Marginal Price Assumptions For Estimating Customer Benefits of Air Conditioner Efficiency Standards:

Comments on the Department of Energy's Proposed Rules for Central Air Conditioners and Heat Pump Energy Conservation Standards Docket Number-EE-RM-500

Prepared for
Appliance Standards Awareness Project

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1. Executive Summary

Marginal electricity prices are one of the most important inputs to DOE's cost-benefit analyses of central air conditioner efficiency standards. These prices determine the amount of direct benefits that households will enjoy from the standards. However, the methodology used by DOE to estimate marginal electricity prices is fundamentally flawed because it relies upon electricity prices that are based on average costs, not marginal costs. Furthermore, it does not account for the fact that air conditioners consume electricity at times when marginal costs are highest.

During the study period of the DOE analysis (2006-2030) US electricity markets will be competitive, and electricity prices will be set on the basis of marginal costs. AEO 2000 assumes that a significant portion of the US electricity market will be competitive by 2008, and that competitive markets will set electricity prices on the basis of marginal costs. DOE's economic analysis of air conditioner efficiency standards should use consistent assumptions.

DOE concludes that marginal prices will be slightly *lower* than average annual prices, by 2.4 $/MWh. However, today's electricity markets suggest that marginal prices during peak periods will be significantly *higher* than average annual prices. We have compiled actual hourly generation prices for those regions of the country that already have competitive wholesale electricity markets (California, New England, New York, and PJM). These prices indicate that during peak summer periods marginal prices tend to exceed average prices by roughly 23 $/MWh on average. Hourly data from regions of the country that are still regulated lead to similar results: during peak summer periods marginal prices tend to exceed average prices by roughly 29 $/MWh on average. On the warmest days of the year, when air conditioners are almost certain to be operating, the differentials are much higher.

In order to determine marginal prices for air conditioner customers, it is necessary to include prices for only those hours during the year when air conditioners operate. We provide an estimate of marginal prices for those hours. We use information on typical air conditioner consumption patterns to determine the hours that air conditioners are likely to operate, for each census region. We then apply the actual hourly generation prices from recent years to these air conditioner hours. Our analysis shows that marginal prices for air conditioner customers tend to exceed average prices by roughly 92 $/MWh on average in currently competitive wholesale electric markets, and by roughly 38 $/MWh on average in currently regulated markets.

If these more realistic marginal prices are used, then higher efficiency standards are more cost-effective than indicated in the DOE's Technical Support Document. Leaving all other DOE assumptions from the NOPR intact (most notably, product costs based on ARI estimates), but assuming marginal prices based on air conditioner periods, the SEER 13 standards result in LCC savings of $297 (roughly six percent) for split air conditioners, and $152 (roughly three percent) for packaged air conditioners.

We also run some scenarios with modified costs of air conditioning equipment, where we assume (a) reverse engineering cost estimates, (b) annual productivity improvements of

0.84 percent per year, and (c) emerging technology cost reductions. Under these assumptions the LCC savings are even more pronounced. The SEER 13 standards result in LCC savings of $402 (roughly eight percent) for split air conditioners, and $299 (roughly five percent) for packaged air conditioners.

Finally, we apply these marginal price and equipment cost assumptions to the national energy savings analysis. We find that the SEER 13 standard results in the lowest total equipment and operating costs, and results in net present value savings of roughly $11.7 billion nation-wide.

We recommend that the DOE employ improved methodologies for estimating the marginal costs for air conditioner customers. The DOE should explicitly recognize that a significant portion of the US electricity market has already become competitive, and that most, if not all, of the rest of the country's electricity markets will be competitive by the early years of the study period. Marginal electricity prices should therefore be based on marginal costs, and not on historic electricity rates. Finally, marginal prices for air conditioner customers should be based on those hours that air conditioners are expected to operate, which tend to be the most expensive hours for purchasing electricity.

2. Historic Retail Rates Are Not A Good Indication Of Marginal Prices

2.1 The DOE Methodology

The DOE's life-cycle cost (LCC) and national energy savings (NES) analyses rely upon marginal electricity rates to assess the economic impacts of air conditioner efficiency standards. Marginal electricity rates are multiplied by the estimated electricity savings to determine the extent to which customer electric bills will be reduced by the efficiency standards. These customer bill reductions are the primary economic benefit of the efficiency standards, and hence it is absolutely essential that the marginal electricity price assumptions present an accurate portrayal of prices that customers will experience over the study period of 2006 through 2030.

The DOE uses historical electricity rates experienced by residential and commercial customers to estimate marginal rates. The 1997 Residential Energy Conservation Survey (RECS) was used to obtain residential prices for a variety of different customers in all regions of the US. Marginal rates were estimated by taking the slope of the regression lines that relate customer bills and monthly customer consumption levels. For each customer included in the analysis, a single marginal rate was estimated for four summer months (June through September) and another marginal rate was estimated for the remaining eight non-summer months. Annual marginal rates were determined by taking a weighted average of these summer and non-summer rates, using seasonal weighting factors.

The DOE finds that on average US residential marginal electricity rates are three percent lower than annual average rates. The historic average and marginal electricity rates were then trended forward to estimate the prices that customers will face during the study period. The trend in electricity prices from the AEO 2000 Reference Case was used to bring the average and marginal prices forward in time.

2.2 Historic Retail Electricity Rates Are Not Based On Marginal Costs

The DOE's methodology for determining marginal rates is fundamentally flawed because electricity prices that customers experienced in 1997 are not a good indication of marginal prices that will be experienced by customers in the future. Retail electricity rates in 1997 were set by state public utility commissions (PUCs), using rate design principles that apply to a fully regulated electricity industry. These rate design principles will not apply to the generation prices that will be determined by future competitive electricity markets.

PUCs use many different types of rate designs to achieve many different objectives. However, it is rare that PUCs explicitly design electricity rates to reflect marginal costs. According to a comprehensive survey conducted by the National Association of Regulatory Utility Commissioners (NARUC), only eight of the fifty state PUCs used marginal costs in establishing rate designs in 1995 and 1996. (NARUC 1997) Instead, rates were usually set in order to allow regulated utilities to recover average (i.e., “embedded”) costs. Average costs can be significantly different from marginal costs.

Furthermore, various rate design options used by state PUCs in the past make it very difficult to "back out" marginal prices using DOE’s methodology. The DOE acknowledges this point in the Draft Marginal Energy Prices Report, where it explains that 84 percent of the 104 utilities surveyed had rates that were not flat or had a mix of rate schedules. Roughly half of these rate schedules had inclining block rates (where rates increase with greater amounts of consumption), while half had declining block rates. (DOE 1999) Declining block rates are a rate feature that utilities offer to some customers with high load factors in order to encourage increased baseload electricity consumption.[1] They are not indicative of marginal costs that air conditioner customers are likely to be exposed to in the future. On the contrary, air conditioning customers purchase electricity at the most expensive seasons of the year and hours of the day, and therefore are more likely to be charged higher marginal prices with increased usage, not lower. Consequently, roughly half of the rate schedules used by DOE to determine marginal prices are certain to be incorrect with regard to future marginal prices for air conditioning customers.

Some utilities offer seasonal rates to customers, which might provide a rough indication of the higher costs experienced during the summer months. However, even these rates are unlikely to capture the actual difference between average electricity prices and marginal prices that will be applied to air conditioner customers. Seasonal rates do not

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[1] Load factor is representation of a customer's peak demand versus baseload demand in percentage terms. It is calculated by dividing the customer's annual energy consumption by the product of his peak demand times all of the hours in the year. A high load factor means that the customer consumes a lot of baseload energy relative to his peak demand, and vice versa. Large industrial customers tend to have high load factors, while residential customers – especially those with air conditioning – tend to have low load factors.

reflect the hourly marginal prices, which can become significantly higher during peak hours. Seasonal rates tend to be an average of prices experienced throughout a season, and therefore mask the seasonal and daily price spikes that can occur during peak periods. Air conditioning customers will purchase electricity during peak summer hours, and hence will be exposed to marginal prices that are significantly above those implied by seasonal rates.

2.3 In Competitive Markets Electricity Prices Will Reflect Marginal Costs

Economic Theory And Competitive Electricity Markets

It is generally accepted economic theory that in competitive markets prices will tend to be based on marginal costs, not on average costs. As US electricity markets become increasingly competitive, customers will increasingly see prices based on marginal costs. DOE acknowledges this point in AEO 2000. In fact, the Reference Case forecast in AEO 2000 assumes that in those regions of the country with competitive electricity markets, the generation price will be set by the marginal cost of generation. (DOE 12/1999, page 66) Other DOE documents related to electricity industry restructuring also point out that as electricity markets become more competitive the generation prices will be based on marginal costs. (DOE 5/1999, DOE 1997)

In the electricity industry there are two factors that will determine the extent to which customers will be charged prices based on marginal costs. First, there is the question of which regions of the country will experience competitive electricity markets and when. The Reference Case forecast in AEO 2000 assumes that five regions of the country – California, New York, New England, Texas and the Mid-Atlantic region (including Pennsylvania, Delaware, New Jersey and Maryland) – will transition to fully competitive electricity markets by 2008. Furthermore, the AEO 2000 Reference Case forecast assumes that the Rocky Mountain Power Area/Arizona, the Mid-America Interconnected Network, and the East Central Area Reliability Council will be "partially competitive," because some of the states in those regions have begun to introduce competition. These fully and partially competitive regions of the country represent roughly 46 percent of all electricity generation in the US – suggesting that a large portion of the US electricity market will soon be subject to prices based on marginal costs.

Furthermore, the AEO 2000 is likely to understate the extent to which electricity markets become competitive during the 2006 through 2030 study period. It only includes those markets that have already begun introducing competition – it does not include those states and regions that will introduce electricity competition in the future. Even if full restructuring is delayed until 2015 in some states, the majority of the study period (2006-2030) will still be subject to market prices both because of full restructuring in the out years and partial restructuring in the early years.

AEO 2000 does include some sensitivity analyses (the Competitive Pricing Cases) that assume that all US electricity markets become competitive over the ten years from 1999 to 2008. These sensitivities are likely to be a more accurate representation of the US electricity markets in the future. (These sensitivities are discussed in more detail in Section 4.2 below.)

Time-Of-Use Rates At The Retail Level

The second factor that will determine the extent to which customers will be charged prices based on marginal cost is the extent to which generation companies will provide power to customers on the basis of real-time prices. Again, it is generally accepted economic theory that in a competitive electricity market generation companies are going to offer customers real-time prices in order to (a) be able to charge customers on the basis of costs incurred for those customers, and (b) provide price signals for customers to curtail load during the most expensive hours.

Many state regulators and generation suppliers are currently promoting time-of-use pricing mechanisms, not just for large customers but for residential customers as well. For example, Illinois regulations require that all electric utilities have real-time pricing tariffs in place by October 1, 2000. In addition, there is significant pressure for advanced metering technologies and competitive provision of metering services, both of which are important precursors and facilitators of time-of-use pricing schemes. For example, California requires that all customers have competitive and advanced metering, although the initial focus is on large customers. New York regulators already require advanced metering for all customers over 50 kW, and are investigating options for smaller customers. Other states, including Massachusetts, New Hampshire, Texas, Nevada, Arizona, Maine, and parts of Pennsylvania, already have or are investigating competitive metering requirements. These regulatory trends and competitive pressures are discussed in more detail in Appendix A.

Some utilities have offered time-of-use rates to some of their customers in the past. In some cases, utilities have found that residential customers are unwilling to significantly alter their electricity consumption patterns in response to time-of-use rates. At the Public Hearing on air conditioner standards on November 16, it was argued that this lack of success with time-of-use rates suggests that they will not be offered to residential customers in the future under competitive electricity markets.

However, the lack of success of historic time-of-use programs does not mean that time-of-use rates will not be offered to customers in the future. In the past, the primary motivation for time-of-use rates was from PUCs and utilities as a means of reducing peak demand and costs. In the future, the primary motivation will be from competitive suppliers who will need to charge customers on the basis of the marginal costs that they incur. Real-time pricing will be an essential pricing mechanism to reduce suppliers' exposure to the risks associated with high marginal costs during peak periods. There already is, and will continue to be, significant pressure from suppliers to provide electricity rates that reflect real-time costs. Even if customers do not respond to the time-of-use rates in the future, generation suppliers will still need to keep them in place in order to accurately recover their costs, and customers will still be faced with actual marginal prices.

Load Response Mechanisms At The Wholesale Level

Similarly, there is increasing pressure from FERC and Independent System Operators to implement mechanisms to allow Load Serving Entities and customers to respond to wholesale price signals. Load response programs in the wholesale electricity markets will provide the information, infrastructure and economic pressure to use time-of-use rates for retail electricity customers.

The current load response programs are primarily reliability tools designed to assist in meeting the electrical demand of customers in capacity constrained situations. They are expected to become increasingly adopted as an essential aspect of a fully competitive market, because they allow customers to respond appropriately to price signals (i.e., they allow for a declining demand curve, instead of one that is a vertical line). ISO New England, PJM, and CA ISO are all developing load response programs, as are some companies such as Portland General Electric. These developments in promoting load response programs are discussed in more detail in Appendix A.

It is important to note that retail competition in the electricity market is not a necessary precondition for time-differentiated pricing options at the retail level. Time-of-use pricing can also be a useful tool for integrated utilities not subject to retail competition, particularly as they start to play in competitive wholesale markets. As price volatility and price differentials increase in competitive wholesale markets, integrated utilities may seek to reduce customer load at peak pricing times in order to be able to free up energy to sell into spot markets. PUC's may begin to encourage and require such practices in order to make sure that the utilities are maximizing the value of their generation assets.

2.4 Air Conditioner Customers Purchase Electricity When Marginal Costs Are Highest

When assessing marginal costs, it is always important to recognize the difference between short-term and long-term marginal costs. In the electricity industry, long-term marginal costs include those necessary to provide new generation capacity to meet incremental demand. In this context, long-term usually refers to a period of three years or more – the time necessary to build a new power plant.

Short-term marginal costs in the electricity industry generally include those necessary to provide electricity during any given hour. In competitive wholesale electricity markets, hourly costs vary widely throughout a day, a week, a season and a year. This degree of variability is partly due to the fuel, operations and maintenance (O&M) costs of the marginal generation unit, and partly due to the fact that in some hours the wholesale cost includes the costs associated with generation capacity. Therefore, in off-peak hours the hourly (i.e., short-term marginal) costs can be quite low, while in peak hours the hourly costs can be quite high.

In considering marginal prices for air conditioning customers, it is essential to consider the hours during which the air conditioners will operate. Residential air conditioners tend to operate during the hottest days of the year and the hottest hours of the day. Electricity demand, and therefore electricity costs, tend to be at their highest levels during these hot days and hours. Consequently, the marginal costs of electricity will be highest during the hours when air conditioners are most likely to operate.

3. Today's Generation Prices Indicate That Marginal Prices For Air Conditioning Will Significantly Exceed Average Prices

3.1 Defining The Period For Calculating Marginal Prices

The wholesale generation prices experienced in the US electricity industry in recent years indicate that the DOE's marginal price assumptions substantially understate the true marginal costs of providing electricity to air conditioning customers. In competitive wholesale electricity markets, generation prices have soared well above average prices during times of peak demand, and indicate that competitive electricity prices can be extremely volatile. Even in those electricity markets that are still regulated, recent experience indicates that marginal prices exceed average prices by substantial amounts.

To demonstrate this point, we have gathered actual hourly electricity prices for most of the regions of the US over the past three years. We then estimate both average and marginal electricity prices for each region. The average electricity price is derived as the simple average of the electricity price for each hour of the year. The marginal electricity prices are derived for three representative periods:

<u>The "summer" period</u>, which includes the months of June, July, August and September. This is the same period that DOE uses for calculating summer marginal costs. This period includes a total of 2,928 hours.

<u>The "summer peak" period</u>, which includes the hours of 12:00 pm through 7:00 pm during the four summer months. This period provides a better approximation of when air conditioners are most likely to be used. This period includes a total of 968 hours.

<u>The "air conditioning" period</u>, which includes only those hours of the year when air conditioners are expected to operate. Ideally, these hours would be identified by using actual hourly load profiles for typical central air conditioners in each region of the country. In the absence of such load profiles, we have made some approximations. We begin with the annual 1997 kWh consumption of air conditioners for each census region, using data from the 1997 RECS. We then divide these kWh by the kW demand of a typical central air conditioner, to determine the number of hours that air conditioners tend to operate in each region. This number ranges from a low of 285 in New England to a high of 1,305 in the West South Central region. We then allocate these air conditioner operating hours to summer and non-summer periods, using the seasonal load breakdowns provided on page 5-59 of the Technical Support Document. For the summer air conditioning hours, we assume that they occur during the most expensive hours – i.e., when the temperature is greatest. For the non-summer air conditioning hours, we assume that the prices paid are equal to the average annual price.

We use these representative peak periods to illustrate the point that marginal prices tend to be much higher than average prices during the periods when air conditioners are likely to be operating. Using the summer period will clearly understate marginal prices for air conditioner customers, because it includes many low-cost hours (e.g., nighttime) when many air conditioners are not operating. In many regions the summer peak period will also understate the marginal prices for air conditioner customers, because it also includes low-cost hours (e.g., cool days) when air conditioners are not operating. For example in New England central air conditioners tend to operate for roughly 285 hours per year, but the summer peak period includes 968 hours. The air conditioning period is likely to provide the best representation of marginal costs for air conditioner customers, because it includes only the number of hours that air conditioners are likely to operate.

It is important to note that the data provided below are for wholesale generation prices, while DOE's cost-benefit analyses use retail electricity rates. The wholesale generation prices do not include costs associated with transmission, distribution and other utility business. Nevertheless, the difference between average prices and marginal prices for wholesale generation is a good indication of the difference between average and marginal retail electricity rates.[2] Hence, our presentation will focus on the differential between average and marginal generation prices.

3.2 Wholesale Generation Prices In Competitive Electricity Markets

We have compiled the hourly generation prices for competitive wholesale electricity markets (including California, New York, New England, and PJM), using the hourly market clearing prices provided by the Independent System Operator in each region. These regions represent roughly 20 percent of the total electricity generation in the US. We included data from the beginning of wholesale competition through October 2000.

Table 3.1 and Figure 3.1 present the wholesale generation prices for these competitive markets, including the annual average prices and the average prices for the three representative peak periods. Appendix B provides a description of the sources and methodology used to compile these hourly prices.

Table 3.1 Wholesale Generation Prices in Today's Competitive Markets

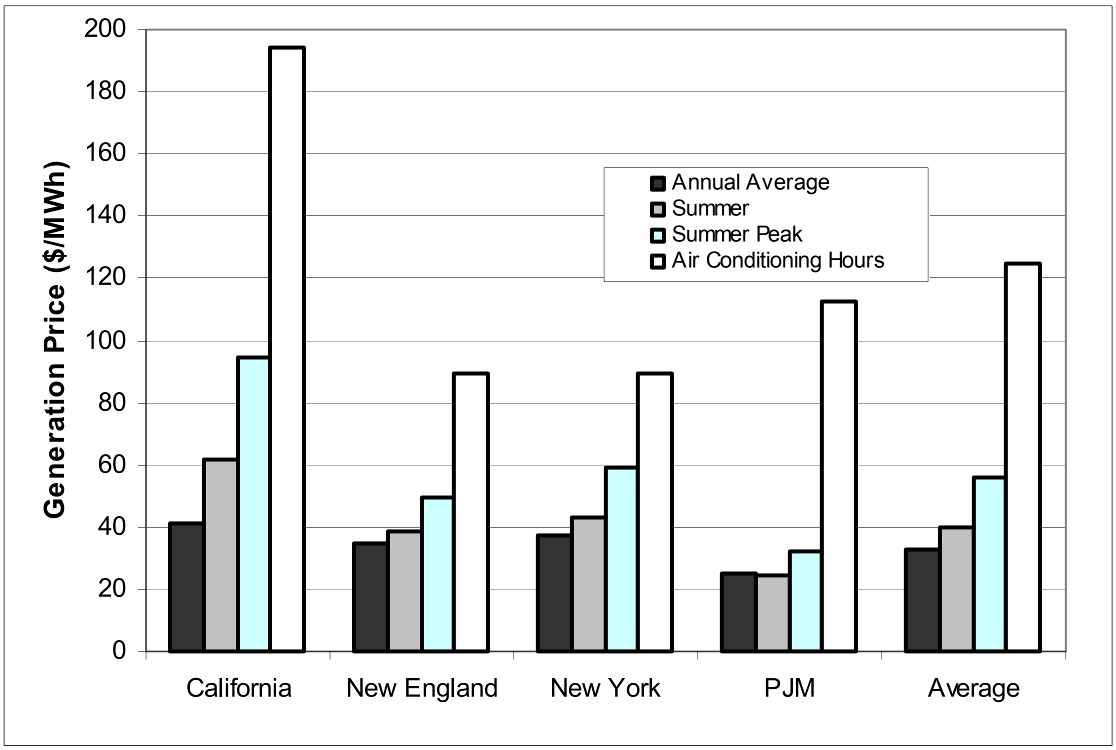
	California	New England	New York	PJM	Average
Generation Price ($/MWh)					
Annual Average	41.1	34.4	37.1	24.8	32.8
Summer	62.0	38.7	43.2	24.2	39.7
Summer Peak	94.5	49.3	59.3	32.1	55.8
Air Conditioning Hours	194.2	89.5	89.1	112.6	125.1
Price Differential ($/MWh)					
Annual Average	0.0	0.0	0.0	0.0	0.0
Summer	20.8	4.2	6.0	-0.5	6.9
Summer Peak	53.3	14.8	22.1	7.3	23.0
Air Conditioning Hours	153.1	55.1	52.0	87.8	92.2

These results demonstrate the importance of defining the proper time period when estimating marginal prices for air conditioner users. During all summer hours, the

2 This point is based on the assumption that transmission, distribution and other utility costs continue to be recovered from customers on the basis of embedded costs. In fact, Independent System Operators and Regional Transmission Organizations are establishing transmission congestion management systems that will result in higher marginal costs for transmission services during peak periods in competitive markets. This effect is not addressed in our analysis.

marginal prices tend to exceed average prices by 6.9 $/MWh on average, whereas during the summer peak hours marginal prices exceed average prices by 23 $/MWh. When only air conditioner hours are considered the marginal price differential is 92 $/MWh. This latter number is due in part to the high prices experienced in California in the summer of 2000. However, the summer peak price spikes that have occurred in California can occur in other competitive markets when capacity becomes tight and there are constraints and delays in bringing new generation capacity on-line. Furthermore, outside of California the marginal price differentials are still quite high, ranging from 52 $/MWh in New York to roughly 88 $/MWh in PJM.

Figure 3.1 Wholesale Generation Prices in Today's Competitive Markets



3.3 Wholesale Generation Prices In Regulated Electricity Markets

For regulated electricity markets we calculated marginal generation prices from the "system lambdas" that utilities are required to report to FERC. The system lambda is in essence the marginal cost of the production of energy for a given region or generator. The markets included in our analysis include roughly 55 percent of the total US electricity generation in 1998 and 1999. We were not able to compile data for the MAPP and WSCC regions, due to insufficient reporting by the utilities.

The system lambda costs are different from the wholesale generation market clearing prices in that they only include variable production costs (i.e., fuel and variable O&M). They do not include any costs necessary to recover the capital investments associated with building new power plants to meet growing demand. Therefore, we have added estimates of such capital costs on to the system lambdas, in order to represent the full marginal cost and to be consistent with the wholesale market clearing prices presented in the previous section.

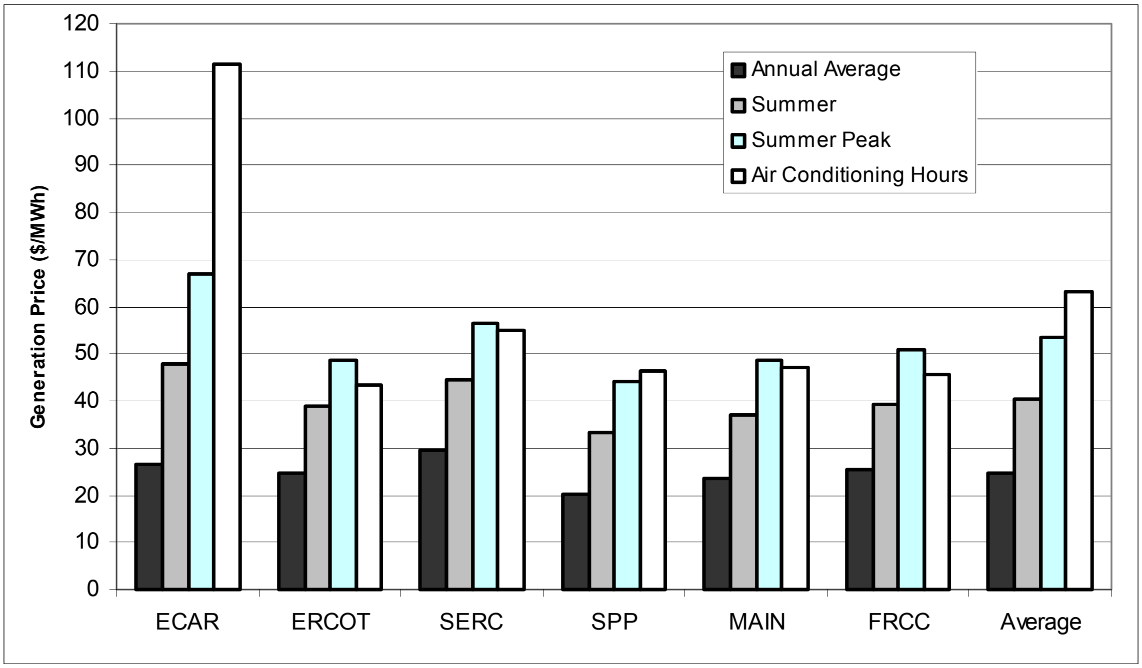
Table 3.2 and Figure 3.2 present the wholesale generation prices for these regulated markets, including the annual average prices and the average prices for the three representative peak periods. Appendix B provides a description of the sources and methodology used to compile these hourly prices.

Table 3.2 Wholesale Generation Prices in Today's Regulated Markets

	ECAR	ERCOT	FRCC	MAIN	SERC	SPP	Average
Generation Price ($/MWh)							
Annual Average	26.7	24.8	29.6	20.1	23.4	25.3	24.7
Summer	47.8	38.9	44.6	33.2	37.1	39.1	40.4
Summer Peak	66.9	48.5	56.5	44.1	48.7	50.7	53.5
Air Conditioning Hours	111.5	43.5	54.9	46.3	47.2	45.5	63.1
Price Differential ($/MWh)							
Annual Average	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Summer	21.1	14.1	15.0	13.1	13.7	13.8	15.7
Summer Peak	40.2	23.7	26.9	24.0	25.3	25.4	28.8
Air Conditioning Hours	84.8	18.7	25.3	26.2	23.8	20.2	38.3

As with the competitive markets, these results demonstrate the importance of defining the proper time period when estimating marginal prices for air conditioner users. Summer period prices exceed average annual prices by 15.7 $/MWh on average, and Summer peak prices exceed average annual prices by roughly 28.8 $/MWh. The marginal prices differential for air conditioning hours is even higher at roughly 38.3 $/MWh. With the exception of the ECAR region, the air conditioning peak hours are not as different from the summer peak hours as was the case for the competitive markets. This is probably due to the fact that our methodology for adding capital costs to the system lambdas probably understates the cost recovery that has been experienced, and can be expected, from competitive markets. Therefore, the marginal price differentials for competitive markets presented in the previous section are a better indication of the marginal price differences that can be expected in the future.

Figure 3.2 Wholesale Generation Prices in Today's Regulated Markets



4. DOE's Use of Historic Marginal Prices Is Unsupported By The Evidence To Date And Is Inconsistent With AEO2000

4.1 DOE Discussion of Marginal Prices in the NOPR

In the Notice of Proposed Rulemaking (NOPR) for this docket, the DOE notes that several parties raise the same concerns that we have detailed above – i.e., that DOE's methodology understates future marginal electricity prices. DOE responds to these concerns by noting that the marginal price estimates were based on the Reference Case electricity forecast from AEO2000, which forecasts declining electricity rates through the year 2020. DOE notes that:

> Although it is certainly possible that future electricity rates may increase in a deregulated climate, the evidence to date (i.e., residential marginal prices are actually lower than average rates and AEO 2000 forecasts project declining electricity rates) convinces us that our current methods for establishing marginal prices are reasonable. (DOE 10/5/2000, page 59601)

Unfortunately, DOE's response here does not address the fundamental problem with its marginal price methodology. Residential marginal prices are not actually lower than average rates. DOE has drawn this conclusion from historic electricity rates, but as described in Section 2 historic electricity rates are not a good indication of marginal electricity prices. The wholesale market price comparisons presented above in Section 3 are a better indication of marginal prices in competitive electricity markets. This evidence suggests that marginal prices are higher than average rates during peak periods, and that DOE's methodology will significantly understate marginal prices.

In order to appreciate why marginal prices exceed average prices, it is useful to reiterate that marginal costs during peak periods will be significantly higher than marginal costs during off-peak periods. Hence, the marginal costs that apply to residential air conditioner consumption will be higher than those that apply during other times of the year.

4.2 Consistency With Assumptions Used In AEO 2000 Forecasts

As noted above in Section 2.3, the Reference Case AEO 2000 forecast assumes that by 2008 a significant portion of the country will have competitive electricity markets where customer prices will be based on marginal costs. In fact, this assumption is part of the reason why the AEO 2000 electricity prices are forecast to decline in real terms in the future.

The DOE air conditioner standards analysis in this docket assumes the same declining electricity prices from AEO 2000. Therefore, in order for this analysis to be internally consistent, it should also assume that a significant portion of the country will have competitive electricity markets where customer prices will be based on marginal costs. If DOE were to assume that electricity markets will not be competitive in the future, then it should assume different (i.e., higher) future electricity prices. We do not recommend this approach, however. We recommend that the DOE analysis in this docket explicitly assume that there will be increased competition in US electricity markets in the future, and that this will lead to electricity prices based on marginal costs.

As noted above in Section 2.3, the AEO Reference Case is likely to understate the extent of competition in electricity markets, because it only includes those states and regions that have already taken steps to introduce competition – it excludes states and regions that will introduce competition in the future. A more realistic approach for the air conditioner standards would assume that US electricity markets are more competitive than is assumed in the AEO 2000 Reference Case.

AEO 2000 also presents some Competitive Pricing Cases, which assume that all electricity markets in the US will be fully competitive by 2008. These cases are likely to be a more accurate representation of the US electricity markets in the future. These cases generally indicate that marginal prices under full competition will be lower than average prices in the Reference Case in 2005 and 2010, but roughly the same in 2015 and thereafter. (DOE 12/1999, pages 20-23)

However, the marginal prices that are presented for the Competitive Pricing Cases are significantly lower than those that will actually apply to residential air conditioning customers, for two reasons. First, the marginal prices reported in AEO 2000 are the averages for all customers. Residential customers will have higher marginal prices than other customers because they have much a lower load factor. Second, air conditioner customers will have higher marginal prices than other customers because they tend to consume electricity during the most expensive hours. Therefore, the marginal prices for air conditioning customers will be significantly higher than those presented for the Competitive Pricing Cases.

In sum, we recommend that the DOE explicitly assume all US electricity markets will have competitive electricity markets by the early years of the study period, and that these markets will provide customers with prices based on marginal costs. Furthermore, the marginal prices should be based on those hours when central air conditioners are expected to operate.

5. Impacts Of Revised Marginal Prices On The Cost-Benefit Analyses

5.1 Revised Marginal Prices

In order to indicate the impact that marginal prices assumptions will have on the cost benefit analysis, we have applied revised marginal prices to the life-cycle costing (LCC) and national energy savings (NES) spreadsheets that DOE prepared for this docket. We leave all other default assumptions (e.g. product life, discount rate, ARI product cost estimates) unchanged. We run two scenarios. First, we assume marginal prices based on the summer peak period. As described above in Section 3, we find that these marginal prices have exceeded average prices by 23 $/MWh in competitive markets and by 29 $/MWh in regulated markets. The marginal price differential that we use is weighted by the central air conditioning consumption assumptions in the DOE's LCC spreadsheet, so the average marginal price differential represents the regional distribution of usage and consumption.

We derive new marginal price assumptions by adding the marginal price differentials from wholesale generation prices to the average electricity price assumed by DOE in the LCC spreadsheet. In this way, our price differential is based on wholesale generation prices, but the marginal price inputs include transmission, distribution and other business costs using the same assumptions as DOE. We also make a small adjustment to account for the fact that some retail rates include fixed customer charges. Customers are not able to avoid these charges with reduced demand, so they should be subtracted from the marginal prices that we have derived. Assuming that fixed customer charges tend to represent five percent of the total rate, on average, we subtract 4 $/MWh from all of the marginal prices.[3]

[3] DOE's Marginal Energy Prices Report notes that fixed charges represent 7.5 percent of its sample electric rates. However, this figure includes minimum charges, so the percent of fixed customer charges will be lower. (DOE 7/1999)

Life-Cycle Cost Results

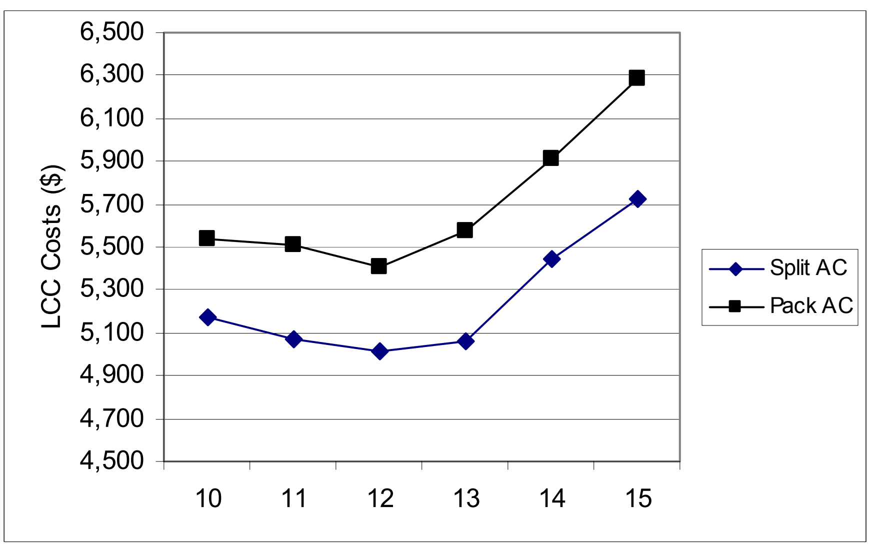
DOE's goal in setting efficiency standards is to achieve the maximum amount of energy savings (i.e., kWh savings) using cost-effective technology.[4] In the context of air conditioners, a technology is cost-effective as long as its life-cycle cost is lower than those for SEER 10 air conditioners.

Our LCC results are presented in Table 5.1 and Figure 5.1. They show that the maximum amount of energy savings that can be achieved cost-effectively is at SEER 13 for split system AC and at SEER 12 for packaged AC, with savings of $112 and $131 respectively. Split air conditioners represent the majority of air conditioners sold.

Table 5.1 LCC Results Assuming Summer Peak Period Marginal Prices

	Split AC		Packaged AC	
SEER Level	Average LCC	LCC Costs (Savings)	Average LCC	LCC Costs (Savings)
10	$5,170	0	$5,541	0
11	$5,068	-102	$5,506	-35
12	$5,015	-155	$5,409	-131
13	$5,058	-112	$5,573	33
14	$5,442	272	$5,911	370
15	$5,725	555	$6,289	749

Figure 5.1 LCC Results Assuming Summer Peak Marginal Prices



4 The efficiency standard law says that "any new or amended energy conservation standard prescribed by the Secretary under this section for any type (or class) of covered product shall be designed to achieve the maximum improvement in energy efficiency… which the Secretary determines is technologically feasible and economically justified" (US Code, Title 42, Section 6295(o)(2)(A)).

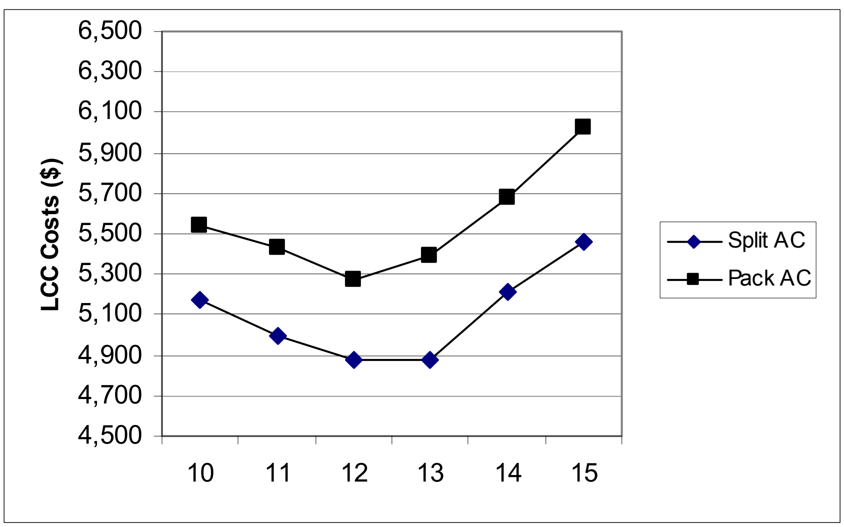
In the second scenario, we assume marginal prices based on the air conditioning period. As described above in Section 3, we find that these marginal prices have exceeded average prices by 38 $/MWh in competitive markets and by 92 $/MWh in regulated markets.

The results are presented in Table 5.2 and Figure 5.2. With these marginal prices, maximum cost effective savings are achieved with SEER 13 standards for split system and packaged equipment. LCC savings for split system AC are $297 (roughly six percent) and for packaged system AC LCC savings are $152 (roughly three percent).

Table 5.2 LCC Results Assuming Air Conditioning Period Marginal Prices

	Split AC		Packaged AC	
SEER Level	Average LCC	LCC Costs (Savings)	Average LCC	LCC Costs (Savings)
10	$5,170	0	$5,541	0
11	4,995	-175	5,433	-108
12	4,881	-289	5,275	-265
13	4,872	-297	5,388	-152
14	5,213	43	5,681	141
15	5,457	287	6,022	481

Figure 5.2 LCC Results Assuming Air Conditioning Period Marginal Prices



National Energy Savings Results

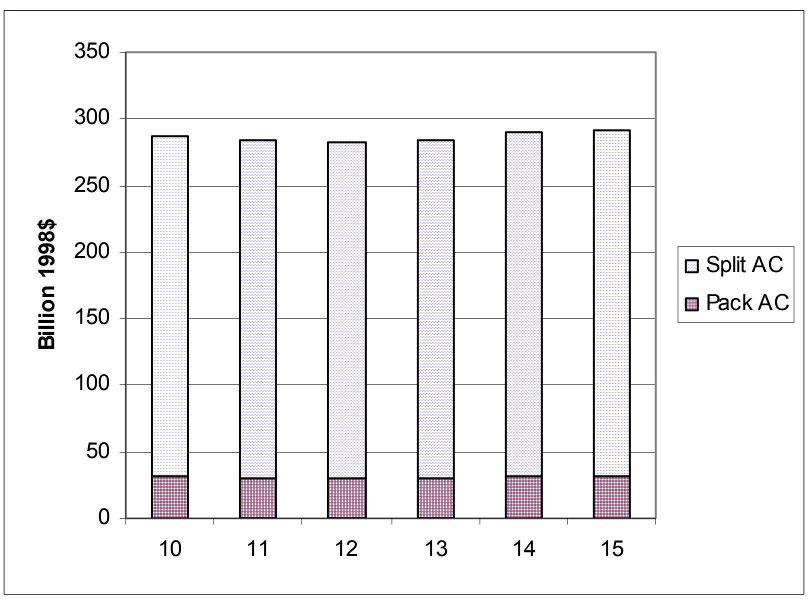
We have also applied these assumptions to the DOE cost-benefit spreadsheets to determine the national energy savings associated with the different efficiency levels. Here we use the *NAECA* scenario, which assumes that equipment efficiencies after adoption of the standards would change in the same pattern as the efficiency changes that occurred in 1992 when minimum efficiency standards first took effect.

In Table 5.3 and Figure 5.3 we present the results for the scenario assuming summer peak marginal prices and modified air conditioner equipment costs. Our analysis shows that the SEER 13 standards result in the lowest total costs, and result in net savings of roughly $3.6 billion nation-wide.

Table 5.3 NES Results Assuming Summer Peak Marginal Prices

National Equipment and Operating Costs, Net Present Value (Billion $)					
SEER	Split AC	Package AC	Total	Net Difference	Percent Difference
10	255.9	30.8	286.7	0.00	0.0%
11	253.7	30.7	284.4	-2.33	-0.8%
12	252.6	30.4	283.0	-3.69	-1.3%
13	252.5	30.7	283.2	-3.56	-1.2%
14	258.2	31.1	289.4	2.64	0.9%
15	259.8	31.5	291.3	4.57	1.6%

Figure 5.3 NES Results Assuming Summer Peak Marginal Prices

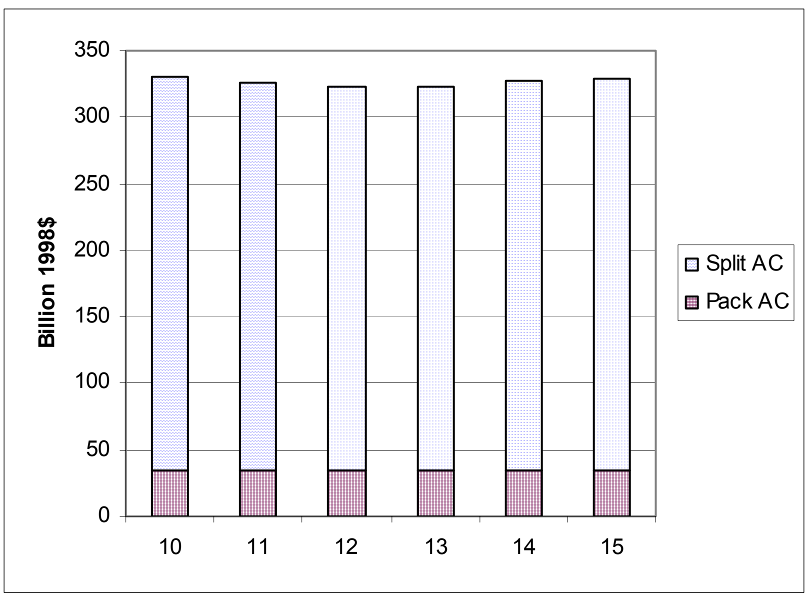


In Table 5.4 and Figure 5.4 we present the results for the scenario assuming air conditioning period marginal prices and modified air conditioner equipment costs. Our analysis shows that the SEER 13 standards result in the lowest total costs, and result in net savings of roughly $7.7 billion nation-wide, a savings of 2.3 percent.

Table 5.4 NES Results Assuming Air Conditioning Period Marginal Prices

National Equipment and Operating Costs, Net Present Value (Billion $)					
SEER	Split AC	Package AC	Total	Net Difference	Percent Difference
10	294.9	35.2	330.2	0.00	0.0%
11	291.3	34.9	326.2	-3.95	-1.2%
12	289.1	34.5	323.6	-6.56	-2.0%
13	287.8	34.7	322.5	-7.70	-2.3%
14	292.6	35.0	327.6	-2.56	-0.8%
15	293.4	35.3	328.7	-1.50	-0.5%

Figure 5.4 NES Results Assuming Air Conditioning Period Marginal Prices and Modified Equipment Costs



5.2 Air Conditioner Equipment Costs – Reverse Engineering Estimates

During the course of this docket, the American Council for an Energy Efficient Economy (ACEEE), Natural Resources Defense Council (NRDC) and others have noted that the DOE's assumptions for air conditioner equipment costs are too high, for a number of reasons. While equipment costs are not the focus of our analysis, it is important to improve upon these assumptions in order to present realistic cost-benefit analysis results.

Therefore, we have prepared additional cost-benefit scenarios, where we modify both the marginal price assumptions and the equipment cost assumptions. We continue to use two different marginal price assumptions: the summer peak period marginal prices, and the air conditioning period marginal prices. We then use the reverse engineering estimates for the air conditioner equipment costs, instead of the estimates prepared by ARI.

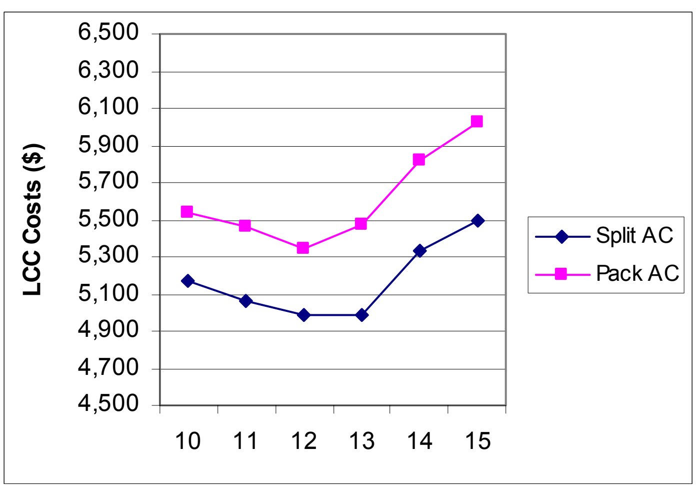
Life-Cycle Cost Results

The results for the revised life-cycle cost analysis are presented in the tables and figures below. With summer peak marginal prices and reverse engineering estimates, maximum cost effective savings are achieved with SEER 13 standards for split system and packaged equipment. LCC savings for split system AC are $180 (roughly three percent) and for packaged system AC the LCC savings are $66 (roughly one percent).

Table 5.5 LCC Results Assuming Summer Peak Period Marginal Prices and Reverse Engineering Equipment Costs

	Split AC		Packaged AC	
SEER Level	Average LCC	LCC Costs (Savings)	Average LCC	LCC Costs (Savings)
10	5,170	0	5,541	0
11	5,057	-113	5,464	-76
12	4,990	-180	5,348	-193
13	4,990	-180	5,475	-66
14	5,335	165	5,821	281
15	5,499	329	6,021	481

Figure 5.5 LCC Results Assuming Summer Peak Period Marginal Prices and Reverse Engineering Equipment Costs

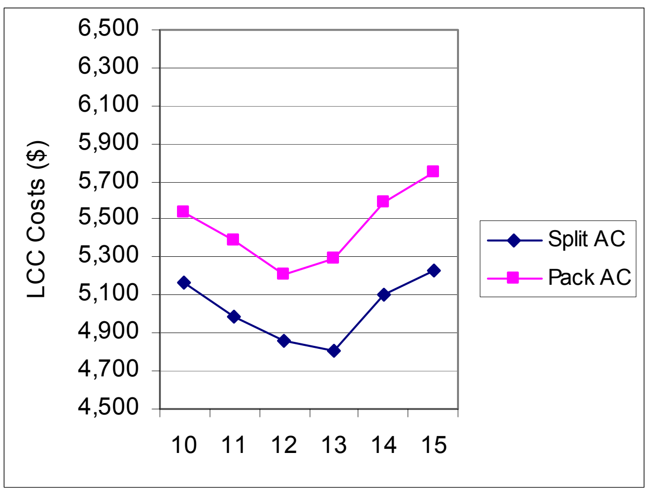


With air conditioning period marginal prices, the LCC savings are even more pronounced. The SEER 13 standards result in LCC savings of $364 (roughly seven percent) for split air conditioners, and $251 (roughly five percent) for packaged air conditioners.

Table 5.6 LCC Results Assuming Air Conditioning Period Marginal Prices and Reverse Engineering Equipment Costs

	Split AC		Packaged AC	
SEER Level	Average LCC	LCC Costs (Savings)	Average LCC	LCC Costs (Savings)
10	5,170	0	5,541	0
11	4,984	-186	5,391	-149
12	4,856	-314	5,214	-326
13	4,806	-364	5,290	-251
14	5,106	-64	5,592	51
15	5,231	61	5,754	213

Figure 5.6 LCC Results Assuming Air Conditioning Period Marginal Prices and Reverse Engineering Equipment Costs



5.3 Air Conditioner Equipment Costs – Additional Cost Improvements

Finally we build upon the previous scenarios by making two additional adjustments to the air conditioner equipment cost assumptions:

- Equipment costs are modified by the emerging technology cost reduction estimates provided by DOE in the Technical Support Document.
- Equipment costs are reduced assuming a 0.84 percent per year productivity factor, beginning from the base year of the analysis (1998). Over the five year period from 1994 to 1998 (1999 data not yet available), Census Bureau Current Industrial Reports data indicates that the real cost of air conditioners declined by 1.7 percent annually. To be conservative, we assume annual productivity improvements at half this level.

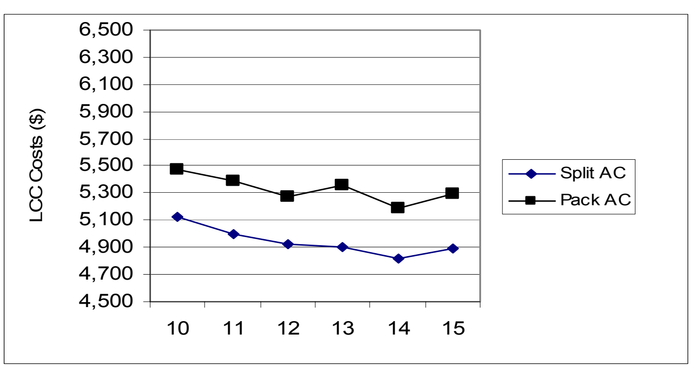
Life-Cycle Cost Results

The results for the revised life-cycle cost analysis are presented in the tables and figures below. With summer peak period marginal prices, standards *higher* than SEER 13 would yield maximum cost effective savings. SEER 13 standards result in LCC savings of $216 (roughly four percent) for split system air conditioners, and $114 (roughly two percent) for packaged air conditioners.

Table 5.7 LCC Results Assuming Summer Peak Period Marginal Prices and Additional Equipment Cost Improvements

	Split AC		Packaged AC	
SEER Level	Average LCC	LCC Costs (Savings)	Average LCC	LCC Costs (Savings)
10	5,120	0	5,476	0
11	5,000	-120	5,390	-86
12	4,924	-197	5,268	-208
13	4,904	-216	5,362	-114
14	4,817	-303	5,191	-285
15	4,892	-228	5,290	-187

Figure 5.7 LCC Results Assuming Summer Peak Period Marginal Prices and Additional Equipment Cost Improvements

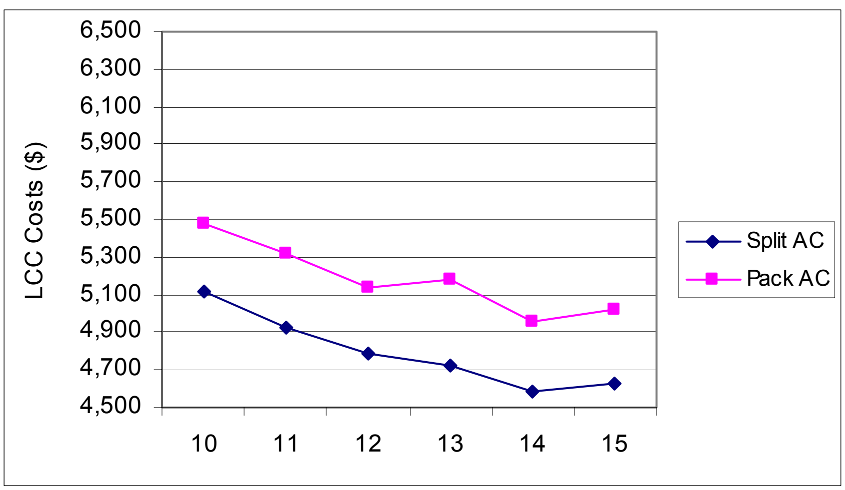


With air conditioning period marginal prices, the LCC savings are even more pronounced at all standard levels. As in the previous scenario, the greatest level of cost effective energy savings would be achieved by standards above 13 SEER. The SEER 13 standards result in LCC savings of $402 (roughly eight percent) for split air conditioners, and $299 (roughly five percent) for packaged air conditioners.

Table 5.8 LCC Results Assuming Air Conditioning Period Marginal Prices and Additional Equipment Cost Improvements

	Split AC		Packaged AC	
SEER Level	Average LCC	LCC Costs (Savings)	Average LCC	LCC Costs (Savings)
10	5,120	0	5,476	0
11	4,927	-193	5,317	-159
12	4,790	-330	5,134	-342
13	4,719	-402	5,177	-299
14	4,587	-533	4,962	-514
15	4,625	-495	5,022	-454

Figure 5.8 LCC Results Assuming Air Conditioning Period Marginal Prices and Additional Equipment Cost Improvements



National Energy Savings Results

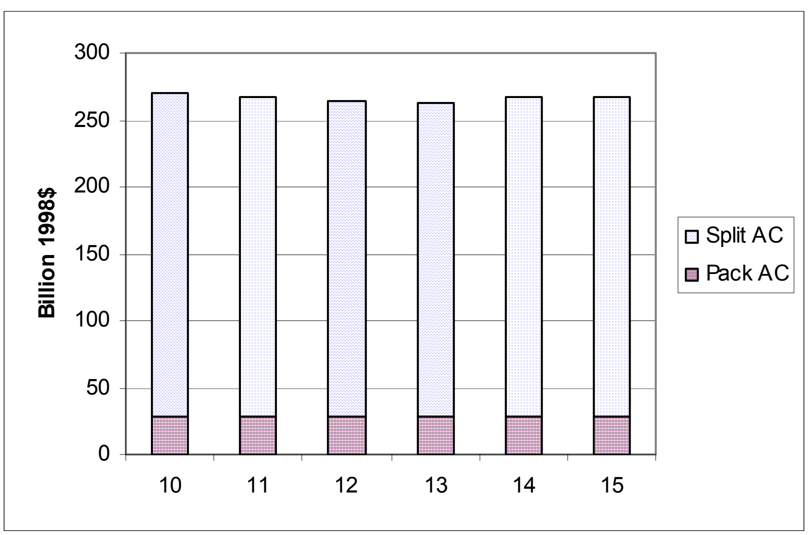
We have also applied these assumptions to the DOE cost-benefit spreadsheets to determine the national energy savings associated with the different efficiency levels. We were unable to incorporate the emerging technology assumptions into the NES spreadsheets, due to a lack of time. Hence, these results do not indicate the full amount of national energy savings that could be obtained under the assumptions discussed in the precious section.

In Table 5.9 and Figure 5.9 we present the results for the scenario assuming summer peak marginal prices, reverse engineering costs, and productivity improvements. Our analysis shows that the SEER 13 standards result in the lowest total costs, and result in net savings of roughly $7.5 billion nation-wide.

Table 5.9 NES Results Assuming Summer Peak Marginal Prices, Reverse Engineering and Productivity Improvements

National Equipment and Operating Costs, Net Present Value (Billion $)					
SEER	Split AC	Package AC	Total	Net Difference	Percent Difference
10	241.4	28.9	270.4	0.00	0.0%
11	238.3	28.5	266.8	-3.58	-1.3%
12	236.4	28.2	264.6	-5.82	-2.2%
13	234.6	28.3	262.9	-7.49	-2.8%
14	238.8	28.9	267.7	-2.67	-1.0%
15	238.9	28.9	267.8	-2.61	-1.0%

Figure 5.9 NES Results Assuming Summer Peak Marginal Prices, Reverse Engineering and Productivity Improvements



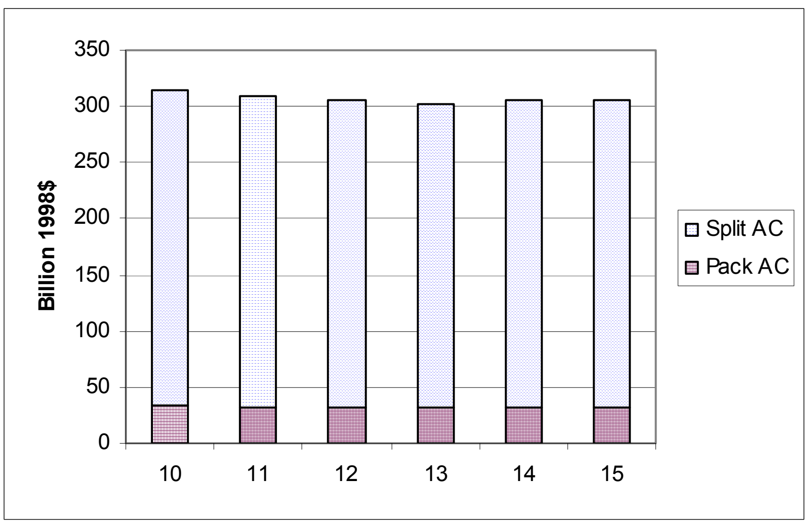
In Table 5.10 and Figure 5.10 we present the results for the scenario assuming air conditioning period marginal prices, reverse engineering costs, and productivity improvements. These results indicate that the SEER 13 standards result in the lowest total costs, and result in net savings of roughly $11.7 billion nation-wide, a savings of 3.7 percent.

Table 5.10 NES Results Assuming Air Conditioning Period Marginal Prices, Reverse Engineering and Productivity Improvements

National Equipment and Operating Costs, Net Present Value (Billion $)

SEER	Split AC	Package AC	Total	Net Difference	Percent Difference
10	281.0	33.4	314.4	0.00	0.0%
11	276.4	32.8	309.2	-5.23	-1.7%
12	273.3	32.3	305.7	-8.74	-2.8%
13	270.4	32.3	302.7	-11.66	-3.7%
14	273.6	32.8	306.4	-8.00	-2.5%
15	272.9	32.7	305.5	-8.87	-2.8%

Figure 5.10 NES Results Assuming Air Conditioning Period Marginal Prices, Reverse Engineering and Productivity Improvements



6. Conclusions And Recommendations

The DOE's methodology for estimating marginal prices clearly understates the marginal prices that US air conditioner customers will face in the future. Instead of being slightly less than average annual prices, marginal prices for air conditioning customers could easily exceed average prices by as much as 30 to 90 $/MWh, depending upon the region of the country and the time of day. The primary reason for this large price differential is that air conditioner customers purchase electricity during the most expensive periods of the day and year.

The DOE should consider alternative methodologies for estimating the marginal costs for air conditioner customers. The DOE should explicitly recognize that a significant portion of the US electricity market has already become competitive, and that most, if not all, of the rest of the country's electricity markets will be competitive by the early years of the study period. Marginal electricity prices should therefore be based on marginal costs, and not on historic electricity rates. Marginal prices for air conditioner customers should be based on those hours that air conditioners are expected to operate, which tend to be the most expensive hours for purchasing electricity.

If more realistic marginal prices are used, then higher efficiency standards are more cost-effective than indicated in the Technical Support Document. The SEER 13 standards result in LCC savings of $297 (roughly six percent) for split air conditioners, and $152 (roughly three percent) for packaged air conditioners, and have lower life-cycle costs than SEER 10, SEER 11, and SEER 12 standards.

In addition, if more reasonable air conditioner cost assumptions are used as well, then the benefits of the SEER 13 standard are even more pronounced, with LCC savings of $402 (roughly eight percent) for split air conditioners, and $299 (roughly five percent) for packaged air conditioners. With regard to national energy savings, the SEER 13 standard results in the lowest total equipment and operating costs, and results in net present value savings of as much as $11.7 billion nation-wide.

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Appendix A

Regulatory And Competitive Pressures To Reflect Marginal Costs In Electricity Rates

Regulatory Trends

There is increasing regulatory pressure to develop a strong demand response to electricity supply. The trend is spurred by new concerns over market efficiency and customer choice as well as the more long-standing driver, bulk power system reliability. Enabling a demand response requires exposing customers to prices that reflect the marginal cost of generation in particular time periods. Therefore, a customer would see real-time price signals or time differentiated price signals so that they could know how to manage their load in response to different prices.

Federal and state regulators are taking steps to facilitate a demand response to price signals. The Federal Energy Regulatory Commission has identified development of demand response to wholesale prices as a critical element of efficient markets. In an Order regarding wholesale electricity markets in New England FERC stated "lack of price-responsive demand is a major impediment to the competitiveness of electricity markets." (Order on Complaint and Conditionally Accepting Market Rule Revisions, Docket No. EL00-83-000 et. al. (the "NSTAR Order", July 26, 2000; at 23). FERC explained

> Based on our experience over the past few years, it is becoming evident that a successful transition to competitive electricity markets will necessarily involve an increased participation of the demand side of the market in making resource decisions. Such participation can serve to discipline prices by bringing supply and demand into balance and thereby reduce calls for intervention in markets through price caps.

At 15-16. Similarly in its recent Order on wholesale markets in California FERC stated:

> Demand side is a critical element of the market. When consumers can receive price signals and have the ability to respond to those price signals by reducing demand, it reduces the overall cost of electricity in the market and reduces the electric bills of all consumers, not just those that responded with a load reduction. Also, a viable demand response program provides an alternative to resource expansion.

Order on California markets, Docket No. EL00-95-000, November 1, 2000, at 42. Although FERC emphasizes the importance of demand response in competitive markets, the Commission states that enabling that demand response is primarily within the control of state policy makers.

A number of state policy makers are taking specific steps to do their part in enabling retail customers to respond to price signals. It is important to note that regardless of whether a state has undertaken retail competition for electric service, advanced metering can be used to provide time-differentiated pricing to customers. Therefore, electric industry restructuring and retail competition are not prerequisites to price responsive load.

Some states are investigating advanced metering and competitive provision of metering services. Others have gone even further to require that some or all customers have advanced meters. For example, New York has already gone through the first stage of implementing competitive metering. The PSC has required advanced metering for all customers over 50Kw. They are currently developing rules and procedures for safety and installation of meters. They hope to have unbundled metering tariffs in place mid-January. They have invited proposals for smaller customers. Similarly in the state of Illinois, Section 16-107 of the Public Utilities Act requires all electric utilities to have residential real-time pricing (RTP) tariffs in place by October 1, 2000. California also requires that all customers have competitive and advanced metering; while the requirement applies to all customers, the state is focusing on large customers initially.

Other states have undertaken investigations of advanced metering, competitive metering, and/or real-time pricing. For example, Massachusetts is currently in the middle of a proceeding to investigate advanced metering and competitive provision of metering services. States such as New Hampshire, Connecticut, and North Carolina have also considered, or are considering, these issues. There are also provisions for competitive metering in Texas, Illinois, Nevada, Arizona, and Maine as well as in some parts of Pennsylvania .

Metering Technologies

Advanced metering technology has developed a great deal in recent years. There are a number of companies that are developing tools for controlling load via the internet (e.g. Stonewater Software developing "Energy1st.com" and Power Web Technologies has "Omni Link" an Internet Energy Platform). These tools allow energy service companies to provide real-time, price-driven load management services to end-use customers. These tools enable customers to see time differentiated price signals, including real-time price signals, and to decide whether to reduce load, or they enable direct control of appliances and machinery (including on-site Distributed Generation) when prices reach a certain level.

These control technologies do not always require an invasive procedure in the home, for example the OmniLink Energy Platform would enable a customer to receive information about real time prices and would enable them to reduce their usage of specific appliances when electricity prices reached specific levels during the day. Johnson Controls provides building automation systems that include a monitoring device that accepts real-time pricing information from energy suppliers. Two-way communication technology would allow the customer to optimize energy consumption and price using real-time pricing information and metered energy data.

Cellnet data systems are deployed in many states throughout the country. While many of the meters have been primarily used to date for remote meter reading and to enhance customer service, the installations provide the option of time differentiated pricing for retail customers. For example electric companies including Kansas City Power and Light, Indiana Power and Light, United Illuminating (in Connecticut), and Puget Sound Energy (in Washington) all have networks that will enable a variety of pricing options for customers.

The cost of these meters is higher than a standard meter, but is not prohibitive. For example, in testimony to the Massachusetts Department of Telecommunications and Energy a provider of internet metering and software technology estimates that:

> "The standard monthly meter costs $25 - $2,700. It is not communications enabled and must be read manually. For an additional $50-$100, the standard meter can be enabled to be remotely read, albeit still on a monthly basis. For the same incremental amount of money, standard meters can be web-enabled and report usage on a user-defined interval (e.g., hourly basis). Other options are available for varying degrees of cost and effectiveness." (DTE 00-41 Comments of Automated Energy, Inc.).

Suppliers anticipate that when states enable competitive provision of metering services

> "will immediately encourage and advance new measurement and reporting technologies and services. The protected monopoly of vertically integrated utilities hindered the advance of electric measurement systems to the point that the standard meter's technology and capabilities are as outdated as the Model T. This scarcity of solutions is a problem that can only be solved by a competitive marketplace." (DTE 00-41 Automated Energy, Inc.).

Load Response To Wholesale Market Prices

A number of utilities as well as ISOs are developing load response programs. These early load response programs are primarily reliability tools designed to assist in meeting the electrical demand of customers in capacity constrained situations. For example, ISO New England, PJM, and CA ISO are all developing load response programs. Similarly certain companies, such as Portland General Electric, are developing load response programs. These are a prelude to full integration of price responsive load into markets. For example, in New England in the long term price responsive load will be integrated into markets through day ahead load bidding (part of the multi-settlement system), as well as real-time load response to wholesale prices.

Many utilities are experimenting with advanced metering for residential customers. Widescale installations of meters make it more cost-effective than just installing a few here and there. For example, in the Massachusetts competitive metering docket Schlumberger Resources Management Services states: "Advanced metering enables a new generation of smart devices that see and respond to price signals. For example, Puget Sound Energy ("PSE") has equipped 200 of its customers with a Home Comfort Control Thermostat. Using a CellNet advanced metering network, PSE sends a signal to the thermostat to adjust the temperature in the home during periods of peak demand.

Customers are free to override the adjustment, and the CellNet network informs PSE which customers have done so."

For residential customers, advance metering could provide an opportunity to respond to real-time price signals, or to participate in a price offering with time-differentiated rates (i.e. the price signal would not be real-time but would nevertheless be differentiated by peak and off-peak or some other temporal distinction). Many utilities already offer time-of-use pricing options to residential customers. For example companies around the country such as PECO, Rochester Gas and Electric, Madison Gas and Electric, Arizona Public Service Company, PEPCo all offer residential time-of-use rates.

Energy service companies (competitive suppliers and retail suppliers) are pushing commissions to enable advanced metering and competitive metering (i.e., so non-distribution companies can install meters). For example, in the Massachusetts proceeding on competitive metering and billing docket, Competitive Retail Providers (Enron Energy Services, Essential.com, Exelon Energy, Green Mountain Energy Company, InSITE SERVICES, L.L.C., NewEnergy East, L.L.C., and SmartEnergy.com) list multiple benefits of advanced metering such as pricing options and load control products and services:

> Pricing options: "Advanced metering enables Suppliers to offer multiple pricing options, such as time of use rates. This increases the number of choices for customers, and enables them to save money by shifting usage to off-peak periods. This is something customers have taken great advantage of in other competitive industries, such as telephone (5 ¢ Sundays) and airlines (Supersaver fares)." [cite]
>
> Load control: "Among the greatest consumer benefits from electric restructuring should be the development of a new generation of "behind the meter" products and services. Among the most exciting should be smart devices that see and respond to price signals. Indeed, a number of manufacturers have developed thermostats that do exactly that. [cite]
>
> However, without advanced metering, these devices cannot provide benefits to consumers. If the customer is going to be billed based on a monthly kWh read, there is no value to the customer in having a thermostat that automatically responds to hourly price signals. A "smart" appliance is no help if you have a "dumb" meter."

DTE 00-41, Comments of Competitive Retail Providers. These companies are urging competitive metering for large customers as a starting point, with the idea of moving to competitive metering for smaller customers over time:

> The best way to bring the benefits of advanced metering to customers is to make metering competitive. As the New York Public Service Commission stated in its order making metering competitive, "The introduction of competition into metering services can lower long term costs, increase customer choices, encourage economic growth, stimulate innovation, and

shift more of the risks of investments to providers." Order Providing for Competitive Metering, NY PSC Case 94-E-0952, p. 7 (June 16, 1999).

For these reasons, many states have made metering competitive, at least for large customers. States that have opted for competitive metering include: New York, California, Illinois, Texas, Nevada, Arizona, and Maine. Metering is also competitive in several utility service territories in Pennsylvania.

Competitive Retail Providers advocate competition in metering for small customers. However, we recognize that opening competition to those customers significantly adds to the complexity of the effort. Therefore, we recommend that Massachusetts begin with metering competition for large customers, and then move to competition for smaller customers once competitive metering for large customers is fully established. DTE 00-41, Comments of Competitive Retail Providers.

Retail suppliers, including vertically integrated electric companies, need not offer small retail customers the option of real-time pricing in order for customers to be exposed to higher prices at times of peak consumption, which generally coincide in the summer with times of air-conditioning usage. It is increasingly likely that, in order to minimize their own exposure to high peak prices, retail suppliers will use pricing tools and rate options to expose customers to prices that reflect the marginal cost of electricity at the time of consumption. Therefore even a simple rate structure that includes off-peak and on-peak prices exposes customers to higher than average prices during the hours of air-conditioning usage in the summer. Such price options are appealing to suppliers since they provide an incentive to customers to reduce their usage during peak pricing times, and thus reduce the supplier's exposure to peak wholesale prices, or allow them to sell surplus electricity at peak pricing times. These options offer customers incentives to modify their energy consumption, without the complexity of a real-time pricing option.

With regulators at the state and federal levels pushing hard to enable customers to respond to price signals, with new and increasingly sophisticated metering technology becoming available, and with multiple competitive suppliers eager to offer a variety of services to customers, real time, or time-differentiated pricing is increasingly available to customers. Indeed in some areas of the country advanced metering and real-time pricing options are even mandatory.

Appendix B

Calculation Of Current Wholesale Electricity Generation Prices

Introduction

The information collected on current wholesale electricity generation prices was taken from several locations. Due to the existence of both restructured, i.e. competitive, markets and regulated markets within the United States it was not possible to find information from a single source. Therefore, data collection from competitive markets and regulated markets will be discussed in turn.

Competitive Markets

Wholesale hourly energy prices were collected from the four functioning competitive markets. Those markets include: New England (ISO-NE), New York, Pennsylvania, New Jersey and Maryland (PJM), and California. These markets represent roughly 20 percent of the total US electricity generation over the past two years.

Data collected from each region reflect hourly wholesale generation market clearing prices from the inception of the competitive market through midnight on October 31, 2000. For example, data in NY was collected from November 18, 1999 through October 31, 2000. Data for each region was taken from the respective Independent System Operator's web-site.

Hourly averages were calculated by averaging all data points collected for the given hour in a day. For example, the average price in New England at 0800 in October is an average of all hourly prices reported for 0800 in the month(s) of October. In this case there were 62 data points used in calculating the average hourly energy clearing price since the market opened in New England on May 1, 1999 (hence data points from October 1999 and October 2000 were used).

Regulated Markets

In those regions where the wholesale markets are not yet competitive, we used system lambdas instead of hourly market clearing prices. A "system lambda" is defined as the price of generating one additional unit of electricity, in this case one megawatt-hour. The system lambda is in essence the marginal cost of the production of energy for a given region or generator.

Every utility reports system lambdas to FERC, in the FERC Form 714. All of our information was taken from the FERC web-site. We complied information for every hour of the year, for the years 1998 and 1999.

The FERC Form 714 requires that all generators report hourly system lambdas on a yearly basis. However, not all respondents provide the required information. Therefore, we were able to be collect data only from those respondents who provided the appropriate information. NERC regions where data was reported include, ECAR, ERCOT, FRCC, MAIN, SERC and SPP. Data for MAPP and WSCC were not collected due to insufficient reporting on the part of applicable respondents. The NPCC and MAAC regions were not included in this analysis, because they contain the competitive electricity markets of New York, New England and PJM. The markets included in this analysis include roughly 55 percent of the total US electricity generation in 1998 and 1999.

Hourly averages were calculated in a similar fashion to those in competitive markets. For example, the hourly average lambda for 0800 in December is an average of the 62 reported lambdas for each respondent in a region. ECAR, for example had 9 respondents report system lambdas for both 1998 and 1999, therefore the hourly average lambda for 0800 in December in ECAR is derived of 558 data points (62 data points from 9 respondents).

The system lambda costs are different from the wholesale generation market clearing prices in that they only include variable production costs (i.e., fuel and variable O&M). They do not include any costs necessary to recover the capital investments associated with building new power plants to meet growing demand. Therefore, we have added estimates of such capital costs on to the system lambdas, in order to represent the full marginal cost and to be consistent with the wholesale market clearing prices described above.

We use a new combustion turbine (CT) as a proxy to estimate the capital costs associated with generation during peak hours. Using assumptions from AEO 2000, we estimate that the fixed costs (capital costs plus fixed O&M) of a new natural gas-fired CT are roughly 55 $/kW-year. We then assume that during our peak summer month period, a CT would operate at a 35 percent capacity factor, and that the fixed costs would be recovered during these hours of operation. This leads to a total fixed cost of 18.0 $/MWh for the peak summer month period. The amount of fixed costs that would be included in average prices for this CT would be 6.3 $/MWh. Therefore, the marginal fixed costs that we added to the system lambda prices for this peak period is 11.7 $/MWh.

For the peak summer day period, we assume that a proxy CT would operate at roughly a 25 percent capacity factor. In other words, during periods of higher peak demand it becomes necessary to dispatch expensive peaking units that operate less often. This leads to a total fixed cost of 25.2 $/MWh, and a marginal fixed cost adder of 18.9 $/MWh.

Our analysis finds that the marginal prices for the regulated markets are generally consistent with those for the competitive markets. This finding supports our methodology of adding capital costs to the system lambdas in the regulated markets.

Web-Pages Used To Obtain Data

ISO-New England:	www.iso-ne.com
New York ISO:	www.nyiso.com
PJM:	www.pjm.com
California:	www.calpx.com
FERC:	www.ferc.fed.us