ/kWh), which

the model multiplies by the hourly value of the loss-of-load probability to produce a time-varying increment to the energy-only spot price.

- An energy-only spot price plus a capacity reservation price (in \$/kW-year), as proposed by the PJM Interconnection and the New England Power Pool. In this case, the user specifies an amount of generating capacity needed for planning reserve, which determines the annual capacity payments (in \$/kW-year) required.

We are using ORCED to examine the issues listed above as functions of the following factors (in addition to the pricing schemes noted above):

- Characteristics of individual generators: type of unit, differences in capital and other fixed costs (\$/kW-year) vs. fuel and variable O&M costs (¢/kWh), dispatchability (e.g., fully dispatchable coal plant vs. must-run nuclear unit vs. stochastic wind plant), forced and planned outage rates (%).
- Customer and load characteristics: shape of load curve, price elasticities of demand, value of unserved energy.
- Generating-resource portfolio: mix of generating units and relationship between available generating capacity and unconstrained peak demand.

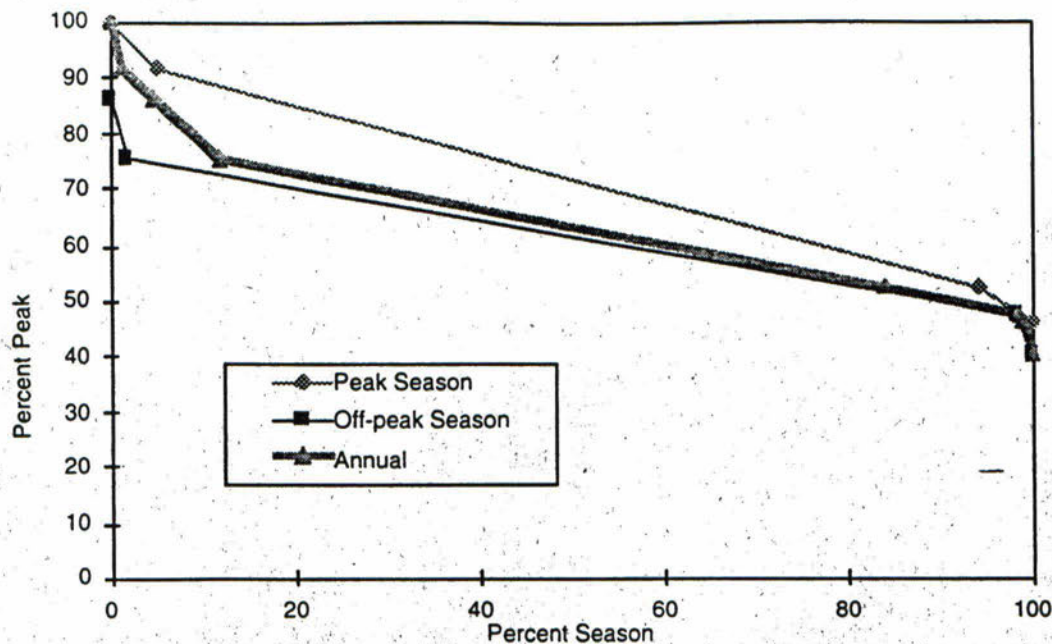
ORCED includes a production-costing model that uses load-duration curves rather than chronological loads as inputs. The model is run twice for each year of simulation, once for an on-peak season and a second time for an off-peak season (Figure 6.1). We define the on-peak season as June through August, and the off-peak season as the remaining nine months (September through May), although the model can accept alternative definitions of the two seasons. The model can incorporate disaggregate inputs on loads and load shapes for the residential, commercial, and industrial customer classes. Data on these class loads are aggregated for use within ORCED, which builds and dispatches generating units to meet aggregate load.

A load-duration curve is created by ordering demand (in MW) in terms of magnitude from highest to lowest. The resultant curve shows the percentage of time that demand exceeds a particular value, ranging from the one-hour peak demand down to the minimum demand.

Use of a load-duration curve to calculate production costs is much simpler and computationally much less burdensome than use of chronological loads (i.e., hour by hour loads). This simplification, however, has a price: because it obscures the timing of loads, one cannot accurately calculate production costs on the basis of generating-unit details, such as minimum and maximum loading points, startup times and costs, and minimum shutdown times. To partially remedy these problems, ORCED analyzes production costs using the two load-duration curves, one for the three-month summer peak period and the other for the nine-month off-peak period. ORCED also simulates the effects of startup costs for those units with capacity factors of less than 10%.

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 26th 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).

Figure 6.1 Example Load-Duration Curves for Peak and Off-Peak Seasons



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 off-peak 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.³ Thus, the higher-cost plants will see demands not only from customers, but "equivalent demands" based on the probability that plants lower in the dispatch order (i.e., less expensive) 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.

Model results include spot prices for each point on the two load-duration curves. These prices are based on the bid prices for each generator. The prices also reflect any externally imposed uplift charge, capacity charge, or emissions taxes. Finally, the prices during high-demand hours reflect generating-unit startup costs and the costs of unserved energy for those hours that unconstrained demand exceeds supply. See Appendix F for more details on the inputs and results from ORCED.

ORCED can be run iteratively to estimate the response of customers to changes in overall and time-of-use electricity prices. User inputs include an overall price elasticity of demand and a time-of-use elasticity. The overall price elasticity adjusts the entire load-duration curve up or down in response to decreases or increases in the average price of electricity. The time-of-use elasticity adjusts each point on the load-duration curve up or down based on price decreases or increases during that time period.

In addition, the model can use the time-of-use elasticity to compute the value of unserved energy (in ¢/kWh) that equilibrates supply and demand when unconstrained demand would otherwise exceed online supply. Alternatively, the user can input an estimate of the value of unserved energy, which is then used to calculate the costs associated with those times when unconstrained demand would exceed supply. A third approach involves user specification of a minimum reserve margin and associated annual capacity payment (in $\text{\$/kW-year}$) to pay for this "extra" capacity.

In addition to dispatching power plants and computing production costs, the model can also "optimize" the mix of generating units available for the year of analysis. (That is, the model includes a capacity-expansion module as well as a production-costing module.) We put optimize in quotes because the factor on which to optimize is almost certain to be different for a competitive electricity industry than it was for the regulated electric utility industry. For example, the model could choose from among the following optimization functions:

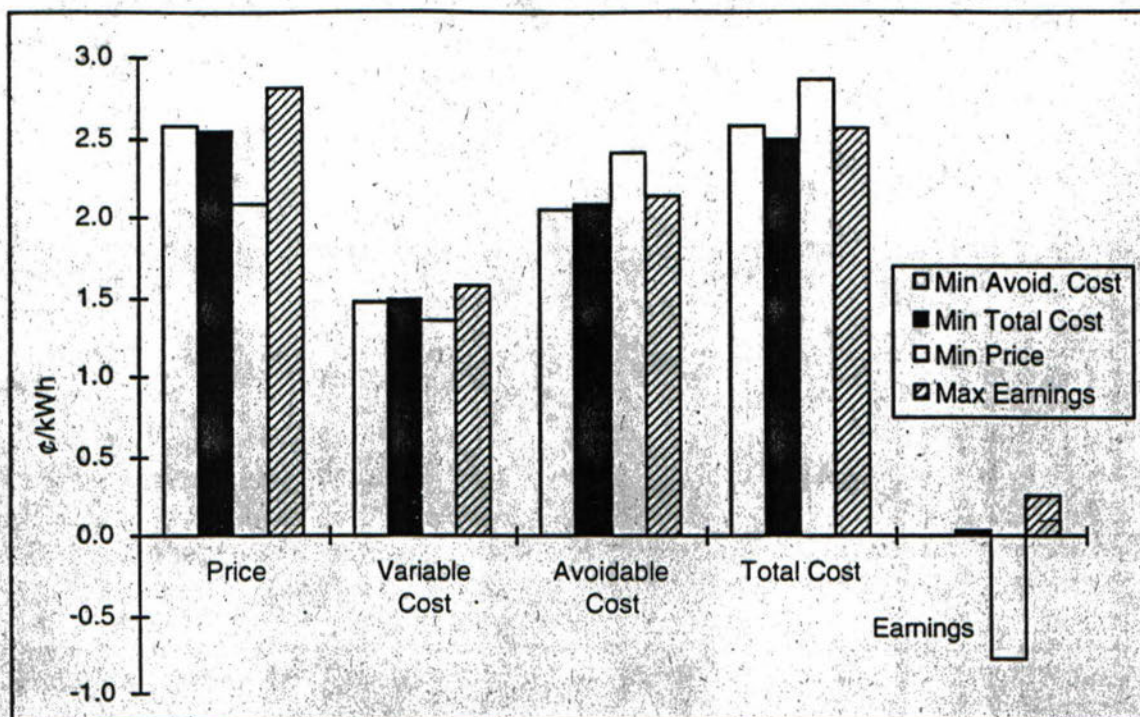
- Minimize total costs;
- Minimize avoidable costs (fuel, variable and fixed O&M);
- Minimize electricity prices; or
- Maximize generator earnings.

In Figure 6.2 we show the impact of different objective functions for optimization. Minimizing price does not necessarily minimize cost, because prices are based on the variable costs only and ignore fixed costs. Given choices of technology, ORCED would select low variable cost but high total cost technologies. Conversely, maximizing earnings does not raise total cost. Instead, the model selects high variable/low fixed cost technologies. For our analysis we chose to optimize on minimizing avoidable costs; we made this choice because it was conceptually the most appealing and the results were the most reasonable for a system-wide optimization. For plants not yet built, their capital costs as well as all operating costs are avoidable. Since no costs have been expended to build them, their construction costs are not "sunk" and can be avoided by not building them.

In addition to specifying the optimization function, the user can also specify constraints on individual generating units or the mix as a whole. For example, the user could set minimum and/or maximum capacity levels for each generator. Maximum levels could be specified for those units that were built earlier. Minimum levels could be specified for those units that must be available for policy reasons (e.g., renewable resources that might not be fully cost-effective but are deemed desirable from a broad societal perspective). Also, minimum levels for new plants may be specified to represent plants built between the current year and the study year. Otherwise, the model may choose not to build these intermediate plants, selecting only those with the most advanced technologies. Constraints could be specified for a minimum capacity reserve margin, for a maximum carbon emission allowance, or to ensure that each generating unit recovers at least its variable plus avoidable fixed costs, and so on.

Since ORCED is written in Microsoft Excel, there are several methods that can be used for optimization. The easiest is to use the built-in Solver tool. A single cell can be identified as the objective function to be minimized, and other cells can be identified as variables, with constraints placed on their values and/or other parameters within the spreadsheet. Since the problem is non-linear, Solver uses a Generalized Reduced Gradient method, running the model thousands of times searching for a solution. Another method, which is generally slower but avoids problems of local optima, is the use of genetic algorithms.

Figure 6.2 Generation Price and Costs Using Different Optimizations (10% Fixed Reserve Margin)



6.4 SCENARIOS FOR 2010

6.4.1 Calibration to EIA AEO97

Before analyzing the two end-use efficiency scenarios, we first calibrated ORCED results to those produced by EIA's NEMS model for 1995 and 2010. Unfortunately, reconciling the two sets of results to each other is difficult because of differences in the ways that the two modeling systems classify various costs (e.g., fuel, variable O&M, fixed O&M, and capital costs associated with generation) as well as EIA's inclusion of administrative and general (A&G) and customer service costs in the basic categories of generation, transmission, and distribution costs.⁴ Because of these difficulties, our numbers do not always match the EIA numbers exactly.

This calibration ensures that the assumptions concerning the mix of generating units, fuel prices, customer demand, environmental regulations, and so on are consistent between ORCED and those developed by EIA. For example, both sets of results assume the continuation of current economic and environmental policies affecting the U.S. electricity industry. However, EPA's proposed regulations to tighten standards for emissions of nitrogen oxides and small particulate matter are reflected in neither the EIA nor the ORCED results.

We first developed a base case for the year 2010 that includes the same mix of generating units (in both capacity and energy) as that produced by EIA, with the same reserve margin (11%), as shown in Table 6.1. In addition to data from the AEO97, we used other data from EIA (EIA 1996b, EIA 1996c, EIA 1995), as well as data from the North American Electric Reliability Council (NERC 1996), the Electric Power Research Institute (EPRI 1993), and a compilation of various official databases by Resource Data International, Inc. (RDI 1996).

Table 6.1 Comparison of Year 2010 AEO97 and ORCED Estimates of U.S. Generating Capacity and Generation

	Percent of generating capacity		Percent of generation	
	EIA	ORCED	EIA	ORCED
Hydro+other renewables	13.4	11.3	9.6	9.2
Coal	35.0	36.9	50.1	50.8
Nuclear	10.2	11.1	15.8	15.5
Oil	3.2	3.1	1.5	0.1
Gas	38.3	37.6	23.0	24.4

ORCED analyzes the generation sector only; the model is silent with respect to the costs of transmission, distribution, and customer service. ORCED produces the following cost estimates for 2010, all expressed in 1995 dollars and adjusted upward by 1/0.93 to reflect the 7% T&D losses between the generator busbar and the customer meter.⁵

Fuel	1.35
Variable O&M	0.18
Fixed O&M	0.51
<u>Capital</u>	<u>1.00</u>
Total	3.04¢/kWh

We developed an estimate of the EIA capital cost of generation by subtracting estimates of the capital costs associated with transmission, distribution, and administrative and general (A&G) services from EIA's total capital cost:

$$[2.32 - (0.52 + 1.46) * 0.63 - 0.08] = 1.00\text{¢/kWh.}^6$$

Total (Trans + Dist) A&G

Our estimate of the EIA fuel cost is based on the sum of EIA's fuel cost plus 88% of its wholesale purchase cost:

$$(0.98 + 0.67 * 0.88) = 1.57\text{¢/kWh.}^7$$

Fuel Wholesale

We used the ORCED estimates of fixed and variable O&M costs to impute a comparable (i.e., equal) value for EIA.

The net result is very close agreement between the ORCED and EIA scenarios for 2010 (Table 6.2). EIA's estimate of the total cost of generation (3.26¢/kWh) is 7% higher than the ORCED result (3.04¢/kWh). The ORCED cost is lower because ORCED dispatches fewer expensive oil-fired resources than does the EIA model (Table 6.1). These differences in dispatch and variable costs occur because ORCED dispatches generation nationwide and ignores transmission constraints. The close agreement between EIA and ORCED results, in spite of all the adjustments required to produce a set of internally consistent and comparably defined terms, is reassuring. It lends confidence to our

development of alternative cases in which we intended to reflect more fully than EIA did the effects of competition in bulk-power markets.

Table 6.2 Comparison of EIA and ORCED Estimates of Generation Costs (1995¢/kWh)

Generation costs	EIA AEO97	ORCED
Capital	1.00	0.99
Fuel	1.57	1.36
O&M	0.69	0.69
Total	3.26	3.04

6.4.2 The Base Case for a Competitive Market

Beginning with the AEO97 case, we developed a case intended to reflect the workings of a fully competitive bulk-power market in the year 2010. (The AEO assumes a continuation of current economic regulation, as indicated above, and therefore does not account for the possible effects of a restructured and largely competitive U.S. electricity industry.) To reflect these changes, we let the model select the amounts of each of the generating units that minimize the sum of variable plus avoidable costs. Instead of specifying the amount of generating capacity that must be online in 2010 (to yield a 10.7% reserve margin in the AEO97 case), we allowed the model to select the amount of capacity that minimized the cost of the power-supply system plus the cost of unserved energy. We used a demand elasticity of -0.05 for those time periods when capacity is insufficient to meet unconstrained demand. The resultant optimization yielded a reserve margin of 6.8%.

In general, we set prices equal to their real-time (hourly) values based on the variable (fuel plus variable O&M) cost of the unit on the margin each hour of the year, adjusted overall electricity demand to reflect lower prices using an assumed overall elasticity of -0.5, and adjusted the load shape to reflect the response to real-time pricing using a value of -0.1 for the price elasticity within each time period.

Beginning with the ORCED run that matches the AEO97 values for 2010, we first reran the model allowing it to select the "optimal" amounts of generating capacity from among all the plants that, according to EIA, are scheduled to come online after the year 1998. (The optimization was based on a minimization of avoidable costs.) We also allowed the model to select plants for retirement. For each of the new plants, we use the levelized fixed charges rate to calculate the annual capital cost of the plant and treat all fixed costs (both capital and O&M) as avoidable.

Next, we adjusted the load-duration curves for the two seasons simulated by the model (peak and off-peak). The new system load has a peak demand that is 3.4% below the AEO97 case and a total demand that is 1.2% higher. We then reran ORCED using the new load shapes. Table 6.3 compares the two sets of results. Although demand is higher in the restructuring case than in the AEO97 base case, carbon emissions are lower. The lower carbon emissions are the result of reduced coal use and increased natural gas use in the restructuring case.

Notice that, under restructuring, the total generating cost goes down 0.3¢/kWh and yet the system average price increases slightly. In a deregulated market, prices will be based on the variable cost (or bid price) of the most expensive plant at that time. This is known as the "market clearing price." Consequently, the link between total costs and prices is broken. Whereas current electric

utility regulation sets prices to recover total costs, future prices may, or may not, be sufficient to recover all costs.

Overall, ORCED prices under restructuring did not differ greatly from the AEO97 price forecast. Part of the reason for this similarity of results is that EIA did assume some cost decreases in their model; we did not assume further O&M cost decreases on a plant-by-plant basis due to the pressure of competition. Also, the objective function used in our cases was to minimize avoidable costs on a system-wide basis. This did not necessarily create the lowest-priced scenario, as discussed in section 6.3. Because prices were similar to those in the AEO97 (less than 5% difference when factoring in transmission and distribution prices), we simply used the AEO97 price forecasts for analysis of energy-efficiency savings in the other chapters of this report.

Table 6.3 Comparison of Year 2010 Forecasts: AEO97 and the ORCED Base Case for a Competitive Electricity Industry

	AEO97	Competitive Industry Restructuring
Peak demand, GW	734	709
Total end-use electricity sales, TWh	3,784	3,828
System load factor, %	62.8	65.7
Reserve margin, %	10.7	6.8
Generation shares, %		
Coal	50.8	47.4
Gas	24.4	29.2
Other	24.8	23.4
Generation prices and costs, ¢/kWh		
Retail price	3.04	3.02
Variable cost	1.43	1.45
Total cost	2.81	2.51
Carbon emissions, MtC	631	625

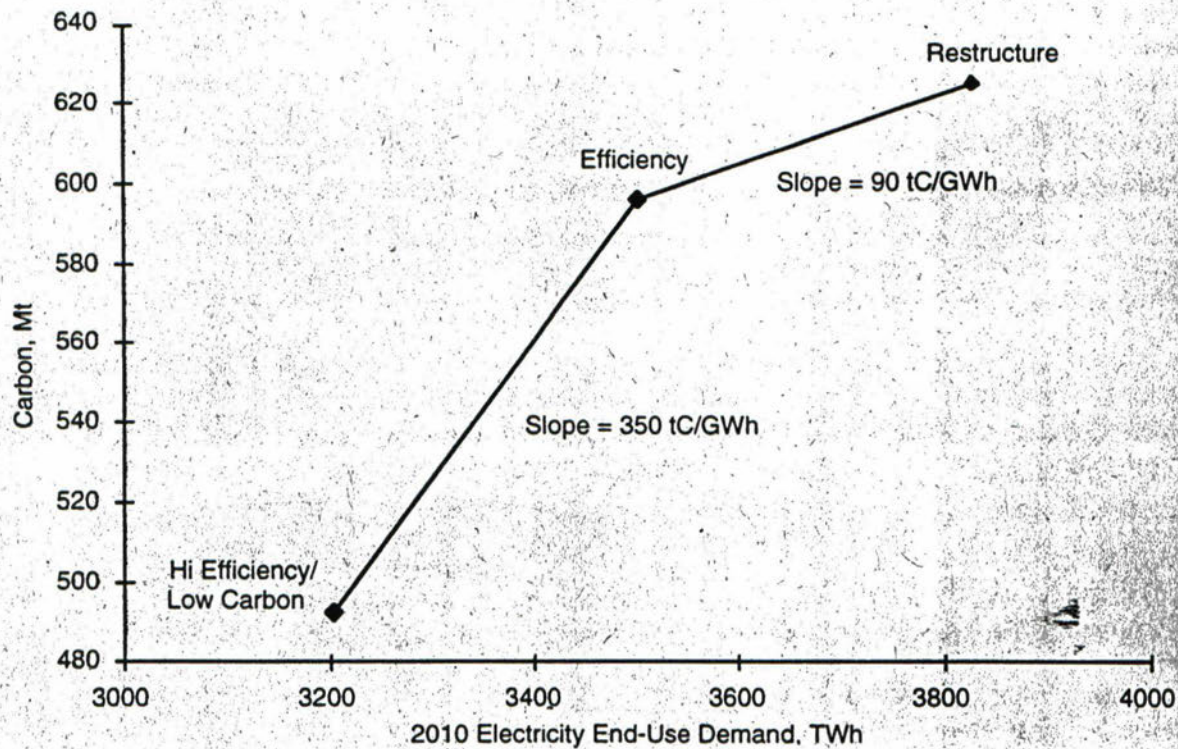
6.4.3 Efficiency and High-Efficiency/Low-Carbon Cases

We next applied the electricity-savings estimates, described in Chapter 3 for the residential and commercial sectors and in Chapter 4 for the industrial sector, to adjust the aggregate load shape for the United States as a whole. We then reran ORCED using the new, lower load shapes. As in the reference case, capacity was optimized to minimize avoided costs, and dispatched on the basis of lowest variable costs. Avoided costs for existing plants only included their variable, start-up, and fixed O&M costs, while plants to be built between 1997 and 2010 also included the annualized capital cost of their construction. As part of the high-efficiency/low-carbon case, we included an additional cost of \$50 per tonne of carbon, to be consistent with the rationale used in the demand-side efficiency scenarios.

Once power plant production levels were determined, carbon production and primary energy use could be calculated. We calculated marginal carbon savings, the carbon saved by the reduction in energy, by taking the difference in carbon production and dividing by the reduction in energy demand. This is in contrast to using the average carbon intensity as an approximation of the carbon saved per unit of energy saved. The marginal carbon and energy savings take into account the change in production mix that occurs with energy- efficiency and carbon-reduction measures. A plot of the carbon savings and primary energy used in each scenario shows the changes as a function of the end-use energy saved (Figures 6.3 and 6.4). The slopes of the lines represent the marginal carbon and primary energy saved.

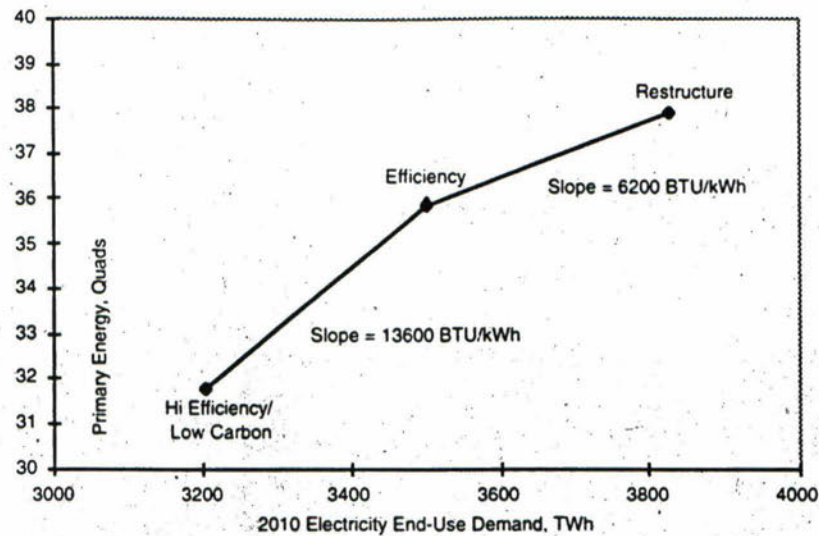
Table 6.4 summarizes the results for the three scenarios. Table 6.5 describes these results in terms of percent change relative to the base case for a competitive utility industry. The efficiency case yielded a 8.5% reduction in electricity end-use energy and the high-efficiency/low-carbon case reduced end-use energy by 16.3% relative to the restructuring case summarized in Table 6.3.

Figure 6.3 Carbon Production Versus End-Use Demand: Reductions Due to Energy Efficiency and Carbon Management



Note: Slope is equal to marginal carbon savings in tonnes of carbon per gigawatt-hour.

Figure 6.4 Primary Energy Production Versus End-Use Demand: Reductions Due to Energy Efficiency and Carbon Management



Note: Slope is equal to marginal energy savings in Btu per kilowatt-hour.

Table 6.4 Comparison of Year 2010 Forecasts: Results of Efficiency and High-Efficiency/Low-Carbon Scenarios

	Competitive Industry Optimization	Efficiency	High-Efficiency/ Low-Carbon
Peak demand, GW	709	651	596
Total Primary Energy used, quads	37.9	35.9	31.8
Total electricity generated, TWh	4,090	3,740	3,420
Total end-use electricity demand, TWh	3,830	3,500	3,200
System load factor, %	65.7	65.5	65.5
Reserve margin, %	6.8	7.9	12.9
Generation shares, %			
Coal	47.4	52.1	46.2
Gas	29.2	22.2	26.0
Other	23.4	25.7	27.8
Generation prices and costs, ¢/kWh			
Retail price	3.02	3.03	3.66
Variable cost	1.45	1.43	2.07
Total cost	2.51	2.46	3.21
Carbon emissions, MtC	625	596	492
Average carbon emissions, kg/MWh	163	170	154
Marginal carbon saved, kg/MWh	-	89	350

Table 6.5 Comparison of Year 2010 Forecasts: Effects of Efficiency and High-Efficiency/Low-Carbon Scenarios

	Change relative to the competitive utility industry base case	
	Efficiency	High Efficiency / Low Carbon
Peak demand	-8.2%	-16.0%
Total energy	-8.5%	-16.3%
System load factor	-0.2% points	-0.2% points
Reserve margin	+1.1% points	+6.1% points
Generation shares		
Coal	+4.7% points	-1.2% points
Gas	-7.0% points	-3.2% points
Other	+2.3% points	+4.4% points
Generation prices and costs		
Retail price	+1%	+21%
Variable cost	-1%	+43%
Total cost	-2%	+28%
Carbon emissions	-4.6%	-21.2%

The efficiency scenario forecasts a lower percentage reduction in carbon (4.6%) than in end-use energy (8.5%) (Figure 6.5). The difference occurs because lower end-use demands translate into less construction and operation of high-efficiency gas-fired combustion turbines and combined-cycle units (Figure 6.6). (Because of their high capital costs, ORCED selects only the minimum amounts of advanced coal and renewable technologies in the base restructuring case.) In the efficiency case, relative to the restructuring case, capacity and generation for combined-cycle units declines by about 27%; capacity for combustion turbines drops 28% (generation drops by 68%); and coal and gas-powered steam plants actually increase their production slightly.

Identification of high-efficiency gas-fired combustion turbines and combined-cycle units as the marginal plants under consideration has the effect of substantially lowering the avoided carbon from electric efficiency improvements. The forecasts contained in AEO97 are consistent with this assumption through the year 2010. For example, page 49 of the AEO97 states that, "of the new capacity [required through 2015], 81 percent is projected to be combined-cycle or combustion turbine technology fueled by natural gas or both oil and gas."

In contrast, the HE/LC case forecasts a higher percentage reduction in carbon (21.2%) than in end-use energy (16.3%). This is because the inclusion of the charge of \$50 per tonne of carbon changes the mix of technologies used to produce electricity so that low-carbon supply options are favored. Over 16% of the coal capacity is retired in this scenario, and the remaining, more-efficient coal plants operate at a lower capacity factor. Overall, generation from coal declines 18% compared to the reference case. Capacity from combined cycle plants actually increases over the amount in the efficiency case, but still has a 14% decline from the reference case. Combustion turbine generation declines 84% from the reference case while combined cycle generation declines only 13%.

Figure 6.5 Energy and Carbon Changes from Restructure Case

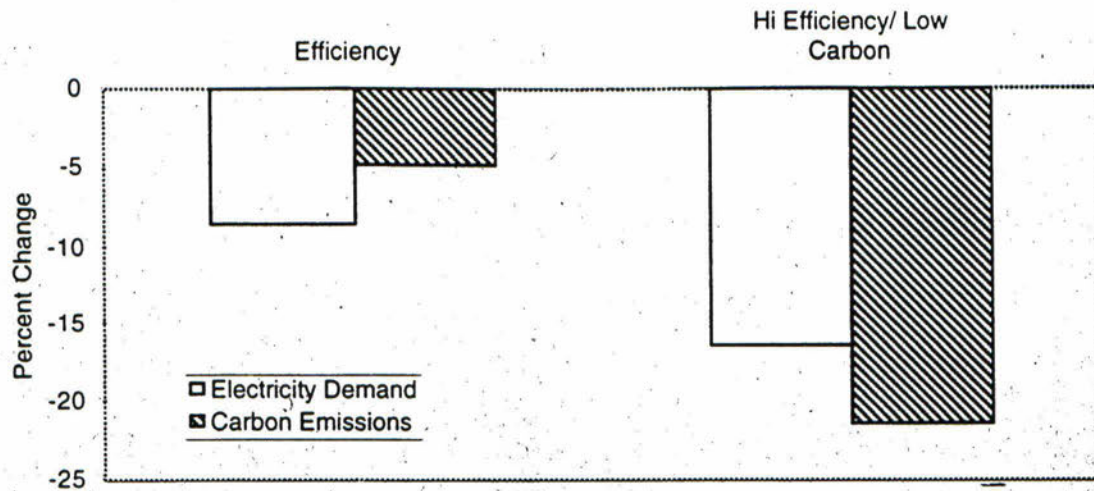
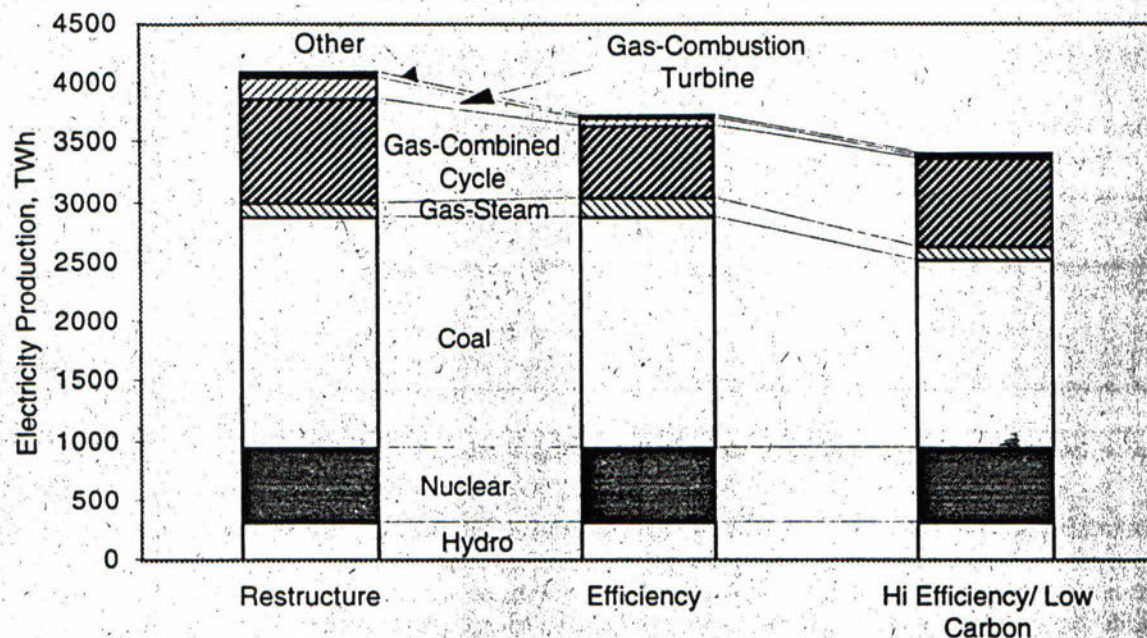


Figure 6.6 Generation by Technology Under Each Scenario



Compared to the reference case, generating prices and costs remain about the same under the efficiency scenario. In the HE/LC scenario, prices and costs increase about two-thirds of a cent because of the additional charge of \$50/tonne of carbon. This carbon charge represents a 1.4¢/kWh increase to the more expensive coal plants, but only a 0.5¢/kWh increase to the better gas-fired combined cycle plants. ORCED redispatched and changed capacities so that the cost increase would be minimized. Note that, although the generation price increases by 21%, the price of generation

7.3.1 Renewable Electricity in 2010

As stated earlier, renewable electric technologies will make important contributions to carbon emission reductions in 2010 in the context of a policy that imposes a \$50/tonne cost on carbon emissions. Estimates of those contributions are presented here. While the scope of this study did not include a thorough and systematic analysis of this issue, the estimates given are based on a number of directly relevant studies. These include, in particular, carefully developed performance and cost projections for renewable electric technologies (Office of Utility Technologies, 1997) and projections of future market penetrations of these technologies (Office of Energy Efficiency and Renewable Energy, 1997).

The potential of biomass cofiring was assessed because that technology provides an opportunity for reasonably straightforward displacement of a significant amount of coal. This assessment, which draws upon another recent analysis, is presented first.

An analysis of the impact of a \$50/tonne cost of carbon on wind power was also conducted, and those results are discussed second. Wind was selected because cost projections for wind power indicate that this technology will be competitive with other electricity generation sources according to the electricity costs modeled in the HE/LC scenario of this study. In addition, wind power is already successfully penetrating electricity markets in the United States and abroad.

This analysis is followed by estimates of carbon emission reductions that would be likely to result from hydropower upgrades and landfill gas capture and use. These estimates are derived from DOE and EPA studies relevant to market projections for those two technologies, respectively (Rinehart et al., 1997; EPA, 1993).

Finally, other key renewable power technologies are discussed briefly. We present estimates of the likely contribution of these technologies in 2010, developed through comparisons and extrapolations from earlier projections (Office of Energy Efficiency and Renewable Energy, 1997).

7.3.1.1 Cofiring Coal with Biomass

Cofiring biomass with coal has the technical and economic potential to replace at least 8 GW of the nation's coal-based generating capacity by 2010, and as much as 26 GW by 2020. Though the current substitution rate is negligible, a rapid expansion is possible with the use of wood residues (urban wood, pallets, and secondary manufacturing products) and dedicated feedstock supply systems (DFSS) such as willow, poplar, and switchgrass.

The current coal-fired power-generating system represents a direct opportunity for carbon mitigation by substituting biomass-based renewable carbon for fossil carbon. Extensive demonstrations and trials have shown that biomass can replace up to about 15% of the total energy input with little more than burner and feed-intake system modifications to existing stations (CONEG, 1996). Since large-scale power boilers in today's 310-GW-capacity fleet range from 100 MW to 1.3 GW, the biomass potential in a single boiler ranges from 15-150 MW.

Preparation of biomass to an appropriate size of less than one-quarter inch, with a moisture content of less than 25%, can be achieved using existing commercial technologies. "Tuning" the combustion output of the boilers causes little loss in total efficiency, implying that the biomass-to-electricity combustion efficiency is close to the 33-37% range of an unmodified coal plant, an efficiency that stand-alone biomass generating capacity has yet to demonstrate.

Economics

The cost of implementing biomass cofiring varies from site to site. It is influenced by the space available for yarding and storing the biomass, the installation of size-reduction and drying facilities, and the nature of the boiler burner modifications required. The cost is expected to be in the range of \$100-\$700/kW of biomass capacity. Early trials indicate that a median value of about \$180/kW is likely. A 100-MW coal plant with 10% biomass substitution would then require an investment of \$1.8 million. There is an O&M cost increase of \$70,000/year over coal, as a result of the need for an additional yard worker to handle the biomass. Assuming a GENCO recovers its investment cost in three years, the annual fuel offset then has to be \$670,000 to cover capital recovery (\$1.8 million) and increased O&M costs (\$210,000 for three years). If the average price of coal is about \$1.40/MBtu (million Btu), the annual fuel cost of coal is \$1.081 million (10 MW of biomass capacity at 85% capacity factor and 32.9% thermal efficiency, 10,337 Btu/kWh). The allowable cost of biomass then is \$411,000, or about \$9/tonne. Above this cost, the biomass would have to be subsidized to encourage a GENCO to use biomass cofiring.

Fuel Costs

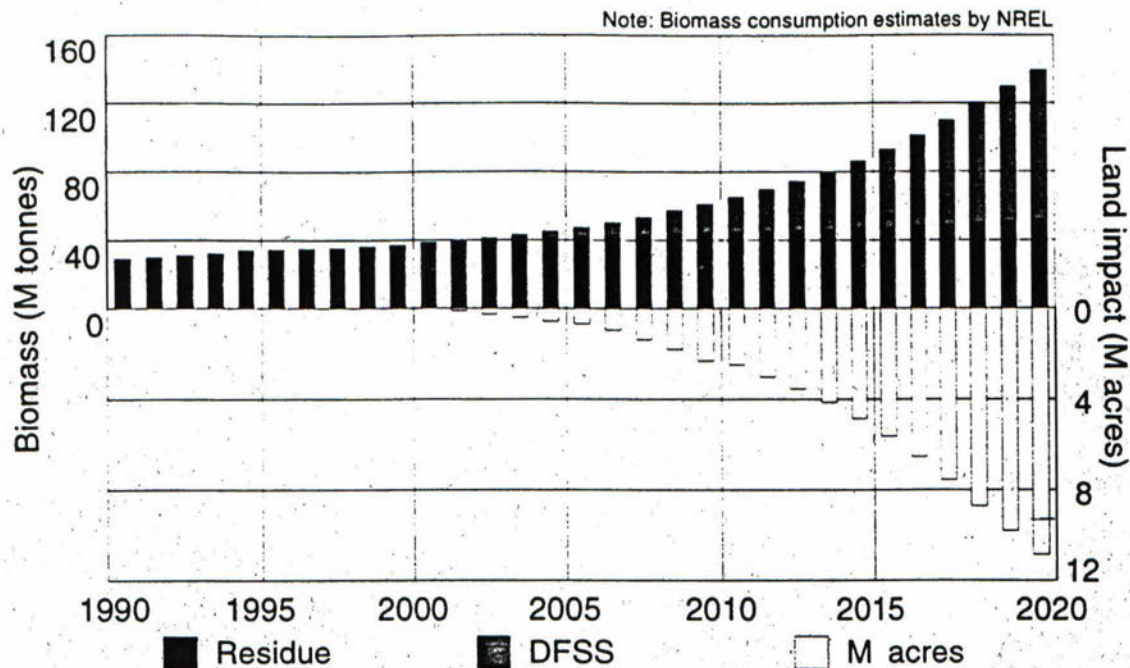
Near-term potential biomass feedstocks are those residues available within a radius of about 50 miles around a plant. Data from existing biomass power plants in the Northeast and California indicate that there are extensive sources of biomass residues available for about \$0.50/MBtu (less than \$9/tonne). Transportation costs limit the range over which such biomass feedstocks can be acquired and, in the long term, there are likely to be dedicated feedstock systems much closer to the power plants. By definition, residues (e.g., urban wood residues, rights-of-way clearance, construction and demolition wood, pallets, and sawdust shavings from secondary wood processing) are finite and will respond to the prices offered for them.

Dedicated feedstocks would not be bound by this constraint. However, such feedstocks are much more expensive than residues. With current technology the price is about \$2/MBtu, although the current development goal is in the range of \$1-\$1.50/MBtu. It is assumed that an estimated 10.4 million acres will be needed to reach a nominal production of 86 Mt by 2020. Because DFSS is in an early stage of development, the model assumes that the initial planting will yield only about 6 tonnes/acre by 2002 (today's state-of-the-art), and that by 2010 the yield will be closer to 8 tonnes/acre. Today's costs are high; \$45/tonne is feasible, but a combination of learning-curve improvements and economies of scale should bring the cost down to about \$32/tonne by 2010. The competing coal price is assumed to be \$1.40/MBtu (\$1.33/GJ) throughout.

Biomass Substitution Potential

The cofiring estimates in this section were derived from a 30 GW scenario for all biomass technologies, developed by NREL for the current Biomass Power Program Strategic Plan. This scenario is for a mix of steam, cofiring, and integrated gasification/combined cycle (IGCC) biomass generation. However, the resource plan that was developed, which included residues and DFSS, is independent of the end use and involves the development of 11-12 million acres of land for DFSS by 2020, or just under 3 million acres by 2010. The resource development shown in Figure 7.11 is used as the basis for this carbon assessment. This indicates that DFSS would come on rapidly after the year 2001 and assumes that residues would be capable of only a small increase in quantity, since much is already being utilized. The average cost of residues is expected to increase gradually, while the cost of DFSS crops is expected to demonstrate a strong learning curve and large economies of scale.

Figure 7.11 30 GW Strategic Plan Scenario



Timing

While a coal-fired station could be modified for cofiring in less than one year (including environmental permitting), a biomass resource assessment, contractual arrangements, and logistics for biomass residues could take the better part of 18 months, based on actual project experience. Although the availability of residues is assumed to be significant and would ultimately supply about 50 Mt, price and availability are likely to be variable. The price will no doubt increase with the level of demand; therefore, the biomass feedstock supply is expected to be a blend of DFSS and residues.

The DFSS component is predicated on making a start on land accumulation (whether purchases, leases, or cooperatives), with land preparation and planting in 1999. A significant effort will be required to initiate development of the 11-12 million acres proposed for 2020; today, discussions are about DFSS demonstrations at the 1000-acre level. Adequate clonal material and management systems for planting, tending, and harvesting will also need to be developed. The crops of choice in much of the Northeast and Southeast are probably woody species, which would require extensive nursery activity to put the needed clonal material in place for planting out. With willow, the first harvest cycle would be four years after planting and a rotation of three years thereafter. For poplar, the cycle is likely to be in the range of six to eight years.

Environmental Issues

Because biomass generally contains significantly less sulfur than coal, cofiring with biomass could reduce SO_x emissions. Early results suggest that there is also a NO_x reduction potential using woody biomass. However, most coal-fired power stations have efficient precipitators and some have sulfur-capture technologies, so the net environmental effect of 10% biomass substitution (on an energy basis) appears to be negligible. The solid wastes (ash) would be little changed in either composition or mass (most biomass has considerably less ash than coal). But some stations sell fly ash to

Portland cement manufacturers, so there may be a need to negotiate the acceptance of mixed biomass and coal ash in such applications with respect to ASTM standards.

The DFSS environmental impact is dependent on the choice of lands for plantations. Replacing annual cropland with perennial DFSS appears to result in a net environmental gain. Results for pasture land are probably negligible and replacement of forest may result in some increased impacts.

The use of residue has the potential to offset landfilling as well as potential methane emissions from landfilling clean biomass materials. Experiences in California indicate that the issue will be one of rationalizing the cost distribution between the waste generator, the hauling contractor, and the generating station receiving the residue rather than it going to a landfill. If such negotiations were successful, and the generating station could guarantee reception of the residues at all times (many urban wood residue generators do not have storage facilities), both residue costs and their availability could improve significantly.

Impact on Carbon Emissions

Given the technical and economic potential described above, it is probably reasonable to assume additional biomass-cofired capacity of 8-12 GW by 2010, which should reduce carbon emissions by 16-24 MtC.

7.3.1.2 Wind Power

The development of wind power systems has progressed quite rapidly since 1980. There are approximately 1800 MW of wind capacity operating in the United States today, and another 4300 MW of capacity overseas (Figure 7.12). This capacity growth is almost certain to continue because of continuing decreases in the cost of wind-generated electricity as well as growing interest in emission-free power derived from local, renewable resources. Figure 7.13 shows the projected cost of wind-generated electricity for wind farms located in Class 4 and Class 6 resource sites (as presented in DOE's 1997 Technology Characterizations). Class 4 sites have average wind speeds of 5.6-6.0 m/s, Class 6 sites have average wind speeds of 6.4-7.0 m/s, both measured at a height of 10 meters. Figure 7.13 also displays the median, 10th percentile, and 90th percentile of electricity generation prices in 2010 based on the HE/LC case described in Chapter 6. As these projections indicate, wind power prices are projected to drop below the median 2010 price for that scenario before 2005. Thus, strictly on a price-of-energy basis, in this scenario wind power will be able to compete favorably with other power sources for several years prior to 2010.

In addition to the price of energy, a number of other factors will affect the extent to which wind power systems will be adopted between now and 2010. These include, for example, the overall market for new power systems, the price penalty that wind power will encounter for providing intermittent power, and the price advantages that wind power will realize because it is a "green" power source and because it is not subject to the risk of future fuel price increases. Because the level of influence of each of these factors has not been analyzed, it is difficult to project their combined impact.

Figure 7.12 Domestic and International Wind Power Capacity, Grid-Connected

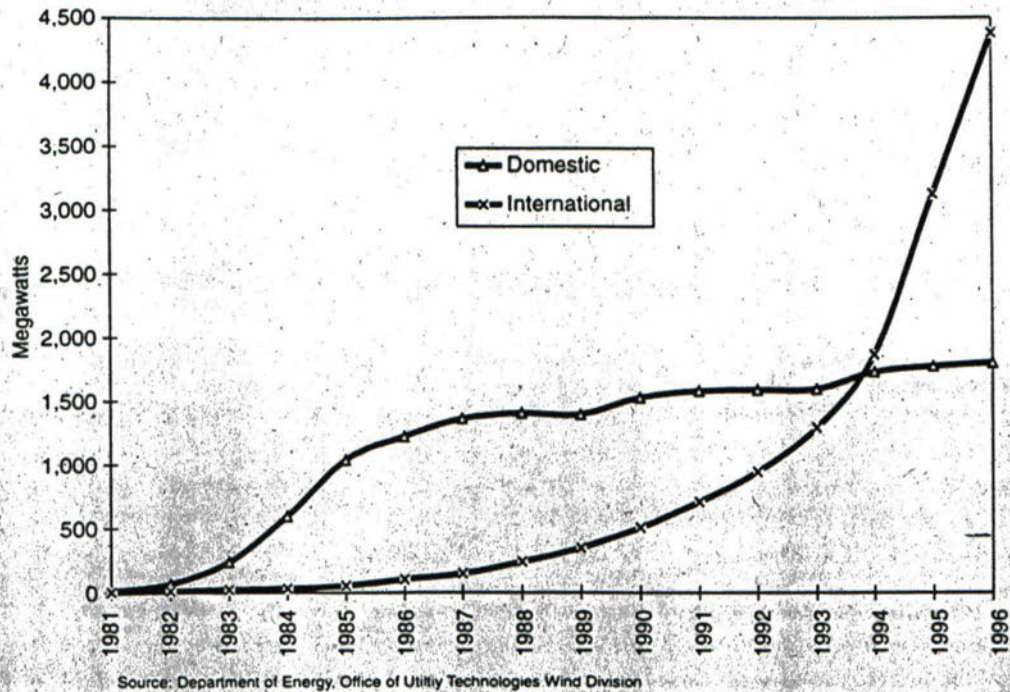
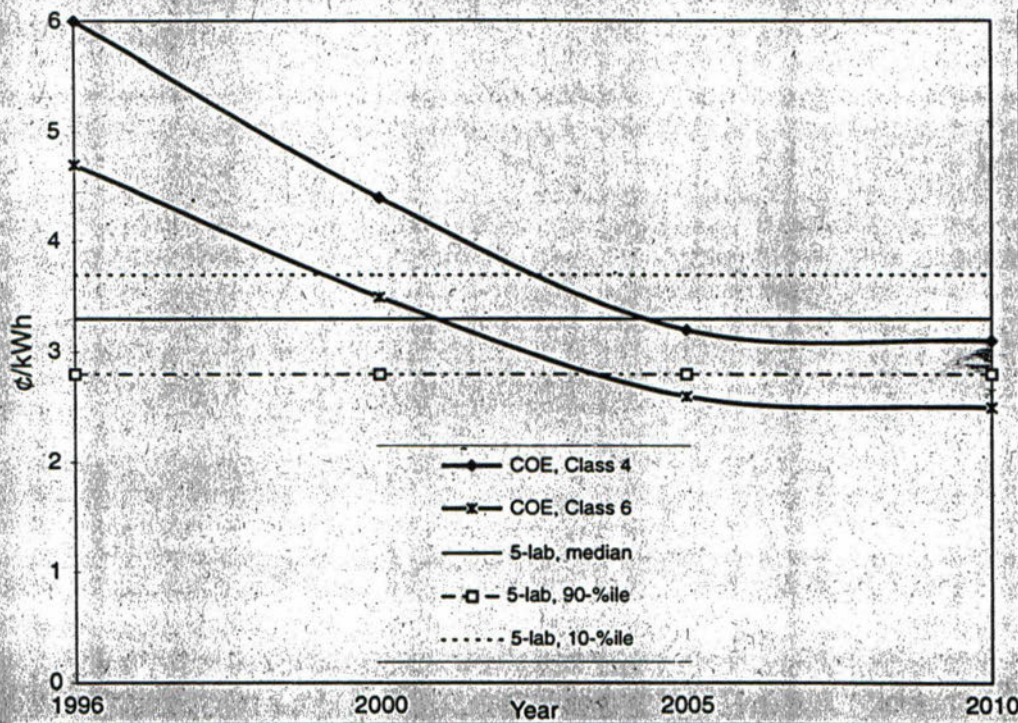


Figure 7.13 Projections of Wind Power Costs



In the AEO97 reference case forecast, EIA projects electricity generation to increase by about 800 TWh by 2010, from 3083 TWh in 1995 to 3874 TWh in 2010 (EIA, 1996). In this context, EIA projects a total of only 3800 MW of wind generating capacity. The Quality Metrics analysis by the Office of Energy Efficiency and Renewable Energy (EERE) of the impacts of its R&D program estimates that additional installed wind power generating capacity will reach 8 GW and contribute approximately 29 TWh to the electricity market by 2010 if wind program goals are met. This will result in a carbon emission reduction of 6 MtC. Neither of these projections, however, assumes a major new market policy to promote wind power.

In the HE/LC case of this study, electricity generation will increase by significantly less than in the business-as-usual case. Thus, the HE/LC scenario presents a much smaller target market for new power-generation sources. However, under the transition of the utility sector to a competitive market, it is very likely that newer technologies with lower generating costs will displace some existing generation capacity with higher generating costs. Moreover, in the HE/LC scenario, generation costs are projected to be more than 25% higher than in the base case. Thus, as illustrated in Figure 7.13, wind power generation costs will be highly competitive in this marketplace, so displacement of higher-cost existing generation by wind is likely. In an attempt to model the penetration of wind under these conditions, the ORCED model was run using the wind technology characteristics developed by the Office of Utility Technologies (Office of Utility Technologies, 1997). As might be expected, the results indicated that the level of wind penetration in this case is quite sensitive to the actual input parameters. According to the model, for example, using the cost and performance characteristics projected by DOE for the year 2005 could lead to the adoption of as much as 50,000 MW of wind power by 2010. Using 160 kg/MWh, the average carbon intensity of the generation displaced (see Chapter 6), this would result in a carbon emission reduction of 28 MtC. Because the ORCED model indicated that this new wind capacity would displace coal-fired generation, a higher conversion ratio (275 kg/MMh) is used to estimate carbon emission reductions, resulting in an estimated reduction of 48 MtC.

This level of penetration would require wind-turbine manufacturing capacity to expand at a rate of approximately 25% per year. As Figure 7.12 indicates, this level of wind capacity expansion has been reached in the past. Europe's experience with wind power also indicates that this technology can expand quite rapidly. It is possible for the manufacturing industry to respond quickly to market demands, since most of the components of wind systems (generators and gearboxes) are readily available, and not specific to wind technology. In 1991, the European Wind Energy Association set a goal of 4 GW of wind by 2000. This goal has been realized already in 1997, and the new targets are 8 GW by 2000 and 40 GW by 2010. Given that Europe is a much more land-constrained continent with generally lower wind resources than the United States, this comparison suggests that 40 GW of wind power capacity can be realized in the United States by 2010 in the context of a strong policy environment.

The HE/LC context of this analysis assumes a policy environment that acknowledges the need to address global warming. In such an environment, renewable energy, including wind power, will be able to demand somewhat higher prices because of consumers' preferences for green power. The value of that premium is not yet known.

It is well-documented that wind resources in the United States are quite extensive. For example, an assessment of wind resources and access to transmission indicates that more than 115 GW of Class 5 and Class 6 sites are within 5 miles of existing lines, and more than 1,000 GW Class 4 sites are within that same range (Parsons et al., 1995). This assessment excludes sites that are not suitable for wind farm development, such as cities and wilderness areas. Thus, 50 GW could probably be developed primarily in Class 5 and Class 6 areas, which means that they will operate with

relatively high capacity factors and low costs of energy. (The Draft Technology Characterizations indicate that capacity factors will be 45% in Class 6 regions and 35% in Class 4 regions by 2005.)

This analysis does not take into account the fact that wind-generated electricity will probably face at least a partial price discounting because wind power is not fully predictable. At this time, the level of this discounting is simply not known. To date, with low levels of penetration into grid-connected generation, intermittency has not been an issue. There are some indications that the range of electricity prices in a competitive market will be fairly narrow. For example, prices for electricity transactions on the Continental Power Exchange during peak hours generally vary only by about 2 cents/kWh (Continental Power Exchange, 1997). This implies that price variations between different generation sources cannot vary by more than that, and it is likely that the difference will be much smaller under full competition.

In summary, analyses indicate that total wind power capacity in 2010 could range from as low as 5 GW, based on a simple extrapolation of today's energy economy, to as high as 50 GW in an environment that includes competitive pricing and policies emphasizing control of carbon emissions. Given these results, it is probably reasonable to estimate that additional wind capacity will be 8-23 GW in 2010. This translates into electricity contributions of 28-81 TWh, resulting in reductions of carbon emissions of 6-20 MtC relative to the BAU forecast for 2010.

7.3.1.3 Increasing Generation and Capacity at Existing Hydropower Plants

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

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

1. Most hydropower plants use dams to raise the water level, which increases the water's potential energy, and allows for regulation of the water availability. Conventional hydropower (with reservoir storage) can provide baseload, intermediate, or peaking power, depending on the availability of water and project design (OTA, 1995).
2. Run-of-river systems do not use large dams or storage reservoirs. Instead, smaller diversion structures are used to channel some of the water through a canal or penstock to a powerhouse, after which the water is returned to the river. Run-of-river systems avoid some of the costs and environmental impacts associated with large hydro facilities.
3. Pumped storage projects use off-peak electricity (usually from a baseload power plant) to pump water to an upper reservoir; this water is later released to flow through a generator during periods of peak demand. Such plants are net consumers of energy. Although pumped storage is not a renewable energy technology, it can result in a net reduction in greenhouse gas emissions when the fuel providing electricity for pumping has a lower carbon content than the fuel being displaced by the pumped storage generation (DOE, 1994).

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

Regulatory measures — such as the licensing of non-federal hydropower projects and the Endangered Species Act — are reducing the environmental impact of hydropower projects, but they are also reducing total electricity production from this energy source. Between 1995 and 2010, 19 GW of hydropower at non-federal projects will be subject to relicensing. Recent trends indicate that relicensing results in an average 8% loss in generation due to the imposition of new environmental constraints on operation.

Under the HE/LC scenario, and assuming a sustained regulatory reinvention effort between now and the year 2010, incentives could be in place to increase hydroelectric power generation in either of two ways. Neither of these opportunities involves the construction of hydropower plants at new sites. However, both will require continued R&D to improve the design of turbine systems and to minimize adverse environmental effects:

- Increasing generation at existing hydropower plants. This option consists of modernizing and upgrading existing turbines and generators to increase their efficiency and/or electrical output. With enabling incentives, upgrading hydropower plants can result in energy production gains of 5%-10%. Hydropower upgrades would also have significant environmental benefits, because new generating technologies offer improved fish passage, better water quality, and new opportunities for improving downstream aquatic habitats.
- Adding generating capacity at existing dams. A recent resource assessment identified 20 GW of undeveloped hydropower capacity at existing dams (Rinehart et al., 1997). About 36,000 GWh of new hydropower generation could be added by developing these sites between 1995 and 2010 (Office of Conservation and Renewable Energy, 1990).

Further expansion of hydropower capacity is possible, but unlikely until after 2010. The national hydropower resource assessment (Rinehart et al., 1997) has identified an additional 11 GW of environmentally acceptable hydropower at undeveloped sites (those requiring the construction of new dams or diversions). These resources may eventually be developed, given more advantageous economics, regulatory reinvention, and/or technology improvements. Further development of efficient low-head generating technologies would encourage deployment at the many low-head sites that are currently unsuitable for hydropower additions.

Considering only the near-term options, and the fact that there may be some loss of hydropower capacity due to relicensing issues and environmental mitigation regulations, net capacity additions by 2010 could be 10-16 GW, reducing emissions by 3-5 MtC. Additional carbon savings can be achieved after 2010 with continuing advancements in generating technologies and environmental mitigation techniques.

7.3.1.4 Landfill Gas

When food scraps and other organic wastes in landfills decompose, they produce methane. Methane is a potent greenhouse gas that is also the main ingredient of natural gas. According to the

Intergovernmental Panel on Climate Change, each kilogram of methane is about 21 times more effective at trapping radiation in the atmosphere than a kilogram of carbon dioxide. Landfills are the largest source of anthropogenic methane emissions in the United States; they are responsible for almost 40% of these emissions each year (EPA, 1997).

New EPA regulations require operators to seal larger, closed landfills with a special cap, collect the gas, and burn it to prevent atmospheric releases of methane. But wells sunk into landfills can capture the gas before it escapes the surface. It can then be used for a variety of applications, including generating electricity.

Today, about 165 landfills recover and utilize methane as a fuel. Various estimates (Governmental Advisory Associates, 1994; EPA, 1997) indicate that between 300 and 750 of the country's 3500 landfills could economically recover methane using currently available technologies. The development of more efficient, less expensive technologies for gas recovery, clean-up, and utilization could accelerate the adoption of landfill gas-to-energy systems. For example, highly efficient, experimental fuel cells have operated on landfill gas processed using new clean-up technology.

By 2010, 0.2-0.5 quads of energy per year could be recovered from the methane in landfills and converted to electricity. Taking into account the difference in the radiative effects of methane and CO₂, this represents the equivalent of 25-53 MtC in reduced emissions (DOE, 1994).

7.3.1.5 Other Renewable Power Technologies

This section examines three more renewable electric technologies: photovoltaics (PV), geothermal power, and solar thermal power. Figure 7.10 illustrates that the costs for these three technologies have also decreased sharply over the past 15 years. It is very likely that this trend will continue. While none of these technologies are expected to contribute as much electricity as biomass cofiring or wind power by 2010, their role in 2010 electricity markets may be significant and growing.

Photovoltaics

Photovoltaics (PV) uses solar cells to generate electricity from sunlight without any emissions or moving parts. This technology has made substantial progress since its first successful application in space. While PV power costs are still significantly higher than the costs of other renewable technologies, sales of PV power systems have been growing steadily, probably because of the many unique advantages of PV. These include modularity (applications can range from solar calculators to power stations), widespread applicability (since adequate solar resources are widely available), and ease of integration into the built environment (through incorporation into building facades, roofing materials, highway sound barriers, parking-lot structures, etc.). The most important application of PV today is in stand-alone systems that provide power to remote water pumps or off-grid residences, for example. Because approximately two billion people live in villages without grid electricity, remote power represents a very large and important market for PV in developing countries.

For grid-connected applications, one of the most promising trends in the past few years is "building-integrated" PV. Numerous buildings have been constructed — primarily in Europe, Japan, and the United States — that incorporate PV panels in windows, awnings, or roofing materials. Thus, the PV panels serve a dual function, which effectively lowers the cost of their role as power generators. In these applications, the PV power directly displaces grid electricity at the end point of the delivery system, where it has the greatest value. Another advantage of PV is that its peak power output generally coincides with peak electricity demand, which further enhances its market value.

Worldwide sales of PV power systems have grown to nearly 100 MW per year, up from 10 MW in 1982, an average annual growth rate of about 20%. This rate of growth is likely to increase as a result of numerous programs promoting PV for village power in developing countries as well as programs promoting greater use of PV in several developed nations. One example is the U.S. Million Solar Roofs program, announced by President Clinton at the United Nations on June 26, 1997. Others include Japan's Sunshine Project, Germany's subsidy of up to 70% of PV system costs, and Switzerland's PV Schools Program.

EIA estimates that total installed PV capacity in the United States will be only 0.2 GW in 2010 (EIA, 1996). However, an independent assessment of the impact of DOE's R&D programs indicates that, by 2010, installed U.S. PV capacity will be approximately 1.3 GW under a BAU scenario (Office of Energy Efficiency and Renewable Energy, 1997). Using this as a starting point, and considering the many advantages of PV, an estimate of installed capacity of 4-7 GW in 2010 is probably reasonable for the HE/LC scenario. This would provide 6-13 TWh of electricity and reduce carbon emissions by 1-2 MtC. One important addition to PV capacity will come from the recently announced Million Roofs Initiative, which will result in 1-2 GW of new capacity.

The market trends for PV in 2010 are probably more significant than its energy and carbon contributions. By 2010, PV energy prices will be substantially lower than they are today, and we will have had considerably more experience with the development and use of building-integrated PV products. In this context, the United States will be moving into a situation in which a significant and increasing fraction of construction includes PV generation capabilities.

Geothermal Electricity

Geothermal power technologies use the thermal energy from underground reservoirs of hot water or steam to produce electricity. With higher temperature resources, the steam is used to drive a turbine directly; with lower temperature resources, a binary technology is used in which the hot water vaporizes another working fluid, which then drives a turbine. These geothermal power-generation technologies are considered fairly mature. The major challenge lies in locating and characterizing the size and longevity of specific geothermal reservoirs.

Approximately 3 GW of geothermal capacity is installed in the United States today. While EIA estimates that geothermal capacity will increase by only 0.2 GW by 2010 (EIA, 1996), DOE's recent Quality Metrics Study indicates that geothermal power capacity will increase by 5.8 GW, and electricity production will increase about 45 TWh, in a BAU scenario (Office of Energy Efficiency and Renewable Energy, 1997). While a \$50/tonne cost of carbon would improve the economics for geothermal, it is not expected to provide as much of a boost as it does for wind or biomass. It is probably reasonable to use the DOE estimate as the lower boundary, and project that total installed geothermal power capacity in 2010 under the HE/LC case will be 8-16 GW. The 6-14 GW increase in geothermal capacity over today's level would reduce carbon emissions by 6-16 MtC.

Solar Thermal Electric Technology

Solar thermal power technologies use mirrors to concentrate direct sunlight onto a thermal receiver, thus creating a high-temperature energy source that can be used with a heat engine to generate electricity. There are three types of solar thermal power systems: parabolic troughs, power towers, and dish/engine systems. Parabolic trough systems use large fields of linear parabolic reflectors, each of which heats a fluid flowing through a receiver pipe located along the focal line of the reflector. About 350 MW of these systems are operating in California. A 10-MW demonstration of a solar thermal power-tower system, which uses large mirrors to direct solar rays to a thermal receiver atop a tower, is also operating in California. The third technology uses individual

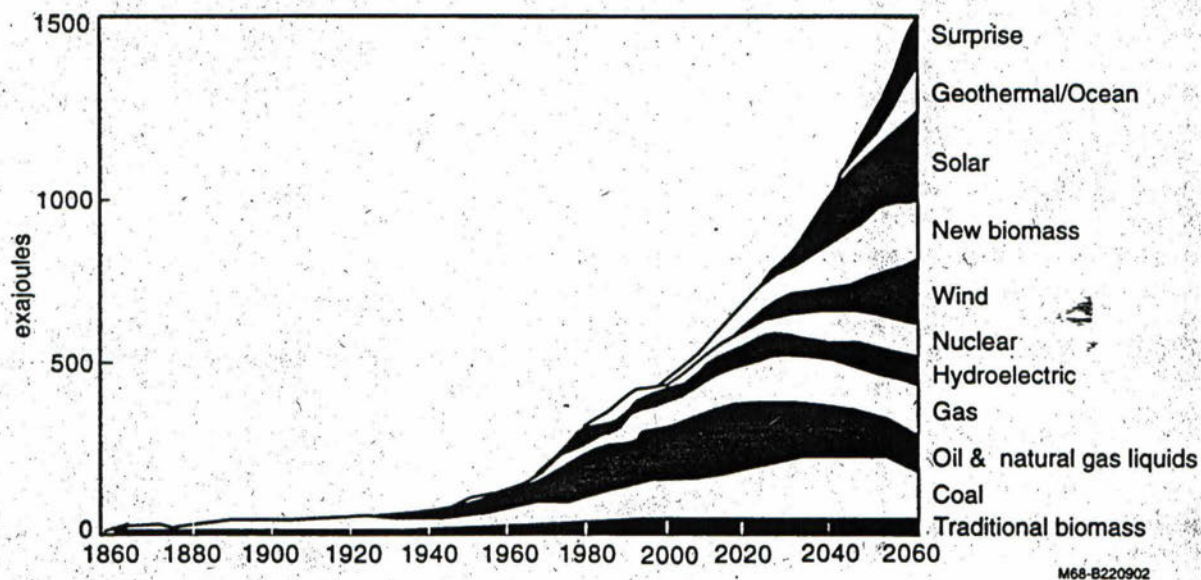
parabolic dish reflectors to provide thermal energy to a Stirling engine mounted at the focal point of the dish. A few individual prototype units, which have power outputs of about 10-25 kW each, are being tested in the United States.

While EIA projects negligible gains for solar thermal generating capacity by 2010 (EIA, 1996), DOE's recent Quality Metrics Study suggests that solar thermal systems will provide approximately 2 TWh of electricity in 2010 in a BAU scenario (Office of Energy Efficiency and Renewable Energy, 1997). Under the HE/LC scenario of this study, an estimate of 0-2 GW capacity and 0-6 TWh electricity generation in 2010 is probably reasonable. This would reduce carbon emissions about 0-1 MtC.

7.3.2 The Long-Term Role of Renewables

As indicated at the beginning of this section, it is quite likely that renewable energy technologies will play a crucial role in limiting carbon emissions and global warming in the long term. Continued domestic and international economic development that does not foster further global warming will require greater energy consumption coupled with lower carbon emissions. The only options are thus low-carbon energy supplies, such as nuclear power or renewables, or the sequestration of carbon emissions from the use of fossil fuels. With the continuing technological development and cost reductions of renewables, renewables may become preferred energy resources some time within the next one to three decades. Moreover, they will probably expand to become the world's primary energy resource in the latter half of the next century. In fact, just such a transition was suggested recently by Shell International (Figure 7.14) (Royal Dutch/Shell Group of Companies, 1996).

Figure 7.14 Sustained Growth Scenario from Shell International (Reproduced courtesy of Shell International Petroleum Company)



This subsection describes the future direction and likely accomplishments of continuing R&D in renewables. This discussion should lend credence to the prediction that non-hydro renewables will make the transition from a minor to a major contributor to the world's electricity supplies.

Biomass Power

The most important R&D areas for biomass power are in gasification/conversion systems and in feedstock production. Gasification involves converting the solid biomass feedstock material to a gas that is cleaned and then burned in a combustion turbine or used in a combined-cycle plant. This technology is currently in the initial demonstration stage of development.

The importance of this technology is that it can take advantage of advanced turbine designs and heat-recovery steam generators to achieve almost twice the efficiency of currently installed biomass technologies (NREL estimates, 1997). High-pressure gasification technologies yield the highest efficiencies, but they also require the development of efficient, cost-effective methods for cleaning the hot gases before they enter the turbine.

On the biomass production side, genetic research is likely to produce energy crop species that provide consistently higher biomass yields on an energy-content basis, thus providing a proportional reduction in biomass feedstock costs. Related research into new species designed for better fuel production also looks promising in terms of significantly decreasing biofuels costs over time. Research into advanced agricultural methods will also lower feedstock production costs over time. Finally, the development of simpler feedstock handling and processing methods will also lead to lower costs. Whole-tree processing methods, for example, which avoid the cost of chipping the wood before processing or use, could reduce the cost of harvesting and delivering the biomass to the power plant by about one-third (OTA, 1995).

Taken together, improvements in biomass power conversion as well as feedstock production and processing could reduce the cost of electricity from biomass to about 3-4 cents/kWh. This would make biomass power very economical in comparison to other mainstream electricity sources. As biomass power expands, most of it will employ dedicated feedstocks. In this context, biomass use will entail low net carbon emissions. These net emissions primarily result from the combustion of fossil fuels in production and delivery, because the carbon emitted during conversion will be reabsorbed as new feedstock grows. Thus, biomass power can become a major contributor to reducing overall carbon emissions from electricity generation in the coming decades.

Wind Power

The technological and economic feasibility of wind power — both in the United States and abroad — has already been well established, as the wind generation capacity curves in Figure 7.12 indicate. Nonetheless, major advances for wind power technology in both the short-term and long-term are likely. These are predicted for the short-term by DOE's cost and performance projections (Office of Utility Technologies, 1997), as illustrated in Figure 7.13.

Wind turbine design is the most critical R&D area. In general terms, the research goals are to produce turbine designs that have half of the material content of today's turbines, at perhaps three-quarters of the material cost (to account for more expensive materials), but with higher efficiencies and longer lifetimes. Such design improvements will not only lower the cost of wind-generated electricity, they will also make it economically practical to utilize the widespread, somewhat lower quality wind resources found in Class 4 wind regimes. Some of the critical research needed to achieve these goals includes continued empirical research into the air-turbine blade interface, computational fluid dynamics modeling of that interaction, and fatigue testing and structural modeling coupled with materials research. This is all aimed at producing more efficient turbine blades that minimize material utilization while extending blade operating lifetimes.

Another important area of R&D concerns the development of direct-drive generators and improved power electronics. This will yield higher conversion efficiencies and more durable power-conversion components, eliminating the need for a gearbox in the drive train. A major challenge will be the integration of advanced components and controls into large-scale, utility-class hardware.

There is also considerable room for improvement in turbine manufacturing processes through process development and automation, since today's turbine blades are still largely built by hand.

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

Another important thrust for research is to address siting issues. For example, the tops of ridges are often good wind sites, but such a visible location for a wind farm can be a cause for concern when the site is either close to a population center or in an area of particularly great scenic value. To date, there have been virtually no studies to understand the local values associated with the visual impact of wind systems relative to other energy technologies in the United States. Yet such analysis could play a key role in decisions about the adoption of wind power in specific regions. Another environmental consideration affecting site selection is the potential risk to birds, particularly raptors, which sometimes fly into the rapidly turning rotor blades. This, too, seems like an issue that may well be resolved through research to understand the scope of the problem relative to other threats to bird species as well as the development of ways to keep birds a safe distance from moving turbine blades.

In summary, the research front for wind power technology is very broad. Achievements are likely to lead to widespread adoption and application of this electric power technology throughout the world, wherever resources are adequate, over the next few decades.

Geothermal Electricity

Both current geothermal power systems and advanced geothermal power technology concepts will benefit from continuing R&D.

Today's geothermal power plants use the thermal energy from hot water and steam in hydrothermal reservoirs to generate electricity. While the power conversion and drilling technologies related to these power plants are considered relatively mature, they will also benefit from R&D in heat exchangers, hot fluid management systems, and new thermal conversion cycles. These activities alone could result in energy cost reductions of at least 20% in the next few years (NREL estimates, 1997).

The most important R&D area for conventional geothermal technology is resource exploration and characterization. The cost of geothermal electricity is highly dependent on resource characteristics such as temperature, depth, sustainable extraction rate, fluid chemistry, and ease of drilling. By 2020, improvements in drilling technology, advanced seismic data gathering, and better computer

modeling and interpretation of the data could lower the average cost of locating and assessing geothermal resources by 50% (NREL estimates, 1997).

In the long term, geothermal power plants could make use of hot dry rock resources — areas of exceptionally hot rock (above 150°C) that have little or no water in them. Energy can be extracted from these zones by injecting water from the surface underground, where it is heated. Although the engineering feasibility of extracting energy from hot dry rock has already been demonstrated (Secretary of Energy Advisory Board, 1995), further R&D is necessary to make the technology commercially viable. With success in that endeavor, the potential for geothermal power would be vastly expanded because hot dry rock resources are widely available.

Photovoltaic Power Systems

Although PV power technology has already experienced major gains in both performance and economics as a result of R&D conducted over the past 30-40 years, there is still considerable potential for further improvements. This is true for essentially all aspects of PV power systems, including research on basic photovoltaic materials, development of high-efficiency PV cells and modules, development of better PV power products, lower cost manufacturing processes, and improvements in the various components of PV systems.

A good example of the potential of PV R&D is found by comparing the module efficiencies of current commercial PV modules with the efficiencies of individual solar cells. For crystalline silicon PV technology, the technology representing about 90% of current sales, commercial module efficiencies are generally between 10% and 15%, while the best laboratory cell efficiencies are well above 20%. For thin-film PV technology, which includes amorphous silicon, copper indium diselenide, and cadmium telluride modules, current module efficiencies are generally well under 10%, but cell efficiencies are above 15%. Thus, in all cases, progress in commercial products would be virtually assured through the replication of established laboratory results. There is also clearly the potential for greater increases in cell efficiencies over today's laboratory results. Some of the research tools that are being applied include computer modeling of various semiconductor materials and atomic-level engineering of new devices to better understand their photovoltaic and electronic properties.

Looking ahead, we find that significantly greater efficiencies are possible. For example, multi-junction cells have been tested with efficiencies above 30%. At this time, these are small, laboratory-scale devices whose initial application is expected to be with concentrators, in which the cost of the cell is significantly offset by the increased solar energy captured by the optical concentrator. However, in a decade or two, it is certainly conceivable that low-cost processes for making similar high-efficiency multi-junction devices will have been developed, which will make it possible to use them in conventional, flat-plate PV modules.

In the area of manufacturing processes, considerable effort is being made to perfect processes that provide uniform, high-quality materials for the thin-film technologies. The fruits of these efforts are likely to be realized in the next few years as a number of firms construct fairly large (5-20 MW per year) manufacturing plants based on the results of process research and development.

There is still considerable progress to be made in the development of PV power products. For example, many PV power systems today are still being individually designed for specific applications. Off-the-shelf PV power systems and consumer products (such as PV walk-lights, lanterns, and battery chargers) are becoming more available, but the commercial PV industry is still a long way from making it as easy to purchase a residential PV system as it is to buy a refrigerator. The development of products that are readily applied to such individual needs will have an

important effect on PV electricity costs because it will increase the volume of sales. A particularly important set of PV products is likely to be PV components for building shells. These include windows, wall materials, awnings, and roofing materials that incorporate PV and are as readily installed as the components they replace in today's building industry. A reasonable long-term target is to have a large fraction of new construction incorporate such building-integrated PV products.

Finally, we will continue to see improvements in the balance-of-system components of PV systems. Examples include power conditioners and controllers, which serve as the electrical operating and interface system for integrating PV power modules with the load and/or the power grid. These components will continue to improve as well as benefit from developments in power electronics. Greater system integration is also likely, simplifying overall system design. A good example is the development of PV modules that incorporate dc-to-ac inverters, an activity that is currently under way.

In summary, PV technology will benefit from major R&D advances for many years to come, and these advances will significantly improve the economics of PV power. Among the implications of these advances, it is likely that PV power systems will reach prices of \$3000/kW by 2010, which is less than half the current average price. Further price reductions will no doubt occur beyond that.

Solar Thermal Electricity

Solar thermal technologies will benefit from R&D in a broad range of areas. For example, successful development of durable silver/polymer reflectors will reduce reflector costs by 25% to 50% for all three technologies, reducing system costs by 10% to 20%. Improved reflectors and receivers will also allow higher operating temperatures and thus higher solar-to-electric conversion efficiencies. Technology advances for Stirling engines will directly benefit dish/engine systems; one of the most important areas is the extension of operating lifetimes between overhauls. The development and application of hybrid solar/natural gas systems will be particularly important for power tower and parabolic trough technologies. These will make it possible to provide dispatchable power and to use combined-cycle technology, as well as smaller solar fields without being penalized by smaller steam turbines, which tend to be less efficient.

By 2020, we are likely to see power-tower conversion efficiencies around 30%, compared with about 15% today, and dish/engine conversion efficiencies of about 35%, up from about 25% in current prototypes. At the same time, these technologies will cost less and be more durable. At this stage, they are likely to be fully competitive with other mainstream power technologies in areas with good solar resources throughout the United States and the rest of the world.

7.4 EFFICIENCY IMPROVEMENTS IN GENERATION AND TRANSMISSION & DISTRIBUTION

Lowering the heat rates of fossil-fueled generation results in greater efficiency (i.e., less fuel burned per electricity generated) and lower carbon emissions. OTA (1991, p. 320), for instance, suggests that improved maintenance could reduce heat rates by 5%, resulting in a reduction of 22 million tonnes of carbon emissions by the year 2000. OTA includes this measure in their "moderate" scenario, viewing it as either a low-cost or a no-cost measure. The rate of improvement assumed by OTA is consistent with a power plant performance monitoring and improvement project conducted by the Electric Power Research Institute (1986; 1989). Hirst and Baxter (1997) also note the value of cutting heat rates for fossil-fuel power plants, as a carbon reduction option. No efficiency improvements to existing fossil plants are assumed in the 1997 *Annual Energy Outlook's* reference case (Schouberlein, 1997).

The Southern Company has had extensive experience with improving the efficiency of their electric utility system. Over a thirteen-year period, the Southern Company was able to reduce its heat rate by 5.8%, lowering it from approximately 10,300 Btu/kWh (in 1982) to less than 9,700 Btu/kWh (in 1994) (Southern Company, 1993; Siegel, 1997). This represents an improvement in fossil system efficiency from approximately 33.2% (in 1982) to 34.8% (in 1994). The current level of efficiency in U.S. fossil-fired power plants is approximately 33%. In addition to improving the company's system-wide heat rate, the Southern Company was able to increase its reliability from 88% (in 1982) to 96% (in 1994) (Southern Electric International, 1996), and was able to increase its availability to approximately 86%. The current availability of U.S. fossil-fired power plants is approximately 81%.

These heat rate and availability improvements to the Southern Company's electric system have provided benefits valued at \$1.1 billion/year. One of the largest benefits to the Southern Company has been from the deferral of 6,000 MW of new capacity. The cost of these heat rate and reliability improvements to the Southern Company is estimated at approximately \$325 million/year. The operation and maintenance activities that comprise these costs include: establishing a heat rate improvement training program, creation of a plant heat rate review board and a system heat rate technical network, assignment of an efficiency engineer at each plant, instituting a program of heat rate monitoring, and investing in design upgrades (Siegel, 1997).

The Southern Company's experience is consistent with the OTA and EPRI estimate that a 5% heat rate improvement is technically feasible at a low cost or at no cost. Such an improvement would result in a concomitant reduction of 5% in the carbon emissions of the utility sector. Based on Chapter 6's HE/LC case (Table 6.4), the electricity sector's carbon emissions in 2010 would be 492 MtC. Although coal generation accounts for only 46.2% of the electricity generation forecasted for 2010, coal plants account for 81% (or 400 MtC) of the carbon produced by the electricity sector. A 5% reduction would represent 20 Mt of carbon emissions. Assuming that 35-65% of this total is feasible, a realistic estimate of the potential reduction is 7-13 MtC.

Improving the efficiency of transmission and distribution (T&D) systems is another supply-side option available to utilities. As with generation, T&D improvements can include both capital investments (for example, new transformers and conductors) and improved operations. Because T&D losses account for only about 7% of total generation, the opportunities to reduce CO₂ emissions through such mechanisms are limited. However, they could nonetheless be cost-effective. Improving T&D efficiency by 10% would cut emissions by almost 1% (Hirst and Baxter, 1997).

7.5 NUCLEAR PLANT LIFE EXTENSION

In both the AEO97 reference case and the restructured case described in Chapter 6, nuclear plants are projected to lose market share in the national mix of electricity generation. Similar trends are forecast worldwide, with the forecasted decline in nuclear power in Europe being particularly large (South, et al., 1997).

In the U.S., the nuclear power capacity of 99.2 gigawatts that existed in 1995 is projected to drop to 88.9 gigawatts in both the AEO97 reference case and the restructured case in 2010. This drop is primarily the result of the retirement of 17 plants whose licenses expire between 1999 and 2010. The combined capacity of these 17 plants is 11.5 gigawatts. The average capacity factor of the remaining plants ranges from 76-79% throughout the forecast, deviating little from the current capacity factor of 77%.

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

Nuclear power is a carbon-free source of electricity. Retaining as much as possible of its current power generation would therefore be an important carbon mitigation strategy in an economy where carbon emissions bear a charge of \$50 per tonne, as in the HE/LC scenario.

AEO97 defines a "high nuclear case" which assumes that every nuclear plant operating in 1996 has an additional 10 years of operation, as long as their operating costs do not exceed 4 cents/kWh. This 2010 forecast results in the closure of only three nuclear plants (totaling 1.3 gigawatts of capacity) due to license expirations and the addition of 10.2 gigawatts of new capacity from 14 plant lifetime extensions (EIA, 1996; Nuclear Regulatory Commission, 1996). Thus, nuclear capacity in EIA's forecast for 2010 grows from 88.9 gigawatts (in the reference case) to 99.1 gigawatts (in the "high nuclear case"). Based on a capacity factor of 77%, this 10.2 gigawatts of capacity expansion from nuclear plant life extensions results in 69,000 GWh of additional nuclear energy in 2010, compared to the reference case.

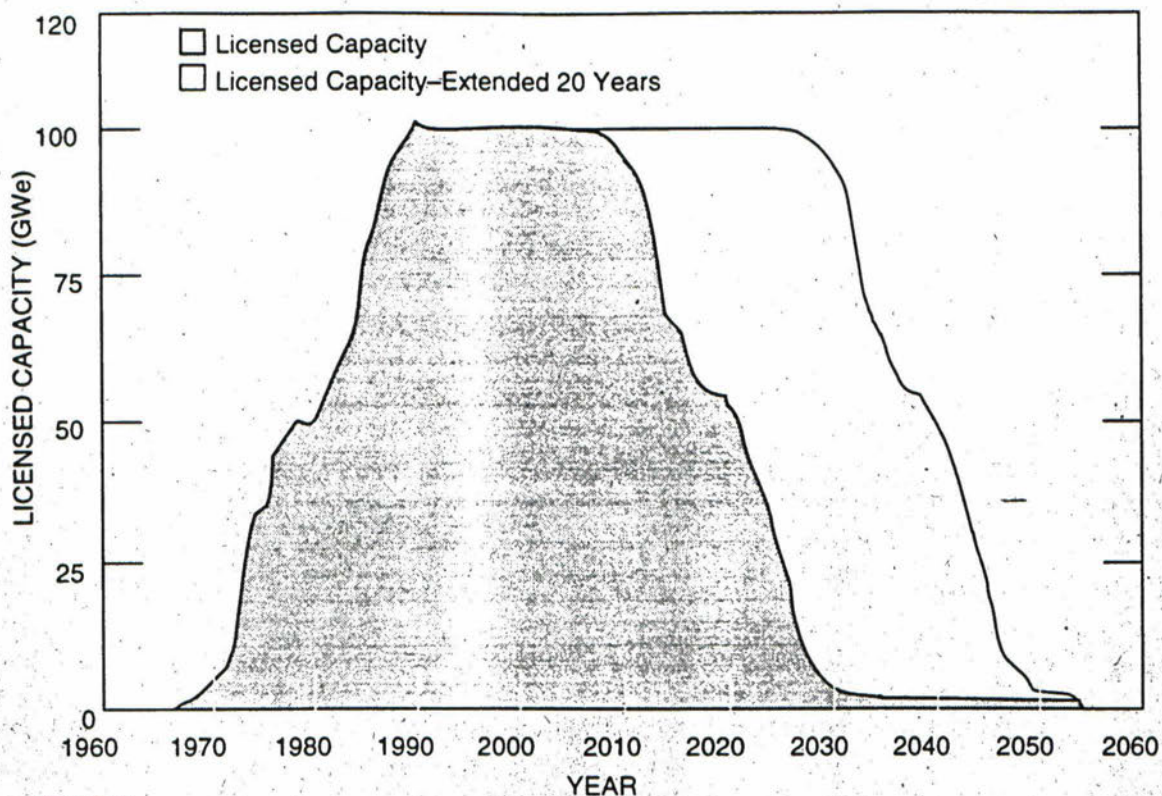
According to EIA's "high nuclear case," 12 Mt of carbon would be offset by this additional carbon-free source of electricity. Using the capacity on the margin in the HE/LC case (with carbon emissions averaging 160 tonnes/GWh), we estimate that the carbon reductions from this additional nuclear resource drop to 11 MtC. A range of 4-7 MtC (from 35-65% of this potential) would appear to be a more realistic forecast for the HE/LC scenario. This range recognizes that it will not be economical or politically feasible to extend the operation of nuclear power plants with licenses that expire by the year 2010.

The AEO97 reference case forecasts that nuclear capacity in the U.S. will decline at an increasing pace after 2010, decreasing from 88.9 gigawatts in 2010 to 62.7 gigawatts in 2015. Thus, with the demand for energy continuing to grow, the impact of nuclear power as a carbon offset declines precipitously over this slightly longer planning horizon. Under the "high nuclear case," the assumed 10-year nuclear plant licensing extensions (subject to the 4 cents/kWh maximum cost) increases nuclear capacity in 2015 from 62.7 gigawatts (in the reference case) to 94.7 gigawatts (in the "high nuclear case"). Thus, the magnitude of carbon offsets offered by this strategy becomes quite significant after 2010.

Figure 7.15 illustrates the accelerated role that nuclear power life extension could have in offsetting carbon emissions after 2010. Only 45 of the nation's 105 nuclear plants have licenses that extend beyond 2020 (Nuclear Regulatory Commission, 1996). An effort to maintain the viability of this capacity could result in a very large contribution to carbon reductions over the next quarter century.

AEO97 does not estimate the cost of its "high nuclear case," although it acknowledges that the physical degradation of some units would have to be reversed. OTA (1991) also notes the potential carbon savings of extending the useful life of all nuclear plants to 45 years, but assumes that this option involves either low costs or saves money. Understanding the effects of aging in order to better manage the aging nuclear infrastructure is an important R&D topic. Pressure vessel embrittlement and the degradation of cables, pumps, and valves can be better managed by advances in materials science and by developing and implementing advanced monitoring technologies. Such technologies are the result of R&D and help maintain the current licensing basis of the nation's nuclear power plants, thereby enabling their operation to extend beyond the initial 40-year licensing period.

Figure 7.15 U.S. Commercial Nuclear Power Reactor Generating Capacity



7.6 ADVANCED COAL TECHNOLOGIES

To test the possible effects on carbon emissions of other advanced fossil-fired electricity generation technologies, we replaced the advanced technologies used by EIA with estimates from DOE's Office of Fossil Energy (see Table 7.6). These estimates changed the construction costs and heat rates for advanced combustion turbines, combined-cycle units, and coal units. ORCED did not select the advanced coal unit with either the EIA or the Fossil Energy estimates of this unit's costs and operating characteristics; in both cases, its initial cost was too high to warrant inclusion in the generation mix. The only significant change to occur was the replacement of the most advanced combustion turbine as specified by EIA with an older combined cycle unit. The net effect of this change on carbon emissions was negligible.

This limited analysis suggests that between now and the year 2010, highly efficient (i.e., a heat rate of about 7000 Btu/kWh) but expensive (i.e., a cost of over \$1000/kW) advanced coal units cannot compete economically with either the generation mix that remains from the 1990s or with gas-fired combined-cycle units.

Table 7.6 Base Case Technologies Compared to Advanced Technologies (costs in 1995\$)

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

7.7 SUMMARY

Table 7.7 summarizes the potential reductions in carbon emissions that could occur as the result of the technology options discussed in this chapter. Each option is intended to reflect roughly the amount that could be achieved under aggressive policies combined with a carbon incentive of approximately \$50/tonne. The total carbon reductions from the options shown in Table 7.7 range from 80 to 117 MtC by the year 2010. Additional carbon reductions may result from landfill gas recovery, photovoltaics, geothermal, and solar thermal resources.

The analysis of renewable energy potential over the next quarter century indicates that with a vigorous and sustained program of research, development, and deployment, renewable energy technologies could be providing a greater and rapidly growing contribution to electricity generation by the year 2020. The potential contributions of carbon sequestration, advanced coal technology, and nuclear power were not explored in this report.

Table 7.7 Carbon Reduction Potential of Selected Electricity Supply Technology Options in the HE/LC Scenario with Carbon Permit Price of \$50/tonne

	High-Efficiency/Low-Carbon Case (MtC)
Converting coal-based power plants to natural gas	44
Cofiring coal with biomass	16-24
Wind	6-20
Hydropower	3-9
Efficiency Improvements	7-13
Extending the life of existing nuclear plants	4-7
Total	80-117

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ENDNOTES

¹ Other approaches include (1) repowering with an advanced coal technology (integrated coal gasification combined cycle (IGCC), or pressurized fluidized bed combustion (PFBC)) or (2) plant performance (efficiency) improvements through various management and technical adjustments. With both of these "other" repowering options, the carbon emissions reduction potential is not as great as with NGCC due to (1) the magnitude of efficiency improvement and (2) the carbon (together with sulfur and nitrogen) content of coal versus natural gas.

² All coal-fired power plants greater than 50 MW, and projected to remain in operation, were considered for NGCC repowering: 22.5 gigawatts (GW) of capacity identified by EIA in AEO97 to be uneconomic were deleted, as were 47.5 GW determined to be unneeded due to end-use energy efficiency improvements (see Section 6). Appendix G-2 discusses the deletion of this capacity from the coal/gas repowering analysis.

³ One million Btu (MBtu) is the equivalent of one thousand cubic feet (MCF) of natural gas. One trillion cubic feet of natural gas is abbreviated as TCF.

⁴ This estimate of gas transmission cost may be high, since it may overestimate the amount of interstate and intrastate pipeline that is needed to serve the repowered capacity. Alternatively, since the costs are averaged over all candidate plants based on gas volume delivered to the repowered site, it may approximate the diseconomies of scale that might arise in expanding compression or building new pipeline to serve only a limited amount of repowered capacity.

⁵ A constant 1995 gas/coal price differential assumes that (1) end-use energy efficiency has an offsetting effect on increased utility gas consumption and/or (2) extraction/production costs for natural gas decline at the same rate as the increase in demand.

⁶ The gas/coal price differential of \$0.72/MBtu represents the 1995 value as reported by EIA in its Annual Energy Outlook (AEO97). It represents a lower bound value, since the differential remains constant over time (and demand), reflecting no price response by the natural gas industry with increasing utility fuel demand. The \$1.18/MBtu reflects the 2010 gas/coal price differential within AEO97. This differential reflects a real natural gas price increase of \$0.40/MBtu (\$2.04/MBtu in 1995 to \$2.44/MBtu in 2010) and a 1.9 TCF increase in utility gas demand.

⁷ "Partial Repowering" is equivalent to the "no additional transmission cost" case.

represents only about half of the total price of electricity. Keeping transmission, distribution, and customer service prices the same, the total price increase would be only 10%.

Because electricity prices are essentially unchanged under the efficiency scenario (changing from only 6.20¢/kWh to 6.22¢/kWh including other components); total electricity costs to consumers decrease by an amount that is proportionate to the reduced electricity demand (i.e., 330 TWh). Thus, the cost reduction is approximately \$20 billion. This value takes into account the savings in transmission, distribution, and customer service costs included in the full retail price of electricity. The high-efficiency/low-carbon case yields slightly lower savings of around \$18 billion. Total energy savings almost double to 630 TWh, but the price increase of 0.65¢/kWh due to the carbon charge cuts into the overall savings.

One way to measure the cost impact of the \$50/tonne of carbon cost is to evaluate the extra cost due to plant operation changes (redispatch, retirements, and new construction). In the high-efficiency/low-carbon case, we construct and operate the plants as optimized with the carbon charge. If we remove the charge, but construct and dispatch plants as in the high-efficiency/low-carbon case, we are no longer operating at minimum cost. The excess above the minimum cost is about \$2.2 billion. Dividing this amount by the tons of carbon saved from the minimum-cost case yields an average cost of \$30 per tonne of carbon saved.

Allocating the carbon savings in the efficiency case between the buildings and industrial sectors, we find that the buildings sector (residential and commercial) saved 19.4 Mt of carbon while the industrial sector saved 9.6 Mt (Table 6.6). The carbon savings for each were proportional to their savings in electricity, since electric generation is determined by the system load.

Table 6.6 Carbon Reductions from Electricity Savings by Sector under the Efficiency and High-Efficiency/Low-Carbon Cases (MtC)

Sector	Efficiency Case	High-Efficiency/Low-Carbon Case
Buildings (Residential)	10.9	49.2
Buildings (Commercial)	8.5	38.3
Industry	9.6	45.0
Total	29.0	132.5

Note: Transport is not included since electricity use in that sector is negligible.

Some of the 133 Mt of carbon that is forecast to be displaced by the high-efficiency/low-carbon case can be attributed to the end-use efficiency improvements in the buildings and industrial sectors. The remaining savings are attributed to the change in electricity generation mix that resulted from the charge of \$50/tonne of carbon. Two methods of allocating the carbon savings between the end-use and supply sectors were examined.

- In the first method, ORCED modeled the high-efficiency/low-carbon case without the \$50/tonne charge in the supply sector. The result was a savings of 56 MtC, attributed to energy efficiency alone. The rest of the carbon savings (77 MtC) is then attributed to the electricity sector.
- In the second method, ORCED modeled the restructure case with the \$50/tonne charge in the supply sector, but without the demand reduction due to efficiency improvements. The result

was a savings of 33 MtC, which is attributed to the electricity sector. The rest of the carbon savings (100 MtC) is attributed to the end-use sectors based on their energy savings.

The results of these alternative allocations (including the distribution of carbon savings across the buildings and industrial sectors) are shown in Table 6.7 and Figure 6.7. The total carbon that is displaced by the lower electricity demand is the same (133 MtC), but the allocation between the end-use and supply sectors varies widely depending on the method used to allocate the savings.

Because the savings involve a synergy between increased energy efficiency and changes to supply dispatching, it is difficult to identify the appropriate allocation of savings for the end-use vs. electricity supply sectors. To simplify matters, we used the average between the two methods described above. Specifically, the following averaging was used:

- The minimum carbon reduction attributed to electricity end-use efficiencies is 56 MtC (Method 1) and the maximum is 100 MtC (Method 2). The average of 78 MtC is therefore assumed for the end-use sector.
- The minimum carbon reduction attributed to the electricity sector is 33 MtC (Method 2) and the maximum is 77 MtC (Method 1). The average of 55 MtC is therefore assumed for the electricity supply sector.

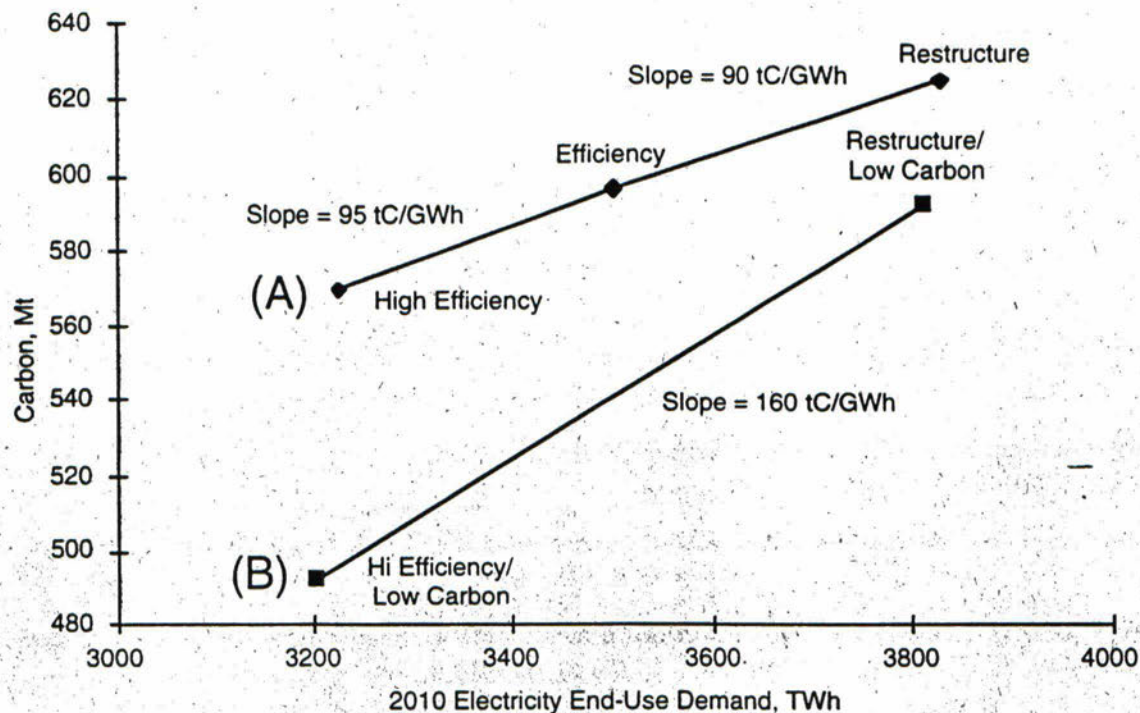
Table 6.7 summarizes this allocation process.

Table 6.7 Allocation of Carbon Reductions from the Electricity Saved by the High-Efficiency/Low-Carbon Case (MtC)

Sector	Method 1: Carbon Reduced by Energy Efficiency First	Method 2: Carbon Reduced by \$50/tC Charge First	Final Allocation by Averaging
Buildings (Residential)	21	37	29
Buildings (Commercial)	16	29	22
Industry	19	34	27
<i>Subtotal</i>	56	100	78
Electricity Sector	77	33	55
Total	133	133	133

Based on the results shown in Figure 6.7, 160 tonnes of carbon are displaced for each GWh of electricity saved in the high-efficiency/low-carbon case with carbon permit price of \$50/tonne, reflecting the introduction of new low-carbon technologies. This is the marginal carbon-to-energy ratio that is therefore used for analyzing the impacts of other carbon management strategies in the electricity sector in Chapter 7. This value is significantly higher than the marginal carbon-to-energy ratio used in the efficiency case (90 tonnes of carbon per GWh of electricity, as also shown in Figure 6.3), for the reasons noted earlier.

Figure 6.7 Carbon Reductions Due to Energy Efficiency and Carbon Management: (A) Without a Carbon Charge and (B) With a Carbon Charge of \$50/Tonne



Note: Slope is equal to marginal carbon savings in tonnes of carbon per gigawatt-hour. In (A), the high-efficiency option represents all the assumptions of the high-efficiency/low-carbon scenario except that there is no charge for carbon.

6.5 SUMMARY

The U.S. electricity industry is undergoing massive change. Because the process is far from complete, it is even more difficult to make estimates about electricity production and use for the year 2010 than it would otherwise be. However, we developed a reasonable and internally consistent picture of electricity demand and supply for the year 2010 on the basis of EIA's AEO97 projection and additional simulations with the Oak Ridge Competitive Electricity Dispatch (ORCED) model.

ORCED was used to simulate the operation of the U.S. electric power supply system in 2010. We first calibrated our input data so that our results closely matched those produced by EIA for its *Annual Energy Outlook 1997*. We then developed a case for 2010 that is intended to reflect the ways in which a fully competitive industry might operate. Compared to the AEO97, these results suggest greater electricity use, lower peak demand, and a generation mix that includes more natural gas and less coal. Thus, although consumption is higher, carbon emissions are lower.

We then simulated the operation of this competitive electricity industry given the efficiency-induced reductions in electricity use in the residential, commercial, and industrial sectors as described in Chapters 3 and 4. The efficiency case reduced electricity demand by 9%, which led to a 5% reduction in carbon emissions. The high-efficiency/low-carbon case reduced electricity use by 16%, which led to a 21% reduction in carbon emissions.

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ENDNOTES

¹ States will continue to oversee power-plant siting and environmental emissions.

² The value of unserved energy is the price that customers would be willing to pay for electricity that is unavailable as a result of demand exceeding supply.

³ The amount of computer time required for a full simulation depends strongly on the number of generators treated probabilistically. We found a reasonable tradeoff between computing time and accuracy when about 10 plants are modeled probabilistically and the other 16 are derated.

⁴ Inclusion or exclusion of the data for cogenerators (which account for about 4% of electricity in the year 2010) is another source of confusion.

⁵ According to AEO97, total generation in 1995 was 3246 billion kWh and sales totaled 3008 billion kWh, implying a loss of 7.3%.

⁶ The 63% multiplier for T&D represents the percentage of T&D costs attributable to capital as opposed to O&M.

⁷ This 88% multiplier is derived from ORCED's estimates of fuel and O&M costs of 1.35¢/kWh for fuel and 0.18 ¢/kWh for O&M. The 88% then is $[=1.35/(1.35+0.18)]$.

Chapter 7

ELECTRICITY SUPPLY TECHNOLOGIES

7.1 INTRODUCTION

The electricity industry has many supply-side options at its disposal to reduce or offset carbon dioxide emissions from electricity production by the year 2010. One of these options, reconfiguring the generation mix to reflect a \$50/tonne charge for carbon, was discussed in Chapter 6. We labeled this option "carbon-ordered dispatching" because it involves the same technologies that were considered in the AEO97 reference case. Electricity was redispatched from the existing generation mix, and the construction and retirement of power plants also changed, but no new technologies were introduced. Chapter 7 considers other electricity supply technology options, including:

- Repowering coal-based power plants with natural gas;
- Implementing renewable electricity technologies;
- Improving efficiency in generation and transmission and distribution (T&D) systems;
- Extending the life of existing nuclear plants; and
- Constructing new power plants using advanced coal technologies.

Each of these options is assessed independently. Because interactions among the options are not taken into account, there is a likely possibility of double-counting with respect to the actual emissions reduction potential.

The viability and costs of these supply options in 2010 are based on the assumption that the electricity grid is transformed by the carbon-ordered dispatching that occurs under the "high-efficiency/low-carbon" (HE/LC) scenario, as described in Chapter 6. Thus, since we assume that considerable decarbonization has already taken place; this chapter addresses the question: What additional supply technology options now make sense in a scenario in which carbon has acquired a value of \$50/tonne? We conclude by discussing the significant contribution that renewable energy technologies can make by the year 2020.

7.2 REPOWERING COAL-BASED POWER PLANTS WITH NATURAL GAS

The conversion of existing coal-fired power plants to operate on natural gas (via repowering) is one option to significantly increase the efficiency of power generation and reduce carbon emissions in the U.S. electric power sector.¹ Natural gas is a less carbon-intensive fuel and its use also reduces emissions of the following criteria air pollutants: sulfur dioxide (SO₂), nitrogen oxide (NO_x), total suspended particulates (TSP), and hazardous air pollutants (HAPs). Our analysis shows that natural gas combined cycle (NGCC) is a cost-effective power generation technology and carbon emission reduction option. Depending upon assumptions regarding the differential in the delivered price between natural gas and coal, the price of carbon permits, and environmental externality values for criteria air pollutants, we found that carbon emissions of up to 238 MtC could be reduced annually through repowering.

7.2.1 Repowering Approaches

The simplest repowering approach is *site repowering*, where the existing power plant site is reused with an entirely new NGCC system. Cost and performance data for the General Electric "H" frame turbine was used; this class of turbine will be the most efficient in the post-2000 period, with the lowest cost per kilowatt of capacity. While site repowering provides the highest cycle efficiency (since none of the existing boiler island equipment is reused), it also requires a greater capital investment (see Appendix G-1).

The more conventional approach is referred to as *steam turbine repowering*. In this case, a new gas turbine and heat recovery steam generator (HRSG) are integrated with the existing steam turbine and auxiliary equipment from the coal plant. Due to age of equipment and the fact that the steam turbine was designed for linkage with a coal-fired boiler, the efficiency of a *repowered* steam turbine plant would be lower than at a *site repowered* plant. The steam turbine repowering option has a higher operating cost (due to the lower efficiency) but a lower capital cost (see Appendix G-1).

The cost-effectiveness (\$/tC) of both repowering options was examined for all coal-fired power plants greater than 50 megawatts (MW).² Included in the cost calculation were the cost of repowering, hook-up, and transmission. We analyzed the site repowering results for the two alternative gas/coal price differentials: \$0.72 and \$1.18 per million Btu (MBtu)³, three price ranges for carbon permits (<\$50/tonne, \$50-100/tonne, and \$101-150/tonne), and three environmental externality values for SO₂ and NO_x (none, low, and high). In addition, a sensitivity analysis was performed to examine the impact on cost-effectiveness if additional natural gas pipeline infrastructure (hook-up and transmission) were not needed to ensure gas deliverability to repowered plants. This sensitivity analysis (referred to as the "no additional transmission cost" case) was conducted only for those power plants that are currently connected to the natural gas pipeline network (i.e., dual-fuel). Appendix G-3 contains a complete description of the methodological steps and key data parameters.

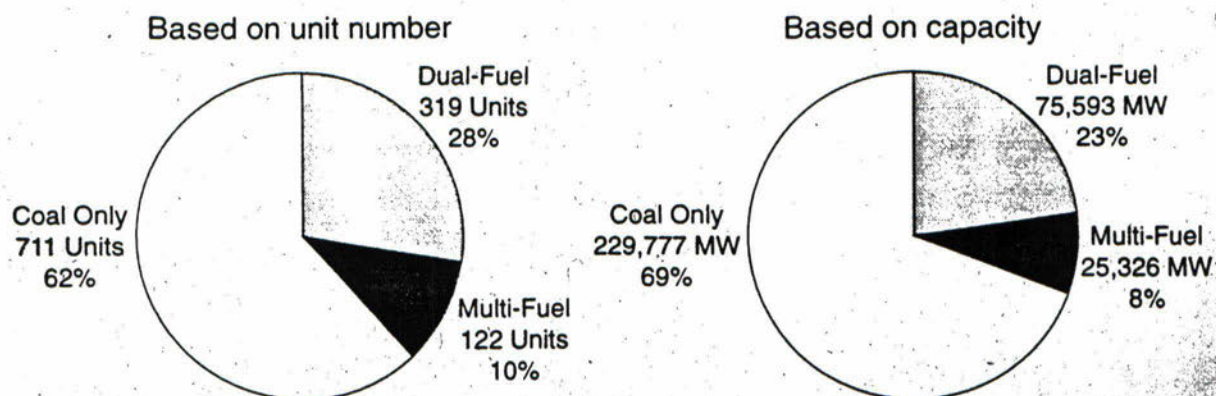
The analytical approach was static in that the cost of repowering was computed for each candidate power plant but the analysis did not optimize unit/plant production cost, dispatch, or system load. Moreover, for the steam repowering case, the largest steam turbine (not each individual steam turbine) at the plant was repowered to generate the equivalent of 1995 plant output (kilowatt-hours, kWh), since this is both more economic and consistent with industry practice than repowering each turbine. Lastly, the gas delivery infrastructure costs (hook-up and transmission) were derived assuming (1) no excess capacity in the current delivery system, and (2) that if such a fuel-switching strategy were implemented, the natural gas pipeline industry would build capacity (even if done incrementally) to meet the total estimated gas requirements of repowering all candidate plants and allocate appropriate delivery costs to each repowered plant. Assumptions regarding gas deliverability are described below in Section 7.2.2.2.

7.2.2 Repowering Issues

In 1995, there was 335 GW of coal-fired capacity at 404 power plants in the United States. Figure 7.1 indicates that this capacity was comprised of:

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

Figure 7.1 Candidate Coal-Fired Power Plants for NGCC Repowering



These categories reflect differences in the investment cost of conversion and deliverability of natural gas (i.e., those plant sites consuming gas in 1995 would have a natural gas pipeline connection, thereby resulting in a lower hookup cost.)

7.2.2.1 Increase in Natural Gas Demand

Utility gas consumption in 1995 was 3.5 trillion cubic feet (TCF). Figures 7.2 and 7.3 show the increases in natural gas demand from this base that would result from either site or steam turbine repowering for each of three cost-effectiveness values: less than \$50/tC, \$50-100/tC, and greater than \$150/tC. The increase in gas demand ranges from 1.0 TCF (<\$50/tC) to 4.9 TCF (\$50-100/tC) in the low gas/coal price differential case without externalities. This quantity of gas for repowered plants represents 29% and 140% increases in 1995 utility gas consumption, respectively.

If all the candidate coal-fired power plants were repowered with NGCC, natural gas demand in the utility sector would increase by 9.0 TCF/yr (site repowering) or 9.4 TCF/yr (steam turbine repowering) to either 12.5 TCF/yr or 12.9 TCF/yr, respectively, an increase of over 250% compared to current consumption levels.

The potential gas price increase resulting from NGCC repowered plants was not analyzed in this study. Only the current and projected gas/coal price differentials expected under AEO97 were included in the cost analysis. However, EIA has prepared a preliminary estimate; they found that an 11 TCF increase in demand would increase natural gas prices by \$3.09/MBtu over 20 years (1995-2015), if coal-fired power plants were converted to natural gas when scheduled for life extension/refurbishment and there was considerable demand-side energy-efficiency investment.

Figure 7.2 Incremental Increase in Gas Consumption Resulting from Coal to Gas Conversion with Constant 1995 Gas/Coal Price Differential (\$0.72/MBtu)

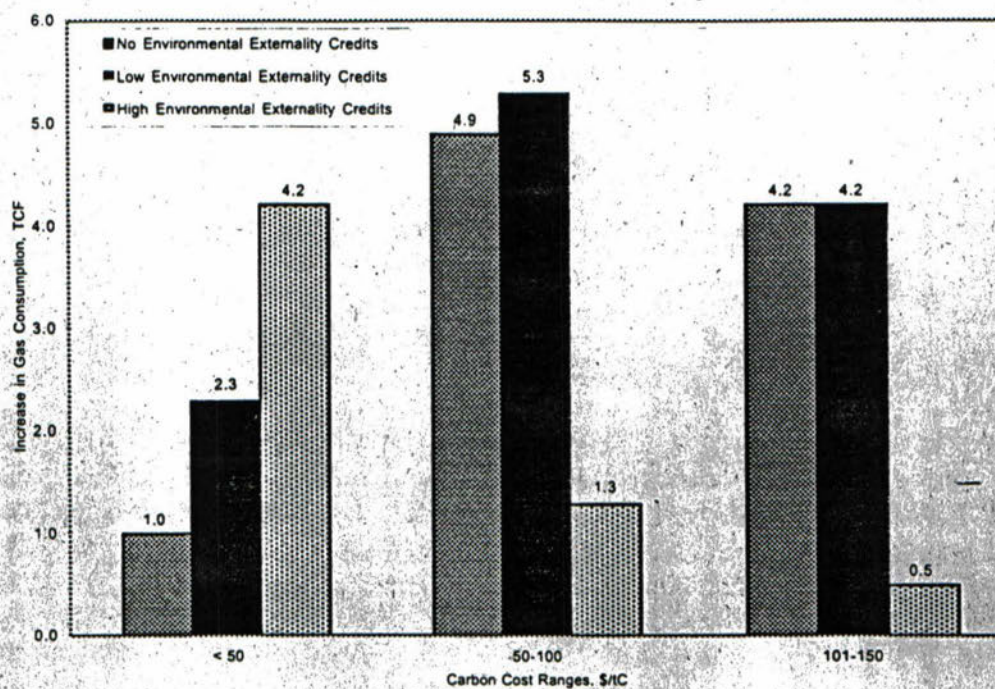
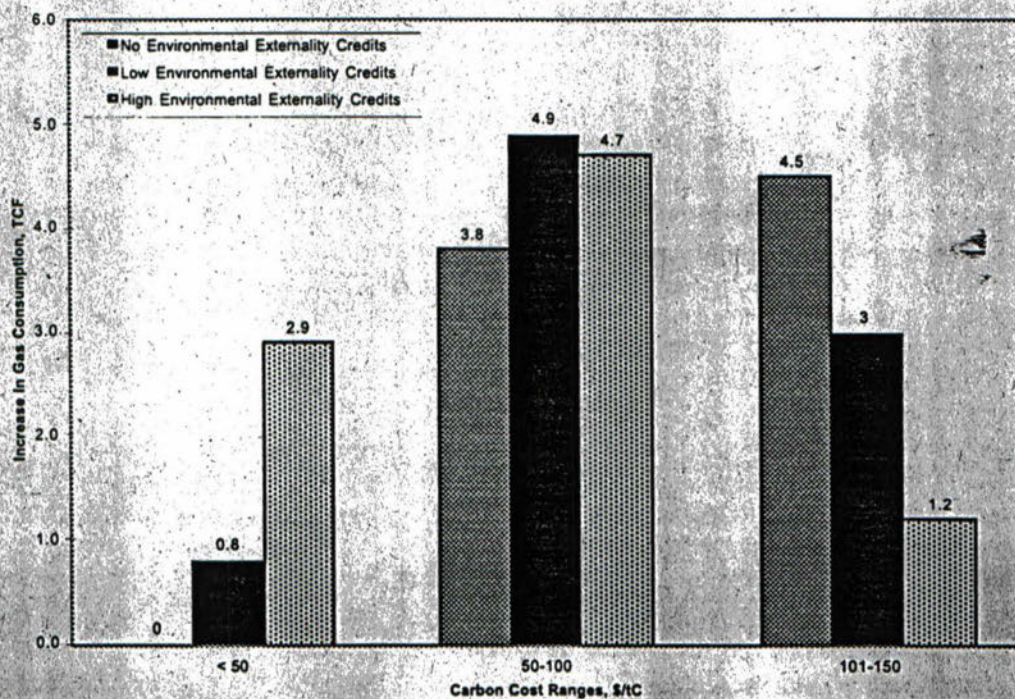


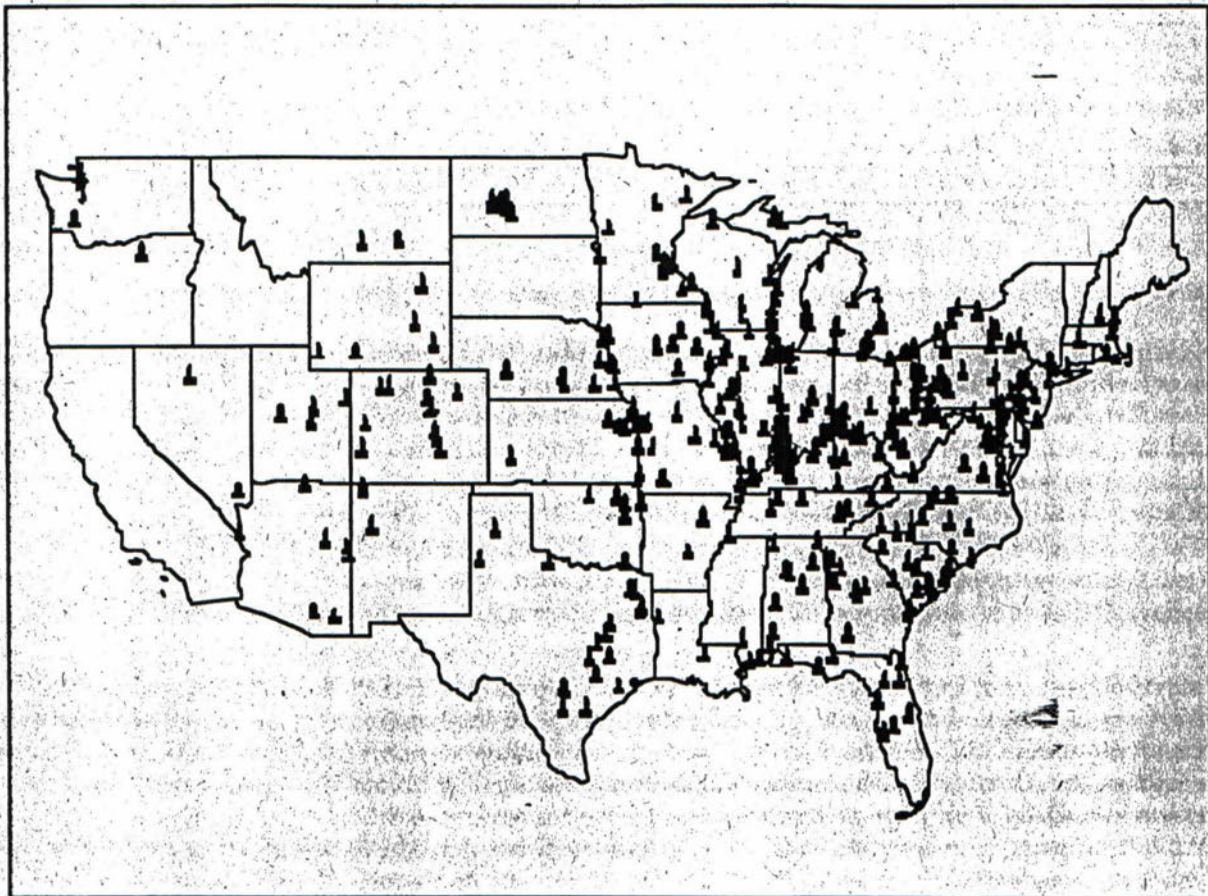
Figure 7.3 Incremental Increase in Gas Consumption Resulting from Coal to Gas Conversion with Constant 2010 Gas/Coal Price Differential (\$1.18/MBtu)



7.2.2.2 Gas Deliverability

The spatial distribution of the initial 404 candidate plants is depicted in Figure 7.4. Some of the candidate plants were not considered for repowering since they were (1) not considered economic by EIA, or (2) determined to be unnecessary due to reductions in demand arising from end-use efficiency improvements.² Most of the plants are located in the Mid-Atlantic, South Atlantic, Midwest, and Plains regions. While these are also primary gas-consuming regions served by major trunk lines, many industry experts believe there is limited unused or underutilized capacity in the current 1.2 million mile pipeline system (transmission – 264,900 miles; distribution – 935,000 miles; field – 62,200 miles). Since this capacity is necessary to accommodate peak winter demand and non-utility growth, it is of little value to power plants considering conversion, since these power plants require firm pipeline commitments.

Figure 7.4 Location of Candidate Plants for Coal/Gas Repowering in the U.S.



Due to the potentially significant increase in utility gas demand that could result from repowering (either site or steam turbine), coal-fired power plants, and the uncertainties regarding when repowering would take place, new pipeline capacity sufficient to serve all candidate plants was developed to ensure deliverability. A detailed assessment was performed (using a geographical information system, GIS) to compute the distance of each candidate power plant to its nearest trunk line. Cost estimates were derived for the cost of upgrading the lines to meet the increased gas demands (see Appendix G-4).⁴ Table 7.1 summarizes the distance of the candidate plants to their closest production zone.

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

Table 7.1 Plant Distance from Production Zone

Range (Miles)	Dual-Fuel		Multi-Fuel		Coal Only		Total	
	# Units	%	# Units	%	# Units	%	# Units	%
60 - 440	48	37	5	12	55	22	108	26
440 - 620	33	25	8	19	64	26	105	25
620 - 890	30	23	15	35	59	24	104	25
890-1,480	19	15	15	35	67	27	101	24
Total	130	100	43	100	245	100	418	100

7.2.3 Emissions Reductions

Based on our analysis, repowering of coal-fired power plants with NGCC is a cost-effective carbon reduction strategy. Tables 7.2-7.4 summarize the site repowering results for the two alternative gas/coal price differentials: \$0.72 and \$1.18 per million Btu (MBtu), three price ranges for carbon permits (<\$50/tonne, \$50-100/tonne, and \$101-150/tonne), and three environmental externality values for SO₂ and NO_x (none, low, and high). The price differential of \$0.72/MBtu represents the 1995 gas/coal price differential held constant, while \$1.18/MBtu is EIA's forecasted price differential for the year 2010.^{5,6} In addition to the "no externalities" case, two alternative market values were used for SO₂ and NO_x: low externalities represent \$0 per ton of SO₂ and \$700 per ton of NO_x; high externalities represent \$100 per ton of SO₂ and \$1400 per ton of NO_x.

As can be seen in Table 7.2, given a carbon permit price of less than \$50/tC and a gas/coal price differential of \$0.72/MBtu, 30 to 119 MtC could be removed via NGCC site repowering, depending upon externality assumptions. When the price differential increases to \$1.18/MBtu, 0 to 83 MtC could be removed from utility emissions. Consequently, we see that a increase of \$0.46/MBtu in the price differential decreases carbon reductions from NGCC repowering by approximately 30 MtC. Although the disaggregated data are not presented, most of the carbon reduction in the <\$50/tC range actually occurs in the \$25-50/tC range.

An ancillary benefit of switching from coal to gas and improving conversion efficiency is reduction in SO₂ and NO_x, two criteria pollutants. At the <\$50/tC level, approximately 50% of the SO₂ and NO_x would be removed (depending on the externality value); at \$50-100/tC and higher almost all the remaining coal-fired SO₂ and NO_x emissions would be eliminated. If all the candidate plants were repowered, almost all of the SO₂ and most of the NO_x would be removed.

The economic value of the SO₂ and NO_x emissions reductions that would result from repowering of the plants was also assessed in this study. Using the methodology described in Appendix G-2, SO₂

was valued from \$0-100/ton; NO_x was valued at from \$700-1400/ton. These values were used as the basis for the environmental externality credits to offset the investment cost of repowering.

Table 7.2 Summary Statistics: Coal to Gas Repowering with a Carbon Permit Price of <\$50/tonne

<i>Constant 1995 Gas/Coal Price Differential (\$0.72/MBtu)</i>					
Externality Cases*	Incremental Carbon Removed (MtC)	Incremental SO ₂ Removed (Mt)	Incremental NO _x Removed (Mt)	Affected GW	Gas Consumed (TCF)**
None	30.3	0.5	0.7	26.8	1.0
Low	66.0	1.2	1.4	63.3	2.3
High	118.6	4.0	2.6	122.6	4.2
<i>Gas/Coal Price Differential in 2010 (\$1.18/MBtu)</i>					
Externality Cases*	Incremental Carbon Removed (MtC)	Incremental SO ₂ Removed (Mt)	Incremental NO _x Removed (Mt)	Affected GW	Gas Consumed (TCF)**
None	0	0	0	0	0
Low	23.6	0.3	0.6	20.2	0.8
High	83.4	2.5	1.9	83.3	2.9

* Two alternative market values were used for SO₂ and NO_x: low externalities represent \$0 per ton of SO₂ and \$700 per ton of NO_x; high externalities represent \$100 per ton of SO₂ and \$1400 per ton of NO_x.

**TCF = trillion cubic feet

Table 7.3 Summary Statistics: Coal to Gas Repowering with a Carbon Permit Price of \$50-100/tonne

<i>Constant 1995 Gas/Coal Price Differential (\$0.72/MBtu)</i>					
Externality Cases*	Incremental Carbon Removed (MtC)	Incremental SO ₂ Removed (Mt)	Incremental NO _x Removed (Mt)	Affected GW	Gas Consumed (TCF)**
None	134.6	4.9	2.7	147.3	4.9
Low	140.4	6.7	2.8	165.6	5.3
High	106.7	5.0	1.8	130.8	4.2
<i>Gas/Coal Price Differential in 2010 (\$1.18/MBtu)</i>					
Externality Cases*	Incremental Carbon Removed (MtC)	Incremental SO ₂ Removed (Mt)	Incremental NO _x Removed (Mt)	Affected GW	Gas Consumed (TCF)**
None	109.6	2.5	2.2	108.9	3.8
Low	134.1	5.0	2.7	146.4	4.9
High	123.9	5.5	2.3	147.6	4.7

* Two alternative market values were used for SO₂ and NO_x: low externalities represent \$0 per ton of SO₂ and \$700 per ton of NO_x; high externalities represent \$100 per ton of SO₂ and \$1400 per ton of NO_x.

**TCF = trillion cubic feet

Table 7.4 Summary Statistics: Coal to Gas Repowering with a Carbon Permit Price of \$101-150/tonne

Externality Cases*	Constant 1995 Gas/Coal Price Differential (\$0.72/MBtu)				
	Incremental Carbon Removed (MtC)	Incremental SO ₂ Removed (Mt)	Incremental NO _x Removed (Mt)	Affected GW	Gas Consumed (TCF)**
None	69.4	4.0	1.2	93.9	2.8
Low	31.0	1.6	0.5	43.8	1.3
High	13.1	0.6	0.2	20.9	0.5
Externality Cases*	Gas/Coal Price Differential in 2010 (\$1.18/MBtu)				
	Incremental Carbon Removed (MtC)	Incremental SO ₂ Removed (Mt)	Incremental NO _x Removed (Mt)	Affected GW	Gas Consumed (TCF)**
None	117.2	6.6	2.3	148.4	4.5
Low	75.1	4.0	1.2	98.6	3.0
High	29.8	1.5	0.4	41.4	1.2

* Two alternative market values were used for SO₂ and NO_x: low externalities represent \$0 per ton of SO₂ and \$700 per ton of NO_x; high externalities represent \$100 per ton of SO₂ and \$1400 per ton of NO_x.

**TCF = trillion cubic feet

7.2.4 Cost-Effectiveness

Figure 7.5 portrays the cost-effectiveness of site repowering with NGCC and the corresponding cumulative carbon removed for the two alternative gas/coal price differentials when no environmental externalities are considered. With a price differential of \$0.72/MBtu, approximately 30 MtC can be removed for <\$50/tC, an additional 135 MtC can be removed for \$51-100/tC, and an additional 77 MtC can be removed for >\$100/tC. When the price differential increases to \$1.18/MBtu, 0 MtC of carbon are removed at <\$50/tC, 110 MtC are removed at \$51-100/tC, and an additional 132 MtC are removed at >\$100/tC.

Figures 7.6 and 7.7 depict the effect of environmental externality credits for SO₂ and NO_x on carbon cost-effectiveness. As mentioned above, in addition to the "no externalities" case, two alternative market values were used for SO₂ and NO_x: low externalities represent \$0 per ton of SO₂ and \$700 per ton of NO_x; high externalities represent \$100 per ton of SO₂ and \$1400 per ton of NO_x. The rationale for these values is explained in Appendix G-3. Both Figures 7.6 and 7.7 (together with Tables 7.2 - 7.4) illustrate that the effect of the environmental externality credit is to shift the carbon cost curve downward and to the right causing more capacity (GW) and carbon removal (MtC) to occur at lower carbon permit price levels.

Because dual-fuel plants are already receiving natural gas (although at lower volumes than a repowered plant), a sensitivity analysis was conducted wherein no hook-up or transmission costs were incurred to deliver an increased quantity of natural gas to these repowered plant sites. This "no additional transmission cost case" is illustrated in Figures 7.8 and 7.9, which depict the two alternative gas/coal price differentials and include externality credits for site and steam turbine repowering. Since transportation costs comprise approximately 30% of the total investment cost, the carbon cost curves shift downward considerably when these costs are removed. In Figure 7.8, approximately 45 GW of coal-fired capacity can be repowered at <\$50/tC, removing 42 MtC of carbon, 1.2 Mt of SO₂ and 0.9 Mt of NO_x. The amount of natural gas required by these repowered plants is 1.5 thousand cubic feet; approximately 50% of 1995 utility consumption.

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

- Potential increase in gas prices from NGCC repowering,
- Actual cost of repowering the candidate coal-fired power plants,
- Excess transmission capacity, and/or economies of scale in delivering the required gas,
- Capacity utilization of the converted plants,
- Costs associated with breaking long-term coal contracts, and
- Other socioeconomic factors (e.g., differential state/federal tax effects, displaced coal miners).

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

Figure 7.5 Carbon Curve for Coal/Gas Site Repowering: No Environmental Externality Credits

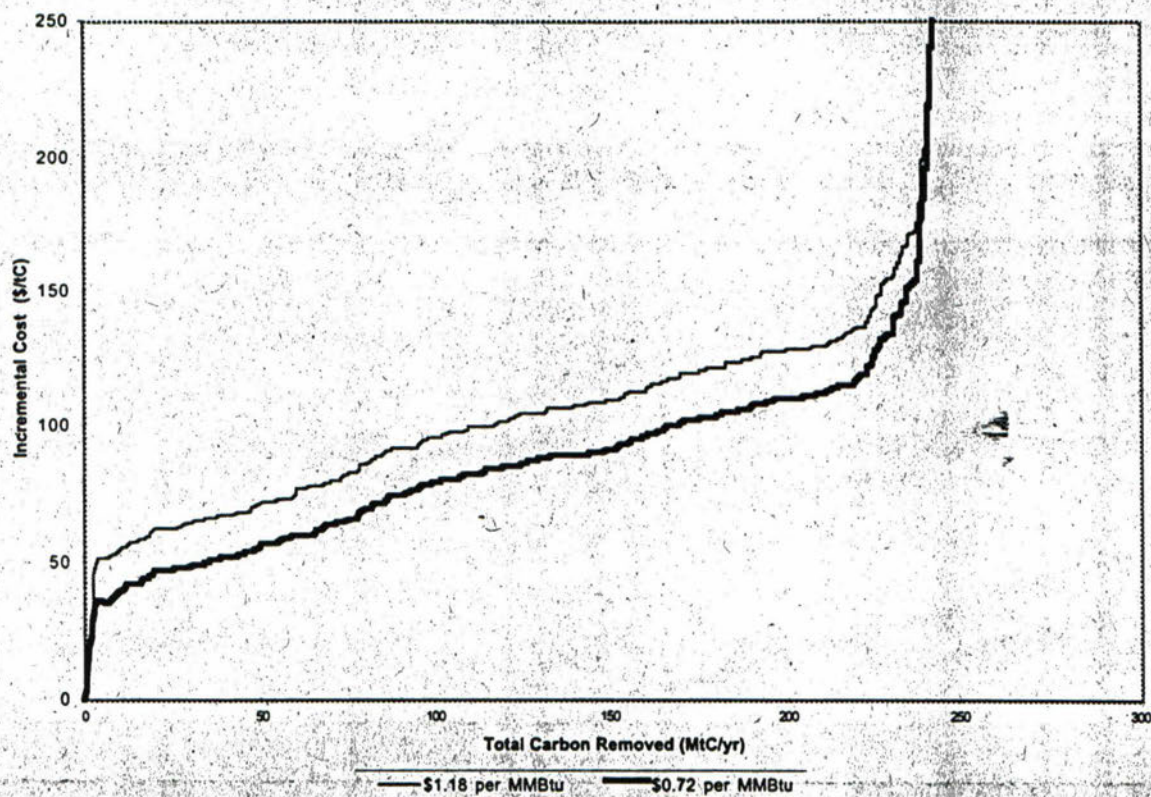


Figure 7.6 Carbon Curve for Coal to Gas Site Repowering: Effect of Environmental Externality Credits on Cost of Carbon Removal with Constant 1995 Gas/Coal Price Differential (\$0.72/MBtu)

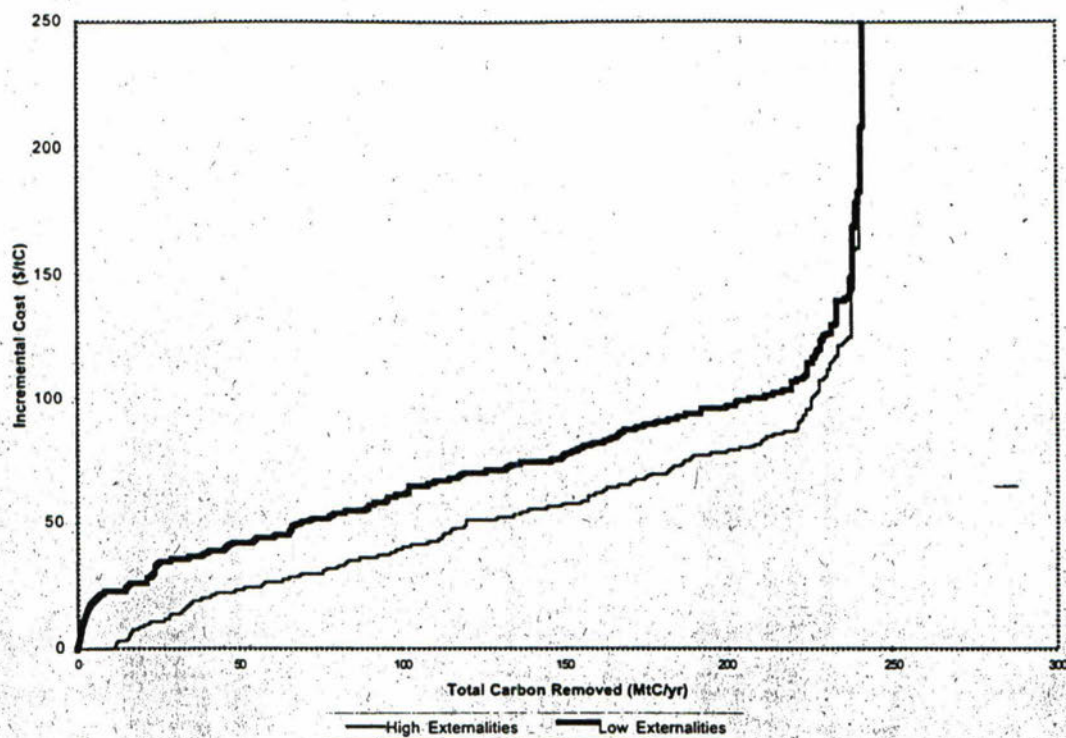


Figure 7.7 Carbon Curve for Coal to Gas Site Repowering: Effect of Environmental Externality Credits on Cost of Carbon Removal with Gas/Coal Price Differential in 2010 (\$1.18 MBtu)

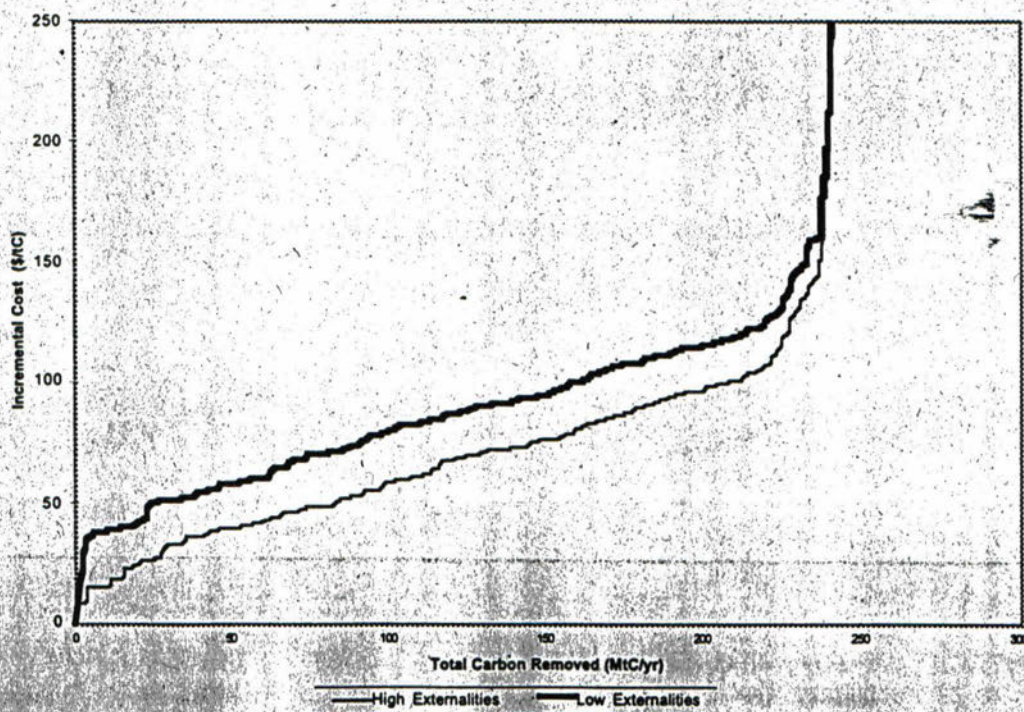


Figure 7.8 Carbon Curve for Partial Repowering⁷: Constant 1995 Gas/Coal Price Differential (\$0.72 MBtu) Low Environmental Externality Credits

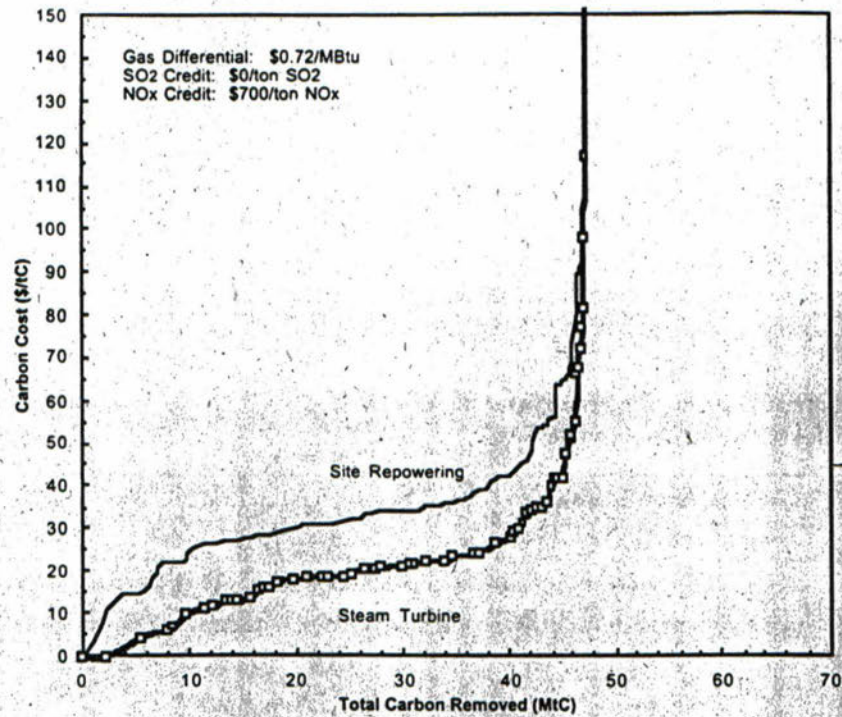
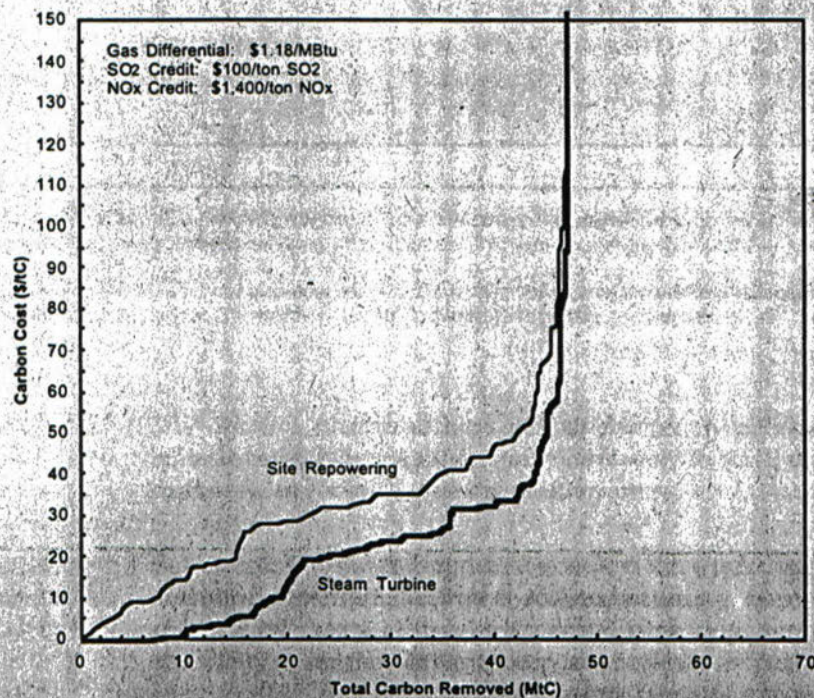


Figure 7.9 Carbon Curve for Partial Repowering⁷: Constant 2010 Gas/Coal Price Differential (\$1.18 MBtu) High Environmental Externality Credits



7.3 RENEWABLE ELECTRICITY TECHNOLOGIES

Over the long term, renewable energy technologies are likely to play a crucial role in limiting carbon emissions and global warming. While aggressive energy efficiency and fuel switching can reduce domestic carbon emissions to approximately 1990 levels by 2010, controlling or reducing carbon emissions beyond that date will require greater energy contributions from low-carbon technologies such as renewables. In other words, renewables will play an essential role in helping the United States to cut carbon emissions in the years beyond 2010.

Renewables will also make important contributions to both domestic and international carbon emission controls by 2010. Renewable technology contributions to domestic electricity and carbon savings in 2010 under the HE/LC scenario are summarized in Table 7.5.

Table 7.5 Additions to Generating Capacity Electricity and Carbon Emission Reductions from Renewables for the HE/LC Case in 2010

Renewable Technology	Capacity Additions (GW)	Electricity (TWh)	Carbon Emission Reduction (MtC) ^a
Included in Scenario:			
Biomass Cofiring	8-12	58-88	16-24
Wind	8-23	28-81	6-20
Hydropower	10-16	23-35	3-5
Subtotal			25-49
Excluded from Scenario:			
Landfill Gas ^b	3-7	20-50	25-53
PV	3-5	6-10	1-2
Geothermal	6-14	47-110	6-16
Solar Thermal	0-2	0-6	0-1
Subtotal			32-72
Total	38-79	182-380	57-121

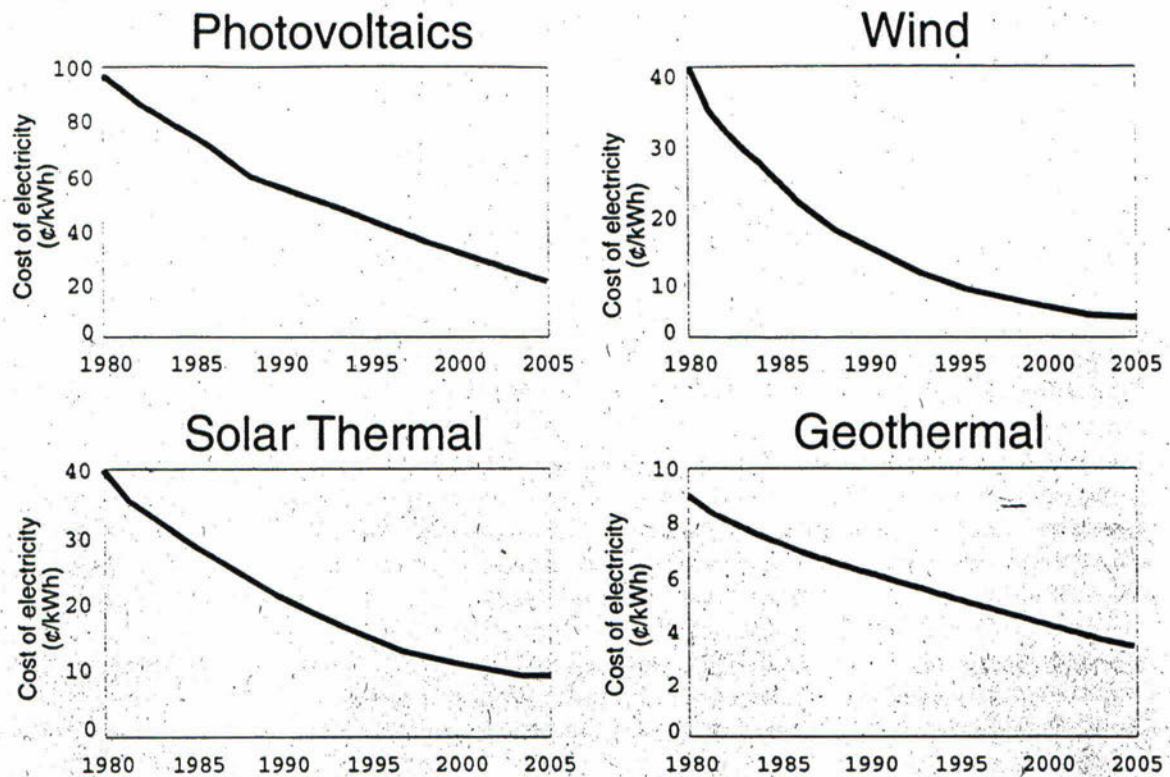
^a These carbon emissions reductions represent the difference between the high-efficiency/low-carbon case and the business-as-usual forecast for 2010.

^b The carbon emission reduction in this case represents the equivalent derived from the prevention of the methane release coupled with its radiation-trapping properties.

This section examines the potential for renewable electricity technologies to reduce U.S. carbon emissions. The contributions of renewables in various end-use sectors, such as transportation, are discussed in other chapters in this report.

Renewables are in the midst of a major, long-term transition, from being "advanced technologies" with only a peripheral market role to becoming mainstream "technologies of choice" in the energy marketplace early in the next century. One clear marker of this transition is the changing cost of electricity from renewable power technologies. Figure 7.10 displays these costs for the period from 1980 to 2005, based on both historical data and recent projections (Office of Utility Technologies, 1997).

Figure 7.10 Historical and Projected Costs of Electricity from Four Renewable Power Technologies



The pace and timing of this transition is difficult to project, however, because it is strongly dependent on such variables as the progress made through research and development, the evolution of energy economy policies, and the magnitude and impact of consumer interest in "green" energy. For example, under the \$50/MtC cost-of-carbon scenario assumed in this study, the adoption of wind power in the United States is likely to increase rapidly on an economic basis. In addition, increasing attention is being focused on consumer interest in green energy. As the electric utility sector moves toward competitive markets, consumers probably will have the option of purchasing power that is environmentally cleaner.

The rate of change will impact the role of renewables in 2010 at least as much as the specific energy contribution of renewables in that year. Therefore, this section discusses the trends as well as the predicted contributions of renewables to the energy supply and to carbon emission reductions in 2010.

A thorough analysis of the role of renewables in 2010, which captures the complexity of their transition, has not been conducted as a part of this study. Instead, this section presents analyses of a few renewable technologies whose role is likely to be quite significant by 2010, and includes a general discussion of the other renewable technologies. A more thorough analysis of the relationship between renewables and reductions in carbon emissions over a longer time frame is the subject of a future study.

Thus, this section discusses the role of renewables in two time frames: (1) developments and contributions by 2010, and (2) the long-term outlook.